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Practical cross-border insights into oil and gas regulation

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Contributing Editors:
Michael Burns & Julia Derrick
Ashurst LLP

ICLG.com

Expert Analysis Chapter

Q&A Chapters

United Kingdom

Michael Burns

Julia Derrick

Ashurst LLP

1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

The United Kingdom ("**UK**") produced 39.5 billion cubic metres ("**bcm**") of natural gas in 2020, or approximately 1 per cent of the world's total production. Although recent years have seen small increases in production, the North Sea is a mature basin showing a gradual decline in production levels, and the 2020 production levels represent approximately 40 per cent of the peak in 2000. Nonetheless, the UK is the second-largest producer of natural gas in Europe after Norway. The UK's proven reserves of natural gas as at the end of 2020 stood at 0.2 trillion cubic metres. The vast majority of these reserves are located in the UK sector of the North Sea ("**UKCS**").

The UK has been a net importer of gas since 2004. The UK imported a total of 48.3 bcm of natural gas in 2020, with 33.2 bcm being imported by pipeline from Norway (23.7 bcm), the Netherlands (1 bcm), Russia (4.7 bcm) and other European countries (0.3 bcm), and 18.6 bcm being imported as liquefied natural gas ("**LNG**") from a number of different countries, with Qatar (9 bcm), the US (4.7 bcm) and Russia (2.9 bcm) being the largest LNG suppliers.

Natural gas is imported into the UK via the following operational pipelines: the Bacton-Zeebrugge Interconnector; the BBL Pipeline between Balgzand in the Netherlands and Bacton in the UK; the Vesterled Pipeline between the Heimdal Riser Platform in the North Sea off the west coast of Norway and St Fergus in the UK; the Tampen Link, which links Statfjord in the North Sea off the west coast of Norway to the Far North Liquids and Associated Gas ("**FLAGS**") Pipeline (terminating at St Fergus in the UK); the Gjøa Pipeline, which links Gjøa/Vega off the coast of Norway to the FLAGS Pipeline in the UK; and the Langeled Pipeline between Nyhamna in Norway and Easington in the UK.

At present, the UK has three LNG import facilities:

- **Grain LNG** – this LNG import and regasification terminal on the Isle of Grain in Kent was commissioned in 2005 and was the UK's first LNG import facility. It is owned and operated by National Grid Grain LNG Limited, a wholly owned subsidiary of National Grid plc ("**NGG**").
- **South Hook LNG** – QatarEnergy (67.5 per cent), ExxonMobil (24.15 per cent) and TotalEnergies' (8.35 per cent) 15.6 million tonnes *per annum* ("**mtpa**") LNG import terminal at Milford Haven in Wales is one of the largest LNG receiving terminals in Europe. The terminal became operational in 2009. All of the primary capacity at the terminal has been purchased by South Hook Gas Company Ltd (a joint venture between QatarEnergy (70 per cent) and ExxonMobil (30 per cent)).
- **Dragon LNG** – this LNG import and storage terminal at Milford Haven in Wales received its first commissioning cargo in July 2009, with a start-up capacity of 4.4 mtpa. It is owned by Shell (50 per cent) and Ancala LNG Ltd (50 per cent).

There are no LNG exports from the UK (other than reloaded cargoes), nor any LNG liquefaction plants.

The UK also has a number of underground commercial gas storage facilities, in the form of depleted gas fields and onshore salt cavity storage, totalling to a capacity of approximately 1.3 bcm.

Natural gas is delivered to one of nine reception points in the UK, either by pipeline (from offshore facilities or pipelines which connect the UK to other countries) to beach terminals (the largest being situated at St Fergus in Scotland and Bacton, Easington and Teesside in England) or by ship to LNG receiving terminals. After treatment in the gas importation terminals, the processed natural gas is usually then piped into the National Transmission System ("**NTS**"), the high-pressure component of the UK's gas distribution network ("**GDN**"). The NTS, which is owned and operated by NGG, transports processed natural gas directly to end users such as power stations and large-scale industrial users or to other offtake points, for distribution within 13 local distribution zones (which are grouped into eight regional GDNs). It is through the GDNs that the majority of the processed natural gas reaches domestic and commercial end users.

The UK continues to export significant volumes of gas by pipeline (despite demand outstripping supply from the UKCS).

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

In 2020, natural gas provided 35.7 per cent of the electricity generated in the UK (down from 40.7 per cent in 2019). The remainder of the UK's electricity was generated predominantly by renewables (43.1 per cent), nuclear (16.1 per cent), coal (1.8 per cent) and other fuels (3.3 per cent). Natural gas provided approximately 34.4 per cent of the UK's final energy consumption in 2020, with petroleum products accounting for 38.5 per cent of fuels used by final consumers, electricity for 19.9 per cent and biofuels for 5.7 per cent. Total final energy consumption

was 13 per cent lower in 2020 compared to 2019 due to the impact of the COVID-19 pandemic.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

The UK's natural gas requirements are not met entirely through domestic natural gas production. See question 1.1 above for specific details on imports.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

See question 1.1 above.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

In recent years (prior to the COVID-19 pandemic), the UK has been a net importer of crude oil, although production levels from the UKCS have remained significant. The UK's crude oil production capacity is the second largest in Europe after Norway. The UK produced 1,029,000 barrels a day in 2020. In 2020, as a result of the COVID-19 pandemic, imports fell to a 17-year low in 2020, and the UK became a net exporter for the first time since 2004.

There are currently six refineries in the UK, which process a significant proportion of the UK's oil into petroleum products. Due to reduced demand for petroleum products in 2020, as a result of the COVID-19 pandemic, the six refineries produced a record low of 48 million tonnes of product in 2020 (in contrast, in 2019 they produced 61 million tonnes of product).

The refineries are supported by a network of petroleum product pipelines, as well as inland and coastal oil storage terminals. Oil is transported by pipeline, rail and sea.

The UK was a net importer of petroleum products in 2019 by 13 million tonnes, which was the same as in 2018. Prior to 2013, the UK was consistently a net exporter of petroleum products but has since been a net importer. However, in 2020 there was a sharp fall and net imports dropped by half to just 6 million tonnes.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

In 2019, petroleum products represented 47 per cent of the fuels used by final consumers (the other main fuels being electricity and gas). Consumption in 2019 was primarily for road transport fuels and aviation fuel. The position was very different in 2020, primarily due to the drop in demand for transport fuels, with petroleum products forming only one-third of total energy demand. The figures for 2021 are expected to be somewhat closer to that in 2019: in the second quarter of 2021, total final energy consumption was 33 per cent higher than in the second quarter of 2020.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

From its peak of 137 million tonnes in 1999, UKCS production has dropped nearly two-thirds to 49 million tonnes in 2020. While 2019 saw the highest level of indigenous production (at 52 million tonnes) since 2011, these production levels are still not sufficient to meet demand, meaning imports are crucial in meeting UK demand for oil.

Based on current levels of demand for petroleum products, the UK may become increasingly reliant on crude oil imports, although the need for imports is likely to be impacted by the gradual transition to non-fossil fuels, particularly in areas such as transport. Norway has historically been the main source of UK crude oil imports; however, there has recently been a sharp decrease in volumes from Norway: in 2016, Norway provided 62 per cent of UK imports but by 2020, this had fallen to 34 per cent (a figure only slightly lower than in 2018 and 2019). In contrast, in 2019 imports from the US increased by 50 per cent compared to 2018 (reaching 11.4 million tonnes) and remained at this level in 2020.

Similarly, notwithstanding its considerable refinery capacity, the UK also relies on petroleum product imports to meet local demand. Domestic supply and demand is not matched on a product-by-product basis, because UK refineries produce petrol and fuel oil for electricity generation. Therefore, the UK is one of the largest importers of jet fuel and road diesel in the Organisation for Economic Co-operation and Development ("**OECD**") and one of the largest exporters of petrol. This remained the position in 2020, despite lower demand for petroleum products.

2.4 To what extent is your jurisdiction's oil production exported?

The UK is a significant exporter of crude oils as well as an importer. Crude oil exports remained stable at 39.8 million tonnes in 2020. What was significant about 2020 was that the UK became a net exporter of primary oils, by 0.5 million tonnes, for the first time since becoming a net importer in 2004.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

The principal legislation governing the development of oil and natural gas reserves is the Petroleum Act 1998 (as amended) ("**Petroleum Act**"). Under the Petroleum Act, all rights to petroleum, including the rights to "search for, bore for and get" petroleum, are vested in the Crown. An independent regulator, the Oil and Gas Authority ("**OGA**") is responsible for the licensing and regulatory oversight under the Petroleum Act. Prior to the establishment of the OGA, the licensing regime was administered by successive government departments responsible for energy policy matters – this was the Department of Energy and Climate Change ("**DECC**") at the time the OGA was established, and is now the Department for Business, Energy and Industrial strategy ("**BEIS**").

A Framework Document entered into between BEIS and the OGA governs the relationship between the OGA and the Government. In particular, the Secretary of State for Business, Energy and Industrial Strategy:

- continues to be responsible for the overall policy and legislative framework within which the OGA operates;

- is ultimately responsible to Parliament for the OGA; and
- must agree to any extension of the OGA's remit, any material deviation from the OGA's Corporate Plan, any changes to the Maximising Economic Recovery ("**MER**") UK Strategy (see below), and any decision to impose financial sanctions in excess of £1 million.

BEIS also retains responsibility for enforcement of the offshore environmental regime and decommissioning obligations. The Health and Safety Executive ("**HSE**") is responsible for enforcing the health and safety regime.

Until recently, the legally binding strategy for the oil and gas industry (formerly referred to as the MER UK Strategy) was focused on "maximising economic recovery" of oil and gas reserves. However, the last two years have seen a significant change of direction for the industry. The MER UK Strategy has been revised and is now referred to as the "OGA Strategy", taking legal effect in February 2021. Significantly, under the new OGA Strategy, licensees are still obliged to take steps to secure that the maximum value of economically recoverable petroleum is recovered, but in doing so they must "take appropriate steps to assist the Secretary of State in meeting the Net Zero Target (see question 3.15 below), including by reducing as far as reasonable in the circumstances greenhouse gas ("**GHG**") emissions from sources such as flaring and venting and power generation, and supporting carbon capture and storage projects".

In September 2020, the Government announced that it would be carrying out a review of its oil and gas licensing policies. Flowing from this review, the Government has said that it will introduce a new "climate compatibility checkpoint" on future oil and gas licensing rounds to ensure they are compatible with wider climate objectives, including net-zero emissions by 2050. This checkpoint will use the latest evidence of the time, examining the UK's demand for oil and gas, the sector's projected production levels, the increasing prevalence of clean technologies such as offshore wind and carbon capture, and the sector's continued progress against its ambitious emissions reduction targets.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

The power to grant licences to explore for, develop and produce oil and natural gas reserves is vested in the OGA pursuant to the Petroleum (Transfer of Functions) Regulations 2016 (previously, it was vested in the Secretary of State). Devolution settlements for Scotland and Wales, under the Scotland Act 2016 and the Wales Act 2017, respectively, have vested onshore licensing powers in the Scottish Ministers in respect of Scotland, and the Welsh Ministers in respect of Wales. Offshore licensing is unaffected by devolution.

In awarding licences, regard must be given to the Hydrocarbons Licensing Directive Regulations 1995, as amended by the Pipe-lines, Petroleum, Electricity Works and Oil Stocking (Miscellaneous Amendments) (EU Exit) Regulations 2018. Licences are usually awarded in licensing rounds where a large number of blocks are made available. The most recent offshore licensing round, the 32nd Seaward Licensing Round, was completed in September 2020 and resulted in the OGA offering for award 113 licence areas over 260 blocks or part-blocks to 65 companies. In recent times, offshore licensing rounds have taken place on an annual basis but no further licensing round has been launched to date. The Government has indicated that no further licensing rounds will take place until the new "climate compatibility checkpoint" (referred to in question 3.1 above) has been finalised.

