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AN OVERVIEW OF THIS ISSUE

We are delighted to introduce this fifteenth issue of Energy**Source**, 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. In this issue, we will be looking at:

We hope that you find Energy**Source** useful and enjoy reading this issue. Please let us know if you have any feedback or if there are any topics that you would like us to cover in future editions.

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SUCH A LONG JOURNEY:

Evaluating the UK's Electricity Market Reform

by Antony Skinner and Justyna Bremen

In the summer of 2014, the complex regulatory framework underpinning the two main pillars of the UK's Electricity Market Reform (EMR) – Contracts for Difference (CfD), to support low-carbon electricity generation, and the Capacity Market, to address security of supply – finally came into force, three years after the Government first set out its plans to reform the UK power market.

With the stage ready, the first CfD allocation round commenced in October 2014, followed closely by the first Capacity Market auction in December 2014. A long journey indeed, punctuated with questions and concerns about the ability of the new regime to achieve its objectives: energy security, affordability and a reduction in greenhouse gas emissions. In this article, we examine the initial outcomes of EMR and what they may mean for the future.

Contracts for Difference

Overview of the regime

Under a CfD, a low-carbon generator is paid a top-up payment above the wholesale price (the reference price), up to a set strike price. The strike price is intended to be an amount equal to that needed to make low-carbon power projects commercially viable. The CfD takes the form of a private law bilateral contract between the CfD counterparty and each low-carbon generator. A government-owned limited liability company – the Low Carbon Contracts Company – has been established to act as the counterparty to CfDs, and to collect from suppliers a levy to fund CfD payments and administer payments under CfDs. A key feature of CfDs is that provision is made for 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.

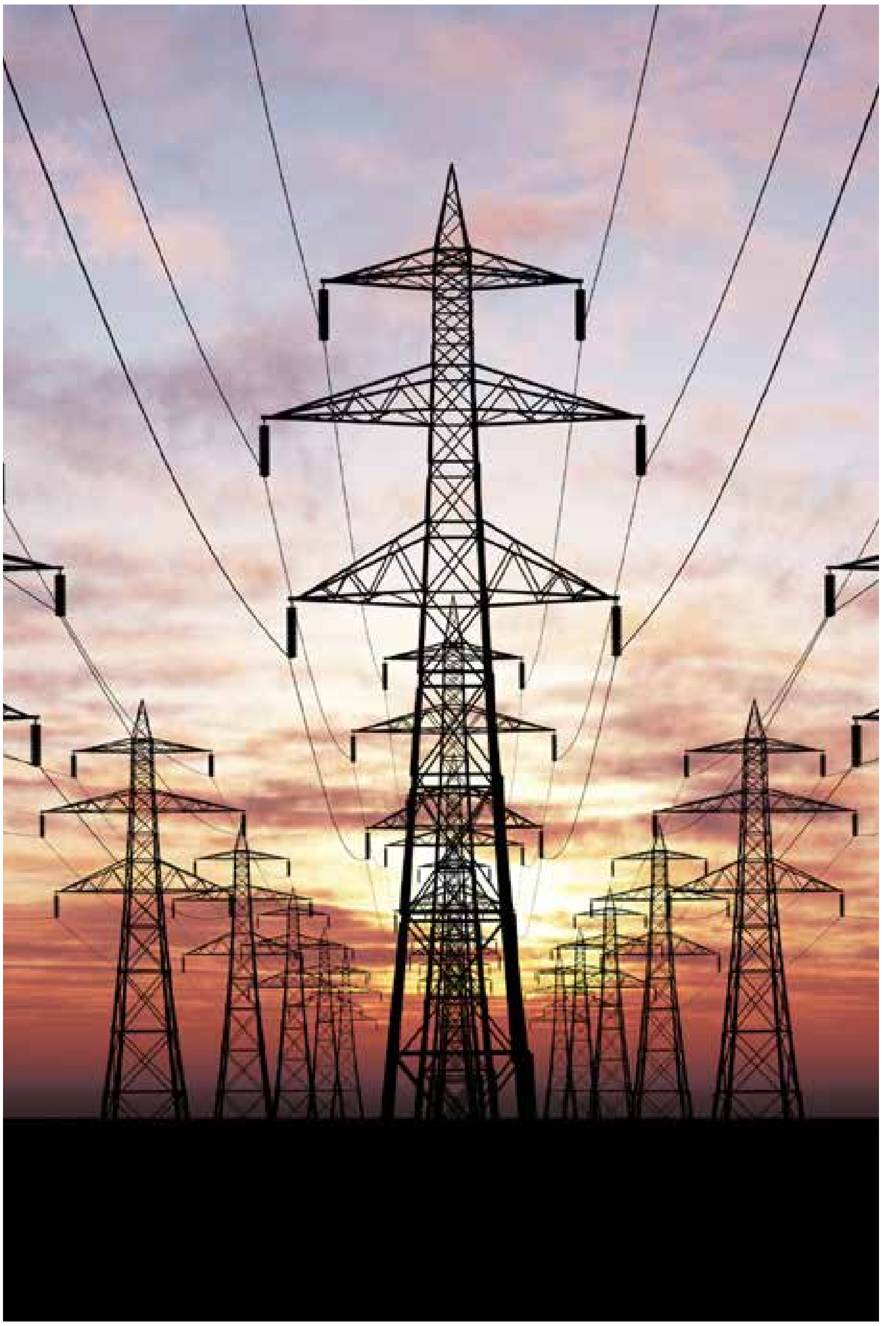
The new CfD regime is replacing the existing Renewables Obligation regime (a green certificate system), which will close to new capacity on 31 March 2017.

For the vast majority of renewable energy projects, CfDs are being allocated to projects through annual allocation rounds. For some low-carbon technologies, where a competitive allocation process is not appropriate at this stage (e.g. nuclear and tidal lagoon projects), CfDs are allocated outside of an allocation round.

In December 2013, the Government published a delivery plan, setting out the strike prices applicable to each renewable energy technology, for each delivery year up to 2018/19. The delivery year, as the name implies, corresponds to a project's target commissioning date.

The first CfD allocation round

The first CfD allocation round commenced on 16 October 2014, triggering a two-week



window for projects wishing to participate in the first allocation round to apply to the delivery body (National Grid). Applications were then assessed by National Grid to check if they met the eligibility requirements, such as the project having planning consent and an agreement with the owner of the relevant distribution or transmission system for connection to, and use of, that system. Once all the applications were received, National Grid valued all of the qualifying applications and compared them to the budget available. Earlier in October, the Government had published the final budget for the round: a total of £300m, representing the total spend per year for contracts assigned in the first allocation round. This overall budget was split into two separate pots: £65m for so-called "established technologies" and £235m for "less established technologies". The budget for less established technologies was subsequently increased by a further £25m.

Established technologies are onshore wind (>5 MW), solar photovoltaic (>5 MW), energy from waste with CHP, hydro (>5 MW and <50 MW), landfill gas and sewage gas. Less established technologies are offshore wind, wave, tidal stream, advanced conversion technologies, anaerobic digestion, dedicated biomass with CHP, geothermal and Scottish Islands onshore wind.

Under the regime, if all the qualifying applicants could have been granted a CfD without exceeding the budget pot for each group of technologies, then an auction would not have been necessary and all the projects would have received a CfD at the strike price set out in the delivery plan – the so-called "administrative strike price". Unsurprisingly, it is to be surmised that more projects qualified for both pots in the budget than could be accommodated, because the allocation process proceeded to an auction. When we say "surmised", this is because, compared to the Capacity Market regime discussed below, the CfD allocation process is less transparent – information about the projects that applied to participate, and the ones that passed the qualification stage, has not been made publicly available.

For the auction, the Government adopted a "pay-as-clear" approach, whereby each project is paid the clearing price for its delivery year within the auction, capped at its administrative strike price. A sealed bid system was used to carry out the actual auction. According to the initial timetable, sealed bids were originally due in December 2014, but the sealed bids submission window was subsequently postponed until February 2015, to allow time to resolve appeals by projects that had been disqualified by the delivery body.

The CfDs being offered

The results of the first CfD allocation round were announced on 26 February 2015. Twenty-seven projects were offered a CfD, worth over £315m (the full list is set out in figure 1). Does this mean that the first allocation round has been a success? We will have to wait another three or four years to determine how many of the projects are ultimately commissioned. But we can make some initial observations based on the strike prices achieved and the projects that have accepted the offer of a CfD.

Offshore wind

Two offshore wind farm projects were successful, in each case achieving a strike price of around £20 less than the administrative strike price. Nonetheless, according to the CfD register, both these projects have accepted the CfD offered. The results have generally been considered to be a win for both the Government and industry. Originally, it was feared that only one offshore wind project would be allocated a CfD, so two projects are seen as a success. In terms of the price, it has been calculated that the level of support is some 14 per cent cheaper than that under the RO regime, thus representing value for money for energy consumers.

Some commentators have pointed out that, while representing a success for the offshore wind industry, the fact that the two projects make up about 54 per cent of the total capacity awarded CfDs proves that the regime is better suited to large-scale projects.

Advanced conversion technologies (ACT)

Three ACT projects were successful, at strike prices comparative to those awarded to the offshore wind projects, which competed against each other for the same pot of money. Once again, the strike prices are roughly £20 less than the administrative strike price. The ACT projects represent just three per cent of the total capacity, in stark contrast to offshore wind.

Energy from Waste with CHP

Two Energy from Waste with CHP projects were offered CfDs, at a strike price of £80, representing 4.5 per cent of the total capacity. These are the only projects that achieved a strike price equal to the administrative strike price. The Energy from Waste with CHP projects competed with onshore wind and solar PV projects for the "established technologies" pot of money.

Onshore wind

Perhaps unsurprisingly, 15 onshore wind projects (amounting to about 35 per cent of the total capacity) were offered CfDs, at strike prices of £82.50 or slightly less. However, as discussed in more detail below, the future of the UK onshore wind industry currently faces great uncertainty, and the CfD auction result may be its last hurrah for some time. Onshore wind has attracted a degree of opposition from various communities and, as a result, the new Conservative Government has pledged to curb its growth.

Solar PV

Five solar PV projects were offered CfDs, making up just 3.5 per cent of the total capacity. The three projects, with a delivery year of 2016/17, achieved a strike price of £79.23, some £35 less than the administrative strike price. Significantly, the other two projects, with a delivery year of 2015/16, achieved a strike price of only £50, a massive £70 below the administrative strike price. At the time the results were announced, there was speculation that this strike price was much too low to allow the projects to go ahead. It seems that this has proved correct – the projects are not listed on the CfD register maintained by National Grid, indicating that the projects did not accept the offer of a CfD.

The results have raised some questions about the future of large-scale solar PV projects in the UK. In October 2014, the Government confirmed that it would be closing the Renewables Obligation scheme to new solar PV generating stations above 5 MW in scale from 1 April 2015, two years earlier than originally anticipated. This means that, looking ahead, large-scale solar PV projects are reliant on the CfD regime for support and will need to compete with the other "established" technologies.

Looking ahead

The next CfD allocation round is scheduled for October 2015. The draft budget notice for the allocation round is scheduled to be published in July 2015. The Government has said that for established technologies, it intends to release £50m for allocation in the October 2015 allocation round for projects commissioning from 2016/17, but indicative spending on less established technologies has not yet been confirmed. No further information is available at this stage. Under the Government's Levy Control Framework (LCF), designed to control spending on support schemes such as the CfD (even though the costs of these are passed down to consumers rather than being funded through general taxation), an overall budget has been set until 2020/21. This means that, in theory at least, there should be some visibility about the likely budget available for future CfD allocation rounds, but this is undermined by the fact that it is not clear how much of the overall budget will be used up by other existing schemes, the potential impact of changes to the wholesale electricity price, and any future changes in government policy direction.

This means that, in the short term at least, investors have limited certainty that budgets will be made available for future allocation rounds. Given the lead time and development costs associated with getting projects "CfD ready", one could argue that there is not sufficient certainty to incentivise developers to progress with their projects.

In a March 2015 report on implementation of EMR, the Energy and Climate Change Select Committee recommended that the Department of Energy and Climate Change "*should commit to publishing more frequent updates of the funds left in the current LCF envelope and clarify rapidly what the timetable and budget of future CfD allocation rounds will be*".

Further uncertainty arises in relation to the period post-2020. Developers of low-carbon projects have gained some comfort from the fact that the UK Government has various commitments to reduce carbon emissions and increase generation from renewables, both at a national and international level. However, the recent election and consequent change in Government, raises some questions about future changes in direction. An immediate result of the change in Government is the fact that the Conservative Party are implementing their manifesto to "halt the spread of onshore windfarms". It has already been confirmed that the forthcoming Energy Bill will amend the planning regime so that planning consent decisions in relation to onshore wind will be taken away from the Secretary of State and given to local authorities instead. The Conservative Party manifesto also said that it will "end any new public subsidy" for onshore wind. On 18 June 2015, the UK Government announced that it would be closing the Renewables Obligation scheme to new projects from 1 April 2016. It is unclear at this stage to what extent CfD support will continue to be available to onshore wind. The Secretary of State has said that "*With regard to CfDs, we have the tools available to implement our manifesto commitments on onshore wind and I will set out how I will do so when announcing plans in relation to further CfD allocations*". It seems likely that CfD availability for onshore wind will be limited in some way at least.

Figure 1 – CfD allocation round auction results

Project name	Developer	Technology	MW	Strike price achieved (£/MWh)	Administrative strike price (£/MWh)	Delivery year
BHEG Walsall	BH EnergyGap (Walsall) Ltd	ACT	26	£114.39	£140	2018/19
Energy Works (Hull)	Energy Words (Hull) Limited	ACT	25	£119.89	£140	2017/18
Enviroparks Hirwaun Generation Site	Enviroparks Operations Ltd	ACT	11	£119.89	£140	2017/18
Wren Power and Pulp	Gent Fairhead & Co. Ltd	EfW with CHP	49.75	£80	£80	2018/19
K3 CHP Facility	K3CHP Ltd	EfW with CHP	45	£80	£80	2018/19
EA1	ScottishPower Renewables (UK) Limited	Offshore Wind	714	£119.89	£140	2017/18[1]
Neart na Gaoithe	Neart na Gaoithe Offshore Wind Limited	Offshore Wind	448	£114.39	£140	2018/19
Dorenell Wind Farm	Dorenell Limited	Onshore Wind	177	£82.50	£90	2018/19
Kype Muir Wind Farm	Banks Renewables (Kype Muir Wind Farm) Limited	Onshore Wind	104	£82.50	£90	2018/19
Clocaenog Forest Wind Farm	RWE Innogy UK Limited	Onshore Wind	96	£82.50	£90	2018/19
Middle Muir Wind Farm	Banks Renewables (Middle Muir Wind Farm) Limited	Onshore Wind	60	£82.50	£90	2018/19
Brenig Wind Farm – Brenig Wind Limited	Brenig Wind Limited	Onshore Wind	45	£79.23	£95	2016/17
Mynydd Y Gwair Wind Farm	RWE Innogy UK Limited	Onshore Wind	40	£79.99	£90	2017/18
Nanclach Wind Farm	Nanclach Limited	Onshore Wind	39.1	£82.50	£90	2018/19
Solwaybank Wind Farm	Solwaybank Energy Limited	Onshore Wind	37.5	£82.50	£90	2018/19
Sneddon Law Community Wind Farm	Sneddon Law Community Wind Company Limited	Onshore Wind	37.5	£79.99	£90	2017/18
Coire Na Cloiche Windfarm	Coire Na Cloiche Windfarm LLP	Onshore Wind	30	£82.50	£90	2018/19
Bad a Cheo Wind Farm	RWE Innogy UK Limited	Onshore Wind	29.9	£82.50	£90	2018/19
Tralorg Wind Farm	PNE WIND UK Ltd	Onshore Wind	20	£82.50	£90	2018/19
Moor House Wind Farm	Banks Renewables (Moor House Wind Farm) Limited	Onshore Wind	16.4	£82.50	£90	2018/19
Achlachan Wind Farm	Achlachan Wind Farm LLP	Onshore Wind	10	£82.50	£90	2018/19
Common Barn Wind Farm	Common Barn Wind Farm Ltd	Onshore Wind	6.15	£82.50	£90	2018/19
Wick Farm Solar Park	Hadstone Energy Limited	Solar PV	19.1	£50	£120	2015/16
Charity Farm	Lightsource SPV136 Limited	Solar PV	14.67	£79.23	£115	2016/17
Royston Solar Farm	Royston Solar Farm Limited	Solar PV	13.78	£50	£120	2015/16
Netley Landfill Solar	REG Netley Solar Ltd	Solar PV	12	£79.23	£115	2016/17
Triangle Farm Solar Park	Cambridgeshire County Council	Solar PV	12	£79.23	£115	2016/17

Capacity Market

Overview of the regime

Under the Capacity Market regime, capacity payments will be made to the providers of capacity, including both generation and non-generation forms of capacity such as demand-side response (DSR) and storage. This is a significant change to existing electricity market arrangements, which only reward generators for the electricity generated.

