

# EnergySource



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## Potential opportunities on the rise

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Private equity:

The “not-so-new” oil and gas investor

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BY PHILIP THOMSON, ANTONY SKINNER AND JUSTYNA BREMEN

Excluding liability for spread costs in oil and gas contracts: The next chapter

BY TOM CUMMINS AND JAMES PRESCOTT

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We are delighted to introduce this seventeenth issue of **EnergySource**, our biannual publication in which we cover a range of legal and transactional issues relevant to the energy sector from our offices across the globe.

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“FROM SURVIVAL TO GROWTH IN A NEW ERA”:

# Future strategies for oil and gas companies

In the face of a slow commodity price recovery in the oil and gas sector, our latest research report “From Survival To Growth In A New Era” has revealed that 83% of companies expect a ‘substantial’ increase in mergers and acquisitions (M&A) in the next three to five years.

Our report compiles the views of CEOs, CFOs and general counsels across some of the world’s largest oil and gas companies with a combined turnover of US\$5.3 trillion and outlines new insights relating to the breadth of industry spending cuts and attitudes towards debt, as well as highlighting steps to be “match fit” for a price recovery.

## Report summary

### Voice of the industry

OVER  
**50**

interviews with  
organisations  
from across  
the world

**\$5.3tn**  
combined turnover



**\$685bn** total  
market cap

### Response to current market challenges



**68%**

of organisations  
were not well  
prepared for the  
depth or duration  
of the low-price  
environment

**87%**

of companies  
have cut or  
frozen CAPEX

**34%**

are currently  
decreasing  
geographical footprint

**41%**

are reducing  
budgets for  
internal operations

**61%** of companies will find it challenging to be sustainably profitable in the next 2-3 years



The key findings from our report include:

- A fast recovery in oil prices is not anticipated – only 15% of respondents estimate that oil will be at US\$60 or above in 12 months' time.
- M&A deal volumes are expected to increase by 50% in 2016 and sustained growth in M&A activity is anticipated on a three to five-year horizon, as companies restructure asset portfolios, seek new growth options and act opportunistically.
- Asia-Pacific is identified as the most attractive region for investment with 31% of companies expecting to pursue their next investment in the region, followed by Africa (22%), Europe (19%) and the Americas (15%).
- Capital investment has been frozen or cut by 87% of companies in their most recent strategic plans (somewhat surprisingly, 13% of respondents indicated that their companies were planning to increase capital spending this year).
- Just 17% of companies have immediate plans to reduce debt levels, while in three to five years almost half of companies expect to have higher debt levels.
- More than one-third of companies plan to issue new equity to support growth in the next five years, with this option most popular for companies in Asia Pacific (37%) and Europe (31%).
- 85% of oil and gas organisations believe that the 'bust' phase of the current cycle has been atypical in terms of its depth and duration, and just over two-thirds conceded they were underprepared for the conditions experienced since the initial oil price drop.

## Conclusion

The expected spike in M&A activity, which is highlighted by our report, is supported by the emergence of a number of recent high profile and large scale M&A transactions and various sales processes initiated by IOCs in the Asia-Pacific region. Sellers and buyers will, however, need to align expectations on risk allocation, particularly for ageing assets, and valuation, where some gaps have been evident in recent times, if potential transactions are to be successfully consummated.

For more information about this research or to receive a copy of the report, please approach the regional contacts below.

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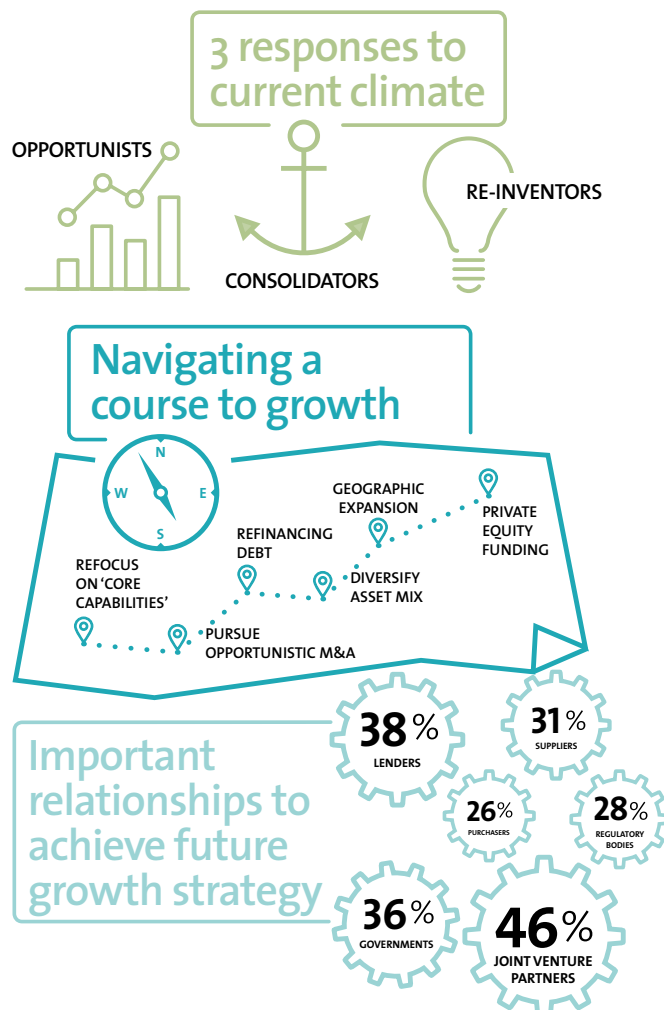
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## LNG TO POWER PROJECTS:

# Potential opportunities on the rise

by David Wadham and Philip Thomson

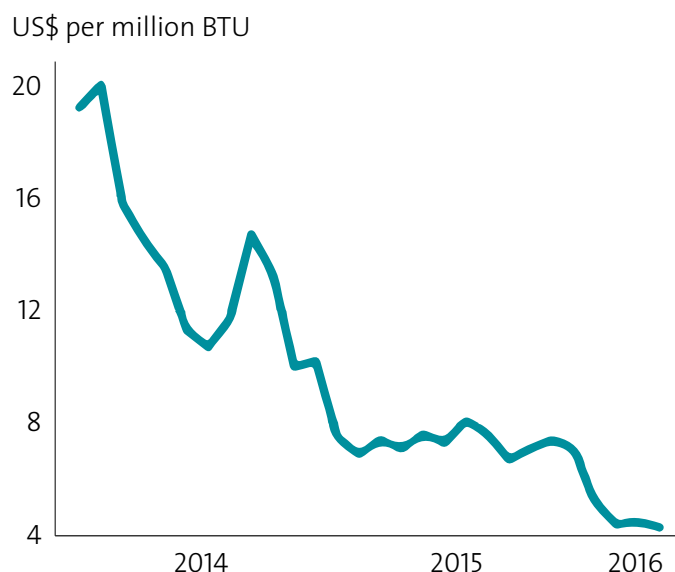
In the face of continuing deficits across the world in power generation capacity, we are seeing increasing consideration of liquefied natural gas (LNG) to power projects as a relatively rapid way of adding significant capacity to the grid.

This article sets out the background to the rise in the potential opportunities for LNG to power projects and examines some of the specific commercial issues that will shape the development of an acceptable (i.e. bankable) project structure.

### Background

There are multiple factors contributing to the serious consideration now being given to LNG to power projects in a variety of locations. One of the main drivers is the falling cost of LNG which allows it to compete with other fuels in many markets. The number of large LNG projects that have recently come on-stream (e.g. in Australia and the US) or are scheduled to do so in the near future, combined with the global gas glut caused by the development of unconventional

Figure 1: Asian LNG Spot prices





resources, have driven LNG prices steadily downwards (see figure 1).

There is also the diminishing attractiveness of coal-fired generation, one of the often cheaper alternatives to gas-fired generation, largely due to environmental considerations. Based on the outcome of the recent COP21 conference in Paris and the associated commitment by the global community to reduce carbon emissions, the trend away from coal-fired generation continues.

Environmental considerations weigh particularly heavily on export credit agencies, who have in the past been among the major funders of coal-fired projects in developing markets. In late 2015, those OECD countries party to the official arrangement for export credits agreed new rules that will take effect in January 2017 and will limit the ability of those countries to provide finance in support of investments in coal-fired plants. A number of commercial banks have followed suit. This represents a significant policy shift away from support for coal-fired generation, particularly in Asia.

Finally, the technology and commercial viability of floating storage and regasification units (FSRUs) has been proved up in recent years. FSRUs can now present a quicker and potentially more flexible solution to the provision of gas storage and regasification facilities than alternative land-based facilities. Indeed, in the last two years, FSRUs have been brought into operation in countries including Brazil (in two separate locations), Lithuania, Indonesia, Kuwait (replacing a smaller FSRU), Egypt, Jordan and Pakistan.

### The opportunities

Many of the opportunities for gas to power are emerging across Africa. This is perhaps no surprise given Africa's deficit in generation capacity and the lack of gas grid infrastructure to support the development of conventional independent power projects (IPPs).

For example, Egypt has recently chartered two FSRUs and is reported to be planning to charter a third.

Elsewhere in North Africa, Morocco has recently launched a request for proposals to appoint advisers in relation to a project for the import of 5 bcm, the development of the associated LNG import and pipeline infrastructure, and two 1,200 MW Combined Cycle Gas Turbine (CCGT) power projects – one at Jorf Lasfar and the other at Dhar Doum.

In sub-Saharan Africa, potential project sponsors are evaluating an LNG to power project in Ghana (notwithstanding the ongoing development of domestic offshore gas reserves). The 1,300 MW Ghana 1000 project led by Endeavor is intending to develop a CCGT in several phases, with the later phases being fuelled by LNG supplied by the Ghana National Petroleum Corporation. South Africa also has ambitious plans to add over 3,000 MW of gas-fired capacity based around LNG fuel supply. More details are expected later this year.

Situated between North Africa and Europe, Malta is in the midst of developing an LNG to power facility. Malta Gas and Power Limited is developing a 200 MW gas-fired power plant at the Delimara power station near Marsaxlokk. The project also involves the development and construction of LNG receiving, storage and regasification facilities for LNG. A floating storage unit will

be leased on an 18-year term and the plant will benefit from an 18-year power purchase agreement (PPA) off-take.

Further afield, in Chile, sponsors including EDF and Cheniere are developing an LNG receiving terminal and an associated 640 MW CCGT. LNG will be supplied by Cheniere under a 20-year LNG sale and purchase agreement (SPA), while the project will include a FSRU chartered from Hoegh LNG under a 20-year charter. Likewise, three Colombian power companies have awarded Sociedad Portuaria El Cayao S.A. E.S.P. a contract to develop a floating LNG import facility, which is currently under construction.

### Structuring considerations

Power plants, developed, constructed and financed on an IPP basis, have a long history of being successfully financed. The construction of a single well-understood asset with limited contractual interfaces leading to the delivery of a steady revenue stream, backed by a long-term sovereign or quasi-sovereign credit, has proved one of the more bankable asset classes.

Clearly, one of the challenges for LNG to power projects is the co-development, and potential co-financing, of the LNG and power infrastructure. Not only do LNG to power projects potentially suffer from “project-on-project” risk due to the interdependency of the construction and commissioning of the gas and power infrastructure, but the project(s) are altogether more complex and require a number of additional risks to be considered and allocated, including potentially flowing various risks through a much longer project contract chain.

There is no set single structure for the development and financing of LNG to power projects, and indeed there are a number of factors that sponsors and their funders will need to consider at the outset that may influence the choice of structure, including the following:

- **Size:** what is the size of the proposed facilities both in capacity and dollar terms? Based on size, would it make sense to undertake a single or two separate (but linked) debt raisings? If two debt raisings are planned, will they be “stapled”, i.e. with the same banks holding the same percentage participations in both loans?



- **Identity of sponsors:** do the potential sponsors all wish to invest equally in the gas and power generation infrastructure, or would it be beneficial to develop a structure that allows ownership in different proportions or indeed to allow different investors?
- **Space:** are there space constraints on land for gas storage infrastructure (that would suggest an FSRU-based solution may be more appropriate) or are marine conditions/facilities inappropriate (so as to suggest a land-based approach to gas infrastructure)? An FSRU-based solution will involve the charter of the FSRU, thus adding to the project contract chain as compared to a land-based project.
- **Local gas demand:** is the gas demand specific to the proposed IPP or is there latent demand for gas (either from industrial consumers or from other IPPs) which would mean that the gas import facilities would serve more than one buyer? If gas demand is very high, an FSRU solution may be too

small-scale to meet that demand. The more diverse the sources of demand for gas, the less the project is dependent on a single source of demand (and, therefore, ultimately revenue).

- **Regulatory requirements:** do local regulatory requirements permit the same person to own and operate the relevant gas and power generation facilities, or indeed the cross-collateralisation of the facilities' assets, in support of the other? Are there "open access" requirements to relevant utility infrastructure?
- **Tax considerations:** are there any tax considerations that would shape the structure? For example, are there withholding taxes that would prevent the on-lending of funds from one project to another?
- **Timing:** how urgent is the demand for incremental energy supply? The FSRU solution typically offers the prospect of quicker project delivery than a land-based terminal.

## Possible structures

Taking account of the above considerations, we set out below some of the possible structures.

**Option 1:** an integrated model with a single project vehicle

This is probably the simplest, although in a sense least flexible, model. Under this model, a single project vehicle develops and constructs both the gas and power infrastructure, and raises the funding to do so under a single financing.

**Option 2:** a regas tolling model with separate project vehicles

Under a regas tolling model, separate project vehicles develop, construct and own the gas and power infrastructure. The gas is purchased by the power company direct from LNG suppliers on the market and the LNG is then stored and regasified by the gas company under a tolling arrangement. Each project company may raise its own financing or the funds may be raised under a single financing (with both the power company and the gas company acting as borrowers).





### Option 3: a gas sales model

Under the gas sales model, separate project vehicles develop, construct and own the gas and power infrastructure. However, the LNG is purchased by the gas company and on-sold as gas to the power company. The power company may be only one of a number of purchasers of gas. The financings will likely be separate and indeed there may be a degree of government ownership in the gas company if the gas is to be sold to multiple end-users.

As stated above, a number of factors will influence the eventual choice of contract model. Option 1 favours smaller and simpler projects, where there is no real likelihood of third party gas sales and no issue with common ownership and operation of gas and power facilities. Option 3 is a more flexible model which may see the greatest degree of independence between the gas and power facilities, with the IPP perhaps acting as an anchor purchaser of gas but with a firm intention of the gas company to sell gas to multiple parties.

Option 2 represents perhaps the middle ground, recognising the reality that the

gas facilities are possibly being developed primarily to serve the power project, but that there are good reasons to preserve some overall flexibility within the structure. It is option 2 that we analyse in more detail below.

