IN-DEPTH

Oil and Gas Law

EDITION 11

Contributing editor
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Ashurst

LEXOLOGY

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Preface

Michael Burns

The convergence of politics, law, business and environmental concerns makes international oil and gas law a fascinating and ever-shifting field. The outbreak of the conflict in Ukraine threw the role of gas in bridging this intersection into particular prominence in 2022, when prices soared and gas supplies were threatened. Maintaining energy security continues to be a priority in 2023 and has given further impetus to the commitments of national governments to accelerate the energy transition. Meanwhile, the scale of the task of achieving net zero has led to questions over the nature and extent of the future role of the oil and gas industry.

Regulating an industry that involves balancing these differing concerns is inherently complex. Against this background, oil and gas practitioners are required to negotiate diverse national law and regulation in the context of a truly international industry. *The Oil and Gas Law Review* aims to assist practitioners in this challenging area by providing an introduction to the fundamental local legal requirements that they must understand when advising clients in a number of jurisdictions.

The Oil and Gas Law Review is made possible by the efforts of its contributing experts, editors and publishers. I would like to thank all those who have been involved in producing this volume, which will serve as a vital resource to many practitioners.

Michael Burns
Ashurst
London
October 2023

Chapter 1

Abu Dhabi

James Comyn and Patricia Tiller[1]

Summary

I INTRODUCTION

The United Arab Emirates (the UAE) is the Organization of the Petroleum Exporting Countries (OPEC)'s third largest crude oil producer. In 2023, the UAE agreed to produce fewer than 2.9 million barrels of crude oil per day (b/d), an OPEC+ production limit that is expected to increase to 3.2 million b/d in 2024.[2] ADNOC's current production capacity is 4.65 million b/d, which the company intends to increase to 5 million b/d by 2027.[3]

Ninety-five per cent of the UAE's proven oil reserves are based in the emirate of Abu Dhabi,[4] one of the seven emirates of the UAE, and Abu Dhabi's production accounts for almost all of the oil exported from the UAE.

The UAE's first oil concession was granted on 11 January 1939. This agreement covered the entirety of Abu Dhabi, both onshore and offshore. The agreement was followed by similar agreements in respect of the other emirates of the UAE. Those subsequent agreements were, however, relinquished after World War II, as were the offshore rights in Abu Dhabi. Abu Dhabi entered into its second oil concession agreement on 9 March 1953, which covered its offshore areas.[5] After a number of amendments, relinquishments and extensions, Abu Dhabi's original onshore concession expired on 10 January 2014, 75 years after its initial grant. Between 2015 and 2017, interests in a new onshore concession were granted to Total (10 per cent), BP (10 per cent), CNPC (8 per cent), Inpex Corporation (5 per cent), GS Energy (3 per cent) and CEFC (4 per cent), with Abu Dhabi National Oil Company (ADNOC) retaining a 60 per cent interest.

The expiry of Abu Dhabi's original principal offshore concession occurred in 2018. Upon its expiry, the concession area was divided into three areas, and interests totalling 40 per cent were granted to international oil companies, with ADNOC retaining a 60 per cent interest in each new concession area. The international oil companies that now hold participating interests are as follows:

- in Um Shaif and Nasr: Total (20 per cent), Eni (10 per cent), PetroChina (6 per cent) and CNOOC (4 per cent);
- in Lower Zakum: Inpex Corporation of Japan (10 per cent), a consortium led by ONGC Videsh (10 per cent), PetroChina (6 per cent), Total (5 per cent), ENI (5 per cent) and CNOOC (4 per cent); and
- in Satah Al Razboot (SARB) and Umm Lulu: Cepsa (20 per cent) and OMV (20 per cent).

The Abu Dhabi government has since launched several competitive bidding rounds for additional onshore and offshore blocks, awarding concessions to various international oil companies.

In recent years, ADNOC has continued to invest across the full range of its business activities, most notably its oil and gas production capacity. These investments have been combined with the listing of minority stakes in some of its businesses on the Abu Dhabi Stock Exchange. These trends are expected to continue throughout 2023 and 2024.

In August and October 2022, ADNOC announced contracts for over US$5 billion in aggregate to hire additional offshore drilling rigs and barges. ADNOC's increased drilling is designed to support the expansion of Abu Dhabi's crude oil production capacity and to enable gas self-sufficiency for the UAE, which currently imports gas from Qatar.

In January 2023, ADNOC combined its 68 per cent stake in ADNOC gas processing and its 70 per cent stake in ADNOC LNG into one global and consolidated business, ADNOC Gas. A 10 per cent stake in ADNOC Gas was listed on the Abu Dhabi Stock Exchange in March 2023. The first shipment of UAE LNG to Germany was delivered to the Elbehafen floating LNG terminal in Brunsbüttel, Germany in February 2023.

In October 2021, the UAE announced its intention to reach net zero by 2050.[6] Renewable and nuclear energy have since become important components of the UAE's energy mix, and an increased focus on decarbonising the oil and gas sector is evident in the UAE's latest projects, including the acquisition by ADNOC of a 24 per cent stake in Masdar's renewables business and a 43 per cent stake in Masdar's green hydrogen business. Masdar's other shareholders are also Abu Dhabi government-owned entities.

This chapter provides an overview of the legal regime in Abu Dhabi as it relates to oil and gas investment.

II LEGAL AND REGULATORY FRAMEWORK

i Constitutional framework

Article 23 of the Constitution of the UAE provides that the natural resources and wealth in each emirate are the public property of that emirate and that the 'community' must preserve and use those resources and that wealth for the public good and in the interests of the national economy.

Subject to the Constitution of the UAE, the laws of Abu Dhabi are the principal source of regulation applicable to the oil and gas industry in the emirate.

The Supreme Council

The Supreme Council for Financial and Economic Affairs (the Supreme Council) is the supreme body charged with overseeing Abu Dhabi's financial, investment, economic, petroleum and nature resource affairs.[7] Formed in December 2020, the Supreme Council assumed the functions of the former Supreme Petroleum Council of Abu Dhabi. Accordingly, the Supreme Council has a number of functions relating to the petroleum industry in Abu Dhabi:

- the Supreme Council lays down and approves public policies and strategies for the regulation of Abu Dhabi's petroleum and natural resources affairs (among others);
- the Supreme Council reviews and approves the annual plans of ADNOC (and other Abu Dhabi government department and owned entities); and
- the Supreme Council is responsible for setting the fiscal framework for the oil and gas industry in Abu Dhabi and, through its secretariat, for overseeing royalty and tax assessment and collection.

The Supreme Council is chaired by the ruler of Abu Dhabi. Its other members include prominent members of the ruling family, senior Abu Dhabi government officials, the chief executive officer of ADNOC and the chief executive officer of Mubadala Investment Company. The Supreme Council is supported by a full-time secretariat.

Abu Dhabi Law No. 8 of 1978 Regarding the Conservation of Petroleum Resources

The principal legislation governing oil and gas operations in the emirate is Abu Dhabi Law No. 8 of 1978 Regarding the Conservation of Petroleum Resources (the Conservation of Petroleum Resources Law). Although this law is drafted in general terms, it imposes high standards on the industry, in particular requiring the use of 'the most efficient scientific techniques' and the use of machinery and materials that conform to international standards, including as regards safety and efficiency.

The Conservation of Petroleum Resources Law covers all stages of upstream petroleum operations. The construction of facilities requires prior consent, including the submission of detailed studies and technical and economic evaluations. All exploration activity requires prior consent and any data obtained must be submitted to the Supreme Council, together with interim and final interpretations of the data.

The law also contains detailed provisions regulating the drilling, completing, reworking and abandonment of wells, including the process for obtaining consent, minimum standards to be met and reporting obligations.

Once producing, an operator must submit monthly production reports for each producing well, including daily production rates, oil–gas ratios, wellhead pressure, sediment and water content and the American Petroleum Institute (API) gravity of oil produced. Studies must be conducted on reservoir behaviour. Operators must also conduct 'supplementary' oil-recovery operations, including gas, water or steam injection if technically and economically justified to maintain production with the prior consent of the Supreme Council and to file monthly reports in respect of those activities.

ii Treaties

The UAE acceded to the New York Arbitration Convention on the Recognition and Enforcement of Foreign Arbitral Awards on 21 August 2006.[8] Abu Dhabi government-owned entities typically require that agreements to which they are party, particularly if the place of performance is within the emirate, are governed by Abu Dhabi law, with disputes being subject to arbitration in Abu Dhabi.

The UAE has signed bilateral investment treaties with over 50 countries, including China, France, Germany, India, Italy, South Korea and the United Kingdom, all of whose international oil companies (IOCs) or national oil companies (NOCs) have invested in the emirate's petroleum sector.

III LICENSING

i Crude oil

Crude oil concessions in Abu Dhabi are granted by the Supreme Council, on behalf of the emirate. Although there is no prescribed form or model suite of oil concession agreements in Abu Dhabi, recent concessions have adopted the following structure:

- An interest in the concession in question is granted by the Supreme Council on behalf of the emirate to IOCs or NOCs with the interest being so granted to such companies not exceeding 40 per cent in the aggregate, with the balance being held by ADNOC (or, in more recent concessions, with ADNOC having the option to hold a 60 per cent interest in the production phase of the concession).
- The concession agreement provides that participating oil companies are entitled to lift their participating interest share of crude oil produced from the concession during its term and to export that crude oil from the emirate.
- ADNOC and the other holders of concession rights sign a joint venture agreement whereby they agree to exploit the concession jointly and set out agreed governance structures (more recent concessions have dispensed with joint venture agreements).
- ADNOC and the other holders of concession rights appoint an operating company to operate the concession on their behalf on a non-profit-making basis. The operating company is typically a company incorporated for this purpose by the ruler of Abu Dhabi by decree, with the operating company being exempted from the UAE Federal Law No. 2 of 2015 on Commercial Companies (the UAE Federal Commercial Companies Law). Initially, each concession area was operated by a separate operating company owned by the holders of the concession in their respective participating interests. In some of the more recent concessions, however, the Supreme Council and ADNOC have sought greater operating and cost synergies by having one operating company operate more than one concession.
- IOCs agree to maximise technology transfer to ADNOC and the operating company pursuant to master technology agreements and to provide support to them pursuant to manpower supply agreements.
- IOCs agree to support various Abu Dhabi institutions, such as the Petroleum Institute and the Masdar Institute, and to assist in the training of UAE nationals.

The Supreme Council expects that the entity that is party to the concession agreements is the parent company of the group or that the parent company guarantees the performance of the obligations of the relevant entity.

ii Gas

Abu Dhabi Law No. 4 of 1976 Regarding the Ownership of Gas by the Emirate of Abu Dhabi (the Gas Law):

- vests in Abu Dhabi ownership of gas discovered or to be discovered in the emirate; and
- grants to ADNOC the right to 'exploit and use' all such gas[9] either alone or in partnership with others, as long as ADNOC's ownership of any project is at least 51 per cent.

Foreign investment in producing the emirate's gas resources therefore occurs pursuant to field entry agreements with ADNOC, with the joint venture being paid a fee by ADNOC for gas produced by the joint venture. Similarly, foreign investment in processing and transporting the emirate's gas resources occurs pursuant to joint ventures, with ADNOC maintaining majority ownership and the joint venture being paid a processing and transportation fee. As in the case of oil concessions, foreign partners are expected to maximise technology transfer to ADNOC and the operating company pursuant to technology support agreements, to provide support to them pursuant to manpower supply agreements and to support various Abu Dhabi institutions, such as the Petroleum Institute and the Masdar Institute, and to assist in the training of UAE nationals.

The exploitation, processing and transportation of the emirate's gas resources remain subject to the jurisdiction of the Supreme Council and any agreements require the prior approval of the Supreme Council.

The Gas Law entitles oil companies operating in the emirate to use gas produced by them for their oil operations, including to generate power, to lift oil from reservoirs, to maintain reservoir pressure and as part of enhanced oil recovery operations. The Gas Law was amended in 2014 to allow ADNOC to charge oil companies for the use of such gas. Subject to the above, the Gas Law requires all oil companies operating in the emirate to deliver to ADNOC gas produced by them.

In practice, ADNOC directs that gas be delivered to ADNOC Gas Processing, an operating company engaged in the extraction of natural gas liquids from associated and natural gas, whose shareholders are ADNOC Gas (68 per cent), Royal Dutch Shell plc (15 per cent), Total SA (15 per cent) and Partex Gas Corporation (2 per cent).

IV PRODUCTION RESTRICTIONS

The UAE has been a member of OPEC since 1967 and has a history of complying with OPEC production requirements. The UAE is represented at OPEC meetings by the UAE Federal Minister of Energy, who is invariably from Abu Dhabi.

Within the emirate, the Supreme Council sets production targets for each field and also determines whether oil is to be exported from the Jebel Dhanna Terminal in Abu Dhabi on the coast of the Arabian Gulf or from the Fujairah Terminal, an export terminal located on the Indian Ocean in the Emirate of Fujairah. The Fujairah Terminal is linked to Abu Dhabi's oil-producing fields by the 405 km long Abu Dhabi Crude Oil Pipeline, which is capable of transporting 1.5 million b/d. The Abu Dhabi Crude Oil Pipeline and the Fujairah Terminal were commissioned in 2012 and are strategically important facilities that allow Abu Dhabi to export its crude oil directly to the Arabian Sea via the emirate of Fujairah, bypassing the Strait of Hormuz, thereby minimising shipping congestion through those straits and saving insurance costs, reducing journey time and allowing loading by very large crude carriers. ADNOC has announced that it is building the world's largest single underground project for oil storage, with a capacity of 42 million barrels of crude oil, in the emirate of Fujairah, adding to its existing storage.

V ASSIGNMENTS OF INTERESTS

The assignment of interests in oil and gas concession agreements (or the direct or indirect transfer of shares in a group company that holds interests in concession agreements) requires the prior approval of the Supreme Council and ADNOC, unless the transfer is to a wholly owned affiliate. Any such proposed transfer would require the early involvement of the Supreme Council and ADNOC, particularly if it is proposed that confidential information be shared with proposed transferees. In considering whether to approve any transfer, the Supreme Council and ADNOC are likely to consider the contribution that the proposed transferee could make to the development of the concession in question and the meeting of production requirements through the deployment of technology and human capital.

VI TAX

The fiscal regime applicable to each oil concession is determined by the Supreme Council upon grant of the concession. Details of each such fiscal regime are not publicly available, but the fiscal regimes typically involve a mixture of royalty and income tax. The Supreme Council is also responsible for overseeing royalty and tax assessment and collection in the emirate.

The UAE, as a member of the Gulf Cooperation Council, applies the Common Customs Law under GCC Customs Union Agreement 2003, which provides for a common 5 per cent tariff on goods imported into a Gulf Cooperation Council member state.

In 2018, value-added tax (VAT) was introduced by the UAE.[10] Most costs incurred in the oil and gas industry are likely to be subject to VAT at the standard rate of 5 per cent. However, both exports generally and the supply of crude oil and natural gas are zero rated, allowing VAT to be recovered in most cases. The UAE does not levy export duties.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

i Environmental Protection Law

Environmental protection in the UAE is principally subject to UAE Federal Law No. 24 of 1999 on the Protection and Development of the Environment (as amended by Federal Law No. 11 of 2006) (the Environmental Protection Law). The UAE Federal Environment Agency is tasked with developing, issuing and revising environmental protection standards in coordination with other relevant bodies and with establishing plans for dealing with environmental emergencies.

The Environmental Protection Law has the following objectives:

- the protection of the environment and the preservation of its quality and natural balance;
- the control of pollution and the avoiding of immediate or long-term damage or adverse impact on the environment resulting from economic development;
- the development of natural resources and the preservation of biological diversity within the UAE;
- the protection of human and animal health; and
- the implementation of the UAE's obligations under international treaties relating to the protection of the environment, the control of pollution and the preservation of natural resources.

Title Two of the Environmental Protection Law deals with the protection of the aquatic environment – both the UAE's coastal waters but also ground and drinking water. Article 18 prohibits the discharge of waste or polluting substances into the environment from onshore or offshore oil and gas fields unless preventative measures are in place and any discharge is treated in accordance with international practices.

Title Two of the Environmental Protection Law prohibits the discharge of oil, hazardous substances, sewage and waste into the marine environment. In the case of the discharge of oil from shipping, the owners of vessels and those operating them are liable for all expenses arising as a result of damage to the environment arising from an oil spill.

Title Three of the Environmental Protection Law deals with the protection of soil and, in general terms, prohibits any activity that damages the natural properties or otherwise pollutes soil, other than in accordance with implementing regulations.

Title Four of the Environmental Protection Law addresses air pollution and, in particular, requires that the burning of any type of fuel, including in the production of crude oil, be minimised and kept within prescribed limits. In this regard, the ADNOC group has adopted a no-flaring policy.

Articles 71 and 72 of the Environmental Protection Law impose a 'polluter pays' regime for liability. Article 71 provides that any person who intentionally or negligently causes damage to the environment or to human health as a result of the breach of the provisions of the Environmental Protection Law is responsible for all the costs of treatment or removal of such damage and is liable to pay compensation for loss incurred as a result, including compensation for loss as a result of the permanent or temporary inability to use any such polluted area, for damage to the environment's economic and aesthetic value and for 'rehabilitation' costs.

ii Role of ADNOC's Environment, Health and Safety Division

The Environmental Protection Law envisages that its licensing provisions are disapplied in the case of entities that have sufficiently robust systems and programmes to protect the environment and to achieve the purposes of the law.[11] Accordingly, the UAE and Abu Dhabi government agencies do not have jurisdiction to license the oil and gas activities conducted by ADNOC group companies; ADNOC is responsible for setting environmental standards for the oil and gas industry in Abu Dhabi and monitoring compliance with them.

The ADNOC HSE Code of Practice issued by ADNOC's Environment, Health and Safety Division must be complied with by all ADNOC group companies.[12] The ADNOC HSE Code of Practice reflects, supplements and frequently exceeds the requirements of the Environmental Protection Law. The ADNOC HSE Code of Practice is supplemented by HSE technical guidance that is not mandatory, but the relevant operator will need to demonstrate that any departure from the technical guidance is at least as effective as the approach recommended in the ADNOC HSE technical guidance.

Decommissioning obligations are typically addressed by the relevant concession agreement or otherwise required by the Supreme Council.

VIII FOREIGN INVESTMENT CONSIDERATIONS

Except for nationals of Gulf Cooperation Council states (including companies incorporated in such a state), legal persons may not carry out commercial activities or establish offices on mainland UAE (i.e., outside one of the free zones) except:

- by establishing a branch or representative office that requires the foreign company to have a UAE national (or a company wholly owned by UAE nationals) as its agent (often referred to as a sponsor) and by registering the branch or representative office in the foreign companies register at the Federal Ministry of Economy;
- through a UAE-incorporated subsidiary, 51 per cent of whose shares must generally be held by one or more UAE nationals;[13] or
- with a Foreign Direct Investment Licence,[14] which permits 100 per cent foreign ownership. However, exploration and production of petroleum products appear on the 'Negative List' of sectors that remain subject to the requirement for majority-UAE ownership.

The Supreme Council and ADNOC also require oil companies that participate in the upstream oil and gas sector to establish a suitably staffed office in the emirate (ordinarily a branch or representative office).

To carry on commercial business in the UAE, companies are also required to obtain a commercial or trade licence from the federal and municipal authorities to carry out their proposed activities. Licences are granted to companies incorporated in the UAE, and to foreign companies operating in the UAE with a local sponsor or agent.

IX CURRENT DEVELOPMENTS

ADNOC continues to progress its 2030 strategy with three key objectives:

- more profitable upstream – a focus on increasing production capacity (including exploring and developing unconventional fields) and re-energising mature fields;
- more valuable downstream – expanding petrochemical production and refining capacity; and
- more sustainable and economic gas supply – improving operational efficiencies and ensuring security of gas supply to the UAE.

In recent years, ADNOC has continued to invest across the full range of its business activities, most notably its oil and gas production capacity. These investments have been combined with the listing of minority stakes in some of its businesses on the Abu Dhabi Stock Exchange. In addition, ADNOC has invested in mid and downstream businesses, including by taking stakes in strategic partners such as OMV of Austria. Finally, we have seen increased investment in parts of the energy transition, such as LNG vessels, green hydrogen facilities and technologies and carbon capture and storage.

These trends are expected to continue throughout 2023 and beyond.

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Endnotes

1 James Comyn and Patricia Tiller are partners at Hunton Andrews Kurth LLP.
2 Energy Intelligence Group, 4 July 2023.
3 ADNOC website (https://www.adnoc.ae/en/OurStrategy/Responsible-Growth).
4 Energy Intelligence Group, 4 July 2023.
5 Mana Saeed Al Otaiba, *The Petroleum Concession Agreements of the United Arab Emirates 1939–1981 (Abu Dhabi)*, 1982, Croom Helm Ltd.
6 UAE Net Zero 2050 Strategic Initiative.
7 Law No. 24 of 2020 concerning the Supreme Council for Financial and Economic Affairs.
8 www.newyorkconvention.org/countries. The UAE is also a party to several regional treaties, including the Riyadh Convention on Judicial Cooperation between States of the Arab League of 1983.
9 Article 2 of Abu Dhabi Law No. 4 of 1976 defines 'gas' to include associated gas, gas within the gas cap of oil reservoirs, non-associated natural gas, including in each case methane, ethane, propane and butane and natural gasoline, pentane and condensate.
10 See Article 45 of UAE Federal Law No. 8 of 2017 on Value Added Tax.
11 See Article 94 of the Environmental Protection Law.
12 The ADNOC HSE Code of Practice and technical guidance must also be complied with by the few independent operators that operate in the upstream oil and gas industry in Abu Dhabi and in which ADNOC has no equity interest – principally: (1) Abu Dhabi Oil Co, Ltd (ADOC) (a company jointly owned by Cosmo Energy Holdings Co, Ltd and JX Holdings, Inc that has been operating in the territorial waters of the emirate since 1967); (2) Bunduq Oil Producing Company (a company 97 per cent owned by a Japanese consortium through United Petroleum Development Company Limited with the remaining 3 per cent held by BP); and (3) Total Abu Al Bukhoosh or TOTAL ABK (a subsidiary of TOTAL SA). The ADNOC HSE Code of Practice and technical guidance are not publicly available.
13 Article 10 of the UAE Federal Commercial Companies Law requires that every company incorporated in the UAE must have one or more UAE national partners (either UAE nationals or companies wholly owned by UAE nationals) whose share in the company must not be less than 51 per cent of its share capital. As noted above, there are a number of exemptions from the UAE Federal Commercial Companies Law, including companies in which a UAE or emirate government-owned entity (such as ADNOC) holds at least 25 per cent of the shares and that operate in oil exploration, drilling, refining, manufacturing, marketing and transmission provided that a provision disapplying the UAE Federal Commercial Companies Law is contained in constitution of the company in question.
14 UAE Federal Decree-Law No. 19 of 2018 on Foreign Direct Investment (the FDI Law) came into force on 30 October 2018 and recognises 100 per cent foreign ownership in mainland UAE for certain sectors and activities set out in a 'Positive List' (confirmed on 17 March 2020 by the UAE Cabinet Resolution No. 16 of 2020). From its inception, the FDI Law established a 'Negative List' of 13 areas or sectors that remain subject to the long-established maximum 49 per cent cap on foreign investor ownership.

Chapter 2

Angola

Lourenço Vilhena de Freitas and João Sequeira Sena[1]

Summary

I INTRODUCTION

In 2021, Angola produced, on average, 1.2 million barrels of oil daily,[2] being one of the largest oil producers in Africa.[3] However, in 2022 Angola overtook Nigeria as the biggest oil producer in Africa. With over 9 billion barrels of proven oil reserves, Angola is committed to unleashing the full potential of its hydrocarbon sector. In 2022, production stood at 1.16 million barrels per day (b/d); nevertheless, this figure is increasing as the country's six-year licensing round and policy reforms take off.[4] Angola's challenge is to try to boost the most important sector of its economy.[5]

The Angolan government has released a strategic plan for the exploration of hydrocarbons between 2020 and 2025 with the approval of new tax incentives to boost the oil industry, after the decline in capital expenditure and investment in the industry to US$3 billion in 2021, against US$15 billion in 2014.

The state of emergency imposed by the covid-19 pandemic had a huge impact on worldwide oil and gas operations, leading to the suspension of drilling activities and substantial limitations on production activities in general. The pandemic has affected all spheres of the Angolan economy, especially the oil and gas sector, both through the decline in prices of commodities and the decrease in the consumption of oil derivatives, but also through the difficulties caused in the mobilisation of resources for the renewal of activities. The Angolan government, in particular its Minister of Mineral Resources, Petroleum and Gas (MIREMPET)[6] of Angola,[7] tried to mitigate the effects of the pandemic in the oil and gas sector, revealing key strategic decisions and efforts on the short-, medium- and long-term outlook for the post-pandemic period.

Since early 2020 until now, the extractive industries have materialised and expedited their reforms with the consolidation of the role of the National Agency of Petroleum, Gas and Biofuels (ANPG)[8] as National Concessionaire (Granting Authority), and the execution of Sonangol EP's Renewal Program. MIREMPET and ANPG have pursued an effort to promote, internationally, the Concession Award Strategy for the 2019–2025 period[9] with the start of several public tenders for oil and gas blocks in both the Benguela and Namibe basins. Furthermore, investment to increase the national oil refining capacity is also planned with new refineries expected to start operations by 2025. The midstream sector is key for Angola, which has led to the development of landmark projects essential to incrementing Angola's refining capacity. An agreement for the construction of the Cabinda Refinery was reached, the bidding was launched for the Soyo Refinery and the review of the technical and financial feasibility studies is underway for the public tender pertaining to the construction of the Lobito Refinery.[10]

This crisis led to major changes that were long due in the Angolan oil and gas industry. During 2021, strategies for exploration in areas of development and marginal fields have begun to materialise. In this sense, the declarations of marginal fields have been approved for the Paje field, Astrea and Juno fields in Block 31, N'singa field (already in production), Lifua, Kambala and N'dola Sul fields in Block 0.

The reform process in the oil and gas sector has continued, particularly through Sonangol EP's Renewal Programme, which includes the privatisation of its non-core activities. However, the lack of market stability in the oil and gas sector and the poor visibility of the immediate future have delayed the privatisation process of the assets linked to the services subsector of the oil and gas industry.

The covid-19 pandemic acted worldwide as a catalyst to promote the transition to cleaner alternative energy sources, including natural gas. Angola has been working on its policies and programmes that aim for the energy transition, without forgetting that the main objective in the short to medium term is still to increase oil and gas production. The objective is to convert thermal power plants from diesel to gas, as is the case with the combined cycle power plant in Soyo, with a capacity of 750MW, or replace them with new hydroelectric plants. In parallel, renewables projects are being developed, namely the construction of a photovoltaic electric power plant in Namibe (50MW), a partnership between Sonangol EP and ENI, which is already in motion.

Angola possesses a liquefied natural gas (LNG) power plant in Soyo that has been in operation since 2012, with an initial processing capacity of one million cubic feet of gas per day, which was founded because of the necessity of monetising natural gas resources, eliminating flaring in oil and gas operations.

Mitigating the natural decline of production represents one of the biggest challenges of the oil and gas sector in Angola, and as a result the Angolan government has recently approved a hydrocarbon exploration strategy[11] that sets forth the following five pillars:

- the permanent availability and accessibility of the areas that constitute the sedimentary basins of Angola for research and evaluation activity;
- expanding geological knowledge and access to oil and natural gas resources;
- ensuring the successful execution of the General Concession Award Strategy in Angola;
- intensifying research and evaluation of concessions for the sedimentary basins of Angola; and
- salvaging exploration projects, the development on marginal fields or other fields, that have already been approved but were suspended because of the pandemic, and the decline in oil prices.

The war in Ukraine is affecting the entire world economy, and, naturally, the first impact in Angola refers to the price of oil. The rise in the price of oil was a trend that had been going on for some time and was accentuated with the outbreak of the war. On 31 January 2022, the price of a barrel of Brent was at US$89.9, on 14 February 2022, the figure stood at US$99.2. With the start of the war, it reached as high as US$129.3 on 8 March 2022. It seems that the equilibrium price of oil in the near future will be between US$95 and US$100 with, of course, the possibility of shocks that will make it rise or fall abruptly.

Considering that Angola's budgeted forecast for 2022 calculated the price of a barrel at US$59, there was a great capital gain from the beginning of the year corresponding to at least 50 per cent more. In this sense, since the budget was balanced, it means that there will be a financial surplus.

Oil price gains do not translate directly into a positive fiscal balance in Angola; unfortunately, there are several constraints that prevent the rise in oil prices from determining a large direct budgetary advantage for Angola.

China is the main buyer of Angolan oil, and although we do not know how the purchase and sale agreements were made, we believe that there are certain automatic restrictions to reflect price fluctuations. In the past, some intermediaries in the buying and selling of oil to China have established fixed price contracts that have greatly damaged the Angolan treasury. China buys about two-thirds of Angolan oil (in fact, 70 per cent), which gives China a monopolistic control over the price, meaning that Chinese purchases are made to minimise price rises, to the detriment of Angolan benefits.

Second, there is debt service; there are contractual mechanisms that imply that a higher oil price implies an increase in debt service (i.e., payments to be made). The Minister of Finance, Vera Daves, has already acknowledged that 'what results from the price increase cannot be done arithmetically with production' and that the price of a barrel of oil, above US$100, forces Angola to pay more to its international creditors.

Regarding the price of fuel sold to the public, which is subsidised by the Angolan state, if the cost of oil increases and the government does not increase the price of fuel, it will have to bear more subsidies and spend more to maintain fuel prices. If it does not, then it will have to contribute to the rise of inflation, which is already high in Angola, and will create further social problems and discontent.

The following four factors must be considered to assess the real impact of rising oil prices on Angola's accounts and economy:

- rising prices;
- relations with China;
- increased debt repayment obligations; and
- increased fuel subsidies.

The preliminary conclusion that can be drawn is that a 50 per cent increase in the price of oil in relation to what is foreseen in the budget leaves a treasury gap that is still accentuated after the increase in debt service payments and the support for the rise in fuel prices, with no doubt that a financial cushion is already creating moderate optimism regarding the Angolan economy.

The Angolan government aims to finish the restructuring process for Sonangol EP, with the dispersion of part of its stock exchange capital, which is expected to be launched in 2026 (although a debt operation was launched in August 2023 in the Luanda stock exchange). The privatisation programme of Sonangol non-core assets should be executed, as should the implementation of its plan for production and exploration, consolidating its position as the main national company. Another important project is the new consortium of gas (NGC),[12] which will be the first non-associated gas development project.

II LEGAL AND REGULATORY FRAMEWORK

i Domestic oil and gas legislation

The Angolan regulatory framework for the exploration and production of oil and gas is essentially established in the Petroleum Activities Law, but the following regulations are essential, and demonstrate what has been a recent effort from MIREMPET to promote the oil and gas industry in Angola and consequently try to increase production.

Law No. 10/04, of 16 November 2004 (Petroleum Activities Law), as amended by Law No. 5/19, of 18 April (Amendment of the Petroleum Activities Law), is a cornerstone of Angola's oil and gas legislation. This law establishes the fundamental principles that govern the exploitation of the country's oil and gas potential, reaffirming the fundamental principle of state ownership of petroleum resources enshrined in the Constitutional Law, as well as the regimes of exclusive concessionaire and compulsory association within the scope of petroleum concessions.

It establishes the rules of access and exercise of oil and gas operations in the available surface and submerged areas of the national territory, internal waters, territorial sea, exclusive economic zone, and continental shelf, but also tries to cover all sectors of the oil and gas 'chain-value', namely the refining of crude oil, the storage, transport, distribution and commercialisation of petroleum.

The definition of 'petroleum', as contained in the Petroleum Activities Law, comprises crude oil, natural gas and all other hydrocarbon substances that may be found in and extracted from a petroleum concession. The Petroleum Activities Law determines that all deposits of liquid and gaseous hydrocarbons existing in the available surface and submerged areas of the national territory, inland waters, territorial sea, exclusive economic zone and continental shelf form part of the state's public domain, and that the mining rights for the prospection, exploration, appraisal, development and production of hydrocarbons (liquid or gaseous) are granted to the ANPG as the holder of such rights.

Law No. 13/04, of 24 December (Petroleum Activities Tax Law), as amended by Law No. 6/19, of 18 April (Amendment of the Petroleum Activities Tax Law), systematises the different tax regimes related to petroleum activities.

Several tax administration procedures have been simplified, adjusting them to today's new technological reality and to the institutional context of the state and the tax administration. The standardisation of the tax systems applicable to petroleum activities set out in this law does not fail to take into account the specificities of the main forms of association in petroleum operations, namely in production sharing agreements (PSAs) and joint venture agreements, particularly with regard to the rate of tax on petroleum income, the determination of taxable income, and the exemption from tax on oil production and transaction tax in PSAs.

The main objective of this law is to establish the tax regime applicable to the entities referred to in Article 3, in relation to the exercise of activities of research, development, production, storage, sale, export, treatment and transport of crude oil and natural gas, as well as of naphtha, ozokerite, sulphur, helium, carbon dioxide and saline substances, when derived from petroleum operations. It is applicable to all entities (domestic or foreign) that carry out petroleum operations within the national territory, as well as in other territorial or international areas over which the law or international agreements confer taxing jurisdiction to the Republic of Angola.

Law No. 11/04, of 12 November (Petroleum Customs Law), is the customs regime for petroleum operations for all the entities that carry out petroleum operations (oil and gas companies and service providers) on their behalf being subject to it. Owing to the high risk involved and the large volume of investments required in this type of operation, it is justifiable that these operations enjoy a different customs regime from that in force for other economic activities. This law establishes the customs regime by which petroleum operations are governed in the areas under the jurisdiction of the Republic of Angola. The National Concessionaire, its associates and the entities that carry out petroleum operations on their behalf are subject to the regime established therein.

Presidential Decree No. 86/18, of 2 April 2018, revoked former Decree No. 48/06, of 1 September and approved the rules and procedures of the public tenders, and the step procedure to acquire the 'quality' of associate of the National Concessionaire, for contracting services and acquiring goods in the petroleum sector. This regulation is applicable to the National Concessionaire and all national or foreign entities of proven technical and financial capacity that wish to associate with the National Concessionaire for the execution of petroleum operations.

Presidential Legislative Decree No. 5/18, of 18 May (Legal Regime on Additional Exploration Activities in the Petroleum Concession Development Areas), establishes the Legal Regime on Additional Exploration Activities in the Petroleum Concession Development Areas, which constitutes an exceptional rule before the General Petroleum Activities law, regulating additional exploration within these areas, cost recovery and deduction, production sharing, procedures, tax, foreign exchange and customs regime, thus revoking former Presidential Decree No. 211/15, of 2 December, which defined the terms and conditions applicable to petroleum exploration activity within targeted development areas.

Presidential Decree No. 52/19, of 18 February (General Strategy for the Allocation of Petroleum Concessions for the period 2019–2025), approved the General Strategy for the Allocation of Petroleum Concessions for the period 2019–2025, establishing the guiding principles for future petroleum concessions, through the identification of critical factors with the objective of ensuring the replacement of reserves to make up for the evident decline in production recorded in recent years.

Presidential Decree No. 282/20, of 27 October (Angola's Hydrocarbon Exploration Strategy 2020–2025), approves the Angola Hydrocarbon Exploration Strategy 2020–2025, which envisages boosting and intensifying the replenishment of reserves, with the objective of mitigating the decline in hydrocarbon production, guaranteeing the development of intense exploration activity, as well as ensuring the development of new oil concessions.

Presidential Decree No. 283/20, of 27 October (Model for Defining the Prices of Crude Oil and Natural Gas Derived Products), revokes former Presidential Decree No. 1/12, of 4 January, and establishing a new Model for Defining the Prices of Crude Oil and Natural Gas Derived Products, including the price regime applicable to the crude oil supply mechanism and the crude oil sale price to national refineries, the taxation regime, and the flexible price adjustment mechanism. It also applies to crude oil refining activity as well as to the logistic import, distribution and commercialisation of derivative products, throughout the national territory, except for the refining, import, distribution and commercialisation of fuel, bitumen and lubricants.

Law No. 26/12, of 22 August (Law on the Transportation and Storage of Crude Oil and Natural Gas), defines the rules and licensing procedures for crude oil and natural gas transportation and storage activities, applicable to these activities when they take place within the scope of petroleum operations provided for in the Petroleum Activities Law, approved by Law No. 10/04, of 12 November, defining also the legal system and the penalty system, the modalities for transporting crude oil and natural gas, the tariffs, safety and environmental protection and the monitoring and inspection of activities.

Decree No. 1/09, of January 27, Law No. 10/04, of 12 November, defines in its Article 2, Paragraph 1, 'petroleum operations' as being the 'activities of prospecting, exploration, appraisal, development and production of petroleum'. Considering that petroleum operations carried out both onshore and offshore require the necessary compatibility with other activities relating to other natural resources exploited in the available areas of the national territory, it was necessary to establish the rules and procedures that would ensure that petroleum operations are carried out in accordance with the fundamental principles and rules set out in the Petroleum Activities Law.

The rules set out in this decree apply to prospecting and concession licences that have been awarded on the date of its entry into force. This regulation applies to all petroleum operations that are carried out onshore and offshore, in accordance with the terms set out in Law No. 10/04, of 12 November 2004. These regulations do not apply to crude oil refining, storage, transportation, distribution and marketing activities.

Presidential Legislative Decree No. 5/18, of 18 May (Legal Regime on Additional Exploration Activities in the Development Areas of Petroleum Concessions), through the ANPG and MIREMPET, intended to maximise the geological potential of the development areas in the existing blocks in Angola. This scheme created an exceptional regime that would make it possible to carry out 'additional' exploration activities in concessions in production periods that reveal potential to rapidly increase the national production of hydrocarbons, without prejudice to the general regime of the law on petroleum activities.

Presidential Legislative Decree No. 7/18, of 18 May (Legal and Fiscal Regime Applicable to the Activities of Prospection, Exploration, Appraisal, Development, Production and Sale of Natural Gas in Angola), establishes a differentiated legislative and fiscal framework for the exploration of natural gas and its associated industries. It applies to national or foreign commercial oil companies that enter into an agreement with the ANPG, in any of the forms provided for in Paragraphs 2 and 3 of Article 14 of the Petroleum Activities Law.

The aforementioned law establishes longer time periods than those usually established for crude oil exploration and determines that the petroleum investing companies carrying out the activities defined therein are not subject, regardless of the contractual regime, to petroleum transaction tax, in addition to determining deductible costs and tax benefits.

Joint Executive Decree No. 331/20, of 16 December 2020, as amended by the Joint Executive Decree 81/23 (Rules and Procedures for Fixing and Changing the Prices of Crude Oil Products and Natural Gas), is applicable to the activity of crude oil refining, as well as the import, logistics, distribution and marketing of crude oil products and natural gas throughout the national territory, except for the activity of refining, import, distribution and marketing of fuel, and lubricants, establishing the applicable price regime, regulating the price formation of oil and natural gas derivatives, the international reference prices, the publication of costs and maximum margins, the updating of prices of oil and natural gas derivatives, supervision and inspection, infringements and fines, recidivism, establishing accessory sanctions and the revocation of Executive Decree No. 132/19, of 6 June, sale price of jet fuel and Executive Decree No. 706/15, of 30 December, and determines that diesel fuel will now have its prices formed under the free price regime.

Finally, the Executive Decree 140/22 of 24 February approves the Regulation that establishes the Rules and Procedures for the Exportation of Fuels, establishing the rules and procedures for the exportation of fuels within the national territory, which requires the issuing of prior export authorisation to be issued by Institute for the Regulation of Petroleum Derivatives (IRDP).

ii Regulation

Decree No. 49/19, of 6 February, created the National Agency for Petroleum, Gas and Biofuels (ANPG) in Angola. This Decree approves the by-laws of ANPG, reorganising the hydrocarbons sector in the country, which was previously administered by Sonangol, the Angolan Concessionaire for Oil and Gas Exploration and Production Activities. ANPG extracted from Sonangol its regulatory role.

This Decree establishes that Sonangol and ANPG must assess the human resources and assets owned by Sonangol for the correct allocation between them, to ensure contractual stability. It also recognises the rights and obligations arising from previous contracts executed by Sonangol EP.

ANPG has the responsibility for implementing all necessary actions for the procurement and management of oil and gas contracts, and the implementation of MIREMPET's policy. ANPG now has generic powers to:

- implement national petroleum policy, in partnership with MIREMPET;
- coordinate with other regulators on matters of common interest;
- propose plans and programmes for the revaluation of reserves and exploration of hydrocarbon resources in the country;
- promote studies for block delimitation procedure;
- promote concession bids;
- execute the respective contracts; and
- stimulate the research and adoption of new technologies focused on the oil market.

Presidential Decree 133/18 of May 18 approved the organic statute of the Petroleum Derivatives Regulatory Institute (IRDP), whose purpose is to regulate the petroleum derivatives sector.

The following are some of its aims:

- protecting the rights and interests of consumers in relation to prices, quality of service and products;
- ensuring the objectivity of regulatory rules and the transparency of commercial relations between the various players in the sector;
- arbitrating and resolving disputes arising in the oil derivatives sector;
- supervising the quality of products sold on the internal market, to ensure that products with specifications prohibited by law do not circulate;
- carrying out routine laboratory analyses;
- regulating commercial relations between the various players in the sector; and
- regulating natural gas distribution and marketing activities on the internal market.

iii Treaties

Angola is a signatory of the New York Convention,[13] and of the International Centre for Settlement of Investment Disputes (ICSID), and has a long-established practice of agreeing to arbitration as the preferred method for settling disputes, even when the state is a party.

Angola has ratified two treaties to avoid double taxation. The first is with Portugal and the second is with the United Arab Emirates, and it has signed several bilateral investment treaties with Brazil, the United Kingdom, Cape Verde, France, Germany, Spain, Italy, Turkey, Russia and South Africa.

Angola is also a signatory of the United Nations Convention against Corruption (UNCAC), and has also ratified important international treaties related to safety and environmental protection for the industry, in particular the International Convention on Oil Pollution Preparedness, Response and Co-operation (OPRC), the International Convention on Civil Liability for Oil Pollution Damage (CLC) and the International Convention Relating to Intervention on the High Seas in Cases of Oil Pollution Casualties.

Another important treaty ratified by Angola on 4 November 2019 was the African Continental Free Trade Area (AfCFTA),[14] an agreement entered into force on 30 May 2019, with the objective of setting up a free trade area to improve regional integration and boost economic growth across the African continent. Among the agreement initiatives, these countries commit to removing tariffs on 90 per cent of goods, with 10 per cent of 'sensitive items' to be phased in later. It also aims to liberalise trade in services and might in the future include free movement of people and a single currency.

III LICENSING

ANPG is the national granting authority, a prerogative formerly 'attributed' to Sonangol EP, with the specific prerogatives of regulating, supervising and promoting the execution of petroleum activities in the field of operations and contracting in the oil, gas and biofuels sector. ANPG therefore supervises the contracting related to oil and gas exploration and production activities.

In Angola, under the terms of the Petroleum Activities Law, petroleum operations may be exercised only through a prospecting licence or a petroleum concession, where the issuing of prospecting licences falls within the jurisdiction of MIREMPET and ANPG, and the grant of a concession for the exercise of mining rights falls under the competence of the government.

Article 12 of the above-mentioned law determines the maximum duration of each of the phases, but the terms of the prospecting licence and of the concession are to be determined in each licence, concession agreement and concession decree. Notwithstanding the maximum term of a prospecting licence is three years, which may be exceptionally extended, following what needs to be a duly justified application submitted by the licensee to ANPG.

To obtain the licence, an application must be submitted for a prospecting licence to the Ministry responsible, together with proof of the applicant's suitability and technical and financial capacity. The application will be assessed, after consulting the National Concessionaire, who may request clarifications from the applicant on the conditions proposed. Once the application has been examined and the applicant has been heard, the Minister will decide on the application by issuing an authorisation decision and issuing the licence, with the relevant fees to be paid.

As for the concession, it is to be deemed to have been awarded on the following dates, in the event that the National Concessionaire:

- associates with other entities under the terms of Article 14 from the moment the respective contract is signed; and
- does not associate with other entities, from the moment the concession decree enters into force.

The concession may be awarded under the following methods: public tender, where Sonangol will associate with third parties to perform operations within a given area, where the concession is awarded by MIREMPET by decree, and, as stated in Article 13 of the Petroleum Activities Law, will take the form of:

- a commercial company;
- a joint-venture (consortium contract);
- PSA; or
- through risk service agreements (RSAs).

The tender proceedings for acquiring the capacity of associate of the National Concessionaire and for goods and services in the oil sector are subject to Presidential Decree No. 86/18, of 2 April, which sets forth the rules and procedures for public tenders in the oil and gas sector. This Presidential Decree defines the public bidding procedure that takes place prior to the award and execution of the corresponding PSA. This process requires the prior qualification of MIREMPET, and the requirements for acceptance may vary depending on the criteria and characteristics of the biding process, in addition to the mandatory characteristics that the candidate company must fulfil in terms of technical and financial capability.

In addition to this, Law No. 41/20, of 23 December, which came into effect on 22 January 2021, establishes the new Public Procurement Law in Angola (LCP), and was recently approved, revoking Law No. 9/16, of 16 June, which is also applicable to all public procurement procedures initiated after that date and to the execution of subsequent contracts. The LCP now covers, among other aspects, administrative concession contracts. In addition, two new procedures were introduced:

- the Electronic Dynamic Procedure aimed at the acquisition of standardised goods and services; and

- the Emergency Contracting, which can only be adopted to deal with unforeseeable situations not attributable to the contracting entity.

As for the changes brought by the LCP, among them we find the lack of the need to sign contracts in written form in certain cases, the creation of a penalty regime, the possibility of a company being removed from the List of Companies in Default, the power or ability to authorise expenses inherent to the formation and execution of contracts, the elimination of the provisional bond and the stipulation of a single bond (the former 'definitive bond') and mandatory for contracts worth more than 182 million kwanzas.

Bidding is currently underway for oil concessions in the onshore Congo and Kwanza Basins under ANPG's control. The tender was awarded in the end of September 2021.[15]

IV PRODUCTION RESTRICTIONS

Each associated company with the concessionaire is entitled to freely dispose of its share of production in accordance with the participating interest in the PSA. Restrictions to this entitlement can only be imposed by a mandatory requirement from the Angolan state, and specifically for the purpose of satisfaction of domestic consumption, or in the event of a national emergency, where the government has the right to the acquisition of the referred production. In this case, the restriction to production may involve the petroleum installations, in addition to the production of the concession area. In the event of war or national emergency declared by the government, all or part of the production may be requisitioned to ensure that Angola's strategic requirements are met. The associated company is entitled to compensation in an amount equal to the market value price of the quantity of the requisitioned product.

The satisfaction of domestic consumption requirements is not to exceed the proportion between the annual output derived from the concession area and the total annual output of petroleum in Angola, nor is it to exceed 40 per cent of the total output from the relevant concession area.

In addition to rules and restrictions that may be embodied in the law or in each of the concession contracts and PSAs, the transfer of the contractual position held by private companies that are associates to ANPG to a third party requires the prior authorisation from MIREMPET, through an official executive decree, and the transfer of a stake or shares representing more than 50 per cent of the associated share capital, deemed equivalent to a transfer of contractual positions. This authorisation is not required if the transfer is made to an affiliate as defined by law, provided the assignor remains joint and severally liable. In the case of transfer to a third party of a stake or shares representing more than 50 per cent of the associated share capital, ANPG is granted the right of first refusal.

V ASSIGNMENTS OF INTERESTS

Subject to prior approval from MIREMPET, requested through ANPG, the concessionaire (or licensee) can assign all or part of its rights to third parties. The sale of 50 per cent or more of the concessionaire's or licensee's shares will be deemed an assignment.

In accordance with Article 16 of the Petroleum Activities Law, 'Associates of the National Concessionaire may only transfer part or all of their contractual position to third parties of proven suitability and technical and financial capacity after obtaining prior authorisation for such from the Minister responsible, in the form of an executive decree'.

Notice that transfers to third parties of quotas or shares representing more than 50 per cent of the share capital of the transferring company will be treated as a transfer of contractual position.

If the transfer is between affiliated companies and if the transferor remains jointly and severally liable for the obligations of the transferee, there will be no need for the above-mentioned authorisation, taking into account that the conditions will be set in the PSA. The National Concessionaire will enjoy the right of pre-emption in the transfers when such transfers are made to non-affiliates of the transferor. If, however, the National Concessionaire does not exercise this pre-emption right, the same will be immediately transferred to national associates enjoying the special status of a national company, in accordance with Article 31(3).

The assignment may be subject to competition sanctioning according to applicable legal provisions.

If the assignment is made by selling a participating interest, the gain (difference between book value and actual selling price) resulting from the proceeds of the sale will be subject to tax.

VI TAX

The Law on Taxation of Petroleum Activities (Law No. 13/04, of 24 December) determines the special tax regime applicable to oil companies carrying out upstream petroleum operations. The tax charges applicable under this regime include petroleum production tax, petroleum income tax, petroleum trading tax, surface tax and the contribution for the training of Angolan staff. Ring-fencing of the tax charges will be applied to each concession or development area, notwithstanding the important ring-fencing rule, and exception to this rule might change soon, to promote the development of marginal fields, the use of new technologies and the retrieval of new reserves.

Under the PSA, which covers most of the oil blocks, the company's share of the 'profit oil' is subject to petroleum income tax (PIT) at a rate of 50 per cent, this tax being increased to 65.75 per cent if the petroleum operations are carried out under an RSA or any other form of business association with the National Concessionaire. In any case, if the oil company is public or fully owned by Angolan citizens, the PIT is reduced to 35 per cent (i.e., the current industrial tax applicable to oil companies).

The petroleum production tax (PPT) is levied on the total oil produced minus oil used in operations and is set at 20 per cent (with a possible reduction to 10 per cent) and the petroleum transaction tax (PTT) is levied on the taxable income at a 70 per cent rate but can be taken as deductible cost against the PIT. Both taxes are not applicable to the PSA's agreements.

Other taxes are as follows:

- surface charge: US$300 per km^2, per year, per concession/development area;
- contribution for the training of Angolan staff (training levy) of oil companies fully owned by the state or Angolan citizens are exempt from training levy;
- US$100,000 – to oil companies that only have a research licence;
- US$300,000 – to oil companies that are carrying out research activities;
- US$0.15 per oil barrel – to oil companies that are in a production stage;
- US$0.15 per oil barrel – to oil companies that carry out oil refining activities;
- 0.5 per cent of the annual turnover – to companies that carry out storage, transportation, distribution and commercialisation activities of crude oil; and
- 0.5 per cent of the values of contracts – to companies that render services to oil companies on a regular basis.

The State Budget Law for 2021 (Law No. 42/20, of 31 December) approved a reduction from 15 to 6.5 per cent of the withholding tax rate applicable to services provided by non-resident entities to oil companies in Angola. In the State Budget Law for 2022 (Law No. 32/21, of 30 December), this disposition is not foreseen.

Regarding VAT, although the production and exploration of oil are exempt, the oil companies are subject to a captivation regime, where the input VAT mentioned in the supplier's invoice is withheld by the oil company and paid directly to the state. Furthermore, the input VAT related to the following costs is not deductible for VAT purposes (but may be qualified as a deductible cost against the company's PIT):

- supply of water and energy;
- services relating to electronic communications and telecommunications; hotel and accommodation services;

- lease of equipment, except if it qualifies as a royalty payment;
- consultancy, legal, tax, financial, accounting and IT services;
- security services; and
- lease of vehicles.

As for oil and gas service companies, Law No. 10/21, of 22 April, which amends the Private Investment Law (Law No. 10/18, of 26 June), provided new amendments to the law with the aim to make private investment more attractive to investors. A new contractual regime was introduced, and the value of the investment and the jobs created are now included among the factors deemed relevant for the allocation of tax incentives.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

In Accordance with Article 24 of the Petroleum Activities Law:

> *When carrying out their activities, licensees, the National Concessionaire and their associates shall take the necessary precautions to protect the environment, with a view to ensuring its preservation, namely with regard to health, water, soil and subsoil, air, preservation of biodiversity, flora and fauna, ecosystems, landscape, atmosphere and cultural, archaeological and aesthetic values.*

The National Concessionaire and their associates are to submit to the ministry in charge, within the legally established time limits, the plans required by current legislation, specifying the practical measures to be implemented with a view to preventing damage to the environment, including environmental impact assessment studies and audits, landscape rehabilitation plans and contractual and permanent structures or mechanisms for environmental management and auditing.

Law No. 5/98, of 19 June (Environment Framework Law), defines the concepts and basic principles of protection, preservation and conservation of the environment, promotion of the quality of life and the rational use of natural resources in accordance with Article 24, Paragraphs 1, 2 and 3, and Article 12, Paragraph 2 of Article 12 of the Constitutional Law of the Republic of Angola.

Executive Decree No. 97/14 approves the Regulation on the Management of Operational Discharges, which establishes the rules and procedures applicable to controlled discharges or overflows of produced fluids, drainage water, sludge and cuttings, generated in the course of petroleum operations both onshore and offshore, establishing discharge prohibitions, regulating main and collateral liquid and solid effluents, gaseous effluents, monitoring and reporting, and establishing the sanctioning regime.

Executive Decree No. 8/05, 5 January, approves the Regulation on the Management, Removal and Deposit of Waste in Petroleum Activity, which establishes rules and procedures on the management, removal and deposit of waste, to be implemented by the operator and other petroleum companies in order to ensure the prevention or minimisation of damage to people's health and the environment.

Executive Decree No. 11/05, of 12 January, on the protection of the environment during petroleum activities, states that notwithstanding the existence of an environmental management plan, oil and other pollutant spills may occur during petroleum activities, and of other polluting products that may occur during the development of petroleum activities either onshore or offshore. It is therefore mandatory to define and standardise the procedures for notification of the occurrence of such spills to MIREMPET by all oil companies.

Decree No. 38/09 approves the Regulation on Safety, Hygiene and Health in Petroleum Operations, which establishes rules and procedures aimed at ensuring that petroleum operations are carried out in accordance with the health, hygiene and safety standards laid down in Angolan and international legislation, through systematic management and continuous improvement, applying to facilities and the entire Life Cycle of Petroleum Operations on land and at sea.

Decree No. 39/00, which approves the Regulation on the protection of the environment in the course of petroleum activities, aims to protect the environment in the course of these activities in order to guarantee its preservation of health, water, soil and subsoil, air, flora and fauna, eco-systems, landscape, atmosphere and cultural, archaeological and aesthetic values, and defines the environmental protection regime to which petroleum activities on land and at sea are subject.

Presidential Decree No. 91/18, of 10 April 2018 ('abandonment of wells and dismantling of oil and gas installations'), sets the rules and procedures applicable for abandonment of wells and dismantling of oil and gas installations in Angolan territory, which are applicable in petroleum operations carried out onshore and offshore. The general principles on which they are based are defined, as well as regulation on the abandonment plan, the handing over of installations and wells to the ANPG, inspection and auditing and the provisioning, methodology and estimation of costs.

According to Presidential Decree 117/20, which approved the General Regulations on Environmental Impact Assessment and Environmental Procedure, when extracting, storing, transporting, processing and producing derivatives and hydrocarbons, a prior Environmental Impact Assessment process must be carried out. This process involves drawing up an environmental impact study to be submitted for approval to the competent authority responsible for the environment. In addition, prior environmental licensing needs to be carried out, which includes the issue of an environmental installation licence, the purpose of which is to authorise the implementation of the work or undertaking in accordance with the specifications contained in the project approved by the entity overseeing the activity, and the issue of an environmental operating licence, which certifies compliance with all the requirements contained, in particular, in the environmental impact study.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

In Angola, the law governing commercial companies is Law 1/04 of 13 February 2004, the Commercial Companies Act, as amended by Law 11/15 of 17 June 2015, which simplified the process for setting up commercial companies.

The Commercial Companies Act foresees three forms of unlimited liability companies (the partnerships, limited partnerships and limited partnership with a share capital) and two forms of limited liability companies (limited liability companies and stock companies). The choice of the company form to be used depends on the weighting of various factors, taking into account the legal regime provided for each of them and the envisaged project. According to the Commercial Companies Act, there are generally no limitations as to the nationality of the participants in a commercial company structure.

In this way, in Angola, when it comes to carrying out petroleum operations, national and foreign companies follow the same legal terms, according to the Petroleum Activities Law.

Regarding the prospecting licensing regime, the legislation makes no distinction as to the subjects of the award. Any national or foreign company with proven suitability and technical and financial capacity can apply to MIREMPET for a licence to assess the oil potential of a given area, according to Article 34.

For the petroleum concession, which is how petroleum operations are carried out outside the scope of the prospecting licence, any national or foreign company may be entitled to it, as long as they prove their suitability and technical and financial capacity to carry out the operations in the respective concession area. To this end, interested companies must join with the National Concessionaire to jointly carry out the following activities, under the terms of Articles 13 and 14 of the Petroleum Activities Law.

In those cases, the National Concessionaire holds, in principle, a majority stake in the associations referred to in Articles 14.2(a) and 14.2(b). However, the government may, in duly justified cases, authorise the National Concessionaire to hold a shareholding lower than 50 per cent, but not less than 20 per cent.

Law No. 10/21 of 22 April, as amended by Law No. 8/22, was recently enacted, amending and republishing Law No. 10/18, of 26 June (Private Investment Law), which establishes the principles and general bases for private investment in Angola.

Considering that the legal framework for private investment in force did not provide for the possibility of negotiating incentives, benefits and other rights for investors, particularly for structuring projects that have a significant economic and social impact, the new law introduced the contractual framework to allow an effective negotiation of benefits and incentives for private investors.

The contractual regime is applicable to all sectors of activity, which allows the negotiation of tax incentives and facilities and the conditions for the implementation of the investment project. Prior declaration and special regimes continue to be applicable. The tax benefits are now referred to in the Tax Benefits Code (Law No. 8/22, of 14 April). The investment amount and number of jobs created are now additional criteria for the purposes of granting benefits and facilities and will be important in the negotiation with the Private Investment and Export Promotion Agency of Angola (AIPEX).