The starting point under the new regime is that, on an annual basis, the Government estimates the total volume of capacity required 4.5 years ahead of the delivery year (running from 1 October to 30 September), and then the System Operator contracts for the required volume of capacity from providers through a central auction process.

The first capacity auction was held in December 2014 for the 2018/19 delivery year. It was open to all types of eligible capacity. This type of auction, four years ahead of delivery, is called a T-4 auction. The first year-ahead (T-1) auction will take place in late 2017, also for delivery in 2018/19.

For each auction, a demand curve is constructed around a target capacity level and an estimate of the reasonable cost of new capacity (the net cost of new entry or Net CONE). The intersection of these points sets the price at which the System Operator will demand the amount of capacity required to meet the reliability standard. For the first auction, Net CONE was based on the estimated level at which new-build CCGT will bid into the Capacity Market, and was set at £49/KW.

Pre-qualification for the first auction

All generation technologies, including existing plant, were eligible to participate in the auction, unless they already receive support through other means (e.g. the Renewables Obligation or CfD). DSR and storage projects were also eligible.

A pre-qualification stage took place ahead of the auction to confirm the eligibility and bidding status of all potential capacity intending to bid. The application window for pre-qualification for the first T-4 auction ran from 4 August to 29 August 2014.

Participation in the pre-qualification process was mandatory for all eligible licensed generators that were eligible, even if those generators did not intend to bid.

The results of the pre-qualification process for the first T-4 auction were announced by National Grid on 3 October 2014.

The first auction

As mentioned above, the first T-4 auction took place in December 2014. Auctions are run on a "pay-as-clear" basis, which means that all successful auction participants (including existing plant) will be paid the same price per unit of capacity, and the price is set by the most expensive successful bidder. Each auction is run in multiple rounds on the basis of a "descending clock" format, which means that providers confirm they will offer capacity at a particular price, and then further rounds are held at a lower price, until the auction discovers the minimum price at which there is sufficient capacity.

To mitigate the risk of existing plant seeking to force up the capacity price, at the pre-qualification stage all participants were required to register whether they wish to participate in the auction as "price makers" (i.e. price setters) or "price takers".

1 EA1 will be built in three phases, with 2017/18 being the delivery year for phase 1.

Existing generators default to being a price taker unless they are a plant that will undergo refurbishment. Price takers are only able to bid up to a relatively low threshold set to allow the majority of existing plant to participate in the auction as price takers. The price taker threshold is determined as one of the auction parameters ahead of each auction. The price taker threshold for the first T-4 action was set at £25/KW/year, being approximately 50 per cent of Net CONE.

The results of the first action were announced on 2 January 2015, confirming that 49.26 GW of capacity was procured, at a clearing price of £19.40/KW.

A total of 64,969.341 MW entered the auction, of which 75.82 per cent received capacity agreements for delivery in 2018/19. National Grid's analysis of the auction results is useful to consider, not just from the point of view of the generators that have been awarded a capacity agreement as a result of the auction, but also the generators that missed out.

Figure 2 shows the breakdown of the so-called Capacity Market Units (CMUs), which were successful, by category. The vast majority of the successful generators are existing plants, and in terms of technology, the majority are CCGT plants. At the time the results were announced, the Government hailed the first auction a success, as capacity agreements had been procured at a clearing price cheaper than anticipated. But questions have been raised about what has actually been achieved, given that one of the aims of the Capacity Market was to procure new capacity.

Figure 2 (Source: National Grid, Final Auction Results – T4 Capacity Market Auction 2014)

	Capacity (MW)	Capacity (%)	Number of CMUs	Number of CMUs (%)
Existing Generating CMU	31,446.770	63.84	170[2]	55.56
Refurbishing CMU	7,048.927	14.31	17	5.56
Pre-Refurbishment CMU	7,967.920	16.18	27[2]	8.82
New Build Generating CMU	2,621.151	5.32	77	25.16
Unproven DSR CMU	165.945	0.34	13	4.25
Proven DSR CMU	8.225	0.02	2	0.65

A total of 15,710.403 MW exited the auction above the clearing price. New-build generating CMUs make up the largest group of capacity that exited the auction. This is not a good result for investors in new-build CCGT projects. The Government had previously formally committed to supporting new gas-fired generation, which it sees as an essential component of the UK's energy mix, at least in the medium term. The Energy and Climate Change Select Committee recommended in its March 2015 report "*that the Government clarifies its ambitions for the future of coal-fired power stations in the Capacity Market and its expectations for both new plant and DSR in the second four-year-ahead Capacity Market auction in 2015*".

Looking ahead

The next T-4 auction will commence on 8 December 2015, for the delivery year beginning on 1 October 2019. Unlike in the 2014 auction, interconnectors will be able to participate in this auction. In January 2016, the first-ever Transitional Arrangements Auction will take place, designed to facilitate the participation of DSR in the enduring Capacity Market. Successful participants in the Transitional Arrangements will see their agreements commence from 1 October 2016. The pre-qualification windows for both auctions will open on 20 July 2015.

2 15 refurbishing CMUs with capacity totalling 2119.236 MW opted to enter the auction with only their pre-refurbishing components. These were treated as Existing Generating CMUs by the IT Auction System. These are listed here (and on the Capacity Market Register) as refurbishing CMUs in their pre-refurbishment state.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THE MEXICAN UPSTREAM SECTOR: Change and opportunity

by Manuel Zapata

In December 2013, constitutional reform opened up to private participation certain oil and gas activities which were previously the prerogative of the state-owned company Petróleos Mexicanos (Pemex). The changes to the constitution have been followed by legislation, enacted between August and October 2014, which provides eligible private companies with the opportunity to bid for exploration and production (E&P) projects.

Although less than a year has passed since the legislation was enacted, the reform is now being implemented. The first E&P projects are in the process of being awarded, and further E&P tender processes will take place throughout 2015.

Pemex has also announced a plan to have around 20 joint ventures with private investors in place by the end of 2015.

This article gives an overview of the new regulatory framework for Mexican E&P, as well as the potential opportunities for private investors resulting from its implementation.

Background

In Mexico, E&P activities have historically been entrusted, on an exclusive basis, to Pemex, and as a general rule private investors were only allowed to participate as service providers to Pemex.

However, although it is one of the largest producers of crude oil, Pemex has been facing some difficulties. Its production has declined for more than nine consecutive years, and although it has vast experience in shallow water fields, most Mexican reserves are found in more complex fields which demand higher technical and financial capabilities. This situation, coupled with high contributions by Pemex to central government, resulting in a weak balance sheet for Pemex, made it clear that urgent reform was required.

The constitutional reform was enacted in December 2013, opening the door for private investment in upstream, midstream and downstream activities in the hydrocarbons sector. This article, however, focuses only on the upstream Mexican sector.

E&P Contracts regime

The new legal framework provides for two instruments that allow for E&P activities: the so-called Entitlements and E&P Contracts. Both are legal instruments that grant E&P rights over specific areas and for specific periods of time (ranging from 25 to 30 years, generally).

The key difference between Entitlements and E&P Contracts is that Entitlements can only be granted in favour of state-owned companies (i.e. when there are reasons justifying that it is in the interest of the state to grant Entitlements rather than E&P Contracts), while E&P Contracts can be awarded to private investors.

In short, private investors can only be granted E&P rights through E&P Contracts. The main characteristics of these E&P Contracts are set out below.

Tender processes

E&P Contracts are always awarded via tender processes (i.e. neither direct awards nor negotiation processes are contemplated by the law). The tender documents establish the type of contract to be awarded on a case-by-case basis, including its main terms and conditions. The new regulatory framework provides for four different types of E&P Contracts:

(i) service agreements;
(ii) profit-sharing agreements;
(iii) production-sharing agreements; and
(iv) licences.

The regime requires that there should be at least 90 days between the formal announcement of commencement of the tender process and the deadline for submitting bids.

The awarding method in each case is to be set out in the relevant tender document. Access to the data room, as well as registration, will normally carry a cost for potential bidders.

Joint ventures

E&P Contracts can be awarded to a bidder acting alone or to a consortium of bidders acting together. Bidders, therefore, can take part in:

(i) incorporated joint ventures, in which all the members hold shares in a special purpose vehicle which will be the bidding company and the potential holder of the E&P Contract; or
(ii) unincorporated joint ventures, through Joint Operating Agreements (JOAs), under which one of the members shall be appointed as operator and which must set out whether the proceeds will be distributed by the Contracting Authority to each member, or only to the operator to further distribute among the other members.

Eligibility requirements

Bidders are required to comply with the technical expertise, financial and other requirements set out in the tender documents. Such requirements include being resident in Mexico for tax purposes and having as their sole corporate purpose the exploration and production of petroleum (except for those members of JOAs not undertaking the operator role).

Transfer of interest in E&P projects

As a general rule, prior authorisation from the National Hydrocarbons Commission (CNH) is required for transfers of interest resulting in a change of control over an E&P project.

Under the new Mexican Petroleum Act, it is not clear whether indirect transfers are also caught by this restriction. However, this may be clarified in further regulations made under the Petroleum Act in rules which may be passed by CNH, or in the relevant tender documents.

If a transfer authorisation request is not dealt with by CNH within the statutory term (around 32 days), then the authorisation will automatically be deemed to have been granted. Please note that those transfers not giving rise to a change of control should be notified to (as opposed to authorised by) the contracting authority within a period of 30 calendar days.

Transfers carried out without fulfilling the above requirements are rendered null and void.

Applicable law

E&P Contracts are governed by Mexican law and can be subject to arbitration. As a general rule, E&P Contracts are governed by the Petroleum Act and by the general laws on private contracts.

Unlike some European jurisdictions, Mexican law does not allow contracting authorities to unilaterally amend the terms and conditions of contracts with the public sector, such as the E&P Contracts.

National content

E&P Contract holders are required to meet the national content requirements set out in the new legal framework (i.e. the required proportion of Mexican goods and services, workforce, investment in infrastructure and transfer of technology, as assessed and supervised by the Ministry of Economy).

These requirements will be set out in the tender documents. The average target of national content for E&P projects in 2015 is set at 25 per cent and is expected to gradually increase to 35 per cent by 2025 (note that E&P activities in deep waters are currently excluded from national content obligations).

The regulators

Under the new legal framework, the key regulatory players at the upstream level are the following:

- The Mexican Ministry of Energy (SENER) is responsible for selecting E&P areas to be tendered. It is required to issue five-year tender plans for that purpose. SENER defines the type of contract to be used in each area, and the technical and other requirements to be met by winning bidders. It also plays an important role in defining the technical terms and conditions of E&P Contracts.
- The Mexican Ministry of Finance (SHCP) is responsible for defining the economic terms and conditions of E&P Contracts as well as the economic criteria to be considered for the awarding of E&P Contracts. It carries out audits of E&P Contracts and it is entitled to hire external auditors to do this.
- CNH is responsible for issuing tender documents following the guidelines of SENER/SHCP and for handling tender processes. It is also responsible for executing E&P Contracts and Entitlements and for supervising the performance of E&P Contracts. It can approve transfers of interest in E&P projects.
- The Mexican Petroleum Fund for Stability and Development is a national trust fund within the Mexican Central Bank which receives, administers and distributes the income resulting from E&P Contracts. It is responsible for making all the payments to contractors that, when applicable, the Mexican state has to make under E&P Contracts.

The role of Pemex

The reforms of the Mexican oil and gas regulatory framework provided for a preferential right over E&P fields in favour of Pemex. In exercising this right, Pemex requested that it retain E&P rights over all of its producing fields (2P), as well as over those fields where it has already made exploration investments and commercial discoveries.

Pemex's request was evaluated by SENER with the technical assistance of CNH, and on 13 August 2014 SENER resolved to grant 120 Entitlements to Pemex, which included all the 2P reserves requested and around 21 per cent of the prospective resources of the country. This award positions Pemex as the fifth-largest company in the world in terms of proven reserves, therefore upstream opportunities for private investors can also be found in potential joint ventures with Pemex.

Pemex can enter into joint venture schemes in the following three scenarios:

Migration to E&P Contracts

Given that private investors cannot hold E&P rights under Entitlements, the only way in which a private investor can participate in E&P projects regulated by Entitlements is by rendering services to the state-owned companies holding such Entitlements (i.e. to Pemex).

However, if so authorised by SENER, upon Pemex's request, an Entitlement can be converted into an E&P Contract. This would allow Pemex to enter into joint ventures with private investors in relation to the E&P activities performed under the converted E&P Contracts.

As a general rule, Pemex will not be entitled to freely choose its partner in this case: the relevant partner must be chosen through a tender process carried out by CNH. However, Pemex will be consulted about the technical, financial and other requirements that are to be met by the partner. As an exception, given that certain pre-existing E&P service agreements entered into between Pemex and private parties will continue in force, if mutually agreed between the services provider and Pemex, the relevant service agreement could be converted into a joint venture agreement without a tender process upon conversion of the corresponding Entitlement into an E&P Contract.

Bidding with Pemex

Pemex is entitled to compete against private investors in tender processes for new E&P Contracts. It is also entitled to take part in joint ventures or consortia of bidders acting together.

In contrast with the limitation on choosing its own partners (i.e. in the case of Entitlements converted in E&P Contracts), entering into joint ventures with third parties for the purpose of bidding for new E&P Contracts is a matter that can be decided by Pemex itself in accordance with its internal rules.

Compulsory joint ventures

The tender documents for E&P Contracts will always require Pemex to have a participation (of at least 20 per cent) in E&P projects relating to fields which are likely to have cross-border basins.

In addition, the participation of Pemex may also be included as an award requirement if:

- the relevant contractual area overlaps, at a different depth, with an area covered by an Entitlement already held by Pemex; or
- there are opportunities to support the transfer of knowledge and technology to Pemex.

In the scenarios outlined above, the tender documents will set out Pemex's mandatory stake in the project, which will not be higher than 30 per cent.

Current allocation rounds

A first bidding round for new E&P Contracts, the so-called "Round 1", has already been launched. It includes 109 fields for exploration and 60 for production, representing around US$8.5bn of annual investment over the next four years.

Under Round 1 there is a diverse portfolio of different types of fields. Therefore, Round 1 has been divided into different tender processes based on the type of fields to be awarded.

Currently there are three tender processes in progress:

- The first tender process already initiated relates to 14 shallow water (exploration) fields to be allocated under 14 E&P Contracts. These E&P Contracts will follow the production-sharing agreement model, and foresee two phases: (i) an exploration phase ranging from three to five years (with up to two yearly extensions); and (ii) a development and production phase of 22 years. There are some 34 companies already registered for this process and the award decision is expected by mid-July 2015.
- The second tender process already initiated relates to some nine shallow water (production) fields to be allocated under five E&P Contracts. As in the first tender process, the contract model chosen is a production-sharing agreement. Around 17 companies are already registered for this process (registration closed on 15 June 2015), and bids must be submitted by 30 September 2015.
- Most recently, on 12 May 2015, the third tender process was formally launched. The third tender process relates to 26 onshore fields to be allocated under 26 E&P Contracts which will follow the licence model. Registration to this process closes in August 2015 and bids must be submitted by 15 December 2015.

Round 1 is also intended to cover deep water fields and unconventional fields and, therefore, tender processes in relation to such fields are also expected to be launched this year.

Pemex, in turn, has also announced its intention to migrate some of its Entitlements, and expects to complete the migration of some 22 Entitlements to E&P Contracts before the end of 2015. It is believed that around ten of those migrated E&P Contracts may give rise to tender processes for private investors to enter into partnerships with Pemex, while the rest could be migrated in order to allow Pemex to enter into joint ventures (without tender processes) with pre-existing E&P service providers.

Untapped potential

Mexico is known as one of the largest untapped oil and gas reserves in the world, with a vast unexplored area. It is believed that oil and gas reserves in the Mexican side of the Gulf of Mexico should be similar to those which are found in the American side of the Gulf. However, in terms of actual production, the difference is considerable. For instance, in relation to shale oil and gas, in 2012 there were around 9,000 authorisations (and around 3,000 wells already drilled) in the US, while in Mexico there were not more than three authorisations. In relation to deep water fields, the US produces around one million barrels per day, while in Mexico not a single barrel has been produced from deep water fields.

This untapped potential represents real opportunities for those companies with large financial capabilities or with the required technical skills.

Although the reforms have already attracted the attention of many global players in the oil and gas sector who are already participating in (or considering) Round 1, there are many challenges for these potential investors. These challenges range from the legal (such as understanding the Mexican business and regulatory environment) to the economic (such as the prevailing low oil price). Security issues in the country also continue to be present. All of these will play a key role in defining the new Mexican oil and gas sector, but it is hoped that the Mexican oil and gas industry will continue its reform momentum.

