ISSUE 11: MARCH 2013

EnergySource

ashurst

AN OVERVIEW OF THIS ISSUE:

We are delighted to introduce the first issue of Energy**Source** for 2013, 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:

DRILLING RISKS There have been numerous oil spills off the coast of California since offshore drilling began in 1896, costing millions to clean up and creating an even greater cost to the local ecosystem. Peter Roberts examines the risks associated with drilling for oil and the environmental protection measures being taken.

ELECTRICITY MARKET REFORM As governments are focusing more and more on reducing the carbon footprint of energy generation, the UK is leading the way with policies to reform the electricity market. Antony Skinner and Justyna Bremen analyse the implications of these policies across a range of renewable energy sources.

OFFSHORE WIND FARMS Developers are having to implement innovative strategies to meet the UK and EU's renewable energy targets, which aim to increase UK offshore wind capacity by nearly 29 GW in the next seven years. Nick Hilder discusses the relationships between offshore wind farm developers and their supply chain, and some of the strategic options available to them.

FRENCH HYDROELECTRIC CONCESSIONS Hydroelectric power is the primary renewable energy source in France and accounts for one fifth of total power generation capacity in the country. Michel Lequien and Jacques Dabreteau summarise the key features of the legal framework governing the tendering of hydroelectric concessions in France and explain the reasons for the delay in opening the market.

AFRICAN MINING Australia's investment in African mining is increasing rapidly and much can be learnt in the region from one of the world's biggest mining countries. Martin Kudnig and Megan Barnett-Smith discuss the key factors drawing companies into Africa and the global initiatives being undertaken to strengthen links with Africa, encourage sustainability, and promote business and investment in the region.

PROJECT BONDS Following new legislation and the global financial crisis, the availability of banks to finance energy and infrastructure projects has been materially affected. Carloandrea Meacci and Nicola Toscano review the introduction of a more modern financing regime and what qualifies as a "project bond".

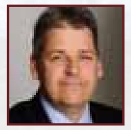
STATE IMMUNITY Two significant cases considering State immunity in English law were reported in 2012. David Salcedo summarises the key points and suggests strategies which commercial parties can adopt to protect themselves from the risks associated with contracting with State entities.

DECOMMISSIONING With costs estimated at around £33bn in today's prices for decommissioning the current oil and gas installations in the UKCS that will go off-stream in the next two decades, tax relief is essential in maximising return and a crucial factor in enabling participants to meet the overall associated costs. Richard Palmer explains how the decommissioning relief deed, a bilateral agreement between the Government and an individual company, can help.

INDONESIAN OIL AND GAS The Constitutional Court of Indonesia has declared BPMIGAS, the implementing body for upstream oil and gas activities, unconstitutional. Sean Prior and Daniel Reinbott consider the consequences of this widely discussed decision for the oil and gas industry in Indonesia.

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

Geoffrey Picton-Turbervill
Head of Ashurst's global energy team
T: +44 (0)20 7859 1209
E: geoffrey.picton-turbervill@ashurst.com



Peter Roberts
Head of energy for the UK, Europe and Africa
T: +44 (0)20 7859 1371
E: peter.roberts@ashurst.com

ENVIRONMENTAL CHALLENGES:

Timbuktu is hot, but California is otter...

by Peter Roberts

Timbuktu was once one of the world's great commercial, intellectual and spiritual centres. Known as the City of 333 Saints, the key architectural feature of Timbuktu was the use of local mud to build its many buildings, including the great Djinguereber Mosque.

That the city's architecture was founded on mud, and that so many great buildings were built with mud, represents a unique paradox that should resonate with today's oil and gas project developers – the realisation of projects of great scale and ambition, through the careful exploitation of local resources.

Whether conceptually or geographically, the California coastline could not be further from what is now a small, dusty town in West Africa. And yet in California the same paradox is prevalent today. In California, this appears in the context of the need to balance the demand for offshore oil and gas exploration with the protection of a key local species – the humble otter.

It is an obvious truth that littoral drilling poses a risk to any marine ecosystem in which the activity is undertaken. That risk will always be mitigated to the greatest extent possible, but a risk it is. Seismic surveys can disrupt the communication and migration patterns of marine mammals, and (despite the best efforts and intentions of contractors and operators) drilling can displace marine sediments and can result in the marine deposit of cuttings and contaminated water.

The California coastline is home to significant reserves of oil and gas but exploration activities in the area have always been fraught with difficulty, particularly regarding the need to balance resource development with local environmental protection.

Drilling for oil and gas offshore California first began in 1896, although the first production did not materialise until 1954. Today, notable offshore fields include Ellwood, Wilmington and the Dos Cuadras field in the Santa Barbara Channel.

This has not been an activity free from controversy. As far back as 1969,

a blowout from a Union Oil rig off the coast of Summerland, just south of Santa Barbara, deposited some 10,000 barrels of oil into the Pacific Ocean. This spillage had a significant adverse impact on local wildlife and the local coastline (which endured a wash-up along some 35 miles of its length). This spillage is often also credited with launching the oil and gas environmental movement in the US, and it certainly heralded an increase in the levels of public opposition to offshore oil and gas drilling in California.

More recently, the Otter Project (www.otterproject.org) has been actively seeking to prevent the expansion of offshore oil drilling along the coast of California, in order to protect the natural habitats of the humble marine mammal. This movement typifies the need to balance the ambitions of resource development with an appreciation of local environmental issues.

US federal and State policy was previously in line with public opposition to offshore drilling, with various moratoria on offshore leasing, although towards the end of the previous Bush administration the executive and legislative moratoria on offshore federal waters leasing were lifted by the then President (albeit with preserved protection for marine sanctuaries) in July 2008. Despite prohibitions on new leasing in State and federal waters, oil and gas drilling and production have, however, continued on existing leases, from existing drilling and production facilities.

Proponents of offshore oil and gas drilling argue that advances in technology make the activity ever more safer. Recent events in the Gulf of Mexico (with the blowout and explosion of the Deepwater Horizon drilling rig on 20 April 2010) have damaged this argument, with the resultant loss of the rig, human life and consequently what proved to be the largest offshore oil spill in US history. This incident added grist to the mill of California's environmentalists, and the debate looks set to take place in another stage with the prospect that the US is finally ready to venture into offshore oil and gas drilling in the Arctic Ocean, offshore Alaska.

Shell has been working its way through a regulatory and bureaucratic minefield but has closed in on securing the final permits from the Obama administration to drill in the Chukchi and Beaufort seas. Again, this has not been without difficulty. The Kulluk drilling rig broke loose of its moorings in a storm on New Year's Eve and ran aground on Sitkalidak Island (albeit without a spillage of fuel). The mishap illustrates the risks of exploring for oil in the Arctic Chukchi and Beaufort seas, where there is only a short drilling season between June and October before the ice sets in for the winter. How matters will develop offshore Alaska remains to be seen.

The success of Timbuktu was built on a recognition of the need to harness local resources for the good of man. Such a symbiosis could be harder to achieve for the oil and gas industry, but continued public antipathy to offshore drilling in environmentally sensitive areas means that there will be no forgiveness for any failure to do so.

It is ironic that the literal translation of "Timbuktu" is "a place covered by small dunes"; perched, as it is, on the edge of the Sahara desert, the relentless encroachment of the desert sands is a constant threat to Timbuktu's continued existence. The offshore oil and gas community can only hope that it manages its affairs such that similar oblivion does not follow.

Peter Roberts
London
T: +44 (0)20 7859 1371
E: peter.roberts@ashurst.com

UK RENEWABLES:

A plethora of government policies

by Antony Skinner and Justyna Bremen

Recently, all discussions of the renewable energy market in the UK have come back to the same theme: the Electricity Market Reform ("**EMR**")[1] package of proposals which, when implemented, will fundamentally change the UK electricity industry, including the way low-carbon generation is incentivised in the UK.

However, in the shadow of EMR, the Government has been taking forward a large number of other policies that impact the renewables market in both the short and longer term. In this article we provide a snapshot of the main issues affecting the highest-profile technologies.

Solar energy

Support under the FiT scheme

Solar energy projects came into the limelight in Great Britain with the introduction of the small-scale FiT scheme, which initially offered very generous rates of support for eligible projects. Since its introduction in April 2010, a large number of changes have been made to the scheme, to allow the Government to control the cost of it. The latest wave of cuts took effect from 1 August 2012. For solar, the new tariff rates are designed to provide a rate of return of between 4.5 and 8 per cent (depending on the size of the installation) for a typical installation. The Government also decided to increase the frequency of degression from every six months to every three months, starting on 1 November 2012, with the amount of degression depending on the rate of deployment in the previous three-month period.

Support under the RO

The outcome of the RO banding review, for the level of RO support offered to projects that become eligible in the period from 2013 to 2017, was published in July 2012, but the Government decided to carry out a further consultation on the level of RO support offered to large-scale solar installations. As a result of that consultation, the Government announced in December 2012 that it would go ahead with a reduction in the level of support offered, notwithstanding widespread opposition from industry, and that it had decided to establish two separate bands for solar PV under the RO from 1 April 2013. For the new building-mounted solar PV band, the level of support has been set at 1.7 ROCs/MWh for new accreditations and additional capacity added in 2013/14, while for the ground-mounted band, the level of support has been set at 1.6 ROCs/MWh. Further reduced rates will apply in future years, as set out in Figure 1.

The very considerable cuts to tariffs under the FiT scheme, soon after it was introduced, were a shock to the solar industry and undermined the business plans and confidence in the industry of many companies, particularly smaller players. The latest rates of cuts in support for solar PV projects, under both the FiT scheme and the RO, have not been as significant as originally tabled by the Government, and it is clear that the solar industry is here to stay, but there has still

1 See the winter 2011 edition of Energy**Source** for a more detailed analysis of EMR, available here: http://www.ashurst.com/page.aspx?id_Content=7365.

In a nutshell: Electricity Market Reform, the Renewables Obligation, the Feed-in Tariff scheme and the Renewable Heat Incentive

The **Renewables Obligation** ("**RO**"), which imposes an obligation on electricity suppliers to source a specified proportion of their electricity from renewable energy sources, has for some time now been the main form of support for renewable energy in the UK. Under the RO, generators are issued Renewables Obligation Certificates ("**ROCs**") based on the net renewable electricity that is generated each month by their accredited renewable generating stations. The number of ROCs issued per megawatt hour ("**MWh**") is determined by the technology/fuel used by the station, its size, and how long it has been accredited under the RO. Suppliers meet their obligation by presenting the required number of ROCs or by making a buy-out payment.

A small-scale **Feed-in Tariff** ("**FiT**") **scheme** was introduced in April 2010. The scheme requires certain licensed electricity suppliers to pay a generation tariff to small-scale low-carbon generators for electricity generated. An export tariff is also payable where electricity is exported to the transmission or distribution network (but not otherwise sold to an offtaker). The FiT scheme replaced the RO as the main support mechanism for solar PV, wind and hydro installations with a declared net capacity of 50 kW or less. Eligible small-scale generators between 50 kW and 5 MW are able to make a one-off choice to receive support under the FiT scheme or the RO.

Electricity Market Reform, being introduced from April 2014, will radically change the existing incentive regime. In particular, the RO regime is being replaced with a new FiTs with Contracts for Difference ("**FiTs CfD**") regime. Between 1 April 2014 and 31 March 2017, eligible renewable energy projects will be able to choose between the RO and FiTs CfD. From 2017 until 2037, the RO will continue to operate for plants already accredited for the RO. The FiTs CfD regime will apply only to plants greater than 5 MW. For eligible installations of 5 MW or less, the existing small-scale FiT regime will continue to be the main form of support.

The **Renewable Heat Incentive** ("**RHI**") was launched in November 2011, as a unique new support mechanism for heat generated from renewable sources. Eligibility is currently limited to the non-domestic sector, with the intention that a domestic scheme will be launched in summer 2013. Under the RHI scheme, a payment is received for each kilowatt hour ("**kWh**") of renewable heat generated, over a 20-year period.

been widespread concern that the new rates may make it difficult for some new projects to be financially viable.

Dedicated biomass and CHP

Level of support

The Government has reiterated that it considers biomass to be an important element of the UK's low-carbon strategy. However, at the same time it has been anxious to control the cost of supporting biomass under the RO, and ensuring that it represents "value for money". One option originally put forward by the Government was a possible "supplier cap", which would impose a cap on the proportion of renewable energy from biomass that suppliers could use under the RO to discharge their obligations. This proposal met with strong opposition from industry, as it could result in a significant de-value of biomass ROCs. As a result, the Government has instead decided to introduce a cap on the total new build dedicated biomass generating capacity that can expect to be supported at 1.5 ROCs/MWh (which is the existing level of support), or 1.4 ROCs/MWh in the case of full accreditations after 31 March 2016. The cap will be set at 400 MW of capacity. Once the cap is triggered, the Government will consult on proposals to restrict further new build dedicated biomass deployment by excluding from grandfathering any further new build dedicated biomass generating capacity coming forward. This means that any plants accredited after the cap is reached will still be eligible to receive ROCs, but will not benefit from protection from any future reductions in the level of support offered or other changes to the RO regime. This would clearly have a detrimental effect on the financial viability of these projects.

