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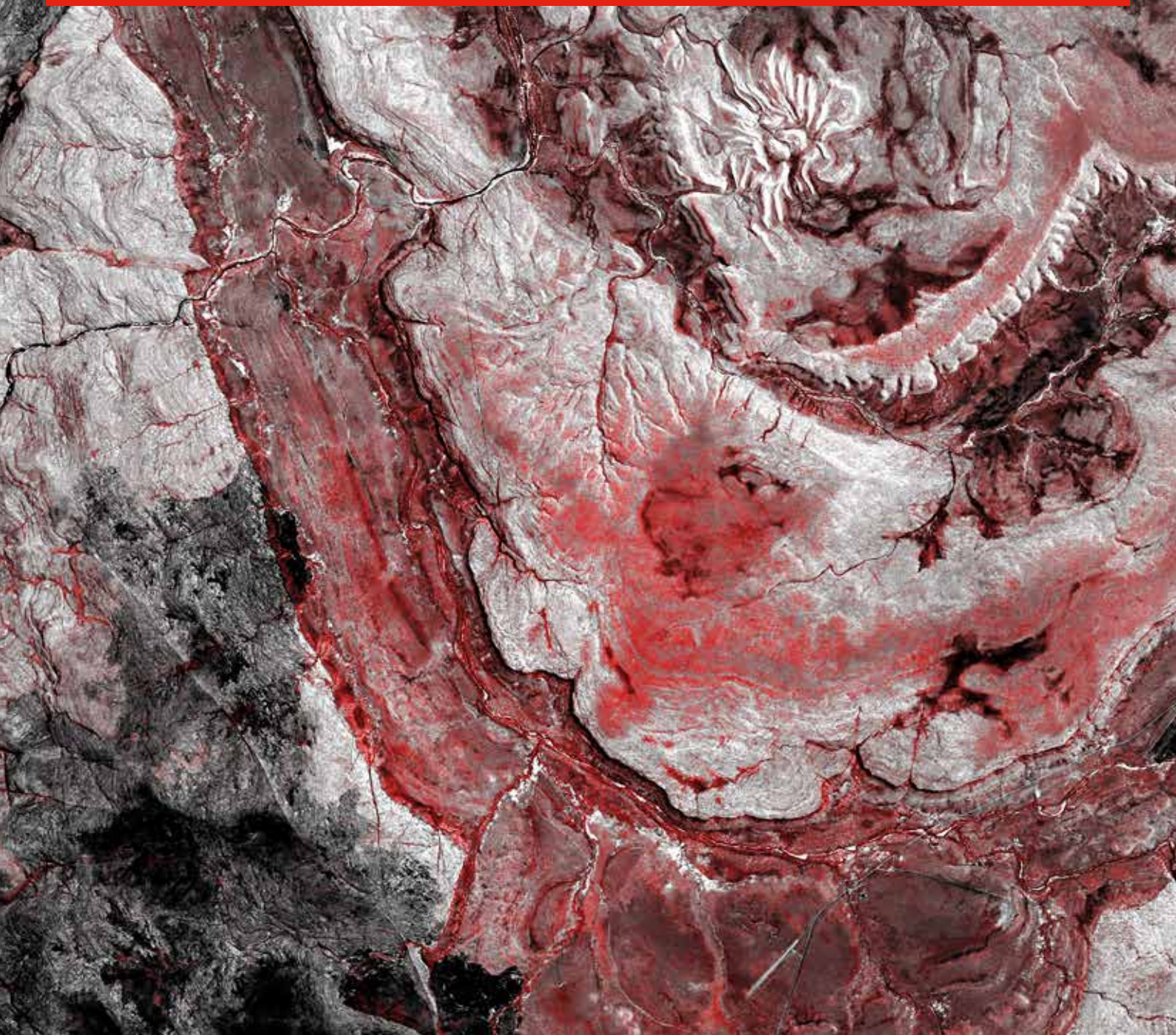
NORTON ROSE FULBRIGHT

Shale gas handbook

A quick-reference guide for companies involved in the exploitation of unconventional gas resources

Second edition



Shale gas handbook

A quick-reference guide for companies involved in the exploitation of unconventional gas resources

A Norton Rose Fulbright guide
June 2015

Norton Rose Fulbright

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Preface

Energy demand worldwide is at its highest levels and growing, with China and India currently vying for the top spot as the principal driver of growth in demand, according to the International Energy Agency. Economies across the globe are becoming increasingly reliant on unconventional resources such as shale gas, placing them high on the global energy agenda. Shale gas development – particularly in Argentina, Russia, China and Australia – is on the rise and has yet to reach peak levels.

As a global legal practice with an established track record in energy, we recognise that the interplay between the growth in shale gas development and the increasing global demand for oil presents an opportunity for the oil and gas industry to capitalize on shale gas exploration.

Members of the oil and gas industry have significantly expanded — and continue to expand — their global footprints. The requirement to respond to issues affecting the global energy market quickly, efficiently and accurately is now ever more critical – both for members of the industry and their advisers.

The aim of this handbook is to serve as a global quick reference guide for all those involved in the exploitation of unconventional gas resources. It contains information on key issues and factors to consider when addressing operational or investment decisions around the world.

We plan to maintain and update this handbook to reflect as closely as possible the current global legal energy landscape. Real-time updates are covered through our hydraulic fracking blog at fracking.nortonrosefulbright.com

Barclay Nicholson
Partner, Houston
Norton Rose Fulbright US LLP

Editor
fracking.nortonrosefulbright.com

An introduction to shale gas and hydraulic fracturing

Shale gas

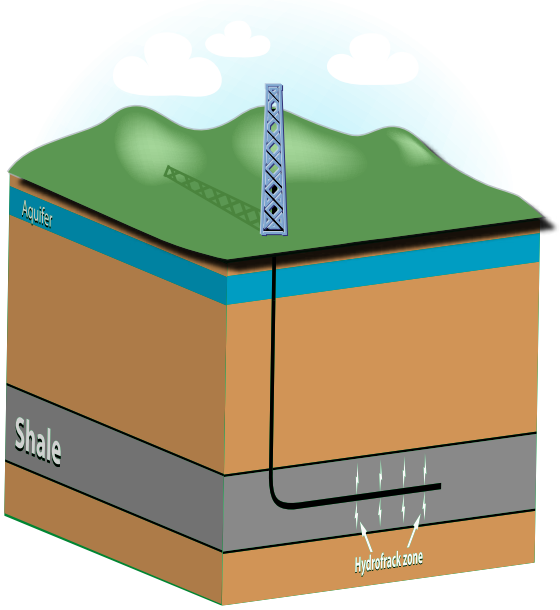
Sedimentary rocks are rocks formed by the accumulation of sediments at the Earth's surface and within bodies of water. Common sedimentary rocks include sandstone, limestone, and shale. Shale is a fine-grained sedimentary mudrock, comprising mostly flakes of various clay minerals, and including tiny fragments of quartz, calcite, other minerals and organic material. Typically having a laminate structure, shale formations are characterised by breaks along thin laminated parallel layers, known as fissility, and by low porosity and very low permeability. Another significant feature is the amount of carbonaceous material found in shale. Black shale is so called by virtue of a high degree of reduced free carbon which gives the rock its characteristic anthracite colour. Shales and other mudrocks contain about 95 per cent of all the organic matter to be found in sedimentary rocks.

Natural gas has formed through the thermogenic processing of carbonaceous material many millions of years old found at a significant depth in the Earth's crust, where higher temperature and pressure have transformed that material into gas. Natural gas consists primarily of methane, together with other hydrocarbons such as carbon dioxide, nitrogen, and heavier hydrocarbons such as ethane and propane. The methane component is typically 80 per cent or more. The proportion of higher hydrocarbons is influenced mainly by the type of organic matter within the geologic formation from which the gas is derived, and its level of thermal maturity. With its high methane content, natural gas is an excellent energy source for heating.

Subjected to high pressures, thermogenic gas would naturally seek pathways to lower pressure environments. Shale gas is such a gas that has been trapped in shale formations that are replete with fissures arising from their laminate and fissile structures, these pathways culminating in dead-ends owing to the classic low porosity and permeability characteristics of shale formations.

A typical example of a shale formations laminate structure

Typically, shale formations in which thermogenic gas has been trapped occur up to 2 to 3km below the Earth's surface, although this can vary widely according to geological exigencies and influences. So, for example, most shale gas plays in the US are far shallower than those indicated in the Karoo Basin in South Africa (anticipated at 3km).



Hydraulic fracturing

Hydraulic fracturing is the mining technique that is used to release the thermogenic gas trapped in tight shale formations. With the gas being trapped in irregular fissures rather than a large reservoir, the standard vertical well solution cannot be used. The process is complicated further in that the shale strata typically stretch in narrow horizontal bands across the geological formations, meaning that optimal production would require horizontal mining.

The hydraulic fracturing technique developed in the US to unlock the gas trapped in shale fissures has been used there for the past 60 years. The process has been developed in compliance with strict State oil and gas regulatory programmes that emphasise protection of groundwater.

In its simplest form, the process might be described as follows:

- A vertical well is drilled to just under the nearest aquifer layer below the surface. During the drilling process, a mixture of water and additives collectively known as 'mud' is pumped into the well bore to cool the drill-bit and flush the rock cuttings to the surface. The mud serves an additional purpose of caking the sides of the well bore, thereby keeping it intact.

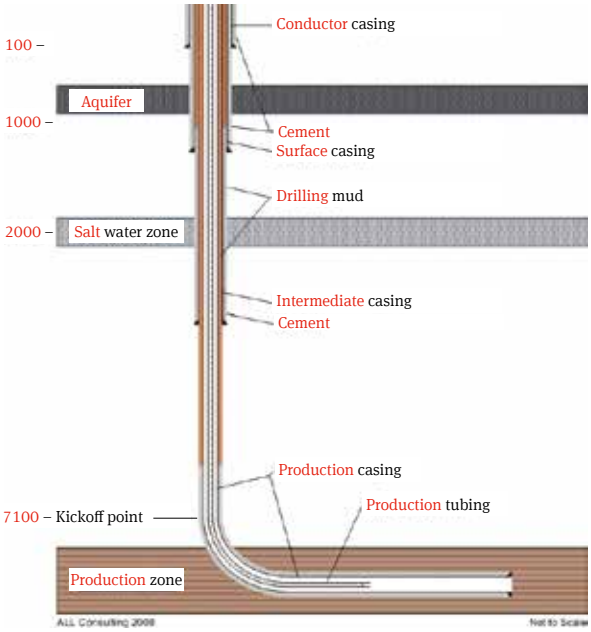
- Once the freshwater aquifer is penetrated, the drill-pipe and bit are removed from the well-bore. Surface casing is then inserted into the well bore, to isolate the freshwater zone from the well bore. Cement is pumped down the casing and out through the opening of the 'shoe' at the foot of the casing. The cement is forced upwards between the side of the casing and the wall of the well bore, thereby completely sealing off the freshwater aquifer from the well bore. This seal will prevent contamination of the aquifer by hydraulic fracture fluids being pumped down the well bore as part of the fracturing process, and contamination by any released gas later flowing up the well.

- Once the cement has set firm, the drill-pipe and bit are once again lowered down the well bore. The cement plug at the foot of the well bore is drilled through, and boring continues to the 'kick-off point', which is a point about 150m above the shale formation and the planned horizontal leg. This is where the drill curve will begin, eventually culminating in a series of horizontally drilled bores.

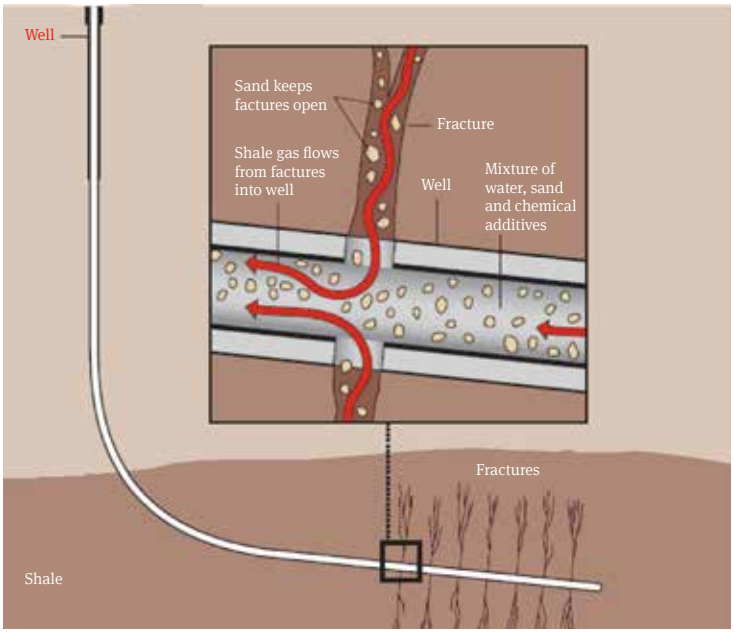
- Again, the drill-pipe and bit are removed from the well bore, and the same casing and cementing process is undertaken. A down-hole drilling motor with instruments capable of measuring the direction and the angle of drill is then lowered into the well bore, to begin the angle-drilling process. It takes about 400m of angle drilling from the kick-off point until the drill direction is horizontal. This horizontal part of the well bore is known as the 'lateral', and is drilled along the shale formation.

- When the target distance in the lateral is reached, the drill-pipe and bit are removed for the final time. Production casing is now inserted into the full length of the well bore, including the lateral. Once again, cement is pumped down the casing, and out through the hole at the end of the lateral, again forcing cement between the casing and the wall of the hole, filling up the 'annulus' – the open space between the production casing and the wall of the well bore.

- Once this process is complete, the drilling rig is removed from the pad on the surface, as it is no longer needed. A temporary 'well-head' is put in place, ready for the crew that will undertake the hydraulic fracturing of the formation and the production of any released gas.



Typical casing zones and cementing for a horizontal well
Graphic: All Consulting



Graphic: A Granberg/Pro Publica

- The first step in the hydraulic fracturing process is to perforate the production casing at appropriate points along the lateral. This is known as the 'perf.' A perforating gun is loaded down the well bore and into the lateral, to the target section. The perforating gun is fired electronically, the gun setting off a charge that shoots small holes through the casing and the cement sleeve, and a short distance into the shale formation. The perforating gun is then extracted from the well bore. The well is now ready for hydraulic fracturing, to open the fissures in the shale formation and to release the trapped gas.

- Hydraulic fracturing is the process in terms of which water, sand and various additives – the 'frac fluid' – are pumped at extremely high pressure down the well bore, out through the perforations, and into the fissures in the shale formation, fracturing the shale. This creates a pathway connecting the shale gas 'reservoir' to the well, allowing released gas to flow into and up the well bore.

- Special additives to the frac fluid, known as proppants, remain in the formation to hold the fractured fissures open. A typical proppant is sand, but recently tiny ceramic balls have proved to be much more effective as a proppant, owing to uniformity in size and weight. Other additives typically included in the frac fluid are as indicated in the graphic on the following page.

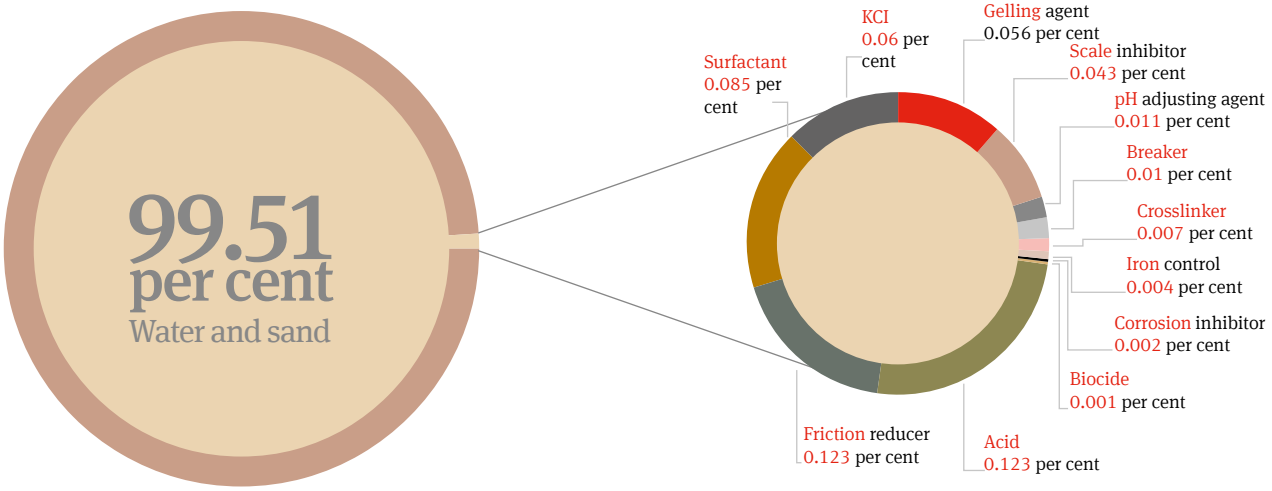
- Most of the frac fluid is recovered up the well bore, although some may be lost in the shale formation. Frac fluid and mud commonly continue to flow up the well bore for the duration of the life of the well. Once gas is released and is flowing up the well bore in feasible production quantities, a permanent production well-head is installed on the surface, to regulate the production of gas flowing from the well.

- Sections of the lateral are fractured sequentially, beginning with the section furthest away from the kick-off point and at the end of the target section of the lateral. Once a section has been perforated, the formation adjacent to it fractured, and the gas pathway opened, that section is plugged and the next section back along the lateral undergoes the same process. Once the entire target section of the lateral has been processed in this way, the cement plugs are bored out, allowing the freed gas to flow up the well bore to the surface.

Laterals can extend in all directions from the vertical shaft, for distances up to 2km. Accordingly, it is possible for the production platform to be centred in an area that has a diameter of 4km. In other words, the surface 'frac pads' from which well bore drilling and hydraulic fracturing operations are conducted can be sited at least 4km apart. Technology is continuously improving, and consequently the laterals are continuously being extended in length.

Typically, a single-stage sequenced hydraulic fracturing operation will use almost 2 million litres of water and about 200,000 kg of proppant to complete the hydraulic fracturing process. For arid areas, the potential use of seawater as the base component in frac fluid is being seriously considered. Resource assessment may determine the feasibility of piping seawater from the coast to central reservoirs for use in hydraulic fracturing operations. That feasibility may be enhanced through the use of the selfsame land traversal rights for the construction of a gas pipeline from the production area back to the coastal area for exploitation.

Companies guard the secrets of the composition of their frac fluids, as these have undergone very extensive and expensive research and development. Special mechanisms are required in order to mitigate environmental concerns through disclosure of the composition of frac fluids whilst at the same time preserving the complete confidentiality of the information and protecting companies' intellectual property rights and their competitive edge.



Graphic: All Consulting

The global resource

In 2013[1], EIA estimated the global technically-recoverable resources of shale gas to be 7,299 trillion cubic feet (TCF). The graphic below illustrates the main technically-recoverable reserves assessed in the 2013 EIA study.

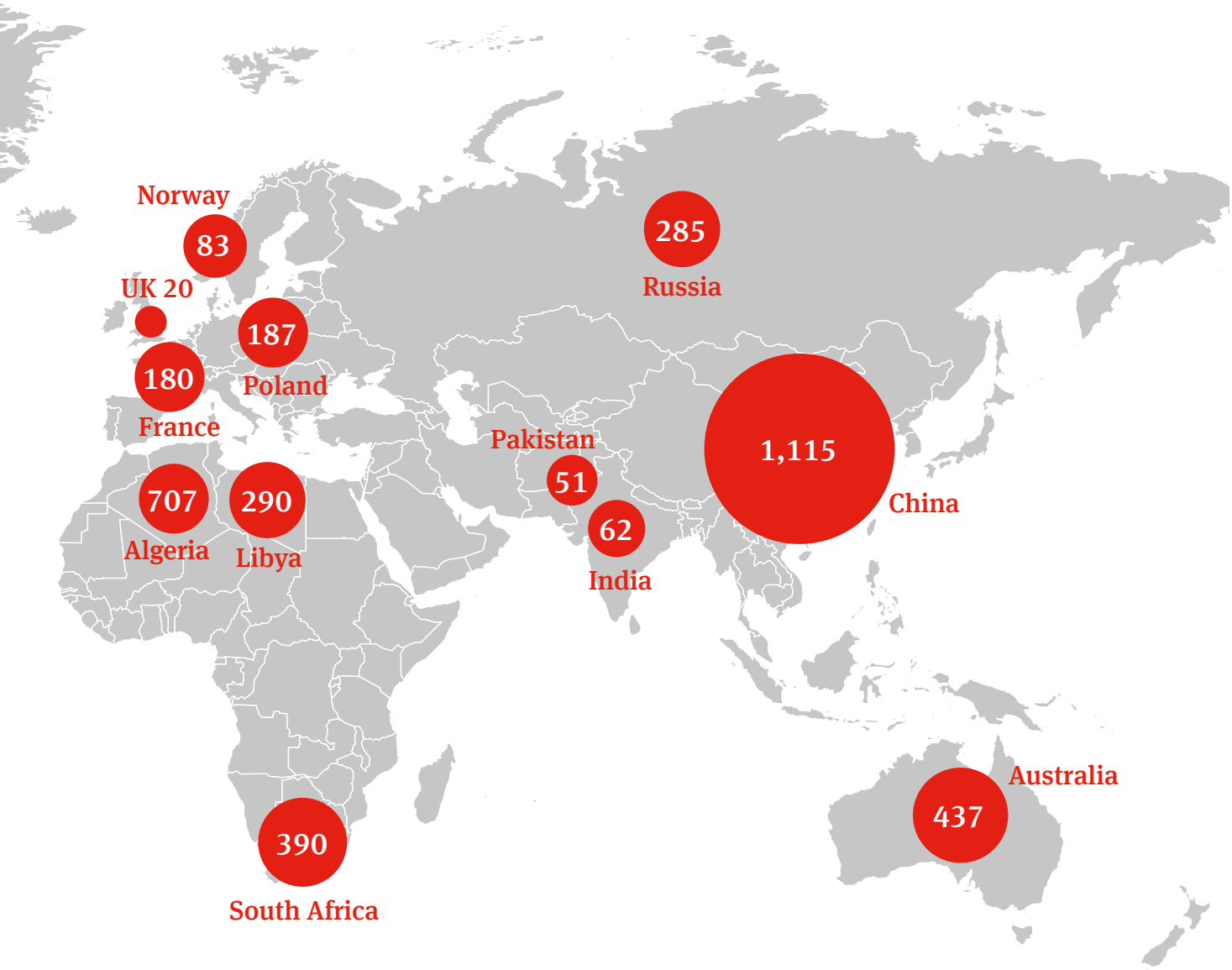
Shale gas was first extracted as a usable fuel in 1821 from shallow, low-pressure fractures in Fredonia, New York. The first hydraulic fracturing process is said to have occurred in the US in 1947. In the 1970s, declining production potential of conventional gas resources prompted the US Government to sponsor research and pilot projects which culminated in major advances in directional drilling techniques and hydraulic fracturing processes. Until then, extracting gas from shale was not considered to be commercially viable.

The US Government further facilitated the unlocking of American shale gas potential through funding of additional extensive research, affording generous tax credits, participating in ground-breaking projects, and subsidising the first horizontal drill in the Barnett play in Texas. Further developing and refining these technologies and processes has permitted prospectors to exploit shale gas resources to the point where unconventional gas now accounts for 20 per cent of US domestic supply, up from 1 per cent just over 10 years ago.

Faced with the 'game changing' potential of shale gas, countries having extensive shale gas estimates look to follow the American experience and seriously consider the confirmation and potential exploitation of those resources[2].

1 Kuuskra, V., Stevens, S., van Leeuwen, T. and Moodhe, K, *World shale gas resources: an initial assessment*. Prepared for: United States Energy Information Administration, 2013. *World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States*. Available at: http://www.eia.doe.gov/analysis/studies/worldshalegas.

2 This study was updated in June 2013, with several significant revisions of resource estimates. US Energy Information Administration, 2013, *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States*. Available at: http://www.eia.gov/analysis/studies/worldshalegas/.



Graphic: The Royal Society

Argentina

The largest Argentinean shale gas play is the Neuquén Basin, which is located on the eastern side of the Andes in Argentina and central Chile and covers an area of over 120,000km^2.

Shale plays in Argentina[1]

In December 2010, Repsol-YPF, then privately owned, discovered 4.5 TCF of shale gas in the Loma de la Lata field of Neuquén.

The Vaca Muerta area, also located in the Neuquén Basin, is quickly gaining international attention as a robust unconventional target. Operators believe that Vaca Muerta could be one of the largest shale basins outside the US. Also in Neuquén is the Los Molles formation, which has significant shale potential. Its resources have been estimated at 167 TCF of gas.

Another important region for shale gas plays is the Golfo San Jorge Basin, which is located in central Patagonia and covers a surface area of approximately 170,000km^2. This intracratonic basin is predominantly extensional, lying roughly in an east-west direction, from the Andean belt to the Atlantic Ocean.

One of the main formations located in the Golfo San Jorge is Aguada Bandera, a shale formation shared by the provinces of Santa Cruz and Chubut. The Aguada Bandera Basin has a confirmed potential of 51 TCF of natural gas. Also in the Golfo San Jorge Basin, well D-129 has 35 TCF.

A less explored basin is the Paraná-Chaco Basin, where gas resources have been estimated at 164 TCF.

Finally, the Austral-Magallanes Basin, located at the south of Argentina and Chile, is believed to have potential for the presence of oil or gas reservoirs. This has yet to be confirmed through further exploration.

Ownership of land and mineral rights

On October 30, 2014, the Argentine Congress enacted a series of amendments to the regime applicable to hydrocarbons. Law No. 27,007 was published in the Argentine *Official Gazette* on October 31, 2014 (the Amendments to the Hydrocarbons Law). It modified Law No. 17,319 (the Hydrocarbons Law), which is the national legal regime.

Under the Hydrocarbons Law, oil and gas fields belong to the national government. Such ownership is separate from surface ownership.

In 2007, the National Congress passed Law No. 26,197 (the Short Law) to settle the specific constitutional question of the provinces' titles to hydrocarbons. The Short Law partially amended the Hydrocarbons Law and provides that ownership of the oil and gas fields and the power to grant exploration permits and exploitation concessions is vested in the provinces or the national government, depending on the location of the field.

Under the Hydrocarbons Law, once hydrocarbons have been extracted, they belong to the company that extracted them. Companies may therefore transport, market and industrialise the hydrocarbons, and market their by-products, in accordance with the regulations established by the Executive Branch.

1 The information in this section is taken from *Technically Recoverable Shale Oil and Shale Gas Resources: An assessment of 137 shale formations in 41 countries outside the United States*, US Energy Information Administration, June 2013. Available at: http://www.eia.gov/analysis/studies/worldshalegas/

1181 TCF
Vaca Muerta formation

This formation in the Neuquén Basin is gaining international attention as a robust unconventional target. Numerous operators believe that this could be one of the largest shale basins outside of the US.

250 TCF

TCF Los Molles formation: Also in the Neuquén Basin, this formation has significant shale potential.

51 TCF

Aguada Bandera basin: One of the main formations located in the Golfo San Jorge, this shale formation is shared by the provinces of Santa Cruz and Chubut.

164 TCF

TCF Paraná-Chaco Basin: This little explored Basin is estimated to have resources of 164 TCF.

Hydrocarbons regulation

During 2014, the national government and the Federal Organization of Hydrocarbon-Producing Provinces (OFEPHI) negotiated several additional amendments of the Hydrocarbons Law in order to create a more suitable legal framework for the exploitation of unconventional resources, such as shale gas.

As a consequence, the current national legal regime of hydrocarbons is based on the Hydrocarbons Law, its recently enacted amendments, and the Short Law.

In general terms, the Amendments to the Hydrocarbons Law considerably changed the panorama with respect to unconventional projects. They introduced specific provisions applicable to such projects where previously there was no distinction in regulation between the exploitation of conventional and non-conventional hydrocarbons. Thus, the exploitation of shale gas and shale oil are no longer carried out under the generally applicable hydrocarbons regime.

Shale gas and other unconventional hydrocarbons are expressly mentioned in new Article 27 bis of the Hydrocarbons Law. This new provision defines and distinguishes different unconventional forms of extracting hydrocarbons and establishes an especially applicable framework for such plays.

The Hydrocarbons Law lays down national criteria on exploration, exploitation, industrialisation, transportation and marketing activities. It also regulates the assignment of rights, as well as the control and sanctions to be enforced by the authorities. It is the principal national regulation covering the main aspects of the hydrocarbon regime.

Principal players and controlling bodies

The State's main players and controlling bodies are outlined below.

National Secretariat of Energy

The Secretariat of Energy is the enforcement authority for the hydrocarbon regime. All national matters related to exploitation, production and refining activities fall within its scope of authority.

Commission for Strategic Planning and Coordination of the National Hydrocarbons Investments Plan

The Commission was created by Decree No. 1,277/2012. Its goals are to ensure and promote the investments required for the maintenance, increase and recovery of reserves that guarantee the short-and long-term sustainability of the hydrocarbon industry. It also concerns itself with reserves that guarantee self-sufficiency in hydrocarbons and those aimed at the exploration and exploitation of conventional and non-conventional resources.

Ente Nacional Regulador del Gas (ENARGAS)

ENARGAS, a regulatory entity created by Law No. 24,076 (the Gas Law), is in charge of supervising and regulating the transportation and distribution of natural gas. Both activities are considered public services.

In addition, the national government currently owns ENARSA and YPF SA.

Energía Argentina Sociedad Anónima (ENARSA)

The government formed ENARSA in 2004 through Law No. 25,943. ENARSA holds title to all the offshore permits granted when it was created (approximately 72 blocks).

ENARSA was also appointed by the government of Argentina to deal with the liquefied natural gas (LNG) programme. ENARSA constructed and operates two new regasification plants, which have been used for the importation of LNG.

YPF SA

In May 2012, the Argentinean Congress enacted Law No. 26,741, which emphasised, among other matters, the public policy interest in the expropriation of 51 per cent of YPF SA and Repsol-YPF Gas SA.

The expropriated shares in the two companies were allocated as follows:

- 51 per cent to the government of Argentina
- 49 per cent among members of OFEPHI.

On March 26, 2014, the Argentine Senate approved an agreement between Repsol and the Executive Branch, which recognised Repsol's right to receive US$5 billion in compensation for the expropriation of its 51 per cent stake in YPF.

Rights, licences and approvals

There are two types of granting instruments, namely: exploration permits and exploitation concessions, which are granted pursuant to the provisions of the Hydrocarbons Law.

In addition, some provinces retain title to areas and enter into service agreements with different companies covering

the exploration and exploitation of hydrocarbons in those areas. In the last few years, provincial oil companies have associated with other oil companies to carry out exploration and exploitation activities in areas under provincial jurisdiction. In most cases, an association with the provincial oil company was a requirement set by the province in order to award a permit or concession.

Exploration permits and exploitation concessions are usually granted by a Decree via the National Executive Branch or the Provincial Executive Branch, depending on the location of the area.

Exploration permits

Characteristics of exploration permits:

- Permits grant the exclusive right to search for oil and gas in the area covered by them.
- Permit holders must inform the authority if any oil or gas is found within 30 days of the discovery. Once the permit holder determines that the area contains commercially exploitable quantities of hydrocarbons (i.e. a 'commercial discovery'), in most cases it has 30 days to apply for the exploitation concession.
- The holder of a permit has an exclusive right to apply for an exploitation concession.

The Amendments to the Hydrocarbons Law eliminated previously existing restrictions that did not allow private companies to hold more than five exploration permits.

One of the most important amendments made to the Hydrocarbons Law was the creation of specific permits for unconventional exploration. In this sense, unconventional projects may have terms of up to 13 years in accordance with the Amendments.

Exploitation concessions

Characteristics of exploitation concessions:

- Exploitation concessions grant the rights to exploit the existing oil and gas discoveries located in the areas of the concession.
- Concessions grant the rights to build and operate treatment plants and/or refineries and all other facilities needed to develop operations.
- Exploitation concessionaires may apply for a transportation concession for the hydrocarbons obtained during exploitation.
- Depending on the jurisdiction, an exploitation concession usually remains in effect for 25 years. The enforcement authority may extend that term for up to ten years, provided the concessionaire has complied with the obligations imposed during the initial term.

An important addition in the Amendments to the Hydrocarbons Law was a novel type of concession with a longer term. The Unconventional Exploitation Concession lasts 35 years of which five years may be allocated to a 'Pilot Project' in order to determine the commerciality of the field.

Additionally, the Amendments to the Hydrocarbons Law give concessionaires the right to request new extensions even if they have already obtained an extension before October 2014 (when the Amendments to the Hydrocarbons Law were passed).

The Amendments to the Hydrocarbons Law also eliminate restrictions on holding more than five exploitation concessions or concessions.

Establishment of a local entity

In order to hold rights, licences and approvals to participate in the Argentinean hydrocarbons sector, it is not necessary to establish a local entity. Foreign investors may register a branch of their own entity in Argentina in order to conduct business within the hydrocarbon sector.

An Argentine branch of a foreign legal entity does not have independent legal existence from the head office. The head office may or may not assign capital to the branch. A duly appointed representative handles local operations for the branch.

However, if a foreign investor decides to organise an Argentine entity, it may use one of the following corporate entities.

Corporation (SA)

The business form of an SA is the most usual way to do business in Argentina. It is a stock company, which requires prior authorisation from the General Inspector of Corporations (GIC). It allows the shareholders to limit their liability to the par value of the shares they have agreed to subscribe. An SA may be considered the equivalent of a US corporation.

Limited liability company (SRL)

An SRL is a limited liability company, which also requires registration with the GIC. The business form of an SRL allows its members to limit their liability to the par value of the membership interests they have agreed to subscribe (except for their responsibility to third parties for actual payment by the other members of the amounts they agreed to subscribe).

Registrations

Oil and gas companies must specifically register with the national and provincial enforcement authorities. At national level, registration is with the Registro de Empresas de Exploración y Explotación de Hidrocarburos (Registry of Oil and Gas Exploration and Exploitation Companies) and the Registro Nacional de Inversiones Hidrocarburíferas (National Registry of Hydrocarbon Investments). Provincial registries and their applicable regulations vary by province.

The Argentine Energy Secretary issued Resolution No. 194/2013 on April 19, 2013, prohibiting companies from registering with the Registry of Oil and Gas Exploration and Exploitation Companies if they act, directly or indirectly, as contractors, or are direct or indirect shareholders, or if they maintain a beneficial ownership relationship with:

- companies that carry out without authorisation, exploration, exploitation or transport activities relating to hydrocarbons in the Argentine Continental Platform, or
- companies that provide services related to hydrocarbon activities to the previously mentioned companies.

Resolution 194/2013 also establishes that companies with exploration permits and exploitation or transport concessions (including their controlling parent companies or controlled subsidiaries or companies with which they maintain a beneficial ownership relationship), are not allowed to:

- participate in unauthorised hydrocarbon exploration, exploitation or transport activities in the Argentine Continental Platform, or in companies that provide services related to hydrocarbons
- provide commercial, logistics or technical support to companies that offer the services referred to in the preceding point
- enter into agreements, transactions, commercial acts, or economic, financial, logistics, technical, consulting or appraisal operations with third parties, for the development of unauthorised exploration, exploitation or transport activities in the Argentinean Continental Platform. Contravention of this prohibition exposes the permit holder or concessionaire to the risk of revocation of their granting instrument.

State participation

Under the Short Law, provinces may exercise the authority and powers of an original owner. However, in accordance with the Amendments to the Hydrocarbons Law, provinces may not in future reserve blocks for any provincial State-owned company.

Provinces continue to exercise powers over oil activities and take charge of the administration of hydrocarbon resources, which includes receiving the corresponding exploration fees and royalties for the production of hydrocarbons.

Some provinces have entered into service agreements with different companies covering the exploration and exploitation of hydrocarbons in areas located within their jurisdiction. To date, no production-sharing contracts have been used in Argentina, as they have not been contemplated in the bidding proceedings.

Taxes, duties, royalties and incentives

Tariffs and duties

Tariffs are applied to the transportation of natural gas and oil through pipelines. Gas pipeline transportation falls within the jurisdiction of ENARGAS.

Export duties on hydrocarbons

After the crisis of 2001, the Argentine National Executive Branch restricted exports, establishing export duties on liquid (crude oil, LPG, derivatives) and gaseous (natural gas) hydrocarbons, using regulatory powers under the Customs Code and Laws Nos. 22,415, 25,561 and 26,217 on Public Emergency.

Currently, a rate for export duties is fixed based on the international crude oil price. The rate uses a formula that applies when the price per barrel of the West Texas Intermediate (WTI) exceeds the reference value of US$80, establishing a cut-off value of US$70/bbl. With respect to imports and exports of natural gas, as in the case of the system for crude oil and derivatives, restrictions have been increasing over the years. This matter is currently governed by Resolution No. 534/2006, as amended by Resolution No. 127/2008, both issued by the Ministry of Economy, establishing a rate equal to 100 per cent.

Fees and royalties

The exploration permit holder must pay an annual fee to the government of the province where the area is located. This is paid in arrears for each square kilometre or fraction thereof, pursuant to established scale and area categories. The Executive Branch is empowered to increase the fee at its discretion.

The following royalty rates apply to the extraction of hydrocarbons:

- 12 per cent of the 'value' of hydrocarbons under an exploitation concession. This rate may be reduced to 5 per cent
- 15 per cent of the 'value' of hydrocarbons extracted under an exploration permit.

In January 2008, the Under Secretariat of Fuels issued Provision 1/2008, which established an artificial value of hydrocarbons for the purposes of calculating royalties. It takes a cut-off value set out in Resolution No. 394/07, issued by the Minister of the Economy, as the minimum value for royalty calculation purposes. This value is US$42/bbl, to which an 'upward' quality adjustment must be applied.

However, under the Amendments to the Hydrocarbons Law, provinces may only charge the current 12 per cent royalty rate on actual sale prices (netted back to the wellhead).

Finally, as of November 2014, concessionaires may obtain a 25 per cent reduction in the royalty rate applicable to unconventional hydrocarbons during the ten years after the end of the Pilot Project, if they request an Unconventional Exploitation Concession within three years.

Taxes

Key national taxes:

- Income tax: 35 per cent on the net taxable income
- VAT: 21 per cent applied on domestic sales of oil and gas, which is added to the producer's sales invoices and passed on to the payer.
- Key provincial taxes:
- Turnover tax: 1–3 per cent. For oil and gas it is usually 2 per cent
- Stamp tax: 1–2 per cent (depending on the provincial jurisdiction).

Incentives

Since the crisis of 2001, the Argentine government has fixed the price of gaseous hydrocarbons, which in 2008 were set at US$0.50 per million BTU (MMBTU). This created a strong disincentive for the drilling and production of domestic gas. It transformed Argentina, which has the highest production and consumption of gas of any South American country, from a net exporter into a net importer of gas.

The first attempt to create incentives took place in 2008, through Resolution 24/2008. This resolution established the Programme of Incentives for Natural Gas Production or 'Gas Plus.' Gas Plus increased the price of gas, from US$0.50/MMBTU to US$5/MMBTU, obtained as a result of investments in unexploited areas, new areas, areas without production since 2004 or tight gas areas.

Most recently, the Commission issued Resolution 1/2013 unveiling the Programme to Stimulate Surplus Injection of Natural Gas. This programme ensures (through payments to the beneficiaries) a minimum price of US$7.50/MMBTU to companies registered in the National Registry of Hydrocarbon Investments and which inject gas into the domestic market in excess of their base injection levels. For these purposes, companies must prepare and adhere to a Project to Increase Total Natural Gas Injection.

Resolution 1/2013 establishes:

- a minimum price of US$7.50/MMBTU for any incremental sales to the domestic market
- a minimum price guarantee of US$2.30/MMBTU in respect to base injection levels (which are subject to incremental quarterly adjustments, from 2013 to 2017)
- that if the producer does not supply volumes in excess of the adjusted base injection levels, it shall be subject to penalties associated to the equivalent cost of supply of LNG, minus US$7.50/MMBTU, multiplied by the amount of the shortfall.

Foreign currency and Central Bank requirements

The foreign currency exchange rate has been increasing since the 2001 crisis. The current official exchange rate is approximately AR$8.5 per US$1.

The acquisition of foreign currency is currently restricted to a limited number of situations. These policies have led to the development of an unofficial exchange rate within the country. Individuals and companies are required to obtain authorisation from the federal tax agency before purchasing foreign currency.

In December 2011, the National Congress approved an anti-terrorism law under which the buying or selling of foreign currency outside the official market may be considered an act of terrorism. Prison sentences of as long as eight years can be imposed for 'conduct that affects the economic and financial order'.

Environmental protection

In accordance with the National Constitution, powers to protect the environment are vested in the provinces and only by delegation in the national government. However, the national government may enact federal laws providing for minimum standards that must be fulfilled throughout the country.

As a result, local laws enacted by the provinces and that apply within their respective jurisdictions coexist with federal laws that apply in the whole country.

The main environment-related federal statutes and regulations are:

- the General Environmental Law, No. 25,675 (GEL)
- the Hazardous Waste Law, No. 24,051 (HWL)
- Law No. 25,612, which establishes minimum environmental protection standards concerning the overall management of industrial waste and of waste generated by services activities
- Law No. 25,675 on minimum environmental protection standards for the adequate and sustainable management of the environment, the preservation and protection of biological diversity, and the implementation of sustainable development. It is commonly known as the Environmental Framework Law (EFL).

In March 2014, the province of Neuquén enacted environmental regulation for unconventional operations, which are specifically applicable to unconventional reservoirs of shale gas.

Environmental impact assessments, audits and safety standards

The GEL provides that any work or activity that may degrade the environment or significantly impair the quality of life of the population will be subject to a prior environmental impact assessment procedure. Activity or work may start only upon completion of the assessment and its approval by the relevant authorities.

In addition, there are other federal rules that provide for mandatory environmental impact studies for specific activities, such as exploration, exploitation, transportation of hydrocarbons, and hazardous waste treatment and disposal. The newly enacted regulations for unconventional operations in the province of Neuquén require the filing of an environmental report to qualify for an environmental licence granted by the Environment and Sustainable Development Secretariat of the province.

Different laws and regulations establish that companies that store hydrocarbons must have an external auditing service for the control of safety standards. In addition, they must carry out an annual audit for the control of safety standards, including impenetrability tests and planning or making repairs to storage systems.

Environmental liability

In general, strict liability applies to environmental damage. Under the EFL, if two or more persons are involved in causing collective environmental damage or if the extent of the damage caused by each cannot be accurately established, all of them shall be jointly and severally liable, without prejudice, if applicable, to the right of contribution among the parties involved. The acting court may determine the degree of liability of each for this purpose.

In addition, the EFL establishes that in cases of collective environmental damage, the damaging party shall be liable for the restoration of the environment to its prior condition, or, if this is technically not feasible, it shall be liable for damages.

The EFL also provides that any individual or legal entity performing activities hazardous to the environment shall take out insurance guaranteeing that any possible damage to the environment shall be repaired. Moreover, if the damage was caused by corporations, liability shall extend to their authorities and professionals, based on their respective involvement.

With respect to criminal liability, the HWL also contains provisions that have been considered to apply throughout Argentina, regardless of the place where the waste has been produced.

Under the HWL, persons whose use of hazardous waste poisons, pollutes or contaminates the soil, water, atmosphere or the environment in general, in a manner dangerous to human health, are subject to imprisonment. When the punishable act is the result of negligence, inexperience or failure to observe rules and regulations, imprisonment of between one month and two years will be applicable. If the use of hazardous waste causes the death of a person, the penalty will be between ten and 25 years' imprisonment. It is worth noting that if a punishable act occurs as a result of the decision of a corporation, the penalty will be imposed on its directors, managers, syndics, members of the supervisory committee, administrators, attorneys or representatives that were involved in the punishable act, without prejudice to any other criminal liabilities that may apply.

Domestic supply and exportation of hydrocarbons

Companies wishing to export hydrocarbons from Argentina must generally file a request with the National Executive for all types of exports, proving that local demand has been satisfied.

Specifically with regard to gas exports, authorisation will always be required by the Executive Branch by means of an export permit. The national government has issued additional regulations to give priority to domestic demand.

See our description above of export duties on liquid (crude oil, LPG, derivatives) and gaseous (natural gas) hydrocarbons.

Enforcement regime in judicial and arbitral alternatives

Argentinean laws expressly allow for the enforcement of judgments and awards rendered in foreign or international jurisdictions. However, local courts are particularly careful in analysing whether a particular judgment or award conforms with Argentina's internal public policy. On any occasion where they are found to be inconsistent, courts will most likely reject their enforcement. Such legal control of awards and foreign judgments is more common whenever the interests of State entities would be affected by the enforcement of the award or judgment in question.

However, in commercial disputes governed by private law, Argentinean jurisprudence is considered favourable to the enforcement of foreign decisions and awards.

Changes to regulatory regime

A significant change in regulation has been the special treatment granted to non-conventional operations provided for in the Amendments to the Hydrocarbons Law.

Additionally, in recent years, the Argentine government has put a lot of effort into changing some of the policies put in place in the 1990s during the 'Menem era', during which the State oil company, YPF, was privatised and sold in large part to Spain's Repsol. For several years after this, State participation in the energy sector was effectively non-existent. More recently, however, the Argentine government has become increasingly involved in the sector.

It has been suggested that the government is trying to take YPF to the position that Pemex, PDVSA or Petrobras hold in their respective countries. Consequently, changes to the regulatory regime to enable the State to intervene more in the energy sector should not be ruled out.

Nonetheless, please see our comments on hydrocarbon regulation above and bear in mind that the province in which an area is located has the power to enact most of the laws and regulations applicable to shale gas investors. Therefore, changes to the regulatory regime may take place at the provincial level.

Opportunities

In May 2011, Repsol-YPF, which was then privately owned, announced the discovery of a deposit that could produce up to 4.5 TCF. Some have called this discovery the third largest of its kind in the world. The deposit is located in the province of Neuquén and its development, according to several press reports, would cost up to US$40 billion.

In May 2012, the Argentine Congress authorised the nationalisation of Repsol-YPF, and the Argentine government took 51 per cent of the company's stock which was the property of Repsol. Since then, Argentina has sought to find a partner to develop the shale gas deposits in Neuquén. Although there have been reported talks, and in some cases MOUs, with Chevron, Dow Chemicals and Bridas, none of those agreements has been successful.

In March 2013, it was reported that four companies have exploration rights over more than 6.8 million acres of the 7.4 million acres in the Vaca Muerta formation. Those companies are YPF (4 million acres), Apache (1.8 million acres), ExxonMobil (1.2 million acres) and Americas Petrogas (close to 1 million acres). The recently created provincial company, Gas y Petróleo de Neuquén (G&P), holds more than 3 million acres and has entered into 62 joint venture agreements for the exploration and production of shale oil and gas.

In June 2013, the US Energy Information Administration of the Department of Energy reported that the Vaca Muerta formation in the Neuquén Basin has 308 TCF of technically recoverable reserves of natural gas and 1,202 TCF of risked gas in place.* Vaca Muerta's appeal is high, but development is still at an early stage.

The business climate

Some analysts have indicated that a deteriorating business climate in Argentina has impacted on development in Vaca Muerta. This is mainly the result of high government intervention in the economy, restrictions to capital and profit repatriation and increasing domestic inflation, which impacts on the costs of projects.

However, companies such as Chevron, Madalena Ventures, EOG Resources, Royal Dutch Shell, Azabache, Petrobras, Pan American Energy, BP, Bridas, Antrim and Energy Wintershall have also seen great opportunity in Neuquén and are currently present in the area.

Other shale gas deposits in the Neuquén area, such as the Loma de la Lata deposits, represent opportunities for foreign investment in Argentina.

During April 2014, the province of Neuquén, represented by G&P, held a roadshow in Houston to tender oil and gas areas in the province. The areas were: El Churqui –Pampa Trill; Parva Negra Oeste; Loma Ancha; Santo Tomás; Portezuelo Minas; Los Álamos –Señal Rocosa; China Muerta –Cañadón de las Horquetas – Loma de Las Piedras; and Collón Cura II.

*Notes

Unrisked reserves are those that have already been developed by drilling and production and therefore have a very reasonable certainty of being produced. On the other hand, risked reserves are either probable or possible reserves, depending on the amount of uncertainty involved.