## Regas tolling structure

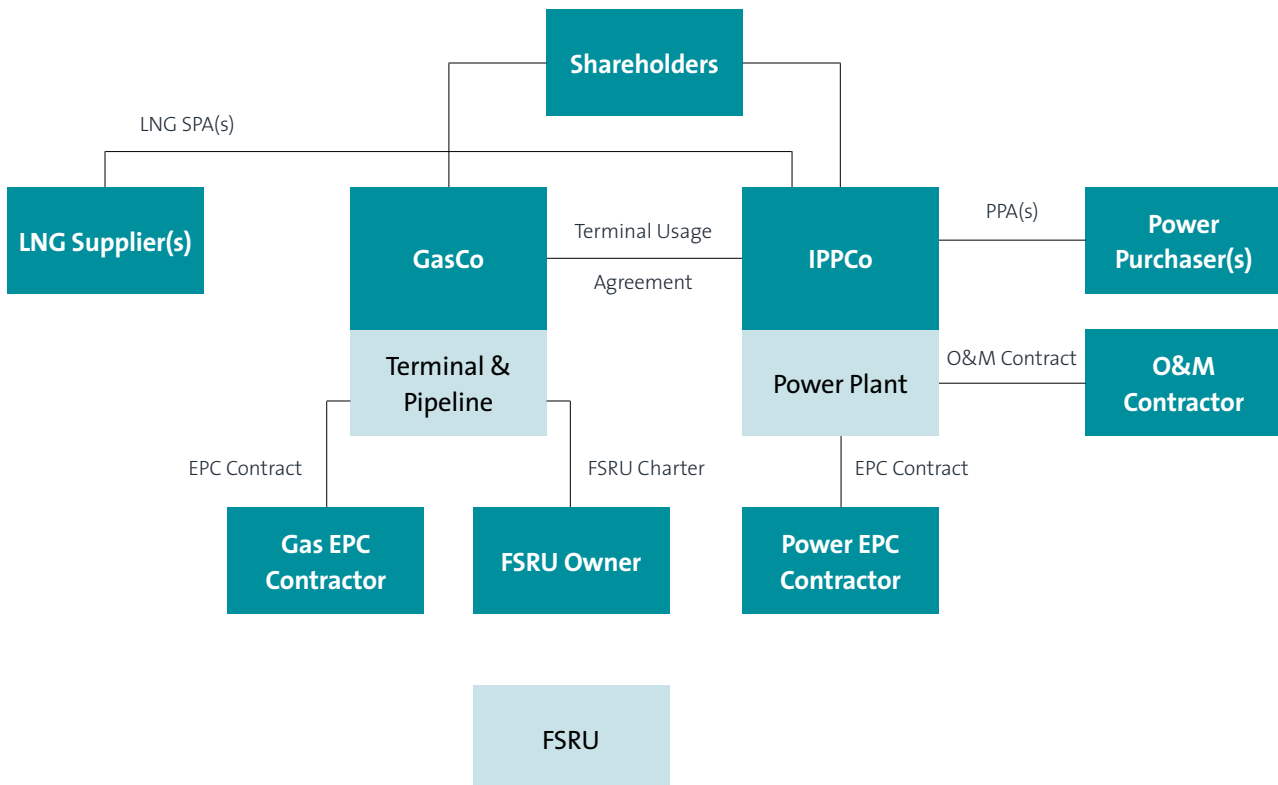
### Basic structure

We set out in figure 2 a possible structure chart for an LNG to power project developed on the basis of a regas tolling structure (excluding finance documents):

As the chart shows, the project will be undertaken by two project vehicles: one developing, owning and operating the gas infrastructure (GasCo) and the other developing owning and operating the power plant (IPPCo).

As mentioned above, the gas infrastructure could be developed on a number of different bases: essentially, all the LNG import, storage and regasification infrastructure could be land-based. The alternative approach would see a minimum of land-based infrastructure, with the storage infrastructure located on a vessel and the regasification equipment located either on a vessel or a jetty.

Figure 2: Possible structure chart for an LNG to power project developed on the basis of a regas tolling structure (excluding finance documents)



IPPCo would undertake the project very much on classical IPP lines, underpinned by a long-term availability-based PPA with a creditworthy off-taker. However, instead of purchasing its gas under a long-term gas supply agreement or structuring its PPA as a tolling agreement with the off-taker supplying the gas and purchasing the resulting electricity, IPPCo in fact enters into one or more LNG sale and purchase agreements. IPPCo then tolls the LNG through the gas facilities under the terminal usage agreement (TUA). Whereas the PPA acts as the primary source of revenue for IPPCo, it is the TUA that underpins the economics of the gas facilities, and the charging structure under that agreement may well be on-regulated to address any “open access” requirements in the jurisdiction.

### Revenue considerations

In relation to a classic gas-fired IPP with a single off-take, the project vehicle is remunerated via an availability-based capacity charge that will cover its fixed costs of constructing and operating the IPP and the shareholder’s equity return. The variable costs of generation – principally, fuel and variable operation and maintenance costs – are paid for through a separate energy charge as and when the plant is dispatched. If the IPP is developed on a tolling model, the issue of matching the gas supply to power off-take does not arise. If there is a separate gas supply agreement, then either the contract must have no minimum annual contract quantity (ACQ) or, if there is an ACQ, then the costs of IPPCo failing to purchase the ACQ must either be mitigated in the gas supply agreement (via make-up provisions or something similar) or passed through to the off-taker under the PPA.

Clearly, in relation to an LNG to power project, the economic structuring is more complex and the TUA and the LNG SPA both need to be taken into consideration. Like the PPA, the TUA will contain some form of fixed payment, perhaps a capacity fee payable by IPPCo that will reserve an element of the terminal’s capacity for the IPP and cover the fixed costs of the procurement/ construction of the gas infrastructure, with a variable charge covering the variable costs of tolling any LNG through the facility. Equally, the LNG SPA with the LNG supplier will be structured on a “take-or-pay”

basis with a minimum ACQ requirement (although there may be some ability to mitigate the LNG payment obligations: see below). Both the fixed costs of the TUA and take-or-pay nature of the LNG SPA will need to be taken into account in the PPA tariff. Clearly, the IPP needs to be predicated on the basis of reasonably high levels of plant dispatch to make economic sense.

### Project-on-project risk

As mentioned earlier, there is also the question of “project-on-project” risk. A delay in the construction of the gas facilities will leave the IPP unable to generate, and similarly a delay in the construction of the IPP will mean the gas facility will stand idle. In both cases, IPPCo will be unable to take delivery of LNG under the LNG SPA, and will potentially be incurring take-or-pay liabilities under the LNG SPA (unless it has, for example, been able to delay the commercial start date). On a typical IPP, construction delay risk would reside wholly with the EPC contractor, whose delay liquidated damages would be set at a level to keep debt and equity whole (subject to appropriate caps).

However, in relation to an LNG to power project with a minimum of two EPC contracts (one for the gas facilities and the other for the power plant) plus possibly a charter arrangement for the FSRU, it is not typically going to be commercially feasible for a delayed contractor under one contract to assume liability for loss of revenue across the entire project. Project sponsors may have to consider other mitigants. These may include:

- careful inter-project scheduling to allow a suitable buffer between scheduled commissioning of the upstream (and possibly cheaper) gas terminal and the scheduled commissioning of the downstream (and possibly more expensive) power plant;
- seeking as much flexibility for IPPCo as LNG buyer as possible around the timing of the commercial start date (including some controls for IPPCo over the “windowing” mechanism to determine the commercial start date) and the initial contractual volumes. Whether the LNG supplier will cede this degree of control will depend partly on its core business model. If the

LNG supplier is a greenfield liquefaction project going through its own commissioning phase at the same time, it will likely want to retain control of the commercial start date under the LNG SPA; whereas if it is a portfolio supplier, it may be able to take a more flexible approach. As regards volume, IPPCo (as LNG buyer) may be able to negotiate reduced ACQ during an initial ramp-up period and downward quantity flexibility in case delay reduces its demand for LNG;

- in the case of a FSRU solution, maximising the contractual flexibility to defer the FSRU’s delivery date and to deploying the FSRU as an LNG carrier to generate alternative revenue pending completion of the power plant;
- ensuring the power plant has a suitable back-up fuel (diesel) storage and unloading capability (although this will inevitably be limited); and/or
- sizing any contingent equity (and debt?) to provide a risk buffer for these events.

Similar project-on-project issues may arise during operations. For example, a forced outage affecting one piece of infrastructure may affect the performance of other infrastructure within the integrated project.

## Financing structures

With two separate project vehicles owning the gas and power infrastructure, and with separate construction and operation arrangements, there are a variety of options that could be considered for the financing:

- **Separate financings**  
Each project could raise finance separately and enter into its own facility agreement with different lender groups.
- **HoldCo financing**  
There could be a single “HoldCo” financing with debt pushed down into each of the subsidiary project vehicles.
- **On-lending structure**  
A single financing, where perhaps the more capex-intensive IPP company could borrow from lenders and on-lend a portion to the gas company.
- **Single financing; dual borrowers**  
A single financing but with each of the



gas company and the IPP company acting as borrowers and jointly and severally liable.

There is no “one-size-fits-all” financing solution for LNG to power projects, and the structure of the financing will need to address the requirements of the specific project, but the following points should be borne in mind:

- While two financings may permit a degree of flexibility (for example, with regard to subsequent separate refinancings and/or being able to allow each lender to opt to fund the asset they are most interested in), there will inevitably be intercreditor arrangements and potentially cross-collateralisation that will tie the two bank groups closely together. Also, there is the general execution risk of needing to close two financings at the same time. The effect on pricing of raising two smaller facilities rather than a single larger facility will need to be considered.
- In relation to the HoldCo and IPP on-lending structures, consideration will need to be given to the tax consequences of the on-lending structure, as well as the potential complexities of up-streaming debt service to lenders and available cash to shareholders.
- The joint and several structure will make the smaller GasCo jointly and severally liable for the debts of the larger IPPCo, and may introduce complexity if there are different shareholder groups for each asset and one of them wishes to sell down. There is also a level of complexity in relation to a dual borrower structure over and above a single HoldCo financing.

## Conclusion

There is significant interest in LNG to power projects as a means of meeting demand for gas-fired power generation in many markets. The industry has delivered a number of successful LNG to power projects, and many others are at different stages of development.

An LNG to power project can be structured on several different models, depending on the specific characteristics of the project in question. Careful consideration of the project documentation will be

necessary to ensure that risks are appropriately allocated, given the large number of project participants likely to be involved. Likewise, there are a number of different financing structures which may be available, depending principally on the composition of the sponsor group(s) and the appetite of the relevant bank market.

*Ashurst's energy team is, and has been, involved in a number of LNG to power projects and a number of other LNG floating and land-based import projects, including advising:*

- EDF on the Octopus LNG to power project in Chile.
- Sociedad Portuaria el Cayao S.A. E.S.P. on the development of a regasification project in Colombia, including the long-term charter of an LNG FSRU from Hoegh.
- PT Perusahaan Gas Negara on the LNG FSRU project originally located at Medan, Sumatra and subsequently relocated to Lampung, Sumatra.
- Klaipėdos Nafta on the Lithuania LNG FSRU project.
- The European Investment Bank and the commercial banks on the financing of the Gate LNG terminal in the Netherlands and its subsequent expansion financings.



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PRIVATE EQUITY:

# The “not-so-new” oil and gas investor

by Michael Burns, James Prescott and Emma Camilleri

**B**y its nature, the oil and gas industry requires substantial capital at various stages of the asset life cycle. Now, arguably more so than ever before, finance from private equity (PE) funds is being seen as one of the most likely sources of capital for organic and inorganic development in the sector.

The drop in the oil price since 2014 coincided with a number of PE funds indicating that they will focus on investment in the sector. A significant amount of press coverage in recent times has focused on PE funds as a new investor in the oil and gas sector (particularly the upstream sector), however, this is not strictly true.

This article provides an overview of the current landscape of PE investment in the oil and gas sector. It begins by highlighting certain key developments in investment

in the sector over the past two decades. It then sets out an introduction to some of the key features of PE transactions, before analysing, at a high level, a number of legal and commercial considerations that are relevant for PE investment in the oil and gas sector.

## Key developments

Over the past two decades, large PE funds have increased their participation in the oil and gas sector. Blackstone's and Warburg Pincus's investment in the independent

exploration company Kosmos Energy in the early 2000s, for example, was a particularly notable transaction. The deal involved a significant initial commitment of US\$300m and a further US\$500m in 2008 to enable Kosmos to accelerate its exploration efforts in West Africa. The investment paid a remarkable dividend when Kosmos discovered the Jubilee field off the coast of Ghana in 2007, one of the most important discoveries in West Africa's history. In 2011, Kosmos listed its shares on the New York Stock Exchange. While such



“pure exploration plays” are quite rare in the PE sphere due to the level of risk involved, it demonstrates the upsides on offer to PE in the industry.

Since then, investment has ramped up substantially. Research by EY into PE investments in oil and gas found that in 2014, PE oil and gas deals around the globe amounted to US\$38.6bn. Furthermore, whilst there was a slow start to 2015, the rest of the year saw activity that was very much in line with previous years, and the first quarter of 2016 has seen deals worth \$7.6bn. While a large proportion of this investment has been in unconventional oil and gas assets (particularly in the US shale industry), funds have begun to emerge with a forward-looking focus on investing specifically in North Sea oil and gas assets.

There are several factors that have driven this pivot towards North Sea

“

*“the first quarter of 2016 has seen deals worth \$7.6bn”*

investment, with one obvious factor being the oil price. As the price of oil fell from its peak in 2014, companies have come under increasing pressure to divest non-core assets in an attempt to cut costs and maintain dividends. The result has been to increase the availability of assets in the region and reduce the number of purchasers competing for those assets.

A second factor is the rise in the number of companies or assets under stress due to a combination of the fall in energy prices and the financial crisis. Funding from banks and the capital markets has largely dried up for these companies, and therefore the need for them to raise capital quickly has left a void which is beginning to be filled by PE. It is also an attractive opportunity for PE funds who focus on increasing value and margins by way of efficient asset management.

In parallel with these situations playing out, we have seen the establishment of, and investment by, a number of funds in North Sea oil and gas. These include the reported US\$500m commitment by Blackstone and Bluewater to newly formed company Siccar Point Energy, which has a specific focus on the North Sea; Carlyle and CVC coming together to establish Neptune Oil & Gas, an entity being led by the former chief executive of Centrica, Sam Laidlaw; and Kerogen Capital who have invested in Zennor Petroleum (formerly MPX UK) and Hurricane Energy.

More broadly, L1 Energy was established as part of the international investment group LetterOne Group and is led by Lord Browne, the former CEO of BP. This has been funded by Russian billionaire Mikhail Fridman with the objective of acquiring a portfolio of currently undervalued oil assets. L1 Energy has also made it clear that it is particularly interested in assets in the North Sea and Europe and, to that end, it made a number of acquisitions in the last two to three years including those of RWE Dea and E.ON's Norwegian assets.

### Types of private equity investment

"Private equity" is an umbrella term that captures many forms of private investment into entities (here referred to as "targets" or the "target") that are not listed on a recognised stock exchange.

The form of investment chosen is largely dependent on the type of assets that the target holds, the life-stage that the target is at, and the degree of risk that the investor is willing to take. The main forms of PE investment include the following:

- **leveraged buy-outs (LBOs)** – a transaction is financed by a mixture of debt and equity. LBOs are typically used to acquire a majority controlling interest in a target and seek to make a profit by increasing the capital value of a target and through financial leverage. The target that is bought out tends to be well established with stable cash flows, which are used to fund the interest and principal on the debt used to finance the acquisition;
- **venture capital** – equity finance is provided to a potentially high-growth target that is embarking on a new venture, which can either be the commencement of the target's activities as a whole or where it is expanding into a new area. The equity investor usually takes a minority stake. Returns are often generated through the development of new technologies and embryonic projects that have not been executed before;
- **growth funds** – like venture capital, these investments are usually made in order to acquire a minority stake in a target. The differentiator between growth funds and venture capital is that growth funds focus on more mature targets that are seeking to expand or increase efficiency, so the investment is seen as somewhat less risky; and
- **infrastructure funds and direct investors** – investors in longer-term stable and public projects; for example, oil and gas pipelines and storage. This provides an investment opportunity for institutional investors who are seeking a low-risk return over a number of years.

An investor's objectives and risk appetite can therefore be carefully aligned with the type of equity investment pursued and the type of activities that the target deals with. For example, an investor seeking high returns may wish to invest in a venture capital fund which might pursue unconventional projects, which tend to use relatively untested methods







and technologies but can potentially achieve high returns. On the other hand, an investment in conventional projects will likely involve a more established target and be more capital-intensive, making it an appropriate investment for an LBO fund.

### Structure of an oil and gas private equity investment

There are a number of features that distinguish PE investment from other forms of investment. One key feature is the fact that a PE fund is managed by a manager who decides what to invest the funds in, and the manager may also, in some instances, take a stake in the investments they choose in order to retain some of the risk of the investment, which is reassuring to the private investors.

