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THE CREDIT CHOICE DILEMMA: navigating finance options

BY NICHOLAS MOORE, DERWIN JENKINSON AND CHRISTOPHER HARDINGHAM

Middle East power: nuclear reactions

BY MHAIRI MAIN GARCIA

A step too far: unauthorised development by joint venture operators

BY LUCAS WILK, PAUL WALKER AND SAM MENGLER

ALSO IN THIS ISSUE:

ashurst

An overview of this issue

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

If you are a regular reader, you may notice that we have given Energy**Source** a new look, as part of an overall brand "refresh". We hope you like it.

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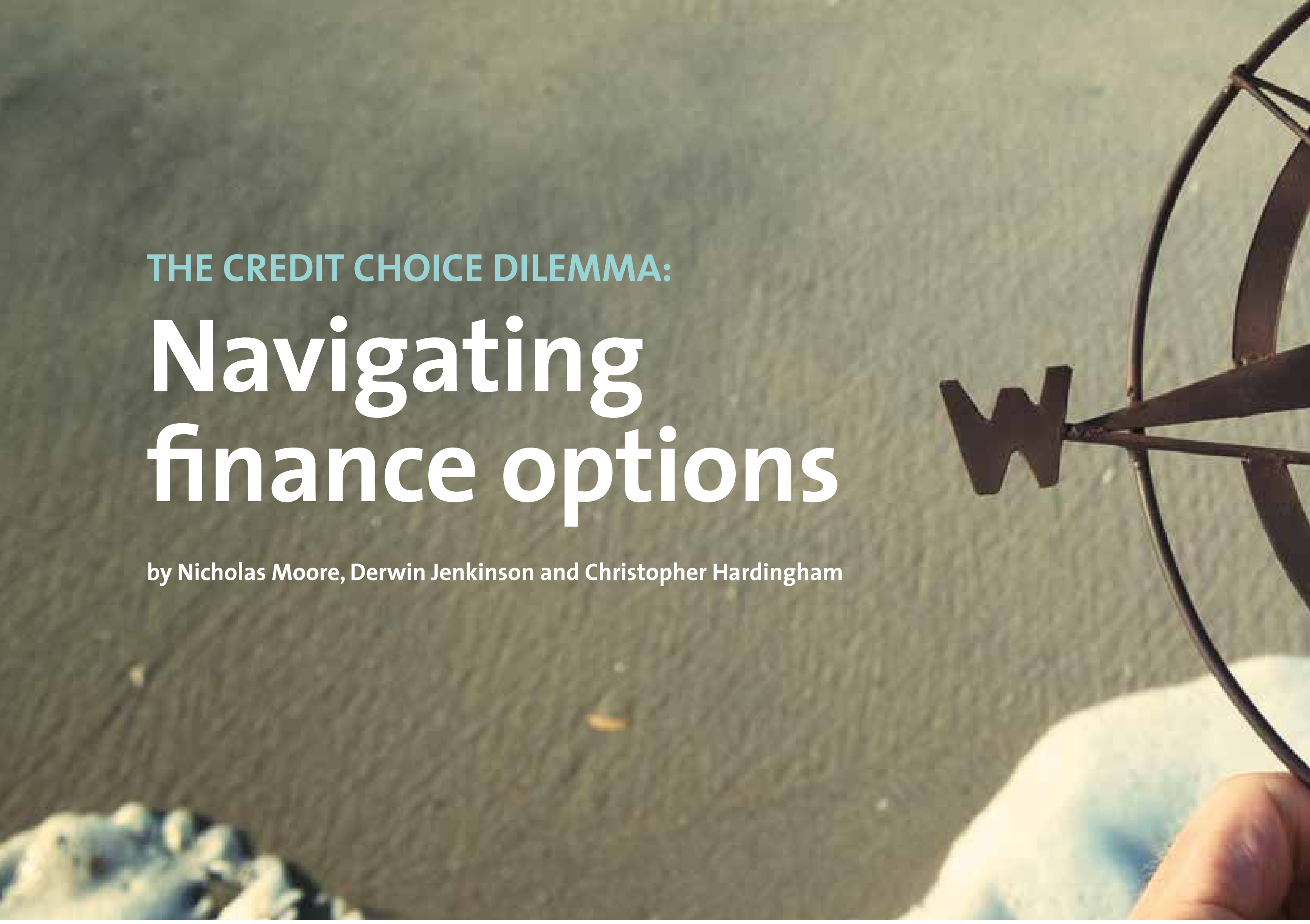
Contents

In this issue we look at:



THE CREDIT CHOICE DILEMMA:

Navigating finance options

by Nicholas Moore, Derwin Jenkinson and Christopher Hardingham

The corporate finance landscape has seen a fundamental shift in recent years. In the UK at least, we have emerged from the constrained credit environment of the credit crisis. Although the oil and gas sector has seen significant volatility in this past year, assessing the current picture, it is clear that treasurers and finance directors in large investment grade corporates in the energy and resources sector are still enjoying the benefits of a range of attractive financing options available to them. But given the possibility of choice, what are the key considerations for treasurers and finance directors when considering a company's financing strategy?

In this article, we consider the typical questions posed by investment grade corporates when faced with the dilemma of pursuing one or more financing strategies.

What has changed and the reasons for this

Current market conditions may well present a unique opportunity. There is undoubtedly a resurgence of bank lending, assisted by a rejuvenated collateralised loan obligations (CLO) market. At the same time, the low interest environment, as an overhang of the economic stimulus package, makes it attractive to lock in rates for longer-term financing. But most commentators predict that, at least in the UK, rates will only be heading in one direction – and that is up. Views vary on how quickly that is likely to happen, as they do for different countries, regions and sectors.

Corporate credit risk has also, more recently, become a factor in debt and equity market volatility, with continued low commodity prices and persistently low oil prices. Financing decisions have also been affected as a result; for example, as reported by the International Financing Review, international oilfield services firm Schlumberger decided to finance the majority of its US$14.8bn acquisition of Cameron International with stock instead of debt, citing volatility in the financial markets.

With the challenges of the last five years still not forgotten, corporates have begun to access alternative sources of capital. This is evident in the growth of Europe, the Middle East and Africa (EMEA) corporate bond issuances. In the past 18 months, however, there has also been a resurgence in loan market activity, primarily driven through refinancings, but also pre-IPO facilities and some significant M&A activity (for example, the proposed SABMiller/AB InBev transaction). DCM volatility (due to, among other things, the China slowdown, anticipated interest rate rises and a lack of bond market liquidity) has also been a factor in the recent uptick in loan market activity.

Diversification of funding brings with it

the benefit of unlocking bank credit lines. Although in the corporate loan markets we are now regularly seeing the pre-crisis "5+1+1" loan tenor structures re-emerging, regulatory capital changes and constrained balance sheets led to tenors of less than five years in the immediate aftermath of the crisis. So, corporates are using short- to medium-term bank facilities to provide more flexible financing for working capital, capex and other expansionary activity such as M&A, and have been turning to the bond markets for longer-term financing requirements (for example, the GDF Suez 20-year bond issued earlier this year, with a record low 1.5 per cent coupon). In fact, the tentative recovery of the M&A market has probably disguised the true extent of recovery of bank balance sheets and appetite for lending. Nevertheless, banks do, of course, continue to be the mainstay of corporate finance for many borrowers.

Key considerations when deciding on a debt solution

To some degree this has always been, and will continue to be, a question of pricing. But corporates are now not only driven by price but also by looking to diversify funding sources and managing refinancing risk by locking in longer tenors. At a recent corporate finance conference, all but one of the topics covered concerned alternative sources of debt, including retail bonds, US and European private placements, Schuldschein and securitisation. Until relatively recently, many corporates would not have been interested in, or seen any need for, such sources of capital.

Therefore, the key considerations are as follows:

Pricing

A number of factors will impact pricing. From a bank lending perspective, this will depend on:

- creditworthiness and sector;
- tenor (which will impact both loan and swap margins) and facility size; and
- lines of ancillary business (which can be used to reduce headline margin costs).

Loan pricing also remains driven by excess liquidity, a continuing demand and supply imbalance, and banks competing against each other to lend.

For a corporate bond, issuer pricing will primarily be determined by:

- credit rating and sector;
- secondary trading of market comparators;
- tenor and features;
- achieving a benchmark public offer issue size (typically viewed as £200m for wholesale bonds) and, conversely, any illiquidity and/or first issue premium;
- in some cases, the depth of sector-specific private placement markets; and
- general market conditions/ macroeconomic events.