Australia

The shale industry in Australia is very much in its infancy and the full extent of shale gas resource is far from being identified. However, both exploration and interest in Australia's shale gas potential have increased significantly in the last few years. According to a report published by the US Energy Information Administration (EIA) in June 2013, Australia enjoys geological and industry conditions resembling those of the US and Canada, with an estimated technically recoverable shale gas resource of 437 TCF.[1]

Shale plays in Australia

Australia is ranked seventh of the 41 countries reviewed by the EIA for shale gas resources, following Mexico and ahead of South Africa. Western Australia alone is estimated to hold the fifth largest reserves of shale gas in the world, being 280 TCF (235 TCF in the Canning Basin and 45 TCF in the northern Perth Basin).[2] Australia's estimated technically recoverable shale gas resource exceeds its estimated recoverable reserves of coal seam gas (as coal bed methane is referred to in Australia). The shale gas reserves already underpin three liquefied natural gas (LNG) projects now being developed, with an aggregate capacity of more than 25 million tonnes per annum, and additional projects have been proposed.

The EIA report assessed 11 formations within six basins in Australia: the Cooper Basin in South Australia and Queensland; the Maryborough Basin in Queensland; the Perth Basin and Canning Basin in Western Australia; and the Georgina Basin and Beetaloo Basin in the Northern Territory. Ranking these six basins in terms of composite play success and prospective area success, the Canning Basin is estimated to have the highest technically recoverable resource of 235 TCF. This is a substantial resource by any standards.

1 Technically Recoverable Shale Oil and Shale Gas Resources: An assessment of 137 shale formations in 41 countries outside the United States, US Energy Information Administration, 2013. Available at: http://www.eia.gov/analysis/studies/worldshalegas/

2 'Natural gas from shale and tight rocks', Fact Sheet, March 11, 2014, Department of Mines and Petroleum, Government of Western Australia

Unassessed shale resources

As the map on page 27 shows, there are several more basins in Australia that have not been assessed. Potential for significant additional resources therefore exists across the country. While some basins are currently the subject of exploration programmes, most remain substantially underexplored.

To help understand the shale potential in Australia, the Onshore Hydrocarbons Section at Geoscience Australia, in collaboration with state and territory geological surveys and energy departments, has begun an assessment of the unconventional hydrocarbon potential of Australian basins.

For those basins with very poor geological control (many of Australia's basins fall into this category), a detailed prospectivity assessment will first be conducted. This will give a better understanding of the petroleum system(s) in the basin and identify zones that are likely to host unconventional hydrocarbons.

For those basins where there has already been significant exploration, such as the Cooper Basin, a resource assessment will be carried out in cooperation with the US Geological Survey. This will utilise existing data and apply probabilistic methodology to estimate recoverable resources. The results will be released on a basin-by-basin basis.

342 TCF Cooper basin

The Cooper Basin – This is the most prospective and commercially viable of all the shale gas reserves in Australia, with an existing conventional oil and gas infrastructure already in place to aid production.

437 TCF

Technically recoverable reserves – The amount it is estimated Australia possesses based on four shale gas basins researched so far – Perth, Canning, Cooper and Maryborough. Industry experts predict up to US$500m will be spent within the next 1-2 years on further exploration and research.

1000+ TCF

The potential amount of recoverable shale gas reserves in Australia, should further research and development be pursued in areas such as Queensland, Western Australia and the Northern Territories. Western Australia alone is estimated to hold the 5th largest reserves of shale gas in the world.

To date, the initial results from early core sampling analysis show that the Georgina Basin has some promise, less so the Amadeus Basin[3]. To help assess the unconventional petroleum resource potential in the Georgina Basin, Geoscience Australia has generated a new mineralogical dataset. However, it is not clear when a prospectivity assessment for the Georgina Basin will be finalised and published.

History of Australia's shale business

There have been very few wells drilled that specifically target shale gas formations. This is partly because of Australia's plentiful supply of conventional and coal seam gas, as well as a lack of land rigs capable of drilling deep enough.

The first two vertical wells specifically targeting shale gas were drilled in 2011 in the Cooper Basin by Beach Energy. Australia's first, and so far only, commercial shale gas production commenced in October 2012 in the Cooper Basin. The vertical test well was drilled only 350m from existing pipeline infrastructure and 8km from a gas processing plant, which enabled it to be brought online quickly. Not all basins are endowed with existing infrastructure of this nature. Those basins in the north of Western Australia and in the Northern Territory are particularly remote and are likely to require substantial capital commitments to develop infrastructure to deliver gas to market.

The Australian industry was initially led by domestic players and nimble international companies with shale gas experience in North America. These companies acquired permits over large areas considered to be the most prospective for shale gas. There has been a steady increase in international interest in Australian acreage, and a number of large global players gained interests in acreage by funding exploration operations and forming joint ventures.

The following is a brief summary of the state of play in some of the more significant basins, although it should be noted that activity and opportunities also exist in several other basins.

Canning Basin

Identified by the EIA report as having the greatest likely resource in Australia, it is no surprise that the Canning Basin has seen a significant amount of activity, led by Buru Energy and New Standard Energy. The EIA report identified the basin as having in excess of 225 TCF of recoverable shale gas, based on the Goldwyer formation alone. The Australian Council of Learned Academies confirmed this assessment and calculated a further 38 TCF of recoverable shale gas in the Laurel formation.

Buru Energy has announced very large gas resources in its petroleum titles. It was the first company to farm out interests to larger foreign investors when it struck a deal with Mitsubishi in June 2010. In November 2013, Apache Energy joined Buru Energy and Mitsubishi's joint venture. On June 20, 2014, Western Australia's Department of Mines and Petroleum approved Buru Energy's Laurel Formation Tight Gas Pilot Exploration programme, which was developed to identify the potential environmental impacts and risks associated with exploration activity. This programme will involve stimulation of tight gas zones in existing vertical exploration wells to assess their commercial potential. Buru Energy intends to drill five firm wells, and up to seven in total, in a continuous drilling programme set to commence mid-May 2015.

ConocoPhillips also joined the action, striking a deal with New Standard Energy in 2011, with PetroChina subsequently acquiring part of that stake from ConocoPhillips in 2013.

Hess also acquired Canning Basin interests in 2012. Other active participants include Key Petroleum and Oilex.

There are challenges to developing a commercial resource in the Canning Basin due to its remote location and lack of existing pipelines, roads and water sources.

Cooper Basin

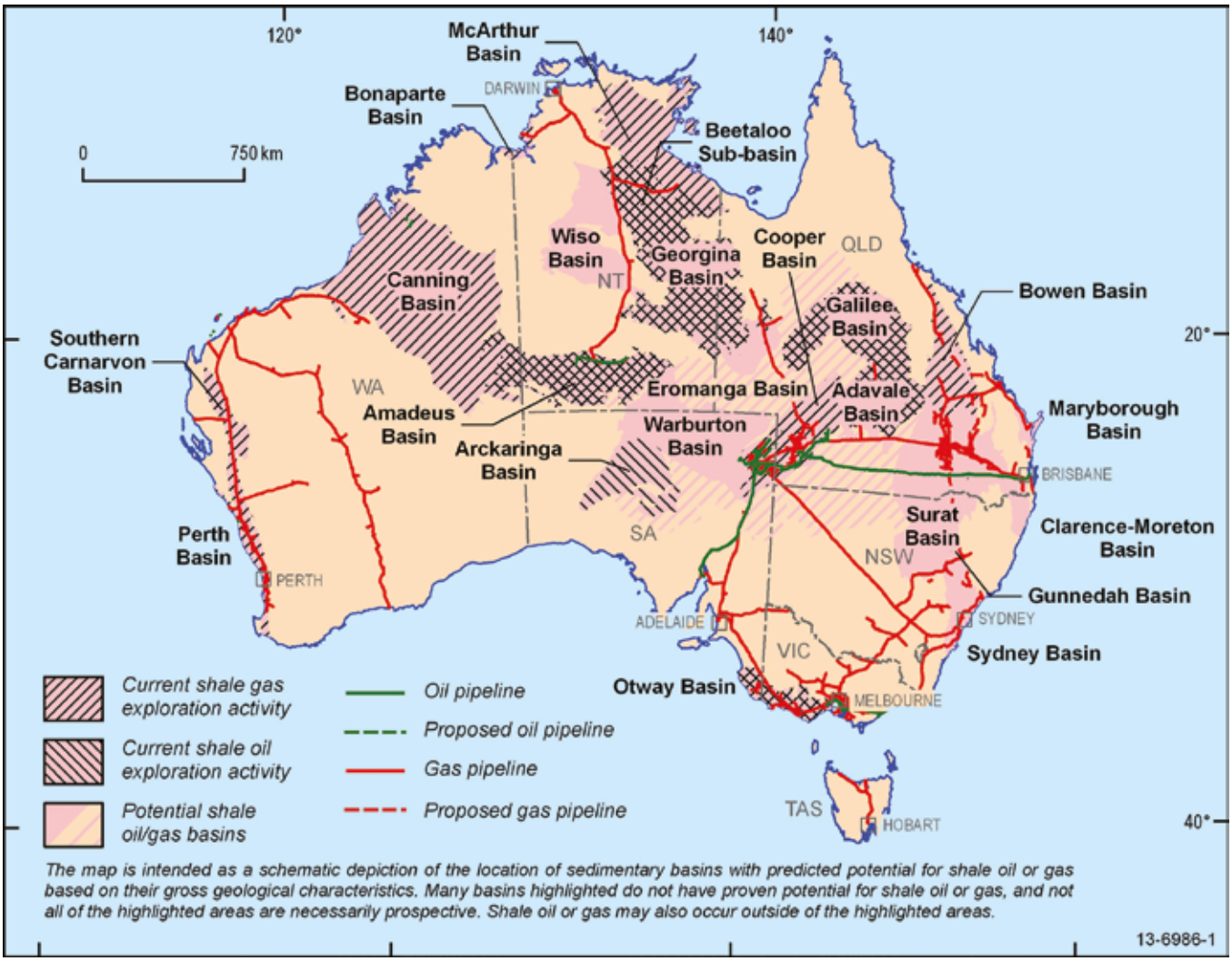
The Cooper Basin may enjoy the greatest viability for commercial development of shale gas. This results from the size of its expected resource (92.9 TCF of technically recoverable resource according to the EIA report) and its close proximity to pipeline networks already in place following decades of conventional oil and gas production in the region.

Companies such as Santos, Beach Energy, Drillsearch Energy, Senex Energy, Strike Energy and Icon Energy have been assessing shale potential in the Cooper Basin. Santos operates the well, boasting the first commercial production of shale gas in Australia in 2012, and other positive drilling results have been enjoyed in the basin. BG Group acquired shale interests from Drillsearch in 2011, and in February 2013 Chevron entered Australia's shale industry by agreeing to fund exploration operations to gain a stake in petroleum titles from Beach Energy.

Perth Basin

There has been significant interest in the Perth Basin because of its close proximity to the Perth city region, its

3 'Gas shale potential of the Amadeus and Georgina Basins, Australia: Preliminary insights', Vu Thi Anh Tiem, Brian Horsfield and Rolando di Primio, Geoscience Australia, Record 2011/10



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existing pipeline infrastructure and tightening gas markets. Western Australia's Department of Mines and Petroleum estimates a technically recoverable resource of 60 TCF in two formations, excluding additional tight gas resources.

Exploration in the Perth Basin has been revitalised in recent years and several fields that may potentially include shale gas have been identified. AWE, Norwest Energy and Origin Energy have been exploring the Perth Basin for shale and tight sandstone gas opportunities. In September 2010, Bharat PetroResources agreed to acquire half of Norwest Energy's interests in two permits in the Perth Basin. AWE drilled the first well with shale gas as the target in 2010. The initial results were favourable and the formation was high-graded for further evaluation. In 2012, three shale gas wells were hydraulically fractured in the northern Perth Basin and the results identified three prospective formations.

Beetaloo Basin

The Beetaloo Basin is more than 3,000m thick and there is evidence that both unconventional and conventional hydrocarbons are present. However, the basin is remote, with very limited access and infrastructure in place and there has been very little exploration for conventional or shale resources. Any discoveries are likely to require a new pipeline to Darwin, which in itself has limited gas demand, and so would need to be commercialised through liquefaction and export as LNG.

Falcon Oil & Gas acquired petroleum titles covering a large area in the Beetaloo Basin in 2008, since then it has drilled 11 wells. On August 21, 2014, Falcon Oil & Gas Australia farmed out 35 per cent of its interest in the petroleum titles to each of Origin Energy and Sasol Petroleum.

Other companies such as Paltar Petroleum, Sweetpea Petroleum and Tamboran also hold petroleum titles in the Beetaloo Basin.

Georgina Basin

The Georgina Basin is a region of proven oil potential. The Southern Georgina Basin is considered to be one of the most prospective onshore basins in Australia, with potential for very large conventional and unconventional gas deposits. However, it is virtually unexplored. Since 2012, there has been a greater interest in the basin from global energy giants, which adds credibility and confidence to the basin's potential.

PetroFrontier has been leading the activity in this remote location, targeting primarily oil-mature source beds, but also dry gas mature rocks. PetroFrontier was joined by Baraka in April 2010 and by Statoil in June 2012.

Central Petroleum also holds petroleum titles in the Georgina Basin and in November 2012 was joined by Total SA.

Ownership of petroleum and the role of government

In Australia, all rights to petroleum and petroleum resources existing at or below the surface of any land or the seabed are vested in the Crown. The Commonwealth government (i.e. federal government) and state and territory governments grant rights to private persons to explore for or produce petroleum through a legislative licensing regime. The licences granted for petroleum exploration or production are commonly referred to as 'petroleum titles'. Petroleum exploration and production activities may only be carried out under the authority of an appropriate petroleum title. When petroleum is produced, property in that petroleum generally passes from the Crown to the petroleum title holder at the wellhead.

The government does not directly engage in commercial petroleum exploration and production via, for example, a national oil company. However, it does provide an orderly and equitable system by which the private sector can undertake such activities. The government's main roles in relation to the petroleum sector are the establishment of broad economic policy, provision of a regulatory framework for petroleum operations, collection and dissemination of geoscientific information with a view to reducing commercial risk in petroleum exploration, and the promotion of petroleum industry competitiveness.

Regulation of onshore petroleum activities

Petroleum legislation

Australia is a federation comprising six states and two territories. Each state and the Northern Territory has its own legislative power to govern onshore petroleum exploration and production activities within its boundaries. Offshore petroleum activities (activities in coastal waters further than three nautical miles from the coastal baseline) are governed under a joint commonwealth–state legislative scheme that provides for a uniform legislative framework. State legislation regulates onshore activities and activities within coastal waters extending up to 3 nautical miles from the coastal baseline.

This guide focuses on the onshore regime. The onshore petroleum regimes in each state are broadly similar but not identical. Western Australia in particular has made recent regulatory changes specifically directed at the shale gas industry, as discussed below.

The onshore petroleum regimes in Australia start from a fundamental position of treating shale resources in the same manner as conventional petroleum resources. For example, the Petroleum and Geothermal Energy Resources Act 1967 of Western Australia defines 'petroleum' to include any naturally occurring hydrocarbon or mixture of hydrocarbons, whether in a gaseous, liquid or solid state. It specifically only excludes oil shale (i.e. hydrocarbons contained in rocks that can only be recovered by mining those rocks as oil shale), and does not exclude oil or gas recovered from shale or other source rock.

Other relevant laws

In addition to the petroleum-specific legislation, there is other legislation that applies to petroleum exploration and production activities. This includes environment and heritage protection legislation (at state, territory and commonwealth level), legislation governing the allocation of onshore water rights, native title and Aboriginal heritage protection legislation, legislation governing industrial relations and workplace health and safety, planning legislation and general land tenure legislation.

State Agreements

Direct agreements may also be entered into between a state government and the proponents of major petroleum projects (known as State Agreements). Such agreements supplement, and in some cases modify, existing state legislation in order

to facilitate a large-scale project. The State Agreements are passed as an Act of state government and given legislative force.

State Agreements generally specify the rights, obligations, terms and conditions for the development of a major resource project and can be for a period of up to 50 years. State Agreements provide projects with long-term certainty and establish a framework for ongoing relations and cooperation between the state and the project proponents.

In late June 2013, the Natural Gas (Canning Basin Joint Venture) Agreement Act 2013 (WA) was passed by the Western Australia parliament. The Act ratifies an agreement between the State of Western Australia, Buru Energy, Mitsubishi and the Mitsubishi subsidiaries, Diamond Resources (Fitzroy) and Diamond Resources (Canning). The agreement seeks to facilitate the development of domestic gas supply and LNG projects (together with associated onshore pipelines), underpinned by shale gas from the Canning Basin.

The agreement provides for a structured process for the grant of the necessary petroleum titles to support the proposed project development. While each phase of the development is subject to approval by the relevant minister, the agreement indicates an overall commitment by the Western Australia government to support the development. In return, the proponents agree (among other things) to supply a minimum amount of gas to the domestic market, support local industry and provide other social and community benefits. The agreement is for an initial term of 25 years with an option to extend for a further 25 years. The proponents must notify the Minister for State Development between December 31, 2015 and March 31, 2016 if they do not intend to proceed with the domestic gas project.

Changes to regulatory regime

There have been recent changes to the regulatory regime, particularly in relation to disclosure of the hydraulic fracturing process. Given that the shale gas industry in Australia is in its infancy, over time we are likely to see more changes to the environment regulations applicable to shale gas.

National Harmonised Regulatory Framework

The Standing Council on Energy and Resources, comprising Australia's energy and resources ministers, has endorsed and implemented a harmonised framework for the regulation of coal seam gas. The National Harmonised Regulatory Framework provides a suite of leading-practice principles to be used as a guidance and reference tool for Australian federal, state and territory government regulators for the coal seam gas industry.

The framework focuses on four key areas of operations, covering the life cycle of the development of natural gas from coal seams: well integrity, water management and monitoring, hydraulic fracturing and chemical use. The framework acknowledges that, although shale gas and coal seam gas have some common exploration and development procedures, the geological and hydrological issues that apply to different forms of unconventional gas are also significant.

There is no expectation that the harmonised regulatory framework developed for coal seam gas will be extended to apply to shale gas. However, it would be reasonable to expect that a similar harmonisation process may subsequently be implemented for the shale gas industry, and that some of the recommendations in the coal seam gas framework could inform that process.

Potential state reform

At present, the potential of onshore conventional gas in Victoria is unknown. In response to community concerns, a moratorium has been in place in Victoria since August 2012 on approvals of new coal seam gas exploration licences and hydraulic fracturing approvals for all existing mineral and petroleum titles. The moratorium on hydraulic fracturing will remain in place until at least July 2015 while a community consultation process and a series of scientific studies on the environmental impact of the industry are conducted. It is anticipated that a report on the consultation process will be made publicly available in July 2015.

The Victoria government is also currently reviewing its regulatory arrangements against the leading principles in the National Harmonised Regulatory Framework. It has noted that the current framework does not fully meet the 18 leading-practice principles and is in the process of considering what actions must be taken before the moratorium can be lifted.

With the increased investment by companies in developing and exploring shale gas potential, there has been an increase in community concern about the environmental impact. The Western Australia government commissioned an independent review of regulations dealing with petroleum and geothermal exploration with a focus on the impact of developments in the shale, coal seam and tight gas activities.[4] The report made 15 recommendations for changes to the regulatory framework. The Western Australia government is in the process of reviewing and improving its

4 'Regulation of shale, coal seam and tight gas activities in Western Australia', Dr Tina Hunter, Faculty of Law, Bond University, July 2011

regulatory framework for onshore gas projects to ensure they are carried out in accordance with best industry practice, and to provide a more robust, enforceable and transparent regulatory framework.

To date there has been no hydraulic fracturing activity in Tasmania. In March 2014, the Tasmanian government introduced a 12-month moratorium on hydraulic fracturing to enable a review of the potential impacts of hydraulic fracturing in Tasmania. The Department of Primary Industries, Parks, Water and Environment of Tasmania provided its final report to the Minister for Primary industry and Water in February 2015. As a result, the Tasmanian government has extended the moratorium on the use of hydraulic fracturing activity for the purposes of hydrocarbon resource extraction in Tasmania to March 2020. A further review on the practice of hydraulic fracturing will be conducted before the moratorium expires.

Land access

In Australia, there is a general principle of multiple land use, which means that different parties may have coexisting rights or interests with respect to the same area of land. The types of land interests that may coexist with onshore petroleum titles include private land, leases from the government for pastoral, agricultural or other commercial purposes, mining (i.e. hard rock mineral) tenements, as well as native title rights and interests.

Private land

Where a petroleum title coexists with private land, operations cannot begin on the private land unless an agreement has been reached with the private land owner as to compensation or the compensation has been otherwise determined by a court. For other types of land interest, the petroleum title holder is generally not prevented from proceeding with operations, but is required to pay compensation to other lawful occupiers of the land who are adversely affected by the petroleum operations. Where there is conflict between onshore petroleum titles and mining tenements, the Minister for Mines and Petroleum makes a decision as to the priority of operations.

Native title

Australian law recognises native title rights of Aboriginal people to land and waters that arise from traditional laws and customs. Registered native title claimants and holders have procedural rights in respect of the grant of new petroleum titles within their native title claim areas.

The main native title process that applies is the 'right to negotiate' procedure. This requires the native title parties to be notified of an application for a new petroleum title, be given the opportunity to make submissions with respect to the grant of the title, and negotiate in good faith the conditions on which the title may be granted. This process usually results in the parties also negotiating an appropriate compensation package for the native title party. If agreement cannot be reached, the matter can be determined by a regulatory tribunal.

Sites or objects of cultural significance to Aboriginal people are also protected and maintained under legislation. Consent is usually required before Aboriginal heritage sites or objects can be disturbed. Compliance with heritage protection protocols is usually a requirement of most negotiated native title agreements.

Types of petroleum and related titles

The petroleum titles required in order to explore for and produce petroleum, including for shale oil and gas, are broadly similar for each Australian jurisdiction, although there are some important differences.

Different petroleum titles are required for each stage in the development of a petroleum project. Generally, titles fall into four main categories: exploration titles, retention titles, production titles and infrastructure titles. The terminology varies between Australian jurisdictions, but the most common terms are exploration permit, retention lease, production licence, pipeline licence and infrastructure licence.

Exploration titles

An exploration title gives the holder the exclusive right to explore for petroleum within the title area. Exploration titles are usually granted for a term of between five and seven years. In most cases they can be renewed, but there is often a requirement to relinquish portions of the title on renewal. Exploration titles usually have minimum work conditions attached to them. Typically, these require a combination of technical, geological and marketing studies, seismic acquisition and the drilling of at least one exploration or appraisal well during the term of the title (and each renewal).

For onshore areas, the release and award system for petroleum exploration acreage differs between jurisdictions. There is either an invitation and competitive tender process, an open application system or a combination of both. Broadly speaking, for areas where there is significant commercial interest, a competitive tender process is likely to apply.

Retention titles

In some jurisdictions, a retention title can be obtained over areas where petroleum discoveries are not currently

commercially viable but are likely to become commercially viable in the future. In Western Australia, for example, the title holder must demonstrate that the discovery is likely to become commercially viable within the next 15 years. The initial term of a retention title is generally five years and may be renewed. When the petroleum discovery is deemed to be commercially viable, the retention title must be converted into a production title.

Production titles

The holder of an exploration title containing a declared discovery is entitled 'as of right' to a production licence over the area containing the discovery. A production title gives the holder an exclusive right to carry out operations (e.g. drilling of developmental wells) for the recovery of petroleum within the relevant licence area.

In Western Australia (for production titles granted after May 25, 2011), South Australia and Victoria, onshore production titles are granted on a 'life of field' basis. In the remaining jurisdictions (and for Western Australia production titles granted prior to May 25, 2011) the term of a production title can vary from 20 to 30 years, and can be renewed at the discretion of the regulator.

Pipeline and infrastructure licences

The holder of a pipeline licence has the authority to construct and operate a petroleum pipeline and ancillary storage tanks and facilities. The key difference between onshore pipeline licences and exploration and production titles is that a pipeline licence is usually only a licence to operate the pipeline infrastructure, and appropriate land tenure – for example, an easement over the pipeline corridor land (although separate access rights may need to be obtained). Infrastructure licences are used for the construction and operation of facilities and services outside a production title area.

Other petroleum authorities

There are also other types of petroleum authorities, such as access authorities and special prospecting authorities. Broadly speaking, these authorities allow for the carrying out of certain approved petroleum activities (e.g. seismic surveys) but not the drilling of wells.

Access authorities generally only allow exploration survey work to be conducted in areas adjacent to an existing petroleum title.

Special prospecting authorities are designed to encourage exploration in areas where little or no exploration has been undertaken. In Western Australia, a special prospecting authority permits a person to undertake exploration work (other than drilling a well) in areas that are the subject of competing applications, areas that have been identified for future acreage release or areas that are not currently under title. Special prospecting authorities may be applied for with an 'acreage option', which enables the holder to apply for an exploration permit within six months of the expiry of the authority. However, the option does not impose any obligation on the government to grant a title, as title is only granted on the merits of the proposed work programme and on satisfying the assessment criteria.

Environmental protection

With increased petroleum activity in Australia and increased concern about its potential environmental impacts, there is a firm emphasis on strengthening regulation to ensure the environment is protected. There is a framework of state and commonwealth legislation applicable to petroleum activities. As onshore petroleum activity has the potential to impact significantly on the environment, the state or territory governments will probably require stringent environmental approval processes to be followed.

A number of states have introduced environmental and safety management regulations that are specifically directed at the unconventional gas industry, or primarily impact on it. For example, additional notification and reporting obligations are required for activities involving hydraulic fracturing. This includes disclosure of chemical compounds added to the water injected in fracturing operations. The Western Australia government, for example, requires 'full public disclosure and transparency for any products, additives, chemicals and substances used in drilling, hydraulic fracturing activities and related petroleum activities'. In September 2014, the Victoria government enacted legislation prohibiting the use of BTEX chemicals (benzene, toluene, ethylbenzene and xylene) in hydraulic fracturing.

State environmental approvals

The environmental regulation of onshore petroleum activity varies between the states and territories, although there are some common features. Most petroleum exploration and production operations require environmental approval under the state or territory petroleum legislation, which is usually issued on the approval of a satisfactory environment management plan. This plan must outline the potential environmental impacts, their significance and how those impacts are to be managed. For hydraulic fracturing activities, it should address, among other things: transport of equipment; fuel, chemical and hazardous materials handling; and management of produced water and flow-back fluid.

Where onshore petroleum activities are likely to have significant environmental impact, a more comprehensive and detailed assessment is required under the relevant state

or territory environmental protection legislation. There are various levels of environmental impact assessment, depending on the environmental significance and complexity of the proposed project. A public consultation process may be required for some projects.

Commonwealth environmental approvals

Actions that will have a significant impact on a matter of national environmental significance require approval under the commonwealth environment legislation (i.e. the Environment Protection and Biodiversity Conservation Act 1999 (Cth)) in addition to state or territory environmental approval. Matters of national environmental significance include listed threatened species and ecological communities, migratory species and areas of high conservation value.

Water

Access to water will be an important consideration for the recovery of shale gas. State and territory governments regulate and manage water resources with the aim of protecting them and promoting sustainable and efficient use of water. Licences and permits are issued for water use under specific water rights legislation. Water generally cannot be taken from a watercourse or groundwater aquifer without a licence. Separate licences are required for the operation of artesian wells.

Foreign investment regulation

Investment proposals by foreign persons are regulated by the Foreign Acquisitions and Takeovers Act 1975 (Cth) and applicable policy guidelines issued by the commonwealth government. The foreign investment law and policy is administered by the Foreign Investment Review Board (FIRB) on behalf of the Treasurer. Certain proposals must be reviewed by FIRB and considered by the Treasurer before they can be implemented, and so FIRB should be notified in advance. These include an acquisition:

- of an interest in a petroleum title, irrespective of value[5]
- of shares in a corporation (or its parent) where more than 50 per cent of that company's assets comprise petroleum titles
- that results in the acquirer obtaining 15 per cent or more of the shares in a 'prescribed corporation' (or that results in foreign persons together holding more than 40 per cent of the shares in the corporation), where the proposal values the company at more than A$252 million
- of the assets of an Australian business (which includes a petroleum project or joint venture) valued in excess of A$252 million, which results in foreign control of that business.

The monetary threshold is higher than A$252 million for acquisitions involving certain investors. For private Chilean, Japanese, South Korean, New Zealand and US investors, the monetary threshold is A$1,094 million.[6] In November 2014, China and Australia completed negotiations for a China-Australia Free Trade Agreement and signed a Declaration of Intent. It is anticipated that the China-Australia Free Trade Agreement will be signed and come into effect in late 2015. This will then increase the monetary threshold for private Chinese investors from A$252 million to A$1,094 million.

The vast majority of Australian companies will be prescribed corporations. In addition, if the value of the Australian part of an international group is more than the monetary threshold or comprises more than 50 per cent of the total value of that group, the group's ultimate parent will be a prescribed corporation.

Likelihood of acceptance of investment proposals

The only basis on which the Treasurer can object to an investment proposal by a foreign interest is if the proposal is contrary to the 'national interest'. From a foreign investor's perspective, this compares favourably with, for example, the 'net benefit' test applied under the Investment Canada Act. Foreign investors in Australia's petroleum industry can expect that approval will not be withheld from a proposal on national interest grounds, other than in unusual circumstances affecting Australia's vital interests and development.

Greater scrutiny will be directed towards investments by state-owned entities to ensure they act commercially. They will also be subject to additional approvals. However, state-owned investors could still largely expect that approval will only be withheld in unusual circumstances. This expectation is subject to any changes in relevant FIRB policy guidelines.

For many years, the Australian government has publicised that it welcomes foreign investment and recognises the contribution that foreign investment is able to make to the development of Australia. Access to new technology, management skills and overseas markets, as well as scope for higher economic activity and employment, are all

5 There is some uncertainty as to whether this applies only to production titles or also includes exploration titles

6 http://www.firb.gov.au/content/monetary_thresholds/monetary_thresholds.asp

positive attributes claimed by the Australian government to derive from foreign investment.

Taxes, duties, royalties and incentives

The Petroleum Resource Rent Tax (PRRT) levied by the federal government currently applies to all petroleum projects in Australia. The PRRT is levied at a rate of 40 per cent of a petroleum project's taxable profits.

There are also royalties imposed by state governments that are payable on petroleum produced from onshore projects. These apply concurrently with the PRRT. The royalty payable is based on the value at the wellhead of petroleum recovered and is levied at a rate of between 10 per cent and 12.5 per cent of the gross wellhead value, less costs incurred. Deductible costs are normally confined to the processing, storage and transport of the petroleum recovered by the producer to the point of sale.

For example, in Western Australia, there are three types of cost that can be deducted against the gross value: the post-wellhead operating costs, depreciation on commissioned post-wellhead assets, and costs of borrowing on commissioned post-wellhead assets. There are deduction limits, which can vary depending on the predominant nature of the project. The royalty payments will be creditable against current and future PRRT liabilities of a petroleum project.

Company tax and several other taxes and fees (including on registration of transactions relating to interests in petroleum titles and carbon tax) will also apply. Specific concessions apply for petroleum production in Australian income tax law. Specific provisions also allow certain expenditures to be deducted or written off. For example, income tax deductions apply to certain exploration and operating costs, such as prospecting right costs, provision of housing and services facilities for employees at, or adjacent to, the production site, royalty payments and depreciation of plant and equipment.

The rates of applicable tax, the nature of costs that are eligible for deduction and the timing of their deductibility are regularly reviewed and are subject to change.

Investment vehicles

A foreign company will be required either to register in Australia as a registered foreign body or set up an Australian subsidiary company before it can carry on business in Australia (which would include acquiring an interest in a petroleum title or a company holding such an interest). An Australian subsidiary will usually need to have at least one Australian resident director.

The choice of structure will largely be driven by tax considerations such as the deductibility of the Australian branch's expenses from the foreign company's income or, conversely, the deductibility of interest on loans used to capitalise the Australian subsidiary. Other factors that may influence the choice of structure include providing additional limited liability with respect to the foreign company's operations in Australia, providing a vehicle by which the operations could be sold at a future time and, potentially, giving greater commerciality to the operations by the registration of an Australian subsidiary.

Enforcement regime in judicial and arbitral alternatives

Foreign judgments

The enforcement of foreign judgments in Australia is governed by both statutory regimes – the Foreign Judgments Act 1991 (Cth) and Foreign Judgments Regulations 1992 (Cth) – and principles of common law and equity. The statutory regime is restricted to specified countries and courts, and requires certain conditions to be met.

Australia is not party to the Hague Convention on Recognition and Enforcement of Foreign Judgments in Civil and Commercial Matters 1971. The principles of common law (for recognition of money judgments) and of equity need to be relied upon where there is no international or statutory agreement under which the foreign judgment can be enforced.

Foreign arbitral awards

Foreign arbitral awards are enforced in Australia under the International Arbitration Act 1974 (Cth). This implements Australia's obligations under the United Nations Convention on the Recognition and Enforcement of Foreign Arbitral Awards 1958 (known as the New York Convention) and gives force to the United Nations Commission on International Trade Law (UNCITRAL) Model Law. Arbitral awards from countries that are signatories to the New York Convention will be binding in Australia as if the award had been made in Australia.

Section 8(2) of the International Arbitration Act 1974 (Cth) provides that a foreign award 'may be enforced in a court of a State or Territory or in the Federal Court of Australia as if the award were a judgment or an order of that court'. The effect of this section is to equate a foreign award with a domestic award for the purposes of enforcement.

In Australia, Sydney has been promoted as a regional centre for arbitration on the foundation of its stable, supportive and trusted legal system and competitive costs. For cross-border contracts, many arbitration agreements select Singapore as the arbitral venue.

Opportunities

There is little doubt that Australia has substantial shale gas resources, although just how much gas is in place, and how much of that will be recoverable, remains to be seen. There is certainly enough prospectivity to have experienced shale gas players such as Chevron and ConocoPhillips commit to large investments. Others, such as BHP Billiton and Shell, express more than a passing interest.

However, a number of challenges will need to be overcome before large-scale commercial development is possible. Unless production wells are close to existing and under-utilised pipeline infrastructure and domestic gas markets, as is the case with the Cooper Basin, substantial capital commitments will be required to develop the pipeline, processing and other infrastructure needed to commercialise recoverable reserves.

The cost of developing projects in Australia is extremely high by global standards, not least because the recent and ongoing parallel development of several world-class LNG projects in the country has driven up the cost of most inputs. Shale gas developments in the remote regions may struggle to be commercially viable on the back of domestic gas prices, and would need to secure LNG export markets in order to reach a favourable final investment decision. The Canning Basin in Western Australia and the various basins in the Northern Territory are attracting significant exploration interest, notwithstanding their remote location and absence of nearby gas demand centres. Success in those locations could lead to the expansion or back-filling of existing liquefaction facilities in the north of Australia.

Mirroring the US

Australia's shale gas industry has been described by some as being a decade or so behind that of the US. In 2006, shale gas production in the US reached a sufficient volume to separate Henry Hub prices from West Texas Intermediate (WTI) spot crude oil prices. It was only in late 2008 that increased production caused US gas prices to trend away from crude oil linked gas prices in Asia. The mega-shale transactions in the US came in earnest in 2009 when ExxonMobil acquired XTO Energy for US$40 billion. Global gas markets have changed since then, and Australian domestic conditions are very different from those in the US.

However, if Australia's geological and industry conditions resemble those of the US, as the EIA report states, and if Australia follows the trend of the US shale industry even to a reduced degree, there are great opportunities for those who enter the Australian shale industry while it is still in its relative infancy.

Brazil

It has been reported that there is no current commercial production of natural gas from shale deposits in Brazil. Nonetheless, Brazil has the potential to become an important producer of shale gas.

Shale basins in Brazil

The greatest potential shale gas deposits in Brazil are located in the Parecis Basin in the state of Mato Grosso, the Parnaíba Basin in the states of Maranhão and Piauí, the Recôncavo Basin in the state of Bahia, the Paraná Basin in the states of Paraná and Mato Grosso do Sul and the São Francisco Basin in the states of Minas Gerais and Bahia.

According to the US Energy Information Administration (EIA) report of June 2013,[1] the Ponta Grossa formation in the Paraná Basin has 80 TCF of technically recoverable shale natural gas reserves and 450 TCF of risked natural gas in place. The Jandiatuba formation in the Solimões Basin has 65 TCF of technically recoverable shale natural gas reserves and 323 TCF of risked natural gas in place. The Barreirinha formation in the Amazonas Basin has 100 TCF of technically recoverable shale natural gas reserves and 507 TCF of risked natural gas in place.

Ownership of land and mineral rights

Oil and natural gas deposits existing in Brazilian territory belong to the Brazilian Federal Government, in accordance with Article 20, Item IX of the Federal Constitution and Article 3 of Law No. 9,478. After production and payment of royalties, the production is owned by the holder of the oil and/or gas concession.

The holder will always exclusively bear all costs and risks relating to the performance and consequences of its operations. In return, the holder will have the sole, exclusive ownership of the oil and natural gas produced and received by it at the Production Metering Point. The Production Metering Point, the metering methods, equipment and instruments are determined in the relevant Development Plan, as approved by the Agência Nacional do Petróleo, Gás Natural e Biocombustíveis (ANP).

Hydrocarbon regulation

Government structure

The government structure is composed of:

- the National Energy Policy Council (Conselho Nacional de Política Energética, or CNPE)
- the Ministry of Mines and Energy (Ministério de Minas e Energia, or MME)
- the Brazilian National Agency of Petroleum, Natural Gas and Biofuels (Agência Nacional do Petróleo, Gás Natural e Biocombustíveis, or ANP).

Both the ANP and CNPE were created by Law No. 9,478 of August 6, 1997 (the Petroleum Law).

Relevant licensing and control body

The relevant licensing and control body is the ANP, which is the regulatory agency that integrates the oil, natural gas and biofuels industries in Brazil.

1 *Technically Recoverable Shale Oil and Shale Gas Resources: An assessment of 137 shale formations in 41 countries outside the United States*, US Energy Information Administration, 2013. Available at: http://www.eia.gov/analysis/studies/worldshalegas/

500 TCF
Potential shale reserves

Recent studies have shown potential shale gas reserves of up to 500 TCF, spread across five separate basins within Brazil.

With the intent to expand shale gas production, the Brazilian government held the first auction for shale gas reserves, which results were announced by the ANP on October 21, 2013. A consortium formed by Petrobras (40 per cent and operator), China National Petroleum Corporation (CNPC) (10 per cent), China National Offshore Oil Corporation (CNOOC) (10 per cent), Shell (20 per cent) and Total (20 per cent), was the sole bidder and winner of the auction corresponding to the Libra oil field, located in the Santos basin.

80 TCF

Ponta Grossa, this formation in the Paraná Basin has 80 TCF of technically recoverable reserves and 450 TCF of risked natural gas in place.

62 TCF

Jandiatuba, based in the Solimoes Basin, along with its technically recoverable reserves it also has 323 TCF of risked natural gas in place.

100 TCF

Barrerinha, in the Amazonas Basin, along with its technically recoverable shale reserves it has an additional 507 TCF of risked natural gas.

State oil companies

Currently in Brazil there are effectively two State oil companies, namely:

- Petróleo Brasileiro SA (Petrobras): a mixed capital corporation (State and private) with shares publicly traded on the New York Stock Exchange (NYSE) and the São Paulo Stock Exchange (BOVESPA). The majority and controlling shareholder of Petrobras is the Brazilian Federal Government

- Pré-Sal Petróleo SA (PPSA):The creation of this State company fully owned by the Brazilian Federal Government was approved on August 2, 2013, as evidenced in the Brazilian *Official Gazette* published Decree No. 8,063. PPSA represents the Brazilian Federal Government in joint ventures for exploration and production in the pre-salt areas under production-sharing contracts (PSCs).

Applicable legislation

The governing laws are:

- Article 177 of the Federal Constitution

- Law No. 9,478 for the concession contract regime

- Law No. 12,351 for the production-sharing regime in the pre-salt areas (the Pre-Salt Law).

Changes to regulatory regime

An important discovery made in Brazil in 2007 prompted considerable change to the hydrocarbon regulatory regime. In 2007, a consortium formed by Petrobras, BG Group and Galp Energia discovered the 'pre-salt area' in a field called the Tupi, in southern Brazil, which is estimated to contain at least five billion barrels of recoverable oil.

Following this discovery, a new legal framework was enacted in December 2010, with the publication of the Pre-Salt Law. The new law introduced PSCs that would govern exploration and production activities in the pre-salt area and in other 'strategic blocks', as defined in the Pre-Salt Law.

Rights, licences and approvals

There are two petroleum regimes in Brazil: concession contracts and production sharing.

Concession contracts

Concession contracts are regulated by Law No. 9,478. The scope of the concession contract is the performance of the operations described in Annex II of each contract ('Work and investment programme') and any other additional activity a holder might undertake within the concession area. Concession contracts aim to enable oil and natural gas to be produced in commercial conditions, and comprise two phases – exploration and production. The exploration phase includes the evaluation and possible discovery of oil and natural gas in order to determine the commercial value of the resource. The production phase also includes development activities.

Application procedures

Any company that meets the technical, financial and legal requirements under the applicable regulations (Law No. 9,478 and Tender Protocol for the Licensing Round) may qualify and bid for the blocks offered during the licensing rounds held by the ANP, after the rounds have been approved by the CNPE.

Companies are qualified as 'non-operator', 'operator C' (onshore only), 'operator B' (onshore and shallow waters) and 'operator A' (onshore, shallow, deep and ultra-deep waters), depending on their expertise and/or technical staff and financial capacity.

The bidders need to pay a participation fee to the ANP and are granted access to a data package. Bids are presented in sealed envelopes during an event held by the ANP. The envelopes specify an amount for the signature bonus (to be paid if the company is awarded the contract), local content estimates and a minimum exploratory programme. The results are released immediately after all envelopes for a specific block have been opened and reviewed by the ANP.

Qualified companies may bid alone or in association with other companies through the formation of a consortium (unincorporated joint ventures) in accordance with Brazilian laws.

Award procedures

Concession contracts can only be awarded to companies incorporated in Brazil with head office and management in the country, irrespective of the nationality of the shareholders. International companies may participate in the licensing rounds. If awarded a block, they must appoint an affiliated company incorporated in Brazil to sign the concession contract.

The ANP adopts the following criteria in assessing bids: (i) the signature bonus, representing 40 per cent in the

calculation of the final grade; (ii) the local content, being 5 per cent for the exploration phase and 15 per cent for the development/production phase; and (iii) the Minimum Exploratory Program.

The final results of the bids for each block are part of an Award Report, submitted to ANP's Board of Directors for ratification, in which the ANP awards the block being licensed to the company or consortium declared the winner. The ANP publishes the results of the licensing round awards in the *Official Gazette* and in the media, after which it must invite the winning companies or consortiums to sign the concession contracts. Once all the contracts are executed, the ANP publishes the statements of the executed contracts in the *Official Gazette*.

On November 28 and 29, 2013, the ANP promoted the 12th Bid Round in which it offered areas in onshore basins with high potential for natural gas originating from unconventional reservoirs. There were 240 potential areas available for bidding, including 110 areas identified as 'new frontiers' in the Acre, Parecis, São Francisco, Paraná and Parnaíba bays and 130 areas in mature bays of Recôncavo and Sergipe-Alagoas.

Following bidding, 72 of the 240 areas were awarded, of which 54 are potentially productive areas of shale gas. Petrobras acquired most of the exploration blocks and will operate 27 blocks by itself and 22 blocks in consortium with other national and foreign private companies. One of the most popular areas was the Paraná Basin.

Production sharing

Despite the fact that the production-sharing regime has been approved through the Pre-Salt Law, it is not yet in place because no areas have been offered under the regime. No PSCs have been disclosed by the Brazilian Federal Government, and many details are still unknown.

PSCs are regulated by the Pre-Salt Law. The contracts will only be signed for the exploration and production of oil, natural gas and other fluid hydrocarbons in the pre-salt and other strategic areas, as defined by the Brazilian Federal Government.

Establishment of a local entity

Concession contracts

Holders of oil and gas concessions need to be established in Brazil, but the equity can be 100 per cent held by foreign entities or individuals. Affiliates of foreign companies, once incorporated in Brazil, are required to provide a parent company performance guarantee to sign the concession contract.

Production sharing

For all the new pre-salt areas to be granted under PSCs, Petrobras will be the sole operator, with a minimum participation of 30 per cent. National and foreign private companies will be able to participate only as non-operators.

Taxes, duties, royalties and incentives

Tariffs

In the concession contract, the holder is required to pay: (i) a participation fee, to be able to bid; (ii) a signature bonus, for the award of the concession contract; and (iii) an annual occupation and retention fee for the concession area. (If onshore and the land is privately owned, this latter amount goes to the landowner.)

Other taxes

Exploration and production (E&P) activities are subject to ordinary tax rules regarding taxes levied on net profits. There is no special income tax regime applicable to the oil and gas sector.

There are several taxes and contributions that are subject to a non-cumulative tax regime (VAT-alike), meaning that the amount of tax collected represents a tax credit that can be used to offset subsequent tax debts.

The remittance of funds abroad is subject to tax on financial transactions (IOF). This is a federal tax that, among other transactions, levies currency exchange contracts at a rate of 0.38 per cent.

Royalties

Royalties correspond to the financial consideration paid by the holders to the Brazilian Federal Government due to oil and gas production. From the date of the start-up of the commercial production of each field, royalties must be paid monthly, in local currency, in an amount equivalent to 10 per cent of the gross revenue deriving from the sale of oil or natural gas. In the light of any particular geological risks, production expectations and other pertinent factors, the ANP may reduce the royalties to a minimum of 5 per cent of the gross revenue.

It is worth noting that rules with regards to royalties and local content may vary per auction.

In addition to royalties, the concession contract establishes the obligation to pay a special participation fee, similar to a royalty, which applies only after a certain level of production is reached. The rates range from 10 per cent to 40 per cent, depending on the location of the field.

Foreign currency and Central Bank of Brazil requirements

As mentioned above, IOF is levied on currency exchange at a rate of 0.38 per cent.

Registration of foreign investment

Under the rules of the Brazilian foreign investment law, it is mandatory for the investor to register a foreign investment with the Central Bank of Brazil, to repatriate the capital invested and to make remittances or reinvestments of profits and other forms of remuneration of the capital brought into Brazil.

The registration of a foreign investment must be submitted electronically by the company receiving the investment (the invested company) and the foreign investor (through its representative in Brazil). The route is the Central Bank's electronic registry system of direct foreign investments, the Registro Declaratório Eletrônico de Investimentos Externos Diretos (RDE-IED). This electronic registration must be made within 30 days of the date of entry of the investment into Brazil, except for registration of investments in goods (tangible assets), for which the term is 90 days from the date of customs clearance.

Environmental protection and socio-economic development

Shale gas is under close scrutiny in Brazil at present because of the environmental issues related to its development.

Investors must take into consideration the strict environmental legal framework, based on which the degree of fault may not be claimed by a polluter in order to avoid joint and several liability. Any party that contributes to pollution damage may therefore be liable for the costs of recovery and/or indemnification of the complete damage. Criminal and administrative sanctions are also applicable in cases of pollution damage.

Environmental impact assessment requirements

Activities that have significant polluting potential because of their nature or size, such as E&P activities, may require an environmental impact assessment (*Estudo de Impacto Ambiental*) and its report (*Relatório de Impacto ao Meio Ambiente* – RIMA) to obtain an environmental licence. In addition to the general rules issued at federal level, states can issue their own rules regarding the environmental licensing procedure.

The environmental impact assessment must follow general guidelines, such as the identification of all technological and project location alternatives, and the assessment of the environmental impact that may arise from the operations as provided in CONAMA Ordinance 01/1986. The environmental study is therefore a full assessment of the activities' impact, including the measures that the operator proposes to adopt to compensate (indemnify) and mitigate such impacts. In some cases (when mandatory according to the law or requested by civil entities, including the Public Attorney Office), public hearings must be called to allow the public to comment on the environmental studies.

Resolution for hydraulic fracturing

Shale gas exploitation uses the technique of hydraulic fracturing, which involves the injection of water and chemicals under high pressure.

Because of the potential pollution effect, the ANP enacted Resolution No. 21/2014 on April 11, 2014, to regulate hydraulic fracturing in unconventional reservoirs. Such activities may now only begin with the ANP's prior authorisation. Note that the resolution was subject to public consultation before Brazil Round 12 (November 2013), resulting in a legal instrument that incorporates the public contributions received.

Resolution No. 21/2014 is enacted to cover the lack of special legislation regarding hydraulic fracturing. It primarily sets out the following: (i) mandatory adoption of an environmental management system, including an effluents control, treatment and disposal plan; (ii) a requirement for preliminary studies to obtain the ANP's operations approval (e.g. fracturing simulations and risk analysis); (iii) standards to be complied with in relation to the activity itself; and (iv) preparation of an emergency response plan.

In addition, a party seeking the ANP's approval to carry out hydraulic fracturing activities in unconventional reservoirs must have obtained and maintained environmental permits that expressly refer to these activities.

