INNOVATION - MAKING DEALS HAPPEN IN NORTH SEA OIL & GAS M&A

Historically, M&A activity in the North Sea has involved the trading of assets between E&P companies, with the traditional approach to asset divestments generally involving the buyer:

(a) paying the consideration (less any deposit) to the seller in full at completion;
(b) taking on all decommissioning liabilities in respect of the interests; and
(c) providing security to the seller in respect of those liabilities.

Many assets in the North Sea are currently effectively for sale (whether they are subject to a formal sales process or not). However, market conditions over the last few years and the advanced maturity of the basin have meant that sellers have not been able to complete sales to the usual buyers on the traditional basis.

The drastic decline in oil price in 2015 and slight recovery through to end of 2016 has shaken confidence in asset valuations. Buyers do not want to pay too much nor do sellers want to sell at an undervalue. Confidence has slowly increased as oil prices have stabilised at around $55 barrel, leading to an upturn in M&A activity. Transacting parties are now increasingly finding ways to share the risks/rewards of future price fluctuations in order to get deals over the line.

In recent years many of the independents have suffered from a capital shortage as traditional sources of both equity and debt funding have dried up. This has limited their ability to access the asset market. However, private equity has started to fill the gap, with Chrysaor, Siccar Point, Verus, Zennor Petroleum and others, recently acquiring (or contracting to acquire) significant North Sea assets.

In particular the recent announcements of key North Sea transactions entered into by BP and Shell selling oil fields and associated infrastructure to EnQuest and Chrysaor respectively could be the sign of a new wave of North Sea M&A deals, necessary to put ownership of certain North Sea assets into “the right hands”, one key element of the MER UK strategy.

Another recent North Sea trend is the acquisition of key infrastructure interests by infrastructure funds such as Antin, Ancala and North Sea Midstream Partners. This is likely to continue.

Decommissioning liabilities continue to be a major issue for sellers and buyers of North Sea assets. However as a result of sellers showing increased flexibility on the retention of liabilities, assets are changing hands where deals would have stalled in the past.

What has become clear from recent completed, signed and attempted transactions in the North Sea is that innovative solutions are required in order to overcome hurdles which have prevented deals from signing or closing in the past. The traditional approach will not be workable in many cases. In this article we will briefly explore some of the key developments in North Sea asset M&A, focusing on:

1. mechanisms to help bridge the value gap between buyers and sellers;
2. new financing structures;
3. infrastructure only disposals; and
4. decommissioning liabilities and decommissioning security.

1. Closing the value gap

Deferred or contingent consideration structures are becoming more common in sale and purchase agreements to allow for sharing of elements of upside or downside. These structures often include one or more of the following elements:

<table>
<tr><th colspan="2">Contingent consideration element</th><th>Comments</th></tr>
<tr><td>1.</td><td>Additional consideration payments based on forward oil price (if higher than a threshold, buyer's consideration is increased, and sometimes if lower, the seller may be required to make a payment to the buyer).</td><td>• The recently announced Shell-Chrysaor deal includes these elements[1].
• This is a relatively straightforward model for bridging the valuation gap, especially where contingent payments are not linked to field production.</td></tr>
<tr><td>2.</td><td>Additional or contingent consideration linked to future production volumes from the asset.</td><td>• This approach can be problematic for sellers given that the buyer, and not the seller, will have "control" of the asset in question.
• Documentation would need to provide the seller with access to relevant field information. Where the asset is owned by a joint venture that information may be confidential under the operating agreement meaning that the parties need consent from co-venturers in order to allow information flow to the seller.
• If the model focusses only on production (and not costs) there is a risk that the buyer is obliged to make payments to seller in circumstances where the asset is losing money. The payment could even render continued production uneconomic from the buyer's perspective.</td></tr>
<tr><td>3.</td><td>Deferred consideration payable on field development approval or first production of hydrocarbons.</td><td>These models appear simple but there are a number of issues to be considered. For example, where payment is linked to field development approval:

• Is the payment triggered in circumstances where the buyer has not approved or is not participating in the approved development? This may arise where the</td></tr>
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[1] http://www.shell.com/media/news-and-media-releases/2017/shell-to-sell-package-of-uk-north-sea-assets-to-chrysaor.html

		buyer's co-venturers opt to sole risk a development under the operating agreement without the buyer's participation. Alternatively, the licence could be relinquished (because the acreage is not developed), the acreage relicensed and subsequently developed by the new licensees. • Can the payment be avoided as a result of the buyer onward selling the interest prior to field development approval?
4.	Seller retention of royalty or net profit interest ("NPI") from asset going forward.	• When drafting royalty/NPI arrangements great care must be taken to clearly identity all the revenues/costs that will be taken into account in determining the payments due to the seller. The seller will be concerned about avoidance/gaming by the buyer. The buyer will want to ensure that the seller's return is not enhanced because revenues are overplayed or certain costs cannot be taken into account in the calculations. Issues to be considered include: - Valuation of receipts. For petroleum sales is it the contracted sales price actually received by the buyer or will there be an independent basis of pricing? - Inclusion of third party tariff receipts - Treatment of insurance proceeds received by the buyer - What happens when the buyer's net income from the asset becomes negative for one or more calculation periods (for example, during a period of prolonged field shutdown)? Does the seller contribute to negative cashflows? Are the accrued losses taken into account in future calculations periods? - Are decommissioning costs taken into account (such that the net profit payment to the seller takes into account the costs at the end of field life)? • Documentation would need to provide the seller with access to relevant field information. Where the asset is owned by a joint venture that information may be confidential under the operating agreement meaning that the parties need consent from co-venturers in order to allow information flow to the seller. • The buyer may also need OGA consent for such an arrangements under the terms of the relevant production licence (for example, on the basis that the arrangement may give a party that is not a licensee a right to proceeds of sale of petroleum which, at the

		time when the agreement is made, has not been won and saved from the licensed area). This has been the case for producers granting flowstreams over their expected future production.
5.	Sales on a tranche basis with buyer option to buy further percentage interest(s).	• This structure may be attractive in circumstances where buyer is not in a position (or is not prepared) to acquire the entire interest at the outset. • Buyer's profits from the initial acquisition can be used to help fund subsequent tranches. • Seller will be locked into the option for a fixed period so will be unable to sell residual share to a third party until the option expires. • This structure may necessitate multiple transfer processes. Where there are a large number of relevant third parties involved this may be unattractive. • Any pre-emption provision in the asset operating agreement should be carefully considered.

Parties entering into contingent consideration structures of this nature should obtain separate tax advice on the tax treatment of the payments.

2. New financing structures

This year we have already seen some new money reserve based lending in the North Sea. However, since the price downturn it has generally been difficult for buyers to access debt finance. As a result we have seen and been involved with a number of novel alternative arrangements to allow buyers to access cash in order to undertake transactions and fund field developments/work.

These arrangements have included:

Funding structure		**Comments**
1.	Loans from sellers to buyers (vendor loans)	The recent Shell deal involved elements of seller finance and repayment in order for the buyer to be able to fund acquisition[2].
2.	Loans from buyers to sellers	These have been a feature in the past where smaller E&P companies farm out an interest in a key development asset.
2.	Forward sales of hydrocarbons and offtaker loans	• Lending companies such as Flowstream[3], trading arms of some oil majors, and trading companies have been involved in transactions where they have either acquired or at least lent against (via a prepayment

[2] http://www.shell.com/media/news-and-media-releases/2017/shell-to-sell-package-of-uk-north-sea-assets-to-chrysaor.html