Foreign investors may now transfer investment-related amounts abroad (e.g., dividends) before the full implementation of the investment project. Domestic credit is now accessible to foreign investors and companies' majority held by them (previously only accessible after implementation of the investment project).

Investors are now exempt from obtaining provisional licences and other authorisations for the purpose of implementing investment projects. In the event that these licences and authorisations prove to be indispensable, the relevant issuing entities are obliged to comply with the deadlines set out in the implementation schedule agreed with the investor.

Companies with prior investments executed without a private investment project may now regularise the registration of the investment (which may entitle the right to repatriate dividends), although with no access to tax benefits.

Under the terms of Article 36-A of the Law No. 10/21, of 22 April:

> *The contractual regime applies to Private Investment projects, carried out in any sector of activity, and involves a negotiation between the promoter of the Investment Project and the Angolan State, regarding the conditions for the implementation of the project, the incentives, and facilities to be granted under the private investment contract.*

Furthermore, under Article 37 'Private investors may freely opt for any of the investment regimes'.

Finally, Article 48, Paragraph 2 allows projects that have already been approved under Law No. 10/18 to be subject to the new regime. Indeed, the law does not determine what new incentives and benefits may accrue to the investor, but it certainly opens the possibility of negotiation, something that the previous law allowed in a very limited way.

This Law applies to private investments of any value, whether made by international investors or not. However, it does not apply to investments made by public domain commercial companies in which the state holds the whole or majority of the capital. Furthermore, it does not apply to those sectors of activity whose investment regime is regulated by a special law, such as the energy, telecommunications and tourism sectors.

Notwithstanding the preceding paragraph, the investment projects regulated by a special law will be registered with AIPEX, for the purposes of statistical control and the granting of private investor status.

ii Capital, labour and content restrictions

The pressing need to develop the national business community and its workforce in the oil and gas sector, as well as the incorporation of national raw materials, to reduce Angolan imports, ensuring the increase in domestic production of goods and services, led to the approval of a new legal regime applicable to the Angolan oil sector. Presidential Decree No.

271/20, of 20 October, revoked former Decree No. 127/03, of 25 November, which established the basic rules to be observed when contracting national companies, suppliers of goods or services (service companies), by companies operating in the oil sector, thus ensuring, as a premise, the protection of the national companies, the use of national services and goods in support of oil operations and the respective industry.

Instruction No. 6/21, of 4 November, was published following the entry into force of the new Local Content regime, approved by Presidential Decree No. 271/20, of 20 October, establishing that all entities that provide services to the oil sector must register and be certified by the ANPG. The legally prescribed deadline for completing the certification process is 180 days after the service provider submits the documents to the ANPG.

The Instruction determines that commercial companies operating in the oil and gas sector must adapt their internal processes to implement the Local Content rules and procedures within a period of six months. Instruction No. 6/21 contains more detailed provisions on:

- the National Concessionaire's Powers and Obligations;
- the time period to request and issue proof of impossibility to acquire goods and services under the preferential regime and consequence for its violation;
- the time period to submit the Annual Local Content Plan;
- the requirements that commercial companies must meet to proceed to online registration and certification by ANPG; and
- information that must be contained in the Human Resources Development Plan.

It has become mandatory to introduce a local content clause in all contracts and Article 34 of the above-mentioned law states that 'contracts entered before October 20, 2020 are valid and remain valid and in force'.

Failure to comply with this obligation constitutes an administrative offence punishable by a fine corresponding to a minimum amount in kwanzas of US$50,000 and a maximum of US$200,000.

For managing and monitoring all activities related to local content, the new regime establishes that the service providers must prepare and submit to ANPG the following documents:

- the annual local content plan;
- the annual human resources development plan, which must be submitted yearly, until 31 October;
- the annual balance of the development plan and human resources, which must be submitted until 31 March;
- the programme contract, which must be signed according to the respective research and production phase or service provision contract;
- the investment plan; and
- the list of contracting foreseen for each quarter (only for associates of the National Concessionaire, holders of service contracts with risk and others who collaborate in oil operations).

Regarding foreign technical assistance and management contracts, it is now necessary to include a detailed programme for training, transfer of know-how, technology, and development of the national workforce.

The new regime maintains the three types of structure:

- exclusivity;
- preferential; and
- competition.

The difference between the referred regimes lies in the type of companies (Angolan or foreign) that have access to the provision of the services in question, and the conditions (preferential or not) for such access.

The services and supplies covered by the exclusivity regime may only be performed by Angolan commercial companies and commercial companies under Angolan law (SCDA).

Under the terms of the law, Angolan commercial companies are defined as companies wholly (100 per cent) owned by nationals, while the latter correspond to companies incorporated in Angola, regardless of the nationality of their partners or shareholders.

In other words, all companies incorporated in Angola are covered also by the exclusivity regime, whether the capital is held by Angolans, foreigners or both. Foreign companies are excluded (incorporated or registered under a foreign law) and are prevented from providing services or supplies to the oil industry covered by the exclusivity regime.

Under the preferential regime, access is allowed to all service providers and suppliers (national or foreign); however, national companies (according to the above-mentioned criteria) enjoy a preferential treatment in the award of the respective contracts. This means that the petroleum company (operator or not) must give preference to national suppliers provided that they are able to provide the intended service or supply with similar quality as an imported product, and provided that the price is equally competitive (not exceeding 10 per cent of the cost of the imported product in accordance with the general rule established in the Petroleum Activities Law).

The new legal regime establishes its own transgressional regime, stating that the violation of the rules established therein may lead to the application of fines ranging from US$50,000 to US$300,000. In addition, accessory penalties of prohibition from one to two years, suspension of establishment operation or prohibition to enter new contracts may also be applied.

In other words, with the entry into force of the new regime, control of the company by nationals as an essential criterion for considering it a national or Angolan company no longer exists. Considering that the previous legal regime for private investment did not foresee the possibility of negotiating incentives, benefits and other rights to investors, namely for structuring projects, such as the oil sector, which will undoubtedly have a significant economic and social impact, the new law introduced the contractual framework to allow an effective negotiation of benefits and incentives to private investors.

Substantial changes in the Angolan local content paradigm in force in the oil sector are embodied in the following aspects:

- in the scope of its application, the current regime also applies to service providers to the oil sector;
- redefinition of the concept of national or Angolan company, and a new criterion was introduced as the SCDA;
- mandatory introduction of local content clause in all contracts;
- obligation to prepare information and documentation to be submitted to the ANPG;
- different transgression regime; and
- different typology of goods and services.

Law No. 10/04, of 12 November (the Petroleum Activities Law), determined that:

> *The Government shall adopt measures to guarantee, promote and encourage the participation of commercial companies owned by nationals in the petroleum sector and establish the necessary conditions for the purpose, (. . .) considering that the operators, as well as all entities that collaborate with them in the execution of petroleum operations must acquire national goods and services, such as incorporating national raw materials, with a view to reducing imports and increasing domestic production.*

However, although the referred law has been in force since 2004 (and although amended), there was in our opinion a clear perception that the use of reservation policies and related regulatory constraints could in fact harm the much-needed foreign investment and undermine ANPG's programme for the auctioning of new oil blocks (onshore and offshore) between 2020 and 2025.

Regarding circulation of capital, Law 10/21, which amended and republished the Private Investment Law, as amended by Law 8/22, admits that foreign investors, after paying the taxes due and setting aside the mandatory reserves, have the right to transfer abroad amounts that correspond to:

- dividends;

- the proceeds of the liquidation of their ventures;
- compensation owed to them; and
- royalties or other remuneration income from unsecured investments associated with the transfer of technology.

iii Anti-corruption

The government has introduced important reforms in recent years, especially regarding revenue and budget transparency. In December 2018, the International Monetary Fund (IMF) approved a grant for Angola of US$3.7 billion, for a three-year extended fund facility to support the country's economic reforms. The IMF's aims are to restore Angola's fiscal sustainability and provide the foundations for economic diversification, including through the implementation of PROPRIV.[16] The IMF has highlighted that the fundamental pillars of its programme include:

- reducing Angola's gross debt through fiscal consolidation;
- increasing exchange rate flexibility through exchange rate depreciation and a commitment to a market-determined exchange rate;
- introducing a supportive monetary policy to reduce inflation and allow the accumulation of international reserves;
- strengthening Angola's banking system through improved governance, credit-risk management and undertaking an extensive asset quality review; and
- updating and bolstering the anti-money laundering and counter terrorist financing frameworks.

Law 19/17, of 25 August (Law on the Prevention and Combating of Terrorism), derogating the Law No. 19/71, of 12 December, establishes preventative and repressive measures to combat laundering of illicitly derived gains and the financing of terrorism. Money laundering and terrorist financing is prohibited, prevented and punished under the terms of this law and applicable legislation.

The purpose of Law 19/17, of 25 August (Law on the Prevention and Combating of Terrorism), is to establish:

- measures to prevent the occurrence of terrorism;
- special investigative and procedural measures;
- measures to support and protect the victims of terrorism; and
- the creation of an organism to coordinate operations and share information on the threat of and the fight against terrorism.

Angola is also a member of the African Convention on Preventing and Combating Corruption, which Angola ratified on 20 December 2017, and has also ratified on 10 December 2003 the United Nations Convention Against Corruption, which intends to cover five main areas:

- preventative measures;
- criminalisation and law enforcement;
- international cooperation;
- asset recovery; and
- technical assistance and information exchange.

The Convention covers many different forms of corruption, such as bribery, trading in influence, abuse of functions and various acts of corruption in the private sector.

IX CURRENT DEVELOPMENTS

The general outline of the 2023-2027 Sector Development Plan was recently published in April 2023 by MIREMPET, which, based on Law No. 1/11, of 14 January, approved the General Regime of the National Planning System.

Presidential Decree No. 316/20, of 17 December 2020, which was approved by the Council of Ministers, defines an action programme for the oil and gas sectors, and focuses on five objectives:

- boosting and intensifying the replenishment of reserves, with the aim of mitigating the sharp decline in hydrocarbon production;
- ensuring self-sufficiency in refined products through the construction of new refineries and the development of petrochemical hubs;
- increasing onshore storage capacity to better accommodate Angola's fuel reserves;
- guaranteeing the supply of natural gas to the iron and steel industries and for the production of electricity; and
- ensuring the implementation of the green hydrogen project to guarantee the production of green ammonia (NH3).

The set targets include:

- the increase of domestic production of crude oil derivatives from 1,968.94 thousand metric tonnes in 2021 to at least 2,971.48 thousand metric tonnes in 2027;
- the construction of three more refineries in operation, in addition to the Luanda refinery, by 2027;
- an increase of 1,260,476 thousand m^3 of onshore storage capacity, to better accommodate the country's fuel reserves; and
- production of at least 280 thousand metric tonnes of green ammonia (by 2027) should be produced per year, following the completion of the green hydrogen plant.

Under the Concession Award Strategy for the 2019–2025 period, the President of the Republic approved the Rules and Procedures of the Permanent Offer Regime for the Promotion of Oil Concessions, through Presidential Decree No. 249/21, of 5 October.

The Presidential Decree No. 249/21, of 5 October is an additional measure to the 2019–2025[17] general bidding strategy and arises from the need to implement new rules, thus allowing for the permanent availability and negotiation of non-awarded tender blocks, 'free areas' in concession blocks, with the intention to boost investment, exploration and production activities for oil and gas, through limited public tenders and direct negotiation procedures, under the terms allowed by the Petroleum Activities Law, in particular Article 44 of Law No. 10/04, of 12 November.

Angola has a pressing need to replace reserves, and only through a more attractive legal and tax framework for the sector could that be possible. The Permanent Offer Regime is intended to guarantee that the punctual proposals from investors have a full response from ANPG and MIREMPET, through rules aligned with the procedures instituted by the above-mentioned regulations of the oil sector, which provide flexibility and clarity in trying to capture value for Angola. Two important projects are currently being developed. First, the 'Barra do Dande project' in Bengo province is of strategic and national interest and is part of the objectives set out in the Angolan government's 2018–2022 National Development Plan, as the main platform for storing and receiving oil derivatives and products for Angola's strategic, security and operational reserves. Therefore, the Presidential Despatch No. 62/21, of 6 May, creates the Barra do Dande integrated development zone. This promotes Dande as an important hub for fuel storage and marketing in the region, which provides a storage capacity of 580,000m^3 of refined products.

The first phase, which was scheduled for completion by the end of 2022 and is intended to meet the country's needs, will also make the process of receiving and distributing refined products more efficiently and less costly. This is a strategic project that began in 2014 but was interrupted in 2016 because of the economic context that the country and the company were experiencing during that period.

In 2023, the ANPG announced the launch of the tender for the award of oil concessions in the Lower Congo and Kwanza onshore basins, which will be open to national or foreign entities. The tender will be awarded for 12 onshore oil blocks, four of which are located in the Lower Congo Basin (CON 2, CON 3, CON 7 and CON 8), and eight in the KWANZA Basin (KON 1, KON 3, KON 7, KON 10, KON 13, KON 14, KON 15 AND KON 19). The estimated potential of these 12 blocks amounts to 1560 MMBO in the Lower Congo Basin and 5440 MMBO in the Kwanza Basin, making a total of 7000 MMBO. The deadline for submitting tenders is, at the moment, set to be 9 November 2023, in compliance with the 40 days provided by law after the official launch of the tender scheduled for 30 September.

In April 2021, ANPG announced the launch of the bidding round for nine onshore blocks, which had a very good reception from national investors. The timeline for this bidding round was quite ambitious, with the Angolan government aiming to:

- receive the proposals by 9 June 2021;
- open the proposals on 10 June 2021;
- evaluate the proposals by 26 July 2021;
- award the concession areas by 13 September 2021;
- negotiate the agreements by 19 October 2021; and
- sign the agreements on 22 November 2021.

However, the planned timeline could not be followed through because the award of the concessions only took place in July 2022 and ANPG also informed the signing of the agreements will take place no later than 30 days after the date on which the authorisation for the award of the referred Concessions is published in the *Diário da República*.[18]

In August 2022, ANPG signed several production share agreements for the blocks previously awarded in the 2020 bidding process.

Specific blocks and basins will be assigned to each licensing round continuing until 2025, in accordance with Presidential Decree No. 52/19, which defines the General Strategy for the Allocation of Petroleum Concessions for the period 2019–2025. The blocks will be awarded by public tender, restricted public tender and direct negotiation, with clear timelines put in place.

The government's plan to accelerate growth in the Angolan energy industry through improved legislation that focuses on supporting and enhancing local businesses development could be key. The most important strategy in the energy industry continues to be human capital and the increased participation of local companies to supply products and services made in Angola, supporting the oil and gas sector. As Angola shifts its focus to energy transition efforts, it must implement investment initiatives that foster local skills development that will drive the hydrocarbons industry.

Collaboration between the African Petroleum Producers Organization and the Organization of the Petroleum Exporting Countries in adjusting to the clean energy transition and promotion of gas monetisation and utilisation is also at the forefront of the Angolan government's strategy.

CUATRECASAS

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Endnotes

1 Lourenço Vilhena de Freitas is a partner and João Sequeira Sena is a principal associate at Cuatrecasas.
2 The lowest level of production in the past 15 years.
3 https://www.statista.com/statistics/1178514/main-oil-producing-countries-in-africa.
4 https://energycapitalpower.com/biggest-oil-producer-in-africa-in-2022/.
5 In accordance with ANPG, the oil production in July 2021 reached 34.185.213bbl.
6 Mr Diamantino Pedro Azevedo.
7 https://mirempet.gov.ao/ao/.
8 https://mirempet.gov.ao/ao/.
9 Presidential Decree No. 282/20 of 27 October approves the Angola Hydrocarbons Exploration Strategy 2020–2025.
10 Angola currently imports around 80 per cent of refined products to satisfy its internal needs, at the expense of enormous quantities of foreign currency. Local refining compensates for part of the losses in low prices of crude with the referred projects aiming, through international investors, to advance in terms of internal self-sufficiency of refined products and the export of surplus to neighbouring countries.
11 The strategy indicates an intensification of exploratory activity for hydrocarbons in Angola, in a manner so as to guarantee the continual expansion of knowledge of oil and gas potential, including non-conventional reserves, for the substituting of reserves and the resulting mitigation of decline and the stabilisation of oil and gas production.
12 ENI, Chevron, Sonangol, BP and Total – Consortium Partners for the development of the Quiluma, and Maboqueiro, fields. The project will include two offshore platforms and a connection to the Angolan LNG plant for the commercialisation of condensate and gas via LNG cargo. Project execution activities are expected to begin late 2022, with first gas planned for 2026, with a forecast production of 330 mmscf/per day.
13 Resolution No. 38/16, of 12 August. Angola acceded to the New York Convention on 6 March 2017, which entered into force on 4 June 2017.
14 As at May 2022, 43 of the 54 signatories (80 per cent) have deposited their instruments of AfCFTA ratification: Ghana, Kenya, Rwanda, Niger, Chad, Eswatini, Guinea, Côte d'Ivoire, Mali, Namibia, South Africa, Congo, Rep., Djibouti, Mauritania, Uganda, Senegal, Togo, Egypt, Ethiopia, Gambia, Sahrawi Arab Democratic Republic, Sierra Leone, Zimbabwe, Burkina Faso, São Tomé & Príncipe, Equatorial Guinea, Gabon, Mauritius, Central African Republic, Angola, Lesotho, Tunisia, Cameroon, Nigeria, Malawi, Zambia, Algeria, Burundi, Seychelles, Tanzania and Cabo Verde.
15 https://theenergyyear.com/news/angola-awards-9-blocks-in-onshore-bid-round/.
16 Presidential Decree 44/21, of 19 February 2021, which updates the Privatisation Programme (PROPRIV) for the period 2019–2022, and updates Presidential Decree 250/19, of 5 August 2019, with the objective of reducing the size of the influence of the Public Enterprise Sector (SEP) in the economy, increasing the quality and variety of services available to the population. The procedures to be adopted for the privatisation of companies are the public tender, public tender by prior qualification, stock exchange auction and initial public offering. It should be reiterated that the concept of privatisation defined in the Privatisation Framework Law, No. 10/19, of 14 May, allows for various forms of privatisation; namely, the sale of shares representing the share capital, an increase in share capital open to subscription by private entities, the sale of assets or the assignment of operation and management rights.
17 The objective of the 2019–2025 strategy was that in 2019, the following blocks were awarded through public tender: Namibe Basin: Blocks 11, 12, 13, 27, 28, 29, 41, 42 and 43; Benguela Basin: Block 10. In 2022, the following blocks were awarded through public tender: Congo Basin: CON1, CON5, CON6; Cuanza Basin: KON5, KON6, KON8, KON9, KON17, KON20. In 2023, the following blocks will be awarded through public tender: Congo Basin: CON2, CON3, CON7, CON8; Cuanza Basin: KON1, KON3, KON7, KON10, KON13, KON14, KON15, KON 19. During 2022, the offshore blocks 16/21 and 31/21 were awarded through limited public tender; however, the Blocks: 32/21, 33/21, 34/21, 7/21, 8/21 and 9/21 were not awarded due to a lack of proposals. During 2025, the following offshore blocks will be awarded through limited public tender: Blocks 22, 24, 25, 26, 35, 36, 37, 38, 39 and 40, and through Direct Award. In this case, Sonangol will directly hire (through risk service agreements) selected contractors to explore certain concessions.
18 https://anpg.co.ao/noticias/anuncio-referente-a-aprovacao-dos-blocos-terrestres-nas-bacias-do-baixo-congo-e-do-kwanza-adjudicados-na-licitacao-2020/.

Chapter 3

Argentina

Pablo J Alliani and Fernando L Brunelli[1]

Summary

I INTRODUCTION

Since the first oil discovery 111 years ago, the Argentine oil and gas sector has worked under different rules and contractual schemes, from service contracts (1950s), risk service contracts (1970s) and agreements with YPF SE under the 'Plan Houston' (1980s), all of them characterised by the omnipresent role of the national state-owned company YPF SE, which owned the exploration and production rights in the hydrocarbons fields, to the 'deregulated' era (1990s) during which YPF SE was privatised, becoming YPF SA, existing contracts were converted into exploitation concessions and exploration permits and exploitation concessions were granted through public bidding rounds organised by the federal government.

Between 2002 and 2012, many of the basic rights permits and concessions holders enjoyed were affected by regulations and governmental practices in a context of an economy that, in general terms, became less investor- and market-friendly. Finally, in 2012, 51 per cent of the shares of YPF SA were expropriated and the 'deregulation' regime was formally repealed.[2] As a result of the policies and practices implemented between 2002 and 2012, production and reserves dropped dramatically, and the country lost the hydrocarbons self-sufficiency that it had achieved during the 1990s.

After the expropriation of YPF SA, the same administration that had been responsible for the policies and practices of the previous decade and for the adverse consequences derived therefrom and the administration's successors showed a more positive change of attitude towards the upstream industry, sometimes driven by the force of big energy balance deficit combined with a drop in investment from E&P companies, and at other times inspired by more genuine private industry and market-friendly ideas. This was evidenced by a new pricing policy and the passing of legislation aimed at encouraging investment in new projects, especially those relating to unconventional resources.[3]

Argentina's technically recoverable shale resources are among the largest in the world and, in recent years, the industry's attention and government policies have been focused on the exploration and development of these resources.[4]

By the time that the current administration had taken office in December 2019, the country had reverted the declining trends of total oil production and total gas production registered until 2018 and 2014, respectively, which were driven by the development of shale resources in the Vaca Muerta formation.[5]

Following a very tough 2020, in which the combination of several problems affecting the Argentine economy, the crash of international oil prices and the covid-19 pandemic resulted in a dramatic reduction in exploration and production activity, the industry showed a consistent recovery, as a result of increasing exports of shale oil and the implementation of a new natural gas promotional regime that made the main producers resume investments that had been put on hold in 2020, along with the launch of new projects.

The increase of shale hydrocarbons production from Vaca Muerta has been of such magnitude that the existing midstream capacity has reached its limit. To overcome this situation, projects to expand the crude oil and natural transportation capacity are being executed. In terms of crude oil, the trunk pipeline operated by Oldelval, which runs from the Province of Neuquén to the Puerto Rosales maritime terminal, on the Atlantic Ocean, is being expanded, so to double its current capacity (from 36,000 cubic metres a day to 72,000 cubic metres a day), while Oleoducto Trasandino SA, operator of the export pipeline running from Rincón de los Sauces (Neuquén) to Concepción (Chile), which had been idle since 2006, resumed operations in July 2023. In terms of natural gas, the first stage of the much-delayed construction of a new pipeline between Tratayén (Neuquén) and Saliqueló (Buenos Aires) began in 2022 and was completed earlier than expected by the most optimistic analysts. Contrary to the initial project designed by the previous administration, the current administration has decided to assign the construction and operation of the new gas pipeline to the state-owned company Energía Argentina SA (ENARSA).[6] A substantial portion of the financing for the project came from a 'one-time' tax on big fortunes applied by the federal state.

The continuity and enhancement of the Plan Gas.AR promotional regime, which allowed producers to be guaranteed a fixed contract of four years and competitive prices to supply local demand and export permits for the warm season, together with a promotional regime focused on providing producers certain limited foreign exchange benefits on their incremental production (compared with the 2021 baseline production), have contributed to the consistent increase of investment and production. These increases have occurred in a very difficult economic context of rampant inflation and devaluation of the Argentine peso, thinning the Central Bank's reserves that restrict supplies and equipment imports and stringent foreign exchange regulations that have virtually reduced to zero any chance of accessing the official foreign exchange market to remit dividends or pay debt abroad.

In 2022, YPF and Petronas entered into a memorandum of understanding for a potential large-scale LNG export project that, after months of negotiations, ended in a LNG projects incentives regime bill submitted by the national Executive to the National Congress in July 2023.

In a year with general elections scheduled for October, in which the current president is not running for re-election, the candidates with chances of taking office in December coincide, although with certain differences, in the importance of continuing and increasing investment aimed at the full development of Argentina's hydrocarbons resources, with the understanding that the window for the massive realisation of their potential will not last forever and that the development of the country's natural gas reserves (largely exceeding the nation's demand) would enable the country to generate massive amounts of exports proceeds during the global energy transition process.

II LEGAL AND REGULATORY FRAMEWORK

In Argentina, the state (the federal government or the provinces, as applicable) owns the hydrocarbons in the subsoil, and the rights that the state grants for the exploration and exploitation of hydrocarbon reserves are separate from surface ownership. Once extracted, the hydrocarbons belong to the companies holding the relevant exploration and production rights.

The National Constitution, as amended in 1994, provides in its Article 124 that 'the eminent domain of the natural resources existing in their respective territories belongs to the provinces'. The provision became effective when Law 26,197, enacted in 2006, amended Law 17,319 (the Hydrocarbons Law) in accordance with Article 124. Therefore, as per the current Hydrocarbons Law, hydrocarbons belong to the provinces where they are located or to the nation if the resources are located in federal territory.

This means that the relevant state (nation or province) owning the resources has full authority to award rights for the exploration, development and exploitation of the resources (exploration permits, exploitation concessions and association agreements with state-owned companies) and is the enforcement authority in connection with these awards and contracts.

i Domestic oil and gas legislation

The federal Hydrocarbons Law, which was amended by, inter alia, Laws 26,197 and 27,007, contains the basic material legislation in relation to the exploration, development and production of hydrocarbons.

In line with the basic rule contained in the National Constitution, the law provides that the hydrocarbons fields located in Argentine territory belong to the public domain of the national state or the provinces where the fields are located and that fields located beyond 12 nautical miles from the shoreline and until the external limit of the continental shelf belong to the federal state.

The law also sets forth, as basic principles applicable to the sector, that:

- the federal state shall establish the general policy in relation to the exploration, exploitation, industrialisation, transport and commercialisation of hydrocarbons;

- the holders of permits and concessions shall own the hydrocarbons extracted by them and shall be able to freely market, transport and industrialise them, subject to such regulatory provisions issued by the federal executive branch on a reasonable and economic basis; and
- during periods in which the production is insufficient to cover domestic needs, the entire availability of locally produced hydrocarbons shall be used to supply domestic demand.

The law provides for an exploration and production licences scheme, as will be explained below.

The Hydrocarbons Law is supplemented by numerous executive orders and resolutions. Other important laws are Laws No. 24,145 (federalisation of hydrocarbons), No. 26,659 (restrictions in connection with the exploration and production of petroleum in the continental shelf) and No. 26,741 (establishing the achievement of petroleum self-sufficiency as a matter of national strategic interest and expropriating the controlling shares of YPF SA).

The Hydrocarbons Law coexists with hydrocarbon laws and regulations passed by certain oil- and gas-producing provinces, such as the Province of Neuquén Hydrocarbons Law No. 2,453, Province of Mendoza Hydrocarbons Law No. 7,526, Province of Chubut Hydrocarbons Law XVII No. 102 or Province of La Pampa Hydrocarbons Law No. 2,675, which, in general, are substantially aligned with the provisions of the Hydrocarbons Law.

ii Regulation

At a national level, the Secretariat of Energy, a subdivision within the Ministry of Economy, is the main governmental body involved in energy regulation. The secretariat's under-secretariat specifically devoted to oil and gas is the Under-Secretariat of Hydrocarbons. Each oil- and gas-producing province has its own oil and gas regulators. Provincial regulators are governed by the federal Hydrocarbons Law and by provincial legislation and regulations.

Under the Hydrocarbons Law, the national policies in respect of exploration, development, production, transportation and marketing of hydrocarbons are determined by the national executive branch. This means that although the provinces own the hydrocarbons, have the power to grant permits or concessions and have regulatory powers regarding the way in which the federal hydrocarbons regime is applied in their territories, the power to establish the national hydrocarbons policy and to pass material legislation remains with the federal government and Congress (as provided by the National Constitution and several federal regulations, such as the Hydrocarbons Law, Law No. 26,197 and Law No. 26,741).

iii Treaties

Argentina is a party to several conventions governing dispute resolution and recognition and enforcement of awards and judgments, including the 1958 New York Convention, approved by Law No. 23,619.[7]

Argentina is a party to 58 bilateral foreign investment protection treaties[8] and to 21 double taxation treaties.[9]

III LICENSING

Private parties can obtain exploration and production rights through superficial inspection permits, exploration permits, exploitation concessions and association agreements with state-owned companies.

i Surface inspection permits

Under a surface inspection permit, the permit holder is granted the right to conduct a surface survey on a certain area, including carrying out geologic and geophysical studies, and employing other methods, such as the drafting of plans or the performance of topographic and geodesic surveys.[10]

Upon the expiry of the term of the permit, the primary data obtained from the surface inspection is to be delivered to the enforcement authority, which may process the data or have it processed by third parties, and may use it as it deems convenient for its own purposes. During the two years following delivery, the information is not to be disclosed without the express consent of the party that performed the surface inspection, except if permits or concessions are awarded in the prospected zone. Surface inspection permits on offshore areas (beyond 20 nautical miles from the coastline) are subject to a specific set of regulations provided for by former Ministry of Energy Resolution No. 197/18.[11]

ii Exploration permits

The holder of an exploration permit has the exclusive right to perform exploratory activities within the permit area and to obtain an exploitation concession if the holder discovers oil or gas in commercially exploitable quantities and conditions (commercial discovery) during the term of its permit.[12]

iii Exploitation concessions

Exploitation concessions grant the exclusive right to exploit the existing hydrocarbon fields located in the concession area.[13]

The exploitation of a field involves the development of its potential. By the same token, the exploitation concession implies for the concessionaire the ability to build and operate treatment plants as well as other facilities needed for the operations, including having the right to request a transportation concession for the transportation of the production out of the concession area.

The hydrocarbons belong to the concessionaire in accordance with its participating interest in the concession, and the concessionaire can dispose of its share of the production freely, subject to the general limitations contained in the Hydrocarbons Law and its supplementary regulations.

iv Association agreements with province-owned companies

Typically, in these agreements the province-owned company is the owner of the exploration and production rights and makes such rights available to the joint venture with the private party or parties.

Usually, the province-owned company holds a 10 per cent participating interest.

The private parties assume all the exploratory risk on an exclusive basis. In some agreements, the private parties are allowed to recover these costs from the province-owned company upon a commercial discovery and the entry into the exploitation stage by applying a certain percentage (usually 50 per cent) of the provincial company’s entitlement to the production. Upon the occurrence of a commercial discovery and the subsequent grant of an exploitation concession on the block, the province-owned company must pay its share of capital and operating expenditures (CAPEX and OPEX).[14]

The hydrocarbons belong to each party in accordance with its participating interest in the contract and each party can dispose of its share of the production freely, subject to the general limitations contained in the Hydrocarbons Law and its supplementary regulations.

The private party (or one of the private parties if there is more than one) is the operator.

The association agreements are awarded, within the framework of a public bidding process called by the executive branch of the relevant province, by the province-owned company, and the award requires the approval by the province.

v Processes by which licences are awarded

Surface inspection permits are granted by the relevant governmental authority upon a request made by a company willing to conduct the surface inspection.

Exploration permits are granted through public bidding rounds. The criteria to award the blocks are based on the work units' commitment made by the bidder and, in some bids, on the entry fee offered by the bidder. The public tender will be awarded to the bidder proposing the highest offer, in accordance with a formula that considers the aspects mentioned above.

Exploitation concessions can be obtained:

- by the holder of an exploration permit, upon the occurrence of a commercial discovery, over all or a portion of the exploration area;
- through a public bidding round in connection with 'proved' blocks (blocks where exploration activities are deemed unnecessary); or
- in the case of unconventional exploitation concessions, by the holder of an exploitation concession that, based on the unconventional potential of the block, asks for a subdivision of the concession area and for the grant of an unconventional concession on the subdivided area with unconventional potential.

Association agreements with state-owned companies are granted through public bidding rounds.

vi Key terms for licences

As per the Hydrocarbons Law, the exploration periods shall be set forth in the terms and conditions applicable to each public bid, within the following maximum terms.

For a permit with a conventional objective, there is a basic term of three years plus three years, plus an extension term of five years. In permits referring to offshore exploration, each of the periods of the basic term can be increased by one year.

For a permit with an unconventional objective, the basic term is four years plus four years, plus an extension term of five years.

At the end of the first period of the basic term, the permit holder is able to keep all the exploration area, while at the end of the second period of the basic term, the exploration area is to be relinquished, unless an extension is requested, in which case at least 50 per cent of the area is to be relinquished.

The term of exploitation concessions is 25 years (30 years for offshore concessions). The term of unconventional exploitation concessions is 35 years.

Concessions can be renewed for 10-year periods, and there is no limit on the number of renewals, which must be requested not less than one year before the expiry of the current term and can be requested by concessionaires that are in compliance with their obligations under the relevant concession. Extensions are not granted automatically but require governmental approval, and thus, in practice, some negotiation is required.

vii Revocation and expiry of licences

Permits and concessions will be revoked for the following reasons:

- failure to pay any annual surface fee within three months of becoming due;
- failure to pay royalties within three months of becoming due;
- substantial and unjustified failure to comply with specified obligations in respect of productivity, conservation, investment, works or special benefits;
- repeated infringement of the duty to submit information, to facilitate inspections by the enforcement authority or to use adequate techniques for the execution of the works;
- failure to comply with the obligations provided in Articles 22 and 33 of the Hydrocarbons Law;
- bankruptcy of the permit or concession holder; and

- death of the individual or dissolution of the legal entity holding the permit or concession.[15]

Before declaring the revocation owing to any of the aforementioned causes, the enforcement authority is to serve notice to the permit or concession holders requiring them to remedy the infringement within the term stated in the notice.[16]

Permits and concessions will expire upon the lapse of their terms or upon relinquishment by the holder. In case of partial relinquishment, the permit or concession will expire in respect of the relinquished area only.[17]

viii Government take

Royalties on the production of hydrocarbons must be paid every month to the relevant province or to the national government.[18]

The Hydrocarbons Law provides for a 12 per cent royalty on the net price obtained from the sale of hydrocarbons produced under exploitation concessions and a 15 per cent royalty on the net sales of hydrocarbons produced under exploration permits.

Royalties can be reduced by up to 50 per cent in tertiary production (enhanced oil recovery and improved oil recovery), extra heavy oil and offshore projects that, owing to their particular productivity issues and location, present especially unfavourable technical and economic characteristics.[19]

During the extension periods of concessions, an additional royalty of up to 3 per cent can be added, with an 18 per cent total cap.

The royalty provided in the law shall be the only government take calculated on the production.[20]

The Hydrocarbons Law establishes that the holders of exploration permits and concessions must pay a fixed yearly fee (payable in advance in January), which is calculated by each square kilometre of the permit or concession area. During the exploration phase, these yearly fees vary depending on the exploration period, as explained below.

Law No. 27,007 allows for an extension bonus to be charged when a concession extension is granted. The maximum bonus shall be equal to the figure resulting from multiplying the proved reserves remaining at the end of the term of the concession by 2 per cent of the average price in the relevant basin for the two-year period prior to the granting of the extension.

IV PRODUCTION RESTRICTIONS

Licence holders own and have the free availability of their share of the petroleum substances produced from the relevant area, subject to the general limitations established in the applicable regulations, basically to secure adequate supply of the domestic market.[21]

In line with the aforementioned, crude oil exports have to be offered to the domestic market first.

Governmental authorisation is required for any gas exports.[22] Liquefied natural gas (LNG) exports that are not subject to a long-term export permit have to be offered to the domestic market first.[23] Market prices apply for crude oil, taking Brent as a reference and applying certain discounts thereon. As regards natural gas prices, there is a mix of regulated and market prices.

Gas for power generation and distributors (who supply the priority natural gas demand) is acquired through tender processes, subject to certain maximum prices. In late 2020 a new incentives plan for the production of natural gas, the 'Plan to Promote the Argentine Natural Gas Production – Supply and Demand Scheme 2020–2024', known as Plan Gas.Ar, was created by Decree No. 892/20. The plan consisted of a call for bids, conducted by the Secretariat of Energy, for the supply of up to 70 MMm^3 per day between January 2021 and December 2024. Producers could commit to supply volumes of up to 70 per cent of their production during the previous winter season, for a price that could not exceed US$3.70 per MMBtu. Decree No. 730/22 amended and expanded the scheme until 2028.

V ASSIGNMENTS OF INTERESTS

According to Article 72 of the Hydrocarbons Law, participating interests in permits and concessions can be assigned, with the prior authorisation of the executive branch (federal or provincial, as applicable), in favour of those that fulfil the financial and technical conditions and requirements needed to be a permit holder or concessionaire.

Under Article 73 of the Hydrocarbons Law, a concessionaire can assign its interest in an exploitation concession as a security interest in respect of loans obtained to finance the upstream operations in the relevant concession area.

Provincial hydrocarbon laws contain provisions in line with the ones described above.

The change of control of the company holding the licence does not require governmental authorisation.

The federal state and most of the provinces do not have any rights of first refusal upon the assignment of participating interests in permits or concessions submitted to the relevant authorities for their authorisation.[24]

The transfer of any upstream licence is subject to the rules of Argentine Antitrust Law No. 27,442, and therefore approval by the antitrust regulator might be required, depending on the specific circumstances of each transaction.

Usually, assignment authorisations can be obtained within 60 or 90 days of the request and the information required being submitted.

VI TAX

Within the national jurisdiction, in accordance with the relevant provisions and as long as they are applicable, upstream companies will be liable for the payment of all federal taxes generally applicable in the country (income tax, value added tax, debits and credits in bank accounts tax) and any applicable customs duties.

They shall also be liable for the payment of all provincial (gross income tax and stamp tax) and municipal taxes in force as of the date of the award. During the term of duration of the permits and concessions, the provinces and municipalities shall not levy new taxes upon the holders thereof, nor increase the rate of pre-existent taxes, except for those rates paid in consideration for the performance of services and as contributions for improvements, or a general increase of taxes.[25]

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

i Environmental laws and environmental regulators

Pursuant to Article 41 of the National Constitution, legislative powers are transferred by the provinces in favour of the federal state for the issuance of basic rules of general application in environmental matters.

Following this criterion, at the national level the hydrocarbons sector is governed by:

- general regulations containing minimum environmental protection standards, such as Law No. 25,675 (the General Environmental Law) and Law No. 24,501 (the Hazardous Waste Law); and
- general regulations and minimum standards specifically applicable to hydrocarbon activities issued by the enforcement authority while exercising the powers delegated by the Hydrocarbons Law to that effect. For a long time, this authority was held by the Secretariat of Energy. Other regulations could also be issued by the Secretariat of the Environment and Sustainable Development.

The main applicable regulations include:

- policies and procedures for the protection of the environment: Resolution SE No. 105/92:

- requires the submission of a prior environmental study before drilling the first exploratory well and commencing development of the reserves;
    - provides for the implementation of an annual monitoring of works and tasks; and
    - sets out in detail technical guidelines to be followed in the exploration and exploitation of hydrocarbons;
- Joint Resolution No. 3/19, issued by the Secretariat of Energy and the Secretariat of Environment and Sustainable Development, published in the Official Gazette on 27 November 2019, set forth a set of rules governing the environmental impact assessments to be conducted in connection with exploration and exploitation activities (excluding the drilling of wells) in the continental shelf subject to federal jurisdiction (beyond 12 nautical miles from the coastline);
- annual environmental monitoring reports: Resolution SE No. 25/04 defines and describes the technical characteristics, structure and scope of environmental studies and annual environmental monitoring reports. The environmental studies include four phases:
    - an initial environmental status;
    - an identification and characterisation of environmental effects and prioritisation of environmental impacts;
    - an environmental impact mitigation plan; and
    - a monitoring plan;
- contingency plans and information about incidents: if an environmental incident occurs, contingency plans must meet the guidelines provided under Resolution SE No. 342/93 and the enforcement authority must be informed within the deadlines and satisfying the requirements established by Resolution SE No. 24/04;
- emission (i.e., venting) of gas to the atmosphere: Resolution SE No. 143/98 establishes guidelines and mandatory limits on this matter and the exceptions, under certain justified circumstances, authorised to exceed these limits;
- safety conditions and maintenance of storage tanks of crude oil and by-products: Decree No. 10,877/60 describes the active and passive defences to be implemented in the facilities. Resolution SE No. 785/05 created the Programme for the Control of Spills from Surface Storage Tanks, which established that companies that have these facilities have to register and inspect the tanks. Companies must also comply with a maintenance plan, report any incidents and report the abandonment of the tanks;
- safety auditing service: Resolution SE No. 419/93 and other supplementary regulations provide for the refineries', storage companies' and operators of service stations' obligation to hire safety auditing services to certify, on an annual basis, compliance with the applicable safety regulations; and
- provincial regulations: the provinces are empowered to supplement the federal regulations with local regulations, provided they do not overstep the established principle of federal law pre-eminence.[26] In this regard, provincial regulations have been passed in connection with several environmental matters, such as a gaseous emissions control regime, subterranean water exploitation regime, groundwater exploitation regime and pressurised devices control regime.

ii Environmental approvals necessary for oil and gas operations

An environmental study must be prepared prior to the development of a new project and submitted to the relevant (provincial or national) environmental enforcement authority. Upon the approval of the study, the operation can begin and the operator shall comply with recommendations, restrictions and conditions (if any) contained in that approval (Resolution SE No. 105/92 and related regulations).

Additionally, the operator will have to obtain an authorisation for the use of water in the project, which shall include the water source and the conditions under which it shall be used, and register with the National Hazardous Waste Generators Registry and the issuance of the Annual Environmental Certificate (Law No. 24,051, Decree No. 831/93 and other regulations).

iii Legal requirements in respect of decommissioning

Resolution No. 5/96 issued by the former Secretariat of Energy established rules and procedures for the abandonment of oil and gas wells, including a timetable for the abandonment of certain wells. On an annual basis the operator shall report the decommissioning works performed in the past year and those to be performed in the following year. Four years before the expiry of the respective concessions, or as from the date of relinquishment of all or part of an exploitation block, the concessionaire must submit a technical and economic study explaining the reasons why the abandonment of each inactive well could be inconvenient. Recommended techniques for performing definitive abandonment are detailed in the same resolution. The technical conditions applicable to the abandonment of gas pipelines and ancillary facilities are established in resolutions NAG 100 and NAG 153 of Enargas.[27] The abandonment of these facilities requires the prior consent of Enargas, which will evaluate whether there is a general interest in keeping the facilities operative.

There is no requirement to constitute a fund to pay any costs associated with the abandonment of wells and facilities.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

There are no foreign investment approvals or restrictions in relation to investment in petroleum.

Foreign investors wishing to hold an interest in an upstream licence will have to:

- register a branch of a foreign company with the Public Registry of Commerce;[28] or
- set up a local company (usually a stock company, a stock company with a sole shareholder or a limited liability company). To act as a shareholder or quota holder of an Argentine company, a foreign company must register with the Public Registry of Commerce with the sole purpose of being a shareholder or quota holder of a local company.[29]

In the City of Buenos Aires, registering a branch may take between 30 and 45 days, while establishing a local company may take between 60 and 90 days, including the registration of the foreign companies that will be the shareholders and the incorporation of the new company.

A branch is not a separate entity from the foreign company that has registered it. A stock company, a stock company with a sole shareholder and a limited liability company are separate entities from their shareholders or quota-holders who limit their responsibility to the integration of their respective capital contributions.

From an administrative point of view, branches are quite simple structures as the only requirement is to have a legal representative, while companies require the appointment of a board of directors or managers. Two-thirds of the members of the board must be Argentine residents.

ii Capital, labour and content restrictions

Capital restrictions

Decree 609/19, issued in September 2019, followed and supplemented by Decree 91/19 and several Central Bank resolutions, reinstated foreign exchange control regulations, similar to those that had been in place during the 2002–2015 period. These regulations have established certain restrictions, including the need to obtain Central Bank's authorisation to access the official foreign exchange market to remit dividends to non-resident shareholders when the amount of dividends to be paid, together with the amount of dividends paid by accessing the official foreign exchange market after 1 January 2020, exceeds 30 per cent of the amount of currency entered into the country by way of capital contributions by the shareholders after such date, the obligation to bring exports' proceeds to the country and trade them for Argentine currency within certain terms, and the prohibition for companies to trade Argentine currency for foreign currency or to transfer foreign currency to accounts outside the country without a specific purpose contemplated in the regulations (like repaying loans to external creditors or paying for imported goods or services).[30] To legally avoid this last restriction, many companies and individuals carry out transactions in which they purchase, with Argentine currency, certain bonds that are then sold for dollars in exchange markets abroad.[31]

Decree No. 277/22 created a promotional regime for the access to foreign currency for an amount equal to a portion (20 per cent for crude oil and 30 per cent for natural gas) of the value of incremental oil and natural gas production.

Local content requirements applicable to oil and gas operations

The Hydrocarbons Law provides that those performing works that it regulates shall prefer to hire nationals and, particularly, residents of the region where the works shall be performed, and that the proportion of nationals employed by each concessionaire or permit holder shall not be less than 75 per cent.[32] In practice, exceptions to the above-mentioned rule are accepted in connection with specialist workers who are not available in Argentina or in the region where operations are conducted.

Decree No. 277/22, which created a promotional regime for the access to foreign currency with proceeds resulting from incremental oil and natural gas production provides that the beneficiaries shall comply with the requirements set forth in certain Regime for the Promotion of Employment, Labour and Development of Regional and National Suppliers of the Hydrocarbons Industry established in the same decree, aimed at fully using regional and national manpower, suppliers and services providers through two different schemes:

- a Regional and National Integration Requirements Scheme; and
- a Preferences Scheme.

Similar provisions can be found in provincial laws and regulations, as well as in the terms and conditions applicable to bidding rounds organised by the provinces.

Furthermore, there are certain provincial regulations establishing an obligation to favour the hiring of services from local suppliers.[33]

Restrictions on the ability to hire foreign workers

There are no restrictions on hiring foreign workers, provided that the applicable immigration regulations are complied with.[34]

iii Anti-corruption

The following is a summary of the anti-corruption regulations.

Public Ethics Law No. 25,188 and its regulatory Decree No. 164/1999

Public Ethics Law No. 25,188 and its regulatory Decree No. 164/1999 set forth the duties, prohibitions and incompatibilities applicable to all public officers and establish that public officers shall, inter alia:

- strictly abide by the National Constitution and the laws;
- act honestly, diligently and in good faith;
- act in the public interest;
- not obtain or receive any personal benefit related to the performance, the delay in performing or the omission to perform any act inherent to their functions;
- use public property only for authorised purposes related to the performance of their duties and shall not use or allow any third party to use any information obtained in connection with their public functions in the benefit of private interests; and

- observe, in any public bidding process, the equality, publicity, free competition and reasonability principles.

The Anti-Corruption Agency is the Authority of Application of Law No. 25,188 and is responsible for preparing and coordinating anti-corruption policies as well as investigating corruption cases. The agency also keeps public officers' assets disclosure records and provides a whistle-blower mechanism on its website.

Argentine Criminal Code

Bribery of foreign or local public officers is prohibited and penalised in Article 258(b) of the Argentine Criminal Code (ACC).

Article 258(b) punishes with prison any person who offers or gives to a public officer from a foreign state or from an international public organisation, personally or through an intermediary, money or any object of pecuniary value or other gifts, promises or benefits, for their own benefit or for the benefit of a third party, for the purpose of having the officer perform or not perform an action related to their function or to use the influence derived from the office they hold in an economic, financial or commercial transaction.

Conversely, Articles 256 to 259 punish both the citizen who bribes an Argentine public officer and the public officer who receives the bribe. The punishment is increased when the public officer is a judge, prosecutor or any other person related to the administration of justice.

Article 256(b) of the ACC sets forth provisions regarding 'improper lobbying', and states that anyone who requests or receives money or any other gift or accepts a promise of such to exert unlawful influence on a public official will be punished.

Criminal liability of legal entities

Law No. 27,401, enacted in late 2017, provides the criminal liability of private legal entities in connection with the offences contemplated in Articles 258 and 258 *bis* described above, Article 265 (negotiations that are not compatible with the exercise of public functions), Article 268 (extortion) and Article 300 *bis* (false or fraudulent financial statements) of the Criminal Code.

The sanctions provided by the law include fines, suspension of activities and dissolution. The company may receive a reduced fine, and it may even be released from any criminal liability if it self-reports an offence provided for in the law, of which it has become aware as result of proper internal controls implemented before the occurrence of the wrongdoing that is being reported, and provided it returns the unlawful benefit obtained.

Anti-corruption conventions

Argentina has signed – without reserves – the following anti-corruption conventions:

- the Inter-American Convention against Corruption (IACAC) 1996;
- the Convention for Combating Bribery of Foreign Officers in International Business Transactions (OECD Anti-Bribery Convention) 1997;
- the United Nations Conventions against Business Corruption 2003; and
- the United Nations Convention against Private Corruption 2003.

IX CURRENT DEVELOPMENTS

The increase of hydrocarbons demand and high prices that followed Russia's invasion of Ukraine evidenced that, had Argentina created a more stable and investment framework since the first shale hydrocarbons projects began in 2010, the lack of which has certainly slowed down the pace of investment, that would have put the country in an excellent position to take full advantage of the current scenario as an exporter of shale oil and, especially, gas, thus generating massive exports proceeds at a time when the country is striving to mitigate the steep decline of its Central Bank's hard currency reserves.

Having said that, despite the challenging context, the industry has managed to develop the Vaca Muerta Formation, which is now a proven world-class resource with productivity rates that match or even beat those of the best American shale players.

This continuing development process has led to a situation that had been identified by the industry years ago, which is the lack of sufficient infrastructure to deal with the increasing Vaca Muerta production that has affected the pace at which several blocks are being developed.

This is the reason that, over the past year and a half, several projects that have focused on the expansion of midstream infrastructure have been carried out simultaneously, despite the challenging financial context.

The financing structures that were used ranged from direct financing from the federal government (with a substantial portion of the funds raised from a one-time only tax on large fortunes), for the President Néstor Kirchner pipeline, to direct investment from the shareholders, pre-payment of firm capacity transportation contracts awarded in open season tenders, loans from multilateral financial institutions and the issuance of notes for other projects. The following four projects are worth mentioning.

- Construction of the first stage of the new President Néstor Kirchner natural gas pipeline. Although the project was delayed for several years, once the financing had been secured and agreements with the contractors executed, the construction was completed in less than one year and complied with a schedule regarded as highly challenging by the industry. This 570 km pipeline between Tratayén (Neuquén) and Saliqueló (western Province of Buenos Aires) is essential to deal with the natural gas transportation bottleneck in the short term and buy some time to develop additional projects in the midterm. At this initial stage, the pipeline's capacity is 11 million m^3 per day (rising up to 15 million m^3 per day with the addition of compression facilities) and will enable the country to save hundreds of millions of Argentine dollars a year in LNG and other fuel imports.
- Expansion of the crude oil pipelines system operated by Oldelval, holder of the Allen-Puerto Rosales transportation concession, which will expand its current capacity from 36,000 m^3 per day to 72,000 m^3 per day. Completion of the first stage of the project is scheduled for the first quarter of 2024 while completion of the whole project is scheduled for mid-2025.
- Expansion of the storage, transportation and shipping facilities (closely related to the Oledelval's pipeline expansion) owned by Oiltanking-Ebytem, a maritime terminal that receives the production transported by Oldelval and through which most of the crude oil exports from Vaca Muerta are made. This project is ongoing and scheduled to be completed by 2025.
- Resumption of operations by the Trasandino Oil Pipeline, an exports-dedicated pipeline owned by Oleoducto Trasandino SA that runs between western Neuquén (Argentina) and Concepción (Chile). In July 2023, the first cargo was exported through the pipeline since 2006.

Other projects are going through their initial stages, such as the second stage of the President Néstor Kirchner pipeline, the modification of the northern trunk gas pipeline to reverse the current direction in which the gas flows from south bound to north bound. This modification will enable the gas produced from Vaca Muerta to reach northern Argentina (replacing the declining supply from Bolivia) and, eventually, Brazil, using spare capacity in the Bolivian transportation system, and the YPF southern Vaca Muerta project, which contemplates the construction of a new 600 km oil pipeline from the Neuquén Basin to the Atlantic Ocean and the construction a new maritime terminal in the Province of Río Negro.

In September 2022, YPF and Petronas entered into a memorandum of understanding for a potential construction of a large-scale LNG export project that would be subject, among commercial and other conditions, to the passing of certain regulations. Although YPF and Petronas were the only parties to the memorandum, it is expected that other players might be interested in participating in the project if it is eventually launched.

As a consequence of the YPF-Petronas memorandum and subsequent negotiations and consultations with the industry, an LNG projects promotional regime bill was submitted by the federal Executive to the National Congress in July 2023. The project contemplates a set of benefits for the promotion of LNG projects, whose main features are as follows:

- eligible projects must focus, as their main objective, in LNG liquefaction, export and commercialisation, including the construction of liquefaction plants and other investments throughout the whole value chain, from dedicated production to transportation and storage facilities;
- tax benefits, including accelerated depreciation of investments for income tax purposes, value-added tax reimbursement or credits to be made in an expeditious manner, and tax stability; and
- export duties between zero and 8 per cent, in accordance with a sliding scale regarding certain LNG international reference values.

As 2023 is a general elections year, with the election holder taking office in December, it is likely that this promotional regime bill will not be discussed and voted on until next year.

The three candidates who may win the election (Patriia Bullrich, Sergio Massa and Javier Milei) have repeatedly expressed that the full development of the country's hydrocarbon resources (basically Vaca Muerta, but also including offshore resources and the Palermo Aike shale formation in the Austral Basin) must be a long-term state policy. They also seem to agree on the need to speed up the developments of these resources, to take advantage of the current international situation and the relentless global energy transition process, in which natural gas is to play a key role.

However, for this mutual consideration to materialise in actual policies that, in turn, trigger the substantial investment required to complete the development and exploitation of the country's resources, it will be necessary to give the industry an adequate and stable regulatory and economic framework. This will be achieved, first, by duly and timely honouring the state's obligations assumed under the promotional regimes that are currently in force and refraining from changing the current rules or their interpretation. Second, until the country's macroeconomy is stabilised and foreign exchange restrictions have generally softened, the industry needs to be guaranteed specific flexible foreign exchange rules, especially to access the foreign exchange market to remit dividends, repay external debt and pay for imports. Regulatory, foreign exchange and tax stability, expressly recognised by law are also essential. Some of these issues have already been addressed by the existing promotional regimes, such as the Plan GasAR, the incremental production incentives regime of Decree No. 277/22, the export duties scheme established by Decree 820/20, Central Bank's Communiqué A 7553 in connection with imports and the LNG projects bill submitted to the Congress earlier this year.

All things considered, although recognising the magnitude of the challenges to be dealt with under Argentina's current economic and financial situation, the oil and gas industry is expected to attract investment in the short and medium term, together with the mining, renewable energy and agribusiness sectors.

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Endnotes

1 Pablo J Alliani and Fernando L Brunelli are partners at Bomchil.
2 YPF SA was expropriated by Law 26,741 while the 'deregulation' decrees were repealed by Decree No. 1,277/12.
3 Among others, incentive plans for the development of new gas resources (SE Resolution No. 1/13) by which a minimum price was guaranteed by the Federal Government; Decree No. 929/13, which established certain tax, exports and free availability of proceeds benefits in connection with projects involving a minimum investment amount; and Law No. 27,007, which amended the Hydrocarbons Law No. 17,319 and enhanced the benefits scheme provided for in Decree No. 929/13.
4 A United States Energy Information Agency's report issued in April 2011 estimated Argentina's technically recoverable resources of shale gas in 774 trillion cubic feet (Tcf), while a similar report issued by the same agency two years later increased its estimate to 831Tcf of shale gas and 30 billion barrels (bbl) of shale oil, which amounts to 70 and 13 times, respectively, the present proved gas and oil reserves of the country. Argentina's technically recoverable shale resources are the fourth and second largest in the world in connection, respectively, with oil and gas.
5 Mr Alberto Fernández (member of a centre-left coalition led by former president Cristina Kirchner), who replaced centre-right orientated Mauricio Macri.
6 Once again, reality as the main driver to force the government to complete the pipeline in time for winter was essential to reduce LNG imports and save the low number of Argentinian dollars that remained in the central bank's vault.
7 Other conventions to which the country is a party are the Convention on the Settlement of Investment Disputes between States and Nationals of Other States; the 1991 Inter-American Convention on International Commercial Arbitration; the 1979 Montevideo Inter-American Convention on the Extraterritorial Efficacy of Foreign Judgments and Arbitral Awards; the 1940 Montevideo Convention on International Procedural Law; the MERCOSUR International Commercial Agreement; and the MERCOSUR Protocol on Jurisdictional Cooperation and Assistance Agreement in Civil, Commercial, Labour and Administrative Matters.
8 Algeria, Armenia, Australia, Austria, Belgium-Luxembourg, Bolivia, Bulgaria, Canada, Chile, China, Costa Rica, Croatia, Cuba, the Czech Republic, Denmark, Dominican Republic, Ecuador, Egypt, El Salvador, Finland, France, Germany, Greece, Guatemala, Hungary, India, Indonesia, Israel, Italy, Jamaica, Korea, Lithuania, Malaysia, Mexico, Morocco, the Netherlands, New Zealand, Nicaragua, Panama, Peru, the Philippines, Poland, Portugal, Romania, Russia, Senegal, South Africa, Spain, Sweden, Switzerland, Thailand, Tunisia, Turkey, Ukraine, the United Kingdom, the United States, Venezuela and Vietnam.
9 Australia, Austria, Belgium, Bolivia, Brazil, Canada, Chile, Denmark, Finland, France, Germany, Italy, Mexico, the Netherlands, Norway, Russia, Spain, Sweden, Switzerland, the United Arab Emirates and the United Kingdom.
10 Hydrocarbons Law, Articles 14 and 15.
11 Resolution No. 197/18 provides for a much longer term (eight years) than that applicable to other areas (12 months plus 12 months' extension), and gives the permit holder commercial exploitation rights, whereby the permit holder has the exclusive right to disclose (subject to a few exceptions) and commercialise the data obtained from the inspection activities, on a non-discriminatory basis, until two years after the expiry of the permit. Surface inspection permits that were already in force could be converted into permits under this new Resolution, at the permit holder's request.
12 Hydrocarbons Law, Articles 16 to 26.
13 id., Articles 27 to 38.
14 The agreements executed by Gas y Petróleo del Neuquén SA – the Province of Neuquén-owned company – provide that, upon the grant of an exploitation concession, the provincial company may opt between keeping its participating interest in the production and CAPEX and OPEX expenditures, or assign the participating interest to the private parties and receive a 2.5 per cent overriding royalty on the production from the concession area.
15 Article 33 provides for the obligation of the permit holder to declare commerciality within a certain term after the occurrence of a commercial discovery. Article 33 refers to the size of each exploitation lot and certain concessionaire's obligations in this respect.
16 Hydrocarbons Law, Article 80.
17 id., Article 81.
18 Royalty is regulated by Articles 59 to 65 of the Hydrocarbons Law and by Decree No. 1,671/1969.
19 Hydrocarbons Law, Article 27 *ter* (introduced by Law No. 27,007).
20 However, in concessions that were extended before the enactment of Law No. 27,007 (2014), extra payments on the production may apply, such as additional payments of up to 3 per cent of the production, and certain windfall profit payments apply, which are triggered when the prices obtained for the hydrocarbons produced from the concession area exceed certain parameters.
21 Hydrocarbons Law, Article 6.
22 Law No. 24,076, Article 3 and Secretariat of Energy Resolution No. 360/21 (issued on 23 April 2021), as amended by Resolution No. 774/22 (issued on 16 November 2022) which, subject to the authority's authorisation, contemplates firm exports (Plan Gas.Ar firm exports, firm exports derived from additional injections during the winter within the Plan Gas.Ar, firm exports of surplus production in a basin), interruptible exports, operational exchanges (with a subsequent obligation to reimport the same volumes that have been exported) and assistance agreements. The destinations of authorised exports of natural gas are Chile, Uruguay and Brazil.
23 Secretariat of Energy Resolution No. 706/21 (issued on 23 July 2021).
24 As an exception, Decree No. 348/15 of the Province of Río Negro provides that the province will have a right to match the commercial terms of the intended assignment and acquire the participation once assignment authorisation has been requested.
25 Hydrocarbons Law, Article 56(a).