The PE fund may also partner with a specialist management team to make the investment. Given that the oil and gas industry is such a specialised sector, the PE fund will be particularly reliant on the expertise of the management team that it partners with.

### Particular legal and commercial considerations for oil and gas PE investments

Having regard to the various types of investment that can be made in the oil and gas sector, there are several legal and commercial factors that are often considered as part of an investment decision.

#### Legal structure and risk

Whether the PE fund joins forces with a management team or otherwise, in most cases a special purpose vehicle (SPV) will be incorporated to acquire the target assets, and it is this SPV that the PE fund will acquire equity in. In some instances, the structure will also include a newly incorporated subsidiary of the SPV, with the investors subscribing for shares at the SPV level and external debt finance being provided to the subsidiary, which will then make the acquisition of target assets. This is beneficial to the investor for a number of reasons, including the fact that the investor can be reassured that they are investing in an entity which will (usually) not have any historic liabilities. This means that due diligence can be limited to the target assets only. Secondly, separate legal personality is established with the



SPV being distinct from the PE fund and management, usually with the aim of shielding the PE fund and management from the liabilities of the SPV (and its subsidiaries) through the principle of limited liability.

However, in the UK, investors need to be aware of the statutory liability regime that applies in relation to the decommissioning of oil and gas installations and pipelines under the Petroleum Act 1998. Broadly speaking, that regime makes all licensees jointly and severally liable for decommissioning of those installations and pipelines, and also extends that liability to associated companies of licensees and certain other persons. Given this potentially significant liability, careful consideration must be paid to the structuring of the investment from the outset to ensure that the PE fund is sufficiently disassociated from the SPV within the legal structure and does not

exercise enough control to bring it within the ambit of this regime. However, this issue needs to be balanced against the competing concern for the PE fund to have enough control to be able to effectively monitor its investment and steer the company's activities in an appropriate strategic direction.

#### **Choosing a management team**

The management team is crucial to any investment being a success. The investors will conduct significant due diligence to ensure that the management team has the appropriate skills and experience of running entities that correspond with the targets that the fund is looking to acquire and driving future growth in line with the PE fund's strategy.

Investors will also want to consider the proposed strategy of the management team. The investors will have some say in the overall strategy of

the target, but it will, under supervision, be the management team that takes this forward and implements it.

#### **Protection of investment and jurisdiction of the SPV**

The jurisdiction of the SPV used as the acquisition/investment vehicle is an important factor for the PE fund to consider to ensure that the fiscal and regulatory regimes in place are going to complement the objectives of the investment.

Tax efficiency is likely to be the biggest driver here. However, from a legal perspective, the PE fund will likely prefer the SPV to be incorporated in a jurisdiction that has a bilateral investment treaty in place with the country where the relevant assets are located, particularly when investing in emerging markets.

#### **Degree of control retained by the investors**

Although a significant degree of trust

will be placed in the management team, the PE fund will likely want to retain levels of control over the business. This is usually provided for in an investment agreement between the PE fund and the management team which will, among other things, set out a number of reserved matters which the PE fund will need to agree on, in addition to the board, before a final decision can be made.

The PE fund will usually expect to have the right, under the terms of the investment agreement, to appoint directors to the board.

### Level of investment

As mentioned above, the objectives and attitude of the PE fund will influence the type of investment, including how much equity they choose to provide. Depending on the attractiveness of the assets concerned, the PE fund may also want to ensure that it has the option to make further investments if the opportunity arises.

If the PE fund is investing in an upstream oil and gas company, the activities of that target will likely require further capital over time, for instance, to invest in further exploration in a particular region. The PE fund may not want to invest in all of these opportunities, but may want to be presented with the option to do so in preference to bringing in a new third party investor. This can be achieved by providing for pre-emption rights in respect of new equity or shareholder debt in the investment agreement.

The parties may alternatively prefer to make it clear from the outset what circumstances will trigger further investment. In such cases, the investment agreement can establish a “line of equity” whereby if the target company or assets achieve prescribed goals or criteria, the PE fund will be committed to taking a further stake or providing additional capital. If this is the case, related issues will need to be dealt with so that the line of equity can be implemented smoothly. For instance, the constitution of the SPV will need to permit increases in capital. The constitution or investment agreement will also need to deal with the consequences (if any) of an increased equity stake held by the PE fund, whether the management team will have a corresponding obligation to take up further equity, and what procedure will be followed if either party defaults on such obligations.

Where the management team defaults on this obligation (if it exists) or chooses not to provide additional capital, the PE fund will likely require an option in the investment agreement to facilitate taking up the managers’ share as well. This can be achieved in two ways: first, the PE fund could include a right to unilaterally provide further equity and proportionately dilute the equity held by the managers. However, this is likely to be unattractive or, at the very least, a disincentive to the managers. Alternatively, the PE fund could be compensated with a preference instead of further equity, so that its investment ranks above that of the managers in a liquidation.

### Degree of risk in oil and gas activities

The PE fund may be reluctant to invest in an oil and gas target with extensive future minimum commitments to fulfil. As demonstrated by the oil price in the last two years, oil and gas companies may need to have the flexibility to be able to adapt their activities to prevailing market conditions. To achieve this, the target should have freedom to select the type of projects it can

expend its capital on. The investment agreement may also support this by setting out a monetary threshold of decisions above which the PE fund must agree in advance, so that it can control how concentrated the target’s expenditure is on a particular type of activity and indirectly support diversification.

In some scenarios, the PE fund may want to obtain a right of syndication in the investment agreement. This could be particularly important, for instance, where the PE fund wants to reduce its exposure to the risks associated with activities that the target is involved in, particularly if it believes that it is no longer likely to see a satisfactory return on its investment. A right of syndication would, in such circumstances, allow the PE fund to reduce all or part of its investment by transferring it to another entity in a syndicate group which would likely be identified by the investment agreement. Importantly, this ensures that the PE fund can remain flexible and can initiate a transfer in order to invest the proceeds in a more attractive opportunity.

### Method of exit

The ultimate aim of any PE investment is likely to be to achieve a successful and profitable exit. This means that, even from the outset, investors will have to consider what type of exit option they want to put in place. Exit strategies include an initial public offering, secondary buyout (where the same management team partners with a new PE fund) and a trade sale.

### Conclusion

PE investment in the oil and gas sector is not new and it is clear from the activity we have seen in 2016 that it is likely to continue. What is new is the geography and the scale of investment in the upstream sector which PE is focused on. In the current environment, PE can potentially provide a new source of capital to the industry where other options are not currently open.

It is important that parties early on in any investment recognise the key issues, particularly those that are bespoke to the sector, and focus on agreeing those terms early to avoid any mismatch in expectations later on.



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THE IRAN QUESTION:

# Where do we stand seven months on?

by Julia Derrick, Tom Cummins, Rob Meade and Zeina Talhouni

**O**n 16 January 2016, a key milestone under the international agreement regarding Iran's nuclear programme, the Joint Comprehensive Plan of Action (JCPOA), was reached. That milestone was Implementation Day. As a result, many of the international sanctions on Iran have been rolled back, giving rise to opportunities for investors.

Implementation Day was triggered by the International Atomic Energy Agency's confirmation that Iran had complied with its nuclear obligations under the JCPOA. It signified the beginning of a programme of sanctions relief for Iran.

Expectations were high. In Iran, there were hopes that sanctions relief would reconnect Iran's economy to the rest of the world, lead to significantly increased foreign investment, and increase revenues from the country's natural resources. In Europe and elsewhere, businesses investigated the potential opportunities that would arise from sanctions relief, eager to exploit any first-mover advantage they could obtain.

Seven months have now passed since Implementation Day. In this article, we consider whether reality has met expectation. Thus far, the story is one of little steps rather than huge leaps.

## Background to the Iran sanctions

Successive sanctions have been imposed on Iran over the years. These sanctions include those imposed by the UN, the EU and the US. They have taken the form of asset freezes on certain individuals and companies; bans on the import, purchase and transport of Iranian crude oil, natural gas and petrochemical products; and a ban on any transactions with Iranian banks and

financial institutions.

The sanctions regimes have been heralded by the institutions that imposed them as a great success. The estimated cost to the Iranian oil and banking industries between 2012 and mid-2015 was more than US\$120bn.<sup>1</sup> It is this economic pressure that has been credited with bringing about Iran's concessions in the JCPOA regarding its nuclear programme.

The JCPOA was agreed between the E3/EU+3 (being China, France, Germany, the Russian Federation, the UK and the US) and the Islamic Republic of Iran on 14 July

<sup>1</sup> See "World Powers Keep Leaning on Economic Sanctions That Seldom Work", 26 April 2016, [washingtonpost.com](http://washingtonpost.com).



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*“Investment in Iran has increased and, despite the already saturated global oil market, Iran has managed to increase production.”*

2015. It was the culmination of lengthy negotiations that began in February 2013. It took Iran just six months to comply with its obligations under the JCPOA and trigger Implementation Day. On that day, as agreed, the UN, the EU and, in part at least, the US, rolled back their respective sanctions regimes. In particular, EU and some US sanctions on the import and transportation of oil and gas and petrochemical products, access to the banking system, energy sector investment, access to transport hubs, and the export of gold and precious metals, were removed.

However, certain sanctions have remained in place. For example, the following remain in effect:

- US primary sanctions (with limited exceptions), which significantly restrict the extent to which US individuals and companies can participate in any Iranian opportunities;
- US and EU sanctions on Iran for terrorism and human rights abuses;
- US and EU sanctions relating to the supply to Iran of nuclear and

arms-related items, the supply to Iran of graphite, certain raw or semi-finished metals, and software with a nuclear or military application, which are to remain in place until October 2023 (Transition Day under the JCPOA); and

- a number of asset freezes for named individuals and companies (including Iranian banks such as Ansar Bank, Bank Saderat Iran, Bank Saderat plc and Mehr Bank).

In addition, following Implementation Day and in response to missile tests being conducted by Iran, the US imposed new sanctions on a number of Iranian entities and individuals that it considered were linked to the Iranian missile programme.

### **The first six months of sanctions relief – a two-sided story**

Since Implementation Day, investment in Iran has increased and, despite the already saturated global oil market, Iran has managed to increase production.

There are a number of examples of increased economic activity.

### **Support for investment in Iran by foreign governments and increased activity between Iran and private sector companies across a range of sectors, including oil and gas**

Since Implementation Day, there has been a steady flurry of announcements regarding new agreements signed between Iran and both foreign governments and private sector companies across a wide variety of industries.

Credit lines are reportedly being made available to companies wishing to invest in Iran and a number of countries have announced measures and bilateral investment agreements to help protect investments made by foreign companies into Iran. For example, to mention a few, it has been reported that:

- Coface (the French export credit agency) has agreed to guarantee French investments in Iran;

- Iran and Italy released a joint statement setting out a plan for bilateral co-operation between the two countries. Cassa Depositi e Prestiti (the Italian state-owned lender) plans to issue credit lines of €4bn to Iranian counterparties to support major infrastructure, oil and gas, and transport projects involving Italian companies, and SACE (the Italian export credit agency) has agreed to guarantee these;
- the Export-Import Bank of Korea intends to make available more than US\$5bn of financing to Korean companies seeking to invest in Iran; and
- Iran and the Government of Japan have signed a bilateral investment agreement on reciprocal promotion and protection of investment between the two countries.

The availability of finance appears to be having a positive impact on interest and investment activity in Iran across a range of sectors including agriculture, health, telecommunications, aeronautics, automotive, transport and energy.

In the energy sector, there have been numerous deals and memoranda of understanding announced, including:

- a memorandum of understanding between OMV and National Iranian Oil Company (NIOC) concerning the evaluation of various fields in the Zagros area in the west of Iran for potential future development;
- a framework agreement between Total SA and NIOC for the purchase of crude oil, and a memorandum of understanding under which NIOC will provide technical data allowing Total to assess potential developments;
- an agreement between Siemens and Mapna (an Iranian power and infrastructure group), under which the two parties will co-operate to deliver gas turbines and associated generators, and a memorandum of understanding to jointly develop a plan to expand and improve Iran's overall power and electricity system;
- a memorandum of understanding between Italy's Saipem and the Razavi Oil & Gas Development company to collaborate in developing the Toos Gas

Field project, with estimated deposits of more than 60bnm<sup>3</sup> of gas;

- an agreement between Greek oil refiner Hellenic Petroleum and NIOC for co-operation for the supply of crude oil, with deliveries to commence immediately, and for the settlement of financial liabilities; and
- a proposed joint venture between Helma Vantage and Kharg Petrochemical Company to produce and export liquefied natural gas and liquefied petroleum gas.

### Release of Iranian Petroleum Contract

On 30 September 2015, the Government of Iran issued the Iranian Petroleum Contract Bill, which sets out the general terms of the new Iranian Petroleum Contract (IPC). The IPC is intended to replace the previous buyback contract, offering more attractive and flexible terms and conditions for international oil companies seeking to undertake exploration and production activities in Iran. Although the full and exact terms of the IPC have not yet been issued, the key terms were discussed at the Tehran Summit in November 2015 with an official release of the full terms anticipated in September 2016. On 3 August 2016, after undergoing several rounds of amendments and modifications, Iran's Cabinet of Ministers approved the general terms, structure and model of the IPC. In a further indication that Iran is getting ready to launch a licensing round, NIOC announced on 18 July 2016 that it would shortly be publishing a preliminary list of international oil companies eligible to take part in tenders to develop its oil and gas fields<sup>2</sup>.

Under this new model, international oil companies are required to form an incorporated or an unincorporated joint venture with the NIOC (or a subsidiary entity), an approach geared towards ensuring the adequate transfer of technology and the satisfaction of local workforce employment thresholds imposed by the state. The joint venture would be entitled to undertake field exploration, appraisal, development and – for the first time since 1979 – production activities with an Iranian entity acting as

<sup>2</sup> See "Iran to name international oil companies eligible to take part in tenders", 18 July 2016, [reuters.com](http://reuters.com).







the owner (or employer) supervising the planning and operation.

In contrast with the previous buyback contract model, the new IPC proposes to abolish the cap on cost recovery in favour of a system whereby costs are regulated through an annual work programme and budget. The IPC will provide for an extended contract duration of up to 20 years from the date of development operations, allowing for increased certainty and significantly longer cost recovery after first production. Remuneration fees will be determined as a percentage of production expressed as a fee per barrel and will be structured in a more flexible manner in order to address dramatic changes in technical and financial conditions, incentivising international oil companies to expand improved oil recovery and enhanced oil recovery techniques that are crucial for maximising the amount of resources extracted from fields. There are a number of areas which remain unclear in respect of the new IPC, notably whether international oil companies will be able to book reserves.

There are a number of areas which remain unclear in respect of the new IPC, notably whether international oil companies will be able to book reserves.

### Increased Iranian oil production

Iran's oil production levels have risen significantly since the lifting of the sanctions. Production currently stands at 3.7m barrels per day, reflecting an increase of almost 60 per cent from last year. Exports have risen at an even greater rate, reaching 2m barrels per day in May 2016 with China importing 800,000 barrels of crude a day.

Oversupply in the oil market has prompted proposals to freeze the output of crude oil among OPEC and non-OPEC countries in a bid to stabilise the market price. At the OPEC meeting in Doha in April 2016, the proposals to freeze output was met with resistance by Saudi Arabia on the basis of Iran's refusal to participate in the scheme. Kuwait has recently voiced its concern around a further collapse in oil prices, requesting that Iran participates in a production freeze. However, Iran has instead been concerned with ramping up its own production and reclaiming its market



share as it competes with Saudi Arabia for customers.

Iranian officials previously stated that its current stance will remain until pre-sanction export levels of 2.2m barrels per day and pre-sanction production levels of 3.56m barrels per day are achieved. Whether or not Iran will be willing to curb oil production in the near future remains a point of uncertainty. A statement issued by a senior Oil Ministry official in April indicated that Iran may be open to co-operating in a renewed effort to restrain output at the next OPEC members' meeting in June. However, at the OPEC meeting in June 2016, it has been reported that Tehran resisted an attempt to set a collective ceiling on output, with its minister of petroleum insisting that Iran deserved a quota of 14.5 per cent of OPEC's overall production. Such a policy would give Iran a quota of 4.7m barrels per day, well above its current output.<sup>3</sup>

#### A tale of hesitation

Although there has been some success in opening the Iranian economy post-Implementation Day, it has not been

the "big bang" moment that some commentators anticipated and that many in Iran had hoped for. Instead, progress has been gradual.