[3] http://flowstreamcommodities.com

		facility or similar product) future production from a field owner for an upfront consideration, thus injecting inject significant capital into the field owner that can be used to fund other transactions. • These arrangements may require OGA approval under the production licence. • The lender will need field production information. Documentation would need to provide the lender with access to relevant field information. Where the asset is owned by a joint venture that information may be confidential under the operating agreement meaning that the parties need consent from co-venturers in order to allow information flow to the lender.
3.	Service or contractor company financing.	• Elements of new field developments are being "financed" by some service companies as a result of invoice deferrals until after first production, or in some cases, production related payments following first production. • These contracts will generally be entered into by the Operator of the asset. Therefore, buyers of non-operated interests will struggle to access arrangements like these except in conjunction with the Operator. • Another trend similar to buyer to seller loans is the larger oilfield service companies looking to effectively wrap the development of an asset on behalf of a smaller independent E&P company (and possibly government owned holding companies depending on the location of the asset) in exchange for an equity style return. For example a high interest rate return on the capex investment together with a royalty/NPI.
4.	Sale and leaseback	• Oil companies looking for capital have been able to sell and leaseback some offshore infrastructure or onshore real estate from some finance providers. • Oil and gas assets are routinely owned by joint ventures and assets will generally be joint property owned by the parties to the joint venture. In practice it can be difficult for individual owners to enter into arrangements like this in respect of their percentage interest in the asset. • This option has been more common for floating infrastructure such as FPSOs or FRSUs which are often financed separately, and where the benefits of such financing for all underlying joint venturers may be clearer

	Combinations of the above	• On large single asset developments the joint venturers will likely now look at combinations of the options above, perhaps as part of what is effectively a project financing. Accountancy and tax advice will be important, particularly as whether an investment is debt or equity may be unclear.

There are significant hurdles in structuring such arrangements, particularly around security. Relevant E&P companies will often have already given some form of first ranking security to existing lenders. Such arrangements, particularly those which constitute financial indebtedness, may require the consent of the existing lenders.

Buyers may be able to create security over their interests in the relevant operating agreement and licence. This would give the lender an advantage over other creditors but in a default scenario, the rights of co-ventures (i.e. forfeiture) could trump the security given to the lender.

3. Selling infrastructure

Maintaining and extending midstream infrastructure is crucial to the longevity of the North Sea and it is likely that the independent ownership of such infrastructure can help maximise the ultimate economic recovery of the UKCS's oil and gas reserves.

Oil company ownership of midstream infrastructure developed at a time when the industry was booming and large-scale fields were being developed. The ownership of infrastructure by E&P companies ensured a low-cost and secure transportation route to shore for their own oil and gas, while they also benefited from transportation tariffs from other oil companies requesting spare capacity in their pipelines.

As many of these original fields mature and move towards decommissioning, those E&P companies now holding the field interest have little to gain from owning the infrastructure but not using the capacity themselves.

While many E&P companies welcome third party business which provides additional income and investment that often extends the life of existing fields, as a standalone business, infrastructure ownership does not provide the profit margin that such companies (and more importantly their shareholders) expect and may be viewed by some as an unwelcome distraction from their core business.

So, in spite of the Infrastructure Code of Practice (which seeks to facilitate fair access to offshore infrastructure), this dichotomy often creates conflicts of interest and, in some cases, a lack of drive on the part of oil company infrastructure owners to take-on new transportation business or to be flexible in respect of the terms. By contrast, infrastructure funds are set-up to do business on lower, albeit safer, returns.

Such infrastructure investments are attractive to investment funds as they can provide low-risk inflation-linked income, with relatively low running costs. Decommissioning costs are often not a major concern as pipelines may often be trenched and buried in situ rather than, as is the case with most offshore platforms, having to be removed entirely. Moreover, the regulatory burden imposed on owners of pipelines is lower than that for production licences and the related platforms and wells. In Norway, returns from gas transportation infrastructure are regulated by the government and are designed to keep major profits with the fields, while allowing a reasonable rate of return on the infrastructure owner's investment. However some infrastructure fund investors in the Gassled system, taking on stakes disposed of the majors, were stung by a post-closing change in the tariff mechanism by the government, evidencing that political risk exists even in Norway.