Diversification of funding and managing refinancing risk

Companies with significant or variable working capital or capex requirements will usually turn to the loan markets to cater for these needs. The flexibility (and savings) afforded under a flexible draw revolving facility cannot be matched in the bond markets. Typically, loan facilities will have short- to medium-term maturities. However, the capital markets in many jurisdictions allow much longer-dated debt tenors which are most commonly issued at a fixed rate of interest (with no hedging required). For obvious reasons, a combination of flexible bank debt alongside long-dated bond financing is attractive. Not least, it reduces the level of refinancing risk to which a company is exposed on a three-to-five-year cycle under traditional bank facilities.

Although larger investment grade corporates have operated on the basis of a capital structure comprising both bank and bond financing for many years, it has not always been a viable solution for all. With the advent of smaller issue sizes and alternative bond products (for example, retail bonds or private placements), capital markets have become more accessible to a wider range of companies. The proposed withholding tax exemption on private placements is an example of a government initiative aimed at unlocking *"new finance for businesses and infrastructure projects"* (Autumn Statement 2014). In the leveraged market, the increased diversification of funding sources has been demonstrated by, for example, the use of super-senior revolving credit facilities alongside a high yield bond issue, or unitranche structures involving direct fund lenders.

Credit terms

Commentary on market standard financing terms is necessarily incomplete without taking into account company, sector and creditworthiness analysis of the relevant borrower. However, in our experience, it is rarely the case that the credit terms alone will drive a financing decision for investment grade corporates. In general, the terms and conditions of a bond tend to provide a less restrictive covenant and event of default package than an equivalent loan. Conversely, it is more difficult (by virtue of the disparate holders and the mechanics of the voting arrangements) to obtain an amendment, waiver or consent in relation to a bond modification, breach or default.

Further down the credit spectrum, the emerging popularity of high yield bond issuance has been an important development. While the scope of credit terms is very similar to those that feature in a leveraged loan (albeit, very differently drafted), the key distinction is that high yield bonds feature incurrence rather than maintenance covenants – in other words, event-driven rather than ongoing performance-based tests.

Other financing products to consider

Although often dependent on the sector in which the corporate operates and/or the credit profile, there are many forms of finance to consider (which may, in some cases, have their origins in traditional bank and bond financing). For example:

- trade receivables financing;
- borrowing base facilities;
- reserve-based lending;
- lease financings;
- (pre-)export credit finance;
- wholesale versus retail bond issues (e.g. issues listed on the London Stock Exchange's Order Book for Retail Bonds);
- private placements (including US private placements) which can be issued with much smaller principal amounts compared with public bond offers;
- convertibles (with a right to convert debt securities into equity) and hybrids (e.g. perpetuals);
- high yield bonds for non-investment grade issuers;
- securitisations or other non-recourse financings of eligible assets; and
- equity capital markets.

Practicalities in raising more than one type of finance

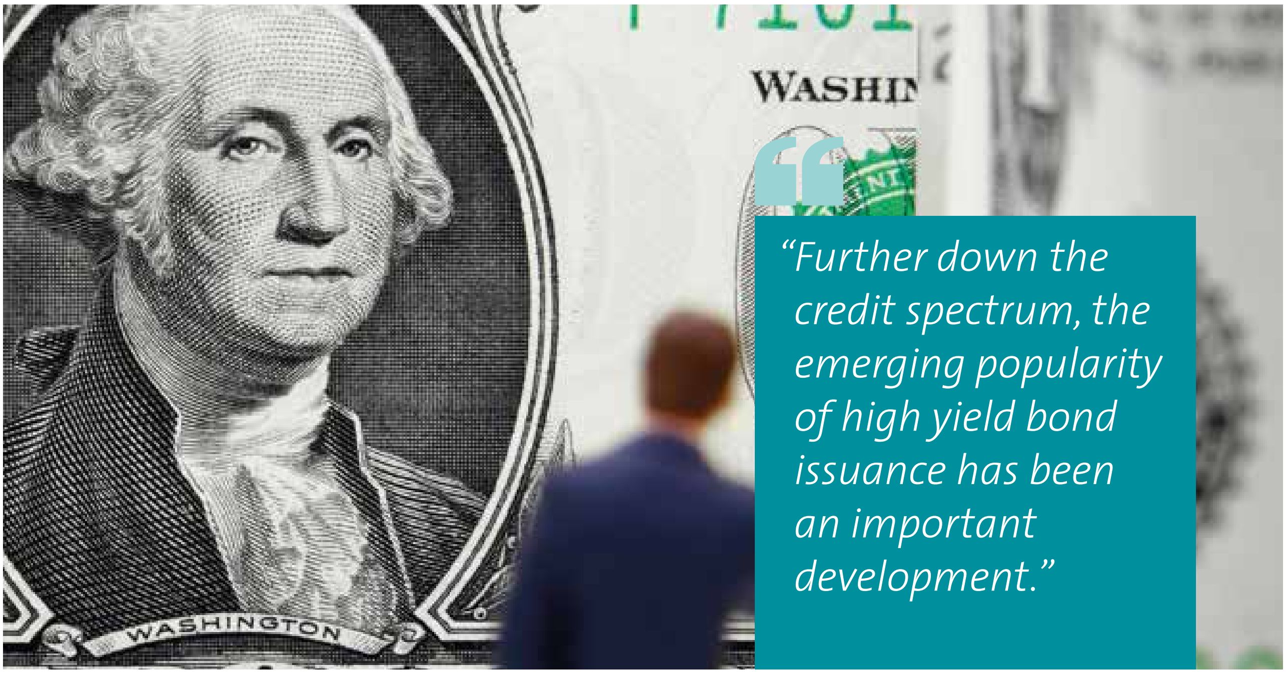
As mentioned above, most investment grade corporates have indebtedness outstanding under both debt securities and banking facilities. For investment grade corporates, the respective classes of debt may have very little (if any) interaction between them. Creditors may only become aware of multiple tranches of debt if at any point the borrower suffers financial difficulties. The ability to raise alternative tranches of debt may depend on "Permitted Financial Indebtedness" definitions or negative pledge restrictions. Most investment grade facilities and bonds do not restrict other forms of unsecured indebtedness (although there may be restrictions on the entity which can issue such other debt). However, an investment grade bank facility will normally restrict secured indebtedness (subject to agreed exceptions and baskets). By contrast, the negative pledge in unsecured bonds often only restricts the issuance of secured bonds (as opposed to other secured borrowings) in order to protect against secured/unsecured bond pricing differentials in the secondary bond market. Security and intercreditor arrangements are more likely features for companies that are further down the credit spectrum or that are seeking credit or rating enhancements. A capital structure comprising multiple secured debt layers will inevitably require intercreditor arrangements to be put in place. If, as is the case with small- and mid-sized independent companies acquiring assets being divested by larger companies, there is no strong parent company standing behind the borrower, the lenders will place much more emphasis on security and cross-guarantee structures.

Companies will usually seek to align their covenant and default packages between the respective classes of debt. However, full alignment might not be achievable or in some cases desirable (for example, the documentation for a particular product may be tied to a market standard precedent which may not translate well into other debt products). In such cases, a company must analyse each set of credit terms in order to determine whether an event or activity is prohibited, and consent from one or more affected creditor groups is required.

Timetable and cost implications

A capital markets transaction is generally more expensive at the outset and time-consuming. The minimum time period for an inaugural capital markets transaction for an investment grade corporate is six to eight weeks (although in some cases it will be longer). Most of the additional time will relate to preparing a Prospectus (or other offering document) for the purpose of obtaining a stock exchange listing of the bonds, including the related due diligence of the group as well as the management time required to "roadshow" the bonds. A bank financing can generally be completed in a shorter time-frame.

However, a number of factors mitigate the time and costs involved in a capital markets transaction:



> *"Further down the credit spectrum, the emerging popularity of high yield bond issuance has been an important development."*

- the transaction costs effectively can be amortised over the longer-dated life of the debt; and
- the establishment of a bond programme will, for subsequent issues, considerably reduce the time period, cost and process of coming to market.

When assessing the correct financing option, the purpose for which the financing is being put in place will often be the deciding factor. The costs, timing and pricing certainty that the bank market affords for event-driven financings cannot be matched by the bond markets. Mechanics, such as "certainty of funds", which can (depending on the nature of the underlying transaction) be made available through the loan markets, will often drive the borrower towards the loan product in an acquisition scenario. However, increasingly many bank financings (and acquisition facilities in particular) are used effectively to bridge a bond refinancing take-out or disposals programme.

Effects of "typical" covenant structures

Set out on pages 8 and 9 is an indicative range of covenants for respective debt classes. Obviously, the covenants will be negotiated for those appropriate to the borrower, its creditworthiness, as well as its business and sector. The borrower may also have existing financing arrangements in place which will influence the covenants included.