The International Energy Agency (IEA) noted in its March 2016 Oil Market Report that "*Iran's return to the market has been less dramatic than the Iranians said it would be; in February we believe that production increased by 220 kb/d [to 3.22 mb/d] and, provisionally, it appears that Iran's return will be gradual*".<sup>4</sup> Although, in an indication that confidence is increasing, the IEA's May 2016 Oil Market Report noted that "*Iranian oil production in April neared 3.6 mb/d... a level last reached in November 2011*".<sup>5</sup>

The more-gradual-than-expected growth can be linked to hesitation among those interested in doing business in Iran and those needed to finance such business. That hesitation stems from uncertainty: uncertainty over the scope of remaining US sanctions; uncertainty over whether the sanctions will "snap back" into place; and uncertainty over the long-term commitment of the US to the JCPOA.

#### The remaining US sanctions

Cash and debt are the lifeblood of many investments and new enterprises. Much of the nervousness over the scope and reach of the remaining US sanctions is found in the banks and financial institutions that are approached to finance investments in Iran or to facilitate transfers to or from Iranian parties.

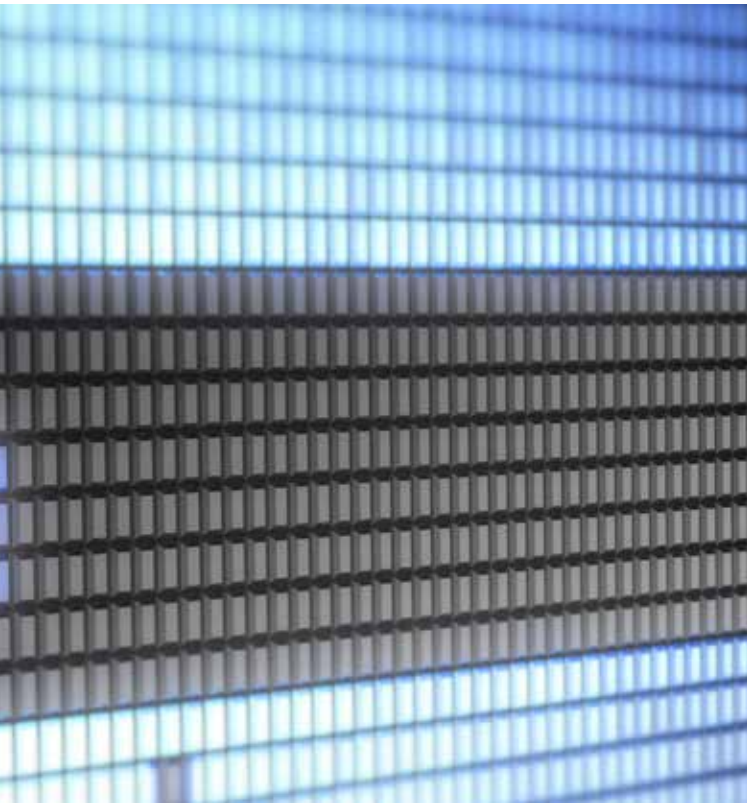
US financial institutions are directly prevented from playing a role in such transactions. However, many non-US financial institutions are also reluctant, possibly in part due to recent memories of the US imposing substantial fines on non-US financial institutions for breach of sanctions. It remains unclear whether the US will seek to prohibit the activities of non-US financial institutions with a US nexus in relation to Iran. Until that clarity is obtained, we can expect the banks to tread carefully. In any event, non-US banks will not be able to do business with Iran in US dollars cleared through the US.

The tale should not be seen as an entirely negative one, however. Change appears to be on the horizon. When asked about the concerns of European banks relating to the remaining US sanctions, US Secretary of State, John Kerry, recently stated that "*Banks in Europe are allowed to*

<sup>3</sup> See "OPEC fails to agree policy but Saudis pledged no shocks", 2 June 2016, reuters.com.

<sup>4</sup> International Energy Agency – Oil Market Report, 11 March 2016.

<sup>5</sup> See "Oil demand growth strengthens in Q1 – IEA", 12 May 2016, ft.com.



*open accounts for Iran, banks in Europe are allowed to do business, banks in Europe can fund programs, lend money. That's absolutely open for business as long as it's not a designated entity, period, very simple".<sup>6</sup> Similarly, on 19 May 2016, a joint statement by Kerry, the foreign ministers of Britain, France and Germany and the EU's foreign policy chief stated that "We will not stand in the way of permitted business activity with Iran, and we will not stand in the way of international firms or financial institutions engaging with Iran, as long as they follow all applicable laws". Whether these statements are enough to boost confidence and trigger the level of investment Iran was hoping for remains to be seen.*

### Snap back

There remains a risk that the sanctions lifted on Implementation Day may snap back into place in the future if Iran violates the JCPOA, and this is not resolved in accordance with the dispute resolution procedure set out in the JCPOA.

Although the snap-back provisions will not give rise to retroactive liability for contracts which are entered into between Implementation Day and any snap back occurring, continued performance of long-term contracts would not be possible. This concern may be having a negative impact on the confidence of potential investors.

It would be sensible for those choosing to take the risk to consider including within their contract provisions that would allow them to exit those contracts without liability should a snap back occur.

### The long-term commitment of the US to the JCPOA

There has been much speculation about the outcome of this year's

US presidential election and its impact on continued US sanctions relief for Iran. This has led to further uncertainty and for many to question the long-term security of any investments they choose to make in Iran.

If the Republicans take the White House, serious doubt may be cast on the long-term commitment of the US to the JCPOA. The Republican presumptive nominee, Donald Trump, has expressed deep dissatisfaction with the deal struck with Iran. Trump has stated that he wants to "dismantle" what he termed a "disastrous" nuclear weapons deal with Iran.<sup>7</sup>

By contrast, the Democratic presumptive nominee, Hilary Clinton, has supported the nuclear deal struck by the Obama administration.

### Where does this leave us?

In the six months since Implementation Day, progress has been made in reintroducing Iran to the global economy. Assets have been unfrozen, there has been an increase in Iranian oil production, and many foreign businesses are beginning to invest in the country. However, uncertainty over the scope of the US sanctions, the potential snap back of EU and US sanctions, and the long-term sustainability of the JCPOA, mean that there is still much nervousness among businesses and financial institutions.

Business confidence will gradually increase if Iran continues to comply with its obligations under the JCPOA and as the scope and impact of the remaining US sanctions becomes clear. This will undoubtedly lead to greater investment into the country.

Has reality met expectation? No, at least not the expectations held by Iran. However, the JCPOA is working and, slowly but surely, investment in Iran is increasing.

<sup>7</sup> See "Trump reveals unorthodox foreign policy views", 22 March 2016, [bbc.co.uk](http://bbc.co.uk)



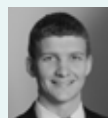
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<sup>6</sup> See [state.gov/secretary/remarks/2016/05/257079.htm](http://state.gov/secretary/remarks/2016/05/257079.htm).





## UK NORTH SEA FISCAL REGIME:

# Where are we now?

by Nicholas Gardner and Tim Gummer

On 17 March 2016, in Budget 2016, the Chancellor announced a number of headline-grabbing measures designed to support the UK oil and gas industry and to encourage investment in exploration, infrastructure and late-life assets. The most prominent announcements concerned “*effectively abolishing*” Petroleum Revenue Tax (PRT) and halving the rate of Supplementary Charge (SC) from 20 per cent to ten per cent. The effect is the reduction of the effective marginal rate of tax payable in respect of all fields on the UK Continental Shelf (UKCS) to 40 per cent.

This article is designed to provide: (i) an update as to where we are now in the context of the fiscal regime which applies to activities on the UKCS; and (ii) analysis of the extent to which the announcements made in Budget 2016 are likely to be beneficial for companies operating on the UKCS, particularly in the context of the current environment of around US\$45 per barrel of oil (at the time of writing).

### Background to the UKCS regime

Oil and gas-related activities on the UKCS are subject to a special fiscal regime and, prior to Budget 2016, profits arising from such activities were subject to ring-fence corporation tax (RFCT) at a rate of 30 per cent, SC at a rate of 20 per cent and, if

development consent was obtained prior to 16 March 1993, PRT at a rate of 35 per cent. This gave an effective marginal tax rate of 67.5 per cent for PRT fields and 50 per cent in other cases.

Investment in the UKCS is encouraged by tax relief being provided for expenditure on research, exploration, appraisal and production, either through capital allowances (broadly, the UK’s form of allowable “tax” depreciation) and also, once production has commenced, through tax deductions for expenses incurred wholly and exclusively for the purposes of an eligible trade. However, a ring-fence applies to all fields (irrespective of when development consent was obtained) which prevents profits arising within the ring-fence (which are subject to RFCT, SC

and, historically, PRT) from being sheltered by losses arising from activities carried on outside the ring-fence.

The majority of expenditure on exploration and development in the pre-production phase is eligible for 100 per cent tax relief in the form of mineral extraction allowances. Expenditure on research and development, before significant reserves have been found, is generally eligible for 100 per cent tax relief in the form of research and development allowances. Other capital expenditure is generally eligible for relief in the form of plant and machinery allowances.

Even before the most recent measures announced in Budget 2016, the UK Government introduced measures in 2014 and 2015 to support its objective of





providing “the right conditions for business investment to maximise the economic recovery of the UK’s oil and gas resources at a time when the North Sea industry is facing considerable challenges”. These measures included:

- (a) the introduction of a “cluster area allowance” in Budget 2014, with effect in relation to investment expenditure incurred on or after 3 December 2014, which is intended “to support the development of high pressure high temperature (HPHT) oil and gas projects and encourage exploration and appraisal within the surrounding area”. The cluster area allowance reduces adjusted ring-fence profits which are subject to SC by 62.5 per cent of the capital expenditure incurred in relation to the cluster area;
- (b) the introduction of an “investment allowance” at Budget 2015, with effect in relation to accounting periods ending on or after 1 April 2015, which is intended “to encourage investment in the UKCS, leading to increased production of oil and gas, helping to increase the UK’s energy security, balance of payments and supporting jobs and supply chain opportunities”. The investment allowance is also

designed “to simplify and replace the historic regime of field allowances”. The investment allowance serves to reduce profits subject to SC by 62.5 per cent of the investment expenditure incurred. The field allowance regime, which was introduced in 2009 and which the investment allowance replaces, was designed to provide an incentive “for the development of new economic but commercially marginal oil and gas fields”. The field allowance operated by reducing the amount of adjusted ring-fence profits which are subject to SC but was considered to be overly complicated and to create an unnecessary administrative burden on UKCS participants;

- (c) the reduction of SC from 30 per cent to 20 per cent with effect from 1 January 2015 (announced in Budget 2015); and
- (d) the reduction of PRT from 50 per cent to 35 per cent for all chargeable periods ending after 31 December 2015 (also announced in Budget 2015).

The trend in recent years has been for the Government to reduce the fiscal burden on licensees, with a focus on incentivising investment in the more challenging and technically demanding fields in the UKCS.

This has continued in the announcements made in Budget 2016 in relation to investment allowances and cluster area allowances, but Budget 2016 also included important announcements in relation to decommissioning and PRT.

### Effective abolition of PRT

The announcements in Budget 2016 in relation to the effective abolition of PRT and the reduction in the rate of SC must be viewed in the context of sustained periods of falling revenues for the Exchequer from the UKCS (see figure 1) and falling oil production in the North Sea (see figure 2). In particular, in the year to 30 June 2015, PRT profits had declined by 55 per cent to £1.116bn and PRT revenues had declined by a similar proportion to £473m, with eight fields out of the total 54 fields having generated 86 per cent of all PRT.<sup>1</sup> The figures in figure 1 show the significant reduction in fiscal revenues from UKCS activities when compared with the total corporation tax receipts from both UKCS and non-UKCS activities received in the same period.

On the one hand, the fact that many companies engaged in UKCS activities are

<sup>1</sup> Statistics of government revenues from UK oil and gas production, released January 2016.

not currently in a taxpaying position will mean that the reduction in the rate of PRT to zero does not provide these companies with any immediate cash-flow benefits.

However, rather than abolishing PRT in its entirety, the reduction of the rate of PRT to zero means that it will still be possible to carry back losses arising in respect of PRT fields to set against historic PRT liabilities in previous accounting periods, and there is no restriction on the number of accounting periods in which any such losses can be carried back.

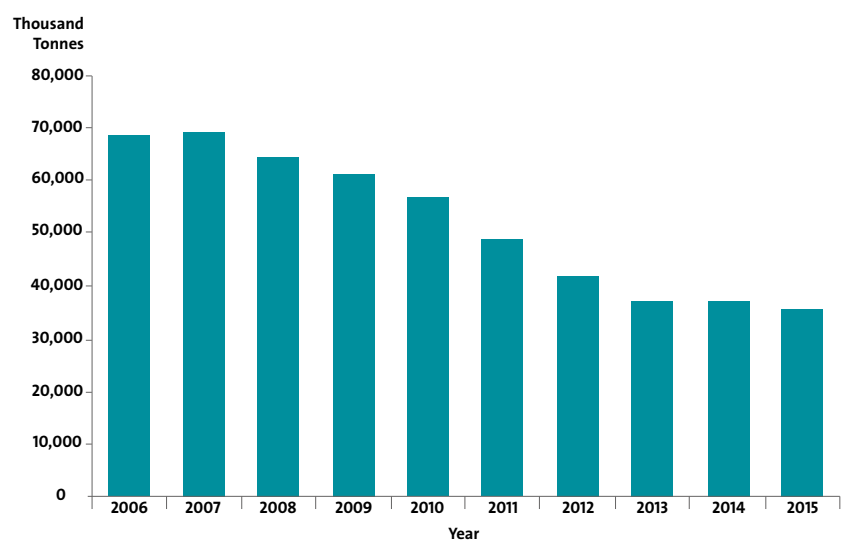
As a result, it may be possible to generate substantial PRT repayments from expenditure on PRT fields for participants with interests in PRT assets. As set out in the latest available government figures (see figure 1), the Government is aware that substantial claims for PRT repayments will be made, as the Government is anticipating that the Exchequer's revenues from PRT will be negative in 2015–16, with more than £500m of PRT repayments being claimed (see figure 1).

The UK tax legislation also enables unused PRT expenditure and PRT losses to be transferred by an old participant (the seller) in a PRT field to a new participant (the buyer) in the event of a sale of the seller's interest in a PRT field. However, the legislation is more restrictive in relation to the transfer of losses by the buyer to the seller following the sale of an interest in a PRT field: in those circumstances, the position is, broadly, that the maximum amount of losses which can be transferred from the buyer to the seller is capped at the amount which had previously been transferred by the seller to the buyer (as referred to above). As a result, it is not possible for a non-taxpaying buyer to surrender PRT losses arising from expenditure incurred by the buyer in relation to a PRT asset to the seller, which has historically paid PRT in order to generate a PRT repayment in the seller's hands.

A group which has interests in both PRT and non-PRT fields may, as a result of the ability to carry back losses to effect repayments of PRT as summarised above, be incentivised to incur expenditure in connection with PRT fields rather than non-PRT fields as a result of the PRT repayments which could be generated as a result of incurring such expenditure.



**Figure 1: UKCS Oil Production 2006-2015**



Source: KAI Data Policy and Coordination, HMRC Tax & NIC receipts, April 2016, gov.uk.





The rule, arguably, creates an asymmetric position in that if a seller carries out significant capital expenditure in respect of a PRT field in question, this may enable the seller to obtain immediate tax relief in circumstances where the buyer would not obtain tax relief for carrying out the same expenditure on the same asset following the transfer of the seller's interest in the licence.