Notification process

To allow the Government to monitor when the cap is likely to be reached, a new mandatory notification process is being introduced for biomass projects seeking to benefit from RO support. Ofgem, the gas and electricity markets regulator, will maintain a register of biomass projects. Developers wishing to be eligible for support and to receive protection under the grandfathering regime will need to supply specified documentation to Ofgem as evidence that a final investment decision has been reached. The Government will engage with the industry in early 2013 on details of the process, such as the information that will be required to be provided. It is intended that the new regime will come into force on 1 October 2013.

This means that from 1 October 2013, only new dedicated biomass projects that are on the notification register at the point of full accreditation will be eligible for support under the dedicated biomass band (1.5 ROCs/MWh to 31 March 2016, then 1.4 ROCs/MWh) under the RO.

Exclusions from cap

Significantly, the cap will not apply to new dedicated biomass CHP plants that achieve certification under the UK's CHP Quality Assurance ("**CHPQA**") programme. For the purpose of the cap exemption, CHPQA assessment will only need to take place once. This means that, for example, if a certified CHP plant loses its heat customers in the future, the exemption will still apply.

Additionally, generators at 50 kWe or less declared net capacity will also be excluded from the scope of the cap. The cap does not apply to plants which convert to biomass, or engage in co-firing (see below).

Sustainability criteria

Sustainability criteria for biomass receiving support under the RO were first introduced in April 2009, with a new requirement for biomass power generators of above 50 kWe capacity using biomass (liquid, solid or gaseous) to provide an annual sustainability report to Ofgem.

In April 2011, the UK widened the annual sustainability reporting requirement

to include a greenhouse gas lifecycle assessment for the resulting biomass electricity ("**GHG criteria**") and also requested additional information on the type of land where the biomass was sourced ("**Land criteria**"). However, up to now, meeting sustainability criteria has not been a prerequisite for being eligible for support under the RO, as the Government wanted generators to be able to familiarise themselves with the requirements.

This is changing from 1 October 2013, with the introduction of a new requirement that power or CHP plants of 1 MWe capacity and above using solid biomass and/or biogas will need to meet the sustainability criteria to be eligible for support under the RO.

Some changes to the criteria are also being introduced – in particular, more stringent GHG emissions-savings requirements. It is proposed that for plants accredited before 1 April 2013, the existing GHG standard will apply, while the new standard will apply to plants accredited from 1 April 2013. The criteria will be grandfathered until April 2020 (subject to any new EU or international requirements), to give generators some certainty when entering into biomass supply contracts. From April 2020, new further revised criteria will come into force and will apply irrespective of the date of accreditation of the relevant plant. The Government consulted on the new requirements in September 2012, with the outcome of the consultation expected to be published in March 2013.

Renewable CHP

As illustrated in Figure 1, there have been some changes to the rate of support offered to renewable CHP plants under the RO, but the most significant change is the treatment of the heat component of the energy generated at CHP plants.

Support under the RHI

Currently, eligible CHP installations may also opt to receive support under the new RHI scheme (in relation to their heat output), in addition to support under the RO. Support under the RHI is only available where the CHP plant is not also receiving the so-called 0.5 ROC "uplift" available to CHP plants certified under the CHPQA programme. To illustrate, a dedicated biomass plant with CHP could claim 1.5 ROCs per MWh plus RHI for its heat, or just support under the RO, in the form of 2 ROCs per MWh.

It has been decided that for new accreditations and additional capacity added in the period 1 April 2013 to 31 March 2015, generators will be able to continue to choose to receive either support under the RHI or the CHP uplift under the RO. However, from 1 April 2015 generators will not be able to opt for a CHP uplift if RHI support is available for the heat element of their energy generation.

CHP certification

In December 2012, the Government published a consultation on changes to the criteria used in the CHPQA. In particular, the consultation proposes amending the Quality Index ("**QI**") formulae for renewable CHP. The current QI for CHP schemes is defined as a function of their heat efficiency and power efficiency. The formulae are being amended to address existing anomalies.

The changes are intended to apply to all new and existing renewable CHP schemes from 1 January 2014. It is intended that transitional arrangements will apply to certain district heating networks that will not satisfy the new QI formulae. It is also intended that the revised formulae used will be grandfathered, so that once a scheme has been certified in accordance with the revised QI formulae, the same QI formulae should be applied for the remaining lifetime of support for the plant (subject to any changes required under EU legislation).

Conversion and co-firing with biomass

In its RO banding review published in July 2012, the Government noted that conversion of coal-fired plants to biomass and co-firing are a cheaper means of producing renewable electricity compared to new build, but they are regarded as a "stop-gap" technology. Nonetheless, the Government would like to encourage coal-fired plants to convert to biomass. For this reason, the definition of conversion is being amended to allow plant owners to convert to biomass on a unit-by-unit basis (rather that the whole plant at once) and still qualify for the conversion band level of support in relation to the converted unit. This is important

Figure 1: Levels of support under the RO for some high-profile renewable energy technologies

Technology	Number of ROCs issued per MWh (each new RO year runs from 1 April)				
	2012/13	2013/14	2014/15	2015/16	2016/17
Building-mounted solar PV	2	1.7	1.6	1.5	1.4
Ground-mounted solar PV	2	1.6	1.4	1.3	1.2
Dedicated biomass	1.5	1.5	1.5	1.5	1.4
Dedicated biomass with CHP	2	2 or 1.5 plus RHI	2 or 1.5 plus RHI	1.5 plus RHI	1.4 plus RHI
Standard co-firing of biomass	0.5	0.3	0.3	0.3	0.3
Co-firing of biomass (enhanced)	0.5	Mid-range: 0.6 High-range: 0.7	0.6 0.9	0.6 0.9	0.6 0.9
Biomass conversion	1.5	1	1	1	1
Energy from waste with CHP	1	1	1	1	1
Onshore wind	1	0.9	0.9	0.9	0.9
Offshore wind	2	2	2	1.9	1.8

because the level of support offered to converted plant is higher than that offered for co-firing.

In a further effort to encourage conversion, a new band of support has been created for so-called "enhanced co-firing" – that is, where a higher proportion of biomass is co-fired. This new band will receive a greater level of support than "standard co-firing", and it is intended that the additional support will allow plant owners to raise the additional finance required for full conversion. The enhanced co-firing band will apply where the generator uses biomass to generate at least 15 per cent of its output. The new bands are set out in Figure 1.

The Government has reduced the levels of support available under the RO for standard co-firing with biomass, and it has said that it is expecting very little standard co-firing with CHP or co-firing of regular bioliquids to come forward during 2013/17 under the RO.

Also, the energy crop uplift for standard co-firing will be removed, with the exception of electricity generated using energy crops supplied under existing contracts where the uplift will remain available until 31 March 2019 or the life of the contract, whichever is earlier.

Energy from waste with CHP

Support under the RO

The existing rate of support under the RO for energy from waste ("**EfW**") CHP plants, at 1 ROC per MWh, is being maintained. ROCs are only awarded for the assumed biomass content of the waste. EfW without CHP is not supported under the RO regime. The reason for this is that it is only the CHP component of the operations (i.e. the generation of heat) that is being "rewarded", rather than the incineration of waste to produce electricity.

Support under RHI

EfW CHP plants may receive support under the RHI, but only if they are not already accredited to receive support under the RO. Currently, the heat produced by EfW CHP is supported under the RHI through the biomass tariff, in relation to the proportion of heat generated from the assumed biomass component of the waste.

In September 2012, the Government consulted on proposals to extend the RHI scheme. In particular, it has been proposed that the types of renewable wastes eligible under the RHI should be expanded, to be consistent with the RO. At the moment, the RHI support is limited to only so-called "municipal solid waste" ("**MSW**"). It is proposed that this will be expanded to cover commercial and industrial waste.

Onshore wind

While some commentators argue that onshore wind has the potential to make communities self-sufficient in terms of their energy needs, it has not been welcomed with open arms. There is a strong division of opinion about whether onshore wind energy should continue to be promoted by government policies, and to what extent. For this reason, in September 2012 the Government launched a call for evidence on onshore wind, focusing on community engagement in and benefits of onshore wind, as well as the costs. The outcome of that call for evidence has not yet been published.

For the time being, as a result of the RO banding review, the level of support offered to new onshore projects from 1 April 2013 is being reduced, from 1 ROC to 0.9 ROC per MWh, on the basis that the capital costs have been falling. The Government has said that any further changes to rates of support will be consulted on and would take effect from April 2014 at the earliest. The setting of strike prices for Contracts for Difference ("**CfD**") will be informed by RO cost data, so any revisions of the RO data as a result of this call for evidence may be taken into account in that process.

Offshore wind

Large-scale offshore wind generation is considered to be a vital component of the Government's strategy to decarbonise electricity generation in the UK. The RO banding review of July 2012 held no surprises for the offshore wind industry, with a slight decrease in the level of support, but not until 1 April 2015, from 2 ROCs to 1.9 ROCs per MWh, once again to reflect anticipated falls in cost.

Antony Skinner
London
T: +44 (0)20 7859 1360
E: antony.skinner@ashurst.com

Justyna Bremen
London
T: +44 (0)20 7859 1848
E: justyna.bremen@ashurst.com

THE WINDS OF CHANGE:

Contracting strategies for offshore wind farm development

by Nick Hilder

The UK Government has fixed its sights on 33 GW of capacity from offshore wind power by 2020. Government policy in this regard is itself driven by the EU's own binding national targets on generation of energy from renewable sources – but binding targets aside, is a goal of 33 GW by 2020 realistic or a case of setting the bar too high?

At the time of publication, UK offshore wind installed capacity stands at approximately 2.6 GW, with further capacity of approximately 1.6 GW currently under construction.

There is certainly some work ahead, but key to achieving the 33 GW aim will be the successful delivery of the so-called "round 3 projects". A comparison of these offshore wind projects against those comprising earlier rounds shows a considerable step-up in terms of scale. On average, these larger round 3 projects boast increased generating capacity, and are located further offshore and in deeper water.

Much has been written about the supply chain issues facing those seeking to harness the wind as a means of electricity generation. A developer of an offshore wind farm can expect to face challenges associated with vessel availability, supply chain bottlenecks for key components (such as high-voltage export cable), availability of appropriate port and harbour facilities as well as the regulatory implications of Ofgem's Offshore Transmission Owner ("**OFTO**") regime. This article examines the changing approaches developers adopt to contracting in an attempt to mitigate and overcome these issues.

The early years

A large number of early offshore wind farms were procured using EPC contracts. Examples include the joint venture between Vestas and KBR for Barrow Offshore Wind Farm and Fluor's EPC contract for the Greater Gabbard Offshore Wind Farm.

With this single point of responsibility approach, the developer of the wind farm places one contract with its selected EPC contractor to deliver the wind farm on a turnkey basis. The EPC contractor will seek to pass down to its sub-contractors the risks and liabilities it assumes in connection with such an undertaking but will remain primarily liable to the developer for any contractual breach. The EPC contractor will also take responsibility for managing the myriad of supply chain contractors together with the interface risks this may involve.

While attractive for developers (particularly those with limited in-house expertise), the high degree of risk transfer afforded by EPC contracting does not come for free. The EPC contractor could be expected to charge a premium for the risks it was underwriting, and given that at the time the EPC contracting approach was being adopted, the offshore wind energy business faced considerable uncertainty in terms of technology and strength of the supply chain, those premiums could be significant. These high premiums inevitably resulted in higher contract prices and, coupled with concerns from developers as to whether any EPC contractor had sufficient experience across all the disciplines and technologies required to deliver a commissioned offshore wind farm that could enter commercial operation at the turn of a key, led some to question whether the EPC wrap offered best value for money. All of these factors have led to the emergence of alternative procurement strategies.

Towards the multi-contract approach

Most signed projects and those currently under negotiation adopt the multi-contract approach whereby the developer contracts directly with suppliers and manages the associated interfaces itself. While the risks associated with the individual contract packages will be much the same as those encountered with the EPC contracting approach (technology, weather, etc.), the cumulative risks faced by the developer may be reduced due to the presence of overall risk management for the project.

In addition to avoiding the risk premiums associated with the EPC contracting approach, the flexibility and control offered by such a structure will be attractive to those developers, including the larger utilities, that can readily accept the contract risks and management requirements. Further, while a "global" EPC wrap of interface risk is unlikely and may not be required, some works packages can be bundled together as mini EPC contracts. This will not remove all interface risk from the project but it will reduce the amount of interfaces the developer is left to manage. For example, it should be possible to place single contracts for the supply and installation of export cables and array cables, with each cable manufacturer responsible for its own installation sub-contractor.

Even if bundling is adopted, the absence of the global EPC contract wrap means that the developer will assume some interface risk. In order to manage these risks, it is imperative that the developer's contracts provide the tools the developer needs to stay on top of those interfaces. Requirements to work towards specified key dates, co-operate with other contractors, compliance with strict reporting procedures, etc., combined with fast-track remedies for a failure to do so will help the developer maintain control. From an organisational perspective, the developer will need to be able to draw on a dedicated interface management team of qualified staff. Given that the industry's limited pool of skilled technicians qualified to oversee and carry out offshore operations is already stretched, this may be more difficult to achieve than it sounds.

Developers' relationship with the supply chain

Without the EPC contractor acting as the middleman with the marine engineering industry, developers will need to form their own relationships with the supply chain. Now is a challenging time to enter the market – the limited capacity of the supply chain and high demand means that suppliers enjoy a strong bargaining position and we have seen this leading to high tender prices and aggressive mark-ups of bid documents. Developers are keen to avoid the adversarial approach outlined above and recognise that promoting long-term collaborative relationships with the supply chain will be at the core of the successful delivery of any offshore wind farm project.