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MINING AND COMMUNITY DEVELOPMENT IN AFRICA: Agreements and principles

by Martin Kudnig and Mary Seely

Natural resources projects can give rise to some of the largest and most complex development opportunities for nations. They can drive economic growth, infrastructure development and employment opportunities.

In the context of developing nations (but not exclusively), natural resorces projects can also result in greater probability of conflict, reduced freedom, increased military spending and leave large areas of the population in greater poverty than before.

Preventing the "resource curse" and ensuring that the benefits of investment in extractive industries reach the communities most affected by projects is a challenge confronting governments across the world. This complex issue is compounded by the fact that projects are being increasingly developed either in less developed countries, such as those in mineral-rich parts of Africa, or in more remote and poorer regions where access to infrastructure and government services is already limited. Developing effective mechanisms to ensure sustainable development is one of the challenges facing government and industry alike.

The move to sustainable development

Development initiatives in the 1980s and 1990s saw bodies such as the World Bank encourage countries to liberalise their mining sectors and open markets to foreign investment. This resulted in broad changes to mining laws, widespread privatisation of state-owned resource companies and the removal of market-distorting subsidies. Such initiatives created long periods of sustained economic growth as governments globally realised the benefits of resource exploitation in the form of taxes, royalties and other payments. However, such benefits tended to flow to the country as a whole and not to the regions most affected by operations. Local initiatives, if any, tended to be ad hoc philanthropic gestures based on the perceived needs of communities, which provided little in the way of lasting benefit for affected communities (see figure 1 for a summary of the main features of different approaches to community development).

In addition, rapid development brought with it negative effects – pollution, environmental degradation, resettlement and social dislocation – which were disproportionately felt by more disadvantaged sectors of society; in particular, indigenous people, remote and regional communities, women and the poor.

Benefits to community and business of different approaches to community development

Isolated financial approach
- Company pays taxes and may contribute to national government funds but no activity at local community level

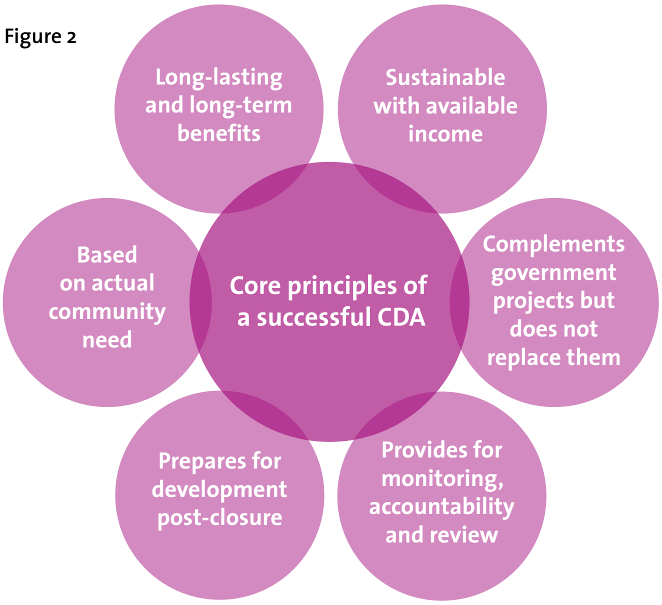
Ad hoc philanthropy
- Donations in response to a request from local government/ community for small infrastructure or emergency with little guidelines or follow-up

Strategic philanthropy
- Company selects and manages an initiative with some consultation or maintenance with local community but low impact appraisal, often focused at mine level

Integrated community development
- Local communities and authority are involved in setting strategy and managing projects
- Long-term independent programme with monitoring and reviewing processes

Figure 1

Figure 2



In response, communities and "civil society" groups have become more vocal in their criticism of government, and NGOs and industry have sought to find ways to encourage poverty alleviation through sustainable development.

In 2004, the World Bank Group published *Striking a Better Balance*,[1] the results of its multi-stakeholder review of the extractive industries. The report concluded that to help ensure local communities receive benefits from extractive industry projects, the World Bank Group should:

- *"require companies to engage in consent processes with communities and groups directly affected by projects in order to obtain their free, prior and informed consent;*
- *require revenue sharing with local communities;*
- *mandate the use of poverty indicators that are monitored systematically;*
- *encourage the incorporation of public health components in all extractive industry projects;*
- *urge NGOs to build the capacity of affected communities; and*
- *set up independent grievance mechanisms".*

Extracting minerals from the ground is inherently a finite and non-sustainable process, but achieving the World Bank's goals would result in projects which convert the natural capital of mineral wealth into human, economic and social capital, resulting in what is considered to be sustainable mining development. Increasingly, community development agreements (CDAs) are seen as a way to achieve these outcomes.

1 *Striking a Better Balance*, Volume 1, Final Report of the Extractive Industries Review, December 2003.

The World Bank's goals and CDAs

With these goals in mind, governments, industry and communities have been seeking more integrated, socially conscious solutions to development challenges. One mechanism to achieve this is the CDA.

A CDA is an *"agreement between an investor and a community that provides a mechanism through which the benefits of an investment project can be shared directly with local communities and other project-affected stakeholders"*.[2] Properly implemented, a CDA can:

- provide long-lasting, sustainable benefits to the communities and individuals most affected by a project;
- contribute to a positive ongoing relationship and dialogue between the affected community and the resource proponent (the oft-mentioned social licence to operate, and free, prior, informed consent – see "Resources projects and communities: The principle of 'free, prior, informed consent'" on p16 of this issue of Energy**Source**); and
- manage expectations around the role of the investor in the community.[3]

Developing a successful CDA

Extensive research has been carried out to determine the elements of a successful CDA and the process for developing one. Research undertaken by bodies including the World Bank, the Columbia Center on Sustainable Investment and the Centre for Social Responsibility in Mining have identified six core principles in common across successful CDAs (see figure 2).

While there is no one way to develop a CDA, both the World Bank in its *Mining Community Development Agreements Source Book* and the International Council on Mining and Metals in its Community Development Toolkit recommend the following four-step process:

Step 1	• **Stakeholder engagement** • Conduct a process to identify the qualified communities which will benefit from the CDA • Develop a plan to engage with them
Step 2	• **Capacity building** • Identify the skills and resources stakeholders will need to effectively participate in the process • Access existing capacity • Support capacity development, e.g. financial support, training and appointing external advisers
Step 3	• **Stakeholder representation and agreement** • Identify the representatives of the community • Negotiate and develop the CDA
Step 4	• **Implementation and feedback mechanism** • Objectives include measurable criteria of performance and impact, not just the delivery of activities and outputs • Mechanism for regular communication between all parties for monitoring and review of activities, and to address grievances

Clearly, preparing and implementing a successful CDA can be a resource-intensive process. It requires an open dialogue with local communities to develop sufficient trust between the parties to facilitate negotiation and agreement. Challenges can arise in determining the correct stakeholders to negotiate with, and ensuring that minorities or marginalised groups within the community are represented. Community groups may also need support during the negotiation process to identify their goals and negotiate on an equal footing with a resource company (i.e. capacity building). For these reasons, experience shows that engaging with the community early in the process is key to the success of a CDA.

Importantly, the process is not completed when the CDA is negotiated and signed. The establishment of a comprehensive monitoring and evaluation system can also be a complex and resource-intensive process, as measurable and realistic indicators of impact have

2 Negotiations Portal, a project of the Columbia Center on Sustainable Investment (negotiationsupport.org/glossary/community-development-agreement).

3 *EI SourceBook – Good Practice Notes, Community Development Agreements*, 2011 and *Mining Community Development Agreements Source Book*, World Bank Group, March 2012.

to be developed and meet stakeholder expectations. Furthermore, an independent monitoring and assessment mechanism has to be designed, and communities have to be encouraged and trained to develop the capacity to manage and monitor themselves. Strong communication links and trust relationships must be maintained throughout the life of the CDA.

Legislative backing

Experience shows there are three main contexts where CDAs are entered into:

- because of a legislative mandate specifically requiring a CDA;
- in circumstances where the legal regime requests consent to be obtained from the indigenous or traditional custodians of the land, and while a CDA is not mandated as part of this process, for the reasons outlined above, it is seen as the natural extension; or
- to resolve conflicts between miners and communities where there has been a dispute over operations. It is in such cases that the concept of a social licence to operate, and free, prior and informed consent, becomes very important.

There are also a limited number of cases where companies have successfully entered into voluntary CDAs. For example, the mining sector in Ghana has strived for best practice, and several companies (most notably Newmont at its Ahafo project) have voluntarily entered into CDAs which are now held out as examples to industry. Well-regarded template documents also encourage companies to enter into voluntary CDAs. For example, the International Bar Association's Model Mine Development Agreement – a guide for states and miners to enter into bespoke mine development arrangements – provides for companies to negotiate one or more CDAs to achieve the development goals. It sets out high level criteria of what a CDA must encompass and provides a detailed set of CDA objectives and guide for local development in its annexures.

Currently, the laws of at least 18 African republics (including Angola, Central African Republic, Democratic Republic of Congo, Equatorial Guinea, Ethiopia, Ghana, Guinea, Ivory Coast, Kenya, Mali, Mozambique, Niger, Nigeria, Sierra Leone, South Africa, South Sudan, Tanzania and Zimbabwe) impose some kind of community development requirement in their mining legislation (and there is legislation to this effect under consideration in Burkina Faso and Togo). Almost all of these laws have come into force post-2002 (with two – Mozambique and South Africa – in 2014, and a further set of changes are currently before Kenya's Parliament) showing the increasing impetus on the part of governments to encourage this type of sustainable development. The World Bank has also recognised its role in mining-led development at both the national and community level, and as part of this role has prepared a set of Community Development Agreement Model Regulations and Guidelines to help nations achieve legislative reforms.

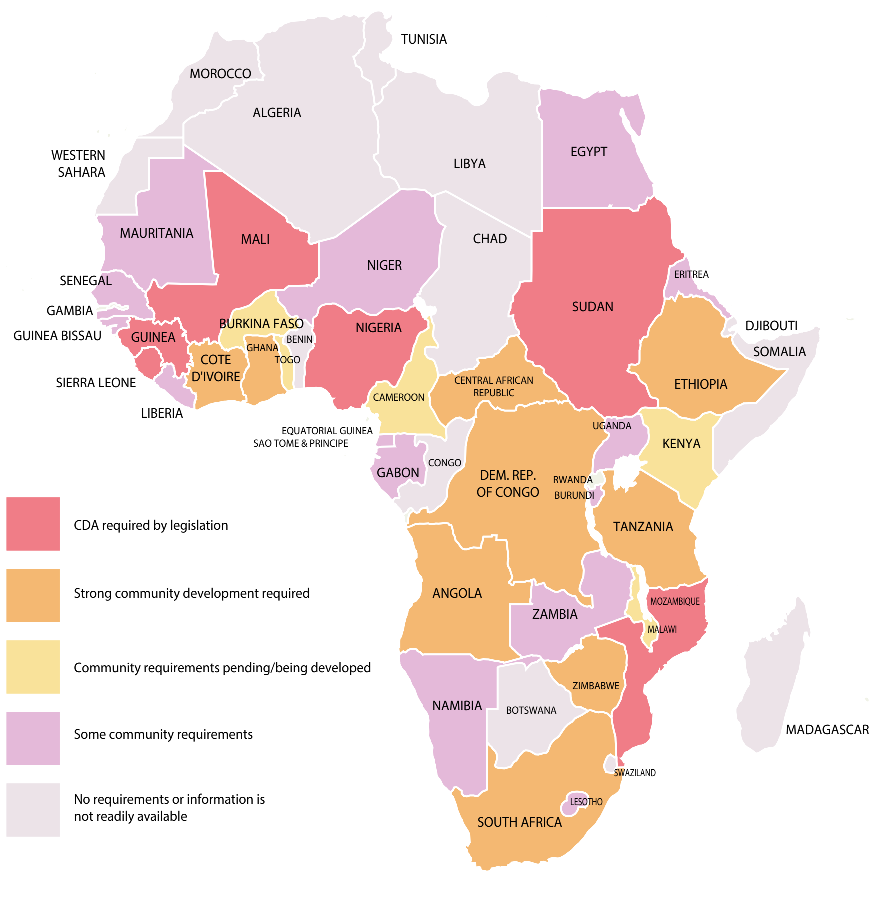
The nature of these obligations range from the creation of local development funds jointly funded by the State and resource companies, to the requirement for a project-specific plan for community development or reporting to the government on how a project will contribute to community development. At the lower end of the scale, many African countries rely on ad hoc local content and generic environmental protection obligations. These obligations may involve an environmental assessment study and rehabilitation plan to be submitted with a mining title application, some protected areas or forestry, national preference and commitments to employ and train nationals, and sometimes an obligation to compensate landowners for use/damage to their land, but often paired with a compulsory purchase right with little protection of indigenous communities or cultural heritage sites.

Countries often introduce community development responsibility by creating new community taxes, choosing to share royalty profits with the local communities or, at the higher end of the scale, by requiring permit holders to contribute to local mining development funds. Community mining royalties exist in Egypt, Ghana, Kenya, Mozambique and Niger. Contributions to development funds are required in South Africa and Zimbabwe.

Beyond the monetary element, countries can require local community development plans, require socio-economic impact studies, or consultation with affected communities. Community development programmes are required in countries such as the Democratic Republic of Congo, Ethiopia, Mali, Namibia, South Africa and Togo. Socio-economic impact assessment studies are required in Burundi and Ghana. Consultation with the affected communities is required in Angola and Mali.

At the top end of the scale, mining title holders in countries such as Guinea, Mozambique and Nigeria have to enter into binding development agreements with the local community to address socio-

Community Development in Africa



economic benefits. See the "Community Development in Africa" map for an overview of the approach to community development obligations across different jurisdictions in Africa.

Whether CDAs should be mandated by legislation is a matter of some contention.[4] Some argue that CDAs have the potential to undermine the role of government in the development agenda, either because resource companies and communities will negotiate between themselves without involving government, or because government will treat CDAs as a way to shift state functions to the private sector. At the same time, legislating to involve government in the process can create conflicts of interest for government, which some view should act as an impartial regulator rather than a participant in the process. There is also potential for the interests of central government to diverge from those of the affected community, which can undermine the negotiation process. Other criticisms of mandatory schemes are that there is no "one-size-fits-all" approach to CDAs and the process inherently needs to be flexible to allow for development in the local context. Mandating form and process in legislation can detract from that flexibility. Mining companies also express concern that a compulsory scheme can result in a feeling of entitlement from community stakeholders. Research conducted in Ghana suggests that this sense of entitlement can lead to stakeholder disengagement, because the process becomes a box-ticking exercise for mining companies, and communities know that, irrespective of the level of participation, they will receive mandated outcomes.[5] One of the reasons CDAs are so effective as a development tool is the fact that they involve such strong collaborations between mining companies and the community, and this can be undermined by mandated outcomes.

On the other hand, those in favour of mandatory schemes argue that effective corporate social responsibility requires a regulatory foundation that promotes growth, employment and good governance. By requiring mandatory participation, government is forced to spend time and money building community capacity to participate in the process and providing support to monitor the negotiation and implementation process. Decades of experience in this sector also shows that there are companies that will fail to engage with communities or support local development agendas without compulsion from government.

Conclusion

Managing sustainable resource development remains a challenge for governments all over the world. Increasingly, there is a significant body of research and experience which suggests that CDAs facilitate a focused way to ensure that those most affected by resource projects are able to see sustainable long-term development. While not without significant cost and challenges, successful CDAs can secure maximum benefit for communities and project proponents alike.

4 See "Accommodating Interests in Resource Extraction: Indigenous Peoples, Local Communities and the Role of Law in Economic and Social Sustainability", Godden, L and Langton, M *et al*, *Journal of Energy and Natural Resources Law* (Vol. 26 No. 1 2008); and *Mining Community Development Agreements – Practical Experiences and Field Studies*, Final Report of the World Bank, June 2010.

5 *Mining Community Development Agreements*, ibid.

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Mining and community development in Africa: a snapshot of legislative requirements

Mozambique

Mozambique's new Mining Law (no. 20/2014) represents a major overhaul of the 2002 legislation, designed to *"adapt the Mining Law to the country's present economic situation ... and ensure competitiveness and transparency"*. The new Mining Law imposes a range of community development obligations on mining concession holders, including:

- As a condition to entry of the mining contract with the Government, mining concession holders must enter a memorandum of understanding (MoU) between the Government, the mining concession holder and the communities affected by the project.
- Mining concession holders are obligated to pay fair and transparent compensation for the use of land belonging to families or communities, which must be fixed in the MoU. If requested by one of the parties, the MoU may be witnessed by a community-based organisation.
- Fair compensation must cover a range of items including support in the development of activities that those covered depend on in life, such as food and nutritional safety, and preservation of historical, cultural and symbolic heritage in ways to be agreed.
- Communities have rights to be consulted and provided with information prior to the granting of any mining concession.
- The Government is obligated to support capacity development. It must create mechanisms to allow the engagement of communities in mining projects located where they are settled, and is responsible for assuring the organisation of the communities in order to promote that engagement.
- In addition to these requirements, the mining contract entered into with the Government must set out a plan for the way communities in the mining area are engaged and benefited by the venture and details of the social responsibility activities to be developed by the mining concession holder. The mining concession holder is also under a general obligation to carry out social, economic and sustainable development actions in the areas of the mining concession.