### Reduction in SC

The reduction in the rate of SC should, however, improve the viability of future projects for all companies from a financial modelling perspective. The Chancellor hopes that reducing the rates of PRT and SC will encourage investment, but in the context of ongoing macro-economic pressures on global oil prices, the less high-profile announcements in Budget 2016 relating to investment allowances

and cluster allowances may have a more immediate effect (as to which, see below).

We would not anticipate that the reduction in the value of deferred tax assets resulting from the reduction in the rate of SC would be of significant concern, particularly for those companies which are currently non-taxpaying, because the deferred tax asset would only be of real economic benefit when the entity in question becomes taxpaying. A possible issue could arise, however, if a write-down in the value of deferred tax assets included on a company's balance sheet significantly reduces the assets of the company in question.

### Investment allowance and cluster area allowance

Prior to Budget 2016, the investment allowance and cluster area allowance were only "activated" (meaning made available to be set off against profits

subject to SC) once income from production in the relevant field had commenced. However, following Budget 2016, the investment allowance and cluster area allowance may be activated when tariff income is received. "Tariff income" is expected to include fees payable to the owners of infrastructure (such as pipelines and platforms) on the UKCS, but we await the publication of the relevant secondary legislation which will contain the definition of "tariff income" for these purposes and details of any commencement provisions of the new legislation.

This proposal should assist companies investing in tariff-generating infrastructure which should, in turn, lead to improved efficiency and reduced ongoing repair and maintenance costs following an upgrade of aging infrastructure on the UKCS.



## Decommissioning

In the context of the current macro-economic challenges facing the North Sea oil and gas industry, decommissioning issues, and particularly the question of with whom the economic burden of decommissioning liabilities should lie, have frequently been a significant challenge to transactions involving the transfer of UKCS licence interests.

A combination of commercial factors has led to certain transactions being structured such that the seller retains some or all of the decommissioning liabilities in question. Purely from a tax perspective, as many companies operating on the UKCS are not currently taxpaying, tax relief in respect of decommissioning costs may be of greater value to a taxpaying seller than to a buyer which is

likely to be non-taxpaying for a number of years.

Provided certain conditions are satisfied, expenditure incurred on decommissioning qualifies for tax relief in the form of capital allowances.<sup>2</sup> The relevant legislation does not, however, state whether a person incurring expenditure on decommissioning must hold an interest in a UKCS licence at the time the expenditure is incurred.

Despite the legislation having been enacted for many years in substantially the same form, at Budget 2016, the Government published a technical note setting out clarifications of HMRC's interpretation of these provisions. This

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<sup>2</sup> Chapter 13 of Part 2 of the Capital Allowances Act 2001 and, in particular, sections 162 to 165 (inclusive).

confirms that: (i) HMRC accept that in a scenario where a buyer and seller agree that the seller will remain liable for decommissioning expenditure after the transfer of a licence interest, the seller may be entitled to tax relief in the form of capital allowances in respect of such expenditure; and (ii) it is not a requirement in these circumstances that the seller holds a notice under section 29 of the Petroleum Act 1998 before a claim for capital allowances can be made by the seller. Albeit it is arguable that since these were not express requirements of the legislation, it would be surprising had it been necessary to satisfy these conditions in order to claim the allowances.

The technical note also states that, in HMRC's view, the seller must be directly liable for the costs of decommissioning and must not simply contribute to the costs incurred by another person. HMRC consider this means that legal action could be taken against the seller in the event that those costs are not met. While the technical note does not specifically address how this should be achieved, we understand from HMRC that they would generally expect the seller to remain a party to the relevant joint operating agreement even after the seller has ceased to hold an interest in the licence itself. This may entail obtaining agreement of any relevant third parties, which may not be straightforward.

Given the significant costs of decommissioning and the factual differences in respect of each transaction, HMRC acknowledge and accept that taxpayers are likely to seek advance clearance from HMRC in order to confirm the tax treatment of decommissioning costs incurred by sellers in these circumstances.

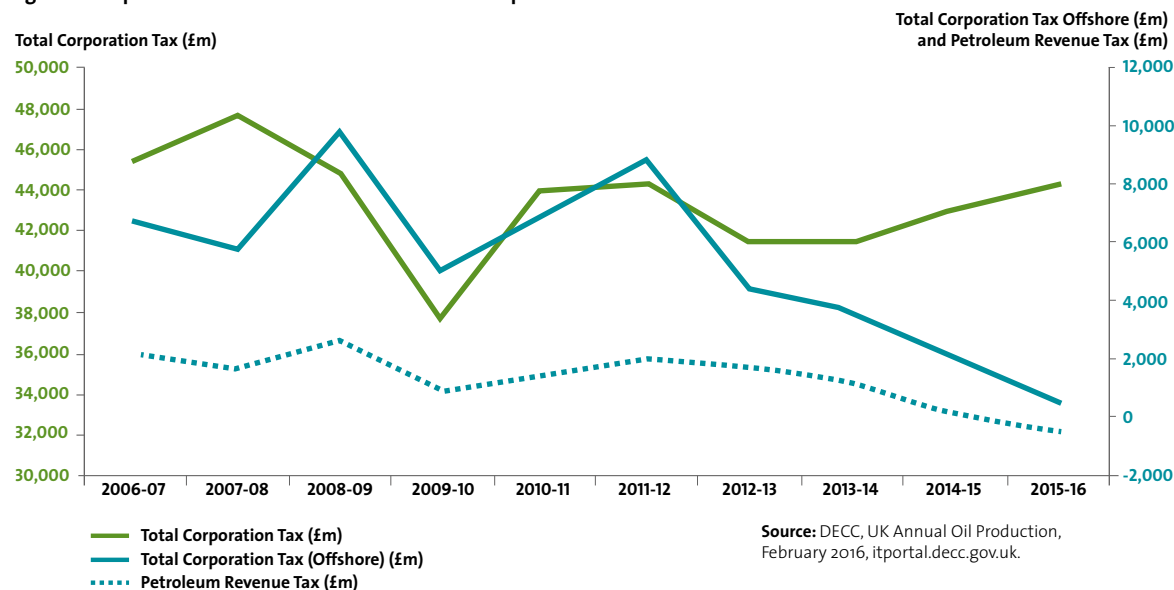
## Carried-forward losses

At Budget 2016, the Chancellor announced reforms to the UK regime relating to the use of corporation tax losses in future accounting periods.

Prior to Budget 2016, corporation tax losses could be carried forward to future accounting periods and could be used to set off against profits arising in the same company from future profits in the same trade.



**Figure 2: Corporation Tax/Petroleum Revenue Tax Comparison**



From 1 April 2017, trading losses will be able to be carried forward to set off against total taxable profits (rather than just profits of the same trade) arising in any member of the company group for corporation tax purposes. However, from the same date, companies will only be able to use losses carried forward against up to 50 per cent of the profits above £5m arising in the group as a whole.

The changes to the use of carried-forward losses is likely to have profound implications for many companies subject to UK corporation tax. However, the Budget 2016 Policy Paper confirms these changes will not apply to the North Sea RFCT regime. Many such companies will, however, be subject to the new rules in relation to activities carried on outside the ring-fence.

### Transferring unactivated allowances

Transactions relating to the transfer of UKCS licence interests are frequently structured such that a buyer provides consideration in the form of cash and the assumption of certain liabilities of the seller. The value of the aggregate consideration payable by the buyer is generally allocated between the parties to items qualifying for allowances (e.g. mineral extraction allowances, investment allowances, cluster area allowances, or plant and machinery allowances) with the balance attributed to the licence interest. This allocation will continue to be required after Budget 2016. This allocation should be made on a just or reasonable basis, otherwise there is a risk that adjustments to the allocation may be made by HMRC as a result of a failure by the parties to make a reasonable apportionment.

Documentation effecting transfers of UKCS licence interests in fields which do not yet generate tariff income and which are not in the production phase should now also include provisions which make clear that: (i) unactivated pools of investment allowances and cluster area allowances transfer to the buyer on completion; (ii) the buyer and seller agree to file their tax returns on this basis; (iii) any expenditure which is incurred in the interim period (i.e. between the effective date and completion) which

is accrued by the seller but ultimately paid for by the buyer is not subject to claim for allowances by the seller; and (iv) subject to the bargaining power of the buyer and the level of potential allowances in question, the seller is incentivised to carry out a detailed review of expenditure incurred by the seller to maximise any claims for allowances by the buyer.

### Conclusion

Only time will tell whether the Chancellor's announcements in Budget 2016 will have the effect of promoting investment in the UKCS and, even then, if global oil prices rise, whether any increased oil production and tax receipts are attributable to the measures announced in Budget 2016 or simply to macro-economic forces. However, for current participants in UKCS activities which are in a taxpaying position, Budget 2016 should bring an immediate benefit in the reduction in the rates of SC and PRT. Furthermore, the measures summarised above are likely to result in PRT assets becoming of increasing interest, and companies are likely to review investment opportunities in infrastructure projects which may become more viable in the context of the amendments to the investment allowance and cluster allowance regimes. For both existing participants and new entrants to the market, the amendments to the decommissioning rules, which frequently hamper the viability of projects and investments, may unlock new sources of capital and new entrants to the market.



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## UK WASTE GASIFICATION:

# Is its future tied to the capacity gap debate?

by Nick Stalbow and Cameron Smith

**W**ith the pipeline of large UK municipal waste procurements coming to an end and the ROCs' deadline looming, the UK energy from waste market has shifted to the development of merchant projects supported by the new Contracts for Difference (CfD) scheme.

With CfD offering support for advanced waste technologies, a large number of waste gasification developers are preparing to bid at auction. However, they face being snuffed out by offshore wind unless the Government is persuaded that there remains a compelling policy need for more waste infrastructure.

### Overview

The nascent UK waste gasification market is on the runway. There are a significant number of greenfield sites secured by

developers as suitable for new waste infrastructure using gasification technology. There is strong interest in these schemes from a significant number of energy and infrastructure funds, and there are a number of technology suppliers actively looking to leverage off their track record outside of the UK. Whether or not the market takes off will turn on two things: (i) the level of support offered by the CfD scheme, and (ii) the ability to secure waste or waste-derived feedstock.<sup>2</sup> These two drivers are closely linked.

### What is “merchant waste” gasification?

Over the last ten years, the UK waste infrastructure market has been dominated by PPP schemes (some supported by PFI credits from central government) under which long-term municipal waste commitments have created a platform for investment in new waste infrastructure. The technology choice for thermal treatment solutions has generally been incineration – an established technology with a track record – although a few recent exceptions have involved gasification technology. With the PPP pipeline now coming to an end, the market for new

<sup>1</sup> Renewables Obligation Certificates issued under the Renewables Obligation scheme.

<sup>2</sup> This is known in the industry as RDF or SRF. References in this article to waste are intended to capture also RDF and SRF derived from the treatment of waste.





infrastructure has moved to a different model based on waste secured from the private sector. This waste originates either from the output of municipal pre-treatment projects or from the trade waste market and is called “merchant waste”. The Government’s support for gasification over incineration and the appetite for merchant supply risk has led to a number of development schemes in the UK of around 100,000–200,000 tonnes per annum throughput, producing around 10-15 MW of electricity. These schemes often have a light mechanical pre-treatment stage as a first step in order to regulate the quality and consistency of the waste feedstock into the gasifier. The electricity is either exported to the grid or to a dedicated offtaker on a private wire.

### Why is there CfD support for waste gasification?

The CfD scheme was introduced, as part of Electricity Market Reform, to continue the

Government’s support for new renewable electricity generation, in particular to meet its binding national target under the 2009 EU Renewables Directive to achieve 15 per cent of all energy consumption (i.e. electricity, heat and transport fuels) from renewable sources by 2020. This target is likely to increase as the EU now moves towards a target of 27 per cent for 2030. A consultation is currently ongoing for a new directive to implement that target. Brexit (the term used to refer to the UK’s decision to leave the EU) creates some uncertainty over whether any new target would be adopted by the UK. If the UK joins the EEA, then it would be adopted. If it trades with the EU through other arrangements, then EU renewable energy and waste-related targets may or may not be a condition of that deal.

The UK counts towards its 2020 target all electricity generated from the biomass element of waste processed through energy from waste facilities

provided that they are combined heat and power (CHP) facilities that meet certain quality criteria: advanced conversion treatment (ACT) (e.g. gasification and pyrolysis) and anaerobic digestion. These technologies are currently also eligible for support under the green certificate Renewables Obligation (RO) scheme, but the RO scheme will be closing to new accreditations on 31 March 2017 (or even earlier, for some technologies), subject to some grace periods. For this reason, going forward, the new CfD regime is the main source of support for low-carbon generation, including waste gasification.

### Key features of CfDs

CfDs are long-term contracts, pursuant to which low-carbon generators are paid a top-up above the wholesale price (the reference price), up to a set “strike price”. CfDs have a two-way payment mechanism, so if the wholesale price is higher than the strike price, the generator will be required

to make a payment back to the CfD counterparty. A strike price for different technologies has been determined using an administrative process, but the allocation process (see below) means that generators may not necessarily receive the strike price or a CfD at all. The CfD contract itself is entered into between the generator and a government-owned company, the Low Carbon Contracts Company (LCCC), which acts as a “conduit” for the payments under the CfD – that is, the LCCC makes the top-up payments to generators under CfDs, but these payments are funded by a levy imposed on licensed electricity suppliers, with the cost passed down to consumers.

For reasons of cost control and to ensure there is competition that drives value for money for the Government, most CfDs (including CfDs for waste gasification projects) are awarded through allocation rounds. This is a key difference between the RO and CfD regimes: under the RO, projects were able to apply for support through accreditation at any time (subject to achieving commissioning and meeting other eligibility requirements), while under the CfD regime, an allocation round is the only opportunity to apply for support.

The first allocation round commenced in October 2014 with much fanfare, and was open to a wide range of technologies. It is important to note that the CfD budget for the first allocation round was divided into two different “pots”: one for established technologies (which included energy from waste with CHP) and one for less established technologies (which included less proven waste technologies such as ACT and anaerobic digestion (see figure 1)). This was driven by the Government’s aim to obtain value for money for mature technologies through immediate competition for a more limited budget, and to stimulate investment in new and innovative technologies which have not yet been widely deployed in the UK and therefore are unable to reduce costs through the scale and maturity of their supply chains. The Government’s stated long-term goal is to secure a diverse mix of low-cost renewable energy generation, which ultimately does not require government support. In the end, because the level of interest in a CfD

exceeded the available budget across all the technologies, the allocation round took the form of an auction for both pots of money. What this meant in practice is that not all applicants were successful; and those who were successful, for the most part, received a strike price lower than the administrative strike price. Among the winners were three waste gasification projects.<sup>3</sup>

Originally, allocation rounds were intended to take place once a year, but there has been a change of approach on this issue. The Government cancelled the second allocation round scheduled to take place in October 2015. Earlier this year, the Government said that it would hold another allocation round by the end of 2016 and another two during the current Parliament (see figure 2). However, this still leaves a high degree of uncertainty, at the time of writing, about the dates of these allocation rounds and, importantly, what technologies will be eligible to participate.

In terms of the budget available for future allocation rounds, the Government announced in its March 2016 Budget that it would “auction Contracts for Difference up to £730 million this Parliament for up to 4 GigaWatts of offshore wind and other less established renewables, with a first auction of £290 million”.

### Why waste gasification relies on CfD

The project economics of waste gasification schemes are heavily reliant on the revenues from electricity generation (the other key revenue being the gate fees for receiving waste). By virtue of their feedstock, the facilities are highly regulated under the Industrial Emissions Directive 2010/75/EU (previously under the Waste Incineration Directive 2000/76/EC) and the Environmental Permitting (England and Wales) Regulations 2010. Capital cost is relatively high per MW of capacity as a result of the combination of the cost of regulatory compliance and an immature supply chain. The technology itself is also relatively untested on a commercial scale, so lifecycle forecasting, availability assumptions and performance

efficiency projections, all present more risk to investors and funders than the proven incineration technologies behind many of the UK waste PPP projects. That technology risk has been highlighted by the recent demise of the largest merchant gasification project in the UK – the Air Products facility in Teesside.