Ongoing environmental reporting rules

CONAMA Ordinances 237/1997, 23/1994 and 350/2004 and Ordinance 422/2011 issued by the Brazilian Institute of Environment and Renewable Natural Resources (IBAMA) also require concessionaires to submit an environmental

control plan or project to the competent environmental agency. This lists the measures to be adopted to mitigate environmental impacts arising from the installation and operation of an oil facility, which were evaluated in the environmental studies.

The implementation of the environmental programme and actions in the environmental control plan may give rise to an obligation to report to the competent environmental agency on a regular basis. For monitoring purposes, the frequency of such reports is normally established in the environmental licences.

Environmental audits

CONAMA Ordinance 265/2000 determines that a company that performs activities deemed to cause significant impact on the environment, such as E&P activities, must present to CONAMA a working programme and related schedule for the performance of environmental audits. According to Law No. 9,966/2000, companies that carry out offshore exploration must perform environmental audits in order to evaluate their management systems and environmental control programmes.

Pollution rules

CONAMA Ordinance 05/1989 created the National Air Quality Control Program (PRONAR). This programme stands as one of the basic environmental instruments for protecting health and welfare and improving quality of life. Its purpose is to enable Brazil's economic and social development to proceed in an environmentally safe way that limits atmospheric pollution. It aims to improve air quality, ensure compliance with the standards established and avoid jeopardising air quality in areas considered not degraded.

In accordance with PRONAR, CONAMA Ordinance 03/1990 was published in order to establish standards for air quality. Also, CONAMA Ordinance 382/06 and 436/2011 establish standards regarding the maximum atmospheric pollutants emissions authorised for fixed sources. CONAMA Ordinances 357/2005 and 393/2007 set out the conditions and standards for effluent discharges.

Emergency preparedness

Law No. 9,966/2000 requires oil companies to create individual emergency and contingency plans. This was further regulated by CONAMA Ordinance 398/2008. Such plans must follow standards similar to those of international conventions, such as MARPOL 73/1978, CLC/1969 and OPRC/1990. However, these standards do not specify the nature of equipment applicable to safety control activities, which depends on the complexity of the activity and a risk analysis. Normally, the competent environmental agencies require the adoption of the 'best practices and technology available' to control E&P activity, including international standards.

Remediation rules

If environmental damage occurs, the National Environmental Policy (Federal Law No. 6,938/1981) determines that the polluting agent must first try to redress the environmental damage (in natural recovery). If environmental recovery is no longer viable, an indemnification in cash is allowed (pecuniary recovery) in order to remedy the environmental damage. In addition, the Public Civil Suit Law (Law No. 7,347/1985) allows the imposition of liability for moral damages, depending on the extent and severity of the incident.

Liabilities and responsibilities

Brazilian laws create strict liability with regards to environmental damage, which may give rise to civil, administrative and criminal issues.

On a civil basis, the operator and non-operators are jointly and severally liable for any damage caused to the environment. This includes damage due to the failure of a service provider or an equipment supplier, which is provided in the concession contract executed by and between the ANP and the concessionaire. Also, National Environmental Policy (Law No. 6,938/81) regulates civil liability for damage caused to the environment. This is of a strict liability nature and irrespective of fault by the responsible entity. This law further expanded the list of agents liable for environmental damage and established joint and several liability among polluting agents. In this sense, if the damage is caused by a service provider's failure, the service provider will also be jointly and severally liable to the government authorities for the environmental damage.

The operator is also subject to administrative penalties, such as the payment of fines. These might be imposed on the service provider, depending on its participation in an event considered to be an environmental infraction. Environmental infractions are regulated by Law No. 9,605/1998, Federal Decree No. 6,514/2008 and also by state legislation. Oil spills are also regulated by Law No. 9,966/2000 and Federal Decree No. 4,136/2002. Penalties are imposed by the competent environmental authority and consist of, among others, fines, full or partial suspension of activities, restrictions on entering into contracts with the government, and the obligation to redress damage. Fines normally range from R$50 to R$50 million. In case of recidivism, this value may be increased by up to 300 per cent.

If environmental pollution occurs, an entity's officer, administrator, director, manager, agent or proxy will also be subject to criminal penalties, as defined in the Environmental Crimes Act (Law No. 9,605/1998). The criminal liability is subjective in nature, which means that it is necessary to obtain proof of fault or wilful misconduct of the party. Criminal liability is not joint and several, and a party is responsible to the extent of its fault.

Domestic supply and exportation of hydrocarbons

Exportation of hydrocarbons is permitted in Brazil. However, the ANP needs to grant an authorisation to export, according to Article 60 of Law No. 9,478.

Enforcement regime in judicial and arbitral alternatives

Under a concession contract signed with the ANP, any dispute related to the terms of the concession contract will be resolved by arbitration. The arbitration procedure follows International Chamber of Commerce (ICC) rules and will take place in Rio de Janeiro. Arbitration will be conducted in Portuguese by three arbitrators, with each party choosing one arbitrator and these two arbitrators selecting the third arbitrator.

Opportunities

The government of Brazil intends to encourage production of natural gas from shale. The Government of Brazil intends to award rights to explore for natural gas in onshore shale deposits in the Parecis Basin in the state of Mato Grosso, the Parnaíba Basin in the states of Maranhão and Piauí, the Recôncavo Basin in the state of Bahia, the Paraná Basin in the states of Paraná and Mato Grosso do Sul, and the São Francisco Basin in the states of Minas Gerais and Bahia. However, environmental and legal hurdles must be overcome before these opportunities can materialise.

Summary

The greatest potential shale gas deposits in Brazil are located in the Parecis Basin in the State of Mato Grosso, the Parnaíba Basin in the States of Maranhão and Piauí, the Recôncavo Basin in the State of Bahia, the Paraná Basin in the States of Paraná and Mato Grosso do Sul, and the São Francisco Basin in the states of Minas Gerais and Bahia.

According to the EIA report of June 2013, the Ponta Grossa formation in the Paraná Basin has 80 TCF of technically recoverable shale natural gas reserves and 450 TCF of risked natural gas in place. The Jandiatuba formation in the Solimões Basin has 65 TCF of technically recoverable shale natural gas reserves and 323 TCF of risked natural gas in place. The Barreirinha formation in the Amazonas Basin has 100 TCF of technically recoverable shale natural gas reserves and 507 TCF of risked natural gas in place.

Canada

Canada has significant shale oil and gas resources and, according to the International Energy Agency, Canada and the US account for virtually all the shale gas produced commercially in the world.

Shale plays in Canada

Some of the most promising Canadian shale fields are just beginning to be developed. For instance, the Horn River Basin in north-eastern British Columbia is thought by some to contain up to 529 TCF of reserves of natural gas, 133 TCF of which is thought to be recoverable. Other prominent shale plays are the Montney, Liard Basin and Cordova Embayment in British Columbia, the Colorado in Alberta, the Bakken in Saskatchewan, the Utica Shale in Quebec, and the Horton Bluff in the Canadian Maritimes.

Canada's National Energy Board (NEB) anticipates Canadian shale gas development will grow from 1.9 billion cubic feet per day (BCFD) in 2013 to up to 3.5 BCFD by 2016. The NEB anticipates annual drilling activity in the Montney and Horn River Basin shales to increase to between 500 and 900 wells by 2020. To provide context, in July 2009, 234 horizontal wells were producing from the Montney Shale.

Montney formation

The Triassic-aged Montney formation is a mature shale and tight gas play spread over approximately 29,000km^2 in British Columbia and Alberta. The British Columbia portion of the Montney is located south of the Horn River Basin, near Dawson Creek, while the Alberta portion is located in the north-western part of Alberta, near Grande Prairie. The Montney underlies the Doig formation, and some call it the Montney/Doig.

It is estimated that the Montney holds one of the largest unconventional resources in the world, with 449 TCF of natural gas, 14 billion barrels of natural gas liquids and 1.1 billion barrels of oil, and annual production estimated to be 3.3–4.4 BCFD by 2020[1].

The Montney is divided into four distinct intervals: upper, middle, middle-lower and lower. The upper Montney, with nearly 90 per cent of the exploration activity to date, and lower Montney, are considered the most prolific[2]. The Montney is not a pure shale gas play, as it consists of a blend of low-permeability sandstone, siltstone and shale. While most of the historical development has occurred on the eastern side of the Montney, the western side is now attracting interest from exploration and production companies[3].

The Montney lies at a depth of 2,000–2,500m (6,600–8,200 ft)[4]. It is comparable to other North American shales such as the Fayetteville Shale, the Woodford Shale and the Barnett Shale. The Montney shale thickness averages over 290m (950 ft) and it has an average porosity of 6 per cent[5].

Geologists have known about the Montney formation for many years. However, it was largely ignored until advances in horizontal drilling and multi-stage hydraulic fracturing technology, combined with a high market price for natural gas, encouraged its exploration and development.

1 National Energy Board, BC Oil and Gas Commission, Alberta Energy Regulator and British Columbia's Ministry of Natural Gas Development, Energy Briefing Note: The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta, November 2013.
2 *Ibid.*
3 *Ibid.*
4 *Ibid.*
5 *Ibid.*

821 TCF Western Canadian Sedimentary Basin

The estimated amount of gas in place in the Western Canadian Sedimentary Basin, where the majority of shale gas reserves in Canada can be found. Many companies are currently exploring Alberta and British Columbia to develop shale gas resources.*

133 TCF

The Horn River Basin in north-eastern British Columbia is thought to contain up to 529 TCF of natural gas, of which 133 TCF is thought to be recoverable.†

145 TCF

The estimates recoverable resources of natural gas at the Muskwa shale site in the Horn River Basin, in northeast British Columbia.

158 TCF

The estimated recoverable resources of natural gas in the Liard Basin where exploratory drilling is well underway. Canada's resources are still in the early stages of development and its full potential is yet to be explored.

* See Supra note 1.

† British Columbia Ministry of Energy and Mines and the National Energy Board. *Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin*, Oil and Gas Report 2011-1, May 2011.

The Montney holds substantial resource potential and opportunities for future growth. Operators have spent over C$2 billion since 2005 acquiring mineral rights in the Montney[6]. Land sales set records several years ago. At a mid-July 2008 auction of the British Columbia government's oil and gas rights, records were broken when buyers collectively paid C$610 million for rights to drill in the Montney area, including C$157 million for a single parcel.

Approximately 3,000 wells were drilled in the Montney until April 2014. Wells generally produce 3-5 million cubic feet per day (MMCFD) on start-up, but are typically followed by rapid declines to long-lived lower production rates. Recoverable gas volumes from the Montney are typically in the 20 per cent range[7]. Some analysts believe that the recovery factor in the Montney could be much higher at up to 50 per cent.

Horn River Basin

The Horn River Basin is a Devonian-aged shale. It encompasses approximately 11,400km^2 (4,400km^2) in north-eastern British Columbia and runs north to Fort Liard in the southern Northwest Territories. The accompanying Cordova Embayment straddles the north-eastern corner of British Columbia and the Northwest Territories[8].

The Horn River Basin has been drilled with over 300 wells, and the adjacent Cordova Embayment with about 340 wells, of which 40 have targeted shale gas[9]. The Horn River Basin is estimated to hold up to 133 TCF of recoverable gas, with annual production predicted to be between 1.5 and 2.5 BCFD by 2020.

The Muskwa, Otter Park and Evie members are subunits of the Horn River Basin, and the Horn River Basin is sometimes referred to as the Ootla/Muskwa Shale[10]. It lies at a depth of 2,370–4,053m (7,800–13,300 ft) and is comparable to the Haynesville shales at a depth of 3,200–4,100m (10,500–13,500 ft). In terms of thickness and porosity, the Horn River Shale is 110–176m (360–580 ft) thick and has a porosity of 4 per cent.

Liard Basin

The Liard Basin is about 9,400km^2 (3,600 square miles) and is situated to the west of the Horn River Basin[11]. It has been drilled with approximately 500 wells, some of which are thought to be among the best shale gas wells in the world.

Colorado Group

The Colorado Group is found throughout southern Alberta and Saskatchewan. It includes the Medicine Hat and Milk River shale sandstones, which for over 100 years have been producing natural gas, as well as the Second White Speckled Shale, which has produced natural gas for decades. In some places, the Colorado Shale is approximately 200m thick, with potential to produce gas from five zones. Shale from the Colorado Group produces through thick sand beds, making it a hybrid gas shale like the Montney. The gas is from biogenic rather than thermogenic origins. This means it has a very low potential for natural gas liquids and is underpressured, which is more difficult to hydraulically fracture. Colorado Group shales are sensitive to water, which also makes them sensitive to fluids used during hydraulic fracturing. As an alternative, operators use nitrogen or mixtures of propane and butane as fracturing carrier fluids.

The total volume of gas in the Colorado Group is difficult to estimate given the wide lateral extent of the shale, the variability of the reservoir and the absence of publicly available analyses. However, there could be at least several trillion cubic metres (one hundred TCF) of gas in place. As of 2009, only about 3 MMCFD was being produced out of a few dozen shallow wells in the Wildmere area of Alberta. Typically, only vertical wells are drilled for the Colorado Shale because of the rock conditions.

Utica Shale

The Ordovician-aged Utica Shale is among the oldest and most widespread shales in North America. The Utica is found from Pennsylvania to New York to Quebec. It can be divided into the Utica deep and Utica shallow. The deep Utica extends from northern New York to Pennsylvania. The shallow Utica is located in Quebec, with the best prospects lying within a corridor along the St Lawrence River between Montreal and Quebec City.

While there is currently no commercial production, Quebec's Utica Shale has historically attracted significant attention from exploration and production companies. Estimates in the shallow Utica Shale in Quebec range from 18 TCF to 40 TCF of natural gas if fully developed.[12] The Utica Shale averages 150m (500 ft) in thickness with a porosity of 3.5 per cent.

Horton Bluff Group

The Horton Bluff Group of the Canadian Maritimes was deposited in the Early Mississippian period about 360 million years ago. The silica content in the Frederick Brook Shale of the Horton Bluff Group in New Brunswick averages 38 per

6 'A Guide to B.C.'s Shale Gas Boom', *B.C. Business*, 18 March 2013.
7 See Supra note 1.
8 See Supra Note 9.
9 See Supra Note 9.
10 See Supra Note 9.
11 BC Oil & Gas Commission, *Hydrocarbon and By-Product Reserves in British Columbia, 2012*.

12 Natural Resources Canada, *Shale Facts*, Retrieved from www.nrcan.gc./energy/natrual-gas/5687.

cent; however, the clay content is also high, averaging 42 per cent. The pay zone appears to be over 150m (492 ft) thick, sometimes exceeding 1km (3,280 ft) in New Brunswick.[13]

An independent analysis indicates 67 TCF of free gas in place in the Frederick Brook Shale of the Sussex/Elgin sub-basins of southern New Brunswick.[14] Another independent analysis indicates 69 TCF of gas is present on the Windsor land block in Nova Scotia.[15] Few shale wells have been drilled in New Brunswick or Nova Scotia.

Other plays

Other Canadian shale gas plays include:

- Canal Shale, Devonian, Northwest Territories
- Duvernay Shale, late Devonian, west-central Alberta
- Exshaw Shale, Devonian-Mississippian, Alberta and north-east British Columbia
- Fernie Shale, Jurassic, west-central Alberta and north-east British Columbia
- Gordondale Shale, early Jurassic, north-east British Columbia
- Klua/Evie Shale, middle Devonian, north-east British Columbia
- Nordegg/Gordondale Shale, late Jurassic, Alberta and north-east British Columbia
- Poker Chip Shale, Jurassic, west-central Alberta and north-east British Columbia
- Wilrich/Buckinghorse/Garbutt/Moosebar Shale, early Cretaceous, west-central Alberta and north-east British Columbia.

Ownership of land and mineral rights

In Western Canada, the surface and mineral rights may be owned by private individuals or entities or by the provincial or the federal Crown.

Early history

In 1670, King Charles II of England granted a charter to what is now known as the Hudson's Bay Company, giving it extensive rights to ownership, trading and government in what was then called Rupert's Land. This vast area extended from east of Winnipeg to the Rocky Mountains. In 1867, the Dominion of Canada was formed; in 1870, the Hudson's Bay Company surrendered to the Dominion this land which then became known as the Northwest Territories. In exchange for the surrendered land, the company became entitled to 1/20th of the 'fertile belt' or habitable portion of Western Canada.

The Dominion government then arranged for the new territories to be surveyed into townships of 36 sections each. Each section contained approximately 259 ha (640 acres or 1 square mile) and was subdivided into four quarter-sections of approximately 65 ha (160 acres). The Dominion Lands Act then operated to convey to and vest ownership in the surface and subsurface in 1/20th of such lands in the Hudson's Bay Company.

To encourage settlement and railroad construction, the Dominion government also gave land to settlers and railway companies. Up to 1887, mineral rights were included with surface rights in such land grants. After that, no new mineral grants were issued. In 1905, Alberta and Saskatchewan became provinces. In 1930, the power to grant both surface and mineral rights was transferred from the Dominion government to the government of Alberta.

Alberta

In Alberta, the provincial government (also known as the Crown) owns 81 per cent of the province's mineral rights or about 5.37 million ha. The remaining 19 per cent are 'freehold' mineral rights, owned either by individuals and companies (such as the successors to the Hudson's Bay Company, early settlers and railways) or by the government of Canada as national parks or military bases, or on behalf of First Nations.

Alberta now leases, but will not sell, the mineral rights it owns. Title to surface rights, however, may be acquired from the province by application to the Department of Environment and Sustainable Resource Development (ESRD).

Alberta Energy issues mineral leases for subsurface tracts owned by the province. These leases are acquired through a competitive bid auction held every two weeks, with the highest bidder winning the parcel. Prior to offering mineral rights, the province may perform a general assessment to identify major surface or environmental concerns. This may result in the attachment of an addendum to the public offering notice, which reflects a surface or environmental concern that could then affect surface access.

13 New Brunswick Department of Energy, Oil & Natural Gas in NB, Retrieved from www2.gnb.ca/content/dam/gnb.
14 See Supra note 13.
15 See Supra note 13.

A Crown lease is for an initial five-year primary term, but if the lands are proven productive, it can be continued indefinitely. A parcel may be proven productive by drilling, production, mapping or being included in a production unit. The money paid for leases goes into provincial coffers. There is no requirement for lessees to provide any work commitments.

British Columbia

The process for acquiring mineral rights in British Columbia is similar to that for Alberta. British Columbia was a British Colony that joined Canada in 1871. The mineral rights are owned privately in only about 4 per cent of the province, the other 96 per cent being held by the Provincial Crown.

Land grants from the province to settlers and others have not included mineral rights. This is because British Columbia issues mineral agreements to the oil and gas industry through public auctions, with the highest bid being granted an agreement entitling exploration and development for a term of three to ten years. The tenure may be renewed or extended indefinitely through further exploration or production. There is generally no requirement to make any work commitments to hold lands.

Nova Scotia

All petroleum located under Nova Scotia lands is by legislation deemed to be vested in the Crown. There are no freehold petroleum rights in Nova Scotia. Lands may be nominated by industry at any time. Usually, this results in a competitive Call for Exploration Proposals. The Nova Scotia Department of Energy reviews the requested parcel(s) and may modify the original parcel size and configuration in consultation with the company that made the nomination.

Public notice of the proposed grant is then given through a Call for Exploration Proposals, posting in industry media and through direct mailings.

The Call for Exploration Proposals remains open for a minimum of 60 days. Applicants submit a bid based on a work commitment, information sufficient to judge their technical and financial capability, and evidence of past experience in exploration. Petroleum rights are then granted to the applicant submitting the best work commitment, providing all other criteria have been met.

The exclusive right to explore is conveyed by an Exploration Agreement, which is a contractual agreement between the applicant and the Minister of Energy. For a conventional petroleum right, at least one well must be drilled in the initial three-year period. Two renewals of three years each are available for lands that continue to be explored. A lease may be issued by the Minister of Energy in response to the filing of an acceptable development programme. The lease is for ten years, with further renewals available upon particular terms and conditions.

However, on September 30, 2014, the Nova Scotia government introduced into the legislature a law which prohibits 'high-volume hydraulic fracturing' of on-shore shale formations until it has conducted more research and gained a better understanding of the province's shale resources.

New Brunswick

In New Brunswick, all oil and natural gas resources are also owned by the province. Sales of rights to explore petroleum, and natural gas rights, are held four times a year. The process is similar to that in Nova Scotia where a company nominates lands, which then triggers the Ministry of Natural Resources to publish a tender notice. Bidding is left open for 60 days. A licence to search may be granted to the company with the greatest work commitment, entitling the holder to explore and produce for a three-year non-renewable term. The licence may be converted at any time to a five-year lease, thus entitling the lessee to produce the resources. A lease may be extended indefinitely by production.

In New Brunswick, the government has also banned hydraulic fracturing, thereby stopping all efforts to develop New Brunswick's shale basins, which are some of the thickest in North America.

Rights, licences and approvals

The NEB regulates certain aspects of the energy industry in Canada, including the construction and operation of inter-provincial and international pipelines, the export and import of oil and natural gas, and oil and gas activities in the Northwest Territories and certain offshore basins. It is an independent federal regulatory agency that reports through the federal Minister of Natural Resources to the Parliament of Canada. Although the NEB has a role, most regulatory activity is at the provincial level through provincial departments, boards or commissions.

Alberta

In Alberta, the Alberta Energy Regulator (AER) issues permits, licences and other regulatory approvals for the development of upstream oil and gas activities. A Geophysical Exploration Approval is required for seismic activities, and a Licence of Occupation, Mineral Surface

Lease or Miscellaneous Lease is needed to access the surface of public lands. For private lands, either an agreement with the landowner or a Right of Entry Order from the Surface Rights Board is required. Operators must be registered with the AER and hold a Business Associate Code to be issued a well, facility or pipeline licence. Additional regulatory approvals are needed for injection and disposal wells, oilfield waste management facilities, flaring, pipelines, roads and other linear disturbances. The AER has also issued numerous regulatory directives covering such things as equipment requirements, measurement, record keeping, reporting, emergency response, inspections, setbacks, noise, well spacing, reservoir and pool development, stakeholder notification and consultation, and equity issues such as common carrier, common processor and rateable take matters. The AER's directives are largely mandatory.

In September 2014, the AER recognised that its regulatory framework needed to evolve to meet the challenges of developing unconventional oil and gas resources and it proposed a new risk-based and play-focused regulatory pilot project. Instead of approving development on a well-by-well or pipeline-by-pipeline basis, all the operators in a field are required to apply for one collective regulatory approval that authorises, under several pieces of legislation, all the wells, pipelines and facilities for the entire field. This unprecedented level of cooperation among numerous companies will also require them to develop joint risk management plans and undertake joint stakeholder engagement throughout the life cycle of the field's development.

The AER has also issued a directive on hydraulic fracturing, setting out new provisions to manage risks associated with hydraulic fracturing operations. The provisions include requirements for operators to undertake an assessment of the risks of inter-well-bore communication between the well they want to hydraulically fracture and offsetting wells. Operators also have to develop a risk management plan that allows for the monitoring of offset wells during such operations and provide a response plan in the event of any inter-well-bore communication. The directive protects potable groundwater supplies by prohibiting hydraulic fracturing shallower than 100m below the potable groundwater horizon or within 200m of a water well. Fracturing is also prohibited within 100m of the top of the bedrock.

British Columbia

The British Columbia Oil and Gas Commission (OGC) oversees oil and gas activities within British Columbia, from exploration and development to drilling and decommissioning. Public safety and environmental issues are also a part of the OGC's mandate. British Columbia's Oil and Gas Activities Act provides a results-based, single-window regulatory framework for regulatory approvals for the industry. Under it, the OGC may issue permits that would otherwise be issued by other government agencies and departments.

Since the hydrocarbon resources in the Horn River Basin and other British Columbia shale plays are believed to be quite substantial, the OGC is preparing for the drilling and production boom that is expected to support numerous liquefied natural gas (LNG) export projects on British Columbia's west coast. That being said, operators in these resource plays face several constraints, including low gas prices, the short drilling season due to the weather and terrain, the lack of existing infrastructure (pipelines and roadways), produced carbon dioxide and emerging water supply issues.

Access to much of north-eastern British Columbia's hydrocarbon resources is limited to the winter months (December to March). As the ground thaws in the spring, it is unable to sustain the weight of the drilling equipment. Both workers and production equipment must therefore be removed before the spring break-up commences. In turn, a short drilling season places limitations on the amount of gas that can be produced in the area. However, improvements in technology can effectively extend the drilling season in northern climates. The ability to drill multiple horizontal wells (8–20 well bores) from a single well pad can increase production during the drilling season and improve project economics for companies operating in the region.

The lack of existing infrastructure, such as pipelines or roadways, is also a limiting factor. Without sufficient pipeline capacity to move gas to markets, much of British Columbia's resources remain shut in. As the area develops, additional pipelines will be required to tie into major export trunk lines and to supply gas to the various LNG projects.

Establishment of a local entity

Several different investment vehicles are available in Canada, each with its own advantages and disadvantages. Tax, liability and other issues are usually the main drivers in selecting the best vehicle and must always be carefully considered.

Incorporation may be undertaken under the federal laws of Canada or provincially under the laws of a province. Generally, incorporation in Canada is a simple and quick process consisting of filing various incorporating forms,

paying a fee and registering with various taxation and other authorities. Capitalisation is a matter of choice, and private corporations' capital and financial information is not shared with the public. Generally, a corporation in Canada has the power of a natural person. A federally or provincially incorporated corporation must be registered in each province and territory where it carries on business.

At least 25 per cent of the federal corporation's directors must be Canadian residents. If there are three or fewer directors, at least one must be a Canadian resident. Some provinces' corporation laws also include residency requirements.

A flow-through entity, such as an unlimited liability company, is commonly used for US investors for US tax reasons.

The use of partnerships and joint ventures is common in Canada, especially in the oil and gas industry. A detailed partnership or joint venture agreement is customary. Limited partnerships are often used to permit tax deductions for the limited partners while still providing limited liability protection.

State participation

There is little State participation in Canada, and no requirement for the State to obtain an interest in a shale project. However, as most mineral resources are owned by the Crown, it can be said that the State 'participates' in shale plays through the collection of Crown royalties.

Taxes and royalties

Taxes

In Alberta, the province has created a Shale Gas New Well Royalty Rate of 5 per cent to encourage new exploration, development and production from Alberta's shale gas resources. To qualify, the well must produce shale gas, have no production prior to May 1, 2010 and be drilled into Crown lands. This reduced royalty rate is available for 36 production months. Alberta also has a Horizontal Gas New Well Royalty Rate and a Coal Bed Methane New Well Royalty Rate, each at 5 per cent, for horizontal (non-shale) and coal-bed methane wells.

Alberta Energy (AE) administers collection of a freehold mineral tax on production of petroleum and natural gas, including production from shale resources, not owned by the province. The tax ensures that private mineral owners contribute to Alberta's infrastructure and regulatory costs.

Royalties

In 2003, British Columbia introduced a series of royalty programmes to ensure that its fiscal regime was competitive with other jurisdictions and that it encouraged development of the province's natural gas resources. Since then, royalty rates have been introduced to encourage marginal and ultra-marginal natural gas wells and credits created for deep gas exploration, summer drilling and infrastructure development.

British Columbia has also created a net profit royalty programme to stimulate the development of high-risk and high-cost oil and gas resources that are not economic under other royalty programmes. Interested parties have to apply to the Ministry of Energy, Mines and Petroleum Resources to access the royalty. The programme requires an investment of at least C$50 million over five years. This includes seismic, road building and drilling, but not land acquisition. The net profit royalty programme allows a net profit royalty to be paid on approved projects, beginning with a royalty rate of 2 per cent of gross revenue while a project is in the pre-payout phase and then increasing as the project pays out and becomes profitable.

Foreign currency and investment

The federal Investment Canada Act establishes requirements for non-Canadians who wish to acquire control of an existing Canadian business or to establish a new unrelated business in Canada either to provide notice to Investment Canada or obtain Investment Canada's approval. The purpose of the Act is to encourage non-Canadians to invest in Canada so as to contribute to economic growth and employment opportunities and to provide for the review of significant investments in Canada by non-Canadians in order to ensure such benefit to Canada.

The thresholds for transactions that are subject to review are C$5 million for direct investments and C$50 million for indirect transactions. However, investors from the World Trade Organisation (WTO) member countries benefit from higher thresholds. New thresholds for review for WTO member investors become effective on January 1 of every year. The threshold for review for WTO investors is C$369 million for the year 2015.

The National Security Review of Investments Regulations (the Regulations) prescribe the various time periods within which the Minister of Energy and/or the Governor in Council must take actions to trigger a national security review, to conduct the review and, after the review, to order measures to protect national security in respect of the

reviewed investments. The Regulations also provide a list of investigative bodies with which confidential information can be shared and that may use that information for the purpose of their own investigations.

Guidelines for investments by State-owned enterprises

The minister has issued guidelines for investments by State-owned enterprises (SOEs) to inform investors of certain procedures that will be followed for the review and for monitoring provisions of the Act where the investors are SOEs. An SOE is an enterprise that is owned, controlled or influenced, directly or indirectly, by a foreign government. In their applications for review, non-Canadian investors, including SOEs, are required to identify their owners, including any direct or indirect State ownership or control. It is federal policy to ensure that the governance and commercial orientation of SOEs are considered in determining whether reviewable acquisitions of control in Canada by an SOE are of net benefit to Canada.

Investors must also demonstrate their strong commitment to transparent and commercial operations. The minister determines whether a reviewable acquisition of control by an SOE is of 'net benefit' to Canada. The burden of proof is on the foreign investor to demonstrate to the satisfaction of the minister that a proposed investment is likely to be of net benefit to Canada. The minister examines, among other things, the corporate governance and reporting structure of the non-Canadian investor, including whether the non-Canadian adheres to Canadian standards of corporate governance such as commitments to transparency and disclosure, independent members of the board of directors, an independent audit committee, equitable treatment of shareholders and adherence to free market principles.

The minister also assesses the effect of the investment on the level and nature of economic activity in Canada, including the effect on employment, production and capital levels in Canada. The examination also covers how the non-Canadian investor is owned and the extent to which it is controlled by a state or its conduct and operations are influenced by a state.

Specific undertakings related to these issues may assist to supplement a non-Canadian's plans for the Canadian business. Examples of undertakings that have been used in the past include appointment of Canadians as independent members of the board of directors, employment of Canadians in senior management positions, incorporation of the business in Canada and the listing of securities of the acquiring company or the Canadian business being acquired on a Canadian stock exchange.

Whether transactions require notification or review

The minister has also issued guidelines to assist investors in determining whether various transactions involving the acquisition of interests in oil and gas properties are subject either to notification or review under the Act. The acquisition of a working interest in a property on which only exploration activities are conducted is not treated as the acquisition of an interest in a 'business', and is not subject either to notification or review. However, the acquisition of a working interest in a property that contains recoverable reserves will usually be treated as the acquisition of an interest in a 'business', and may be subject either to notification or review, depending on the size of the interest being acquired and the asset size of the business.

With respect to oil and gas properties, the relationship among the participants in a particular field or well will ordinarily constitute a joint venture. If the interest being acquired, combined with any existing interest owned by the investor in the property, does not exceed 50 per cent, there is no acquisition of control and the transaction is not subject to the Act. However, if the minority interests being acquired represent all or substantially all of the oil and gas business of the vendor, there will be an acquisition of control of the vendor's business.

A royalty interest or a net profit royalty is not considered a voting interest or an asset used in carrying on the Canadian business. Therefore, the acquisition of a royalty or net profit interest will not ordinarily be treated as the acquisition of control of a business.

Each property or well governed by a separate operating agreement is treated as a separate business. Therefore, if the investor is acquiring a package of interests in separate properties and there is no acquisition of a majority working interest in at least one of those properties, there will be no acquisition of control of any business, notwithstanding the value of the investment.

Each set of properties subject to a unitisation or pooling agreement is treated as one Canadian business. Therefore, where an investor is acquiring working interests in one or more properties that are the subject of a unitisation or pooling agreement, they may acquire a majority interest in one or more of the properties without being subject to the Act, so long as their overall holdings will not constitute a majority of the interests in the unit or pool.

Assessing the value of an entity

Where control of an entity is acquired, its value is assessed on all its assets, as shown on the audited financial

statements of the entity for its most recent fiscal year (i.e. book value). With respect to the acquisition of a controlling interest in an oil and gas property or unit, the 'entity' is the joint venture between the participants on the property or unit. Financial statements are not ordinarily prepared in relation to the activities of the joint venture. Therefore, to determine the asset value of the joint venture, it is necessary to aggregate the value of the individual interests in the joint venture.

Environmental protection and socio-economic development

Businesses in Canada are subject to federal, provincial, territorial and municipal environmental regulation. Federal and provincial governments both have jurisdiction over environmental matters, and their environmental statutes and regulations at times overlap. Despite efforts to harmonise environmental standards throughout the country, businesses must consider the potential impact of environmental regulation undertaken by all levels of government in multiple jurisdictions. Many Canadian environmental statutes provide for substantial maximum fines and other penalties for violations.

Federal regulation

Federally, the Canadian Environmental Protection Act 1999 (CEPA) regulates the introduction, marketing, use and disposal of toxic substances in Canadian commerce. CEPA includes broad enforcement powers. Regulations under CEPA govern, among other things, the import and manufacture of substances new to Canada, and the import and export of hazardous waste. Hence, CEPA is used to regulate the chemicals used in hydraulic fracturing and the export of oilfield waste out of Canada.

The federal Fisheries Act prohibits, among other things, the deposit of a deleterious substance in any water where fish may be present. It also prohibits the harmful alteration, disruption or destruction of fish habitat. Hence, drilling and production fluids used in shale gas developments cannot be discharged into fishery waters, and roads, seismic lines and pipelines must be constructed so as to avoid harm to fish habitat. Other federal environmental legislation of importance to shale developers includes the Navigation Protection Act, the Hazardous Products Act, the Migratory Birds Convention Act, the Species at Risk Act and the Transportation of Dangerous Goods Act.

Canadian Environmental Assessment Act, 2012

Certain large-scale projects must also satisfy the requirements of the Canadian Environmental Assessment Act, 2012 (CEAA). CEAA applies to projects listed in a regulation, which for oil and gas projects includes projects proposed in wildlife and bird sanctuaries, projects with power plants of 200 MW or more, certain large projects involving sour gas and LNG projects. If CEAA applies, then proponents of such projects are prohibited from acting in a way that may cause an environmental effect in connection with their project. This applies until:

- the Canadian Environmental Assessment Agency (the Agency) decides, after undertaking an environmental screening of the designated project, that no environmental assessment (EA) is required, or
- the Agency decides, after considering an EA study, that the proponent complies with the conditions set out in a decision issued by the Minister of Environment that the project is not likely to cause significant adverse environmental effects, or
- the federal Cabinet decides that any likely adverse environmental effects are justified.

Under CEAA, certain designated projects are automatically subject to an EA, while other designated projects are subject, at least at first, to screening. Designated projects automatically subject to an EA include those regulated by the NEB and those made subject to an EA by future regulations or ministerial order. All other designated projects are subject to a screening. Under a screening, the proponent has to submit a project description to the Agency. If the Agency considers it complete, a summary of the project description is posted to the CEAA internet site, and the public has 20 days in which to provide comments. Within 45 days after the posting, the Agency must decide if an EA is required. The Agency undertakes a screening-level assessment of the designated project to guide its decision.

For designated projects for which an EA is required, the Agency must post notice of the commencement of the EA on the CEAA internet site. Within 365 days from the initial posting, a decision must be issued as to whether the designated project is likely to cause significant adverse effect on federal jurisdiction. The decision may include conditions whereby mitigation measures and follow-up programmes are set out. The conditions must be directly linked or necessarily incidental to the exercise of a federal power or performance of a federal duty that enables the designated project to be carried out. To get to the stage of issuing a decision, the Agency requires the proponent of a designated project to collect information and undertake an EA study. A draft of the study must be made available by the Agency for public comment. After taking into account any public comments, the Agency finalises the study and provides it to the minister who then issues the decision as to whether the project is

likely to cause significant adverse effect on matters of federal jurisdiction. If likely to cause such an effect, the decision is then sent to the federal Cabinet to decide if the significant adverse effects are justified.

Provincial and territorial regulation

Canada's ten provincial and three territorial governments are also very active in the area of environmental regulation. Generally speaking, these regulatory regimes employ both a standards-based system (i.e. specified emission criteria) and an objectives-based system (i.e. prevention of adverse effects).

An example is Alberta's Environmental Protection and Enhancement Act (EPEA), which provides a framework for the undertaking of project EAs, the issuance of approvals and other environmental permits, the prevention and remediation of pollution and various requirements to decommission, remediate and restore well, pipeline and facility sites.

First Nations

First Nations have special legal rights in Canada. In 1982, existing aboriginal and treaty rights were recognised and affirmed in Section 35(1) of the Constitution Act 1982. The courts continue to clarify the nature of existing aboriginal and treaty rights and, as a consequence, define the legal relationships between the federal government, the provinces and First Nations. Specifically, government decision-makers have legal obligations to consider and potentially accommodate claimed aboriginal rights and title which might be impacted by government decisions.

Moreover, decision-makers are required to consult where decisions or actions could potentially infringe upon aboriginal rights, including title or treaty rights. No infringements can be justified without consultation occurring. In short, governments are legally required to consult with First Nations and seek to address their concerns before impacting on claimed or proven aboriginal rights, including title or treaty rights.

Historically, as part of the process to make peace with the Indian tribes, the federal Crown entered into treaties whereby certain blocks of land were reserved for individual First Nations bands. The bands were also granted various rights to unoccupied Crown lands, including the right to hunt, fish and trap. Present-day oil and gas grants by the Crown to industry commonly involve or affect these lands and therefore the Crown has a legal duty to consult and accommodate the bands' rights in granting land rights and regulatory permits to the industry.

The government of Alberta's First Nations Consultation Guidelines on Land Management and Resource Development describe Alberta's policy to consult with First Nations where land management and resource development on Crown land have the potential to adversely impact on First Nations' rights and traditional uses. The duty to consult rests with the Crown. However, as manager of the consultation process, Alberta has delegated some procedural aspects of its duty to the project proponents. The guidelines require proponents to consult with First Nations in accordance with the policy.

Domestic supply and export

In Canada, both the federal government and some provincial governments have enacted gas export regulatory requirements.

The NEB regulates, among other things, the export and import of natural gas. Under the National Energy Board Act, a licence is required from the NEB to export natural gas. The NEB may issue the licence if it is satisfied that the quantity of gas to be exported does not exceed the surplus remaining in Canada after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of gas in Canada.

The NEB has historically used a market-based procedure (MBP) to review natural gas export licence applications. The MBP was founded on the premise that the marketplace will generally operate in a way such that Canadian requirements for natural gas will be met at fair market prices. The MBP had two parts. The first component was a public hearing, which included:

- a complaints procedure allowing Canadian natural gas users the opportunity to examine the application and complain to the NRB if they could not purchase gas on similar terms and conditions, including price
- an export–import assessment
- a consideration of any other public interest matters.

The second part was an ongoing monitoring of markets to identify those that were malfunctioning or where there was doubt about the ability of Canadians to meet their future energy requirements at fair market prices.

In June 2012, amendments to the Act were passed which affected the NEB's review of gas export applications. As a result of amendments, the MBP is no longer in effect. Hearings for gas export licences are no longer mandatory, and when reviewing an application for a licence, the NEB

can only consider whether the quantity to be exported is surplus to Canadian needs, taking into account trends in discovery of the resource. For natural gas export applications filed since the NEB Act was amended, the NEB has utilised a written public notice and comment process in place of an oral public hearing and the complaints procedure.

For gas to be exported out of Alberta, a gas export permit must first be obtained from the AER under the Gas Resources Preservation Act. Such permits are easily obtained. The AER uses the permit as a mechanism to collect statistical information on gas exports.

Outside of the United States, Canada is essentially the only other nation with significant shale gas production. Although some of the most promising shale gas fields are just beginning to be developed, the resource potential is large. A stable and experienced regulatory regime and a predictable financial environment is leading to continued interest in Canada's shale gas resources.

China

China's oil fields are drying up. The pressing need for the People's Republic of China (China) to develop new energy sources is a key driving force for the shale gas fever that has swept across the country in recent years. China has identified several onshore shale gas regions, including the Northwest region, Qingzang region, the upper Yangzi (Yunnan, Guizhou and Guangxi) region, the mid and lower Yangzi and Southeast regions, and the East and Northeast regions. Since 2009, when China started shale gas exploration, the reserves being invested in these areas have reached 130 billion cubic metres (BCM) and about 200 wells have been drilled to date.

Current status

China is believed to have the world's largest known shale gas reserves. It is estimated by the Ministry of Land Resources (MLR) that the reserves of shale gas in China amount to 885 trillion cubic feet (TCF) while the US Energy Information Administration puts China's reserves at 1,275 TCF, which is even larger than the combined reserves of the USA and Canada.

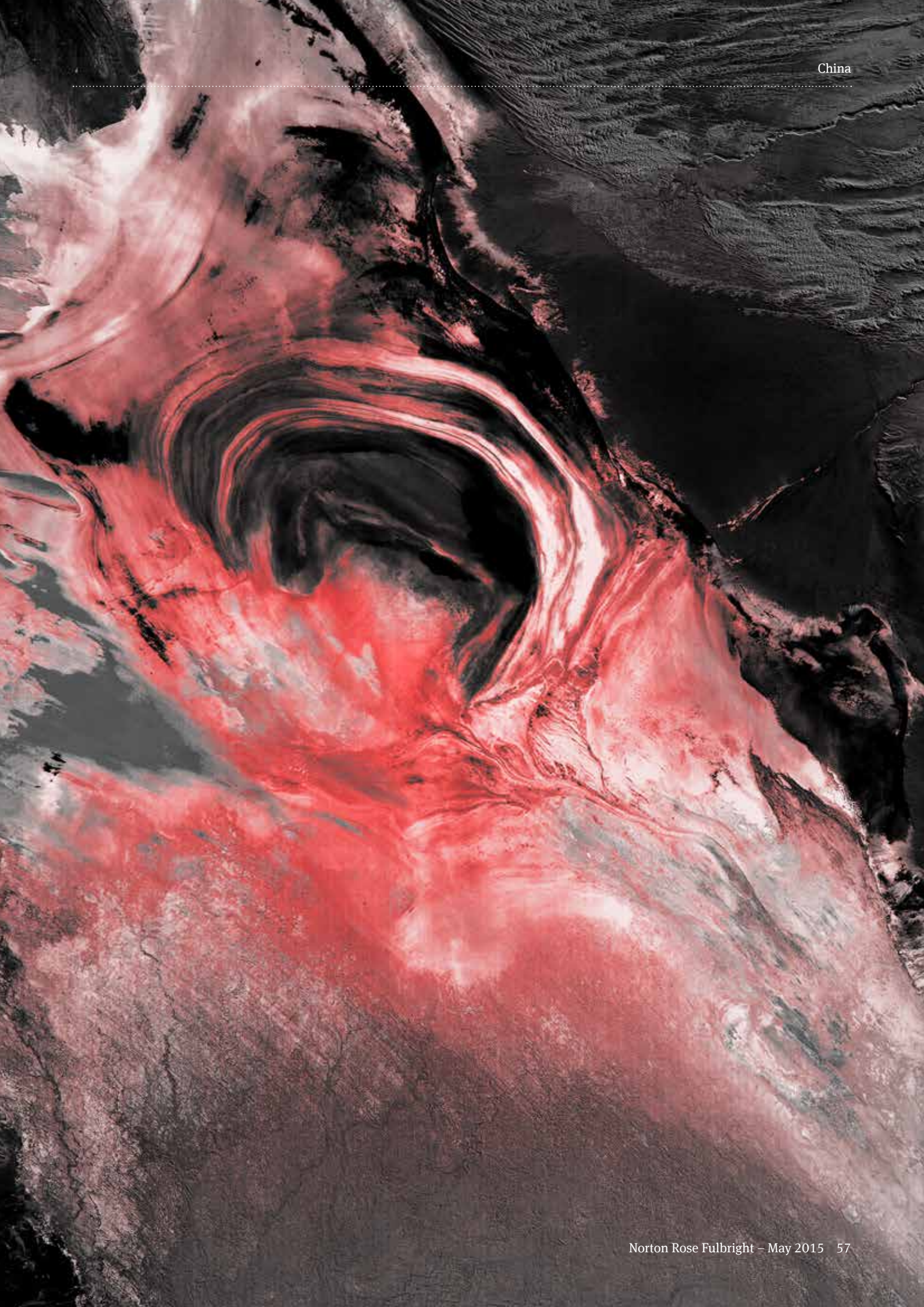
According to China's 12th Five-year Plan for Shale Gas (launched in March 2012, the Five-year Plan), China should be extracting 6.5 BCM of shale gas in order to meet at least 10 per cent of the country's energy demands with shale gas by the end of 2015. Further, in a national meeting held in September 2014 to draw up the energy sector development blueprint for the next five years, it was proposed that the yearly output for shale gas should reach 30 BCM by the end of 2020.

To achieve these targets, China has accelerated the issuance of exploration licences for shale gas reserves. By the end of July 2014, 54 exploration licences were issued, covering an area of 170,000km^2 with 400 exploration wells in total. In a recent shale gas and liquefied natural gas (LNG) industry development seminar, held in Huadian, a government official confirmed that China's shale gas production reached 1.93 BCM in 2013 and could reach 1–1.5 BCM by the end of 2014 (the actual 2014 production has not been disclosed to public). The 6.5 BCM target in the Five-year Plan will probably therefore be achieved.

Shale gas history

The study of shale gas reserves in China only commenced in 2004, and a preliminary geological survey of the known shale deposits was carried out in 2005. From 2006 to 2007, the MLR analysed shale gas prospects in China, and during 2008 it conducted a comprehensive study of the comparative geological conditions in the US and China for shale gas deposits. The shale gas prospects in the upper Yangzi region were the focus of a follow-up study, and a number of areas in the region were earmarked for trial development. In 2009, a number of blocks were listed as priority shale gas development projects, but at the time, shale gas was not listed as a type of separate mineral in China. In May 2010, China saw its first successful hydraulic fracturing exercise using US fracturing technology.

It was only in December 2011 that shale gas was designated by the MLR as a separate mineral, distinct from conventional hydrocarbons and categorised as the 172nd mineral asset. Shale gas was then listed by the People's Republic of China's National Development and Reform Commission (NDRC) as one of the priorities in the Five-year Plan. The move signals that the exploration and exploitation of shale gas is exempt from the current restrictive legal regime that is in place for conventional hydrocarbons in China. This development has opened up shale gas exploration and production beyond



the 'big three,' generally known as Sinopec, PetroChina and CNOOC, the three state-owned companies that dominate the Chinese oil and gas market.

Generally, the big three have previously been considered to lack experience in the unconventional hydrocarbon sector. However, during the 2008 crisis, their State-financed capital flow gave them the flexibility to expand globally and establish partnerships with other international oil companies, thus gaining the required technical expertise. Though their success in the shale gas fields at home has so far been moderate, there has been some progress. The Fuling shale gas field in Chongqing, Sichuan province, developed by PetroChina, has seen some exciting breakthroughs in the development of horizontal drilling and hydraulic fracturing technologies. Sinopec has announced new findings in the monitoring of microseisms and has finally worked out a comprehensive set of its own prospecting techniques for vertical and horizontal fracturing. PetroChina has reportedly made a significant breakthrough by successfully applying the horizontal drilling and hydraulic fracturing technologies to two pilot shale projects located in Sichuan and Yunnan provinces in Southwest China. CNOOC reported recently that it had obtained the basic skills required for drilling and completion and is capable of conducting the initial design of the necessary equipment. The achievements of Shaanxi Yanchang Petroleum Group are even more impressive; the group has successfully conducted trials for carbon dioxide fracturing, the very latest technique that has caught the attention of the leading shale gas players looking for a liquid-free fracturing solution.

Hydrocarbon regulation

Four major government authorities regulate China's shale gas sector: the National Energy Administration (NEA), the MLR, the NDRC and the Ministry of Finance (MOF).

The NEA is mainly responsible for high-level supervision of the energy sector. This includes developing plans and standards for unconventional gas exploration and launching industry policies and incentives to encourage the development of the unconventional gas industry. On July 31, 2013, the NEA approved the establishment of the Shale Gas Industry Standard Commission. The Commission is tasked to set technical standards and guidance for shale gas exploration and exploitation.

The MLR is responsible for the general administration of mineral issues, including organising the research and planning of potential shale gas production blocks, running tendering processes and seeing to the registration and issuing of exploration and exploitation licences.

The NDRC is involved in designing the pricing system for natural gas. For example, it sets the price for natural gas throughout the entire value chain, including production, transmission and consumption. However, according to the first Shale Gas Industry Policy (the Shale Gas Policy) introduced on October 30, 2013, the wellhead price of shale gas is no longer set by the NDRC.

The MOF is responsible for providing fiscal support to the shale gas players in the prospecting phase.