Kenya

Kenya's Parliament is considering two pieces of legislation that will see major changes to its mining law and the manner in which natural resources projects generally are implemented.

The Mining Bill 2014 contains a number of obligations on parties to take into account the rights of communities affected by mining projects, including:

- Prior to the grant of a mineral right, the applicant must seek the consent of the community that is in occupation of the land.
- A mineral right may be granted subject to conditions concerning a number of factors, including community development.
- The Cabinet Secretary may enter into an agreement with the holder of a mineral right with respect to activities under that mineral right which will include terms and conditions in relation to community development plans.

Most importantly, the Mining Bill mandates that holders of a mining right in relation to a large-scale operation (which includes mining operations where the area exceeds two contiguous blocks, or which will extract more than 25,000 cubic metres, or use specialised prospecting, mechanised mining technologies or chemicals including mercury, cyanide or explosives) to implement a community development agreement.

Although the draft Bill does not prescribe the contents of the community development agreement, it does define the community *"as a group of individuals or families who share a common heritage, interest or stake in identifiable land, land-based resources or benefits that may be derived from the land resources"*.

The second bill under consideration, the Natural Resources (Benefit Sharing) Bill, applies in relation to the exploitation of petroleum, natural gas, minerals, forest resources, water resources, wildlife resources and fishery resources. The purpose of this bill is *"to establish a system of benefit sharing in resource exploiters, the national government, county governments and local communities"*. The Bill provides for a system of national, county and local benefit sharing, and the creation of regulated bodies to oversee the negotiation and implementation of such benefits.

The Bill establishes a national Benefit Sharing Authority to, among other things:

- Co-ordinate the preparation and oversight of "benefit sharing agreements" between local communities and "affected organisations" (an "affected organisation" is any organisation involved in the exploration of a natural resource to which the Act applies).
- Collect and administer funds set aside for community projects identified under a benefit sharing agreement.
- Monitor the implementation of any benefit sharing agreement entered into.
- Conduct research on exploitation and development of natural resources and benefit sharing in Kenya, and make recommendations to national and county governments on the better exploitation of natural resources in Kenya.

The Benefit Sharing Authority will prescribe royalties payable and provide for revenue collected to be shared:

- 20 per cent to create a national sovereign wealth fund; and
- 80 per cent to be shared between the national government and the country governments in a ratio of 60:40. These funds are required to be used for projects which are prioritised by County Benefit Sharing Committees and Local Benefit Sharing Forums.

Under the Bill, every "affected organisation" will enter a county benefit sharing agreement with the respective county government to provide for the non-monetary benefits that will accrue to the county.

At a county level, each county will establish a County Benefit Sharing Committee with power, among others things, to negotiate with affected organisations, monitor the implementation of projects, and convene public forums to facilitate public participation in the negotiation and implementation of county benefit sharing agreements and the proposed community projects.

Local communities will also create a Local Benefit Sharing Forum of five elected representatives, which will in turn work with the County Benefit Sharing Committee to negotiate local community benefit sharing agreements, identify local community projects to be supported by money flowing as a result of the Bill and oversee the implementation of such projects. Every "affected local community" will enter into a local community benefit sharing agreement with the County Benefit Sharing Committee.

Both the Mining Bill and the Natural Resources (Benefit Sharing) Bill demonstrate a commitment by the Kenyan Government to creating sustainable development in all aspects of natural resources exploitation. Elements of each of the building blocks for best practice community development can be seen in the legislation including identifying communities, providing for ways to engage, and capacity building, monitoring and follow-up mechanisms. No doubt both pieces of legislation will be keenly monitored by the mining industry and development organisations as potential models for future development initiatives.

RESOURCES PROJECTS AND COMMUNITIES:

The principle of "free, prior, informed consent"

by Gavin Scott and Clare Lawrence

Momentum behind recognition of the principle of "free, prior, informed consent" (FPIC) as a human right of indigenous peoples has been building for several decades. For nation states, FPIC raises questions about how far indigenous peoples' right to self-determination can push against traditional notions of sovereignty and state ownership of natural resources. The content of FPIC, and whether it provides indigenous peoples with a veto over natural resource projects, remains a contentious issue for resource-producing nations and has direct implications for companies operating in the natural resources sector.

The legal origins and development of the FPIC principle explored in this article demonstrate that, increasingly, resource project developers are expected to act consistently with some form of FPIC standards. A failure by resource project developers to invest in early, appropriate and considered FPIC processes can create significant commercial and operational risks for natural resource projects once operations commence and impacts occur.

What are the legal origins of FPIC?

Identifying the "legal origins" of FPIC is not an easy task, and arguably depends on whether one sees FPIC as a basic right in itself, a mechanism through which other rights are protected or a "best practice" process for engaging with indigenous peoples. Fundamentally, FPIC is contentious because there is no universal definition of its content.

The first recognition of FPIC-related principles in the international law context came in the Indigenous and Tribal Populations Convention, 1957 (No. 107) (Convention 107), adopted by the International Labour Organisation (ILO) in 1957, which entered into force in 1959 and was ratified by 27 member states. Convention 107, which still remains in force for 17 ILO members, provides a qualified recognition that indigenous populations *"shall not be removed without their free consent from their habitual territories except in accordance with national laws"* and for particular reasons (Article 12).

Convention 107 was replaced by the Indigenous and Tribal Peoples Convention, 1989 (No. 169) (Convention 169) in 1989 and which entered into force in 1991. Article 16 of Convention 169 builds on the rights recognised in Convention 107 and provides that where *"relocation of [indigenous] peoples is considered necessary as an exceptional measure, such relocation shall take place only with their free and informed consent"*. However, like Convention 107, it does not go so far as to require that consent be obtained and, in that case, permits indigenous peoples to be removed from the lands they occupy *"only following appropriate procedures established by national laws and regulations, including public inquiries where appropriate"*.

Although not couched in the language of consent, Article 7(1) of Convention 169 provides that indigenous people *"shall have the right to decide their own priorities for the process of development as it affects their lives ... and the lands they occupy or otherwise use ... and to exercise control, to the extent possible, over their own economic, social and cultural development"*. Although qualified *"to the extent possible"*, this *"right to decide"* embodies the fundamental right to self-determination that is central to the rights-based construction of FPIC, and is arguably more relevant to the development of a legal principle of FPIC than the limited rights in relation to forced relocation.[1]

However, it has been observed that the ILO conventions were not developed in a vacuum, and that the principles set out in the ILO conventions reflect the evolving human rights narrative that is founded in the UN's Universal Declaration on Human Rights (UDHR), adopted in 1948, and subsequently their International Covenant on Civil and Political Rights (ICCPR), adopted in 1966, and International Covenant on Economic, Social and Cultural Rights (ICESCR), also adopted in 1966. These instruments recognise the inalienable human rights to participate in and enjoy cultural life,[2] the *"right to own property alone as well as in association with others"* and to not be arbitrarily deprived one's property,[3] and the right to self-determination,[4] which are integral to the rights-based conception of FPIC. These internationally recognised and universally endorsed rights to culture, property and self-determination formed the backdrop to the FPIC narrative, which has tended to enunciate FPIC, not as a stand-alone right in itself, but as a safeguard for, or component of, these underlying substantive rights.[5]

To what extent does FPIC apply to natural resource projects?

The UN's Declaration on the Rights of Indigenous Peoples (UNDRIP), adopted by the General Assembly on 13 September 2007, has become the focal point of the modern FPIC debate. It built upon the rights of indigenous peoples to own, use, develop and control their traditional lands and resources, as recognised in Convention 169, strengthened the prohibition on forcibly removing indigenous peoples from their land without their free, prior and informed consent, confirmed the right of indigenous peoples to self-determination, and confirmed the state obligation to consult in good faith with indigenous peoples in order to obtain their free, prior and informed consent before taking measures that may affect them or approving projects which affect their lands or resources.

Although, as a resolution of the General Assembly, the UNDRIP is not binding on member states, it received overwhelming endorsement and serves as an *"interpretive guide for determining the content and scope of indigenous peoples' rights"*.[6] However, the extent to which UNDRIP established FPIC as a principle of international law remains subject to debate. For example, Canada's recent *Statement on the World Conference on Indigenous Peoples Outcome Document* unequivocally asserts that the UNDRIP does not reflect customary international law.

Similarly, the ILO Conventions, while legally binding, are only binding on the relatively few states that have ratified them, and mechanisms to enforce non-compliance can be limited.

The application of FPIC principles to natural resource projects is even more limited, not least of all because states are not always directly involved in such projects. More accurately, the expansion of the global marketplace and the growing economic and political influence of multinational corporations means that states are no longer the biggest participants in the international development economy. For example, private investment in development projects, particularly in large infrastructure and natural resource projects, has exceeded national or multilateral investment since the 1990s.[7]

The international community has responded to the increasing impact of corporate behaviour on human rights by recognising that corporations have a *"responsibility to respect human rights [as] a global standard of expected conduct for all business enterprises wherever they operate ... [which] exists independently of State's abilities and/or willingness to fulfil their own human rights obligations"*.[8] The OECD's *Guidelines for Multinational Enterprises*, for example, provide a multilaterally agreed code of responsibility for business conduct, and repeat the statement in the UN's *Guiding Principles on Business and Human Rights* that *"[r]espect for human rights is the global standard of expected conduct for enterprises"* regardless of the activities of the state in whose jurisdiction they operate. Indeed, the UN has favoured the adoption of a *"general rule that extractive activities should not take place within the territories of indigenous peoples without their free, prior and informed consent"*,[9] and emphasises that the corporate responsibility to respect human rights includes compliance with international standards concerning the rights of indigenous peoples and the UNDRIP in particular.

The project finance industry has also moved to adopt various forms of FPIC standards. Multilateral financiers, such as the International Finance Corporation (IFC) and regional development banks, as well as private financiers, have incorporated FPIC standards in a relatively consistent fashion, primarily through the risk assessment processes they apply to potential investments.

In the case of the IFC, its *Performance Standards on Environmental and Social Sustainability*, supplemented by *Guidance Note 7 – Indigenous Peoples* (Performance Standards), sets out an "operational" formulation of FPIC that applies where, for example, projects will be located on land or develop resources subject to traditional ownership or customary use and adverse impacts can be expected. Distinct to the rights-based approach, the IFC's construction of FPIC *"builds on and expands the process of informed consultation and participation ... [but] does not necessarily require unanimity and may be achieved even when individuals or groups within the community explicitly disagree"*.[10] This process-oriented formulation of FPIC explicitly does not confer a veto and seeks

1 B. McGee, "The Community Referendum: Participatory Democracy and the Right to Free, Prior and Informed Consent to Development", *Berkeley Journal of International Law*, 27/2 (2009).

2 UDHR, Article 27(1); ICCPR, Article 27; ICESCR, Article 15(1).

3 UDHR, Article 17.

4 ICCPR, Article 1; ICESCR, Article 1.

5 M. Satterthwaite and D. Hurwitz, "The Right of Indigenous Peoples to Meaningful Consent in Extractive Industry Projects", *Arizona Journal of International and Comparative Law*, 22/1 (2005).

6 C. Doyle and J. Cariño, *Making Free Prior & Informed Consent a Reality: Indigenous Peoples and the Extractive Sector*, Indigenous Peoples Links (PIPLinks), Middlesex University School of Law and The Ecumenical Council for Corporate Responsibility (2013).

7 A. Missbach, "The Equator Principles: Drawing the Line for Socially Responsible Banks? An Interim Review from an NGO Perspective", *Development*, 47(3), Society for International Development (2004).

8 *Guiding Principles on Business and Human Rights: Implementing the United Nations' "Protect, Respect and Remedy" Framework*, United Nations (2011).

9 J. Anaya, *Extractive Industries and Indigenous Peoples: Report of the Special Rapporteur on the Rights of Indigenous Peoples*, United Nations (2013).

10 *IFC Performance Standards on Environmental and Social Sustainability*, International Finance Corporation (2012).

to accommodate the prospective nature of major project developments, where many aspects or potential impacts may be unknown when investment or approval decisions are made.

The Inter-American Development Bank and European Bank for Reconstruction and Development have both adopted similar policies that, among other things, require project developers to obtain the agreement of indigenous communities through good-faith negotiation where a project risks adversely impacting the community or requires their resettlement. While the Asian Development Bank and African Development Bank have adopted less onerous and somewhat ambiguous requirements, framed in terms of "safeguard mechanisms" and "meaningful consultation", they nevertheless require developers to obtain "broad community support" in certain circumstances.

Similarly, over 70 per cent of the private international project finance market has adopted the Equator Principles (EPs);[11] a voluntary and industry-governed initiative that adopts the Performance Standards as a risk management framework for large-scale projects in developing countries. Once adopted, financiers agree to require their clients to comply with the EPs as a condition of their lending arrangements. However, implementation and compliance is enforced at the discretion of each financial institution. The EPs expressly adopt the procedural requirements necessary for borrowers to achieve FPIC as described in the Performance Standards.

Given most large-scale natural resource projects involve a syndicate of lenders, there is a high probability that at least one lender will have adopted the EPs. This means that, even where the IFC is not involved, the Performance Standards will likely form the basis of the project's social and environmental risk management framework. This gives the Performance Standards tremendous influence as they, and their construction of FPIC, become increasingly institutionalised in industry methodologies and practices.[12]

FPIC requirements are also finding their way into the policies of natural resource industry bodies. For example, the International Council on Mining and Metals (ICMM), an organisation of 21 of the world's largest mining and metals companies and 35 mining and commodity associations, requires members to *"uphold fundamental human rights and respect cultures, customs and values in dealings with employees and others who are affected by our activities"*.[13] The ICMM's Indigenous Peoples and Mining Position Statement further describes how natural resource proponents should operationalise FPIC requirements, largely in a similar fashion to the IFC's Performance Standards.

Given the ICMM is comprised of private natural resource companies, it is not surprising that it supports a pro-development and "best practice" construction of FPIC. More noteworthy is the fact that 21 of the world's largest and most influential mining companies felt compelled to form an alliance and publish statements on the extent to which FPIC applies to natural resource projects. The ICMM's participation in the FPIC debate reflects the struggle of natural resource companies to mediate the international community's expectation that they will respect FPIC requirements with the practical and commercial realities of operating in often ill-equipped and under-resourced regulatory environments.

How will the natural resources industry face FPIC?

FPIC has emerged as an enduring force of global reform in the natural resource context, notwithstanding the ambiguity regarding its legal status. Irrespective of whether FPIC should apply to natural resource projects as a question of law, as a matter of commercial practicality, natural resource companies will increasingly be faced with FPIC principles in the development of new projects. There are strong and growing incentives for project developers to implement FPIC principles, and the operational and commercial risks of not engaging with local indigenous groups, or doing so poorly, can be significant.

As a starting point, it should be acknowledged that the size and scale of natural resource projects around the globe has been increasing, while *"much of what remains of [the world's] natural resources is situated on the lands of indigenous peoples, result[ing] in increasing and ever more widespread effects on indigenous peoples' lives"*.[14] Large-scale natural resource projects are precisely the kinds of projects that are likely to cause profound, yet frequently unforeseen, social and economic impacts for indigenous communities.

Those "unforseen impacts" represent the most significant non-technical risks for natural resource projects, and are estimated to account for up to 75 per cent of cost and schedule failures.[15] In one analysis of 190 projects operated by international oil proponents, non-technical risks, and stakeholder-related risks in particular, accounted for nearly half of the risk factors faced by the companies, with one company estimated to have experienced up to a US$6.5bn "value erosion" over a two-year period from such risk.[16] Similarly, a recent Ernst & Young report identified "social license to operate" as the third largest business risk for the mining and minerals sector.[17]

A proponent's ability to effectively manage the range of environmental, social and governance issues associated with natural resource projects has been found to be positively correlated with the delivery of projects on time and budget.[18] Disputes relating to land use and associated company–community conflict can result in physical disruptions to production, legal action, campaigning by civil society groups, insecurity of mining rights and stricter environmental management requirements.[19] The resulting costs for project proponents can include significant delays, planned projects may not proceed or those projects underway may be forced to close, significant senior staff time devoted to managing conflict and opportunity costs arising from inability to pursue future projects or expansion opportunities.[20] These hidden costs are often overlooked

11 *About the Equator Principles*, Equator Principles Association (2011).