Onshore licensing rounds are held less often, with the last onshore licensing round being held in 2014.

"**Out of round**" licences may also be granted in certain circumstances. On 1 August 2019, the OGA launched a restricted out of round offer for two blocks, 3/24c and 3/29c, around the Northern North Sea Rhum Field.

Licences take the form of a deed, pursuant to which the licensee is bound to observe the conditions of the licence. The conditions of the licence (referred to as the "**Model Clauses**") are published in secondary legislation. The secondary legislation applying to current licence awards are:

- the Petroleum Licensing (Exploration and Production) (Seaward and Landward Areas) Regulations 2004 for exploration, production and exploration and development licences for the 12th and subsequent licensing rounds for landward areas, and 22nd and subsequent licensing rounds for seaward areas;
- the Petroleum Licensing (Production) (Seaward Areas) Regulations 2008 for seaward area production licences for the 25th and subsequent licensing rounds; and
- the Petroleum Licensing (Exploration and Production) (Landward Areas) Regulations 2014 for landward petroleum exploration and development licences issued in the 14th and subsequent landward licensing rounds, as well as new landward exploration licences.

The Model Clauses attached to existing licences are not affected by the issue of subsequent sets of Model Clauses, except through specifically retrospective measures. While most licences follow a standard format, the OGA may consider adapting licence terms in some circumstances.

UK licences are both contractual and regulatory in nature: contractual, being executed as a deed providing for the contractual transfer of rights from the Crown to the licensee to develop petroleum resources in return for a financial reward; and regulatory, because the Model Clauses are embodied in statutory regulations, and the terms upon which a licence is granted may be unilaterally amended by Parliament. Licences may be granted to one or more licensees; however, legally, only one licence exists, which is held collectively by the licensees who are jointly and severally liable in respect of obligations arising under, and operations conducted pursuant to, the licence.

It is important to note the distinction in the UK between the application of English law and Scottish law in the UKCS (and to a lesser extent, Northern Irish law in non-North Sea fields). Although the Model Clauses applying to licence awards in English and Scottish areas of the UKCS will be substantially the same, the jurisdictional distinction is particularly important as different arbitration provisions will apply to a licence, depending on whether it is situated in the English or Scottish area of the UKCS (see question 13.1 below). The Isle of Man issues licences for its own onshore area and territorial waters. Similarly, the devolved Government in Northern Ireland issues licences for onshore areas in Northern Ireland.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

The two types of offshore licences are the Seaward Production Licence ("**SPL**") and the Exploration Licence. However, over

the years, the Secretary of State issued various variations on the SPL to take account of the particular circumstances of the field. These have been "traditional" SPLs, as well as so-called Promote Licences, Frontier Licences, and licences specifically drafted to cover the redevelopment of a decommissioned field (e.g. Argyll/Ardmore). More recently, the OGA introduced a new variation on the SPL – the Innovate Licence. The OGA has said that from the 29th Licensing Round, all new offshore production licences will be Innovate Licences, "offering greater flexibility for each applicant to design a work programme around particular circumstances". The introduction of the "Innovate Licence" has no impact on licences already issued.

For onshore exploration and production activities, a Petroleum Exploration and Development Licence ("**PEDL**") is required. Most recently, the Petroleum Licensing (Exploration and Production) (Landward Areas) Regulations 2014 introduced Model Clauses to allow an onshore Exploration Licence to be granted for a term of three years.

The different types of licences currently being issued, in more detail, are as follows:

- **Offshore Exploration Licence**: A non-exclusive offshore Exploration Licence enables the licensee to carry out exploratory seismic surveys over large unlicensed geographical areas of the offshore sector where an SPL would be impractical and prohibitively expensive, in return for a modest annual rental payment. Such licences are typically granted for a three-year term (with the possibility of a further three-year extension if certain terms and conditions have been met). Exploration drilling below certain depths (typically 350 metres) is usually not permitted.
- **Offshore SPL**: An SPL is usually granted in respect of a relatively small geographical area (typically, not more than several hundred square kilometres) on the UKCS. It covers the full life of a field from exploration to decommissioning. It grants the licensee the exclusive right to undertake various activities within defined phases, which are: exploration (typically four years); appraisal, during which the licensee must draw up and submit a field development plan (four years); and production of oil and natural gas (18 years, with a possibility of extension). The licence will expire at the end of each phase unless the licensee has made sufficient progress to move to the next phase. Typically, the licensee must surrender 50 per cent of its acreage at the end of the exploration phase and all acreage not covered by the field development plan at the end of the appraisal phase. An annual rental payment is payable, which is proportional to the acreage covered by the licence and which escalates each year after the initial exploration period.
- **Innovate Licence**: The "Innovate Licence" is an offshore SPL that offers applicants more flexibility in relation to the lengths of the initial term and the second term. For example, for the 31st offshore licensing round, the maximum duration of the initial term was set at nine years, up to six years for the second term, and 18 years for the third term (but extendable if still in production). Another key feature of the Innovate Licence is that the initial term is divided into three phases: phase A, for studies and reprocessing; phase B, for shooting new seismic; and phase C, for drilling wells.
- **Onshore Exploration Licence**: Similarly to an offshore Exploration Licence, an onshore Exploration Licence grants rights to explore only, not to produce, and is non-exclusive.
- **Onshore PEDL**: The onshore PEDLs are similar in form to the offshore SPL and include Model Clauses and a three-phase lifespan. Licensees are granted the exclusive right to explore for, and exploit, petroleum in a specified area. The exploratory phase for onshore PEDLs is six years, the appraisal phase is five years, and the production phase for a PEDL is 20 years, subject to a governmental discretion to extend. Licensees are required to relinquish 50 per cent of the acreage at the end of the exploration phase. However, under the new Model Clauses set out pursuant to the Petroleum Licensing (Exploration and Production) (Landward Areas) Regulations 2014, the usual obligation to relinquish at least half of the initial licensed area is now subject to a new power for the OGA to agree with the licensee to the creation of so-called Retention Areas and Development Areas. Where this is agreed, the licensee may retain the Retention Areas and Development Areas into the second term. During the production period, the OGA may remove acreage that is not comprised in either a Retention Area or a Development Area.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

As a matter of law under the Petroleum Act, all rights to oil and natural gas are vested in the Crown. However, the State does not participate directly in oil and natural gas production, other than having an economic interest in the development of oil and natural gas through the imposition of acreage rental and certain taxes (see question 3.5 below). The UK no longer has a state petroleum company, and oil and natural gas development is carried out entirely by private companies or foreign state-owned companies under licences granted by the Secretary of State or the OGA.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

The taxation regime that applies to profits derived from oil and gas production in the UK and the UK Continental Shelf is made up of three main components, summarised below. In the past, a royalty regime applied; however, this was abolished on 1 January 2003. In recent times, the Government has taken steps to reduce the tax payable by oil and gas companies, to encourage further investment and also in response to the lower oil price.

- **Petroleum Revenue Tax ("PRT")**: PRT technically applies to net income from oil and gas extraction, but only in respect of those fields for which development consent was given prior to 16 March 1993. Ring Fence Corporation Tax and the Supplementary Charge (see below) are also payable in respect of profits from these fields; however, PRT is deductible when calculating these charges. PRT was originally levied at a rate of 50 per cent and was reduced to 35 per cent from 1 January 2016. However, it was announced in the UK Budget in March 2016 that PRT would be effectively abolished and the rate of PRT would be reduced to zero for all chargeable periods ending after 31 December 2015.
- **Ring Fence Corporation Tax ("RFCT")**: RFCT applies to profits from oil and gas-extraction activities and rights in the UK and UKCS instead of normal Corporation Tax. It applies regardless of when development consent was given, and aims to prevent profits from these activities being reduced for tax purposes by the setting off of losses from other non-oil and gas-related trading activities. The profits

from oil and gas extraction activities and rights are "ring fenced" and treated for tax purposes as a separate trade, so that only losses derived from these activities can be set off against profits from these activities. The current rate of RFCT is 30 per cent (*versus* 19 per cent for "non-ring fence" profits). RFCT liabilities are based on the book profits of the company which are then adjusted to arrive at the taxable profits. Deductions are available for items such as capital expenditure, plant and machinery allowances, research and development, expenditure on mineral exploration and access, and decommissioning.

- **Supplementary Charge**: A Supplementary Charge is also imposed on profits arising from any ring-fenced activities. The Charge was first introduced in 2002, at a rate of 10 per cent. In 2011, the Government raised the rate of the Supplementary Charge from 20 per cent to 32 per cent. The Government's rationale was that the rise in oil prices had provided unexpected profits for oil and gas companies. Following a fiscal review launched in 2014, the Supplementary Charge was reduced to 30 per cent and was subsequently further reduced to 20 per cent from 1 January 2015 and has now been further reduced to 10 per cent with effect from 1 January 2016.
- **Field allowances**: In order to encourage development of remaining reserves, a system of "field allowances" was introduced in 2009, to apply to small or new, technically challenging fields (for example, deep-water gas fields and ultra-heavy oil fields). A field allowance reduces the amount of adjusted ring fence profits for the licensee's accounting period on which the company's Supplementary Charge is charged.

An annual charge, called a rental, is also payable under each licence. Rentals are charged at an escalating rate on each square kilometre the licence covers at that date. This method of calculating the rental provides an incentive to licensees to surrender acreage they do not want to exploit. The amount of the rental is relatively small. Taxation, discussed above, is the main means by which the Government derives revenue from oil and gas resources.

3.6 Are there any restrictions on the export of production?

There are no restrictions on the export of production. See question 4.1 below for the regulatory regime that applies to gas interconnectors.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

There are no restrictions on currency exchange or on the transfer of funds derived from production out of the jurisdiction.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

The OGA's consent is required before any transfer of a licence interest can be made, including a transfer to an affiliate. The transfer approvals process has in recent years been streamlined in line with the general policy to encourage the transfer of licence interests. The application for consent to licence assignment must be made using the OGA's e-licence administration system (the Petroleum E-Licensing Assignments and Relinquishments System, or "**PEARS**"). The OGA will consider the proposed transfer having particular regard to the technical and financial capability of the proposed transferee, in particular, where the proposed transferee is likely to have to bear some of the decommissioning costs in respect of the field. The OGA is likely to undertake a more detailed assessment if the proposed transferee is a new entrant into the UK upstream petroleum industry or if the transfer would result in a change of operatorship.

In some circumstances, the OGA may provide an opinion of "**no objection in principle**" to a proposed transfer, which is to occur at some point in the future after the transferee and proposed transferee have made financial commitments (such as earn-in arrangements).

On a change of control of a licensee, the Model Clauses do not impose any requirement for the OGA's approval. However, the OGA has the power to require the licensee to procure a further change in control and a failure to comply with such requirement is specified as a ground for revoking a licence under the Model Clauses. In practice, licensees who are the subject of a change of control usually request an assurance from the OGA that this power will not be exercised.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

In considering whether to award a licence or approve a licence assignment, the OGA will have regard to the financial capacity of the proposed licensee. The OGA will not consent to an award or assignment if the company is not able to demonstrate its ability to meet its expected financial commitments, liabilities and obligations under the licence or if the company is insolvent or appears likely to become insolvent. Each licence applicant must demonstrate to the OGA's satisfaction that it is financially viable, that it is likely to continue business for the foreseeable future, and that it has sufficient financial capacity to fund its share of the anticipated work, meeting costs within a reasonable timeframe and decommissioning costs.