Negotiating flexibility in today's market

Most market participants in investment grade financings agree that it is currently more of a borrower's market. Banks are actively lending and in the capital markets institutional investors are chasing yield. This, coupled with a relative lack of M&A activity, has led to fierce rivalry among financiers to provide competitive pricing, terms and tenors. Other factors, such as renewed CLO activity (allowing quicker recycling of bank balance sheets), more frequent high yield issuance windows and increased European focus of US private placement investors has a significant influence on this dynamic. For corporates lower down the credit spectrum, particularly those operating in more problematic sectors, the ability to achieve favourable terms is less certain. Indeed, the markets for some forms of lending (for example, reserve-based lending) has contracted considerably given current market conditions.

Risks of pricing/costs changing

Other than in underwritten deals, where market flex terms may need to be negotiated for the purposes of syndication, banks are willing to price and hold margin before financial close. The all-in interest rate cost in the loan markets does not tend to be fixed, however, as the banks usually lend on floating rate terms. Even so, bank financing still offers more upfront pricing certainty than an equivalent capital markets transaction. That is because a public bond issue is more sensitive to short-term market movements at the time of pricing (both gilts/treasuries and basis points).

In evaluating the pros and cons of raising fixed versus floating rate debt, the true cost is not always apparent at the time of the original financing. Swap mark-to-markets have left many borrowers out of the money in recent years when paying break costs. That compares to buy-back or make-whole/Spens costs on early redemption of corporate bonds (although such "prepayments" are reasonably infrequent). Although the bank market offers upfront pricing certainty, the level and complexity of bank regulation (Basel III/CRD IV/Dodd–Frank, for example) potentially leaves borrowers exposed to increased costs over the life of the transaction which are difficult to quantify. Issuers in the capital markets do not face the same uncertainty of regulatory capital costs, which is attractive to some corporates.

Investment Grade credit

Loans	Bonds
Credit support ***Security:*** none. ***Guarantees:*** position varies but can include parent only, material companies and/or guarantor coverage test.	**Credit support** As for loans.
Mandatory prepayment events Illegality and change of control. If event-driven, position varies, but equity proceeds, other debt and DCM issue proceeds and/or disposal proceeds are common.	**Early redemption events** Issuer call option for withholding tax reasons at par. Other redemption events may include a change of control put option (generally accompanied by a rating downgrade requirement) or an issuer call option at any time at make-whole or premium (such as 101 per cent). An issuer call option at par at any time during the three-month period prior to maturity (which allows more flexibility when refinancing) is becoming increasingly common.
Representations Package varies, but typically includes status, binding obligations, no conflict, power, validity, governing law, *pari passu*, tax, no default, no filing or stamp taxes, no misleading information, financial information, MAC, litigation, sanctions.	**Representations** Similar to loans but extended in favour of Arrangers/Lead Managers only rather than Bondholders. In addition, securities laws and Prospectus-specific representations.
Covenants ***Financing reporting:*** tends to be annual and semi-annual only. ***Financial covenants:*** (if any) tend to be limited, with semi-annual testing on maintenance basis. ***General undertakings:*** package varies, but typically includes authorisations, compliance with laws, negative pledge, disposals, subsidiary indebtedness, merger, change of business, sanctions. Depending on credit strength or deal specifics, restrictions on acquisitions may be included.	**Covenants** ***Financial covenants:*** rarely seen in investment grade corporate bonds, although may be included in structured corporate bonds for certain sectors (e.g. infrastructure). ***Other covenants:*** status (or *pari passu*) and negative pledge. Negative pledges in investment grade corporate bonds generally only restrict the granting of security for similar types of debt (i.e. bonds, notes and other tradeable capital markets instruments). Negative pledges that restrict the granting of security for any indebtedness (so-called "all moneys" negative pledges) are rare. If there is a trustee, the trust deed will contain additional covenants by the issuer/guarantor to enable the trustee to perform its functions (provision of financial statements and other information sent to shareholders, maintenance of listing, provision of compliance certificates, access to books of account, etc.).
Events of Default Typical package includes non-payment, breach of financial covenant and other obligations, misrepresentation, cross-default (or cross-acceleration if strong credit), insolvency, creditors' process, unlawfulness and repudiation, ownership of obligors, MAC.	**Events of Default** As for loans, except cross-acceleration/payment default is more common than cross-default, MAC generally not included, and there is no misrepresentation default.

Reporting and information covenant requirements

A significant difference between a capital markets transaction and a bank facility is the public-versus-private nature of those financings. The contractual information covenants in a bank facility may be more extensive and may require information to be provided on a more frequent basis than the equivalent provisions in a bond. However, dissemination of information to the public is regulated by legislation in the capital markets. This requires timely publication, not only of ongoing periodic information but also market announcements of any non-public price-sensitive information which could have a significant effect on the price of the bonds. For many first-time issuers, this represents a significant change in a company's culture regarding information management and public disclosure.

Parties to be mandated

For a bank facility, this will usually comprise the arranging bank(s), facility agent, security agent (if security is being provided), lending banks and, if hedging is contemplated, swap counterparties. For certain multi-bank transactions, bookrunners and/or underwriters may also need to be appointed. Unless the facility is self-arranged by the borrower, typically one of the syndicate banks will also be appointed to co-ordinate the process (including documentation). For a capital markets transaction, there are usually more third parties involved, including one or more banks as bookrunners/underwriters, a trustee, paying agent(s), the rating agencies and perhaps also a ratings adviser.

Management time involved

As with any financing, a significant degree of management time will be involved. For a bank financing, this will be primarily the chief financial officer and group treasurer and, of course, board- and potentially shareholder-level approvals. Preparing a bond Prospectus typically involves a much wider level of participation from the business. This is because the Prospectus must summarise, among other things, all aspects of the business which are relevant to investors. However, if the bank facility transaction is to be syndicated to lenders outside the borrower's core group of relationship banks, an information memorandum will typically need to be prepared and a "roadshow" process may be required, which will involve more parts of the business. In both cases, senior management will also be expected to participate in the due diligence process.

Provision of financial statements

Any financing will include representation coverage on the preparation and accuracy of financial statements. Whereas the obligation to provide financial statements in a bank facility will be contained in the information undertakings section in the facility document (the frequency of provision of which will vary according to the credit), the obligation for a bond issuer will be driven by market standards, US rules and any relevant listing requirements. In the EU, for example, a bond issuer (or guarantor) must include within its Prospectus two years of audited financial statements in order to obtain a regulated market listing (unless an exemption applies). If consolidated financial statements are prepared, they must be in accordance with International Financial Reporting Standards

Non-Investment Grade/Crossover credit

Loans	Bonds
Credit support ***Security:*** share security and/or full asset security, depending on jurisdiction. ***Guarantees:*** comprehensive guarantor coverage test, depending on jurisdiction.	**Credit support** As for loans.
Mandatory prepayment events As per Investment Grade plus, depending on credit and facility purpose, disposal proceeds, insurance proceeds, acquisition proceeds, excess cashflow.	**Early redemption events** As for investment grade credit. For high yield bonds, issuer call provisions often include: a prohibition on optional redemption by the issuer for an initial period (typically four or five years) unless a substantial redemption premium is paid (thereafter, the premium declines on a sliding scale); change of control put at a premium; a right for the issuer to offer to repurchase a proportion (typically 35–40 per cent) of the bonds (typically at a premium) out of the proceeds of a public equity offering of the issuer's or its parent's shares; and an obligation to offer to repurchase the bonds if the group sells assets and does not reinvest the proceeds in the business or use the proceeds to pay down senior debt within a specified period.
Representations As per Investment Grade plus, depending on credit and facility purpose, among others, solvency, environmental laws, anti-corruption, security and financial indebtedness, title to assets, IP, group structure, COMI, pensions.	**Representations** Similar to loans but, as for investment grade, will not be extended to bondholders.
Covenants ***Financing reporting:*** comprehensive reporting: annual, quarterly and monthly financial statements, budget, auditor sign-off on annual compliance certificates. ***Financial covenants:*** comprehensive financial covenants with quarterly testing on maintenance basis. Where loan sits alongside a high yield bond, incurrence-based covenants are increasingly seen. ***General undertakings:*** as per Investment Grade plus, depending on credit and facility purpose, among others, environmental, anti-corruption, tax, JVs, *pari passu*, loans-out or credit, guarantees, distributions/share issues, insurance, pensions, IP, arm's length terms, hedging, guarantors.	**Covenants** Status and negative pledge, commonly "all moneys" rather than capital markets indebtedness only. For high yield bonds and (to a lesser extent) crossover credits, the covenant package will often be complex, although on the whole less restrictive than covenants contained in senior loan facilities. Unlike loans, financial and other covenants will be "incurrence"-based rather than "maintenance" tested. The package will depend on the strength of the credit but typical examples include limitation on incurring indebtedness which would breach fixed charge coverage or leverage ratios (although ordinary course or refinancing generally permitted); limitation on dividends, distributions and other "restricted" payments; limitation on liens; limitation on transactions with affiliates; merger, consolidation or sale of assets; and limitation on disposals. Reporting covenants will be limited to public information including quarterly, semi-annual and annual reporting (e.g. no budgets).
Events of Default As per Investment Grade plus, depending on credit and facility purpose, among others, audit qualification, expropriation, litigation, pensions.	**Events of Default** As for loans, except cross-acceleration/payment default is more common than cross-default, MAC generally not included, and there is no misrepresentation default.

or an equivalent accounting standard. For transactions marketed to qualified institutional investors in the US, at least three years of financial statements are required and there are requirements regarding how recent financial statements must be to avoid the financial information being "stale".