12 See T. Wilson, "No, really – what are the 'Equator Principles'?", *Institute of Public Affairs Review*, 59, (2007); and A. Meyerstein, "Transnational Private Financial Regulation and Sustainable Development: An Empirical Assessment of the Implementation of the Equator Principles", *New York University Journal of International Law and Politics*, 45 (2013).

13 *Sustainable development framework*, International Council on Mining and Metals (2014).

14 As footnote 9.

15 L. Brewer and R. McKeeman, "Non-Technical Risk Leadership: Integration and Execution", paper presented at the SPE/APPEA International Conference on Health, Safety, and Environment in Oil and Gas Exploration and Production, 11-13 September 2012, Perth, Australia.

16 J. Ruggie, *Business and human rights: further steps toward the operationalization of the "protect, respect and remedy" framework*, Report of the Special Representative of the Secretary-General on the issue of human rights and transnational corporations and other business enterprises (2010).

17 "Business risks facing mining and metals 2014-2015", EYGM Limited (2014).

18 "280 projects to change the world", Goldman Sachs Global Investment Research (2010).

19 *The Financial Risks of Insecure Land Tenure: An Investment Review*, prepared for the Rights and Resources Initiative by The Munden Project LLC (2012).

20 R. Davis and D.M. Franks, "The costs of conflict with local communities in the extractive industry", Paper presented at the First International Seminar on Social Responsibility in Mining, 19-21 October 2011, Santiago, Chile.

by developers. In this regard, research has shown that community conflicts over environmental and social concerns can incur costs up to US$20m a week in operating expenses for large-scale mines (with capital expenditure of between US$3bn and US$5bn).[21] At the company level, the risk of reputational damage can also be significant.

Other potential costs are less obvious. For example, failure to abide by FPIC principles that are incorporated into financing arrangements may affect a company's credit rating, as credit ratings agencies consider the risks of non-performance with lending facilities. Additionally, political risk insurance may be rendered void where consultation with local landowners is not undertaken or local communities assert that proponents have engaged in coercive practices in order to obtain their consent.[22]

The forced withdrawal of London-based Vedanta Resources from its proposed Orissa bauxite mine in India provides a good example of the range of legal, commercial and reputational risks associated with poor stakeholder engagement practices. In that case, local indigenous community opposition led to blockades, government petitions, the involvement of two major international human rights NGOs, civil activism at Vedanta's headquarters and shareholder meetings in London, and litigation in both India and the UK, resulting in government approval for the project being withdrawn, high-profile divestments by major shareholders and reductions in Vedanta's credit rating. The Vedanta example also illustrates how effective powerful civil society groups can be in organising sophisticated activist campaigns and leveraging publicity to generate reputational and commercial risk.

In many conflicts, a lack of communication and consultation features prominently; in one analysis of 25 cases of company–community conflict in the extractive industry, a lack of communication and consultation features as either a proximate or underlying issue in more than 70 per cent of cases.[23] The culturally charged nature of respectful engagement under FPIC processes creates a very complicated environment for corporate representatives, and increasingly requires engagement with local and international NGOs to bridge the cultural gap.[24] In reality, concluding FPIC processes with unincorporated community groups, which can have diverse and dynamic leadership structures and internal vested interests, is incredibly challenging. Even documented community approval can be tenuous once projects are commissioned and impacts become real or community leadership changes.

This charged environment presents a confronting challenge for natural resource proponents, as a project *"that is tainted with allegations from indigenous peoples that their rights are being violated and that international law is being breached will be difficult to take forward, regardless of whether or not there are actual breaches or legal violations"*.[25] In that sense, the question of whether mining companies should be subject to FPIC requirements is arguably moot. The reality is that indigenous groups, the international community and civil society organisations expect that mining companies will abide by human rights standards, and there are substantial legal and commercial risks for companies that fall short of those expectations.

Conclusion

Although natural resource companies are not subject to legal obligations with respect to FPIC, there are clear expectations that proponents will abide by FPIC requirements. Those expectations have been addressed primarily through the incorporation of FPIC standards in risk management processes. While this "operationalisation" of FPIC is having an institutional effect on international mining practices, the most significant reasons why natural resource companies should comply with FPIC standards are the economic costs and commercial risks associated with non-compliance.

FPIC is not a new concept, but as mining operations encroach further towards city centres and social media is increasingly used as a tool to oppose mining developments, there is a growing sense that FPIC will become, sooner or later, just another cost of doing business for the natural resources industry. However, in an increasingly competitive global market with rapidly shifting commodity prices, it is important that any additional costs associated with FPIC requirements are reasonable and proportionate. Ignoring expectations of local and international communities that FPIC requirements will be satisfied can lead to severe consequences for natural resource companies. In reality, the commercial imperatives to abide by FPIC requirements supersede the legal debate. The central question is therefore how will natural resource companies deal with the increasing need to recognise FPIC principles in the development of new projects, rather than whether they should do so.

21 D.M. Franks *et al*, "Conflict translates environmental and social risk into business costs", Proceedings of the National Academy of Sciences (2014).

22 As footnote 19.

23 As footnote 20.

24 As footnote 17.

25 *ILO Convention 169 and the Private Sector*, International Finance Corporation (2007).

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TURNING WASTE INTO POWER:

Opportunities and developments in the GCC

by Cameron Smith, Jennifer Moore and Alice Cowman

The continued use of landfill and uncontrolled dumping of waste is a global problem from which the Gulf Cooperation Council (GCC) region is not immune. In this context, waste-to-energy (WtE) projects can present an opportunity and solution which holds significant benefits for governments, local communities and international investors.

This article examines the key drivers behind the growth in WtE, the state of the market in the GCC region, and the commercial and regulatory issues that are key to the success of such projects.

The waste issue

The GCC countries are among the highest per capita producers of municipal solid waste (MSW) in the world (see figure 1). Today, residents of the UAE produce an average of 2.5 kg of waste a day per person, which amounts to 2.5m kg of MSW daily in the emirate of Sharjah alone.[1] This can be compared to just 0.5 kg per person per day in New Delhi or 0.85 kg per person per day in Beijing.

1 Bee'ah, UAE.

NSW Generation (in kgs) per person per year

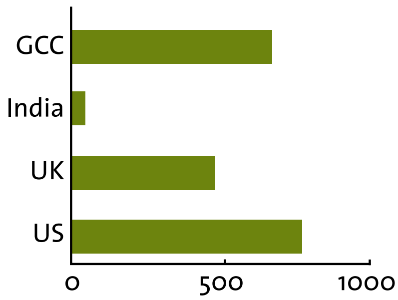

Figure 1 (Source: Frost and Sullivan)

Across the GCC, rapid economic growth, industrialisation and modernisation have given rise to: (a) greater volumes of municipal, commercial and industrial waste; (b) waste of a different complexity and composition, such as different types of plastics, agricultural wastes and residues, and electrical and electronics equipment waste; and (c) increasing demands for energy.

The majority of waste in the Middle East is sent to landfill, which is space-intensive and uses up valuable land that could be put to better use. Uncontrolled disposal of untreated or inadequately treated waste causes health and sanitation issues, as well as environmental pollution such as air pollution from the uncontrolled burning of waste, and contamination of groundwater and surface water by leachate. In other jurisdictions (particularly across Africa), the uncontrolled and unregulated dumping and landfilling of waste has led to widespread disease and death.

The recycling rate in the GCC region is as low as ten per cent compared with a current average of 22 per cent or higher in other high-income countries,[2] but the region is working hard to improve this statistic.

What is waste-to-energy?

WtE facilities create energy in the form of electricity or heat from the treatment of waste products. The use of waste to produce biogas and electricity dates back to the early twentieth century. However, due to dwindling fossil fuel resources, a greater awareness of the social and environmental hazards of poor waste management, a reduction in available landfill capacity and a global focus on reducing greenhouse gases, the development of WtE projects has increased significantly over the last 20 to 30 years. There are different types of WtE processes, the main ones being:

LFG capture

Landfill gas (LFG) emissions from landfill can be flared or captured and utilised to minimise pollution, or can be captured to generate power or fed into the gas network.

Combustion

Combustion (or incineration) is the burning of waste to recover the energy content of waste as either heat or electricity.

Gasification

Gasification is the thermal treatment of waste in a low oxygen environment so that full combustion cannot occur, resulting in the production of electricity, heat or syngas (which can be converted into high-quality diesel biofuel) and far less production of ash and residue.

Anaerobic digestion

Anaerobic digestion is the non-thermal treatment of biological waste, such as food, which produces digestates that can be used as fertiliser and biogas which can be used to generate heat and electricity.

Why waste-to-energy?

Waste diversion is the most preferred option for dealing with the waste issue after the "three Rs": reduce, reuse or recycle. Although incineration is a less favoured option in terms of the preferred options of dealing with waste, it is, nonetheless, a viable and attractive option for the following reasons:

- Incineration can reduce up to 90 per cent of the disposed waste going to landfill.
- Energy from waste can be cost-competitive as compared with other renewable technologies in certain circumstances. A 2012 US energy administration study placed WtE ahead of solar PV and solar thermal in terms of cost-efficiency.
- Even well-managed sanitary landfills emit LFG, which is a mixture of methane, carbon dioxide and trace constituents. Methane emissions from landfill represent 12 per cent of total global methane emissions and, with 12 times the potency of carbon dioxide, are significant contributors to climate change. LFG capture is required in many jurisdictions and generating energy from captured LFG makes sense for current landfills.
- WtE can be part of the solution to meet the future energy demands of the MENA region's rapidly growing population through renewable energy.

2 The World Bank.

Worldwide WtE market revenues (which accounted for US$19bn at the end of 2012) are expected to reach US$29bn by 2016.[3] The market in the GCC has grown from 20 to 25 per cent in the last three years.[4]

What is the current market interest in the region?

An overview of developments and programmes in the region

Although the GCC is widely considered to have huge potential for WtE technology, the sector's development is still relatively small, with only 0.25 to 0.3 TWh of energy currently being produced from waste across the region.

Qatar was the first GCC country to implement WtE on a large scale with its Domestic Solid Waste Management Centre (DSWMC) (see below). However, other countries are rapidly following suit. Abu Dhabi is expected to follow Qatar's approach by developing its own 100 MW WtE plant through an EPC model, and several municipalities in Saudi Arabia are considering projects. The emirate of Sharjah is also reportedly in discussions with technology providers.

Nearby, in South East Asia, Singapore is at the forefront of the WtE industry with the National Environmental Agency (NEA) currently procuring Singapore's sixth incineration plant, the second plant to be offered to the private sector as a PPP. The first WtE plant PPP was tendered in 2004 and was awarded under a design-build-own-operate scheme. The plant can treat up to 900 tonnes of solid waste daily and generate approximately 22 MW of green electricity. NEA collects the gate fees from waste collection and pays the developer an availability payment for the facility, for the amount of waste accepted and for the electricity generated.

3 Frost & Sullivan, 2014.

4 Ibid.

Significant projects

Kuwait – Kabd MSW facility

On average, per capita waste generation is approximately 1.4 to 1.5 kg per day in the State of Kuwait, making it one of the largest per capita waste generators in the world. The Kuwaiti Government (advised by Ashurst LLP, PwC and Fichtner GmbH & Co. KG) has invited bidders to qualify to tender for the development of an ambitious WtE plant that will treat 50 per cent of Kuwait's MSW. The WtE plant, to be procured on a build-operate-transfer basis, will benefit from an availability payment and will generate its own electricity, selling the excess power generated to the Kuwaiti Government under an offtake agreement.

Case study: Sweden's waste management success

Sweden is a global leader in recovering energy from waste. With a waste strategy of "reduce, reuse, recycle, recover", only one per cent of its waste is sent to landfill. In 2009, 49 per cent of all Swedish household waste was converted into energy. In the last decade, WtE has expanded at a rapid rate in Sweden, as the country changed its policies to become more environmentally friendly and achieve a more diversified energy mix.

From 1999 to 2010, waste incineration with energy recovery increased from 39 per cent to account for 49 per cent of the country's waste treatment methods. In 2009, through approximately 32 Swedish WtE facilities, 13.9 TWh of energy was produced through incineration, of which 12.3 TWh was used for heating and 1.6 TWh for electricity. This amounted to 15 per cent of Sweden's district heating needs and 2.45 per cent of the country's total energy needs.

Jordan – MSW facility tendered in Amman
Greater Amman Municipality has recently issued a request for proposals to bid for the contract to design, build, operate and transfer a MSW facility in Amman. The project will have an initial processing capacity of 1,200–1,500 tonnes per day of MSW with at least two processing lines. The facility will be designed to allow further expansion to process additional MSW disposed in landfills to a level of approximately 2,500 tonnes per day. It is anticipated that the facility will be commissioned in April 2018.

Bahrain – bids received for WtE project
Bahrain's Municipalities and Urban Planning Affairs Ministry is currently evaluating bids for a 390,000 tonnes per year WtE facility. This project was first tendered in 2008, but was later cancelled before its recent retendering. The project is planned to be developed as a 25-year build-operate-transfer scheme, which will include the following components: (i) initial pre-sorting/recycling; (ii) processing for the treatment of domestic waste; (iii) recycling of construction waste; (iv) composting of green and garden waste; (v) thermal treatment plant for the elements no longer able to be reused or recycled; and (vi) a sanitary solid waste landfill. The plant will process 100,000 cubic metres a day.

Qatar – Domestic Solid Waste Management Centre
One of the most promising developments in the GCC has been the creation of the DSWMC at Mesaieed. Receiving waste transported by about 300 trucks per day, the DSWMC is helping Qatar achieve its goals to reduce waste sent to landfills from 92 per cent to 64 per cent, and raise recycling rates from the current eight per cent to 20-25 per cent.

The facility consists of a solid waste management centre that sorts waste, separating out anything that can be recycled and removing organic waste to make compost. The remainder, about 40 per cent, is burnt in an incinerator and the energy emitted is used to produce electricity. Only the leftover ash needs to go to landfill; this is estimated to be five per cent of the volume of waste that was previously dumped.

Dubai – Al Qusais Landfill Site
The LFG flaring project, located at the Al Qusais Landfill Site in Dubai, is a trailblazer for LFG capture in the GCC. This small-scale project has twin goals: (i) direct reduction of harmful LFG, odours and volatile organic compounds; and (ii) power generation. The 52-hectare landfill has been operational since 1989 and is still active. It demonstrates the UAE's fantastic potential to make use of LFG; the country's low rainfall means gas trapped in the landfill is not pushed down into the water table by rainwater. This makes it easy to extract the gas. The Al Qusais landfill project is mitigating the potential damage caused by over 350,000 tonnes of carbon dioxide a year, which is equivalent to taking 60,000 cars off the road. Its power capacity is currently at 12 MW, with the potential to be expanded to 20 MW.

This project is the first of its kind in the UAE and the legislative framework still needs to be developed to support it. This means that although the plant is producing electricity, it cannot yet be connected to the grid. A small portion of the flared gas produced is currently used to power an engine that provides for all the electrical needs of the landfill and Dubai Municipality's site offices. It is hoped that surplus power will in future will be connected to Dubai Electricity and Water Authority's network once an appropriate legislative framework is in place.

Sharjah – Waste Management Centre at Al Saj'ah
Bee'ah, a PPP company established in 2007, has a mission to tackle waste in the region and lead Sharjah as the first city in the Middle East to achieve zero waste going to landfill by 2015. Bee'ah's Waste Management Centre consists of facilities to treat and process waste for reuse in the economy, and includes the third largest material recovery facility in the world. This has an annual capacity of 500,000 tonnes, of which 60 per cent can be recycled via facilities at the Waste Management Centre (such as a tyre recycling facility and a construction and demolition waste recycling facility). It also features a liquid waste processing centre and a compost plant.

What are the barriers to development of WtE in the GCC?

Economics

Costs

Given the cost of developing WtE plants, these facilities are usually not financially competitive in their own right as pure electricity generating facilities (in competition with gas-fired plants, for example) without a strong regulatory and enforcement regime, and appropriate financial incentives.

Where the option of simply dumping waste or flaring LFG (or not installing any system at all) exists, investors are unlikely to put forward the capital for LFG capture or other WtE schemes unless it will be sufficiently profitable to justify the set up and maintenance costs of a WtE facility. Waste disposal in the GCC is generally carried out at low or no cost to the local population and at little cost to the relevant municipal authority, particularly where waste can be landfilled or dumped, and there are no overriding policies or macroeconomic drivers to avoid landfill. However, this is changing and certain countries now charge gate fees (although some argue that these are still at too low a level to be effective). High gate fees can make landfill costs prohibitive and energy recovery a more economical alternative means to dispose of waste. Gate fees also provide an additional revenue source for WtE projects.