However, there are challenges to be overcome in transferring pipelines into the hands of infrastructure funds:

Challenges		**Comments**
1.	Ownership structure.	The main challenge in the North Sea is that unlike the major assets transferred to date which involved infrastructure assets held under an infrastructure-specific joint venture, much of the offshore pipeline and infrastructure network in the UK is more closely integrated and owned in common with existing E&P infrastructure (platforms, wells and the like) and a key consideration for an owner seeking to sell its stake in a pipeline will be how to delink it from existing E&P infrastructure, while protecting the hydrocarbon evacuation route. From a legal perspective the wells, platform and pipeline evacuation route all typically constitute "joint property" under the joint operating agreement. A separate joint venture would therefore require to be set up to manage the infrastructure and an interest in that joint venture then sold to the buyer. Save in the case of 100% owned assets, this "split" will require the consent of co-venturers which may or may not be forthcoming (unless a similar deal is offered to them which they are willing to accept). In some cases a trust or synthetic transfer of income structure may be possible in order to pass a "beneficial" type of interest to a fund where the legal interest cannot be transferred without co-venturer consent, this is unattractive to a fund from the perspective of it seeking true ownership of, and thereby legal security over, the asset.
2.	Co-venturer security demands	Joint operating agreements often include a provision requiring that an asset owners seeking to transfer its interests in an asset satisfies the co-venturers as to the financial capability of the proposed buyer. This often leads to requests from co-venturers for security from the buyer in respect of its liabilities (primarily

		decommissioning liabilities but sometimes also for operating costs or costs in respect of any expected investments). Infrastructure funds use, for structural reasons, special purpose companies for individual transactions which are usually unable to give guarantees from parent or affiliate entities, or to obtain letters of credit or the like from financial instructions. This means that innovative legal and commercial approaches are required in order to satisfy co-venturers' financial capability concerns and related decommissioning security requirements. Recent solutions include placing monies in trust and ensuring adequate insurances are in place, although both can add significant cost.

4. Decommissioning and decommissioning security / security generally

Decommissioning and decommissioning security has been one of the principal features, and hurdles to overcome, in upstream oil and gas M&A over the last few years. Albeit with a few historic exceptions, sellers have typically required a "clean break" from decommissioning liabilities on the sale of producing assets. As a result they have required the buyer to put up continuing security, in the form of a letter of credit or parent company guarantee, for the seller's benefit. This is because under the Petroleum Act they cannot achieve a clean break from a legislative perspective and must attempt to do so contractually.

With the growing maturity of North Sea assets, and particularly given the recent fall in the oil price, the net revenue remaining in many oil fields might be less than or only marginally exceed anticipated decommissioning costs. Potential buyers do not want to take on liability for decommissioning where there is little if any guarantee of profit at the end of the day. Sellers are therefore left with a near-term choice as to whether to hold onto assets until end of field life, or to exit and use any cash generated from such exit for other purposes. The net result of a requirement for buyers to take on liability for decommissioning and /or for security provision has been that some relatively recent planned sales simply have not happened at all.

There have been recent positive developments making provision of decommissioning security, in particular, more economic. While in the past a request for security might have been made separately by sellers and the buyer's new JV partners (and potentially even the government), the advent of the industry standard field-wide DSA has alleviated the requirement to provide multiple security in the majority of cases. Additionally, the recent contracts entered into between government and industry (decommissioning relief deeds), assuring to a large degree availability of tax relief on decommissioning expenditure, has allowed buyers to move away from provision of security on a "pre-tax" to a post-tax" basis, reducing security required by between 50 and 75%.