26 National Constitution, Article 3.
27 Enargas is the national gas regulator.
28 General Companies Law No. 19,550, Article 118.
29 id., Article 123.
30 Access to the foreign exchange market to repay loans to affiliates is currently restricted.
31 This implies an additional cost as well as certain risk in respect of the market value of the bonds used in the transaction, as the bonds must comply with a minimum five-day 'parking' term before they can be sold. The performance of these 'blue chip swaps' prevents the relevant person to access the official foreign exchange market for a certain period.
32 Hydrocarbons Law, Article 71.
33 For example, Neuquén Law No. 3338, which replaced the regime formerly provided by Law No. 3,032. This Law contains an obligation to acquire a minimum of 60 per cent of the contractual amount from companies based in Neuquén, which is calculated on an annual basis, in respect of each item or type of activity. This preference must be granted if the economic offer submitted by the Neuquén company is up to 7 per cent greater than the best offer submitted by the other companies, provided that the Neuquén company accepts to reduce its prices to match the best offer received.
34 Immigration Law No. 25,871, its Regulatory Decree No. 616/2010 and supplementary dispositions enacted by the enforcement authority, the National Immigration Directorate.

Chapter 4

Austria

Andreas Gunst, Oskar Winkler, Dimitar Hristov, Kenneth Wallace-Mueller and Valentina Eigner[1]

Summary

I INTRODUCTION

With a land area of 83,879km² and a population of approximately 9.1 million, Austria is the 14th largest country in terms of land area and the 15th largest in terms of population in the European Union, constituting 1.7 per cent of the population of the European Union.

According to Statistic Austria,[2] gross consumption of natural gas in Austria was 288,460TJ in 2022 and gross consumption of fuel oil in Austria was 239,182TJ for that year. Production is considerably lower and therefore Austria heavily relies on oil and gas imports, particularly from the Russian Federation. Austria continuously strives to further diversify the number of its oil and gas suppliers and the corresponding supply routes, and benefits from its substantial oil and gas storage facilities. Following the Russian invasion in Ukraine in February 2022, Austria has intensified its endeavours to reduce its energy dependence from the Russian Federation by enhancing diversification of supplies and by promoting renewable energy. These steps are to be achieved, not without controversy, by increasing domestic gas production through new drill holes; major new natural gas discovery by OMV (formerly Österreichische Mineralölverwaltung AG – a partly federal state-owned company) in Lower Austria is very timely in this regard (see Section IX). Currently, 9 per cent of the domestic gas demand and 5 per cent of the domestic oil demand is covered by its own production.

Despite being a net importer of oil and gas, Austria has a respectable domestic upstream gas sector, with key fields in the Vienna Basin in Lower Austria and the Molasse Basin in Upper Austria and Salzburg.

The Austrian upstream sector is dominated by three companies. According to GeoSphere Austria:

OMV is responsible for approximately 88.5 per cent of crude oil and 85.2 per cent of natural gas liquids produced; Rohöl-Aufsuchungs AG (RAG), a privately owned company, is responsible for approximately 9.5 per cent of oil and 14.8 per cent of gas; and ADX VIE GmbH, has been responsible for 2 per cent of oil since 2019.

These figures refer to 2022 and have decreased significantly compared to the previous year.

In addition to its upstream sector activities, Austria plays a central role in the European midstream natural gas sector, with the Central European Gas Hub at Baumgarten an der March being the main transit point for imported Russian gas to Western Europe.

Beyond domestic production, OMV is heavily involved in the international upstream sector, with operations in, inter alia, the North Sea, Tunisia, New Zealand, Romania and Yemen. OMV is the operator of Austria's only refinery in Schwechat. In addition to its upstream activities, RAG focuses on drilling technology and on large-scale gas storage, boasting a storage capacity of approximately 6.3bcm. In mid-2019, ADX VIE GmbH purchased two oil and gas fields (Gaiselberg and Zistersdorf) from RAG. ADX VIE GmbH, OMV and RAG carry out activities in the hydrocarbon extraction sector.

This chapter will focus on Austrian domestic oil and gas exploration and production.

II LEGAL AND REGULATORY FRAMEWORK

Owing to its size and administrative structure, Austrian energy legislation is fairly comprehensive with one central act regulating oil and gas exploration and production as well as general mining activities on the federal state level, with the enactment of certain minor pieces of legislation being delegated to the relevant ministry or to the state governments.

The administrative role is again very centralised, with Section VI of the Federal Ministry for Finance (the Ministry) responsible for the performance of a great deal of administrative duties in the upstream sector.

Given the greater development and importance of the mid- and downstream sectors in Austria, a greater amount of legislation has been enacted and further administrative bodies are involved in these sectors in comparison with the upstream sector.

i Domestic oil and gas legislation

The central legislative act for the exploration and production of oil and gas is the Mineral Resources Act 1999,[3] applicable to the entire federal state.

Owing to its membership in the European Union, Austria has implemented a number of directives that apply to the upstream energy sector. The Oil and Gas Licencing Directive,[4] which aims to ensure non-discriminate access to oil and gas exploration and production, was implemented in Austria under the Federal Procurement Act 2006,[5] which was replaced in 2018 by the new Federal Procurement Act 2018 (Federal Procurement Act).[6]

The Stocks of Crude Oil and Petroleum Products Directive,[7] intended to address the issue of European Union energy security, was implemented by the Oil Stockholding Act 2012,[8] the Energy Steering Act 2012,[9] the Oil Statistics Regulation 2011[10] and the Gas Statistics Regulation 2012.[11]

The Offshore Directive[12] proposes measures to protect offshore oil and gas activities and was implemented under the Mineral Resources Act 1999 by imposing reporting obligations on companies registered in Austria in the event of serious accidents during their offshore oil and gas activities outside the European Union.

Regulation (EU) 2017/1938 concerning measures to safeguard the security of gas supply[13] sets out directly applicable measures to enhance security of gas supply. On a national level, it is supplemented by the Energy Steering Act 2012.

On the basis of these key acts, a number of regulations have been issued detailing specific provisions, such as accident management and waste disposal, which are introduced below.

ii Regulation

As described in Section II, the Ministry plays a very central role in the Austrian upstream sector. The Ministry derives its powers from the Mineral Resources Act and other relevant legislation, as described below. It is primarily responsible for the development of national oil and gas policy, and it authorises and manages the exploration and production on behalf of the federal state.

iii Treaties

As a Member State of the European Union, Austria is part of the internal market for gas,[14] having implemented the European Third Energy Package and the Energy Union, both of which aim to liberalise the European natural gas market. In addition to the above-mentioned European directives, the reporting provisions of the Regulation on Wholesale Energy Market Integrity and Transparency (REMIT)[15] have a direct effect on Austrian gas market participants, as detailed below.

Austria is a signatory to the Energy Charter Treaty (ECT), which aims to facilitate the trade of energy between the signatory states, initially including major players such as the European Union and its Member States,[16] the Russian Federation, Ukraine and Australia. However, the Russian Federation never ratified the Energy Charter Treaty and finally announced in 2009 its withdrawal as signatory state. The ECT provides specifically for non-discriminatory trading rules for energy, reliable cross-border transit flows, the protection of direct foreign investment, the promotion of energy efficiency, and an international dispute resolution scheme between participating states and between investors and host states. After Italy's withdrawal from the ECT in 2016, in 2022 several other EU Member States, such as Spain and France, also announced their withdrawal. Austria has so far neither ruled out its withdrawal nor committed to it. On 7 July 2023, the European Commission proposed a coordinated withdrawal from the ECT for itself, its Member States and Euratom.

Austria has entered into several bilateral agreements on energy matters, including with both the Czech Republic[17] and Slovakia[18] regarding cooperation in oil and gas exploration.

Germany[19] and Austria signed a bilateral agreement on joint responsibility for the use and filling of gas storage facilities and on the transport of the stored gas in the event of a gas shortage in February 2023.

III LICENSING

i Right to explore and produce

Oil and gas are considered property of the federal state pursuant to Section 4(1)(2) of the Mineral Resources Act, and the federal state has the right to explore for and produce oil and gas.

It may alternatively transfer the exercise of this right in specific exploration areas for a specific duration to individuals, companies or commercial law partnerships, provided that these possess the necessary technical capabilities and financial resources.

Pursuant to Section 183 of the Federal Procurement Act, as rights owner for the exploration and production of oil and gas on the federal territory, the federal state must transfer these rights in accordance with the fundamental freedoms of the European Union, the principle of non-discrimination, the principles of free and fair competition, and the equal treatment of bidders for the rights.

The Mineral Resources Act additionally makes provision for the exploration for geological structures in which gas may be stored underground.

Instead of the transfer of rights being carried out by means of a licensing regime or a production sharing agreement, a civil law contract is concluded with the Ministry, in return for an 'appropriate' consideration.

This consideration comprises either an 'area interest' for exploration or a 'field interest' and 'production interest' for production (including the right to acquire the oil or gas produced) for the duration of the transfer. Pursuant to Section 69(1) of the Mineral Resources Act, this consideration may, however, be suspended when deemed necessary to:

- avert a macroeconomic imbalance;
- avert a deterioration in the competitive structure of the mining rights holder;
- avert a deterioration of the security of supply of the market with state-owned mineral resources;
- improve the utilisation of resources by federal mineral resources; or
- protect other economically important concerns.

From a practical perspective, primarily, OMV, RAG and ADX VIE GmbH are involved in the exploration and production of oil and gas in the Austrian federal territory, whereby the federal state has 31.5 per cent ownership of OMV through the Austrian State Holding Company.

ii Work programme

A key condition of exploration and production of oil and gas by both the federal state and any rights holder is the submission of a work programme for approval by the Ministry in accordance with Sections 71 and 72 of the Mineral Resources Act.

The work programme must include details on the nature, extent and aim of the proposed work, its chronological order, the proposed plant, the planned safety systems and measures to restore the land use upon decommissioning, and the name of the responsible person. Any material changes made to an approved work programme, specifically the performance of work other than that previously declared or the use of different means, must be approved by the Ministry.

An exploration report must be submitted to the Ministry at the end of each calendar year, which contains details on the outcomes of the exploration.

iii Further approvals

Pursuant to Section 119 of the Mineral Resources Act, any drilling project or probe that exceeds a depth of over 300 metres requires approval by the Ministry as a mining plant. Following application, a consultation period will begin, whereby the site will undergo inspection and the concerns of any neighbours to the site will be taken into account.

The drilling approval may be time-limited, and can be issued only when the following criteria have been fulfilled:

- the affected landowners have agreed to the plans, or if not possible, the issuance of an expropriation court order issued in accordance with Sections 148 to 150 of the Mineral Resources Act;
- the use of state-of-the-art measures to prevent avoidable emissions;
- the use of measures to ensure that subject to current medical science, no harm will come to the health or lives of individuals and that no unreasonable nuisance will be caused to individuals;
- the use of measures to ensure that no unreasonable levels of harm to the environment or water will be caused by waste products;
- the use of measures to ensure that, if possible, any waste is prevented or recycled, and that other waste will be properly disposed of in a commercially reasonable manner; and
- the use of measures to ensure that any air pollution complies with the relevant state regulation in accordance with Section 10 of the Air Pollution Control Act 1997.[20]

As the transfer of exploration and production rights is governed by a civil law contract, and with no draft publicly available, it is difficult to establish any standardised key terms beyond what is prescribed by legislation.

iv Registration and reporting obligations

Of relevance to gas producers, REMIT entered into force on 28 December 2011, with the aim of increasing the stability and transparency of the European wholesale energy markets, as well as tackling market manipulation and insider trading.

By virtue of the direct effect, Austrian gas producers (but notably not oil producers), defined by REMIT as market participants who enter into contracts for the sale of wholesale energy products on the wholesale energy market, are subject to a number of reporting obligations.

Pursuant to Article 4(1) of REMIT, Austrian gas producers are obliged to publish information to the European Agency for the Cooperation of Energy Regulations[21] on the capacity and use of their production facilities, as well as any planned or unplanned unavailability.

Pursuant to Article 8(1) of REMIT, Austrian gas producers are further obliged to submit information on:

- gas sold;
- the price and quantity;
- the dates and times of execution;
- the parties to the transaction;
- the beneficiaries of the transaction; and
- any other relevant information.

Gas producers subject to this Article 8(1) obligation must furthermore register with the Austrian national regulatory authority,[22] Energie-Control Austria, in short, E-Control.[23]

In accordance with Section 11(2)(1) of the Gas Statistics Regulation 2012, the gas production plant operator must register itself with E-Control.

IV PRODUCTION RESTRICTIONS

As described above, Austria has implemented the Stocks of Crude Oil and Petroleum Products Directive into a number of national acts and regulations.

The aim of the Directive and therefore of these acts and regulations is to mitigate an energy supply crisis in the European Union by maintaining a minimum stock level, maintaining information on these stock levels and ensuring the accessibility and availability of the stocks.

Oil producers and oil importers are required by Section 3 of the Oil Statistics Regulation to submit monthly oil production data and oil import data, respectively, to the Ministry.

Gas producers are required to submit a monthly report on the physical imports and exports of gas through pipelines that make up part of their production facilities pursuant to Section 5(2) of the Gas Statistics Regulation, as well as on the total monthly production volume and own consumption as per each production plant pursuant to Section 5(4). Furthermore, gas producers must submit the maximum production rate, detailed information on and a graphic of the plant pipelines, and the technical maximum capacity per injection and feed out point per border station on an annual basis, pursuant to Section 7(2). E-Control publishes the submitted data from all market participants subject to reporting obligations on an annual basis.

Imports and exports of oil are regulated by the Oil Stockholding Act. While the importation of oil is highly regulated, whereby all import activities must be reported to the Ministry, there is no regulation, and therefore, under normal circumstances, no restrictions of oil exports from the Austrian market into the markets of EU Member States.

Should there be a direct threat to the Austrian energy supply, however, the federal state is permitted to block all energy exports (both oil and gas) in accordance with Section 18 in conjunction with Section 4 of the Energy Steering Act, to be carried out by means of a regulation enacted by the Ministry.

V ASSIGNMENTS OF INTERESTS

As described in Section III, the exploration and production of oil and gas within the Austrian federal territory are governed by a civil law contract. Provisions relating to assignments of interest, right of first refusal or preferential purchase rights upon transfer, and consideration as a condition to granting approval to transfer or waiving rights of first refusal may be included; however, as no draft contract is publicly available, it is difficult to determine whether these terms have been considered.

VI TAX

i Corporate income tax

Limited liability companies and stock companies are considered corporations within the meaning of Section 1 of the Corporate Income Tax Act 1988,[24] and subject to corporate income tax. Corporations are subject to unlimited corporate income tax if they have their seat or place of management within Austria. Non-Austrian corporate tax residents (with neither a seat nor place of management in Austria) are subject to limited corporate income tax for only certain sources of income in Austria.

According to Section 7 of the Corporate Income Tax Act, the tax base for the corporate income tax is the yearly income of the corporation. The starting point for the calculation of the taxable income is the profit according to the external accounting under the provisions of the Austrian Commercial Code.[25] In the course of the calculation of the taxable income, the profit according to the external accounting is adapted with increases and reductions to meet the requirements of the provisions of the tax law. These adaptations can, for instance, be required for the depreciation or valuation of assets, and the consideration of non-deductible expenses. The Corporate Income Tax Act includes controlled foreign company rules, rules on participation exemptions, consolidated tax groups and non-deductible expenses.

The taxable income of the corporation is subject to corporate income tax at a rate of 24 per cent (23 per cent as of 2024). Under the provision of Section 8 of the Corporate Income Tax Act, losses from previous years may be used to set off the taxable profit in the amount of a maximum of 75 per cent of the tax base of the current year (exemptions apply).

At the level of a shareholder of a corporation, profit distributions are in general subject to withholding tax in the amount of 27.5 per cent for individuals or 24 per cent for corporations (23 per cent as of 2024). Dividends received from an Austrian resident company are, in general, tax exempt. Dividend payments received from foreign companies are tax exempt only if certain prerequisites are met.

Austria has transposed the EU anti-tax avoidance directives ATAD I[26] and ATAD II[27] and therefore has implemented controlled foreign company (CFC) rules, general anti-abuse rules (GAAR), exit taxation rules and hybrid rules.

ii Value added tax

Corporations trading in oil and gas are considered entrepreneurs within the meaning of Section 2 of the Value Added Tax Act 1994.[28] The provisions of supplies or services in exchange for a consideration performed in Austria by such entrepreneurs in general are subject to value added tax.

Under the provision of Section 10 of the Value Added Tax Act, the applicable value added tax rate in Austria is 20 per cent of the consideration. As regards the sales of oil and gas produced upstream, pursuant to Section 10(1) of the Value Added Tax Act, oil is subject to a 20 per cent VAT rate, whereas pursuant to Section 10(2)(4)(c), gas is subject to a 10 per cent VAT rate. Depending on downstream processing, individual oil- and gas-derived end products may have different VAT rates from the upstream products.

iii Mineral oil tax

The mineral oil tax is a consumption tax. According to Section 1 of the Mineral Oil Tax Act 2022,[29] mineral oil that is produced or imported to Austria, as well as motor fuels and heating fuels, is subject to mineral oil tax in Austria. Most hydrocarbon-containing products are covered by this law.

Section 3 of the Mineral Oil Tax Act includes a detailed list of the applicable tax rates for most sorts of taxable products. All products not included in this list are subject to tax, with the tax rate applicable to a product on the list that comes closest to the product not included.

According to Section 21, the tax liability for mineral oils in general arises if the taxable product is released into free circulation (i.e., by removal from a tax warehouse). Special provisions apply to motor and heating fuels. For these fuels, the tax liability arises once they are first delivered for their intended purpose.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

In accordance with the Environmental Impact Assessment Act 2000,[30] operations involving the production of oil and gas must undergo an environmental impact assessment by the Ministry if their production exceeds certain thresholds. Pursuant to point 29 of Annex 1 of the Environmental Impact Assessment Act, these thresholds are either when the production of oil exceeds 500 tonnes of oil equivalent (toe) per day per probe or when the production of gas exceeds 500,000m³ per day per probe. A simplified assessment procedure is to be performed if production is carried out in protected areas either when the production of oil exceeds 250toe per day per probe or when the production of gas exceeds 250,000m³ per day per probe.

In addition to the above-listed criteria and approvals, rights holders must present the Ministry with a 'waste disposal plan' two weeks prior to commencement of operations at the latest in accordance with Section 117a of the Mineral Resources Act. This must be reviewed every five years, and should the activity have materially changed be amended appropriately. The aim of this waste disposal plan is to reduce or avoid waste and any damaging effects, and to establish short- and long-term disposal of waste as a result of exploration and production activities.

As described in Section III, prior to exploration and production, the rights holder must provide information on measures to restore the land usage upon decommissioning. Decommissioning of exploration and production equipment is specifically regulated in Section 119(14) of the Mineral Resources Act, whereby unless the rights holder has previously submitted a 'closure plan', including information on the intended conveyance of property, the person in possession of the plant must notify the Ministry.

If submitted, a closure plan must be submitted to the Ministry for approval pursuant to Section 144 of the Mineral Resources Act. This must include:

- a precise description of the closure procedure including safety measures;
- a description of measures to ensure the safety of individuals and property during decommissioning;
- a description of planned measures to restore land usage;
- information regarding the conveyance or alternative of any remaining property;
- the main geological and deposit-mineralogical documentation and documentation regarding the production activities performed by the rights holder; and
- a list of existing production operations or a map of underground operations.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

Undertakings with their seat within the European Economic Area (EEA) (including European Union Member States) or Switzerland are not bound by any limitations in investing in the Austrian oil and gas upstream market.

Undertakings with their seat in a third country (i.e., not an EEA country or Switzerland) wishing to invest in the Austrian oil and gas upstream market are subject to the Foreign Investment Screening Act.[31] The Foreign Investment Screening Act has replaced the previous investment control regime under the Foreign Trade and Payments Act 2011,[32] and has considerably tightened the requirements and broadened the scope of application.

As of 11 October 2020, approval by the competent authority (Federal Minister of Digitalisation and Business) is required for those wishing to:

- take over;
- invest in (only when acquiring voting shares of more than 10 per cent, 25 per cent or 50 per cent);
- acquire a controlling influence in; or
- purchase essential assets of an Austrian company that is involved in energy supply.

Should an investor from a third county aim to circumvent this rule through use of an undertaking with a seat in the EEA or Switzerland, the Ministry may, in certain circumstances, conduct a review to ensure the above provision is enforced.

ii Capital, labour and content restrictions

Capital and labour from EEA countries or Switzerland into Austria are not and must not be limited by virtue of the European Union fundamental freedoms of capital and labour.

Austrian employers of workers posted from third countries – and by extension employers with a seat in EEA member countries or Switzerland – must apply to the Public Employment Service for either a 'posting permit' for workers or an 'employment permit' depending on the duration of the posting period.

In any case, a visa is required for posts of less than six months, and for those with posts exceeding six months a 'posted worker stay permit' is required. To obtain this, in accordance with Section 59 of the Settlement and Residence Act 2005[33] the worker must fulfil the criteria listed in Part 1 of the Act and provide confirmation of guaranteed work in accordance with

Section 11 of the Employment of Foreign Nationals Act 1975[34] or an employment permit as a posted worker in accordance with Section 18 of the Employment of Foreign Nationals Act 1975.

iii Anti-corruption

The Federal Bureau of Anti-Corruption (FBAC) is responsible for security and police matters regarding corruption for the entire federal state. The FBAC has been given its powers under the Law of the Federal Bureau of Anti-Corruption.[35]

Anti-corruption measures are primarily regulated in Sections 302 to 313 of the Austrian Criminal Code,[36] whereby such corruptive practices are generally punished by imprisonment between six months and a maximum of 10 years, depending on the financial value of the advantage gained.

There are currently no significant anti-corruption issues in the Austrian upstream energy sector.

IX CURRENT DEVELOPMENTS

In July 2023, OMV announced the Wittau Tief-2a exploration well in Lower Austria to be a confirmed new natural gas discovery. After five months of operations, the well was drilled at a final depth of 5,000 metres. A preliminary evaluation indicates potential recoverable resources of approximately 48 TWh (28 million barrels of oil equivalent). After full development of the discovery, OMV expects its natural gas production in Austria to increase by 50 per cent. This is the largest natural gas discovery in Austria in 40 years.

In early 2023, the Renewable Gas Act was introduced. This Act is intended to ensure that, from 1 January 2024, gas suppliers are obliged to replace a certain proportion of fossil natural gas with renewable gas in the future ('green gas quota'). The quota model is intended to increase the share of renewable gas produced domestically, thereby reducing dependence on imports and increasing security of supply.

To accelerate the expansion of renewable energies, the Austrian government agreed on a package of laws at the beginning of 2023 that is intended to make a significant contribution to faster and simpler approval of wind power plants. The energy package includes measures for faster procedures for power plants through an amendment of the Environmental Impact Assessment Act 2000, an expansion offensive for photovoltaic plants by means of a new Renewable Expansion Acceleration Act, as well as an expansion of biogas production in Austria through a new Renewable Gas Act. To date, only the amendment to the Environmental Impact Assessment Act 2000 has been implemented, which has accelerated the approval of energy transition projects and increased procedural efficiency.

In April 2022, an amendment to the Gas Industry Act 2011 was enacted to ensure a certain stock of natural gas (see newly introduced Sections 18a–18d Gas Industry Act 2011) with the aim of improving the general security of gas supply in view of the ongoing Russian invasion in Ukraine.[37] The distribution area managers are now obliged to procure and maintain strategic gas reserves (measured based on the total gas volume supplied to network users in January of the respective year). The gas reserves had to be made available for the first time on 1 November 2022. Any release will then take place separately by decree of the Federal Minister for Climate Action, Environment, Energy, Mobility, Innovation and Technology. This new measure, which will – unless extended – be in force until 30 September 2025, for the provision of strategic gas reserves should prevent orders to large consumers to curb gas consumption in the event of a crisis.

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Endnotes

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Chapter 5

China

Yan Gao[1]

Summary

I INTRODUCTION

On the basis of information disclosed by China's National Energy Administration (NEA)[2] in July 2023, China's annual crude oil production has shown an increase from 189 million tonnes to 205 million tonnes over the past five years. The annual natural gas production has demonstrated growth from 1.602 billion cubic metres (bcm) to 2.201bcm within the same timeframe. Notably, the exploration and development of offshore oil and gas resources have progressively extended to deeper water areas, with China's offshore crude oil production reaching 58 million tonnes in 2022.

In the context of the 'Seven-Year Action Plan' advanced by Chinese oil and gas companies, China experienced a significant upsurge in its proven geological reserves in 2022. The petroleum reserves increased by nearly 1.46 billion metric tonnes, and were primarily sourced from the Ordos Basin, Bohai Bay Basin (including offshore areas) and the Tarim Basin. The same year also witnessed a substantial increase in proven geological reserves of natural gas, exceeding 1.2 trillion cubic metres. This notable expansion was chiefly attributed to successful exploration efforts in the Ordos Basin, Sichuan Basin and Tarim Basin.

Among the fluctuations in global oil and gas consumption and the influence of geopolitical factors in 2022, the Chinese oil and gas market maintained overall stability, and there have been substantial efforts to enhance upstream exploration and development, consistent drives towards infrastructure expansion and continued commitments to advancing the reform in the oil and gas sector. Meanwhile, there is a call for strengthening international energy cooperation and establishing a more robust framework for high-quality international energy partnerships.

II LEGAL AND REGULATORY FRAMEWORK

i Domestic oil and gas legislation

China does not have legislation specifically for the upstream oil and gas sector. The legal basis for oil and gas exploration and development is provided in the Mineral Resources Law and its implementing regulations. Such legalisation stipulates the basic principle that mineral resources, including oil and gas resources, are owned by the state and that the State Council exercises the ownership rights over mineral resources on behalf of the state. Except under special circumstances, exploration and mining of mineral resources must be applied for and approved separately with exploration rights and mining rights and be registered accordingly.[3]

The Administrative Measures on Registration of Blocks for Exploration of Mineral Resources are major administrative measures that standardise the exploration phase of oil and gas. To explore for oil and gas resources, an exploration licence must be obtained. Exploration rights can be obtained by means of first-apply-first-approve, agreements, tendering and bidding, or auction or listing.[4]

The Administrative Measures on Registration of the Mining of Mineral Resources are major administrative measures that standardise the mining phase of oil and gas. To mine oil and gas resources, a mining licence must be obtained. Mining rights can be obtained by means of first-apply-first-approve, agreements, tendering and bidding, or auction or listing.[5]

The Regulations on Exploitation of Onshore Petroleum Resources in Cooperation with Foreign Enterprises and the Regulations of the People's Republic of China on Exploitation of Offshore Petroleum Resources in Cooperation with Foreign Enterprises are significant administrative regulations governing foreign investors entering into agreements with Chinese national oil companies (NOCs) for the cooperative exploitation of oil and gas resources in China.

In addition to the above-mentioned laws and regulations, those engaged in upstream oil and gas business in China must abide by relevant laws and regulations regarding, inter alia, project investment, environmental protection, work safety, land use, labour protection, tax and public health.

ii Regulation

A multi-departmental shared administrative regime is employed in the upstream oil and gas sector in China.[6]

The Ministry of Natural Resources (MNR) is responsible for the supervision and administration of the upstream exploration and exploitation of oil and gas resources, including issuing exploration licences, mining licences, reviewing and recording mineral resources reserves and registering the transfer of mining rights.[7]

The National Development and Reform Commission (NDRC) is responsible for:

- finalising and issuing oil and gas planning prepared by the NEA;
- approving major energy investment projects; and
- organising the formulation of regulations and policies on oil and gas-related pricing.

Furthermore, in conjunction with the Ministry of Commerce, the NDRC draws up and jointly promulgates the Special Administrative Measures (Negative List) on Access to Foreign Investment (Negative List), which regulate the sectors in which foreign investors are restricted or prohibited from investing.[8]

The NEA is responsible for:

- organising and formulating industrial policies and related standards for oil, natural gas and other energy sources;
- preparing oil and natural gas planning; and
- approving, endorsing and reviewing energy fixed-asset investment projects.[9]

The Ministry of Ecology and Environment (MEE) and local ecology and environment management departments are responsible for issuing approvals for Environmental Impact Assessments.[10]

The Ministry of Emergency Management (MEM) and local emergency management departments are responsible for issuing licences for hazardous chemicals business operation and work safety licences.[11]

The Ministry of Commerce (MOFCOM) is responsible for:

- jointly promulgating with NDRC the Negative Lists;
- formulating management measures for import and export commodities;
- issuing import and export licences;
- formulating policies on foreign investment;
- approving the establishment and changes of foreign-invested enterprises according to law; and
- approving the articles of association for major foreign investment projects and major changes according to law.[12]

The Ministry of Finance (MOF) is responsible for:

- formulating tax policies for oil and gas; and
- jointly determining the fee rates for mineral resources compensation fees with relevant departments of the State Council.[13]

iii Treaties

China is a party to significant conventions governing dispute resolution and recognition and enforcement of awards and judgments, including the New York Convention, the Singapore Convention on Mediation and the 1965 Washington Convention.

China is also a signatory to significant bilateral or multilateral investment treaties stipulating oil and gas development related matters, including the Regional Comprehensive Economic Partnership Agreement and governmental Memorandum of Understanding on energy, oil and gas development with several countries (e.g., Philippines, India, Saudi Arabia, Egypt, Peru and Australia).

As of the end of April 2020, China has officially signed 107 double taxation avoidance agreements, of which 101 agreements have entered into force.[14]

III LICENSING

i Mineral rights and Sino-foreign cooperation petroleum contract

Those who propose to explore and exploit oil and gas must apply for the exploration rights and mining rights, respectively, as well as corresponding registration of such rights. The exploration rights and mining rights can also be collectively referred to as the mineral rights.

In addition to the mineral rights mentioned above, according to relevant requirements of the NDRC and the NEA, projects engaged in the exploration and development of oil and gas are required to complete filling procedures in the National Online Approval and Supervision Platform for Investment Projects (Online Platform).

Commencing on 30 June 2019, China lifted the restriction that the exploration and development in the oil and gas sector by foreign investors are limited to the form of either joint venture or cooperation with Chinese enterprises. Foreign investors are permitted to participate in the development of upstream oil and gas by setting up a wholly foreign-owned enterprise (WFOE) after obtaining corresponding mineral rights.[15]

Foreign investors can also participate in the upstream exploration and development by entering into petroleum contracts with NOCs for cooperative exploration and development of oil and gas. China National Petroleum Corporation (CNPC) and China Petrochemical Corporation (SINOPEC) enjoy the exclusive right to cooperate with foreign investors in onshore petroleum exploration, development and production in the areas approved by the State Council for foreign cooperation.[16] China National Offshore Oil Corporation (CNOOC) enjoys the exclusive right to cooperate with foreign investors in offshore projects.[17] Zhonglian Coalbed Methane Limited Liability Company, CNPC, SINOPEC, and Henan Coalbed Methane Development and Utilization Co, Ltd enjoy the exclusive right to cooperate with foreign investors in the coalbed methane sector.[18] Under the Sino-foreign cooperation model, NOCs are generally the entities to apply for and obtain the mineral rights.

In 2012, the majority (97 per cent or more) of oil and gas exploration rights and mining rights are concentrated in the hands of NOCs.[19] In 2020, more than 95 per cent of the registered oil and gas exploration and development blocks were controlled by NOCs.[20] This means that most of the oil and gas blocks with development potential have already been acquired by NOCs, and the participation in China's oil and gas sector by foreign investors is still dominated by Sino-foreign cooperation model at present, although foreign investors are permitted to apply for the exploration or mining rights of oil and gas by setting a WFOE.

ii Process of acquiring the mineral rights and entering the petroleum contract

Mineral rights

Methods of obtaining the mineral rights

Mineral rights can be obtained by granting or transfer. Obtaining the mineral rights by granting is the dominant method in practice.

The granting of mineral rights can be further divided into several categories, namely those granted:

- mineral rights based on first-apply-first-approve;
- by agreements;
- by tendering and bidding; and
- by auction or listing.

To date, China has established a system of granting mineral rights mainly through tendering and bidding, auction and listing.

Owing to the fact that oil and gas resources have different technical characteristics of exploration and mining compared with those of other mineral resources, China currently implements a system of integrated oil and gas exploration and mining rights, whereby the owner of mineral rights who discovers oil and gas resources of commercial value decides to carry out the development may proceed with the exploration upon the approval of the plan for integration of exploration and mining by the MNR, and will, within 5 years of the plan, enter into the contract for the granting of mineral rights and register with the MNR in accordance with the laws.[21]

Statutory requirements

The statutory requirements for a mineral rights holder are that it is a company registered in China with a net asset of no less than 300 million yuan.[22] In practice, a WFOE meeting the requirements above is explicitly permitted to participate in the tendering and bidding organised by the MNR.[23]

Application for obtaining exploration licence and mining licence

Applicants for the exploration licences are normally required to submit the following materials to the MNR:

- an application form for registration and a drawing or map showing the mining block for the proposed exploration;
- a copy of the applicant's business licence;
- a work plan for exploration, or a contract for exploration or supporting documents for commissioned exploration;
- an implementation plan for exploration and its annexes;
- proof of the source of funds for the exploration project;
- proof of payment of the proceeds from the granting of mineral rights or disposal with considerations; and
- other materials required by the MNR.[24]

Applicants for the mining licences are normally required to submit the following materials to the MNR:

- an application form for registration and a drawing or map showing the mining block for the proposed exploration;
- a copy of the applicant's business licence;
- proof of payment of the proceeds from the granting of mineral rights or disposal with considerations;
- an approved geological prospecting report;
- comments on the evaluation and results of the announcement of the geological environmental protection and land reclamation;
- plans for the development and utilisation of the mineral resources;
- the exploration licences; and
- other materials required by the MNR.[25]

Regarding oil and gas resources, the applicants may also apply for the mining licence for rolling exploration and development pursuant to relevant regulations.

The MNR will determine whether to grant or deny the application for the licences within 40 days following the receipt of the application and notify the applicants of the result. If the application is granted, the applicant of mining rights will, within 30 days following the date of the receipt of the notification, pay royalties for the utilisation of the mineral rights and the proceeds from the granting of mineral rights in accordance with relevant laws and regulations,[26] go through the registration formalities and receive the licence.[27]

Petroleum contract for Sino-foreign cooperation

Regarding oil and gas blocks for Sino-foreign cooperation, foreign investors are mainly identified by NOCs through the process of tendering and bidding, as well as negotiation. It is suggested that foreign investors interested in participating in these Sino-foreign cooperation projects closely follow up on the information released by NOCs and set up good communications with them.

iii Key terms of mineral rights and Sino-foreign cooperation petroleum contracts

Mineral rights

The exploration licensee is entitled to, inter alia, conduct exploration in the areas, within the terms and on the proper objects prescribed by the exploration licence and is obligated to, inter alia, commence the exploration operation within 6 months from the date of the exploration licence.[28]

The mining licensee is entitled to, inter alia, conduct mining activities within the mining scope and terms as prescribed by the mining licence and is obligated to, inter alia, conduct construction of a mine or mining within the approved term.[29]

Petroleum contract for Sino-foreign cooperation

Foreign investors participating in oil and gas development via Sino-foreign cooperation model will set up a branch, subsidiary or representative office in China.

Unless otherwise provided by laws and regulations or agreed in the petroleum contract, the foreign investor who enters the petroleum contract will, in general, invest solely in exploration, be responsible for exploration operations and undertake sole risks of exploration. After the discovery of an oil (gas) field with commercial exploitation value, the foreign investor and the NOC will jointly invest in the development and production phases of the cooperation project.[30] Normally the foreign investor will be the operator and undertake the development and production operations, until production operations are taken over by the NOC as stipulated in the contract.

iv Term of the mineral rights and petroleum contract for Sino-foreign cooperation

Mineral rights

An exploration licence for oil and gas is valid for up to seven years. If there is a need to extend the period for exploration, within 30 days prior to the expiration, the exploration licensee must file for an extension with the MNR. The period of each extension can be extended up to five years.[31]

The exploration licence may be revoked by the MNR if there is a failure to fulfil the minimum exploration investment, among other reasons.[32] The validity period of the mining licence is is valid for up to 30 years, which is to be determined in accordance with the scale of mining construction. The maximum validity period of the mining licence for rolling exploration and development of oil and natural gas is 15 years. The mining licence may be revoked by the MNR if there is a failure to submit annual reports, among other reasons.[33]

Petroleum contracts for Sino-foreign cooperation

The terms under petroleum contracts for Sino-foreign cooperation generally include exploration phase, development phase and production phase. Normally, the overall term of a petroleum contract must not exceed 30 consecutive contractual years from the effective date of the contract.

IV PRODUCTION RESTRICTIONS

i Restrictions on production entitlements

In practice, Sino-foreign cooperation through petroleum contracts remains the predominant model chosen by foreign investors.

The NOCs will enter the petroleum contracts with foreign investors to cooperate in the exploitation of onshore or offshore petroleum resources in China. Costs and expenses will be recovered in kind from the produced oil or gas, or both, pursuant to the petroleum contracts, and remuneration will be obtained. The NOCs must report relevant information of petroleum contract to the MOFCOM.

The products are to be allocated in the order and proportions stipulated in the petroleum contracts. Taking a petroleum contract between an NOC and a foreign company (as the contractor below) as an example, crude oil production and allocation are subject to the following sequence and proportions:

- 5 per cent of the annual gross production of crude oil is used for payment of the value-added tax (VAT);
- 62.5 per cent of the annual gross production of crude oil is used for payment or recovery in the following sequence:
  - royalty;
  - the crude oil less the amount of crude oil for payment of royalty is 'cost recovery oil';
  - the remainder of the 'cost recovery oil', after payment for operating costs, is deemed as 'investment recovery oil'; and
  - after recovery of an oil field's development costs and deemed interest or costs, or both, for the additional development project and deemed interest thereon from the field by the parties, the remainder of the investment recovery oil is automatically regarded as part of the 'remainder oil' set forth below;
- the remainder of the annual gross production of crude oil after the allocation referred to in the above sections are deemed as 'remainder oil'. Remainder oil is divided into 'share oil' of the NOC and 'allocable remainder oil'; and
- the allocable remainder oil of each oil field in each calendar year is shared by the parties in proportion to their respective participating interests in the development costs.

The product sharing stipulated in the petroleum contract will be subject to the supervision of the finance and taxation authorities of China.

ii Restrictions on exports of oil and gas

The state may impose restrictions or prohibitions on the exports of certain goods.[34] According to the Announcement on Issuing the Catalogue of Goods Subject to Export Licence Administration (2023) (Catalogue 2023), 43 types of goods are subject to export licence administration in 2023, including crude oil and liquefied natural gas (LNG).[35]

Parties engaged in foreign trade operations exporting goods listed in Catalogue 2023 must apply for an export licence. The export licence is to be presented to the customs for clearance procedures.[36]

Crude oil

Pursuant to Catalogue 2023, the export of crude oil requires a quota and an export licence applied with quota certification documents.[37]

Natural gas

Pursuant to Catalogue 2023, the export of liquefied natural gas requires an export licence.[38]

iii Requirements for sales of production into local markets

Foreign contractors may generally sell the oil and gas to which they are entitled within the territory of China to the NOCs or adopt other means of sale as agreed upon by both parties to the petroleum contract. However, they cannot violate relevant state provisions on the sales of oil productions within the territory of China.[39]

Licensing requirements

Oil and gas-related products (e.g., natural gas and crude oil) are generally classified as hazardous chemicals.[40]

The state implements a licensing system for the operation of hazardous chemicals. Enterprises engaged in the operation of hazardous chemicals msut obtain a licence for the operation of hazardous chemicals.[41]

Conditions

According to the Measures for the Administration of Licences for the Operation of Hazardous Chemicals, entities applying for hazardous chemical operation licences must be duly registered as enterprises in China, and meet basic conditions, such as:

- the business premises, facilities, buildings and structures meet the requirements of relevant national standards and industry standards;
- the main person in charge and work safety management personnel possess safety knowledge and management capabilities; and
- sound work safety rules, regulations and operating procedures are in place.[42]

Therefore, unless foreign investors are duly registered as enterprises in China and meet all the above requirements and qualifications, theoretically they are unable to obtain the hazardous chemical operation licences, and thus cannot directly sell oil and natural gas into the local markets.

iv Laws applicable to price setting

The Price Law is the fundamental law regulating pricing practices in China and provides the overall legal basis for the administration of oil and gas prices.

Oil prices

According to the Measures for the Administration of Oil Prices, crude oil prices are market-adjusted prices.[43]

Natural gas prices

Owing to the monopolistic characteristics of the upstream natural gas market, the upstream natural gas price has been subject to long-term government control in China.

In 2013, China shifted the pricing administration of natural gas from ex-factory prices to city-gate prices. City-gate prices are government guidance prices with maximum ceiling price administration applied.[44]

The current city-gate prices consist of the actual settlement prices (including VAT) at natural gas ex-factory (or first station) and pipeline tariffs.[45]

During 2015–2018, the NDRC promulgated several policies, requiring higher marketisation of natural gas prices, and shifting from maximum city-gate price administration to benchmark city-gate price administration.[46]

The policy of city-gate prices as government guidance prices is slightly eased. For city-gate prices of, inter alia, offshore gas, shale gas, coal bed methane, coal gas and liquefied natural gas, as well as the city-gate prices of natural gas in provinces with competitive conditions, prices are formed by the market. For city-gate prices of other domestically produced onshore pipeline natural gas, current pricing mechanisms still apply for the time being (i.e., government guidance prices).[47]

China's natural gas pricing mechanism has shown a trend of gradual liberalisation with market-based pricing being introduced where conditions allow according to policies and laws.

Pipeline tariffs

Inter-provincial pipeline tariffs are set by the state pricing authority, except for pipelines for enterprises' internal use only.[48]

Natural gas city-gate prices include natural gas pipeline tariffs, and therefore the pricing mechanism for natural pipeline tariffs is also noteworthy.

Inter-provincial natural gas pipelines operated by China Oil & Gas Pipeline Network Corporation

In 2018, the NDRC promulgated the Measures for the Administration of Natural Gas Pipeline Tariffs (Interim), stipulating government-set prices for inter-provincial natural gas pipeline operated by China Oil & Gas Pipeline Network Corporation (PipeChina), based on the methodology of 'permitted cost plus reasonable return'. In principle, tariffs of inter-provincial pipelines operated by other market entities follow those of the PipeChina.[49]

Natural gas pipelines within administrative regions of provinces

Several provinces (including Guangdong, Guangxi, Zhejiang, Shandong and Chongqing) have promulgated measures for the administration of natural gas pipeline tariffs within their respective administrative regions, with government-set prices applied.

V ASSIGNMENTS OF INTERESTS

In China, the transfer of upstream interests is mainly achieved through the transfer of mineral rights or, for foreign investors in cooperation with a NOC, the assignment of interests under petroleum contracts.

i Transfer of mineral rights

According to laws and regulations, mineral rights in the upstream sector include the exploration rights and the mining rights. The transfer of either one of them requires approval from the MNR.

Having met the specific conditions for transferring the exploration or mining rights, rights holders for exploration and mining can apply for the approval for such transfers with the MNR for issuing licences. Agreements pertaining to the transfer of rights become effective upon obtaining approval from the MNR. Presently, laws and regulations do not expressly specify any government's rights of first refusal in the context of rights transfer.

Following the transfer of rights, it is necessary to update the licence with the MNR. Under the condition of having already fulfilled legal requirements of payments related to acquiring the mineral rights, there is no specific regulation that mandates any form of payment to the government authority for the purpose of obtaining approval for the transfer of mineral rights.

ii Assignment of interests under petroleum contracts

In petroleum contracts to be entered into with NOC, it is typically stipulated that foreign investors may assign part or all of its rights or obligations, or both, under the contract to any of its affiliates with the prior consent of NOC. However, if they intend to transfer any rights or obligations within the scope of the contract to any third party, prior approval from the NOC must be obtained and, under equal conditions, the NOC has the right of first refusal to such transfer.

In terms of the transfer of rights through a change of control, laws and regulations do not explicitly stipulate whether government approval is required in such cases. On the basis of practical experience, it is generally understood that if the change of control does not result in a change in the legal entity or the legal representative of the rights holder, there is no need to apply for approval from a relevant government authority or register the change. At the level of petroleum contracts, it may be stipulated that the foreign investor is to obtain prior approval from the NOC before effecting a change of control.

VI TAX

The tax regime applicable to upstream oil and gas operators in China mainly includes the following.

i Resource tax

According to the Resource Tax Law, mineral right holders conducting the exploration and production of crude oil, natural gas, shale gas and natural gas hydrates are to pay resource tax at the rate of 6 per cent on the sales amount.[50] Under the Sino-foreign cooperation model, companies involved, such as NOCs and operators, are responsible for paying the resource tax if the petroleum contract was signed after 1 November 2011. If the petroleum contract was signed prior to 1 November 2011, relevant companies must continue to pay royalty instead of resource tax during the term of the contract.[51]

ii Environmental protection tax

If the company directly emits taxable pollutants to the environment in the process of mining of oil and gas, it is to pay the environmental protection tax in accordance with the Environmental Protection Tax Law. The specific tax amount shall be determined depending on the type and quantity of the discharged pollutants.[52]

iii Enterprise income tax

According to the Enterprise Income Tax Law, the applicable enterprise income tax rate is 25 per cent.[53]

iv VAT

The applicable VAT rate is 9 per cent for the sale of gas, and 13 per cent for the sale of crude oil.[54] Under the Sino-foreign cooperation model, pursuant to the PSC, the NOC and foreign operator are to pay VAT of 5 per cent in kind without input VAT credit.[55]

v Special petroleum proceeds

In 2006, China implemented special petroleum proceeds on crude oil. Currently, the threshold price for this levy stands at US$65 per barrel. The special petroleum proceeds are considered non-tax income and are collected by the Ministry of Finance.[56]

Tax incentives for upstream oil and gas operators

Currently, China has no tax incentives for upstream oil and gas operators.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

i Applicable environmental laws

China's environmental legislation applicable to the oil and gas sector is structured based on the Environmental Protection Law, the Marine Environment Protection Law and the Environmental Impact Assessment Law.

Addressing environmental issues connected to pollution prevention and control throughout oil and gas production processes, these are collectively regulated by laws such as the Atmospheric/Soil/Water Pollution Prevention and Control Law, as well as the Law on the Prevention and Control of Environment Pollution Caused by Solid Wastes.

ii Applicable environmental administrative regulations and department rules

In the field of oil and gas development in China, the relevant administrative regulations and departmental rules primarily focus on environmental protection issues related to offshore petroleum exploration and development.

Primary regulations and rules encompass the Regulations Concerning Environmental Protection in Offshore Oil Exploration and Exploitation, the Administrative Regulation on the Prevention and Treatment of the Pollution and Damage to the Marine Environment by Marine Engineering and the Measures for the Implementation of the Regulation on the Administration of Environmental Protection for Offshore Oil Exploration and Exploitation.

iii Governmental authorities responsible for environmental regulation

In China, the governmental authorities responsible for environmental regulation primarily include the following departments.

NDRC

The NDRC's Department of Resource Conservation and Environmental Protection is responsible for implementing sustainable strategies, optimising resource use, promoting clean production, and overseeing carbon reduction and energy conservation.

MEE (formerly known as the Ministry of Environmental Protection as of 2018)

MEE's main responsibilities include establishing ecological systems, coordinating environmental issues, achieving emission goals, approving projects, managing pollution, addressing climate change and enforcing ecological regulations.

MNR

MNR's core responsibilities include unifying resource rights registration, promoting responsible development, supervising exploration and managing mineral resources.

MEM

MEM provides guidance for safety emergencies, including production, natural disasters and geological hazards. It also oversees safety in industrial, mining and trade sectors.

iv Key environmental approvals

Engaging in upstream oil and gas exploration and development activities in China involves key environmental approvals primarily related to environmental impact assessments and the issuance of emission permits.

Environmental impact assessment

According to the requirements of the Environmental Impact Assessment Law, carrying out construction projects in China necessitates the analysis, prediction and assessment of potential environmental impacts post-project implementation. Measures and actions to prevent or mitigate adverse environmental effects are to be proposed, followed by continuous monitoring.[57] Consequently, projects need to undergo the environmental impact assessment process in accordance with the aforementioned law before commencement.

On the basis of the varying degrees of environmental impact caused by construction projects, China employs a categorised management approach for environmental impact assessment, involving the preparation of distinct environmental impact assessment documents, which includes environmental impact assessment reports/forms/registration forms for construction projects.

For documents in the form of reports and forms, the construction entity is to submit them to the competent ecological and environmental authority for approval. For documents in the form of registration forms, China follows a record-keeping management approach. Projects whose environmental impact assessment documents have not been reviewed by government authorities or have not been approved after review are prohibited by law from commencing construction.[58]

In addition to the Environmental Impact Assessment Law, as per the provisions of the Regulations on the Administration of Construction Project Environmental Protection, construction projects requiring the establishment of environmental protection facilities are to be designed, constructed and put into operation simultaneously with the main project.

Pollutant discharge permit

In China, if projects are likely to generate pollutants such as solid waste, wastewater or exhaust gases that need to be discharged into the environment, corresponding pollutant discharge permits must be obtained. Without obtaining the necessary permits, the discharge is prohibited.[59]

Pollutant discharging entities are to apply for a pollutant discharge permit to the local ecological and environmental authority at or above the municipal level where the production and operation site is located.

On the basis of factors such as the amount and emissions of pollutants produced by polluting entities and the degree of their impact on the environment, China distinguishes between key management (decision usually made within 30 to 45 days) and simplified management (within 20 days) for such entities when applying for pollutant discharge permits. Once approved, the permit is valid for a period of five years.

Regarding legislation for decommissioning, laws and regulations mainly regulate the abandonment of infrastructure for offshore oil and gas production operations. The laws and regulations involved mainly include Interim Provisions on Administration over the Abandonment and Disposal of Offshore Oil and Gas Production Facilities, Interim Measures on the Management of Abandoned Offshore Oil Platforms and Environmental Technical Requirements for Disposal of Offshore Oil and Gas Production Facilities (Draft for Comment).

v Decommissioning requirements

According to the above laws and regulations, as per the decommissioning requirements for operators of offshore oil and gas facilities, operators must:

- prepare development and decommissioning plans before offshore oil and gas field development, with an option to revise the decommissioning plan three years into production;
- apply in writing for decommissioning at least 90 business days before ending production, and they can only proceed after receiving regulatory approval;

- create a disposal plan for offshore oil and gas facilities and file it with the national energy authority before disposal; and
- start decommissioning within one year of production cessation unless there are valid reasons or new purposes.[60]

Furthermore, the Interim Provisions on Administration over the Abandonment and Disposal of Offshore Oil and Gas Production Facilities specifically outline the dedicated provisions regarding decommissioning fees that offshore oilfield investors are required to pay as part of their responsibility and obligations for the disposal of production facilities.

According to these Interim Provisions:

- investors in offshore oil and gas fields share decommissioning costs based on their investments, and these costs fund environmental protection and ecological restoration;
- investors in Sino-foreign cooperative offshore oil and gas fields deposit monthly decommissioning fees in designated banks, and the interest generated contributes to the decommissioning fund chosen by investors; and
- the decommissioning fee account is managed under the oil and gas field account and supervised by the joint management committee and regulatory authorities.[61]

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

Selection of investment entity

Sino-foreign cooperation model

When foreign investors intend to collaborate with CNPC or SINOPC in the exploration of onshore petroleum resources, it is necessary to establish branches, subsidiaries or representative offices that are registered in China.[62] For the collaboration with CNOOC in the exploitation of offshore petroleum resources, foreign investors are to establish a branch or representative office in China during the development and production phases.[63]

In practice, it is common for a foreign operator to use its overseas entity to sign the petroleum contract, and then for the implementation of the petroleum contract to apply for the business registration in China and meanwhile obtain a (non-legal person) business licence prior to commencing any production activities.

Acquisition of mineral rights

Following the implementation of the Foreign Investment Law on 1 January 2020, China has removed the special requirements on forms of entity to be established by foreign investors. Generally, it is permitted for foreign investors to set up in the form of a WFOE or a Sino-foreign Joint Venture (JV) with Chinese partners. Theoretically, if a foreign investor intends to directly acquire the mineral rights of oil and gas resources from the government, it is to incorporate in China either a WFOE or a JV with a net asset of no less than 300 million yuan.[64] However, in practice, it requires further observation of the implementation of such a policy in the upstream oil and gas sector.

Foreign Investment Security Review

Foreign investors who plan to invest in any important energy resources that concern the national security are required to voluntarily report their investment before proceeding with the investment.[65] As no regulations presently define the scope of important energy resources, foreign investors are advised to communicate with relevant departments of the NDRC prior to investing in the oil and gas sector to mitigate potential compliance risks.

Timeline and procedures for establishment

A foreign investor may apply to establish a company or a branch in China either online or on-site. Application materials need to be prepared pursuant to relevant regulations and the requirements of the registration authority. The registration authority will conduct a formal examination on the application materials, verifying their completeness and adherence to legal requirements.

On the basis of our experience, an estimated time frame of setting up a WFOE is around one to three months, depending on the completeness of necessary application documents and supporting materials.

ii Capital, labour and content restrictions

Foreign exchange control

The conversion of renminbi into other currencies, including dollars, is regulated by the Foreign Exchange Control Regulations. State Administration of Foreign Exchange (SAFE) supervises the flows of foreign exchange. China's foreign exchange transactions are divided into two categories: current account items and capital account items. Current account items refer to goods, services, incomes and transactions items of frequent transactions related to the international balance of payments. Capital account items refer to transactions of international balance of payments that result in changes in external assets and liabilities, including capital transfers, direct investment, securities investment, derivatives and loans.[66]

In the upstream oil and gas sector, overseas funding of foreign investors to be invested in the exploration and production in China is normally treated as a capital account item, for example, the injection of registered capital of WFOE, payments of cash calls or shareholder loan.

Labour

Notably, companies intending to employ foreigners in China are required to comply with the Regulations on the Administration of Employment of Foreigners in China, and to obtain a PRC foreigner employment licence specifically for the hiring of foreigners.[67] Furthermore, a petroleum contract normally sets up the principle of hiring Chinese citizens as a priority.

iii Anti-corruption

The anti-corruption legal framework of China consists of the criminal law, the Law Against Unfair Competition, and internal laws and regulations of the Chinese government and the Communist Party of China (CPC). Criminal law addresses crimes related to offering bribes to state and non-state officials, as well as the acceptance of bribes by these officials. The law also encompasses the bribery of foreign public officials and officials of public international organizations. From the perspective of fair competition and protecting the legitimate rights and interests of operators and consumers, the Law Against Unfair Competition requires that companies must not seek trading opportunities or competitive advantages through bribery. Provisions of the Chinese government and CPC internal rules on anti-corruption mainly apply to government officials and CPC members.

IX CURRENT DEVELOPMENTS

i Stability of energy supplies

In 2021, the Chinese government emphasised the urgency of promoting energy reform and securing steady supplies of energy. Significant governmental policies and opinions, including the Energy Production and Consumption Revolution Strategy (2016-2030), the 14th Five-Year Plan for Modern Energy System the Guidelines on Fully, Precisely, and Comprehensively Implementing the New Development Concept and Excelling in Carbon

Peak and Neutrality, the Action Plan for Carbon Peaking by 2030, and the 2022 Government Work Report, all underscore the need to ensure energy security and balance the interests of pollution abatement, carbon reduction and energy stability.

Looking ahead to future trends of energy supply, the NEA convened a nationwide energy summit[68] in Beijing earlier this year, focusing on enhancing capabilities of energy production and supply, increasing oil and gas productions, accelerating the expansion of oil and gas pipelines, bolstering reserve capacity, fostering robust international energy cooperation and forging a high calibre of international energy collaboration framework. In the sector of upstream oil and gas, the head of NEA affirmed in a press conference held in April this year the intensification of efforts towards augmented exploration, development, storage and production of oil and gas. This commitment seeks to ensure the sustained annual production of 200 million tonnes of domestic crude oil and maintain a natural gas self-sufficiency rate exceeding 50 per cent.