If the company has a parent company with significant financial capacity, the OGA may require a parent guarantee to support the company's financial obligations either under the company's existing licences and any future licences to which the company becomes party, or on a licence-by-licence basis.

As production licences confer exclusive rights, all the appropriate technical and financial capacity to contribute to the delivery of the MER UK Strategy has been an important criterion for the acceptability of a company to be a licensee, although now that the MER UK Strategy has been revised and reissued as the OGA Strategy, in the future additional criteria relating to the OGA Strategy may become applicable. In addition, there are other requirements of licensees, such as the establishment of a tax base, finance, residence and organisational structure and for offshore licensees there are safety and environmental capability requirements under the Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015.

Under the Petroleum Act, the Secretary of State may require a person to take action where it is not satisfied that such person will be capable of carrying out its decommissioning obligations (which may include the provision of security, such as a letter of credit) in order to reduce the risk to the UK taxpayer (who would otherwise bear this liability). It also obliges companies to provide adequate financial information (including management accounts and revenue predictions) in order to enable the Secretary of State to assess whether decommissioning security

ought to be provided at an earlier stage. Any funds set aside in a secure manner (such as a trust or other arrangement which was established on or after 1 December 2007) to meet decommissioning obligations will not be accessible to creditors under insolvency legislation.

The Secretary of State may also require participants to enter into a Decommissioning Security Agreement ("**DSA**"), where it is deemed that the participants may be unable to pay for decommissioning costs following any request to submit a decommissioning programme (see question 3.12 below) to which the Secretary of State may or may not be a party. The Secretary of State may become a party to a DSA where there is "substantial unmitigated risk" associated with a particular field (i.e. a risk that there will be a lack of funds to carry out decommissioning), to ensure changes to the DSA cannot be made without the Secretary of State's consent or to facilitate action by the Secretary of State to resolve a default situation. BEIS does not prescribe a standard form DSA; however, the agreement must meet certain minimum requirements if the Secretary of State is a party.

Oil & Gas UK, the industry body for the UK offshore oil and gas industry, published a template DSA in 2006 in response to widespread calls and after a lengthy industry-wide consultation and drafting process. This template DSA functions as a flexible stand-alone agreement and is now often negotiated along with the joint operating agreement prior to approval by BEIS of the field development plan for a new field, or on the next transfer of an interest in the relevant licence for an existing development.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

The creation of charges over licence interests is subject to the conditions under the Model Clauses attached to each licence, requiring consent from the OGA (previously the Secretary of State). However, in most cases, licensees are not required to apply for individual consent. The Open Permission (Creation of Security Rights Over Licences), granted by the Secretary of State on 6 February 2012, still applies and automatically grants consent to the creation of a variety of charges over licences, including fixed or floating charges and debentures, on the condition that the licensee notifies the OGA within 10 days of the creation of the security of:

- the date of creation of the security;
- the amount of money or other liabilities to be secured by the charge;
- which licences are the subject of the security; and
- the identity of the chargee.

The fact that a proposed security interest falls outside the scope of the Open Permission does not mean that the creation of such a security interest will not be approved, rather that it will be subject to the OGA's individual approvals process.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

While oil and natural gas development is principally regulated and controlled through the terms of the licence, various statutory controls also exist. The main statutory controls relating to offshore oil and natural gas development in England and Wales (separate controls will apply in some cases in relation to Scotland) include, under the following broad categorisations and as amended:

Environmental

- Ozone-Depleting Substances Regulations 2015.
- Environmental Protection Act 1990.
- Fluorinated Greenhouse Gases Regulations 2015.
- Greenhouse Gas Emissions Trading Scheme Order 2020.
- Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) Regulations 1998.
- Merchant Shipping (Prevention of Pollution by Sewage and Garbage from Ships) Regulations 2020.
- Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015.
- Offshore Chemicals Regulations 2002.
- Offshore Combustion Installations (Pollution Prevention and Control) Regulations 2013.
- Offshore Installations (Emergency Pollution Control) Regulations 2002.
- Offshore Petroleum Activities (Conservation of Habitats) Regulations 2001.
- Conservation of Offshore Marine Habitats and Species Regulations 2017.
- Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005.
- Offshore Petroleum Production and Pipe-lines (Assessment of Environmental Effects) Regulations 1999.
- REACH Enforcement Regulations 2008.
- Marine and Coastal Access Act 2009.
- Energy Act 2008.

Health and Safety

- Health and Safety at Work etc. Act 1974.
- Health and Safety at Work etc. Act 1974 (Application outside Great Britain) Order 2013.
- Offshore Installations and Pipeline Works (Management and Administration) Regulations 1995.
- Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996.
- Offshore Installations (Prevention of Fire and Explosion, and Emergency Response) Regulations 1995.
- Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015.
- Pipelines Safety Regulations 1996.
- Offshore Installations (Safety Zones) Regulations 1987.

The regulators and organisations in England and Wales (these may be different for operations in Scotland and Northern Ireland), from whom authorisations may need to be obtained or who may need to be consulted, include BEIS, the HSE and the Department for Environment, Food and Rural Affairs, and their relevant departmental units, the Joint Nature Conservation Committee or coastal conservation bodies such as Natural England.

The Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015, the Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015 and the Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) (Amendment) Regulations 2015 were enacted in 2015 to implement the requirements of the EU Offshore Safety Directive (2013/30/EU). The EU adopted the Offshore Safety Directive on 10 June 2013 as a direct response to the Deepwater Horizon disaster. The Directive required the creation of an offshore Competent Authority. BEIS and the HSE, working in partnership, have established the Offshore Safety Directive Regulator ("**OSDR**") to act as the UK's Competent Authority for

the purposes of the Directive. Post-Brexit, EU-derived domestic health and safety legislation continues to apply; however, it has been amended under the Health and Safety (Amendment) (EU Exit) Regulations 2018. Moreover, the OSDR has become the Offshore Major Accident Regulator ("**OMAR**"). The role of the OMAR is to oversee industry compliance with the offshore safety regulations and to undertake related functions such as accepting, assessing, approving and/or inspecting relevant Safety Cases, Oil Pollution Emergency Plans, Well Notifications and other notifications.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

The decommissioning of offshore installations and pipelines is regulated under Part IV of the Petroleum Act. Responsibility for ensuring compliance rests with the Offshore Petroleum Regulator for Environment and Decommissioning, which is part of BEIS. In contrast, the decommissioning of onshore installations is partly governed by local planning rules. The main objective of the decommissioning regime under the Petroleum Act is to ensure that the cost of decommissioning is not borne by BEIS and, therefore, taxpayers.

While responsibility for the offshore decommissioning regime remains with BEIS, rather than the OGA, the Energy Act 2016 did make some amendments to the decommissioning regime to recognise the OGA's role and the drive towards cost reduction and collaboration. In particular, before the Secretary of State approves a decommissioning programme (see below), he or she must first consult the OGA.

Decommissioning obligations arise when the Secretary of State serves a notice ("**section 29 notice**") to the operator of the field and each of the licensees, requiring them to submit a decommissioning programme (referred to in the legislation as an "abandonment" programme). Once the decommissioning programme is approved, following BEIS's review of the detail, including the cost estimates, the section 29 notice-holders are legally obliged to carry it out on a joint-and-several liability basis.

BEIS will usually request the submission of a decommissioning programme three or more years before cessation of production, although for smaller fields BEIS may require a programme at the time of approval of the final field development plan. BEIS may also serve a section 29 notice on:

- any person having an ownership interest in the installation or pipeline;
- a parent company or associated companies of a licensee;
- any person intending to carry on specified activities in relation to the installation or pipeline in the future;
- any transferor of an interest in an offshore installation or pipeline where such transferor has failed to obtain the consent of the Secretary of State to the transfer; and
- any licensee and parties to joint operating or similar agreements in relation to a petroleum exploration or extraction licence, regardless of whether such party benefitted or had the potential to benefit from the particular installation.

Typically, BEIS will utilise this wider class of parties if it is of the view that the decommissioning arrangements proposed by the operator and licensees are unsatisfactory. In addition, and crucially, section 34 of the Petroleum Act extends the right to issue a section 29 notice to anyone who, at any time since the first section 29 notice for the installation is issued, was liable to have a section 29 notice served on it, i.e. former licensees.

Until such time as the section 29 notice has been withdrawn, the licensee remains liable for decommissioning obligations. When an asset changes hands, the Secretary of State may release a former licensee from its section 29 obligations. In most cases, the section 29 notice will be withdrawn, provided that BEIS is satisfied that an adequate DSA is in place (see question 2.9 above). However, in some circumstances, the Secretary of State may use its "claw-back" power under section 34 to impose liability on a party previously released from its decommissioning obligations.

A Decommissioning Relief Deed regime gives the Government statutory authority to sign contracts (referred to as Decommissioning Relief Deeds) with oil and gas companies to provide them with certainty about the tax relief they will receive for the cost of decommissioning assets.

The Government and industry are also currently considering the feasibility of reusing oil and gas infrastructure, that would otherwise be decommissioned, for carbon transport and storage. While the proposals and options are still being finalised, as part of the Government's broader policy development work in relation to carbon capture, usage and storage ("**CCUS**"), if existing oil and gas infrastructure is redeployed for CCUS, then this is likely to involve some changes to the decommissioning regime. In particular, if the infrastructure is redeployed for CCUS, then arrangements may be put in place to relieve the original owners of the infrastructure of all or some of the decommissioning liability that they would otherwise bear under the current regime.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

A different regulatory regime applies to the development of gas storage projects, depending on whether the project is onshore or offshore. A third-party access ("**TPA**") regime also applies.

The Energy Act 2008 created a new offshore gas storage licensing regime, which entered into force on 13 November 2009, in respect of gas storage and recovery of stored gas, or unloading of gas to installations or pipelines within the offshore area, comprising both the UK territorial sea and the defined "Gas Importation and Storage Zone" area beyond. For any initial non-intrusive exploration activities, a developer of a potential gas storage project will be granted a standard offshore Exploration Licence in the same way as for any other petroleum exploration activities under the Petroleum Act, for a term of up to three years (with a possible extension of a further three years). Following this initial phase, a developer will need to apply for a gas storage licence, which will have separate exploration, appraisal and production phases, and its duration will be determined on a case-by-case basis. The licence will import Model Clauses and will also require the developer to submit a gas storage development plan to the OGA for approval.

In addition, offshore gas storage facilities also require a contractual grant of rights (in the form of a lease or authorisation) from, and on the payment of consideration to, the Crown Estate Commissioners, under the Crown Estate Act 1961.

In respect of onshore gas storage projects, one permitting route is under section 4 of the Gas Act 1965, which provides for licensed gas transporters to obtain a storage authorisation order from the Secretary of State in order to develop or use underground natural porous strata for the storage of gas. The more usual permitting route for onshore gas storage projects is under the Planning Act 2008. Under the Planning Act 2008, an onshore underground gas storage project must be authorised by a development consent order granted by the relevant Secretary

of State (following an application to the Planning Inspectorate) if the working capacity of the facility is expected to be at least 43 million standard cubic metres, or the maximum flow rate is expected to be at least 4.5 million standard cubic metres per day. Facilities which are configured below those thresholds will remain within the jurisdiction of the local planning authorities.

Gas storage facilities must also comply with health and safety and pollution control regulations. Where a depleted gas reservoir is being converted into a gas storage facility, a petroleum licence is also likely to be required.