Tax basics relevant to the various forms of financing

Under UK tax law, a borrower incorporated in the UK is generally required to withhold on payments of interest unless an exemption applies. In relation to a bank financing, the relevant exemptions typically include payments to a UK bank or Treaty Lender (provided, in the latter case, the appropriate treaty directions from the relevant tax authorities have been obtained in advance). A bond issuer will usually rely upon the quoted Eurobond exemption. This provides that interest payments on securities listed on a recognised stock exchange may be paid free of withholding. There is often a gross-up clause included in the terms and conditions to protect certain classes of lenders from any change of law risk (although, typically, this would be accompanied by a right for the issuer to be able to call the bonds at par in such circumstances). In relation to more structured corporate transactions, the level of tax analysis and structuring involved can be more complex (e.g. thin capitalisation rules, transfer pricing, group tax arrangements and securitisation SPV tax treatment).

Conclusion

As this article illustrates, investment grade corporates now have an enviable range of financing products to choose from. But having learned the lessons of the financial crisis, that choice is now being made more carefully. The drive to more diverse and alternative sources of finance is reflective of more sophisticated corporate treasury policies. As for any multiplicity of options, this creates a dilemma. Picking the optimal product(s) and financing window will be the new challenge for treasurers who, until recently, were grappling with very different problems.

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MIDDLE EAST POWER:

Nuclear reactions

by Mhairi Main Garcia

As an alternative source of energy to conventional sources, such as oil and gas, nuclear energy provides continuous, reliable base-load power, with low carbon emissions. Worldwide, there are currently over 435 commercial nuclear power reactors operating in 31 countries, producing more than ten per cent of the world's electricity.[1]

The trend towards nuclear is now being seen in the Middle East, with a number of states developing nuclear energy capabilities or considering the possibility of nuclear power generation. This article considers the nuclear state of play in the region, with a focus on the status of implementation of the relevant international conventions relating to nuclear power.

1 See the article "Nuclear Power in the World Today", updated February 2015, world-nuclear.org.

Background

The Middle East states and in particular the Gulf Cooperation Council (GCC) states have witnessed rapid economic development and population growth, resulting in increased power needs across the region. With the exception of Qatar, the hydrocarbon-producing GCC states all suffer a shortage of sweet natural gas, the main feedstock for conventional power plants in the region. In particular, Saudi Arabia and the United Arab Emirates (UAE) are grappling with a shortage of available natural gas in selecting the feedstock for their power plants. Non-hydrocarbon-producing states, such as Jordan, are heavily dependent on fuel imports as feedstock.

A number of countries in the region (including Jordan, Kuwait, Oman, Saudi Arabia and the UAE) are seeking to develop alternative energy sources to help satisfy their power demands. While some states are successfully developing their nascent renewable energy sectors, particularly in the field of solar energy, nuclear energy is seen as a viable economic alternative to provide energy security, promote energy diversification and feed the region's spiralling power demands. The International Atomic Energy Agency (IAEA) predicts that nuclear generation installed capacity in the Middle East will grow to between 8.6–13.4 GWe (gigawatt electrical) by 2030.[2] The World Nuclear Association has recently reported that of the 45 countries where nuclear power is under serious consideration, 14 are in the Middle East and North Africa. The UAE is leading the way with four commercial power reactors currently under construction, the first of which is scheduled for commissioning in 2017.

2 Source: IAEA, GOV/INF/2014/13-GC(58)/INF/6, 4 August 2014.

Nonetheless, nuclear power does have its drawbacks. The potential for environmental disaster is real. In the wake of the Fukushima disaster, Kuwait cancelled its proposed nuclear programme, opting instead for conventional and renewable power sources.

Another concern of the international community about the use of nuclear power in the Middle East is the threat of a proliferation of nuclear weapons in a region saddled with conflicts and instability. The focus when nuclear energy is discussed, whether it is in the context of peaceful use or otherwise, inevitably veers towards Iran. This article will not assess the case of Iran; instead, it will concentrate on the liability conventions and, in particular, the status of regulation and liability in the UAE, Saudi Arabia and Jordan – three countries committed to developing the peaceful use of nuclear energy and nuclear power generation capacity. This article does not attempt to discuss the pros and cons of nuclear power from a safety, environmental, political or cost perspective; it is limited to reviewing the applicable liability and regulatory regimes that are being, or have been, established in the UAE, Saudi Arabia and Jordan.

The system of international conventions recognises that nuclear incidents have wide-ranging repercussions and there is a need for a harmonised liability system. In order to secure the necessary technical know-how and fuel required for nuclear power generation, states must sign up to the comprehensive liability and safety conventions related to nuclear energy. Middle East states are gradually catching up with other nuclear actors and are signing up to the international nuclear energy legal and regulatory regime. The practices of the UAE, Saudi Arabia and Jordan will be considered in this context. These countries have also signed up to a number of safety-related conventions as well as several bilateral co-operation agreements with nuclear-producing states which have know-how, access to fuel and spent fuel facilities.

"A number of countries in the region (including Jordan, Kuwait, Oman, Saudi Arabia and the UAE) are seeking to develop alternative energy sources to help satisfy their power demands."

The international liability regime

The Vienna Convention on Civil Liability for Nuclear Damage 1963 (the Vienna Convention), as amended by the Protocol to amend the Vienna Convention (the Protocol), sets out minimum standards to provide financial protection against damage resulting from certain peaceful uses of nuclear energy. It applies to nuclear damage arising out of nuclear incidents occurring at nuclear installations (land-based reactors, factories for the production or processing of nuclear material, facilities where nuclear material is stored), or in the course of transport of nuclear material (nuclear fuel (excluding natural and depleted uranium) and radioactive products or waste) to, or from, such installations.

A fundamental principle of the Vienna Convention is exclusive liability of the operator of a nuclear installation to the exclusion of any other person. This liability is strict and does not require an injured party to prove fault or negligence on the part of the operator. Liability may only be excluded when the nuclear incident is directly a result of an act of armed conflict, hostilities, civil war or insurrection.

Under the Vienna Convention, as amended by the Protocol, the minimum liability is set at 300m Special Drawing Rights (SDRs, as defined by the International Monetary Fund), equivalent to approximately US$420m. Operators must cover potential liability through insurance or other financial security. Any claims for compensation for loss of life and personal injury must be brought within 30 years (this was previously set at ten years) from the date of the nuclear accident.

The Vienna Convention is one of two major conventions setting out requirements relating to liability arising from the peaceful use of nuclear energy. The other major convention is the Paris Convention on Third Party Liability in the Field of Nuclear Energy, an OECD convention, which sets out similar terms to those of the Vienna Convention. The Contracting Parties to the Paris Convention are not parties to the Vienna Convention and vice versa; however, the Joint Protocol Relating to the Application of the Vienna Convention and of the Paris Convention (the Joint Protocol) provides for a mutual extension of the benefits of the special regime of civil liability for nuclear damage set forth under each Convention.

In addition to the Vienna Convention, the Convention on Supplementary Compensation for Nuclear Damage (CSC) applies in relation to nuclear damage arising out of nuclear incidents occurring both at nuclear installations and in the course of transport of nuclear material to and from such installations. The CSC aims to increase the amount of compensation available in the event of a nuclear accident through public funds to be made available by the Contracting Parties on the basis of their installed nuclear capacity and UN rate of assessment. The CSC similarly provides for exclusive and strict liability of the operator. The CSC came into force in April 2015 after Japan deposited its instrument of acceptance, at which point the conditions for entry into force of the CSC, being the ratification of the CSC by at least five signature states with a minimum of 400,000 units of installed nuclear capacity, were satisfied.

The UAE and Saudi Arabia

Nuclear power offers an alternative energy source which can be used by the UAE and Saudi Arabia, both hydrocarbon rich countries, to reduce their dependence on, and consumption of, finite oil and gas resources, and to make these resources available for the lucrative export market.

United Arab Emirates

The UAE is the most advanced country in the Middle East in the development of its nuclear programme. It is now a party to several conventions and bilateral agreements and is successfully implementing an ambitious nuclear power programme.