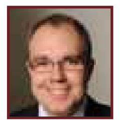
A popular way of creating these collaborative relationships is to adopt long-term framework or partnering agreements with members of the supply chain. For instance, Scottish and Southern has negotiated a number of alliance contracts with Atkins, Siemens, Subsea 7 and Bifab for the development of its wind farm interests, including the Beatrice site in Scottish territorial waters. Typical arrangements include offering suppliers a pipeline of work in return for volume discounts and/or guaranteed production slots. Additional benefits will flow from using pre-agreed contracts to limit negotiation time and legal expense. The developer will also need to consider how (if at all) it wants to share the benefits of its alliances with any of its joint venture partners. This can be particularly relevant where a developer has different joint venture partners across its portfolio of projects – should the developer's partner on project A share the benefit of a price reduction in raw materials that is generated through the award of a contract by the developer for the unrelated project B?

Other developers combine framework agreements with direct strategic investments in the supply chain. For instance, DONG with Siemens owns A2Sea, a company specialising in foundation and turbine installation. Not only should this guarantee DONG vessel availability in the very tight market for such specialised marine heavy lifting equipment but A2Sea also owns CT Offshore, a contractor specialising in the installation of subsea electrical cable.

Impact of the OFTO process

So far this article has focused on the relationships between the developer and its supply chain, but in our view no article on offshore wind farm contracting strategies would be complete without a brief consideration of the impact of the OFTO process. Most new projects will fall into the OFTO enduring regime, giving the developer the choice of whether it or the OFTO licensee designs and constructs the wind farm's transmission assets. In our view, construction of offshore transmission assets by a developer with a subsequent transfer to the OFTO licensee offers a number of benefits, including additional scope for supply chain partnering and associated economies of scale. Importantly, this also allows the developer closer control of the transmission works and opportunities to mitigate the risk of having generation capability but no means of exporting power.

While the transfer of the transmission asset takes effect once those assets are complete, the developer should make provision for such a transfer from the outset and factor the need for such transfer into its procurement strategy. This strategy should ensure, for instance, that if a particular contractor works on generation and transmission assets, it enters separate contracts: one for generation assets and one for transmission assets. This removes difficulties with partial transfer of contracts (and associated guarantees, etc.) and would allow the developer to neatly transfer the transmission asset contract while retaining the generation asset contract. From a structuring perspective, a developer may also consider incorporating a SPV to own the transmission assets and enter the relevant contracts. This would allow the developer to transfer the transmission assets by selling the SPV instead of separate asset disposals and may be more efficient in terms of tax.



Nick Hilder
London
T: +44 (0)20 7859 1020
E: nick.hilder@ashurst.com

FRENCH HYDROELECTRIC:

Update on the renewal of French hydroelectric concessions

by Michel Lequien and Jacques Dabreteau

Hydroelectric power accounts for 12 per cent of electricity production in France and generates about 71 TWh annually, out of a total of 480 TWh.

Installed hydroelectric power capacity is currently 25.3 GW, which represents one fifth of total generation capacity in France. Hydroelectric power is the primary renewable energy source in France.

The size of the 2,000 hydroelectric power stations that are currently operational in France varies: nearly 400 hydropower stations with a capacity in excess of 4.5 MW are operated under a concession granted by the State, whereas the others – small, micro or pico installations under 4.5 MW – are operated pursuant to an authorisation given by the *Préfet* (representative of the State Government) of the *département* in which the installation is located.

Around 80 per cent of French hydropower stations are operated by EDF[1] and 12 per cent by GDF Suez, through its subsidiaries CNR (Compagnie Nationale du Rhône) and SHEM (Société hydroélectrique du Midi). In addition, a number of smaller players operate small installations (e.g. Poweo, Direct Energie, local independent generators, etc.).

In 2010, the French Government announced that it would tender for ten new hydroelectric concessions by 2015. These concessions are intended to involve the regrouping of around 50 existing concessions[2], half of which will expire between 2012 and 2015. With an aggregate installed capacity of 5,300 MW, the new hydroelectric concessions will represent 20 per cent of France's hydropower capacity.

None of the announced tenders for the renewal of hydroelectric concessions has yet been launched and it is currently unclear when the process will start or what form it will take.

There are various reasons that may explain the delay in opening the French hydropower concession market and we discuss these in the second part of this article. First, we provide a summary of the key features of the legal framework governing the tendering of hydroelectric concessions in France.

The legal framework

Hydropower stations are primarily governed by the law of 16 October 1919 relating to the utilisation of hydroelectric energy (*loi du 16 octobre 1919 relative à l'utilisation de l'énergie hydraulique*), as amended.

The law of 16 October 1919 sets out the fundamental principle that energy cannot be produced from water resources (tides, lakes or rivers) without a concession (for plants with an output capacity in excess of 4.5 MW) or an authorisation (where output capacity is equal to or below 4.5 MW).

During the 20th century, the vast majority of the major hydropower installations in France were developed by EDF under long-term concessions granted by the State for the design, construction and operation of these installations.

Until 2008, hydroelectric concessions were renewed in accordance with the renewal procedure provided in decree no. 94-894 of 13 October 1994 (*décret n°94-894 du 13 octobre 1994 relatif à la concession et à la déclaration d'utilité publique des ouvrages utilisant l'énergie hydraulique*). This decree provided for a very long procedure for renewal stretching over a period of a minimum of 11 years. The decree further provided for a preferential right for the benefit of the incumbent concessionaire, according to which, at the expiry of the concession, if the incumbent wanted to continue the operation of the station, the concession was renewed for its benefit without any tendering procedure.

The law of 16 October 1919 also made it possible to postpone the renewal procedure (*délais glissants*), and thereby maintain the incumbent as a concessionaire. Numerous concessions have been tacitly extended on this basis over the years.

Non-compliance of the legal framework with EC principles

The legal regime for the renewal of hydroelectric concessions established by decree no. 94-894 of 13 October 1994 was not compliant with the principles of European Community ("**EC**") law, and in particular with the principle of freedom of establishment and free movement of services. In July 2005, the European Commission decided to take France to the European Court of Justice on the basis that its legislation favoured the incumbent hydroelectric concession-holders, as it was ensuring that existing concessionaires retained their concessions for an indefinite period of time.

Taking into account the position of the Commission, France adopted decree no. 2008-1009 of 26 September 2008 modifying the decree of 13 October 1994, to cancel the preferential right of incumbent concessionaires and to provide an effective tendering regime.

Applicable renewal procedure

The amended decree of 13 October 1994 sets out two renewal procedures:

- for simple projects or installations, the relevant procedure is the classical procedure for the awarding of public service concessions set out in law no. 93-122 of 29 January 1993 (the so-called "*Sapin* Law")[3]; and
- for complex projects or installations, a specific procedure is set out in title 1 of the decree.

Most of the hydroelectric concessions to be renewed are "complex projects or installations" within the meaning of the decree so their renewal is governed by the specific procedure.

For concessions of 100 MW or more, the awarding authority is the Ministry in charge of energy, and for the other concessions the awarding authority is the *Préfet*. In both cases, the application process is administered by the office of the *Préfet*.

Before the renewal procedure is commenced, the competent authority must receive from the incumbent concessionaire a "concession-end report" (*dossier de fin de concession*). The report is intended to provide a detailed description of the nature and state of the relevant installation, as well as details of ongoing or planned works, information about the operation of the concession, and an economic appraisal (*bilan économique et social*) of such operation over the past ten years. This is an essential document as it contains key information for the assessment of the concession at the time of its renewal.

The renewal procedure for "complex installations" consists of a formal open-tender process, with a prequalification phase to select operators based on their technical and financial capacity, and their ability to ensure the continuity of the public service and equality between users of the service.

Based on the prequalification applications, the awarding authority establishes the shortlist of applicants who will be invited to submit an offer. The selected candidates will then receive the tender documentation (*dossier de consultation*).

The tender documentation contains, among other things, the model of the concession contract to be concluded with the State (*cahier des charges type des enterprises hydrauliques concédées*). The tender rules may also provide for a "dialogue" phase. The dialogue is aimed at allowing each candidate to present its views on the characteristics of the concession and possible suggestions and/or alternative proposals (*variantes*). The authority is not obliged to organise a dialogue with bidders.

Whether a dialogue phase is taking place or not, the awarding authority will invite candidates to submit a bid (*invitation à remettre une offre sous la forme d'un dossier de demande de concession*).

Bid evaluation criteria

The amended decree no. 94-894 expressly sets out three criteria on the basis of which bids are to be evaluated, but the competent authority may also provide for additional criteria in the *dossier de consultation*. The three criteria are as follows:

- **Energy efficiency** (*efficacité énergétique de l'exploitation*): the nature and level of investments committed by candidates for the modernisation/upgrade of the installations will play a key role in the evaluation of their offer.
- **Balanced and sustainable water management** (*respect d'une gestion équilibrée et durable de la ressource en eau permettant la conciliation de ses différents usages*): this criterion refers to the obligation imposed upon the future concessionaire to ensure that the various uses of water resources (tourism, agriculture, fishing, environmental protection, etc.) are reconciled and managed in a balanced and consistent manner.
- **Economic and financial terms of the concession** (*conditions économiques et financières pour l'Etat*): this criterion refers in particular to the annual concession fee payable to the State, which will be proportional to the turnover of the station. Under the law of 16 October 1919, the concession fee was limited to a maximum of 25 per cent of such revenues; it has recently been amended[4] and now gives the competent authority the right to set the cap applicable to the concession fee on a case-by-case basis for each concession.

Negotiations

Decree no. 94-894 does not regulate the

1 447 installations totalling a generation capacity of 22,000 MW.
2 86 per cent of these hydroelectric power stations are currently operated by EDF and 14 per cent by GDF Suez through its subsidiaries.
3 Article 41 of law no. 93-122 of 29 January 1993 *(loi n°93-122 du 29 janvier 1993 relative à la prévention de la corruption et à la transparence de la vie économique et des procédures publiques).*
4 By law no. 2010-788 of 12 July 2010 (*Loi n° 2010-788 du 12 juillet 2010 portant engagement national pour l'environnement* also called the "Grenelle 2" Law).

manner in which negotiations must be conducted. The authority enjoys a high degree of freedom in the selection of the concessionaire and can freely negotiate with all or only certain of the candidates that have submitted an offer. Negotiations may be carried out with several candidates in parallel or in sequence, if the first negotiation is not conclusive. All of the terms of the candidate's offer can be negotiated, including financial terms. At the same time, the negotiation cannot result in a fundamental review/restructuring of the terms of the concession as originally tendered, or of the candidate's offer.

Processing of the application and execution of concession contract

The selected candidate becomes a "retained applicant" (*pétitionnaire retenu*), i.e. it is not yet a concessionaire, whose application for the concession (*dossier de demande de concession*) will then be processed by the administration within a period of approximately 12 months, leading to a formal approval of the selection of the concessionaire and the terms of the concession.

Current status of the tender process

Following the French Government's announcement in 2010, several major European energy companies, as well as French industrial and other companies, have expressed strong interest in participating in the tenders for the renewal of the hydroelectric concessions[5]. Certain of them have already formed consortia and all of them have actively started working, setting up dedicated teams, appointing advisers, visiting sites, meeting with local authorities and other stakeholders, publicising their ambitions and closely monitoring developments.

Developments have been very slow, however, and it is not clear when the tender procedure for the first concession will be launched.

There are several reasons that can explain the delay in the process.

- **Technical:** the concession-end reports (*dossiers de fin de concession*) that must be prepared by the incumbent concessionaires, and which contain crucial information and data on the concessions coming up for renewal, are substantial documents that will play a key role in the future tender procedures. They take a significant amount of time for the outgoing concessionaires to prepare, as well as for the administration to review and assess.
- **Organisational:** the DGEC[6], which is the department of the Ministry for Ecology, Sustainable Development and Energy in charge of managing the renewal process, appointed its technical, financial and legal advisers only at the end of 2011.
- **Political:** the renewal of the hydroelectric concessions, which is expected to result in the opening of the market to new entrants and allow them to acquire significant generation capacity, is a very sensitive issue. It will potentially reduce the share held by the "historical" operators, hence modifying the existing equilibrium on the French electricity market. It also has a significant impact at a local level, with local authorities wishing to be closely involved in the process and to secure benefits in terms of revenues and local employment.

The political sensitivity of the issue certainly explains why the process was not launched before the presidential election of May 2012 and the ensuing national elections of June. It was generally expected, however, that the process would start once the new government settled in.

Yet, to the surprise of the market, Delphine Batho, the Minister for Ecology, Sustainable Development and Energy, announced on 24 October 2012 that while it was acknowledged that the process was already very advanced, options other than a retendering of the hydroelectric concessions were currently under consideration.

Since then, it would seem that the Government has not made the renewal of hydroelectric concessions one of its priorities. On the contrary, it appears that it intends to take more time to review and reassess its options. It is unclear, however, what alternatives are being alluded to by the Minister, since half of the concessions forming part of the programme announced in 2010 will soon be reaching their normal term and can no longer be validly extended for the benefit of their incumbent holders.

Indeed, we understand that the DGEC is still actively working on the basis of a scenario involving the tendering of the new regrouped concessions as these were designed in 2010.

