

Shale: A guide to tailoring legislation, SPAs, farm-in agreements and JOAs in developing basins

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Aim and Structure of Paper

Aim

This paper aims to provide governments, developers and investors with: an understanding of current regulatory and contractual practice in the UK and elsewhere; and a perspective on: (a) regulatory changes; and (b) contractual arrangements needed, to facilitate new unconventional developments in unconventional basins.

Structure

This paper is structured so as to analyse the UK experience before applying it, and other lessons learned globally, as follows:

United Kingdom:

- UK - the story so far; and UK - next steps.

Global application:

- Unconventional developments - characteristics;
- Licence / concession issues (including a UK case study);
- Sale and purchase / farm-in issues; and
- Joint operating agreements.

Executive Summary

The United Kingdom (UK) Government, with broadly cross-party political support, was quick to seize the initiative in promoting the

development of unconventional gas developments. Such initiative was quickly followed by a number of high profile (albeit limited scale) investments in early stage shale developments in the UK, perhaps most notably by the French major, Total. Other developing unconventional gas regimes will, therefore, be interested to learn what, if anything, governments can do to attract a limited pool of international petroleum investors to their fledgling unconventional developments.

Learning from the UK example thus far in summary is:

- early political alignment may attract investor interest;
- clarification on an existing regulatory approach gives some investor certainty, and may be sufficient for initial investment by some;
- detailed amendments to regulation or other enhancements of the governance framework may be required to attract more substantive investments and lead to significant drilling activity; and

where amendments are not made, and in any event, investors may make do with risk allocation in joint venture and other arrangements, where relevant.

United Kingdom – the story so far

A strong offshore industry base from which to build

The UK's offshore oil and gas industry is mature, approaching late life and decommissioning in a number of instances, and has long been a source of national wealth, fuel security and employment. Many UK-based oil and gas service companies now export their expertise gained in the North Sea around the world.

Indeed the UK also has an active conventional onshore oil and gas exploration industry, albeit significantly smaller than the offshore, including the substantial Wytch Farm field in Dorset, developed by BP. Indeed, onshore:

"In the UK today, there are 120 sites with 250 operating wells producing between 20,000 and 25,000 barrels of oil equivalent a day,"

according to the UK Onshore Operators Group.

Significant shale resources onshore but uncertain economic recovery
Scientists from the British Geological Survey (BGS) estimated (in a Government-commissioned report published in July 2013) that the total volume of gas in place (GIP) in the Bowland-Hodder shale in northern



England is some 1300 trillion cubic feet (central estimate). This large volume of gas “resource” potential comes with a health warning, as being distinct from “reserves” that can “technically and economically be expected to be produced” from a geological formation. A paper published by the UK Department for Energy and Climate Change in July 2013, called “Resources vs Reserves”, goes on to note that:

“DECC does not consider that there is sufficient understanding of the geology, or experience of the engineering costs or production to make a reliable estimate of the Bowland-Hodder shale gas reserves at this stage. Estimates of reserves will develop and improve with increasing exploration drilling in the years ahead.”

Lord Browne, the former chief executive of BP, now chairman of UK shale gas developer Cuadrilla Resources, perhaps effectively summed up the UK’s prospects of being able to economically “unlock” UK shale, when he spoke at a shale event in 2013, where he described UK shale as:

“Something that could be, but I’ve no idea as to whether it will be”.

One of the interesting characteristics of UK shale resource is the substantially greater thickness of UK shales (for example, in comparison to many of the shale plays in the USA). This means that drilling multiple horizontal wells from a single well-

pad may be particularly attractive (and given high population densities in the UK which may prohibit sprawling developments). This also presents interesting challenges to the commercial energy lawyer wishing to adequately document multi-horizon drilling programmes for example, as discussed in further detail later in this paper.

Irrespective of the characteristics and uncertainty of the ability to economically “unlock” shale and other unconventional resources (such as coal bed and coal mine methane) in the UK, a number of larger oil and gas companies (like Total, GDF Suez and Centrica) have now purchased interests in existing shale developers or plays in the UK. An increasing number of less well-known developers are also active in the sector (including Coastal Oil and Gas, Celtique Energy, Dart Energy, Eden Energy, Egdon Resources and IGas Energy), some of whom have led the way in what was previously considered a niche area in the UK. Most recently, the UK has seen the beginnings of a consolidation in the market, with IGas buying Australian-listed Dart Energy; and Egdon Resources exchanging licence interests for shares, with Alkane Resources. Whilst some will simply regard the larger players’ investments as modest early stage options to participate, they can also be seen as significant success indicators in the pursuit of the UK’s appraisal phase of its potential unconventional oil and gas development industry. It should, however, be noted that such

early stage investments are yet to be translated into applications for unconventional drilling permits in the UK.

[Public opposition was widely reported](#)

The success in attracting a number of early investments into unconventional developments onshore in the UK was all the more significant, given widespread reporting of two minor earthquakes in 2011 associated with Cuadrilla’s drilling programme, said to be caused by hydraulic fracturing (fracking), and popular protest against fracking, perhaps most graphically pictured around Cuadrilla’s operations in the village of Balcombe during the summer of 2013. Protest initiatives (misconceived or otherwise) such as the acquisition of “ransom” strips of land, designed to strand shale developments, were also mooted.

Although efforts have been made by both Government and the industry to “win hearts and minds” over to the cause of unconventional gas (see further below), it is not yet clear whether the industry can yet be sure of having won what is sometimes referred to as a “social licence” (as distinct from any official permission) in the UK. There remain two vigorous strands of opposition to shale gas exploitation in the UK. The first is mostly made up of people worried about the environmental impacts of the industry on their local area (in terms of everything from earthquakes and traffic movements to water contamination and house prices). The second is a less localised group made up, in general, of en-

environmental NGOs and others who perhaps take the view that, more or less, all additional exploitation of hydrocarbons, and any move which they see as potentially displacing lower carbon means of generating electricity, is to be resisted on principle. UK administrative law gives both groups considerable scope to delay the progress of shale developments by challenging official decisions to allow them to proceed.