Current legal framework

The principles guiding China's shale gas policies are set out in the Five-year Plan. The current legal framework for the exploration and exploitation of shale gas is based on the Notice Regarding the Strengthening of Shale Gas Exploration, Exploitation, Supervision and Administration, October 2012 (the Notice), circulated by the MLR following the Five-year Plan. The Notice serves as a guideline both to private enterprises and local government administrative authorities engaged in shale gas activities.

In the Notice, the MLR emphasises the strategic importance of shale gas as a clean energy source and urges better regulation for the market to ensure its healthy and sound development in the long run. The MLR, but not its local branches, shall be directly responsible for the administration and registration of shale gas exploration and exploitation rights. The exploration rights shall mainly be conferred by public bidding and licensing. All parties are encouraged to participate in exploration and exploitation activities as long as they are independent legal entities with sufficient funding. They must also hold licences for exploration of oil, gas or any other kind of gas minerals, or partner with holders of those licences. Foreign enterprises with shale gas mining and exploration technology are especially encouraged to create joint ventures to invest and actively participate in the industry to promote further growth.

To curb any potential speculative hoarding by shale gas exploration licence holders, all such licence holders are required to make commitments to the MLR regarding the investment amount, exploration plan, progress and so on. The MLR is responsible for supervising licence holders to ensure compliance with the operational plans and the MLR's requirements.

Fines imposed by the MLR

Failure to meet the investment commitments will lead to fines imposed by the MLR.

It is reported that in November 2014, Sinopec was fined RMB 7.97 million by the MLR for its failure to spend about one-quarter of its RMB 591 million contracted investment

on the Nanchuan shale block. Similarly, Henan Provincial Coal Seam Gas Development and Utilization was fined RMB 6.03 million for spending only half of its commitment on the Xiushan shale block. These two cases have shown that Chinese regulatory authorities are willing to implement disciplinary procedures applicable to oil and gas exploration and exploitation activities.

Natural resources laws and regulations

As the Notice includes no specific law or legislation that supplants the existing legal regime, it must currently be read in conjunction with the existing natural resources laws and regulations.

Although there have been reports that the NEA was in the process of drafting shale gas regulations, it has not announced when they will be made available for public consultation.

The Shale Gas Policy

The Shale Gas Policy issued pursuant to the Five-year Plan has the goal of promoting more rapid and healthy growth of the shale gas industry, increasing domestic shale gas supply, reducing carbon emissions and improving the safety of the energy supply.

In addition to the favourable policies that have been in place since the first half of 2013, the Shale Gas Policy has introduced a number of new supportive measures and incentives to encourage growth in the shale gas sector. Key measures and incentives include:

- Identifying the shale gas industry as one of the strategic developing industries that will enjoy tax incentives and financial supports set out in the 12th Five-year Plan for Strategic Emerging Industry.
- Setting up pilot zones to display and apply cutting-edge technologies and equipment and advanced management systems for shale gas exploration and exploitation.
- Encouraging hydrocarbon infrastructure (especially transmission pipelines, and compressed natural gas (CNG) and LNG facilities), development and opening up of investment opportunities throughout the shale gas value chain to all types of companies.
- Implementing stricter environment protection policies that require, for example: assessment of environmental impact before a shale gas project can be initiated; and a ban on exploration and exploitation activity in nature reserves, scenic areas, drinking water conservation areas or areas with geological hazards.

The Shale Gas Policy is viewed as another attempt by the Chinese government to encourage the development of the shale gas industry. However, detailed implementation rules are needed before the industry in China can advance significantly.

Ownership of land and mineral rights

As designated by the laws in China, the State owns the land in urban areas and certain land in rural areas, while the farmers collectively own the rural land not owned by the State. Individual and legal entities are allowed to carry out mining-related operations on land in China only after they have obtained land use rights (LUR). Rights are conferred through a licensing procedure, including a feasibility study of the proposed mining project, verification and approval by relevant government authorities at local or national level and, finally, registration. If the land on which the project is to be carried out was originally farming land, it first needs to be converted to 'construction land' before going through the application for the LUR. This is not always an easy task.

Mineral resources, either near the earth's surface or deeper underground, belong exclusively to the State. The State ownership of the mineral resources is absolute, regardless of the ownership and use of the land on which they are sited and regardless of whether LUR have been granted to an entity for any purpose whatsoever.

In order to facilitate exploration and exploitation for shale gas, the MLR has proposed in its Notice Regarding the Strengthening of Shale Gas Exploration, Exploitation, Supervision and Administration to initiate a pilot scheme to grant provisional shale gas exploration and prospecting LUR by way of leasing State-owned land to the relevant entities. However, detailed guidelines for this are still being discussed and assessed by the relevant authorities.

Rights, licences and approvals

Generally speaking, both shale gas exploration and exploitation (collectively called 'mining') activities in China are subject to the MLR's regulation. Exploration and exploitation rights are licensed separately and it is a precondition to obtain such mining licences before entering into the shale gas market.

Public bidding rounds

Shale gas exploration rights are mainly obtained through public bidding to ensure a competitive environment in the shale gas sector. The MLR has successfully launched

two rounds of public bidding for such rights. The first was initiated in 2010 for four shale gas blocks, and only six State-owned enterprises were invited to participate. The second, held in September 2012, partly removed the obstacles for private and foreign investors set out in the first bidding round.

Each bidder was required to have a registered capital of more than RMB300 million and to possess oil, natural gas or other types of gas mineral exploration qualifications or to partner with an entity with such qualifications. International energy companies with developed advanced technologies and extensive experience were not allowed to participate directly in the tendering round. However, they were encouraged to form joint ventures with Chinese counterparties as the controlling shareholder, and to provide technology and services in the exploration and exploitation for shale gas. The winners of the bid could gain a three-year exploration permission in the designated block. This was timed from the issue of the exploration licence and could be further extended.

Although two rounds of bidding have been held, and various companies have entered into the industry, progress has been slower than expected. Many of the winners of the second round of bidding lack oil and gas exploration experience. In addition, the parcels offered in the second round of bidding were generally considered to be of poor quality. As a result, little profit could be generated from the exploration activities in the near term. This slow progress has caused a delay to the third round of public bidding, which was originally planned for the end of 2013 and might now be held in 2015.

Rights of licence holders

The holders of existing oil and natural gas exploration and prospecting licences in China are allowed to engage directly in exploration and prospecting for shale gas within their respective licensed oil and gas blocks. Firstly, though, they must apply to expand the exploration and prospecting scope of the licence or go through a mining right amendment procedure and submit an operational implementation plan.

Existing oil and natural gas mining licence holders' rights may also be affected by the shale gas potential of their respective mining blocks. The MLR may amend the scope of the mining right by including shale gas exploration or prospecting if the licensed oil and gas block has a clear shale gas potential. If the shale gas potential of an oil and gas block is unclear, and the licence holder of the block has neither become fully involved in the oil and gas exploration nor engaged in shale gas exploration, the licence holder will be forced to quit the block and will not be allowed to conduct any further oil and gas mining activities within the block. The MLR will instead establish a shale gas exploration right on the block for public tender, in order to develop the shale gas potential.

To facilitate prospecting for shale gas, companies that have started exploration for shale gas within licensed shale gas blocks are permitted to apply for a provisional prospecting licence or to transfer part of the existing shale gas exploration blocks to shale gas prospecting sites. Firstly, though, the required application and registration procedures must be satisfied and approvals must be obtained.

Shale gas mining licence holders are not allowed to commence shale gas activities until an agreement is filed with the MLR, signed by the licence holder and guaranteeing the safety of shale gas operations. The local MLR office will be responsible for supervising shale gas activities and making sure that the licence holder complies with its commitments and operational plans as well as with the MLR's other relevant regulations.

Establishment of a local entity

Historically, the energy sector in China has been highly controlled and regulated by the State, and mining licences have never been issued directly to any foreign incorporated companies.

Under the current regulatory framework, applicants for shale gas exploration licences must be PRC-incorporated companies, either in the form of a fully domestic enterprise, or a joint venture, with the Chinese party as its controlling shareholder. In terms of shale gas prospecting, the holders of shale gas prospecting licences intending to commence prospecting activities must establish a project company in the region where the shale gas block to be explored is located. This is intended to boost the economic development of the local area. At this stage, there are no further requirements detailing how such companies should be structured and organised.

State participation

In terms of the investment proportion, there is generally no requirement for a mandatory equity or participating interest to be held by the State in an exploration or production company involved in hydrocarbon activities. However, natural gas-related licences have, in practice, been issued only to a handful of State-owned companies. According to the Foreign Investment Industry Guidance Catalogue, effective from January 30, 2012, foreign investments in the exploration and development of shale gas and shale liquids

now fall within the encouraged category of the catalogue. This allows foreign investors to set up joint ventures with their Chinese partners and to enjoy certain administrative and tax benefits. In practice, as has been shown in the past two rounds of public tendering, the joint venture bidders have been required to have a Chinese partner holding a controlling stake within the entity.

In terms of the form of investment, foreign investors are required to participate in the onshore oil and gas market by partnering with Sinopec or PetroChina. Both parties must enter into a cooperative agreement based on a standard Production Sharing Agreement (PSA) provided by the Ministry of Commerce (MOFCOM). The final PSA should also be subject to the approval of MOFCOM. However, it is not yet clear whether it will be mandatory for foreign investors wishing to participate in the Chinese shale gas market to enter into PSAs with their Chinese partners as well. Although there is no detailed regulation in place, it seems that the PSA is a method that is favoured by the Chinese government. In April 2013, the government approved the first PSA relating to shale gas between PetroChina and Royal Dutch Shell, under which both sides agreed to explore and produce unconventional gas in southwest China's Sichuan province.

In May 2013, the State Council and the NEA issued a new policy to remove the requirement for government approval with respect to certain new energy exploration and development projects in China. MOFCOM's approval would no longer be required for PSAs entered into by Chinese and foreign companies for conventional oil and gas and coal-bed methane projects in China, if they meet certain thresholds. It remains unclear whether the new policy will apply to shale gas projects. However, based on our informal discussions with NEA and MOFCOM officials, it is likely that the shale gas regulatory regime will follow suit.

Taxes, duties, royalties and incentives

According to the Shale Gas Policy, all legitimate holders of shale gas exploration and development licences are entitled to enjoy complete or partial exemption from exploitation royalties. With respect to any imported shale gas equipment (including the associated technologies and for self-use only) that are not available or cannot be produced in China, the importer can apply for an exemption from customs duties.

The State financial subsidies introduced by the Subsidy Policies for the Development and Use of Shale Gas will remain in place. Between 2012 and 2015, the central government will offer RMB0.4/m^3 in financial subsidies to companies that have successfully developed shale gas prospects and installed properly calibrated meters so that they are able to measure accurately the amount of shale gas produced. Further, the Shale Gas Policy encourages financial support for shale gas companies from local governments, which have discretion on the level of financial subsidies they wish to offer to the shale gas development companies.

As the shale gas industry is categorised as one of the strategic emerging industries, shale gas companies are now eligible for additional tax incentives, financial subsidies and financial support introduced by the 12th Five-year Plan for Strategic Emerging Industry. According to the Tentative Measures for the Management of Special Funds for the development of Strategic Emerging Industries, a special fund is financed by a central budget to support start-up venture capitals, cooperation between industry and academics, technological development and regional development of strategic emerging industries.

The Shale Gas Policy further provides that more industry-specific tax benefits (for example, resource tax, value-added tax and income tax) shall be formulated and adopted in order to encourage shale gas exploration and exploitation. However, details of the proposed new tax incentives have not been made available to the public. Some market insiders believe that the Chinese government will borrow ideas from the existing tax incentive policies for coal-bed methane because the Five-year Plan has stipulated that financial support policies for the shale gas industry should be implemented by reference to the policies for the coal-bed methane industry.

Foreign currency and Central Bank requirements

China maintains a tight foreign exchange control system. All foreign-invested enterprises (FIEs) are required to register with the local State Administration of Foreign Exchange (SAFE) authorities in the area in which they are registered. An FIE can only borrow up to the mandatory limit, which is the balance between its total investment and registered capital. It should be noted that there are separate rules governing the total investment to registered capital ratio and the minimum registered capital requirement.

An FIE must register its foreign debts, either in foreign currency or offshore renminbi, with the relevant SAFE authorities that monitor the cross-border flow of funds. An FIE will also be required to satisfy certain conditions in order to remit its after-tax profits as dividends to its offshore shareholders. These conditions include paying up its registered capital in accordance with an approved timetable,

making up any losses incurred in previous years of operation and allocating a certain proportion of its after-tax profits to the FIE's own statutory enterprise funds. At the point of remittance, the FIE must submit the requisite documents to designated banks that can operate foreign exchange activities. The banks will review the documents. Upon being satisfied that the relevant requirements have been met, they will facilitate the payment of dividends to the offshore shareholders either by using the foreign currency that the FIE has in its accounts or allowing the FIE to purchase foreign currency with its RMB income.

Under the enterprise income tax law, repatriation of profits by foreign investors is subject to withholding tax at a rate of 10 per cent in China, unless a preferential tax rate is available under a reciprocal tax treaty.

Environmental protection and socio-economic development

The development of the shale gas industry in China has partly been stalled by environmental concerns.

Although using shale gas could help reduce greenhouse emissions, hydraulic fracturing uses a large amount of chemically treated water that is injected through seams of rock at high pressure to force the gas inside to seep out so it can be collected. If the process is not managed properly, it can cause serious contamination to waterways, which would be disastrous for drought-plagued China. The fracturing process also produces noise, traffic and surface disruptions and may create problems for farmers or other residents living near the site. According to experts, shale gas in China contains high levels of non-hydrocarbon gases, particularly hydrogen sulphide. This is a toxic and corrosive pollutant, which could lead to air pollution and corrode drilling equipment unless strict emission standards and advanced drilling and gas purifying technologies are implemented.

Under current resources legislation, applicants for natural gas exploration and prospecting licences are required to submit an environmental assessment report to the MLR for approval. This must be prepared by a qualified third-party environment assessment institution. However, since there has not yet been any national standard for dealing with environmental issues, it may not be possible to carry out effective and accurate environmental assessments. It is reported that the Ministry of Environmental Protection might commence a study for the drafting of a Shale Gas Environmental Assessment Standard. The work is expected to continue for at least three years.

Domestic supply and exportation of hydrocarbons

China is still a net importer of hydrocarbons. Its rapid economic growth and the strong demand for clean energy are making it increasingly thirsty for natural gas.

In order to meet the demand for hydrocarbons, the NDRC, MLR and NEA jointly issued a development plan for China's shale gas. This Five-year Plan for Shale Gas lays out an overall target and four milestones to be achieved between 2011 and 2015 including:

- completion of a nationwide shale gas survey and appraisal
- production output to reach 6.5 BCM per year
- development of suitable methods, technologies and equipment for China's shale gas survey, appraisal, exploration and production
- establishment of technical standards, rules and policies regulating activities in relation to China's shale gas development, such as reserve survey, appraisal and certification, test and analysis, exploration and production, and environmental measurements.

The Five-year Plan was intended to establish a foundation for China's shale gas development from 2016 to 2020. Building on the results of the Five-year Plan, the government was expecting to increase and encourage greater investments in shale gas reserves to achieve a total shale gas output of 60–100 BCM by 2020. However, this expectation has since been adjusted downwards to around 30 BCM by 2020 because of the technical and geographical difficulties facing the industry.

Although the expected output of shale gas has been adjusted downwards, the Chinese government still appears to be confident in the long-term development of the shale gas industry. In April 2014, the NDRC issued an official guideline regarding guaranteeing the long-term supply of natural gas. This indicated that China would enhance its policy support for the supply of natural gas, especially shale gas. According to the guideline, the total natural gas supply capacity is expected to reach 400–420 BCM by 2020, and third-party access to natural gas pipelines and LNG receiving and storage facilities will be further promoted by policy reform.

Enforcement regime in judicial and arbitral alternatives

The Contract Law of China provides that 'parties to a foreign related contract may choose the applicable law for the resolution of their disputes, unless the law provides otherwise'.

If a foreign company wishes to enter into a joint venture with a Chinese company related to assets situated outside Chinese territory, the Chinese party would face no particular restriction under Chinese law. It would be free to choose English, New York or any other applicable law to govern these arrangements between the parties. However, there are restrictions as to choice of law in relation to investments in China. The most important of these is that certain types of contract must be governed by PRC law. These include Chinese/foreign joint-venture contracts to be performed in China and Chinese/foreign contracts for the joint exploration and development of natural resources in China. On this basis, it is very likely that the main contractual arrangements a foreign investor may enter into to invest in upstream projects in China (including the PSA) will have to be governed by PRC law. In practice, even if this were not the legal position, the bargaining power of the Chinese parties may well be such that they would insist on it in any case.

Arbitration proceedings and judgments

There is a large degree of scepticism on the part of foreign investors about the ability of the Chinese courts to resolve disputes effectively and about their impartiality when hearing disputes between foreign companies and Chinese companies, especially State-owned ones. The standards differ significantly for the different courts in China. Although the predictability and consistency of court judgments seem to be improving, foreign investors generally prefer to provide for disputes to be resolved by arbitration. Additionally, depending on the Chinese entity and court involved, it is sometimes difficult to enforce a Chinese court judgment. Similarly, while it is theoretically possible to enforce foreign judgments in China (which has reciprocal enforcement of judgment conventions with certain jurisdictions), in practice it is very difficult to persuade a Chinese court to enforce a foreign court judgment against a Chinese party.

Arbitration proceedings in China are governed by the Chinese Arbitration Law 1994, provisions of the Civil Procedure Law 1991 and numerous interpretations, minutes, regulations, replies and notices. The Arbitration Law 1994 is not based on the United Nations Commission on International Trade Law (UNCITRAL) Model Law although it is comparable in its scope. Foreign-related arbitration awards and domestic awards are subject to different rules of enforcement. The court will examine even the substantive issues in dispute when reviewing a domestic award. Where the China International Economic and Trade Arbitration Commission (CIETAC) arbitration rules are adopted, the tribunal may be expected to arrive at its conclusion by reference not only to the governing law of the dispute but also to international practice and concepts of fairness and reasonableness.

Foreign arbitration institutions

The position of foreign arbitration institutions in China is anomalous. For example, the International Chamber of Commerce (ICC) is not an 'arbitration commission' for the purposes of the Arbitration Law 1994. There is therefore some doubt about the enforceability of awards published in ICC arbitrations conducted in China. In addition, there are presently disagreements between the CIETAC commission in Beijing and the sub-commissions in Shanghai and Shenzhen, resulting in CIETAC Beijing opening new offices in Shanghai and Shenzhen. Accordingly, there are now rival CIETAC bodies operating in the same cities. These developments have led to uncertainty, including questions about the enforceability of awards either from the new offices or from the original sub-commissions.

An offshore arbitration is generally the best option for foreign investors if PRC law does not govern the relevant agreement. It is similarly preferred if PRC law governs the agreement, but the dispute has an international element – for example, if one party to the dispute is a foreign entity. China is a signatory to the New York Convention, although it has exercised the reciprocity and commerciality reservations. It has also extended the application of the New York Convention to Hong Kong and Macau. However, Chinese courts may hold offshore arbitration invalid if the dispute is not sufficiently 'foreign-related'.

Problems and appeals

There is no appeal mechanism against a refusal by the Intermediate People's Court's decision not to enforce an award. However, there exists an internal court system for reviewing decisions relating to the refusal to enforce a foreign award, which goes all the way up to the Supreme People's Court. There appears to be no formal right of representation during the stages of the internal review process, but there is no objection to lodging directly with the Supreme People's Court a full set of the documents submitted at the Intermediate People's Court. Furthermore, the Supreme People's Court is open to informal discussion. However, this internal review is thought to be limited to awards issued in foreign institutional arbitrations and not ad hoc arbitrations.

The time limit for starting enforcement proceedings in China is very short, being only six months for companies and 12 months for individuals from the date of the award.

Regulation on the operation of hydrocarbon infrastructure

Over 80 per cent of China's oil and gas pipelines are owned and operated by PetroChina, and third-party gas producers have no ready and low-cost access to these pipelines. This is one of the key areas that the Shale Gas Policy is tasked to address.

On February 13, 2014, the NEA published the Measures for Regulation of Fair and Open Access to Oil and Gas Pipeline Networks (the NEA Measures). These will be effective for a trial period of five years. The NEA Measures aim to grant third-party producers access to oil and gas pipelines when there is 'excess capacity'. However, the conditions for access are still subject to the operator's discretion and the NEA Measures have not made it clear how excess capacity is to be defined.

On February 28, 2014, the NDRC also published the Management Measures for Natural Gas Infrastructure Construction and Operation (the NDRC Measures). These encourage State-owned companies, private companies and foreign companies to invest in the natural gas infrastructure sector and to liberalise the market further by promoting fair competition.

The NEA Measures and the NDRC Measures echo the requirements under the Shale Gas Policy, which push for the liberalisation of the shale gas market and have received a positive response from the market. In May 2014, Sinopec announced plans to promote private investment in shale gas transportation. In August 2014, the China National Petroleum Corporation (CNPC) was reported to have set the basic principles for opening up its pipeline infrastructure to the market, with pipeline capacity contracted on a 'first come, first served' basis. However, some commentators remain sceptical about the near-term effects of these measures and call for more detailed guidelines on how the measures should be implemented in practice.

Opportunities

The progress of shale gas production in China has been slow despite China having potentially one of the world's largest shale gas reserves, increasing support from the central government and continuously improving drilling techniques and equipment. The main reason for such disappointing progress is that most of the exploitable shale gas blocks in China are located in the geographically complex remote mountainous regions in the north-west, where water shortage is a barrier to commercial production of the shale gas, and in the south-west, where the high population density compounds the difficulties for commercial production of shale gas.

Helping shale gas developers overcome these difficulties requires further reform in the industry, clear guidelines for effective implementation of tax incentives, and effective financial support measures. These are in addition to continuous development of suitable drilling techniques and equipment. Only then will the shale gas development goal set out in the Five-year Plan be achievable.

Role of central Chinese government

The Chinese central government has shown its willingness to:

- increase support for the innovation and improvement of shale gas technology
- classify shale gas technology research and development as a significant national project
- promote the shale gas exploration project
- encourage the establishment of a shale gas research and development centre
- encourage international cooperation and exchanges.

The central government will also be working on improving shale gas infrastructure, with solutions that depend on the location of the reserves. For reserves close to the existing natural gas pipeline network, the government will encourage transportation pipeline construction at the shale gas production fields and the connection of these pipelines to the existing natural gas pipeline network. For reserves far from existing natural gas pipeline networks, or new wells (production output of which is ramping up), the government will encourage the construction of small-scale LNG or CNG facilities to capture the gas produced to avoid flaring the gas. The construction of transmission pipelines will take into account the production phase of the relevant shale gas wells.

Many city gas companies are looking at setting up LNG logistic hubs, building and owning LNG refill stations or providing LNG bunkering services to commercial shipping and fishing boats at Chinese ports. To capitalise on these trends, LNG equipment manufacturers will need to invest further in improving product quality and innovation.

Role of provincial governments

In addition to the efforts made by central government, the shale gas industry may see more vigorous promotion from the provincial governments of the shale-rich provinces. They will be the driving force behind favourable local policies to help the shale gas developers accelerate their development progress in the shale prospects. For them, success in shale gas development will push up the local GDP growth and help to meet local energy demands. So far, Sichuan, Chongqing and Guizhou have released their own shale gas development plans. Hunan has released its local technical standards for shale gas drilling.

Some provincial governments are seeking delegated powers to allow them to issue exploration licences at a provincial level to shale gas companies for exploration activities in their own regions. For example, it was reported that Hunan has applied to the MLR for permission to issue exploration licences for five shale gas blocks in Changde, Shimen, Lianyuan, Zhangjiajie and Cili. Although the MLR has not officially confirmed the report or the speculation about the new licensing policy, the application from Hunan provincial government has demonstrated a need for further derogation in the current shale gas regulatory regime.

Colombia

In 2008, the Colombian government made the decision to pursue the development of unconventional hydrocarbons and, in 2011, it ordered production of technical regulations, formulation of incentives for exploration and production, and creation of rules for the award of areas for exploration and production.

Shale play details and status of play

The publication, Hart Energy, included the unconventional reservoir, La Luna Shale, in the top 20 unconventional plays in the world[1].

Colombia has three basins with representative prospectivity: Middle Magdalena Valley, Cordillera, and Cesar Rancheria. The potential is estimated at about 32 TCF of recoverable volumes (Arthur D. Little Analysis).

Comparisons have already been drawn between the La Luna field in the Middle Magdalena basin and the US's giant Eagle Ford shale. Further shale oil and gas deposits lie in the Cesar basin to the north, Catatumbo, near the Venezuelan border, and the Boyacá province to the north of Bogota.

IHS estimates Colombia's shale could hold over 3,000 Tcf of gas, and the country's oil industry association pegs its unconventional resources at 92 billion boe on a P50 proven and probable basis. On 2012, consultancy Arthur D Little ignited interest in the Andean country after putting recoverable shale and tight gas reserves at 35 Tcf and shale oil potential as high as 14 billion boe.

Finally, the ANH, according to numerous studies and publications has claimed that Colombia is the third country in South America with the greatest potential for shale gas and shale oil deposits after Argentina and Brazil.

1 http://www.epmag.com/argentina-and-colombia-are-hot-shale-trail-680786#p=3

Ownership of land and mineral rights

Under the Colombian Constitution, all natural hydrocarbons reservoirs in existence within the Colombian territory, whatever their nature, belong exclusively to the Republic. Therefore, the ownership of the land is different from the ownership of the subsoil and the natural resources located therein.

Holders of exploration and production (E&P) rights may use the land required for exploration and exploitation activities, even if it is privately owned by third parties. If no agreement can be reached with the land owner, Colombian law provides for mandatory servitudes and easements, and even the possibility of expropriation.

Additionally in the Llanos Basin is the Gacheta formation close to the border with Venezuela with 2 TCF of technically recoverable gas reserves.

Hydrocarbons regulation

In 2008, the Colombian government made the decision to pursue the development of unconventional hydrocarbons with policy document No. 3517, issued by the Council for Economic and Social Policy (CONPES). In 2011, the government ordered:

- The Ministry of Mines and Energy (MME) to issue technical regulations for unconventional hydrocarbons

32 TCF Colombia Basin

The total potential shale basins in Colombia are 32 TCF according to the National Hydrocarbons Agency in 2012.

29 TCF

The largest basin is the Middle Magdalena Valley Basin with 29 TCF of technically recoverable reserves of natural gas and 289.5 TCF of gas in place.

18 TCF

Specifically, within the Middle Magdalena Valley the La Luna/Tablazo formation is one of the most important with 18 TCF of technically recoverable reserves of natural gas.

2 TCF

Additionally in the Llanos Basin is the Gacheta formation close to the border with Venezuela with 2 TCF of technically recoverable gas reserves.

- The National Hydrocarbons Agency (ANH) to create rules for the award of areas for the exploration and production of unconventional hydrocarbons

- The MME, the ANH and the Gas Regulatory Entity (CREG) to jointly develop and create incentives for the exploration and production of unconventional hydrocarbons.

Accordingly, MME issued Resolution 180742 of 2012, establishing the procedures for the exploration and exploitation of hydrocarbons in unconventional deposits. Its objective is to ensure that the conduct of these activities guarantees the sustainable development of natural resources in compliance with good industry practices.

Resolution 180742 defines a conventional deposit as a rock formation where hydrocarbon accumulations occur in stratigraphic and/or structural traps. It is characterised by a unique natural pressure system, so that the production of hydrocarbons from part of the field affects the pressure of the reservoir's whole extension. The resolution defines an unconventional deposit as a rock formation with low primary permeability to which stimulation has to be performed to improve the mobility conditions and hydrocarbons recovery.

ANH issued Accord 004 of 2012, which establishes the main terms and conditions required to award hydrocarbons exploration and production areas, and Accord 003 of March 26, 2014, which builds upon Accord 004 of 2012 to include the terms and conditions required to award exploration and production contracts over unconventional resources. These regulations apply both to existing blocks with potential for unconventional resources and to new blocks that have yet to be awarded. For those blocks awarded prior to 2012, contractors are required to request the ANH to enter into an additional contract for exploiting and exploring unconventional resources. Companies already holding areas with potential for shale gas resources (as mentioned above) will have three years to convert their existing concession to the new regime for the exploration and production of unconventional resources.

Conventional v unconventional hydrocarbons

Table 1 illustrates the main differences between conventional and unconventional hydrocarbons regulation.

	Conventional hydrocarbons	Unconventional hydrocarbons
Exploratory period	Six years from the date Phase 0 ends.	Nine years from the date Phase 0 ends.
Production period	24 years as of the commercial discovery notice.	30 years as of the commercial discovery notice.
Regulation	Resolution 181495 of 2009	Resolution 180742 of 2012 Resolution 90341 of 2014
Relinquishment	According to the current 2014 regulation, mandatory relinquishment of areas is enforced on the contractor, depending on the type of area, as follows: • Type 1 (Conventional) Onshore: if the area is greater than 45,000 hectares, the contractor must return to the ANH 50 per cent of the area or the amount of hectares in excess of 45,000 once the first exploratory phase of the exploration period is finished. • Type 1 (Conventional) Offshore: if the area is greater than 45,000 hectares, the contractor must return to the ANH 50 per cent of the area or the amount of hectares in excess of 45,000 once the second exploratory phase of the exploration period is finished. • Type 2 (Unconventional): no relinquishment of area during the exploratory period.	For unconventional oil fields, there is no mandatory relinquishment of areas until the end of the exploration period.
Royalties	In accordance with Law 756 of 2002, there is a sliding scale for royalty rates (calculated as a proportion of the daily gross production, based on the monthly average production per field), as illustrated below: **Production in barrels per day (bpd)** — **Royalty rate** up to 5,000 BPD — 8 per cent flat rate 5,000 to 125,000 BPD — 8 to 20 per cent sliding scale 125,000 to 400,000 BPD — 20 per cent flat rate 400,000 to 600,000 BPD — 20 to 25 per cent sliding scale Greater than 600,000 BPD — 25 per cent flat rate For onshore gas fields and offshore gas fields at depths up to 1,000 ft, the applicable royalties are equal to 80 per cent of the royalties applied to onshore light oil fields. For offshore gas fields at depths greater than 1,000ft the applicable royalties are equal to 60 per cent of the royalties applied to onshore light oil fields.	Law 1530 of 2012 under Article 14, first subparagraph, sets forth that a royalty of 60 per cent of the participating percentage of the royalties equivalent to the exploitation of conventional light oil fields shall be applied to unconventional resources.

Table 1: Regulation – differences between conventional and unconventional hydrocarbons regulation

Government structure

Ministry of Mines and Energy

MME is responsible for the overall regulation of the energy sector, including any policies relating to hydrocarbon exploration and production activities. It is responsible for overseeing upstream activities, such as drilling of exploration wells and payment of the corresponding royalties to the nation.

National Hydrocarbons Agency

ANH is responsible for managing hydrocarbons and defining the contracting policies and regulations for their exploration and exploitation. ANH is in charge of administering oil and gas reserves in Colombia.

State oil company

The Empresa Colombiana de Petróleos (Ecopetrol) was created in 1951 as a wholly State-owned public entity whose main corporate purpose was to carry out all the activities related to the oil and gas industry in Colombia.

The transformation of Ecopetrol in 2003 released it from State functions as the sole administrator of the oil source and, in 2004, ANH was created to perform this role and manage the hydrocarbon reserves in Colombia.

CREG

The Colombian Commission for the Regulation of Energy and Gas (CREG) is responsible for regulating the electricity and gas public services as provided by law 142 and 143 of 1994. Regulatory commissions have the task of regulating monopolies in the provision of utilities, when competition is not actually possible and, in other cases, to promote competition between utilities providers, in order for the operations of the monopolists or competitors be economically efficient.

Regulatory framework

Decree 1760 of 2003 created ANH as a special administrative unit assuming the administration of the hydrocarbons resources. ANH grants E&P rights to private entities by means of E&P contracts and technical evaluation agreements (TEA).

Through a TEA, contractors may conduct exploration activities within the granted area and obtain exclusivity and conversion rights. By means of these rights, no third party may be granted an E&P contract overlapping with the TEA areas during the term of the contract and two additional months, or until the contractor selects an area for conversion to an E&P contract, whichever occurs first. E&P contracts grant to the contractor the exclusive right to explore for and produce conventional and unconventional hydrocarbons within a limited area.

Contractual regime

For E&P rights granted from 2004 to 2014, there are two main regulatory sub-regimes. Table 2 presents their main features.

Acuerdo 008 of 2004	Acuerdo 004 of 2012	Acuerdo 003 of 2014
This Acuerdo established certain minimum operational, financial, technical and legal requirements to be complied with by the companies in order to prove their capacity to enter into the agreement and comply with its obligations. It established the following methods for granting areas: • Direct award: 'first come, first served' basis • Competitive bids: open bidding processes through which certain groups of areas were granted to bidders offering the best terms to the ANH. Offer request: bidding processes for special areas that the Board of the ANH had reserved owing to their special conditions and characteristics and which are aimed towards specific companies, based on their conditions and expertise.	This Acuerdo replaced Acuerdo 008 and eliminates the possibility of awarding areas on a first come, first served basis. It establishes the following methods for granting areas: • Competitive bids (open and closed), ruled by the terms of reference drafted based on the investigations that reflect the implementation of exploration and exploitation projects, the areas to be assigned, and the verifications in social and environmental matters to be carried out. • Direct award: only exceptionally and with the corresponding justification. It includes new restrictions to assignments by the contractor under the E&P contract and regulates the change of control of the contractor. The operator must always hold a 30 per cent participating interest in the contract. It establishes evaluation criteria for purposes of the bid offers, including additional exploratory programmes, additional participating interest for the ANH and other economic benefits. It eliminates the 'restricted operator' capacity established under Acuerdo 008, which allowed operators without operational capacity to obtain from the ANH one to three blocks under special circumstances.	This Acuerdo adds to Acuerdo 004 of 2012 the parameters and applicable rules for the development of unconventional fields. It establishes that the exploration period will be extended to nine years for unconventional fields, and the production period to 30 years. For blocks awarded prior to 2012, contractors are required to request the ANH to enter into an additional contract for exploiting and exploring unconventional resources.

Table 2: Main features of the contractual sub-regimes

Under the rules established in Acuerdo 004 of 2012, areas for exploration and exploitation of hydrocarbons will be awarded through bidding processes and, exceptionally, through direct award processes.

The terms of reference prepared by the ANH will have to follow certain parameters defined in the Acuerdo 004 of 2012, as follows.

Legal capacity

- Only legal entities may present a bid for an area. They can be national or foreign entities.
- Bids may be presented individually by an entity or collectively by means of a consortium, temporary union or promise to incorporate a company.
- In order to be qualified as operator, the bidder must prove that its corporate purpose expressly includes exploration and production activities of hydrocarbons.
- The operator must have been incorporated at least five years prior to presenting the bid. Non-operator bidders must have been incorporated at least one year prior to presenting the bid.

- The company must have a duration term equivalent to the term of the E&P contract plus three additional years.

- Bidders cannot: (i) have any incompatibilities, inabilities or conflict of interest; (ii) be in status of liquidation or have any pending litigation; (iii) permit any of its activities to be related to or made in connection with illegal activities, or made to finance illegal activities or to enable money laundering; and (iv) be a party to a contract with the State whereby unilateral termination due to breach of its obligations has been declared within the past five years.

- In case the bidder is a foreign entity, it has to commit itself to: (i) create a company or a branch in Colombia; and (ii) appoint a legal representative in the country upon award of the area by the ANH.

- The legal representative of the company shall have full authority to present the bid and comply with its obligations on behalf of the company.

- The operator must maintain at least a 30 per cent participation in the contract.

Financial capacity

To determine the financial capacity, the bidder must provide:

- financial statements for the periods requested by the ANH in the terms of reference

- projected cash flow for the following years as required by the ANH in the terms of reference.

The terms of reference will establish the minimum requirements for the patrimony and the mechanism and criteria to be used for the evaluation of the financial capacity.

The ANH may request the granting of additional security by the bidder, such as letters of credit and escrow accounts.

Some companies are not subject to the financial evaluation process. They are:

- Companies listed as an upstream company in the latest edition of The Energy Intelligence Top 100: Ranking the World's Top Oil Companies, issued by *Petroleum Intelligence Weekly*.

- Companies that show they have been ranked with a 'BBB' by Standard & Poor's, 'Baa' by Moody's or 'BBB' by Fitch Ratings.

Operational capacity

The bidder must demonstrate that it has the operational experience required in the terms of reference to undertake the activities under the E&P contract in terms of production levels and reserves volume. ANH may also request previous experience in terms of the number of wells drilled, E&P contracts previously executed or in place, and quality certificates to prove technical and operational capacity.

Companies listed as an upstream company in the latest edition of The Energy Intelligence Top 100: Ranking the World's Top Oil Companies, issued by Petroleum Intelligence Weekly, are not subject to the operational evaluation process.

Environmental capacity

The bidder must prove that it has implemented and executed a system for the environmental management, measure and follow-up of the operations and activities causing an impact on the environment and natural resources.

ANH may require the contractor to obtain the certificate ISO14001, or any other equivalent certificate, within the three years following the execution of the E&P contract.

Social responsibility

The bidder must prove that it has implemented and executed rules, practices and goals in terms of corporate social responsibility.

Rights, licenses and approvals

TEA

The scope of the TEA is limited to exploration activities to evaluate the potentiality of an area and to identify specific areas in order to enter into an E&P contract.

Within the first 90 days following the execution of the contract, the contractor must confirm the presence of indigenous or Afro-Colombian communities in the area. It must request a certification from the Colombian Institute of Rural Development and the Ministry of Justice. The contractor must inform the ANH during Phase 0 if minority communities are present or not. Once Phase 0 has elapsed, the TEA has a 36-month term.

E&P contract

Scope

The E&P contract gives the contractor the right to perform exploratory activities in an assigned area and to produce the hydrocarbons owned by the State that are discovered in said area, based on specific programs. This is in exchange

for the payment of government take, consisting of royalties, economic rights and contributions for the training, institutional strengthening and technology transfer.

Term
Exploration period – for conventional fields, upon completion of Phase 0, the exploration period begins and has a duration of six years, divided in phases, each with a minimum work programme. For unconventional fields, the exploration term is nine years from the date of award.

Production period – for conventional fields, the duration of the production period is 24 years as of the commercial discovery notice for conventional hydrocarbons and 30 years for unconventional hydrocarbons.

Exploitation term – for unconventional fields, the exploitation term runs for a maximum of 30 years from the declaration of commerciality.

Exclusivity
Contractors under the current E&P contracts are entitled to exclusivity in the area of the contract. However, under TEAs, ANH has the power to conduct or authorise the conducting of any type of geophysical, geochemical, geological, cartographic or photo-geological studies and works within the area assigned for technical evaluation.

Subcontractors
The contractor may enter into subcontracts for petroleum services in order to develop activities. However, in no case may the holder subcontract the operation of activities under the E&P contract without obtaining the prior approval of the ANH.

Assignment and change in control requirements
Assignment authorisation – the contractor may assign or transfer, in whole or in part, its interests, rights and obligations thereunder, only with the prior written authorisation of the ANH.

Change in control authorisation – any transaction that implies a change of the beneficiary or the controlling party of the contractor or of any of the members of the contractor, will be understood as a form of assignment and will require prior ANH authorisation.

Corporate reorganisation – any merger or spin-off of the contractor will require prior authorisation from the ANH.

Guarantees
Parent company guarantee – when a controlling company accredits any capacity during any bidding process of any of its subsidiaries, through which it assumes joint and several liability for the commitments and obligations undertaken by its subsidiary, a joint and several debtor guarantee is required. The other applicable guarantees are:

- 'Stand-by' letter of credit for 50 per cent of the total cost set for the minimum exploration program and 50 per cent of the additional exploration program
- Third-party liability insurance, for which the validity will be equal to the term of duration of the contract, from the effective date and three additional years. The amount of the insurance shall be: US$10 million for conventional onshore fields; US$50 million for offshore fields; and US$30 million for unconventional fields
- Insurance policy for labour obligations – the amount of the insurance will be:
  - For the exploration period: 5 per cent of the annual investment for each phase or 10 per cent of the total annual costs of the personnel designated to work in the exploration area for each calendar year.
  - For the evaluation and production period: 10 per cent of the total annual costs of the personnel designated to work in the production areas for each calendar year.

Fines
If during the performance of an E&P contract there is any default of an obligation by the contractor, the ANH may impose fines.

Fines will be 1 per cent of the value of the activity that was not performed, per day of breach, up to 10 per cent of the value of the activity, regarding obligations having a determined value. Regarding obligations with an indefinite value, fines will be imposed for up to US$100,000.

Indemnity
The contractor shall indemnify, defend and hold the nation, the ANH and its employees and properties, or any third parties, harmless from any claim or action arising from actions or omissions in the development or performance of the agreement.

Termination
E&P contracts will terminate in any of the following situations: the contractor's resignation; the expiration of the exploration period without filing a notice of discovery; failure to submit an evaluation programme upon expiration of the exploration period; expiration of the production period; and by mutual consent of the parties.

Also, the contractor may unilaterally terminate the agreement as long as it has complied with the corresponding obligations in the contract and gives written notice to the ANH one year in advance.

Establishment of the local entity

Under Colombian corporate law, a corporate vehicle must be incorporated in order to operate any kind of trade or business in the country. Said vehicle may be either a local branch of a foreign company or a local Colombian company. The most common and suggested vehicles used by foreign oil and gas companies are simplified stock companies and branches of foreign companies.

For foreign company branches, the foreign investor must file certain documents before the Chamber of Commerce related to the creation of the foreign company. The assigned capital for the branch must be registered as foreign investment before the Central Bank.

These branches may not acquire foreign currency in the exchange market by any means, and must fund their local expenses in Colombian currency. They may rely on the exchange market to transfer abroad the foreign currency received from: internal sales derived from the exploitation/sale of products or the rendering of their services; profits; and the foreign investment in case of the liquidation of the branch.

Branches of foreign companies that are part of the oil and gas industry must be registered at the MME.

Simplified stock companies require at least one shareholder. The corporate purpose can be any legal business activity without having to refer to a specific business activity. There is no minimum capital, and simplified stock companies are not required to have a Board of Directors.

State participation

Subsoil fees

During the exploration period, the subsoil rights are as shown in Table 3.

Area Size	For the first 100,000 Hectares		For each additional hectare	
Duration of the phase	<18 months	> 18 months	< 18 months	> 18 months
Onshore	US$2.68	US$3.57	US$3.57	US$5.34
Offshore	US$0.90			

Table 3: Subsoil fees

For areas assigned for evaluation or for production, the contractor must pay to the ANH a fee in US dollars, which is the result of multiplying the hydrocarbons production by 13 cents of a dollar, plus US$0.1356, per barrel of liquid hydrocarbons. For natural gas, this amount is US$0.01356 per 1,000 cubic feet.

The values set in table 3 above must be updated each year according to the variation percentage of the Producer Price Index (PPI) published by the Department of Labor of the United States of America.

Royalties

Royalties are calculated as a proportion (between 8 per cent and 25 per cent) of the daily gross production based on the monthly average production per field, as illustrated in Table 1.

A royalty of 60 per cent of the participating percentage of the royalties applicable to the exploitation of conventional light oil fields will be applied to unconventional resources.

Royalties paid are considered as a deductible expense in the income tax.

Technology transfer

This contribution is paid to the ANH for the professional and specialised formation related to the oil and gas sector. The amount of the contribution will not exceed US$127,112.

High prices fee

The contractor pays to the ANH a fee for 'high prices' (which is similar to windfall profits tax) on the production it owns, either in kind or in cash, at the ANH's election, in the following cases:

- Liquid hydrocarbons (except for extra-heavy hydrocarbons) – as of the moment at which the accumulated production of the assigned area, including the volume pertaining to royalties and tests, exceeds 5 million barrels, and the price of the marker crude 'West Texas Intermediate' (WTI) exceeds the base price Po

- Natural gas – after the lapsing of five years from the start-up of production of natural gas and when the average sales price thereof exceeds the base price Po.

The value of the fees for high prices will be determined using the following formula: Q = [(P – Po)/P] x S

Where:

Q = Economic right (fee) to be delivered to the ANH

P = Marker price (WTI for crude oil or average sales price of natural gas)

Po = Base referential price according to Table 4

S = Participation percentage according to Table 5

API gravity of liquid hydrocarbons produced	Po (US$/Bl) (year 2014)
Higher than 29° API	35.22
Higher than 22° API and lower than or equal to 29° API	36.59
Higher than 15° API and lower than or equal to 22° API	37.95
Discoveries located at more than 300m water depth	43.37
Higher than 10° API and lower than or equal to 15° API	54.20
Liquid hydrocarbons associated to unconventional oil fields	81
Exported natural gas: distance on a straight line between point of delivery and point of reception in point of destination	Po (US$/MMBTU)
Less than or equal to 500km	8.15
More than 500 and less than or equal to 1,000km	9.49
More than 1,000km or liquefied natural gas plant	10.85

Table 4: Base referential prices

Price WTI (P)	Participation percentage (S)
Po ≤ P < 2Po	30 per cent
2Po ≤ P < 3Po	35 per cent
3Po ≤ P < 4Po	40 per cent
4Po ≤ P < 5Po	45 per cent
5Po ≤ P	50 per cent

Table 5: Participation percentage

Production sharing

In E&P contracts resulting from a bid process, ANH will receive the 'X-factor', which is the percentage of gross production after royalty offered by the contractor during the bidding process.

Taxes, duties, royalties and incentives

Corporate income tax
The current applicable income tax rate on net taxable income is 39 per cent. This tax is slated to be temporarily increased to 40 per cent in 2016, 42 per cent in 2017 and 43 per cent in 2018. Congress might extend the temporary increase or make it permanent. In the absence of the extension, the rate will be 39 per cent from 2019 onwards.

Profit tax
Capital gains tax is an additional tax on specific income with its own taxable base. It taxes the profits on the sale of assets (other than inventory) held by the taxpayer for more than two years. Law 1607 of 2012 lowered the capital gains tax rate from 33 per cent to 10 per cent.

Hydrocarbons tax
Activities related to hydrocarbons are subject to the general corporate tax regime. There is no special tax for hydrocarbons.

Tax credits
Taxes paid abroad on foreign source income will be considered as a deduction of tax payable in Colombia up to an amount that does not exceed the tax payable on the corresponding income in Colombia.

Remittance taxes
There is no remittance tax applicable in Colombia.

Taxes on financial transactions
The Colombian Bank debit tax is 0.4 per cent of the withdrawal amount from savings and checking accounts, credit card transactions, loan disbursements and certain other transactions.

Indirect taxes
The most important indirect taxes affecting hydrocarbon-related activities are VAT and financial transactions tax.

Stamp taxes
The national stamp tax is currently 0 per cent. However, certain departments in Colombia, especially those in the Caribbean Region, may have a local stamp tax that is triggered in certain cases. The amount is up to 1 per cent of the gross income set forth in the document or taxed activity.

Customs duties
The import of oil and gas assets is, in general, subject to customs duties (that is, VAT of 16 per cent on Cost Insurance and Freight (CIF) value plus tariff between 0 per cent and 20 per cent on CIF plus VAT). Under the various free trade agreements and other international agreements on trade, tariffs may be reduced to 0 per cent, depending on the good, its origin and the terms agreed therein.

Tariffs
Tariffs on imports in Colombia range from 0 per cent to 20 per cent, depending on the imported goods, their origin and the application of international agreements with preferential rates. If a duty-free zone is established in an offshore area, such tariffs will not apply.

VAT
VAT is triggered on the sale of goods in Colombia, the rendering of services within Colombian territory and the import of taxed goods. For hydrocarbon activities:

- oil sold in Colombia to be refined is VAT excluded
- oil exported is VAT exempt
- oil sold in Colombia not to be refined is taxed at 16 per cent
- gas sold in Colombia is VAT excluded
- gas exported is VAT exempt.

Allowable deductions
As a general rule, expenses incurred during the tax year that are not recorded as assets (and therefore will not be amortised) are deductible.

In the case of acquisition or exploration and exploitation costs related to non-renewable natural resources, the amortisation can be calculated using either the special system of technical estimation of the operating units cost, or the straight line method. In both cases, the amortisation term cannot be lower than five years. If the exploration investments do not succeed, the amount invested can be amortised in the year in which it is declared as unsuccessful or within the following two years.

Royalties
Please refer to the section on royalties under 'State participation' above.

Foreign currency and Central Bank requirements
The ordinary exchange control regime applies to Colombian individuals, legal entities and branches of foreign companies not subject to the special regime. Pursuant to this regime, all transactions between residents must be paid in Colombian currency. Currency for transactions subject to the mandatory use of the exchange market must be sent abroad or brought to Colombia using the authorised entities and/or mechanisms.