On the sellers' part, while a sale for positive consideration and a clean-break is still the most desirable outcome, we have been involved in several recent sales of assets where elements of decommissioning or decommissioning liabilities have been retained by the seller in order to get deals "across the line". The expectation is that the buyer will be able to extend field life through greater investment in upgraded production facilities, infill drilling or tie-backs of satellite fields, which the seller was not prepared to carry out. Even where the sale price is small or negative there is benefit to a seller in the ‘time value of money’ that is gained by delaying its decommissioning spend and reallocating its resources elsewhere meantime. There is also a hope that by extending the life of the field, the decommissioning industry will be more developed at the time the decommissioning takes place, resulting in costs savings from the application of new technology and greater economies of scale. Similarly it will be in the buyer’s interest to extend field life and receive revenues from on-going production for as long as possible, knowing that it will not be responsible for costs of decommissioning the existing infrastructure at end of field life.

Additionally, many new buyers, especially private equity vehicles, acquiring mature assets may not at the end of field life have paid enough tax to ensure they can claim the full benefit of tax relief against decommissioning costs, and from an overall economic perspective it may from an overall economic perspective, assist a transaction take place if the seller were to decommission and claim the tax relief in such circumstances.

The following are examples of the approaches that we have recently used:

<table>
<tr><th colspan="2">Approach to decommissioning liabilities</th><th>Comments</th></tr>
<tr><td>1.</td><td>A sale of the asset and re-transfer to the seller at the point of decommissioning.</td><td>This may be in the form of an outright sale or a lease. This is simplest for assets where the sellers hold a 100% interest (as otherwise existing co-venturer consent would be required).
The seller may be better set-up to undertake the decommissioning than the buyer (for example by being able to use existing experience, efficiencies of scale and the like).
If the seller will be carrying out the decommissioning activities the seller will need to ensure that the facilities are managed in the interim in a fashion which will allow the seller to safely take back control of and decommission the facilities.
The seller will require a continuing interest in the asset in order to police addition of new facilities, drilling of wells, interim decommissioning, third party tie-ins, transportation and processing arrangements via the transferred infrastructure, ease of termination of field agreements in a hand-back scenario, and others. However, extensive continuing administration required on the part of the seller removes one of the key reasons for selling in the first place, namely the overheads and time dedicated to the relevant asset in its portfolio.</td></tr>
<tr><td>2.</td><td>The seller remaining liable for (some or all of) its (transferred) percentage share of decommissioning of the assets</td><td>While this is the simplest approach contractually, the seller will lose control over decommissioning spend unless it caps its liability or seeks contractual control</td></tr>
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	but simply paying the cost at end of field life rather than requiring an asset-re-transfer.	over decommissioning activities. Often, as in some recent deals, this is "shared" between buyer and seller. • Sellers will wish to ensure that they do not take on liability for any developments which post-date their exit from the field.
3.	The seller transferring decommissioning liabilities to the buyer but providing interim credit support in order to secure the costs of decommissioning at a field/co-venturer level, and obtaining back to back security from the buyer where the buyer cannot meet the co-venturers' security credit requirements.	• Here the seller would take the credit risk of the buyer's back-to-back security being weaker than its own, knowing that it may be at risk of being liable to co-venturers for the buyer's share in any default. • Economically attractive because a seller may be able to provide a "free" parent company guarantee whereas the buyer might otherwise have to provide an "expensive" letter of credit which also uses up its borrowing capacity under, for example, a reserve based lending facility.
4.	Build-up of cash security from field profits.	A commercial arrangement whereby funds are paid into trust out of field profits on a tranche basis, more slowly than the "normal" DSA security calculation would require. Such an approach has found favour in recent infrastructure related deals but involves the seller being willing to take in increased risk until the fund builds up. However cash funding is economically unattractive and has historically been little used.

At the same time as addressing any decommissioning security concerns, there is still a nervousness in the industry more widely around the potential for buyers to fund routine expenditure in respect of the assets being required, partly borne out of the recent insolvencies of First Oil, Iona Energy and Xcite. A buyer may therefore also have to commit to putting monies into trust or making provision for alternative security in order to get the deal through and again, innovative solutions can be required, using some of the options explored earlier in this article.

There is no standard form – innovative approaches are required.

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