There is no doubt that public opinion is something that any Government will have to manage in seeking to encourage unconventional gas development. However, the absence of certain English cultural sensibilities regarding the countryside, the interplay with other ongoing UK-specific energy policy debates, and various idiosyncrasies of UK law may mean that this is a slightly more straightforward task for Government to undertake in other jurisdictions.

The UK Government was pro-active in its intervention

Cuadrilla's seismic incidents led it to postpone fracking in Lancashire and saw the UK Government suspend such activity across the UK. After a year of research (including the recommendations of an independent report), the Government then concluded that the seismic risks associated with fracking can be managed effectively with suitable controls, and accordingly lifted the fracking moratorium at the end of 2012.

At the time, the Secretary of State for Energy and Climate Change (SoS) noted:

"Shale gas represents a promising new potential energy resource for the UK. It could contribute significantly to our energy security, reducing our reliance on imported gas, as we move to a low carbon economy... We are still in the very early stages of shale gas exploration in the UK and it is likely to develop slowly. We are strengthening the stringent regime already in place with new controls around seismic risks. And as the

industry develops we will remain vigilant to all emerging evidence to ensure fracking is safe and the local environment is protected."

The Government was then quick to pre-empt and head off public and other potential objections to unconventional development, by first issuing guidance in relation to the most visceral focus for public objection (i.e. fracking), and then embarking on a series of publications which aggregated access to existing onshore oil and gas regulation, to explain how the various activities comprised in a shale gas development are regulated under the existing planning, petroleum, HSE and other regulatory regimes. Certain potential gaps in regulation were identified, and thereby possibly highlighted until further investigation concluded that the relevant issues were adequately addressed by existing legislation

The UK's offshore oil and gas industry is mature.

(for example, a report was produced on greenhouse gas emissions from shale development). This may have helped to further take the sting out of potential objections, and give comfort that the sufficiency of existing regulation was being approached in a thorough manner.

The SoS also announced in 2012 the creation of a new Office for Unconventional Gas and Oil (OUGO) to oversee the regulation of the unconventional development industry in the UK, although it should be noted that OUGO is not a new regulator, but simply a sub-division or department within the SoS's licensing authority, the Department for Energy and Climate Change (DECC). It may also be noted that most have, so far, focused on unconventional gas (rather than oil) development (although in May 2014,

DECC published a British Geological Survey study of the Weald Basin in southern England, which estimates oil resources of 2.2-8.5 billion barrels of oil, but implies much may be in non-commercially recoverable oil shale). This general focus on gas so far, perhaps relevant in the context of US experience, where many shale gas reservoirs (like the Barnett Shale) were found to contain oil windows or rich gas (generating natural gas liquids), which was not originally anticipated.

The creation of OUGO did, however, perhaps indicate a perception of a need for a regulatory "one-stop shop" to help coordinate regulatory responses amongst the relatively numerous regulatory bodies onshore, who were perhaps perceived to lack the regulatory unity or coordination of the offshore industry. It is not clear whether OUGO sees itself as carrying out this function at an operational, as opposed to a policy level. There is also a risk that as the Government moves to establish a much more powerful and well-resourced regulator to take over responsibility for administering the licensing of the UK's offshore oil and gas industry, with a clear mission to "maximise economic recovery" from the UK's Continental Shelf, the more complex and less institutionally focused on-shore approvals regime may suffer by comparison with the new offshore arrangements.

It should be remembered that the UK oil and gas industry already has mature systems of regulatory and commercial governance, and environmental regulation. Broadly speaking, these already provided a means of dealing with issues raised by unconventional gas plays. Hence the UK's decision to highlight existing legislation coverage in general, rather than to embark on more organic reform.

The UK Government supported the industry body

Whilst OUGO, DECC and Government initiatives were quick to fill any perceived regulatory vacuum, so too was the Government prompt

to suggest support for the recently reinvigorated onshore oil and gas industry body, the UK Onshore Operators' Group (**UKOOG**). It would be perhaps a longer-term benefit to the Government, to focus liaison with the unconventional developer community at large, via a single, enfranchised industry body (as is for example the case with the offshore oil and gas industry in the UK, which is substantially focused through the successful Oil and Gas UK), rather than with individual developers, where a group response or consultation is required.

The Government has encouraged UKOOG's efforts at self-regulation. These have included the publication (in February 2013) of guidance on best practice for shale well operation, and (in June 2013) of a Community Engagement Charter (Charter), which recommends payments of:

- £100,000 per well site where fracking takes place; and
- at the production stage, 1% of revenues,

of which, approximately two thirds is intended to benefit local communities directly and approximately one third is intended to benefit communities at a county (i.e. more regional) level.

Whilst the US has not generally had similar community benefit initiatives, it is interesting to note that in the US, local ad valorem taxes are sometimes used to provide relief for road repairs etc. occasioned by the influx of heavy vehicles.

The Charter represents a recognition on the part of the industry of the need to provide some sort of direct financial benefit to communities affected by shale gas developments. It remains to be seen how this can be done most effectively and equitably, and (where local authorities are involved) without tainting the process of determining whether to grant planning permissions for

developments. It is submitted that Community Interest Companies (**CICs**) may be a useful tool in this context. CICs, were established in 2005 to address the previous lack of an "off-the-shelf" legal vehicle for non-charitable social enterprises in the UK, have been used successfully in making payments to communities impacted by wind developments, for example. One benefit of CICs (from a shale developer's perspective) is that once it can be demonstrated that CIC activities are carried on for the benefit of a community or a section of a community, the CIC should have significant flexibility in determining how funds received from a developer (which are otherwise "locked" assets under CIC rules) are to be allocated. This could be significant, as developers and others may be keen to minimise the time spent having to engage with individual community members.