Reflecting the above drive for escalated production and supply, the MNR issued a directive on 30 May 2023 aimed at enhancing the scrutiny of plans for mineral resource development and utilisation. This directive led to the approval of 27 oil and gas overall development plans, among which 21 plans were proposed by CNPC secured endorsement, along with three plans presented by CNOOC, and an additional three plans jointly put forth by Shaanxi Yanchang Petroleum (Group) Co Ltd, and Yanchang Oilfield Management Bureau. These plans encompass diverse projects such as the Hedian 201 Block in Gansu's Ordos Basin, the Putao North Oil Development Project in Xinjiang's Tuha Basin, the Da Fengshan Oilfield Project located in Qinghai's Qaidam Basin, the Bai Ma Block Shale Gas Development Project in the Chongqing-Sichuan Basin's Fuling Gas Field, the Tianran Gas Development Project in Sichuan Basin's Tongnanba Gas Field, the Huizhou 26-6 Oil and Gas Development Project in the Pearl River Mouth Basin of the South China Sea, the Weizhou 12-1 Oil Development Project in the Beibu Gulf Basin of the South China Sea, and the Zichang Oil and Gas Development Project within Shaanxi's Ordos Basin.

Additionally, China's most recent discoveries in the oil and gas sector include:

- on 19 October 2022, CNOOC unveiled a ground-breaking find – the Bao Dao 21-1 gas field – located in Qiongdongnan Basin off the south-eastern coast of Hainan Island. Notably, this marks China's inaugural deepwater, deep-layer gas field, with proven geological reserves exceeding 50bcm. This achievement represents a breakthrough in the Songnan-Bao Dao Depression, a feat unmatched for over five decades; and
- on 1 March 2023, CNOOC once again made headlines by revealing the discovery of the Bohai 26-6 oilfield in the Bohai Sea. Distinguished as China's largest metamorphic rock buried hill oilfield, with proven geological reserves surpassing 130 million tonnes of oil equivalent. It has the potential to yield over 20 million tonnes of crude oil and an impressive 9bcm of natural gas.

ii Energy transition and green development

As early as September 2020, China's leadership made a momentous announcement at the United Nations General Assembly. The commitment was clear: China endeavours to attain its carbon dioxide emissions peak before 2030 and is dedicated to achieving carbon neutrality by 2060. These dual carbon goals have since emerged as China's fundamental targets in its proactive stance against climate change and in its pursuit of a trajectory aligned with green, low-carbon growth.

Between 2021 and 2023, the country has embarked on a comprehensive journey, issuing a series of targeted implementation plans and action-oriented strategies. Notable among these are the Opinions on Fully Implementing the New Development Concept and Effectively Achieving Carbon Peak and Neutrality, the Action Plan for Achieving Carbon Peak by 2030, the Comprehensive Work Plan for Energy Efficiency and Emission Reduction during the 14th Five-Year Plan, the Technology-Driven Implementation Plan for Realizing Carbon Peak and Neutrality (2022-2030), the Carbon Peak Implementation Plan in Urban and Rural

Construction Sectors, and the Action Plan for Enhanced Standardisation to Promote Energy Carbon Peak and Neutrality. These documents form a phased, sector-specific roadmap to propel energy conservation, emission reduction and sustainable development in China.

In harmony with central government's dual carbon strategy and guided by the innovative '1+N' policy framework, various provinces across the country have taken proactive measures. They have successively issued implementation blueprints tailored to the dual carbon strategy's objectives. National and industry standards supportive of this strategy have also been established, covering, inter alia, carbon emission validation, energy efficiency, non-fossil fuel energy, novel power systems, the clean harnessing of fossil fuels, resource cyclic utilisation and carbon sequestration.

At the heart of the drive to achieve carbon peak and carbon neutrality lies the China Carbon Emission Trading Market. Commencing in 2011 with pilot programmes in cities such as Beijing, Tianjin and Shanghai, this market officially launched trading in July 2021. By 22 December 2022, the China Carbon Emission Trading Market achieved a cumulative trading volume exceeding 10 billion yuan. This translated to a total traded quota of 223 million tonnes and a cumulative trading value of 10.121 billion yuan.[69]

According to a notification released by NEA at the end of February this year, titled Action Plan for Accelerating Oil and Gas Exploration and Development and Advancing New Energy Integration (2023-2025), China is poised to bolster the synergy between upstream exploration development and the renewable energies during the 14th Five-Year Plan period. China is set to advance the realms of renewable energy and low-carbon, carbon-negative industries, intensifying the development and utilisation of clean energy and fostering a shift in energy consumption patterns in production.

Among the ongoing trend towards green and low-carbon transition, China's major oil companies are actively propelling the development of renewable energy projects. Notably, in July 2021, SINOPEC embarked on a significant endeavour, the initiation of China's first million-ton-level CCUS (carbon capture, utilisation and storage) project,[70] known as the Qilu Petrochemical-Shengli Oilfield CCUS project. Additionally, SINOPEC's Inner Mongolia Ordos Solar-Hydrogen Integration Demonstration Project broke ground in February of this year in Wushenqi. Similarly, CNPC's Angang 550,000-kilowatt Wind Power Project in Qian'an County, Jilin Oilfield, which stands as its largest onshore wind power project under construction, secured approval from the Jilin Provincial Development and Reform Commission back in 2022. These significant initiatives reflect the latest strides in the traditional oil and gas industry's transition toward greener and more low-carbon future.

In addition to the key words of energy supply and green development, China is advancing the ongoing reform in the oil and gas realm, and the realisation of the National Integrated Pipeline Network represents the latest advancements and accomplishments in reform, entailing equitable and open access to oil and gas pipeline infrastructures. The endeavour seeks to provide non-discriminatory services to eligible third-party customers, thereby elevating operational efficiency and catering to the demands of energy supply.

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Chapter 6

Denmark

Michael Meyer[1]

Summary

I INTRODUCTION

There are oil and gas deposits in the Danish part of the North Sea and, at the time of writing, there were 19 oil- or gas-producing fields. The first concession (the Sole Concession) was granted to AP Møller-Maersk back in 1962 and covered the entire Danish area. Over the years, the Sole Concession has been amended by agreements made with the Danish government, and areas have gradually been handed back to the Danish state.[2]

In December 2020, a broad majority in the Danish Parliament reached an agreement on the future of Danish oil and gas production (North Sea Agreement 2020).[3] The North Sea Agreement 2020 constitutes, inter alia:

- a cut-off date of 31 December 2050 for all oil and gas extraction;
- a cancellation of the eighth licensing round, all future licensing rounds and the open-door procedure (however, two procedures – the mini-rounds and neighbour-block procedures – still exist); and
- reduction of the geographic area for issuance of licences.

The North Sea Agreement 2020 has been implemented through amendments to the Danish Subsoil Act, which entered into force on 1 January 2022.

Prior to the North Sea Agreement 2020, the Danish Energy Agency (DEA) finalised eight rounds of applications to obtain licences for the exploration of hydrocarbons in the North Sea.[4] The Danish state participates through the independent entity Nordsøfonden[5] in all licences granted since 2005 – no matter the procedure – with a 20 per cent stake.[6] In addition, Nordsøfonden participates with a 20 per cent stake in the Sole Concession.

Denmark has been a net exporter of oil and gas since 1997. The DEA forecasts that Denmark will be self-sufficient with regard to natural gas until 2034 with the exception, however, of 2020–2024, which is mainly attributable to the redevelopment of the Tyra field that began in September 2019 and is scheduled to continue until winter 2023–2024.[7]

For 2023, the DEA anticipated an oil production of 3.4 million m^3 and a production of natural gas (sales gas) of 0.9 billion normal cubic metres (Nm^3). As at 1 January 2023, Denmark's reserves of oil and sales gas are estimated to be 139 million m^3 and 77 billion Nm^3, respectively, with both figures including contingent resources.[8]

II LEGAL AND REGULATORY FRAMEWORK

Danish upstream oil and gas activities are regulated through a number of different acts, statutory orders and guidelines.

i Danish oil and gas legislation

The Danish Subsoil Act[9] (DSA) constitutes the primary regulation on Danish upstream oil and gas activities. The DSA is supplemented by, inter alia, the Danish Continental Shelf Act[10] (CSA) and the Danish Pipeline Act[11] (DPA). The following sections set out an overview, including key provisions, of the DSA, CSA, DPA and associated statutory orders.

The Danish Subsoil Act

The DSA sets out the basic legal framework for the exploration and exploitation activities concerning raw materials and hydrocarbons in the Danish subsoil and on the Danish continental shelf. Several of the provisions in the DSA implement EU directives.[12] The DSA is based on the view that the exploration for and exploitation of Denmark's raw materials covered by the act require comprehensive societal management.

The DSA covers prospecting, exploration and exploitation of hydrocarbons and any other use of the subsoil.[13] All reservoirs of raw materials, including hydrocarbons covered by the act, belong to the Danish state.[14]

Consequently, initiation of all major activities, such as prospecting, exploration and exploitation requires a separate licence granted by the Danish Minister for Climate, Energy and Utilities[15] (or the DEA pursuant to delegation).[16] In respect of the relevant European Union law, this allows the Danish government to make societal considerations, for example, and ensure accommodation of such considerations through specific terms in the licences.

Prior to the North Sea Agreement 2020, licences for the exploration and exploitation of oil and gas have been granted through licensing rounds, the open-door procedure, mini-rounds or the neighbour-block procedure. In the future, the number of procedures is to be reduced to the latter two. Historically, the preferred procedure has been licensing rounds. Since 1983, areas in the North Sea have been offered to interested companies in a total of eight licensing rounds; however, the eighth licensing round has been cancelled as a result of the North Sea Agreement 2020.

A licence is granted based on a model licence with supporting documents containing detailed terms and conditions. A licence is considered private property in Denmark and is governed by Danish law. However, a transfer of a licence is, inter alia, subject to prior approval from the DEA (see Section V).

To obtain a licence to initiate exploration of and extraction from the subsoil as referred to in the DSA, a fee of 25,000 Danish kroner is payable.[17] Expenses borne by the authorities in relation to licensing activities under the DSA or in relation to the other activities governed by the DSA, CSA or DPA must be reimbursed by the applicant.[18] Additionally, a licensee is obliged, free of charge, to submit samples and other information obtained in the exercise of activities covered by the DSA to the DEA and to the Geological Survey of Denmark and Greenland (GEUS).[19]

The Danish Continental Shelf Act

The CSA is based on the UN Convention on the Continental Shelf.[20] The purpose of the act is to create an elaborate Danish administrative basis for, inter alia, the sovereignty over mineral deposits, pursuant to the Convention on the Continental Shelf.

Under the CSA and in accordance with the requirements set out in the DSA, exploitation or exploration of natural resources on the Danish continental shelf and Danish territorial waters can only take place with a licence awarded by the Danish state.[21]

Additionally, the CSA specifically requires a permit for the establishment of power lines and pipelines for transportation of hydrocarbons in Danish territorial waters and on the Danish continental shelf.[22]

The Danish Pipeline Act

The purpose of the DPA is to improve the recovery of crude oil and condensate in the fields located in the Danish part of the North Sea and to reduce the environmental impact of transportation and landing. Under the DPA, the owner, currently Danish Oil Pipe A/S[23] (a subsidiary of Ørsted A/S), operates the pipeline on the Danish continental shelf from the Gorm field to Fredericia as well as separation facilities.[24] Any party recovering liquid hydrocarbons in the Danish part of the North Sea is obliged to connect the field facility to the pipeline and use it to transport the crude oil and condensate intended for refining or marketing in Denmark.[25] This obligation can be exempted by the relevant Minister if the connection to the pipeline is considered uneconomical or inconvenient.[26] In practice, the Minister's powers under the DPA are carried out by the DEA.[27] The DPA also governs the users' payment of the costs of capital for establishing the facilities as well as operating costs deriving from the use hereof.[28] Anyone may, against payment, be granted access to upstream pipelines and upstream systems (e.g., pipelines operated or constructed as a part of an oil or gas production along with the technical facilities related hereto) provided that they meet the third-party access requirements.[29]

In June 2023, an act was passed to authorise the Minister for Climate, Energy and Utilities to implement changes to the pipeline transporting crude oil from the North Sea and to decide on the timing for its decommissioning as well as additional rules for the operation of the pipeline.[30]

ii Regulation

Regulation on safety and protection of the environment

Regulation on safety and protection of the environment for upstream oil and gas activities is primarily set out in the Offshore Safety Act,[31] the Act on Protection of the Marine Environment,[32] the Environmental Impact Assessment Act,[33] the Statutory Order on Offshore Impact Assessment (Statutory Order on OIA)[34] and the Statutory Order on Safety Zones and Zones for the Observance of Order and the Prevention of Danger.[35]

The purpose of the Offshore Safety Act is to promote a high level of health and safety offshore in line with society's technical and social development. The act sets out a framework within which the market participants themselves may solve any health and safety issues that arise.[36] Under the act, licensees must ensure that health and safety risks associated with offshore oil and gas activities are identified, assessed and reduced as much as reasonably possible.[37]

The Act on Protection of the Marine Environment contributes to the protection of nature and the environment in order for society to develop a sustainable basis for respecting human conditions of life and protecting vegetation and animal life.

The Environmental Impact Assessment Act and the Statutory Order on OIA concern environmental impact assessments, appropriate assessments regarding international nature conservation areas and protection of certain species in Danish territorial waters, in the Danish exclusive economic zone and on the Danish continental shelf. Certain projects related to the DSA, CSA and DPA (e.g., the production of oil) may only be initiated after an environmental impact assessment and certain other impact assessments have been conducted.

Under the Statutory Order on Safety Zones and Zones for the Observance of Order and the Prevention of Danger, fixed installations, drilling rigs and drilling ships, among others, used for or in connection with exploration or extraction of raw materials on the Danish continental shelf must be surrounded by a safety zone.[38]

Regulation of taxation

Taxation of the upstream oil and gas fields is regulated in the Act on Taxation of Income Originating from Production of Hydrocarbons in Denmark (the Hydrocarbon Tax Act)[39] and in the Act on the Assessment and Collection of Taxes in connection with Production of Hydrocarbons (Act on Assessment and Collection).[40]

See Section VI for further information on the taxation schemes for upstream oil and gas activities.

Regulatory agencies

The DEA is an agency under the Ministry of Climate, Energy and Utilities and is, inter alia, responsible for matters relating to energy supply and consumption.[41] The DEA is responsible for the entire chain of tasks concerning energy production and supply, transportation and consumption, including energy efficiency and savings. Additionally, the DEA is responsible for the Danish national CO_2 targets and initiatives to limit emissions of greenhouse gases. The power to award licences for exploration and exploitation of oil and gas is not among the DEA's powers but rests with the Minister.[42]

In addition to the DEA, the Danish Utility Regulator (DUR) has a supervisory and appeal function in the energy sector.[43] The DUR's tasks are set out in the acts regulating the supply of electricity, natural gas and district heating. The director of the DUR is formally appointed by the Minister for Climate, Energy and Utilities, but the Minister has no powers of instruction in relation to the DUR's director or staff. Accordingly, the DUR is fully independent of the government and its personnel cannot seek or receive instructions from any other entity or individual in the performance of their duties and shall perform their duties with impartiality.[44] Disputes regarding access to the upstream gas pipelines and fees and prices connected hereto are referred to the DUR with recourse to the Danish Energy Board of Appeal.[45]

iii Treaties

In addition to the New York Convention,[46] which has been ratified by Denmark,[47] there are no other significant conventions or bilateral agreements specifically relevant to litigation in exploration or the production of oil and gas. Reference is made to the Act on Administration of Justice[48] and the Danish Arbitration Act.[49]

Double taxation

Under the Hydrocarbon Tax Act, foreign persons and companies carrying out hydrocarbon activities in areas fully or partly subject to Danish sovereignty are subject to taxation in Denmark on the income from the activity from the point in time when the activity commences. However, if Denmark has entered into a double taxation treaty with the country where the foreign company has residency for tax purposes, the treaty may modify the Danish tax liability.

III LICENSING

Any right to explore for or produce hydrocarbons requires a licence granted in pursuance of the DSA[50] based on one of the licensing procedures outlined in Section II.i. Historically, the DEA has finalised eight rounds of applications for licences to explore for hydrocarbons in the North Sea.[51] In the future, the number of procedures will be reduced to mini-rounds based on an unsolicited application and the neighbour-block procedure, which can be used when special geological and procedural conditions are present. Nordsøfonden[52] will participate with a 20 per cent stake in any licence awarded.

The model licence terms are set out by the DEA within the framework of the DSA and supporting regulation as set out in Section II.i. The main terms of the model licence published in connection with the eighth licensing round were as follows:

- delineation of the area where the licensee obtains the exclusive right to explore for and – in the case of commercially exploitable finds – produce oil or natural gas or both. Certain other rights may be allocated to third parties;[53]
- the frame for the work programme to be adhered to by the licensee;[54]
- the obligation to enter into a joint operating agreement within 90 days following granting of the licence;[55]
- extensive information requirements to the DEA and the DEA's rights of participation as an observer as well as confidentiality obligations;[56]
- liability issues (strict liability), insurance obligations, obligation to provide security;[57]
- regulation of revocation and termination of the licence, including decommissioning of facilities and the Danish state's right of assignment of facilities intended for long-term use without payment of consideration;[58]
- the full immunity granted by the licensee regarding any claim that may be raised against the Danish state following the licensee's activities;[59] and
- dispute resolution (the ordinary Danish courts unless agreement is made on an arbitration procedure) with venue in Copenhagen. Any licence granted is subject to the Danish law in force.[60]

If there are several parties to a licence (as will usually be the case owing to the participation of Nordsøfonden), they are, as part of the model licence terms, obliged to enter into a joint operation agreement (JOA) regarding the exploration and production of hydrocarbons. The JOA is subject to the DEA's approval.

The terms of the most recent model JOA (2019) regulate, inter alia:

- the duration of the JOA;
- the obligations and responsibilities of the operator (e.g., information to the licensees, records to be kept, expenditures and change or removal of the operator);
- the set-up and working of the organising committee, including voting procedures;
- the work programmes to be performed with budgets, fees and accounting procedures;
- procedures in case one or more parties wants work undertaken that has not been approved by the organising committee (sole risk operations); and
- offtake of hydrocarbons and regulation of assignments, encumbrances, withdrawals and defaults in payments.

The JOA is an agreement between the participants covered by a licence and the parties to a JOA may agree to changes in the wording of the JOA provided, however, that any such change is approved by the DEA.

IV PRODUCTION RESTRICTIONS

A licence to establish and operate pipeline systems for use regarding activities covered by the DSA may be restricted by conditions issued by the Minister. Accordingly, a licence may be granted on terms restricting, inter alia, dimensions, transport capacity and ownership.[61] There are no further restrictions on production entitlements except for oil in crisis situations (oil emergency stocks).[62] Additionally, there are no restrictions on export of oil and gas produced in Denmark.

In respect of the above-mentioned DPA and the general requirements set out in the Statutory Order on Access to Upstream Pipelines,[63] there are no specific requirements for sales into the local markets.

Laws applicable to price settings

In accordance with the Statutory Order on Access to Upstream Pipelines,[64] prices, terms and conditions are negotiated between the parties.[65] The overall conditions must not discriminate between applicants and the final agreement, including the prices, and must be reported to the DUR. The DUR ensures that the owners of the pipelines do not abuse their (in reality) monopoly rights.[66]

Furthermore, the Danish Competition and Consumer Authority will apply the prohibitions against anticompetitive agreements and abuse of a dominant position in Sections 6 and 11, respectively, of the Danish Competition Act. These provisions are equivalent to Articles 101 and 102 of the Treaty on the Functioning of the European Union (TFEU).

V ASSIGNMENTS OF INTERESTS

It follows explicitly from the DSA that a licence may neither directly nor indirectly be transferred unless the DEA approves the transfer, including any terms and conditions attached to the transfer.[67] Accordingly, any transfers of shares that may result in a controlling interest in a licensee or the entering into agreements that may have a similar effect must be approved by the DEA. This also applies to transfers of shares or parts in a licence if there are several licensees to the same licence.[68] The DEA may only approve a transfer of a licence if, after the transfer, the (new) licensee or licensees are also assessed to possess the necessary technical and financial capabilities. To approve a transfer, whether in whole or in part, the DEA may impose conditions on the parties to the transfer.[69] The Danish state has no preferential right of purchase for licences awarded under the DSA.

Even though a transfer has been approved by the DEA, the transferor of a licence for exploration or production of hydrocarbons retains a secondary financial liability for any decommissioning expenses regarding facilities existing at the time of the transfer. This secondary financial liability remains in force irrespective of any subsequent transfers of (or part of) the licence.[70]

It is a condition for approval of a transfer that the transferor issues a statement of acceptance of the secondary financial liability towards the licensees from time to time and the Danish state, unless an exemption is awarded.[71]

It follows from the DSA that any expenses incurred by the DEA in the handling of a licence, including the approval of a transfer, shall be borne by the licensee or licensees.[72]

Licences granted under the DSA receive immunity from legal prosecution.[73]

VI TAX

i The Danish hydrocarbon tax regime

The tax regime applicable to companies engaged in hydrocarbon exploration and production in Denmark consists of a combination of corporate income tax and hydrocarbon tax combined with a special hydrocarbon tax allowance.

In general, companies engaged in oil and gas activities are subject to the generally applicable Danish tax rules applicable to Danish companies and branches, with the adjustments provided in the Hydrocarbon Tax Act[74] and the Hydrocarbon Tax Assessment and Collection Act.[75]

Under the Hydrocarbon Tax Act, foreign persons and companies that carry out hydrocarbon activities in areas fully or partly subject to Danish sovereignty are subject to taxation in Denmark on the income from the activity from the time the activity commences. Hydrocarbon activity includes preliminary investigations, exploration and recovery of hydrocarbons and activities related therewith, including the installation of pipelines, supply services and transport by ship and pipeline of recovered hydrocarbons. However, if Denmark has entered into a double taxation treaty with the country where the foreign company has residency for tax purposes, the treaty may modify the Danish tax liability.

All companies involved in oil and gas exploration are required to report hydrocarbon activities and tax liability to the Danish tax authorities. The relevant forms and further information can be found in English on the Danish tax authority's website.[76]

Taxpayers liable for hydrocarbon taxes are subject to special rules regarding the tax assessment pursuant to the Hydrocarbon Tax Assessment and Collection Act, which entails, inter alia, that separate tax returns must be filed for ordinary corporate income (income not covered by the hydrocarbon tax rules) and for each hydrocarbon income stream.[77]

ii Tax rates and income types

The two-string Danish hydrocarbon tax system combines corporate income tax at the rate of 25 per cent[78] (Chapter 2 income) and a special hydrocarbon tax at a rate of 52 per cent (Chapter 3A income) for the income year 2022. The overall effective tax rate for Chapters 2 and 3A income is 64 per cent for the income year 2022.

Income covered by Chapters 2 and 3A includes first-time sales of hydrocarbons, gains and losses on licences, exploration rights and assets used for hydrocarbon activities and financial income related to the activities.

Income related to, inter alia, hydrocarbon feasibility studies, services to hydrocarbon companies, the construction of pipelines, services and transportation of hydrocarbons is not covered by Chapters 2 or 3A. This income is subject to the ordinary corporate income tax rate at 22 per cent for the income year 2022.

iii Ring-fencing

The ring-fence[79] exhaustively lists the streams of income that are subject to separate tax assessment under Section 20B of the Hydrocarbon Tax Act. In general, expenses and tax losses not related to Danish oil and gas activities may not be offset against the Chapters 2 and 3A oil- and gas-related taxable income. However, Chapter 2 losses may be offset against ordinary corporate income.

iv Incentives

In general, Chapters 2 and 3A tax losses realised after 2002 may be carried forward indefinitely. A special hydrocarbon tax allowance has been introduced to ensure that the 52 per cent Chapter 3A hydrocarbon tax is levied exclusively when production from a field is particularly profitable. The Chapter 3A hydrocarbon tax allowance is an uplift of 30 per cent on the depreciation allowance of qualifying expenditures, including capitalised exploration costs and investments made in production plant and equipment. The allowance applies only to the tax basis for hydrocarbon tax. The uplift is allowed as a 5 per cent deduction per year over a six-year period and is granted in addition to the ordinary tax depreciation of plant and machinery and amortisation of capitalised exploration costs over a five-year period.

Additionally, political agreement has been reached to reduce taxation for oil and gas exploitation in an 'investment window' from 2017 to 2025. The purpose of the political agreement is to incentivise hydrocarbon operators to rebuild the Tyra field through which almost all natural gas from the Danish North Sea fields is transferred. The incentives are contained in Chapter 3B of the Hydrocarbon Tax Act.

The agreement provides for, inter alia, a raise in the hydrocarbon deduction from 5 to 6.5 per cent (capital uplift) and an accelerated timing of capital allowances meaning that investments made within the investment window may be subject to capital allowances from the time of investment rather than from the time of delivery of an asset ready to generate revenue.

Uptake of the incentives to which taxpayers covered by the Hydrocarbon Tax Act are entitled is voluntary; however, the investment window also contains an additional surplus tax, which becomes payable if global oil prices reach certain thresholds. This surplus tax is imposed at either 5 per cent or 10 per cent and may be offset in the hydrocarbon tax.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

i Summary of environmental laws and regulations applicable to oil and gas operations

The most relevant environmental laws and regulations applicable to oil and gas activities are the Act on Protection of the Marine Environment, the DSA, the Environmental Impact Assessment Act, the Statutory Order on OIA, the Statutory Order on Alerts Regarding Pollution of the Sea from Oil and Gas Facilities, Pipelines, etc,[80] and the Statutory Order on Safety Zones and Zones for the Observance of Order and the Prevention of Danger.

Licences for offshore projects with a risk of affecting the environment may only be granted and utilised pursuant to an environmental impact assessment (EIA)[81] and an impact assessment regarding international nature conservation,[82] as well as after consultation with the members of the affected general public, authorities and organisations.[83]

Exploration activities such as pre-investigations (e.g., seismic surveys) and drilling may not always require the preparation of an EIA or other impact assessments.[84] As a rule, any planned work, including well drilling, shaft sinking, driving adits and drifts, may only be initiated after obtaining prior approval from the DEA.

ii Details of regulatory agencies with responsibility for environmental regulation

In addition to the DEA and the DUR, the Danish Environmental Protection Agency (EPA) is the main regulatory authority for environmental regulation in Denmark.

The EPA is an agency under the Danish Ministry of Environment. The Ministry is responsible for legislation and is the authority in charge of major national responsibilities and particularly complex tasks. The EPA prepares legislation and guidelines and grants authorisations in several areas.

iii Description of any key environmental approval necessary for oil and gas activities

When working with upstream oil and gas activities offshore, it is necessary to obtain permission for each and every significant step undertaken. Environmental authorisations, as well as EIAs, may also be required depending on the specific project and its location.

iv Summary of legal requirements in respect of decommissioning

The DSA regulates the decommissioning of oil and gas facilities such as the decommissioning of physical structures on- and offshore. The DSA includes provisions set out in the Convention on the Continental Shelf of 1958 and the Sea Law Convention of 1982. The DSA also regulates the effect of licence expiry, cessation, relinquishment or revocation.

A licence under the DSA may be conditional upon the Danish state being entitled to take over all or part of any facilities, equipment and installations intended for long-term use, as well as any required accessories and materials.[85] The licensee is required to have the capacity to remove all or part of, inter alia, any facilities and installations.[86]

VIII FOREIGN INVESTMENT CONSIDERATIONS

There are no legal requirements regarding the type of entity (e.g., partnership and limited liability company) that may apply for a licence. As Denmark is part of the European Union, the freedom rights set out in the TFEU (e.g., the free right of establishment and free movement of capital) apply in Denmark.

Licences are granted after close assessment of the applications based on the criteria listed in the DSA[87] and the terms and conditions stated in the licensing documents. Among these criteria is, inter alia, a requirement to demonstrate the necessary technical and financial capabilities.[88] There are no specific requirements or limitations on using foreign companies or hiring foreign workers in connection with upstream oil and gas activities in Denmark. However, in connection with obtaining a licence for exploration for and production of hydrocarbons, companies participating in the licence must be registered with the tax authorities in Denmark and provide the necessary information for that purpose. As an alternative, companies can, for example, establish a Danish subsidiary or register a business address in Denmark.

In July 2021, a new act on the screening of foreign direct investment (FDI) in Denmark, called the Investment Screening Act (ISA), entered into force. The ISA puts Denmark on the list of countries with a general cross-sectoral FDI screening regime. The ISA effectively applies to transactions closed, or agreements implemented on or after 1 September 2021. In addition, the ISA is supplemented by three executive orders issued by the Ministry of Industry, Business and Financial Affairs, which provide clarifications on the scope of application and further definitions of the concept of particularly sensitive sectors and activities, application procedure and on confidentiality. The ISA aims to prevent foreign direct investments and certain special economic agreements from posing a threat to national security or public order in Denmark through screening and possible interventions. The FDI regime is supervised and enforced by the Danish Business Authority, which has been granted wide investigation and decision powers.

IX CURRENT DEVELOPMENTS

Following the election on 5 June 2019, the Danish Social Democratic Party formed a new minority government on 27 June 2019 supported by the other left-wing parties of the newly constituted Danish Parliament. In line with the tendencies of the 2019 European Parliament election held just before the Danish election, the new government has a strong focus on the climate agenda. Accordingly, the political agreement between the government and its supporting parties proclaims that Denmark will lead the way in combating the climate crisis, assume the international leadership role for the green transition and do what it takes to honour the Paris Agreement.

Against this background, a new climate act was adopted in the summer of 2020.[89] This climate act commits current and future Ministers to reduce greenhouse gas emissions by 70 per cent by 2030 (compared with 1990 levels) and reach net zero emissions by 2050 at the latest. The climate act contains a mechanism for setting milestone targets (the target for 2025 is a reduction of greenhouse gas emissions by 50–54 per cent) and a principle of no backsliding is established (a new climate target must not be less ambitious than the most recently set target). Annually, the Danish government will develop climate action plans that will outline specific policies to reduce emissions for all sectors.

In the light of the climate act, in December 2020, a broad majority in the Danish Parliament reached an agreement on the future of Danish oil and gas production (North Sea Agreement 2020).[90] The North Sea Agreement 2020 constitutes, inter alia:

- a cut-off date of 31 December 2050 for all oil and gas extraction;
- a cancellation of the eighth licensing round, all future licensing rounds and the open-door procedure (however, two procedures – the mini-rounds and neighbour-block procedures – still exist); and
- reduction of the geographic area for issuance of licences.

The North Sea Agreement 2020 has been implemented through amendments to the DSA.

However, despite the North Sea Agreement 2020, a mini-round for two North Sea fields – Elly and Luke – has been opened by the DEA[91] owing to the DEA's receipt of an unsolicited application from BlueNord in April 2023. The structural assumption is that Nordsøfonden, representing the Danish state, will hold a 20 per cent stake, while the remaining 80 per cent will rest with the winning bidder. The mini-round has sparked criticism for going against the climate act passed in 2020 and the prospects of net zero emission by 2050. However, the government has made it clear that the mini-round is within the framework of the North Sea Agreement 2020 and that the gas produced is not envisaged to be consumed in Denmark.

Regarding the infrastructure, the recent year included commissioning of the Baltic Pipe. The Baltic Pipe[92] is a combined on and offshore gas pipeline connecting Denmark and Poland to Norwegian gas fields to ensure security of supply, increase competition and reduce prices and CO_2 emissions. The pipeline is connected to the Norwegian Europipe II in the North Sea, runs through Denmark and connects to the Polish gas grid east of Denmark across the Baltic Sea. The Danish section of the project involves a new 110km offshore pipeline, 210km of additional piping onshore, a new compressor station in Zealand and an expansion of the receipt terminal in Jutland. The Baltic Pipe has been operating on full capacity since December 2022 with 85 per cent of the capacity allocated exclusively to Poland for the next 15 years.

Denmark's domestic natural gas production is also set to increase with the redeployment of the Tyra platform. The original Tyra platform started production in 1984 and has since been expanded with several satellite platforms. However, owing to subsidence, remodelling was necessary. As a result, the Tyra field's production was temporarily suspended in September 2019. The Tyra field is expected to be recommissioned in the winter of 2023–2024. When operation resumes, the Tyra platform is expected to deliver gas equivalent to 80 per cent of Danish gas production.

Furthermore, recent developments include Project Greensand,[93] which is the world's first offshore project for carbon capture and storage (CCS) aiming to store CO_2 in the Danish offshore Siri field. The project was commenced in the first half of 2023 by INEOS and Wintershall Dea. DEA estimates that Denmark holds a total storage potential of 22 billion tonnes of CO_2 with Project Greensand storing 8 million tonnes annually by 2030.

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Endnotes

1 Michael Meyer is a partner at Gorrissen Federspiel. The author is grateful to his colleague, legal counsel Jacob Sandholt, for his assistance with this chapter.
2 For further information, see the Danish Energy Agency's web page www.ens.dk (partly in English). In 2018, Total acquired Maersk Oil.
3 See https://en.kefm.dk/news/news-archive/2020/dec/denmark-introduces-cutoff-date-of-2050-for-oil-and-gas-extraction-in-the-north-sea-cancels-all-future-licensing-rounds.
4 The first round took place in 1984, the second in 1986, the third in 1989, the fourth in 1995, the fifth in 1998, the sixth in 2006, the seventh in 2016, and the eighth round was concluded in February 2019 (but cancelled as a result of the North Sea Agreement 2020).
5 Nordsøfonden (the North Sea Fund) is established by law, see Act No. 527 of 28 May 2014 on a public fund to manage the state's participation in hydrocarbon licences and a public entity to administer the fund.
6 Nordsøfonden does not at the time of writing participate in licences 7/86 and 1/90 (Lulita), 7/89 (South Arne), 4/95 (Nini), 6/95 (Siri), 5/98 (Hejre) and 16/98 (Cecilie).
7 See the publication 'Resources and Forecasts' by the DEA, dated 31 August 2023, available at https://ens.dk/sites/ens.dk/files/OlieGas/ressourcer_og_prognose_2023_dk_endelig_version.pdf.
8 For details, see ibid.
9 Consolidated Act No. 1533 of 16 December 2019 with subsequent amendments.
10 Consolidated Act No. 1189 of 21 September 2018 with subsequent amendments.
11 Consolidated Act No. 807 of 13 August 2019 with subsequent amendments.
12 Inter alia, Directive (94/22/EC) on the conditions for granting and using authorisations for the prospection, exploration and production of hydrocarbons, the Habitats Directive (92/43/EEC), the Birds Directive (79/409/EEC), Directive (2009/31/EC) on the geological storage of carbon dioxide and the Offshore Safety Directive (2013/30/EU).
13 Section 1(2) of the DSA and similarly Section 1 of the CSA.
14 Section 2 of the DSA.
15 Lars Aagaard was appointed Minister for Climate, Energy and Utilities in December 2022.
16 Statutory Order No. 1068 of 25 October 2019 on the Danish Energy Agency's powers and tasks.
17 See Section 2 in Statutory Order No. 419 of 2 June 2005 on the Payment of Fees connected with Certain Licences Issued pursuant to the Act on the Use of the Danish Subsoil.
18 See Statutory Order No. 661 of 1 June 2018 on Reimbursement of Expenses related to the Authorities' Administration in connection with Hydrocarbon Activities.
19 See Sections 2 and 3 of Statutory Order No. 56 of 4 February 2002 on Submission of Samples and other Information about the Danish Subsoil.
20 Ratified by Denmark on 31 May 1963.
21 See Section 1 of the CSA.
22 See Sections 3a and 4 of the CSA.
23 The pipelines are as part of the political agreement entered into regarding the IPO of DONG Energy A/S (now Ørsted A/S) to be divested to the state-owned company Energinet. The listing took place on 9 June 2016, but the divestment is still in process.
24 See Section 1 of the DPA.
25 See Section 2 of the DPA. With regard to the other infrastructure in the Danish part of the North Sea, the DSA was amended on 1 January 2018 to improve third-party access (i.e., access to another licensee's infrastructure on predictable and reasonable terms).
26 See Section 2(3) of the DPA.
27 See footnote 16.
28 See Sections 3 and 3c of the DPA and Statutory Order No. 78 of 26 January 2018 on the Payment for Transport of Crude Oil and Condensate.
29 See the Statutory Order No. 1410 of 16 December 2019 on Access to the Upstream Pipelines and Upstream Systems.
30 Act No. 744 of 13 June 2023.
31 Consolidated Act No. 125 of 6 February 2018.
32 Consolidated Act No. 1032 of 25 June 2023 on the Protection of the Marine Environment.
33 Consolidated Act No. 4 of 3 January 2023 on Environmental Impact Assessment of Plans and Programmes and of Specific Projects.
34 Statutory Order No. 434 of 2 May 2017 on Impact Assessments, etc. Offshore.
35 Statutory Order No. 657 of 30 December 1985.
36 Section 1 of the Offshore Safety Act.
37 Section 5 of the Offshore Safety Act.
38 Section 1 of Statutory Order No. 657 of 30 December 1985.
39 See Consolidated Act No. 1820 of 16 September 2021 with subsequent amendments.
40 See Consolidated Act No. 1886 of 1 October 2021 with subsequent amendments.
41 See Statutory Order No. 1068 of 25 October 2019 on the DEA's Duties and Powers.
42 id., Section 8.
43 See Act No. 690 of 8 June 2018 on the Danish Utility Regulator with subsequent amendments and Statutory Order No. 163 of 26 February 2000 on the Danish Utility Regulator's Duties.
44 See Section 2 of Act No. 690 of 8 June 2018 on the Danish Utility Regulator with subsequent amendments.
45 See Sections 6–8 of Statutory Order No. 1410 of 16 December 2019 on Access to the Upstream Pipelines and Upstream Systems. See also Section 37a of the DSA deals with appeals against DEA's decisions under the DSA.

46 The New York Arbitration Convention on the Recognition and Enforcement of Foreign Arbitral Awards, New York, 10 June 1958.
47 Statutory Order No. 117 of 7 March 1973 with subsequent amendments.
48 Consolidated Act No. 1655 of 25 December 2022 on Administration of Justice with subsequent amendments.
49 Act No. 553 of 24 June 2005 on Arbitration with subsequent amendments.
50 Section 5 of the DSA.
51 The first round took place in 1984 and licences based on the seventh round were awarded in the spring of 2016. The eighth round has been cancelled as a result of the North Sea Agreement 2020.
52 See Section I.
53 The model licence terms, Sections 2 and 3 with Annex 1.
54 id., Section 4 with Annex 2.
55 id., Section 18.
56 id., Sections 19–22.
57 id., Sections 30–32.
58 id., Sections 34–37.
59 id., Section 38.
60 id., Section 40.
61 Section 17(2) of the DSA.
62 Section 17a of the DSA and Act No. 354 of 24 April 2012 on Oil Preparedness.
63 Statutory Order No. 1410 of 16 December 2019 on Access to the Upstream Pipelines and Upstream Systems.
64 ibid.
65 See Section 5 of Statutory Order No. 1410 of 16 December 2019 on Access to Upstream Pipelines and Upstream Systems.
66 ibid.
67 See Section 29(1) of the DSA.
68 A provision to this effect is also included in the model licence for the eighth round, Section 33.
69 See Section 29(2) of the DSA.
70 See Section 29a of the DSA.
71 See Section 29a(5) of the DSA.
72 Statutory Order No. 661 of 1 June 2018 on the Reimbursement of Costs with subsequent amendments.
73 See Section 29(3) of the DSA.
74 Consolidated Act No. 1820 of 16 September 2021 with subsequent amendments.
75 Consolidated Act No. 1886 of 1 October 2021 with subsequent amendments.
76 See www.skat.dk.
77 That is, for separate income under Part 2 and for hydrocarbon income pursuant to Part 3A of the Hydrocarbon Tax Act.
78 The ordinary corporate income tax of 22 per cent added 3 per cent for hydrocarbon activities.
79 See Section 4 of the Hydrocarbon Tax Act.
80 Statutory Order No. 909 of 10 July 2015 with subsequent amendments.
81 Under the Environmental Impact Assessment Act.
82 See Sections 28(a), 28(b) and 28(c) of the DSA and the Statutory Order on OIA.
83 See Section 35 of the Environmental Impact Assessment Act and Section 6 of the Statutory Order on OIA.
84 See generally the Environmental Impact Assessment Act and the Statutory Order on OIA for more detailed descriptions (i.e., offshore projects that necessitate the preparation of an EIA, requirements concerning the contents, other information to be submitted and procedures to follow).
85 See Section 8 of the DSA.
86 See Section 24(a) of the DSA.
87 See Section 12(a) of the DSA.
88 ibid.
89 Act No. 965 of 26 June 2020 on Climate with subsequent amendments.
90 See https://en.kefm.dk/news/news-archive/2020/dec/denmark-introduces-cutoff-date-of-2050-for-oil-and-gas-extraction-in-the-north-sea-cancels-all-future-licensing-rounds.
91 See https://ens.dk/sites/ens.dk/files/OlieGas/letter_of_invitation_in_danish_1.pdf.
92 For more information about the Baltic Pipe, please visit www.baltic-pipe.eu or www.energinet.dk.
93 For more information about the project, see https://www.projectgreensand.com/.

Chapter 7

Dominican Republic

Katherine Rosa Rodríguez, Gisselle Valera Florencio and Andrea García Camps[1]

Summary

I INTRODUCTION

The Dominican Republic is considered a frontier region with promising potential for the upstream oil and gas industry, mainly because of its geological setting and the long-known presence of crude in the subsoil. Despite this opportunity, historically the country has seen little or no activity in the exploration and production hydrocarbons sector.

Although the exact amount of national oil reserves remains unknown (and production has not yet started), there are currently four frontier basins of interest in the Dominican Republic: the Cibao Basin, the Enriquillo Basin, the Azua Basin and the San Pedro de Macorís Basin.[2]

Now, having successfully concluded its first licensing round for oil and gas in November 2019 with the award of a production sharing contract (PSC) to a US multinational corporation, and the start of the studying phase in December 2022 for the second licensing round with the award of a technical evaluation contract for the performance of geochemical studies to a United Arab Emirates corporation, the government hopes to continue to entice key investors to this incipient market and to build on this effort through the launch of successive licensing rounds, and by providing flexible contract terms and guarantees, favourable fiscal terms, and a solid legal framework and policy for the development of upstream activities.

These licensing rounds are part of the country's National Development Strategy for 2030, established by Law 1-12, dated 25 January 2012, which aims to develop a coherent and sustained strategy for short-, medium- and long-term onshore and offshore oil exploration and exploitation, while ensuring environmental sustainability.

Going forward, to retain the interest of potential investors and drive the growth of the Dominican upstream oil and gas market, it will be critical that the state continues to provide attractive contractual terms, along with a stable, robust and transparent set of rules applicable to the upcoming public tender processes. Moreover, investors will closely observe the performance of the PSC awarded in the first licensing round, as well as the results of the geochemical studies awarded for the second licensing round, and will likely use it as a reference point to shape their own outlook as to the progress and maturity of the industry.

II LEGAL AND REGULATORY FRAMEWORK

The 2015 Dominican Constitution provides in its Article 14 that the non-renewable natural resources in the territory and maritime spaces under national jurisdiction are a patrimony of the nation. Furthermore, Article 17 of the Constitution establishes that mining and hydrocarbon deposits and, in general, non-renewable natural resources may be explored and exploited only by private parties, under sustainable environmental criteria, by virtue of concessions, contracts, licences, permits or quotas, under the conditions determined by law. The exploration and exploitation of hydrocarbons in the national territory and in maritime areas under national jurisdiction are considered activities of high public interest.

i Domestic oil and gas legislation

In the Dominican Republic, oil and other hydrocarbons are expressly excluded from the scope of Mining Law 146, dated 4 January 1971. Thus, the primary legislation governing the onshore and offshore upstream oil and gas industry is Law 4532-56, dated 31 August 1956, amended by Law 4833, dated 17 January 1958 (Law 4532). This law provides that contracts executed by the executive branch for upstream hydrocarbons are subject to the approval of the National Congress and, once approved, may not be revoked, altered or modified without the consent of the contracting parties. In addition, the contractual rights for exploitation in favour of private parties are to be granted for an unlimited time and with the surface extension agreed upon.

Other important legal norms regarding upstream oil and gas are as follows:

- Presidential Decree 83-16, dated 29 February 2016, which establishes the regulation for hydrocarbons exploration and production (Hydrocarbons Regulation);

- General Environmental Law 64-00, dated 18 August 2000, which provides the framework for the protection, restoration and improvement of the environment, as well as for the regulation of environmental authorisations applicable to projects with varying degrees of environmental impact, such as the upstream hydrocarbons sector (Law 64-00);
- Law 100-13, dated 30 July 2013, which creates the Ministry of Energy and Mines (MEM) (Law 100-13);
- Law 47-20 on public–private partnerships, dated 20 February 2020, which establishes a legal framework to regulate the start, selection, awarding, contracting,[3] execution, follow-up and termination of public–private alliances for projects of social interest, such as the exploration and exploitation of hydrocarbons in the country (Law 47-20);
- Resolution R-MEM-REG-001-2016, issued by the MEM on 8 January 2016, which requires that any party interested in performing geological and geophysical studies to evaluate the country's hydrocarbon potential obtains a permit from MEM (Resolution 001-2016); and
- Resolution R-MEM-REG-012-2019, issued by MEM on 4 February 2019, which requires that any party interested in drilling wells for the exploration and production of hydrocarbons includes geophysical recordings of each well in its work programme, to determine the porosity, permeability, density, clay content, formation fluid, well calibration and dip of the strata or layers that comprise the subsoil (Resolution 012-2019).

ii Regulation

The MEM is the governing public body for upstream oil and gas in the Dominican Republic,[4] in charge of the formulation and administration of the national energy and metallic and non-metallic policies. Consequently, it supervises other agencies linked to upstream oil and gas, such as the National Energy Commission, the National Geological Service and the General Agency of Mining. Among others, MEM has the mandate to:

- formulate, direct and coordinate the national policy on exploration, exploitation and transformation of metallic and non-metallic minerals;
- stimulate the prospecting, exploration and exploitation of energy resources of hydrocarbons, coal and natural gas;
- order or carry out the necessary studies to evaluate the potential of hydrocarbons;
- grant exploration permits and concessions for the exploitation of hydrocarbons; and
- coordinate with the Ministry of Environment and Natural Resources (MIMARENA) the evaluation procedures for hydrocarbon exploration and exploitation proposals.

In this regard, MIMARENA formulates, executes, administers and supervises the national policy for the protection of the country's environment and natural resources. It has the power to evaluate projects that may cause an environmental impact and to grant and oversee the corresponding environmental authorisations, including sanctions for non-compliance.

iii Treaties

The Dominican Republic is a contracting party to the 1958 Convention on the Recognition and Enforcement of Foreign Arbitral Awards (New York Convention), ratified on 11 April 2002, and to the 1975 Inter-American Convention on International Commercial Arbitration (Panama Convention), ratified on 2 February 2008.

It is also a contracting party to several bilateral (BITs) and multilateral (MITs) investment treaties. In respect of the former, the country has ratified BITs with Spain (1995), Ecuador (1998), Taiwan (1999), Haiti (1999), France (1999), Cuba (1999), Chile (2000), Argentina (2001), Finland (2001), Morocco (2002), Panama (2003), Switzerland (2004), South Korea (2006), Italy (2006) and the Netherlands (2006). It has also signed and ratified a 2019 Economic Partnership Agreement (EPA) with the United Kingdom, pending ratification by the latter. In relation to the MITs, the most significant in place are the 2004 Dominican Republic-Central America Free Trade Agreement (DR-CAFTA) and the 2008 Economic Partnership Agreement between the Caribbean Forum (CARIFORUM) and the European Union.

The Dominican Republic has entered into two double taxation treaties in force: one with Canada (1977), which deals with taxes on income and capital, and the other with Spain (2014), covering income tax.

III LICENSING

The licensing regime for upstream oil and gas in the Dominican Republic is structured by way of international public tenders for the award of technical evaluation contracts or PSCs executed with MEM, in representation of the state, through a special power of attorney granted by the Dominican president.

These public tenders are carried out by MEM, subject to the public procurement legislation in force, that is, Law 340-06 on purchasing and contracting of goods, services, works and concessions, dated 18 August 2006, amended by Law 449-06, dated 6 December 2006, and Presidential Decree 543-12, dated 6 September 2012, which approves the regulation application for Law 340-06.

In this regard, technical evaluation contracts authorise companies to evaluate hydrocarbon potential and to identify the zones of greatest prospective interest within a certain area. Conversely, PSCs authorise contractors to explore and exploit hydrocarbons in a specific area, while the state receives a royalty consideration for the transfer of the ownership rights of the hydrocarbons extracted by the contractor. The Hydrocarbons Regulation also recognises the possibility of executing other types of contracts for upstream oil and gas, such as maximum quota contracts and public–private partnership contracts.

Under Article 31 of the Hydrocarbons Regulation, PSCs must stipulate, at least, the following:

- the object, the application and the specific area or contracted area;
- the terms and conditions under which the exploration, exploitation or technical evaluation rights are granted;
- the minimum investment commitment by the contractor, set by MEM;
- the terms and conditions of the work during the exploration or exploitation phases, which shall include those related to the technical control of the operations, work schedules, budget, production, royalty, supply, and the possibility of revising it when circumstances so require;
- all matters related to the use of gas;
- the maximum validity term, a unilateral termination clause in favour of the state, the rights and conditions, the obligations of decommissioning, rehabilitation or remediation in the event of abandonment or expiry of the term, the penalties and the liability of the parties;
- the taxes applicable to the contractor, in accordance with the legislation in force;
- the performance bond by the contractor, to ensure the correct execution of the PSC and the guarantee fund for the protection of the environment and natural resources; and
- the obligation to previously submit to MEM any transfer, lease, assignment or legal continuity of the upstream rights, as well as changes in the shareholding composition, for its approval and registration.

IV PRODUCTION RESTRICTIONS

In the Dominican Republic, there are no legal restrictions on oil and gas production entitlements, export or sale of production into the local market. Notwithstanding, under the model PSCs approved for the first licensing round, the state (through MEM) shall have a preference right to acquire all or part of the hydrocarbon production owned by the contractor. In respect of price setting, Article 35 of the Hydrocarbons Regulation establishes that national production of hydrocarbons is primarily destined to cover the needs of the country and the national reserve, as defined by the state, through MEM. For this purpose, every contractor is obliged to sell to the state the production necessary to satisfy the domestic market, at the market price determined and fixed in accordance with the prices of the international market for equivalent crude oil. Furthermore, MEM must issue the necessary norms for the establishment of the procedure of price determination, although to date this is still pending.

V ASSIGNMENTS OF INTERESTS

In accordance with Article 5 of Law 4532, unless the executed corresponding PSC provides otherwise,[5] the contractor may assign it to another person or entity which assumes all obligations and responsibilities arising from such contract, or subcontract with other persons or entities all or part of the exploration and production activities and benefits recognised in the PSC, as well as encumber its contractual interest as security for the financial operations that it carries out. All whole or partial assignments, encumbrances, transfers or leases of such contracts, as well as any changes to the shareholding structure of the contractor company, must be notified and approved by MEM before their execution, pursuant to Articles 6 (letter h), 31 (letter j) and 33 of the Hydrocarbons Regulation, and later registered with the General Agency of Mining, as mandated by Articles 5 (Paragraph) and 7 of Law 4532.

To this end, the assignee company must meet the same conditions and requirements as the assignor contractor. When the assignment or transfer is partial, the assignor and the assignee shall be jointly and severally liable for compliance with the terms of the contract before the state and third parties.

Neither the legislation in force nor the model onshore and offshore PSCs approved by MEM for the first (and presumably subsequent) licensing rounds recognise a right of first refusal or preferential purchase in favour of the state in case of contract transfer. Similarly, the structure of the transfer (direct transfer versus change of control) would not, in principle, affect the government's approval process, and there are no provisions requiring the payment of a consideration to the state (e.g., cash payments, amendments to underlying licence terms) as a condition to grant the assignment or transfer approval.

In any case, given that the Dominican Republic just recently awarded its first and (to date) only PSC in November 2019, there have been no cases to draw from dealing with requests for authorisation of assignment, encumbrance or transfer of PSCs. Currently, on the basis of the model PSCs used for the first licensing round, MEM has 15 business days to respond to any such request, either authorising or rejecting it, including its motivations for the decision.

VI TAX

Pursuant to Article 6 of Law 4532, companies that have executed PSCs with MEM shall enjoy the exonerations and reductions of taxes, fees or duties specified in the corresponding contract.

In general terms, the tax regime applicable to upstream oil and gas operators in the Dominican Republic is the following:

- tax stabilisation: model PSCs contain a stabilisation clause by virtue of which the state guarantees the contractor tax stability for the full validity period of the PSC, so that contractors will only be subject to the tax regime in force as of the contract signature date;
- minimum state participation: to ensure an appropriate distribution of project benefits, PSCs also include a 'minimum state participation' (PME) provision, under which contractors are required to pay the state at least 40 per cent of the benefits attributable during the life of the project, equivalent to the total oil revenues;
- local governments contribution: according to Article 117 of Law 64-00, in the case of non-renewable natural resources, the state shall allocate 5 per cent of the net benefits received in favour of the municipalities in which the exploitation is executed to develop projects identified in the corresponding municipal development plans elaborated by the Ministry of Economy, Planning and Development. The highest amount to be assigned for the corresponding municipalities shall be US$5 million per year by contract;

- shared state income: contractors shall pay the state a monthly participation income, calculated based on a formula described in the model PSCs that takes into account, among other factors, the average daily production in the corresponding month and the commercialisation monthly average price on the wellhead;
- income tax: upstream oil and gas activities are subject to corporate income tax at a rate of 27 per cent, pursuant to Law 11-92, which approves the Tax Code, dated 16 May 1992 (Tax Code). The recoverable costs for income tax include the costs and investments incurred during the exploration and productions phase in the contract area. In this regard, admitted as recoverable costs are all expenditures indispensable for the performance of oil and gas activities, counted from the effective date of the PSC, capped at 95 per cent of the gross income per period;
- import duties: PSC contractors may enter into the country the machinery and equipment necessary for oil exploitation under a temporary admission regime, supervised by the General Agency of Customs;
- rental of surface rights: depending on the phase of the project, contractors are required to make annual rental payments to the state, as follows:
  - for the first exploration phase, US$25 per km^2;
  - for the subsequent exploration phases, US$50 per km^2; and
  - for the production phase, US$500 per km^2; and
- overseas payments: during the exploration phase, payments made abroad to non-residents shall not be subject to a withholding tax. Conversely, in the production phase, payments made abroad to non-residents are subject to a 10 per cent withholding tax. Normally, overseas payments are taxed at the same rate as income tax (i.e., 27 per cent), but the model PSCs grant a preferential fiscal treatment to investors in the form of this cutback to 10 per cent.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

As established above, the main legislation applicable to oil and gas operations in the country is Law 64-00, which outlines the framework for the protection, restoration and improvement of the environment and regulates environmental authorisations for all types of projects. MIMARENA is the principal regulatory agency responsible for environmental matters. It directs and executes the national environmental policy, evaluates the impact of projects, infrastructure, industries or activities that, because of their nature, may affect the environment or natural resources in any way and grants the corresponding authorisation, according to the magnitude of the effects that they may cause.

On this subject, MIMARENA has classified different kinds of projects into four categories, depending on their potential effects to the environment. Such classification determines the requirements that companies will have to submit to MIMARENA upon requesting the authorisation in question. The interested party must apply for an 'Environmental Authorisation for New Project' with MIMARENA, which evaluates the request and determines the authorisation required for the project.

In the case of upstream oil and gas operations, pursuant to Resolution 0013-2014, issued by MIMARENA on 22 September 2014, which approves the regulation for the environmental evaluation procedure, both oil wells and natural gas and carbon ore exploration are classified as 'A' type projects, meaning that they may cause significant potential impact and thus require the issuance of an environmental licence, whereas oil exploration without industrial testing is classified as a 'B' type project, equivalent to a moderate potential impact and requiring the obtention of an environmental permit.[6]

As part of the approval process, class 'A' projects must prepare and present an environmental impact study with MIMARENA, whereas class 'B' projects must deliver an environmental impact declaration, in both cases based on the terms of reference issued by the institution's Environmental Evaluation Agency for the project in question.

Regarding the decommissioning of upstream hydrocarbon projects, the model PSCs contain the contractual requirements for decommissioning of the contract areas. In this regard, the contractor shall be obliged to carry out all the operations related to the abandonment of the contract area. Furthermore, the project development plan, as well as each work programme and budget submitted for the approval of MEM, shall contain a section related to the abandonment, including an estimate of the activities necessary for the final plugging of wells, restoration, remediation and, when applicable:

- environmental compensation of the contract area;
- uninstallation of machinery and equipment; and
- orderly and free delivery of debris and rubbish from the contract area.

These activities must be carried out in accordance with the best industry practices and the applicable regulations. Before plugging a well or uninstalling any equipment, the contractor must notify MEM at least 60 calendar days in advance.

Finally, according to the model PSCs, contractors shall open a custody or escrow account in a banking institution approved by MEM, to create a reserve to fund decommissioning operations of the project. Contractors may not make use of these funds for any purpose other than carrying out decommissioning operations and shall not have the right to grant them as guarantee, assign or dispose them in any way.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

Foreign investors with oil and gas operations in the country may act through a branch in the national territory (considered as a permanent establishment for tax purposes), in which case they shall be fully recognised and have the same rights and obligations as national corporations, pursuant to Law 479-08 on Companies and Limited Liability Proprietorships, dated 11 December 2008, amended by Law 31-11, dated 8 February 2011 (Law No. 479-08). Furthermore, under Law 479-08 and the Hydrocarbons Regulation, these foreign corporations are required to submit themselves to Dominican law, establish a domicile in the country and matriculate in the Mercantile Registry of the competent Chamber of Commerce and Production and in the National Taxpayers Registry (RNC) of the General Agency of Internal Revenue (DGII).