The UAE became a party to the Protocol in 2012 and, by virtue of this, is a party to the Vienna Convention. Under the Vienna Convention, if a dispute concerning the Vienna Convention cannot be settled by negotiation, the Contracting Parties may submit the dispute to arbitration or refer it to the International Court of Justice. The UAE's accession to the Protocol is subject to a reservation disapplying this provision (Article XX A.2); it expressly does not consider itself bound by this provision.

Furthermore, the UAE is a party to the Joint Protocol and, in July 2014, the UAE ratified the CSC, the only Middle East state to become a party to the CSC. The UAE's ratification of the CSC is subject to the same reservation which applies in relation to the Vienna Convention regarding dispute resolution.

The UAE transposed the Vienna Convention into domestic legislation by way of a federal ratification decree, Federal Decree No. 32 of 2012, issued on 8 April

2012, on the Ratification of the Protocol to Amend the Vienna Convention on Civil Liability for Nuclear Damage (the Civil Liability Law). The Civil Liability Law closely follows the Vienna Convention and therefore enshrines in UAE law the key concept of absolute operator liability for nuclear damage, subject to the Vienna Convention's very limited exceptions. Under article 4 of the Civil Liability Law, the operator[3] of a nuclear facility has the sole responsibility for any nuclear damage caused by a nuclear accident. The person suffering the damage does not need to prove negligence or fault on the part of the operator to claim against the damage suffered. The definition of "nuclear damage" matches paragraph 1(k) of the Vienna Convention, as amended by the Protocol, and includes death and personal injury, loss of or damage to property, economic loss, cost of restoring the impaired environment and loss of income from an economic interest arising from using or enjoying the environment. The UAE has set the limit of the operator's liability for nuclear damage at 450m SDRs, which is 50 per cent higher than the minimum set by the Vienna Convention, as amended by the Protocol.

In addition, the UAE has signed up to a number of the regulatory and safety standards set by the IAEA. Federal Decree Law No. 6 of 2009 on the Peaceful Use of Nuclear Energy (the Regulatory Law) prescribes the nuclear regulatory regime (establishing the Federal Authority for Nuclear Regulation (FANR) and the requirements for licensees and operators). The Regulatory Law provides that the operator is responsible for all matters related to safety, nuclear safety, nuclear security and radiation protection and is solely responsible for compensating any damages that may affect individuals or properties as a result of any negligence made thereby in operating the nuclear facility, or not following the safety and nuclear safety requirements, according to the international treaties and agreements and the legislation of the state.

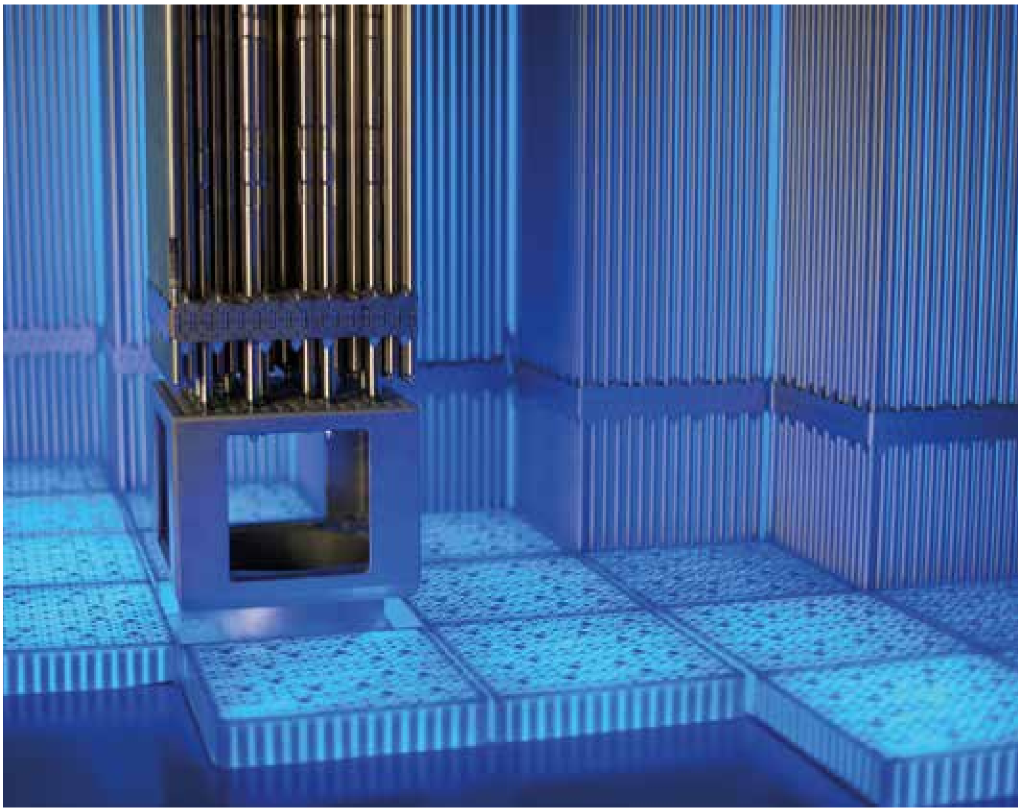
FANR determines all matters relating to the control and supervision of the nuclear sector in the UAE, in particular nuclear safety and security, radiation protection and safeguards. All obligations under the relevant international treaties, conventions and agreements entered into by the UAE are carried out by FANR. The Regulatory Law prohibits the development, construction or operation of uranium enrichment or spent fuel reprocessing facilities within the UAE. There are, additionally, a number of regulatory guides in relation to nuclear-related activities in the UAE, which can be found on FANR's website at fanr.gov.ae.

In 2009, the UAE established by decree the Emirates Nuclear Energy Corporation (ENEC) to evaluate and implement nuclear power plants within the UAE. Among its responsibilities, ENEC is responsible for overseeing the design, construction and operation phases of nuclear power projects and working closely with the Abu Dhabi and federal governments to ensure that the civil nuclear power programme is aligned with the industrial infrastructure plans of the UAE. Upon its establishment, ENEC appointed a consortium led by the Korea Electric Power Corporation to construct four nuclear plants in Abu Dhabi, totalling 5.6 GW. All four plants are now under construction, with the first due to be commissioned in 2017. The other three plants are scheduled to be completed and operational by 2020.

Accordingly, the UAE now has in place a relatively comprehensive nuclear energy legal regime. Nonetheless, it commenced the tender process for the new nuclear plants in Abu Dhabi in 2009, prior to becoming a party to key regulatory and safety conventions, in particular the Vienna Convention. This is indicative of the UAE's (and, in particular, the Emirate of Abu Dhabi's) drive to commence nuclear projects as quickly as possible.

Saudi Arabia

In terms of domestic implementing legislation, Saudi Arabia is not as advanced as the UAE. In 2009, the Saudi Government announced that it intended to pursue a nuclear power programme on its own. In 2010, it established the King Abdullah City for Atomic and Renewable Energy (KA-CARE) in accordance with Royal Decree A/35, with the aim of building a sustainable future for Saudi Arabia by developing a substantial alternative energy capacity fully supported by world-class local industries. KA-CARE has the stated



3 Consistent with the Vienna Convention, transporters and handlers can been deemed the operator for purposes of the Civil Liability Law.

aim of deploying the most advanced and thoroughly tested technologies in Saudi Arabia, paying attention to safety, security and safeguards of the highest international standards when installing its planned nuclear reactors, due to generate 17.6 GW of power (originally by 2032 although this date was extended to 2040 at the beginning of 2015). Procurement of the planned reactors has yet to commence.

KA-CARE is the competent authority tasked with meeting Saudi Arabia's obligations with regard to all agreements signed, or to be signed, by Saudi Arabia regarding nuclear energy. It is responsible for supervising and controlling all works related to the use of nuclear energy and the resultant radioactive waste.

Pursuant to the Council of Ministers Resolution No. 369 of 2010 and Royal Decree No. M/69 of 2010, Saudi Arabia acceded to the Vienna Convention and the Protocol, both of which were ratified in 2011. In the same manner as the UAE, Saudi Arabia included a reservation in its accession to the Protocol, providing that Saudi Arabia does not consider itself bound by any of the dispute settlement procedures provided for in Article XX A.2 of the Convention.

The Vienna Convention liability regime has still to be transposed into domestic legislation. KA-CARE has reportedly completed the drafting of the Saudi nuclear law and civil liability law for nuclear damage; these laws are under review and revision by international and national partners, in preparation for submitting for adoption to the national legislative authorities.