It is also worth noting that the Ministry for Ecology, Sustainable Development and Energy has recently made certain announcements suggesting that the renewal process is not abandoned but merely postponed. In particular, the Ministry announced that it intends to publish a methodological guide on the concession-end reports, but without a detailed indication as to its proposed contents and without setting out any deadline for such publication.

The Ministry further announced that decree no. 94-894 of 13 October 1994 is currently being amended to provide for the creation of a "bid advisory committee" (*comité consultatif des offres*), whose role will be to monitor the tender process. The decree could also be amended to provide for closer involvement of local authorities in the concessions renewal process and, possibly, also to create a new award criterion called "competition enhancement" (*développement de la concurrence*), which would implement a recent recommendation by the French competition authority (*Autorité de la concurrence*)[7].

The above suggest that significant uncertainties as to the timing of the renewal process still remain.

Our view is that it will be postponed by at least a further six months, as it seems unlikely that the Government would launch the process in the middle of the ongoing energy transition debate (*débat sur la transition énergétique*) which it has just initiated. The debate is due to close in May 2013, followed by a bill in June. According to recent information, however, this may slip to the end of the year.

In the meantime, the Government will review and likely bring certain modifications to the procedure, such as greater involvement of local authorities in the process, so it is reasonable to expect that the programme for the renewal of the French hydroelectric concessions will eventually be launched by the end of 2013.

5 The following companies and consortia have publicly expressed their intention to participate: Alpiq, BKW, EDF, GDF Suez via SHEM, Vattenfall-SNCF-Rhodia, E.ON-Hydrocop Concessions, Fortum, Statkraft, Iberdrola, Direct Energie-Axpo, Enel, Verbund-Poweo and CNR-Gaz électricité de Grenoble.

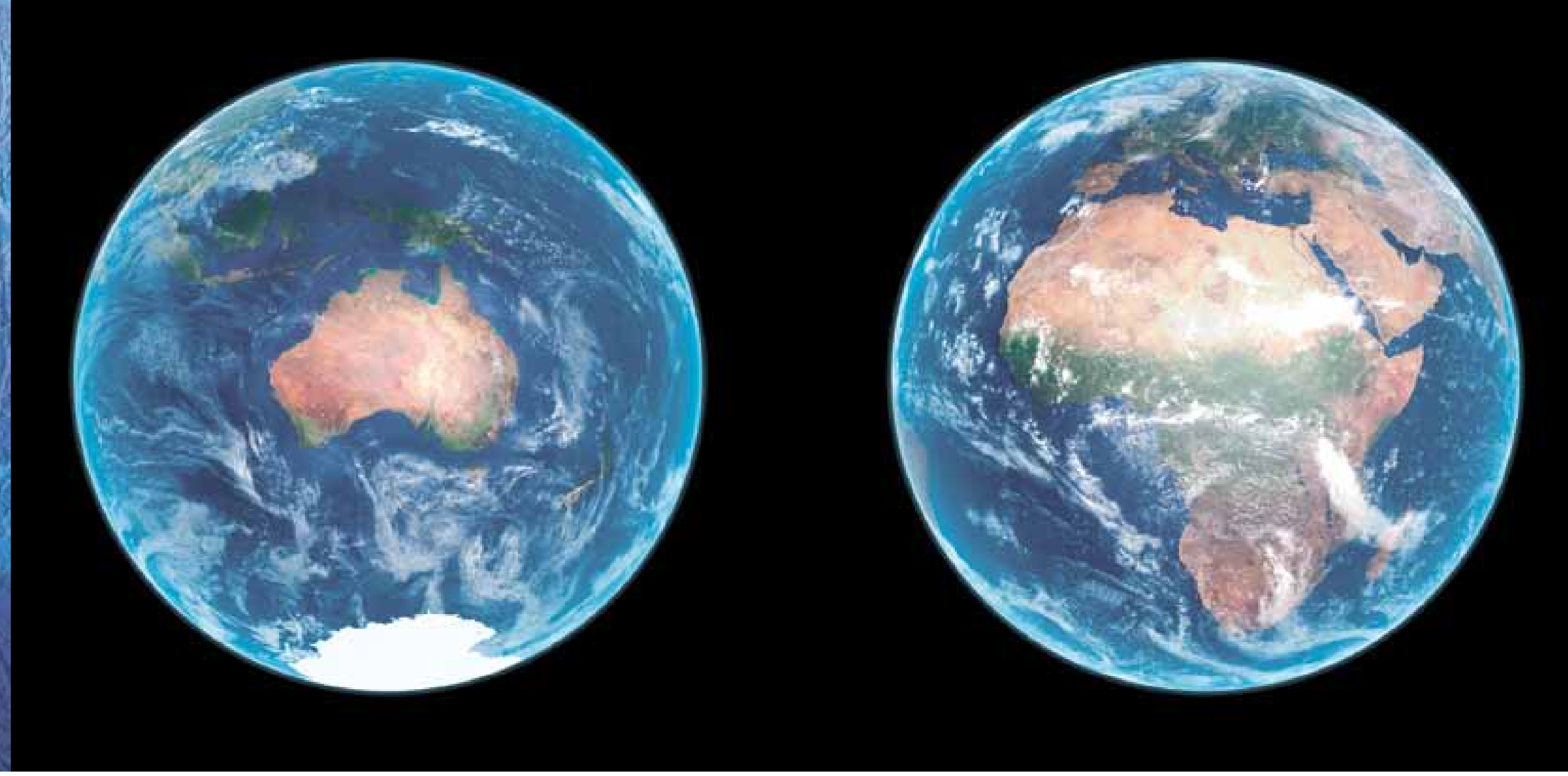
6 *Direction Générale Energie et Climat* of the Ministry of Ecology, Sustainable Development and Energy (*ministère de l'Écologie, du Développement durable et de l'Énergie*).

7 Competition Authority, Opinion No. 12-A-09 of 12 April 2012, in which the competition authority recommends the introduction of this new criterion in order to improve the access of alternative energy suppliers to base-load electricity produced by hydropower stations at a competitive rate.

Michel Lequien
Paris
T: +33 (0)1 53 53 55 77
E: michel.lequien@ashurst.com

Jacques Dabreteau
Paris
T: +33 (0)1 53 53 53 69
E: jacques.dabreteau@ashurst.com

CONTINENTAL SHIFT:



Australia's mining expertise in Africa

by Martin Kudnig and Megan Barnett-Smith

Australian resource companies have more projects in Africa than any other region in the world.[1]

According to the Department of Foreign Investment and Trade, some 227 Australian companies have assets in Africa, accounting for interests in over 620 individual mining projects across 42 countries.[2]

Australia is investing in Africa's mining sector in increasing levels, and in a number of ways. It is sharing its expertise to assist African countries in maximising the benefits of their mineral resource wealth, grow their economies and unlock the socio-economic benefits of a sustainable mining sector. But it is not only Australian companies and the African countries involved that stand to benefit from such investment. Global resource houses, large multinational corporations, and junior exploration and mining companies with interests in the region will all gain from positive developments in this region. As a major international law firm, Ashurst is also in a position to share its renowned Australasian energy and resources legal capability with clients in Africa.

The African attraction

Africa is a resource-rich continent, replete with opportunities for the resources industry. Australian government agencies, companies and individuals have shown a keenness to invest in such opportunities.

Africa contains an estimated 30 per cent of the planet's resource reserves.[3] It has 12 per cent of the world's petroleum[4] and some of the largest known reserves of platinum, diamonds, cobalt and bauxite.[5] Eleven of the top 50 countries in terms of proven oil reserves are African.[6] South Africa, Ghana and Tanzania feature in the world's top 20 gold producers and Zambia and the Democratic Republic of the Congo ("**DRC**") feature in the world's top 20 copper producers.[7]

Rising commodity prices coupled with escalating demand, particularly from China, has attracted miners to pursue iron ore and coal projects in Africa. According to Ernst & Young, seven of the ten biggest mining deals completed last year were in Africa.[8] Vast ore deposits have led to an iron ore renaissance in West Africa[9] (particularly Guinea) while Mozambique's geographic proximity to Chinese and Indian markets has spurred a flurry of activity over coal projects.[10]

Australia is one of a number of countries which have long understood Africa's potential. One need not travel to many mining projects in Africa before hearing an Australian accent among professional team members.[11]

In 2011, Australian resource companies had 203 projects on the ground in Africa in the mining sector, 24 in oil or gas production/exploration and one geothermal exploration project.[12] Committed and planned investment by Australian companies in African resources totals more than US$50bn.[13] Australia is ranked in the top five country investors of new projects by job creation (2003-2011) in Cameroon, the DRC, Ghana, South Africa and Tanzania.[14]

Reference to these figures is not to suggest, however, that doing business in Africa is without risk. Indeed, Africa faces significant challenges, particularly in the areas of infrastructure and governance. But the potential returns to be earned on capital, notwithstanding the risks, appear to be attracting increasing investment by Australian and other international companies in Africa's mining sector.[15]

Overall, the story of economic growth in Africa appears positive and set to continue. According to IMF forecasts, seven of the ten fastest-growing economies in the world (2010-2015) are African (Ethiopia, Mozambique, Tanzania, the DRC, Ghana, Zambia and Nigeria),[16] although growth is by no means solely attributable to a growing resources sector.

Australia is well placed to share its mining expertise with Africa

Like Africa, Australia is a vast continent of natural wealth. It is one of the world's biggest mining countries and mineral commodities account for a significant proportion of Australia's export earnings. Australia is an effective manager of foreign investment in mining and a global leader in mining technology and sustainable mining.

For these reasons, Australia has much experience to share with resource-rich

Ashurst's African expertise

Ashurst has a long history in Africa (including drawing up the contract for the cutting of the Cullinan Diamond in 1907). Our practice in the region has grown rapidly in the last decade and we regard Africa and the corporations and financial institutions that have operations there as a key part of our international practice.

Our new combination substantially reinforces our energy and resources capability in Africa, in particular bringing extensive mining investment and project development capability from Australia and South East Asia.

We have brought together the extensive regional experience of our lawyers to create a group of 25 partners focused on servicing our clients' needs across the continent. Key features of our Africa group include:

- A strong track record of successfully concluded deals in Africa.
- In-depth knowledge of the legal systems and business life in the region.
- Experience of working seamlessly with African law firms.
- Established, well-developed relationships with leading players interested in the region.
- Multi-lingual capability including Arabic, English, French, Spanish and Portuguese.
- A strong working relationship with ALN (formerly Africa Legal Network), an association of leading firms in 14 different countries across Africa.

Ashurst is also an active member of International Lawyers for Africa, an initiative that aims to build legal capacity in Africa.

Ashurst is excited about the possibilities presented by growing resources sectors in Africa. We look forward to sharing our expertise and enviable regional experience in the mining industry with our clients.

1 International Mining for Development Centre, "Australian mining investment in Africa more than $50 billion: DFAT", available at http://im4dc.org; Speech delivered by Melissa Parke MP on behalf of Former Foreign Affairs Minister Kevin Rudd MP to the Australia-Africa Business Council, 24 February 2011 available at: http://www.foreignminister.gov.au/speeches.
2 Joint Standing Committee on Foreign Affairs, Defence and Trade, "Inquiry into Australia's Relationship with the Countries of Africa", 23 June 2011, available at: http://www.aph.gov.au/Parliamentary_Business/Committees/House_of_Representatives_Committees?url=jfadt/africa%2009/report.htm.
3 Ibid.
4 Speech delivered by Melissa Parke MP, op cit.
5 Joint Standing Committee on Foreign Affairs, Defence and Trade, "Inquiry into Australia's Relationship with the Countries of Africa", op cit; Deloitte, "Deloitte on Africa: Resource-seeker or market-seeker?" 2012, available at: http://www.deloitte.com/assets/Dcom-SouthAfrica/Local%20Assets/Documents/Deloitte%20-%20Market%20Seeker%20or%20Resource%20Seeker.pdf.
6 Ernst & Young, Africa attractiveness survey, 2012, available at: http://www.ey.com/Publication/vwLUAssets/EY_2012_Africa_attractiveness_survey/$FILE/attractiveness_2012_africa_v17.pdf.
7 Ibid.
8 Ibid.
9 Morgan, M J, "Africa now a Mecca for mining investment", African Business, 383, February 2012: 28-30.
10 Ibid; The Economist Intelligence Unit, "Mozambique economy: Mozambique's coal boom: not inevitable", EIU ViewsWire, 3 December 2012.
11 "Australians exploring new frontiers: Engineering, Geology, Mineralogy, Metallurgy, Chemistry, etc", Engineering and Mining Journal, 2001: 48-50, 52-56.
12 Joint Standing Committee on Foreign Affairs, Defence and Trade, "Inquiry into Australia's Relationship with the Countries of Africa".
13 International Mining for Development Centre, "Australian mining investment in Africa more than $50 billion: DFAT", op cit.
14 Ernst & Young, Africa attractiveness survey, op cit.
15 Joint Standing Committee on Foreign Affairs, Defence and Trade, "Inquiry into Australia's Relationship with the Countries of Africa", op cit.
16 Ernst & Young, Africa attractiveness survey, 2012.

African countries. Ways in which Australia has been assisting African countries to meet the challenges associated with growing a mining sector include, among other things, providing technical assisting and hosting regular study tours to Australia, supported by the Australian Mining Industry and mining companies including Rio Tinto, BHP Billiton and Newcrest.[17] Scholarships awarded to African officials for formal study also strengthen relationships between Australian and African individuals, governments and organisations, and build capacity and knowledge-sharing around issues of governance and regulation, community and environmental sustainability, and operational effectiveness and safety.