Conversely, investors may opt to establish a local subsidiary of the foreign corporation for their operations. In this regard, Law 479-08 recognises various types of companies, of which the most frequently used are limited liability companies, corporations and simple corporations, given that they provide more flexible structures, while the liability of partners is limited to their respective contributions. As an overview, below are the basic characteristics of the aforementioned corporate vehicles:

- limited liability companies (LLC): formed with a minimum of two members and a maximum of 50, who are not personally liable for corporate debts. In the event an LLC should be composed of more than 50 members, it must transform into a corporation, within a two-year term. For their formation and operation, these companies do not need to have a minimum authorised or paid-in capital;
- corporations: may be public or private in nature and are formed by two or more persons under a corporate title, composed exclusively of shareholders, whose liability is limited to their capital contributions. The minimum authorised capital for corporations is 30 million Dominican pesos, of which at least 10 per cent must be paid-in capital. As opposed to other types of corporate vehicles, corporations are legally allowed to make public offering of securities; and
- simple corporations: similar requirements and characteristics to those of ordinary corporations, but with a reduced minimum authorised capital of 3 million Dominican pesos and minimum paid-in capital of 300,000 Dominican pesos.

Generally, the establishment of a local subsidiary can be completed in three to four weeks. To this end, the interested party must complete the following steps:

- register a commercial name for the company in the National Office of Industrial Property (ONAPI);
- pay the incorporation tax with the DGII (1 per cent of authorised capital);

- matriculate the company in the competent Chamber of Commerce and Production, by filing the executed incorporation documents (e.g., by-laws, minutes of constitutive general assembly, trade name certificate issued by ONAPI, receipt of payment of incorporation taxes); and
- register the company in the RNC of the DGII.

ii Capital, labour and content restrictions

The Dominican Republic does not have any restrictions in place regarding the movement of capital or access to foreign exchange.

There are, however, certain local hiring requirements applicable to oil and gas operations and which potential investors must take into consideration. Under Article 135 of the Labour Code, at least 80 per cent of the total number of workers of a company must be of Dominican nationality. Similarly, under Article 136 of the Labour Code, the wages received by Dominican nationals must amount, in aggregate, to at least 80 per cent of the value corresponding to the payroll of the entire personnel. Workers who carry out technical work, supervision or management are exempt from the provisions of Article 136.

iii Anti-corruption

There have been no reported corruption issues related to oil and gas matters in the Dominican Republic, although the industry is still emerging. As per the legal framework, the country is a party to the Inter-American Convention against Corruption, ratified by Resolution 489-98 issued by the National Congress on 1 November 1998. There are also several laws that prohibit and deal with corruption in the public sector, the most important of which are Law 41-08 on Public Service, dated 16 January 2008, the 1884 Criminal Code, Law 448-06 on Bribery in Trade and Investment, dated 6 December 2006, and Law 120-01, which creates the Ethics Code for Public Servants, dated 20 July 2001, and Law No. 155-17 on Money Laundering and the Financing of Terrorism, dated 1 June 2017.

IX CURRENT DEVELOPMENTS

In July 2019, the Dominican Republic launched its first upstream oil and gas licensing rounds, through an international public tender, which concluded in November 2019 with the award of a PSC (signed in October 2020) to Apache Dominican Republic Corporation, LDC, a subsidiary of the US firm Apache Corporation, for the exploration and exploitation of San Pedro de Macoris offshore basin.[7] The contract was also approved by the National Congress, as required by Dominican law.

Under the contract, Apache will make an initial investment of US$5 million for exploration in the first four years, at its own cost and risk. In the second phase, the company will invest another US$8 million for the next three years. If the oil discovery is successful, a third phase will see Apache make an investment of around US$100 million in exploitation of the exploratory well.[8]

This first licensing round had 14 blocks on offer, including 10 onshore blocks (six in the Cibao Basin, three in the Enriquillo Basin and one in the Azua Basin) and four offshore blocks (all in the San Pedro de Macorís Basin), with a maximum size/block of 500 km^2 onshore and 2,500 km^2 offshore.[9]

Prior to the covid-19 pandemic, the Dominican government had already announced that it would launch a second auction covering the areas not awarded during the first round and others not previously offered, as proposed by stakeholders and approved by MEM as part of the second-round schedule.[10] However, this new round has been delayed, presumably until investment conditions improve.

To facilitate information and expedite the assessment process for stakeholders, MEM also created the National Hydrocarbon Database, a free public access digital compendium and archive 'for all geological, geophysical and seismic information collected through hydrocarbons exploration and prospecting on Dominican soil and sea dating back to 1904'. The database contains 1,491 maps and drawings, 805 seismic profiles, 212 well logs, 321 files or reports and 209 '9-track' and three '8-track' magnetic tapes with seismic lines in various regions of the country.[11]

Furthermore, the Dominican Republic joined the Extractive Industries Transparency Initiative (EITI), a multi-stakeholder organisation that sets the global standard for the good governance of oil, gas and mineral resources, and is currently in the process of validation under the 2016 EITI Standard. In this regard, the most recent decision by the EITI Board, dated 14 February 2020, recognised that the country 'has made meaningful progress in implementing the 2016 EITI Standard', and granted a six-month term, until 14 August 2020 (later extended to 1 April 2023), to allow the country to 'carry out corrective actions regarding the requirements relating to production data, subnational transfers, and the outcomes and impact of EITI implementation'.[12]

In May 2022, the Dominican government concluded the international public tender for the installation of two natural gas terminals with a total capacity of 840 MW in Manzanillo, Montecristi.[13] The Manzanillo project will include a natural gas discharge, storage and distribution terminal.[14] Manzanillo Gas & Power – a consortium composed of Haina Investment Company, Shell Gas & Power Development (Shell) and Energía de las Américas – will be responsible for the construction of the first 420 MW generation block, developing the terminal and a combined-cycle power plant. Meanwhile, the second-generation block, which will contribute the remaining 420 MW to the infrastructure, was awarded to Manzanillo Energy, composed of Coastal Dominicana, Manzanillo Energy and Lindsayca.[15]

In October 2022, MEM set an international public tender for the planning and execution of a geochemical study in terrestrial sedimentary basins with a focus on hydrocarbon exploration as part of the first phase of the second licensing round for oil and gas.[16] Geolog Surface Logging DMCC (Geolog), the company that won the auction in December 2022, has already begun the sample collection phase, which will bring clarity to companies involved in the exploration of upstream oil and gas in the assignment of areas for exploration and production of oil and gas in the country.[17]

More recently, the Executive Branch submitted a bill of law to the Senate that seeks to modify Law 4833, which regulates onshore and offshore upstream oil and gas, to allow foreign investors to explore and exploit hydrocarbons in the country.[18] Current regulations prohibit foreigners to carry out these practices.

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Endnotes

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Chapter 8

Ghana

Nana Serwah Godson-Amamoo and Antoinette Lady Arko[1]

Summary

I INTRODUCTION

i Historical overview

The upstream oil and gas activities in Ghana involve the exploration, development and production of hydrocarbons. These activities are undertaken offshore in the Tano Basin and Cape Three Points Basin in the Western Region (mostly referred to together as the Western Basin), the Saltpond Basin in the Central Region, the Accra/Keta Basin and onshore in the Inland Voltaian Basin.[2]

The first recorded hydrocarbon exploration was undertaken by the West Africa Oil and Fuel Company in 1896.[3] Other companies did some exploration work from 1905 to 1925,[4] and by independence in 1957, 21 wildcats had been drilled for exploration. Key among these was the Saltpond Field (the first offshore producing field), which started production in 1978, peaked at 4,500 barrels per day and shut down in 1985. By the mid-1980s, Ghana had 54 wells (onshore and offshore).[5] Commercial oil production resumed in 2009 following Ghana's first significant deepwater oil discovery of 2007 from the Jubilee field, in the offshore Tano/Cape Three Points Basin. Held by a consortium of international oil companies (IOCs) and Ghana National Petroleum Company (GNPC) and operated by Tullow Oil, the Jubilee field has proven reserves of approximately 3 billion barrels.[6]

The success of the Jubilee Field immensely reduced the perceived investment risk in the Ghanaian upstream industry, resulting in increased investment in the sector. Between 2013 and 2023, over 14 exploration licences have been issued. These include licences to Heritage Oil, AGM Petroleum, Britannia-U, Sahara Energy, Eco Atlantic, Amni, Medea Development, Base Energy, ExxonMobil and Springfield E&P. This has led to increased exploration activities and over 26 more discoveries in the Western Basin, including Odum, Mahogany Deep, Teak, Akasa, Pecan PN-1, Pecan South 1A, Nyankom, Afina and Eban.

Ghana currently hosts three producing oil and gas projects:

- Jubilee (Tullow);
- Offshore Cape Three Points (OCTP) (ENI/Vitol); and
- Tweneboa, Enyenra and Ntomme (TEN) (Tullow).

The estimated reserves of the producing fields are as follows:

- Jubilee: 278.66 million barrels (mmbbls) of oil and 271.47 billion cubic feet (Bcf) of gas;
- TEN: 140.02 mmbbls of oil and 273.83 Bcf of gas; and
- OCTP: 108.26 mmbbls of oil and 910.4 Bcf of gas.[7]

A fourth field, Pecan, estimated to hold 268 million barrels, has recently been approved for development. Additionally, there are several contract areas at various stages in the exploration phase, including:

- Central Tano, (Amni) – exploration;
- East Cape Three Points (Medea Development) – exploration:
- West Cape Three Points Block 2 (Springfield) – appraisal of Banda and Odum discoveries;
- Deepwater Cape Three Points West (Eco Atlantic) – exploration; and
- Offshore Cape Three Points Block 4 (ENI) – appraisal of Eban and Akoma discoveries.

In 2014, Ghana initiated arbitral proceedings in Germany at the International Tribunal for the Law of the Sea (ITLOS) regarding a longstanding dispute on delimitation of the maritime boundary between Ghana and Ivory Coast in the Atlantic Ocean. Ivory Coast had laid claim over some offshore oil concessions and adjoining seabed being developed and exploited within Ghana's territory.[8] On 23 September 2017, the Special Chamber of ITLOS resolved the dispute in favour of Ghana, paving the way for the approval of the Greater Jubilee Full Field Development Plan in October 2017. This permitted Tullow and its joint venture partners to prepare for a multi-year incremental drilling programme that integrated the nearby Mahogany and Teak discoveries in the West Cape Three Points Block with the Jubilee Field.

Commencing at 1,100,000 barrels in 2009, Ghana's crude oil production peaked at 71,439,585 barrels in 2019 followed by a three-year average decline of approximately 10 per cent. Total crude production in 2022 is reported at 51,756,481 barrels.[9]

ii Legislative overview

The first legislative framework for upstream oil and gas activities in Ghana was adopted by the government in the mid-1980s. Key laws included the Ghana National Petroleum Corporation Act 1983 (PNDCL 64), which established the national oil company, the Petroleum (Exploration and Production) Law 1984 (PNDCL 84) for the regulation of petroleum activities and the Petroleum Income Tax Law 1987 (PNDCL 188). PNDCL 84 and PNDCL 188 have subsequently been repealed by the Petroleum (Exploration and Production) Act 2016 (Act 919) (the E&P Act) and the Income Tax Act 2015 (Act 896).

The Fourth Republican Constitution of 1992 stipulates that:

> *every mineral in its natural state in, under or upon any land in Ghana, rivers, water course throughout Ghana, the exclusive economic zone, any area covered by the territorial sea or continental shelf in the Republic of Ghana is the property of the Republic of Ghana and is vested in the President on behalf of, and in trust for the people of Ghana.*

As a check on the powers of the President, the Constitution mandates the establishment of specialised commissions to manage the utilisation of natural resources and the prior approval of Parliament for all natural resource-related transactions, including the grant of mineral rights in Ghana.[10] More recent legislation includes the Petroleum Commission Act 2011 (Act 821), which established a regulator for the upstream petroleum industry,[11] and the Petroleum Revenue Management Act 2011 (Act 815) as amended, which guides the management and use of petroleum revenues. The above legislation, together with other supporting regulations, guidelines and policies, provide a composite framework for the upstream oil and gas industry.

iii Industry and foreign investment overview

On the basis of the established institutional and regulatory framework and international best practice, Ghana has developed a model petroleum agreement, which is the basis for investor engagement and the grant of petroleum rights. The petroleum agreements are executed between GNPC, the government, IOCs and indigenous Ghanaian companies (IGCs). Currently, there are 10 upstream operators at varying phases in petroleum operations under 14 petroleum agreements. Notable E&P companies that have been attracted to the Ghanaian upstream include Kosmos, Vitol, Tullow, ENI, Aker, Anadarko, Hess, Equinor, Lukoil and PetroSA.

iv Developments in gas

Ghana, through the Volta River Authority (VRA) is part owner of the West African Gas Pipeline (WAGP). VRA (16.3 per cent), Nigerian National Petroleum Corporation (25 per cent), Royal Dutch Shell (18 per cent), Société Togolaise de Gaz (SoToGaz – 2 per cent) and Société Beninoise de Gaz SA (SoBeGaz – 2 per cent) own the pipeline through the West African Gas Pipeline Company Limited (WAGPCo). WAGP has been operated by Chevron since it became operational in 2008 supplying natural gas from contributing gas fields to Ghana, Nigeria, Benin and Togo.[12]

In 2011, the government established the Ghana Gas Company Limited (GGCL) to build, own and operate gas infrastructure to gather, process, transport and market natural gas resources. GGCL and SINOPEC concluded an engineering, procurement, construction and commissioning agreement in 2012 for the development of the Western Corridor Gas Infrastructure Development Project. Phase one of the project, commissioned in September 2015, consisted of a pipeline (onshore and offshore), a gas processing plant and an NGLs export system at Atuabo in the Western Region of Ghana. At full capacity, the facility produces 160 million standard cubic feet (mmscf) of lean gas,[13] 500 tonnes of liquefied petroleum gas (LPG), 80 tonnes of pentane and 45 tonnes of condensates daily.[14]

ENI's OCTP Integrated Oil and Gas Development Project started gas production from two deep-water subsea wells connected to the floating production storage and offloading *John*

Agyekum Kufuor in the Sankofa field in 2018. The OCTP project has gas processing capacity of 5.93 million standard cubic metres per day and supplies over 50 per cent of gas to thermal power plants through a 63km pipeline to Sanzule on the coast.[15] The project is connected to the gas infrastructure of the West Africa Gas Pipeline (WAGP) via phase 1 of the Takoradi–Tema Interconnection Project (TTIP) otherwise known as the WAGP reverse-flow project to allow the reverse-flow of gas from the Western Region of Ghana to the Tema power enclave for power production and other industrial use. The TTIP was initially contracted to transport 60 mmscf of gas per day. However, over the years, the TTIP has transported an average of 90 mmscf of gas per day from Ghana's Aboadze terminal to Tema power plants.

II LEGAL AND REGULATORY FRAMEWORK

The Constitution of Ghana vests untapped natural resources, including oil and gas resources, in the President of Ghana for and on behalf of the people of Ghana. To ensure the efficient exploitation, management and utilisation of petroleum resources and revenues accruing therefrom, a robust legal and regulatory framework has been developed to support the growth of a strong, sustainable and investment conducive upstream industry.

i Domestic oil and gas legislation

The main legislation relating to the upstream oil and gas sector is as follows:

- the Ghana National Petroleum Corporation Act 1983 (PNDCL 64);
- the Petroleum (Exploration and Production) Act 2016 (Act 919);
- the Petroleum Commission Act 2011 (Act 821);
- Petroleum (Local Content and Local Participation) Regulations 2013 (LI 2204) as amended;
- Petroleum (Exploration and Production) (General) Regulations 2018 (LI 2359) as amended;
- the Petroleum Hub Development Corporation Act 2020 (Act 1053);
- the Petroleum Exploration and Production-Data Management Regulation 2017 (LI 2257);
- Petroleum (Exploration and Production) (Health, Safety and Environment) Regulations 2017 (LI 2258);
- the Petroleum Revenue Management Act 2011 (Act 815) as amended;
- Petroleum (Exploration and Production) (Measurement) Regulations 2016 (LI 2246);
- Petroleum Commission Fees and Charges Regulations 2015 (LI 2221); and
- Petroleum (Exploration and Production) (General) (Amendment) Regulations 2019 (LI 2390).

ii Regulation

Government of Ghana (through the Ministry of Energy)[16]

The Presidency expresses its ownership and control over oil and gas activities through the Ministry of Energy.[17] The Ministry is responsible for the formulation, implementation and monitoring of sector policies. The Minister of Energy represents the government of Ghana in the negotiation of petroleum related agreements, the grants of petroleum rights and resolution of disputes.[18]

Parliament

Parliament is mandated by the Constitution to consider and ratify all petroleum agreements[19] or, where applicable, to exempt particular transactions from ratification[20] by a resolution of at least 75 per cent of its members.[21]

Petroleum Commission

As regulator, the mandates of the Petroleum Commission include:

- promoting planned, well-executed, sustainable and cost-efficient petroleum activities;
- recommending to the Minister national policies on petroleum activities;
- monitoring compliance with national policies, laws, regulations and agreements;
- complying with health, safety and environmental standards in petroleum activities;
- promoting local content and local participation in petroleum activities; and
- receiving applications and issuing permits for specific petroleum activities.[22]

iii Treaties

Ghana is signatory to the New York Convention and the Convention on the Settlement of Investment Disputes. Foreign arbitral awards are enforceable under the Alternative Dispute Resolution Act 2010 (Act 798), provided that the court is satisfied, inter alia, that the award was made under the New York Convention or other international convention ratified by Parliament.

Foreign judgments are enforced in Ghana based on the doctrine of reciprocity and Ghana has relationships with countries such as Brazil, France, Israel, Italy, Japan, Lebanon, Senegal, Spain, the United Arab Emirates and the United Kingdom. Countries without reciprocity must institute a fresh action. Ghana has ratified eight out of 25 signed bilateral investment treaties with China, Denmark, Germany, Malaysia, the Netherlands, Serbia, Switzerland and the United Kingdom.[23] Furthermore, double taxation agreements have been ratified with the Netherlands, Mauritius, Czech Republic, Switzerland, Belgium, Denmark, France, Germany, Italy, South Africa and the United Kingdom.[24]

III LICENSING

Prior to the E&P Act, petroleum licences were primarily awarded through direct negotiations. The E&P Act introduced a competitive bidding process for the grant of petroleum rights.[25] The law also vests the Minister of Energy with power to award petroleum rights without a competitive tender within defined circumstances and in a fair and transparent manner. The key processes in competitive tendering include:

- publication of an invitation to tender or invitation for direct negotiations by the Minister of Energy;[26]
- submission of expression of interest;[27]
- formal invitation to tender;[28]
- submission of bids;[29]
- decision on bids;[30]
- negotiations;[31] and
- entry into petroleum agreements.[32]

An expression of interest among others shall include general corporate information of the interested person, the specific block, a preliminary geological prospectivity of the area, financial and technical capabilities and the bidder's objective for engaging in petroleum activities in Ghana.[33] The formal invitation to tender will state, inter alia, the nature of blocks on tender, the tender process timeline, fees, information on access to data and bidding documents.[34] Bids are evaluated based on their responsiveness to the bid requirements and objective criteria prescribed by law, including rate of proposed royalty, bonus, knowledge transfer plan and health and safety.[35] Bids are opened publicly, and a list of participating bidders must be published in the gazette, national newspapers and the website of the Ministry of Energy. The preferred bidders are to negotiate the terms of the petroleum agreement with the Minister's team comprising senior officials from the Ministry of Energy, Petroleum Commission, the GNPC, the Attorney General's Department, the Ghana Revenue Authority and other advisers and consultants as required. The draft petroleum agreement must be approved by Cabinet and ratified by Parliament before it becomes effective and enforceable.

Direct negotiations for the award of a petroleum agreement may be adopted where:

- only one interested investor expresses interest in a block after an invitation to tender;[36]

- all or part of the area offered for tender in the competitive bidding process has not become the subject of a petroleum agreement, but the Minister determines that it is in the public interest for that area to be subjected to a petroleum agreement; and
- the Minister, in consultation with the Petroleum Commission, determines that direct negotiations represent the most efficient manner to achieve optimal exploration, development and production of petroleum resources in a defined area.[37]

The Ministry of Energy has developed the MPA, which is regularly updated and forms the basis for negotiation of new petroleum agreements. The key terms include:

- incorporation of the contractor in Ghana;
- the area of activity;
- a defined exploration period of up to seven years subject to extensions;
- state benefits, including carried and paid interest, additional oil entitlement, income tax, royalties, rental of government property and surface rent;
- contractor benefits, including the right to receive, remit, keep and utilise freely abroad all the foreign currency obtained from the sales of the petroleum;
- the right to request payment for sale of its oil entitlement in foreign currency;
- restrictions on assignment (subject to consent of the Minister);
- conditions for relinquishment;
- obligations of the contractor, including time for notification of discoveries, commencement of appraisal programmes and submission of development plans;
- the Commission's oversight of petroleum operations such as approval of work programme and budget prepared and submitted by the Commission;
- establishment of a joint monitoring committee between the contractor and the Commission to review, approve, reject or request modifications of the work programme of the contractor, audit the cost of operations, procurement processes and employment contracts made by the investor;
- content of development plans, including a plan for utilisation of associated gases;
- sharing, measurement and pricing of crude oil;
- conditions for use and flaring of natural gas;
- conditions for discovery and production of natural gas;
- environmental safety provisions, including the regulator's right to inspection and emergency reporting;
- title to equipment;
- relinquishment and decommissioning;
- local content (procurement of goods and services, contribution to training); and
- dispute resolution (mandatory 30-day period for consultation and negotiation, arbitration under the Arbitration Institute of the Stockholm Chamber of Commerce, Stockholm, Sweden).

The term of a petroleum agreement is up to 25 years and may be terminated early in accordance with its terms. The conditions for early termination include:

- relinquishment and surrender of the entire contract area;
- failure to give notification of a discovery after the maximum exploratory period;
- contractor's failure to commence operations within the time limit for commencement;
- submission of false information to the Petroleum Commission;
- assignment of rights without the consent of the Minister;
- insolvency or bankruptcy of the contractor; and
- material breach of the contractor's obligations.

IV PRODUCTION RESTRICTIONS

The total production of oil and gas from a contract area is based on proposals by the contractor as approved in a production schedule in a plan of development. The allocation of crude oil among the partners is based on the parties' interests as specified in the relevant petroleum agreement. A contractor is entitled to export all its crude oil entitlements. However, during emergencies affecting local supply, the Minister may request a contractor to sell all or part of its entitlement to the government to meet domestic requirements, subject to a fair price determined by world market prices of comparable crude oil sold at arm's length for export in major petroleum markets, adjusted for quality, location and conditions of pricing, delivery and payment.[38]

V ASSIGNMENTS OF INTERESTS

Contractors and subcontractors are prohibited from transferring interests in petroleum agreements directly or indirectly without the prior written consent of the Minister.[39] The E&P Act also prohibits the transfer of 5 per cent or more of the shares in a contractor or subcontractor's company without regulatory approval.[40] The Minister may impose conditions for approval of the assignment.[41] A petroleum agreement must also include a pre-emptive right to GNPC where a contractor intends to dispose of its interest in a petroleum agreement.[42]

VI TAX

The taxation regime for the upstream oil and gas sector is governed by the relevant petroleum agreement and the following applicable tax legislation; the Petroleum Income Tax Law, 1987 (PITL), the Income Tax Act, 2015 (ITA) as amended and Income Tax Regulations, 2016 (LI 2244). PITL, the ITA and all petroleum agreements in place to date provide for a 35 per cent rate for petroleum income tax.[43] Royalty rates are contractual and are set in the petroleum agreement. Negotiated rates in existing petroleum agreement range from 4 to 12 per cent of the gross production of crude oil.

Other impositions include:

- withholding taxes on payments from contractors to sub-contractors at 7.5 per cent (residents) and 15 per cent (non-residents);[44]
- contributions to the Local Content Fund, where the contractor's obligation is set in the petroleum agreement and that of the sub-contractor is a mandatory 1 per cent of the sub-contractor's revenue from contracts;[45]
- National Health Insurance Levy (NHIL) of 2.5 per cent;[46]
- Ghana Trust Fund Levy (GETFL) of 2.5 per cent;[47] and
- Covid-19 Health Recovery Levy (CHRL) of 1 per cent.[48]

Corporate income tax is calculated net of all approved expenses incurred in the petroleum operations as petroleum costs. Allowable deductions include rental fees, royalties, interest and maintenance costs.[49] Expenses such as research and development, bonus payments for petroleum licence and breach-related costs are not allowed.[50]

Employees are subject to personal income tax depending on their nationality and income with some exemptions for foreign employees working in Ghana for periods under 183 days.[51] Petroleum agreements may also exempt VAT, customs duties and taxes on imported equipment subject to parliamentary approval.[52]

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

The legal framework requires strict compliance with all environmental laws, including the Environmental Protection Agency Act 1994 (Act 490), the Environmental Assessment Regulation 1999 (LI 1652) and the best international industry practices.

i E&P Act and Petroleum (Exploration and Production) (Health, Safety and Environment) Regulations, 2017

The E&P Act and the petroleum agreement mandate industry participants to undertake petroleum operations in a safe and prudent manner. The Petroleum Regulations authorise the Minister to make regulations and guidelines on environmental protection, including the prevention of pollution and pollution damage from petroleum activities. The Petroleum Regulations aim to prevent the adverse effects of petroleum activities on health, safety and the environment and are strictly enforced. There are strict prescriptions on the manner in which oil and gas activities may be conducted and the standards to be maintained. These include operational standards and the requirement for the installation of equipment. A contractor is required to submit a decommissioning plan to the Minister for approval within two to five years before ceasing operations or the expiry of the licence or petroleum agreement. Licensees or contractors are also required to establish a decommissioning fund. For well abandonment, the contractor is required to notify the Commission, and treat and plug the well with the approval of the Commission and according to best practices.[53] A contractor is strictly liable for any loss or damage during decommissioning.[54]

ii Environmental Protection Agency (EPA) Act 1994 (Act 490)

This Act empowers the EPA to formulate environmental policies, prescribe standards and issue permits and abatement notices. The EPA can also request an environmental impact assessment (EIA) for oil and gas activities that may adversely affect the environment.[55]

iii Environmental Assessment Regulations 1999 (LI 1652) as amended (2002)

LI 1652 provides requirements for the following assessments to be undertaken:

- preliminary environmental assessments;[56]
- EIAs;[57]
- environmental impact statements;[58]
- environmental management plans;[59]
- environmental certificates;[60] and
- environmental permitting.[61]

The EPA has issued various guidelines for the EIA process in oil and gas activities. These include guidelines for offshore oil and gas development, dispersant importation and use, oil waste management and the dispersant policy. These require preliminary assessments for small- to medium-impact scale undertakings and EIAs for field development and production activities.

The E&P Act requires the restoration of affected areas and removal of hazardous items after petroleum operations.[62] Contractors are required to submit decommissioning plans for approval.[63] The contractor is responsible for decommissioning and the creation of a decommissioning fund during the life of the oil field to finance the decommissioning process.[64] Annual reports are submitted to the EPA for reviews and monitoring.

iv The role of the Ghana Maritime Authority

The Ghana Maritime Authority (GMA) is responsible for monitoring, regulating and coordinating activities in Ghanaian waters, including oil and gas activities.[65] It ensures safety and security in the environment, and issues permits for various activities, including the operation and movement of offshore drilling equipment and vessels.[66]

The GMA also implements Ghana's obligations as a member of the International Maritime Organization (IMO)[67] and ensures compliance with the design, construction and equipment requirements for offshore drilling units.[68]

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

Foreign investors are required to incorporate a limited liability company in Ghana that holds the interest in a petroleum agreement or to participate in the petroleum upstream industry.[69] The entity is required to register, obtain and maintain the relevant permit from the Petroleum Commission for the purpose of its business. Foreign investors who participate in the oil and gas service sector may operate through a joint venture with a minimum of 10 per cent

Ghanaian ownership, a strategic alliance or a channel partnership with a Ghanaian partner. Entities with foreign ownership are required to register with the Ghana Investment Promotion Centre before starting operations.[70]

ii Capital, labour and content restrictions

LI 2204 regulates local content and local participation in the upstream oil and gas industry. Some of the key stipulations include the following:

- minimum of 5 per cent indigenous participation (other than GNPC) in petroleum agreements;[71]
- minimum of 10 per cent Ghanaian ownership in service providers, increasing to 50 per cent in five years and 60–90 per cent after 10 years;[72]
- 100 per cent Ghanaian ownership for IGCs;[73]
- provision of services through channel partnerships and strategic alliance as alternative arrangement for collaboration with foreign companies;[74]
- specific goods and services reserved for IGCs;[75]
- minimum local content targets for areas such as front-end engineering design (FEED), fabrication and construction, materials and procurement, well drilling services, marine operations and logistics services and transportation, supply and disposal services;[76]
- submission of a local content plan prioritising local goods, services, local professionals and a training plan;[77] and
- sub-plans for employment and training,[78] research and development,[79] technology transfer,[80] legal[81] and financial.[82]

LI 2204 places an obligation on contractors to hire more Ghanaians over time and aim for almost 100 per cent indigenous employment within 10 years of starting petroleum operations.[83] Employment in the sector is also regulated under the Labour Act and the Pensions Act for both Ghanaians and expatriates.

iii Anti-corruption

The Petroleum Commission monitors compliance with national law on anti-corruption and bribery. Foreign entities are monitored by other public agencies for compliance with foreign anti-corruption legislation that has extraterritorial effects.

The E&P Act and LI 2359 provide mandatory rules on competitive tendering and direct negotiations to ensure a fair, open and transparent award of petroleum rights. A public register of all petroleum agreements has also been created.[84] Furthermore, anti-corruption warranty and reporting commitments are included in petroleum agreements, covering compliance with the anti-corruption laws of Ghana, investor home countries and international law, including the Convention on Combating Bribery of Foreign Public Officials in International Business Transactions, the United States of America Foreign Corrupt Practices Act 1977 and the United Kingdom Bribery Act 2010.

IX CURRENT DEVELOPMENTS

i National Energy Transition Framework

The government of Ghana has published the Energy Transition Framework 2022–2070 to guide Ghana's journey towards a net-zero future. The framework is aimed at 'decarbonising the energy sector and reaching net-zero emissions by 2070 while ensuring socioeconomic growth and the use of Ghana's natural resources'.[85] The framework is expected to complement existing efforts with new measures, such as increased renewable energy penetration, conversion of thermal plants to natural gas and the integration of nuclear power into the energy mix.[86] The framework has outlined specific net-zero targets for 2030, 2040, 2050 and 2070.

The following key strategies have been identified:

- decarbonisation – increased tree planting to offset emissions, investment in renewable energy projects, use of natural gas as a transition fuel for industry and transport, use of electric vehicles and nuclear energy, among other things;
- energy access and security – rapid oil and gas exploration and development, expanding gas infrastructure, increased use of LPG, exploitation of lithium and other resources for clean energy;
- energy efficiency – promotion of energy efficiency programmes, use of efficient lighting and construction of energy efficient building; and
- cross-cutting – decentralisation of the transition process, funding mechanisms, increase education and regional cooperation, and local content and participation.

The implementation of the framework is estimated to cost approximately US$562 billion.

ii Industry recovery from the impact of covid-19 pandemic

Following recovery from the covid-19 pandemic, the Ghanaian upstream industry has seen a sturdy growth in activities. All IOCs have resumed full operations following an industry-wide restitution of the time lost to the various licences as a result of the pandemic. In addition to technical operations, there has been some M&A activity in the sector. Notable developments include the following.

Aker Energy-AFC acquisition transaction

In April 2023, the Africa Finance Corporation (AFC) through its investment subsidiary, AFC Equity Investment Ltd, acquired 100 per cent of the shares in Aker Energy through an indirect share sale transaction with the ultimate shareholders of Aker Energy. Following the transaction, AFC is now the sole shareholder of Aker Energy and a 50 per cent owner of the Deepwater Tano Cape Three Points (DWT/CTP) block offshore Ghana, comprising discoveries of 450 to 550 million barrels of oil equivalents, including the Pecan field. AFC had previously invested US$200 million in senior secured bonds in the DWT/CTP block development.[87] Upon completion of the transaction, Aker Energy changed its name to Pecan Energies.[88]

Anadarko-Kosmos acquisition transaction (Jubilee and TEN fields)

In October 2021, Occidental Petroleum Corporation announced the sale of Anadarko WCTP's interest in the Jubilee Field and TEN field to Kosmos and GNPC.[89] Tullow completed the exercise of its pre-emption rights to acquire parts of Anadarko's interest in the Jubilee and TEN fields.[90] PetroSA has also exercised its right of pre-emption and the transaction is yet to receive final approval by the state.[91] In line with GNPC's strategy to increase its interests in existing oil blocks in Ghana, the Anadarko-Kosmos transaction involved a further acquisition of a 7 per cent interest by GNPC regarding the DWT/WCTP assets.

Production in the Jubilee Southeast field

In July 2023, Tullow announced the successful delivery of first oil from the Production in the Jubilee Southeast (JSE) field area, an extension of the Jubilee field that was developed based on the Greater Jubilee Full Field Development approved by the government of Ghana in October 2017. The development, which was completed over three years, cost approximately US$1 billion with most of the sub-sea infrastructure being fabricated in Ghana, and the works being undertaken by Ghanaian workforce.[92]

Implementation of the Ghana Value Maximisation Plan

The Ghana Value Maximisation Plan (GVMP) is a 10-year investment plan currently being executed by the Jubilee and TEN partners. It was launched in 2021 and entails over US$4 billion of capital investment aimed at delivering increased oil production in the Greater Jubilee TEN fields. The partners planned to undertake a multi-year, multi-well drilling campaign. Tullow successfully drilled and completed a drilling campaign of three wells, which increased oil production in the Jubilee field by 11.7 per cent. In its first two years of implementation, the daily average production in the Jubilee field rose from 74,000 barrels of oil per day (74.9 kbopd) to 83,000 barrels of oil per day (83.6 kbopd) as of the end of 2022. In 2022, the Jubilee field contributed 60 per cent of total oil production, although production in other fields declined.[93] The plan is estimated to deliver approximately US$13 billion (at an oil price of US$65 to US$70 per barrel of oil) in net value to the government of Ghana through, inter alia, royalties and taxes.

iii Approval of development plan for Pecan Field

Pecan Energies in July 2023 announced the approval of the Plan of Development and Operation (PDO) for the DWT/CTP block, by the government of Ghana. The PDO presents an overall plan for phased development and production of the resources in the DWT/CTP contract area. The phased development will begin with the Pecan field in two phases: Phase 1a and Phase 1b. The Pecan field is the largest of several discoveries in the contract area with 268 million barrels expected to be produced in Phase 1a+1b with a CAPEX of US$3.5 billion. In total, it is estimated that all discoveries in the DWT/CTP contract area have a recoverable resource potential of 550 million barrels.[94] The field development is anticipated to commence following final investment decision by the partners by the end of 2023.

iv AGM relinquishment of SDWT block

In March 2023, AGM Petroleum and its owners announced a decision to relinquish the South Deep Water Tano (SDWT) block offshore Ghana to the government of Ghana due to challenges in securing the substantial investment required to proceed with the project. In the course of the 10-year term of the licence, AGM carried out substantial activity in the contract area, namely seismic reprocessing and the drilling of two ultra deepwater wells, including the Nyankom discovery. Nyankom is situated at water depths of 2700–3000 metres, with 127 million barrels of proven oil reserves with an estimated 400–650 million more in its immediate surroundings.[95]

v Ghana and Eni dispute over unitisation of Eni and Springfield blocks

Eni, the operator of the OCTP and OCTP Block 4 contract areas in Ghana, instituted a claim against the government of Ghana at the London Court of Arbitration in 2021, seeking:

- a declaration that a directive of the government (through the Minister of Energy) in respect of the unitisation of its Sankofa field and Springfield's Afina field represents a breach of the petroleum agreement; and
- an order against Ghana for the payment of damages for losses suffered by Eni in this regard, and payment of all costs and expenses arising out of the arbitration.[96]

The matter is currently ongoing. The dispute followed an April 2020 ministerial directive that Eni and Springfield unitise the development of their respective Sankofa and Afina blocks. Eni declined to comply with the directive, prompting Springfield to institute an enforcement suit against Eni. The High Court of Ghana ordered Eni to pay 30 per cent of all revenue generated from the Sankofa field, into escrow until the final determination of the suit.[97] The Supreme Court of Ghana on 7 June 2022 upheld the High Court's decision.[98]

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Chapter 9

Greenland

Michael Meyer[1]

Summary

I INTRODUCTION

Greenland, the world's largest island, is one of the areas in the world where oil and gas resources have been least explored despite the fact that Greenland has considerable potential hydrocarbon resources. This is largely owing to the extreme natural conditions, remote location, sensitivity towards environmental issues and thus high exploration costs. Greenland became an integral part of the Danish Realm in 1953. Along with Denmark, Greenland was an EU member from 1973 until a referendum in 1985, in which Greenland left the union and has not been a member since.

Following a referendum in 1979, the Danish Parliament granted Greenland self-government. In 2008, another referendum regarding Greenland's autonomy was held. On the basis of the results of the 2008 referendum (although non-binding) and the adoption of the Greenland Self-Government Act,[2] Greenland has had self-government from 21 June 2009. Greenland has extensive self-government under the Greenland Self-Government Act, but Denmark still exercises control over several policy areas on behalf of Greenland, including foreign affairs, security and financial policy (in consultation with Greenland's self-rule government). As part of self-government, Greenland owns and has disposal rights over all mineral resources, including oil and gas resources located within Greenlandic territory. Furthermore, Greenland has had all legislative and executive powers regarding mineral resources from 1 January 2010 under the Mineral Resources Act.

Oil and gas licensing in Greenland started in the early 2000s, with licensing rounds in 2002, 2004, 2006, 2010 and 2012–13. In addition, Greenland has offered separate open-door procedures in the Jameson Land and south-west Greenland areas. Additionally, licensing rounds have been conducted for the Disko-Nuussuaq area (2016), Baffin Bay (2017) and Davis Strait (2018). However, no licences have been granted in the latest licensing rounds, but two licences were granted in 2019. Despite several exploration licences being awarded, there is no oil or gas production in Greenland to date.

Certain non-exclusive prospecting licences and exclusive exploration and exploitation licences for hydrocarbons have been granted to, inter alia, various international oil companies from Europe and North America. Each licence is granted for a defined geographical area and time period. However, during the past years, several of the major players have surrendered some or all of their licences. To date, the exploration activities have not led to any exploitation activities.

Considering these circumstances, on 31 January 2020, the government of Greenland launched an oil strategy for the period 2020–2024. The plan includes a proposal to modernise the legislation. On 24 June 2021, the Greenlandic government decided to cease issuing new licences for oil and gas exploration in Greenland, and therefore the open-door procedures have been closed, and the upcoming licensing rounds have been cancelled. This means that only activities based on existing licences may be conducted.

II LEGAL AND REGULATORY FRAMEWORK

Greenland exercises its own control over licensing for oil and gas exploration and production, under the authority of the Ministry of Mineral Resources. The decision of the Greenlandic government to not issue further licences must be seen in this light. Consequently, it is expected that the legal and regulatory framework is amended to be aligned with this decision. The rest of this chapter deals with the applicable legal and regulatory framework.

i Domestic oil and gas legislation

The origin of Greenland's regulation of mineral resources, including oil and gas, is the formerly applicable Danish Mineral Resources Act. The current regulation is found in the Mineral Resources Act[3] (the Act) entering into force on 1 January 2010. The Act transfers the former joint Greenlandic and Danish responsibility for the natural resources in Greenland to the sole responsibility of Greenland. Subsequent changes regarding, for example, the relevant authorities, appeals and the transfer of certain rights and obligations to the

Greenlandic government entered into force on 1 January 2013 with additional changes to obligations regarding public hearings of environmental impact assessments (EIAs) and social sustainability assessments entering into force on 1 July 2014. Most recently, the Act was amended in the autumn of 2018[4] and in the autumn of 2019.[5] The Act is a framework act setting out the main principles of the administration of the mineral resources and subsoil activities. Within this framework, the government of Greenland is entitled to impose specific provisions in, for example, model licences. Notably, in 2023, a comprehensive revision of the legislation in the mineral resources area was implemented; however, this legislation does not apply to hydrocarbons, which remain governed by the Act.

ii Regulation

The general authority for hydrocarbons is the Ministry of Mineral Resources (MMR), including the responsibility for strategy, policymaking and social impact assessments (SIAs). Environmental aspects are handled by the Environmental Agency for Mineral Resources Activities (EAMRA) under the Ministry of Science and Environment. The day-to-day aspects of the industry and licence applications are handled by the Mineral Licence and Safety Authority (MLSA). Licensees and other parties covered by the Act communicate with the MLSA and receive all notifications, documents and decisions from the MLSA (i.e., a one-door administrative authority). In general, licences for hydrocarbons are granted by the government.[6]

The aim of the Act, and as such the responsibility of the government and of the established authorities, is to ensure that performance of activities required under the Act is carried out in accordance with acknowledged best international practices under similar conditions. Complaints about decisions made by the MLSA or the EAMRA may be brought before the government within a six-week time limit from the date of notification.

iii Treaties

In 1972, Denmark acceded to the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards. It was confirmed that the convention would apply to Greenland as of 10 February 1976. Furthermore, judicial decisions enforceable in Denmark, based on, for example, conventions to which Denmark is a party, are recognised as enforceable by the courts in Greenland.

There are no significant trade or bilateral investment treaties entered into by Greenland; however, Greenland is a member of the World Trade Organization and its rules apply to Greenland.

Greenland has entered into double taxation agreements with Denmark, the Faroe Islands, Iceland and Norway.

Furthermore, bilateral agreements on the exchange of information have been made between Greenland and several other countries.

III LICENSING

An overview of the licensing regime for hydrocarbons (oil and gas) is set out below.

The licensing generally takes place on standard 'model terms' which may be amended according to the requirements for the licence in question.

Hence, the focus here is on the requirements set out in the Act as these requirements establish the framework for the terms of the licences granted. In general, any party may apply for a licence for prospecting, exploration or exploitation within a specific geographical area. During the application process for exploration or exploitation, the MLSA will, in particular, attach importance to the technical and financial capabilities of the applicant as well as how the applicant intends to carry out the exploration or exploitation or both, as set out in more detail below.

i Hydrocarbons

Historically, licences for hydrocarbons have been awarded through one of the following procedures:

- an open-door procedure by which a certain geographical area, within a specified period of time as determined by the Greenlandic self-government, is open for applications for licences;
- a licensing round whereby the government of Greenland offers a specified geographical area for licensing based on specific licensing terms;
- a 'specific licensing round' if an application for a licence for an area has been handed in outside of a licensing round and the government is of the opinion that the application should be considered; and
- a 'neighbouring procedure' whereby a licensee based on geological or exploitation considerations is granted a licence to an adjoining geographical area.

Regardless of the specific licensing procedure, any licence for prospecting, exploration or exploitation of hydrocarbons is granted through an application process operated by the MLSA. Any licence will be granted in accordance with the Act and will be based on the terms and conditions published in connection with the licence procedure in question. Any licence will be subject to the payment of fees and charges stated in the licensing documentation. Certain fees and charges may be changed during the term of the licence.

Irrespective of the procedure used, a prospecting licence may be granted for a period of up to five years with the possibility of extensions. A prospecting licence is non-exclusive, and therefore several different licences for prospecting may cover the same geographical area.

In respect of licences for exploration, such licences are usually granted for up to 10 years with the possibility of extensions of up to three years at a time. Licences for exploration are normally exclusively for the area covered by the licence. In general, the terms of an exploration licence will set out the obligations on the licensee to explore the area as well as obligations in respect of areas that must be relinquished during the term of the licence.

A licensee holding a licence for exploration of a specific geographical area has a right to obtain a licence for exploitation in that area, provided that the licence terms of the exploration licence have been fulfilled.

Licences for exploitation are normally granted for a period of 30 years. A 'stand-alone' exploitation licence may be granted for a period of up to 10 years with the possibility of multiple extensions; each extension may be granted for a period of up to three years.

The aggregate period of (extended) exploitation licences may not exceed 50 years.

ii Restrictions on foreign participation, capital requirements and legal immunity

Any licence for exploitation of hydrocarbons may only be granted to a public limited company domiciled in Greenland (see Section VIII.i). A licensed company may only carry out the activities set out in the licence and may not be subjected to joint taxation, unless joint taxation is mandatory. Furthermore, licensed companies must trade on arm's-length terms and not be more thinly capitalised than the rest of the group of companies to which the company holding the licence belongs. However, the licensed company's loan capital may exceed the shareholders' equity by up to a ratio of 2:1.

Any licence issued under the Act receives immunity from legal prosecution.

iii General requirements for licensees

Licences under the Act will generally include:

- terms on the fees and charges payable to the Greenland self-government during the licence period;

- that a company fully owned by the Greenland self-government is entitled to join in the licence on specified terms;
- that the licensee may be required to employ local labour to a certain extent (see Section VIII.ii);
- that the licensee may be obligated to process exploited minerals in Greenland; and
- that a licensee may be required to conduct surveys and prepare and implement plans to ensure that exploration and exploitation of the mineral resources in question are socially and environmentally sustainable.

A prospective licensee for hydrocarbons under the Act is subject to a number of more or less strict criteria.

Particular importance is attached to the technical capabilities of any potential licensee for exploration or exploitation licences. In short, the MLSA considers the expert knowledge of the applicants and their previous experience in exploration or exploitation of hydrocarbons in general, as well as specifically in places with conditions comparable to those of Greenland.

An exploration or exploitation licence will usually place an obligation on the licensee to make very substantial investments prior to the commencement of any commercial activities. Additionally, there are specific requirements regarding the capital or financing of the licensee that must be upheld as set out above. Hence, the financial capability of any potential licensee of hydrocarbons is closely considered. The MLSA generally requires a full parent company guarantee as well as an insurance policy to cover any liability arising under the licence applied for. Any licensee of offshore activities must be a member of the Offshore Pollution Liability Association Ltd (OPOL).

Under the previously planned, but now cancelled, open-door procedures in 2020 and the licensing rounds in 2021, the fee for the submission of an application was published to be 50,000 Danish kroner and 200,000 Danish kroner for the granting of an exploration and exploitation licence or for the extension for exploration purposes. The annual fee for an exploitation licence was published to be one million Danish kroner. Furthermore, the licensee must reimburse the MLSA for all costs and expenses incurred in the processing of the application. Additional amounts based on, inter alia, royalties and drilling commitments will also be payable.

iv Specific technical and financial selection criteria

In the selection of licensees for exploration and exploitation licences, particular importance is attached to the technical and financial capabilities of the applicant, as well as the relevant authorities' assessment of the applicant's former activities in Greenland (if any). If there is more than one applicant for a specific geographic area, particular importance will be attached to the date of the application, the applicant's previous experience from activities in Greenland and possible previous fieldwork carried out by the applicant in the geographic area covered by the licence. Additionally, the applicant's offer to provide training and employment to Greenlandic labour for fieldwork regarding the specific exploration project is considered.

Furthermore, an applicant's past lack of efficiency or instances of non-performance of obligations under previous licences will also be taken into consideration by the MLSA in the assessment. Additionally, other relevant, objective and non-discriminatory criteria may be taken into consideration to select among equally qualified applicants.

IV PRODUCTION RESTRICTIONS

Under the Act and the standard terms for hydrocarbon prospecting licences (dated March 2009), there are no restrictions on production entitlements, exports of oil and gas or sales of production into the local markets and no laws applicable to price setting related to oil or gas. This does not, however, preclude the government from applying these or similar production restrictions in the granting of a licence on a case-by-case basis.

V ASSIGNMENTS OF INTERESTS

Under the standard terms for hydrocarbon prospecting licences (dated March 2009) and in accordance with the Act, a licence or any part thereof cannot be directly or indirectly transferred to any other party unless the transfer is approved by the government of Greenland. A similar wording is included in the model licence for the 2021 licensing round. There are no express statutory rights of first refusal or preferential purchase rights upon transfer. A fee is payable on approval of any transfer.

VI TAX

The tax authorities of Greenland consist of two administrative bodies: the Tax Administration and the National Tax Board.

The Greenlandic tax system is quite simple compared with most other developed countries, with only a few tax and fiscal acts.

Companies pay corporate income tax. Companies subject to the Mineral Resources Act may apply for a partial exemption reducing the corporate income tax rate, insofar as this exception follows from the mineral resources licence.

The corporate tax rate is 25 per cent for both Greenlandic and foreign companies from 1 January 2020. On top of the corporate tax, there is a 'surcharge' of 6 per cent of the corporate tax payable. Licensees to oil and mineral licences are exempt from the 6 per cent surcharge according to current practice.

Furthermore, licensees must pay certain fees and surplus royalties to the government pursuant to the Mineral Resources Act. The model licence terms for upcoming rounds in Baffin Bay contained surplus royalty levels of 3.75 per cent, 8.75 per cent and 15 per cent at 35 per cent, 45 per cent and 55 per cent internal rates of return, respectively. However, the royalty levels are likely to differ between licences and should therefore be scrutinised on an individual basis.

A licence to mineral resources may include provisions for the payment of an annual fee calculated based on the size of the area covered by the licence (land fee). Furthermore, conditions on payment of a fee calculated based on, inter alia, extracted raw materials (production fee) or conditions on payment to Greenland of a share of the profits from the activities under the licence (dividend fee) may apply. The fee provisions are set out in the licences.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

The Act contains elaborate provisions on the protection of the environment. The provisions aim to prevent, limit and control pollution of and other impact on nature and the environment owing to activities carried out pursuant to the Act. It is a general prerequisite that any activities to be carried out under the Act that may result in pollution must be carried out in a place where the danger of pollution is limited to the extent possible. Furthermore, any licensee meeting the obligations under a licence must ensure and promote the use of the best available techniques, including the least-polluting facilities, machinery, equipment, processes, technologies, raw materials, substances and materials and the best possible measures for the reduction of pollution insofar as this is technically, practically and financially feasible.

Regarding the more general protection of the environment, the Act sets out that if an activity or a facility is presumed to have a significant negative impact on the environment, a licence or an approval may only be granted based on, inter alia, an assessment of the impact of the activity or facility on the environment and after the public and the authorities being affected have had an opportunity to express their opinion.

This requires that an EIA is carried out prior to, for example, exploitation of hydrocarbons. The EIA must be carried out and paid for by the applicant according to the guidelines issued by the authorities. Additionally, the authorities may require that an SIA is carried out in the event that an activity under the Act is assumed to have a significant impact on social conditions. This assessment must also be carried out at the cost of the applicant and in accordance with the guidelines set out by the authorities. The authority responsible for the SIA is the MMR.

Environmental damage is defined as:

- the pollution of the soil, the sea, the sea floor, the subsoil, water or air;
- pollution of or other negative impact on the climate;
- pollution of or other significant negative impact on nature, including human beings, fauna or flora; and
- significant disturbance of nature, including human beings, fauna or flora owing to noise, vibrations, heat and light.

The party responsible for environmental damage is stated as the party performing, being in charge of or supervising the performance of an activity under the Act. In this respect, if the party concerned is a party other than a licensee of the licence relating to the activity, the licensee is jointly and severally liable and responsible for the activity in question.

On the basis of the licence's strict liability for (also) environmental damage, the licensee must pay compensation for this damage. Hence, compensation must be paid for personal injury and loss of dependency, damage to property, other financial losses, reasonable costs of measures to prevent and mitigate pollution and any other negative impact on the environment, climate and nature. The same applies to the restoration of the environment and nature. The amount of compensation payable may under certain circumstances be reduced to a lower amount than the actual amount of damage.

There is special regulation of offshore facilities. The authorities may set out regulations to mitigate the health and safety risks on offshore facilities and it is the obligation of the licensee to identify, assess and reduce the risks to the extent possible. The authorities will set up an emergency committee with the task of coordinating the actions of the authorities in the event of accidents or emergencies.

Any licence granted under the Act sets out the obligations of the licensee regarding clean-up and demolition of plants and other facilities established by the licensee as well as the monitoring by the authorities of such activities.

Any application for exploitation must set out a detailed plan with the steps to be taken upon cessation of exploitation activities regarding the plants and other facilities established by the licensee and how the area in question will be left (closure plan). In the event that the licensee intends to leave behind certain facilities that, owing to environmental, health or safety reasons will require maintenance or other measures, the closure plan must include such maintenance and other measures as well as the monitoring thereof. Furthermore, the closure plan must set out how it will be implemented financially. The closure plan must be approved prior to the commencement of any exploitation activities, and the approval may include the provision of measures regarding environmental protection, health and safety. The licensee may be obliged to provide (financial) security to ensure the fulfilment of the closure plan.

Any suspension of exploitation activities requires prior approval to ensure that the facilities are adequately maintained and monitored during the suspension. Any closure plan must at all times be kept up to date considering the current exploitation activities of the licensee. The licensee must accept that the closure plan, including the financial security provided during the term of the exploitation licence, may require amendment by the authorities owing to developments in the exploitation activities and the general development of society or both.

Licensees are subject to strict liability for any acts or omissions under the licence causing damage. However, the compensation payable may be reduced or even lapse if the aggrieved party has intentionally or (grossly) negligently contributed to the damage.

The licence terms will usually require the licensee to take out insurance coverage for liability or the provision of other (financial) security. Regarding offshore activities, membership of OPOL is mandatory for the operator of the activities.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

As a starting point, licences for exploitation of hydrocarbons may only be granted to a public limited company domiciled in Greenland. Accordingly, the other forms of legal establishment (private limited company and branch of a foreign company) are not suitable for oil or gas licensees.

The formation of a public limited company requires one or more founders. The founders must sign a memorandum of association containing the articles of association of the company. Furthermore, the memorandum of association must contain information about, among other things, the rules concerning subscription to the share capital, formation costs and the valuation of possible assets to be taken over by the new company. There are no residence requirements for the founders of companies in Greenland. However, a company may only have one shareholder who is a foreigner or a foreign entity.

ii Capital, labour and content restrictions

There are no restrictions in Greenland on movement of capital or access to foreign exchange.

According to the Act on the Regulation of the Accession of Labour to Greenland,[7] an employer must prove that a vacancy cannot be filled by local workers before hiring foreign (including Danish) labour. The purpose of the act is to ensure that Greenlandic labour forces get priority access to work available in Greenland. However, to promote investment and completion of large-scale projects of particular importance to Greenland's economic development, Greenland has enacted the Act on Construction and Works in relation to Large-Scale Projects[8] (the Large-Scale Act).

iii Anti-corruption

Procedures in Greenland generally operate in a transparent manner, with limited perceived exposure to or reputation of corruption. In March 2015, the MMR introduced its zero-tolerance policy on corruption. In accordance with international recommendations, the MMR stated that it aims to forestall potential corruption risks by implementing a proactive anti-corruption policy. The policy also sets out guidelines applying to all employees of the MMR and its subordinate institutions on how to respond to corruption and the risk of corruption. Zero tolerance applies to conflict of interest, bribery, fraud, extortion and other forms of corruption as detailed in the policy. Greenland has also enacted the Act against Money Laundering,[9] setting out detailed measures against money laundering.

IX CURRENT DEVELOPMENTS

On 31 January 2020, the government of Greenland adopted a new oil and gas strategy for the period 2020–2024. The main focus of the strategy was to promote oil and gas exploration in Greenland. To pursue this focus, several tracks were identified, including:

- opening of new licence areas (both onshore and offshore); and
- adapting competitive framework conditions, such as reduced taxes under a new 'first-mover' scheme to apply during the strategy period.

The oil strategy for 2020–2024 was suspended on 24 June 2021 for the reason described below.

Around a year later, a new government was formed and the focus changed. On this basis, on 24 June 2021, the government of Greenland decided to cease issuing new licences for oil and gas exploration in Greenland, and hence the open-door procedures have been closed, and the upcoming licensing rounds have been cancelled. In short, Greenland has halted new exploration.

Greenland's national oil company, Nunaoil (now NunaGreen), announced in 2018 that it had initiated a comprehensive resource assessment project to identify the areas of Greenland that have the greatest petroleum exploration potential.[10] The project is now cancelled due to the political decision not to grant licences for oil and gas exploration.

Taking the recent developments into account, it is unlikely, and would require a policy change, for further oil and gas exploration and exploitation activities to commence in Greenland. This is underpinned by the fact that in November 2022, the Greenlandic government decided to change the name and objective of the state-owned hydrocarbon company NunaOli A/S, so that this company in the future could focus exclusively on renewable energy under the name NunaGreen A/S. Furthermore, the Greenlandic government proclaimed on 1 November 2021 to sign the Paris Agreement and has accordingly begun the preparation of a climate strategy. Efforts in this regard continue to be ongoing.

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Endnotes

1 Michael Meyer is a partner at Gorrissen Federspiel. The author is grateful to his colleague, legal counsel Jacob Sandholt, for his assistance with this chapter.
2 Act No. 473 of 12 June 2009 on Greenland's Self-Government.
3 Inatsisartut Act No. 16 of 27 November 2018. The amendment act entered into force on 1 January 2019 and concerned changes for reasons of consistency following the introduction of new legislation on hydro power and on municipal administration.
4 Inatsisartut Act No. 39 of 28 November 2019. The amendment act entered into force on 1 January 2020 and removed the requirement that the applicant must delineate 'commercially exploitable deposits', see Section 29(2). Further, the amendment act outlines that a company with an exploitation licence, and exclusively the licensee or licensees, may carry out prospecting and exploration within their exploitation licence, cf. Section 29(4). Finally, the amending act outlines that if the licensee or licensees do not meet the stipulated deadlines, then their licence may be lapsed or revoked by the government, see Section 30(2).
5 Inatsisartut Act No. 26 of 13 June 2023 on Mineral Activities.
6 For more information, see www.govmin.gl.
7 Inatsisartut Act No. 27 of 30 October 1992 with subsequent amendments.
8 Inatsisartut Act No. 25 of 18 December 2012 with subsequent amendments.
9 See the section on resource assessment on Nunaoil's website, www.nunaoil.gl.
10 Inatsisartut Act No. 5 of 19 May 2010.

Chapter 10

India

Venkatesh Raman Prasad[1]

Summary

I INTRODUCTION

India is the third largest energy consumer in the world,[2] and oil and gas, according to source-wise consumption of energy, comprised around 38 per cent of overall energy consumption during 2021–22.[3] As of April 2022, the country had estimated reserves of about 651.77 million metric tonnes of crude oil and about 1,138.67 billion cubic metres of natural gas.[4] In 2022–23, crude oil production was about 29.2 million metric tonnes (provisional),[5] and the natural gas production of the country was about 34,450 million metric standard cubic metres (provisional).[6] With this level of production, about 87.4 per cent of the crude oil and about 43.9 per cent of the natural gas consumed in India are imported.[7]

The Indian government has occasionally adopted various licensing regimes with a view to enhance domestic production of hydrocarbons. As a general principle, an acreage awarded under a licensing regime continues to be regulated under such a regime, and any subsequently amended regime is applicable to acreages awarded under that regime. Therefore, at present, different blocks are governed by different licensing regimes (depending on when they were awarded).