[The UK Government announced fiscal incentives](#)

The Government then promoted early stage investment in unconventional appraisal and development, by announcing in the UK Chancellor of the Exchequer's Autumn Statement of 2013, a new tax regime for onshore oil and gas developments (so called "well-pad" tax allowances). Although, in practice, these will apply to all onshore developments, not just unconventional developments, the UK Chancellor announced that these would be:

"the most competitive in Europe" and having "an effective tax rate for shale gas projects lower than in the US".

Legislation was introduced in the Finance Act 2014 (which should take effect in the summer of 2014) to amend the UK Corporation Tax Act 2010's imposition of a "supplementary charge", with a new onshore well-pad allowance, which should remove 75% of capital expenditure incurred by a company in relation to an onshore oil and gas development site, from its adjusted



ring-fence profits which are subject to the supplementary charge, subject to certain capacity limits (for production yield).

This will affect capital expenditure incurred from 5 December 2013 on an onshore oil and gas related activity, and should in general see UK onshore shale company profits taxed at 30% rather than the previous 62%. Therefore, in a development costing £100 million, a company may be eligible for the reduced 30% rate for its first £75 million of taxable profit, a saving of £24 million.

Oil and gas developers are already also eligible for full tax relief on relevant capital expenditure, which may be offset against UK oil and gas profits made onshore or offshore, to reduce taxable profits. Amendments are also proposed to increase capital expenditure depreciation periods in the relevant oil and gas ring-fence from six to ten accounting periods, to reflect the longer time often taken to reach profitable production in unconventional developments.

It may be noted that contractual decommissioning deeds have recently been offered by the UK Government to the offshore oil and gas industry, to guarantee current tax treatment (tax deductibility of decommissioning costs) in the future. This was implemented to reduce the risk of future governments removing such relief, and thus creates greater certainty and aims to reduce commercial decommissioning security provisioning amounts substantially. It is suggested by

some commentators that there may be scope in the future to extend such decommissioning deeds to onshore oil and gas developments (where decommissioning costs are generally much lower). However, such argument may tend to encourage the imposition of the wider offshore decommissioning regime to the onshore, which is likely to be unwelcome amongst developers, as it includes an infamous ability to “claw back” unpaid decommissioning costs from previous licensees and others, in the event that those now responsible fail to pay.

[The UK Government continued publishing information](#)

Most recently (April 2014) DECC published a series of documents providing guidance to frequently asked questions about shale oil and gas, and fracking:

- Facts about fracking;
- **Fracking UK shale:** climate change;
- **Fracking UK shale:** planning permission and communities;
- **Fracking UK shale:** regulation and monitoring;
- **Fracking UK shale:** safety from design to decommissioning;
- **Fracking UK shale:** understanding earthquake risk;
- **Fracking UK shale:** water; and
- Background note on shale gas and hydraulic fracturing.

Whilst none of these publications is particularly detailed, they do provide a relatively comprehensive base of headings from which to engage public opinion.

In the meantime, politicians have continued to publicly highlight the potential benefit of UK development of unconventional. The SoS reiterated the potential role of UK shale gas in hedging security of supply concerns in the context of the Russia/Ukraine conflict, as recently as May 2014.

[These initiatives gained wide stakeholder engagement](#)

Well-pad allowances onshore, regulatory coordination and the perceived relatively low political risk of the UK, have not only attracted inward foreign investment as highlighted earlier, but have also seen domestic investors, landowners and others who are keen to benefit from unconventional developments, show significant interest. Certain local authority councils have, for example, tendered for the provision of shale development services to drill potentially on council land. Such developments could benefit from a perceived ability to garner local support (or at least dissipate local objection), where a community is able to see development revenues more directly benefiting the locality, via a local authority's equity interest. Indeed the Government also now intends to allow local councils to keep business rates generated from unconventional development revenues within their localities.

The involvement of local councils in development and in receiving benefit from unconventional developments could, however, give rise to potential conflicts of interest (as they may be the same authorities which are involved in making planning consent decisions for unconventional developments). In order to overcome restrictions designed to prevent potential conflicts of interest, there may be an increasing incentive to use structures such as community interest companies, as referred to earlier (and even perhaps alliancing arrangements).

[The UK Government now plans new legislation to remove remaining road blocks](#)

Whilst the UK Government's explanation as to how shale gas and other unconventional developments would be facilitated under existing legislation, developers and protest groups have highlighted land access rights (and trespass laws in particular) as being an impediment

to development. Because it is not lawful to drill horizontally underneath land without the owner's permission, developers may need to seek the consent of a wide range of landowners, and owners of strategic plots may “hold out” so as to frustrate or slow down developers' plans (see further below). Whilst there is already a lengthy, costly and uncertain legal mechanism for obtaining land access rights compulsorily through the courts in situations where agreement may not be reached with a landowner, UK Government sources have indicated (according to reports in the Financial Times and the BBC) that it may propose new legislation in the Queen's Speech on 4 June 2014 (to be implemented thereafter), as part of an Infrastructure Bill, which may provide automatic access rights for shale development. Indeed, DECC published a “Consultation on Proposal for Underground Access for the Extraction of Gas, Oil or Geothermal”, on 23 May 2014, in which it proposes a new statutory right of access to companies extracting petroleum (or geothermal energy) in land at least 300 metres below the surface. This would involve a £20,000 one-off payment (which amount is volunteered by the industry) for each “unique” lateral well longer than 200 metres (meaning a horizontal plane of pipelines at the same depth would only attract one payment). DECC's preference is that payments would be made to a relevant community body rather than individual landowners. A public landowner (and presumably community-based) notification system would be established, again based on the same industry voluntary “agreement” (but with a legislative enforcement right where voluntary regulation is not honoured).

Regulation can however be a blunt instrument, capable of being overcome by invention. In the US for example, operators have developed the flexible drilling

techniques necessary to avoid land owned by those unwilling to negotiate sub-surface access rights, even at great depths. Regulation has gone further, by imposing requirements to maintain a certain distance from unleased tracts of land. Development under the DFW Airport is a good case in point, it has seen the operator drill directionally in flowing curves, avoiding unleased land, and in compliance with Government “set back” requirements, whereby a well cannot be located closer than 100-142 metres from the outside boundary of an unleased tract.