17 AusAID, "Australia's Mining for Development Initiative", October 2011, available at: http://www.ausaid.gov.au/Publications/Pages/9578_1521_9550_2458_5168.aspx.

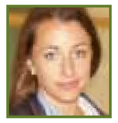
Global initiatives

Of course, it is not only Australian companies and organisations that are keen to be involved in Africa's growing resources sector. The following are some examples of global initiatives, involving international mining companies and organisations, that strengthen links with Africa, encourage sustainable mining, and promote business and investment in African countries:

- The Extractive Industries Transparency Initiative ("**EITI**") is a multi-stakeholder coalition of governments, companies, investors and civil society organisations that promotes and advises on the implementation of a global standard for transparency of payments from natural resources[18]. The next EITI Global Conference will be held on 23-24 May 2013 in Sydney, Australia.
- The International Mining for Development Centre was established in 2011 and is hosted by the Energy and Minerals Institute, University of Western Australia, in partnership with the Sustainable Minerals Institute, University of Queensland. It provides developing countries throughout the world with access to education, training and technical advice relevant to the mining industry.
- AMIRA International Ltd is an independent association of minerals companies which develops, brokers and facilitates collaborative research projects.[19] For example, it is currently building the geoscience research capacity of four West African universities in Burkina Faso, Ghana, Guinea and Senegal.[20]
- Investing in African Mining Indaba 2013 (global mining conference, 4-7 February 2013, Cape Town, South Africa).
- The annual Africa Down Under Mining Conference (28-30 August 2013, Perth, Australia).

18 See http://eiti.org.
19 See http://www.amira.com.au.
20 AusAID, "Mining for Development in Africa", available at: http://www.aa-partnerships.org/downloads/Mining_for_Development_in_Africa_ENG.pdf.

Martin Kudnig
London
T: +44 (0)20 7859 1679
E: martin.kudnig@ashurst.com



Megan Barnett-Smith
Melbourne
T: +61 3 9679 3238
E: megan.barnett-smith@ashurst.com

ITALIAN PROJECT BONDS: A new era for infrastructure and energy financing

by Carloandrea Meacci and Nicola Toscano

It is no secret that five years of financial crises of all sorts, from the collapse of Lehmans in 2008 to the risk of a Euro break-up in 2011/2012, have rattled the financial markets, particularly in Southern Europe.

Coupled with the new Basel III requirements that have made long-term bank financings very expensive, the availability of banks to finance energy and infrastructure projects has been materially affected. As a result, either bank loans have not been available or they have only been available on very expensive terms.

Against this background, the Italian Government acknowledged that the Italian financing market was too dependent on bank loans (upwards of 80 per cent) and that a new legal and tax regime was required to facilitate access to non-bank sources of finance, such as capital markets in particular, in line with more mature markets such as the USA, where the majority of financing transactions are not bank loans but capital markets deals.

Traditionally, capital markets transactions in Italy, i.e. bond issuances, have been a sensible alternative to bank loans only if the issuer/borrower was a listed company (which is usually not the case for project-financed energy and infrastructure deals). Indeed, obsolete and detrimental legal and tax rules prevented non-listed companies from issuing bonds exceeding a 2:1 debt (i.e. the amount of the bond) to equity ratio (unless a mortgage was granted to the bondholders), levied a hefty withholding tax on interest payable under them, and prevented deductibility of interest payable by the issuer in certain circumstances.

In order to address the above issues, a number of new laws[1] have been recently approved, introducing a more modern regime for bonds, both in comparison to the previous Italian regime and, even more surprisingly, in comparison to other European countries.

1 See decree no. 1/2012 (converted into law no. 27/2012) also known as the "Liberalisation Decree", decree no. 83/2012 (converted into law no. 134/2012) also known as the "First Growth and Development Decree" and decree no. 179/2012 (amended and converted into law no. 221/2012) also known as the "Second Growth and Development Decree".

Under the new regime, a fundamental distinction is to be made between (i) bonds denominated as "project bonds", which are issued to finance core infrastructure projects ("**Project Bonds**") and (ii) other bonds, originally denominated as "mini bonds", which are issued for any other purpose ("**Other Bonds**").

Project Bonds

In order for a bond to qualify as a Project Bond, it must meet the following requirements:

- it must be issued to finance or refinance a core infrastructure project;
- it must be placed and transferred only among "qualified investors";
- it must meet certain formal requirements; and
- if it is subscribed by an insurance company which wants to take advantage of an ad hoc 3 per cent basket of its technical reserves, the construction risk must be guaranteed by a financial institution and the issuer's financial statements must be audited.

Each of these requirements is described in more detail below.

If a bond qualifies as a Project Bond, then a favourable legal and tax regime applies whereby among other things:[2] (i) the old 2:1 debt-to-equity ratio described above is no longer applicable nor the requirement for a mortgage to exceed such limit, so an issuer can issue Project Bonds in the amount it considers appropriate; (ii) no withholding tax is applicable on the interest payable to the bondholders (excluding retail and a few residual categories of bondholders) provided that the Project Bond is issued by 25 June 2015 and the bondholder is tax resident in a white-list country for tax purposes;[3] and (iii) the security package securing the Project Bond (which would otherwise be subject to registration taxes that could be as high as 2 per cent of the bond issuance) is almost tax-free (i.e. subject only to a €168 registration tax).

The particular requirements for a bond to qualify as a Project Bond are as follows:

2 Other positive aspects of the new regime include that in the case of termination of a PPP concession due to the awarding authority's default or revocation of the concession for public interest, the priority of the lenders over the termination payments has been extended to holders of Project Bonds.

3 Therefore this withholding tax regime is even more attractive than the regime for bank loans which are subject to withholding if the lender does not have a branch in Italy.

- The core infrastructure projects in relation to which Project Bonds can be issued are limited to the following: BOT concessions (e.g. toll roads, undergrounds and hospitals),[4] PPP projects,[5] LNG receiving terminals, national electricity distribution grids, gas distribution grids (both national and local), gas storage facilities, local public services, electronic communication grids and public telecommunications.
- The "qualified investors" among which Project Bonds must be placed include banks, investment companies, certain registered financial intermediaries, insurance companies, SGR, SICAV, pension funds and "large companies" as defined by the Italian stock market regulator, Consob[6].
- The formal requirements that Project Bonds must meet include that the bond must specify the name of the bondholder (*titoli nominativi*) and the documentation related to their offer must contain a warning about their high-risk profile.

4 SPVs established pursuant to Art. 156 of the Public Procurement Code.

5 SPVs holding contracts of public private partnership under Art. 3, paragraph 15 – ter of the Public Procurement Code.

6 These are companies that meet at least two of the following conditions: (i) annual total balance sheet equal to €20m; (ii) annual net turnover equal to €40m and (iii) equity equal to €2m.

- The construction[7] guarantee required for insurance companies to take advantage of the ad hoc basket of technical reserves can be provided by banks, certain registered financial intermediaries, insurance companies, Cassa Depositi e Prestiti, SACE, EIB, banking houses and private equity funds. These guarantees must, among other things, be irrevocable and unconditional. The unconditional nature of such guarantees could make them quite difficult to obtain, and we understand that lobbying efforts are under way to seek to soften this requirement. Similarly, there are a number of technical and practical glitches affecting the rules governing the application of the ad hoc basket which we understand market operators are trying to address with the Italian insurance regulator IVASS (formerly ISVAP).

7 Whether the guarantee should cover only the construction risk and not the operational risk is a matter of interpretation of the insurance regulation on technical reserves (IVASS regulation no. 36 of 31 January 2011 as amended on 18 July 2012). On the one hand, this regulation makes reference to Project Bonds backed by the guarantee issued under Article 157, paragraph 3 of the Public Procurement Code which literally makes reference only to a guarantee during the construction phase, to be detailed by a ministerial decree. However such ministerial decree, when eventually issued, provided that the guarantee may also cover the operational phase. Although there are reasonable arguments to believe that the guarantee required by IVASS was intended to cover only the construction risk, we would strongly recommend confirming this point with IVASS before any actual transaction is structured. Furthermore, according to an interpretation of the IVASS regulation, if no guarantee is provided, an insurance company could potentially still invest its technical reserves in Project Bonds provided that it meets the general requirements for investments of technical reserves in bonds. Interestingly, compared with these requirements the 3 per cent new ad hoc basket for Project Bonds described above seems to represent an actual advantage mainly/only if the Project Bond is not listed.

Interestingly, a Project Bond does not need to be listed.

Other Bonds

As noted above, bonds issued to finance projects other than the core infrastructure projects indicated above do not qualify as Project Bonds and therefore the favourable legal and tax regime described above does not apply. This is material, given that so many projects do not fall within the core infrastructure projects, e.g. many energy projects, including all renewable energy projects.

However, new rules have also been introduced in relation to Other Bonds, i.e. those different from Project Bonds, issued to finance projects which are not core infrastructure projects.

Under the new rules, Other Bonds also benefit from (i) the cancellation of the old 2:1 debt-to-equity ratio described above and the requirement of the mortgage to exceed such limit, and (ii) the non-application of withholding tax on the interest payable to the bondholders (excluding retail and a few residual categories of bondholders).[8] In addition, a special limitation to deductibility of interest payable provided for bonds issued by non-listed companies does not apply.

This favourable regime is subject to the following requirements:

- the Other Bonds must be listed in an EU or Norway regulated market or multilateral trading system (MTF);
- the bondholder must be resident in a white-list country for tax purposes; and
- the issuer must be a *società per azioni* (limited liability company).

These requirements do not seem particularly difficult or expensive to meet.

Unfortunately, unlike for Project Bonds, the security package for Other Bonds is subject to the ordinary tax treatment, i.e. registration taxes equal to 2 per cent (for the mortgage) or 0.5 per cent (for the other notarial security documents) of the amount of the bond[9] apply[10]. However, Ashurst is structuring a number of transactions where these issues are sought to be partially mitigated through, for example, intercreditor agreements where there is a parallel bank loan and/or a security structure whereby the secured amount is just a fraction of the bond, with the right for the bondholders to increase the secured amount upon breach, for example, of the distribution ratios. Non-notarial security documents can be structured as exchange of correspondence and be essentially tax-free except in very remote circumstances.

8 Other positive aspects introduced by the new rules on Other Bonds include the possibility for certain Other Bonds to introduce a subordination clause (whereby the bondholders agree to be subordinated to other creditors of the issuer, which may be relevant for mezzanine funds) and/or a participation clause (whereby the amount payable to the bondholder is proportional to the profits of the issuer within certain limits, which may be useful in a restructuring scenario).

9 To be precise, the registration tax is in most cases levied on the secured amount rather than the amount of the bond, but usually the security document secures at least 100 per cent of the principal bond amount.

10 To be precise, the registration tax can be reduced to €168 per notarial security document (except the mortgage and the assignment of receivables by way of security) if the grantor of the security secures its own indebtedness (which is usually the case when the issuer coincides with the owner of the asset and is therefore not the case when the bond is issued by a holding company in the context of a portfolio financing).

Conclusions

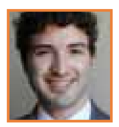
We are seeing a huge interest in Project Bonds and Other Bonds from all players, ranging from issuers (who need a new source of financing), banks (who need to satisfy the debt appetite of their clients without using their balance sheet), and insurance companies (who need and wish to cover their technical reserves), to even the bondholders themselves (who need to find new, profitable ways to deploy their funds). In this last respect, it is interesting to see that many private equity funds, which traditionally invested only in equity, are now setting up large funds to invest in debt; Project Bonds and Other Bonds are an ideal instrument to match all these different needs.

Another reason why we see so much interest in this product is that it is competitive vis-à-vis a traditional bank loan in terms of both cost and maturities. In terms of maturities, long tenors are available from many investors who wish to achieve the so-called "matching of assets and liabilities" (e.g. insurance companies), whereas banks prefer short-term loans due to Basel III. In terms of cost, the return on a Project Bond or Other Bond for an Italian energy or infrastructure project is usually linked to Italian government bonds (usually 1 or 2 per cent above ten-year government bonds). The combination of the cost of government bonds continuing to decrease in recent months (from a peak of more than 6 per cent in June 2012 to just above 4 per cent in January 2013) and the cost of bank loans (including hedging costs, which are not applicable to bonds) remaining high (6-7 per cent all in) explains the interest in this product.

Clearly, not all is positive. In particular, the real appetite of bondholders to invest in a new product, coupled with the initial transaction costs (higher than for a normal debt transaction) and the country risk still perceived by some investors, will be the biggest challenges.

However, based on the hundreds of conversations that we have been having with various industry players, we are optimistic that the changes will not be simply academic.

Carloandrea Meacci
Milan
T: +39 02 85 42 34 62
E: carloandrea.meacci@ashurst.com



Nicola Toscano
Milan
T: +39 02 85 42 33 20
E: nicola.toscano@ashurst.com

STATE IMMUNITY DEVELOPMENTS IN 2012:

What you need to know

by David Salcedo

Two significant cases considering State immunity in English law were reported in 2012. The cases represent a stark reminder to commercial parties of the significant risks associated with contracting with State entities.

This article summarises the key points in the cases and suggests strategies which commercial parties can adopt to protect themselves from these risks.

What is State immunity and why is it important?