The special exchange control regime is applicable only to branches of foreign entities engaged in oil and gas activities that are not subject to the obligation of reimbursing currency obtained from their exports. Under the special exchange regime, imports are non-reimbursable. That is, the importer does not have to pay them using the exchange market, and entering into foreign indebtedness or international lease agreements is not allowed. The reason for this is that, in these types of activities, resources are usually provided by the same entity engaged in doing business in Colombia, via capital investments or supplemental investments to the assigned capital.

Environmental protection and socio-economic development

The Ministry of Environment and Sustainable Development (MADS) is in charge of managing environment and renewable natural resources. It is responsible for guiding and issuing the environmental planning and development policies and regulations to secure the recovery, conservation, protection, management and sustainable use of renewable natural resources and the environment of the nation.

Regional environmental corporations (CARs) also issue regional permits for the use of natural resources.

The National Authority of Environmental Licensing (ANLA), a specialised administrative unit, is the public entity in charge of granting the corresponding environmental licenses in the oil and gas sector.

Liabilities

The environmental authority may impose penalties arising from the breach of the enforceable environmental regulations.

The holder of the E&P rights to carry out activities under the granting instrument is exclusively responsible for any environmental liabilities.

Environmental impact assessments, reporting rules and audits

Environmental diagnostic of alternatives

Prior to requesting an environmental license, the contractor must request from the environmental authority its opinion on whether or not an environmental diagnostic of alternatives (EDA) is needed for the upcoming project.

Environmental licenses

The ANLA has responsibility for supervising environmental matters and granting the corresponding licenses in the hydrocarbon sector in the following cases:

- Seismic shooting that requires the construction of roads and offshore exploration in depths up to 200m.
- Drilling activities that are not within the hydrocarbon production fields of the contractor.
- Exploitation of hydrocarbons, which includes drilling, construction of facilities for development of the project, internal transportation of fluids within the same field, and any other related infrastructure part of the exploitation activity.
- Transportation of liquids outside of the fields and the construction of storage facilities.
- Points of delivery and transfer stations of liquid hydrocarbons.
- Construction of refineries and facilities used during this process.

Exploration phase

The environmental impact assessment (EIA) is the basic instrument used for the execution of projects and activities that require an environmental license. The EIA must include the following information:

- Project location and activities to be carried out
- Use of natural resources during the project
- An environmental impact study and risk assessment
- Economic analysis of the positive and negative impacts of the project
- An abandonment plan upon termination of the project.

The environmental license is granted by the environmental authority, ANLA, and can be understood as the authorisation granted by such competent authority for the execution of the determined activity or project.

Other types of permit, concession and authorisation may be needed to carry out certain activities that require the use of specific natural resources and that may cause an environmental impact.

Production phase

Once the exploration period is completed, the contractor must obtain a global environmental licence (GEL), which is required for the development of works and activities related to hydrocarbons exploitation.

Prior consultation process

E&P activities in the area of influence of defined indigenous or African-Colombian territories or communities of the project are subject to a prior consultation process with such communities (*consulta previa*). The purpose of this consultation is to include mitigating measures for the negative impacts while maximising positive impacts.

If the affected communities still resist supporting the project after such a consultation process, the final decision will be made by the MME.

New license regime (Decree 2041 of 2014)

According to this new regime, a developer that has an existing license for exploitation of conventional hydrocarbons, and intends to explore or exploit unconventional hydrocarbons in the same area, will have to apply for a modification of the existing license.

Environmental sanctionatory regime (Law 1333 of 2009)

The purpose of the sanctionatory regime is to protect natural resources and the environment. In the regime, the negligence or misconduct of the offender is presumed. If the presumed offender does not overcome the presumption of negligence or misconduct, it will be subject to sanctions.

The only available defences against environmental responsibility are: act of God, force majeure, sabotage, act of third party or terrorism.

Contractual environmental liabilities

Duty of information

The contractor must keep the ANH informed, on a timely and permanent basis, about the progress of compliance with environmental and social formalities. It must give timely notice to ANH of any difficulty that may arise in the course of the foregoing formalities and that may affect the terms agreed in the E&P contract.

Term to commence actions to obtain environmental permits and licenses

In order to carry out activities that require licenses or any other environmental authorisations, the contractor must start all required actions with the competent authorities no later than 90 calendar days prior to the scheduled date of commencement of the activity.

If the contractor does not meet these terms or fails to exercise due diligence regarding compliance with the required formalities, this will give rise to the declaration of default by the ANH.

Nonetheless, delays resulting from the previous consultation process are very common. If the contractor handles the processes diligently, there will be grounds for requesting a suspension of obligations under the E&P contract or an extension of the contractual terms.

Domestic supply and exportation of hydrocarbons

Pursuant to Colombian law, oil may be freely exported. However, according to the Petroleum Code, hydrocarbon producers may first be required to satisfy the internal necessities of the country and sell their production to supply the domestic demand. In this case, hydrocarbons will be paid for at international prices.

Gas may also be freely exported, and exports may be limited if the gas is needed to satisfy domestic supply.

Enforcement regime, in judicial and arbitral alternatives

Enforcement regime

Under Colombian constitutional law, first instance (Lower Court) judicial and/or administrative decisions may be challenged through recourses/appeals. In addition, the nature of the dispute and the circumstances surrounding the case may grant extraordinary recourses to plaintiffs and/or defendants which are to be decided by the Colombian Higher Courts.

As Colombia is not a common law jurisdiction, courts are not compelled to follow judicial precedents.

Decisions from foreign jurisdictions

Foreign court judgments and arbitration awards are enforced in Colombia through an exequatur procedure. The procedure consists of presenting the decision or award before the Supreme Court of Justice for it to consider whether to issue the exequatur or deny it.

Changes to regulatory regime

The latest changes to the regulatory regime applicable to the oil and gas industry includes the issuance by the MME

of Resolution 90341 of 2014 and the Acuerdo 003 of 2014 issued by the ANH. This regulation specifically excludes the exploration of coal-bed methane.

Opportunities

The latest bidding competitive process took place during 2014. There will be further investment opportunities in the sector through new bidding processes to be opened by the ANH in the future. Farm-ins or similar arrangements may also be implemented or opportunities may arise via the assignment of participations in the E&P contracts already executed by the ANH or the contracts entered into by Ecopetrol.

Mexico

The Mexican hydrocarbons industry was closed to private sector participation from 1938 until December 16, 2013, when the Federal Constitution was amended to open all segments of the industry to competition. This reform was designed to allow Mexico to significantly increase its hydrocarbons production and reserves in a competitive environment. With approximately 24,806 mmboe of 2P reserves and 105,361 mmboe of prospective resources and many unexplored basins, Mexico should become one of the most attractive jurisdictions worldwide for private investment in the hydrocarbons sector. The first exploration and extraction contracts will be awarded by the end of 2015, thus generating significant levels of foreign investment and economic activity, not least into the country's prospective shale gas basins.

Shale play details and status

In December 2013, Mexico amended its Federal Constitution to implement a new energy reform, one of several structural reforms proposed by the President in order to modernise the country. The pressing need for Mexico to develop new energy sources was a key driving force in this process, which ended the State monopoly in the hydrocarbons sector and allows private investment and participation in all areas of the hydrocarbons industry.

Mexico has large prospective shale gas and shale oil resources along the Gulf of Mexico Basin, since the prolific Eagle Ford shale formation in Texas extends into Mexico and accounts for two-thirds of Mexico's shale gas resources.

According to the Mexican Energy Secretariat (SENER), which is in charge of managing and regulating all means of energy within the country, the national oil company, Petróleos Mexicanos (PEMEX), began the systematic assessment of shale resources in 2010. As a result, the potential to produce hydrocarbons from shale was identified in the following geological provinces: Chihuahua, Sabinas-Burro-Picachos, Burgos, Tampico-Misantla and Veracruz.[1]

Shale gas was produced by PEMEX for the first time in March 2011, in Coahuila state, in a formation that is part of the Eagle Ford area. PEMEX estimated Mexico's shale gas potential in the range of 150 to 459 trillion cubic feet (TCF), with an average resource of 297 TCF (equivalent to approximately 60 billion barrels of oil) within a prospective area of 43,000km^2.

According to an Inter-American Development Bank discussion paper on shale gas in Latin America, (which considered a study by Advanced Resources International), Mexico has the second largest technically recoverable shale gas deposits in Latin America. This ranks it among the largest in the world.[2] At the end of 2013, the expectation was that 150 wells would be drilled by 2016, and PEMEX had identified a budget of approximately US$200 million for shale gas development.[3] The development of shale resources provides Mexico with a unique opportunity to increase its long-term production of hydrocarbons and its energy sustainability.

1 SENER website: http://www.energia.gob.mx/webSener/shale/shale_en.html [last visited on February 19, 2015].

2 The New Energy Landscape: Shale gas in Latin America, David R. Mares for the Inter-American Development Bank and the Inter-American Dialogue Energy Working Papers Series, Infrastructure and Environment Department Discussion Paper No. IDB-DP-253, December, 2012. Available at: http://issuu.com/idb_publications/docs/dipapaers_en_79871.

3 'Latin America at forefront of oil shale shake-up', November 14, 2013. Available at: http://www.institutionalinvestor.com/article/3279853/banking-and-capital-markets-emerging-markets/latin-america-at-forefront-of-oil-shale-shake-up.html#.VGxPh_mG99A

150-459 TCF
Mexico Basin

*Petróleos Mexicanos has estimated Mexico's shale gas potential to be in the range of 150 to 459 TCF, with an average resource of 297 TCF. It has identified over 200 shale gas resource opportunities in five different geological provinces in eastern Mexico: Chihuahua, Sabinas-Burro-Picachos, Burgos, Tampico-Misantla, and Veracruz.**

343 TCF

The Eagle Ford shale gas resource estimate in Burgos Basin was reduced from 454 TCF in 2011 to 343 TCF in 2013. This resulted in an increase in the estimate for oil resources in the area.

393 TCF

The Eagle Ford and Tithonian shale formations in the Burgos Basin are estimated to have 343 TCF and 50 TCF respectively of technically recoverable shale gas resources.

393 TCF

The Eagle Ford and Tithonian-La Casita formations in the Sabinas Basin are estimated to have 100 TCF and 24 TCF respectively of technically recoverable shale gas resources.

* SENER website: http://www.energia.gob.mx/webSener/shale/shale_en.html [last visited on February 19, 2015].

Ownership of land and mineral rights

The general rule, set out in Article 27 of the Mexican Federal Constitution, is that the State is the owner of the subsoil, as well as of all non-renewable resources located within it. Under the Federal Constitution, all natural hydrocarbon reservoirs in existence within the Mexican territory, whatever their nature, belong exclusively to the State and are also inalienable.

In order to comply with the subject matter of the entitlements (asignaciones)[4] or contracts, State Productive Enterprises (SPEs) may enter into agreements with private parties. Provisions reiterating that the hydrocarbons in the subsoil are the property of the nation must be contained in the entitlements to SPEs and in the exploration and extraction contracts (E&E contracts) awarded to SPEs or private investors.

SPEs or private investors granted contracts for exploration and production activities will be able to 'report' such contracts, and the expected economic benefits from them, for accounting and financial purposes. However, this only applies if such contracts explicitly stipulate that all hydrocarbons within the subsoil remain the property of the State.

Land rights

Under Mexican law, ownership of land, which may belong to any particular individual or entity, is different from ownership of the subsoil and the natural resources located within it. The State may grant exploration and extraction rights over such natural resources without involving the transfer of property land rights.

Under the Hydrocarbons Law, hydrocarbons activities are deemed to be in the public interest and, accordingly, prevail over any other private or public activity that requires surface or subsoil use.

Companies granted hydrocarbons exploration and exploitation rights are not required to own the land where exploration and extraction activities are to be carried out. The Hydrocarbons Law authorises the establishment of legal easements or the necessary surface occupation or use of privately owned land by third parties.

The terms and conditions, including the considerations, for the acquisition, use, enjoyment or encumbrance of the land, property and rights needed to perform oil and gas-related activities are negotiated between the owners, possessors or holders of such land or property rights and the holders of entitlements or E&E contracts. Such terms may be enforced by the Agrarian Law Office when required.

Hydrocarbons regulation

On December 16, 2013, the Mexican Federal Congress approved the Energy Reforms Decree, which amended Articles 25, 27 and 28 of the Federal Constitution and included 21 transitory provisions that further develop the constitutional reforms and contain other energy policy measures. All rules contained in the Energy Reforms Decree constitute the boundaries that govern the changes that can be made at the secondary legislation level. The Energy Reforms Decree came into force on December 21, 2014, the day after its publication in the Official Journal of the Federation (Diario Oficial de la Federación, or DOF).

The amendments to the Federal Constitution allow investors, whether national or foreign, to participate in the exploration, production and refining of hydrocarbons.

Prior to the enactment of the Energy Reforms Decree, PEMEX exclusively carried out hydrocarbons exploration and extraction activities. The private sector had a limited supporting role, consisting of providing services to PEMEX. Private sector participation in natural gas upstream activities began in 2004 through multiple service contracts. Several companies entered into these as integrated services contractors to PEMEX Exploración y Producción (PEP).

The E&E contracts contemplated in Article 27 of the Federal Constitution are granted by the National Hydrocarbons Commission (Comisión Nacional de Hidrocarburos, or CNH) under competitive bidding processes. CNH has the assistance of SENER, and of the Treasury and Public Credit Secretariat (Secretaría de Hacienda y Crédito Público, or HACIENDA), which establishes the economic conditions for the bidding processes and the fiscal terms of the E&E contracts. Its purpose is to allow the nation to obtain, in time, revenues that will contribute to its long-term development.

To implement the opening of the hydrocarbons sector, under the Third Transitory Provision of the Energy Reforms Decree, PEMEX was mandated to become an SPE within a period of two years, in accordance with applicable Mexican laws.

The secondary legislation package included eight new laws and the amendment of 13 pre-existing laws. On October 31,

4 'Entitlement' is defined in Article 4 (V) of the Hydrocarbons Law as 'the legal administrative act whereby the Federal Executive Branch of the Government awards exclusively to an Entitled Party the right to carry out Hydrocarbons Exploration and Extraction activities in the Entitlement Area, for a specific term'. They are known as asignaciones in Spanish. 'Entitled party' is defined in Article 4 (VI) of the Hydrocarbons Law as PEMEX or any other State Productive Enterprise that holds an entitlement and is the operator of an Entitlement Area.

2014, regulations were issued for seven existing and new laws.

Government agencies

SENER

SENER is responsible, among other things, for the overall regulation of the energy sector, issuing policies relating to hydrocarbons exploration and extraction activities, overseeing upstream activities, carrying out energy planning for the mid and long term, and determining the economic and social directives applicable to the national energy sector. It establishes the technical parameters that must be obeyed in CNH's bidding processes, establishes the technical design of E&E contracts, and defines exploration and extraction areas and the type of contract awarded.

Under the Hydrocarbons Law, SENER's powers include the following:

- Selecting the contract areas for E&E contracts, with the assistance of CNH
- Granting, modifying and revoking entitlements
- Authorising the assignment of entitlements by PEMEX to another SPE
- Issuing the technical guidelines for the bidding processes of alliances or associations with legal entities[5], when PEMEX or other SPEs request the migration of the entitlements
- Fixing the mandatory participation of PEMEX in E&E contracts over blocks that have the potential for discovery of transboundary reservoirs
- Issuing the guidelines for public policy regarding hydrocarbons, petroleum products and petrochemicals.

HACIENDA

HACIENDA is in charge of managing and controlling the Federal Government's economic policy in financial, fiscal, expenditure and public debt matters. It is responsible for collecting taxes and verifying the correct payment of royalties from hydrocarbons production. Under the Hydrocarbons Law, HACIENDA sets the economic conditions for the different E&E contracts, and determines the variables for awarding E&E contracts in bidding processes carried out by CNH, among others.

Under the Hydrocarbons Law, HACIENDA's powers include the following:

- Setting the economic conditions pertaining to the tax conditions of the E&E contracts
- Determining the variables for awarding the E&E contracts in the bidding processes
- Participating in the administration and accounting audit regarding the tax conditions of the E&E contracts
- Issuing its opinion to SENER regarding the unitisation of extraction fields or reservoirs.

CNH

CNH is a decentralised agency of the Federal Government, which regulates and supervises the extraction of hydrocarbons. It has the technical capacity to define the expansion plans of Federal Government, and has authority over the annual investment programmes and operations contracts for the exploration and extraction of hydrocarbons. CNH's jurisdiction over energy projects ends at the point of delivery. (So, in the case of oil, for example, its jurisdiction ends with delivery to a pipeline or storage facility.)

CNH also authorises recognition and surface exploration works and carries out seismic and geological studies. It provides technical support to SENER for the selection of the entitlement areas. It approves the exploration and development plans for entitlements. It conducts the bidding process for the award of E&E contracts and the alliances or associations of PEMEX or other SPEs with legal entities, if entitlements migrate to E&E contracts.

Under the Hydrocarbons Law, CNH's powers include the following:

- Entering into E&E contracts with PEMEX, other SPEs or legal entities
- Providing technical support to SENER for the selection of the entitlement areas
- Carrying out the technical management and supervising the observance of the terms and conditions of the entitlements

5 'Legal entity' means a commercial partnership or corporation organised pursuant to Mexican legislation (Hydrocarbons Law, Article 4 (XXV)).

- Approving the exploration and development plans for entitlements, and their modifications
- Conducting the bidding process for the alliances or associations of PEMEX or other SPEs with legal entities, in the cases of entitlements that migrate to E&E contracts
- Authorising the entering into of alliances or associations in which the contractor's corporate or administrative control, or the control of operations in the contract area, are assigned, in whole or in part
- Issuing the regulations and supervising their observance by entitled parties, contractors or authorised parties in respect of the matters under its jurisdiction
- Approving the exploration plans or extraction development plans submitted by entitled parties and contractors.

National Centre for Natural Gas Control

The National Centre for Natural Gas Control, a new government agency, is responsible for transportation and storage[6] of natural gas and for the operation of the national gas pipeline system.

CRE

Under the Hydrocarbons Law, the Energy Regulatory Commission (CRE) regulates and grants storage, transport and pipeline distribution permits. It approves the bases for the bidding processes conducted by the National Centre for Control of Natural Gas. It approves (with the favourable opinion of SENER) the creation of integrated systems. It renders its opinion on the planning of the expansion of transportation and distribution of natural gas and liquefied petroleum gas, in accordance with the guidelines for this purpose issued by SENER, among others.[7]

ANSIPA

The National Agency for Industrial Safety and Environmental Protection in the Hydrocarbons Sector (ANSIPA) is a new government agency. It regulates and supervises operational safety and environmental protection, which involves overseeing the installation and abandonment of facilities and the overall control of waste products from hydrocarbons-related operations.

According to Article 5 of the ANSIPA Law, ANSIPA will have 30 attributes, among which the most relevant are to:

- Issue the technical measures within the scope of its competence, in order to deal with emergencies, critical risk situations or events that may cause serious damages to persons, property and the environment. If necessary, ANSIPA requests the support of the competent authorities to apply such measures.
- Issue the bases and criteria for the regulated parties to adopt the best practices for industrial safety, operating safety and environmental protection that may be applicable to the sector's activities.
- Set the guidelines for the structuring and operation of the administration systems.
- Impose safety or enforcement measures, and penalties that may be applicable according to the relevant legislation.

Mexican Stabilization and Development Fund

Under Article 28 of the Federal Constitution, a public trust denominated the Stabilization and Development Fund of Mexico (Fondo Mexicano del Petróleo para la Estabilización y el Desarrollo) (the 'Oil Fund') will be established by HACIENDA with the Mexican Central Bank. This is a fiduciary institution, entrusted with receiving, managing and distributing the revenues resulting from entitlements and E&E contracts, with the exclusion of taxes.

Rights, licences and approvals

Surface surveying and exploration activities

Article 37 of the Hydrocarbons Law allows the conduct of surface surveying and exploration[8] activities (which require the authorisation of CNH) to persons that do not have an entitlement or an E&E contract. The authorisation to carry out these activities does not grant exploration rights, or preferential rights with regard to entitlements or E&E contracts.

6 'Storage' is defined in Article 4 (II) of the Hydrocarbons Law as 'the storage and safeguarding of Hydrocarbons, Petroleum Products and Petrochemicals in closed storage facilities that may be located on land surface, in the sea or subsoil'.

7 'Integrated systems' are defined in Article 4 (XXXVI) of the Hydrocarbons Law as 'interconnected pipeline transportation and storage systems, grouped for tariff/rate purposes, and which have the general conditions for providing the services allowing the operating coordination between the various facilities'. 'Transportation' is defined in Article 4 (XXXVIII) of the Hydrocarbons Law as 'the activity of receiving, delivering and, as the case may be, taking of Hydrocarbons, Petroleum Products and Petrochemicals, from one place to another through pipelines or other means, without implying the sale or marketing of such products by whoever does this through pipelines'. 'Distribution' is defined in Article 4 (XI) of the Hydrocarbons Law as a 'logistics activity related to the distribution, including the transportation, of a given volume of Natural Gas or Petroleum Products from a certain location to one or several destinations previously assigned, for their Retail Sale to the Public or final consumption'.

8 'Surface surveying and exploration' is defined in Article 4 (XXXII) of the Hydrocarbons Law as 'all evaluation studies that are conducted only by activities over the land or sea surface in order to consider the potential existence of Hydrocarbons in a given area; these activities include the work for the acquisition, processing, re-processing or interpretation of information or data'.

Permits required under the Hydrocarbons Law

The Hydrocarbons Law establishes permit requirements for industrial and logistic activities throughout the hydrocarbons exploration, extraction and supply chain. This law includes provisions relating to the permit application process, suspension and revocation, among others.

According to Article 48 of the Hydrocarbons Law, a permit will be required for the treatment and refining of oil, processing of natural gas, and exporting and importing of hydrocarbons, liquefied petroleum gas, petroleum products[9] and petrochemicals. These permits are issued by SENER.

Article 48 also specifies that a permit will be required for each of the following activities: transportation, storage, distribution, compression, liquefaction, decompression, regasification and retail sales of hydrocarbons, petroleum products and petrochemicals. These permits are issued by CRE.

According to Article 49 of the Hydrocarbons Law, the terms and conditions of the permit required for the marketing of hydrocarbons, petroleum products and petrochemicals in Mexico sets out specific obligations for traders. (The permit itself may be granted by CRE under Article 48 of the Hydrocarbons Law.)

The parties interested in obtaining the permits referred to above, and contained under Title Three of the Hydrocarbons Law, must submit their application or request to SENER or to CRE, as the case may be, in accordance with the criteria established in Article 50 of said law. Article 51 specifies that permits will be granted in accordance with the Hydrocarbons Law Regulations, and may be terminated or cancelled owing to any of the eight causes set out in Article 54 of the Hydrocarbons Law.

Article 53 of the Hydrocarbons Law sets forth that the assignment of the permits or of the performance of the activities regulated thereunder may only be made with the prior authorisation of SENER or CRE, as the case may be. Authorisation requires that the permits are in force, the assignor has fulfilled all its obligations, and the assignee meets the requirements to be a permit holder and undertakes to comply with the terms of the obligations contemplated in said permits.

SENER or CRE, depending on the type of permit, will decide within a term of 90 calendar days following the date on which the assignment approval request is made. If a resolution is not issued by SENER or CRE, as the case may be, within the foregoing term, it shall be deemed to have approved. Any assignment made without observing the provisions of Article 53 shall be null and void.

Under Article 58 of the Hydrocarbons Law, the activities and services that are covered by a permit are deemed to be in the public interest.

Article 85 of the Hydrocarbons Law provides for an extensive list of sanctions resulting from the violation of some of the permits mentioned above.

Establishment of the local entity and Central Bank requirements

In general terms, under Mexican corporate law a corporate vehicle must be incorporated in order to operate any kind of trade or business in the country. Such vehicle may be either a local branch of a foreign company or a local Mexican company. However, the Hydrocarbons Law requires that private holders of E&E contracts be legal entities, organised pursuant to the laws of Mexico[10]. As such, foreign investors will be required to organise local subsidiaries (whether a partnership or corporation) in order to participate. The same requirement applies to private investors that enter into associations with PEMEX.

Subject to the foregoing caveat, there are different structures that investors may use for investment vehicles in Mexico. They range from setting up a commercial corporation or branch to forming a joint venture or trust. The General Corporation Law recognises the existence of six types of commercial organisations or structures. However, in daily corporate practice in Mexico, the type of company most utilised is a limited liability stock corporation or a limited liability company.

The General Corporation Law provides that a foreign company has legal existence and is entitled to set up branches in Mexico when it is recorded in the Public Commercial Registry in the location where it intends to set up the branch. It must obtain the prior authorisation of the Department of Foreign Affairs and Department of the Economy. In order to obtain such authorisations, among other requirements, the foreign company must prove that it has been incorporated in accordance with the laws of its country and that its charter and by-laws contain no provisions that are contrary to Mexican law.

9 'Petroleum products' are defined in Article 4 (XXVIII) of the Hydrocarbons Law as 'products obtained from the refining of Petroleum or the processing of Natural Gas and that directly derivate from Hydrocarbons, such as gasoline, diesel, kerosene, fuel oil and Liquefied Petroleum Gas, among others, different from Petrochemicals'.

10 Transportation is defined, in Article 4 (XXXVIII) of the Hydrocarbons Law, as 'the activity of receiving, delivering and, as the case may be, taking of Hydrocarbons, Petroleum Products and Petrochemicals, from one place to another through pipelines or other means, without implying the sale or marketing of such products by whoever does this through pipelines.'

In order to obtain authorisation from the Department of Foreign Affairs to open a branch office, it is necessary to file a notice in which the company waives its right to invoke the protection of its government in matters related to the acquisition of ownership of property in Mexico.[11]

Exchange controls

Under Mexican laws, there are no exchange controls on the import or export of capital. Foreign currencies may be bought and sold freely and there are no restrictions on the maintenance of foreign currency bank accounts in Mexico.

Pursuant to the Foreign Investment Law, foreign investors receive the same legal treatment as local investors, and are able to invest in major economic activities in the country.

State participation, taxes, duties, royalties and incentives

Under Article 18 of the Hydrocarbons Law, the consideration established in the E&E contracts will be subject to the provisions of the Hydrocarbons Revenues Law (Article 1). This sets the system for the revenues to be received by the State as a result of hydrocarbons exploration and extraction activities carried out under the entitlements and contracts[12] referred to in Article 27, Paragraph 7 of the Federal Constitution and in the Hydrocarbons Law, as well as the consideration[13] to be set forth in the contracts.

The forms of consideration provided for in the E&E contracts will be calculated and delivered to the State and the contractors according to the mechanisms set forth in each E&E contract, and following the rules set out in the Hydrocarbons Revenues Law. The payment to the State of this consideration does not exempt contractors from complying with their tax obligations as set out in the Income Tax Law and other tax provisions (Hydrocarbons Revenues Law, Article 4).

Contract fee for the exploration stage

In each licence contract, profit-sharing contract and production-sharing contract, there will be included a monthly payment in favour of the State on account of the contract fee for the exploration stage.

This fee is applied on the basis of the portion of the contract area pursuant to the E&E contract that is not in the production stage, according to specific rates.[14] The rates are updated in January every year, according to the variations in the National Consumer Price Index for the immediately preceding year (Hydrocarbons Revenues Law, Article 23).

Royalties

Each licence contract, profit-sharing contract and production-sharing contract will include a monthly payment in favour of the State on account of royalties. The amount of the royalties is determined, for each type of hydrocarbon, by applying the relevant rate to the contract value of oil,[15] the contract value of natural gas[16] and the contract value of condensates[17], as the case may be (Hydrocarbons Revenues Law, Article 24).

Tax on hydrocarbons exploration and extraction activities

Contractors are obliged to pay a tax on the hydrocarbons exploration and extraction activities in the contract area defined in the relevant E&E contract (Hydrocarbons Law, Article 54). This tax is calculated on a monthly basis, applying specific fees[18] per square kilometre comprised in the contract area (Article 55).

The contractor will determine the tax per month or fraction thereof, and must pay it no later than the 17th day of the immediately following month. The tax provisions and the general rules issued by the Tax Administration Service apply (Hydrocarbons Law, Article 56).

11 *Ibid.*

12 'Contract' under the Hydrocarbons Revenues Law, Article 3, means a contract for exploration and extraction.

13 'Consideration' means that which is set forth in each contract in favour of the State or the contractor (Hydrocarbons Revenues Law, Article 3).

14 The applicable rates are: 1,150 peso perkm^2 during the first 60 months of the term of the E&E contract; and 2,750 peso perkm^2 as of the 61st month of the term of the E&E contract and thereafter.

15 'Contract value of oil' is the result of multiplying, during the relevant period: i) the contract price of oil, and ii) the volume of oil, in barrels, at the measuring point of the contract area (Hydrocarbons Revenues Law, Article 3 (XXIV)). In turn, 'contract price of oil' means the price of the oil produced in the contract area, in US dollars per barrel, determined during each period at the measuring point, based on the terms of Article 25 of the Hydrocarbons Revenues Law, in accordance with the mechanisms established in each E&E contract (Hydrocarbons Revenues Law, Article 3 (XV)).

16 'Contract value of natural gas' is the result of multiplying, during the relevant period: i) the contract price of the natural gas, and ii) the volume, in million BTUs of natural gas, at the measuring point of the contract area (Hydrocarbons Revenues Law, Article 3 (XXIII)). In turn, 'contract price of natural gas' means the price of the natural gas produced in the contract area, in US dollars per million BTUs, determined in each period at the measuring point, in terms of Article 25 of the Hydrocarbons Revenues Law, as provided by the mechanisms established in each contract (Hydrocarbons Revenues Law, Article 3 (XXIV)).

17 'Contract value of condensates' is the result of multiplying, during the relevant period: i) the contract price of the condensates, and ii) the volume of the condensates in barrels, at the measuring point of the contract area (Hydrocarbons Revenues Law, Article 3 (XXI)). In turn, 'contract price of condensates' is the price of the condensates produced in the contract area, in US dollars per barrel, determined during each period at the measuring point, in terms of Article 25 of the Hydrocarbons Revenues Law, in accordance with the mechanisms established in each contract (Hydrocarbons Revenues Law, Article 3 (XIII)).

18 The applicable fees are: 1,500 peso during the exploration stage and 6,000 peso during the extraction stage.

Considerations under licence contracts

Pursuant to the Hydrocarbons Revenues Law, licence contracts provide for the following types of consideration in favour of the State:

- a signing bonus
- the contract fee for the exploration stage
- royalties (determined in accordance with Article 24 of the Hydrocarbons Revenues Law)
- a contractual consideration derived from the application of a rate to the hydrocarbons' contractual value.[19]

The signing bonus is determined by HACIENDA for each E&E contract. The amount and payment conditions will be included in the bidding conditions for the award (in the case of a new award) or in the E&E contract itself (in the case of a contract resulting from the migration of an entitlement). The signing bonus will be paid in cash by the contractor to the State through the Oil Fund (Hydrocarbons Revenues Law, Article 7).

The other considerations in favour of the State, set forth in the licence contracts, are paid monthly in cash by the contractor, as provided for under the E&E contract (Hydrocarbons Revenues Law, Article 8).

The mechanisms for determining the amounts of the royalties and the contract fee for the exploration stage are common to all licence contracts, profit-sharing contracts and production-sharing contracts.

The rate (or mechanism for determining the rate) to be applied to the hydrocarbons' contractual value for determining the amount of the contractual consideration is set out in the applicable licence contract.

In order to allow the State to capture 'extraordinary profits, if any, generated by the Extraction of Hydrocarbons' this rate is modified through an adjustment mechanism included in the licence contract (Hydrocarbons Revenues Law, Article 10). The mechanism is a formula set by HACIENDA for each E&E contract. It increases the consideration in favour of the State, based on the profitability of the contractor in each period, by modifying any of the parameters that determine the consideration paid under the E&E contract (Hydrocarbons Revenues Law, Article 3(X). The amount of this contractual consideration will not be known until the release of the bid conditions and model contract for any contract area. The rate applied in such determination may be a candidate for a bid variable in any bidding process to award same.

In the migration of areas under entitlements to the licence contract scheme, HACIENDA will define the consideration to the State described above, ensuring that the revenues for the State over time are not lower than those that would have been obtained under the original entitlement.

The consideration in favour of the contractor under licence contracts will be the transfer of the hydrocarbons after they have been extracted from the subsoil, in accordance with the contract, as long as the contractor duly complies with its consideration payment obligations.

Considerations under profit-sharing contracts

Profit-sharing contracts will set out the following types of consideration in favour of the State (Hydrocarbons Revenues Law, Article 11):

- The contract fee for the exploration stage.
- Royalties (determined in accordance with Article 24 of the Hydrocarbons Revenues Law).
- Consideration to be determined by applying a percentage to the operating profit.

The operating profit is determined for each period by deducting from the hydrocarbons' contractual value:

- The amount of royalties actually paid by the contractor during the period, and
- The consideration corresponding to cost recovery, determined pursuant to Article 16 of the Hydrocarbons Revenues Law.

The percentage (or mechanism for determining the percentage) of the operating profit to be allocated to the State is not specified in the Hydrocarbons Revenues Law. It will presumably be set out in the applicable profit-sharing contract (and/or the bidding conditions for the award of such contract), and may be a prime candidate for a bid variable in any bidding process to award same.

19 'Hydrocarbons' contractual value' means the amount of the contractual value of the oil, the contractual value of the natural gas and the contractual value of the condensates (Hydrocarbons Revenues Law, Article 3 (XXII)).

The State will capture 'extraordinary profits, if any, generated by the Extraction of Hydrocarbons' by amending the percentage of operating profits allocated to the State through an adjustment mechanism to be included in the profit-sharing contract (and/or the bidding conditions for the award of such contract). This will operate in the manner described above for considerations under licence contracts (Hydrocarbons Revenues Law, Article 15).

The consideration in favour of the contractor in profit-sharing contracts will be (Hydrocarbons Revenues Law, Article 11):

- The recovery of costs, subject to the provisions of Article 16 of the Hydrocarbons Revenues Law.
- The remainder of the operating profit after covering the consideration in favour of the State.

The consideration in favour of the contractor for recovery of costs will be the amount that is equivalent to the costs, expenses and investments recognised in accordance with the guidelines for this purpose issued by HACIENDA on March 6, 2015 (Hydrocarbons Revenues Law, Article 16).

Article 19 of the Hydrocarbons Revenues Law enumerates 15 items of cost, expense or investment that are expressly not recoverable. These include:

- Those in excess of reference or reasonable market prices, as established in the rules and bases for the registration of costs, expenses and investments under the E&E contract.
- Those that are not strictly essential for the activity subject to the E&E contract, any others specified in each E&E contract because of particular circumstances or situations, and those established in the guidelines issued for such purpose by HACIENDA (Hydrocarbons Revenues Law, Article 19 (XIV) and (XV)).

The consideration received by the contractor for recovery of costs in any period will not exceed the 'cost recovery limit'. The 'cost recovery percentage' used in determining the cost recovery limit will be set by HACIENDA in the bidding conditions and/or the applicable E&E contract. The costs, expenses and investments recognised for cost recovery purposes that are not recovered by the contractor in any period as a result of the application of the cost recovery limit are carried forward indefinitely for recovery in subsequent periods (Hydrocarbons Revenues Law, Article 3 (IX) and (XII) and Article 16).

Under profit-sharing contracts, contractors are required to deliver the total contractual output[20] to the trader[21], who will deliver the income resulting from the marketing thereof to the Oil Fund. In turn, the Oil Fund will retain the consideration due to the State and will deliver to the contractor the consideration to which it is entitled for each period, according to the provisions of the E&E contract (Hydrocarbons Revenues Law, Article 11).

Considerations under production-sharing contracts

Production-sharing contracts will set out the following types of consideration in favour of the State (Hydrocarbons Revenues Law, Article 12):

- the contract fee for the exploration stage
- royalties (determined in accordance with Article 24 of the Hydrocarbons Revenues Law)
- a consideration to be determined by applying a percentage to the operating profit.

The operating profit is obtained as described in the section on profit-sharing contracts, above.

The State will capture 'extraordinary profits, if any, generated by the Extraction of Hydrocarbons' by amending the percentage of operating profits allocated to the State through an adjustment mechanism to be included in the production-sharing contract (and/or the bidding conditions for the award of such contract) (Hydrocarbons Revenues Law, Article 15).The adjustment mechanism operates in the manner described in the section on licence contracts above.

The consideration in favour of the contractor in production-sharing contracts will be (Hydrocarbons Revenues Law, Article 12):

- the recovery of costs, subject to the provisions of Article 16 of the Hydrocarbons Revenues Law
- the remainder of the operating profit after covering the consideration in favour of the State.

The consideration in favour of the contractor for recovery of costs will be the amount that is equivalent to the costs, expenses and investments recognised in accordance

20 'Contractual output' means the hydrocarbons extracted in the contract area during the relevant period, measured at the measuring point, in accordance with the provisions issued by the National Hydrocarbons Commission (Hydrocarbons Revenues Law, Article 3).

21 'Trader' means the legal entity that is contracted by the National Hydrocarbons Commission, at the request of the Oil Fund, to provide its services to the nation for the marketing of the hydrocarbons received by the State under a contract (Hydrocarbons Revenues Law, Article 3).

with the guidelines for this purpose issued by HACIENDA (Hydrocarbons Revenues Law, Article 16).

- In regard to the costs that are not recoverable and the consideration received by the contractor for cost recovery, please refer to the section on profit-sharing contracts above.

Considerations under service contracts

Under service contracts, the contractors deliver the entire contractual output to the State. The consideration in favour of the contractor will always be in cash and will be set out in the applicable contract, considering the standards and usage of the industry.

The consideration in favour of the contractor set out in a service contract is paid by the Oil Fund out of the revenues generated by the marketing of the contractual output derived from each service contract (Hydrocarbons Revenues Law, Article 22).

Environmental protection and socio-economic development

Mexico has a broad set of regulations distributed among government and administrative authorities in charge of defining policies for specific areas. The General Law on Ecological Equilibrium and Environmental Protection (LGEEPA) of 1998 defines policy guidelines that must be followed by the Secretariat of the Environment and Natural Resources (SEMARNAT), the main regulatory agency on environmental matters in Mexico, in charge of ensuring the protection, conservation and proper use of natural resources.

The section on government agencies above describes the powers and attributes of ANSIPA, which was created as part of the Energy Reforms Decree.

Enforcement regime, and judicial and arbitral alternatives

The administration of justice in Mexico is regulated under Article 94 of the Federal Constitution, which provides that the judicial power of the Federation is divided among the Supreme Court of Justice, the Electoral Tribunal, the Constitutional Tribunal, Circuit Collegiate and Unitary Courts, and District Courts. The Supreme Court is the highest court for criminal, labour, civil and commercial matters.

Under Article 21 of the Hydrocarbons Law, all disputes pertaining to E&E contracts, except for disputes under Article 20 pertaining to the administrative rescission of the E&E contract, may be settled through the application of alternative dispute resolution mechanisms. These include arbitration agreements upon the terms set forth in the Fourth Title of the Fifth Book of the Mexican Commercial Code and international treaties regarding arbitration and the settlement of controversies to which Mexico is a party.

The exclusion of disputes pursuant to Article 20 is significant, as it provides that declarations of administrative rescission by CNH are not subject to arbitration and that the contractor's only recourse in such circumstances is to the Mexican courts.

Article 21 of the Hydrocarbons Law sets forth more details on the arbitration, stating that: CNH and the contractors shall in no event submit to foreign laws; and that, in any event, the arbitration procedure will always abide by specific provisions, contained therein.

There is a significant concern with the limited scope of the dispute resolution provision contemplated in Article 21 of the Hydrocarbons Law. Article 20 contemplates administrative rescission and, under Article 21, it is not possible to submit controversies related to any of the serious causes under Article 20 to arbitration. If CNH alleges a serious breach, the contractor's only recourse is to cure the alleged breach within the cure period or appeal through an internal procedure administered by CNH.

Moreover, there is a practical concern that arises when there is a breach that overlaps between serious causes and other provisions of the E&E contracts. Such overlap can give rise to competing claims in different venues being filed.

Lastly, there are no major issues regarding the rule of law and enforceability of contractual rights in Mexico. Domestic court decisions and arbitration awards are enforced by legal means available to the parties in litigation, such as executory proceedings.

Opportunities

Oil and gas players may be invited to Mexico as partners of PEMEX in existing Round Zero acreage (e.g. the migration of Round Zero entitlements to E&E contracts) or through bid rounds that CNH will organise in order to award E&E contracts for selected open acreage.

When participating in the bid rounds, private investors will be able to present individual bids or enter into joint ventures (such as joint bidding agreements) with other private investors and/or PEMEX and/or other SPEs in order to present joint bids.

Currently, PEMEX is expected to enter into farm-out agreements with private parties in order to establish ten joint ventures with upstream players in acreage that was awarded to PEMEX as a result of Round Zero. In this round, PEMEX was awarded:

- 100 per cent of the areas in production it requested
- 83 per cent of Mexico's current proven and probable reserves
- 21 per cent of Mexico's prospective resources.

This initiative will refer to fields that demand high capital investments, are technically complex or are good farm-out candidates as a result of other strategic considerations. Through these farm-outs, PEMEX seeks to accelerate development or increase production, access best practices and technologies and reduce its capital investment requirements or operational capabilities.

Round One was announced on August 13, 2014 and is the first of potentially multiple periodic bid rounds that CNH will organise. In the aggregate, this will represent opportunities for upstream players to obtain the rights to areas that were not awarded to PEMEX as a result of Round Zero. In this regard, the Hydrocarbons Law allows PEMEX and other SPEs to enter into alliances or associations during the bidding process for the award of E&E contracts. It is expected that 169 blocks will be offered in Round One, and these are to be awarded before September 2015. Of these, 109 blocks correspond to exploration projects and 60 to extraction projects.

Local content

According to the Seventh Transitory Provision of the Mexican Energy Reforms Decree, minimum local content and other measures for promoting national participation in operations under entitlements and E&E contracts is to be mandated by laws subsequently enacted.

The aggregate of hydrocarbons exploration and extraction activities performed pursuant to entitlements and E&E contracts must reach, on average, 35 per cent of national content. This goal does not apply to exploration and extraction of hydrocarbons in deep and ultra-deep waters (Hydrocarbons Law, Article 46), that will have specific goals set by the Economy Secretariat in accordance with the characteristics of such plays.

The entitlements and E&E contracts will establish a minimum national content percentage to be gradually met by the entitled parties and contractors. This percentage will be established by SENER, with the opinion of the Economy Secretariat. With regard to the E&E contracts, the goal for the degree of national content must be included in the conditions for the bidding and award of said contracts (Hydrocarbons Law, Article 46).

The minimum average percentage of national content set out in Article 46 of the Hydrocarbons Law will increase gradually, starting from 25 per cent in 2015 and reaching at least 35 per cent in 2025 (Hydrocarbons Law, Twenty-Fourth Transitory Provision).This goal will exclude deep and ultra-deep water activities, for which the Economy Secretariat, with the opinion of SENER, will establish the values for 2015 and 2025, based on the national content study of said activities for the first semester of 2014.

Entitled parties, contractors and the permit holders referred to in the Hydrocarbons Law must provide information to the Economy Secretariat regarding the degree of national content of the activities they perform, according to the provisions issued for this purpose by the Secretariat (Hydrocarbons Law, Article 126).

If the Economy Secretariat determines that an entitled party or contractor has failed to meet the required national content, it will advise CNH so that the relevant penalties may be imposed, according to the provisions set in the entitlement or the E&E contract (Hydrocarbons Law, Article 46).

The Netherlands

The Netherlands has a longstanding history in natural gas, which forms its most important energy resource. Since the 1950s, the Netherlands has successfully operated the large Slochteren and Bergermeer fields as well as a large number of smaller onshore and offshore fields. The estimated conventional natural gas reserves amounted to 1,090 bcm in January 2013, but with fewer new gas fields coming online in the future, and the larger ones reaching maturity, the Netherlands is exploring the development of new reserves such as shale gas, tight gas and coal-bed methane.

Approximately 25 per cent of the total European gas reserves are located under Dutch soil, and the Netherlands is the largest natural gas producer in the EU. Energie Beheer Nederland (EBN) estimates that the total quantity of gas that is currently available for production is approximately 950 bcm, with the Groningen gas field accounting for approximately 780 bcm. In 2013, the Groningen gas field produced 54 bcm and around 26 bcm Groningen equivalent of gas were produced from some 300 small gas fields. In 2013, the Netherlands produced in total 80 bcm of natural gas.

Shale plays in the Netherlands

Hydraulic fracturing/stimulation is not new to the Netherlands. Since the 1950s, these techniques have been used in the production of conventional gas. Over 200 wells have been fracked in the Dutch subsurface, onshore and offshore. Between 1995 and 2012, 70 wells were hydraulically stimulated in the Netherlands. Although hydraulic fracturing of shale formations is new to the Netherlands, this technique does not differ significantly from conventional hydraulic fracturing.

Shale plays are generally present at a depth of 3,000–4,000m (10,000–12,000 ft). The estimated volumes range from 200 to 500 bcm. The largest two potential shale formations are the Posidonia and the Geverik Laagpakket plays.

The exact volume of technically and economically recoverable shale gas reserves in the Netherlands is currently unknown, as no test drilling has yet occurred. The Dutch government has granted exploration permits to Brabant Resources (a subsidiary of Cuadrilla Resources Ltd), Hardenberg Resources (also a Cuadrilla subsidiary) and Hexagon Energy (a DSM subsidiary) for exploratory drillings in Noord-Brabant, the Noordoostpolder and the Peel.

In September 2013, following substantial debate and public resistance to shale gas, the Dutch Minister for Economic Affairs issued a temporary moratorium on hydraulic fracturing (including exploratory drilling). The moratorium is expected to continue until more research is conducted into the most suitable locations for the extraction of shale gas and the potential benefits to society. This research is expected

19 TCF

Estimated recoverable reserves

It is estimated that The Netherlands has approximately 19 TCF of technically recoverable shale gas reserves, according to the US Energy Information Administration. This is less than other European countries such as Poland (187 TCF), France (180 TCF) and Sweden (41 TCF).

To date there has been limited development of the shale gas industry in the Netherlands. Compared to Poland, relatively few companies appear to be involved in early exploration and appraisal and drilling has yet to take place.

43 TCF

The natural gas reserves of the Netherlands are estimated at 43 TCF but with fewer new gas fields coming online in the future The Netherlands is exploring development of new sources.

2.79 TCF

TCF Natural gas – The Netherlands is already self-sufficient in natural gas: its domestic conventional gas industry produced 2.79 TCF in 2009, of which around a third was exported primarily to its European neighbours

to include a general environmental impact assessment and a review of the effects of hydraulic fracturing on the environment, health and inhabitants. The research should be complete in the third quarter of 2015, and should provide the Dutch government with the necessary information to decide whether hydraulic fracturing will be allowed in the Netherlands, where and under what conditions.

Ownership of land and mineral rights

Under the Dutch Mining Act (*Mijnbouwwet*), a landowner holds title to the top layer of his land down to a depth of 100 m. The State owns all minerals (*delfstoffen*) that are present in the subsurface at more than 100m in depth. Dutch shale plays are expected to be at a depth of 3,000–4,000m (10,000–12,000 ft), so they are held by the State.

The Mining Act contains the general licensing framework in relation to exploration, production and underground storage activities, subject to various internationally accepted criteria and public objection-and-appeal procedures, as described further below. On the basis of the Mining Act, undertaking such activities in respect of oil and gas is prohibited without a licence granted by the Minister of Economic Affairs.

Once a licence is granted, landowners must allow the exploration and production of minerals. For the first 100m (300 ft) this is based on the Act on the Removal of Private Law Impediments to Public Works (*Belemmeringenwet Privaatrecht*). Below a depth of 100m (300 ft), such an obligation flows from the Mining Act.

After extraction of the minerals, by operation of law, the ownership of the extracted minerals transfers to the party that has the production licence in respect of the area from which they were extracted.

Energie Beheer Nederland BV

The Dutch State-owned company EBN plays an important role in the Dutch upstream market. On behalf of the Dutch State, EBN invests in the exploration, production and underground storage of natural oil and gas in the Netherlands, alongside national and international oil and gas companies. EBN is responsible for a major part of Dutch natural gas revenues and advises the Dutch government on the mining climate and on new opportunities for making use of the Dutch subsurface.

EBN supports the planned exploratory drillings in the Netherlands through its 40 per cent interest in the partnership holding the exploration permit in Brabant, which is suspected to be 'on hold' under the moratorium until at least the third quarter of 2015.