Finally, gas storage facilities were also subject to the TPA regime under the European Gas Directive 2009/73/EC ("**Third European Gas Directive**") and the Gas Regulation, which also forms party of the EU's Third Energy Package. The Directive enabled Member States to choose between negotiated third-party access ("**nTPA**") rights, where third parties must be able to negotiate rights of access to gas storage facilities on the basis of good-faith negotiations leading to a voluntary commercial agreement, and regulated third-party access ("**rTPA**") rights, where third parties must be given a right of access to gas storage facilities on the basis of published tariffs. The UK implemented the nTPA regime and this has been retained following Brexit. Under UK law, TPA rights in relation to gas storage, both onshore and offshore, are principally regulated by the Gas Act. Under this legislation, unless it has been granted a TPA exemption, the owner of a gas storage facility is required to publish its main commercial conditions of contract for access to storage capacity at least once a year and must ensure that such conditions do not discriminate against any potential applicants. If a third party makes an application for access, then the owner of the facility must negotiate in good faith and endeavour to reach an agreement with the applicant for storage capacity. If the parties are unable to reach agreement, the party seeking access can apply to the Office of Gas and Electricity Markets ("**Ofgem**") to consider the application and for Ofgem to give any appropriate directions to the facility owner to grant access if this would not prejudice the efficient operation of the facility.

Exemptions from the application of TPA rights may be granted where Ofgem is satisfied that use of the facility by other persons is not necessary for the operation of an economically efficient gas market (the *de minimis* exemption), or where the following conditions are met:

- the facility (or the significant increase in capacity) will promote security of supply;
- the level of risk is such that the investment to construct or to modify the facility would not be made without the exemption;
- the facility will be owned by a person other than the connected gas transporter;
- charges will be levied on the users of the facility or the increase in capacity;
- the exemption will not be detrimental to competition, the operation of an economically efficient gas market, or the efficient functioning of the connected pipeline system; and
- the European Commission is or will be content with the exemption.

The Article 22 exemption derives from Article 22 of the European Gas Directive 2003/55/EC, and is restated in Article 36 of the Third European Gas Directive.

The Electricity and Gas etc. (Amendment etc.) (EU Exit) Regulations 2019 amended the TPA regime so that, following the end of the Brexit transition on 31 December 2020, the European Commission no longer plays a role in the TPA regime.

3.14 Are there any laws or regulations that deal specifically with the exploration and production of unconventional oil and gas resources? If so, what are their key features?

The regulatory regime that applies to the development of unconventional oil and gas resources is the same that applies to conventional oil and gas. For a time, it was thought that shale gas could make a contribution to the UK's economy and energy security and, therefore, the Government implemented various specific measures aimed at facilitating the development of a shale gas industry in the UK, by addressing some of the regulatory barriers faced by the industry, while at the same time addressing concerns about the safety and environmental impact of shale gas development. The specific measures included provisions in the Infrastructure Act 2015 to include a number of conditions or "safeguards" that were required to be met before the OGA would issue a well consent for carrying out fracking operations, as well as a new land access regime to give developers an automatic right to use "deep-level land" to exploit petroleum without the consent of the landowner.

However, shale gas development attracted a high degree of controversy and local community opposition in the UK. In November 2019, the OGA published a report which concluded that it is not possible with current technology to accurately predict the probability of tremors associated with hydraulic fracturing. On the basis of this, the Government decided that no further shale gas operations would be permitted to proceed in England. These restrictions have also been applied elsewhere in the UK.

3.15 What has been the impact, if any, of the "energy transition" on the oil and gas industry in your jurisdiction, and are there any policies or laws/regulations that require the oil and gas industry to decarbonise? Are there any policies or laws/regulations relating to the development of low-carbon hydrogen and its use in conjunction with on in place of natural gas, or the development of carbon capture and storage?

In recent years, there has been a change in direction for UK energy policy. In particular, in 2019 the Government set a new net-zero carbon by 2050 target ("**Net Zero Target**") for the UK, and there has been growing recognition that, in order to achieve this objective, carbon reduction policies must be adopted across all industry sectors, including upstream oil and gas. In January 2020, the chairman of the OGA noted in a speech that "the world of 2020 is not the same as the world of 2015" (2015 being when the OGA was established as a new regulator) and that the oil and gas industry's "social licence to operate is under serious threat". As noted in question 3.1 above, more recently the need to decarbonise has been given legal effect in the new OGA Strategy.

The Energy White Paper, published in December 2020, recognises the upstream oil and gas industry's contribution to the economy but confirms the Government's intention that upstream operations are decarbonised so that the UK Continental Shelf becomes a "net zero basin" by 2050. There are a number of policy and regulatory initiatives being taken forward to achieve this. In particular, the Net Zero Strategy, published in October 2021, commits the Government to work with the industry to address barriers to electrification of oil and gas production by Q4 2022 and continue to drive down routine flaring and venting. Also, as mentioned in question 3.1 above, the Government is introducing a new "climate compatibility

checkpoint" for future licensing rounds. Recognising the degree of Government support and collaboration required for the oil and gas industry to achieve these decarbonisation goals, the North Sea Transition Deal, published in March 2021, which sets out various commitments by the oil and gas industry and the Government, will play a key role.

Clean hydrogen is also expected to be a key element of the UK's decarbonisation pathway. The Government published a UK hydrogen strategy, together with a consultation on the business models for deploying clean hydrogen and a consultation on a "UK Low Carbon Hydrogen Standard", in August 2021. The hydrogen strategy states that the Government's vision is that "by 2030, the UK is a global leader on hydrogen, with 5GW of low carbon hydrogen production capacity driving decarbonisation across the economy and clear plans in place for future scale up". The strategy states that the Government intends to support both electrolytic and carbon capture-enabled hydrogen – that is, "blue hydrogen" and "green hydrogen". However, green hydrogen plants are expected to play a greater role during the 2020s. The overall future demand for clean hydrogen is still not completely certain, as it is subject to factors such as the feasibility of using it for domestic heating (which is the subject of some pilot trials); however, if the development of blue hydrogen is taken forward, this will be key development in terms of both the UK's decarbonisation goals and also the longer-term success of the UK oil and gas industry.

CCUS will be key to the development of not only blue hydrogen but also to decarbonise gas-fired electricity generation and industry sectors where the switch from using fossil fuels in industrial processes is more difficult in the short to medium term. Following earlier policy initiatives to develop CCUS in the UK, the current Government programme to develop CCUS is making steady progress. It is intended that at least one CCUS power plant will be operational by 2030. To enable industry to invest in CCUS as a means of decarbonisation, the Government is designing and implementing a business model to provide revenue support for such investment, with the intention that the new commercial framework will be finalised by 2022. The business model and regulatory regime being developed for the carbon transport and storage network ("**T&S network**") is, in some ways, not dissimilar to that applying to the downstream gas networks. It is currently envisaged that a transmission and storage operator ("**T&S Co**") will own and operate a T&S network. The revenue of T&S Co will be subject to an economic regulatory regime. As part of the economic regulatory regime, T&S Co will be granted a licence by an economic regulator, with the licence governing the permitted revenue of T&S Co. Under the terms of the licence, the permitted revenue of T&S Co will be subject to periodic price controls and there will also be various targets and incentives that will result in T&S Co either being able to increase its profits or, conversely, suffer reduced profits if it fails to achieve those outputs and targets. It is envisaged that, at least initially, transport and storage capacity will be developed in separate clusters, with the T&S network of each cluster operated by a separate T&S Co, although it is contemplated that eventually those separate clusters could be expanded into a single UK carbon network. In November 2021, the Government announced that the HyNet and East Coast CCUS "clusters" have been confirmed as "Track-1 clusters" for the mid-2020s. The Government has said that if the clusters represent value for money for the consumer and the taxpayer, then, subject to final decisions of Ministers, they will receive support under the Government's CCUS programme.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

In general, any person participating in the operation of a gas interconnector must hold a Gas Interconnector Licence issued by Ofgem under the Gas Act (see question 7.1 below for a more detailed discussion of the downstream gas market regulatory regime). "Participating" includes co-ordinating and directing the conveyance of natural gas into, or through, a gas interconnector, or making a gas interconnector available for the conveyance of natural gas. The holder of a Gas Interconnector Licence cannot hold a Gas Transporter Licence, Gas Shipper Licence or Gas Supplier Licence (see question 7.1 below).

The construction of a gas interconnector will need to comply with the regulatory requirements, applying in respect of the construction of offshore pipelines and infrastructure (see question 6.2 below).

Gas interconnectors are subject to the rights of TPA under the Gas Act 1995 (see question 6.6 below for further details).

Each gas interconnector will have an international treaty associated with it. The treaty will apply in addition to UK legal requirements and will usually clarify various legal, technical and safety issues relating to the gas interconnector.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

There are no special regulatory requirements that apply to the cross-border imports or exports of oil or oil products, other than the payment of any customs duties or taxes applicable, and compliance with any of the applicable requirements discussed in question 10.1 below. From time to time, specific limitations may apply, such as the restrictions on trade with Iran that applied until recently. Also, in the event of an actual or threatened emergency in the UK 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.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

Offshore and onshore pipelines and associated infrastructure are subject to different legal regimes in the UK. This section will focus on offshore infrastructure because the majority of the UK's oil and natural gas production is derived from offshore fields in the UKCS. Offshore infrastructure includes offshore platforms and pipelines, onshore gas processing terminals and pipelines connecting those terminals to the NTS.

Offshore infrastructure is generally constructed, owned and operated by private companies – in most circumstances, by licensees developing offshore oil and natural gas fields. Given that the UKCS has been in production for over 40 years, there

is a well-established network of offshore infrastructure bringing oil and natural gas production ashore.

The construction and operation of offshore infrastructure is principally governed by the Petroleum Act. The terms of the applicable production licence and field development programme approved by the OGA will also regulate the construction and operation of offshore infrastructure to a large extent.

For the regulatory framework relating to gas storage facilities, please see question 3.13.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

The construction and operation of offshore infrastructure must be carried out in compliance with the terms of the applicable production licence. The Model Clauses applicable to a production licence (refer to question 3.2 above) prohibit licensees from installing any permanent structures or carrying out any works for the purpose of extracting petroleum from an area or conveying petroleum to a place on land without the authorisation of the OGA (previously the Secretary of State) or without having a development and production programme in place which the OGA has either approved or served on the licensee. The Model Clauses also set out the process pursuant to which programmes are prepared and submitted by the licensee and either approved or rejected by the OGA (previously the Secretary of State).

To construct an offshore pipeline, a Pipeline Works Authorisation ("**PWA**") issued by the OGA (previously the Secretary of State) under the Petroleum Act is required. The Energy Act 2008 expanded the definition of offshore pipelines to include "all apparatus, works and services associated with the operation of such a pipe or system". This includes pipelines used for the conveyance of hydrocarbons, water, chemicals, apparatus for the supply of energy for operations, hydraulic control lines or umbilicals, as well as services (for example, the provision of fuel or power). The PWA will usually be issued to the operator of the licensee group wishing to construct the pipeline (the "**holder**") and will authorise the licensees (the "**users**") to use the pipeline and apparatus.

Under the terms of the PWA, the holder may be named as operator. The operator will be responsible for organising or supervising the construction and operation of the pipeline and ensuring compliance with all relevant legislation prevailing at the time. The holder must also provide the OGA with advance notice of any proposed modifications to the pipeline and any changes to the holder, owners, users or operator of the pipeline.

See question 3.11 for further government regulatory controls, including environmental and health and safety.

A party wishing to construct certain onshore pipelines must obtain a pipeline construction authorisation from the Secretary of State, pursuant to the Pipe-lines Act 1962 (as amended). The proposed pipeline owner must demonstrate to the Secretary of State that it has consulted with certain bodies, most notably local authorities, as well as landowners and occupiers affected by the proposed pipeline routing. The application must specify the rights and consents required to enable the pipeline to be constructed, and the extent to which the applicant has been successful in obtaining such consents. Where the applicant has been unable to negotiate access rights or easements by way of voluntary agreement with landowners or occupiers, subject to the Secretary of State approving the application, the applicant may be entitled to exercise powers of compulsory purchase pursuant to the Pipe-lines Act 1962. Onshore pipelines which are to be constructed by Gas Transporters and which meet the criteria set out in the Planning Act 2008 require development consent instead of a pipeline construction authorisation under the Pipe-lines Act 1962.