In the UK, gate fees were introduced and ratcheted up by the UK Government over a period of years to ensure that landfilling became progressively more expensive in comparison to other waste treatment and disposal routes. This has been a very effective way to create market incentives for the development of WtE facilities. However, these steps have been taken in conjunction with other measures to prevent the unlawful disposal and dumping of waste.

Price of power

Prevailing electricity and gas rates may not be sufficient to incentivise the development of WtE projects in their own right, but may provide additional revenue for WtE facilities which have a dependable long-term gate fee revenue stream.

Uncertainty in carbon markets

Certain WtE projects have in the past relied on revenue from the sale of Certified Emission Reduction certificates (CERs) where a project has been able to obtain registration under the Clean Development Mechanism. However, following falls in CER prices, confidence in the sale of CERs as a long-term stable revenue stream has been reduced. Where such "green certificates" are priced properly and provide a reliable revenue stream, the finance ability of these projects is enhanced.

Policy

Untested regulations

Investment regimes and legal frameworks to encourage the development of WtE and other renewable energy projects need to be developed and implemented. Change in the law, risk and untested implementation also remains a concern for investors. WtE facilities are easier to develop in jurisdictions where the management of MSW and commercial waste is highly regulated and illegal dumping is punished.

Lack of awareness

Policymakers and managers of solid waste sites may not be aware of the existence of landfill emissions, their harmful effects, or the potential fuel value and uses of the lost waste.

Furthermore, any attempt to introduce landfill taxes and charges associated with waste collection and disposal need to be accompanied by public awareness campaigns to educate the public about the benefits of better treatment of waste.

Electrical system interconnection for offtake

Inconsistent, complicated or poorly devised standards for connecting small-scale renewable or WtE projects to the grid infrastructure are a major obstacle, particularly for projects that lack the resources to handle expensive or lengthy connection processes. Solid waste sites typically consume small amounts of electricity and need to sell the excess power generated to the grid to be viable.

Land

Some of the GCC countries, such as Saudi Arabia, Oman and the UAE, have vast amounts of undeveloped land, meaning there is no immediate pressure to cut back on landfill as land is readily available at little to no cost. By contrast, WtE schemes have been very successful in jurisdictions where landfill capacity is not readily available, such as in the Netherlands, Singapore or the UK.

What can policymakers and the public sector do to encourage the development of WtE projects?

Improving the economics – financial policy support

Generation incentives

Generation incentives offered consistently over a specified number of years (i.e. which give long-term, reliable revenue certainty) can encourage large WtE investments that would otherwise prove too costly. Tying the incentive directly to generation rather than the construction of a plant ensures that the motivation is to produce power in a timely, efficient manner.

Subsidies

Subsidies can come in many forms, such as production grants, tax holidays and exemptions (for example, on import customs duties on equipment), feed-in tariffs (FITs) and low interest/preferential loans to producers. In Europe, a range of measures have been employed in order to drive forward the development of WtE projects. These measures include:

- feed-in tariffs and the availability of green certificates (in a variety of forms);
- renewable heat incentives (such as the renewable heat incentive scheme in the UK);
- enhanced capital allowances and other tax incentives; and
- the imposition of landfill taxes and landfill allowance trading schemes.

In Europe and Asia, the incentives have, to date, focused on the renewable energy production side of the equation, although, given the pressures to reduce landfill in some jurisdictions, there has also been increasing attention given to issues of waste supply and waste reduction.

Feed-in tariffs

FITs are a proven method of incentivising the generation of energy. Although there are some variations in FIT schemes around the world, the central premise of a FIT scheme is that a renewable energy generator is guaranteed a certain level of payment for its electricity, over a fixed long-term period. The obligation to buy the electricity at the set tariff is usually imposed on the utility/supply company(ies). Different rates are typically set for individual technologies, such as solar, wind and biomass/biogas. The costs of paying higher rates for renewable energy is typically passed on to the consumer. FITs are set for a certain number of years to ensure long-term predictability for investors. Each year, the rates offered to new projects are lowered as more projects are built and, theoretically, their economic competitiveness and technological efficiency increases. The aim of the policy is that, once a FIT scheme has been in place for some time, the industries will outgrow the need for government support and will be able to stand on their own in the market.

Tipping fees and landfill restrictions

Waste collection and disposal is expensive and has other costs. Charging little or nothing for waste disposal within the GCC neither encourages waste diversion nor private sector efforts at better waste disposal. Although Sweden, for example, has an abundance of land relative to its population, its landfills are expensive. As of 2005, average tipping fees were equivalent to €135 per tonne. In contrast, Abu Dhabi currently charges just AE$250 (approximately €50) per tonne and in Dubai it is free (although there is talk of introducing a charge for commercial users similar to Abu Dhabi's). With cheap landfill disposal, there is little chance of either public or private sector engagement in better waste management or WtE development.

Energy purchase requirements

The cost structure of a WtE project changes dramatically when there is a requirement to produce or purchase energy from renewable sources, and when WtE is defined by the relevant authorities as a renewable source. For example, in the UK, electricity retailers have a statutory obligation to source a defined portion of their electricity from renewable sources (although the current Renewables Obligation scheme is being phased out and being replaced with a new Contracts for Difference regime[5] involving top-up payments above the wholesale electricity price). In the UK, WtE generation is deemed to be a renewable energy source if it also includes the generation of heat as well as electricity. Such highly efficient WtE

5 For more information on Contracts for Difference see the article on Electricity Market Reform on page 3 of this issue of Energy**Source**.

plants therefore get the benefit of "green certificates", which can be sold to electricity retailers, or a Contract for Difference (under the new regime).

Non-financial policy support

In addition to financial support, the following elements need to be present as part of the overall policy and regulatory environment to facilitate WtE projects:

Access to the grid

As for any generation project, third party access to the grid is essential. WtE projects are likely to be smaller-scale than conventional thermal power, and are therefore more likely to connect to the distribution network. A well-defined regime for access to the distribution network, with transparent terms, is key.

Connection standards for distributed generation

Well-planned connection standards make connecting to the grid an attractive option for small-scale WtE systems without compromising on the safety and reliability of the overall system. To design effective standards, a number of factors should be considered to address the needs and concerns of all stakeholders. These include promoting broad participation during standards development, addressing a range of technology types and sizes, and taking into consideration existing barriers to connection.

Regulatory framework for thermal treatment of waste

It is important that the regulatory framework contemplates the thermal treatment of waste to avoid uncertainty, particularly in terms of environmental and planning consents. A transparent licensing and planning regime which is capable of enabling all key consents and permits to be efficiently obtained in a way which is incapable of subsequent challenge is an essential ingredient.

Dispute resolution

It is also important to note that investors and banks will look for a legal framework which facilitates dispute resolution and the enforcement of any awards or decisions which arise.

Regulation of waste collection

Also key is an organised waste collection industry, and a developed regime regulating it, that facilitates the centralised collection of municipal and commercial waste and discourages illegal, unregulated disposal of such waste.

Ownership of the waste stream

Projects need creditworthy, long-term suppliers of waste, which may mean municipal authorities/local government or, alternatively, financially stable and technically proficient corporate entities.

Heat/power offtake

Last, but not least, a project needs to secure creditworthy long-term power and/or heat offtakers, which may be public utilities or corporate offtakers of good financial standing.

What the private sector can do to encourage the development of WtE projects

International companies have long been cognisant of reducing waste, not only for their environment conscience but also to save costs. In the US, Dr Pepper has committed to recycling 80 per cent of solid waste in its manufacturing facilities. Coca-Cola has been using recycled plastic since 1991, and Evian now have 50 per cent of recycled material in its bottles. The private sector can drive change – and often more efficiently than the public sector, which is driven by profit margins.

In the UK this year, there has been the first example of a private sector company not just recycling but supporting its own WtE plant. The supermarket chain Sainsbury's has a store now entirely powered by its own food waste. Sainsbury's delivers food to an anaerobic digestion plant and the energy generated through bio-methane gas is delivered back to them. Although this is also spurred on by high electricity costs and a higher cost of landfill disposal in the UK than the GCC, this eye-catching project might become the first model for future private sector development of WtE in this region. Even if some government support is required, the tariff and costs could be lowered for the public sector if the private sector can see economic benefits from such a project.

Private sector companies in the waste management industry have also been at the forefront of many of the public education campaigns, designed to inform the public about the benefits of recycling and reuse of waste, as well as the perils of landfilling waste. Those companies in the waste management sector that have embraced new technology and invested in WtE facilities have benefited from higher returns, due to their enhanced ability to profit from trading in recyclable products and shifting their focus towards renewable energy generation.

Conclusion

Due to such a high production of waste in the GCC, there is great opportunity and scope to turn waste into recycled products, captured LFG and valuable green energy to reduce the ever-growing carbon footprint of GCC citizens. To do so would be in line with regional initiatives, such as the State of Energy Report in Dubai 2014, which sets out how the Municipality of Dubai is focused on increasing renewable energy sources and decreasing waste-to-landfill.

To do this, governments in the GCC will need to promote awareness and encourage the diversion of waste from landfill and the generation of green energy and other by-products from waste.

This could be achieved by adapting policies on waste collection and introducing a gate fee for commercial and institutional waste collection. Not only will this provide funding towards incineration and LFG plants, it will also encourage companies and individuals in the GCC to cut down on waste production. To enable green energy to be seen as a viable alternative to fossil fuels, policymakers could also consider providing FITs or other financial advantages such as low interest loans and grants.

With the proper planning and development, WtE initiatives and projects have the potential to play a significant role in helping GCC policymakers move towards an integrated, sustainable waste management solution for the region, reducing the carbon footprint of GCC companies and citizens, and moving forward into the field of green energy.

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INVESTING IN INDIA:

Lessons learned from major energy projects

by Ben Rollason and Gopika Pant

It has been estimated that India must spend approximately US$100bn every year to meet the energy demands of its rapidly growing economy.[1] In this article, we highlight some issues for potential investors to watch out for, based on our experience of advising foreign investors in major projects in India's energy sector.

The energy challenge

According to the World Bank, India's economy has recorded an average growth rate of over seven per cent each year in the past decade, despite the global economic downturn. This trend is expected to continue, with the country's economy expected to grow by approximately 5.5 per cent each year in the period between 2015 and 2035. On this basis, India is set to become the world's third largest economy by 2035.[2]

However, there are obstacles to overcome if India is to achieve its economic potential. Key among these is its national energy shortage. As the country's economy has grown, so too has its energy needs. National energy shortages, combined with an inadequate domestic energy infrastructure, threaten India's ability to sustain its pace of economic growth.

1 *The Economic Times* (India), 13 April 2015.

2 BP Energy Outlook 2035, February 2015.

India as an investment destination

To tackle the challenges posed by its energy demands, India needs major investment into its energy sector. In the words of Fatih Birol, the Director and Chief Economist of Global Energy Economics at the International Energy Agency: *"India needs three things for its energy sector: investment, investment and investment"*.[3]

The Modi Government is aware of the threat the energy challenge poses to national prosperity, and recognises the need to attract international investment into the energy sector. As befits a prime minister who has been described as *"the most pro-business, pro-investment political leader in the world today"*,[4] under Prime Minister Modi's tenure, the Indian Government has announced significant legislative and policy changes aimed at liberalising the country's energy market and attracting foreign investment into the energy sector.

3 As footnote 1.

4 Forbes (2014, speech by CLSA's Asian market strategist Chris Wood), 6 March 2015.

However, notwithstanding the improving investment environment, India remains a challenging destination for foreign investors. There are many reasons for this, and below we highlight six issues – or lessons learned – which investors should be aware of and factor into any investment plan.

Lesson one: government-affiliated companies may be inflexible but they may also have significant political clout

Investing alongside Indian Government Companies (GOCs) presents significant advantages for foreign investors into the country's highly regulated energy sector. Indian GOCs, with their strong links to central government, are generally better equipped to lobby government to address the specific concerns of foreign investors in relation to relevant Indian public policy and legislation; a recent example of this being the Indian Government's willingness to address concerns regarding India's civil nuclear liability regime raised by foreign investors into the country's nuclear sector.

However, with those benefits come certain challenges, since Indian GOCs can be inflexible about certain issues. For example, Indian GOCs will typically only agree to a dispute resolution process which is based in India; this is often difficult for foreign investors to accept due to the perceived limitations of the Indian court process. Similarly, long-term supply or offtake contracts (for feedstock or refined products) are rare given that committing to a certain price for the long term is perceived as difficult by Indian GOCs. Nonetheless, some investors have been able to secure long-term supply contracts and non-Indian arbitration clauses. In our experience, there is typically a greater chance of reaching a suitable compromise where both parties engage in dialogue and aim to find creative solutions to ensure that an investment takes place.

Lesson two: be pragmatic about due diligence

The due diligence concept is well established in India. However, Indian companies, and particularly Indian GOCs, are not always able or willing to disclose to potential investors the level of information which investors would normally require for a thorough due diligence exercise, due to internally imposed restrictions and the regulatory regime.

India's corporate culture has a significant bearing on the practicalities of conducting due diligence in the country. For example, Indian GOCs may be reluctant to use virtual data rooms for all relevant documents due to concerns over information flow. Instead, the use by Indian GOCs of physical data rooms with no or limited copying rights is still a relatively common feature of due diligence, even in large-scale transactions. There may also be a debate about whether more sensitive information, such as relevant pricing information, will be made available at all.

In our experience, continuous dialogue with the relevant Indian counterparty regarding the benefits of disclosing information, and describing how the use of efficient virtual data rooms and the grant of printing rights can be beneficial to both parties, can make the due diligence process faster and more efficient.

For foreign investors considering an investment into major energy projects involving Indian-listed companies, there are also regulatory restrictions to factor in. India's current insider trading regulations, issued by the Securities and Exchange Board of India, restrict or limit the information which may be disclosed during a due diligence process. Broadly, Indian-listed companies wishing to disclose price-sensitive information may only do so if they also disclose such information to the market – which, unsurprisingly, they are often reluctant to do. This is, of course, often the information which a potential investor would wish to review as part of its due diligence. Again, continuous dialogue with the relevant Indian counterparty regarding the benefits of disclosure and the strategic timing of any necessary public disclosures (in accordance with the relevant regulations) may allow for a greater degree of overall disclosure.

Finally, a number of important public records (for example, those relating to land rights, bankruptcy, civil litigation and criminal prosecutions) are not available online. Where online public records are available (for example, certain intellectual property registers or filings with the registrar of companies), these may only cover fairly recent filings. This all makes the process of checking and obtaining public records time-consuming, which needs to be factored into the due diligence process early on.

In many cases, the obstacles to a comprehensive due diligence exercise may be overcome by engaging closely with the relevant parties to ensure that expectations are aligned in relation to expected outcomes and timing. The due diligence process will likely impact on transaction timelines, and it is important to factor this in when timetabling transactions in order to allow sufficient time for the work to be done properly.

Lesson three: under Indian law, indemnities may afford less protection than a foreign investor expects

Under English law, the inclusion of well-drafted indemnities in favour of an investor in the relevant transaction documents is a well-recognised and reliable way of allocating risk. Broadly, if an indemnity is triggered, an investor would expect to recover its loss on a dollar-for-dollar basis. However, under Indian law, indemnities may not operate in the same way and may afford an investor less certainty of outcome.

There is a risk under Indian law that the general contractual principles obliging a claiming party to mitigate its loss also apply to indemnities. Accordingly, any indemnities should be drafted to expressly exclude the obligation of the indemnified party to mitigate any loss which forms the subject of an indemnity claim.

Under Indian law, an indemnity claim will only be upheld by a court or arbitral tribunal if it is deemed to constitute an "absolute obligation" on the indemnifying party. There is no established principle under Indian law to determine whether an indemnity amounts to an "absolute obligation", and this question is instead determined by the court or arbitral tribunal on a case-by-case basis. To ensure that the court or arbitral tribunal uphold the indemnity claim as intended, the drafting needs to make clear the absolute nature of the indemnity obligation and should be as tight and as clear as possible.

Finally, in the event of a dispute between the indemnified party and the indemnifying party as to the nature or extent of any liabilities and losses suffered by the indemnified party, an Indian court or arbitral tribunal may only consider that loss which is deemed to be reasonable and direct and may exclude indirect or remote loss. So, a dollar-for-dollar recovery may not be available in the same way as under English law, and any claim may instead be subject to the tests of reasonableness and directness of loss. Applying these tests to an indemnity may significantly reduce the scope of loss for which an indemnified investor could recover (for example, it may restrict any ability to recover for losses relating to financing arrangements which an investor has entered into in connection with an investment), and this may run counter to a foreign investor's intention behind seeking an indemnity in the first place.