Risks from shale gas exploration and production

In 2011, the Dutch Ministry of Economic Affairs ordered a study of the possible risks of exploration and production of shale gas, which was carried out by a consortium of three reputable Dutch geotechnical consulting firms, Witteveen + Bos, Arcadis and Fugro. The study concerned the identification, analysis, management and mitigation of possible risks and effects of exploration and exploitation of shale gas and coal-bed methane in the Netherlands. Additional research was required to determine the local effects.

Areal footprint and increase activities

The consortium reported that, when compared with conventional gas extraction, the areal footprint of shale gas activities will be larger. Shale gas activities will also lead to increased industrial activities per drilling site. The extent of the burden largely depends on local conditions and so location-specific investigations are recommended in order to determine the specific mitigating measures that should be taken.

Carbon footprint

Under current Dutch rules, the flowback water that is used in fracking needs to be stored in closed tanks where the methane can be contained and captured. Even if the methane is captured in the tanks, the consortium concluded that the carbon footprint will be somewhat larger than it is with conventional gas, also due to the higher intensity of the logistics.

Groundwater

One of the risks most associated with shale gas and coal-bed methane is pollution of groundwater through leakage of fracking fluid and methane. This can occur in three ways:

- By failure of the well bore integrity. This means that production fluids or methane can leak through the well casing or cementation. This risk is larger than during conventional gas exploration and production since more wells are drilled and the casing experiences more pressure as a result of the fracking. However, these risks are regarded as manageable in the report, because the formations are at large depths, there are strict requirements as to the quality of the well bore and there is adequate supervision and enforcement.

Graphic: TNO: Netherlands Organisation for Applied Scientific Research TNO

- By the migration of fluids or methane directly from the shale or coal bed or through another existing well. The risk of migration from the shale layer or coal bed is regarded as very small because of the large depths at which the shale or coal is located. If the well is abandoned in a proper fashion, this should not pose a risk.

- By spillage or leakage at the drill site. The report concludes that this risk can be minimised in the Netherlands because the process water needs to be stored in closed tanks situated on watertight floors. Another way to mitigate the effect of possible pollution is to use additives that are less harmful for people, nature and the environment.

Safety

The report states that the accumulated operational safety risk per location may be higher than for conventional gas exploration and production due to the larger number of wells, longer drilling and large transport volumes. The consortium concludes, however, that shale gas exploration does not suffer from the high risk of blowouts and that risks of surface activities can be calculated with the risk models currently in use.

Earthquakes and subsidence

Earthquakes can occur due to the high-pressure injection of fracturing fluids in or near active fracture zones in a seismic active area. The fracking itself generates vibrations with a magnitude smaller than 1 on the Richter scale, which cannot be felt at the surface. The report indicates that earthquakes induced by fracking, if any, will not exceed magnitude 3 on the Richter scale. It concludes that this risk can be mitigated because mining companies can be required to determine the likelihood of fracking-induced earthquakes and monitor possible earthquakes through the work plans and survey plans required under Dutch mining law.

The (conventional) gas production in the Groningen gas field causes approximately 50 earthquakes per year. A more severe earthquake with a magnitude of 3.6 on the Richter scale occurred in Loppersum (Groningen) in 2012, prompting the Dutch government to assess the risk of earthquakes in the future, including in relation to assessing potential exploration and production of shale gas.

Current status

Following the consortium's report, the Minister of Economic Affairs ordered an environmental impact assessment (*Plan-MER*) by Arcadis, also taking into account feedback from a special commission for environmental impact assessment (*Commissie voor de m.e.r*). In addition to the issues identified above, the commission advised that the following should be taken into account:

- the general question of whether shale gas is beneficial to society from the perspective of the transition to sustainable energy

- the exploration and production of shale oil

- areas excluded from shale gas activities and whether restrictions should only be horizontal and not vertical

- production of a clear timeline showing how shale activities can be developed, following the conclusions about the environmental and societal impact.

It is currently envisaged that the results of this assessment will be published towards the end of 2015 in a *Structuurvisie Schaliegas*. This high-level report on spatial planning will inform the Minister of Economic Affairs' conclusions, in cooperation with the Minister of Infrastructure and Environment, about whether shale oil/gas activities will be allowed in the Netherlands, in which areas and under what conditions to limit the impact on nature, the environment and inhabitants.

The *Structuurvisie* will explicitly not provide clarity on specific locations within the areas indicated as feasible for shale oil/gas activities or related specific conditions. It will serve as guidance for market parties wishing to develop such activities.

Regulatory framework

There is currently no specific regulatory regime for fracking and shale gas exploration and production in the Netherlands, as it is considered to be part of the activities relating to well construction and maintenance.

However, the Minister of Economic Affairs has now ordered the drafting of amendments to current legislation, encompassing, as a minimum, the introduction of a separate status for fracking activities and a specific regime in respect of planning and execution of fracking activities, especially in relation to prior submission of reports to guarantee all safety and environmental standards are met. This is expected to be published before summer 2015.

For exploration and production of shale gas, a separate exploration and operating permit must be obtained under the Mining Act from the Minister of Economic Affairs. The current permit regime grants the holder of an exploration permit a production permit for that same area upon request. This secures a party's position in the event that an exploratory drilling is successful, especially since only one exploration or production permit will be granted for a

specific area and no production permit will be granted prior to the expiration of the exploration permit.

The Mining Act

The Mining Act states the requirements and conditions to prevent dangerous incidents. Preventative measures can involve technical, organisational, procedural or supervisory aspects set by the relevant European Union (EU) directives, requiring:

- an exploration production/extraction permit, which includes approval of a production plan setting out the planned activities, costs, produced amounts and possible consequences with regard to movements in the subsurface
- independent inspection by the State Supervision of Mines (*Staatstoezicht op de Mijnen*)
- several general regulations regarding the design, operation and monitoring of mining works where products are stored.

Once exploratory drillings have shown that an economically recoverable amount is achievable in the area, a production permit can be requested. A production permit (concession) could be regarded as 'exclusivity' for that area. The party having the exploration permit is granted a production permit upon request if such a permit is requested before the exploration permit expires.

If the production permit is requested by a party other than the holder of the exploration permit, or is requested after the expiration date of the exploration permit, the minister can give other parties the opportunity to apply for a production permit. In such event, the applicant must demonstrate:

- that it is economically viable to extract the shale gas
- the applicant's financial position and capabilities
- the method of execution
- the applicant's social responsibility.

National coordination regulation

In addition to these permits, various other approvals and permits are required for the production of shale gas, such as those for land use, construction, establishment of surface and underground facilities, and for the performance of actions that may influence the quantity and quality of groundwater in protected nature conservation areas.

In principle, these various approvals and permits each have their own application process via various relevant authorities. In practice, shale gas projects may avoid the separate licensing procedures if the National Coordination Regulation (NCR, *Rijkscoordinatieregeling*) is applied.

The NCR for the State, provinces and municipalities came into force in 2008 under the new Spatial Planning Act (SPA, *Wet ruimtelijke ordening*) and applies to mining activities covered by the Mining Act. It appoints one government organisation as the responsible authority and aims to make the decision-making process for changes to spatial plans and associated permitting procedures faster and more efficient.

Exploration and production (E&P) infrastructure projects concerning large energy projects that are considered to be of national interest, and that need to be incorporated into spatial plans, have become subject to the NCR regulation.

Other applicable permits that are covered by the NCR are the SPA, the General Provisions Environmental Law and the Water Act:

- The SPA (*Wet ruimtelijke ordening*) regulates the establishment and modification of spatial planning in the Netherlands. This law requires local governments to draw up more indicative plans (structural visions), but also applies to civic integration and binding zoning plans. It provides the opportunity to lay out general spatial plans, which are further elaborated in local spatial planning. Buildings, pipelines and other installations associated with gas production are reviewed in relation to existing zoning requirements.
- The General Provisions Environmental Law (*Wet algemene bepalingen omgevingsrecht*, or 'Wabo') contains various rules and frameworks for activities that may affect the physical environment. It was established to provide a simplified and faster permitting procedure for building, space and the environment. Known as the 'All-in-One' permit, this is an integrated permit for the physical aspects of building, housing, monuments, space, nature and the environment. For shale gas production, the environment and building requirements are especially relevant. Any possible effects on protected nature conservation areas play an important role. Although the purpose of the Wabo is to grant a permit for an entire project, it is possible that each drilling location would require an All-in-One permit because of the distance between the well pads.
- The Water Act covers quality and quantity of surface water, groundwater and the protection of water management works, such as dams. It is formed by the integration of eight historic water laws and its main purpose is the instrumentation of integrated water management.

The Crisis and Recovery Act

The Crisis and Recovery Act 2010 (*Crisis-en Herstelwet*) applies to major construction projects and projects in the field of sustainability, energy and innovation. It accelerates the procedures for these large projects, while maintaining the necessary safeguards for responsible decision making. The Act contains a large number of amendments that shorten procedures, reduce the number of necessary permits and licences, and provide more clarity in administrative responsibilities. The law also aims to give the construction industry an economic boost during the credit crisis.

At the introduction of the Act, a total of 58 projects were identified to which the law applies. However, upon the recommendation of the Prime Minister, new projects can be appointed by way of order in council (*Algemene Maatregel van Bestuur*). There are temporary measures applicable to these projects, which include appeal procedures and environmental impact assessments. The Crisis and Recovery Act was introduced as a temporary measure but was extended for an indefinite period in April 2013.

Establishment of a local entity

The Netherlands provides an attractive structure for oil and gas investments because of its vast network of tax treaties on the avoidance of double taxation, and its bilateral investment treaties (BITs). Its various initiatives provide a stable and attractive regulatory framework for the development of energy projects. Its adherence to the Energy Charter Treaty establishes a multilateral framework for cross-border cooperation in the energy industry and protection of energy investment.

Several different investment vehicles are available. The main Dutch business organisations are limited liability companies that take the form of either BVs or NVs. Recently, the rules for BVs have been relaxed in several respects, so that incorporation of a Dutch BV or restructuring of a group of companies can be done both easily and quickly. Some of the new rules apply automatically, while others need to be made applicable through amendment to the articles of association. It is therefore useful to review the articles of existing Dutch BVs to ensure that these changes in law are used to their full advantage.

Poland

Since 2010, the mood in the Polish shale gas sector has deteriorated from early enthusiasm to notable pessimism. As a result, the government now intends to reinvigorate the sector with a new set of regulations aimed at promoting shale gas exploration and future exploitation.

Shale play details and current status

In 2011, the US EIA's (Energy Information Administration) initial estimates indicated that Polish shale reserves were the largest in Europe. Poland was reckoned to have 5.8 trillion cubic feet of proved natural gas reserves and 187 trillion cubic feet of technically recoverable shale gas resources[1]. In 2013, the shale gas resource estimate was reduced from 187 trillion cubic feet to 148 trillion cubic feet[2]. Recent Polish estimates have been more conservative, in the range of 346–768 billion cubic feet[3]. Poland uses 16 billion cubic feet of gas a year[4].

As can be seen in the map on page 103, there are numerous areas with potential for significant shale gas resources. Most of the shale gas is located in the Baltic Sea Basin, the region of Lublin voivodeship or Lublin province and Podlaskie voivodeship.

The total number of shale gas targeted licences has fallen from a peak of over 110 in 2012 to below 60 as of February 1, 2015[5]. Major companies – including Chevron, ExxonMobil, Marathon Oil, Cuadrilla, Eni and Talisman Energy – have pulled out of the country. On the other hand, there are new entrants such as Stena. The largest number of licences is held by State-controlled PGNiG and other State-controlled companies that are active in this field include LOTOS Petrobaltic and PKN Orlen.

The number of shale gas exploration drillings has also decreased, leaving PGNiG and PKN Orlen as leaders[6]. This slow progress in exploration activities is attributed to the reduced estimates, slow rate of exploration, legal and regulatory uncertainties and challenging geology. No shale gas exploitation licences have so far been issued, though there are strong hopes that this may change in the near future.

Hydrocarbons regulation

Oil and gas exploration activities, like other geological and mining activities, are subject to general Polish mining regulations, in particular the Geological and Mining Law of June 9, 2011 (consolidated text: the Journal of Laws from 2014 No. 613 as amended). From a legal point of view, exploration and exploitation of shale gas deposits are therefore no different from conventional hydrocarbons or any other underground natural resources.

The general mineral ownership rule

As a general rule, deposits of hydrocarbons[7], hard coal, methane (as an accompanying mineral), brown coal, metal ores (with the exception of bog meadow iron ores and native metals), ores of radioactive elements, native sulphur, rock salt, potassium salt, magnesium-potassium salt, gypsum and anhydrite, and precious stones, irrespective of the place

1 World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States, US EIA April 2011 (http://www.eia.gov/analysis/studies/worldshalegas/archive/2011/pdf/fullreport.pdf?zscb=76208994).

2 Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41Countries Outside the United States, US EIA June 2013 (http://www.eia.gov/analysis/studies/worldshalegas/).

3 First Report: Assessment of shale gas and shale oil resources of the lower paleozoic Baltic-Podlasie-Lublin Basin in Poland, PIG March 212 (http://www.mos.gov.pl/g2/big/2012_03/564f242a1e48822a3bde24b90ffe76c0.pdf).

4 Source: www.mg.gov.pl

5 Source: http://www.mos.gov.pl/g2/big/2015_02/3c2663cbad333b3d9288542a050b5dcf.pdf

6 Source: http://www.mos.gov.pl/g2/big/2014_12/4e2f2c0f46c4a3e14d260061bb82d251.pdf

7 Defined as crude oil, natural gas, and their natural derivatives, as well as methane found in hard coal deposits, except for methane found as an accompanying mineral (article 6 sec. 1 point 16 of the Geological and Mining Law).

148 TCF Reserve estimates

The US Energy Information Administration estimates that Poland's technically recoverable shale gas reserves are amongst the largest in Europe, although this has not yet been confirmed by exploratory drilling.

13 TCF

Having conducted test drilling at three concessions located in northern Poland, one energy company has estimated that there is at least 13 TCF of recoverable shale gas reserves, much more than previously conservative estimates suggested.

109 Concessions

According to the Ministry of Environment, as of April 2013, 109 concessions for exploration have already been granted, covering 88,000km^2 and over 40 exploration wells.

June 2010

The first exploration drilling commenced in June 2010 in the Lubień region in the northern part of Poland.

where they are found, are covered by mining ownership. The right of mining ownership is vested in the State Treasury, which may use the resource constituting the object of mining ownership[8] and dispose of its right through establishment of a mining usufruct only.

The US Energy Information Administration estimates that Poland's technically recoverable shale gas reserves are amongst the largest in Europe, although this has not yet been confirmed by exploratory drilling.

Rights, licences and approvals

In order to conduct exploration or exploitation activities in Poland, an entity needs to obtain a licence for exploration or exploitation activities, issued by the Minister of Environment, and enter into a mining usufruct agreement.

From January 1, 2015, the licence and mining usufruct agreements regarding hydrocarbons may apply to both exploration and exploitation, or solely to exploitation.

As far as non-hydrocarbon minerals are concerned, it will not be possible to obtain one licence and conclude a mining usufruct agreement covering both exploration (or prospecting) activities and extraction activities. In such a case, the entity needs to obtain an additional licence and a mining usufruct agreement covering the exploitation of a particular mineral within a specified area in order to extract minerals.

Licences

Exploration or exploitation of underground natural resources in Poland requires a licence. This is issued for a limited period (from three to 50 years) and authorises exploration or exploitation activities within a pre-defined area.

The tender process

As a general rule, granting a licence to explore hydrocarbon deposits and extract hydrocarbons from deposits should be preceded by tendering. The relevant authority is obliged to communicate its intention to grant a licence ex officio by way of tendering, specifying in the announcement, in particular:

- the location of the area of the intended activity
- detailed conditions of the tendering
- the time limit for commencement of the intended activity
- the term for which the licence is to be granted
- the essential conditions of the contract of establishment of a mining usufruct, in particular determination of the space in which the activity will be carried out, its duration and a minimum amount of remuneration for the establishment of the mining usufruct.

In line with the Geological and Mining Law, these conditions of tendering should:

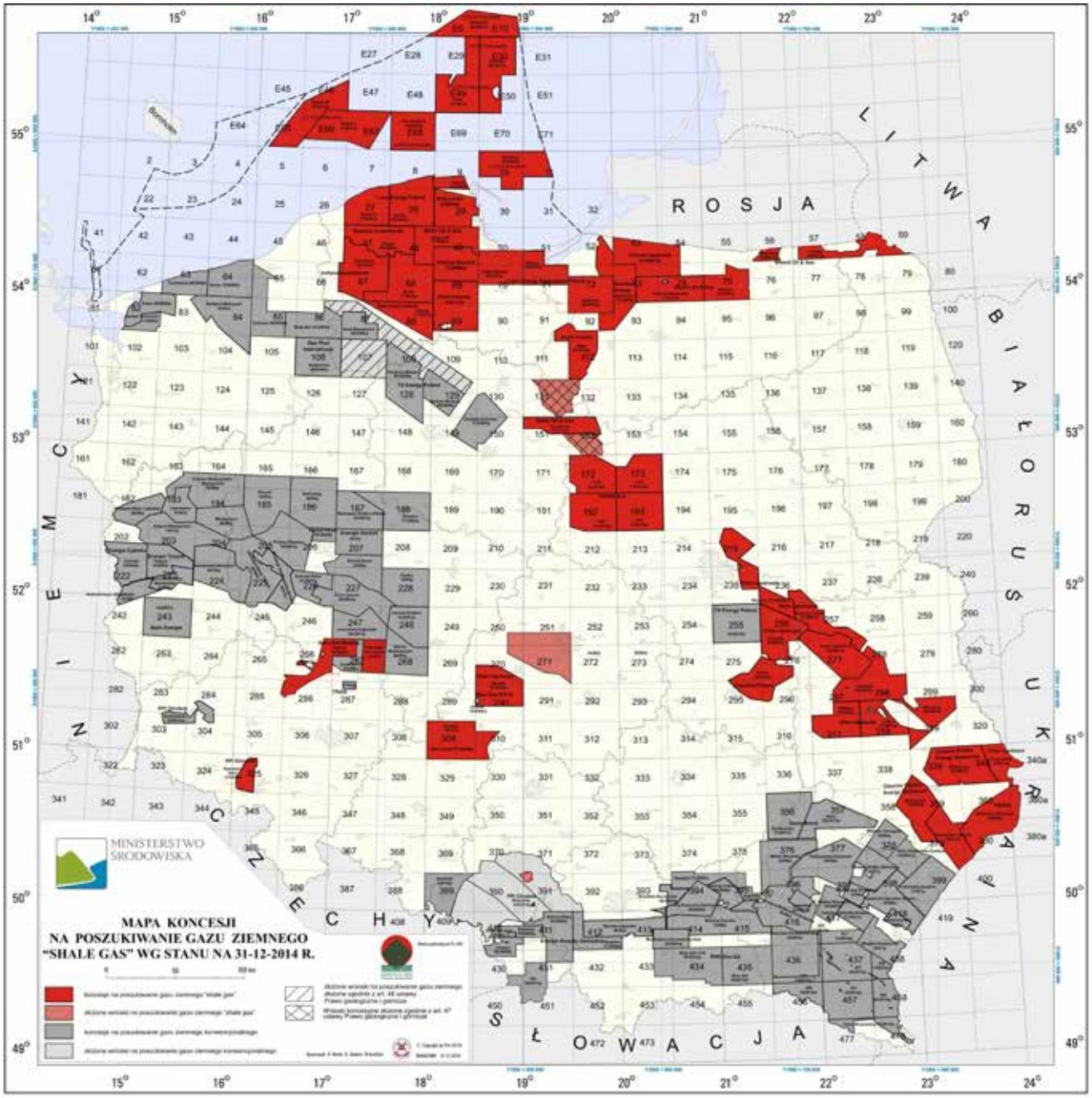
- be non-discriminatory
- give priority to best systems of prospecting or exploring hydrocarbon deposits or extracting hydrocarbons from deposits
- be based on the following criteria: (i) technical and financial capabilities of the bidder; (ii) proposed technology for conducting the work; and (iii) proposed amount of remuneration for establishment of the mining usufruct.

Prior to announcing the tender, the authority obtains an environmental decision (see below) and performs consultations or obtains opinions necessary to grant a licence. The entity that obtains a licence, by operation of law, assumes the rights and obligations of a party to the environmental decision and other opinions and arrangements made by the authority. The tendering procedure is not required when:

- the licence area is permanently available and is on the list of areas for which a licence may be granted without being preceded by tendering
- the licence area was already tendered for but no licence has been granted
- the activity refers to a licence area from which the licensed entity resigned
- the area is covered by a priority to establish a mining usufruct.

If it is possible to grant a licence without a tender, the authority should publish the information on initiating proceedings and on the decision, concluding the proceedings without delay. Any proceedings initiated later than the date of the announcement in the Public Information Bulletin are discontinued by operation of law.

8 Article 10 sec. 1, sec. 2 and sec. 5 of the Geological and Mining Law. Deposits of hydrocarbons, hard coal, methane existing as an accompanying mineral, brown coal, metal ores, with the exception of bog meadow iron ores and native metals, ores of radioactive elements, native sulphur, rock salt, potassium salt, magnesium-potassium salt, gypsum and anhydrite, precious stones, irrespectively of the place where they can be found, shall be covered by mining ownership. Deposits of brine, curative and thermal waters shall also be covered by mining ownership



Graphic: Polish Ministry of The Environment

*The map presents licence areas already covered by: (i) applications for shale gas exploration licences (light red); (ii) final shale gas exploration licences (dark red); (iii) applications for conventional gas exploration licences (light grey); (iv) final conventional gas exploration licences (dark grey). Published by the Environmental Ministry as of December 31, 2014.**

* Source: http://www.mos.gov.pl/g2/big/2015_01/a9cce08d428b4b385b111450a6f2f4cc.jpg

Payment for exploration and exploitation rights
A licensee is obliged to pay for the right of exploration or exploitation of underground natural resources. The amount of such payment and manner of payment is provided in the licence. The amount of payment is calculated by multiplication of the fee rate for the given type of resource and the number of square kilometres of area on which a licensed activity is performed.

Transfer, cancellation, limitation and expiry of licences
A licence may be transferred to a third party that:

- accepts all terms and conditions of the licence
- has rights to geological information, real property and a mining usufruct or a right to acquire this right
- is able to prove that it can fulfil all requirements for the contemplated exploration and/or exploitation activities.

The transfer of the licence also results in the transfer of the mining usufruct.

A licence may be cancelled or limited in its scope without any compensation if the licensee infringes provisions of the mining regulations. In particular, this may apply with respect to environmental protection or the proper management of the underground natural resources. It may also apply if the licensee does not fulfil the terms and conditions of the licence (including failure to commence operations or their permanent completion), despite prior notice to rectify such acts or omissions.

A licence expires: with the lapse of its time limit; if it becomes obsolete; in case of a licensee liquidation; or in case of the waiver of a licence by the licensee.

Mining usufruct

The beneficiary of a mining usufruct has a right to explore or exploit underground natural resources to the exclusion of any other third parties, subject to the provisions of laws and regulations and the provisions of the mining usufruct agreement.

The mining usufruct is created by agreement with the Minister of Environment (acting in the name of the State Treasury) for a specific period not longer than 50 years. Such agreement is executed immediately after the relevant licence is granted. If a licence expires or is revoked, the mining usufruct expires.

The tender process
In accordance with the Polish Geological and Mining Law, save for a certain limited number of exclusions, the grant of a mining usufruct with respect to exploration for or exploitation of hydrocarbons requires a prior tender. Tenders for such concessions will be regulated by separate provisions of the mining regulations. Nevertheless, conditions of tendering should be non-discriminatory and will be based on the following criteria:

- technical and financial capabilities of the bidder
- proposed technology for conducting work
- proposed amount of remuneration for establishment of a mining usufruct.

Other aspects of mining usufructs
The mining usufruct is granted for consideration. The amount of such consideration is subject to the mining usufruct agreement and may be paid in one or more instalments as agreed.

In matters not regulated by the Geological and Mining Law, the relevant provisions of the Civil Code on tenancy are applied to a mining usufruct.

The current Geological and Mining Law does not regulate the possibility of disposal of a mining usufruct. The lack of any provision regulating the possibility of transferring a mining usufruct, and the change of auxiliary use of the regulations on leases, mean that further analysis would be required as to whether any disposal of a mining usufruct is possible.

The environmental decision

Exploration or extraction works 'may potentially always significantly influence [the] environment'. As a consequence, the prospective applicant needs to obtain an environmental decision prior to applying for a licence for exploration or extraction of a mineral.

Projects that have, or may potentially have, a significant effect on the environment must first obtain a decision on environmental conditions (environmental decision) in accordance with the Act of October 3, 2008 on Access to Information on Environment and its Protection, Public Participation in Protection of Environment and on Environmental Impact Assessment (the EIA Act). The environmental decision is required prior to the issuance of the decisions listed in Article 72, Section 1 of the EIA Act including, among other things, decisions to issue licences for prospecting and exploration for mineral deposits and licences for the extraction of minerals from deposits.

The environmental decision should be attached to an application for any of the decisions listed in Article 72, Section 1 of the EIA Act within four years of its issuance The validity of the environmental decision may be extended for the following two years if the investor obtains a confirmation that the given investment was realised in stages and the conditions provided in the decision have not changed.

Procedure for the environmental decision

The procedure for issuing an environmental decision usually involves conducting an environmental impact assessment, including preparing a report on the likely impact of the project on the environment. The procedure comprises a public consultation stage in which anyone can submit complaints and recommendations within a 21-day period for review by the relevant environmental authority. The EIA Act entitles ecological organisations to participate in public consultations and to have rights as a party to the proceedings. In particular, ecological organisations have the right to appeal against a decision issued in a procedure requiring public consultation.

In the environmental impact assessment procedure, the applicant should submit its selected investment performance scenario. It should also present any possible alternative scenarios that the applicant previously considered, as well as a justification of its final choice. The authority may choose one of the alternative scenarios instead of the applicant's choice. If the applicant does not agree to implement that alternative scenario, the authority would refuse to issue the environmental decision.

The environmental decision may require compensation or a limit to the impact on the environment or oblige an investor to present post-completion analyses.

Since the procedure for issuing an environmental decision usually involves conducting an environmental impact assessment, it is difficult to predict the timeframe for the procedure. It may take three to six months or even longer, especially if the proposed area of exploration or extraction works is environmentally sensitive.

The environmental decision is transferable with the consent of the party to whom the relevant decision has been issued.

Legal title to real property

A mining usufruct agreement granting rights to explore the Earth's crust does not automatically give the right to access the surface of the land and perform exploratory works from there. This issue is left to general rules of law concerning the right to use and dispose of property and, in particular, is left to the consent of the land owner. To access and perform exploratory works on the ground, an entrepreneur therefore needs to possess title to the surface of the land in the form of ownership, a perpetual usufruct right or other contractual right to land, such as a lease or tenancy agreement.

Lease of property

According to the provisions of the Civil Code, there are two types of land leases:

- *Najem* involves the right to use the land. If entered into for a term exceeding ten years, it may be terminated by notice ten years after its effective date. However, if it is concluded between business entities, it only becomes terminable after 30 years.
- *Dzierżawa* involves the right to both use and derive benefits (fruits) of the land, which becomes terminable 30 years after its effective date.

Ownership and perpetual usufruct rights

Under Polish law, ownership is the most extensive title to real property, under which the owner of real estate is entitled to use an area of real estate for an unlimited period of time to the exclusion of any third-party right and may freely dispose of his right to the real estate. Ownership may only be limited by statutory law, principles of community life and the socio-economic purpose of the ownership.

Acquisition of land by foreigners

The regulation on acquisition of land by foreigners in Poland results in certain restrictions as to acquisition of agricultural or forestry land or establishing a perpetual usufruct right in favour of a foreign entity. The Act of March 24, 1920 on Acquisition of Real Property by Foreigners provides that the acquisition of real estate by a foreigner generally requires a permit issued by a minister competent for internal affairs in the form of an administrative decision. However, foreigners who are citizens or companies of a Member State of the European Economic Area (EEA) are not required to obtain a permit.

Notwithstanding the above, foreigners who are citizens or companies of a Member State of the EEA are still obliged to obtain a permit for the acquisition of agricultural and forest real estate within 12 years from the date of accession of the Republic of Poland to the European Union (EU), that is from May 1, 2004. Such permit is not required for the purchase of shares in a company that is the owner or a perpetual usufructor of such type of real estate.

Perpetual usufruct
Perpetual usufruct resembles a leasehold established for a period of 40–99 years (with the possibility of an extension), but the legal nature of this estate should be considered more as a freehold. The following may be held under perpetual usufruct:

- lands owned by the State Treasury and situated within the administrative limits of towns and settlements
- lands owned by the State Treasury situated beyond those limits, but covered by a real estate special development plan of a town or settlement and designated to serve its economic needs
- lands owned by municipalities or their unions.

The perpetual usufructor is entitled to:

- use the land to the exclusion of any third party
- dispose of his right to the land
- own buildings and other facilities erected on the land let for perpetual usufruct
- exercise a right to purchase the land when an owner of the land wants to sell it
- request an extension of the right of perpetual usufruct for a further 40–99 years, within the last five years before the expiry of the original time of the perpetual usufruct
- obtain remuneration for the buildings and other facilities erected on the land upon the expiry of the perpetual usufruct
- enjoy the right to transform the perpetual usufruct into ownership when specific requirements are met.

Changes to regulatory regime

Hydrocarbons Act
In April 2014, the government agreed on a draft act to amend Polish geological and mining law and other laws that are focused on hydrocarbon prospecting and production. The Hydrocarbons Act was adopted in July 2014 and came into force on January 1, 2015.

Under the Act, the previous system of separate prospecting, exploration and exploitation licences is abandoned. A unified prospecting, exploration and exploitation licence system now applies and such licences will be issued for a defined period from ten to 30 years.

Prospecting and exploration activities can last for a maximum of five years. The prospecting period can be extended once if necessary to complete the prospecting phase, but for no longer than one year.

Commencement of the production phase will be subject to first obtaining an 'investment decision'. This in turn will require prior approval of the geological and investment documentation, as well as a decision on the environmental terms and conditions of the investment.

Any hydrocarbon licence transfer will be subject to prior consent from the Minister of Environment. The Act prohibits the transfer of any licences as a result of merger, acquisition of an enterprise (ongoing business) in a bankruptcy proceeding or other acquisition of such enterprise (ongoing business).

Tendering for hydrocarbons licences
New hydrocarbon licences will be granted through tenders to be announced by the Ministry of the Environment.

The Act introduces a specific qualification procedure in relation to bidders for the exploration or exploitation of hydrocarbons. In addition to verifying that bidders have the necessary resources and experience to conduct exploration and exploitation activities, the qualification procedure is supposed to check whether a bidder is controlled by a 'third country' or a citizen of a third country. A third country is a State that is:

- outside the EU, the European Free Trade Association or NATO
- not a party to the EEA agreement
- not a party to agreements with EU member States or an agreement with the EU on free trade.

If a bidder is controlled by a third country, the qualification procedure must verify whether this may endanger the safety of the State.

Strengthening the Ministry of the Environment's position
Under the Act, the Minister of Environment is obliged to commence a proceeding to withdraw a licence if the licensee does not fulfil the provisions of the licence, such as in the event of:

- failure to conduct activities provided for in the concession
- permanent cessation of licence activities

- failure to observe the schedule for geological works
- failure to document geological works
- failure to provide the mining authorities with current parameters of hydrocarbons exploitation.

The minister must request the licensee to remedy notified infringements and indicate the manner in which it will do so. If the licensee fails to do so, the minister may cancel the licence or, if the schedule is breached, withdraw a concession or limit its scope without compensation. The minister may terminate the cancellation or concession withdrawal proceeding only if no infringements have taken place, or infringements have been caused by force majeure, or the relevant infringements are remedied.

Royalties from January 1, 2016
From January 1, 2016, the royalties for gas exploitation significantly increased from a rate of PLN 6.38 (approx. €1.57; approx. US$1.78) per thousand m³ in the case of methane-rich natural gas and PLN 5.31 (approx. €1.31; approx. US$1.48) per thousand m³ in the case of natural gas. Rates for oil exploitation will also slightly increase.

Type of mineral	Unit of measurement (IU)	Royalty rate (PLN/IU)	Royalty rate in € and US$
Methane-rich natural gas exploited in the amount of more than 2,500 thousand m³ in a calculation period	thousand m³	24.00	approx. € 5.92 approx. US$6.72
Methane-rich natural gas exploited in the amount of less than 2,500 thousand m³ in a calculation period	thousand m³	6.23	approx. € 1.53 approx. US$1.74
Natural gas exploited in the amount of more than 2,500 thousand m³ in a calculation period	thousand m³	20.00	approx. € 4.93
Natural gas exploited in the amount of more than 2,500 thousand m³ in a calculation period	thousand m³	5.18	approx. US$ 5.60 approx. € 1.27 approx. US$ 1.45
Oil exploited in the amount of more than 1,000 tonne in a calculation period	tonne	50.00	approx. € 12.34 approx. US$14.00
Oil exploited in the amount of less than 1,000 tonne in a calculation period	tonne	36.84	approx. € 9.10 approx. US$10.31

Table: Mineral royalties from January 1, 2016

Transitional provisions
The Act contains several transitional provisions that are material for existing hydrocarbons licence holders and other interested parties.

Prospecting, exploration and exploitation licences issued before January 1, 2015 will remain in full force. Exploitation licences issued before January 1, 2015 will become licences under the Mining Act.

Generally, a prospecting and exploration licence holder will be authorised to apply to the ministry to change its licence into a prospecting, exploration and exploitation licence under the terms and conditions of the Act. This application must be filed within two years of the Act coming into force. During the procedure to change the status of the licence, the ministry will check whether such holder is controlled by a third country.

A prospecting and exploration licence will not expire on the dates specified in the licence if a procedure to change its status is pending.

The holder of a prospecting and exploration licence that has not changed into a prospecting, exploration and exploitation licence will be authorised to apply to the ministry to change the status of its licence where particular geological conditions and proper management of the resource so warrant. In such cases, the licence's validity may be extended for a maximum of three years. The provisions regarding control by third countries apply to this procedure.

An exploration licensee may demand that a mining usufruct be established, with priority over others, within five years of delivery of the decision approving the geological documentation, if it:

- has documented a resource to a degree that enables it to prepare the pre-feasibility study for a deposit, and
- obtained a decision approving the geological documentation of such deposit before the Act came into force.

An exploration licensee may demand that a mining usufruct be established, with priority over others, within three years of delivery of the decision approving the geological documentation, if it:

- has documented a resource to a degree that enables it to prepare the pre-feasibility study for a deposit, and
- obtains a decision approving the geological documentation of such deposit after the Act came into force.

The holder of a prospecting and exploration licence issued before January 1, 2015 may be awarded an exploitation licence without a tender pursuant to the terms and conditions of the Act.

Hydrocarbons Investment Act

In mid-September 2014, the Ministry of the State Treasury announced a draft Act that would set out particular rules for the preparation and realisation of investments concerning prospecting, exploration, exploitation and transportation of hydrocarbons. The draft act was presented for approval by the Polish Government approval in February 2015.

The main aim of the draft Hydrocarbons Investment Act is to expedite the realisation of such investments by accelerating and simplifying the administrative procedures relating to prospecting, exploration, exploitation and transportation.

One of the main features of the Act is the limited application of zoning regulations to prospecting, exploration, exploitation and transportation of hydrocarbons. In particular, if hydrocarbon investments are not foreseen under local zoning plans, they can be realised under individual zoning (investment) decisions.

The Act also introduces accelerated procedures for the issuance of decisions concerning hydrocarbon prospecting, exploration, exploitation and transportation, such as environmental permits regarding investment, decisions on the exclusion of real estate from agricultural or forest activities and water permits.

Securing real estate

The Act includes separate provisions on securing real estate for prospecting and exploration purposes. Such procedures concern public roads and railways, third-party real estate and real estate of unregulated legal status. If the investor cannot obtain an agreement or consent for the use of real estate, a *voivode* (public administration office) will be obliged to issue a decision allowing for such use.

Revised timescales

According to the Act, environmental permits regarding investment will be issued within 45 days of application. Decisions on the exclusion of real estate from agricultural or forest activities will be issued within 14 days of receipt of the relevant application. Water permits will be issued within 30 days of receipt of the relevant application. If these timeframes are not observed, the relevant authorities will be subject to penalties amounting to approximately PLN1,000 (€240) for each day of delay.

Additionally, the timeframes for issuing of building permits and use permits regarding hydrocarbon prospecting, exploration, exploitation and transportation have been shortened to 30 days and 21 days respectively. Commencement of the hydrocarbon production phase will be subject to an 'investment decision'. The provisions of zoning regulations will not apply (e.g. on the adoption of local zoning plans). It therefore seems that procedures in this respect will also be shortened, as in practical terms the adoption of local zoning plans may take 12 months or longer.

The Act also shortens appellate procedures regarding decisions issued in relation to the activities covered in the Act. Decisions will be subject to immediate enforcement. The term for appealing a decision will be shortened from 14 days to 7 from its delivery (or to 14 days from its public announcement).

Court appeal procedures are also expected to be shortened.

According to the Ministry of the State Treasury, these changes should reduce the preparatory stage before the commencement of exploration drillings from between seven and 12 months to three months.

The Act is subject to further public consultation and intergovernmental and parliamentary works.

Conclusions

The Polish Government embraced shale gas enthusiastically as a way of reducing its reliance on imported energy from Russia. However, since the launch of exploration in 2010 and 2011, the estimates have been downgraded and geological conditions for drilling have proved difficult.

The shale gas sector was originally attracted by estimates of massive shale gas reserves in Poland. However, sharp falls in world energy prices in the past few months have forced energy majors to limit spending and suspend or abandon investment projects.

Recent and planned changes in Polish regulatory framework bring hope for revival of its shale gas sector. However, it still remains to be seen whether such changes will result in a prompt development of the Polish shale gas sector.

Russia

The shale industry in Russia is at an early stage of development, and potential shale gas reserves have not yet been fully identified. There are no active projects to develop or produce shale gas deposits, and Gazprom, the leading Russian gas producer, recently stated that it is not interested in pursuing such projects in the near future as its natural gas reserves are more than sufficient to meet internal and external gas market demands.

Recent international sanctions imposed on the Russian energy sector have further postponed the development of potential shale projects. Nevertheless, the Russian government recognises the long-term importance of the shale industry and has announced plans, together with Gazprom, to conduct a geological assessment of potential shale gas reserves.

Potential gas shale deposits in Russia

In its June 2013 report, the US Energy Information Administration (EIA) assessed several formations in Russia, including the Upper Jurassic Bazhenov Shale in the West Siberian Basin. This formation stretches across much of the basin, outcropping at the basin edges and reaching depths of over 16,400ft (5,000m) in the central northern region. According to the EIA report, Bazhenov Shale is organically rich, siliceous shale and is the principal source rock for conventional oil and gas produced from the West Siberian Basin. Bazhenov Shale is estimated to hold 1,920 TCF (trillion cubic feet) of risked shale gas, with 285 TCF assessed as risked, technically recoverable shale gas resource.

According to the EIA1, other formations that may contain shale gas are the Lower Jurassic Tyumen and the Lower Cretaceous Achimov formations (which are also located in the West Siberian Basin) and the Domanik Shale formation in the Timan-Pechora Basin. The Lower Jurassic Tyumen formation is not considered to be a prospect in the northern areas of the basin where it is projected to be at depths greater than 16,400ft (5,000m). There is insufficient publicly available data about the other two formations to enable a quantitative assessment of resource[1].

According to publicly available information, there are several other formations that have not been assessed, but which may contain shale gas resources. Among them are the Chitino-Ingodinskaya and Ononskaya Mesozoic structural low and Pre-Ural foredeep formations, and formations in the Leningrad and Kaliningrad regions.

As natural gas reserves gradually deplete, it can be expected that the development of the shale gas industry in Russia will become of increasing interest to both Russian and foreign oil and gas companies.

1 *Ibid.*

1920 TCF Bazhenov Shale

*Bazhenov Shale in the West Siberian Basin is estimated to hold 1,920 TCF of risked shale gas in place, with 285 TCF assessed as risked, technically recoverable shale gas resource.**

Other formations may contain shales with gas potential, but there is no publicly available quantitative assessment of resource in relation to those formations.

There are currently no active projects relating to development or production of shale gas deposits in Russia.

* Technically Recoverable Shale Oil and Shale Gas Resources: An assessment of 137 shale formations in 41 countries outside the United States, US Energy Information Administration, 2013. Available at: http://www.eia.gov/analysis/studies/worldshalegas/

Key legal issues

Subsoil licensing

There are certain technical requirements relating to hydraulic fracturing and handling of poisonous liquids pumped in subsoil, all of which may be directly relevant to production of shale gas. However, there is currently no Russian legislation specifically relating to shale gas. The exploration, development and production of any shale fields will be carried out under existing laws that apply to all other oil and gas exploration, development and production activities.

The principal law governing subsoil use in Russia is the Law of the Russian Federation No. 2395-1 'On subsoil', dated February 21, 1992, as amended (the Subsoil Law). The Subsoil Law introduced a licensing system governing the geological study, exploration and production of natural resources, including hydrocarbons.

The Subsoil Law establishes the basic principles and features of the licensing and regulatory framework for the oil and gas industry, and contains rules governing the issue, transfer, surrender and revocation of subsoil licences. Detailed rules relating to licensing and control over the use of subsoil resources are set out in a number of regulations issued by the Russian government itself or through its ministries and agencies, including the Ministry of Natural Resources and Ecology.

State ownership of minerals

Under the Subsoil Law, the Russian State is the sole owner of the subsoil and its ownership right to the subsoil is inalienable. Accordingly, oil companies may only obtain rights to 'use' subsoil (not to own it), and such rights can only be granted by the State. However, title to extracted products generally passes to the licence holder from the moment they reach the surface.

Licensing of subsoil use

The Federal Agency for Subsoil Use (Rosnedra) and its regional divisions are vested with the exclusive authority to issue, execute, register, suspend and revoke hydrocarbon-related subsoil licences, except for licences for Deposits of Federal Importance (see separate section below) which must be authorised by the Russian government.

A subsoil use licence only establishes the basic rights granted to the licence holder. The majority of the terms and conditions are documented in a separate licence agreement, which is an integral part of a subsoil licence.

Subsoil licences are only transferable to an entity that is 50 per cent or more owned by the original licence holder or to an entity that owns 50 per cent or more of the original licence holder. Transfers are only permitted under certain circumstances. Additional restrictions apply to the transfer of a licence for Deposits of Federal Importance to a legal entity in which a foreign investor exceeds certain ownership or control thresholds. This means that joint operating agreements of the type commonly in use in other markets tend not to be used in Russia, as the usual transfer of licence rights and obligations to an operator cannot be made. Oil and gas projects are therefore often structured as incorporated joint ventures.

Types of subsoil licences

Rights to explore for and produce minerals are generally granted by Rosnedra under three main types of subsoil licence:

- exploration licence – for the geological survey and assessment of a subsoil plot
- production licence – for detailed exploration and production of natural resources
- combined licence – for geological survey and assessment, detailed exploration and production of natural resources.

An exploration licence may not be issued for Deposits of Federal Importance (see separate section below). Use of these plots may only be granted under a production licence or a combined licence.

Issue of subsoil licences

There are a number of methods to obtain subsoil licences. They include:

- Filing an application to obtain an exploration licence – if there is only one applicant for an exploration licence, it will be issued without holding an auction or tender (see below for the differences between these).
- An auction/tendering procedure – if two or more applications are received for the same exploration licence, there will be an auction for a combined licence. Combined licences are awarded by auction or tender and production licences may also be issued in either of these ways.
- Converting an exploration licence into a production licence – if the holder of an exploration licence discovers mineral resource deposits through exploration work conducted at its own expense, it may apply to obtain a production licence. The process of converting an exploration licence into a production licence is not automatic, and there is a risk that the subsoil authorities may decide not to convert the licence on certain grounds. The law contains an exhaustive list of such grounds.

- A decision by the Russian government, granting the right to use Deposits of Federal Importance (see separate section below)
- A decision by Rosnedra, granting a short-term right to use the subsoil for a plot where the previous subsoil user's right has been terminated.
- Acquiring a bankrupt company that holds a subsoil licence under bankruptcy legislation.

The major difference between an auction and a tender is in the criteria for determining the winner. In the case of an auction, the only criterion is the offer price (although in order to qualify to take part in an auction, the applicant should, as in the case of tenders, also meet certain financial, technical and other requirements).

For a tender process, a number of different criteria are taken into account. These include the technical and scientific level of the geological exploration programme, the subsoil utilisation level, the completeness of the extraction of subsoil deposits, the level of investment in the social and economic development of the territory, and environmental and national security considerations. If the relevant criteria are equally satisfied by two or more participants in a tender, the participant that offers the highest price will win. Unlike in an auction process, in tenders with only one participant the participant may be awarded the relevant subsoil rights. In recent years, subsoil licences have mostly been granted through auctions.

Term of licences

Subsoil licences are granted for a limited period of time, which is stipulated in the licence.

An exploration licence is usually granted for five years, but may also be granted for seven or ten years (depending on the location of the subsoil plot). The term for geological exploration may be extended for the period required to complete exploration (subject to a number of requirements).

The term of a production licence is the production life of the field. This period is calculated on the basis of a feasibility study into developing the relevant type of mineral deposit, having regard both to expected use and the protection of the subsoil. In practice this is usually 20–25 years. The term of use of a subsoil plot may be extended for the life of the deposit. The licence holder must apply for an extension and must be in compliance with the licensing requirements in order to be eligible.

Periodic reviews

Government authorities undertake periodic reviews to ensure that subsoil licence holders comply with the terms of their licences and with applicable legislation. A licence holder can be fined for failing to comply with the terms of its subsoil licence and, under the Subsoil Law, a subsoil licence can be revoked, suspended or restricted in certain circumstances.

Other licences

In order to carry out subsoil works under a subsoil licence, a subsoil user may also need to obtain other technical licences for various types of works. These include use of explosives, flammable and chemically hazardous industrial facilities, loading/uploading activities with hazardous cargo, various transportation activities, and deactivation of waste materials. The procedure for obtaining these licences is set out in separate legislation.

Land-related issues

The key land-related issues are outlined below.

Land access

Exploration and development of mineral deposits is generally not possible without access to, and use of, ground surface areas. Under Russian law, a subsoil licence does not automatically entitle a licence holder to occupy the land necessary to carry out its activities. Access rights and rights to use any land must therefore be obtained separately from obtaining a subsoil licence and in the course of subsoil use (unless the licence holder owns or is otherwise entitled to access and use such land prior to obtaining a subsoil licence).

Land use rights are obtained for the parts of the licence area actually being used, which would typically include the plot being extracted, any access areas and any areas where other extraction-related activity is taking place.

Russian legislation on land access rights does not definitively state at what stage a subsoil user should initiate the procedure for obtaining the right to access relevant land. The formalisation of a subsoil user's land rights for the purposes of geological exploration and subsoil use is carried out under the procedure stipulated by Federal Law No.136-FZ 'Land Code of the Russian Federation', of October 25, 2001 (as amended or supplemented from time to time) (the Land Code). Under the Subsoil Law and the Land Code, land plots can be granted for the purposes of subsoil use after the subsoil licence has been issued to the subsoil user and supporting documents and project recultivation works have been approved.

In practice, the procedure for obtaining land rights to a land plot required for exploration and development is lengthy. Depending on the subdivision of the Russian Federation in which the plot is located, it may take several months. This is partly because of inconsistencies in the various legal acts governing the process of allocating land plots, and also partly because the system of cadastral registration and formation of land plots is incomplete in Russia.

Land categorisation issues can also present difficulties. The Land Code categorises land into one of seven categories (e.g. agricultural lands, forest fund lands and industrial lands) and imposes restrictions on the use of land in particular categories. It can be problematic if the land plots required for the performance of work under a subsoil licence belong to different land categories, and the subsoil user may need to apply to transfer the land from one category to another so as to extract minerals or perform exploration works. For example, agricultural land can be used for pipelines without being converted to another category, but not for oil and gas extraction. Some other land categories (e.g. industrial or forest land) can be used without the need for a transfer of land category.

Obtaining lease or ownership rights

The process of obtaining land rights is governed by federal and regional legislation. Although regional legislation should not contradict Russian federal law, in practice inconsistencies arise. This results in some ambiguity and irregularity in the procedure of obtaining land rights.

The majority of land plots in Russia are owned by federal, regional or municipal authorities which, through public auctions, tenders or private negotiations, can sell, lease or grant other rights of use over land to third parties.

Subsoil users generally obtain either a lease right or an ownership right over land plots.

Lease of land for subsoil use activity

The general principle, as established by the Land Code, is that land plots in State or municipal ownership that are required for the performance of works associated with subsoil use, should be granted for lease without the need for a tender or auction. The Russian government establishes the procedure and general principles for calculation of the amount of rental payments for such land plots.