With the exception of certain pipelines, the environmental management of onshore pipelines (and the onshore hydrocarbon industry generally) is primarily overseen by the Department for Environment, Food and Rural Affairs, the Environment Agency (in England), Natural Resources Wales (in Wales), the Scottish Environmental Protection Agency (in Scotland) and local authorities.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

In relation to onshore oil and gas pipelines, the Secretary of State has powers under the Pipe-lines Act 1962 to authorise a person proposing to construct a pipeline to compulsorily acquire land if a voluntary arrangement cannot be reached between such party and the landowners, lessees and occupiers of the land in question. In relation to offshore pipelines, the consent of the Crown Estate is necessary for all oil and gas pipelines that cross the seabed within UK territorial waters (12 nautical miles off the coastline).

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

A licensee wishing to develop offshore oil and gas fields in close proximity to existing infrastructure will usually seek to negotiate access arrangements (e.g. gas transportation agreements) with the infrastructure owners. If the licensee is unable to agree a satisfactory access arrangement with the infrastructure owners, then the licensee may apply to the OGA to require access to be granted.

Please refer to question 6.6 for information on the TPA regime.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

Because offshore pipeline systems are generally privately owned, licensees wishing to connect new pipelines into existing pipeline systems or to interconnect existing pipeline systems will generally need to negotiate contractual arrangements with the existing pipeline owners. Rights of TPA are discussed in more detail in question 6.6 below.

Any connection of new pipelines to existing offshore pipeline systems will also need to comply with the authorisations and requirements referred to in question 6.2 above.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

The Energy Act 2011 sets out the TPA regime that applies to all upstream oil and gas pipelines and processing facilities. Under

the regime, owners of upstream infrastructure are required to annually publish their main commercial conditions for access. Third parties wishing to obtain access to such facilities negotiate in good faith directly with the owners in the first instance on the basis of these published commercial terms. Where a party that seeks access to upstream oil and gas infrastructure cannot agree rights of access with the owner, it has the right to apply to the OGA (previously the Secretary of State) for a notice granting the relevant rights. The OGA may consider such an application only if he or she believes that the parties have had reasonable time in which to reach an agreement. In exercising its powers to determine TPA disputes, the OGA is required to act in accordance with the MER UK Strategy, as well as various factors set out in section 82 of the Energy Act 2011, which include, among other things:

- the capacity which is or can reasonably be made available in the pipeline or facility in question;
- any incompatibilities of technical specification which cannot reasonably be overcome; and
- difficulties which cannot reasonably be overcome and which could prejudice the efficient, current and planned future production of petroleum.

If the OGA decides that access should be granted, it may serve a notice to that effect on the parties. This may allow for such things as: connections to be made to the owner's infrastructure; authorisation of the owner to recover any necessary payments from the applicant; and setting out the terms of access. In deciding the terms on which any access should be granted, one of the main issues is the need to identify the relevant costs and risks and to decide on fair and appropriate terms. These will have to be decided on a case-by-case basis.

Importantly, the OGA can issue an access notice under his own initiative, where parties have had reasonable time in which to reach an agreement and there is no realistic prospect of an agreement being reached.

The Energy Act 2011 regime was amended by the Energy Act 2016 to vest the relevant powers in the OGA and to introduce some reforms to the regime. In particular, the Energy Act 2016 introduced some changes to the regime to ensure that the application process does not need to be restarted where there is a change in ownership of the relevant assets or interests.

The Code of Practice on Access to Upstream Oil and Gas Infrastructure on the UKCS ("**Infrastructure Code of Practice**") was launched in 2004 (and since revised, most recently in August 2017) to help open up access to infrastructure on the UKCS for new users so that small adjacent fields could be made economically viable. It provides a framework to oil and gas infrastructure owners and users for the process which should be followed in seeking, offering and negotiating access to offshore infrastructure. The Infrastructure Code of Practice applies to offshore and onshore oil and gas infrastructure up to the point that natural gas enters into the NTS. The Infrastructure Code of Practice is intended to clarify, streamline and facilitate the timely resolution of access requests on a negotiated, non-discriminatory basis. The Infrastructure Code of Practice is voluntary and is not legally binding. As such, it does not fetter the OGA's discretion under the relevant legislation; however, where an application is made to the OGA to exercise its statutory powers relating to TPA disputes, the OGA will consider the extent to which the parties involved have adopted the Infrastructure Code of Practice's procedures.

The Gas Act 1995 deals with TPA to downstream gas processing facilities – that is, facilities not covered by the Energy Act 2011 regime, described above. The provisions in the Gas Act 1995 apply to facilities that process gas for the purpose of the gas being put into storage, an LNG import or export facility, a gas interconnector or a distribution system pipeline. Ofgem, the regulator responsible for downstream gas and electricity markets, enforces these provisions.

Exemption from the application of TPA rights may be granted in special circumstances and is only available in relation to interconnectors, LNG facilities and gas storage facilities. In Great Britain, Ofgem has the power to grant such exemptions. In deciding whether to permit an exemption, Ofgem will consider the participants' market shares and any concerns over capacity-hoarding.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

Parties are free to agree the terms upon which oil or natural gas is to be transported. However, if a third party is unable to agree satisfactory terms of access with the pipeline owner (including the applicable tariff), the third party can make an application to the OGA to require access to be granted. Please refer to question 6.6 above for further details.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

The Gas Act establishes the regulatory framework for the downstream gas market in Great Britain. Ofgem is the gas and electricity markets regulator. It operates under the direction and governance of the Gas and Electricity Markets Authority ("**GEMA**"). Ofgem is responsible for the regulation of the gas market in England, Scotland and Wales. The regulatory regime is founded on a licensing system, which provides that certain key activities cannot be undertaken without a licence, or, in some instances, an exemption from the requirement to hold a licence. The Gas Act makes it an offence (punishable by a fine) for a person to engage in the relevant activities without a licence or an exemption.

The five types of gas licence are:

- **Gas Transporter Licence** – authorising the licensee (a gas pipeline operator, "**Gas Transporter**") to convey gas through pipelines to any premises within an area specified by the licence (such area may be held by the Gas Transporter or extend to pipelines operated by another Gas Transporter). The Gas Act imposes a duty on Gas Transporters to, amongst other things, maintain an efficient and economical pipeline system and facilitate competition in the supply of gas.
- **Gas Interconnector Licence** – authorising the licensee to convey gas into, or through, a gas interconnector or to make such an interconnector available for use for the conveyance of gas.
- **Gas Shipper Licence** – authorising the licensee (a gas wholesaler, "**Gas Shipper**") to contract with a Gas Transporter for gas to be introduced into, conveyed by means of, or taken out of a pipeline system operated by that Gas Transporter either generally or for purposes connected with the supply of gas to any premises specified in the licence. Gas Shippers purchase natural gas from upstream producers or other traders or wholesalers and

enter into contractual arrangements with Gas Transporters for the natural gas to be transported to the customers of Gas Suppliers. Each Gas Transporter is required to have in place a network code setting out the applicable transportation arrangements to enable Gas Shippers to use the Gas Transporter's pipeline. The individual Gas Transporter's network code will incorporate the Uniform Network Code ("**UNC**"), which sets out the detailed arrangements in relation to the supply and transportation of natural gas through the NTS. Gas Shippers agree to be bound by the UNC by entering into, or acceding to, a framework agreement with a Gas Transporter.

- **Gas Supplier Licence** – authorising the licensee (a gas retailer, "**Gas Supplier**") to supply gas to any domestic or non-domestic premises through pipelines. Customers benefit from the competition that exists between Gas Suppliers as a result of the UK having an open gas supply market.
- **Smart Meter Communication Licence** – as part of a new regulatory regime for the roll-out of smart metering in Great Britain, the Gas Act 1986 has been amended to provide for the licensing of a person providing a smart meter communication service. The licence is also referred to as a Data and Communications Company ("**DCC**") Licence. In September 2013, Smart DCC Ltd was granted the DCC Licence by DECC. The DCC Licensee will manage the smart metering service on behalf of its users and will contract with, and manage, the data and communications service providers. The Smart Energy Code ("**SEC**") is a new industry code which is created and comes into force under the DCC Licence. It is a multi-party contract which sets out the terms for the provision of the DCC's smart meter communications service and specifies other provisions to govern the end-to-end management of smart metering. The DCC, energy suppliers and network operators are required by conditions of their licences to become a party to the SEC and comply with its provisions. Other bodies who wish to use the DCC's services, such as energy efficiency and energy service companies, must accede to the SEC in order to do so.

All gas licences are subject to standard conditions imposed by the Secretary of State, but Ofgem is authorised to amend or modify these conditions as appropriate.

To facilitate effective competition, the Gas Act de-links the transportation, shipping and supply of natural gas and prohibits a person from holding a Gas Transporter Licence or a Gas Interconnector Licence with any other type of gas licence.

The regulator, Ofgem, is responsible for granting licences. In granting licences, Ofgem takes into account the technical and financial suitability of applicants, their ability to comply with relevant health and safety standards, and their ability to discharge their licence obligations.

Industry codes provide another important layer of regulation. This is achieved through licence conditions which require licensees to maintain or become parties to the relevant industry codes. The most important of these is the UNC, mentioned above.

NGG is the owner and operator of the high-pressure NTS. There are eight GDNs which each cover a separate geographical region of Britain. In addition, there are a number of smaller networks owned and operated by Independent Gas Transporters: most but not all of which have been built to serve new housing. The entire UK network comprises 6,600 km of high-pressure national and regional transmission systems and around 275,000 km of lower pressure local distribution systems. The owners and operators of the NTS and the GDNs are each required to hold a Gas Transporter Licence, as discussed above.

Northern Ireland operates its own gas market, under the oversight of the devolved Government in Northern Ireland, and its own regulator, the Utility Regulator.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

As mentioned in question 7.1 above, a Gas Transporter Licence issued under the Gas Act is a key authorisation required for the operation of a distribution network. In addition, there are a large number of planning, environmental and health and safety requirements that apply during the construction of a distribution network, as well as during the ongoing operation of the network. For example, the Gas Safety (Management) Regulations 1996 require each Gas Transporter to prepare a Safety Case document that sets out in detail the arrangements in place in relation to issues such as the management of gas escapes.

7.3 How is access to the natural gas distribution network organised?

The Gas Act imposes a general duty on gas transporters (i.e. network operators) to provide access. The Act states that a gas transporter must, in relation to its authorised area: develop and maintain an efficient and economical pipeline system for the conveyance of gas; and comply, so far as it is economical to do so, with any reasonable requests by third parties to connect to that system, and convey gas by means of that system to any premises; or to connect to that system a pipeline system operated by another authorised gas transporter.

Specific duties to facilitate this access are dealt with in more detail in the terms of the licence conditions set out in the Gas Transporter Licence held by operators of gas transmission and distribution networks. In particular, network operators are required to maintain charging methodologies, relating to transportation (use of system) charges as well as connection charges, which set out the principles of and methods used to calculate charges. Any charges must be cost reflective, facilitate competition and reflect developments in gas distribution. The licence conditions expressly state that access to the system must be granted in accordance with the provisions of the Gas Act and the Third European Gas Directive as it applies as domestic legislation from 1 January 2021. Under the Gas Act, licence-exempt network operators are also required to grant TPA.