The uncertainty around the use of indemnities under Indian law introduces an element of enforcement risk and may increase overall transaction risk for a foreign investor. Where possible, it may therefore be preferable for a foreign investor to protect itself against any specific transaction issues by dealing with them before deal completion. Typically, this could be achieved by the use of specific conditions precedent in the relevant transaction documents requiring (as a condition to completion of the deal) that the specific issues are removed or resolved. Clearly, however, the use of conditions precedent will not be appropriate for all identified issues, either because such issues cannot practically be resolved in advance or because the length of time they will take to resolve precludes their resolution prior to deal completion.

Where specific issues cannot be

removed or restricted in advance of deal completion, investors will need to address them through the use of contractual mitigants in the transaction documents. Clearly, indemnities will still form an important part of the suite of contractual mitigants. However, if contracting under Indian law, investors should be aware of the uncertainties around the enforcement of indemnities and should ensure that any indemnities are drafted as precisely as possible to clarify the absolute nature of the obligation and the basis for recovery, and to reduce (to the extent possible) any opportunities for the indemnifying party to make a successful challenge.

Lesson four: watch out for restrictions on repatriating money awarded pursuant to a contractual claim

Irrespective of the governing law of the transaction documents, all foreign investors must obtain the approval of the Reserve Bank of India (RBI) before they can repatriate out of India any amount awarded to them under a contractual claim. This restriction applies regardless of whether the claim has been mutually settled and agreed between the parties, or awarded to an investor pursuant to a court order or arbitral judgment.

There are no formal principles or guidelines which apply when the RBI considers a repatriation request from a foreign investor. Instead, each repatriation request is treated on a case-by-case basis. However, in practice, the RBI does usually permit repatriation of any amounts awarded to foreign investors pursuant to a court order or arbitral judgment. There is less certainty where a settlement has been reached, and to be sure of being able to repatriate the relevant funds, it may be necessary to obtain a court order or arbitral judgment (even where the relevant claim is not disputed by the contractual counterparties).

There are no fixed timelines for the process of obtaining RBI approval. In addition, the pursuit of a contractual claim through arbitration or before the Indian courts can be a lengthy process. Therefore, in terms of assessing enforcement risk, it is important to factor in a long time period from initiating a claim to actual receipt of any funds, if successful.

Given the uncertainty around obtaining RBI consent for repatriation, as well as the timing issues, one option is to look at structuring a transaction to avoid the requirement for RBI approval altogether, and many foreign investors opt to structure their transactions accordingly. Options include structuring the transaction so that any investment is made by an "onshore" Indian entity, or so that an "offshore" entity of an Indian counterparty provides the relevant contractual assurances. In either case, the aim is to ensure that no funds will be flowing out of India, so there will be no requirement for RBI approval.

Lesson five: do not underestimate the time it takes to satisfy conditions precedent

Similarly to the due diligence process, the process of satisfying conditions precedent can take a relatively long time in India. Accordingly, it is important to build into the transaction timeline (and the transaction documents) sufficient time for the satisfaction of conditions precedent. This issue is particularly pertinent in the context of any third party consents which are required to be obtained (for example, any regulatory consents). One potential method of shortening the period of time required for the satisfaction of conditions precedent is to consider whether the investor can assist the Indian counterparty in dealing with the relevant conditions precedent. For example, if one of the conditions precedent requires the entry into of long-term offtake agreements, the investor may wish to consider whether it can assist in concluding such agreements, either by offtaking the relevant product itself or by assisting in identifying a third party who is willing to enter into such an agreement.

Lesson six: regulatory restrictions may limit the effectiveness of put/call options and deferred consideration mechanisms

Under India's foreign exchange laws, any sale of shares by or to a person not resident in India must be at a price which represents the "fair value" for the shares.

This means that any share transfer provisions in transaction documents (such as, for example, any put or call options relating to an event of default under a shareholders' agreement) must not purport to transfer shares at less than "fair value". Accordingly, a foreign investor will not be able to rely on mechanisms for the transfer of shares at a discount as a means of discouraging or penalising contractual non-compliance by an Indian counterparty.

It is also worth noting that India's foreign exchange laws do not permit the withholding of all or any of the share purchase price by foreign investors. Instead, full consideration for the share purchase price must be paid by foreign investors at the point of deal completion and deferred consideration mechanisms for share purchases, linked to post-completion performance milestones, are not permissible under Indian law.

Conclusion

India has huge energy requirements and investment needs but foreign investors face certain challenges. In particular, the distinctive character of India's corporate culture and the applicable foreign investment laws may require foreign investors to adjust their investment mindset.

Foreign investors considering an investment into India's energy sector need to look at an early stage at the full range of transaction structuring options available, including the use of "onshore" and "offshore" entities and the relevant transaction governing law, in order to maximise certainty of outcome and mitigate transaction risk. Clearly, using local expertise is also essential in order to manage potential investment pitfalls.

The existence of a challenging market for foreign investors is not a feature which is unique to India – all markets (whether developed or emerging) have their own complexities. However, what India does possess, which many markets currently lack, is a great wealth of potential investment opportunities and an increasingly hospitable environment for foreign investors. Those investors who acknowledge and respond appropriately to the challenges and issues associated with investment in India's energy sector are most likely to secure the best outcomes.

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OIL AND GAS INDEMNITIES:

Interpretation revisited

by Tom Cummins and Fiona Tsung

Participants in upstream oil and gas projects have always been exposed to high levels of risk, ranging from substantial upfront capital investments to risk of damage to property or loss of life. A recent case serves as a reminder of how important it is for parties to express clearly in their contracts how different types of losses and liabilities are to be dealt with.

The potentially serious consequences that can result from comparatively minor acts or omissions mean that contractual allocation of risk is critical to the efficient implementation of exploration, development and production activities. The oil and gas industry has long been developing sophisticated contractual liability models to that end.

These models are expected to come under ever-increasing pressure against the backdrop of sustained lower oil prices and the need for cost-efficiency. Decreasing revenues and low demand for oilfield services mean that industry participants will be determined to use existing contractual provisions to avoid risk-associated costs where possible.

In this context, in the recent case of *Transocean Drilling UK Limited -v- Providence Resources Plc* [2014] EWCH 4260 (Comm), the English High Court considered a number of risk allocation provisions customarily used in contracts between operators and third party contractors in the offshore oil and gas sector. The case raised issues of importance to the energy industry and the wider construction industry, as it involved the interpretation of remuneration provisions and an exclusion clause in an amended version of the standard LOGIC form contract (the suite of LOGIC standard service contracts is used by the industry in the UK).

Contractual risk allocation

The fundamental premise of risk allocation is to allocate the risk to the party agreed to be best placed to manage the risk and/or its consequences. In the upstream contractual context, risk is typically allocated by using a combination of limitation of liability and indemnity clauses. These clauses will address liability connected with, among other things:

- death and personal injury;
- property loss or damage; and
- environmental damage.

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 model, one party is responsible for its own losses caused by the other party's acts or omissions. Knock-for-knock clauses have become standard practice in upstream oil and gas projects as a means of distributing risk, with parties typically agreeing to hold each other harmless for their own losses caused by damage to property or equipment or injury to personnel. Most commonly, in upstream service contracts:

- injury to a party's own personnel and damage to a party's own property is allocated on a knock-for-knock basis;
- loss suffered by third parties as a result of the operator's or contractor's conduct is allocated on a fault basis;

- usually, each party's own consequential loss is allocated on a knock-for-knock basis; and
- each party's liability is supported by a contractual indemnity.

The rationale for knock-for-knock clauses is that for the type of damage intended to be covered by a knock-for-knock clause, it makes more economic sense for each party to bear its own loss rather than engage in costly and lengthy litigation to determine the degree to which each party's own negligence or fault contributed to the damage. A knock-for-knock regime also lessens the insurance burden on the parties, as each party is only required to take out insurance to cover the death or personal injury of its own personnel and damage to its own property. But, as the *Transocean* case bears out, it is important for parties to realise that knock-for-knock provisions are intended to have a rather specific and limited application – they are not intended to shield each party from all liability to the other.

Case background

The claimant, Transocean, entered into a drilling contract with the defendant, Providence, for the provision of a rig to drill an appraisal well in the Barryroe Field off the south coast of Ireland. Delays occurred due to various operational issues with the equipment, especially the blowout preventer (the BOP).

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

Transocean claimed remuneration of US$13m and £3.5m in accordance with the day rates specified in the contract. It argued that the day rates applied irrespective of any breach of contract by it.

Providence brought a counter-claim for wasted costs comprising sums payable to personnel, suppliers and service providers (spread costs) incurred by Providence during the delay period as a result of Transocean's alleged breaches.

The court therefore had to consider the following two main issues:

- whether Transocean was entitled to be paid for days when it had failed to provide services (due to its own fault), and whether the knock-for-knock regime had any bearing on this issue; and
- whether Providence's spread costs fell within a clause under the contract which excluded the parties' liability for consequential loss.

Remuneration and fault

The court found that the main cause of the delay was the build-up of debris in the BOP which Transocean should have detected and removed as part of its maintenance of the BOP. The court therefore determined that Transocean had failed to exercise due diligence in maintaining the rig and the equipment.

The rig contract provided for different day rates to be applied according to the functions the rig was performing at any given time – an approach common in many rig contracts. Transocean argued that:

- it was entitled to continue to be paid the day rates while fixing equipment failures, even if these were caused by its negligence;
- the day rates regime contained a "complete code", setting out the different rates of remuneration applicable in all eventualities, irrespective of breach by Transocean, and comprised an agreed allocation of risk irrespective of fault; and
- it made good commercial sense to allocate risk in a way which did not depend upon burdensome investigations into the cause of the equipment failure and whether it was a breach by Transocean.

The court rejected Transocean's arguments, and stated that:

- rig contracts are not imbued with any special status, and the principles for interpretation of contracts apply in the same way to rig contracts as to any other contract for goods and services;
- the day rates regime did not constitute a complete contractual code so as to allow the contractor to be paid where operations were delayed due to its own breach of contract; and
- there was nothing in the wording of the relevant clauses to make it clear that Transocean was entitled to be paid at the appropriate day rate when the rig was not performing due to Transocean's breach.

In effect, Transocean was trying to apply the principles underlying a knock-for-knock regime to the remuneration provisions – losing sight of the express wording of the contract, and also the very specific and limited application of knock-for-knock

clauses. The court summed up the position succinctly, saying that: *"Outside the specific situations covered by the knock-for-knock regime to be found in Clause 18 of the Contract, which is not uncommon, hirers of a rig are no more likely than any other person who contracts for the provision of goods and services to agree to pay something for nothing, particularly if the failure to perform is due to the negligence or default of the payee"*.

Consequential loss and spread costs

Transocean tried to resist Providence's claim for spread costs by arguing that these spread costs were a claim for "loss of use" and therefore fell within the definition of consequential loss set out in the contract.

The court adopted a narrow interpretation of "loss of use" to mean the loss of expected profit or benefit to be derived from the use of the rig. The "loss of use" language in the exclusion clause in this contract included additional language not found in the LOGIC standard contracts (i.e. the loss excluded extended to *"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"*). The court interpreted "cost of use" (as used in the clause) to mean the cost of hiring in equipment or services, or replacing property, the benefit of which had been lost, in order to mitigate the loss of benefit. It had no application to the spread costs in this case, where the costs were for equipment and services which were provided. Providence did not lose the use of that equipment or those services, which remained available to it, which was why it incurred wasted expenditure (i.e. spread costs).

While recognising the ability of commercial parties to apportion risk of loss as they see fit, the court said that in case of any ambiguity, the starting point for interpreting an exclusion clause will be to construe it against the party seeking to rely on it. The court further stated that there was a starting presumption that neither party intended to abandon the remedies available under the law for a breach by the other, and emphasised the need for express drafting to reflect a clear intention to the contrary.

The court determined that if the exclusion clause was construed as Transocean had argued, the effect would be to exclude any liability for damages for which Transocean would otherwise be liable. The court would not readily construe a clause as having this effect, because to do so would be to render the primary performance obligations effectively devoid of contractual content since there would be no penalties for non-performance.

Lessons learned

The decision in *Transocean* may be seen as sounding a warning and a reminder to parties and their legal advisers about the need for clear drafting of remuneration and liability provisions. The key points to take away from the case are that:

- knock-for-knock provisions, while a commonly accepted feature of upstream service contracts, apply to a specific category of damage and, in the absence of express drafting, will not disapply the usual rules of construction of contracts;
- provisions which seek to exclude liability need to be carefully drafted, with express reference to any heads of loss intended to be excluded; and
- parties should review their standard terms to ensure that they clearly reflect the allocation of risk they are prepared to accept.

In relation to their existing contracts, operators are advised to give careful consideration to their remuneration clauses, as there might be scope to claw back fees that were paid for services that were never provided due to a contractor's breach. Operators might also be able to recover spread costs incurred by paying third parties for equipment, cost of personnel and services, wasted as a result of delays caused by a contractor's fault. Drilling companies and other service providers, on the other hand, should assess the risk, under existing contracts, of having to cover an operator's spread costs in the event that an operator seeks to recover such costs.

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INFRASTRUCTURE ACT 2015:

One step forward and one step back for UK shale gas?

by Michael Burns and James Prescott

The passing into law of the Infrastructure Act 2015 (the Act) is a noteworthy step in the evolution of the regulatory regime for shale gas in Great Britain. The Act, which began its passage to the statute book in the House of Lords on 5 June 2014, was given Royal Assent on 12 February 2015.

The Act follows in the tradition of the various UK Energy Acts of the past decade by dealing with an assortment of issues bound by an energy and infrastructure theme. The Act deals with highways, renewable energy projects, a new strategy for maximising economic recovery of UK petroleum, and onshore petroleum and geothermal energy, among other things.

Particular attention has been, and will continue to be, given to the latter of these changes – those relating to onshore petroleum (and to some extent geothermal energy) – which are principally aimed at facilitating the exploration and development of shale gas in the UK by the process of hydraulic fracturing, or "fracking".[1]

This article discusses the Act's provisions in relation to fracking, which came into force on 12 April 2015, dealing with land access for drilling and a number of protections or "safeguards" aimed at addressing the concerns associated with fracking.

Background

Issues

Shale gas extraction is a contentious topic in the UK. To date, the debate has largely focused on potential economic benefits versus environmental concerns and community opposition. What makes the debate complicated is the fact that while the industry is still in its infancy in the UK, there are many "unknowns" fuelling arguments about shale gas's potential to make a significant contribution to natural gas production in the UK, and the upsides and downsides of pursuing its development in the UK.

Although there is still considerable uncertainty as to the volume of recoverable shale reserves in the UK, based on the three

1 The hydraulic fracturing sections of the Act do not apply to Scotland.

studies conducted to date,[2] it is certainly possible that shale gas could materially contribute to the UK's energy security and economy. At a time when production from the UK Continental Shelf is gradually declining, the UK Government and industry is eager to embrace new sources of natural gas. Shale gas development also has the potential to generate substantial tax and export revenue for the Government, creating both jobs and growth, as evidenced by the booming US shale gas industry. However, the industry has also attracted a high degree of scrutiny and notwithstanding strong scientific evidence to the contrary, community groups, landowners and other stakeholders have continued to raise concerns about fracking in terms of issues such as potential seismic activity, site traffic, ground water contamination and the uncontrolled release of hydrocarbon gas.

Against this background, the Government has had to balance the need to ensure that the regulatory regime for shale gas does not impose unnecessary burdens on the industry, while at the same time addressing both real and perceived risks. That balancing exercise is reflected in the provisions of the Act.

Overview of the existing regulatory landscape

The starting point is that shale gas is essentially bound by the same regulatory framework as conventional onshore oil and gas. Recognising that shale gas projects are, by their nature, different to conventional gas projects, the Government has issued various guidance on the application of the regime to shale gas projects. However, other than some changes to licence conditions (discussed below), the Act is the first piece of UK legislation to set out provisions specifically dealing with shale gas development.

Key features of the onshore oil and gas regime

Under the Petroleum Act 1998 (Petroleum Act), a company wishing to undertake onshore oil and gas exploration and production in Great Britain is required to obtain a licence – a Petroleum Exploration and Production Licence – which grants the company exclusive rights to undertake various activities within defined phases, namely exploration, appraisal and production. It should be noted in this context that Northern Ireland has its own onshore oil and gas regime, modelled on the Petroleum Act. Furthermore, the Scotland Bill 2015, recently laid before Parliament, will transfer responsibility for onshore petroleum licensing to the Scottish Ministers.

Each licence incorporates licence conditions, referred to as "model clauses", which impose various requirements and obligations on the licensee. In 2014, the Government introduced a new set of model clauses[3] for onshore oil and gas, which include a handful of changes specifically aimed at accommodating shale gas development as opposed to conventional oil and gas. In particular, the new licence

2 The Bowland-Hodder study of June 2013, the Weald Basin study of May 2014 and the Midland Valley of Scotland study of June 2014.