Where land is not owned by a federal, regional or municipal authority, rents are determined by agreement between the land owner and the licence holder. If the lease agreement entitles the owner of land to change the rent level (as is often the case), it is entitled to do so as frequently as once a year. Rental rates for private land are not restricted by legislation.

Ownership right

Russian legislation allows private land ownership and the transfer of land from one person to another (except in the case of forest fund land, over which it is not possible to obtain a private ownership right).

The acquisition of State and municipally owned land plots by companies is generally carried out through an auction procedure. Foreign companies and individuals may own land on the same terms as Russian companies and individuals, with certain exceptions. The most notable exceptions are prohibitions on foreigners owning land near Russia's borders and in certain other territories specified by federal law. Also, agricultural land plots may not be owned by foreign citizens or entities, or by a Russian company that is more than 50 per cent owned by foreign shareholders.

Registration of rights and cadastral registration of land plots

Under Russian law, ownership rights to land plots and rights to lease land for a term of one year or more require registration in the State's Register of Rights to Real Estate (the Register). Such rights are registered by the registration authority in the relevant territory where the property is located and only become valid upon registration. Information from the Register is publicly available and can be used to confirm registered ownership rights.

Only land plots with a State cadastral number may be bought and sold. This number is issued when the land plot is registered in the Real Estate Cadastre that records the details of land plots, such as their measurements and boundaries. Most land in Russia has not yet been incorporated into the Real Estate Cadastre, which presents significant problems and requires the majority of subsoil users to apply for the cadastral registration of land prior to obtaining ownership or lease rights.

Forestry issues

Federal Law No. 200-FZ 'Forest Code of the Russian Federation', of December 4, 2006, as amended (the Forest Code) distinguishes between the following types of forests:

- Protection forests – to be developed for the purpose of preserving environmental and other benefits.
- Exploitation forests – intended for producing high-quality wood and other forest resources.

- Reserve forests – where woodcutting has generally been frozen for more than 20 years (except for certain limited instances).

The exploitation forest regulations start from the principle that the forest can be used for any type of activity permitted by the Forest Code (including for geological exploration and subsoil plot development). In contrast, the protection forest regulations establish strict limitations on any such activity.

There are numerous subcategories within each of the above forest types that determine what they may be used for. Depending on the subcategory of a particular forest, selective or clear cutting of trees and/or construction of geological exploration and subsoil plot development facilities may be restricted. Certain concessions exist for subsoil users who obtained licences prior to December 31, 2010.

Under the Forest Code, forest plots are granted for the purpose of geological exploration and subsoil plot development on a leasehold basis. Although a forest plot lease agreement is generally entered into following an auction of the relevant lease rights, an exemption exists in relation to lease rights for the purposes of geological exploration and subsoil plot development. A forest plot lease agreement for such purposes can be concluded for a term of up to 49 years.

Where geological exploration does not require tree cutting or the construction of geological exploration facilities, such activity may be carried out with the written permission of the State or local authorities without the need for a forest plot lease.

Protection of rights of indigenous peoples

Depending on the location of a shale gas project, Russian legislation on the protection of indigenous peoples may need to be taken into account. Under such legislation, indigenous peoples are empowered to participate in administering laws regulating the protection of the environment and natural resources, and may claim damages for any harm caused to the environment. Regional authorities may also restrict commercial activities in the traditional lands of indigenous peoples.

If land within the traditional territories of indigenous people is sought for purposes not connected with their traditional activities (e.g. for subsoil use or construction purposes), there may be referenda or meetings to resolve issues of land allocation. The relevant executive bodies or local self-governing authorities will then make a decision on the preliminary approval of the location of facilities based on the results of such referenda and gatherings.

In addition, there are laws relating to the protection of specific groups of indigenous peoples. For example, laws recognising the status of indigenous peoples in the north, Siberia and the far east of Russia provide that the exploitation for commercial purposes of natural resources situated in territories of 'traditional natural use' (i.e. specially protected territories intended for the traditional natural occupation of such peoples) will only be permitted where such exploitation does not violate the legal regime of such territories. These may include prohibitions on changes to the designated purpose of land or on the allocation of land rights to fulfil needs that are contrary to such purpose, the establishment of secured zones or districts with restricted areas of operation, and prohibitions on the construction of industrial objects.

Health, safety and environment

The main health, safety and environmental issues are set out below.

Health and safety

An entity conducting subsoil operations in Russia is responsible for maintaining a safe working environment and ensuring that hydrocarbon exploration, development and production activities are carried out according to applicable industrial safety requirements. The principal law regulating industrial safety in Russia is Federal Law No. 116-FZ, dated July 21, 1997, 'On industrial safety of dangerous industrial facilities', as amended (the Health and Safety Law) and its regulations, which contain safety rules and place strict obligations on companies when carrying out subsoil use operations.

Activities in relation to regulated industrial sites are subject to a State industrial safety review. Any deviation from project documentation is prohibited unless reviewed by a licensed expert and approved by the Federal Service for Ecological, Technological and Nuclear Supervision (Rostekhnadzor) or another relevant regulatory authority.

Entities engaged in such activities have a wide range of obligations under the Health and Safety Law and labour legislation, including obligations to maintain industrial safety controls, insurance for third-party liability for injuries caused in the course of operation of industrial sites, personnel training programmes and systems to cope with industrial accidents.

Any company or individual (including company officers) violating industrial safety rules may be subject to fines, administrative suspension of business activity (for up to 90 days) and/or civil liability in the form of compensation of losses (including compensating individuals for any loss of earnings and health-related damages). Individuals may also be subject to criminal liability in the form of a fine or imprisonment.

Environment

Environmental matters in Russia are regulated primarily by Federal Law No. 7-FZ, dated January 10, 2002, 'On protection of the environment', as amended (the Environmental Protection Law) and by a number of other federal and local environmental protection laws and regulations, including in relation to water and soil, processing, management and disposal of hazardous substances and waste, discharge of substances into the air, decommissioning and clean-up operations in respect of contaminated sites, and flora and fauna protection.

A range of environmental authorisations, permits and approvals is required in relation to the development and operation of a subsoil use project in Russia.

Operations that may affect the environment must be approved by environmental expert commissions. Conducting such operations without a mandatory State ecological expert review may result in civil, administrative or criminal liability, as well as in revocation of licences (including subsoil licences). Environmental impact assessments may be required as part of this process.

As a general rule, a legal entity or individual who causes harm to the environment must compensate the State for such damage in full according to rates or estimation procedures approved by environmental authorities. Furthermore, if an entity's operations violate environmental laws and regulations or cause harm to the environment or to any individual or other legal entity, then environmental authorities may suspend its operations. A court action may also suspend (for up to 90 days), fine or order compensation from, any legal entity and its employees that fails to comply with environmental laws and regulations. In addition, individuals who are in default may be subject to criminal liability in the form of fines or imprisonment. Courts may also impose clean-up obligations on violators.

Insurance

To the extent that a shale gas producer is unable to allocate or transfer risk when conducting subsoil use operations, it will need to consider taking out insurance. There are some risks that require mandatory insurance, for example, insurance for causing harm as a result of an accident or incident on a hazardous production facility.

Restrictions on export of geological information

When conducting due diligence of a shale gas project and planning for ongoing monitoring and review of project operations, there are certain restrictions under Russian law with respect to the transfer of geological information abroad that must be taken into account.

The transfer of geological data outside of the territory of the Customs Union (between Russia, Kazakhstan, Belarus and Armenia) requires an export licence from an authorised State body. Export includes both physical transfers abroad of media containing geological data and, arguably, electronic transfer of geological data, in particular by electronic mail or by uploading information to a virtual data room, especially where the relevant electronic server is located outside the Customs Union. Obtaining an export licence can be a complex exercise.

Additionally, in some circumstances, geological data can be considered a State secret to which Russian State secrecy laws may be applicable. In such cases, other restrictions with respect to obtaining and disclosing of geological data may be applicable.

Investment structuring and other considerations

Investment structuring

Most Russian projects in the area of subsoil use involve:

- an investor acquiring equity in a company that already has a subsoil licence

or

- an investor (in most cases through its Russian affiliate) being granted a subsoil licence from the State.

The choice between these two basic structures depends on various factors including, primarily, the existing licence status.

In both cases, a factor to be considered is the jurisdiction in which a project investor will hold its equity. Essentially, it may acquire (or establish) an offshore holding company that owns the licence holder or directly own shares (or participation interests) in the Russian licence holder. The

choice of jurisdiction is influenced by various factors, primarily tax structuring, but also the flexibility and sophistication of corporate, banking, legal and accounting regulations and infrastructure, legislative stability and exit strategies.

Another factor to consider is whether the project will be wholly owned or a joint venture and, if the latter, the percentage breakdown of the various investors' interests.

The acquisition of the shares of a company that holds a subsoil licence is a very common investment structure. Typically, a limited liability company or a non-public joint stock company is used to hold a subsoil licence.

Other considerations relating to transactions

Legal, technical and financial due diligence of the target company, its operations and the relevant subsoil licences is key to an acquisition in Russia. This is arguably even more important than in western jurisdictions because of the lack of reliable and searchable public registers. The due diligence process will help inform the negotiating position for any acquisition.

The major terms and conditions of an acquisition are often agreed by a non-binding letter of intent or similar preliminary document executed by the parties. This is followed by definitive, negotiated and fully legally binding agreements.

The transaction terms and structure, and its timetable, are heavily dependent on the status of the licence (and of the company that holds the relevant licence) and on the nature of the acquirer. This is particularly so if the subsoil use licence relates to a 'Deposit of Federal Importance' and the acquirer is a foreign entity or a member of a group that includes a foreign entity (see below).

Other issues to be considered are the need for Russian anti-monopoly approvals and the choice of law governing the deal agreements. Where a transaction involves a foreign element, Russian law usually permits the use of non-Russian law to govern the terms of the acquisition documentation. The most typical choice of law is English law, with international arbitration selected as the dispute resolution forum. Russia is a party to the 1958 New York Convention on the recognition and enforcement of foreign arbitral awards.

Deposits of Federal Importance

Deposits of Federal Importance include, among other things, deposits that:

- contain reserves of at least 70 million tons of recoverable oil or 50 billion m^3 of gas
- are located in inland sea waters, territorial sea waters or on the continental shelf of the Russian Federation

or

- can only be developed using land designated for defence and security purposes.

The list of Deposits of Federal Importance is officially published and maintained by Rosnedra. Once a subsoil deposit is included in the list, it retains its status as a Deposit of Federal Importance even if the remaining reserves drop below the relevant threshold and notwithstanding any changes resulting from amendments to the Subsoil Law. However, even deposits which are not included in the list may be treated as strategic if they satisfy the qualifying criteria.

Rules relating to Deposits of Federal Importance

Additional rules apply to Deposits of Federal Importance as follows:

- They may only be operated by a legal entity that is established in the Russian Federation.
- The preliminary consent of the Russian government, issued under a procedure established in the Subsoil Law, is required prior to detailed exploration and development.
- The Russian government may veto the issue of a production licence to the subsoil user that made the discovery of a Deposit of Federal Importance if:
  - in the course of geological exploration under an exploration licence, a discovery is made and the relevant deposit meets the Deposit of Federal Importance criteria
  - a foreign investor holds an interest in the subsoil user (or the subsoil user is under the control of a foreign investor) that made the appropriate discovery

  and

  - a threat to the 'national defence and security of the State' is deemed to have arisen. There are no clear guidelines on what constitutes such a threat and, as at the date of publication of this guide, there are no known cases where this power has been applied.

- If the discovery of a deposit that meets the criteria of the Deposit of Federal Importance is made under a combined licence by an entity in which a foreign investor holds an interest, the Russian government has the right to terminate the licence. In such circumstances, the Subsoil Law provides for payment to the subsoil user of compensation for geological works carried out plus an additional premium. Such compensation and other reimbursement is payable from the federal budget pursuant to a procedure established by the government. There has been much criticism that these compensation principles are not aligned with the Russian constitution and a number of international treaties to which Russia is a party.

- Under Federal Law No. 57-FZ of April 29, 2008, 'On the procedure for making foreign investments in business entities of strategic importance for national defence and State security' (the Strategic Investments Law), the Russian government monitors foreign control and ownership over strategic sectors of the economy, including the oil and gas sectors.

If a proposed transaction involves the direct or indirect acquisition of shares (or participation interests) in an entity that holds a subsoil licence in relation to a Deposit of Federal Importance by a foreign acquirer (or a member of a group that includes a foreign entity), such acquisition may require approval by a special government commission chaired by the Prime Minister which is responsible for overseeing foreign investment into strategic sectors. As a general rule, a foreign investor is obliged to obtain the prior consent of the commission for a direct or indirect acquisition of:

- more than 5 per cent of the shares (or participation interests) in such an entity where a foreign entity with State participation is a party to the transaction

- more than 25 per cent of the shares (or participation interests) in such an entity where a foreign entity without State participation is a party to the transaction.

Sanctions

When assessing potential shale projects, it is important to consider the sanctions regimes that are currently in effect against Russia, and any potential sanctions that may be applied in future.

As of the date of publication of this guide, a number of countries and groups of countries (including the US and the EU) have imposed sanctions that restrict potential investment in the Russian energy industry. Broadly speaking, the sanctions have taken direct aim at the Russian energy industry in two ways. They:

- prohibit the supply into Russia of certain oil and gas-related equipment, technologies and services for use in specified future Russian oil projects (including shale oil projects)

- restrict the access of a small number of partially State-owned Russian energy companies to EU sources of capital.

It will be important to seek advice as to the exact nature of any sanctions prior to making an investment or providing equipment or services to the Russian energy industry. Although the current sanctions do not apply to gas exploration and production, many of the shale projects that the sanctions are designed to target may involve both oil and gas and could therefore potentially be affected.

Gas export restrictions

Following the adoption of Federal Law No. 117-FZ 'On gas export', on July 18, 2006, the exclusive right to export gas from Russia was transferred to the owner of the unified gas supply system, which is currently Gazprom (and its wholly owned subsidiaries).

In 2013, Gazprom's monopoly on the exporting of gas was relaxed by the partial liberalisation of the gas export system. As a result, Gazprom's (and its subsidiaries') exclusive export right was restricted to natural gas in gaseous form, while the list of companies that could export liquefied natural gas (LNG) was extended to certain other categories of subsoil users, such as:

- subsoil users with the right to use Deposits of Federal Importance and whose subsoil use licence as of January 1, 2013 provided for:
  - the construction of LNG plant
  - the transportation of produced gas for liquefaction to a LNG plant
- Russian subsoil users (and their wholly owned subsidiaries) where:
  - the Russian State holds more than 50 per cent of the share or charter capital (and/or in which the Russian State is able to dispose, directly or indirectly, of more than 50 per cent of the total number of the voting shares/participation interests)

- the subsoil user has the right to use subsoil plots located within inland sea waters, territorial waters, the continental shelf, the Black Sea or the Azov Sea

- the subsoil user produces LNG from the gas extracted from such subsoil plots.

The export of gas is a licensed activity, and gas export licences are issued by the Ministry of Energy. Any exporter of gas is obliged to inform the Ministry of Energy about its gas export activity.

South Africa

The Main Karoo Basin covers approximately 700,000km^2 of the central part of South Africa. It is the erosional remnant of 100 million years of sedimentation in the heartland of the supercontinent known as Gondwana. This basin is where the majority of South Africa's onshore fossil fuel reserves are located.

The South African resource

In the late 1960s, Soekor (now PetroSA) began onshore exploration for conventional oil accumulations as part of the national strategy to establish energy independence for apartheid South Africa. The exploration programme proved unsuccessful, Perceived low prospectively caused the Soekor focus to shift offshore, particularly to the Cape South East Coast, where several significant oil and gas discoveries were made subsequently.

The Soekor onshore exploration programme around the Cradock area had evidenced significant natural gas occurrences, both at the surface and at intervals in the deep boreholes, indicating an active petroleum system. At the time, natural gas was not a recognised fuel resource in South Africa.

The change in the US domestic situation, coupled with improvements in technology and the feasibility of exploitation, prompted the US Energy Information Agency US (EIA) to commission a comprehensive evaluation of shale gas resources in several regions outside the US.

Extrapolating the old Soekor gas data, the US EIA identified three Ecca shale formations in South Africa – the Whitehill, the Prince Albert and the Collingham formations. In aggregate, this is an area of approximately 183,000km2 with potential for shale gas. Of particular interest is the Whitehill formation, which contains large tracts of organically rich, thermally mature black shales. The US EIA estimated a total recoverable resource of gas within the formations of 485 trillion cubic feet (TCF). This was perceived by the Task Team appointed by the South African Department of Mineral Resources to investigate the feasibility of shale gas production as being a favourable scenario.

A key uncertainty in the prospectivity of the Whitehill formation is the intrusion of kimberlite dykes, dolerite dykes, and sills not found in gas-bearing shales elsewhere in the world. It is thought that the dolerite intrusions could have resulted in thermal degassing of the shale formation. It is also possible that the crystallised rock may provide conduits for, or barriers to, fluid migration (both groundwater and frack-fluid), which has significant environmental implications. This uncertainty is likely to continue until such time as exploration wells are drilled and hydraulically fractured, as part of a resource-confirmation process.

Graphic: Petroleum Agency of South Africa continue until such time as exploration wells are drilled and hydraulically fractured, as part of a resource-confirmation process.

The Task Team believes the US EIA report may have overstated the total organic carbon by weight value in the estimation of the Collingham and Prince Albert resources. Accordingly, in a 'low-case' scenario, that is an unfavourable scenario, the Task Team has significantly reduced the prospective extent of the resource in the Whitehill formation, and has excluded the Collingham and Prince Albert formations from consideration. Nevertheless, the Task Team still arrives at an estimate of approximately 30 TCF of technically recoverable shale gas in the Karoo Basin under such a 'low-case' scenario.

The Task Team advises that the South African government can confidently decide on resource confirmation and exploitation, as 30 TCF remains a 'game changer' for South Africa's energy self-sufficiency and economic development.

485 TCF Ecca Shale

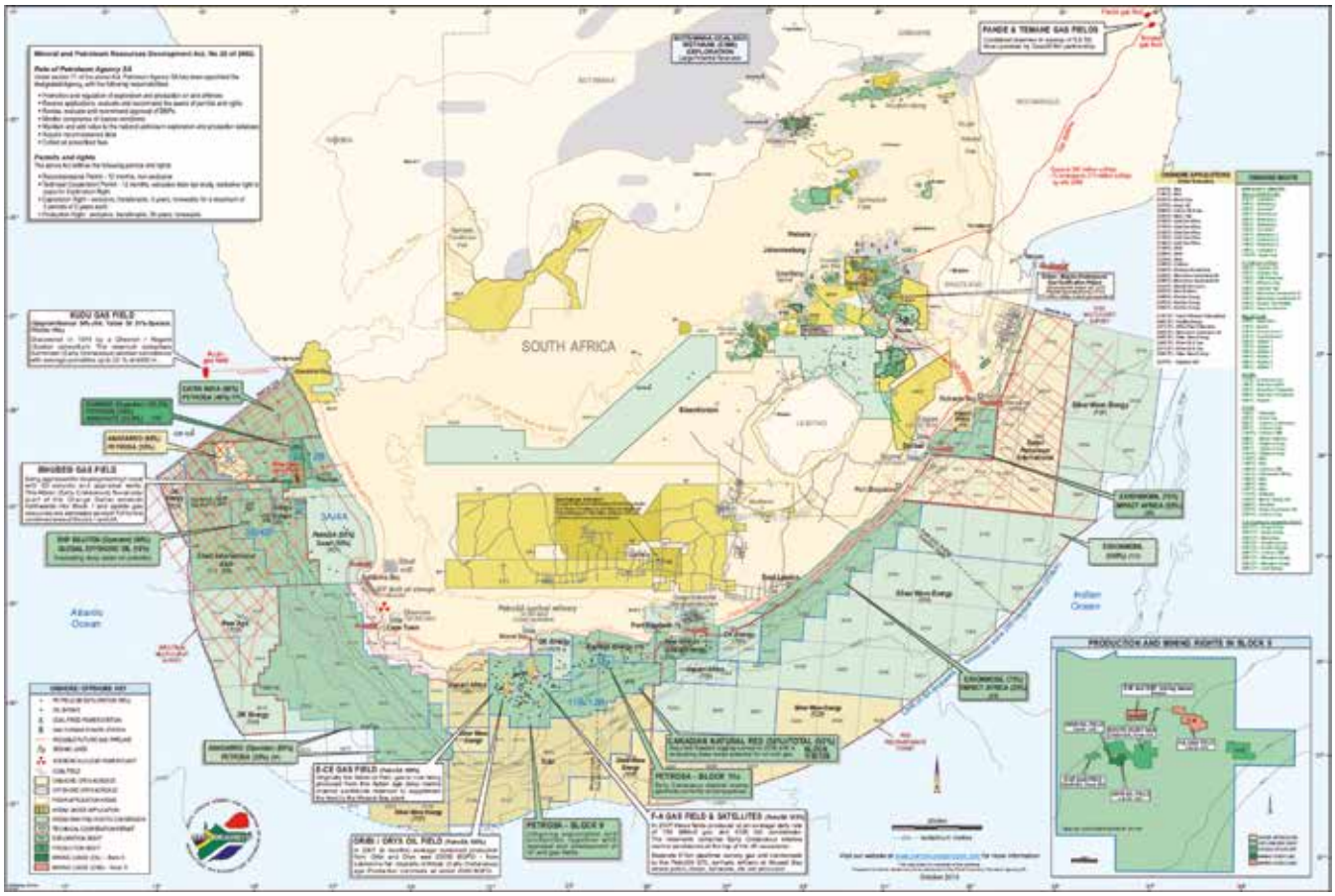
There are three identified Ecca shale formations in South Africa – the Whitehill, the Prince Albert and the Collingham formations. Whitehill is of particular interest because of the unusual dykes and sills not found in gas-bearing shales elsewhere.

700,000 km²

South Africa has the eighth largest shale gas reserves in the world, according to recent estimates by the US Department of Energy. The Karoo region is believed to have some of the world's biggest reserves of shale gas according to the United States Energy Information Administration.

30 TFC

Until there is further exploration, it is expected that there will be a minimum of 30 TCF of recoverable reserves. This remains a 'game changer' for South Africa's energy self-sufficiency.



Graphic: Petroleum Agency of South Africa

The US EIA has revised its assessment of the South African resource a second time since publication of its revised report issued in June 2013. The revised assessment takes account of sill intrusions and the complex geology throughout the Karoo Basin, with this 'unusual' condition representing risk in the exploration for and production of shale gas in the region. Consequently, the US EIA has reduced the South African shale gas prospective area by 15 per cent and 'significantly risked' the remaining resource. On its desktop revision, the US EIA now estimates the South African resource to be of the order of 390 TCF.

Mineral and hydrocarbon regulation

The main legislation governing exploration for and exploitation of minerals and petroleum in South Africa is the Mineral and Petroleum Resources Development Act (MPRDA). The Department of Mineral Resources is the government authority responsible for the administration, control and management of petroleum resources and the regulation of petroleum exploration and production. Under the MPRDA, shale gas is defined as 'petroleum'.

Environmental regulation

Until recently, the environmental regulation of petroleum exploitation was addressed in the MPRDA and the regulations promulgated under it. For various historical reasons, minerals and petroleum exploitation were each subject to a special environmental regime. However, recent amendments to both the National Environmental Management Act, 1998 (NEMA) and the MPRDA have brought petroleum within the ambit of NEMA.

Applicants for exploration and production rights will need to secure an environmental authorisation in terms of NEMA as a condition for the grant of the exploration or production right.

Section 24 of NEMA empowers the Minister of Environmental Affairs to list activities that may not commence without an environmental authorisation. An environmental authorisation is granted on the basis of an assessment conducted in terms of the Environmental Impact Assessment Regulations. The Minister of Environmental Affairs has recently published for comment an updated version of the Environmental Impact Assessment Regulations together with updated listing notices, containing various exploration and production-related activities. It is anticipated that the new environmental regime will commence once the final version of the regulations and listing notices are promulgated.

Under the new system, the Minister of Mineral Resources is the competent authority to grant environmental authorisations for activities related to exploration and production of shale gas. The Minister of Environmental Affairs will serve as the appeal authority.

The Minister of Mineral Resources has published draft Technical Regulations for Petroleum Exploration and Exploitation (the Technical Regulations). The final version is expected to be promulgated in the first quarter of 2015. The Technical Regulations are intended to establish comprehensive technical and environmental standards for the conduct of hydraulic fracturing in South Africa. They govern, among other things, well design and construction, well abandonment, drilling fluid management of waste and management of water. They supplement existing regulation of environmental impact assessments.

Ownership of land and mineral rights

Exploration and production rights granted under the MPRDA are limited real rights with respect to the land to which they relate. The holder of an exploration or production right is entitled to enter the land to which such a right relates, explore or produce for its own account on such land, and, subject to the National Water Act 1998, to use water from any natural water resource situated on such land.

Previously, mineral and petroleum rights in South Africa could be acquired and registered separately from the title to the land. However, the MPRDA vested South Africa's mineral and petroleum resources in the people, with the State as custodian. The State grants the right to explore for and exploit these resources to third parties, and the State benefits through fiscal revenues. This is likely to change and it can be anticipated that there will be increased participation by the State in actual projects.

In accordance with the MPRDA, the holder of a petroleum right may access the land over which the right has been granted. A land owner may not preclude the holder of the right from entering their land. However, the holder of a right is obliged to notify and consult with the land owner or lawful occupier of the land before commencing exploration or production activities. The land owner may be entitled to compensation for any loss that they sustain by reason of the petroleum operations on their property.

Rights, licences and approvals

The Petroleum Agency of South Africa (PASA) is the authority designated by the Minister of Mineral Resources to perform the functions in the MPRDA relating to the management and regulation of exploration and production rights. PASA's mission is to promote exploration for onshore and offshore oil and gas resources and their optimal development on behalf of government. PASA regulates exploration and production activities, and administers the national petroleum exploration and production database.

Reconnaissance operations, technical cooperation studies, exploration operations and production operations may only be conducted within South Africa with the appropriate statutory authorisation as provided for in the MPRDA.

Applications for permits and rights

Applications for a reconnaissance permit (RP), technical cooperation permit (TCP), exploration right or production right must be submitted to PASA. Prescribed application fees are payable and the regulations specify the supporting documentation as to technical and financial capability that should accompany these applications.

The MPRDA does not confer any discretion upon PASA when accepting applications for such authorisations. PASA must accept applications for processing if the specified criteria are met. Once an application is accepted, PASA must process the application in terms of the provisions of the MPRDA and its regulations.

If the applicant complies with all the requirements stipulated under the MPRDA and the regulations, PASA is obliged to recommend to the minister that the application is accepted. The minister, in turn, has limited discretion. If the application is fully compliant with the requirements of the MPRDA and regulations, the Minister must approve it. However, the minister has a discretion in relation to the appropriateness of the proposed work plan, and/or the proposed social development obligations.

Once an application has been approved, the relevant permit is issued or the negotiation of the actual terms of the exploration or production right commences. 'Negotiation' is a misnomer, because the terms of the exploration or production right are standard. They are only departed from in exceptional circumstances and where such departure is in the interests of the State. Once the exploration right or production right has been notarially executed, there is a 60-day period to lodge the right for registration in the Mining Titles Registration Office. Failure to do so will cause the right to lapse.

First mover and exclusivity principle

Under the present framework, a first mover to apply for a right or permit over acreage not subject to any other applications, rights or permits is exclusively entitled to be granted that right subject to compliance with the requirements of the MPRDA. The holder of a TCP has an exclusive entitlement be granted an exploration right over the technical cooperation area, provided its application is compliant. In turn, the holder of an exploration right has an exclusive right to apply for and be granted a renewal of the exploration right or a production right over the exploration area.

Assistance to historically disadvantaged people

One of the objects of the MPRDA is to reform the petroleum industry and bring about equitable access to South Africa's petroleum resources. The Minister of Mineral Resources has the right to facilitate assistance to historically disadvantaged South Africans (HDSAs), to enable them to participate in exploration and production operations. Section 1 of the MPRDA defines 'historically disadvantaged South African' to include juristic persons that meet certain conditions.

There are currently two charters that provide a framework for progressing empowerment of HDSAs in the context of mining, exploration and production.

Mining Charter

The Broad-Based Socio-Economic Empowerment Charter for the South African Mining Industry (the Mining Charter) sets a target of 26 per cent HDSAA ownership of the mining industry, to be achieved over a period of 10 years. This period expired at the end of 2014 and, at the time of writing, the target has not been revised.

Liquid Fuels Charter

Under the Charter for the South African Petroleum Liquid Fuels Industry Empowering Historically Disadvantaged South Africans in the Petroleum and Liquid Fuels Industry (the Liquid Fuels Charter) an interest of not less than 9 per cent should be reserved for HDSAs in all exploration and production rights in the country's offshore area. In practice, the 9 per cent has increased to 10 per cent.

The Minister of Mineral Resources currently applies the Liquid Fuels Charter to onshore and offshore exploration and production rights, although it is the Mining Charter that is envisaged in the MPRDA.

The award of an exploration or production right is conditional on compliance with the Liquid Fuels Charter. In the case of exploration rights, this condition operates as a discretionary requirement. In the case of production rights, it is a mandatory statutory requirement.

The way in which HDSAs earn or pay for the 10 per cent is not legislated. Therefore this is open to negotiations between applicants and the HDSA, subject to the 'unofficial approval' of PASA.

Compliance with the Liquid Fuels Charter only becomes compulsory at the production stage. However, the holder of an exploration right must make a sincere attempt before or during the period of this right to find a suitable partner who is a HDSA to take up shareholding/equity.

The terms and conditions of the exploration right impose further duties relating to the employment of HDSAs, skills transfer and procurement.

Establishment of a local entity

Any person may apply for permits and rights under the MPRDA. However, the Companies Act requires foreign companies to register with the Companies and Intellectual Property Commission within 20 business days after they begin to conduct business in South Africa.

A foreign company is regarded as conducting business if that company is a party to one or more employment contracts within South Africa, or is engaging in a course of conduct, or has engaged in a course or pattern of activities within South Africa over a period of at least six months, such as would lead a person reasonably to conclude that the company intends to continuously engage in business in South Africa.

In other words, if a foreign company is actively participating in exploration, it will at the very least be required to register as an external company.

State participation

In its current form, the MPRDA does not provide for a mandatory equity or interest to be held by the State in an exploration or production company or right. However, the terms and conditions of exploration and production rights must be approved by the Minister of Mineral Resources. As indicated, such terms are 'negotiated' between PASA and an applicant on the basis of PASA's standard draft Exploration Right (Draft ER) and/or PASA's standard draft Production Right (Draft PR).

The Draft ER and Draft PR provide for an option in favour of the State to acquire a maximum participating interest of 10 per cent. Upon the exercise of this option, the State becomes a party to any joint operating agreement in relation to the relevant production. It is required to contribute a proportionate share of the production costs and expenses, but is not required to contribute towards past expenses for any exploration or appraisal operations. The State does not pay any other amount for the acquisition of this 10 per cent interest through the exercise of the option.

Taxes, duties, royalties and incentives

Participants in petroleum operations in South Africa will be subject to income tax and royalties. The 10th Schedule to the Income Tax Act sets out the income tax rules applicable to oil and gas companies.

South Africa has numerous double tax treaties with other countries, many of which will reduce the taxes payable by petroleum companies.

In terms of the Royalty Act, an extractor of mineral resources must pay a royalty in respect of the transfer of any mineral resources extracted within South Africa. The royalty to be paid is calculated as a percentage of the gross sales of the extractor.

As regards incentives, the fiscal stability provisions of the Income Tax Act and the Royalty Act provide that a person operating in the petroleum industry may elect that the income tax or royalty regime, as it was when the person obtained the operating rights, remains applicable for the duration of their petroleum operations.

Foreign currency and Central Bank requirements

Foreign nationals can freely transfer capital into South Africa. However, investments must be reported to the exchange control authorities and share certificates evidencing investments must be endorsed 'non-resident' so that dividends can be freely repatriated. Reserve Bank approval will also be required should any foreigners wish to invest by way of loan capital.

Environmental protection

In addition to requiring applicants for exploration and production rights to obtain environmental authorisation for their operations, NEMA imposes several other obligations directed at environmental protection.

An applicant for an environmental authorisation must, before the environmental authorisation is issued, make financial provision (in the form of insurance, bank guarantee, trust fund or cash) for rehabilitation, closure and ongoing post-decommissioning management of negative environmental impact of the exploration or production operations. The Minister of Mineral Resources is also empowered to determine that a portion of the financial provision is retained following the closure of the operations in order to cover latent or residual environmental impacts.

NEMA also confirms that rights holders are responsible for any environmental damage, pollution or ecological degradation resulting from their operations and provides for criminal liability in certain circumstances, including personal liability in the case of company directors under certain circumstances.

Changes to regulatory regime

In March 2014, Parliament passed the Mineral and Petroleum Resources Amendment Bill, 15 of 2013 ('the Bill') and referred it to the President for assent. The President has not assented to the Bill but has instead referred it back to the National Assembly, the lower house of Parliament, on the basis of various constitutional reservations. The National Assembly must now reconsider the Bill and decide whether to pass it with our without amendments or to rescind it.

The Bill proposes broad changes to the current regulatory framework for both conventional and unconventional petroleum resources. Most of the provisions that affect the petroleum industry will require the promulgation of regulations for their implementation.

The most significant amendments proposed pertain to State participation in exploration and production projects. If the bill is brought into operation, the State would have the right to acquire a 20 per cent 'free carried interest' in all new exploration and production rights, from the effective date of such rights. Free carried interest is an 'interest allocated to the State in exploration or production operations without any financial obligation on the State'. In addition to the free carried interest, the State may acquire a further unlimited interest either through acquisition at an agreed price or through a production-sharing agreement. The Bill is silent on what the case would be in the event that parties cannot agree on the price.

The Bill defines a production-sharing agreement as 'an agreement between the State and the petroleum company on how the extracted resource will be shared between the State and the petroleum company'. The terms and conditions of the production sharing agreement have not been published by the State.

Current status

In May 2010 and August 2010, Bundu Gas & Oil Exploration (Pty) Ltd and Falcon Oil & Gas Ltd respectively lodged applications for exploration rights in the south-central and central parts of the Karoo Basin. The ministerial decision on these applications are pending.

In December 2010, Shell Exploration Company BV lodged three separate applications for exploration rights over three discrete blocks across the south-central part of the Great Karoo Basin. Two such applications were accepted by PASA on December 13, 2010 and the third was accepted on December 14, 2011.

In February 2011, the Minister of Mineral Resources imposed a moratorium on the processing of new applications for permits and rights over the Karoo Basin. The moratorium specifically provides that the applications received prior to the imposition of the moratorium were not affected by it. A few weeks later, the minister announced a further non-statutory moratorium on the processing of existing applications for exploration rights, pending the findings of the government Task Team.

The Task Team reported to the minister in mid-2012. In September 2012, the Cabinet announced that it endorsed the Task Team's recommendation of proceeding with limited exploration for shale gas, in order to confirm the South African resource, subject to strict monitoring and augmentation of the current regulatory framework.

The Technical Regulations on Petroleum Exploration and Exploitation (The Technical Regulations) were first published for comment in October 2013. They are intended to prescribe good international petroleum industry practices and standards and were formulated following a series of consultations with regulatory authorities in mature shale gas regions. Among other things, the regulations make provision for full disclosure of frack-fluid composition.

The regulations follow from a recommendation by a government Task Team established by the Department of Mineral Resources (DMR). The Task Team recommended that the government authorise initial hydraulic fracturing subject to the condition, among others, that the current regulatory framework is augmented by appropriate regulations, controls and coordination systems.

Hydraulic fracturing has also been declared a 'controlled activity' under the National Water Act, which means that no person may undertake hydraulic fracture operations in South Africa without first having obtained a water use licence. Such a licence is granted only if the applicant can demonstrate that there is sufficient water available to undertake the activity concerned, and that such use will not have a deleterious impact on the South African water resource.

The initial February 2011 moratorium has since expired and a further moratorium was imposed on February 3, 2014. This similarly excludes from its ambit the three applications for exploration rights that were submitted prior to February 1, 2011, subject to the proviso that no hydraulic fracturing will be permitted until such time as the Technical Regulations have been published.

Opportunities

It is clear from the National Development Plan and the DOE Determination on the Baseload IPP Procurement Programme that the State intends to forge ahead with exploration for and production of shale gas in the Karoo Basin. In light of the State's apparent intention to implement a competitive rights application process, this will in all probability lead to significant opportunities for future participation by other interested parties. The President's statement at the State of Nation address on February 12, 2015 noted that Eskom has been instructed to switch from power generation by diesel to gas.

United Kingdom

Resource

The UK shale gas industry is still in its infancy. Ahead of more drilling, fracture stimulation and testing there are no reliable indicators of potential productivity. However, by analogy with similar producing shale gas plays in the USA, the British Geological Society (BGS) has estimated that the UK shale gas reserve potential could be as large as 150 billion cubic metres of natural gas (bcm), which is 5.3 trillion cubic feet (TCF). This is very large compared with 2-6 bcm estimate of undiscovered gas resources for onshore conventional petroleum in the UK.

In June 2013, the US Energy Information Administration published a report in which it estimated that the UK has 9 TCF estimated proved natural gas reserves (quoting the Oil & Gas Journal, Worldwide Report, December 3, 2012) and up to 26 TCF of unproved wet shale gas technically recoverable resources. However, the Energy Information Administration has acknowledged that these estimates are uncertain given the relatively sparse data that currently exists, and further work will be required to verify and test them further.

The Unconventional Hydrocarbon Resources of Britain's Onshore Basins – Shale Gas, published by BGS in 2012, identified significant potential areas of shale gas in northern England, including Widmerpool Gulf near Nottingham and a large area centred on the Elswick Gasfield, near Blackpool. In July 2013, BGS published a further report, 'The Carboniferous Bowland Shale gas study: geology and resource estimation' for the Department for Energy and Climate Change (DECC) which contains estimates of shale gas in place in two genetically defined levels in that area, but which does not contain reliable estimates of the amount of recoverable shale gas, as this requires further investigation. In June 2014, BGS published further reports on the potential shale gas resources in Wales and the Midland Valley of Scotland. Shale reserves were identified in both areas, though BGS recognised the need for further exploration and research to quantify the reserves more accurately.

The diagram overleaf shows an outcrop of the main black shale formations in UK and selected oil and gas wells and gas fields, and was produced by BGS in the 2012 report.

Regulation

The Royal Society and the Royal Academy of Engineering have reviewed the risks associated with shale gas and concluded that the health, safety and environmental risks associated with fracking can be managed effectively in the UK by implementing and enforcing best operational practice. DECC has reported that shale gas emissions are similar to those of conventional gas and lower than those of coal and LNG, which has led the Secretary to State to describe shale gas as a 'bridge' to a low carbon future.

We discuss below the key permissions required under the regulatory regime in the UK and changes which have been implemented or which are proposed to enhance the potential for shale gas exploitation.

Regulators

In the UK there has been a transfer of powers from the UK parliament to assemblies in Wales, Scotland and Northern Ireland. The legal and regulatory regimes in each jurisdiction differ.

The consenting process for shale gas reflects that for other types of hydrocarbon exploration, where a number of regulatory bodies and government departments have responsibility for regulation. These include DECC (who conduct licensing rounds and issue drilling and exploratory licences in England, Wales and Scotland through the Petroleum Act 1998); mineral planning authorities (England and Wales)/local planning authorities (Scotland) who consider applications for land use planning permissions and decide if an environmental impact assessment is

required; the Environment Agency (England), the Scottish Environmental Protection Agency (Scotland) (SEPA) or Natural Resources (Wales) who consider applications for environmental permits; the Health and Safety Executive (HSE) who consider well design and risk of major accidents and hazards to people and the Department of Communities and Local Government (DCLG) who publish planning guidance. In addition there are a number of statutory consultees who must be consulted before a planning application is determined.

In December 2012, the Office of Unconventional Gas and Oil (OUGO) was established within DECC with responsibility for co-ordinating the activities of the various regulatory bodies and government departments with the intention of creating a streamlined planning and regulatory system. It also has responsibility for informing and engaging the public about various applications and delivering benefits to the local community directly from any development in their area.

In Northern Ireland the Department of Enterprise, Trade and Investment (DETI) and the Department of the Environment are the primary government departments with regulatory responsibility for determining applications for drilling/gas production, planning permission and environmental permits. Generally DETI follows the policy developments of DECC.

Key permissions under the regulatory regime

Petroleum Exploration and Development Licences (PEDLs)

Shale gas exploitation is covered by the UK regime for all oil and gas exploration and development. A UK PEDL allows a company to pursue a range of exploration activities, including exploration and development of unconventional gas, subject to necessary drilling/development consents and planning permission. PEDLs are issued by DECC following competitive bid rounds and provide their holders with exclusive rights to explore for and produce petroleum in the licenced area.

The 14th onshore licensing round closed in October 2014 for both conventional and 'unconventional' oil and gas exploration, which includes shale gas. About half of the UK landmass is available, controversially, this included ten National Parks and other protected areas (see further below). DECC expects about 50–150 unconventional licences to be awarded in this round (which are to be announced later in 2015).

Oil and gas extraction starts with an exploration phase, which may include the performance of seismic surveys. A test bore is drilled (following seismic surveys) to explore the reserve's potential. The next phase is extraction or 'development'. Some companies who are drilling mainly for conventional oil and gas have decided to drill deeper than they otherwise might have, in order to see whether there is prospective shale within their licensed areas ('coring' is envisaged in these cases but no fracking is currently involved).

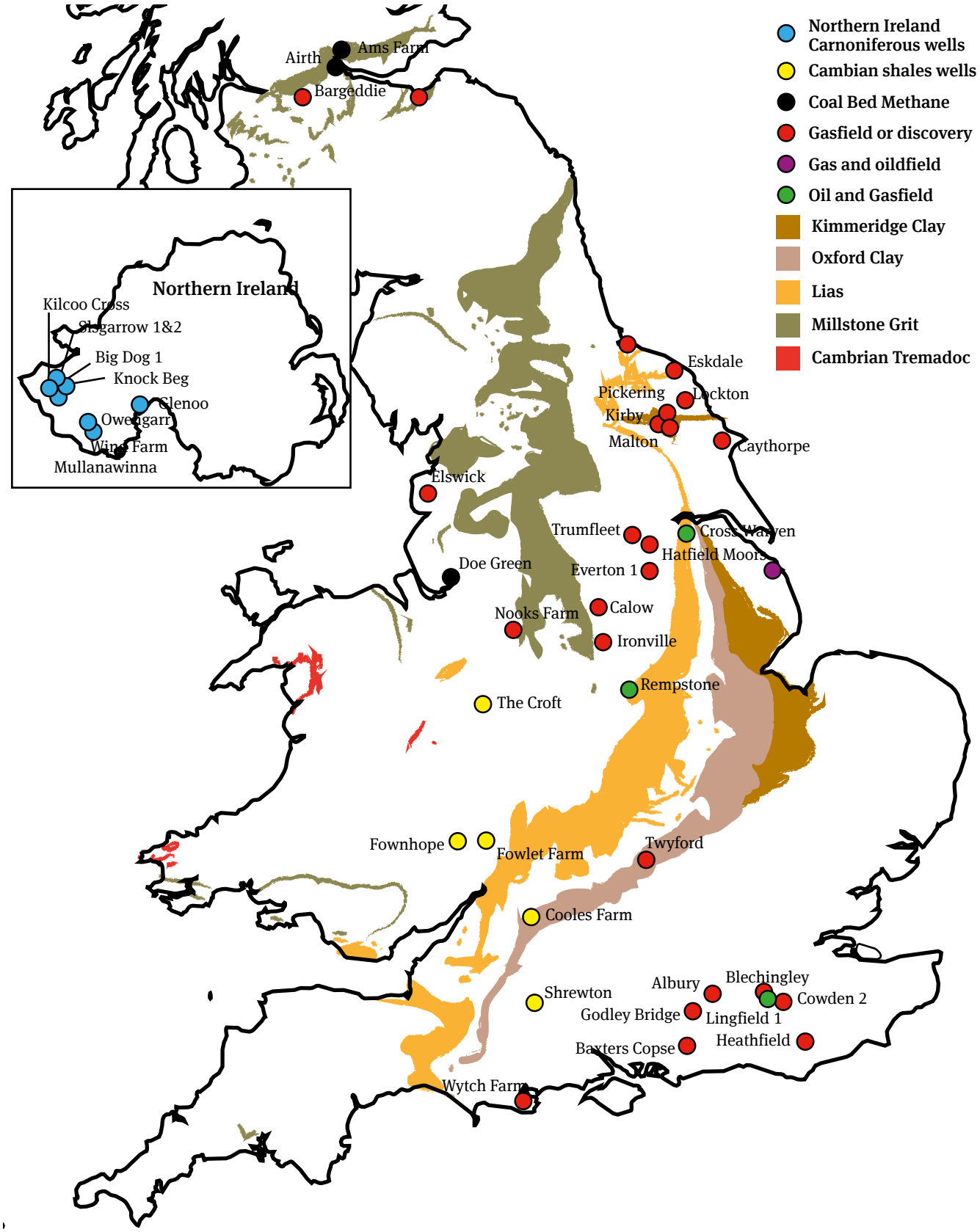
The terms of PEDLs require DECC's approval of the operator. One of the issues DECC checks before approving an operator is coverage of sufficient financial resources/relevant insurance provision. Licences issued by DECC do not grant their holders rights to commence drilling operations. Rather, DECC consent must be obtained prior to commencement of operations and DECC is able to impose conditions when granting such consent. Operators are also required to have a development programme approved by DECC prior to commencing commercial extraction.

Other permissions

PEDLs allow a company exclusivity in an area to search for, bore and extract hydrocarbons. However, other permissions are required before fracking can commence which include:

- planning permission
- access rights from landowners
- Environmental Permits from the Environment Agency (EA), including mining waste permits for drill cuttings, spent drill muds and drill fluids, flow back fluids, waste gases and waste left underground. An Environmental Permit will also be needed if large quantities of gas are to be flared and for groundwater activities, depending on the local hydrology
- compliance with health and safety regulations and approvals from the Health & Safety Executive (HSE)
- consent to drill and frack from DECC.

All drilling operations are subject to notification to the HSE, so that health and safety risks can be monitored. Each site is assessed by the EA or, in Scotland, the SEPA, who regulate discharges to the environment, issue Environmental Permits, water abstraction licences and are statutory consultees in the planning process. The EA and HSE have issued a joint working strategy on working together to ensure a joined up approach and that there is appropriate monitoring and inspection of unconventional oil and gas operations. This is intended to provide a robust regulators' framework to ensure that all the activities involved in fracking are reviewed by the relevant regulatory authority.


Northern Ireland Carnoniferous wells
Cambian shales wells
Coal Bed Methane
Gasfield or discovery
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Oil and Gasfield
Kimmeridge Clay
Oxford Clay
Lias
Millstone Grit
Cambrian Tremadoc
Northern Ireland
Kilcoo Cross
Slugarrow 1&2
Big Dog 1
Knock Beg
Glenoo
Owengarr
Wind Farm
Mullanawinna
Airth
Ams Farm
Bargeddie
Eskdale
Pickering
Lockton
Kirby
Malton
Caythorpe
Elswick
Trumfleet
Cross Wayven
Hatfield Moors
Doe Green
Everton 1
Calow
Nooks Farm
Ironville
Rempstone
The Croft
Fownhope
Fowlet Farm
Twyford
Cooles Farm
Shrewton
Albury
Blechingley
Cowden 2
Godley Bridge
Lingfield 1
Heathfield
Baxters Copse
Wytch Farm

Planning permission

As with all other proposals for oil and gas developments, proposals for shale gas exploration or extraction are subject to the requirements of the Town and Country Planning Act 1990, administered by the Minerals Planning Authority (MPA) for the area in which the reserve is located. DECC's consent for all drilling or production operations for oil and gas is given only once planning permission has been obtained.

The MPA takes the decision in accordance with its development plan subject to taking into account material considerations such as the policy set out in the National Planning Policy Framework (NPPF) and the 'Minerals' section of the online National Planning Practice Guidance (NPPG).

Since January 2014, the requirement to serve notice on individual owners and tenants of land on the above-ground area where works are required has been retained, but the requirement for owners of land beyond this area (i.e. the owners of land where solely underground operations may take place) has been removed.

When a decision is made on a planning application, it must be determined in accordance with the adopted local development plan, taking into account any 'material considerations'. While there is no definitive list of 'material considerations', they include national policy, the views of statutory consultees such as the EA and most other representations made in relation to the planning application. Certain types of issues have been held by the Court not to be 'material' considerations: these include issues such as loss of property value and loss of a view.