The four broad categories of licensing regime that are presently applicable are discussed below.

i Nomination regime (for blocks awarded till late 1970s)

Under this regime, the petroleum exploration licence (PEL) was granted to the two national oil companies – Oil India Limited (OIL) and Oil and Natural Gas Corporation Limited (ONGC) on a nomination basis.

ii Pre-NELP regime (for blocks awarded between 1980 and 1995)

Pre-NELP Exploration Rounds: 28 exploration blocks were awarded to private companies. OIL and ONGC were given the right to participate in the blocks after discovery. At the end of the financial year 2022–23 (i.e., as on 1 April 2023), nine pre-NELP production sharing contracts (PSCs) were active.[8]

Regarding pre-NELP discovered field or development rounds, for the small, medium-sized and discovered fields (proven reserves as discovered by ONGC and OIL), petroleum mining lease (PML) was granted to private parties for these fields. The Indian government has signed 28 PSCs for 29 discovered fields. At the end of the financial year 2022–23 (i.e., as on 1 April 2023), 21 PSCs were active.[9]

iii NELP regime (for blocks awarded between 1997 and 2010)

The new exploration licensing policy (NELP) was implemented from 1999.[10] Blocks were awarded to companies (including private and foreign companies) through an international competitive bidding process.

The NELP regime was based on the 'production sharing model' (i.e., the Indian government is paid a part of the profits, after deducting the costs incurred by the contractor). The percentage of profit proposed to be paid by the contract was one of the biddable criteria. Some 254 production sharing contracts were signed under nine licensing rounds. At the end of the financial year 2022–23 (i.e., as on 1 April 2023), 33 PSCs under NELP regime were active.[11] One of the main issues with the regime is that there is an excessive oversight by the Indian government (through management committee), as the costs incurred by the contractors have to be approved by the Indian government.[12] Additionally, the approval of the above-mentioned management committee is also required for any discoveries as well as the field development plan, causing further delays.

iv HELP regime (for blocks to be awarded after 2016)

To further attract the private participation and foreign investments, in 2016, the Indian government introduced the hydrocarbon exploration and licensing policy (HELP).[13]

The key features of HELP include:

- uniform licence for exploration and production of all forms of hydrocarbon, including non-conventional hydrocarbons such as shale gas, coal bed methane, tight gas and gas hydrates, can open acreage licensing policy (OALP) under which prospective bidders have the option to carve out exploration blocks;
- a revenue sharing model with the Indian government;
- marketing and pricing freedom for the crude oil and natural gas produced;
- reduced royalty rates at the well head for crude oil and natural gas;
- unified licensing for conventional and non-conventional resources; and
- exploration rights on all of the contract area for the full life of the contract.

In February 2019, the Indian government approved a 'policy framework on reforms in exploration and production of oil and gas', pursuant to which the parameters under the policy are applicable from the fourth bidding round under OALP which was launched on 27 August 2019. The policy focuses on exploration and highlights a shift from revenue maximisation to production maximisation.[14]

Some of the key reforms include the following:

- for Category I basins (that have established production): an increase in weightage of minimum work programme and decrease in weightage of revenue share for evaluation of bids, a ceiling of 50 per cent on revenue share at higher revenue point and a reduction in timelines for completion of minimum work programme;
- for Category II and III basins (that have contingent and prospective resources, respectively): the award of exploration blocks solely on work programme and no production and revenue sharing (except in case of windfall gain);
- the grant of concessional royalty if production commences within four years in the case of onshore and shallow water blocks, and within five years for deep water and ultra-deep water blocks; and
- the constitution of a committee of external eminent persons or experts for dispute resolution. Parties under existing contracts may also choose to refer disputes and differences to the committee provided that the parties agree in writing and agree not to invoke arbitration under the applicable host government contract.

Regarding the new OALP Round VIII (Eight), recent modifications have also been brought under the bidding documents (including the Model RSC), which cover the following changes:

- single stage liquidated damages for delays in commercial production timelines, instead of dual liquidated damages imposed for delays in commencement of development operations and commercial production;
- the definition of 'force majeure' specifically includes pandemics, national trade sanctions and embargoes under applicable laws of India and terrorism;
- retention period of three years has been introduced in the event that commercial viability of discovery cannot be established upon completion of the appraisal programme. Pursuant to payment of prescribed retention fees, a retention period is allowed after government approval for factors such as development of infrastructure and technology for sub-commercial discoveries and market linkage; and
- change in consortium is allowed during bidding stage without affecting the benefit of originator incentive. However, the operator cannot change until the contract has been signed.[15]

To date, seven OALP bid rounds have been completed under the HELP regime wherein 134 blocks have been awarded.[16] Presently, OALP bid round VIII has been announced with 10 blocks on offer and, specifically for offshore blocks, the offshore bid round (OALP bid round IX) has been announced with eight offshore blocks on offer.[17] Additionally, three bid rounds have been completed for the discovered small fields (DSF) under the HELP regime wherein bids were received for 90 contract areas and 84 revenue sharing contracts (RSCs) were signed.[18]

As noted above, one significant change that has been introduced under HELP is the unification of licensing regime as applicable to conventional and non-conventional resources. Prior to the HELP regime, under the NELP regime, the contractors could explore and produce only conventional resources (i.e., crude oil, condensate and natural gas) but not coal bed methane (CBM) or shale. For the exploration of CBM, a separate host government contract regime was in place where four CBM bid rounds took place in 2001, 2003, 2005 and 2008, respectively, through which 29 CBM blocks were awarded and in addition two other CBM blocks were awarded on a nomination basis.[19] For unconventional resources, separate policies were formulated by the Indian government such as the CBM policy (1997)[20] and policy dated 14 October 2013 granting permission for shale gas and oil exploration and exploitation to national oil companies, for blocks awarded to these companies on a nomination basis.[21] Under HELP, the contractors are able to explore and produce unconventional resources under a single licence for the block. Furthermore, the Indian government in August 2018 approved the policy on exploration of unconventional hydrocarbons policy to permit exploration and exploitation of unconventional hydrocarbons such as shale oil and gas and CBM under the existing PSCs, CBM contracts and nomination fields.[22] Pursuant to the above, the Indian government announced the launch of a special bid round for CBM on 22 September 2021 where 15 onland CBM blocks have been offered by the Indian government through international competitive bidding with an objective to augment domestic production of petroleum.[23]

Despite these aforementioned efforts of the Indian government, the sector has not yet witnessed investments from foreign players in recent bidding rounds[24] and the production level remains low.

II LEGAL AND REGULATORY FRAMEWORK

India has a federal constitution, whereby legislative powers are distributed between the central and the state legislature.[25] Pursuant to Article 246 of the Constitution of India, the regulation and development of oil fields, mineral oil resources, petroleum and petroleum products fall within the jurisdiction of the Union Parliament; that is, the federal legislative body of India. The state governments, however, have the power to regulate matters such as right of use and access to land, labour, water and local government. In the case of environment, both the state government and the Indian government have the power to make laws. Accordingly, while the contract for exploration and production of hydrocarbons is executed by the Indian government, the licences and approvals for undertaking activities relating to exploration and production for onshore blocks are to be obtained from state governments along with the approval of the Indian government. For the petroleum mining lease (PML), which is required to commence production, the recommendation of the Indian government is required for the state government to process the application. For the offshore blocks, the Indian government has the licensing powers.

i Domestic oil and gas legislation

The following are the key pieces of legislation pertaining to the upstream oil and gas sector:

- the Oilfields (Regulation and Development) Act 1948[26] (the Oilfields Act): the Oilfields Act is the primary legislation governing the upstream oil and gas sector. The Oilfields Act incorporates provisions relating to licensing and leasing of oil and gas blocks. In this regard, the Oilfields Act provides for rule-making power of the Indian government with respect to mining leases and mineral oil development[27] and royalty rates to be paid by the holder of a mining lease;[28]
- the Petroleum and Natural Gas Rules 1959 (the PNG Rules): the PNG Rules enacted under the Oilfields Act provide detailed provisions for the granting of licences and leases for both offshore and onshore areas. The PNG Rules prohibit prospecting or mining of

petroleum except in pursuance of a PEL or a PML granted under the PNG Rules.[29] By an amendment of July 2018, the definition of 'petroleum' under the PNG Rules has been amended to include shale and other hydrocarbons. The amendment is in line with the HELP regime under which the licensing for conventional and non-conventional hydrocarbons has been unified;

- the Mines Act 1952 (the Mines Act) and Oil Mines Regulations 2017: these detail provisions relating to the health, safety and welfare of workers in oil mines. The Mines Act also highlights the duties of owners, agents and managers and the penalties in cases of contravention of the provisions; and
- the Petroleum and Natural Gas (Safety in Offshore Operations) Rules 2008 (the PNG Safety Rules): the PNG Safety Rules have been framed under the Oilfields Act and prescribe safety standards and measures to be taken for the safety of offshore oil and gas operations. The PNG Safety Rules provide for the manner of preparation of information and records; various consents and intimations in relation to the offshore installations; safety, health and environment measures, among others; and prescribe the penalties for contravention of the PNG Safety Rules.

Apart from the above legislation, the Indian government occasionally promulgates policies, standards, directives and guidelines for governing various aspects of the upstream oil and gas sector (including policies for the award of concessions for exploration of blocks and contractual structure to be followed).

ii Regulation

The following are the key regulatory and administrative agencies concerned with the upstream oil and gas sector in India:

- the Ministry of Petroleum and Natural Gas (MoPNG): this is the nodal ministry at the federal government level that supervises the exploration and production activities of petroleum and natural gas, and administers various pieces of legislation, including the Oilfields Act;
- the Directorate General of Hydrocarbons (DGH): pursuant to its resolution dated 8 April 1993, the MoPNG established the DGH with the objective of regulating and overseeing the upstream activities in the petroleum and natural gas sector and also to advise the MoPNG in these areas. The major responsibilities of the DGH include technical advisory to the MoPNG with respect to exploration and optimal exploitation of hydrocarbons and adequacy of development plans proposed by companies, review of exploration programmes, reassessment of reserves as discovered and estimated by companies and advising the Indian government on formulation of safety norms and regulations in oilfield operations.[30] The DGH is not an independent regulator and works under the administrative control of the MoPNG;
- the Oil Industry Safety Directorate (OISD): the OISD is the safety regulator for upstream offshore blocks operating under the MoPNG. It has been designated as the 'competent authority' for implementation of the Petroleum Safety Rules and exercises powers and functions under the PNG Safety Rules;[31]
- the Directorate General of Mines Safety (DGMS): this is the regulatory agency under the Indian government's Ministry of Labour and Employment, and is responsible for safety of the onshore blocks; and
- the Petroleum and Natural Gas Regulatory Board (PNGRB): this is the regulator for the midstream and downstream sector and has been empowered to regulate the refining, storage, transportation, distribution, marketing and sale of petroleum, petroleum products and natural gas. Therefore, transportation and evacuation of petroleum by pipelines outside the delivery point are subject to the PNGRB's oversight and regulations with respect to, inter alia, tariffs and technical safety standards.

In addition to the above, there are other general regulatory and administrative bodies looking into matters such as the environment, defence, shipping, labour and tax that may be relevant for a company operating in the oil and gas sector in India.

iii Treaties

India is a signatory to the Convention on the Recognition and Enforcement of Foreign Arbitral Awards 1958 (the New York Convention) as well as the Geneva Convention on the Execution of Foreign Arbitral Awards 1927. If a party receives a binding award from a country that is a signatory to either of the conventions, and is notified as a convention country by India, the award would then be enforceable in India subject to the satisfaction of the Indian courts of the enforceability of such awards. For enforcement of a foreign award, under either of the aforementioned conventions, the enforcing party has to fulfil certain requirements prescribed under the (Indian) Arbitration and Conciliation Act 1996, such as production of arbitration award.

India's bilateral investment treaties

From 1994 to 2015, India entered into 83 bilateral investment treaties (BITs), which were largely negotiated based on the Model BIT of 1993.[32] In December 2015, India adopted a revised model text for its BITs.[33] The Indian government proposes to replace the existing BITs with the revised text. In light of the proposed renegotiation of the BITs, in 2016, the Indian government issued notices to 58 countries to terminate the then applicable BITs after completion of the initial term. Accordingly, BITs executed with the 58 countries expired in 2017.[34] Furthermore, India has circulated a proposed joint interpretative statement to the counterparties for the 25 BITs for which the initial term has not been completed. The joint interpretative statement was issued to align the ongoing treaties with the text of the revised BITs and to clarify the ambiguities in the text of the existing treaty. Subsequent to the revised model text of 2015, BITs were concluded with Colombia,[35] Bangladesh,[36] Belarus[37] and the Kyrgyz Republic[38] and an investment cooperation and facilitation treaty has been concluded with Brazil.[39]

According to the United Nations Conference on Trade and Development (UNCTAD), which keeps an account of the number of investment disputes, a total of six known investor–state dispute settlement cases are pending against India and there are three cases where the home state of the investor or claimant is Indian.[40]

Recent developments regarding India's double taxation avoidance arrangements regimes

India has double taxation avoidance arrangements (DTAAs) with more than 90 countries, including Australia, Canada, Germany, Mauritius, Singapore, the United Arab Emirates, the United Kingdom and the United States.

III LICENSING

As noted under Section I, the licensing regime can be broadly categorised under nomination, Pre-NELP, NELP and HELP regimes. PSCs have been entered into with contractors under the NELP and Pre-NELP regimes, and RSCs are entered into for blocks awarded under the HELP regime. There have been organised licensing rounds (competitive bidding) under the NELP and HELP regimes. However, there is a difference between the two regimes regarding the manner in which acreages are determined. While under NELP, the blocks on offer were determined by the Indian government; under HELP, the Indian government has introduced the concept of open acreage policy wherein the companies can choose the blocks from the designated area, which are subsequently put for bidding.

Post the award of blocks and execution of the contract, the contractor is required to obtain a PEL for the entire contract area as per the provisions of the Oilfields Act and the PNG Rules. Under the terms of the PEL, the licensee is granted an exclusive right to operations relating to the information drilling or test drilling and right to lease over any part of the licence area.[41] Subsequently, for carrying out development and production activities, the contractor is required to obtain a PML for parts of the contract area encompassing discoveries. Under the PML, the lessee has an exclusive right in the leased land to conduct mining operations for petroleum and natural gas and has the right to carry out construction in the leased area for full enjoyment of the lease or to fulfil the obligations under the lease.[42]

The Indian government has been empowered to grant PEL or PML in respect of any land vested in the union or in offshore areas and the state governments have the power to grant PEL or PML over the lands vested with the state government.[43] The Territorial Waters, Continental Shelf, Exclusive Economic Zone and Other Maritime Zones Act 1976 provides for the granting of licence by the Indian government to explore and exploit the resources of the continental shelf and exclusive economic zone.[44]

IV PRODUCTION RESTRICTIONS

As per the provisions of the PNG Rules, the Indian government may, by way of a special or general order, restrict the amount of oil or gas to be produced, by a lessee in the respective allotted field, in the interest of conservation of oil resources.[45] Furthermore, the terms of PSC/RSC provide that until India becomes self-sufficient, oil and natural gas produced in India are to be sold within the domestic market in India. Therefore, the freedom to sell hydrocarbons is limited to sale in India and the same cannot be exported.

The price at which the gas produced is to be sold has undergone various changes over the years, and pricing freedom, which is one of the key features of HELP, is a relatively new concept in the sector. A brief background of the gas pricing regime followed in India is as follows.

Prior to November 2014, the gas pricing regime was broadly divided under two heads: administered pricing mechanism (APM) and non-administered pricing mechanism (Non-APM).

The APM regime covered the gas sold by state-owned oil and gas companies, from blocks that were given to them on a nomination basis and under this mechanism, where the Indian government determined the price at which gas was to be sold. The Non-APM regime regulated the price of gas produced from the Pre-NELP blocks and NELP blocks. Under the Non-APM regime, the price of gas was to be determined based on the provisions of the PSC executed by the parties. Accordingly, the price of gas produced from the Pre-NELP blocks was determined by the Indian government, and the price of gas produced from NELP blocks was to be based on a formula approved by the Indian government.

In October 2014, to bring about uniformity in the gas pricing regime, the MoPNG notified the New Domestic Natural Gas Pricing Guidelines, 2014 (the Gas Pricing Guidelines), which took effect from 1 November 2014. The Gas Pricing Guidelines prescribe a formula for determining the well head price of gas produced, and this price is notified on a half-yearly basis by the Petroleum Planning and Analysis Cell (PPAC). The price determined in accordance with the Gas Pricing Guidelines was applicable to all gas produced in India (including gas from Nominated Blocks, Pre-NELP blocks, NELP blocks and CBM blocks), except in specified circumstances.

In March 2016, the Indian government notified the Marketing including Pricing Freedom for the Gas to be produced from Discoveries in Deepwater, Ultra Deepwater and High Pressure-High Temperature Areas Guidelines,[46] allowing pricing freedom for all discoveries in deepwater, ultra-deep water and high temperature-high pressure areas, which were yet to commence production as on 1 January 2016. Pursuant to these guidelines, the parties could sell gas at a price up to the ceiling price notified by PPAC on a half-yearly basis. In March 2016, by introduction of HELP, contractors have marketing and pricing freedom with respect to all hydrocarbons produced. The HELP regime is applicable prospectively to the blocks allocated under HELP, and not to the blocks that were awarded prior to enforcement of HELP. Accordingly, unless otherwise notified, the Gas Pricing Guidelines, the Deep Water, Ultra Deep Water, High Pressure-High Temperature Area Guidelines and the CBM Pricing Guidelines will continue to be applicable to blocks awarded or nominated prior to enforcement of HELP.

The Indian government, by its resolution dated 28 February 2019, has also permitted marketing and pricing freedom for new discoveries under existing contracts where the field development plan would be approved after the date of issuance of the policy. On 7 October 2020, the Cabinet Committee on Economic Affairs approved 'Natural Gas Marketing Reforms', whereby marketing freedom would be granted to the Field Development Plans (FDPs) of blocks in which production-sharing contracts already provide pricing freedom.[47] The objective of the policy is to have a procedure for discovery of the market price of natural gas that is sold by the gas producers. For this, guidelines have been issued for sale of natural gas through an e-bidding process. In this respect, several e-bidding platforms have been empanelled by the Indian government through DGH and the guidelines for conducting the e-auction of natural gas have been specified by the government.[48] As on 30 June 2023, 36 e-auctions have been conducted.[49]

Recently, on 7 April 2023, as a step to protect natural gas pricing from adverse market fluctuations in the international gas markets, the Indian government notified changes to the New Domestic Natural Gas Pricing Guidelines, 2014,[50] whereby the price under the aforementioned guidelines would now be 10 per cent of the Indian Crude Basket Price (defined by PPAC from time to time), as declared on a monthly basis. Earlier, under the guidelines of 2014, the price of gas was determined on a half-yearly basis and was linked with prices in international gas trading hubs, such as Henry Hub, National Balancing Point, Alberta Hub and Russia. Furthermore, as per the notification, the prices of gas produced from nomination fields will be subject to a floor (US$4 /MMBTU) and a ceiling (US$6.5 / MMBTU), whereby the ceiling would increase by US$0.25/MMBTU each year at the end of two financial years; that is, financial year 2023–2024 (1 April 2023 to 31 March 2024) and financial year 2024–2025 (1 April 2024 to 31 March 2025). The notification clarifies that subject to provisions of the PSCs, the price declared by PPAC on a monthly basis would also be applicable where the contracts of NELP or Pre-NELP blocks provide for the Indian government's approval of prices.

V ASSIGNMENTS OF INTERESTS

According to the PNG Rules, the holder of a PEL or PML may assign its rights subject to the prior written approval of the government that has granted the licence or lease.[51] Additionally, restrictions on the assignment of participating interests emanate from the applicable PSC or RSC as the case may be. The contractor is required to seek prior approval of the Indian government for:

- assignment of participating interest;
- mortgage of participating interest;
- change in control of the member, or its parent company; or
- change in relationship of the contractor with the companies providing guarantee (which is typically the parent company).[52]

Various foreign companies have raised concerns about this approval requirement, as any change of control at the parent company of the contractor would require a prior approval of the Indian government, in the same manner as the assignment of the participating interest.[53]

VI TAX

i Income tax

The Indian government enters into agreements with contractor entities for the joint performance of conducting exploration, development or production operations for oil and gas. Levy of income tax is computed as per the Income Tax Act, 1961 (the IT Act). The profits and gains of the entities participating in such operations are computed based on the determined value and revenue realised on the sale of oil and gas as per the contract, reduced by applicable deductions as per the IT Act. Certain specific deductions in the terms of contract are also allowed in lieu of or in addition to corresponding allowances under 'Profits and Gains of Business or Profession' in the IT Act. These include expenditure incurred for exploration and drilling operations, including infructuous or abortive exploration expense subject to prescribed conditions.[54]

Non-residents engaged in the business of supplying plant, machinery, facilities or services in connection with prospecting or extraction of mineral oils are subject to a presumptive tax regime, wherein taxable profits are deemed to be 10 per cent of the gross revenues.[55]

ii Goods and services tax

Goods and services tax (GST), a single tax on the supply of goods and services, formulates the indirect tax regime applicable in India. Under GST, credits of input taxes are available in the subsequent stage of value addition, making GST a tax only on value addition at each stage. Crude oil, petrol, natural gas, fuel jet and diesel are currently excluded from the ambit of GST levy, whereas other oil products (such as liquefied petroleum gas, naphtha and kerosene) are included within the ambit of GST. As a result, upstream oil and gas companies can take advantage of input tax credit on GST paid only on the manufactured value-added products covered under GST.[56]

Tax paid on inputs (e.g., purchase of machinery and raw materials) is deducted from the tax on output for the final output product. Tax credits cannot be used for products excluded from GST, as tax credits are not fungible between the erstwhile indirect tax regime (e.g., central excise duty and state value added taxes) and new taxation system under GST. This is on account of procurement of goods and services for upstream and downstream sector being in the ambit of GST, and the majority output being outside the purview of GST.[57] This implies that the majority of GST paid on goods and services by oil and gas companies is a cost to them in addition to the cost of compliance under both the old and new tax regimes. This results in the end consumer bearing the burden for the increase in cost of such products.[58]

Hence, oil and gas companies have to deal with two parallel systems of indirect taxation. While they incur GST charges on services and inputs used for operations, they cannot offset this against value added tax and excise duty on output, such as crude oil and diesel, resulting in stranded taxes.

iii Tax incentives

Various special allowances and incentives are applicable to companies engaged in the Indian oil and gas sector.

Foreign companies are exempt from tax on income earned from sale of crude oil to any consumer in India. The conditions for the aforementioned are that:

- the income is earned in Indian currency;
- the agreement for such sale and the foreign company are approved and notified by the central government; and
- the foreign company does not have any other activity in India.

Furthermore, any income accruing or arising to a foreign company on storage of crude oil in any facility in India and its sale to any consumer in India and on account of sale of leftover stock of crude oil, if any, from the facility in India after the expiry of the agreement or the arrangement is also exempt from tax subject to certain conditions.[59]

Allowance may be claimed in relation to expenditure made by way of infructuous or abortive exploration expenses for any area surrendered before commencement of commercial production, drilling or exploration activities or services in respect of physical assets, and depletion of mineral oil in the mining area (subject to the terms of the agreement with the Indian government).[60]

Deduction is allowed for any capital expenditure incurred for 'laying and operating a cross-country natural gas or crude or petroleum oil pipeline network for distribution, including storage facilities being an integral part of such network subject to certain conditions'.[61]

In the cases of new machinery or plant that have been acquired or installed after 31 March 2005, a sum of 20 per cent of actual cost of the machinery or plant is allowed as deduction when the taxpayer is engaged in the business of manufacture or production of any article or thing or in the business of generation, transmission or distribution of power.[62]

Regarding customs, full exemption from payment of basic customs duty and partial exemption from integrated GST is allowed on specific goods imported for use in petroleum or CBM operations, subject to fulfilment of other prescribed conditions.[63] In a recent amendment, the requirement to submit an essentiality certificate from DGH has been abolished and the list of equipment that was eligible for exemption from customs duty has been revised.[64]

Furthermore, oil and gas companies are eligible for purchase or sale of petroleum products not covered under GST, at a concessional rate of sales tax for interstate transactions, upon submission of prescribed statutory declaration forms.[65]

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

The environmental approvals and permissions that are required to undertake oil and gas operations in India include general environmental approvals as provided under the environmental legislation and specific approvals based on the location of the oilfield.

The general environment approvals include:

- environmental clearance: under the Environmental Impact Assessment Notification of 2006 as notified under the Environment (Protection) Act 1986 and the Environment (Protection) Rules 1986, it was mandatory to obtain environmental clearance to undertake exploration and production activity in the oilfield. However, recently, the Indian government categorised onshore and offshore oil and gas exploration activities as 'B2 category' for seeking prior environmental clearance. By this change, the exploration activities will now require environmental clearance from the states concerned and also an environment impact assessment report or public hearing will not be required. However, the development or production activities for offshore or onshore fields will continue to be covered under category A and require an assessment.[66] Furthermore, as per the office memorandum dated 18 November 2020, the Indian government has streamlined the process for granting environmental clearance to expedite the process of granting the environmental clearance;[67]
- consent to establish and consent to operate: under the Water (Prevention and Control of Pollution) Act 1974 and Air (Prevention and Control of Pollution) Act 1981, the consent to establish and consent to operate is required to be obtained by the respective state pollution control board. However, the projects requiring environment clearance may be exempted from consent to establish requirement subject to the prescribed conditions;[68] and
- authorisation for handling hazardous waste: under the Hazardous Wastes (Management, Handling and Transboundary Movement) Rules 2016, authorisation from the state pollution control board is required for generating, processing, treating, packaging, storing and transporting waste (generated from drilling for oil and gas production).

The approvals based on the location of the oilfield include:

- coastal regulation zone: under the Coastal Regulation Zone Notification 2011, exploration and extraction of oil and natural gas in the coastal zone require permission from the Ministry of Environment, Forest and Climate Change;
- forest clearance: if the exploration and production operations involve diversion of forest land, then forest clearance under the Forest (Conservation) Act 1980 read with the Forest (Conservation) Rules 2003 is required to be obtained; and
- wildlife clearance: if the exploration and production activities are planned in and around protected areas such as national parks and wildlife sanctuaries, in addition to the environmental clearance and forest clearance, clearance under the Wild Life (Protection) Act 1972 is also required.

i Environmental requirements specific to PSCs and RSCs

Apart from the obligation contained under the environment laws, the PSCs and RSCs also provide for certain additional obligations in relation to protection of the environment. The terms of the contracts stipulate that the contractor shall conduct the petroleum operations with due regard to environmental protection concerns. In this regard, the contractors are required to adopt modern oilfield and petroleum industry practices and standards (under the terms of PSC) or good international petroleum industry practices and standards (under the terms of RSC), including advanced technologies, practices and methods of operations for the prevention of environmental damage.[69] The relevant clause further provides that in the event of an emergency, such as accident, oil spill and fire, the contractor shall implement a relevant contingency plan and perform such site restoration as may be necessary.

ii Decommissioning and site restoration

In relation to decommissioning and site restoration, the PNG Rules provide that on termination of the exploration licence or mining lease, the area and any wells contained in it must be delivered in good order and condition.[70] For six months after the licence or lease ends, the former licensee or lessee can remove or dispose of any petroleum recovered during the licence or lease period, along with stores, equipment, tools and machinery and any improvements on the land covered by the licence or lease that the state government permits.[71] As per the terms of the PSCs and RSCs, the contractors are required to remove all equipment and installations from the contract area in a manner as agreed with the Indian government pursuant to an abandonment plan.[72] The contractor is required to prepare and submit a proposal to the Indian government for site restoration, including an abandonment plan and requirement of funds for site restoration and annual contribution.[73] Furthermore, the contractor is obligated to perform all necessary site restoration activities as under any specific guidelines, rules or regulations that have been formulated by the Indian government in relation to site restoration.[74] In this regard, the site restoration and abandonment guidelines for petroleum operations have been issued by the Indian government, which prescribes provisions for obligations regarding decommissioning of offshore and onshore production sites.[75]

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

As per the Foreign Direct Investment Policy (FDI Policy), read with the Foreign Exchange Management Act 1999 (FEMA) and the Foreign Exchange Management (Transfer or Issue of Security by a Person Resident Outside India) Regulations 2017, 100 per cent foreign direct investment (FDI) is permissible under the 'automatic route' (i.e., without the approval of the Indian government for exploration and production in oil and gas fields).[76] Accordingly, a foreign company can undertake operations in the oil and gas sector either by itself or as a consortium with an Indian partner. A foreign company can undertake exploration and production activities in India without incorporating a company in India. Most foreign companies operating in this sector have set up a project office. The setting up of a project office is regulated under the Foreign Exchange Management (Establishment in India of a Branch Office or a Liaison Office or a Project Office or any other Place of Business) Regulations 2016, as may be amended from time to time.

ii Capital, labour and content restrictions

As discussed above, 100 per cent FDI is permitted under the FDI policy and as per the provisions of FEMA, certain restrictions can be placed on the transactions based on their classification as current account transactions and capital account transactions.[77] Current account transactions are permissible unless specifically restricted by the Indian government and all capital account transactions are specifically prohibited unless specifically permitted by the Indian government.

Regarding local content and employment to Indian citizens, the PSCs and RSCs provide that:

- the contractor shall, to the maximum extent possible, employ (and require the operator and its subcontractors to employ) Indian citizens having appropriate qualifications and experience;[78] and
- give preference to the purchase and use of goods (equipment, materials and supplies) that are manufactured, produced or supplied in India subject to their timing of delivery, quality and quantity required, price and other terms.[79]

iii Anti-corruption

The Prevention of Corruption Act 1988 (PoCA) is the primary legislation for prevention of corruption in India. As per the amendment of July 2018 to PoCA, commercial organisations, including companies that are either incorporated or undertaking business in India, can be specifically charged as bribe givers and are punishable with a fine.[80] The Central Vigilance Commission (CVC) is the apex vigilance institution and is free from any executive control. The CVC, pursuant to the mandate granted to it under the Central Vigilance Commission Act 2003, can conduct inquiries into allegations of offences committed under the PoCA by certain categories of, inter alia, public servants, government companies, societies and local authorities. The Black Money (Undisclosed Foreign Income and Assets) and Imposition of Tax Act 2015 regulates the undisclosed foreign income and assets and imposes penal taxes on undisclosed foreign income and assets. Additional criminal liabilities have also been included under the legislation for non-disclosure of foreign assets and wilful attempts to evade taxes.

The Prevention of Money Laundering Act 2002 (PML Act) and the Prevention of Money-Laundering (Maintenance of Records) Rules 2005 prohibit and criminalise money laundering activities in India. Under the PML Act, 'money laundering' is defined as any process or activity connected with the proceeds of a crime listed in the schedule to the PML Act, and projecting or claiming it as untainted property.[81] In a recent judgment from the Supreme Court of India, it was held that the word 'and' appearing before the phrase 'projecting or claiming it as untainted property' would have to be read as 'or' thereby giving an expansive interpretation to the meaning of money laundering.[82] As per the judgment, projecting or claiming the property as untainted property would constitute an offence of money laundering independent of other acts, which may constitute an offence under the PML Act.

To prevent money laundering activities, the PML Act requires all banks, financial institutions and persons engaged in certain designated activities to maintain records of all transactions undertaken. An operator of an upstream oil and gas block does not qualify as a reporting entity under the PML Act and the PML Rules.

The Companies Act 2013 also contains provisions with respect to statutory audits, corporate governance requirements, annual filing requirements among others that, inter alia, seek to prevent fraud and instances of money laundering. Furthermore, pursuant to Section 216 of the Companies Act 2013, the Indian government has the power to initiate investigation to find out the real beneficiary of a financial transaction undertaken by a company.

IX CURRENT DEVELOPMENTS

Some of the current developments in the sector are outlined in this section.

i Recent bidding rounds

In relation to the ongoing licensing rounds, under the HELP regime, seven bidding rounds have been completed, whereby 134 blocks have been awarded to successful bidders for the OALP fields.[83] OALP bid round VIII was announced on 7 July 2022 with 10 blocks proposed to be awarded. As at June 2023, DGH announced that 13 bids had been received for these 10 blocks.[84] In the case of the DSF, under the HELP regime, three bidding rounds had been completed whereby bids were received for 90 contract areas and 84 revenue sharing contracts (RSCs) were signed.[85] At the time of writing, the bid round VIII of OALP fields is yet to be completed. The DGH also announced a special Offshore Bid Round (OALP Bid Round-IX) under HELP. This round has been announced pursuant to the Indian government opening up 99 per cent of the 'No-Go' area of the Exclusive Economic Zone (EEZ) for hydrocarbon exploration and development. Presently, it has been proposed that under OALP Bid Round IX, eight blocks will be offered for bidding.[86]

ii Deregulation in sale of domestically produced crude oil

On 11 July 2022, the Indian government announced that with effect from 1 October 2022, the condition in PSCs to sell crude oil to government or government nominee or government companies shall be waived off, and if such a condition is mentioned in any PSC, the PSC shall stand amended accordingly.[87] The notification further states that unless the PSC provides otherwise, royalty, cess, other statutory levies and contractual payments such as profit petroleum and revenue share shall be valued based on the actual sales price or the price of the Indian Basket of crude oil, as calculated by PPAC on a monthly basis, whichever is higher. However, domestic crude oil exports will continue to be disallowed.

iii Revisions to regulated gas pricing

On 7 April 2023, the Indian government notified changes to the New Domestic Natural Gas Pricing Guidelines, 2014.[88] Some of the key changes notified include the following.

- The price of domestic gas under the guidelines will be 10 per cent of the Indian Crude Basket Price (defined by PPAC from time to time), as declared on a monthly basis. Earlier, under the guidelines of 2014, the price of gas was determined on a half-yearly basis and was linked with prices in international gas trading hubs (i.e., Henry Hub, National Balancing Point, Alberta Hub and Russia).
- Specifically for gas produced from nomination fields, the price will be subject to a floor (US$4/MMBTU) and a ceiling (US$6.5/MMBTU), whereby the ceiling would increase by US$0.25/MMBTU each year after the completion of two financial years; namely, financial year 2023–2024 (1 April 2023 to 31 March 2024) and financial year 2024–2025 (1 April 2024 to 31 March 2025).
- Subject to provisions of the PSCs, the price declared by PPAC on a monthly basis would also be applicable where the contracts of NELP or Pre-NELP blocks provide for the government's approval of prices.
- Gas produced specifically from new wells or well intervention in the nomination fields would be allowed 20 per cent premium and such gas would be subject to government policy related to commercial utilisation of natural gas.

iv Conditions for e-bidding for gas sold under the e-bidding regime

As noted above, pricing freedom and marketing freedom were granted for gas, which is produced from discoveries in Deepwater, Ultra Deepwater and High Pressure-High Temperature fields, pursuant to a notification of 21 March 2016. On 13 January 2023, the Indian government issued a notification[89] clarifying certain aspects in relation to the discovery of market price and further trading of gas from such discoveries. As per the notification, while discovery of price can take place through e-bidding (as contemplated under an earlier notification certain conditions), further conditions and clarifications have been provided that include specification of end use and use as trader by the bidders, permissibility regarding resale of unconsumed gas (subject to conditions separately to be notified by the Indian government) and conditions of resale of gas by traders.

v Simplification of processes

To facilitate the ease of doing business and attract investments in the Indian upstream oil and gas sector, the Indian government had introduced a simplified procedure for approval process under the PSCs in three categories (self-certification, deemed approval on expiry of 30 days and full approval from the Indian government).[90] In July 2021, with the aim of enhancing the ease of doing business, the processes have been further simplified and rationalised.[91]

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Endnotes

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Chapter 11

Iraqi Kurdistan

Florian Amereller and Dahlia Zamel[1]

Summary

I INTRODUCTION

The Republic of Iraq, including the Kurdistan Region of Iraq (KRI), is a country vested with many easily exploitable oilfields. The exploration and production of oil in Iraq started as early as the 1920s. The Iraqi oil sector was fully nationalised by the central Iraqi government in 1975.

The Kurdistan Region Ministry of Natural Resources (MNR) estimates the KRI's reserves at 45 billion barrels of oil (bbls) and at 25 trillion cubic feet (tcf) of proven gas reserves and up to 198 tcf of largely unproven gas. If the KRI were an independent country, the amount of oil and gas reserves would place it among the top 10 oil-rich countries in the world. However, the region is still an integral part of the Republic of Iraq even though it enjoys semi-autonomy. According to the report prepared by Deloitte on the Kurdistan Regional Government of Iraq Oil production, export, consumption and revenue for the period of 1 October 2022 to 31 December 2022, the KRI's total exported and consumed oil for Q4 2022 stood at 40,175,186 bbls, up from 38,730,175 bbls in Q3 2022.[2]

Up until the coming into force of the current Iraqi Constitution of Iraq in 2006, the KRI played no active role in the development or utilisation of the substantial oil and gas reserves in the KRI. Since then, the Kurdistan regional government (KRG) enacted the Kurdistan Oil and Gas Law No. 22/2007 (KOGL) and concluded more than 50 production-sharing contracts (PSCs) with international oil companies (IOCs). Initially, the contracting partners were minor oil companies, and then in 2012, ExxonMobil pioneered as the first major IOC, followed by Chevron, Total and Gazprom.

Given certain constitutional ambiguities regarding the management of oil and gas in Iraq, the KRG and the central government in Baghdad are constantly at odds over the authority to administer and dispose of oil being produced in the KRI.

To date, Baghdad and the KRI remain at odds over the region's oil reserves and the rights of the KRI to export crude oil independently of Baghdad's Ministry of Oil (MoO) and State Organization for Marketing of Oil (SOMO), the Iraqi oil marketing organisation. In February 2022, the Iraqi Federal Supreme Court (FSC) issued a decision in a claim filed by the MoO from 2012 deeming the KOGL unconstitutional for violating Articles 110, 112, 115, 121 and 130 of the Iraqi Constitution of 2005 (FSC Decision). The FSC Decision did not in and of itself annul the PSCs entered into by the KRG but did provide that the Ministry of Oil may pursue the annulment of such PSCs.

In the absence of a legal means to force the KRI to comply with the FSC Decision and hand over oil and gas operations to the MoO, the MoO has taken various measures to pressure the KRG, including commencing legal proceedings against nine IOCs operating in the KRI requesting annulment of their PSCs, renewing a blacklisting policy for oil service companies that operate in both the KRI and central Iraq, threatening such oil service companies with blacklisting in central Iraq if they do not cease operations in the KRI, and the continued threat that budget allocations for the KRI under the federal budget law will not be made. The MoO was successful in obtaining several court decisions purporting to annul various PSCs entered into by the KRG. However, similar to the FSC Decision, the central government of Iraq has little means of enforcing these court decisions and hence the parties to the PSC continue to operate with no change.

Major crisis for the KRG came in 2023 when Turkey suspended operations of the Iraq–Turkey pipeline in the wake of the arbitral award handed down against Turkey for payment of US$1.5 billion in damages to the central government of Iraq for permitting the KRG to use the Iraqi-Turkey pipeline to export oil without approval from the central government of Iraq. Iraqi and Kurdish exports through the Turkish Ceyhan port have been suspended since March 2023 leaving the KRG without any means to export its oil. Consequently, the KRG and the central government of Iraq have resumed talks on a federal oil and gas law.

II LEGAL AND REGULATORY FRAMEWORK

Iraq's legal framework for the petroleum industry is quite ambiguous. Pursuant to the Iraqi Constitution, 'oil and gas are owned by all the people of Iraq in all the regions and governorates'.[3] However, the exploration and production of oil and gas are not governed by the Iraqi Constitution. It only states that 'the central government, with the producing governorates and regional governments, shall undertake the management of oil and gas extracted from present fields, provided that it distributes its revenues in a fair manner in proportion to the population distribution in all parts of the country . . . and this shall be regulated by a law'.[4]

The Iraqi Constitution does not define 'present fields', which fall under the shared jurisdiction. Management of other oil and gas resources that are not 'present fields' are not expressly regulated in the Constitution. Nonetheless, the term 'present fields' does not reflect common concepts of the oil industry such as 'proven – probable – possible', 'developed – undeveloped' or 'producing – non-producing'. That said, the KRG maintains that 'present fields' refers only to the oil and gas fields that were producing at the time of enactment of the Iraqi Constitution in 2005 and that all other oil and gas resources therefore fall under the competency of the KRI. Hence, the KRG regards itself as the competent authority to regulate all oil and gas resources in the Kurdistan region other than 'present fields'. The central government in Baghdad rebuts this interpretation of the Iraqi Constitution and believes that the KRG lacks the requisite constitutional authority to sign contracts with foreign oil companies, which it deems illegal.

Pursuant to Article 112(1) of the Constitution, the foregoing varying interpretations should have been regulated by a law creating a comprehensive and fair framework for the management of the Iraqi oil and gas sector, including the rights and competencies of the governorates and regions to have an active role in the management and a share of the revenues. For years, the KRG and the central government failed to agree on a unified federal oil and gas law in implementation of the Iraqi Constitution.

In the continuing absence of a comprehensive federal oil and gas law, in 2022 the FSC issued the FSC Decision and the MoO commenced proceedings and were successful in annulling several of the KRI PSCs.

i Domestic oil and gas legislation

The Iraqi Constitution gives the regions the right to legislate on any matters that do not fall within the exclusive jurisdiction of the central government[5] and, pursuant to the Kurdistan National Council (the predecessor to the current Kurdistan parliament) Decision No. 11/1992, federal laws passed after 1992 are not applicable in the KRI unless specifically adopted pursuant to a KRI law. The Constitution further provides that where a conflict exists between a federal law and a regional law, the regional law shall prevail.[6]

Premised on the foregoing, in 2007 the KRI legislator passed the KOGL. The KOGL applies to all petroleum operations in the KRI. According to the KOGL, no federal legislation and no agreement, contract, memorandum of understanding or other federal instrument that relates to petroleum operations applies in the KRI except with the express agreement of the relevant authority of the KRG.[7] Hence, the federal Iraqi legislation and regulations with respect to petroleum operations are not applied in the KRI.

In April 2013, the KRI adopted the 'Law of Identifying and Obtaining Financial Dues to the Kurdistan Region – Iraq from Federal Revenue' (the Financial Rights Law). The Financial Rights Law grants the KRG the right to independently export crude oil produced in the KRI if the central government fails to pay the KRG its share of revenues (including oil revenues), budget items, other national allocations and reparations.

ii Regulation

In addition to the Kurdistan parliament, which is the legislative body of the KRI and passes its laws, the regulatory agencies competent for overseeing upstream oil and gas activities in the Kurdistan region are as follows:

- the Regional Council for the Oil and Gas Affairs of the Kurdistan Region – Iraq (Regional Council): the Regional Council consists of the Prime Minister, the Deputy Prime Minister, the Minister of Natural Resources, the Minister of Finance and Economy and the Planning Minister;[8] it mainly formulates the general principles of petroleum policy, prospect planning and field development and approves petroleum contracts;[9] and
- the Ministry of Natural Resources of the Kurdistan Region: the MNR oversees and regulates all petroleum operations in the KRI[10] and it negotiates and signs PSCs on behalf of the KRG jointly with the Prime Minister representing the Regional Council. The Minister of Natural Resources may license petroleum operations (i.e., all upstream and downstream activities[11] to third parties[12] after approval of the Regional Council.

Other agencies and ministries such as the Social Security Directorate, the Residency Directorate and the Ministry of Agriculture and Water and Irrigation have regulatory oversight for their areas of competence that fall within the activities of IOCs operating in the KRI.

iii Treaties

Pursuant to the Iraqi Constitution, the central government in Baghdad has the sole authority to sign and ratify international treaties and agreements.[13]

Iraq has signed several bilateral investment agreements; however, only a very limited few have entered into force – France, Japan and Kuwait – all others are pending ratification by the Iraqi Council of Representatives.

In addition, Iraq has entered into bilateral free trade agreements with Algeria, Egypt, Jordan, Lebanon, Oman, Qatar, Sudan, Syria, Tunisia, the United Arab Emirates and Yemen.

On 11 July 2005, Iraq and the United States penned a Trade and Investment Framework Agreement. The Iraqi government ratified the agreement in December 2012. The aim of this agreement is to promote and facilitate investment and trade between the two countries. At present, the United States does not have a bilateral investment treaty with Iraq.

With regard to judicial cooperation and dispute resolution, Iraq, including the KRI, is a signatory state of the Riyadh Arab Agreement for Judicial Cooperation of 1983 (the Riyadh Convention). According to the Riyadh Convention, each contracting party shall recognise the judgments made by the courts of any other contracting party in civil cases having the force of *res judicata* and shall enforce them in its territory.[14] Nonetheless, judgments made against the government or against any of its employees in respect of acts undertaken in the course of duty or exclusively on account thereof are exempted.[15] The same applies to awards of arbitrators.[16]

The ICSID Convention entered into force in Iraq on 17 December 2015.

The Iraqi Cabinet in 2018 voted to approve Iraq's accession to the Convention on the Recognition and Enforcement of Foreign Arbitral Awards of 1958 (NY Convention), which came into force in Iraq when the law ratifying it was published in the Official Gazette on 31 May 2021. According to the ratification law, the NY Convention will not apply in Iraq retroactively to awards issued prior to its coming into force, will only apply with regards to other member states based on reciprocity and will only apply to awards issued in commercial matters.

III LICENSING

To date, the KRG has signed more than 50 PSCs with IOCs on terms that are more favourable to private investors than the technical services contracts (TSCs) and development and production services contracts (DPSCs) signed by the MoO.

The MNR has the discretion over whether to invite applicants for licensing or to award licences based on direct negotiation.[17] In all cases, an applicant or invitee must demonstrate technical and financial capability. It also needs to have a record of compliance with the principles of good corporate citizenship, and a commitment to the Ten Principles of the United Nations Global Compact.[18]

Key features of the PSC are to be negotiated with the MNR based on the Model PSC published by the KRG,[19] which includes that:

- a signature bonus[20] and a capacity-building bonus[21] are payable by the contractor once the PSC becomes effective;
- the KRG has the right to participate in the PSC through one of its public companies with a stake of up to 25 per cent after commercial discovery;[22]
- the contracting partner is usually a consortium consisting of an IOC and a carried Kurdish national company with an undivided interest of between 20 and 25 per cent in the PSC. The Kurdish public company may, at its discretion, assign part or all of its government interest to a third party;[23]
- the term of the PSC varies in accordance with advancement. The exploration period lasts for five years (comprising an initial sub-period of three years and a second sub-period of two years) and may be extended for a further two years.[24] Upon commercial discovery, the development period extends to 20 years with two possible extension periods of five years each;[25]
- during the exploration period, an annual surface rent of US$10 per square kilometre is payable. However, this exploration rental is, as it constitutes petroleum costs, recoverable;[26]
- 25 per cent of the initial contract area, excluding production areas, shall be relinquished at the end of the initial term next to an additional 25 per cent of the remaining contract area, excluding production areas, at the end of each extension period;[27]
- in the event of a commercial discovery, a production bonus is payable[28] in addition to a recurring royalty (i.e., a portion of petroleum produced).[29] Usually, the royalty rate for export crude oil and natural gas is set at 10 per cent;
- once commercial production commences, the contractor is entitled to recover all petroleum costs (e.g., production costs, exploration costs, development costs and decommissioning costs) incurred from the hydrocarbons produced.[30] The remaining 'profit petroleum' is split between the KRG (through its public company) and the contractor pursuant to the quotas stipulated in the PSC;[31] and
- during the exploration period, the contractor may terminate the PSC at the end of each contract year.[32] Once the development period has been entered into, the contractor has the right to terminate the PSC at any time.[33]

Unlike the TSCs and DPSCs offered by the central Iraqi Ministry of Oil, the PSC provides the contractor with a share in the petroleum discovered, and therefore an interest in the value of the petroleum produced.

However, given the recent developments culminating in the FSC Decision finding the KOGL and the KRI's export of crude oil unconstitutional, as well as the Iraq-Turkey pipeline being shut down, it is unlikely that the KRG will enter into any new PSCs for the foreseeable future until a balanced Federal Oil and Gas Law is passed.

IV PRODUCTION RESTRICTIONS

At present, the MNR does not impose any restrictions on the exploration, development and production of hydrocarbons (cost and profit oil) in the KRI. As per the PSC, the contractor shall be entitled to receive and export freely any available petroleum (cost and profit oil) to which it is entitled under the agreement.

Through the PSC, the KRG reserves oil for local markets. Upon written request of the MNR, any amount of crude oil produced that the KRG deems necessary to meet the KRI's internal consumption requirements must be sold and transferred to the KRG at the international market price. All contractors active in the KRI must be treated equally in this regard.[34]

At present and based on the FSC Decision and the current closure of the Iraq Turkey pipeline, production in the KRI has come to a near standstill with insufficient storage facilities to accommodate extracted but unexported crude oil.

As part of Iraq, the KRI has committed to comply with its share of Organization of the Petroleum Exporting Countries (OPEC) cuts of Iraqi production quotas.

V ASSIGNMENTS OF INTERESTS

The KOGL provides that the relevant contract relating to petroleum operations shall specify the rights of the MNR to approve or be notified of any assignment (in any form, whether by transfer, conveyance novation, merger, etc.) and changes in control of any contracting entity.[35] In practice and based on the Model PSC published by the MNR, PSCs normally give the KRG the right to approve any assignment, whether to an affiliate, another contracting entity or to a third party. In the case of a transfer or assignment to a third party, however, the contractor must present reasonable evidence of the assignee's technical and financial capability.[36] This requirement is not applicable to an assignment to an affiliate or to another contracting entity.

Neither the KOGL nor the Model PSC provides for a right of first refusal or any other pre-emptive rights of the KRG.

Prior consent of the KRG is required for a change of control to a third party that, according to the Model PSC, applies to any direct or indirect change of control of a contracting entity, in which the market value of such entity's participating interest in this contract represents more than 75 per cent of the aggregate market value of the assets of such entity and its affiliates that are subject to the change in control.[37]

The Model PSC provides that any assignment or change of control 'will not give rise to any tax, imposition or payment whatsoever in the Kurdistan Region, whether currently existing or which may become applicable in future'.[38]

The Model PSC provides that an assignee must enter into an agreement whereby the assignee undertakes to be bound by the terms of the PSC in the then-current form.

VI TAX

According to the KOGL,[39] all persons associated with 'petroleum operations' are liable for all applicable taxes of the KRG, including:

- surface tax;
- personal income tax;
- corporate income tax;
- customs duties and other similar taxes;
- windfall profits or additional profits tax; and
- any other tax, levy or charge expressly included in its petroleum contract.[40]

On the basis of the above, upstream oil and gas operations would be subject to the tax laws and regulations applicable to all commercial activities in the KRI, in particular the Income Tax Law No. 113/1982 (KRG ITL).[41] According to the KRG ITL, all commercial activities are subject to a flat corporate income tax rate of 15 per cent on profits.

The current KOGL does not contain any tax exemption for IOCs and other upstream operators active in the KRI. It does, however, provide that a petroleum contract may exempt a contractor from tax by law. No such law has been enacted to date.

In the absence of a KRI oil and gas tax law and as an incentive for major IOCs to invest in the KRI, the Model PSC is structured to provide the IOCs, their affiliates and subcontractors involved in petroleum operations with a de facto tax exemption. In this regard, Articles 31.1 and 31.2 of the Model PSC provide for several rights and obligations related to taxes in connection with the PSC.

On the one hand, the Model PSC purports to exempt contactor entities from all taxes including but not limited to capital gains tax, customs and imports duties other than corporate income tax. On the other hand, the Model PSC also provides that, upon submission of appropriate tax returns by the contractor entity, the government shall pay all income tax on behalf of the contracting entity directly to the KRG tax authorities from the government's share of profit petroleum. In addition, the government shall indemnify the contractor entity against any liability to pay any taxes assessed or imposed upon such contracting entity that relate to the tax exemptions granted by the PSC.[42]

According to the Iraqi Constitution, no tax may be imposed nor an exemption made except pursuant to a law.[43] Therefore, the exemption provided under the PSC does not legally bind the KRI tax authorities; a view widely shared by the KRI Ministry of Finance.

The IOC is obliged to withhold and pay personal income tax and social security contributions on behalf of its employees pursuant to applicable law. Foreign employees, however, were exempt from personal income tax until a decision by the Ministry of Finance in January of 2021, which states that all expatriate employees of oil and gas companies in the KRI are subject to payments of personal income tax.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

Both the KOGL and the Model PSC contain similar provisions pertaining to health, safety and environment. In addition to the requirement for all applicants for a PSC to include conditions for protecting the environment, preventing, minimising and remedying pollution, an IOC is required under the PSC to adhere to prudent international petroleum industry practice with regard to environmental protection as well as applicable laws.[44] IOCs are also required to make payments towards an Environment Fund.[45] In July 2021, the MNR issued a decree obliging all IOCs operating in the KRI to cease all gas flaring in the region.

In 2010, an independent Environmental Protection and Improvement Board was established in the KRI by Law No. 3/2010, which has assumed the oversight and supervisory role for the enforcement of KRG Law of Environmental Protection and Improvement No. 8/2008 (Environment Law).

In addition to specific obligations related to standards for the protection of water, soil, air and biodiversity, any person conducting any activity that has an environmental impact must obtain prior approval from the Environmental Protection and Improvement Board.

Non-compliance with the obligations of the Environment Law may result in no less than one month of imprisonment or fines of between 150,000 and 200 million Iraqi dinars, or both.[46] In addition to the specific penalties provided for in the law, anyone who causes environmental damage shall be subject to civil compensation and responsibility for removing or correcting the damage.

Under the Model PSC, the IOC must present a decommissioning plan to the management committee at least 24 months before the estimated date of the end of commercial production including environmental considerations. The IOC has the right, but not the obligation, to create a 'decommission reserve fund' during the last 10 years of the PSC's term. Amounts paid towards the fund shall be recoverable by the IOC as petroleum costs in accordance with the terms of the PSC.[47]

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

The KOGL requires that any IOC operating in the KRI pursuant to a PSC shall establish an office in Kurdistan.[48] The term 'office' as used does not specify whether the 'office' must be a branch office or a separate local legal entity such as a subsidiary limited liability company. In practice, however, the MNR gives preference to the registration of branch offices.

Registering a branch entails submission by the parent company of its corporate documents, financial statements and undertakings to assume liabilities of branch as well as a letter of intent and corporate resolution resolving on the establishment of a branch office in the KRI.

Specifically for oil and gas activities, evidence of registration on the MNR Approved Vendor List (an online registration platform)[49] or a decision by the MNR approving this registration is also required.

The approval and certificate of registration of the branch is usually issued within two to three weeks of the date of submission of the completed set of documents to the Register of Companies.

ii Repatriation of foreign currency

As of October 2023, the Iraqi Council of Ministers and the Central Bank of Iraq (CBI) have imposed several measures intended to bolster confidence in the Iraqi economy and the local currency. Among these measures are severe restrictions on the use of US dollars in Iraq as well as transactions that may be funded in foreign currency through Iraqi licensed banks. Regarding foreign investments and repatriation of profit or capital, the CBI regulations only expressly permit the repatriation of capital and profits from projects that operate under a federal investment licence, which is not the case for oil and gas-related activity. Dividends from Iraqi companies may also be repatriated after the settlement of all local taxes. Additionally, the Council of Ministers issued a decree in September 2023 that provides that all local contracts of the public sector are to be concluded in Iraqi dinars unless payable by letters of credit with a foreign intermediate bank. Existing contracts will continue to be paid in US dollars but new contracts with the public sector are to be concluded in Iraqi dinars. It is not clear to what extent these restrictions will also apply to the oil and gas sector in the KRI, if at all.

iii Preference to local resources

IOCs and subcontractors are required under a PSC and local law to provide training to local employees and, where possible, 'to maximise knowledge transfer to the people of the region'.[50] Training may include scholarships, funding for education[51] and secondment of government employees to the IOC.[52] Costs for training contained in the training plan and advance funding are recoverable as petroleum costs under the PSC.[53]

The Model PSC entitles the IOC to hire foreign personnel whenever the personnel from the KRI and other parts of Iraq do not have the requisite technical capability, qualifications or experience.[54]

As with employment, IOCs and their subcontractors are required to give preference to partnering with local companies and using local products and materials. It is noteworthy that, in selecting IOCs, the government is entitled to give preference to IOCs that partner with local companies.[55] The training programme submitted by the IOC is also one of the considerations in selecting IOCs.

During 2021, the MNR commenced a secondment programme requiring all IOCs to accept secondees from the MNR as well as to provide secondees to the MNR.

iv Anti-corruption

Kurdish officials launched a strategic good governance and transparency campaign as early as 2009 in cooperation with the international consulting firm PricewaterhouseCoopers. All PSCs provide that any reasonably proven violation of the anti-corruption laws applicable in the KRI shall render the PSC void *ab initio*.

While certain compliance issues regarding doing business in Kurdistan remain, on the basis of the above it seems reasonable to exempt the KRI from the general corruption ranking of Iraq.

In 2020, the Oil and Gas Products Anti-Smuggling Law No. 3/2020 was passed by the Kurdish Parliament in which certain corrupt practices were criminalised, including the smuggling of oil and its by-products, embezzlement and sale of oil products that are assigned to the government or non-governmental authorities, fraud or manipulation of any licence or official document for the purpose of smuggling. The foregoing carries a penalty of imprisonment of five to 10 years in addition to a fine of four times the amount of the violation.

IX CURRENT DEVELOPMENTS

In May 2022, in light of the February FSC Decision that found the KOGL unconstitutional and put the validity of the KRG's PSCs with IOCs into question, a commercial court in Baghdad summoned the IOCs operating in the KRI to appear before the court. Of the nine claims filed by the MoO before the Baghdad courts, the court has annulled seven of the KRI PSCs. Following negotiations between the KRG and the central government, further proceedings have been temporarily halted.