A government-backed top-up above the wholesale electricity price is therefore key to investment in these merchant gasification projects, unless they can secure fixed, long-term power purchase agreements significantly above the current wholesale electricity price. Without that support, the project economics will be affected by price fluctuations in the electricity market and may become more sensitive to movements in merchant waste gate fees.

While there is talk of waste gasification and pyrolysis plants potentially being self-funding without the need for central government subsidies, it is likely that any such schemes are several years away. Until then, the CfD regime is critical for their economic viability, particularly where third party capital is required.

### Will waste gasification be blown away?

The waste gasification industry is concerned that all of the Pot 2 money could be awarded to offshore wind, crowding out the other technologies in the pot. This is mainly due to the large scale of offshore wind projects and the risk that offshore wind developers are able to bid more competitive strike prices than ACT developers at the CfD auction. On the latter point, ACT developers argue that offshore wind is further down the experience cost curve in terms of deployment and supply chain, and it is therefore perceived by funders and investors to represent a lower level of risk (therefore attracting lower funding costs). In contrast, the gasification sector has achieved relatively small-scale deployment to date in the UK and the economies of scale and operational track record are still developing. Gasification developers therefore face tough competition from offshore wind at the CfD auctions, in addition to the competitive tension from other gasification projects.

<sup>3</sup> For a full analysis of the results of the first allocation round, see our earlier article “Such a long journey: evaluating the UK’s Electricity Market Reform”, EnergySource, Issue 15, July 2015.

**Figure 1: CfD technology split**

Pot 1 – Established technologies	Pot 2 – Less established technologies
<ul style="list-style-type: none"> <li>Onshore wind (&gt;5 MW)</li> <li>Solar photovoltaic (&gt;5 MW)</li> <li>Energy from waste with CHP</li> <li>Hydro (&gt;5 MW and &gt;50 MW)</li> <li>Landfill gas</li> <li>Sewage gas</li> </ul>	<ul style="list-style-type: none"> <li>Offshore wind</li> <li>ACT (gasification and pyrolysis)</li> <li>Wave</li> <li>Tidal stream</li> <li>Anaerobic digestion</li> <li>Dedicated biomass with CHP</li> <li>Geothermal</li> <li>Scottish Islands onshore wind</li> </ul>

**Figure 2: CfD allocation rounds (post and planned)**

CfD allocation round	Date	Budget available
1	February 2015	£325m for delivery years through to 2020/21
	October 2015 – allocation round cancelled	Nil
2	Before the end of 2016	To be announced – total commitment is £730m and this first of three rounds is expected to allocate £290m with effect from 2021/22 onwards, but the exact amount is to be confirmed
3	Before the next election, but no date fixed as yet	To be announced – but it will be a proportion of the remaining £730m commitment
4	Before the next election, but no date fixed as yet	To be announced – but it will be a proportion of the remaining £730m commitment

## Gasification can be protected within Pot 2

If the new Department for Business, Energy and Industrial Strategy (BEIS) is minded, it has the statutory powers to protect ACT within Pot 2. Under the existing provisions in the CfD scheme (Regulation 11 of the Contracts for Difference (Allocation) Regulation 2014), the Secretary of State has a discretion to ring-fence a certain allocation to certain technologies within Pot 2 (less established technologies). This can be done by ring-fencing a proportion of the funds or capacity of electricity generation from the pot for the benefit of certain technologies within that pot (minima), or by capping the proportion of funds or capacity of electricity generation from the pot that can be used up by a certain technology within that pot (maxima). BEIS has not yet (at the time of writing) signalled an intention to deploy either, but if these powers are exercised, it seems more likely that a maxima is imposed on the pot of money that will be made available to offshore wind because that

approach is less likely to raise state aid issues.

## The case for protecting ACT within Pot 2

Developers will argue that there are compelling reasons for using the statutory power to impose minima on ACT or maxima on offshore wind. In particular, they will point to the following:

- Critical-stage support: ACT is at the point where it needs support in order to promote further innovation, improve operating efficiencies and reduce its cost base, eventually leading to a sustainable, subsidy-free industry. It is not as far down the experience cost curve as offshore wind;
- Energy security: ACT provides base-load generation, as opposed to the intermittent generation of variable renewable energy sources;
- Grid stability: ACT is embedded generation capacity, supporting the grid on a 24/7 basis, aiding grid stability;
- Renewable heat: ACT can provide the

opportunity to develop dedicated heat networks around plants, contributing to another key strand of the UK Government's renewable energy policy; and

- UK manufacturing: ACT projects provide local jobs during construction and operation, and the ACT industry has a relatively high number of UK manufacturing and technology companies.

These arguments are persuasive in their own right, although the other renewable technologies in the pot might well argue that they also tick some of these boxes, or that these are not of themselves sufficiently compelling to distort competition within the CfD pot.

But there is one argument that ACT developers can deploy which should be persuasive to the Government in its own right: new waste infrastructure helps to discharge a separate government commitment under the Landfill Directive 1999/31/EC in relation to the diversion of biodegradable waste from landfill. The Government has made binding landfill diversion commitments and, if it accepts that there is a waste capacity gap that will lead to it falling short of those commitments, then it accepts the need to support more waste infrastructure to reduce that gap.

In the short-term, Brexit should not impact on the Government's landfill diversion commitments because the commitments are binding until the formal process leading to the UK's exit from the EU is completed. In the long-term, the Brexit strategy may require the UK to continue to comply with renewable energy and waste-related targets (e.g. because it joins the EEA), or the UK may choose to adhere to or exceed the EU target because of its own climate change and waste policies.

## What is the waste capacity gap?

The Landfill Directive 1999/31/EC sets targets for the reduction of biodegradable municipal waste being sent for disposal in landfill. When the UK adopted this legislation, it was landfilling over 80 per cent of its biodegradable municipal waste (BMW) at the 1995 baseline date. EU-wide targets were established for 2006, 2009





and 2016. Countries like the UK, with a challenging baseline position, were given four-year derogations. As it stands, by 2020, the UK must reduce the amount of BMW that goes to landfill to no more than 35 per cent of the total amount of BWM in 1995 (by weight). Whether it will comply with that target, and avoid potentially significant fines from the EU, requires an analysis of the amount of BMW that will arise in 2020 and the capacity in the UK and abroad for diverting that waste from landfill.

### So how big is the waste capacity gap?

According to reports from environmental consultancy Eunomia, the UK was on course to meet its 2020 landfill commitment waste and there would not be any capacity gap. This view may

well have influenced the decision by the Department for Environment, Food and Rural Affairs (Defra) to withdraw PFI credit support in 2010 from seven waste procurements that had not yet reached financial close. Subsequently, in February 2013, Defra withdrew support from a further three waste procurements, saying that “we are investing 3.6 billion in 29 waste infrastructure projects. This will reduce the amount of waste sent to landfill, promote recycling and stimulate economic growth. We now expect to have sufficient infrastructure in England to enable the UK to meet the EU target of reducing waste sent to landfill. Consequently the decision has been taken not to fund the remaining three projects”. As discussed below, there are some divergent views from different studies

on whether there is a capacity gap. Full details of the reports referred to are set out in figure 3, while figure 4 summarises the assumption underlying the capacity estimates.

#### Eunomia predicts overcapacity

Issue 5 of Eunomia’s Residual Waste Infrastructure Review (published on 28 November 2013) states that “without any change in residual waste quantities, however, there would be overcapacity of 13.8 million tpa if the 21.4 million tpa of waste treatment capacity that has planning consent reaches financial close and subsequent operation”. It goes on to say that “modelling of our central scenario suggests that the capacity gap between residual waste arisings and available treatment capacity will fall over

**Figure 3: Reports into UK waste treatment capacity**

Author	Report	Date of report	Capacity gap estimate (tonnes per annum)	
			2020	2025
Eunomia	Residual Waste Infrastructure Review, Issue 5	November 2013	Overcapacity	Overcapacity
SITA	Mind the Gap	February 2014	11.7m	5.7m
GIB/Tolvik	The UK residual waste market	July 2014	4m – 7.7m	No forecast given
Biffa	The Reality Gap – UK residual waste treatment capacity – making sense of the arguments	September 2015	8.25m – 8.5m	4.36m – 5.88m
Eunomia	Residual Waste Infrastructure Review, Issue 10	May 2016	Overcapacity	Overcapacity

**Figure 4: Capacity forecasting assumptions**

*The assumptions behind the capacity forecasts  
Recycling performance (the higher the recycling levels, the lower the amount of residual waste):*

- Annual forecasting of total waste arisings (requires extrapolation of trends, including correlation with economic growth/decline);
- Sources for national waste tonnages data across municipal and trade waste;
- The annual availability percentage of existing facilities that are operational or under construction;
- The number of consented but undeveloped schemes that will reach financial close;
- The effect of schemes reaching financial close on the viability of other consented schemes that have not yet reached financial close;
- The level of repatriation of waste exports to Europe where local gate fees are equivalent or marginally more expensive;
- Expansion of existing facilities;
- Closure versus upgrading of old facilities;
- Government intervention (e.g. the recent proposal for an incineration tax in Sweden);
- Cement industry demand; and
- Landfill availability.

time, decreasing from the current (based on 2012/13 arisings data) level of 12.9 million tonnes, and moving to a situation of potential overcapacity in the UK in 2017/18 of around 3.0 million tonnes, and rising to an overcapacity of 10.1 million tonnes in 2020/21”.

#### **SITA enters the debate**

Shortly after Eunomia’s 2013 report (February 2014), SITA published a report called “Mind the Gap”. That report put forward a different set of assumptions from Eunomia, and argued that only commercial and industrial waste generators and national waste management companies (i.e. not government sources) were in a position to accurately forecast future trends. It estimated the capacity gap at 17.8m tonnes in 2020 and 5.7m tonnes in 2025.

#### **GIB and Tolvik join the debate**

Shortly after the SITA report (July 2014), the UK Green Investment Bank (GIB) and Tolvik Consulting joined the debate. GIB added an influential voice because of its public sector mandate and its proximity to the Government. Tolvik are well regarded as a market leader in waste catchment analysis for sponsors and lenders to the waste and biomass sector.

The report estimated a waste capacity gap of between 4m–7.7m tonnes in 2020. In arriving at that range, it set out its own assumptions and noted that “our analysis is in line with some of the leading waste market participants’ recent reports such as SITA, who also cite the need for an increase in the level of investment into this sector to meet the projected level of available residual waste in 2020 and beyond”.

#### **Biffa enters the debate**

Biffa entered the debate in September 2015, forecasting a 2020 capacity gap of 8.25m–8.5m tonnes and a 2025 capacity gap of 4.36m–5.88m tonnes. Its report is dismissive of methodologies used by Eunomia, saying that “the fact that Eunomia’s capacity gap disappears sooner than others is a reflection of their choice of criteria and maths”. They clarify that to mean “an over reliance on theoretical mathematical modelling” and disregard for local market dynamics.

#### **Eunomia continues to predict overcapacity**

Eunomia’s most recent report was published in May 2016. It shifts its focus to a wider analysis of waste arisings versus waste capacity in the UK and Western/Northern Europe. This is due to rapid and significant growth in the export of waste from the UK to Europe, growing from 250,000 tonnes in 2011 to 3.4m tonnes in 2015 – a feature of an open market where excess tonnage in the UK is feeding excess capacity on the continent. This latest report forecasts overcapacity in 2020, assuming that waste continues to be exported to Europe in current quantities. Eunomia’s view is that repatriation of that waste is only likely to happen when there is overcapacity in the UK, resulting in downward pressure on gate fees.

#### **Where will we end up?**

The allocation of renewable technologies to the different CfD pots (established versus less established) and the use of minima/ maxima are difficult decisions for the Government, involving a plethora of competing interests and policies. There is no doubt that the gasification developers are out there in significant numbers and preparing to participate in the auctions. The ability of this emerging sector to eventually stand on its own two feet turns on the Government’s willingness to support it under the CfD scheme, so that it can eventually compete on a level playing field against other renewable energy schemes. That may well turn on a difficult debate over the UK’s waste capacity gap, where competing methodologies either warn against sliding into the same over-capacity issues that have plagued some European countries, or otherwise advocate urgent intervention in order to avoid under-capacity that could result in the UK failing to meet its 2020 landfill diversion target. That, in turn, will depend on the UK’s continuing commitment to that 2020 target and subsequent targets, either as a continuation of its trading arrangements with the EU or as a result of UK policy in its own right.



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PREPARING FOR DISASTER:

# The EHS issues

by Andy Waite

Incidents which cause environmental harm or injury/illness to workers or neighbours can have significant consequences for the companies that are responsible for them. Preventing those incidents must, therefore, be a priority, but if the worst happens they must be managed so as to minimise physical/ environmental damage as well as liabilities and the risk of an adverse response from the regulators and the media. This article summarises the key issues for energy companies to consider in the UK context.

## Prevention

In order to prevent incidents, management must have a clear understanding of the legal obligations which affect their operations. At a high level these include:

- requirements for environmental permits/licences;
- prohibitions/restrictions on pollution;
- duties to avoid unduly disturbing neighbours; and
- duties to protect employees and others.

At the operational level that involves thorough familiarity with permit and licence conditions as well as establishing and enforcing procedures which put into practice both those conditions and general environmental and health and safety (EHS)

laws. That task can seem daunting, and in response, many companies produce well intentioned EHS manuals running into hundreds of pages with detailed instructions on how to deal with every conceivable eventuality. The problem with such manuals is that few people (other than the authors and EHS managers) have the time or often the inclination to read them.

Brief, clear written instructions on how to avoid environmental and health and safety incidents are more likely to be effective, if only because employees can easily read, understand and follow them. However, even clear written instructions by themselves are rarely sufficient: busy workers may overlook them. “Tool box” talks are an invaluable way of ensuring

that employees know how to carry out their work in a way that protects the environment, promotes health and safety and minimises the company’s risk of liability. Bold and simple notices may also serve as useful reminders. In the oil and gas and utilities industries companies are more mindful of prevention, but care should be taken not to become complacent.

Examples of points to cover in a toolbox talk include:

- which liquid substances should or should not be poured into particular drains and sewers. (This, of course, implies management knowledge of whether the drains/sewers lead to watercourses or public sewers and the conditions attached to any relevant



environmental permit or trade effluent consent);

- what to do/who to report to if equipment or plant is found to be defective, corroded, dangerous or otherwise likely to result in unwanted or unlawful emissions;
- simple operational procedures to ensure that permit emission limits are not breached and that other permit conditions and legal requirements are complied with; and
- good housekeeping “rules” to minimise problems.

## Incident response

If an incident occurs which has adverse consequences for the environment or the health, safety or welfare of employees or others, three issues have to be dealt with:

- the immediate response to the incident to minimise its consequences;
- a decision as to whether to notify the relevant regulatory authority; and
- how to deal with officers of the regulatory authority if they carry out an investigation.

The way in which those matters are managed is likely to affect the outcome in terms of what action is taken by the regulatory authority and the amount of any penalty imposed in the event of a criminal conviction. Many environmental and health and safety incidents are strict liability criminal offences (no negligence or intent has to be proved) but the extent of culpability as well as the company's behaviour after the incident has a profound effect on the authority's decision as to what action to take (particularly whether to prosecute) and on the amount of any fine imposed by the courts. Recent guidance from the courts in the UK, as well as official sentencing guidelines, have markedly increased the normal range of fines with the intention that the punishment should be real.

The priority will inevitably be “first aid”: for example, to prevent further pollution and as far as possible to contain any spillage that has occurred so as to avoid or minimise the risk of material escaping off-site and polluting watercourses, groundwater or neighbouring properties.