Saudi Arabia is moreover set to establish an independent regulator, the Saudi Arabian Atomic Regulatory Authority, to oversee its civil atomic energy programme and ensure all safeguards are in place. The authority has yet to be established, although a lot of preliminary work and co-operation in advance of its establishment have been completed. What is more, KA-CARE has launched an initiative to study and establish a special purpose vehicle for nuclear activities. This will be a creditworthy and independent entity, in charge of building and operating nuclear power plants in Saudi Arabia. It will operate as the commercial arm of Saudi Arabia in designing and operating nuclear power plants and research reactors, which aim to localise up to 60 per cent of the value chain.

Jordan

Energy diversification is a key priority for Jordan, given its heavy dependency on foreign energy imports. Ninety-seven per cent of the oil and natural gas used for energy consumption in Jordan is imported. Crude oil and oil products and natural gas account for more than 90 per cent of Jordan's total primary energy demand, with domestic sources of oil and natural gas satisfying only around three per cent of that demand. Nuclear power generation offers an alternative source of energy which is independent of the frequent supply fluctuations associated with hydrocarbon imports.

Jordan has therefore developed a five-point nuclear energy strategy to:

(i) rely on nuclear power to meet an increasing demand for electricity;
(ii) fuel its nuclear power programme with indigenous uranium;
(iii) manage steps of the nuclear fuel cycle, including waste management, in accordance with international standards;
(iv) invest in national human resources to support the programme; and
(v) secure funds for nuclear energy development.

Jordan started setting out a statutory framework for nuclear power as far back as 1987. Historically, the Jordan Nuclear Energy Commission, which was established in 2001, was responsible for developing strategy. This entity was replaced in 2007 by the Jordan Nuclear Regulatory Commission (JNRC), an independent regulatory body established pursuant to Law No. 43 of 2007 on radiation, protection and nuclear safety and security (Law 43), with responsibility, among other things, for regulating, monitoring and controlling the use of nuclear energy and protecting the environment and human health. Law 43 was amended in 2014 by Law No. 17 of 2014 regarding the restructuring of institutions and governmental organisations, which merged the JNRC into a new Energy and Minerals Regulatory Commission (EMRC). EMRC's objectives include restructuring the power sector and ensuring power is supplied safely and at competitive prices. It also monitors and resolves electricity consumer complaints. There is concern that this change in the regulatory structure may raise issues about the independence of the regulatory body.

Also in 2007, Law No. 42 of 2007 (the Nuclear Energy Law) established the Jordan Atomic Energy Commission as an independent entity tasked with, among other things, defining technical criteria and specifications, drafting regulations, establishing companies with the public and private sectors to develop nuclear power plants and to represent Jordan in Arab, regional and international nuclear energy-related initiatives and forums. According to the IAEA 2014 Mission Report on the Integrated Nuclear Infrastructure Review Mission Phase 2, the Nuclear Energy Law is inadequate to support the planned nuclear power programme, given that it does not fully reflect the provisions of the applicable international legal instruments. A number of key obligations

"KA-CARE has launched an initiative to study and establish a special purpose vehicle for nuclear activities. This will be a creditworthy and independent entity, in charge of building and operating nuclear power plants in Saudi Arabia."

are contained in regulations and instructions. The IAEA has recommended drafting a new comprehensive nuclear energy law.

Pursuant to Royal Decree and Council of Ministers Resolution No. 1629 dated 15 September 2013, Jordan acceded to the Vienna Convention and the Protocol, both of which were ratified on 27 April 2014. In a similar way to the UAE and Saudi Arabia, it included a reservation in its accession to the Protocol providing that Jordan does not consider itself bound by either or both of the dispute settlement procedures provided for in the Protocol (namely, arbitration or referral to the International Court of Justice). There is currently no domestic legislation transposing the provisions of the Vienna Convention; however, in accordance with article 33(1) of the Jordanian Constitution, no ratifying law is required to transpose the obligations into domestic law, since the King has the express authority to ratify treaties and agreements.

In March 2015, Jordan and Russia signed an agreement regarding the development of nuclear power. The agreement sets out the framework for the development of two nuclear reactors, which will have a combined capacity of 2,000 MW. Construction of the first plant is due to commence in 2017, with commercial operation expected between 2022 and 2024.

Finally, in contrast to the UAE and Saudi Arabia, Jordan has significant deposits of uranium. It is reported that Jordan has between 85,000–140,000 tonnes of uranium oxide resources (reports vary). It is hoped these indigenous resources will eventually serve as a natural hedge against fluctuations in uranium fuel prices; production of uranium from mines in central Jordan could be around 2,000 tonnes annually which could be used to fuel domestic reactors with a surplus to export.[4] Nonetheless, Jordan will initially source its nuclear fuel needs from global nuclear fuel suppliers and any plans to enrich fuel are longer-term intentions which will require extensive co-operation in terms of establishing the required safeguards and sourcing technology and personnel.

4 Source: Jordan Atomic Energy Commission.

Why the reservations?

As stated above, the Protocol is subject to an express reservation by each of the UAE, Saudi Arabia and Jordan that they are not subject to the dispute settlement procedures provided for in the Protocol (and therefore the Vienna Convention). In this regard, it should be noted that the UAE, Saudi Arabia and Jordan, although entitled as member states of the United Nations to appear before the International Court of Justice, have not accepted the compulsory jurisdiction of the Court (this is the case with all Middle East states with the exception of Egypt which has accepted compulsory jurisdiction in relation to certain disputes surrounding the operation of the Suez Canal).

Non-nuclear-specific laws

This article has focused on nuclear-specific laws and specifically those related to liability and regulation. Each of the three jurisdictions – the UAE, Saudi Arabia and Jordan – have a number of laws of general application which will impact on issues related to both regulation and liability, as well as safety. The nuclear-specific laws should be read together with the other applicable laws, in particular the applicable civil and environmental laws.

Conclusion

The development of nuclear power programmes reflects a trend by states in the Middle East attempting to move away from sole dependency on hydrocarbon fuels as feedstock for the increasingly power-hungry region. However, the process is complex and time-consuming. Becoming a party to the key international conventions and entering into bilateral co-operation agreements with other nuclear power states is critical; however, that in itself is not enough to kick-start a nuclear power programme. These obligations must be transposed into domestic law, appropriate regulatory mechanisms and a regulatory authority must be put in place in accordance with best practice. There needs to be continual co-operation with other nuclear power states in order to secure the necessary know-how, technology and experienced personnel. To date, the UAE has led the way in the region in satisfying these requirements. Jordan and Saudi Arabia are still some way behind in terms of establishing the comprehensive domestic frameworks necessary to develop a successful programme but, particularly in the case of Jordan, the momentum is there.

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A STEP TOO FAR:

Unauthorised development by joint venture operators

by Lucas Wilk, Paul Walker and Sam Mengler

A recent Australian court case considered the circumstances in which a joint venture participant was entitled to apply for removal of the operator of the joint venture. The case has some important implications for the drafting and interpretation of joint operating agreement (JOA) provisions relating to joint venture participants' control of operations under a JOA. It is a useful reminder of the principles applicable not just under Australian law, but also other common law jurisdictions, such as English law.

The case – *Apache Oil Australia P/L & Ors -v- Santos Offshore P/L* [2015] WASC 318 – concerned the Spar Joint Venture; a project between subsidiaries of Apache Corporation and Santos Limited for the development of the Spar gas field off the North West Coast of Western Australia. The case is notable because of the legal and commercial issues it highlights, and also because it is very unusual for resource joint venture disputes to lead to formal court proceedings and published judicial decisions.

The dispute centred around the work programme and budget for development of the Spar-2 well. Specifically, it concerned whether the operator (Apache Oil) had materially breached the principal agreement governing the Spar Joint Venture – the Spar JOA – by conducting development activities in respect of the Spar-2 well at its own expense and without prior approval of the decision-making body for the joint venture (the operating committee). A material breach would allow removal of Apache Oil as operator.

Summary of events leading to the dispute

The Spar Joint Venture was formed in respect of a production licence held over an area of the Spar gas field. Apache Oil and its related companies held a 55 per cent interest in the joint venture. The other participant, Santos Offshore, held the remaining 45 per cent.

In late 2010, the Spar Joint Venture drilled, tested and completed the Spar-2 well. The target reservoir demonstrated very high productivity. At that stage, the plan was to tie the Spar-2 well back to a development on the adjacent Halyard gas field in order to transport the gas to Varanus Island for processing.

Between 2011 and 2013, Apache Oil conducted on its own account the following activities related to developing the Spar-2 well, without prior sanction of the operating committee:

- engaging its parent company to manage the Spar project on its behalf;
- completing front-end engineering design for the project;

- completing a process of identifying, tendering and evaluating long lead items;
- awarding contracts for major items of equipment; and
- corresponding and engaging with regulators with respect to the project.