United Kingdom – next steps

New licensing round in 2014

The UK’s last onshore oil and gas licensing round, the 13th licence round, was in 2008, and saw 60 applications for 182 blocks by 54 companies, 20 of which were for coal bed methane, and which resulted in 93 licences being offered. A 14th licensing round is planned for 2014, with areas for licensing expected to coincide with those areas identified by the Government-commissioned reports as having unconventional resources available.

The precise licence areas and terms of the expected 14th round licences are a matter for speculation, but DECC published a consultation (which closed on 28 March 2014) on its Environmental Report for its proposals for further onshore oil and gas licensing, as part of the required strategic environmental assessment process, and a precursor to the perhaps likely subsequent licensing round (without pre-empting the decision-making process, the report states that the option of awarding no licences in the 14th round is “incompatible with the main objectives” of the Government’s plan, and is therefore perhaps unlikely).

Existing licence terms require amendment for shale

As noted further below, the existing licence terms that DECC uses for onshore licences were drawn up

to suit the context of conventional developments and are not always a good fit for the unconventional context. If this lack of differentiation between conventional and unconventional licences persists, it may be problematic because it gives rise to potential uncertainties (requiring regulators and developers to have to rely on an informal understanding or expectation as to the application (or not) of the strict letter of the law) and, at worst, the possibility of legal challenge by protest or other groups. As such, it is regarded by an increasing number of developers as an unnecessary risk which they may like to be mitigated by regulatory intervention.

Parallels may be drawn from the UK when analysing international regimes

An analysis of current onshore UK Petroleum Exploration and Development Licences (PEDLs) highlights a number of areas ripe for amendment (in order to better accommodate horizontal drilling, hydraulic fracturing and other features of unconventional developments), and as such provides a useful comparison with other developing shale jurisdictions, where a licence, or indeed as it is suggested, production sharing or service-contract based concessions, will be equally likely to require specific adaptation.

Unconventional developments – characteristics

In order to analyse whether PEDLs are fit for the purpose of facilitating assured unconventional developments, it is necessary to first set the scene with a basic understanding of the differences between unconventional and conventional developments, and more specifically in the context of shale developments.

Horizontal drilling / hydraulic fracturing

Horizontal drilling may be used to follow horizontal strata of shale to increase a well’s productive area or “pay zone,” which may lead to

horizontal wells crossing different surface land boundaries, which can create issues, as could the inability of a legal regime to differentiate between hydrocarbon deposits at different depths.

Surface rights issue

It is an oddity that in the UK, on the one hand, private landowners have no entitlement to hydrocarbons under their land, but on the other hand, developers are obliged to seek (and ultimately pay for) their consent to drill under their land - even at depths of several kilometres. Under UK law, mineral rights are vested in the Crown, and thus the right to explore for hydrocarbons over a given area of land (which is likely owned by a separate landowner) is granted by the licensing authority, the SoS via DECC. But a licensee who seeks to rely merely on the licence when it drills under a private landowner’s land is likely to be found to have committed an unlawful act (trespass). As a result landowners (particularly if they are opposed to a development in principle) may be in a position to extract a high price for their consent for horizontal drilling, for example, under threat of legal action seeking a court order to cease drilling or pay damages. Developers have been made nervous, and potential landowner-protestors emboldened, by the case of *Bocardo SA v Star Energy* [2010] UKSC 35, in which admittedly the Court did not grant an injunction in respect of a horizontal well drilled without consent, but did award nominal damages.

The lack of any automatic entitlement of landowners to receive a royalty or other financial incentive from hydrocarbons produced from under their land makes their consent harder to obtain. If a landowner therefore fails to agree commercial compensation with a developer for land access rights such as for horizontal drilling, a developer may seek compulsory access rights and establish landowner’s compensation under a procedure set out in the Mines (Working Facilities and



Support) Act 1966. Some have doubted whether this process can be used effectively (or at all) in the unconventional gas context. It involves application to the relevant Secretary of State and then referral to the High Court, at significant delay and administrative cost, which is likely to be a substantial disincentive to developers, not to mention the potential for judicial review in relation to the Secretary of State's referral.

Potential residual liability by a landowner for pollution caused by a developer or site remediation upon decommissioning (in the event of a developer's insolvency or failure to remediate, for example) may increasingly lead UK landowners to also seek security provision from developers before voluntarily providing land access consent, however remote such eventuality may appear.

It is for these reasons that any simplified process of access to land rights, such as those referred to above and expected to be announced in the Queen's Speech on 4 June 2014, will likely be welcomed by developers.

The creativity or otherwise, of the solution adopted, will be interesting to see. Whilst UK landowners are very unlikely to be given a route to sharing profits derived from mineral rights, a novel, perhaps analogous, approach was taken in the US state of Texas, with respect to "Relinquishment Act" land. In this case, the State government developed a concept of allowing a surface owner to enter

into oil and gas leases for the State, and then the State agreed to split earnings with the surface owner.

[Different depths](#)

It is submitted that, particularly where shale deposits are deep, developers may, over time, wish to explore for or develop hydrocarbon deposits which sit beneath or above conventional hydrocarbon fields, or indeed licensing authorities may wish to encourage exploitation at differing depths. Whilst licensed blocks have been split in some jurisdictions over time, on a case by case basis, licensing authorities have not generally designed licensed areas to allow horizon splits, particularly given the technical and commercial challenges of allocating the risks and rewards of developing one depth at the potential expense of another. It is submitted that the ability to split horizons in the future, particularly in deep shale such as in the UK, where land is relatively scarce, should be considered by licensing authorities in the context of horizon splits successfully implemented in other jurisdictions.

Whilst horizon splits have occurred in various jurisdictions in a conventional context, it is conceded that facilitating this in specifically unconventional contexts appears novel.