State immunity is a principle of international law that has become part of the national law of many States. The principle derives from the theory of the sovereign equality of States, as a consequence of which one State has no right to judge the actions of another by the standards of its national law. The primary source of English law on State immunity is the State Immunity Act 1978 ("**Act**").

State immunity can apply not only to States and governments but also to separate entities acting "*in the exercise of sovereign authority*".[1] It protects an entity in two ways: by conferring *immunity from adjudication* (also known as immunity from suit) and by conferring *immunity from enforcement and execution*.

1 Section 14(2)(a) of the Act.

If a party is immune from adjudication, the court will be prevented from considering claims against that party and from adjudicating those claims by awarding a judgment or declaring rights and obligations against the immune party. If a party is immune from enforcement and execution, the court will be prevented from recognising a foreign judgment or an arbitral award against the immune party, and from making and executing orders or injunctions against the immune party.

In practice, this means State entities can and do raise State immunity:

- to argue that the court or arbitral tribunal does not have jurisdiction over the State to hear a dispute;
- to claim immunity from injunctive relief or specific performance;
- to argue that a national court does not have jurisdiction to recognise and enforce an arbitral award or foreign judgment granted against a State; and
- to claim immunity from execution or enforcement of an arbitral award or judgment against a State's assets.

The law of State immunity therefore determines the ability of a private party to sue a State or State entity and to enforce a judgment or arbitral award it might obtain against a State's assets.

Risk management

Commercial parties resort to a range of methods in order to manage the risk of State immunity when contracting with State entities. Primarily, these are:

- Obtaining an express waiver from the State entity of its immunity from adjudication and from enforcement/execution. This is invariably the safest approach and should be insisted on wherever possible. However, there is anecdotal evidence that State entities are increasingly refusing expressly to waive their immunity.
- Where a waiver has not been obtained and a dispute arises, seeking to exploit an exemption to State immunity in the Act.
- "Self help", i.e. structuring a transaction to ensure that the commercial party is in a position to recover any losses caused to it as a consequence of the State entity's conduct without recourse to the courts.
- "Chasing assets", i.e. once a judgment or arbitral award has been obtained against a State, searching for assets belonging to the State and entities associated with it, sometimes across a range of jurisdictions with varying approaches to State immunity and, once located, bringing enforcement proceedings against those assets.

La Générale des Carrières et des Mines -v- F. G. Hemisphere Associates Llc[2]

Gécamines demonstrates the difficulties commercial parties may encounter when bringing enforcement proceedings against assets belonging to an entity that appears in many respects to be part of a State but which, on a strict legal analysis, may be found not to be. However, the flip side is that it will now be more difficult for State entities that are separate legal entities to claim entitlement to immunity in the first place.

2 [2012] UKPC 27.

The facts

F. G. Hemisphere – a fund that invests in distressed assets – purchased two arbitral awards against the Democratic Republic of the Congo ("**DRC**"). It sought to enforce the awards in Jersey, against assets of La Générale des Carrières et des Mines ("**Gécamines**"), a corporation owned by the DRC.

Gécamines and the DRC were closely connected. Gécamines was formed and wholly owned by the DRC. All of its assets originated from the DRC in the form of mining concessions. In addition, the DRC held considerable power and potential control over the entity. The board of directors, the chair of its management committee and the commissioners of its accounts, for instance, were appointed and could be removed by the President of the DRC. Furthermore, during the relevant period, the State had a power of veto over Gécamines' decisions to dispose of property, contract loans, increase or decrease assets and enter into contracts for goods and services in an amount equal to or more than US$20,000. In light of these connections, F.G. Hemisphere contended that Gécamines was an "organ of the state" and that, as such, Gécamines' assets were the assets of the DRC. On that basis, F.G. Hemisphere argued it could enforce the arbitral awards it had purchased against Gécamines' assets.

The decision

Despite the close connections between Gécamines and the DRC, the Privy Council was not persuaded that Gécamines constituted an "arm of the State". In coming to its decision, it noted that:

- Gécamines had its own legal personality.
- Gécamines was a party to 35 joint venture operations enabling it to exploit the mining licences that it held.
- Gécamines had outstanding applications to transform 37 research licences into mining licences, to which the DRC authorities had not yet responded.
- Gécamines' accounts occupied over 30 pages, including an auditor's report by PwC, and showed sales of copper, cobalt, zinc and other materials, to a value of circa US$28m, about 40 per cent of which was overseas. They also recorded a number of transactions involving the State, relating to both services rendered and tax due, with items claimed in each direction. In several cases, they recorded negotiations, agreements or set-offs reached or under discussion with the State. Gécamines' accounts also contained an extensive list of outstanding loans from institutions such as the EEC and Investec, in relation to a number of which it had negotiated debt relief and supervisory payment schedules.

In light of these facts, the Privy Council held that Gécamines and the DRC were not so closely connected that they should have to bear each other's liabilities. Gécamines was a real and functioning corporate entity which was clearly distinct from the executive organs of the State.

The Privy Council held that the modern principles governing State immunity required appropriate recognition of the existence of separate legal entities established by States, particularly for trading purposes. This was the case even where such entities exercise sovereign authority, in which case a special "functional immunity" would be afforded to those particular acts. In distinguishing between an organ of the State and a separate entity, the Privy Council explained that only in extreme circumstances would a State-owned entity be held to constitute an arm of the State. The strong presumption is that the separate legal personality of a State-owned entity should be respected. The Privy Council stated that when applying the test, the courts should look at the evidence in the round and consider the particular circumstances to determine whether the entity and the act could properly be characterised as sovereign.

Practical implications

Gécamines may be a help or a hindrance to commercial parties, depending on the particular circumstances. The decision clearly makes life more difficult for those who assumed that a judgment or arbitral award against a State could be enforced against assets belonging to an entity connected with, but legally separate from, that State. However, for those who have contracted with a separate entity that is closely connected with a State, *Gécamines* makes it less likely that, in the event of a dispute, such separate entity will be able to assert State immunity merely by virtue of such close connection.

SerVaas Inc -v- Rafidain Bank and Others[3]

SerVaas considers one of the exceptions to immunity from enforcement under the Act. In broad terms, the relevant exception, frequently referred to as the "commercial purposes" exception, provides that a State will not be entitled to immunity from enforcement in respect of property which is "*for the time being in use or intended for use for commercial purposes*".[4]

The facts

Prior to the First Gulf War, SerVaas contracted with the Iraqi Ministry of Industry to supply equipment, machinery and related services for the commissioning of a metals facility. Rafidain was a State-controlled Iraqi commercial bank whose assets in the UK were frozen as a consequence of the United Nations sanctions regime against Iraq. SerVaas subsequently obtained judgment in default against the Iraqi Ministry of Industry for payments due under the metals facility contract.

In 2008, the English High Court sanctioned a scheme of arrangement for the distribution of Rafidain's assets to its creditors. Iraq's claims in the scheme were admitted for US$253.8m. SerVaas sought a third party debt order against Rafidain in relation to the debt payable to Iraq by Rafidain under the scheme, seeking an order that Rafidain pay SerVaas the money necessary to satisfy the judgment it had obtained against the Iraqi Ministry of Industry.

On 30 November 2010, the Iraqi Ambassador to the UK signed a certificate confirming, among other things, that Iraq's admitted claims in the scheme of arrangement, as well as any assets or distributions received in respect of those scheme claims, had never been used, were not in use and were not intended for use by or on behalf of Iraq for any commercial purpose.

The decision

The Supreme Court unanimously found in favour of Rafidain. It confirmed that in order for the commercial purposes exception from immunity from enforcement to apply, the party seeking enforcement must establish that the relevant assets are currently "*in use or intended for use*" for a commercial transaction. It is insufficient for the assets merely to be connected with a commercial transaction. On an ordinary and natural reading of the phrase "in use for commercial purposes", it could not be said that a debt arising from a transaction was "in use" for that transaction. Parliament had intended an assessment of the use to which the State had chosen to put the property, not a retrospective analysis of all the circumstances which gave rise to the property. Accordingly, on the facts, the nature of the origin of the debts was not relevant to the question of whether the property in question was in use for commercial purposes. The Supreme Court noted that the certificate issued by the Iraqi Ambassador gave rise to a presumption that the relevant assets were not in use or intended for use for commercial purposes, which SerVaas was unable to rebut.

Practical implications

SerVaas is likely to make it more difficult for parties seeking to enforce against State assets located in the UK. The origin of those assets is now clearly irrelevant for the purposes of determining whether the commercial purposes exception applies. What matters is whether they are presently in use for commercial purposes or intended for such use. The fact that a State can raise a presumption that assets are not in use or intended for use for commercial purposes simply by issuing a certificate to that effect, as the Iraqi Ambassador did in *SerVaas*, gives States another line of defence when faced with enforcement action against their assets in the UK.

Lessons to be learned

In light of *Gécamines*, commercial parties contracting with State entities would be well advised, wherever possible, to try to structure their transaction with an entity with separate legal personality from the State that: (a) has sufficient assets in a suitable jurisdiction against which, in the event of a dispute, enforcement can be sought; and (b) confirms it is acting in a purely commercial, non-governmental capacity and gives an express waiver of State immunity.

Relying on the commercial purposes exception to immunity from enforcement always carried risks. After *SerVaas*, such reliance appears riskier still. Commercial parties have greater cause than ever to demand an express waiver of immunity from enforcement when dealing with State parties.

David Salcedo
London
T: +44 (0)20 7859 2347
E: david.salcedo@ashurst.com

3 [2012] UKSC 40.
4 Section 13(4) of the Act.

DECOMMISSIONING RELIEF DEEDS:

Driving down the cost of decommissioning

by Richard Palmer

The cost of decommissioning oil and gas installations and pipelines on the UK Continental Shelf ("**UKCS**") is a significant one. Estimates from the Department of Energy and Climate Change ("**DECC**") put the cost at around £33bn in today's prices for decommissioning the current installations that will go off-stream in the next two decades.

The Petroleum Act 1998 establishes a decommissioning regime which protects the taxpayer from bearing decommissioning costs. The Secretary of State can serve notices requiring recipients to submit a costed decommissioning programme for approval, which then gives rise to a decommissioning obligation. While the liability usually rests with current licensees, it can also extend to other parties, such as owners of the offshore installations, former licensees and their respective parent and associated companies.

Because decommissioning is an inherent cost of doing business on the UKCS, obtaining tax relief for such costs is critical in maximising return and a crucial factor in enabling participants to meet the overall cost of decommissioning. HM Revenue & Customs ("**HMRC**") indications suggest the gross cost of £33bn referred to above is in reality a net cost of only £13bn after tax. Tax relief for such costs is given at the point they are incurred and the decommissioning carried out. Relief is given not just against ring-fence corporation tax ("**RFCT**") and supplementary charge ("**SC**") but also against petroleum revenue tax ("**PRT**") where the expenditure relates to fields within the PRT regime. There are currently just over 100 fields within the PRT regime (those given development consent before 16 March 1993) but only a minority of these generate PRT receipts. The relief for decommissioning costs (which typically takes the form of a 100 per cent deduction for qualifying expenditure) is available at a rate of 30 per cent for RFCT, 20 per cent for SC and 50 per cent for PRT.

Decommissioning costs will generally produce losses both for RFCT/SC and PRT purposes. While those losses can be carried back indefinitely for PRT purposes, there are restrictions in relation to RFCT/SC. Originally, carry-back of losses for RFCT/SC was limited to three years, but following consultation with industry this was extended to allow losses to be carried back to 2002, with losses being offset against most recent profits first.

Security for decommissioning costs

Not only can the Secretary of State require security for decommissioning costs from notice recipients if there are risks to the taxpayer, but as a result of the joint and several liability of each of the parties to bear the decommissioning costs regardless of whether they have a continuing interest in the field, transfers of field interests inevitably require the incoming interest holder to provide acceptable financial security in respect of decommissioning liabilities.

It may also be a requirement under

the joint operating agreement that all co-venturers provide security. Security is typically provided through letters of credit and facility arrangements with third party financiers, the issue of bonds by a bank or institution with a certain minimum credit rating or contributions made by participants into a designated trust arrangement. Historically, security has been calculated and posted on a gross (i.e. pre-tax) basis, taking no account of the tax relief that the participant might obtain. Largely, that was due to the lack of certainty as to when and what tax relief would be available. The consequent additional cost in providing security meant that participants had less funds to invest in extraction. It was against this background that the UK Government and industry have worked over the last two years towards bringing down the cost of security. The objective is to provide certainty as to the tax relief available so that security can be required and posted on a net-of-tax basis. The outcome of such work should be greater investment in the UKCS by existing licensees and an increase in the potential number of new entrants. Both are needed by the UK Government as it seeks participants to extract the 20m barrels of oil equivalent that are estimated to remain in the UKCS.

The culmination of the work between Government and industry was a consultation document issued in July 2012, which has now been followed by a summary of responses and draft legislation contained in Finance Bill 2013, published on 11 December 2012. So, what exactly is the proposed approach?

The proposed approach

The method that the Government has chosen to deliver certainty of tax relief such that participants can adopt net (i.e. post-tax) securitisation arrangements is through a decommissioning relief deed ("**DRD**"). The DRD is intended to cover both the tax relief position when a participant incurs expenditure on its own decommissioning liabilities as well as in a "default scenario". This is where the participant is required to pay for another party's share of decommissioning, known as "imposition decommissioning expenditure".

How does the DRD work?