As mentioned above, an important question arises of whether, and if so when,

to contact the regulatory authority. There is no absolute right answer: each case depends on its own facts. However, as a general rule, except in the most minor incidents, it is safer to report the matter to the local officer of the regulator by e-mail (to ensure that there is a record) and by telephone as soon as possible after the incident. There are several reasons why this course of action should be followed:

- environmental permits usually contain conditions requiring incidents to be reported (in which case failure to do so is a criminal offence);
- the competent authority must be informed as soon as practicable of the occurrence of a major accident at a COMAH site ;
- if there is significant harm to protected areas or water bodies or harm to human health due to land pollution (in any such case actual or imminently threatened), EU rules require the incident to be reported to the regulator who will then direct the on-going clean-up operation;
- as indicated above, openness and co-operation will affect the regulator's approach to the matter and the amount of any fine imposed by the court if the regulators decide to prosecute; and
- irrespective of the outcome of the current incident, openness with the regulators is likely to help maintain a good relationship with them in the future.

The initial report should be brief and factual, explaining what has happened and the steps being taken to deal with it. It should be sent by the manager whose job it is to deal with the incident and not be delegated to anyone else. Above all, the notification should not accept blame on the part of the company.

## Dealing with the regulators

### Investigative powers

Regulators have wide statutory powers to assist them in carrying out their functions. Those powers are most likely to be exercised in the aftermath of an incident. Employees of the company should understand these powers and know how to react to officers of the regulatory authorities who exercise them.

Obstructing a regulatory officer or failing to co-operate without reasonable excuse is usually a criminal offence. A request should be made by the appropriate employee to the officer for documentary evidence of his or her identity and authority to investigate. Generally, its production by the officer is a statutory requirement. Clarification should also be requested about which statutory powers are being exercised. The Code of Practice on Powers of Entry states that the officers should generally provide a Notice of Powers and Rights in standard format.

The relevant powers of the regulatory officer usually include the following:

- entering premises at reasonable times except in an emergency (with a police constable if serious obstruction is anticipated). A warrant can be obtained from a Justice of the Peace if entry has been refused or refusal is reasonably anticipated. The Code of Practice states that where it is appropriate and practicable to do so, reasonable notice (usually not less than 48 hours unless otherwise specified in relevant legislation) should be given before exercising a power of entry;
- examining and investigating the premises or anything on the premises;
- directing that all or part of the premises be left undisturbed for the purposes of the examination or investigation;
- dismantling or testing any article or substance which has caused the incident or is likely to cause harm (but not so as to damage or destroy it unless necessary); and
- taking away any such article or substance for the purposes of examination and presentation as evidence.

If the regulator considers that its own statutory powers of search and investigation are insufficient it can, if working with the police, ask them to use their powers to obtain a search warrant – for example, under section 8 of the Police and Criminal Evidence Act 1984. A search warrant can be issued by a Justice of the Peace if he/she is satisfied (subject to certain conditions) that an indictable offence (i.e. an offence triable in the Crown Court) has been committed and there is

material on the premises which is likely to be of substantial value in investigating the offence.

### Obtaining statements

Investigating officers usually have statutory powers to obtain statements from witnesses they believe can provide useful evidence. These powers, which are exercisable at any time during the investigation, include:

- requiring any person (reasonably believed to be able to do so) to give any information relevant to the examination or investigation and to sign a declaration of truth of the answers given. Usually, the employee can nominate another person to be present, which should generally be the company's lawyer or in default the "incident manager". Generally, no answer given pursuant to such a requirement can be used as evidence against the person giving it in any proceedings, although it can be used as evidence against the employer or another employee. However, in some cases, such as pursuant to the Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005, such answers can be used in evidence against the person providing them; and
- requiring the production of records which are required to be kept or which are necessary for the officer to see for the purpose of the examination or investigation. It is important to be aware of exactly what "records" can be required to be produced by the regulator. Under the relevant provisions of the Environment Act 1995, this may only extend, for example, to test results rather than commentary in a report by consultants. If the records are protected by legal professional privilege they do not generally have to be produced. The issue of which documents are privileged is not addressed here.

Regulators also have powers to obtain information from individuals where such powers do not provide any protection against self-incrimination. Examples include notices to obtain information



which may be served under section 71 of the Environmental Protection Act 1990 (in relation to possible waste offences) and regulation 60 of the Environmental Permitting (England and Wales) Regulations 2010 (in relation to investigations of regulated facilities). In such cases, recipients of a notice are obliged to provide the information requested even though it may be used in evidence against them in the event of prosecution. Failure to do so without a reasonable excuse is a criminal offence.

Regulators investigating a possible criminal offence generally request an interview under caution with a senior representative of the company under the Police and Criminal Evidence Act 1984 (PACE) procedures. Interviews conducted under PACE are taped and can be used in evidence against the interviewee, the company and/or other employees,

directors and managers. Attendance at a PACE interview is not compulsory but failure to do so could have the following consequences:

- the risk of an adverse inference being drawn from failure to mention something known to the potential interviewee which is later relied on at a trial; and/or
- a heavier sentence if the failure to attend is brought to the court's attention during sentencing.

On the other hand, there are potential disadvantages in agreeing to attend a PACE interview:

- the company representative may not have all the relevant information to answer questions, particularly if other employees have been directly involved in the incident and its management; and/or

- the company representative may inadvertently say something in the interview which provides ammunition to the prosecution.

The alternative is to offer to provide written responses under caution to the regulator's questions. This procedure avoids the disadvantages listed above and enables the company to set out its version of events in the best light possible. Some regulators agree to the written response procedure. Others decline it on the grounds that "it does not allow for flexibility during the interview as a result of responses made that a verbal interview would and it allows for the creation of credible but false evidence". In that case, it is probably better for the company's representative to attend the interview, answer any factual questions which she/he is able to answer, and in cases where she/he does not have the information available, to offer to provide the information in writing after the interview. If there is any objection from the regulator, the interviewee can rely on the right to silence. Under those circumstances, it is unlikely that any adverse inference could be drawn.

Prior to attending a PACE interview, it is advisable to ask the regulator for a list of questions or, if that is not forthcoming, a list of the areas to be covered in the interview and the general line of questioning to be adopted. There is no obligation on the regulator to provide this information in advance but sufficient information must be provided to enable the company to understand the nature and circumstances of the offence so that the questions can be answered honestly.

Regulators sometimes seek voluntary statements from employees which are subsequently typed up and presented to the employee as a witness statement which she/he is asked to read and sign. Such a statement is admissible in evidence against the employee who signs it as well as against the company and any other employee.

### Response to the regulator's visit

It is obviously beneficial for management and the workforce to know what to do when a regulatory officer calls. Whenever possible, she/he should be asked to wait for the company's appropriate "incident manager" and if the delay will not be too long the company's lawyer (see below). A substitute should be available in case the usual incident manager is not. Any other employee should avoid contact with the regulatory officer if possible and if approached direct the officer to the "incident manager". If the officer formally (under a statutory power – see above) requires an employee to give information then the employee should require a suitable person to be present (preferably a lawyer – see below – or, in default, the incident manager) and should not answer any questions until then.

As soon as possible the in-house legal team or external lawyers should be asked to attend to monitor the investigation and take a note of everything the officer does and all items removed. The lawyer should also be present at any interview, whether mandatory or voluntary, to provide advice and to record all questions and answers. If it appears that the employee's position will prejudice that of the company or vice versa, the employee should have separate legal representation.

In any event, when speaking to the regulatory officer (whether statutory powers are used or not) it must be remembered that she/he is attending in a formal capacity and is seeking evidence. Any comment made may end up as evidence against the company. It is therefore important to be both co-operative with any regulatory investigation and ensure that anything said is factually correct.

### Regulatory enforcement powers

Regulatory authorities such as the Environment Agency and the Health and Safety Executive have extensive powers to deal with incidents and compliance failures. These range from giving advice at one end of the scale to permit revocation or prohibition notices at the other. Depending on the relevant legislation, they may serve enforcement/improvement notices requiring steps to be taken to remedy contraventions, prosecute for criminal offences or in some cases impose civil penalties as an alternative to prosecution.

The course chosen by the regulators should aim to be proportionate to the incident and they will take account of a number of factors including the seriousness of the harm, the degree of fault on the part of the operator, as well as the operator's response to the incident and the extent of co-operation with the regulator. Those matters will also be relevant to any sentencing court in the event of a prosecution.

### Incident management plan

An incident needs to be managed properly to:

- minimise impacts on the health and safety of persons on and off the site, and on the environment;
- comply with all applicable legal requirements;
- satisfy the requirements of the regulatory authorities and demonstrate that the company is maintaining a co-operative approach;
- minimise liabilities (for example, to employees and neighbours); and
- manage any adverse public relations and media attention.

For that reason an incident management plan should be established to:

- identify members of the incident team;
- set out the key emergency actions which are to be taken;
- establish the company's response procedures both internally and for dealing with the regulators, neighbours, the press and other third parties; and
- undertake an internal investigation as soon as possible after the incident. Steps should be taken to gain legal professional privilege for the investigation report if so desired.

While "prevention is better than a cure", it is inevitable that most energy companies will at some point face an EHS incident. It is therefore crucial that companies plan ahead to ensure the best possible outcome.



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**BREXIT:**

# Implications for projects in the UK energy sector

by Philip Thomson, Antony Skinner and Justyna Bremen

**O**n 23 June 2016 the UK held a referendum (EU Referendum) to decide whether the UK should remain a member of the European Union (EU). The outcome of that referendum is that the UK has decided to terminate its membership of the EU (referred to as “Brexit”). To quote a rather overused but apt expression, it is still early days, and it is difficult to make conclusive predictions about the full impact of Brexit on the UK energy sector. Nonetheless, below we have summarised the key likely legal implications for the energy sector once Brexit is implemented, as well as the key issues to consider when reviewing existing contracts relating to UK assets or projects or entering into new projects.

## Timing and process

It is important to understand that the EU Referendum has no immediate impact on the UK’s legal standing as a member of the EU. The first step in the exit process is that the UK Government must serve notice on the European Council, under Article 50 of the Treaty on the European Union that the UK wishes to leave the EU. This will trigger a period of up to two years, during which the UK and the remaining 27 Member States will negotiate the steps for the UK’s withdrawal from the EU. The two-year period can be extended, but only with the unanimous consent of the 27 remaining

Member States. As at the date of writing, we do not know when the UK Government will send this notice and, accordingly, when that period will commence, although the Prime Minister has stated that she does not intend to initiate the Article 50 process before the end of 2016. During this period, the UK will remain a member of the EU (albeit without participation rights in key decision-making forums), and will remain subject to EU laws.

Once the withdrawal agreement has been finalised, or the two-year period has expired (whichever is earlier), the UK will cease to be a member of the EU, and the

exercise of unravelling UK and EU law may begin. The first step will be the repeal of the European Communities Act 1972, which effectively incorporates EU law into UK law. However, repealing this Act will leave the UK with many voids in its domestic legislation. What seems likely is that transitional legislation (effectively retaining much of the legislation derived from EU law) will be used to bridge those voids until they can be properly analysed and appropriate legislation can be enacted to meet the objectives of Brexit. Certain areas of law will likely be prioritised over others for such analysis and legislation,

particularly those that meet the UK's objectives in relation to Brexit.

### Immediate, indirect impact

Leaving aside the legal and regulatory impact of Brexit being implemented, there has been an immediate, indirect effect on the UK's economic and political landscape. The EU Referendum result took the world's stock and commodity markets by surprise, and triggered significant falls in sterling, and an immediate fall in the FTSE-100, although this has now recovered. The price of oil remained broadly stable, and the banks did not show signs of the systemic stress that occurred during the banking crisis of 2008/2009. The EU Referendum vote also triggered a political crisis with the resignation of the Prime Minister, who has now been replaced by a new Prime Minister, Theresa May. Upon taking office on 13 July 2016, Theresa May immediately undertook a ministerial and departmental reshuffle. The Department of Energy and Climate Change, which had previously been in charge of policy matters relating to oil and gas, power, energy markets and climate change, has now been replaced with a new Department for Business, Energy and Industrial Strategy.

The new department brings together responsibilities for business, industrial strategy, science, innovation, energy, and climate change.

### Upstream oil and gas sector

The fundamental structure of the UK upstream oil and gas industry and its governing legal regime, including the licensing system, is unlikely to be significantly affected by Brexit. However, it now seems almost certain that Scotland will hold a second referendum to decide whether Scotland should become fully independent from the rest of the UK. While it is premature to speculate about the outcome of a referendum that has not yet been announced, if Scotland did decide to proceed with full independence, then this would have a significant impact on the UK Continental Shelf (UKCS) oil and gas industry because much of UKCS oil and gas reserves lie in Scottish Waters. The responsibility for onshore petroleum licensing in Scotland and Wales is already being transferred to the respective devolved Governments.

Leaving aside the prospect of a possible referendum on Scottish independence, it should be noted that

the regulatory framework applying to the upstream industry, and in particular environment and health and safety regulation, is highly developed independently of EU law, and any impact is likely to be minor. The offshore decommissioning regime mainly stems from international conventions and domestic legislation, and would therefore be largely unaffected. Freed from the strictures of the EU state aid regime (though still subject to WTO rules) the UK Government could choose to support key infrastructure in the UKCS (e.g. pipelines and terminals) necessary to extend the life of the basin.

### Gas and electricity markets

The UK's decision to privatise and liberalise its gas and electricity utilities and markets originally came independently of any requirements to do so under EU law. The UK has one of the most competitive and liberalised gas and electricity markets in Europe. Some of the requirements have been shaped by the successive EU "Energy Packages" of Directives and Regulations but the UK Government would be unlikely to change what is, by and large, a well regulated and functioning market. For





instance, for UK onshore transmission system operators, while there could potentially be an easing of the ownership unbundling formalities, it must be remembered that the UK model sought to ensure operational independence of TSOs and non-discriminatory third-party access well before the EU rules were introduced. For new interconnectors between the UK and remaining EU Member States, the practical impacts also seem likely to be limited in areas such as ownership unbundling and third-party access, not least because even if the UK were to adopt a more generous approach, at least part of the interconnector would still be within an EU Member State.

There may be some regulatory gaps that will need to be filled as a result of EU Regulations and other legal instruments no longer applying to the UK – for example, the new REMIT regime which seeks to prevent energy market manipulation and insider trading.

Importantly, the UK Government will need to decide whether the UK will still participate in the single European gas and electricity market which the EU has been striving to create, and that has been seen as desirable from an energy security point of view. If the UK removes itself from the initiative and its core institutions, this may have a negative impact on arrangements for gas and electricity trading across existing and proposed interconnectors. For instance, the UK will no longer have a say in the development of the European Network Codes which are intended to help in making a single energy market a reality.

## Renewables

The removal of EU renewable energy targets, under the Renewable Energy Directive, could give rise to greater uncertainty for the renewables industry. The UK has its own national targets relating to reduction of emissions, but the EU targets, requiring a specific percentage of electricity to come from renewables, have played an important role in shaping UK energy policy. Likewise, EU targets for diverting waste from landfill, under the Landfill Directive, have been one of the factors incentivising the development of energy from waste projects.

On a positive note, only days after the EU Referendum, the UK Government



passed into law the fifth carbon budget under the Climate Change Act 2008, committing the UK to cutting greenhouse gas emissions by 57 per cent compared to 1990 levels, during the period 2028 to 2032, as recommended by the Committee on Climate Change. Moreover, the Secretary of State for Energy and Climate Change reiterated, in a speech made on 29 June 2016, that *“however we choose to leave the EU, let me be clear: we remain committed to dealing with climate change”*.

In terms of the key mechanisms established by the Government to incentivise investment in low-carbon generation, the Government has confirmed a number of times that the next Contracts for Difference allocation round is still intended to take place by the end of 2016.

The lifting of restrictions imposed by the EU state aid regime may give the UK Government more flexibility in relation

to how it structures different support mechanisms for different technologies, targeting those technologies that are in line with current Government policy. Whether this is welcome or not would depend on the relevant sector, because it could, for example, give the Government greater flexibility to discriminate against certain renewable energy technologies (e.g. onshore wind).