US practice for example, has not generally addressed the issue, and indeed highlights the issue not as a regulatory opportunity and challenge, but more as a potential operational obligation. Indeed some writers have noted that the

failure to develop all portions of a productive shale, may trigger an implied obligation of the lessee or operator to develop all parts of a shale (including at differing depths), but which is currently far from viable.

Indeed, many mineral owners in the US have their oil and gas leases draughted to require the release of the lease, below the deepest depth from which production is established, after a certain time (following execution of the lease). In response, operators have taken to stacked drilling (being the drilling of parallel, vertical well-bores, each going to different "kick-off" depth). In other instances, operators have farmed-out of undeveloped horizons.

As with conventional resource farm-outs or sales of deeper horizons (which have indeed been facilitated by some regulators), when analysed thoroughly, a robust allocation of potential resource damage, pollution liability and other implications of drilling through another party's shallower resources to get to deeper resources, provides much to interest the legal draughtsperson.

[High initial production profile / steeper decline curves](#)

Although shale developments as a whole may typically lack the same high level of geological uncertainty that is evident in conventional exploration, the first shale developments in any newly exploited area do typically require an ongoing and therefore expensive drilling campaign in order to learn the commercially viable technique

to “unlock” production from a known resource, and to prolong and continue such production. Learning how to unlock a particular shale resource is an iterative process: what works in the Marcellus Shale in the US, may not work in the Baltic Basin in Poland or the Bowland Shale in the UK. This is clearly distinct from conventional developments where relatively modest seismic and exploratory techniques precede substantive drilling costs and whereupon, once sufficient hydrocarbons are discovered, commercial production may be established from a single reservoir with one or few wells. The need to drill continuously in order to fully exploit a shale resource is more like a manufacturing process, with a need to develop an efficient process.

To put it another way, drilling costs are generally higher per well than for conventional plays (as each well drains only its own fractures), and generally require an on-going drilling campaign to fully exploit a resource and to maintain production, rather than a conventional play in which hydrocarbons tend to flow automatically under pressure, once struck.

Experience is key

As such, developers may need prolonged concession rights over a large area and, given the iterative process of developing the drilling, completion and production techniques and know-how necessary to be commercially viable, the experience of a shale operator is of much importance, and invariably the result of trial and indeed error. It is also important to remember that all shale plays are different, and may not all be productive.

In the US for example, there is much variation in shale characteristics. There can be certain geological risk, as in the Haynesville Shale, on the Texas and Louisiana border, where only portions of the resource are commercially productive.

However, in the Barnett Shale around Fort Worth, Texas, the resource contains “sweet spots” which are as much as 50% more productive than the balance of the blanket shale. The Barnett Shale has another interesting geological factor in that the productive areas are underlain by the Viola Limestone, which protects the Barnett from water encroachments from the deeper Mississippian formation.

One substantial engineering exercise in each shale is considering how far apart to put the fracturing stages within each well-bore, and then considering how far apart to put the well-bores, so that the fractures barely touch the adjacent fracture, and so that no unbroken areas remain (to maximise recovery). It is interesting to note that in the US fractures have been found to propagate through the weakest rock (usually the rock with the most hydrocarbons), often for around 100+ meters from the point at which the fracturing fluid is injected.

Environmental and other factors

Environmental factors, in the broader sense, are of course critical. For example, the density and proximity of buildings and the natural environment may preclude meaningful seismic studies. The environmental footprint of a shale development is such that one well-pad may host multiple well bores.

Whilst environmental concerns and protections aimed at preventing the ingress of fracking chemicals (such as biocides, hydrochloric acid, proppants etc.) into water courses is well-known, less publicised concerns such as the potential for methane release from potentially tectonically fractured plays, such as in the UK, may gain greater focus.

Whilst much research is ongoing to try to develop “dry” fracking techniques, at present, the ability to source significant quantities of water, by road tanker or otherwise, and to store, recycle, treat and dispose of

waste water, remains central to shale developments.

Gas export infrastructure (and compulsory or other arrangements for third party access to existing infrastructure) will clearly be needed for commercial off-take of production and, unlike a conventional exploration phase, an unconventional appraisal of commercial production rates and sustainability may involve earlier and more prolonged gas and other disposal issues. Gas flaring for test quantities before a pipeline is built will need regulatory consent, and it may be noted that in a number of jurisdictions, gas flaring is not in general permitted (including in the US for example, except in connection with oil production).

Licence / concession issues

Given the backdrop of the above characteristics of unconventional developments, it makes sense to now consider (in generic and jurisdictionally non-specific terms) the extent to which existing licence or concession terms are fit for purpose in terms of giving developers comfort that they have a robust licensing regime in which to frame their investments and to pursue unconventional developments. Similarly, governments may become increasingly concerned to ensure that developers have not only sufficient funding for ongoing drilling campaigns (necessary to maintain cash-flow), but also have sufficient technical capabilities for a specifically unconventional development.

Fiscal terms

Indeed fiscal terms may need to be more favourable to recognise that shale plays are often considered to be higher risk, similar to frontier areas. Idiosyncrasies generated by evolved taxation, cost recovery and other fiscal calculations may need to be tailored. Ring-fencing by “field” in the classic sense may clearly be inappropriate for a shale play, for example.

Exploration and development versus pilot and production periods

Traditional production sharing contracts provide a developer (i.e. a “contractor”) with a relatively short exploration period in which to make a commercial discovery, followed by a longer development and production period. By contrast, a shale development will typically be assessing a known resource for quality, area focus and economic development processes. Whilst a pilot or appraisal period may

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be relatively short, a longer period (up to 50 years in some cases) may be needed to drill the number of wells required. The typical conventional concept of relinquishment of acreage unused during an exploration period does not therefore sit well in an unconventional context. Relinquishment may therefore need to be more limited or perhaps deferred or voluntary.

Work commitments

Typical work commitments focused around seismic and well commitments in the conventional sense will likely need tailoring to the unconventional circumstance as will other definitions. Operations, which function more like a manufacturing process rather than discrete steps, may suit multi-year work programmes and budgets rather than a development plan as such.