All Gas Shippers must accede to the UNC, which defines the rights and responsibilities for users of the GB gas transportation system (the NTS and GDNs) and provides for all system users to have equal access to transportation services. Participation in the market under the UNC is through forward-nominated trades with counterparties and physical or non-physical within-day trading. Both balancing and charging take place on a daily basis. In addition to the balancing requirements, the UNC also deals with a number of other issues, including entry and exit requirements, emergencies and storage.

If parties are unable to agree upon access arrangements, an application can be made to Ofgem to exercise its powers in relation to TPA (see question 7.4 below).

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

As mentioned in question 7.3 above, the Gas Act requires every Gas Transporter to comply with any reasonable request for it

to convey gas by means of its pipeline system to any premises, provided it would not prejudice the efficient operation of the Gas Transporter's pipeline system.

The Third European Gas Directive also requires that non-discriminatory TPA to distribution and transmission pipeline systems be provided, and that the gas regulator have the power to determine any disputes arising in relation to such access. In compliance with the requirements of the Third European Gas Directive, the Gas Act provides for Ofgem to determine any such access disputes (previously so-called "**Article 41 disputes**"). While EU law no longer has direct application from 1 January 2021, these requirements have been retained as domestic law, with Ofgem continuing to be the body that determines such disputes. Ofgem retains this power following the end of the Brexit transition period on 31 December 2020, but such disputes are no longer referred to as "Article 41 disputes".

Disputes about connections and use of system can also arise in relation to specific obligations of the transporter under the terms of their Gas Transporter Licence. Ofgem has a wide range of dispute resolution powers that may be applicable in this context, and is able to determine disputes between system operators and Gas Shippers, as well as between system operators and gas users wishing to connect their premises to the system.

An application to Ofgem could involve a request by the applicant that the relevant system operator increase the capacity of the relevant pipeline through modification of associated works and apparatus, or for the installation into any such pipeline of an interconnection point. If Ofgem determines the dispute in favour of the applicant, by making an order requiring access to be granted, the applicant will generally be obliged to pay for the reasonable cost of the relevant work, as determined by Ofgem.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

Gas Transporters charge connection and use of system charges derived by reference to price-control formulae and subject to price control by Ofgem. From 1 April 2013, Ofgem introduced a new performance-based model to set price controls, referred to as "**RIIO**" (which stands for "**Revenue set to deliver strong Incentives, Innovation and Outputs**"). Building upon the previous Retail Price Index formula (which used the rate of inflation as a benchmark and subtracts an efficiency factor to provide the permitted changes in network prices), the RIIO model, among other features, uses rewards and penalties related to output delivery, and introduces an innovation stimulus package. It also extended the price control period to eight years from the previous five; however, Ofgem has now reverted to using a five-year period.

The RIIO-GD2 price control sets out the outputs that the eight GDNs must deliver for their consumers and the associated revenues they are permitted to collect for the five-year period from 1 April 2021 until 31 March 2026. An equivalent price control review – RIIO-T2 – applies to gas transmission for the five-year period from 1 April 2021 until 31 March 2026.

Under the terms of the Gas Transporter's Licence, a Gas Transporter must conduct its business to ensure that neither it nor any of its related companies obtains any unfair commercial advantage.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

Please see the requirements and restrictions referred to under question 7.1 above.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

Trading takes place at a number of points in the gas supply chain. In the mid-1990s, gas was principally traded from producers to Gas Shippers at the onshore entry points into the NTS, known as the "**beach**". Beach trades are usually contractually documented under gas supply/sale agreements.

More recently, gas is predominantly traded after leaving the beach and entering the NTS, at the National Balancing Point ("**NBP**"): a virtual location created by the UNC. Over-the-counter NBP trades are principally made on the terms of the "**NBP '97**" contract (which was updated and reissued in 2015 as "NBP 2015"), although International Swaps and Derivatives Association ("**ISDA**") contracts (with a gas annex attached) are also used. In order to effect a trade, a party makes a nomination via Gemini (a dedicated computer application operated on behalf of NGG), setting out the volumes of gas that it contracts to deliver or offtake from another party, the date and the entry or exit point to the NBP, unless the trade is solely within the NBP.

The NBP is also where NGG, the Transmission System Operator, balances the NTS on a daily basis. The UNC moved balancing from a monthly to a daily regime when it was introduced in 1996 (then called the "**Network Code**"), placing an obligation on NGG to physically balance the NTS each day. NGG passes on the costs of any shortfall to the Gas Shippers: a delivery shortfall by a Gas Shipper will require the Gas Shipper to pay a punitive charge of the System Marginal Buy Price (which may be the highest price traded by NGG that day). Conversely, a Gas Shipper long of gas will be cashed out at the System Marginal Sell Price (which may be the lowest price traded by NGG that day).

Gas can also be physically traded at the NBP via an anonymous, screen-based, within-day gas market: the on-the-day commodity market ("**OCM**"). This allows Gas Shippers to fine-tune their daily positions and allows NGG to purchase and sell gas in order to balance the NTS. The OCM is operated by an independent market operator, ICE Endex.

Any party that wishes to arrange for the conveyance of gas through the NTS must hold a gas shipper licence. However, in October 2012, Ofgem confirmed that parties not involved in the physical conveyance of gas through the network, but who simply trade gas as a commodity at the NBP, do not require a gas shipper licence. The party will also need to accede to the UNC, irrespective of whether it is involved in the physical conveyance of gas through the network.

Regulation (EU) No. 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency ("**REMIT**") came into force on 28 December 2011. REMIT, being an EU regulation, previously applied directly to parties engaging in gas trading in the UK, imposing prohibitions on insider trading, market manipulation and an obligation to publish inside information and to report suspicious transactions. This has now been retained as domestic legislation as "UK REMIT", by virtue of the European Union Withdrawal Act 2018 as amended, and regulations made under that Act. Ofgem, the gas and electricity markets regulator, has powers to enforce REMIT in Great Britain. The Electricity and Gas (Market Integrity and Transparency) (Enforcement etc.) Regulations 2013, which entered into force

on 29 June 2013, give Ofgem the necessary powers to enforce the REMIT provisions relating to the prohibition on insider trading and market manipulation, the obligation to publish inside information and to report suspicious transactions. Under the Regulations, Ofgem has investigative powers and can impose unlimited penalties. In addition, the Electricity and Gas (Market Integrity and Transparency) (Criminal Sanctions) Regulations 2015 supplement the civil penalties available under the 2013 Regulations by adding criminal penalties for particularly serious cases of breach of REMIT provisions relating to insider trading and market manipulation.

Under EU REMIT, market participants are required to register with a national regulatory body and report transactions to the Agency for the Cooperation of Energy Regulators ("**ACER**"). Under UK REMIT, ACER no longer plays a role. Furthermore, initially at least, market participants are not required to report their transactions to Ofgem in the same way that they had to report their transactions to ACER before 1 January 2021; however, this could change in the future. Market participants who are currently registered with Ofgem for the purposes of the REMIT regime, but who also engage in energy trading in the EU, will need to register with a national regulatory authority in an EU Member State to allow them to comply with the EU REMIT regime.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

There is no obligation to trade only bundled products. Instead, gas as a wholesale commodity, entry and exit capacity on the NTS and balancing services can all be traded independently.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

There are no LNG liquefaction or export facilities in the UK, and in view of the UK being a net importer of natural gas, no such facilities are planned. However, there are a number of existing LNG import sites currently operating in the UK (detailed in question 1.1 above).

9.2 What governmental authorisations are required to construct and operate LNG facilities?

The construction and operation of LNG facilities must comply with the relevant environmental, planning and health and safety requirements referred to in questions 3.11 and 3.13 above. There are no specific UK Government authorisations required to construct and operate LNG facilities, other than the offshore unloading licence discussed in question 3.13 above. The offshore unloading licence, introduced under the Energy Act 2008, is intended to facilitate the future development of any offshore fixed or floating LNG receiving terminals.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

The Third European Gas Directive (to the extent it now applies as part of UK domestic legislation) provides that terms and conditions for the provision of such services by LNG system operators, including rules and tariffs, must be established in a non-discriminatory and cost-reflective way and must be published (see question 3.13 above for further details).

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

The Third European Gas Directive requires EU Member States to implement a regime of TPA to LNG facilities, which in the UK is implemented in the Gas Act. The EU Gas Regulation, which forms part of the EU's Third Energy Package together with the Gas Directive, also applied directly. Since 1 January 2021 (after the Brexit transition period ended), these requirements continue to apply as domestic legislation.

Unlike the nTPA regime that applies to gas storage facilities, which is discussed in question 3.13 above, the regime that applies to LNG facilities is rTPA. This means that access is based on published tariffs and/or other terms and obligations which have been approved by the regulator.

Specifically, under the Gas Act, the owner of an LNG facility must publish the main commercial conditions relating to the grant to another person of a right to have gas treated at the facility. Any charges for using the facility, or the method for calculating such charges, must be approved by Ofgem. The conditions of access must not discriminate against any applicants. Any third party that wants to have gas treated at the LNG facility has the right to apply to the owner. If the owner refuses the application, then that party can make an application to Ofgem for the grant of rights to use the facility.

The TPA exemptions regime that applies to LNG facilities is similar to that described in relation to storage facilities in question 3.13 above.

Each of South Hook LNG, Dragon LNG and Grain LNG has been granted an exemption by Ofgem from the application of TPA rights under the Gas Act, which exemptions have been approved by the European Commission (which, prior to 1 January 2021, possessed the right to veto the granting of such an exemption in Great Britain). Each of these exemptions was granted on the condition that the access arrangements in respect of the LNG facilities contained capacity management and anti-hoarding measures. At present, there are no LNG facilities in Great Britain which are subject to rTPA.

Ofgem retains the right to revoke an exemption if market circumstances change.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

The downstream oil sector, unlike gas, is not subject to the oversight of a market regulator like Ofgem. Nonetheless, there are some specific regulatory requirements that apply, mainly relating to energy security and environment and health and safety issues.

As a Member State of the International Energy Agency, the UK is required to implement certain emergency oil-stocking obligations. The UK meets its international obligations by directing companies to hold stocks. Section 6 of the Energy Act 1976 allows the Secretary of State for Business, Energy and Industrial Strategy to give directions to businesses producing, supplying or using petroleum products within the UK market, requiring them to hold minimum levels of oil stocks. The Oil Stocking Order 2012 sets out the type, location and uses of stocks of crude liquid petroleum and petroleum products that may be counted towards an obligated person's stocks.

The Renewable Transport Fuel Obligation ("**RTFO**"), established under the Renewable Transport Fuel Obligations Order 2007, imposes an obligation on fuel suppliers to ensure that sustainable renewable fuel makes up a percentage of the volume of fuel they supply for road transport and non-road mobile machinery, tractors and recreational craft that do not normally operate at sea. In 2018, the Government introduced new targets under the RTFO, increasing the biofuels volume target from the previous 4.75 per cent to 9.75 per cent by 2020, and 12.4 per cent by 2032. For each litre of biofuel (or kilogram of biogas) supplied, a Renewable Transport Fuel Certificate ("**RTFC**") is issued. Obligated suppliers meet their obligation by redeeming RTFCs or by paying a fixed sum for each litre of fuel for which they wish to "buy-out" of their obligation. The effect of the RTFO is to create a subsidy and market for biofuels, which are typically more expensive than petroleum products. In practice, suppliers blend biofuels with conventional oil products to comply with the RTFO.