## Nuclear industry

Brexit has the potential to have a significant impact on the UK’s nuclear power regime. The European Atomic Energy Community (EURATOM) has a separate legal personality from the EU, but its Member States and institutions are the same. The Nuclear Safety Directive and Radioactive Waste and Spent Fuel Management Directive, both promulgated under the auspices of EURATOM, form





an important part of the international framework that underpins the UK's statutory regime for nuclear power. And the EURATOM Supply Agency plays a key role in the supply of nuclear fuels to Member States. The UK Government will need to ensure that it takes appropriate steps to avoid Brexit having a negative effect on the progress of the UK's nuclear power generation policy.

### Existing contracts

The most immediate concern for many companies is the impact of Brexit on existing contracts. There are two separate issues that companies may be considering:

- first, the immediate market reaction to Brexit may mean that some companies may be looking for an exit strategy from existing contracts; and
- second, companies may be concerned about whether there is any effect on

the business efficacy of existing contracts.

#### Can an existing contract be terminated?

While every contract needs to be considered individually, below we have set out some observations of general application:

- **express Brexit clause:** if the contract contains a clause specifically dealing with the impact of Brexit, then this should be considered first;
- **force majeure:** under English law, there is no general principle of force majeure but contracts often include express force majeure provisions, which generally operate to suspend contractual rights and obligations on the occurrence of a force majeure event, with an ultimate right of termination if the event continues. A force majeure event is typically defined

as an unforeseeable event outside the control of the parties which prevents or delays the affected party's performance of its obligations. The definition of force majeure needs to be checked in each individual case, but it is unlikely that Brexit would constitute a force majeure event;

- **hardship/material adverse change:** the contract may include a "hardship clause", or an express provision designed to accommodate changed circumstances, such as a price review clause or a "material adverse change" clause. The difficulties associated with such clauses are twofold: first, the question arises whether circumstances are such that the clause is triggered; and second, such clauses often provide for a contract re-negotiation rather than termination, and unless sufficiently certain, there is a risk that such a clause may not be enforceable under English law;
- **change in law:** long-term contracts, in particular, often include detailed provisions dealing with the consequences of changes in law that occur after the contract is entered into. Such a clause could, potentially, be triggered once the UK Government takes steps to implement Brexit. However, changes in law arising from Brexit could be excluded from the operation of the clause on the basis that they were foreseeable, although this is a complex point that will need to be considered in the context of each individual contract. Even if such a clause is triggered, it may be the case that it does not give rights of termination, but instead provides for an adjustment of the contract price; and
- **frustration:** in certain very limited circumstances it may be possible for a party to argue that the contract is frustrated. The doctrine of frustration operates to discharge the contract automatically, excusing both parties from their future obligations where a frustrating event occurs. A frustrating event is one which: occurs after the contract has been formed; is so fundamental as to be regarded both as striking at the root of the contract and as entirely beyond what was



contemplated by the parties when they entered the contract; is not the fault of either party; and renders further performance of the contract impossible, illegal, or radically different from that contemplated by the parties at the time the contract was formed. This is a high threshold. Case law has established that a contract will not be discharged by frustration where a contract is simply more expensive to perform; there are changes in economic conditions; or where the seller under a sale of goods contract is let down by its own supplier.

#### **Impact on the business efficacy of existing contracts**

Parties may be concerned about the impact of Brexit on their ability to perform their contracts from a legal and regulatory perspective. The first thing to note is that, as mentioned above, the EU Referendum outcome in itself has no impact on the UK's status or the application of EU law.

There will, inevitably, be an impact on some contracts once the UK formally ceases to be a member of the EU. It may be prudent for companies to conduct a review of their key contracts to check how they might be impacted by Brexit. Some of the main issues to consider are as follows:

- **references to EU-related concepts:** check the contract for references to EU-related concepts – for example, definitions of “European Union”, “European Community” or “European Economic Area” – to determine how their interpretation post-Brexit will impact the contract, and to determine whether or not there is a need for clarification now or renegotiation in the future; and
- **references to EU legislation or obligations arising under EU legislation:** the contract may refer to EU legislation, UK legislation which implements EU legislation, or obligations arising under either of these. In some cases no amendment

may be necessary, as the interpretation provisions in the contract may allow for the contract to be interpreted in light of the changed position, without changing the substance of the contract. As mentioned above, the contract may include an express clause dealing with what happens upon Brexit, or a change in law clause which, if triggered, may provide for a mechanism for any changes required to the contract. In other cases, the contract may not provide for any change mechanism, but the obligations arising under EU law may go to the heart of the contract, and it may be necessary for the parties to try to agree how the contract should be amended.

#### **Future-proofing new contracts**

Going forward, it is essential that companies seek to, as far as practicable, “future proof” any new contracts being entered into. Below we have set out some



of the key issues to consider in the context of contracts in the energy sector:

- **express Brexit provisions:** depending on the specific circumstances relating to the contract, the parties may wish to include express provisions in the contract to say that the contract cannot be terminated once Brexit is implemented. Alternatively, depending on the subject matter of the contract, the parties may want to have termination rights upon the occurrence of a specific event;
- **change in law:** it is important to ensure that any change in law provision in the contract deals with Brexit appropriately. In particular, to avoid any uncertainty, the parties need to decide at the outset whether changes in law resulting from the implementation of Brexit are intended to trigger the change in law provision, even if they are considered to be foreseeable changes, or not. Given that there is some uncertainty about the impact in some areas, it is important for the change in law clause to cater for situations where the parties may need to agree changes to the contract. To ensure that the clause is enforceable, provision needs to be made for what happens if the parties cannot agree – for example, it may be appropriate to provide that the matter will be referred to expert determination;
- **EU-related concepts:** as already mentioned above in the context of existing contracts, watch out for references to the

EU, EU institutions and EU laws, and consider how the interpretation of such terms will impact on the interpretation of the contract post-Brexit implementation;

- **compliance with law clauses:** check carefully all compliance with law provisions, and provisions dealing with permits or authorisations required by the parties, as these types of clauses are likely to be impacted by changes in law;
- **governing law:** Brexit should not deter parties from choosing English law. The reasons for choosing English law, such as certainty and respect for party autonomy, will not change. It remains just as good a choice of governing law post-Brexit as it does now. And, whatever model replaces the current governing law regime, the English courts' approach to governing law will be broadly the same: they will continue to uphold governing law clauses, as will the rest of the EU. That said, and as previously mentioned, those contracts where EU law is an issue will need to be reviewed; and
- **jurisdiction clauses:** the position is slightly more complicated in relation to jurisdiction clauses. In short, the general position is that unless enforcement of English judgments in the EU is an issue, Brexit should not impact on parties' approach to dispute resolution clauses. Once the UK leaves the EU it will, subject to whatever arrangements are negotiated, lose the automatic right to enforce judgments throughout the EU. Although it is highly likely that the UK will agree a replacement regime, there is uncertainty. If this uncertainty is a cause for concern, companies should consider the risks and look at other potential options. These include English-seated arbitration, already a popular forum choice in the energy context.

## Looking ahead

It seems likely that it will take time for the full impact of Brexit to become clear, as it will be shaped by factors such as the model adopted for the UK's relationship with the EU after its exit from the EU, and the policy decisions made by the Government in relation to various areas of the law currently affected by EU law. During this time of uncertainty and transition, it is still "business as usual" for energy companies, but it is important to "stress test" the future impact of Brexit on transactions and projects.



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EXCLUDING LIABILITY FOR  
SPREAD COSTS IN OIL AND GAS  
CONTRACTS:

# The next chapter

by Tom Cummins and James Prescott

In an article last year,<sup>1</sup> we considered the implications of the High Court decision in *Transocean Drilling UK Limited-v-Providence Resources plc* [2014] EWHC 4260 (Comm). The allocation of risk is critical to upstream oil and gas participants where relatively minor acts or omissions can have potentially serious consequences, and the High Court's ruling highlighted the need for parties to carefully consider the drafting of their remuneration and liability provisions.

Transocean recently successfully appealed part of this judgment with regards to the interpretation of consequential loss. This article discusses the appeal decision and what it means for operators and service providers going forward.

## The facts

The *Transocean* case involved the interpretation of remuneration provisions and an exclusion clause in an amended version of a standard LOGIC form contract. Transocean, the claimant, entered into a drilling contract with the defendant,

Providence, pursuant to which Transocean was to provide a rig to drill an appraisal well in the Barryroe field off the southern coast of Ireland. Drilling activity was delayed between December 2011 and February 2012 due to various operational issues which were caused by Transocean's failure to maintain the rig adequately.

By way of background, contracts for services to be provided by third party contractors commonly allocate liability either on a fault basis or on a knock-for-knock basis. In a conventional fault-based model, a party is only liable to the extent that it contributed to, or caused, the loss. In a knock-for-knock regime, each party

is responsible for its own losses caused by the other party's acts or omissions, regardless of fault. Such knock-for-knock provisions, also known as mutual indemnity or mutual hold harmless provisions, have become a standard method of allocating risk in upstream oil and gas projects, and were included in the drilling contract between Transocean and Providence in relation to particular types of loss.

Providence refused to pay Transocean's day rates during the delay on the basis that no remuneration was due for the provision of the rig since the delay was caused by Transocean's breaches.

<sup>1</sup> "Oil and Gas Indemnities: Interpretation Revisited", *EnergySource*, Issue 15, July 2015

Transocean claimed for payment of the day rates on the basis that they applied regardless of any breach of contract by it (i.e. it claimed that the principles underlying a knock-for-knock regime were applicable to the remuneration provisions). Providence counter-claimed for wasted costs comprised of sums payable to personnel, suppliers and service providers (spread costs) incurred by Providence during the delay as a result of Transocean's breaches, which Transocean argued were excluded by a mutual indemnity which excluded liability for consequential loss.

## High Court decision

The case in the High Court centred on two main issues: (i) whether Transocean was entitled to be paid for days when it had failed to provide services, and whether the knock-for-knock regime had any bearing on this issue; and (ii) whether Providence's spread costs fell within a clause under the contract which excluded the parties' liability for consequential loss. The court held that the answer was "no" in relation to both issues, effectively limiting the applicability of knock-for-knock provisions and narrowing the types of losses that may be excluded from a contract, in the absence of express drafting.<sup>1</sup>

## Court of Appeal decision

In *Transocean Drilling UK Ltd-v-Providence Resources plc* [2016] EWCA CIV 372, Transocean appealed to the Court of Appeal on the High Court's decision on the second issue, contending that Providence was not entitled to recover as damages the spread costs during the period of delay as these fell within the scope of the exclusion of liability clause. The court allowed the appeal by taking a wider approach to interpretation than that adopted by the High Court.

The clause at issue defined consequential loss as including "loss of use (including, without limitation, loss of use or the cost of use of property, equipment, materials and services including without limitation, those provided by contractors or subcontractors of every tier or by third parties)". Following several principles of interpretation, the High Court judge found that there was no "loss of use" and as a result spread costs did not fall within the definition of consequential loss. First, the court said that in case of any ambiguity (which it found was the case with this clause), the starting point for interpreting an exclusion clause was to construe it against the party seeking to rely on it. It also stated that there was a presumption that neither party intended to abandon the remedies available under the law breach by the other, and emphasised the need for clear drafting to reflect any intention to the contrary. Furthermore, it found that the list of words in brackets was to be interpreted within the meaning of "loss of use". In this context, cost of use meant the cost of hiring or replacing equipment or services in order to mitigate the loss of a benefit previously received, and therefore this had no application to the spread costs which were already provided and which Providence did not lose the use of.

The Court of Appeal disagreed with the High Court's interpretation. It accepted that "loss of use" would ordinarily refer to the loss of the ability to make use of some kind of property or equipment owned or under the control of the relevant party, which would not include the wasted costs in question. However, the

Court of Appeal found that the words in brackets (which amended the standard LOGIC form contract used) were clearly wide enough to include wasted spread costs and expanded the expression "loss of use". In particular, the court noted the reference to "without limitation" on two occasions and disagreed with the High Court's application of principles of interpretation, mainly on the basis that the words used were in fact clear enough to be unambiguous and were intended to flesh out the meaning of "loss of use" rather than limit it. It also departed from the High Court and Providence's argument that a broad interpretation of the exclusion clause would render Transocean's performance obligations effectively devoid of contractual content since there would be no liability for non-performance. The Court of Appeal found that the contract would not be devoid of legal content purely because the parties have excluded consequential, rather than direct, loss from the liability provisions.

While some may question whether the wording was in fact unambiguous, the decision places an emphasis on the principle of freedom of contract, particularly in the context of a knock-for-knock regime where parties have negotiated a detailed scheme for the apportionment of liabilities. It also places emphasis on the fact that this was a fully mutual clause negotiated between parties of equal bargaining power.

## Conclusion

The court's decision has been welcomed as a reaffirmation of the freedom of commercial parties to determine the terms on which they wish to do business. However, operators and contractors alike should recognise that there has been no change of law and that courts may still be inclined to interpret clauses more narrowly where there is ambiguity or where a party seeks to rely on a clause drafted for its own benefit.

It is also important to reiterate that Transocean's appeal only related to the consequential loss issue and not the applicability of the knock-for-knock regime to remuneration provisions. Primacy will be given to the language chosen by the parties when construing, and in order to give full effect to, knock-for-knock provisions, and therefore in the absence of express drafting such provisions will not disapply the usual rules of construction of contracts when determining liability.

Notwithstanding the Court of Appeal's decision, parties should continue to be prudent and consider whether their clauses are drafted specifically enough to apply a knock-for-knock regime to particular types of loss and also to capture the types of loss they intend to be excluded.



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# Stop press

## Ashurst sponsors the Africa Energy Forum 2016



Ashurst recently sponsored the 18th Africa Energy Forum, the global investment meeting for Africa's power, energy, infrastructure and industrial sectors, held in London in June. This year David Wadham, our utilities industry co-head, spoke on the "Renewables in Morocco"

panel to discuss Morocco's very ambitious renewables programme and success story.

## A stronger energy team

Ashurst continues to build on its strength in the energy sector with significant new partner hires and promotions. We have recently welcomed London-based Africa focused oil and gas and mining partner Yann Alix and energy disputes partner Matthew Saunders, Singapore-based energy partner Jon Ornlousson and Frankfurt-based energy partner Maximilian Uibeleisen.

The firm also recently promoted six resources and infrastructure lawyers to the partnership: Julia Derrick and Donna Fleming in London, Rebecca Dixon in Sydney, Guillaume Aubatier in Paris, Stuart James in Perth and Hendrik Theismann in Frankfurt.

## Ashurst continues to receive strong industry and market recognition

Ashurst was been labelled "the clear winner" by The Australian following the recent release of the Chambers Asia Pacific Guide for 2016. Chambers & Partners prepared a table of the top thirty firms for the publication, where Ashurst was ranked number one when measured by the overall number of practice groups that were ranked, ranging from band one to band five.

Global Vice Chairman Mary Padbury said the results reflect the impact of work undertaken over several years, commenting: "We achieved outstanding results and significantly enhanced our rankings across the region, which is fantastic recognition of our market standing. We topped the table by receiving more rankings than any other firm – a tremendous achievement and recognition of our leading practice in Australia. It's an indication of the benefits of collaboration and sharing ideas across our network of offices, investments made to make us a leading firm in the region and work over a number of years."

In Australia, we increased our rankings in six areas including a return of our Band 1 ranking in Energy & Natural Resources. Overall across the Asia-Pacific region, the firm attained 145 individual rankings including 31 top rankings as Band 1, Senior Statesmen, Star Individuals and Eminent Practitioners. Thirty-six individuals moved up a ranking and 22 achieved a new ranking.

This latest achievement is one of several recent accolades for Ashurst, which include:

- Australian Firm of the Year at the Chambers Asia-Pacific Awards 2016;
- SEA Energy and Resources Team of the Year at the Asian Legal Business SE Asia Law Awards 2016;
- Best Renewables Law Firm of the Year at the TopLegal Awards 2016; and
- Middle East Energy, Mining & Utilities M&A Legal Adviser of the Year at the Mergermarket Middle East M&A Awards 2016.

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