One approach from the US which may be adapted by regulators struggling to form a view on

work commitments (and indeed relinquishment-related issues) for example, is allowing a large block to be held so long as the operator maintains a “continuous drilling programme”, meaning that a new well must be started within, say, 180 days of completion of the prior well. A failure to meet the drilling deadline, typically results in the loss of all acreage outside the acreage attributable to the existing wells. This, in turn, relies on attributing the appropriate area to each well. The Texas Railroad Commission, for example, has set out a required number of acres (20 or 40), and then allows an additional 20 or 40 acres for each additional 584 or 826 feet, respectively, of lateral length of well-bore. In turn, many private lessors (wishing to encourage drilling and hence revenue) incorporate these limits into their commercial arrangements with operators, so as to describe the acreage that may be retained by each well-bore, at the termination of a lease, for managing a failure to continue drilling.

Commercial discovery

Indeed the concept of a “commercial discovery” is typically defined with reference to a natural gas field. As shale and coal gas do not accumulate in conventional fields, a different definition will likely be needed, which recognises the iterative nature of a project becoming commercial in the unconventional context.

This is of course relevant because the contractor is often exposed to geological and exploration risk on its own (subject to joint venture arrangements) until a commercial discovery is announced and production commences. From that point on, cost recovery and profit hydrocarbons are often shared with a host state (and any carry period typically ends and any back-in right typically commences), meaning the state is exposed to a share of production costs, only once valuable commercial production commences.

It is suggested that in the situation of a conventional development which is highly capital intensive from an earlier phase, states should be exposed to such risks earlier on, before “commercial” production commences, particularly in situations where pre-commercial gas produced may not be sold by a contractor. This funding tension may be particularly acute in the case of national oil company participation funding where typical carry arrangements may be insufficient.

If the contractor is to be left bearing development risk until an agreed stage of commercial production is reached, then the existing production sharing agreement may not allow the sale of pre-commercial production gas. This may be a substantial problem where it is necessary to flow gas from a number of wells over a protracted period (for example, to establish commerciality), which could encourage greater flaring and could make it uneconomic for a developer to move from a pilot phase into production. It is understood that this issue has been partially addressed in Indonesian coal bed methane production sharing contracts, for example, by allowing pre-commercial production gas to be sold (albeit on terms which share revenue with the state).

Once commercial viability is established, a field development plan must generally be submitted. Only fields within the plan are likely to be eligible for cost recovery against production, so contractors must choose whether to expose capital to a small or larger scale operation at a time when there is much commerciality uncertainty remaining. The option of submitting a later plan revision to expand an area risks the host state increasing the economic rent payable for such area following initial success. As ever, having a transparent licensing process and policy which gives developers certainty remains key.

Transfers

Given that the importance of a shale operator's experience in "unlocking" the commercial viability of shale production in a given area remains key, licensing authorities may wish to ensure sufficient technical capability of a replacement operator in unconventional development, together with comfort that valuable know-how, staffing and intellectual property remain following a transfer, to avoid having to "re-invent the wheel". Regulators may also wish to consider to what extent such know-how is required to be shared with the regulator and potentially disseminated more widely to adjacent blocks and, if so, when.

Water and infrastructure

Access to water abstraction and any existing gas infrastructure will naturally need specific consideration where not provided for already by separate arrangement.

Licence regime case study

Whilst the above issues are pertinent to many production sharing regimes, licence regimes also have comparative issues. Indeed regulators in all jurisdictions may be mindful of not wishing to draw investment into their unconventional resource developments at the expense of later-life or other conventional plays, particularly as conventional developers in a jurisdiction also start to enter the unconventional market.

As such, and for reasons of administrative ease also, it is suggested that the UK regulator, DECC, may be keen to avoid a two tier system which differentiates between conventional and unconventional developments if possible, particularly given the different approaches already applying onshore versus off-shore (e.g. in relation to decommissioning treatment). That said, there is a contrary argument to suggest, given the substantial depth of shale resources in the UK, that provision should be more formally made to allow conventional and

unconventional developments to proceed over the same land footprint at differing depths or horizons, in order to better use mineral resources.

However, it is perhaps worth considering some examples of the latest (2008) UK onshore PEDL and associated model terms set out in legislation (Model), in order to highlight areas which would perhaps suit amendment in the unconventional context:

- Mandatory relinquishment of 50% of the licence area at the end of the initial term of six years is clearly sub-optimal for a shale developer needing certainty over an area throughout a drilling campaign (although relinquishment may



be avoided on a bespoke basis where the regulator considers it necessary to recover petroleum, under Model clause 4(5)).

- The second term in a PEDL is currently five years, with a distinct 20 year production period thereafter. Similarly, this separation does not lend itself well to a pilot / appraisal phase (which is likely to include some production). Re-alignment along the lines of a dual appraisal phase followed by a commercial production phase may be more suitable.
- A typical work commitment for the initial term (e.g. drilling one typically vertical well and conducting seismic work) could do with tailoring to the unconventional situation, perhaps

to include ongoing development obligations after initial appraisal.

- Use of terms like "Oil Field" (which means strata forming part of a single geological petroleum structure, according to Model clause 23(1) which deals with unitisation), in the context of requirements to unitise, conduct petroleum measurement and elsewhere, could have unintended consequences if requiring compliance in the unconventional context.
- Whilst Model clause 27 treats data required to be provided by a licensee to DECC as confidential, clause 27(d) allows the relevant Minister, the relevant local council and others, to publish: "any of the specified data of a geological, scientific or technical kind" after as little as four years. Clearly this may be of concern to operators and other owners of sensitive intellectual property who are keen to keep such data confidential. There may be arguments to suggest that the nature of data necessary to "unlock" a shale, for example, should in fact be treated as proprietary and therefore be subject to greater confidentiality restrictions.
- Perhaps the most stark example of a licence term which may require amendment in the unconventional context, however, is Model clause 19(1)(d) under the heading "Avoidance of harmful methods of working", which requires licensees to: "prevent the entrance of water through Wells to Petroleum-bearing strata except for the purposes of secondary recovery..." Few would argue that water injection for hydraulic fracturing amounts only to secondary recovery, and therefore an amendment to remove any ambiguity would appear prudent.