The basic principle is that the DRD sets a "reference amount", being a benchmark amount of tax relief for decommissioning expenditure against which the DRD holder compares whether or not it has actually achieved that amount of relief through the tax system. Where it has not, then a shortfall claim can be made under the DRD and a shortfall payment made by HM Treasury. That payment will not be a taxable receipt.

RFCT and SC

A distinction has to be drawn between a default and a non-default scenario. In the non-default scenario for RFCT and SC (subject to the restriction of SC to 20 per cent), where the DRD holder is meeting its own decommissioning liabilities then the reference amount will be calculated by applying the prevailing rate of RFCT (or SC, but capped at 20 per cent) to the expenditure. If the expenditure generates losses that are offset against previous profits (i.e. carry-back) then the reference amount will be calculated using the rate of RFCT at the time those profits were taxed. If the DRD holder has insufficient tax capacity because, for example, that has been reduced by taking on a defaulting party's decommissioning costs, then a shortfall payment can be claimed under the DRD. Although the relief is capped at 20 per cent for SC, in a movement from the original consultation position, the Government has indicated that it will adjust the reference amount where the combined RFCT and SC marginal rate is greater than 50 per cent so that the combined rate of relief is not less than 50 per cent.

In the default scenario, the reference amount is fixed at 30 per cent for RFCT and capped at 20 per cent for SC. Unlike the non-default scenario, the RFCT rate is fixed and is not calculated by reference to prevailing tax rates. If the actual amount of relief the DRD holder can access through the tax system is less than the reference amount, a claim under the DRD can be made.

There is a statutory definition of decommissioning expenditure which defines the categories of expenditure that qualify. It is helpfully wide and there is also an extension so that decommissioning expenditure on onshore infrastructure which is used for the purposes of offshore production will also qualify.

Anti-avoidance

In order to protect the Exchequer against potential "misuse" of the DRD system, amendments are proposed to the Capital Allowances Act 2001 which will restrict the available capital allowances applying to the decommissioning expenditure. These measures are aimed at artificially inflated claims and inappropriate claims under the DRD.

The first measure is to restrict allowances to the mere cost of providing a decommissioning service where the provider is a connected party. In limited circumstances (e.g. for planning or project management services) a cost-plus method can be used to determine expenditure. The maximum amount of the "plus" has yet to be set. This is an improvement on the proposals contained in the original consultation document which indicated that there would be no allowances at all for decommissioning costs paid to a third party. It is unfortunate that HMRC could not be persuaded simply to accept transfer pricing principles (i.e. arm's length pricing) as being the sole determinant of the quantum of allowable expenditure.

A targeted anti-avoidance rule operates to restrict allowances where the transaction has an avoidance purpose – i.e. one of the main purposes was to obtain a tax advantage that would not otherwise be obtained. Given that RFCT, SC and PRT will be covered by the General Anti-Abuse Rule that will be introduced in April 2013, it is disappointing that a targeted anti-avoidance rule is also necessary. The draft DRD published also contains an anti-abuse clause so as to prevent DRD holders from obtaining an enhanced entitlement under the DRD – broadly, including features in a transaction the main purpose of which is to secure a payment from the Government under the DRD. Further protection for the Exchequer comes in the form of a clawback mechanism in the event that a DRD holder recovers from third parties in respect of expenditure that has given rise to a shortfall payment.

The DRD:

- is a bilateral agreement between the Government and an individual company;
- covers all the company's assets;
- defines the type of expenditure on which tax relief can be claimed;
- establishes the amount of tax relief the company will receive in both default and non-default scenarios;
- allows the company to claim a shortfall payment if the level of tax relief is not achieved; and
- will be a standard document with exactly the same terms for every different counterparty.

PRT

For PRT purposes, guaranteeing tax relief and calculating the reference amount is more complicated because it is a field-based tax. As with RFCT, there will be a distinction between a default and a non-default scenario.

In the non-default scenario, the reference amount is linked to the DRD holder's own PRT history and how much PRT it has paid, which will be certified by HMRC. If the DRD holder has insufficient PRT capacity because it has incurred a defaulting party's decommissioning liabilities, then the PRT reference amount will be increased. This will enable it to obtain shortfall payments under the DRD in respect of subsequent non-default expenditure. Both the form of the certificate and the certification process itself remain to be finalised by the Government. Information provided by a DRD holder for the purposes of the DRD will be subject to a confidentiality obligation on the Government unless waived by the DRD holder.

In a default scenario, while the reference amount needs further refinement, the DRD holder will have the option of applying a reference amount based on its own (and its predecessors') field history or the PRT tax history of the defaulting party and its predecessor. That should deal with the issue raised in consultation that the defaulting party might have insufficient PRT history and itself would have been looking to access a prior owner's PRT history, for example because an interest in the field has changed hands a number of times.

As in a non-default scenario, the certification process for a field will be a key element in ensuring that the DRD works properly and that participants sign up to DRDs. Certificates will need to be issued regularly (possibly six-monthly or yearly) as there is the possibility that companies could be under-securitised if there are changes to the PRT history and certification after security has been calculated and posted. We would expect that contractual decommissioning security arrangements would provide for security to be recalculated and posted as certificates are issued. Further work on the certification process will be done during final consultation.

Further drafting will also be required to ensure that the availability of unrelieved field losses ("**UFLs**") correctly dovetails with how the DRD applies. In a default scenario, for example, once a payer has carried back losses against its own PRT history, any remaining losses will not generate a UFL. Such losses will push a payer into making a DRD claim.

The legislation will also cover the position if PRT is abolished (as many would hope, given the relatively small number of fields to which it applies). In those circumstances the reference amount is calculated as of the last period of account where PRT is in place.

Will the approach work?

Given the close working between Government and industry and the extensive consultation, there is every likelihood that the DRD approach will enable companies to agree to adopt post-tax security arrangements for the costs of decommissioning and for financiers to use post-tax estimates of decommissioning costs when assessing liabilities. Most participants engaged in the UKCS seem prepared to sign up to bilateral DRDs with Government. Problems will arise in PRT fields for those that do not sign up and therefore would not have a certified PRT field history. Our experience of more recent asset transfers in the UKCS is that the decommissioning security agreements entered into by outgoing and incoming interest holders now provide a contractual commitment to move to providing security on a post-tax basis when the DRDs come on-stream.

These decommissioning security agreements usually provide for the establishment of trusts and for actual cash to be put into the trust or make alternative provision in favour of the trustee (e.g. standby letters of credit, unconditional demand bonds) by the licence holder. Without more those trusts would be within the scope of the UK inheritance tax regime such that inheritance tax charges could apply when monies were paid out of the trust or on each ten-year anniversary. It is therefore helpful that the Government has acknowledged and drafted the legislation to confirm that UK inheritance tax will not apply and the property in the trusts will not constitute relevant property for the purposes of inheritance tax.

Taken as a whole, the draft legislation to introduce the DRDs, clarify the definition of decommissioning expenditure, remove inheritance tax and narrow the anti-avoidance provisions should deal with most of the issues raised by industry during the initial consultation phase and, as a consequence, the net cost of decommissioning should reduce. Security will, we believe, move to being provided on a net-of-tax basis. Continued engagement on the PRT reference amount, the certification process, the confidentiality waivers required from taxpayers to disclose a PRT history for a field and the relationship between the anti-avoidance provisions and the General Anti-Abuse Rule will take place in early 2013. We expect this to result in final draft legislation that is acceptable to industry and the participants who will become DRD holders. As a result, the policy objectives to increase investment in the UKCS and encourage more entrants should therefore be achieved.

Richard Palmer
London
T: +44 (0)20 7859 1289
E: richard.palmer@ashurst.com

INDONESIA:

Overview of the dissolution of BPMIGAS and its implications for the oil and gas industry

by Sean Prior and Daniel Reinbott

On 13 November 2012, the Constitutional Court of Indonesia ("**Court**") in effect declared BPMIGAS, the implementing body for upstream oil and gas activities, unconstitutional. The decision has attracted widespread publicity and speculation, as it has potentially wide-ranging implications for the oil and gas industry in Indonesia.

In this article, we:

- summarise the decision and its reasoning;
- summarise the resulting Presidential and Ministerial decrees issued in response to the decision; and
- highlight matters which, as a result of the decision and resulting decrees, require further detailed confirmation and consideration for oil and gas participants to better assess their Indonesian legal and strategic position.

Summary of Constitutional Court decision no. 36/PUU-X/2012

Application

The applicants sought a declaration from the Court that the following Articles of Law No. 22 of 2001 on Oil and Gas ("**Oil and Gas Law**") were inconsistent with Constitutional Law 1945 ("**Indonesian Constitution**") and therefore invalid:

Article 1(19), Article 3(b) and Article 6

Article 1(19) and Article 6 of the Oil and Gas Law contemplate that upstream oil and gas business activities are to be conducted through a co-operation contract which requires that: (i) ownership of the natural resources remains within the Indonesian Government until the delivery point; (ii) control of the operational management rests with BPMIGAS; and (iii) all the capital and risks under the co-operation contract are borne by the contractors.

Article 3(b) of the Oil and Gas Law contemplates that one of the objectives of the oil and gas business activities is to guarantee transparency and competition for downstream business activities.

Article 1(23), Article 4(3), Article 9, Article 10, Article 13, and Article 44

Article 1(23), Article 4(3) and Article 44 of the Oil and Gas Law contemplate the establishment of BPMIGAS as the implementing body for upstream oil and gas activities, whose roles and functions are to control and supervise the management of upstream oil and gas business activities under co-operation contracts.

Article 9, Article 10 and Article 13 contemplate that the execution of upstream oil and gas business activities shall be undertaken by Indonesian business entities and permanent establishments (offshore companies).

Article 11(2)

Article 11(2) of the Oil and Gas Law contemplates the requirement to report any signed co-operation contract to the House of Representatives.

In the alternative, the applicants sought a declaration that the Oil and Gas Law is inconsistent with the Indonesian Constitution and therefore that the entire law should have no binding legal effect.

Reasons for the application

The reasons given by the applicants as to why the existence of BPMIGAS, as the implementing body for upstream oil and gas business activities, would be inconsistent with the Indonesian Constitution were:

- Article 33(2) of the Indonesian Constitution contemplates that production sectors which are important for the country and affect the life of the people should be under the powers of the State. Article 33(3) of the Indonesian Constitution further contemplates that land, waters and natural resources within shall be under the control of the State and shall be used to the greatest benefit of the people. Article 33 represents the concept of "State control" over the natural resources within the Indonesian territory.
- Article 4(3) of the Oil and Gas Law, which contemplates that the Government, as the holder of the mining rights, establishes BPMIGAS, undermines the concept of "State control" under Article 33(2) and (3) of the Indonesian Constitution. The reason it does so is because not all the elements of the concept of State control are satisfied. BPMIGAS is only a State-owned legal entity (as opposed to a fully-functioning State-owned company), and it cannot directly engage in exploration and production activities. In addition, as BPMIGAS does not have a board of commissioners/supervisors, this could lead to its powers being exercised in an unlimited fashion.
- The fact that BPMIGAS is authorised to act for and on behalf of the State as the State party to co-operation contracts is inconsistent with Article 33(2) of the Indonesian Constitution. This structure results in the State being in a vulnerable position as the State could be subject to a dispute with the contractor party and if the State loses the case, this would be to the detriment of the benefit that the Indonesian people are intended to derive from natural resources. On that basis, it would be better if co-operation contracts were entered into by a State-owned company.

Set out below are the reasons for the other declarations sought by the applicants, which were ultimately rejected by the Court.

- As Article 28(2) of the Oil and Gas Law, which contemplated that the determination of fuel oil and natural gas prices are subject to reasonable market prices, has been declared as being null and void by the Constitutional Court in its earlier decision, Article 3(b) of the Oil and Gas Law, which contemplates that one of the objectives of the Oil and Gas Law is to ensure that the oil and gas downstream sector will be conducted through a fair, effective and transparent business competition mechanism, must also be declared null and void.
- Pursuant to Article 9 of the Oil and Gas Law, the downstream sector is open to not only State-owned companies, but also to private business entities. The application argued that if State-owned companies engage in the downstream sector, they have to compete domestically, which restricts them in practice and this could weaken the State's control over natural resources.
- The unbundling system adopted under the Oil and Gas Law is viewed as benefiting foreign investors rather than the Indonesian people.
- The co-operation contract is viewed as an international contract and therefore co-operation contracts must not only be acknowledged, but also be approved by the House of Representatives.

Decisions of the Court

The decision of the Court is summarised below:

- The Court partially accepted the applications and held that the following provisions pertaining to the establishment, roles and functions of BPMIGAS as the implementing body for upstream oil and gas business activities were not consistent with the Indonesian Constitution and therefore did not have any legally binding effect:
  - Article 1(23), Article 4(3), Article 41(2), Article 44, Article 45, Article 48(1), Article 59(a), Article 61, and Article 63;
  - the phrases "*with the Implementing Body*" under Article 11(1), "*through the Implementing Body*" under Article 20(3), "*pursuant to Implementing Body's consideration and*" under Article 21(1), and "*the Implementing Body and*" under Article 49 of the Oil and Gas Law;
  - all matters in relation to the implementing body under the elucidation[1] of the Oil and Gas Law.
- On the basis of the Court's decision above, the Court further decided that the functions and roles of the implementing body for upstream oil and gas business activities must be resumed and conducted by the Government of Indonesia, through the Ministry of Energy and Mineral Resources, until a "new law" is passed.
- The Court acknowledged in its considerations that, since the existence of BPMIGAS is inconsistent with the Indonesian Constitution and that BPMIGAS is to be considered as being dissolved as at the date of the Court's declaration, it is essential to confirm that all the co-operation contracts which have been signed between BPMIGAS and the contractors remain valid until they expire.