In response to the Baghdad proceedings, the KRG filed various claims against the MoO before the Erbil court, including an injunction against the MoO to prevent the MoO from hindering the performance of various PSC, as well as a criminal complaint against an MoO official. The Erbil civil court have ruled on some of the injunction in favour of the MNR and issued a decision prohibiting the MoO from interfering with the PSCs and their performance. Others remain under review.

While the various litigations between the KRG and central government over the constitutionality of the KOGL have been ongoing, the FSC amended its rules of procedure to include Article 45, which states that the court 'may, when necessary, and whenever constitutional and public interest dictates, change a previous principle on which it has ruled in one of its decisions, provided that this does not affect the stability of legal positions and acquired rights'. This amendment, previously deemed unlikely, appears to be a political move for a window of cooperation. This amendment could provide an opportunity for the KRG to restore the constitutionality of the KOGL through the possibility of the FSC Decision being reversed.

Former Minister of Natural Resources Dr Ashti Hawrami has held the position of Deputy Prime Minister for Energy Affairs since July 2019. In 2021, Dr Kamal Atroshi was appointed the new Minister of Natural Resources, and in 2022, resigned over health issues in the midst of the turmoil surrounding the FSC Decision. The Minister of Electricity is currently the acting Minister of Natural Resources.

The current central government of Iraq appears to be more amenable to reaching a long-term solution to the 20-year dispute regarding oil and gas produced in the KRI. Various press statements indicate that negotiations regarding the Federal Oil and Gas law are progressing. Furthermore, the Iraqi parliament passed a budget law for 2023–2025. Under the current budget law, the KRG is to deliver to the central government all oil produced in the KRI to be marketed and sold by SOMO at SOMO's selling price, which exceeds the price of crude that the KRG was able to get on the market. In exchange, the central ministry of finance is to pay the budget allocations due to the KRG. It is very difficult to say how matters will progress with so many variables at play.

At the very least, Kurdistan will have to cooperate more with Baghdad to be able to export any oil since Turkey will no longer permit the KRG to export through its Ceyhan port, giving Baghdad the upper hand.

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Endnotes

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2 https://gov.krd/english/information-and-services/open-data/deloitte-reports/deloitte-report-2022/.
3 Article 111, Iraqi Constitution.
4 Article 112(1), Iraqi Constitution.
5 Article 115, Iraqi Constitution.
6 Article 121(2), Iraqi Constitution.
7 Article 2, KOGL.
8 Article 4, KOGL. An amendment to this article was approved by parliament to add the chief of staff to the council, but the amending law has yet to be published in the Kurdistan Gazette and to come into force.
9 Article 24(1), KOGL.
10 Article 6(1), KOGL.
11 Article 1 No. 18, KOGL.
12 Article 3(4), KOGL.
13 Article 107(1), Iraqi Constitution.
14 Article 25(b), Riyadh Convention.
15 Article 25(c), Riyadh Convention.
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17 Article 26, KOGL.
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19 The Model PSC is at https://ens.dk/sites/ens.dk/files/OlieGas/ressourcer_og_prognose_2021_dk.pdf.
20 Article 32.1, Model PSC.
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24 Article 6.2, Model PSC.
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28 Articles 32.3 and 32.4, Model PSC.
29 Article 24.1, Model PSC.
30 Articles 25.3 and 25.4, Model PSC.
31 Article 26, Model PSC.
32 Articles 45.3 and 7.4, Model PSC.
33 Article 45.4, Model PSC.
34 Article 16.15, Model PSC.
35 Article 30, KOGL.
36 Article 39.2, Model PSC.
37 Article 39.6, Model PSC.
38 Articles 39.4 and 39.6, Model PSC.
39 There is considerable controversy as regards the KRG's constitutional right to legislate on matters relating to taxation. According to Article 110(3) of the Iraqi Constitution, 'formulating fiscal policy' falls within the exclusive jurisdiction of the federal government. The KRG's interpretation of this article distinguished between 'formulating policy' and 'regulating taxes' where the latter falls within the competencies of the regional government. In practice, this question has not been subject to judicial review and the federal government has neither imposed nor collected any taxes in the KRI since 1992.
40 Article 40, KOGL.
41 Adopted and amended in Kurdistan pursuant to the KRG Law No. 26/2007 as amended from time to time.
42 Article 31.1, Model PSC.
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45 Article 37(1)(10), KOGL and Article 23.8, Model PSC.
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Chapter 12

Nigeria

Mofesomo Tayo-Oyetibo[1]

Summary

I INTRODUCTION

The Nigerian upstream oil and gas regulatory framework has become robust after the enactment of the Petroleum Industry Act (PIA) in 2021. Under the PIA, the upstream sub-sector has a separate regulator known as the Nigerian Upstream Regulatory Commission (the Commission). The Commission is responsible for both the technical and commercial regulations of upstream petroleum operations in Nigeria. Nigeria's proven reserves have hovered around 37 billion barrels of crude oil (bbl) in the past 10 years. More recently, the reserves have declined from 37.5 billion bbl in 2017 to 36.9 billion bbl in 2020.[2] Similarly, Nigeria has an estimated 206.5 trillion cubic feet (Tcf) of proved natural gas reserves at the beginning of 2023[3] and dry natural gas production in Nigeria averaged about 1.5Tcf between 2012 and 2021, and dry natural gas consumption averaged 649 billion cubic feet (Bcf) over the same time period.[4]

The Nigerian upstream oil and gas sector is dominated by international oil companies (IOCs). Chevron, Shell, Mobil, Agip, Addax and Total currently dominate the oil industry, accounting for over 80 per cent of the country's crude oil production. Activities in this sector are carried out under various arrangements, including joint ventures (JVs) and production sharing contracts (PSCs) with NNPC Limited. Other contractual arrangements include sole risk contracts and risk service contracts. The IOCs also hold more than 90 per cent of the oil reserves and operating assets. Production by IOCs has shrunk over the past 10 years by an annual average of 4 per cent, while marginal field players have increased production by up to 15 per cent annual growth rate.

Refining capacity in Nigeria is expected to increase by 400 per cent between 2020 and 2025 as new refineries, such as the Dangote Refinery, spring up in addition to the rehabilitation of the Port-Harcourt refinery.

II LEGAL AND REGULATORY FRAMEWORK

The principal laws regulating Nigeria's oil and gas industry are as follows:

- the Constitution of the Federal Republic of Nigeria 1999 (as amended);
- the Land Use Act, 1978;
- the Petroleum Industry Act, 2021 (the PIA);
- the Companies Income Tax Act (CITA), Cap C21, LFN 2004 (as amended);
- the Companies and Allied Matters Act, 2020 (the CAMA);
- the Nigerian Oil And Gas Industry Content Development Act 2010 (the Local Content Act);
- the Environmental Impact Assessment Act; and
- the National Oil Spill Detection and Response Agency (Establishment) Act.

In Nigeria, ownership of petroleum, mineral oils and natural gas reserves is vested in the federal government of Nigeria by virtue of the Constitution and the Land Use Act. The PIA also vests ownership of petroleum within Nigeria and its territories in the federal government of Nigeria.[5]

The PIA is currently the principal act for the oil and gas industry in Nigeria. It repealed previous laws regulating the sector such as the Petroleum Act 2004, the Nigerian National Petroleum Corporation Act 1977 and the Petroleum Profits Tax Act 2004.

The PIA provides for two regulatory agencies to be responsible for the technical and commercial regulation of petroleum operations: the Nigerian Upstream Petroleum Regulatory Commission (NUPRC) and the Nigerian Midstream and Downstream Petroleum Regulatory Authority. In addition to these agencies, the PIA made new changes to the Nigerian National Petroleum Corporation (NNPC) by providing for its incorporation as NNPC Ltd (NNPCL), a limited liability company in which the Federal Government is presently the sole shareholder. NNPCL no longer operates as a statutory corporation but as a limited liability under the Companies & Allied Matters Act 2020.

The PIA's objective is to promote openness and accountability in the sector by strengthening governing institutions and encouraging international investment through changes to the industry's governance, administrative, regulatory and fiscal framework. The primary aim is to address immediate revenue needs while securing long-term industry investment.

The Local Content Act provides that all regulatory authorities, operators, contractors, subcontractors, alliance partners and other entities involved in any project, operation, activity or transaction in the Nigerian oil and gas industry shall consider Nigerian content as an important element of their overall project development and management philosophy for project execution. It further provides that Nigerian independent operators shall be given first consideration in the award of oil blocks, oil field licences, oil lifting licences and in all projects for which contract is to be awarded in the Nigerian oil and gas industry, subject to the fulfilment of such conditions as may be specified by the Minister of Petroleum Resources. Exclusive consideration should be given to Nigerian indigenous service companies that demonstrate ownership of equipment, Nigerian personnel and capacity to execute such work to bid on land and swamp operating areas of the Nigerian oil and gas industry for contracts and services contained in the Schedule to this Act. Compliance with the provisions of the Local Content Act and promotion of Nigerian content development will be a major criterion for award of licences, permits and any other interest in bidding for oil exploration, production, transportation and development or any other operations in Nigerian oil and gas industry. The Nigerian Content Development and Monitoring Board established under the Local Content Act has responsibility for implementation of the provisions of the Act.

i Domestic oil and gas legislation

The rights to, and ownership of, oil and gas reserves in Nigeria are principally governed by the Constitution of the Federal Republic of Nigeria 1999 (as amended) (the Constitution), the Land Use Act, 1978 and the PIA. The Constitution and the PIA vest ownership of all petroleum resources within Nigeria, its territorial waters, continental shelf and the exclusive economic zone in the government of the federation of Nigeria (the Nigerian government).[6]

To this end, the rights to own and develop oil and natural gas reserves are transferred by the Nigerian government to participants through awards of licences and leases in accordance with the PIA. Participants may also acquire interests directly from existing mineral rights holders, subject to obtaining the required regulatory approvals or consent.

The licences and lease granted under the PIA are the petroleum exploration licence (PEL), petroleum prospecting licence (PPL) and petroleum mining lease (PML). These three can only be granted to a company incorporated in Nigeria under the CAMA.

Licences and leases are generally granted subject to the terms of the PIA and other terms agreed in the relevant contractual arrangements under which they are granted. The legal status of licences and leases is both statutory and contractual: statutory is based on whether the licences and leases are subject to the terms of the PIA and regulations made by the Commission; and contractual is based on whether the licences and leases create a contractual relationship between the licence or leaseholder and the Nigerian government.

Petroleum rights may be granted under several model petroleum arrangements, including the following:

- PSCs;
- risk service contracts;
- profit sharing contracts;
- concession agreements; and
- any other internationally recognised form of contract for the exploration and production of petroleum.

ii Regulation

The following primary government ministries and agencies are charged with the regulation of the oil and gas industry in Nigeria.

Ministry of Petroleum Resources

The Ministry of Petroleum Resources is responsible for policy formulation and supervising their implementation. It is also charged with the responsibility of issuing applicable upstream licences such as the PPL and the PML, which may be used to grant investors or companies the rights to develop oil and gas reserves in Nigeria. It also performs a supervisory function over the other primary regulators, operators and stakeholders in the oil and gas industry to ensure compliance with all applicable laws and regulations.

NUPRC

The NUPRC regulates upstream sector activity. The upstream activities include the exploration for petroleum, petroleum development and production. The PIA empowers the NUPRC to grant PELs and recommends qualified applicants to the Minister of Petroleum for PPLs and PMLs.

The NUPRC has the statutory responsibility of ensuring compliance with petroleum laws, regulations and guidelines in the upstream oil and gas sector. The discharge of these responsibilities includes monitoring operations at drilling sites, producing wells, production platforms and flowstations, and monitoring crude oil export terminals, and all pipelines carrying crude oil and natural gas.

Federal Ministry of Environment

The Federal Ministry of Environment ensures environmental compliance of participants in the oil and gas industry. The Ministry administers the Environmental Impact Assessment Act 1992 (the EIA Act). The law requires an environmental impact assessment (EIA) for development projects that are likely to have significant adverse effects on the environment. It also monitors waste management. The Ministry also issues permits for operations in the oil and gas industry.

Nigerian Content Development and Monitoring Board

The Nigerian Content Development and Monitoring Board (NCDMB) assesses & approves Nigerian content plans developed by operators in the industry.

Federal Inland Revenue Service

The Federal Inland Revenue Service (FIRS) is responsible for the collection of companies income tax generally and also certain specific oil industry related taxes like natural gas tax, by the virtue of Sections 302 (7) and (8) of the PIA.

National Oil Spill Detection and Response Agency

The National Oil Spill Detection and Response Agency has the general objective of co-ordinating and implementing the National Oil Spill Contingency Plan for Nigeria and is responsible for surveillance and ensuring compliance with all existing environmental legislation and the detection of oil spills in the petroleum sector.

iii Treaties

International treaties that are ratified and domesticated by Nigeria also continue to regulate petroleum-related activities in Nigeria. Some of the conventions that have been ratified include the International Convention on Civil Liability for Oil Pollution Damage 1969, International Convention for the Prevention of Pollution of the Sea by Oil 1954 (as amended in 1962) (which has been incorporated under the Oil in Navigable Waters Act 1968), International Convention for the Prevention of Pollution from Ships 1973 and 1978 Protocol (Ratification and Enforcement) Act 2007 and the International Convention on the Establishment of an International Fund for Compensation for Oil Pollution Damage 1971.

Nigeria is a party to the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards 1958, which is made applicable in Nigeria by the provisions of the Arbitration and Mediation Act 2023.

Nigeria is also a signatory to the International Centre for Settlement of Investment Disputes Convention and consequently enacted the International Centre for Settlement of Investments Disputes (Enforcement of Awards) Act in November 1967 (the ICSID Act). The ICSID Act provides that if the award duly certified by the Secretary-General of ICSID is filed in the Nigerian Supreme Court by the party seeking its recognition for enforcement in Nigeria, the award shall for all purposes have the same effect as an award contained in a final judgment of the Supreme Court and be enforceable accordingly.

On 16 May 2017, Nigeria ratified the Paris Climate Change Agreement and subsequently signed on to the Global Gas Flaring Partnership (GGFR) principles for global flare-out by 2030.

III LICENSING

The administration of licences in the upstream oil and gas sector is one of the key roles that fall within the purview of the NUPRC. Under the PIA, the applicable licences for the upstream petroleum sector in Nigeria include:

- the PEL, which is granted to qualified applicants to carry out petroleum exploration operations on a non-exclusive basis. The PEL is valid for three years and may be renewed for another three years, subject to the fulfilment of prescribed conditions in the PIA;
- the PPL, which is granted to qualified applicants to drill exploration and appraisal wells and undertake corresponding test production on an exclusive basis. In addition, a PPL holder may carry out petroleum exploration operations on a non-exclusive basis. A PPL for onshore and shallow water acreages is for a period of not more than six years, comprising of an initial exploration period of three years and an optional extension period of three years. For deep offshore and frontier acreages, it is for a duration of not more than 10 years, comprising of an initial exploration period of five years and an optional extension period of five years. Furthermore, the area provided for in a PPL must not exceed:
    - 350km² for any onshore or shallow water acreages;
    - 1,000km² for any deep offshore acreages; and
    - 1,500km² for any frontier acreages; and
- the PML, which is granted to qualified applicants to win, work, carry away or dispose of crude oil, condensate and natural gas on an exclusive basis, drill exploration appraisal wells and to carry out the related test production on an exclusive basis; it may also be granted to carry out petroleum exploration operations on a non-exclusive basis. A PML is for a period of 20 years, which includes the development period. Where a development period for a PML is not stipulated, the development period is for a period of five years for an onshore lease and seven years for a lease in shallow water or deep offshore or a lease in a frontier acreage. Furthermore, a lessee of a PML may, not less than 12 months before the expiration of the lease, apply in writing to the Commission for a renewal. Notably, a PML that ceases to produce in paying quantities for a period of not less than 180 days may, except for unforeseeable circumstances or any other reason acceptable to the NUPRC, be revoked by the NUPRC.

IV PRODUCTION RESTRICTIONS

The NUPRC allocates a domestic gas delivery obligation (DGDO) to upstream producers based on domestic gas demand requirements. Gas supplied in fulfilment of the DGDO is subject to the regulated pricing framework.

New pricing formula for gas-based industries is CP[7] = NRP[8] * (1 + EPF[9]) <= EPP.[10] The floor price for GBIs is US$0.90 per 1 million British thermal units (MMBtu) while the ceiling price is the applicable domestic base price for the relevant year.

An oil exporter must obtain a clearance permit certificate from the Federal Ministry of Industry, Trade and Investment. Additionally, the PIA authorises both the NUPRC and the Authority to issue export permits and certificates of quality and quantity to exporters of crude oil and petroleum products. Notably, the grant of an export permit is subject to a crude oil producer's compliance with its crude oil supply obligations to the domestic market. Additionally, proceeds of oil and gas exports are required to be repatriated into the export proceeds domiciliary account within 90 days, failing which the exporter will be barred from participating in all segments of the foreign exchange market in Nigeria.

The price of liquefied natural gas (LNG) supplied to the domestic market is not regulated as parties are free to contract on a market-based willing-seller-willing-buyer arrangement. However, the feedstock gas sold to the LNG plant is subject to the export parity price, which is the average prior-year price of total gas sold by gas producers to Nigeria LNG Limited (NLNG).

For imports, a Nigerian company may apply for an import permit for petroleum products, subject to having access to appropriate storage facilities that could be either owned or leased from third parties. An importer of petroleum products is required to obtain a certificate of quantity upon the arrival of the vessel in Nigeria.

Regarding gas, the PIA restricts gas producers from exporting gas unless the exporting producer has complied with its annual domestic gas delivery obligation allocated to it by the NUPRC by supplying the allocated gas volume to the domestic market.

Companies engaging in cross-border sales or deliveries of natural gas may be subject to various taxes and duties, including customs duties pursuant to the Customs and Excise Management Act (the CEMA). The CEMA applies to all goods that are imported into Nigeria. Other taxes include value-added tax (VAT), which is at a standardised rate of 7.5 per cent for imported LPG. However, locally produced LPG is exempt from VAT.

The Pre-Shipment Inspection of Exports Act of 1996 (the PIEA), particularly Section 2 requires that all oil exports (defined to include crude oil and petroleum products) from Nigeria be inspected and certified by a pre-shipment inspection agency before they can be shipped out of the country. The purpose of this inspection is to ensure that the exports meet all relevant quality, safety and technical standards, and to prevent the export of substandard or fraudulent goods. Section 11 of the PIEA requires an exporter of goods, including petroleum products, to open, maintain and operate a foreign currency domiciliary account in Nigeria into which all export proceeds must be paid.

On a sectorial level, prior to the exportation of natural gas, Section 110 of the PIA requires holders of a PML to comply with their various domestic gas delivery obligations (DGDOs). We have recently seen the inclusion of these DGDOs in the terms and conditions of a PML. The DGDOs of natural gas producers and suppliers in Nigeria generally ensure that enough natural gas is made available for domestic use, in accordance with the terms of any licences or other agreements that may be in place, and that the same is supplied to domestic consumers in a safe, reliable and efficient manner, in accordance with good industry practice.

Furthermore, commercial contracts typically outline the terms and conditions under which gas will be sold or delivered. These contracts may contain provisions related to pricing, payment, delivery terms and other terms and conditions specifc to the transaction.

V ASSIGNMENTS OF INTERESTS

The provisions of the PIA provide that holders of PPLs or PMLs must not assign, novate or transfer their licences or leases or any right, power or interest, nor should shareholders of incorporated joint ventures sell or transfer their shares without prior written consent of the Minister of Petroleum Resources. Ministerial consent is granted upon the recommendation of the NUPRC. In this respect, a change in control in the holder of a lease or licence is deemed to be an assignment.

The procedure for obtaining consent is that the transferor or assignor must apply to the NUPRC for approval of the transfer and the NUPRC has a maximum of 60 days to act on the application by recommending to the Minister whether to grant or refuse ministerial consent. The Minister has 60 days from receipt of the NUPRC's recommendation to grant or refuse consent for the transaction. If no response on the application is received within 60 working days from the Minister's receipt of the NUPRC's recommendation, ministerial consent shall be deemed to have been granted.

The Nigerian government does not have a right of first refusal or preferential purchase rights upon transfer and ministerial consent may be given once it is shown that the proposed transferee is a company incorporated in Nigeria, is of good reputation and standing, has sufficient technical knowledge, experience and financial resources to effectively carry out the responsibilities of a lessee or licensee and has complied with the Federal Competition and Consumer Protection Act.

VI TAX

Under the PIA, hydrocarbon tax is payable by upstream companies operating in onshore and shallow water areas at the varied rates of 15 or 30 per cent. The petroleum resources subject to hydrocarbon tax are crude oil, field condensates and natural gas liquids derived from associated gas and produced in the upstream of the measurement points.

Furthermore, companies income tax (CIT) is applicable to all companies involved in upstream, midstream or downstream petroleum operations at the rate of zero, 20 or 30 per cent, depending on the companies' annual turnover. However, most entities operating in the Nigerian petroleum industry may likely reach the annual turnover threshold to trigger the 30 per cent CIT rate.

Other applicable taxes include:

- the tertiary education tax at the rate of 2.5 per cent of assessable profits;
- police fund levy at the rate of 0.005 per cent of net profits;
- VAT at the rate of 7.5 per cent on taxable goods and services;
- capital gains tax payable at the rate of 10 per cent of the profits from the sale of the qualifying assets; and
- National Agency for Science and Engineering Infrastructure levy at the rate of 0.25 per cent of profits before tax of commercial companies and firms with turnover of 1 billion naira and above covering certain sectors, including the oil and gas sector.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

The PIA makes provisions for environmental regulation of oil and gas operations and requires a licence or lease holder engaging in upstream and midstream petroleum operations to submit for approval an environmental management plan in respect of projects requiring EIA to the NUPRC or Nigerian Midstream and Downstream Petroleum Regulatory Authority (NMDPRA).

The obligation placed on a licence or lease holder by the PIA in this respect is mandatory and must be carried out within one year of the effective date or six months after the grant of the applicable licence or lease. The PIA provides for financial contribution for remediation of environmental damage. In this respect, the PIA makes it a condition for a licensee or lessee to pay a prescribed financial contribution to an environmental remediation fund for the rehabilitation or management of negative environmental impacts before the licence or lease shall be granted. The essence here is to take care of the negative environmental impact that may be associated with the operations of the licence or lease.

Furthermore, the PIA imposes the obligation on licence or lease holders to assess their environmental liability annually and increase their financial contribution to the satisfaction of the NUPRC or NMDPRA. Still in a bid to ensure environmental protection on oil and gas operations, the PIA makes provisions for the prohibition and penalties of gas flaring. The PIA provides that a licence or lease holder or a marginal field operator who flares gas or vents natural gas commits an offence and is liable to a fine as prescribed by the NUPRC in a regulation under the PIA.

The procedure for decommissioning is contained in Sections 232 and 233 of the PIA, which require that:

- prior approval is obtained from the NUPRC to carry out decommissioning;
- the licensee must submit a decommissioning programme with cost estimates, measures, methods and EIA. Consultations with stakeholders are essential. The approval criteria include individual circumstances, potential reuse, comparative assessments, sustainable environmental development and adherence to international practices;
- the licensee or lessee must establish and maintain a decommissioning fund with an independent financial institution in the form of an escrow account accessible by the NUPRC. This fund is exclusively for decommissioning in Nigeria; and
- the licensee or lessee must inform the NUPRC of the fund's establishment within three months from the commencement of the operation and provide annual statements of accounts.

In essence, failure to comply with the decommissioning plan allows the NUPRC to access the fund and engage a third party for decommissioning. Contributions to the fund depend on approved plans for upstream operations. Yearly amounts are estimated and approved by the NUPRC.

Contributions to the decommissioning fund are eligible for cost recovery and tax deduction, but decommissioning costs disbursed from the fund are not. Any excess in the fund after approved decommissioning will be considered income and returned to the licensee or lessee after withholding profit oil and taxes. The NUPRC has enforcement powers and maintains a public database of installations.

Further to the PIA provisions, in 2021 the NUPRC issued the Upstream Decommissioning and Abandonment Regulations, 2021 to regulate decommissioning.

i The EIA Act

The EIA Act principally governs environmental impact assessments for the oil and gas industry in Nigeria.

The EIA Act requires that where the extent, nature or location of a proposed project or activity is such that it is likely to have a significant effect on the environment, an EIA must be undertaken. It lists projects for which an EIA must be carried out, the circumstances in which it shall be required and circumstances in which it may not be required. Sectors and projects for which an EIA must be carried out include exploration and exploitation for petroleum.

The petroleum sector projects include:

- oil and gas field development;
- construction of offshore pipelines in excess of 50km in length;
- construction of oil and gas separation, processing, handling and storage facilities;
- construction of oil refineries; and
- construction of product depots for storage of petrol, gas or diesel (excluding service stations) that are located within 3km of any commercial, industrial or residential areas and have a combined capacity of 60,000 barrels or more.

ii National Oil Spill Detection and Response Agency (Establishment) Act 2006

The National Oil Spill Detection and Response Agency (NOSDRA) Act established NOSDRA in 2006 as an institutional framework to co-ordinate the implementation of the National Oil Spill Contingency Plan (NOSCP) for Nigeria in accordance with the International Convention on Oil Pollution Preparedness, Response and Co-operation (OPRC 90) to which Nigeria is a signatory.

The NOSCP is a national system for responding promptly and effectively to all oil pollution incidents occurring in Nigeria. It presents a consensus opinion through the participation of all relevant stakeholders – local and international – in its preparation. It is for use by all operators in the oil and gas sector of Nigeria involved in exploration, exploitation, production and transportation.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

Bidding rounds in Nigeria are governed principally by the provisions of the PIA, the Petroleum Licensing Round Regulations 2022 (the Regulations) and the Deep Offshore Licensing Rounds Guidelines dated 21 December 2022 (the Guidelines). The Mini-Bid Round 2022 is the first licensing round to be conducted pursuant to the PIA, which introduced significant changes to the fiscal and regulatory framework for oil and gas exploration in Nigeria.

The bidding round usually follows a two-stage bidding process. The first qualification stage involves the paring down by the NUPRC of the initial list of applicants based on certain specified pre-qualification criteria. The shortlisted applicants are then invited to participate in the bidding stage by submitting technical and commercial bids. Applicants will have access to relevant block data primarily via a virtual data room and an online platform through which applicants can register and submit relevant bidding documents, although a physical submission of bids is also required by the Regulations. Qualifying applicants are required to purchase multi-beam, two-dimensional and three-dimensional seismic data available in respect of the blocks from approved multi-client vendors and provide evidence of this purchase as part of the submission of technical bids. The winning bid will be the highest value bid based on the highest aggregate number of points scored by a bidder upon the combined assessment of both the signature bonus proposals submitted by a bidder and the work programme proposals showing the number of exploration wells that the bidder will commit to drilling during the initial term of a PPL. Bidders are expected to submit details of work experience and the proposed work plan for the blocks of interest.

To prequalify for the bidding rounds, an applicant needs to meet certain minimum financial, technical and legal requirements. The minimum financial qualification is set at US$200 million. Compliance with the minimum financial qualification may be demonstrated, in terms of the annual turnover of an applicant or an applicant's cash at hand, the same amount. The minimum financial qualification can also be demonstrated by an applicant with the aid of a letter of credit from a reputable financial institution or by demonstrating that the applicant's market capitalisation is equal to the minimum financial qualification, as well as with either a bank guarantee or a parent company guarantee, in the said amount.

To meet the minimum technical criteria for pre-qualification, an applicant must have demonstrable experience in deep offshore operations (for offshore licensing) up to a minimum of five years. Technical ability can be demonstrated in a number of ways, including providing relevant information on the technical ability of the applicant and on the technical experience of a majority of the applicant's promoters, management team, technical partner or parent company. Applicants who wish to demonstrate technical competence using a technical partner are required to provide a technical support or partnership agreement as evidence.

Applicants may apply either as a consortium or as a single entity. For consortium applications, an operator must be designated, who must own a minimum participating interest of 20 per cent. All applicants must submit incorporation documents revealing details of shareholders and directors as well as the memo or articles of association, profile of promoters or management team, valid tax clearance certificate and organisational chart of the applicant. Non-resident foreign applicants who decide to participate in the bidding rounds will also need to submit the above-mentioned documents but would need to incorporate a local entity in the event that the bid for a block is successful. The Regulations make it clear that only a company incorporated in Nigeria under the extant Companies and Allied Matters Act may be awarded a PPL. Bidders will be required to execute a confidentiality agreement and a bid guarantee, and provide beneficial owner information using standard formats provided by the Commission.

Application and registration fees

Applicants are required to pay the sum of US$5000 as a registration fee and the sum of US$20,000 per block as an application and processing fee. Applicants will also be required to pay the relevant data purchase fee to approved data vendors, in addition to fulfilling additional qualifying criteria.

Establishment of enterprises by investors

Foreign companies may invest in any enterprise in Nigeria, including acquisition of interests in the Nigerian petroleum industry. However, these foreign companies are generally precluded from carrying out such business (including activities within the Nigerian petroleum industry) in Nigeria, except through a separate legal entity incorporated in Nigeria. The PIA also provides that a licence or lease will only be granted to a company incorporated and validly existing in Nigeria under the Companies and Allied Matters Act 2020.

Furthermore, foreign companies carrying out business in Nigeria are required to be registered with the NIPC and obtain a business permit from the Federal Ministry of Interior. Generally, 100 per cent foreign ownership of a local entity through which a foreign company carries on business is permitted. However, pursuant to the provisions of the Nigerian Oil and Gas Industry Content Development Act 2010, first consideration is required to be given to companies that have at least 51 per cent Nigerian ownership in the award of oil blocks, oilfield licences, oil lifting licences and all projects for which contracts are to be awarded in the Nigerian oil and gas industry. Exclusive consideration is also required to be given to Nigerian indigenous service companies that demonstrate ownership of equipment, Nigerian personnel and capacity to execute such work to bid for contracts and services on land and swamp operating areas of the Nigerian petroleum industry.

Timing and procedure for establishment of a local entity or branch of a foreign entity

Incorporating a company in Nigeria can be carried out within one week if all the necessary documents are in place and provided for the application for incorporation. Company incorporations are conducted at the Corporate Affairs Commission and can be made online.

To complete an incorporation, the following procedure is to be followed:

- search and reserve available company name. A name may be disallowed if it currently exists with another owner or incorporates disallowed words, such as government and council, without necessary authorisation;
- complete all statutory forms;
- pay filing fees and stamp duty; and
- submit the application for incorporation.

Once approved, the certificate and other incorporation documents can be downloaded online.

ii Capital, labour and content restrictions

The Nigerian foreign exchange market is regulated by the Central Bank of Nigeria (CBN) and the main legislation regulating foreign exchange in Nigeria is the Foreign Exchange (Monitoring and Miscellaneous Provisions) Act (the FX Act). Foreign exchange transactions are also regulated by the Foreign Exchange Manual (FX Manual) issued by the CBN pursuant to the FX Act.

Regarding export operations, the FX Act mandates all exporters, including oil and gas exporters, to open and maintain a foreign currency domiciliary account into which may be retained foreign currency corresponding to the entire proceeds of the export concerned. All petroleum exporters are required to ensure that all export proceeds are repatriated and credited to their export proceeds domiciliary account in Nigeria within 90 days from the bill of lading date.

Notably, the FX Act and the Nigeria Investment Promotion Commission Act (the NIPC Act) guarantee the unconditional transferability of funds, through an authorised dealer (an entity licensed by the CBN to operate as an authorised dealer in the Nigerian foreign exchange market) in freely convertible currency for investments in Nigeria. For an investor to be permitted to be able to freely repatriate capital and proceeds in foreign currency using the Nigerian foreign exchange market, the capital must have been imported into Nigeria through an authorised dealer. At the point of importation of capital into Nigeria, the authorised dealer converts the capital into local currency and issues an electronic CCI (eCCI).

The eCCI evidences the importation of capital for the stated purpose and facilitates unconditional transferability and repatriation of funds with regard to both earnings and capital in foreign currency using the Nigeria foreign exchange market. Funds that may be repatriated in foreign currency unconditionally through an authorised dealer includes all dividends (net of taxes), profits attributable to the investment made and interest on loans (net of all applicable taxes) or capital upon divestment from Nigeria. The repatriation of proceeds of investment capital must also be carried out through an authorised dealer. Of note, the non-issuance of an eCCI does not impact the legal right of an investor to earn investment proceeds; however, the investor would not have access to the official foreign exchange market for the purpose of repatriation of funds.

Regarding repatriation of profits derived from production and held in an export proceeds domiciliary account, under the FX Manual and circulars issued by the CBN, holders of export proceeds domiciliary accounts have access to funds in their accounts for eligible transactions. The CBN has provided a list of eligible transactions that can be financed with proceeds of oil and gas exports and the items provided include principal and interest payment and dividend payment.

A local company that intends to employ foreigners in Nigeria is required to assume immigration formalities and certain responsibilities for those employees. This entails obtaining several approvals and permits required by the Nigeria Immigration Service (NIS).

Expatriate Quota is an approval by the Minister of Interior, permitting a Nigerian company to employ a foreign employee. Expatriate Quotas are issued to companies that have met the criteria for engaging the services of expatriates on a long-term basis. For an expatriate to work in Nigeria, the company employing the expatriate would need to be incorporated in Nigeria. Furthermore, any company having foreign shareholders is required to obtain a business permit before carrying on business in Nigeria.

It typically takes approximately 10 to 12 weeks to obtain the business permit and EQA. Upon the grant of the EQA, the company is expected to apply to the Nigerian Embassy in the expatriates' country, requesting that the employee be granted a Subject to Regularisation Visa (STR Visa). The STR Visa is to be used for a period of 90 days during which the company must make an application to the Comptroller General of the NIS to regularise the stay of the expatriate.

iii Anti-corruption

Nigeria signed the United Nations Convention Against Corruption on 9 December 2003 and ratified it on 24 October 2004. It also adopted the African Union Convention on Preventing and Combating Corruption in 2003 and ratified it in 2006.

Nigeria has a myriad of laws relating to anti-corruption, anti-money laundering, anti-bribery and related matters, of these the two principal ones are the Independent Corrupt Practices and Other Related Offences Act 2000 (ICPC) and the Economic and Financial Crimes Commission Act 2004 (EFCC).

Section 23 of the ICPC imposes a duty on both public officers and private individuals to report bribery transactions. While it imposes a duty on a public officer to whom a bribe is offered to report the incident to the ICPC or the police, it also imposes a similar duty on private individuals from whom bribery is demanded. Failure to report such an incident without reasonable excuse is an offence punishable with imprisonment or a fine, or both.

There have not been any key amendments in 2022 to these principal legislations. However, there was an amendment to the Money Laundering Act 2011, which made it mandatory for deposit money institutions to report to the Special Control Unit Against Money Laundering under the EFCC any single lodgement in excess of 5 million naira in the case of an individual and 10 million naira for a corporate body.

Duties to prevent corruption

The expectation of all relevant legislation regarding corruption, bribery, money laundering and the enforcement agencies is that individuals and companies have an obligation or duty to prevent corruption by setting up compliance programmes to that effect.

Compliance programmes

The Anti-Money Laundering Act requires that the following compliance and control mechanisms be established:

- designation of an anti-money laundering (AML) chief compliance officer at management level;
- identifying AML regulations and offences;
- highlighting the nature of money laundering;
- identifying money laundering red flags and suspicious transactions;
- setting out reporting requirements;
- conducting customer due diligence;
- taking a risk-based approach to AML; and
- having a record-keeping and retention policy in place.

Enforcement bodies and areas of competence and authority

The EFCC

The EFCC is in charge of the following:

- investigating and prosecuting economic and financial crimes;
- acting as the nationwide co-ordinator for Nigeria's anti-money laundering drive;
- acting as the designated Nigerian Financial Intelligence Unit; and
- implementing the Advance Fee Fraud Act, the Failed Banks Decree, the Money Laundering Act and the Banks and other Financial Institutions Decree.

The ICPC

The ICPC has the following key functions:

- investigating reports of corruption with specific reference to government and public officials;

- investigating government establishments and the public's susceptibility to corruption; and
- educating and enlightening the public on corruption with a view to enlisting and fostering public support for its anti-corruption campaign.

The Special Fraud Unit of the Nigerian Police Force

The special fraud unit and anti-fraud section of the Nigeria police force investigates high-profile local and international fraud cases.

IX CURRENT DEVELOPMENTS

The NUPRC is in the process of a mini-bid round for seven offshore blocks. The process has been ongoing since the beginning of the year and is not yet concluded.

Nigeria is expected to implement over 115 new oil and gas projects across the upstream sector between 2023 and 2027 in a bid to maximise the development and exploitation of energy resources to achieve energy security and drive economic growth.

i AKK Pipeline

The Ajaokuta-Kaduna-Kano (AKK) pipeline is a 614km-long natural gas pipeline being developed by NNPC Limited. It will run from Ajaokuta to Kano in Nigeria and is estimated to cost approximately US$2.8 billion. It is being implemented using a build and transfer public-private partnership model, in which the contractor is providing full funding. Construction was commenced in July 2020 with commissioning expected to happen in 2023.

The project will result in the establishment of a connecting pipeline network between the eastern, western and northern regions of Nigeria. It also aims to create a steady and guaranteed gas supply network between the northern and southern parts of Nigeria by using the country's widely available gas resources. In addition, the development is expected to reduce the volume of gas flared annually in Nigeria and the consequent environmental impact of flaring.

ii Dangote Petroleum Refinery

Dangote Oil Refinery is a 650,000 barrels per day integrated refinery project under construction in the Lekki Free Zone near Lagos, Nigeria. It is expected to be Africa's biggest oil refinery and the world's biggest single-train facility. The pipeline infrastructure at the Dangote Petroleum Refinery is said to be the largest anywhere in the world, with 1,100km to handle 3Bcf of gas per day. The Refinery is expected to meet 100 per cent of the Nigerian requirement of all refined products and also have a surplus of each of these products for export. Dangote Petroleum Refinery is a multi-billion dollar project that will create a market for US$21 billion per annum of Nigerian crude. It is designed to process Nigerian crude with the ability to also process other crudes.[11]

iii Seven new regulations

The NUPRC has issued seven new regulations aimed at providing a regulatory environment that assures efficiency, predictability, clarity and effectiveness to the Nigerian oil and gas industry.

The seven new regulations are as follows:

- Nigeria Upstream Petroleum Measurement Regulations, 2023;
- Production Curtailment and Domestic Crude Oil Supply Obligation Regulations, 2023;
- Frontier Basins Exploration Fund Administration Regulations, 2023;
- Nigeria Upstream Decommissioning and Abandonment Regulations 2023;

- Significant Crude Oil and Gas Discovery Regulations, 2023;
- Gas Flaring, Venting and Methane Emission (Prevention of Waste and Pollution) Regulations, 2023; and
- Nigeria Upstream Petroleum Unitisation Regulations, 2023.

Earlier, five regulations were successfully gazetted between June and October 2022. They are as follows:

- Petroleum Licensing Round Regulations 2022;
- Petroleum Royalty Regulations 2022;
- Domestic Gas Delivery Obligations Regulations 2022;
- Conversion and Renewal (licences and leases); and
- Nigeria Upstream Petroleum Host Communities Development Regulations 2022.

All 12 regulations and others to be soon finalised will serve as the key regulatory tools to be deployed by the NUPRC in the discharge of its statutory functions under the PIA regime. Eighteen regulations have initially been identifed as priority. Issuing the regulations represents a signifcant milestone achievement for the NUPRC in its continued stride towards the attainment of the goals of the PIA and the reformation of the upstream petroleum sector.

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Endnotes

1 Mofesomo Tayo-Oyetibo is a partner at Tayo Oyetibo LP. The author would like to thank Joseph Felix and Zachariah Gira for their contributions to this chapter.
2 PWC, 'The Petroleum Industry Act, Redefining the Nigerian oil and gas landscape' (2021). The Petroleum Industry Act Series <https://pwcnigeria.typepad.com/files/the-petroleum-industry-act-insights-series_august-2021.pdf> accessed 25 September 2023.
3 Worldwide Look at Reserves and Production, 'Oil & Gas Journal, Worldwide Report [Table]', 25 September 2023.
4 US Energy Information Administration, International Energy Statistics database, last accessed on 25 September 2023.
5 Section 1, Petroleum Industry Act, 2021.
6 Section 44(3), Constitution of the Federal Republic of Nigeria, 1999 (as amended).
7 CP is the applicable gas price in $/MMBtu.
8 NRP is the National Reference Price, which is US$1/MMBtu (subject to a change by the Authority).
9 EPF is the End Product Factor, which is described by the following formula (CMPP - PRP)/PRP.
10 EPP is the ceiling price, which is the domestic base price applicable for any year.
11 https://www.dangote.com/our-business/oil-and-gas/.

Chapter 13

South Africa

Megan Rodgers, Margo-Ann Werner, Heinrich Louw and Amore Carstens[1]

Summary

I INTRODUCTION

The South African upstream oil and gas regulatory landscape is on the cusp of a legislative transition as the country awaits enactment of the Upstream Petroleum Resources Development Bill (UPRDB). The UPRDB was introduced into the national assembly on 1 July 2021 and once passed, the UPRDB will separate upstream oil and gas activities from the mining sector. As of January 2022, South Africa's estimated crude oil reserves are 15 million barrels, all of which are located offshore,[2] and the natural gas reserves were estimated at only 25.1 billion cubic meters (bcm) as at 2021. There is significant opportunity for gas production in South Africa, with TotalEnergies' announcement in 2021 of two significant gas discoveries, namely the Bulpradda and Luipard prospects. The Block 11B12B joint venture has since applied for a production right. Production of the domestic oil and gas reserves has the potential to spark a much-needed energy transition in the country. Currently South Africa's offshore oil and gas acreage is occupied by a mix of junior, major and supermajor oil companies, as well as the national oil company, and we stand at the precipice of an exciting period in the development and production of gas and condensates, both onshore and offshore, all of which could positively impact the South African economy.

II LEGAL AND REGULATORY FRAMEWORK

i Domestic oil and gas legislation

The Mineral and Petroleum Resources Development Act No 28 of 2002 (MPRDA) and the Mineral and Petroleum Development Regulations issued thereunder (Petroleum Regulations) is the national legislation that regulates both the mining sector and the upstream petroleum exploration and production sector. The MPRDA states that the petroleum resources of the nation are the common heritage of the people of South Africa, and the state, duly represented by the Minister, is the custodian thereof for the benefit of all South Africans.[3] Chapter 6 of the MPRDA contains the legislative framework for petroleum exploration and production activities in South Africa.

Section 2 of the MPRDA sets out the objects of the MPRDA, which include:

- recognising the right of the state to exercise sovereignty over the mineral and petroleum resources in South Africa;[4]
- promoting equitable access to mineral and petroleum resources to all South Africans;[5] and
- expanding opportunities for historically disadvantaged persons by facilitating participation entry into the petroleum sector.[6]

These, along with the other objects, ultimately colour the provisions of the MPRDA with a noble purpose of furthering the interests of all people in South Africa.

In addition to the MPRDA, the Mining Titles Registration Act No 16 of 1967 (MTRA) seeks to ensure that permits and rights granted under the MPRDA are properly registered and enforceable against third-party claims. Upon such registration, the exploration and production rights become a real right to property; property in this context being the natural resource.

As in the ordinary course, domestic legislation must be read and interpreted to further the objects of the Constitution of the Republic of South Africa, 1996 (Constitution). On 6 December 2014, the Department of Mineral Resources and Energy (DMRE) the Department of Environmental Affairs as it was known then (DEA) and the Department of Water and Sanitation (DWS) issued a joint statement announcing that environmental regulation would be removed from the scope of the MPRDA and would be regulated under the National Environmental Management Act 107 of 1988 (NEMA), which would give rise to the 'One Environmental System'. The implementation of the One Environmental System was given effect by the National Environmental Management Amendment Act and the Mineral and Petroleum Resources Development Amendment Act 49 of 2008. Accordingly, NEMA is the overarching regulatory framework for environmental matters related to exploration and production activities and the Minister is the responsible authority for implementing the environmental provisions under NEMA, insofar as it relates to exploration and production activities.[7]

Other important legislation includes the Income Tax Act 21 of 1996 (ITA), the Value Added Tax Act 89 of 1991, the Mineral and Petroleum Resources Royalty Act, 2008 and the Transfer Duty Act 40 of 1949.

ii Regulation

The main regulatory bodies responsible for overseeing upstream oil and gas operations are the Department of Mineral Resources and Energy (DMRE), the Petroleum Agency of South Africa (SOC) Limited (Petroleum Agency) and the Mineral and Petroleum Titles Registration Office (MPTRO).

Other key regulatory agencies in South Africa include:

- Department of Forestry Fisheries and the Environment (DFFE), which is responsible for protecting, conserving and improving the South African environment and natural resources;
- Department of Water and Sanitation (DWS), which has overall responsibility for and authority over South Africa's water resources and their use;
- National Energy Regulator of South Africa (NERSA), with the mandate to regulate and determine tariffs and pricing for the electricity, piped gas and petroleum pipelines industry;
- International Trade Administration Commission, responsible for the issuing of import and export permits for inter alia the import and export of petroleum in accordance with the ITA Act; and
- the South African Maritime Safety Authority, with powers to approve Oil Spill Contingency plans required to be developed in connection with exploratory and production drilling.

Section 3(2)(a) of the MPRDA specifies that the state acting through the Minister may grant, issue, refuse, control, administer and manage, inter alia, any petroleum permit or petroleum right. Section 103 of the MPRDA grants the Minister the power to delegate any power or assign any duty conferred on him in the MPRDA (except for the powers to make regulations or deal with any appeal) to the Director-General, the Regional Manager or any officer.[8]

On 14 December 2006, the Minister delegated the powers conferred under Section 3(2)(a) of the MPRDA to the Director-General, the delegation of which remains in full force and effect as at the time of writing.[9] Subsequently, on 3 May 2012, the Minister amended the aforesaid delegation so as to extend a delegation of the Section 3(2)(a) powers to issue, refuse and notify an applicant of refusal of a petroleum permit to the Deputy Director-General: Mineral Regulation of the Department of Mineral Resources (DDG), the delegation of which remains at full force and effect as at the time of writing.

The net effect and intent of the aforementioned delegations being that the Director-General is authorised to grant, refuse, control, administer and manage any petroleum right and the DDG is authorised to grant, refuse and notify an applicant of refusal of a petroleum permit.

The Minister is authorised in Section 70 of the MPRDA to designate an organ of state or wholly owned and controlled agency or company belonging to the state to perform the Chapter 6 functions. The Petroleum Agency has been designated as such and is thus required to perform all the functions listed in Section 71 of the MPRDA.[10]

The DMRE is responsible for the regulation, transformation and promotion of the mineral and energy sector. The DMRE also oversees compliance with the provisions of the MPRDA and NEMA in relation to the mining sector as well as the oil and gas sector in South Africa. The DMRE, duly represented by the Minister and his or her delegates, is responsible for the granting, issuing or refusal of the rights and permits under the MPRDA and serves as the competent authority for the granting of environmental authorisations in terms of NEMA in accordance with Section 38A of the MPRDA.

In addition to the granting or refusal of rights under the MRDA, the Minister and his or her delegates are empowered to cancel or suspend permits and rights should the holder thereof, inter alia, conduct its operations in contravention of the MPRDA, breach the terms and conditions of its right or permit or contravene a condition in the environmental authorisation.[11]

The Petroleum Agency promotes exploration and production activities within the Republic. Notable functions of the Petroleum Agency, as listed in Section 71 of the MPRDA, include the promotion of onshore and offshore exploration and production activities. The Petroleum Agency is also responsible for receiving applications in connection with various rights and permits and making recommendations to the Minister. In sum, the Petroleum Agency acts in an advisory role with a remit to promote exploration and production activities in South Africa.

The MPTRO is responsible for the registration of exploration and production rights and the recording of reconnaissance and technical cooperation permits (TCPs).

iii Treaties

South Africa is a party to the New York Convention, which has been enacted into domestic legislation by way of the Recognition and Enforcement of Foreign Arbitral Awards Act 40 of 1977. South African courts are generally willing to enforce any valid arbitration award on the same basis as a judgment of the High Court of South Africa, unless the court finds exceptional reasons for not doing so. South Africa is not a party to the International Centre for Settlement of Investment Disputes (ICSID).

Domestically, the Institute of Legal Proceedings Against Certain Organs of State Act 40 of 2002 seeks to make provision for notice requirements in connection with any legal proceedings instituted against an organ of state. In terms of this act, a notice of intention to institute legal proceedings must be served on an organ of state within six months from the date on which a cause of action arose.[12] In this regard, court processes may not be served on the organ of state before the expiry of 30 days after the notice of intention to institute legal proceedings was served on the relevant organ of the state.[13]

In practice, dispute resolution clauses in upstream-related permits and rights often provide for disputes to be settled by way of arbitration in accordance with the rules of the Arbitration Foundation of Southern Africa.

Bilateral investment

South Africa is signatory to a number of bilateral investment treaties (BITs) with countries such as the United Kingdom, the Netherlands, Switzerland and France.

However, South Africa has begun terminating its BITs with the intention of replacing them with South African domestic legislation in the form of the Promotion and Protection of Investment Act 22 of 2015, which came into effect on 13 July 2018. The aim of this Act is to protect foreign investors in South Africa.

Accordingly, South Africa has opted to replace the treaty protections with those stipulated in the Promotion and Protection of Investment Act 22 of 2015.

III LICENSING

The MPRDA provides for four types of granting instruments in the context of petroleum:

- a reconnaissance permit;
- a technical cooperation permit (TCP);
- an exploration right; and
- a production right.

The MPRDA makes provision for the submission of six types of applications:

- an application for issuing a reconnaissance permit;
- an application for issuing a TCP;
- an application for granting an exploration right;
- an application for granting a production right; and
- an application for granting a renewal to exploration rights or production rights.

Applications for the issue of a TCP, exploration rights and production rights are processed on a first-come, first-served basis if there are competing applications (namely, applications over the same area) received on different dates. If applications are received on the same day, they are regarded as received at the same time and in this particular scenario the MPRDA expressly states that a competing application that has been submitted by an HDSA company must be given preference over all other applications submitted on the same day.[14]

i Reconnaissance permits

A reconnaissance permit may be applied for under Section 74 of the MPRDA. Under this permit, the holder is permitted to undertake only geological, geophysical or photographical surveys and any remote sensing techniques. This permit is valid for 1 year and cannot be renewed. An application for the grant or issue of a reconnaissance permit, and the application documents to be submitted in support of such application, are expressly set out and listed in Section 74 of the MPRDA read with regulation 18 and Form K, Annexure I of the Petroleum Regulations. Holders of a reconnaissance permit do not enjoy exclusive rights, and the permit holders are obliged, in terms of Regulation 22 of the Petroleum Regulations, to supply the Petroleum Agency with all data, reports and interpretation generated as soon as possible after completion of the operations.

ii TCPs

A TCP can be acquired under Section 77(1) of the MPRDA and enables the holder thereof to carry out desktop studies, acquire seismic data and data from other sources, including from the Petroleum Agency. This permit is valid for one year and cannot be renewed. In addition, one cannot conduct exploration activities under this permit. An application for the grant or issue of a TCP, and the application documents to be submitted in support of such application, are expressly set out and listed in Section 76 of the MPRDA read with Regulation 23 and Form L, Annexure I of the Petroleum Regulations. In the event that an application for a TCP does not comply with the acceptance requirements contained in Section 76(1) and Section 76(2) of the MPRDA, the Petroleum Agency must notify the applicant in writing of that fact within 14 days of receipt of the application and return the application to the applicant.[15] If an application for a TCP meets the acceptance criteria, then the merits of the application are assessed by the Petroleum Agency; such merits relate to the applicant's demonstration of its access to financial resources, technical ability and whether or not the applicant is in contravention of the MPRDA.[16] TCPs are granted for a period not exceeding one year and are not transferable and not renewable.[17] Holders of TCPs have an exclusive right to apply for an exploration right over the area covered by a TCP, and a TCP in respect of which an application for an exploration right has been lodged will remain in force until such time as the application for an exploration right has either been accepted or rejected.[18]

iii Exploration rights

An application to grant an exploration right and the application documents to be submitted in support of such application are expressly set out and listed in Section 79 of the MPRDA read with Regulation 28 and Form M, Annexure I of the Petroleum Regulations. In terms of Section 79(1), the application once prepared and compiled by the applicant must be lodged at the office of the Petroleum Agency, in the prescribed manner, together with a prescribed non-refundable application fee.[19] The Petroleum Agency must, in terms of Section 79(2) of the MPRDA, accept an application for a exploration right if such application has met the requirements of Section 79(1) and no other person holds a technical cooperation permit, exploration right or production right for petroleum over any part of the same area. The Petroleum Agency must, in terms of Section 79(2) of the MPRDA, accept an application for an exploration right if the application has met the requirements of Section 79(1) and no other person holds a TCP, exploration right or production right for petroleum over any part of the same area. In the event that an application for an exploration right does not comply with the acceptance requirements contained in Section 79(1) and Section 79(2) of the MPRDA, then the Petroleum Agency must notify the applicant in writing of that fact within 14 days of receipt of the application and return the application to the applicant.[20]

If an application for an exploration right meets the acceptance criteria, then the Petroleum Agency must, within 14 days from the date of such acceptance, require the applicant to:

- notify and consult with any landowner, lawful occupier and any interested and affected party; and
- prepare and submit the relevant environmental reports required in terms of Chapter 5 of NEMA.

The MPRDA states that an exploration right must be granted by the Minister if the criteria set out in Section 80 of the MPRDA has been demonstrated by the applicant and met.[21] Exploration rights are granted for an initial period of three years and on application can be renewed for up to three further periods not exceeding two years each.[22] An application for renewal of an exploration right must be granted if the holder of the exploration right has complied with the terms and conditions of the exploration right, the approved exploration work programme and the provisions of the Act.[23] An application for renewal of an exploration right, and the application documents to be submitted in support of such application are expressly set out and listed in Section 81(1) and (2) of the MPRDA read with Regulation 33 and Form M, Annexure I of the Petroleum Regulations. Neither the MPRDA nor the Petroleum Regulations as stated above require an applicant for renewal to relinquish an exploration area in order for the application to be accepted by the Petroleum Agency. An exploration right that is the subject of a renewal application will remain in force until such time as the application has either been accepted or rejected.[24] The holder on an exploration right has the exclusive right to apply for a production right over the exploration area.

iv Production rights

An application for the grant of a production right and the application documents to be submitted in support of such application are expressly set out and listed in Section 83 of the MPRDA read with regulation 34 and Form N, Annexure I of the Petroleum Regulations. In terms of Section 83(1), the application once prepared and compiled by the applicant must be lodged at the office of the Petroleum Agency, in the prescribed manner, together with a prescribed non-refundable application fee.[25] The Petroleum Agency must, in terms of Section 83(2) of the MPRDA, accept an application for a production right if such application has met the requirements of Section 83(1) and no other person holds a technical cooperation permit, exploration right or production right for petroleum over any part of the same area. In the event that an application for a production right does not comply with the acceptance requirements contained in Section 83(1) and (2) of the MPRDA, then the Petroleum Agency must notify the applicant in writing of that fact within 14 days of receipt of the application and return the application to the applicant.[26] A production right is valid for 30 years and is renewable for further periods each of which cannot extend beyond 10 years.

The terms and conditions of the reconnaissance permits, TCPs, exploration and production rights are open to negotiation but must comply with the provisions of the MPRDA and must be approved by the Minister.[27]

Although not expressly provided for under the MPRDA, a standard condition contained in exploration and production rights is an option, afforded to the state, to participate via a 10 per cent carried interest in all exploration and production rights granted by the Minister. A further standard term to exploration and production rights under the MPRDA includes the participation of historically disadvantaged persons (HDPs). In this regard, the granting of production rights must give effect to the transformative objectives of the MPRDA, including the objects of the Charter For the South African Petroleum and Liquid Fuels Industry (Charter).[28] The Charter enjoins all signatories to aid in the redistribution of ownership in the petroleum industry to HDPs. This usually translates into a condition under production rights whereby holders are required to onboard an HDP partner with a 10 per cent participating interest.

Exploration rights (including any subsequent notarial deed of renewal or assignment) and production rights must be lodged for registration at the MPTRO within 60 days from the date of execution thereof. The Regulations to the Mining Titles Act provide that the MPTRO must register an exploration right within 10 working days from the date days this is lodged with the MPTRO.[29] Once an exploration right or production right has been registered by the MPTRO, it creates a real right which is enforceable against third-party claims.[30]

The effective dates for the rights and permits mentioned above are not prescribed by law. However, the Supreme Court of Appeal, in the case of *Minister of Mineral Resources v. Mawetse (SA) Mining Corporation (Pty) Ltd*[31] held that the effective date of an exploration right or the renewal of such right, as the case may be, is the date on which the granting of such right or renewal is communicated to the holder by the Petroleum Agency. Accordingly, the period of the applicable permit or right commences on the day the Petroleum Agency issues a letter to the holder thereof that such permit or right has been granted.

IV PRODUCTION RESTRICTIONS

The National Energy Regulator of South Africa (NERSA) is mandated in terms of the Gas Act 2001 (Gas Act) to determine the maximum prices to be charged by individual gas distributors and traders. To exercise this power, NERSA must determine that there is inadequate competition in the gas industry. NERSA is the authority regulating and determining tariffs and pricing for the electricity, piped gas and petroleum pipelines industry in terms of the Electricity Regulation Act 4 of 2006, the Gas Act and the Petroleum Pipelines Act 60 of 2003. The construction of new upstream pipelines currently requires an application to NERSA. Oil prices are not regulated by legislation in South Africa.