3 See the Petroleum Licensing (Exploration and Production) (Landward Areas) Regulations 2014.

conditions make the usual relinquishment obligations subject to new provisions allowing for the creation of "Retention Areas" and "Development Areas", enabling licensees to retain a greater proportion of the licence area for longer, where the licence relates to shale gas deposits.

In addition to the licence requirement, a company wishing to explore and develop onshore petroleum must also comply with the procedures and regulations set out by industry agencies and regulators, including the newly established Oil and Gas Authority[4] (OGA), the Health and Safety Executive (HSE) and the Environment Agency (EA). For instance, shale gas developers need to obtain various environmental consents and permits from the EA, including mining waste permits, a water abstraction licence, and an assessment and approval of the chemicals used in fracking. Similarly, developers require various consents from the OGA under their licence conditions before they can undertake exploration and production activities. Before granting consent, the OGA will liaise with both the HSE and the EA, and the developers will have to undertake various assessments to satisfy the OGA that there are no outstanding environmental or safety issues (including contingency plans for resolving issues or ceasing production in the event of specific safety hazards).

Developers also need planning permission, which is administered by minerals planning authorities (MPAs) under the Town and Country Planning Act 1990. When considering an application, an MPA will consult with agencies (such as the EA) and affected stakeholders (such as landowners), and must determine applications within a 13-week period in accordance with planning policies, unless material considerations are relevant. These material considerations include air quality, traffic and risk of contamination, most of which are considered to be applicable to shale gas extraction, meaning the planning process may be more time-consuming than usual for shale developers. The Government also issues Planning Practice Guidance for MPAs, with the most recent revision relating to "planning for hydrocarbon extraction" released in March 2014. This revision states that, where an application for planning permission for the development of unconventional hydrocarbons represents major development, then planning permission should be refused in National Parks and Areas of Outstanding Natural Beauty (AONBs) except in exceptional circumstances and where such development is in the public interest.

Land access

Further, shale developers wishing to carry out a project must also consider the common law position relating to land access, under which they are required to negotiate land access agreements with the relevant landowners, usually in return for compensation. Developers need land rights for access to and location of the drilling pad itself, as well as permission from all landowners beneath whose land they drill, otherwise they may be found to be trespassing. It is worth mentioning the *Bocardo*[5] case here, where the Supreme Court found that an oil and gas company had committed trespass by drilling and installing pipelines under the landowner's land, notwithstanding that the deepest well was 2,800 feet below the surface and did not affect the landowner. This issue has been identified as a particular barrier to development in the shale gas industry.

Where developers are unable to obtain the consent of landowners, the Mines (Working Facilities and Support) Act 1966 sets out a statutory regime for land access rights required to conduct mining operations, known as the ancillary rights regime. The Petroleum Act allows licensees to use the ancillary rights regime to apply to the court, via an initial application to the OGA (previously the Secretary of State), for a right to enter upon land and to sink boreholes in the land for the purpose of petroleum operations, including laying pipes. However, a court can only grant ancillary rights to a licensee if it has not been "reasonably practicable" for the licensee to obtain such rights by negotiation with the landowner, and such a grant is "expedient in the national interest".

Although the Government has incrementally introduced new guidance to make the existing regime more "shale gas friendly", there are inevitably hurdles that still exist for developers in a landscape that was not created with unconventional gas exploration in mind. In light of this contextual background, the Act has introduced two significant measures aimed at addressing these issues, as discussed in more detail below. The first of these has been to streamline the land access regime, which goes some way to oiling the wheels for shale gas development in the UK. The second is a set of "safeguards" which seek to balance the environmental concerns associated with fracking against the objective of facilitating the development of this new industry.

Land access for underground drilling

What the Act says

The Act introduces a new land access regime to address the land access issues posed by underground drilling. By virtue of section 43 of the Act, developers now have an automatic right to use "deep-level land" to exploit petroleum or geothermal energy without the consent of the owner, which reforms the land access position under the common law. "Deep-level land" is defined as any land at a depth of at least 300 metres below surface level.

Section 44 then provides further detail on this right of use. Firstly, it stipulates a wide array of activities or ways in which the right of use may be exercised, which include, among others, drilling, boring, fracturing, installing and removing infrastructure, and passing any substance through deep-level land. It then sets out that the right of use may be exercised for the purposes of *"searching for petroleum or deep geothermal energy, assessing the feasibility of exploiting petroleum or deep geothermal energy, preparing for exploiting petroleum or deep geothermal energy, decommissioning and any other activity which falls to be continued or undertaken in consequence of ... exploiting petroleum or deep geothermal energy"*.

Other notable details of section 44 are that the right of use encompasses the right to leave deep-level land in a different condition from the condition it was in before an exercise of the right of use, and that landowners are absolved of liability for any loss or damage caused by a developer's exercise of its right of use over that land.

The Act also provides for two schemes that may be implemented by the Secretary of State. These schemes do not qualify the new automatic right of access, however they would, if implemented, fashion a form of exchange or compensation with landowners and the community in return for the automatic right of access. The first relates to payments. Currently, the shale

4 The newly established OGA has taken over the function of regulating the upstream oil and gas industry from DECC, as from 1 April 2015. The OGA is currently established as an Executive Agency of the Department of Energy and Climate Change, and the relevant legislation (primarily the Petroleum Act) still refers to the relevant powers being exercised by the Secretary of State for Energy and Climate Change. The forthcoming Energy Bill 2015 will establish the OGA as an independent body and amend the legislation to refer to the various powers being exercised by the OGA.

5 *Bocardo SA -v- Star Energy* [2010] UKSC 35.

gas industry has already proceeded with a voluntary payment system, under which developers have committed to make a one-off payment to the community for each unique horizontal well that extends by more than 200 metres. However, if the Secretary of State is not satisfied with this system, section 45 gives him the power to make regulations for a separate payment scheme, whereby payments are to be made to landowners or other persons who benefit from the land that is subject to the fracking operations.

Similarly, section 46 allows the Secretary of State to introduce regulations for a notification scheme, under which certain groups or individuals will be notified of a developer's exercise (or intended exercise) of its right to use an area of land for fracking. These regulations may prescribe to whom such a notice is to be given, displayed or published, the information to include in a notice and the manner in which the notice is to be given, displayed or published. The notification scheme may also require details of the payment scheme to be included, but will not offer landowners or the community the right to object to the use of the land. Both schemes may impose obligations on developers or other specified persons to provide information about the proposed right of use, payments and/or notifications.

Implications of new land access regime

Given that the previous land access regime was seen as a major barrier to entry to the UK shale gas market, from an industry perspective, this reform is seen as a positive step. An automatic right of access overcomes the delays which are caused by having to negotiate access agreements and/or compensation with landowners, particularly where there are multiple owners. It removes the risk of committing trespass, as in the *Bocardo* case discussed above, in the event that an oil and gas company drills beneath land, either intentionally or inadvertently, without first negotiating appropriate access. What is also important is that the Act has been drafted with shale gas development in mind, and consequently the language is wide enough to capture a range of activities undertaken as part of the fracking process. Nevertheless, it is important to recognise that this new land access regime does not apply to the exploitation of petroleum or deep geothermal energy where the works are undertaken at a depth that is less than 300 metres below surface level. Significantly, this means that access to and location of the drilling pad will still require negotiation with, and the consent of, landowners or, failing that, an application to the OGA under the statutory ancillary rights regime.

As would be expected, the introduction of the automatic right of access has been considered by some as controversial, not least because it paves the way for shale gas development, but also because the Act does not introduce a right to object and allows developers to leave land in a different condition to that which existed before they exercised their right of use, and to leave any infrastructure or substances in the land. The new land access provisions were preceded by a public consultation by DECC on the proposals, which received a large number of responses opposing the new regime. It is often said that a strong Government needs to sometimes make unpopular decisions for "the greater good" and this is no doubt an instance where, on balance, the Government realised that reform was needed.

Environmental and community safeguards

What the Act says

The second measure to explore is section 50 of the Act, which introduces new sections 4A and 4B into the Petroleum Act, outlining 13 conditions or "safeguards" that must be met before the OGA[6] may issue a well consent for carrying out fracking operations. It also outlines the documents that should be produced to sufficiently satisfy the OGA that the conditions have been met, although the absence of a document will not mean that a condition has not been met. Most of these conditions codify what is already industry practice. Sections 3 and 4 of the Petroleum Act govern the licensing procedure and requirements in relation to conventional gas exploitation.

The conditions are as follows:

1 **Depth.** Fracking is prohibited at depths of less than 1,000 metres below surface level, unless the OGA gives consent.
2 **Environmental impact.** The environmental impact of the development which includes the relevant well must be taken into account by the local planning authority.
3 **Well integrity inspection.** Appropriate arrangements must be made for the independent inspection of the integrity of the relevant well.
4 **Methane in groundwater.** The level of methane in groundwater must be, or will have been, monitored in the period of 12 months before the associated fracking begins (and arrangements must be made for the publication of the results of such monitoring).
5 **Methane in the air.** Appropriate arrangements must be made for the monitoring of emissions of methane into the air.

6 Until the forthcoming Energy Bill 2015 amends the legislation, the various relevant provisions, including the new provisions included in the Petroleum Act by the Infrastructure Act 2015, still refer to the various powers being exercised by the Secretary of State for Energy and Climate Change.

6 **Groundwater sources.** The associated fracking will not take place within protected groundwater source areas.
7 **Protected areas.** The associated fracking will not take place within other protected areas.
8 **Cumulative effects.** In considering an application for the relevant planning permission, the local planning authority must (where material) take into account the cumulative effects of that particular application and other applications relating to the exploitation of onshore petroleum obtainable by fracking.
9 **Substances.** The substances used, or expected to be used, in associated fracking, must be approved or be subject to approval by the relevant environmental regulator.
10 **Restoration.** In considering an application for planning permission, the local planning authority must consider whether to impose a restoration condition in relation to the particular development.
11 **Relevant undertakers.** The relevant undertaker (for example, water companies) must be consulted before the granting of the relevant planning permission.
12 **Informing the public.** The public is to be given notice of the application for the relevant planning permission.
13 **Community benefit.** A scheme must be put in place to provide financial or other benefit to the local area.

Even if these conditions have been satisfied, the OGA (previously the Secretary of State) must still be satisfied that it is appropriate to issue consent, and may issue the consent subject to any conditions which it thinks appropriate.

Implications of the safeguards

The conditions laid out in the Act were the subject of lengthy debate in Parliament. The Infrastructure Bill visited the House of Lords for 13 sessions and the House of Commons on 16 occasions. The opposition (the Labour Party) had requested a number of changes to make the conditions more onerous. It has been claimed by the opposition and some environmental groups that the final version, which received Royal Assent, contained a "watered-down" version of what had been proposed and accepted by the House of Commons in the weeks leading up to Royal Assent.

Two conditions in particular were in the firing line on the charge of being watered-down. The first relates to mandatory environmental impact assessments – the requirement that each site be monitored for 12 months prior to any fracking activity and subject to an environmental impact assessment. The finalised wording only requires the environmental impact to be taken into account and there is no requirement for a full assessment.

The second relates to National Parks and AONBs. Under proposals put forward by the Labour Party, fracking under these areas was to be prohibited. However, this has now been replaced with the concept of "protected areas" and there is no specific mention in the Act of National Parks or AONBs, meaning that horizontal drilling for shale gas may take place underneath these areas provided that the drilling pad is located outside of their boundaries. The Government took the view that a total ban under (and in) National Parks and AONBs would unduly constrain the industry, and that it was not practical to guarantee that fracking would not take place under those areas. "Protected groundwater source areas" and "other protected areas" are currently undefined, and the Secretary of State has an obligation to draft secondary legislation defining these terms before 31 July 2015, having consulted with the relevant agency (EA in relation to England, the Natural Resources Body for Wales in relation to Wales).

Other proposals that were rejected included a requirement for monitoring methane emissions after a site has been decommissioned, long-term monitoring of other gases and a proposal for members of the local community to be notified individually.

While the backtracking on these conditions may be welcomed by the industry and seems to offer shale gas developers flexibility, less bureaucracy and a larger area of resources to carry out fracking operations (analysis by the *Guardian* estimates that National Parks and AONBs make up approximately 40 per cent of the area of England being offered for shale gas exploration[7]), there is a risk that the ambiguous nature of the relevant provisions of the Act may actually cause additional uncertainty for developers.

In addition to the uncertainty about what constitutes a "protected area", the Act is also guilty of leaving other terms vague and undefined. It may be difficult to know what amounts to "appropriate arrangements" or the extent to which certain factors must be taken into account in considering a planning application, resulting in developers being overcautious in conducting operations, contrary to what the Act is seeking to achieve. Similarly, it is unclear whether authorities are required to follow the advice of the undertakers they have consulted, and who will be responsible for funding the schemes to provide financial or other benefit to the community. The Act is silent on these issues, meaning that further guidance may be needed to clarify the obligations of the developers and the authorities. It therefore may be that the final "safeguarding" provisions lead to an unsatisfactory result for both sides of the debate.

Conclusion

The Act represents a strong commitment by the Government to foster the development of a shale gas industry in the UK, backing rhetoric with legislative action. It is clear that the design of the land access provisions for underground drilling was the subject of careful consideration, and represents a welcome development for industry. However, the "safeguarding" provisions of the Act are perhaps not the best example of careful and considered law-making, representing, rather, a compromise position.

In March 2015, an industry taskforce called for even more radical changes to get the industry off the ground, including a new regulator to replace the various regulatory bodies currently involved. Calls for further reform are likely to get louder in light of recent events. In June 2015, a local authority, Lancashire County Council, rejected a planning application by Cuadrilla Resources to start test fracking at a site on the Fylde Coast in Lancashire, notwithstanding the fact that it had been recommended for approval by the County Council's planning officer. The decision, seen as a setback for the industry, is regarded by many as evidence that regulatory reform must go hand-in-hand with local community buy-in.

How far regulatory reform will go remains to be seen.

7 "Fracking set to be banned from 40% of England's shale areas", *Guardian*, 2 February 2015.

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STOP PRESS:

Ashurst's energy M&A team strengthened by new partner hire

Ashurst is delighted to announce the appointment of James Wood as a London-based partner in our corporate division. James specialises in public and private M&A, demergers and other corporate finance transactions, advising leading corporates, investment banks and private equity firms. James advises clients on complex, cross-border transactions in many countries around the world, focusing on the mining and metals sector, as well as the oil and gas space.

Ashurst's global head of corporate, Simon Beddow, said: "*James is a very high calibre senior partner who will play a key role in further developing our practice. The breadth of his international experience, including his background working in Asia Pacific and his sector expertise, has powerful synergies with the firm's objectives and clients. James will further enhance the scale and depth of our offering and we look forward to welcoming him to the team*".

Ashurst announces new Managing Partner in Asia

Ashurst announces that Rupert Burrows has been appointed Managing Partner of Tokyo. Having worked in Tokyo for over 20 years, Rupert has a wealth of expertise in international infrastructure projects in the electricity, oil and gas, chemicals and transport sectors as well as corporate M&A deals. Rupert replaces project finance partner John McClenahan.

Commenting on his appointment, Rupert said: "*Operating in Tokyo for 25 years, we have significant strength in our key areas of project finance, banking and corporate, and we undertake some of the market's most high-profile and complex transactions for Japanese clients. Earlier in the year, we announced that senior partners Matt Bubb (Head of Asia) and Dominic Gregory were relocating to Tokyo to further strengthen the business. I am looking forward to ensuring we capitalise on all opportunities, working closely with other offices across Asia, Australia, Europe, the UAE and the US*".

Global awards highlights

Ashurst has recently been named Energy & Resources Law Firm of the Year at the Asian Legal Business Southeast Asia Law Awards, hosted in Singapore, where the firm's Asia Managing Partner, Matthew Bubb, was also awarded Managing Partner of the Year. Global head of resources and infrastructure, Mark Elsey, commented that: "*Winning the award for energy and resources is a great accolade and a fitting testament to the calibre of our team. Ensuring we are global leaders in the resources and infrastructure sector is a key priority for Ashurst, and to be recognised by these prestigious awards, following on from our recent successes at the Partnerships and Infrastructure Journal Awards in London, demonstrates our excellent profile and market recognition in these key areas for the firm across the globe*".

Celebrating a bumper awards season this year, Ashurst's global energy team have won an array of global awards, including Legal Adviser of the Year, Gold Award at the Partnerships Awards 2015 and Europe and Africa Law Firm of the Year at this year's IJ Global Awards, hosted in London. For further information, please visit our news page: www.ashurst.com/media

This publication is not intended to be a comprehensive review of all developments in the law and practice, or to cover all aspects of those referred to. Readers should take legal advice before applying the information contained in this publication to specific issues or transactions. For more information please contact us at aus.marketing@ashurst.com or email@ashurst.com.

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