Whilst the above examples happen to be gleaned from UK licensing

provisions, it is submitted that a similar analysis and identification of areas ripe for clarification or amendment may be conducted in the context of most existing licensing, production sharing, concession and other oil and gas regimes, which have not yet been specifically tailored to unconventional developments.

Sale and purchase / farm-in issues

Whilst there is a limit to the amount developers can do to lobby for regulatory changes to the licensing or concession regimes in most jurisdictions, developers often seek to reallocate or spread regulatory and other risks, either amongst a joint venture group or, if acquiring an interest after the initial grant, by some reallocation of risk as against a seller or farmor in the medium term (or at least by seeking certainty as to the acquisition of valuable intellectual property and other assets needed for preserving enduring value).

It is therefore worth considering the impact of the characteristics of an unconventional development on a sale and purchase or farm-in agreement, being the most typical secondary commercial arrangement under which a developer or investor will acquire its interests outside the initial licence or concession application process. There is a discussion of joint venture arrangements (typically via a joint operating or development or other contractual agreement) later in this paper.

Value

Establishing an accurate value for an unconventional play may in the first instance be more difficult than the relatively commoditised methods which are developed for valuing conventional reserves, which may for example be subject to an independent consultant's confirmation or opinion as to proven (P1) hydrocarbon reserves. Not so in a shale play for example, where reserves may be impacted by rock permeability, geo-mechanics, drilling and completion techniques.

Such interactions may mean that it is not possible to establish sufficient certainty as to reserve levels, unless production has commenced and a seller is able to evidence remaining resources in combination with a history of past performance with a given expenditure, drilling campaign and stimulation techniques adopted.

Whilst indemnity or warranty assurances for given resource levels are possible to mitigate such uncertainty, they are an imperfect way of trying to claw money back, after the (non) event.

Unconventional plays are therefore perhaps particularly suited to earn-in or "cash and carry" arrangements, whereby a shale developer shares burdensome drilling costs, for example, with an investor who is able to carry a developer's costs by way of its purchase price but may defer part payment until cash is needed for drilling phases. Clearly, there are a number of corporate and asset sale variations on this theme.

The scale and visibility of unconventional projects tends to magnify the significance and thus complexity of negotiating earn in arrangements.

Assets

Investors will be keen to ensure that they acquire everything necessary for successful production, ranging from concession rights, land access, planning permission, water access and disposal, together with any pipeline transportation rights.

Well logs, test data and intellectual property can be regarded as proprietary information by operators, meaning that transfer or access (and onward transfer rights can be an issue, together with transitional support and secondee-type arrangements. Retaining an operator's valuable know-how within a project's confines can be a significant driver in setting up a special purpose vehicle to act as operator (and can sometimes simplify future land right and

other transfer issues), but this will understandably tend to be resisted by operators.

Areas of mutual interest

Similarly, an investor may be reluctant to fund development where it risks seeing its investment in unlocking a shale leave with an operator or its staff to develop an adjacent block which has substantially the same geology. For this reason, area of mutual interest (AMI) protection will often be included somewhere within the suite of transfer, development or operational agreements to the effect that parties will not develop a defined acreage (and possibly stratigraphy) without the other(s), during a given period. AMI protection is often linked with a requirement to maintain alignment of interests throughout the AMI, and with pre-emption or preferential purchase rights upon a further sale or change of control, largely to protect against those who cannot meet funding or operational commitments. The interaction of AMIs and competition law, should also be considered in relevant jurisdictions.

Control

Another central focus for transfer agreements such as farm-ins (i.e. where an ongoing collaboration is to be established, rather than an outright sale) are control rights, largely over budgets, spending and procurement, not to mention protecting an investor's brand and reputation from damage, in the event its partner does not adhere to the same operational standards, potentially causing injury or damage to the environment.

Joint operating agreements

Understanding the existing JOA paradigm

Joint ventures in upstream oil and gas developments are generally conducted on the basis of holding contractual interests in unincorporated joint ventures, rather than for example by way of shareholdings in a company. This practice has evolved for a number of reasons:

- first, partners may prefer to be taxed individually on a “look through” basis, rather than being potentially subject to corporate taxes at the consortium level, in addition to individual taxation at the shareholder level;
- second, partners may wish to segregate liability and, under a typical unincorporated joint operating agreement (JOA), typically apportion joint liability (incurred under a licence or concession) severally, in proportion to respective interests held. A partner may separately wish to ring-fence certain of its exposure by holding its JOA interest via a corporate holding vehicle;
- third, JOAs have established commoditised provisions and principles over the years (such as the “no gain, no loss” principle of operatorship);
- fourth, assignment of interests is perhaps more easily facilitated under a JOA; and
- fifth (and arguably most importantly), such segregation allows separate off-take and marketing arrangements for hydrocarbons produced (and indeed may be commercially required in certain US tax mitigation scenarios).

Another relevant factor, when considering whether such unincorporated joint venture structures are also appropriate for unconventional developments, is simply that these have become common practice in the oil and gas industry and are well-understood.

Whilst such unincorporated structures are therefore likely also to be replicated for unconventional developments, it is submitted that this existing paradigm should at least be challenged thoughtfully, before adopting a JOA structure.