Apache Oil was motivated to undertake these activities without seeking prior approval in order to achieve perceived efficiency advantages (both as to time and cost). The dispute came to a head when, in mid-2013, Apache Oil obtained approval from the operating committee for the preparation of a field development plan, a work plan and budget, and then submitted those materials for committee approval. The documents identified the work that Apache Oil had done on the project and that it was (by then) already 19 per cent complete. Santos Offshore responded by giving Apache Oil notice of material breach of the Spar JOA and, following expiry of the cure period, informed Apache Oil that it intended to remove Apache Oil as operator. Apache Oil then sought a court declaration that Santos Offshore could not remove it as operator.

Before the dispute had been resolved, the operating committee actually approved the field development plan, work plan and budget submitted by Apache Oil. In voting in favour of approval, Santos Offshore reserved its rights in relation to the alleged material breach by Apache Oil.

Main issues in the case and findings of the Court

The Spar JOA provided for two types of authorised operations: "Joint Operations" and "Exclusive Operations". A Joint Operation was an operation conducted by the operator on behalf of all parties with the approval of the operating committee. An Exclusive Operation was an operation by fewer than all parties. An Exclusive Operation could only be pursued in limited circumstances, after the operating committee had rejected a proposal for an analogous Joint Operation.

Apache Oil argued that, even though it had conducted the development operations mentioned above without approval as a Joint Operation or an Exclusive Operation, the Spar JOA did not prohibit a party taking steps on its own account for the development of a discovery. It also argued that Santos Offshore had waived, or cured, any breaches by approving (as part of the operating committee) the field development plan, work plan and budget related to those activities.

The Supreme Court of Western Australia rejected Apache Oil's arguments, finding that:

- the operator could not, under the Spar JOA, undertake development activities which were neither Joint Operations or Exclusive Operations, and without prior operating committee sanction. The JOA did not contemplate any other type of allowable development, and Apache Oil's unauthorised development was a material breach because it deprived other joint venture participants of having influence or input on budgets, contract awards and project timing; and
- Santos Offshore had not cured or waived the breaches, even though it voted to approve the field development plan, work plan and budget related to the activities, because: (a) there was no inconsistency in Santos Offshore choosing to progress the development of the Spar-2 well while also maintaining its contention that Apache Oil's earlier conduct meant that it was unsuitable for the operator role; and (b) Santos Offshore had expressly reserved its rights against Apache Oil at the time it voted.

As a result, the Court found that Santos Offshore was entitled to remove Apache Oil as operator under the Spar JOA.

What are the lessons for resource joint venture participants?

While primary attention must always be given to the express drafting of the relevant governing agreements and the factual context, there are some general lessons to be learned from the *Apache Oil -v- Santos Offshore* decision.

First, contractual procedures for obtaining the approval of the decision-making body for venture development activity should be commercially efficient in terms of the required steps and timescales. Close attention should be given, when the JOA or other governing document is being drafted, to their practical workability. The more cumbersome the approval procedures are, the greater the temptation for operators, particularly if they are aligned with a substantial percentage of venture participants, to bypass formal approval processes in the interests of efficiency.

Second, the JOA should be explicitly clear about whether, and (if so) when, a party may take steps on its own account for the development of a discovery. Problems in either respect create fertile ground for inter-venturer disputes.

Third, if a JOA does not clearly authorise development activities by individual venturers without sign-off from the formal decision-making body, it is likely to be a risky strategy for operators to undertake such activity simply due to a belief in the advantages of that approach (whether as to cost and time savings, or otherwise). Even if co-venturers ultimately accept what has been done, that may not prevent a finding that unauthorised activity renders the offending operator unsuitable to continue to hold the position.

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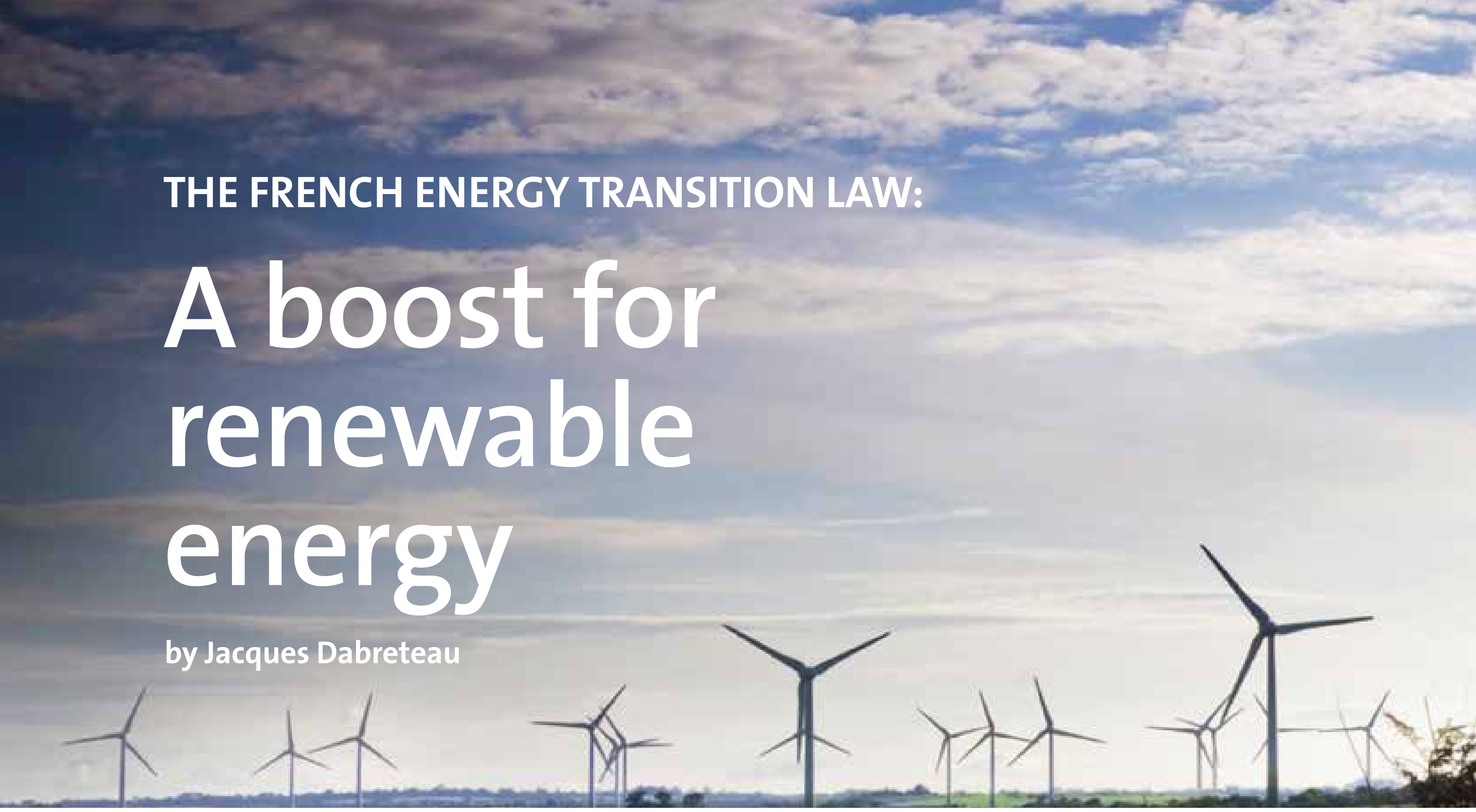

THE FRENCH ENERGY TRANSITION LAW:

A boost for renewable energy

by Jacques Dabreteau

The long-awaited law on "Energy transition for green growth" (*loi n°2015-992 du 17 août 2015 relative à la transition énergétique pour la croissance verte*) (the Energy Transition Law) was finally published in the Official Journal on 18 August 2015. Described by Ségolène Royal, the Minister for Ecology, Sustainable Development and Energy, as "*the most advanced and ambitious piece of environmental legislation in Europe, and probably the world*", the new Law sets down ambitious new targets for energy efficiency and transition from fossil fuels in the transport, housing and electricity sectors. As such, the Energy Transition Law has important implications for the renewable energy sector in France.

Introduction

As the host country of the 2015 UN Climate Change Conference (COP21), held in Paris between 30 November and 11 December 2015, France has made a point of showing its strong commitment to "energy transition" – that is, a new economic model which combines growth and sustainable development based on energy savings and the development of renewable energies.

In this context, France has made ambitious commitments in the Energy Transition Law, including:

- a 50 per cent reduction of the country's final energy consumption by 2050 (with an intermediary step of 20 per cent reduction by 2030);
- a 30 per cent reduction in the primary energy consumption of fossil energy by 2030; and
- a drastic reduction of the share of nuclear energy in the French energy mix, down to 50 per cent by 2025 (compared to the current 75 per cent share).

To ensure that energy transition becomes reality, not merely a laudable but vague principle, an extensive set of measures is required to implement this fundamental shift of the French energy policy, as discussed below.