The Government decided not to include oil and gas extraction projects within the remit of the major infrastructure planning regime. Therefore, planning decisions will be made by local planning authorities unless they are recovered by the Secretary of State for his own determination or the initial decision of a local planning authority is appealed.

Ownership of land and mineral rights

The rights to all oil and gas in Great Britain and its territorial sea belong to the Crown (the expression 'the Crown' describes the collective structure of central government in the United Kingdom carried on in the name of the monarch, rather than that such rights are the personal property of the monarch). This has been the case since the Petroleum (Production) Act 1934. This differs from the US where the rights vest in the private land owner. As stated above, DECC issues licences on behalf of the Crown to authorise the exploration, drilling and production, etc. However, in order to access the relevant minerals that exist in onshore licenced areas, operators needs to enter into agreements (leases, easements, licences, or other land use agreements) with landowners where they do not own all or any of the land required for their operations. In addition to the drilling site, the extraction of shale gas can involve horizontal drilling, so the consent of any neighbouring landowners across whose land the drilling will be undertaken will be necessary. Failure to obtain consent could result in a trespass action or proceedings to obtain an injunction to stop drilling.

A procedure to apply for ancillary rights that are needed to enter, use or occupy land for (amongst other things) laying and maintaining pipelines is also available to licence holders under the Petroleum Act 1998.

Land access reforms

In 2010, in the landmark *Bocardo* case[1], the Supreme Court found that an oil and gas company had committed trespass by drilling and installing pipelines under the landowner's land, even though the deepest well was at 2,800ft below the surface. The case is significant because it confirmed that any activity on or under a landowner's land will constitute trespass, even if it is deep underground and has no impact on the landowner. To avoid committing trespass, an oil and gas company must come to an agreement with the landowner or, failing that, if permission is refused, apply for so called ancillary rights pursuant to the provisions of the Petroleum Act 1990 and the Mines (Working Facilities and Support) Act 1966. Under the current regime, arranging access with multiple landowners can cause long delays.

The Government proposed to streamline the underground access regime and make it easier for companies to drill for shale gas through a new Infrastructure Bill. The Infrastructure Bill was enacted and implemented on February 12, 2015 and changes access rights for licence holders as follows:

1. A right of access –automatic underground access rights (onshore) to shale gas operators to undertake horizontal drilling occurring at least 300m below the surface

2. A community payment – there is potential for secondary legislation to make companies pay for the above right of access. Such payments are intended to be spent on projects to benefit the community

1 *Bocardo SA v Star Energy* [2010] UKSC 35

3. Notification – there is potential for secondary legislation to introduce a public notification system under which the company will set out drilling proposals along with details of any payments or method for obtaining payment.

The land access regime does not apply to any works above 300m depth. Therefore, access for the drilling pad itself will be subject to negotiation with the landowner or the ancillary rights regime. While it is clear that shale gas development has been the impetus for the reforms, the regime is intended to apply to all onshore oil and gas, as well as geothermal energy.

Third party access rights to infrastructure (also applicable to France, Germany, Poland and Romania)

The rules governing third party access rights are particularly important where access to a national pipeline network will be critical for the commercial success of shale gas developments (as will often be the case). The rules governing access to energy infrastructure in the UK are set out in EU and national regulatory legislation relating to the gas and electricity markets.

Generally, third party access (TPA) to infrastructure must be granted where capacity is available (subject to limited exceptions) on the basis of non-discriminatory and cost reflective tariffs. It is, however, possible for major new infrastructure to be granted an exemption from the provisions relating to third party access for a certain period of time by the energy regulatory authority in the UK, Ofgem (or the national energy regulatory authority in any other relevant EU Member State) subject to the approval of the European Commission.

The EU or UK competition (antitrust) rules may also apply where access to infrastructure is restricted, for example in the following circumstances:

- Where energy utilities agree or co-ordinate supplies between networks to discourage TPA
- Where an energy utility refuses TPA in the absence of any realistic alternative infrastructure (the infrastructure is considered an 'essential facility'), unless the refusal can be objectively justified, e.g. for reasons such as lack of capacity or connection, obligations under take or pay contracts, or public service obligations
- Where an energy utility grants TPA on the basis of excessive tariffs or unreasonable conditions.

Taxation

Profits from shale gas production are currently subject to the general 'ring fence' fiscal regime for oil and gas. This is the regime that applies generally to the exploration for, and production of, oil and gas in the UK and UK Continental Shelf. Broadly, this comprises 'ring fence' corporation tax and supplementary charge, with a combined marginal tax rate of 62 per cent (subject to a number of categories of reliefs). In the Autumn Statement 2014, the UK Government announced there would be a reduction in the supplementary charge by 30 per cent, bringing the aggregate rate down to 60 per cent. However, the UK Government has introduced a number of measures designed to incentivise investment and support the development of the UK's shale gas industry. In particular, in the 2014 Finance Act, the new onshore field pad allowance and an extension of the 'ring fence expenditure supplement' was introduced.

The pad allowance would operate in a similar way to existing field allowances, by exempting a portion of production income from the supplementary charge, thereby reducing the effective tax rate on that portion to 30 per cent (at current tax rates). The allowance is based on 75 per cent of reviewable capital expenditure. Unlike current field allowances, the pad allowance would avoid the requirement for a clearly delineated field and would instead be based at the pad level (where a pad is the term used to describe the drilling and extraction site). Pad allowance would be based on the capital expenditure incurred in relation to the shale gas pad and would be designed to enable relief for the high upfront costs associated with shale gas projects.

The ring fence expenditure supplement (RFES) allows companies to uplift their losses (or pre-trading expenditure) by 10 per cent for up to six accounting periods (to maintain the time value of the losses until they can be offset against future profits). For shale gas projects, RFES was extended in 2014 from six to ten accounting periods. From 2015, the extension of the period is also to be applied to offshore projects.

EU regulations (also applicable to France, Germany, Poland and Romania)

At one stage the European Commission was expected to propose legislation to require a specific consent framework for unconventional oil and gas. This could have created a similar framework to that put in place for carbon capture and storage. Following extensive lobbying, the Commission determined only to publish a Recommendation to Member States. This invites Member States to build upon existing European regulatory requirements to:

- plan ahead of developments and evaluate possible cumulative effects before granting licences
- carefully assess environmental impacts and risks
- ensure that the integrity of wells is up to best practice standards
- check the quality of local water, air and soil before operations start, in order to monitor any changes and deal with emerging risks
- control air emissions, including greenhouse gas emissions, by capturing the gases
- inform the public about chemicals used in individual wells
- ensure that operators apply best practices throughout projects.

These requirements are unlikely to give rise to any changes to the existing UK regulatory regime.

In October 2013, as part of a more general revision of the Environmental Impact Assessment (EIA) Directive, the European Parliament voted to require that 'Exploration, evaluation and extraction of crude oil and/or natural gas trapped in gas-bearing strata of shale or in other sedimentary rock formations of equal or lesser permeability and porosity ... ', be subject to a mandatory EIA before permits are granted. However, this requirement was not adopted in the final EIA Directive.

Next steps

The UK Government sent clear signals that it supports the shale gas industry and is trying to enhance the ability for it to develop through its changes to land access rights in the Infrastructure Act 2015.

Licences for shale gas exploration will be awarded as a result of the current licensing round. In conjunction with the potentially more streamlined system and rights of access, the gates may be opened in the UK for large scale shale gas exploitation to commence in the near future. However, developers and investors should not underestimate the challenges that lie ahead and the regulatory and political hurdles that need to be overcome to initiate shale gas extraction.

Although the Government has introduced a number of helpful measures to support shale gas, there is widespread public concern in the UK. This makes it difficult to secure planning permission – even where development is restricted to exploration to determine if hydraulic fracturing in the area is commercially viable.

During the passage of the Infrastructure Bill in Parliament, the Government was forced to accept a number of amendments which tightened regulation around hydraulic fracturing activity; it also agreed to a moratorium on hydraulic fracturing in National Parks, Areas of Outstanding Natural Beauty and Sites of Special Scientific Interest. In Scotland, Scottish Ministers announced a moratorium on granting new consents for hydraulic fracturing while further research is undertaken.

The potential prospect for investment in shale gas exploitation in the UK look promising but only with the benefit of a carefully planned and well-executed investment strategy which accommodates the current regulatory delay and political risk.

United States

Shale gas was first produced in the United States (US) from a well in Fredonia, New York, in 1821. For the next hundred years, small quantities of natural gas were produced from shallow, low-pressure shales in the Appalachian and Illinois Basins for consumption in nearby cities. The development of large-diameter pipelines enabled transmission to more distant markets, leading to a dramatic growth in production.

By the late 1940s, the advent of hydraulic fracturing, a process of vertical and horizontal drilling to fracture rock formations and stimulate the flow of oil and gas, made it possible to access far more resources. In the last ten years, additional technological advances in hydraulic fracturing have made vast reserves of tight oil and shale gas technically and economically recoverable.

US shale plays

In terms of shale gas alone, the continental US holds approximately 567 TCF of unproved technically recoverable resources. The US proved gas reserves have increased from approximately 323 TCF in 2012 to 354 TCF in 2013. The shale formations that hold these oil and gas reserves are intensely varied, with unique exploration criteria and operational challenges. The diversity is best appreciated through a brief look at the major shale regions.

Barnett Shale (Texas)

As the use of hydraulic fracturing increased in the late 1980s and early 1990s, Texas' Barnett Shale gained major attention. The rise of gas prices in the late 1990s further spurred production and investment from global oil and gas companies, such as Devon Energy, Chesapeake Energy, XTO Energy and EOG Resources. Compared with larger formations, the Barnett Shale spans a relatively small area of approximately 5,000 square miles in and around Fort Worth, Texas. Nonetheless, since 1993, more than 12.6 TCF of gas have been produced, with over 16,000 gas wells and approximately 962 permits issued in 2014. The Barnett Shale is the second largest shale gas play in the US.

Fayetteville Shale (Arkansas and Oklahoma)

At approximately 9,000 square miles, the Fayetteville Shale is almost twice the size of the Barnett Shale and was once the most active play in the US. However, lower natural gas prices have slowed development there since 2009, with companies re-allocating resources to newer gas plays. Nonetheless, the largest producers, including Chesapeake Energy, Petrohawk Operating Company and XTO Energy (which was acquired by Exxon Mobil Corporation in 2010) have continued to invest in the region, hopeful that a resurgence in gas prices will provide greater profitability.

Woodford Shale (Oklahoma)

Discovered in 1939, the Woodford Shale covers roughly 4,700 square miles. Commercial drilling began in earnest in 2005, as fracturing and drilling advancements made commercial development profitable. The Woodford was one of the earliest US shale plays to steadily produce substantial amounts of both oil and gas. The combination of falling natural gas prices and gradually depleting gas reserves has led to a decrease in development of natural gas reserves and greater focus on liquid and wet gas extraction. Although annual well completions peaked in 2008 at 534, hundreds of additional wells producing both oil and natural gas have been drilled since then.

1161 TCF Recoverable reserves

The US currently has the world's largest shale gas recoverable reserves at 1,161 TCF and is a market leader in terms of extraction and processing technology.

75 TCF

Estimated at 75 TCF, the Haynesville shale gas field is now the largest producing gas play in the US, surpassing the Barnett shale reserve.

33 TCF

The Barnett shale reserve in Texas is one of the largest and most successful in the US. Before 2009, 70 per cent of all US gas shale production came from Barnett.

20 TCF

The Fayetteville shale reserve in Arkansas is another key gas play in the US, having benefited significantly from the methods deployed at Barnett.

Permian Basin (West Texas and New Mexico)

Covering roughly 75,000 miles, the Permian Basin has historically been the most productive and lucrative formation in the continental US. Since the first commercial well completion in 1921, it has become home to over 7,000 individual fields, producing 1,350,000 billion barrels (Bbbl) of oil per day in 2013. Nationally, the Permian Basin accounts for 18 per cent of the crude oil produced each year.

Bakken Shale (North Dakota, Montana and Canada)

The Bakken Shale covers nearly 200,000 square miles in sparsely populated areas of the northern US. The formation is estimated to hold upwards of 365 Bbbl of oil, with daily production measured at 1.13 million barrels (Mbbl) of oil per day in 2014 and projected to reach 3 Mbbl by 2020.

Marcellus Shale (primarily Pennsylvania, New York, West Virginia and Ohio)

The enormous Marcellus formation is estimated to hold approximately 40 per cent of all the shale gas in the continental US. Estimates for the play predict production of 15 billion cubic feet per day of natural gas. Drilling techniques and lessons learned from development in the Barnett Shale have been implemented in the Marcellus with great success and new wells are producing more than 600 million cubic feet per day. The shale is responsible for 75 per cent of natural gas production growth in the US.

Haynesville-Bossier Shale (East Texas and Western Louisiana)

The Haynesville-Bossier Shale covers approximately 9,000 square miles and holds an estimated 251 TCF of recoverable gas. This play is part of a challenging geologic layer through which operators had historically drilled to reach other known productive formations. The Haynesville-Bossier Shale started to become accessible through advances in horizontal drilling and fracturing in the 1980s. The formation is significantly deeper than other unconventional sources and therefore poses major technical and geological hurdles for development and production.

While much of the formation's potential remained untapped as late as 2008, development came rapidly and, by February 2010, the Haynesville-Bossier Shale was responsible for over 10 per cent of all onshore drilling in the US. The shale has recently experienced an increase in production.

Eagle Ford Shale (Texas)

The Eagle Ford Shale covers approximately 20,000 miles in south and east Texas, not far from the Barnett Shale. The formation is significant because it is an unusually productive source of both wet and dry gas, as well as oil. The formation's reliable production has brought an exponential increase in permitting and development in the region. Since 2009, initial production rates have increased.

Utica Shale (Pennsylvania, New York, West Virginia, Ohio and beyond)

The Utica Shale lies below the Marcellus Shale, but covers nearly twice as much surface geographic area (170,000 square miles), extending from West Virginia to Canada. Industry innovation and advances in technology and drilling techniques have made this once untouchable deep play one of the most attractive prospects for domestic and global investment. However, due in part to the current legislative drilling moratorium in New York, most activity is in Ohio. Natural gas production in the Utica Shale reached 1.3 billion cubic feet per day in September 2014.

Ownership of land and mineral rights

Modern US shale operations implicate both traditional and new issues related to ownership of land and mineral rights. There is a well-developed body of law governing the relationships between surface owners and mineral owners, where those two interests are separate. With the recent development of hydraulic fracturing and horizontal drilling, the lateral relationships between adjacent mineral owners have also generated disputes. In response, courts have faced new challenges to adapt well-settled law to address 21st century conditions.

Mineral estate

Although land and mineral rights are governed by state law, there is nationwide consensus on certain fundamental legal principles. The mineral estate is generally said to own the rights to the oil, gas and other types of minerals. Thus, where the surface estate and mineral estate are owned separately, the rights to any natural gas fall within the mineral estate. Under common law, any conflict between the two estates over use and enjoyment of minerals is typically resolved in favour of the mineral estate.

Some states have tempered the dominance of the mineral estate by adopting the accommodation doctrine, which requires reasonable methods of developing the mineral estate. However, even in those states, if no reasonable method is available, mineral estate owners may employ any means of development they desire. At least ten states have superseded common law through legislation that grants surface estate owners additional rights in the form of surface damage statutes. These laws generally require notification and negotiation over liquidated damages before entry.

Source: The US Energy Information Administration (EIA): Shale plays in the US.

Rule of capture

The law regarding protection from neighbouring mineral estate owners has taken on increased urgency as shale development and horizontal drilling have gained popularity. One source of conflict is based on the geological characteristics of the shale itself. Because of the layered nature of the shale formations, fracturing and extraction in one location can affect oil and gas resources located horizontally from the well.

The common law rule of capture grants rights over migratory natural resources to whoever 'captures' them. The Texas Supreme Court has recognised the rule of capture in Coastal Oil & Gas Corp. v. Garza Energy Trust, August 29, 2008, in which the Court cited the rule in dismissing the landowners' claims that an operator drilling on adjacent property was draining their mineral resources. Thus, the rule of capture creates a race to the resource, incentivising mineral estate owners to extract their oil and gas (and that of their neighbours) before someone else does.

Subsurface trespass

Subsurface cross-border conflicts have also arisen where a well bore has physically invaded a neighbouring property. In the subsequent trespass suits, courts have often dismissed the claim, explaining that government-sanctioned pooling removed the plaintiff's rights to its underground resources.

Compulsory or 'forced' pooling statutes are common in oil and gas producing states. These statutes require landowners and/or operators in an area that has been designated as a spacing unit to participate jointly in the development of the mineral interests of that unit. Similar to eminent domain or condemnation proceedings, forced pooling allows landowners or operators to apply directly to the state oil and gas regulatory agency to compel all mineral interests in the designated spacing unit to participate in its development.

Subject to the unit agreement provisions, oil and gas within a pool become fair game for any member in the pool. Thus the legal boundaries of a mineral estate have become increasingly porous.

Leasing of mineral rights

The rights to develop, explore and produce oil and gas from lands owned by another are obtained through an oil and gas lease. Concessions and production-sharing agreements, which are commonly associated with State-owned oil companies, are not typical in the US.

Basic oil and gas lease provisions

Primary and secondary terms

An oil and gas lease is a conveyance of the fee mineral estate to a lessee for a particular period of time. First, there is the primary term for a fixed number of years or months, followed by the secondary term which holds the lease in force by production from the lease. Federal competitive and non-competitive leases are for a term of ten years. After the primary term expires, a lease will usually terminate unless:

- there is a well producing in paying quantities or a well capable of production in paying quantities
- qualifying drilling operations are in progress
- the lease is entitled to receive an allocation of production from an off-lease well.

Bonus and royalty payments

The mineral owner/lessor generally receives a one-time, negotiated bonus payment (e.g. US$50 per acre) as consideration for signing the lease. In addition, the lessor receives a royalty interest in all production from the lease. The royalty payment rate is a defined fraction of the amount or value of the oil or gas removed or sold from the lease. A royalty of 1/8 of production was common for many years, but royalty rates are now more negotiable (generally ranging from 1/8 to 1/4). Federal leases require a royalty of no less than 1/8.

Shut-in royalty clause

In some instances, a well may be capable of producing in paying quantities, but the well's production may be limited or even halted because of external factors that prevent processing and sale of the gas, such as lack of available pipeline capacity. In order to protect the lessee under these circumstances, leases generally have a negotiated 'shut-in royalty' clause that allows the lessee to pay a set fee (e.g. US$50 per acre) in lieu of actual production.

Leasing on federal and state lands

Oil and gas leasing on about 570 million acres of federal and Native American lands is governed by the Mineral Leasing Act of 1920 (as amended) and the Mineral Leasing Act for Acquired Lands of 1947 (as amended), which give the Department of the Interior's (DOI) Bureau of Land Management (BLM) responsibility. The Federal Onshore Oil and Gas Leasing Reform Act of 1987 requires that all public lands that are available for oil and gas leasing be offered by competitive auction on a quarterly basis. The maximum competitive lease size is 2,560 acres in the lower 48 states and 5,760 acres in Alaska.

The process for leasing on state lands is similar to the federal procedure, with each state having its own requirements.

Environmental regulation: federal

The oil and gas industry is regulated by multiple levels of government. Congress and certain state legislatures have attempted to develop a general energy policy in order to promote the domestic exploration and production of oil and gas and other sources of energy while protecting the environment.

Delegation of authority

The US Congress enacts federal environmental laws and the US Environmental Protection Agency (EPA) implements them by promulgating regulations, including minimum standards for air quality, water quality and waste management.

With some exceptions, federal environmental statutes provide that the EPA may delegate to a state environmental agency the authority to administer the federal regulatory programme in the state. To be approved as a delegated authority, a state programme must be at least as protective of the environment as the corresponding federal programme. In fact, many states simply adopt the federal scheme without significant alteration. If the state has complied with the federal requirements, the EPA 'delegates' to the state the right to manage the federal programme, but retains authority to oversee, and may become involved in the regulatory process or pursue enforcement directly against a violator in certain circumstances. Thereafter, the states apply and enforce the standards by issuing permits and enforcing compliance with state regulations.

In general, the federal environmental laws do not pre-empt state law, but rather supplement it. The states may create their own requirements, irrespective of whether they have been delegated authority to enforce federal programmes. States may, of course, enact or issue laws or regulatory provisions that are even stricter than the federal system, or may enact certain types of protections in the absence of federal provisions. In fact, with the exception of most federal and tribal (Native American or Indian) lands, states

are generally left to govern the traditional oil and gas programmes for exploration and production activities that occur within their borders.

Federal jurisdiction

In some instances, several federal agencies may have overlapping responsibilities or jurisdiction. Selected laws specifically address which of one or more agencies have responsibility in such cases.

For example, the Clean Water Act (CWA) is designed to restore and maintain the chemical, physical and biological integrity of the nation's waters. The CWA directs the Administrator of the EPA and the Secretary of the Department of Homeland Security (in which the US Coast Guard (USCG) operates), as well as the Secretary of the Army, to issue various rules and regulations within each agency's assigned area of expertise. The EPA is tasked with developing guidelines for the issuance of permits for the discharge of dredged or fill materials into navigable waters, including wetlands. However, it is the US Army Corps of Engineers (USACE) that is tasked with issuing the actual discharge permits. Therefore, with respect to drilling operations that may impact jurisdictional wetlands, the EPA issues water quality regulations and stormwater permits, but operators would apply to the USACE if a discharge or fill permit were required.

Similarly, with regard to the discharge of oil or hazardous substances to waters of the US under the CWA, and related provisions of the Oil Pollution Act of 1990 (OPA) regarding Spill Prevention, Control and Countermeasure (SPCC) plans, both the EPA and USCG are tasked with issuing rules and enforcing the provisions. On a very simplified basis, the EPA has jurisdiction over 'inland' waters and onshore facilities, while the USCG generally has jurisdiction over waters seaward of a coastline, offshore facilities and vessels.

The BLM is another relevant agency with jurisdiction over oil and gas operations on federal and tribal lands. It generally has duties under the Federal Land Policy and Management Act, the National Environmental Policy Act (NEPA) and the Endangered Species Act (ESA). For example, for operations on federal or tribal lands, the BLM is responsible for issuing well permits to lessees or operators, which includes provisions for completion activities.

Other relevant federal environmental statutes include:

- Resource Conservation and Recovery Act (RCRA), which regulates the management of solid and hazardous waste
- Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), which regulates the clean-up of contaminated sites and unpermitted releases of hazardous substances
- Clean Air Act (CAA), which governs air emissions
- CWA and the Safe Drinking Water Act (SDWA), which protect surface and drinking water respectively.

Hydraulic fracturing

Hydraulic fracturing is not currently regulated at federal level, but proposed statutes and rules from various federal agencies are making their way through the legislative process.

The Safe Drinking Water Act

The SDWA may be the federal statute under which hydraulic fracturing is regulated in the future. The SDWA directs the EPA to promulgate regulations that will protect drinking water sources from contamination. Underground injection means 'the subsurface emplacement of fluids by well injection'. However, the SDWA exempts from the definition fluids or propping agents (other than diesel fuels) injected pursuant to hydraulic fracturing operations related to oil, gas or geothermal production activities. Congress has proposed to amend the SDWA to govern hydraulic fracturing, but past attempts to do so have failed to achieve a consensus, and Congress' latest attempt to amend the SDWA also failed.

Flow-back wastes may not be injected into the subsurface without a permit under the SDWA. Injection wells for the disposal of oil and gas-related wastes are classified as Class II wells within the EPA's Underground Injection Control (UIC) programme. Thus, while the initial injection of hydraulic fracturing fluids is not currently regulated under the SDWA, the re-injection of wastewater generated by the fracturing process is subject to the requirements of the SDWA.

Environmental Protection Agency

In 2012, the EPA issued its first-ever regulations aimed at reducing air pollution from hydraulic fracturing operations. The regulations target emissions from compressors, oil storage tanks and other oil and gas equipment. They generally direct owners or operators of fractured and refractured wells to flare or send to pipeline gas when physically possible.

For each well completion operation begun on or after January 1, 2015, 'green completions' (technologies that capture emissions) must be used.

Bureau of Land Management
In 2012, the BLM issued its proposed rules, setting new standards for fractured wells on roughly 700 million acres of public land as well as 56 million acres of Native Indian lands. The rules include the following requirements:

- All chemicals used in hydraulic fracturing must be publicly disclosed after the completion of the procedure.
- Operators must submit an estimate of the volume of flow-back fluids to be recovered and specify methods of managing and disposing of them.

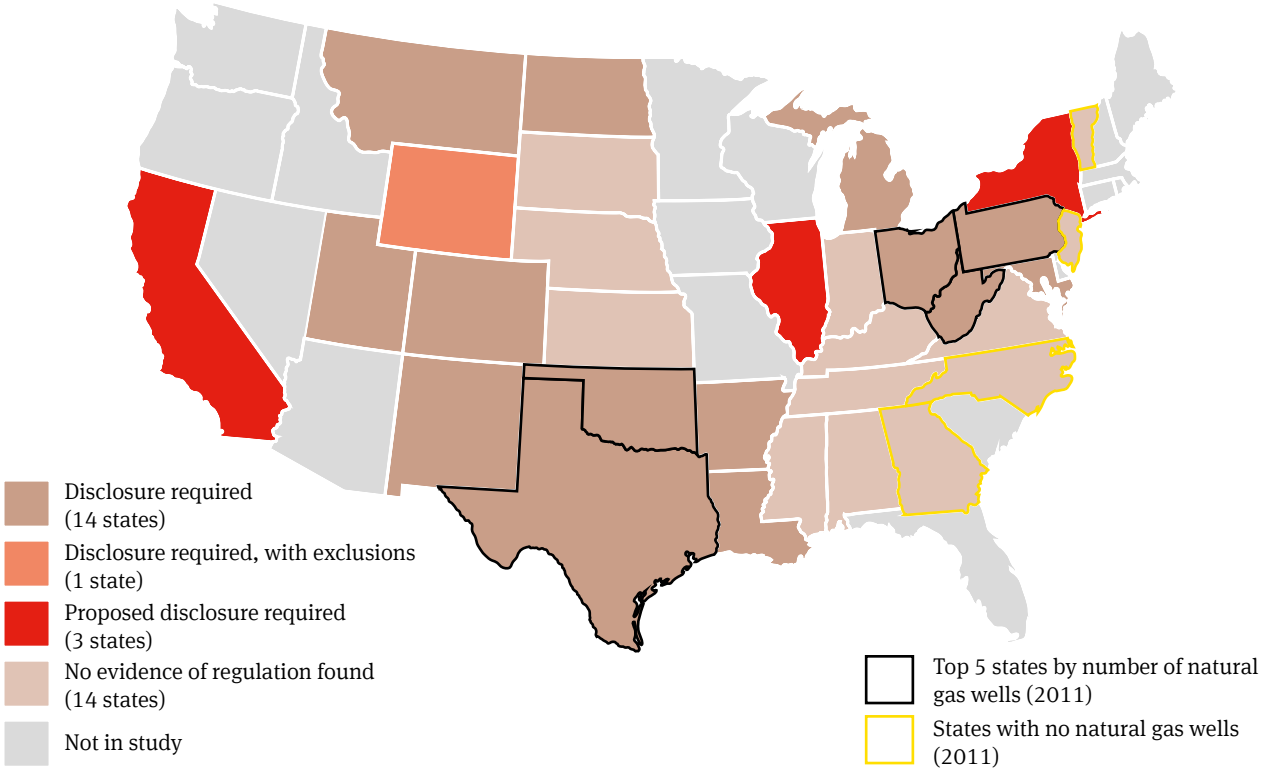
Environmental regulation: states

Although the federal government touches many aspects of oil and gas operations and delegates some of its authority to the states, states play the primary role in regulating the industry within their borders. State statutes provide broad regulatory frameworks and authorise one or more state agencies to promulgate and enforce more specific rules. States with a long history of oil and gas activities generally have agencies devoted exclusively to that sector, while those relatively new to the field have added the responsibility to their existing environmental agencies.

Rules governing exploration and production tend to be the most comprehensive. While these regulations vary considerably from state to state, they tend to share some common areas of focus, such as drilling permits, taxes and fees, spacing and setbacks, pooling and unitisation, public notice, recordkeeping and reporting, equipment maintenance, casing and cementing, prohibitions against wasting resources, nuisance control, safety precautions, waste storage and disposal, contamination prevention, and plugging and abandoning wells.

Regulation of transmission and processing operations are often less developed and are therefore less centralised or uniform. Some states with nascent oil and gas sectors have yet to respond fully to the burgeoning industry with coherent midstream regulation.

Fracturing fluid disclosure requirements



Source: US Energy Information Administration: Number of Producing Gas Wells

In some states, portions of operations at oil and gas exploration and production sites may be under the jurisdiction of more than one agency. For example, in Texas, the Railroad Commission regulates most of the environmental aspects of these operations, although the Texas Commission on Environmental Quality generally issues air permits and wastewater discharge permits.

Hydraulic fracturing

Hydraulic fracturing is regulated largely at state level, generally through oil and gas well regulations or Class II injection well regulations.

Some states (Arkansas, Oklahoma, West Virginia and Wyoming) require permits to be issued before hydraulic fracturing can be used. Other states have issued moratoriums on hydraulic fracturing. In Maryland, an existing de facto moratorium (in place by virtue of the state's refusal to grant any new permits for activities using hydraulic fracturing) has been followed by legislation introduced to the state Senate for the purposes of enacting an official moratorium. Pennsylvania also has a moratorium in effect in some of the watershed areas of the Delaware River Basin.

Vermont has completely banned hydraulic fracturing and New York recently announced that it will also do so.

Disclosure of hydraulic fracturing fluids

In April 2011, members of the US Congress issued a report concluding that the chemicals used in hydraulic fracturing were not widely disclosed.[1] The FracFocus website was launched to provide the public with objective information on hydraulic fracturing, the chemicals used and the purpose they serve, and the means by which groundwater is protected.[2]

There are currently 25 states that have disclosure regulations in force while several other states are considering regulations. Briefly, several states require that the disclosures be made public at the FracFocus website while others require disclosure to state agencies. A few states require the submission of Material Safety Data Sheets for certain chemicals. Some states require some disclosure before hydraulic fracturing begins. Others require disclosure within a given number of days after well completion (e.g. Texas specifies 30 days) and still others require disclosure both before and after.

The level of disclosure often depends on the extent to which the state allows trade secret protections. Some states allow the oil and gas companies to withhold information at their discretion or to submit fewer details about proprietary chemicals, except in medical emergencies.

Environmental regulation: local

The powers of municipal governments to regulate oil and gas operations vary significantly from state to state. Generally, local governments have control over issues relating to land use and zoning, and relating to the health, safety and welfare of their communities (often referred to as the 'home rule'). Municipalities have relied on both sources of power when attempting to regulate the industry.

Land use and zoning authority has been used to justify setbacks from buildings and water bodies, conditional use permitting (setting conditions under which an area may be used for oil and gas operations) and exclusionary zoning (prohibiting oil and gas operations in certain areas). Home rule powers have been cited as the basis for a wide range of municipal regulations, including outright drilling bans.

States such as Texas and Oklahoma, with their long histories and widespread support of oil and gas development, have entrusted local governments to regulate within their traditional scope of authority. However, other states have held that, because state law completely occupies the field of oil and gas law, municipalities are pre-empted from regulating the industry.

Permitting

In all states with active shale exploration and production, an operator must obtain a permit before drilling. The demands of permit applications vary somewhat from state to state. The application generally requires information about a well's location, construction, operation and reclamation.

Most applications also require at least some of the following: a fee (ranging from a nominal amount in some states to US$10,000 in at least one), a plan of the site, a security bond, various operational plans and notice to nearby landowners. Agency officials review the applications for regulatory compliance and may require a site inspection before approval.

1 Chemicals Used in Hydraulic Fracturing, US House of Representatives, April 2011
2 https://fracfocus.org

States also differ as to the type of activity that requires a permit. For example, many states require permits for seismic operations, well-deepening activities, re-entry and enhanced recovery. Midstream operators often need to obtain permits for transporting and processing oil and gas.

Permit requirements also vary within states. Some states impose special conditions for resource-rich regions or urban areas. Additionally, local governments throughout the state, to the extent they are not pre-empted by the state, often require permits for issues such as well placement in flood zones, noise level, setbacks, site maintenance and traffic.

Water acquisition
Hydraulic fractured wells, which are common in US shale plays, are stimulated by injecting a high volume of water and other fluids into the underground formation. Operators often obtain the necessary water from freshwater sources regulated by the state. In order to withdraw from state waters, a certain level of approval is often necessary. The regulatory burden varies considerably between states, with some states requiring nothing more than submission of a pre-withdrawal report, while others force operators to undergo lengthy approval and application processes to obtain water. Additionally, regional water-permitting authorities, with interstate authority over entire watersheds, may also require pre-approval.

Flow-back fluids
Once fracturing is completed, the fluids rise back up to the surface and are referred to as flow-back. Following the flow-back, additional naturally occurring fluids in the shale formations (known as brine or produced water) also ascend to the surface.

Storage of brine and flow-back drilling waste, generally held in onsite pits and tanks, is subject to permitting requirements. Subtitle C of RCRA regulates the handling and storage of hazardous waste. Although most wastes associated with the exploration and production of oil and natural gas are excluded from the definition of 'hazardous waste' under the RCRA, unused fracturing fluids or acids at an oil and gas site would not be exempt.

Exempted wastes may be regulated by state law, even if the wastes are exempt from federal hazardous waste regulations. States universally require operators to obtain a permit before constructing a waste storage facility and to submit reports throughout its operation. Construction itself is prescribed by rules establishing proper storage methods, materials, liners and dimensions. Some state rules will also define allowable distances between waste storage facilities and residences, surface waters and/or groundwater aquifers.

Storage of fluids
Operators must prepare an SPCC plan. The SPCC Programme (SPCCP) sets forth various planning requirements and operational standards relating to the prevention and containment of discharges of oil (or oily substances) into US waters, the response to such an event and the reporting of it.

In addition to an SPCCP plan, certain facilities may need to prepare a Facility Response Plan to address potential worst-case oil spills. This would apply in the case of facilities near water with sensitive ecological environments or with large storage capacities, States may have their own spill prevention and response programmes, but they are enforceable by the state authorities, not the federal government.

Disposal of waste
Flow-back fluid is first treated (generally at wastewater treatment facilities) and then, depending on the state, may be discarded through injection into disposal wells, discharge into surface water and/or recycling back into the fractured well. Injection is the most common and widely approved method. Under the SDWA, underground injection well operators must generally obtain a permit. Hydraulic fracturing well operators that send wastewater to third-party disposal well service providers do not have to obtain a permit.

Discharge to surface waters, where allowed, requires a National Pollutant Discharge Elimination System (NPDES) permit and will typically be done by the wastewater treatment facility. Flow-back recycling has also increasingly been encouraged by several states. This method is increasing in popularity, but often presents regulatory, economic and logistical obstacles. Some states have also allowed operators to sell their brine to municipal governments to be applied to road surfaces for ice and dust control, but not their flow-back fluid.

Air emissions
To regulate air emissions, the federal CAA may require a construction permit and/or an operating permit. This will depend on the quantity of air pollutants that a source has the potential to emit, the particular pollutants emitted and the geographic area where the source is located. The construction permit, or new source review permit, specifies emission limits, required air pollutant control devices, operating limitations and record-keeping requirements. Despite its name, a new source review or construction permit, once issued, will typically continue to apply after the source begins operating. In some states, a construction or new source review permit will be rolled into or redesignated as an operating permit once operations begin.

In some circumstances, federal rules may require that an operator obtains an operating permit. An operating permit does not typically impose significant new operational limitations. Instead, it compiles all air quality statutory, regulatory and permit requirements and requires that a facility operator periodically certifies compliance or reports any deviations from compliance. For both new source review and operating permits, state-level permits may be required even if no federal permits are needed.

Enforcement and adjudication

Like many other industrial businesses, oil and gas companies are subject to enforcement at federal, state and local levels. Enforcement is most frequently based on environmental regulations, although oil and gas companies need to be aware of a wide variety of ever-evolving laws and substantive legal areas.

The federal and state enforcement mechanisms are structurally similar — the relevant laws and regulations allow for three types of enforcement actions: administrative, civil and criminal. While an agency cannot issue administrative and civil penalties for the same violation, it can administer them along with criminal penalties, as the violations are considered separate.

Administrative enforcement

Administrative actions are handled by the agency overseeing the applicable programme. The agency may issue a notice of non-compliance, a notice of enforcement or a similar notice to inform the violator of the problem. Administrative penalties are issued directly by the agency without involvement of a court, although an administrative hearing may occur before finalising the penalty amount.

Civil enforcement

Civil penalties, or civil judicial penalties, are typically enforced by the federal or state Attorney General's office on behalf of the agency. Civil penalty actions are filed in federal or state court. The court decides whether a violation has occurred and, if so, the amount of civil penalty and/or injunctive relief. Civil penalty amounts are generally the highest among the three types of enforcement, even though criminal violations are considered the more serious or harmful violations.

Criminal enforcement

Criminal fines or penalties are less common and are reserved for severe violations. Most laws and regulations discussed here allow the applicable Attorney General's office or prosecutor to file a criminal action in federal or state court. The judge or jury decides guilt or innocence, and the court assesses a criminal fine and/or a term of imprisonment if the guilty party is an individual. Corporations and other business entities may only receive fines. However, sanctions including the loss of permits or the ability to contract with the government may occur as a result of a conviction.

State enforcement

Penalties for violations of state environmental laws vary by state and statute. However, penalties usually include administrative, civil and criminal fines, similar to the federal system. Criminal fines or penalties may be imposed for particularly severe violations. States also have the ability to bring an administrative proceeding to achieve another result, such as enjoining a particular activity or forcing compliance with the statute. Additionally, many states have citizen suit provisions, wherein impacted citizens may file a civil action to compel compliance of the alleged violator.

Taxes, royalties, duties and incentives

This section provides a broad overview of tax obligations and incentives at each level of government. While the details may change over time, the fundamental structure and concepts are likely to endure.

Federal tax obligations and incentives

Authority and code

The Internal Revenue Service (IRS) is the principal taxing authority at federal level, with the US Customs Service of the Department of the Treasury handling customs duties.

Federal tax regulations provide numerous special rules and deductions relating to income taxes charged for exploration and production of oil and gas. Tax exceptions include expenditures relating to pre-drilling exploration costs, intangible drilling costs, accelerated depreciation of oilfield equipment and depletion of subsurface resources.

Income tax

In the US, domestic companies are subject to income tax on their worldwide income, including income from foreign branches, at a rate of 35 per cent. Income of foreign corporations from US sources that is not subject to withholding tax or treaty protection is also subject to income tax at 35 per cent. This rate applies to oil and gas activities and non-oil and gas activities.

Excise tax
The Oil Spill Liability Trust Fund provisions of the OPA impose a per-barrel excise tax, collected from the oil industry on petroleum produced in or imported to the US. The Energy Improvement and Extension Act of 2008 extended the per-barrel excise tax through to December 2017 and increased it from US$0.05 to US$0.08 for 2009–16 and to US$0.09 for 2017.

Tariffs
Tariffs on oil imports range from US$0.05 to US$0.52 per barrel, depending on the type of petroleum. Oil and petroleum products from some countries are duty-free because of trade agreements and Congressional programmes.

Royalties
In addition to taxes, operators on public land must also provide the government with royalties in lieu of lease payments. For federal land, the BLM requires a royalty equal to 12.5 per cent of the market value of the site's production.

Tax incentives
There are also various tax incentives that apply to all industries. Corporations are entitled to deduct certain expenses and lost capital in order to reduce their tax burden. For example, taxpayers may deduct for asset depreciation. Oil and gas companies do this through Percentage Depletion, which accounts for the reduction in available underground resources through the process of extracting them. Other cross-industry incentives are fashioned more as rewards. The Manufacturer's Tax Credit was passed in 2004 to encourage companies to relocate overseas jobs back to the US.

Many industries, including oil and gas, also enjoy certain tax incentives that are specifically tailored to them. In addition to depreciation under the Percentage Depletion, the US tax code allows oil and gas companies accelerated depreciation of oilfield equipment. The Enhanced Oil Recovery Tax Credit applies to costs incurred as part of efforts to increase the amount of crude oil that can be extracted from an oil field. The Marginal Well Tax Credit reduces tax liability for operators of wells that produce little or low-quality oil and gas.

Oil and gas companies are also able to deduct Intangible Drilling Costs — those not part of the final operating well, including costs of drilling and preparing wells, survey work, ground clearing, drainage, wages, fuel, repairs and supplies. Also, while investors may not normally deduct losses on bad bets, those supporting oil and gas ventures may deduct losses through an exemption from the passive activity loss rules.

All these incentives make it more possible to pursue business opportunities that would otherwise be too risky.

State tax obligations and incentives

Income tax
States may impose additional tax liability. Like the federal government, most states impose a corporate income tax on businesses operating within their boundaries. The tax rate ranges significantly from state to state, and also within each state, based on income. Some jurisdictions impose progressive income-based rates while others charge a flat rate regardless of income level. Operators could expect to pay nearly 10 per cent of taxable income in states such as New York, none at all in Wyoming and a range of rates in other states. Moreover, just as with the federal income tax, oil and gas companies may be able to shield themselves from state income tax liability by organising as limited liability companies (LLCs).

Sales tax
Most states also enforce taxes upon the sale or use of tangible personal property. Similar to income tax, these taxes are not industry specific, although certain specified discounts or extra charges may be applicable to oil and gas companies. It is worth noting that some states impose a combined sales and use tax while others have independent sales taxes and use taxes. Rates range considerably from upwards of 8 per cent in some states to 2 per cent in others, and even no tax at all in a few. Moreover, many municipal governments add an additional local sales tax of usually no more than 2 or 3 per cent.

Severance tax
Many states with active drilling operations also impose additional oil and gas-related taxes. These are known as severance taxes as they are associated with the process of severing natural resources from land within the state. Some states structure their tax rates based on the amount of production (e.g. dollars per 1,000 cubic feet of gas or per barrel of oil), while others gear them to the market value of production. Tax rates also differ between natural gas production and crude oil production. Operators can expect to pay anywhere from nothing to as much as 9 per cent of market value. In many states, oil and gas companies must also pay additional taxes in far smaller amounts. These go directly to state-created funds intended to counteract the industry's effect on local infrastructure, environment, education and other public resources.

Royalties
States may also demand royalties for operations on state-owned land. Rates vary considerably among the states from as low as 12.5 per cent in some to upwards of 25 per cent in others.

Tax incentives
Although states subject oil and gas companies to additional taxes, they also often offer various tax incentives to lighten the burden. A fair number of states mirror federal programmes by providing tax reductions for marginal wells, enhanced wells, expanded wells and reactivated wells. States are continually crafting nuanced incentives to compete for the industry's business.

Local tax obligations

Tax liability continues at local level. Municipalities are responsible for generating revenue to fund some of their programmes, and particularly to administer public education. The most common way to do so is through property taxes.

As with the taxes already discussed, property taxes vary considerably from state to state, and even from one municipality to the next. Tax rates around 1–2 per cent of the assessed real property value are common, although rates as high as 7 per cent are possible in some areas. At the opposite extreme, some states do not impose any property tax or consider it included in their oil and gas severance tax. Municipalities may also charge a tax on personal property, or more specifically on the equipment used to produce and transmit oil and gas.

Litigation involving shale and hydraulic fracturing

The number of civil cases involving hydraulic fracturing is rising. Many of these lawsuits (including class actions) concern allegations of groundwater contamination and have been filed by landowners in Arkansas, Colorado, Louisiana, New York, Ohio, Pennsylvania, Texas and West Virginia against oil and gas companies.

Nearly all the plaintiffs in these suits are landowners who leased oil and gas rights to the defendants, or who only own surface rights or who reside close to hydraulic fracturing operations. Other shale and hydraulic fracturing lawsuits concern earthquakes, environmental issues, regulatory enforcement, municipal bans, government regulations, and oil and gas lease disputes.

Plaintiffs in these cases have alleged a variety of causes of action, including nuisance, negligence, trespass, strict liability, breach of contract, fraud or fraudulent concealment or misrepresentation, premises liability, assault, intentional infliction of emotional distress and violations of state environmental statutes. The landowners seek compensatory damages (diminution in property values, loss of use and enjoyment of property, cost of remediation, personal injury and emotional distress), punitive damages and injunctive relief to stop or limit drilling.

Opportunities

The shale revolution is underway in the US. Driven by technological advances, high prices for other energy resources and the political will to achieve energy independence by increasing domestic production, natural gas development and production is soaring and promises even greater results in the future. As the shale plays have emerged, so too has demand for services and investment that will allow successful development of the resource. As a result, there are suddenly enormous opportunities and numerous entry points for investment throughout the US.

The potential of many shale formations in the US creates unprecedented opportunities for companies capable of accessing the resources, companies that provide ancillary services, and the entities and individuals that own the rights to the resources.

Midstream and downstream opportunities

However, the opportunities extend far beyond the wells. Once the resources are extracted, there are plentiful opportunities in the 'midstream' segment, which is typically understood to include transportation and refinement of the raw resources. For example, there is an ongoing need for construction and maintenance of infrastructure to link shale formations to markets. Many of the shale formations are in areas where there was no previous need for large-scale infrastructure to transport oil and gas. In those areas, such as the Marcellus Shale states, development of infrastructure could reduce inefficiencies that arise from unnecessary transportation via existing infrastructure. Some of these inefficiencies are due to lack of refining capability near the shale plays and this lack of capacity offers yet another opportunity for entry and investment.

Further downstream, there are opportunities to develop distribution infrastructure aimed at end users. As development continues and the industry matures, the universe of end users has expanded in remarkable ways as well. For example, there is an emerging market for vehicles powered by natural gas. Given the sustained high prices for petrol, and limitations associated with electric cars, natural gas is becoming the fuel of choice for many companies and individuals. Some states have even passed legislation incentivising this market. Currently, the primary limitation on expansion of the natural gas vehicle market is a lack of publicly available refuelling stations. This lack of infrastructure has made the vehicles more attractive to companies that can purchase a fleet of vehicles and construct their own refuelling stations. Given the clear economic advantages provided by natural gas vehicles, this appears to be yet another opportunity that is simply waiting for the right investor.

There are obstacles to be navigated and uncertainties related to development of resources in areas not previously associated with the oil and gas industry. However, there is enormous potential for investors capable of identifying and exploiting opportunities to participate. The stability of the US' energy programme rests firmly on shale gas development and the use of horizontal drilling and hydraulic fracturing throughout the country. As a result, there is no longer a question as to whether the shale revolution in the US represents an unprecedented opportunity; the only question remaining is who will seize that opportunity.

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Contacts

Barclay Nicholson
Partner and editor of the Hydraulic Fracking blog, Houston
Norton Rose Fulbright US LLP
Tel +1 713 651 3662
barclay.nicholson@nortonrosefulbright.com

Simon Currie
Global head of energy, Sydney
Norton Rose Fulbright Australia
Tel +61 2 9330 8236
simon.currie@nortonrosefulbright.com

William Wood
Head of energy and infrastructure – United States, Houston
Norton Rose Fulbright US LLP
Tel +1 713 651 5537
william.wood@nortonrosefulbright.com

Vincent Dwyer
Head of Asia Pacific – energy, Singapore
Norton Rose Fulbright (Asia) LLP
Tel +65 6309 5458
vincent.dwyer@nortonrosefulbright.com

Anne Lapierre
Head of EMEA, Paris
Norton Rose Fulbright LLP
Tel +33 1 56 59 52 90
anne.lapierre@nortonrosefulbright.com

Chrysten Perry
Head of energy – Canada, Calgary
Norton Rose Fulbright Canada LLP
Tel +1 403 267 8170
chrysten.perry@nortonrosefulbright.com

Matt Ash
Head of energy – South Africa, Cape Town
Norton Rose Fulbright South Africa Inc
Tel +27 21 405 1201
matt.ash@nortonrosefulbright.com

Rachel Dawes
Global head of business development – energy, London
Norton Rose Fulbright LLP
Tel +44 20 7444 3162
rachel.dawes@nortonrosefulbright.com

Authors

Argentina
Leopoldo Olavarria
Daniela Jaimes
Gustavo Mata

Australia
Liz Allnutt
Joanna Yoon

Brazil
Leopoldo Olavarría
Carla Martinez

Canada
Alan Harvie

China
Fei Kwok
Barbara Li

Colombia
Leopoldo Olavarría
Laura Pulverail
Dagoberto Ospina

Netherlands
Matthijs van Leeuwen

Mexico
Leopoldo Olavarría
Maria Paula Silva

Poland
Adam Kozlowski

Russia
Aydin Jebrailov
Anatoly Andriash
Julian Traill
Dinara Dorizo

South Africa
Matt Ash
Lizel Oberholzer
Jane Blomkamp

United Kingdom
Caroline May
Duncan Field
Lucy Bruce Jones
Tim Baines

United States
Barclay Nicholson

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