In addition, the Motor Fuel (Road Vehicle and Mobile Machinery) Greenhouse Gas Emissions Reporting Regulations 2012 require suppliers of both biofuels and fossil fuels for use in road vehicles and non-road mobile machinery to report annually on the GHG intensity of the fuels that they supply. The requirements are now extended to include GHG reduction targets, such that obligated suppliers will need to achieve a 6 per cent reduction in GHG emissions for their fuel supply. They can meet these reduction targets by redeeming GHG credits, which evidence the use of fuels with a GHG emissions intensity below the 2020 target level.

There are also a large number of environmental and health and safety requirements that apply to facilities that process or store oil and oil products. The most significant of these are the Control of Major Accident Hazards Regulations 2015. The aim of these Regulations is to prevent major accidents involving dangerous substances and limit the consequences to people and the environment of any accidents which do occur. Operators of refining plants will normally require an environmental permit issued pursuant to the Environmental Permitting (England and Wales) Regulations 2016, among other environmental permits and consents. Manufacturers or importers of oil products are also required to comply with the EU's REACH Regulation, which requires registration of all the chemical products circulated in the EU market by EU-based manufacturers and importers, as well as non-EU companies exporting their products to the EU.

In April 2018, the Government confirmed that it will implement a suite of new regulatory measures designed to protect against fuel supply disruptions. The new measures, subject to some minimum thresholds, are intended to apply to the whole downstream oil and oil product industry. The regulatory measures, described as "fuel resilience measures", include:

- measures to allow the Government to monitor fuel resilience, such as a requirement for industry to report incidents or risks of disruption to fuel supplies; and
- measures to allow the Government to protect fuel supply, such as an ownership test to enable the Government to intervene for the protection of fuel supply, where operators or owners of critical downstream oil infrastructure do not meet satisfactory levels of financial soundness or operator competence.

After some delay in implementing these fuel resilience measures, in 2021 the Government published the draft Downstream Oil Resilience Bill.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

The price of crude oil that is bought and sold around the globe is directly or indirectly determined by reference to crude oil benchmarks, also known as oil markers. There are three primary benchmarks: West Texas Intermediate ("**WTI**"); Brent Blend; and Dubai. Other well-known blends include the Opec Reference Basket, Tapis Crude which is traded in Singapore, Bonny Light used in Nigeria and Mexico's Isthmus.

Price formation in respect of the most widely used oil markers, WTI and Brent Blend, happens on futures exchanges, respectively the New York Mercantile Exchange ("**NYMEX**") and Intercontinental Exchange ("**ICE**"). The price formation mechanism on the exchanges is, in turn, correlated with the physical availability of the crude oil in the reference market. The physical reference market for Brent Blend is crude oil that is produced in the North Sea.

The price for crude oil to be delivered on a forward basis is often determined by reference to the relevant futures price. Most oil cargoes and consignments that generally take place in Europe, Africa and the Middle East reference the Brent ICE futures contract.

Apart from offering a benchmark price for physical consignments of oil, futures contracts also provide a tool to eliminate the risk relating to price fluctuations in the future. Most crude oil is traded on a forward basis. Where a price for oil to be delivered in the future is fixed at the outset, the seller must seek protection against a decrease in price. The buyer will have the opposite need. This makes forward sellers and buyers natural holders of "short" and "long" positions on the futures market.

However, the futures market is not purely made up of entities that have an interest in physical oil. A large part of the market is speculative in nature. Namely, it consists of futures positions taken by those who wish to have exposure to the price of crude oil. Furthermore, the futures contracts referred to above provide for reference prices for so-called over-the-counter derivatives that are entered into bilaterally either for hedging purposes or for speculative purposes.

The combination of futures trading and over-the-counter derivatives is commonly referred to as "paper trading", as opposed to the physical trading of crude oil. A much larger number of paper trades of crude oil take place than the physical crude oil trades that inform the relevant benchmark price.

Participants in both the physical and paper crude oil markets include producers, refiners, independent trading houses and, increasingly, the commodity trading arms of investment banks.

Physical trading of crude oil remains largely an unregulated activity. It is subject to rules for the handling and transportation of hazardous and polluting materials, as discussed in question 10.1 above. Crude oil paper trading comes within the scope of new rules on derivatives trading, most notably the Markets in Financial Instruments Directive ("**MiFID**") and MiFID II, as they apply as UK domestic legislation from 1 January 2021.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

As far as UK activities are concerned, competition law can be enforced by the UK national competition authority, the Competition and Markets Authority ("**CMA**"), and the sectoral

regulators with concurrent competition law enforcement powers, of which the most relevant to the natural gas sector is Ofgem. Note that Ofgem has no role to play in the oil market.

After the expiry of the Brexit transition period on 31 December 2020, EU competition law only applies to conduct in the UK insofar as it affects competition in the EU.

As regards the interaction between the UK national competition authorities:

- Pursuant to the Competition Act 1998 (Concurrency) Regulations 2014 and the Gas Act 1986, Ofgem and the Director General of Gas for Northern Ireland (within the Northern Ireland Authority for Utility Regulation) have concurrent powers with the CMA to investigate suspected anti-competitive activity and take action for breaches of competition law in the gas sector. In particular, the CMA and Ofgem have concurrent powers to apply and enforce Chapter I and II of the Competition Act 1998 (which prohibit anti-competitive agreements and abuse of a dominant position – see further question 11.2 below).
- Before commencing an investigation, Ofgem is required to first consider whether it would be more appropriate to take action under the Competition Act 1998 before exercising its regulatory powers.
- The interaction between Ofgem and the CMA is further governed by a Memorandum of Understanding dated 18 January 2016 which deals with matters of general co-operation between the two regulators, as well as the principles to be applied to case allocation.

Ofgem or, in cases that raise public interest considerations, the Secretary of State, can refer a market in the natural gas sector to the CMA for an in-depth market investigation under the Enterprise Act 2002, if there are reasonable grounds for suspecting that any feature, or combination of features, of that market prevents, restricts or distorts competition. The CMA has considerable remedial powers if it concludes that a market operates such that there is an adverse effect on competition, including in extreme cases requiring divestments. In June 2014, Ofgem used these powers to refer the UK energy market to the CMA for an in-depth market investigation. The CMA issued its final report in June 2016.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

UK competition law applies where the agreements, business practices or behaviour concerned may affect trade within the UK.

Anti-competitive agreements

Chapter I of the Competition Act 1998 prohibits agreements and concerted practices which, by object or effect, may prevent, restrict or distort competition. Agreements may be formal, informal, written, oral or tacit understandings between businesses. The prohibition on anti-competitive agreements only applies where there is an appreciable prevention, restriction or distortion of competition.

Some agreements, such as price-fixing or market-sharing cartels or (generally) resale price maintenance obligations, are considered anti-competitive by their nature, regardless of their actual effects (known as "**object restrictions**"); others, such as exclusive purchasing and supply obligations, will only infringe the law where anti-competitive effects can be shown.

Agreements and concerted practices which *prima facie* prevent, restrict or distort competition may nevertheless benefit from an exemption where, broadly speaking, the anti-competitive effects are outweighed by pro-competitive benefits for consumers (in practice, exemptions will not generally be available in cases involving "object restrictions").

In the UK, individuals involved in cartel activity (defined as agreements relating to price-fixing, market/customer sharing, output limitation or bid-rigging) may be subject to criminal prosecution for the so-called "criminal cartel offence" under the Enterprise Act 2002. If found guilty, an individual may face an unlimited fine, up to five years' imprisonment and/or director disqualification (see question 11.3 below).

Abuse of dominant position

Chapter II of the Competition Act 1998 prohibits conduct by one or more undertakings which amounts to the abuse of a dominant position. The essence of dominance is the ability to behave independently of competitive pressures, i.e. the behaviour of customers, suppliers and competitors. An undertaking may have a sole dominant position or a collective dominant position together with other competitors, although the latter is rare. UK competition law does not provide statutory market share thresholds for defining dominance. There is a rebuttable presumption of dominance where market shares are persistently 50 per cent or more and, as a general rule, dominance is unlikely to be a concern where market shares are less than 40 per cent. Factors such as the size and number of competitors and customers, the ease of setting up a new business in competition ("**barriers to entry**") and the strength of customers ("**buyer power**") are all relevant to the assessment of dominance.

Holding a dominant position in a particular market is not prohibited under UK competition law; what is prohibited is the *abuse* of that dominant position. Examples of potential abuse of a dominant position include charging unfair prices (which could be excessively high for consumers or excessively low in order to drive a competitor out of business) or imposing other unfair trading conditions, refusing to supply an existing customer without good reason, limiting production, markets or technical development, or applying different conditions to similar transactions with different parties.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

Both the CMA and Ofgem (under the Competition Act 1998) have a broad range of powers to apply and enforce the Chapter I and II prohibitions under the Competition Act 1998. In short, these powers include the ability to:

- investigate suspected infringements, including requesting information and documents, interviewing individuals and conducting unannounced "dawn raids";
- impose interim measures during the investigation (in practice, this happens very rarely);
- give directions to bring an infringement to an end;
- accept binding commitments which address competition concerns without an infringement being found; and
- impose financial penalties on undertakings of up to 10 per cent of an undertaking's group worldwide turnover in the business year preceding the date of the decision in the event of an infringement.

In addition to these powers, the CMA may bring a prosecution for the criminal cartel offence under the Enterprise Act 2002 (see question 11.2 above for further information).

Finally, pursuant to the Company Directors Disqualification Act 1986 (as amended by the Enterprise Act 2002), the CMA and/or Ofgem may apply to the court for an order disqualifying

an individual from acting as a director of a company for up to 15 years. An order will be granted where the individual has been the director of a company involved in a breach of competition law and the court decides that the director's conduct makes him or her unfit to be concerned in the management of a company. The regulators also have the power to accept a Competition Disqualification Undertaking from a director instead of applying for an order.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

Mergers and acquisitions involving UK businesses in this, or any, sector may be subject to the UK merger control regime contained in the Enterprise Act 2002.

Before the end of the Brexit transition period (on 31 December 2020), as a general rule, UK merger control did not apply to a transaction if the EU Merger Regulation was triggered. Transactions may be subject to EU and UK merger control in parallel.

UK Merger Control

A merger is subject to the UK merger control regime where:

- the target has an annual turnover in the UK of more than £70 million; or
- as a result of the merger, the merged entity will have a share of supply in the UK (or a substantial part of the UK) of goods and services of at least 25 per cent, and that share of supply is increased as a result of the merger.

The Government had also lowered the jurisdictional thresholds for mergers in certain key sectors, including defence, quantum technology and computing hardware. This is not considered further here as it will rarely relate to the oil and gas sector, and it will be superseded by the new national security and investment regime as of 4 January 2022 (see below).

It should be noted that the UK merger control regime applies to transactions involving the acquisition of "material influence", as well as the transactions involving the acquisition of a controlling interest. A shareholding of around 15 per cent has, in certain circumstances, been considered sufficient to constitute "material influence". For example, the CMA has found material influence where a shareholder, in practice, has the ability to block special resolutions because of the spread of other shareholdings and general patterns of attendance at shareholders' meetings, and where the acquirer's position and expertise in the sector is expected to influence shareholders and/or affect policy formulation (for example, in February 2019 the CMA opened a merger inquiry into the proposed acquisition by RWE AG of a 16.67 per cent stake in E.ON). Moving up through the levels of control, e.g. from material influence to a controlling interest, will also potentially trigger the application of the regime.

The substantive test applied in UK merger control is whether the transaction may be expected to result in a substantial lessening of competition in any market or markets in the UK.

Merger control review in the UK is a two-stage process. At Phase 1, the CMA undertakes an initial review of the transaction and, where it has no material competition concerns about the merger, it will issue a clearance decision. Where there are material concerns about the impact of the merger on competition, the CMA may either accept undertakings from the parties to address those concerns, or it may refer the merger for an in-depth Phase 2 review. At Phase 2, the CMA may clear the merger either unconditionally or subject to conditions, or it may prohibit the merger. During the review process, the CMA has wide powers to request information from the parties, and will also consult interested third parties (such as customers, suppliers and competitors) for their views when assessing the likely impact of a merger.