The International Trade Administration Act 71 of 2002 (ITA Act) provides that an exporter of petroleum products must obtain an export permit from International Trade Administration Commission (ITAC).[32] A requirement for the issuing of an export permit is that the exporter has obtained a recommendation from the DMRE. On 3 November 2006, DMRE published the Petroleum Export Guidelines. In terms of the Petroleum Export Guidelines, DMRE must issue a recommendation to an applicant seeking to export, inter alia, crude oil, unless it is the opinion of DMRE that such export may:

- result in a shortage of crude oil; or
- not be in the public interest to issue such recommendation.[33]

Applications for export recommendations must be made in writing to DMRE by completion of the relevant form supplied by ITAC. DMRE must within 24 hours of receipt of an application issue a recommendation to ITAC and issue a copy thereof to the applicant. If DMRE declines to do so, reasons must be provided.[34] South Africa is currently not an exporter of crude oil; it is a net importer of both crude oil and gas.

V ASSIGNMENTS OF INTERESTS

The holder of an exploration right is able to cede or assign the exploration right or an interest therein, subject to the approval of the Minister.[35] A cessionary or assignee will be required to prove, among other things, their technical and financial ability to conduct the proposed exploration operation optimally in accordance with the exploration work programme.[36]

Once the cession or assignment has been approved by the Minister, the cedent, cessionary (or assignor, assignee) and the Petroleum Agency of South Africa (PASA), acting on behalf of the Minister must execute a notarial deed of assignment at the office of PASA before a notary public (a Notarial Deed of Assignment). The cessionary or assignee is thereafter required to submit the Notarial Deed of Assignment for registration at the MPTRO within

60 days in accordance with the Mining Titles Registration Act, No. 16 of 1967. Once the Notarial Deed of Assignment has been registered with the MPTRO, it creates a real right that is enforceable against third-party claims.

Section 102 of the MPRDA permits the holder of an exploration right to amend the terms and conditions of the exploration right and the exploration work programme but subject to obtaining prior Ministerial consent.[37]

VI TAX

i Applicable tax regime

The South African Revenue Service (SARS) is responsible for collecting revenue and ensuring compliance with tax laws.

The taxes that are applicable to the oil and gas industry may include:

- income tax and capital gains tax (CGT) in terms of the ITA;
- value added tax (VAT), levied under the Value Added Tax Act No 89 of 1991 (VAT Act);
- royalties, which are imposed by the Mineral and Petroleum Resources Royalty Act No. 28 of 2008 read with the Mineral and Petroleum Resources Royalty No 29 of 2008 (Administration) Act; and
- carbon tax, imposed in terms of the Carbon Tax Act No 15 of 2019.

ii Income tax and CGT

South Africa applies a residence-based income tax system, meaning that South African residents are subject to income tax on their worldwide income, while non-residents are taxed on their income from South African sources. Residents are further subject to CGT on their worldwide capital gains, while non-residents are subject to CGT only in respect of capital gains arising from the disposal of immovable property (or rights therein) situated in South Africa, or movable property attributable to a permanent establishment in South Africa, unless a double taxation agreement (DTA) provides otherwise.

A resident, in relation to juristic or legal entities, means any person who is incorporated, established or formed in South Africa or who has a place of effective management in South Africa. Branches of offshore companies will not fall within the definition of resident, but they may still be subject to South African income tax and CGT on the basis that they derive income or capital gains from a South African source, unless they can rely on a DTA for protection.

Resident and non-resident companies currently are subject to income tax at a rate of 27 per cent and to CGT at an effective rate of 21.6 per cent.

The Tenth Schedule to the ITA contains a number of favourable provisions for oil and gas companies, including a special dispensation in respect of deductions from oil and gas income. In respect of an oil and gas right, oil and gas companies currently can claim up to 200 per cent in deductions for capital expenditure incurred during exploration. The Tenth Schedule also currently authorises the Minister of Finance to conclude binding fiscal stability agreements with an oil and gas company. These agreements have the effect of guaranteeing that the provisions of the Tenth Schedule (as per the date of concluding the agreement) continue to apply in respect of that right as long as the right is held by the oil and gas company.

iii VAT

Persons who make taxable supplies in the course of an enterprise conducted wholly or partly in South Africa, irrespective of whether they are a resident or non-resident, must register as VAT vendors, provided that the minimum threshold is reached. VAT vendors collect output VAT from their customers and claim credits for input VAT paid by them. The difference is paid to SARS.

VAT is generally levied at a rate of 15 per cent at each stage of the distribution chain, although certain supplies are subject to VAT at a rate of zero per cent (referred to as zero-rated supplies), while other supplies, such as financial services, are treated as exempt.

A person must register as a VAT vendor if it carries on an enterprise and the total value of taxable supplies during the previous 12 months exceeds 1 million South African rands, or will exceed 1 million South African rands within the next 12 months.

A special voluntary registration regime applies to companies engaged in the mining of minerals, metal, oil, gas or natural gas resources (for example, both exploration and extraction).

iv Mineral and petroleum resource royalty

The royalty applies to any entity that holds a prospecting right, retention permit, exploration right, mining right, mining permit or production right or a lease or sublease in respect of such a right, or any entity who wins or recovers a mineral resource extracted from within South Africa. The royalty is triggered on the transfer of a mineral extracted from within South Africa.

The rate for the royalty is determined according to a formula and it differs between the refined and unrefined conditions of the mineral resource. Currently it is a minimum of 0.5 per cent to a maximum of 5 per cent for refined minerals and a minimum of 0.5 per cent to a maximum of 7 per cent for refined minerals.

v Carbon tax

The Carbon Tax Act imposes a levy on any person who conducts any number of listed carbon dioxide-producing activities, including several attributable to the extraction and processing of petroleum products.

In the 2022 national budget, the government announced its intention to ramp up the carbon price and strengthen the price signals to promote behaviour changes over the short, medium and long term. It proposed increases in the carbon tax rate for the 2023 to 2025 tax periods by a minimum of US$1 and increasing gradually to US$20 in 2026 and at least US$30/tCO2e in 2030.

The following rate increases were ultimately legislated for the relevant calendar years:

- 2023 – 159 rands;
- 2024 – 190 rands;
- 2025 – 236 rands;
- 2026 to 2030 – 308, 347, 385 and 424 rands; and
- 2031 – to be announced by the relevant minister.

In addition, the energy efficiency tax incentive and electricity price neutrality commitment is extended until the end of 2025.

vi Other

In addition, oil and gas companies may be liable for transfer duties on the transfer of immovable property and securities transfer taxes on the transfer of securities. South Africa further imposes withholding taxes on dividends, royalties and interest.

The dividends tax is a tax on the shareholder receiving the dividend, which is collected by the company declaring the dividend. Dividends tax is imposed currently at a rate of 20 per cent but may be reduced to zero per cent under the Tenth Schedule to the ITA or under a DTA.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

i Authorisations and competent authorities

Applicants for exploration and production rights under the MPRDA must obtain an environmental authorisation (EA) issued in terms of Section 24 of NEMA and the NEMA Environmental Impact Assessment Regulation (EIA Regulations), which require that an environmental assessment is undertaken for certain activities that are listed in the regulations (Listed Activities). The Listed Activities were amended in June 2021 to also include and make provision for hydraulic fracturing operations and expansions.

On 30 June 2023, certain provisions in the National Environmental Management Laws Amendment Act 2 of 2022 (NEMLA IV) came into effect, thereby amending the NEMA. NEMLA IV has introduced the following amendments that are applicable to the oil and gas sectors:

- the new definition of 'environmental mineral and petroleum inspector', which means a person designated as an environmental mineral and petroleum inspector in terms of Section 31BB of NEMA;
- a new definition for 'financial provision', which now means the amount that is to be provided in terms of NEMA by a holder of an old order right or applicant, guaranteeing the availability of funds to fulfil the obligation to undertake progressive rehabilitation, decommissioning, closure and post-closure activities, including the pumping and treatment of polluted or extraneous water to ensure that the state does not become liable for those costs that should be covered by a holder of an old order right or applicant;
- applications for an EA for (1) a reconnaissance permit; (2) a TCP; (3) an exploration right; and (4) a production right must be made simultaneously with applications for these rights with the associated application for an EA;
- activities undertaken unlawfully where there has been commencement of a listed activity, an EA will be directed by the competent authority to immediately cease the activity pending a decision on the application submitted in terms of Section 24G of NEMA;
- the compete overhaul of Section 24P on financial provision for remediation of environmental damage, which now requires the holder of an EA pertaining to mining activities (including hydraulic fracturing) to maintain its financial provision until it is issued with a closure certificate by the Minister of Mineral Resources and Energy. The holder must also subject the financial provision to an independent audit that must be submitted to the Minister of Mineral Resources and Energy. The holder must also annually undertake the mitigation, remediation and rehabilitation measures; and
- the increase in the penalties for certain offences has increased to a fine not exceeding 10 million rand or imprisonment not exceeding 10 years, or to both a fine and imprisonment.

On 4 August 2023, a notice was published inviting comments of DFFE's intention to amend the EIA Regulations and Listed Activities. The amendments currently proposed and that may have a bearing on exploration and production activities include:

- the new definition of 'offshore activities', which means activities as identified in the EIA Regulations Listing Notice 1 of 2014, Listing Notice 2 of 2014 or Listing Notice 3 of 2014, published in terms of the NEMA, the activities of which are proposed within the exclusive economic zone and continental shelf of the Republic referred to in Sections 3,4,7 and 8 of the Maritime Zones Act, 1994 (Act No.15 of 1994); and
- the amendment of Regulation 39 of the EIA Regulations to exempt applicants for an EA to carry out hydraulic fracturing and offshore activities from having to obtain landowner consent prior to applying for an EA and the inclusion of the requirement to notify the relevant organ of state in instances where activities will be undertaken on coastal public properties.

The timelines, processes and costs associated with applying for an EA will depend on whether a basic assessment or an Environmental Impact Assessment (EIA) is appropriate for the project. This would be determined by a qualified environmental consultant referred to as an Environmental Assessment Practitioner (EAP) in terms of the NEMA EIA Regulations. Although the EAP undertakes the assessment on behalf of the applicant, it is required to be independent. The applicant is responsible for the cost of the environmental assessment.

The Minister of Mineral Resources and Energy is the competent authority for the granting of EAs for activities related to exploration and production, while the Minister of Forestry, Fisheries and the Environment would act as the appeal authority.

In June 2015, the Minister of Mineral Resources (now the Minister of Mineral Resources and Energy) published Technical Regulations for Petroleum Exploration and Exploitation (the Technical Regulations) under the MPRDA, which apply to onshore exploration and production operations. These attempted to establish technical and environmental standards for the conduct of hydraulic fracturing in South Africa. However, in July 2019, the Supreme Court of Appeal of South Africa ruled that the Technical Regulations had been improperly promulgated and were therefore invalid. The court ordered that the Technical Regulations be set aside. The Minister of Forestry, Fisheries and the Environment published the proposed Regulations Pertaining to the Exploration and Production of Onshore Oil and Gas Requiring Hydraulic Fracturing, which set out the monitoring and environmental impact assessments requirements for hydraulic fracturing, the prohibition of certain activities associated with hydraulic fracturing, the identified geographical areas where hydraulic fracturing is prohibited and set out the monitoring requirements before and during operations.

Another material environmental authorisation that will likely be triggered by onshore oil and gas exploration and production is the need for certain authorisations in the National Water Act 36 of 1998 (NWA). On 7 May 2021, the Minister of Human Settlements, Water and Sanitation (DHSWS) (as the DWS was known then) published the 'Regulations for the use of water for exploration and production of onshore naturally occurring hydrocarbons that require stimulation, including hydraulic fracturing and underground coal gasification, to extract and any activity incidental thereto that may impact detrimentally on the water resource' (Draft Regulations), in terms of Section 28(1)(g) of the NWA, which focus exclusively on water use licences (WUL) required for onshore exploration and production operations for unconventional oil or gas development and regulate the exploration for shale gas through the use of hydraulic fracturing. However, these Draft Regulations have not yet been finalised and enacted into law.

Depending on the nature of the petroleum operations, other environmental licences and permits may be required. Such licences may include a waste management licence issued in terms of the National Environmental Management: Waste Act 2008, or an atmospheric emissions licence issued in terms of the National Environmental Management: Air Quality Act, 2004.

ii Environmental enforcement

NEMA provides for the appointment of environmental management inspectors (EMIs) within the DMRE to control compliance with environmental obligations. The appointment process, functions, powers and standards that apply to EMIs are governed by Section 31 of NEMA.

These EMIs have the power to investigate, issue compliance notices and admission of guilt fines, and in more extreme cases hand over cases involving criminal liability to the National Prosecuting Authority for prosecution. Failure to comply with a compliance notice may also result in the revocation of the EA or licence in respect of which contravention occurred.

iii Decommissioning and financial provisioning

Holders of an exploration or production right must obtain a closure certificate in the event that:

- the right lapses, is abandoned or cancelled;
- the relevant operations are ceased; or
- any portion of the right is relinquished.

Closure certificate applications must be submitted to the Petroleum Agency within 180 days of the lapse, expiry or cancellation of the right in question.

In addition, an EA must be obtained to decommission the operations, with decommissioning now referred to as 'closure' in terms of the EIA Regulations and Listed Activities. The EIA process in support of the EA application must be initiated before the submission of an application for a closure certificate. Finally, on closure, an exploration or production right holder will be required to execute approved rehabilitation and closure plans. The Financial Provisioning Regulations, 2015 published under NEMA require that exploration or production right applicants and holders must make financial provision for the rehabilitation, closure and ongoing post-decommissioning management of negative environmental impacts. On 27 August 2021, the Minister of Forestry, Fisheries and the Environment published proposed amended regulations in respect of financial provisioning (2021 Proposed NEMA Regulations). The Minister subsequently published proposed amended regulations in respect of financial provisioning on 11 July 2022 (2022 Proposed NEMA Regulations), which are intended to repeal and replace the FP Regulations and supersede the 2021 Proposed NEMA Regulations. The 2022 Proposed NEMA Regulations do not apply to an applicant or holder of an offshore operation, where the activity involves a seismic survey but no drilling of stratigraphic wells. The 2022 Proposed NEMA Regulations are also no longer applicable to applicants for a Section 11 Deed of Assignment. The 2022 Proposed NEMA regulations are currently undergoing public consultation. As it currently stands, the Financial Provisioning Regulations, 2015 are still applicable. In terms of the transition period, the Financial Provisioning Regulations, 2015 state that a holder of an offshore oil or gas exploration or production right, who applied this right prior to 20 November 2015, regardless of when the right was obtained, must by no later than 19 February 2024 comply with the financial provisioning requirements (see above for the overhaul of Section 24P of NEMA concerning new financial provision requirements).

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

For the purpose of a holder of an interest in an exploration right, the MPRDA itself does not require such holder to register a foreign company branch in South Africa or to acquire or incorporate a subsidiary company in South Africa; however, this obligation is imposed by the Companies Act 71 of 2008 (Companies Act). A foreign company that carries on business activities in South Africa must either:

- register a branch with the Companies and Intellectual Property Commission (CIPC) within 20 business days after it first begins to 'conduct business activities' in South Africa; or
- acquire or incorporate a subsidiary company in South Africa.

A holder qualifies as continually engaging in business in South Africa by virtue of its interest held in the exploration right. Accordingly, a holder must within 20 business days after acquiring an interest in the exploration right either register a foreign company branch in South Africa, or acquire or incorporate a subsidiary company in South Africa.

The registration of a foreign company branch will require the foreign entity to appoint a legal representative, resident within South Africa, who will accept service of documents on behalf of a foreign company branch. Additionally, SARS requires that all companies – including foreign companies with branches registered in South Africa – appoint a public officer with whom SARS will communicate in respect of the taxation affairs of the company. The public officer must be resident within South Africa. The role of a public officer, while separate from that of legal representative, is in practice fulfilled by the same person.

The registration of a foreign company branch does not create a legal entity separate from the foreign parent company that registers the branch (whereas acquiring or incorporating a subsidiary in South Africa involves creating an entity with separate legal personality from the foreign parent company). Accordingly, if foreign investors wish to protect the foreign parent company within its group from local liability or litigation, acquiring or incorporating a subsidiary to hold its interest in the exploration right is preferable to registering a foreign company branch. Moreover, in its current form the UPRDB contains a requirement that a holder be incorporated in South Africa. This will mean that those holders who elected to register a foreign company branch to hold their interest in an exploration right, and any new holders acquiring interests in exploration rights after enactment of the UPRDB (in its current form) will be required to acquire or incorporate a subsidiary company in South Africa to hold their interests under exploration rights. Generally, it takes between three and six weeks to register a foreign company branch.

A foreign company wishing to incorporate a subsidiary company in South Africa may do so in one of two ways:

- acquire a shelf company that has already been formed; or
- incorporate a new private company afresh.

For the purpose of holding an interest in an exploration right, only a limited liability private company must be used. In practice, purchasing a shelf company can be more efficient in terms of time and cost as the company is already in existence, having been formed for the specific purpose of being sold to a third party. The shares in the shelf company can be transferred to the shareholders within a day or two and the company may then proceed with business. The other details of the shelf company such as the details of the directors and company name can be amended within a few weeks. Generally, it takes between two to four weeks to register the amendments to a shelf company. Alternatively, incorporating a new company in South Africa affords a foreign investor the opportunity to create a new corporate entity without the need to amend prior details. The company is therefore built *de novo* and customised to suit the needs of the shareholders. The incorporation of a new company in South Africa takes longer than a shelf company because the registration of amendments to a shelf company may be quicker than the registration of a new company. A new company may not commence business until a certificate to commence business has been issued by CIPC, which usually takes between six and eight weeks from the date of lodgement with the CIPC.

ii Capital, labour and content restrictions

There are no specific legislative requirements that relate to the employment of local personnel in the upstream oil and gas industry. Similarly, there are no legislative restrictions on the ability of oil and gas companies to hire foreign workers. However, regard must be shown to the objects of the MPRDA, in particular, the object to meaningfully expand opportunities for historically disadvantaged persons[38] and to promote employment and advance the social and economic welfare of all South Africans.[39] It is for this reason that the standard form exploration right and production right used by PASA require that the holder of the right employ South Africans with appropriate qualifications and experience, giving preference to historically disadvantaged persons and taking into account the operational requirements of the right holder. The standard form exploration right and production right often require holders to implement a programme for future recruitment, and to propose a training programme for South African graduates in various disciplines of oil and gas production.

The standard form exploration right and production right also require the holder to make an annual contribution to the Upstream Training Trust. The Upstream Training Trust administers the contributions and provides bursaries to South Africans to study at universities in South Africa to gain the skills required for the oil and gas industry.

iii Anti-corruption

The key legislation aimed at combating corruption in South Africa is the Prevention and Combating of Corrupt Activities Act, 2004. In South Africa, the concept of bribery is referred to as 'corruption', and the Prevention and Combating of Corrupt Activities Act broadly defines corruption as directly and indirectly receiving or giving gratification from or to another person to act or influence the other person to act in a manner that:

- is illegal, dishonest, unauthorised or biased, among other things;
- amounts to breach of a position of authority, breach of trust or violation of a legal duty or set of rules;
- is designed to achieve an unjustified result; or
- amounts to any other unauthorised or improper inducement to do or not do anything.

Gratification is also broadly defined as including money, loans, donations, employment and benefit of any kind.

The Prevention and Combating of Corrupt Activities Act applies in both the private and public sectors, and persons convicted of offences under the act are liable to a fine or imprisonment, including life imprisonment.

The penalty provisions of the Prevention and Combating of Corrupt Activities Act differentiate between categories of offences. The majority of offences are penalised by a fine or imprisonment for a period of up to 18 years. Other categories, such as the concealment of the offence of corruption or being an accessory after the offence, carry a lesser penalty, namely a fine or imprisonment of up to 10 years. The court has discretion to impose the fine equal to five times the value of the gratification involved in the offence.

IX CURRENT DEVELOPMENTS

As hinted to above, the most anticipated development in the South African upstream oil and gas sector is the enactment of the UPRDB.

In its simplest form, the UPRDB introduces a separation of the regulatory frameworks governing mining and upstream petroleum exploration and production that were previously dealt with together under the MPRDA. This separation allows the emerging and nuanced upstream oil and gas sector to be regulated entirely separately from the more established mining sector. On 1 July 2021, the UPRDB was introduced to the National Assembly, and on 17 May 2022, DMRE briefed the Portfolio Committee on the salient provisions of the UPRDB.

During this briefing, the DMRE reiterated the importance of the UPRDB, its contribution to the development and growth of the upstream petroleum industry, and the need to promote investor certainty by passing the UPRDB. These provisions include:

- the introduction of the petroleum right that will cover both an exploration phase and a production phase; accordingly, separate exploration rights and production rights will no longer be granted upon enactment of the UPRDB;
- two types of licensing rounds that will be triggered by ministerial notices in the Government Gazette:
    - a notice defining the application criteria that includes a minimum work commitment; and
    - the open-door system where the criteria for award of the right is not predetermined;
- the provision for a 20 per cent carried state interest in all petroleum rights remains; holders will be entitled to recover a maximum of 50 per cent and 100 per cent of the state's share of exploration and production rights, respectively; and
- a requirement that all petroleum rights must have a minimum of 10 per cent Black participation on commercial terms.

From the salient provisions presented to the Portfolio Committee, it is clear that no new amendments to the UPRDB have been made or are being proposed by the DMRE since the iteration introduced to the National Assembly on 1 July 2021. In its concluding remarks, the DMRE stated that the passing of the UPRDB remains a critical step towards ensuring the energy security of the country. This echoes the recent address by President Cyril Ramaphosa at the 2022 Investing in African Mining Indaba that in order for South Africa to achieve energy security, foster social and economic development, eradicate energy poverty and enable its transition to a low or zero-carbon future, exploration and development of its oil and gas resources must continue.

The Portfolio Committee agreed on 24 May 2022 that there will be two phases for public participation associated with the UPRDB, namely written submissions and public hearings. On 28 June 2022, the first phase commenced, as the Portfolio Committee invited the public to submit written comments and indicate any interests in making oral submissions on the UPRDB. Written submissions were due by 29 July 2022.

Public hearings in South Africa's nine provinces commenced on 17 February 2023 and ended on 28 May 2023. Having now completed the public participation process, the UPRDB will be reconsidered by the National Assembly, which will debate and vote on the passing of the UPRDB with or without amendments. If the National Assembly approves the UPRDB, it will move to the National Council of Provinces. Once the UPRDB has passed through both the National Assembly and the National Council of Provinces, it will be translated into one other official language and submitted to the President's office for signature. The President also has the option to refer the UPRDB to the Constitutional Court for a decision on its constitutionality.

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Endnotes

1 Megan Rodgers, Margo-Ann Werner and Heinrich Louw are directors and Amore Carstens is an associate at Cliffe Dekker Hofmeyr Inc.
2 *Worldwide Look At Reserves and Production*, Oil & Gas Journal, December 2021.
3 Section 3(1) of the MPRDA, read with Section 3(2) of the MPRDA.
4 Section 2(a) of the MPRDA.
5 Section 2(c) of the MPRDA.
6 Section 2(d) of the MPRDA.
7 Section 38A of the MPRDA.
8 Section 103 read with Section 1 MPRDA. In terms of Section 1 of the MPRDA, 'Regional Manager' means the officer designated by the Director-General in terms of Section 8 of the MPRDA as a regional manager for a specific region and Officer means any officer of the Department of Mineral Resources and Energy appointed under the Public Service Act 103 of 1994.
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10 Government Notice 733 Government Gazette 26468 dated 18 June 2004.
11 Section 47 of the MPRDA.
12 Section 3(2) of the Institute of Legal Proceedings Against Certain Organs of State Act 40 of 2002.
13 Section 5(2) of the Institute of Legal Proceedings Against Certain Organs of State Act 40 of 2002.
14 Section 9 of the MPRDA.
15 Section 76(3) of the MPRDA.
16 Section 77(1)(a) of the MPRDA.
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22 Sections 80(5) of the MPRDA, read with Section 81(4).
23 Section 81(3) of the MPRDA.
24 Section 81(5) of the MPRDA.
25 Section 83(1) of the MPRDA.
26 Section 83(3) of the MPRDA.
27 Regulation 29 of the Petroleum Regulations.
28 Section 84(1)(i) Mineral Petroleum Resources Development Act, 28 of 2002.
29 Regulation 34 and 35 of the Mining Titles Registration Act No 16 of 1967.
30 Mineral and Petroleum Resources Development Act 28 of 2002, Section 5.
31 *Mineral Resources v. Mawetse (SA) Mining Corporation (Pty) Ltd* 2016 (1) SA 306 (SCA).
32 Section 6(1) of the International Trade Administration ITA Act read with the Guidelines at Paragraph 13.
33 See Paragraph 15 of the Guidelines.
34 See Paragraph 20 of the Guidelines.
35 Section 11(1) of the MPRDA.
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37 Section 102 of the MPRDA.
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39 Section 2(f) of the MPRDA.

Chapter 14

United Kingdom

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Summary

I INTRODUCTION

The oil and gas industry in the United Kingdom is in a period of transition. While continuing to address the realities of the UK continental shelf (UKCS) as a mature and complex basin and the operational and financial challenges resulting from the ongoing conflict in Ukraine and the aftermath of the covid-19 pandemic, the industry continues to adapt and play a pivotal role in helping to deliver energy security and a net zero future through energy transition initiatives such as emission reduction targets, floating windfarms, carbon capture, usage and storage (CCUS) and clean hydrogen.[2] These factors have shaped trends in the UK oil and gas industry's transactional and operating landscapes in recent times, as well as informing a number of recent legislative developments – in particular relating to innovation and 'decarbonisation' initiatives.

The revised Oil & Gas Authority (now trading as the North Sea Transition Authority (NSTA)) Strategy (the OGA Strategy) came into force on 11 February 2021, which amended the 'maximising economic recovery' (MER UK) strategy (described in more detail below) to ensure that energy demand is met while ensuring an orderly energy transition and reducing reliance on imports.[3] The UKCS still remains fiscally competitive with material new discoveries.[4] In 2022, production from the UKCS accounted for 67 per cent of the United Kingdom's oil (and related products) consumption and 44 per cent of gas[5] and it is estimated that there are potentially 6.4 billion barrels oil equivalents (boe) yet to be discovered in the UKCS as at the end of 2021.[6]

The UK government is reviewing the long-term future of the existing fiscal regime for oil and gas and, in July 2023, issued a call for evidence requesting input from industry stakeholders, including how different elements of the regime incentivise or discourage investment, whether it can act as a barrier to transition to net-zero and decarbonisation, and how the regime could be made more predictable and stable.[7]

Deal activity increased in 2022, with total mergers and acquisitions (M&A) spend increasing from approximately US$4.9 billion in 2021 to approximately US$7.1 billion in 2022.[8] This growth looks to continue in 2023, with over £7.8 billion of new acquisitions announced in the first half of 2023, showing that investors are still being attracted to opportunities in the UKCS despite the challenges faced by the industry.[9] A variety of transactions have occurred across all stages of the upstream oil and gas life cycle, including exploration prospects, pre-development opportunities, producing fields and late-life assets. Recent transactions have resulted in a more diverse ownership landscape on the UKCS and a significant trend that has developed is the increasing proportion of assets, production and investment opportunities that have been acquired by private equity-backed companies. Infrastructure investors have increased their exposure to the midstream across various asset classes, including pipelines, storage and liquefied natural gas.

The UKCS retains significant resources and a continued focus on exploration and development of new fields. Exciting prospects continue to be developed, for example, the NSTA approved three new Field Development Plans in 2022 and to date in 2023.[10]

Total production from the UKCS was just under 500 million boe in 2022, or 1.36 million boe per day, which was the same amount as in 2021.[11] Offshore Energies UK (OEUK) estimates that overall gas production has fallen around 7 per cent over the past five years and oil production is now 26 per cent lower than in 2018.[12] The UKCS still retains over 10 to 15 billion boe yet to be produced, which represents a significant level.[13]

II LEGAL AND REGULATORY FRAMEWORK

i Domestic oil and gas legislation

The principal legislation governing exploration and production of crude oil, gas and shale gas in the United Kingdom is the Petroleum Act 1998 (as amended) (the Petroleum Act). The Petroleum Act governs all oil and gas exploration and production in the United Kingdom (other than onshore in Northern Ireland), and underpins a regime whereby licences are granted, by the NSTA (and by the Welsh Ministers, for onshore oil and gas in Wales, and the

Scottish Ministers, for onshore oil and gas in Scotland), to persons to 'search and bore for and get' petroleum in a specified geographical area. Ownership of petroleum vests in the Crown, and petroleum produced within the licence area transfers from the Crown to the licence holder at the well head.

The Petroleum Act is supplemented by the Energy Act 2016, the Infrastructure Act 2015 and various environmental and health and safety legislation.

ii Regulation

The Department for Energy Security and Net Zero (DESNZ) is responsible for delivering security of energy supply, encouraging greater energy efficiency and seizing the opportunities of net zero to lead the world in new green industries.[14]

The NSTA is a fully independent regulator and a government-owned company, with the Secretary of State for Energy Security and Net Zero (the Secretary of State) as the sole shareholder who is ultimately responsible to Parliament for the NSTA.

The NSTA is the entity responsible for petroleum licensing and regulation of the upstream oil and gas sector, including:

- oil and gas licensing;
- oil and gas exploration and production;
- oil and gas fields and wells;
- oil and gas infrastructure; and
- carbon storage licensing.

A key principle of the Petroleum Act is the MER UK strategy, which aims to maximise the economic recovery of UK resources. In February 2021, the OGA Strategy (amending the earlier MER UK strategy) came into force to ensure that net zero is a part of the MER UK strategy, including by obliging licensees to reduce as far as reasonable in the circumstances greenhouse gas emissions from sources such as flaring and venting and power generation and to support CCUS projects. The OGA Strategy is binding on the NSTA, various industry participants, the Secretary of State and licence holders, operators and owners of offshore installations. The NSTA has enforcement powers in respect of compliance with the OGA Strategy, and it is required to act in accordance with its OGA Strategy when:

- exercising its functions under the Petroleum Act or Part 2 of the Energy Act 2016;
- exercising functions or powers under a petroleum licence; and
- using its ancillary powers (e.g., to assist or advise the government).

iii Treaties

The United Kingdom is a signatory to treaties including the Energy Charter Treaty, which regulates energy-specific matters, and the Geneva Convention on the Continental Shelf 1958 and the UN Convention on the Law of the Sea, which sets the limits of the state's territorial sea and access to the continental shelf and beyond. Regionally, the United Kingdom is a signatory to the Convention for the Protection of the Marine Environment of the North-East Atlantic, the mechanism that started in 1972 and by which 15 governments and the European Union cooperate to protect the marine environment of the north-east Atlantic.[15]

Additionally, the United Kingdom is a party to conventions governing the recognition and enforcement of foreign arbitral awards, including the UN Convention on the Recognition and Enforcement of Foreign Arbitral Awards, the Geneva Convention on the Execution of Foreign Arbitral Awards 1972 and the UN Convention on the Settlement of Investment Disputes between States and Nationals of Other States.

In respect of tax, the United Kingdom has an extensive network of double tax treaties with other jurisdictions that are broadly designed to prevent a taxpayer from having to pay tax in more than one jurisdiction on the same income, profits or gains. The extent to which any UK taxing rights may be restricted under a particular treaty depends on the nature of the income, profits or gains in question and the terms of the relevant treaty.

III LICENSING

The Petroleum Act vests all rights to petroleum in the Crown but permits the NSTA to grant licences to 'search and bore for and get' petroleum to persons deemed fit and exploration for and production of petroleum in the United Kingdom and on the UKCS can only be undertaken under the terms of these licences. A company wishing to participate in the UK upstream oil and gas sector must bid for a licence or acquire an interest in existing assets, with any acquisition being subject to regulatory consents.

The NSTA is responsible for issuing licences through competitive licensing rounds that generally take place every year, and the OGA Strategy is applied by the NSTA in each licensing round. Separate rounds are held for seaward (offshore) licences and landward (onshore) licences. In exceptional circumstances, where there are compelling reasons provided by a company, the NSTA may issue a licence outside of a licensing round.

Licences take the form of a deed, pursuant to which the licensee is bound to observe the conditions of the licence. These detailed terms and conditions are prescribed in a series of 'model clauses', which are set out in secondary legislation under the Petroleum Act. The model clauses applicable to a particular licence are those that are in force at the time the licence was granted and are not affected by subsequent sets of model clauses, except through specific retrospective measures.

UK licences are both contractual and regulatory in nature – contractually, being executed as a deed and providing for the contractual transfer of rights from the Crown to the licensee, and regulatory, because the model clauses are encompassed in statutory regulations, and Parliament may unilaterally amend the terms upon which a licence is granted. Legally, only one licence exists, although a licence may be granted to one or more licensees, who will be held jointly and severally liable in respect of obligations arising under the licence.

The Petroleum Licensing (Applications) Regulations 2015 contain the application process for licences. The NSTA will only grant a licence to an entity that has the appropriate technical and financial capacity to contribute to the OGA Strategy.

The different types of licences currently being issued are as follows:

- seaward production licences: these are the main offshore production licence, which run for three successive periods or terms, namely exploration, development and production. The licence requires fulfilment of the relevant work programme, agreed with the NSTA, before it can proceed to the next term; however, a licensee who quickly fulfils the required obligations and obtains the relevant consent during the initial terms will not be prevented from commencing production under the licence prior to the third term. Production licences expire automatically at the end of the term unless the licensee has advanced the work programme sufficiently to commence the next term. The licence will expire at the end of its initial term unless varied by agreement, or the licensee has completed the work programme, all sums have been paid, and the licensee has relinquished 50 per cent of the initial licence area. Each production licence also requires payment of an annual fee (known as rental), charged on an escalating basis for each square kilometre covered by the licence at that date and for licensees to relinquish areas that are not being exploited;
- landward production licences: the onshore equivalent of seaward production licences as described above (formerly referred to as petroleum exploration and development licences);
- offshore innovate licences: the innovate licence offers greater flexibility during the initial and second term as the applicant can propose the durations of the initial and second terms. The 'offshore innovate licence' replaced the traditional, promote and frontier versions of the seaward production licence, described below (which still remain relevant for many existing offshore production licences); and

- exploration licences: an exploration licence is non-exclusive and covers the United Kingdom's entire offshore area apart from those areas covered by any production licences that are in force at the time. These are commonly used by seismic contractors who gather data to sell rather than exploiting the resources themselves, or by holders of a production licence who wish to explore outside the areas where they hold or require exclusive rights. The NSTA grants both seaward and landward exploration licences. The annual payment is significantly lower than that of production licences and covers exploration relating to hydrocarbon production, gas storage, carbon capture and sequestration or any combination. An exploration licence grants rights to explore for petroleum, but not to extract it, and enables licence holders to carry out seismic surveys and to drill wells for core-sampling to a maximum depth of 350 metres below the seabed.

The 'traditional, promote and frontier licences' are no longer issued, but many remain in existence:

- traditional licence: this was the most common type of offshore production licence. They were granted with licence term lengths of four years for the initial term to complete the initial work programme, following which the licensee was required to relinquish 50 per cent of its acreage to move to the next phase. The second term was for another four years, and finally reaching a production phase for an 18-year third term (other than in relation to the 27th and 28th licensing rounds where greater flexibility was introduced for certain licences);
- promote licence: aimed at small and start-up companies, applicants did not need to prove technical or environmental competence or financial capability before the award of the licence, but they were required to do so within two years of the start date of the licence. Otherwise, the terms of the various phases and relinquishment obligations were the same as a traditional licence; and
- frontier licence: this licence had an exploration phase of six years to allow companies to evaluate larger areas and look for a wider range of prospects, but the terms varied based on the terrain. Licensees were required to relinquish 75 per cent of the acreage at the end of the third year of the initial exploration phase, and a further 50 per cent at the end of the initial exploration phase.

In September 2022, the UK government introduced a new Climate Compatibility Checkpoint (the CCC) to ensure that future oil and gas licensing rounds are compatible with wider climate objectives, including achieving net zero emissions by 2050.[16] The CCC is an informative, data and narrative-based checklist to inform government Ministers on whether to endorse any licensing rounds implemented by the NSTA. The CCC includes three tests, but does not bind Ministers to a particular outcome:

- whether the UK oil and gas industry has met historical and projected performance targets against the emissions targets set out by the North Sea Transition Deal, which were agreed to by the sector in 2021;
- whether the UK oil and gas sector's greenhouse gas emissions intensity is higher or lower than other global producers in terms of associated production emissions when benchmarked internationally; and
- whether the United Kingdom is expected to remain a net importer of oil and gas.

However, judicial review proceedings are currently ongoing (on 25 July 2023, hearings were held at the High Court but the outcome is currently pending) in relation to the introduction of the CCC and its supposed lack of consideration of the downstream greenhouse gas emissions that would arise as a result of the new licensing round.

This assessment is also against the backdrop of the British Energy Security Strategy (published on 7 April 2022), which stated that the need for energy security will also be taken into account when assessing potential future licensing rounds. On 30 March 2023, DESNZ published the Energy Security Plan and the Net Zero Growth Plan highlighting its commitment to maximising production of UK oil and gas.[17] The UK government confirmed that it will continue to award oil and gas exploration licences and accelerate approvals to bring forward production dates, subject to environmental considerations, as part of the

Gas and Oil New Projects Regulatory Accelerators announced in the British Energy Security Strategy. Following the 33rd licensing round in 2023, the UK government announced that it is offering around 100 new oil and gas licences for the North Sea, with the first licences to be awarded in the autumn of 2023.[18]

BEIS also conducted a new Offshore Energy Strategic Environmental Assessment to enable future renewable leasing for offshore wind, wave and tidal devices and licensing or leasing for seaward oil and gas rounds, hydrocarbon and carbon dioxide (CO_2) storage and offshore hydrogen production and transport. Following public consultation, the process was adopted in September 2022.[19]

IV PRODUCTION RESTRICTIONS

There is no national oil company in the United Kingdom that is directly involved in oil and gas exploration and production activities in the UKCS. Oil and gas exploration and production are regulated by restrictions on the award and transfer of licences, and requirements relating to approval of work programmes and how that work is performed. There are no special regulatory requirements that apply to the exports of oil or oil products, other than the payment of applicable duties or taxes, and compliance with International Energy Agency's oil stocking obligations. Additionally, in the event of an actual or threatened emergency in the United Kingdom that will affect fuel supplies, the Secretary of State may use emergency powers under the Energy Act 1976 to regulate or prohibit the production, supply, acquisition or use of substances used as fuel.

V ASSIGNMENTS OF INTERESTS

The NSTA's consent is required for a licence to be sold, transferred, assigned or otherwise dealt. Any transaction that results in a company joining a licence, or withdrawing from a licence, is deemed to be a licence assignment. The NSTA will consider any assignment made without prior consent, a very serious breach of the model clauses and grounds for immediate revocation of the licence or to reverse the assignment. There are a number of issues that the NSTA considers when deciding whether to give approval, including:

- compliance with the EU 2013 Offshore Safety Directive (as implemented in the United Kingdom under domestic legislation);
- the technical and financial capacity of the assignee;
- decommissioning costs;
- effect on operatorship arrangements; and
- fragmentation of licence interests (i.e., creation of less than 5 per cent interests).

The company selling its licence interest (the transferor) must apply to the NSTA for its consent. The transferor will need to obtain much of the information the NSTA needs from the acquiring company (the transferee). Consent will not be granted unless the NSTA has all required information. The NSTA reviews and considers the form of the deed of assignment used by the parties and provides for approved draft deeds of assignment. Regarding offshore licences, the NSTA may consult with DESNZ and the Health and Safety Executive (HSE) (in pursuit of the Offshore Safety Directive). Licence assignment applications are processed online through the UK Energy Portal using the online Petroleum E-business Assignment and Relinquishment System. On 28 March 2023, the NSTA launched a consultation on their proposed guidance on the conduct of licence assignments in the UKCS with the focus on providing confidence to current licensees and future potential assignees. The consultation process closed on 23 May 2023 and, at the time of writing, the guidance has not yet been published.

The NSTA's consent to proceed with a change of control of a licensee is not expressly required; however, the NSTA does have the power to require either a further change of control or revocation of the licence, upon a change of control. As a result, best practice is to apply to the NSTA in advance of a change of control and seek comfort that the NSTA will not exercise its powers. The application should demonstrate that the proposed change of control would not impact the ability of the licence holder to meet its obligations under the licence. The NSTA may require a parent company guarantee from the new corporate parent to replace any existing parent company guarantee that may have been issued before the change in control.

The NSTA used its power for the first time on 12 May 2023, when it revoked three offshore petroleum licences in respect of Fujairah Oil and Gas UK 12 Limited (FOG) for FOG's failure to comply with a notice requiring further change of control, such notice being issued after FOG failed to meet certain regulatory requirements.[20] The relevant licences remain in force in respect of the other licensees.[21]

The Energy Bill (the Bill), introduced on 6 July 2022, will provide the NSTA with additional powers to prevent an undesirable change of control of a licensee. The Bill will amend the model clauses to permit the NSTA intervening at an earlier stage of the transaction, by requiring written consent at least three months prior to the date of the occurrence of the change of control rather than seeking to remedy the change of control.[22]

The creation of a charge on a licence also requires the consent of the NSTA. To facilitate ordinary course transaction financing, and to eliminate the cumbersome need for prior consent, 'open permission', which is a form of automatic consent, applies to any fixed or floating charge or debenture. The licensee must give notice to the NSTA within 10 days of creation of the charge, providing certain information about the charge. If the holder of a charge intends to enforce the security interest, it will be caught as a licence assignment, and the procedures described above in respect of licence assignments will apply.

VI TAX

The tax system applicable to oil- and gas-related activities in the United Kingdom (and the UKCS) consists of a special fiscal regime, comprising four main elements:

- ring fence corporation tax (RFCT): RFCT is charged at 30 per cent on taxable profits arising from a company's 'ring fence' trade of oil and gas extraction. These profits are not subject to the normal corporation tax regime; instead, the 'ring fence' ensures that companies involved in the exploration for, and extraction of, oil and gas in the United Kingdom and on the UKCS are not able to use losses from other activities to reduce these profits;
- supplementary charge (SC): the SC is charged at 10 per cent on 'adjusted ring fence profits', as if it were an amount of corporation tax. In calculating the profits subject to the SC, finance costs are left out of account. There are allowances available to incentivise investment; these reduce profits subject to the SC by a proportion of amounts of qualifying investment expenditure, but cannot create a loss;
- petroleum revenue tax (PRT): this is an additional level of tax on the profits derived from particular fields. The rate of PRT was reduced to zero with respect to chargeable periods ending after 31 December 2015, but it has not been abolished and thus losses can be carried back against past PRT payments; and
- energy profits levy (EPL): this levy of an additional 35 per cent (up from the original 25 per cent) on adjusted ring fence profits was introduced as a temporary windfall tax in May 2022 and will be phased out 'when oil and gas prices return to historically more normal levels' by means of an Energy Security Investment Mechanism, which will apply so that the EPL will not apply if oil and gas prices remain at or below US$71.40/bbl and £0.54/thm, respectively, for two consecutive quarters.[23] A sunset clause removes the levy from 31 March 2028. As with the SC, financing costs are left out of account in calculating the chargeable profits, but the levy also leaves out decommissioning costs. Capital expenditure and some operating and leasing expenditure will attract investment allowances at 29 per cent (down from the original 80 per cent, although the investment allowance will be retained at a rate of 80 per cent for decarbonisation expenditure). Unlike the SC allowances, these will not be required to be activated by relevant income, and will be capable of generating (or increasing) a levy loss.

The headline rate of tax on oil and gas exploratory and extractive activities in the United Kingdom and on the UKCS is therefore currently 75 per cent (inclusive of the windfall tax).

As well as the specific investment allowances forming part of the SC and Energy Profits Levy, investment in the UKCS is encouraged by tax relief being provided for expenditure on research, exploration, appraisal and production through capital allowances (broadly, the United Kingdom's form of allowable 'tax' depreciation) and, once production has commenced, through tax deductions for expenses incurred wholly and exclusively for the purposes of an eligible trade. The government has also signed decommissioning relief deeds with oil and gas companies to provide certainty on the tax relief that they will receive when decommissioning assets, as further described in Section VII.ii.

In the context of UKCS transactions, decommissioning issues, particularly the question of with whom the economic burden of decommissioning liabilities should lie, have frequently been a significant challenge to transactions involving the transfer of UKCS licence interests. The traditional position has been that buyers would provide sellers with an indemnity for all decommissioning liabilities whether they arise on or before the agreed economic date or date of the agreement.

There has been, however, an increasing trend towards sellers of licence interests retaining a proportion of the decommissioning liability (as, historically, it was likely that the new owners would not be able to get effective tax relief for decommissioning costs, because of having paid insufficient amounts of corporation tax and SC by the time the decommissioning of those assets occurred). This has been particularly relevant in the context of late-life assets where a seller is likely to have significantly greater tax capacity than a buyer. However, the Finance Act 2019 introduced transferable tax histories (TTHs) for oil and gas companies, which provide companies buying North Sea oil and gas fields with certainty that they will get tax relief for the decommissioning of the asset as, on purchasing the asset, they are able to make a joint election for the buyer to acquire some of the previous owner's tax history (namely, historical profits on which ring-fenced corporation tax and supplementary charge have been paid). The buyer is then able to set the costs of decommissioning the fields at the end of their lives against the TTH.

TTHs are beneficial for a number of UKCS participants including:

- taxpayers selling licence interests who may be able to dispose of UKCS assets and thereby unlock capital to be employed in further exploration and development activity (whether in the UK or elsewhere) if a transaction can be structured such that the seller's TTH is transferred to the buyer; and
- buyers of such assets who may have greater certainty that tax relief will be obtained for the cost of decommissioning activity.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

i Environmental impact and safety

While oil and gas activities are primarily regulated by the licence and the Petroleum Act, various other statutory provisions apply in respect of environmental and safety issues. The model clauses also generally require licensees to avoid harmful methods of working, by, for example, operating in accordance with 'good oilfield practice' and to take all steps practicable to prevent the escape of petroleum, including into any waters in or near the vicinity of the licensed area.

The principal competent authorities for health and safety in the UKCS are DESNZ's Offshore Petroleum Regulatory for Environment & Decommissioning unit (OPRED) and the HSE. OPRED and HSE work in partnership, which since the United Kingdom left the European Union, is now known as the Offshore Major Accident Regulator (OMAR). The competent authority was originally established in 2014 as the Offshore Safety Directive Regulator following the Deepwater Horizon disaster in 2010, to regulate offshore major accident hazards.

Following the Piper Alpha offshore platform explosion in 1988, and the subsequent Cullen Inquiry, in 1992 the United Kingdom developed the safety case regime as the central plank of offshore health and safety law. Although the United Kingdom has left the European Union, the current Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015 still apply and impose obligations on the relevant dutyholder (being the relevant operator for production installations or owner for non-production installations) to prepare safety cases and submit them to be approved by the OMAR for all offshore installations. The Pipelines Safety Regulations 1996 impose separate duties on operators of pipelines.

More generally, the majority of the Health and Safety at Work etc. Act 1974 (HSWA) is applied offshore via the Health and Safety at Work etc. Act 1974 (Application outside Great Britain) Order 2013. The effect of this is that employers remain under the HSWA's core duties, including to ensure the health and safety of employees and others who may be affected by a business's activities.

The NSTA has the power to issue financial penalty notices carrying fines of up to £1 million under the Energy Act 2016, in respect of:

- a failure to comply with a duty to act in accordance with the OGA Strategy;
- a breach of a term or condition of an offshore licence; or
- other breaches of the Energy Act 2016 that are sanctionable under the Energy Act 2016.

It may also issue an enforcement notice, order the removal of the operator of a licence and ultimately revoke a licence for one or all of the licence holders in the event of non-compliance with applicable requirements.

OPRED is principally responsible for enforcing the environmental regime applicable to offshore oil and gas activities (and also decommissioning) in the United Kingdom. The offshore environmental legal regime covers a broad range of topics, of which the principal environmental matters covered are as follows:

- oil pollution and emergency pollution control;
- discharges of hydrocarbons and chemicals to water;
- waste management;
- emissions to air (e.g., from combustion activities);
- marine licensing (e.g., depositing objects on the seabed or dredging);
- emissions trading, fluorinated gases, ozone depleting substances and energy auditing; and
- environmental impact assessment and habitat protection.

While the majority of environmental offences are criminal in nature, the Offshore Environmental Civil Sanctions Regulations 2018 (the OECS Regulations) give OPRED powers to impose civil sanctions in respect of breaches of some existing offshore oil and gas environmental regulations. The civil sanctions available to OPRED are fixed and variable monetary penalties; previously, the breaches could only be sanctioned through criminal prosecution. OPRED will, in each case, consider whether the imposition of a civil sanction is appropriate. This will include consideration of a number of factors, including whether a civil sanction is proportionate given the seriousness of the breach and the compliance history of the offender. OPRED can only impose a civil sanction where it is satisfied that a breach has been proven beyond reasonable doubt (the criminal burden of proof).

Following the Deepwater Horizon disaster, the Offshore Safety Directive 2013 (2013/30/EU) extended liability for environmental damage under the EU Environmental Liability Directive (2004/35/EC) to offshore oil and gas operations. Although the United Kingdom has left the European Union, the Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015 (2015 Regulations) still apply and provide that the licensee will be responsible for the prevention and remediation of damage incurred during operations carried out for or on behalf of the licensee or operator. Furthermore, under the 2015 Regulations, licensees are required to make adequate financial provision to cover liabilities for the duration of operations.

In addition to statutory obligations, liabilities may arise under common law torts such as nuisance and negligence, or under contract. Parties suffering harm or damage caused by operations of an offshore installation may claim under a voluntary oil pollution compensation agreement to which all offshore operators active in the UKCS are party. Membership of the Offshore Pollution Liability Agreement (OPOL) is a condition of the NSTA granting a licence and thus all operators will in practice be party. OPOL generally subjects operators to strict liability for pollution damage. Operators agree to accept liability for up to a maximum of US$250 million per incident (with US$125 million to covering pollution damage claims and US$125 million for remedial measures). Above the US$250 million cap, recovery by third parties will be dealt with as a matter of civil law.

ii Decommissioning

Oil and gas operators in the United Kingdom are increasingly decommissioning their assets as they are reaching the end of their useful economic lives. Operators' expenditure on decommissioning is rising and there is expected to be a significant increase in expenditure over the next three years, reaching around £1.8 billion in 2023-25.[24]

The Petroleum Act imposes an obligation on licensees to pay for the decommissioning and proper removal of offshore installations from the seabed, other than in exceptional circumstances. Decommissioning of these installations (including pipelines) is regulated by DESNZ, through OPRED. The NSTA, pursuant to the OGA Strategy and the Energy Act 2016, is required to assess decommissioning programmes to ensure they meet the OGA Strategy's principal objectives based on cost savings, future alternative use and collaboration. In its Decommissioning Strategy, the NSTA has stressed that decommissioning costs could be higher if action is not taken to improve commercial practices.

The Secretary of State, under Section 29 of the Petroleum Act, has the power to serve a 'Section 29 Notice' to anyone owning an 'interest' in an installation 'otherwise than as security for a loan' and associated companies (broadly 50 per cent owned direct or indirect affiliates) of companies that are directly liable. The Section 29 Notice will either specify the date by which a decommissioning programme for each installation or pipeline is to be submitted or provide for it to be submitted on or before such date as the Secretary of State may direct. A Section 29 Notice would typically be issued to the operator of the field and each of the licensees, but the power of the Secretary of State to issue a Section 29 Notice to other relevant parties is broad and should be considered in transaction structures in an M&A context. It is expected that the NSTA will send a Section 29 Notice to this wider class of parties if it finds the decommissioning arrangements proposed by the operator and licensees to be unsatisfactory.

The Secretary of State has the power to withdraw Section 29 Notices – for example, in respect of withdrawing licensees – but it would be unusual for this to occur without a replacement notice being served on an incoming licensee. Additionally, DESNZ has the power to reissue any Section 29 Notice (under Section 34 of the Petroleum Act) but the risk of a licensee (or other interested party or related person as set out above) reincurring liability is always present, and they may be potentially liable for the decommissioning of that field until decommissioning is complete.

The Section 29 Notice requires the recipient to submit a decommissioning programme (setting out the methods and measures to decommission disused installations or pipelines, or both). Once the decommissioning programme is approved, following the NSTA's review of the details including the cost estimates, the notice holders are legally obliged to carry it out on a joint and several liability basis. If a programme is not carried out or its conditions are not complied with, the Secretary of State may, by written notice, require remedial action to be taken. Failure to comply with any such notice is an offence, and the Secretary of State can carry out the remedial action and recover the costs from the person to whom the notice was given.

The Secretary of State can require decommissioning security at any time, with the security being ring-fenced from creditors in an insolvency situation, if it believes that there is an unacceptable level of risk of decommissioning costs falling to government. The industry and the regulators have developed a Decommissioning Security Agreement, commonly entered into by all licensees, providing for security to be held on trust by an independent security trustee. This security may be provided by a standby letter of credit, performance bond or insurance product, parent company guarantee or cash.

OPRED monitors the financial health of operators to determine their financial position compared with their anticipated costs to decommission assets. For example, it assesses operators' ratio of assets to liabilities in their accounts and has access to data provided by a consultancy firm on operators' financial health.

The Secretary of State is currently unable to recover the full costs incurred in performing its regulatory functions for oil and gas decommissioning from the oil and gas industry because of the scale, complexity and duration of the offshore decommissioning activities. The Bill will provide the Secretary of State with powers to establish a charging scheme to update the current cost recovery mechanism, and will specify which regulatory functions can be charged for.

Decommissioning relief deeds to give operators greater certainty about the tax relief that they will receive for decommissioning. These deeds guarantee that tax relief for decommissioning will not be lower than under 2013 rules and provide certainty that operators will receive tax relief should they incur any additional decommissioning costs because of the default of another party. The rationale is that this will reduce the amount of security required (previously security was given without taking account of tax relief, therefore, increasing the amount), which will free up funds for asset transactions and investments, and discourage early decommissioning.

With much decommissioning expenditure in the UKCS forecast to be deferred to the late 2020s and early 2030s (expenditure is predicted to exceed £2 billion in 2028, 2030 and 2031), the UK government plans to support the development of the UK decommissioning sector and its major role to play in the energy transition. Oil and gas assets and their component parts are already being reused and repurposed for CCUS, hydrogen production and offshore wind.[25]

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

To be a licensee, a company must have a place of business in the United Kingdom, meaning that they have a staffed presence in the United Kingdom, they are registered as a UK company or they have a registered UK branch.

The National Security and Investment Act 2021 (NSIA) provides the UK government with powers to investigate and prohibit transactions on national security grounds. It is unlawful to complete a transaction that is notifiable within the energy sector without prior approval from the Secretary of State and civil and criminal penalties may be imposed.

ii Capital, labour and content restrictions

There are no restrictions on the movement of capital or access to foreign exchange and no local content or local hiring requirements applicable to oil and gas operations in the United Kingdom.

iii Anti-corruption

The UK Bribery Act 2010 establishes offences relating to giving bribes, taking bribes, bribing a foreign public official and failing to prevent bribery and applies to activities in the United Kingdom and can apply to activities overseas. A bribe is a financial or other advantage and is deliberately broad. A company guilty of an offence is liable to a fine.

IX CURRENT DEVELOPMENTS

i The energy transition and the Energy Bill

Through the Bill (which is completing its passage through both Houses of Parliament), the government intends to encourage private investment in clean technologies such as CCUS and hydrogen to support the next phase of the energy transition. To attract private finance and remove market barriers to investment in CCUS, the Bill (if passed) will establish a regulatory framework, with key measures including:

- providing the Secretary of State with powers to provide financial assistance, which may include capital investment, for CO_2 transport and storage networks;
- establishing an economic regulation model for CO_2 transport and storage, with statutory objectives and granting legal powers for Ofgem (the economic regulator of CO_2 transport and storage);
- Funded Decommissioning Programmes, which ensure that funds are available for safe decommissioning of offshore CO_2 transport and storage infrastructure at the end of its operational lifetime;
- a special administration regime in the event of insolvency of CCUS companies to provide stability, safety and security of the CO_2 transport and storage network; and
- step-in rights for the Secretary of State in the event of a licence termination, again to provide stability of the network or to ensure its safe decommissioning.

There are also measures in the Bill to support the emitters who will connect to the CO_2 transport and storage networks that are being developed. In particular, as with CO_2 transport and storage networks, the Secretary of State will be provided powers to provide financial assistance and also to incur expenditure to support the establishment of low carbon hydrogen production. In relation to funding of hydrogen, the Bill will require a counterparty to manage the contracts (with the Secretary of State being provided powers to designate and direct such counterparty) and it is expected that from 2025, subject to a consultation, all revenue support will be levy funded.

The Bill also introduces a number of measures that specifically address the challenges faced by the oil and gas industry and provides the Secretary of State three key powers to maintain continuity of core fuel supplies and maintain or improve its resilience: direction making (e.g., directing an operator to prioritise the production of a particular fuel), information power (e.g., imposing a duty for major operators to report incidents which pose a significant threat to the continuity of fuel supply) and financial assistance power. The Bill will also ensure that OPRED have powers in connection with offshore energy activities involving oil and gas, gas unloading and storage, CO_2 storage and hydrogen production and storage. The aim of these powers is to provide for the protection of habitats for protected sites or species and ensuring there will be emergency plans to respond to pollution incidents (e.g., a major oil spill).

The Bill also considers other aspects of the energy transition, including:

- economic regulation reforms;
- changes to strategic oversight;
- nuclear sector measures; and
- consumer-facing measures, including remaining open-minded about onshore reserves.

The Bill is currently completing its passage through both Houses of Parliament, with its report stage and third reading scheduled for 5 September 2023.

ii Carbon licensing round

On 14 June 2022, the NSTA launched the United Kingdom's first-ever carbon storage licensing round with 13 areas offered for licensing and on 18 May 2023, the NSTA offered awards for 20 carbon storage licences at offshore sites, including near Aberdeen, Teesside, Liverpool and Lincolnshire, covering a total area of 12,000 square kilometres.[26] The new storage sites could make a significant contribution to the aim of storing up to 30 million tonnes of CO_2

per year by 2030, approximately 10 per cent of total UK annual emissions.[27] It is envisaged that this will be the first of many licensing rounds as it is estimated that as many as 100 CO_2 stores could be required to achieve the net-zero by 2050 target.[28]

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Endnotes

1 Michael Burns is a partner, Naomi Nguyen is a senior associate and Michael Choi is an associate at Ashurst.
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