To take one example, land access, ownership and similar rights needed

for an onshore shale play in the UK may be numerous, making individual transfers of land interests cumbersome in the event of a change of partner. Whilst this issue is typically dealt with by requiring an operator to hold legal title to land as joint property of the partners and is not therefore typically an issue, if a partner (or its financier) is required to be named as a legal title owner for reasons of security, then the UK restriction of a maximum of four legal title owners may be a problem. Second, in the UK, trying to ring-fence via a corporate structure against residual liability for decommissioning obligations offshore is ineffective due to the regulator’s ability to “pierce the corporate veil”, although this may not necessarily be the case for an onshore unconventional project. Third, given the importance placed on proprietary intellectual property developed by the joint venture in “unlocking” a shale area, non-operating partners may be reluctant to allow such intellectual property to be held outside a corporate structure. Fourth, there is a practical argument to suggest that if developers wish to attract new investment from private equity investors (or perhaps even relevant local landowners, communities and businesses) who may be unfamiliar with, or less used to the existing paradigms of JOA structures, such investors may more comfortably and therefore readily invest in a corporate structure (governed by a more commonly understood shareholders’ agreement). It is noted that in Poland for example (where, under current legislation, there may be only one concession holder), corporate joint venture holding structures have an added imperative, if oil companies are to have direct interests in a concession in order to be able to “book” reserves from a hydrocarbon accounting perspective. This current position is expected to change with new legislation, to allow a JOA model/ more than one concession holder.

Tailoring JOAs for unconventional developments

Given that an unincorporated structure will still be appropriate in perhaps most unconventional joint venture contexts, it is worth noting that the tailoring and use of unconventional JOAs have evolved differently in all developed and developing jurisdictions, in order to take account of local conditions.

Perhaps surprisingly, given the relatively developed nature of US shale developments for example, a culture of drilling first and then back-filling documentation is prevalent. This approach (together with the great volume of US unconventional developments) means that a body of judicial precedent has evolved in the USA in particular, which means JOAs are becoming increasingly sophisticated as well as providing a useful knowledge-bank for the international JOA drafter, when trying to determine a comprehensive approach.

No one size fits all

What is clear is that no one JOA model fits all situations internationally. The Canadian Association of Petroleum Landmen and the American Association of Professional Landmen have developed differing approaches for adapting their conventional JOAs (not to mention state by state variations). The Association of International Petroleum Negotiators (**AIPN**) have established a drafting committee to tailor their conventional JOA for unconventional development. A number of Polish developments have independently tailored the AIPN form (which had the added complication of tailoring for a civil law jurisdiction). In the UK, where in conventional developments the Oil and Gas UK (**OGUK**) model JOA is typically used, both the AIPN and OGUK conventional standards have been tailored for use in the UK. Some oil companies have similarly developed their own or

hybrid forms. A number of areas of focus appear common to most and form the basis of the following observations.

Scope

When starting to tailor an unconventional JOA, scope will be an initial consideration, i.e. whether an upstream development and production project is intended to include development of midstream transportation or processing infrastructure.

As with licence and concession tailoring, a conventional JOA will need amending for the different pilot / appraisal and commercial development phases of the project and will require amending for horizontal drilling and other criteria.

Several definitions from “commercial discovery” to “well” to “well deepening” and various others will likely need amendment. The variation of possibilities and sometimes judicially guided definition of terms are subject to significant variation in differing US states alone.

Multi-year work programmes and budgets may be required, as may inserting limits on an operator’s withdrawal rights (and those of other funding partners) during potentially longer initial periods than is typical under conventional JOAs. Liability of withdrawing parties upon withdrawal also requires consideration. Allowing a party to withdraw from a JOA in a conventional context (following completion of agreed work programmes) is somewhat self-regulating, in that a party which has paid its share of capital expenditure during the expensive exploration phase is more likely to be able to secure funding for development and is incentivised to remain in the venture until production cash flow is achieved. By comparison, a shale development, for example, requires an early and ongoing capital intensive drilling programme to commence and maintain cash flow.

Confidentiality and restrictions on using know-how on adjacent developments may be of heightened importance, together with a number of other locally tailored considerations which justify a thesis in and of themselves.

Perhaps the most commercially challenging and complex area to draft in an unconventional JOA relates to sole risk, non-consent and reinstatement provisions.

Conventional JOAs often allow a party to conduct operations in the joint venture area at its own sole risk, where other partners do not wish to participate. Such sole risk operations are relatively easily incorporated in conventional plays of few wells, high pressure reserves and large field discoveries, but less so in unconventional developments where the inverse is typically the case. In addition, the iterative nature of developing the techniques necessary to unlock a shale area does not lend itself well to allowing an operator to divert its attentions to another area, which may detract attention

from joint operations. In addition, commingling of off-take from a shared well-pad or vertical well is a recipe for much potential complexity. Will parties be allowed to drill sole-risk horizontals from a shared vertical well? What if parties disagree as to an optimal number of fracture operations? How is commingled production from differing horizontal wells with differing stimulation techniques applied at different times to be allocated once produced at a single vertical well-head?

It is for this reason that some JOAs avoid the issue by simply not allowing sole risk operations (without consent). Whilst deferring this issue may be a tempting negotiating approach in early stage basin developments, it can create future problems and may deter some investors used to the sophistication and flexibility of sole-risk provisions,

which allow differences of opinion, drilling priority and funding abilities to be accommodated.

Whilst a detailed analysis of JOA provisions for unconventional developments is beyond the remit of this paper, it is also worth touching upon one central tenet of JOAs referred to earlier, namely the ability for parties to legislate for potentially separate lifting (and marketing) of hydrocarbons. Under a conventional JOA, parties typically either sell their entitlement in a commingled stream or else lift separately (with a gas balancing agreement or provisions for under or over-lifting discrepancies). In a shale development, however, the ability to stop and start production in order to make up for under or overlifts is influenced by the timing of capital deployment on drilling operations (to increase production), and by the fact that it may not be possible to reduce production by choking or shutting-in a well, without damaging a well or resource. Thus, if Party A for example fails to lift its entitlement due to its failure to complete commercial off-take arrangements, should Party B bear the cost of further drilling or stimulation in order to allow Party A to catch up?

Those looking to tailor guidance, legislation and commercial arrangements in developing basins, in order to encourage, sustain or participate in unconventional hydrocarbon developments, are recommended to draw upon the already evolved and broad base of international experience available.

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"I am delighted to acknowledge the kind assistance and unique perspective of US shale expert Martin Gibson, energy partner at Dentons US LLP, in the preparation of this paper."

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