It is important to note that the UK merger control regime is voluntary and non-suspensory. This means that parties are free to complete their transactions without notifying them to the CMA or, in the event that the transaction is notified, without waiting for a clearance decision. However, the fact that a merger is not notified by the parties does not mean that it will escape scrutiny under the UK merger control regime. The CMA has the power to review mergers regardless of whether they are notified, and has a dedicated mergers intelligence team responsible for monitoring merger activity in the UK. The CMA may also learn about a merger through liaison with other competition authorities who have received a (very often mandatory) notification of the merger in question.

The CMA may impose "initial enforcement orders" (often referred to as "**hold separate**" orders) to prevent any (further) integration of the merging parties pending the outcome of the CMA's investigation. In practice, hold separate orders are imposed on substantially all completed mergers at the earliest opportunity in Phase 1. Further, whilst the CMA is not able to prevent formal legal completion of a transaction, it can impose a hold separate order in respect of an anticipated merger, which prevents any integration steps being taken either before or after completion. Finally, the CMA can order the reversal of any integration steps that may already have been taken. These powers must be taken into account in considering whether to proceed with the merger without notification and/or clearance.

The Enterprise Act 2002 also allows the Secretary of State to intervene in relation to mergers which raise public interest considerations. The details of the procedure followed in such cases are beyond the scope of this publication, but further information can be found in the UK chapter of *ICLG – Merger Control*.

The role of Ofgem in mergers

Mergers in the gas sector are reviewed under the Enterprise Act 2002 in the usual way; however, Ofgem will provide its views to the CMA at Phase 1 and, where a reference is made, Phase 2 on the impact of the merger and whether it may be expected to result in a substantial lessening of competition, given its specialist knowledge of market conditions in the sector. However, the ultimate decision rests with the CMA.

It should be noted that, separately from the merger control assessment, Ofgem will always consider whether additional or amended licence conditions should be imposed in light of the merger; for example, the introduction or enhancement of financial ring-fencing provisions. The effect of mergers in regulated sectors will also be taken into account when Ofgem undertakes more in-depth regulatory reviews of regulated markets.

National Security and Investment regime

On 29 April 2021, the Government passed the National Security and Investment Act 2021, which will significantly strengthen the Government's powers to investigate and potentially prohibit transactions on national security grounds. The National Security and Investment Act will enter into force on 4 January 2022 and will replace existing provisions for public interest intervention in merger cases for reasons of national security.

The National Security and Investment Act 2021 contains a mandatory notification regime, backed up by criminal sanctions, for transactions involving the acquisition of a right or interest (typically a holding of more than 25 per cent) in 17 key sectors. For these transactions, clearance must be obtained before closing.

Certain activities in the energy sector are caught by the mandatory notification regime, including the ownership and operation of upstream petroleum facilities, gas distribution and transmission networks, gas processing facilities, LNG import/export facilities and other infrastructure relating to the storage, refining/processing oil and transportation of oil.

The regime also includes a voluntary notification process (underpinned by a "call-in" power) for other transactions that may affect UK national security interests.

The National Security and Investment regime applies to UK and non-UK investors.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

Limitations on acquisitions are generally a matter for the competition authorities (see section 11 above) and have traditionally not been subject to a test based on the nationality of the purchaser. Whilst the National Security and Investment regime referred to in question 11.4 above applies to both UK and non-UK investors, whether a relevant investor is a foreign entity is likely to be a relevant consideration in the Government's assessment.

The Third European Gas Directive required Member States to implement a special certification process to be followed where a transmission system owner or transmission system operator is controlled by a person from a non-EU country. As part of the process, Ofgem is required to make an assessment about whether foreign ownership or control of the transmission system would give rise to any risk to security of supply. This requirement has been retained in UK domestic law; however, as from 1 January 2021, Ofgem is no longer required to consult the European Commission.

In relation to licences for the exploration and development of oil and natural gas resources, the OGA imposes certain residence requirements on licensees. In order to be a licensee, companies must have a place of business in the UK. If the company is licensee to a licence which covers a producing field, then the company must either be registered at Companies House as a UK company or carry on its business through a fixed place in the UK. Additionally, more practical residence requirements may also be imposed by the OGA on a case-by-case basis if the company is also going to be the operator of the licence to ensure that the operator is able to manage operations properly.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

All regulation in the UK, including competition, environmental, health and safety and other sector-specific concerns, were previously constrained by the requirements of EU law, but this is no longer the case as from 1 January 2021. However, on 24 December 2020, the EU and UK reached a Trade and Cooperation Agreement ("**TCA**"), which applies as of 1 January 2021. While the TCA is foremost a complex free trade agreement, the TCA also provides for regulatory and technical co-operation between the UK and the EU on a range of energy matters, such as energy trading, access to networks, infrastructure planning, security of supply, gas decarbonisation and offshore energy.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

In the context of the licensing regime under the Petroleum Act, if a dispute relating to a licence arises between the OGA and a licensee, then, pursuant to the Model Clauses, the dispute is required to be referred to arbitration unless the licence expressly provides that the matter under dispute is to be determined, decided, directed, approved or consented to by the OGA. The arbitration is, by a single arbitrator, appointed by the OGA and the licensee or, if they are not able to agree, by the Lord Chief Justice of England (or the person specified in the Model Clauses if the dispute applies to a licensed area within the Scottish or Northern Irish areas).

The OGA has also been vested with new powers under the Energy Act 2016 to consider disputes between industry participants. The OGA has the power to compel parties to participate in the dispute resolution process; however, the OGA's ultimate findings are not legally binding (in contrast to the OGA's decisions in TPA disputes).

Elsewhere in this chapter, TPA disputes have been discussed. Depending on whether the dispute relates to downstream or upstream infrastructure, an application for resolution of the dispute can be made to Ofgem or the OGA.

In relation to disputes arising in the context of the downstream gas market, involving the holders of licences issued under the Gas Act and other third parties, the Gas Act sets out various provisions for the determination of disputes by Ofgem. In addition, the Gas Act sets out various enforcement powers. If a gas licence holder has a decision made against it by a government authority pursuant to these enforcement powers, reasons for this decision must be given and any representations or objections which have been made in relation to the dispute must be considered by the authority. If a licence holder desires to question the validity of an order, or appeal a penalty imposed, it may apply to the High Court within 42 days of service of the notice of the decision. Judicial review may also be available where all other avenues for appeal have been exhausted. In particular, judicial review is often the main remedy if a party wishes to challenge Ofgem's decision-making process. The Gas Act sets out a separate regime relating to decisions made by Ofgem in relation to licence condition modifications. Under the relevant provisions of the Gas Act, if Ofgem proposes licence condition modifications (relating to the licences discussed in question 7.1 above), then an appeal against a decision of Ofgem to amend the licence conditions can

be made to the CMA by the licence holders, certain materially affected persons or a qualifying body representing them. Market participants may also appeal to the CMA certain decisions by Ofgem relating to industry code modifications.

It should also be mentioned that under the Housing Grants, Construction and Regeneration Act 1996 ("**HGCRA 1996**"), there is a statutory right for parties to a construction contract to refer their disputes to adjudication. Parties cannot contract out of this right. Although oil and gas operations are excluded from the HGCRA 1996, advice should be sought with regard to ancillary activities which involve construction operations.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

The UK ratified the New York Convention on 24 September 1975 and the New York Convention came into force on 23 December 1975. The UK applies the New York Convention only to the recognition and enforcement of awards made in the territory of another contracting state.

ICSID was ratified by the UK on 19 December 1966, and came into force on 18 January 1967.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

There is no special difficulty in litigating, or seeking to enforce judgments or awards, against the Government. Public bodies enjoy no immunity against litigation in the UK and are subject to the rule of law on the same basis as individuals and non-state-owned organisations and other entities.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

We are not aware of any instances where foreign corporations or organisations have obtained commercial judgments or awards against UK Government authorities in the context of the oil and natural gas sector. However, the legal system in England and Wales is internationally recognised as being independent and impartial. There is no reason why foreign corporations could not obtain judgments or awards against the Government.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

Large-scale change and reform

As mentioned elsewhere in this chapter, the Government is currently pursuing a large number of policy and regulatory initiatives designed to implement the UK's net-zero carbon goals. It is probably true to say that in the last 12 months or so, the Government has published an unprecedented number of strategy and consultation documents relating to energy policy. Many of these proposals will have an impact on the oil and gas industry in the short to medium term. The upstream oil and gas industry is currently in the process of evolving to meet decarbonisation objectives and, going forward, oil and gas operations are likely to be associated with offshore hubs that may include clean hydrogen production, CCUS and/or offshore wind. Existing upstream infrastructure that is no longer required may be repurposed for use for transportation of carbon dioxide or hydrogen. The downstream gas sector will also be impacted, particularly if hydrogen trials prove that it is feasible to use hydrogen blending or pure hydrogen for heating. Reforms are also being currently developed in relation to system operation of the gas network. The Government and Ofgem published a consultation in July 2021 proposing the establishment of a new, independent entity – a Future Systems Operator – which would have system operation responsibilities across both the electricity and gas systems. One of the leading justifications for change, discussed in the consultation, is the fact that the transition to net-zero will require a much more integrated energy system and will increase the complexity of operational and planning challenges across both electricity and gas, and this in turn is likely to increase the synergies associated with fulfilling the technical roles needed to drive net zero in both the electricity and the gas systems.

Retail energy supply market failures

2021 saw a steep rise in global wholesale gas prices. This has created difficult market conditions for retail energy suppliers in Great Britain. This is particularly the case for domestic suppliers, because domestic suppliers are subject to a cap on the tariff price that they can charge their domestic customers for gas and electricity. The cap was introduced by the Government under the Domestic Gas and Electricity (Tariff Cap) Act 2018 and it was intended to protect customers who were subject to standard variable and default electricity and gas tariffs. However, the rise in gas prices (an associated rise in electricity prices) has meant that suppliers are paying more for wholesale gas and electricity than they can pass on to their domestic customers. This has resulted in a large number of smaller suppliers becoming insolvent. In November 2021, Ofgem published consultation proposals to reform the methodology used to calculate the tariff cap to better reflect the costs of energy suppliers in the current market.

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Michael Burns is a partner in Ashurst's corporate practice and Ashurst's global co-head of energy, based in London. Michael specialises in M&A, joint ventures and major project development with a focus on the energy and infrastructure sectors. He leads Ashurst's energy and infrastructure M&A business in EMEA. Michael's clients include multinational corporates, financial institutions, governments and high-net-worth individuals.

Ashurst LLP
London Fruit & Wool Exchange
1 Duval Square
London E1 6PW
United Kingdom

Tel: +44 20 7859 2089
Fax: +44 20 7638 1112
Email: michael.burns@ashurst.com
URL: www.ashurst.com

Julia Derrick is a partner in Ashurst's energy and resources team based in London and has a broad range of experience in corporate and commercial matters, with a particular focus on the upstream and midstream oil and gas sectors. Her experience includes advising clients on acquisitions and disposals of upstream oil and gas assets, development of upstream and midstream oil and gas projects (including LNG liquefaction and regasification projects), and sales arrangements for oil, gas and LNG.

Ashurst LLP
London Fruit & Wool Exchange
1 Duval Square
London E1 6PW
United Kingdom

Tel: +44 20 7859 1117
Fax: +44 20 7638 1112
Email: julia.derrick@ashurst.com
URL: www.ashurst.com

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