The Court refused all of the other declarations sought by the applicants.

Reasons for the decisions in relation to the dissolution of BPMIGAS

Below is a summary of the key reasons given by the Court in reaching its decision to declare BPMIGAS unconstitutional:

- The concept of "State control" under Article 33 of the Indonesian Constitution must be interpreted in a broad sense to cover organisational function (*bestuursdaad*), regulatory function (*regelendaad*), managerial function (*beheersdaad*), and supervisory function (*toezichthoudensdaad*) for the greatest benefit of the people. Out of these four functions, the managerial function is the most important under the "State control" concept, which means that the State must conduct direct management of natural resources.[2]
- The ultimate holder of the mining right (that is, the right to explore for and exploit natural resources) is the Government of Indonesia. Under the Oil and Gas Law, the Government, as the holder of the mining right, established BPMIGAS as a separate entity. As BPMIGAS is responsible for exercising part of the "State control" role over

1 The elucidation is the explanation of the law which is attached to the law itself when the law is issued.
2 The Court, however, did not further elaborate on how the State would be deemed as conducting direct management of natural resources, and therefore would be deemed as exercising the managerial function of the "State control" role.

oil and gas activities, BPMIGAS must engage directly in the management of oil and gas operations. However, since the functions of BPMIGAS are only limited to control and supervisory functions while the actual oil and gas operations are conducted by contractors, the Government cannot directly exercise its "State control" functions over the management of upstream oil and gas business activities through BPMIGAS. As a result, the concept of "State control" (that is, direct involvement of the State in the management of oil and gas operations) is not entirely reflected through BPMIGAS's functions.[3]

- The fact that BPMIGAS is the State party to the co-operation contract is viewed as restricting the implementation of the "State control" role, particularly the regulatory function, over oil and gas. The separation between the regulatory function and the managerial function could derogate from "State control" over oil and gas.
- The implementation of "State control" over oil and gas would be more effective and efficient without additional bureaucracy arising from the existence of BPMIGAS. The Government can exercise its managerial functions over oil and gas by granting rights and authority to one or more State-owned companies to manage the upstream oil and gas business activities.
- BPMIGAS's existence is viewed as being potentially "*corruptive and inefficient*".[4]

Presidential decree no. 95 of 2012

The Government reacted swiftly to the Court decision. Presidential decree no. 95 of 2012 on Transfer of Implementation of Duties and Functions of Upstream Oil and Gas Business Activities ("**Decree 95**") was issued to ensure the continuity of upstream oil and gas business activities following the dissolution of BPMIGAS by the Court's decision no. 36/PUU-X/2012.

The following is a summary of Decree 95:

- The duties and functions of BPMIGAS are transferred to the minister responsible for the oil and gas sector (i.e. the Minister of Energy and Mineral Resources ("**MEMR**")) until the issuance of a new law.
- All the co-operation contracts which have been signed between BPMIGAS and any business entity or permanent establishment remain valid until their respective terms expire.
- All the management processes of upstream oil and gas activities which are currently carried out by BPMIGAS are to be taken over by the MEMR.

Ministerial decrees no. 3135 of 2012 and no. 3136 of 2012

Following the issuance of Decree 95, the MEMR issued two further decrees on 13 November 2012.

First, decree no. 3135 K/08/MEM/2012 regarding Transfer of Duties, Functions and Organisation in the Implementation of Upstream Oil and Gas Business Activities ("**MEMR Decree 3135**") provides that the duties and functions of BPMIGAS, as the implementing body for upstream oil and gas activities, are transferred to the Temporary Upstream Oil and Gas Business Activities Implementation Unit ("**SKSPMIGAS**"). SKSPMIGAS is a special unit under the jurisdiction of, and responsible to, the MEMR.

MEMR Decree 3135 further provides that all of BPMIGAS's personnel are transferred to SKSPMIGAS. All matters relating to operational activities, including personnel, finance and assets of BPMIGAS, are assumed by SKSPMIGAS. The existing organisational structure of BPMIGAS is to be adopted by SKSPMIGAS.

Decree no. 3136 K/73/MEM/2012 ("**MEMR Decree No. 3136**") provides that the status and title of each of BPMIGAS's officers and staff shall remain the same, with the same salary, allowances and benefits, under the newly-established SKSPMIGAS. However, the position of head of BPMIGAS is no longer applicable (as the Minister of Energy and Mineral Resources is the head of the unit, to comply with the Court's decision).

Implications for the industry and future developments

Transfer of duties and functions of BPMIGAS to SKSPMIGAS

The message from the Government and the Ministry has been that it should be "business as usual" following the Constitutional Court's decision.

The speed at which Decree 95 was issued, as well as its broad and decisive statements, was received favourably by members of the industry, many of whom were anxious to see that there were no gaps created as a result of the Court's decision. While the Court's decision may have taken both the Government and BPMIGAS by surprise, comfort may be taken from the Government's emphatic response.

As mentioned above, the Temporary Upstream Oil and Gas Business Activities Implementation Unit, SKSPMIGAS, is a special unit under the authority of and responsible directly to the MEMR, and not the Directorate General of Oil & Gas ("**MIGAS**"). Previously, many key decisions relating to production sharing contracts ("**PSCs**") were, in any case, required to be approved by the Minister. There was also a degree of co-operation and consultation between BPMIGAS and MIGAS. Therefore in this regard there is, in practice, some consistency of approach under the new regime. The consolidation of management, supervisory and control functions under the MEMR has the potential to streamline the regulation and implementation of upstream business activities.

A temporary measure

The Court's decision and the decrees have made it clear that the transfer of BPMIGAS's roles and functions to the MEMR/SKSPMIGAS is a temporary measure, pending issuance of a new law/regulation.

The issuance of a new oil and gas law has been talked about in the industry for a number of years. It has always been appreciated that the passing of a new oil and gas law could be politically very challenging. The Court's decision could reduce the political sensitivity for a number of aspects of the new law, given that the role and functions of BPMIGAS were at the core of the initiatives being considered for the new law.

However, a difficult decision remains as to the identity of the final entity with whom BPMIGAS's previous roles and functions will rest. The Court's decision referred to an Indonesian entity or company, which has led to speculation that the roles and functions might be returned to Pertamina, the State-owned oil and gas company. There were also references in the Court's decision to "*one or more*" State-owned entities, which has led to further speculation.

The transfer of the former roles and functions of BPMIGAS to the MEMR can be viewed as being logical and potentially beneficial for a number of reasons. In particular, combining the managerial, supervisory and control functions, which were referred to in the Court's reasoning, under the one government body should reduce some administrative overlap and increase co-ordination between the different functions. As mentioned earlier, this arrangement may also create efficiencies in terms of obtaining certain approvals. Given the similarities between SKSPMIGAS and BPMIGAS, there may not be too many difficulties in understanding the roles of MIGAS, the MEMR and SKSPMIGAS under the new regime. This promotes the Government's "business as usual" approach.

However, the similarities between SKSPMIGAS and BPMIGAS have already resulted in some questions being raised as to how the new arrangements are different to the previous BPMIGAS arrangements. There have been reports that the applicants who initiated the recent Court decision are displeased with the new arrangements for this very reason and intend to test the validity of the decrees by approaching the Court again.

Validity of PSCs

Part of the Court's reasoning for the dissolution of BPMIGAS (that is, the concept of State control and the exploitation of natural resources for the benefit of the Indonesian people) may be viewed as casting a shadow on the future of PSCs in Indonesia, and this has been focused on by some commentators. However, the Court did conclude that co-operation contracts which have been signed between BPMIGAS and the business entity or permanent establishment remain valid until their term expires. This has been supported by the Presidential decree.

However, the issuance of future host co-operation contracts, as well as the nature of future fiscal arrangements in Indonesia, will remain under question until further guidance is issued by the MEMR, and ultimately pending enactment of the new oil and gas law. One point to note is that the Court did not declare that Article 11(2) (and a number of other provisions relating to co-operation contracts which were the subject of the application) of the Oil and Gas Law was unconstitutional, which is a positive sign for the future grant of PSCs in Indonesia. The objection of the Court appears to have been that BPMIGAS was the State party to PSCs, which meant that (in the Court's view) the State was unable to exercise its management role over PSCs. There have been some questions raised in relation to the Court's reasoning on this point.

In terms of the award of new blocks, because the tender process is run by MIGAS, there is unlikely to be significant change. However, the identity of the State party to future PSCs is not entirely clear. Given the Presidential decree and MEMR decrees, it is arguable that the State party will be SKSPMIGAS, although we anticipate that the MEMR and Government may play more of a role in the final execution process of future PSCs. We will need to await the MEMR's guidance on these points.

Validity of other agreements and of BPMIGAS policies and decisions

We understand that the general intention is for previous agreements entered into by BPMIGAS to continue to be valid, and for previous BPMIGAS policies and procedures to be applied by SKSPMIGAS.

However, the Court's decision does create some uncertainty in relation to these matters. Some comments have already been made within the industry that if BPMIGAS was held to be unconstitutional, then its decisions may also be invalid. Regardless of the objective of the Presidential decree, we consider that there are some key issues which have not been clearly addressed in both the Presidential decree and the two newly-issued MEMR decrees, such as:

- the status of existing approvals, decisions and policies of BPMIGAS, such as plans of development, seller's appointment arrangements and working guidelines (or PTKs); and
- in terms of decisions and decision-making authority, it is not clear if there will be clear delegation of authority from the Minister to officers of SKSPMIGAS, or if the decisions will be binding without regard to the potential new oil and gas law (that is, whether any decisions could be subject to review in the future).

We understand that to deal with these issues, there will be further clarification and confirmation in writing from the Government. We expect this will be issued shortly to provide legal certainty for the contractors and the other stakeholders in the oil and gas industry.

Concerns raised by foreign investors

One final aspect that warrants some mention, but which should not necessarily be overplayed, is the motivation behind the application which was made to the Court, and the potential impact on future investment. There does appear to have been a nationalistic motivation behind the application and the Court's seemingly broad and purposive interpretation of Article 33 of the Indonesian Constitution. Investors may feel that there might be pressure on the new regulator to adopt a regime which is more Indonesian-friendly (either on paper or in practice) given the nationalistic sentiment which seems to have led to this decision.

Sean Prior
Jakarta
T: +62 21 2996 9216
E: sean.prior@ashurst.com

Daniel Reinbott
Singapore
T: +65 6416 9529
E: daniel.reinbott@ashurst.com

3 The Court did not further elaborate whether the assignment of the managerial function from the Government to BPMIGAS is consistent with the Indonesian Constitution. For example, the fact that BPMIGAS, as the State party to the co-operation contract, is indeed involved in the management of the co-operation contract through its approvals of work programmes and budgets under co-operation contracts could be viewed as "direct management" of the Government over oil and gas.

4 The Court did not provide an explanation on how BPMIGAS's existence is viewed as being potentially "*corruptive and inefficient*".

STOP PRESS:

Ashurst opens new office in Jeddah

We are delighted to announce that we have expanded our Middle Eastern offering with the launch of an office in Jeddah by establishing an association with Saudi lawyer Faisal Adnan Baassiri. Our Saudi office will focus on energy, transport and infrastructure matters and offering corporate services in the region, especially in Jeddah. From offices in Abu Dhabi, Dubai and Jeddah, Ashurst resources and co-ordinates deals across the GCC countries as well as Jordan, Algeria, Egypt, Lebanon, Morocco, Tunisia, Yemen and beyond. We also advise regional clients on deals in Asia, Europe and Africa, working together with our strong network of international offices.

This association reflects the ongoing investment Ashurst is making in the region and adds to a number of significant instructions and high-profile recent successes in the energy and resources sector, including advising the preferred bidders on the Muharraq WWTP (Bahrain's first waste PPP) and the lenders to the successful consortium in relation to the Shuweihat 3 IWPP.

"The economy in Saudi Arabia is undergoing significant expansion, which is set to continue over the next few years. There are substantial business opportunities that fit well with our regional strategic focus on the energy, transport and infrastructure industries. Moreover, the market also provides extensive opportunities for general corporate, finance and other legal work. This is the first step for us in the Kingdom and we are confident that our offering will grow in breadth and depth.

The right people are key to any new venture. We are very fortunate to be able to establish a presence in Jeddah with such a highly respected practitioner. We have a longstanding relationship with Faisal and have every confidence that he is exactly the right person for us and that he will make a significant contribution to the success of our new venture."

Joss Dare, Head of Ashurst in the Middle East

Ashurst London energy and resources team is bolstered by partner relocation

We are delighted to announce that specialist energy and resources partner Martin Kudnig, previously based in our Melbourne office, will be relocating to London. Martin's relocation from Melbourne to London is an exciting prospect for Ashurst's energy and resources team. His expertise in the acquisition, disposal and development of mining and oil & gas assets, and in Africa-based projects, will provide considerable scope for our London team's expansion in these areas. Martin is a highly experienced and well regarded lawyer. His practice also includes infrastructure and resources/energy project development, the preparation and review of sale and purchase agreements, joint venture agreements, commodity sales agreements and construction contracts for major infrastructure and resources and energy projects.