Under the Energy Transition Law, several economic sectors and industries are required to contribute to energy transition,[1] but it is clearly intended that renewable energy shall play a key role in the implementation of the energy transition. The law provides for a substantial increase in its share in the French energy mix: renewable energy is to represent 23 per cent of the gross final energy consumption by 2020 and 32 per cent by 2030. Moreover, renewable energy is to represent 40 per cent of overall energy production by 2030.

In other words, the French energy transition is primarily relying on the accelerated development of renewable energy and an increase in its share in the French energy mix, together with a significant decrease in the share of nuclear energy, which is currently the dominant source of electricity in France. In order to meet these objectives, the law establishes a new regulatory framework that is designed to foster the development of renewable energy.

It is doubtful, however, that the

1 Construction and housing through energetic renovation, transport with the promotion of energy-efficient vehicles, nuclear safety, waste reclamation, etc.

Energy Transition Law will allow France to effectively meet all of its ambitious objectives. On the one hand, the reshuffling of the regulatory framework applicable to electricity generation from renewable energy sources clearly confirms the Government's strong support of renewable energy. On the other hand, however, the new framework applicable to the long-awaited opening of the French hydroelectric concessions market to new operators is aimed at maintaining the status quo rather than at the creation of a liberalised hydropower market.

Changes to the support framework for renewable energy

Prior to the changes introduced under the Energy Transition Law, the subsidisation of electricity production from renewable energy sources was based on two mechanisms, namely:

- the "purchase obligation" (*obligation d'achat*) mechanism, pursuant to which Électricité de France (EDF) or, as the case may be, local distribution companies (*entreprises locales de distribution*) are obliged to purchase the energy produced from renewable sources on the basis of a feed-in tariff determined by ministerial order (*arrêté*).[2] It goes without saying that, in practice, the feed-in tariff has at all times been substantially higher than the market price; and
- the call for tenders (*appel d'offres*) mechanism, pursuant to which a power purchase agreement (PPA) is entered into between the selected bidder(s) and EDF (or, as the case may be, a local distribution company) on the basis of the purchase price submitted in the tendering process. A call for tenders can be organised by the Energy Minister when it is apparent that the available energy generation capacity does not meet the objectives of the multi-annual energy plan (*programmation pluriannuelle de l'énergie*), in particular in terms of production technologies (*techniques de production*) and geographical spread of generation facilities.

Following the entry into force of the new European guidelines on State Aid for environmental protection and energy[3] on 1 July 2014, a reorganisation of this framework was necessary. In particular, the guidelines set out that, as from 1 January 2016, support mechanisms for renewable energy cannot take the form of a feed-in tariff but instead should be based on a premium (*prime*) paid to the energy producer in addition to the market price of the electricity sold on the market.[4] In addition, according to those guidelines, aids should, in principle,[5] be granted following calls for tenders as from 1 January 2017.

In accordance with the European guidelines, the Energy Transition Law provides for a new compensation scheme which is intended to gradually replace the "purchase obligation" for certain sources of renewable energy.

The new scheme is based on "additional compensation" (*complément de rémunération*), which takes the form of a premium payable to the renewable energy

2 e.g. for wind farm facilities, see order of 17 June 2014 establishing the purchase conditions of energy produced by onshore wind farm facilities *(arrêté du 17 juin 2014 fixant les conditions d'achat de l'électricité produite par les installations utilisant l'énergie mécanique du vent implantées à terre).*

3 Communication from the Commission, Guidelines on State aid for environmental protection and energy 2014-2020 (2014/C 200/01).

4 This new mechanism will apply to installations with an installed capacity exceeding 500 kW, or 3 MW or 3 generation units in the case of wind farm facilities.

5 This mechanism will apply to installations with an installed capacity exceeding 1 MW, or 6 MW or 6 generation units in the case of wind farm facilities.

generator. The additional compensation is designed to cover the costs borne by the generator for the construction of its facilities and guarantee a "normal" (i.e. reasonable) return on invested capital, as well as shielding the generator from the volatility of the wholesale energy market.

In practice, the compensation will be payable in relation to all electricity generated, and shall be equal to the difference between a "target purchase tariff" (*tarif d'achat de référence*) and a "target market price" (*prix de marché de référence*), both of them determined in accordance with specific ministerial orders and different for each source of renewable energy.[6] The compensation will be paid on a monthly basis with an annual reconciliation. In addition, a "management premium" (*prime de gestion*) will be paid to generators in order to compensate them for costs associated with access to the energy market, such as transaction costs and network balancing costs. The value of any "guaranteed capacity" (*valorisation des garanties de capacité*) held by the energy producer will, however, be deducted from the calculation of the additional compensation in order to avoid excess remuneration.

The additional compensation can take two different forms:

- The "open window" (*guichet ouvert*) mechanism, pursuant to which EDF must enter into a "contract for difference" (*contrat de complément de rémunération*) for a maximum duration of 20 years[7] at the request of the energy producer and under certain conditions, in particular, the provision of the compliance certificate of the installation issued by a certified body in accordance with the provisions of the Energy Code.
- The call for tenders mechanism, the terms of which will determine whether the preferred bidder(s) will enter into either a PPA (i.e. the electricity will not be sold on the energy market) or a contract for difference (i.e. the electricity will be sold on the energy market).

The Energy Transition Law also provides for a "back-up" system for renewable energy generators who are unable to sell their electricity on the market. Provided that the generator can justify the impossibility, i.e. where it has not been able to contract with an aggregator (an operator in charge of selling the energy on the market on behalf of the generator) or where the aggregator itself has failed to sell the electricity, the generator may request a "buyer of last resort" (*acheteur en dernier recours*) to enter into a PPA with the generator, and in such a case the PPA shall be granted to the generator instead of a contract for difference. The PPA will be for a maximum period of three months that can be renewed on demand of the generator. The remuneration paid by the buyer of last resort to the energy producer shall not exceed 80 per cent of the total remuneration that would have resulted from the sale of energy on the market plus the "additional compensation" described above. According to the draft decrees for the implementation of the Energy Transition Law (the Draft Decrees), the buyer of last resort will be selected for a maximum five-year period by the Energy Minister following a competitive process. This back-up system is being implemented in recognition of the fact that the aggregator market is still emerging, but will probably be removed once the market becomes sufficiently mature.

Impact of new regime for renewables generators

The "additional compensation" scheme described above will have a series of material consequences for the renewable energy market.

It will first prompt a reorganisation of the off-take for certain renewables: aggregators will play an increasingly important role, as they will provide the interface between smaller "merchant" producers and the electricity market by pooling generation capacity from various producers; this will reduce the risk of forecasting errors and avoid associated penalties. It is also likely that the increased exposure of renewable energy generation to market risk will affect the bankability of certain renewable energy projects. Finally, new contracts will be needed to organise the relationships between generators and electricity buyers, electricity buyers and aggregators, etc.

Based on the Draft Decrees, the "additional compensation" scheme will not apply to all renewable energy sources, however; at first, it will only apply to the

6 At the time of writing, the ministerial orders have not yet been enacted.

7 A specific maximum duration per renewable energy source will be set in the ministerial orders.

following types of renewable energies:

- hydroelectric energy (facilities with an installed capacity equal or less than 1 MW);
- waste-to-energy installations;
- biogas facilities (with an installed capacity comprised between 500 kW and 12 MW);
- geothermal energy;
- co-generation facilities (with an installed capacity equal or less than 1 MW); and
- onshore wind farms.

A number of renewable energy projects will not, therefore, fall within the scope of the "additional compensation" scheme, at least not in the short term.

The Draft Decrees further provide a list of energy generation installations, including onshore and offshore wind farms, certain solar PV plants (i.e. those with an installed capacity less than 100 kW), which remain subject to the purchase obligation.

French onshore wind farms benefit from a specific exemption, which means that the current purchase obligation mechanism is still applicable for ten years following the decision of the Commission dated 27 March 2014.[8] However, the Minister of Energy has recently indicated that the mechanism might be reviewed after 2018. As regards solar PV plants with an installed capacity exceeding 100 kW, those that are developed on the basis of a call for tenders will benefit either from a PPA or a contract for difference, depending on the terms of the call for tenders.

Moreover, renewable energy installations/projects that have applied for the benefit of the purchase obligation before the entry into force of the decrees implementing the Energy Transition Law will continue to benefit from the purchase obligation mechanism and the corresponding feed-in tariff, provided, however, that the facilities are commissioned within 18 months of the entry into force of the decrees.

The Energy Transition Law undoubtedly confirms the Government's commitment to the generation of electricity from renewable energy sources but also shows that such support shall now be on more market-driven, less expensive terms. At the same time, the co-existence of two remuneration mechanisms (purchase obligation and additional compensation), and the complex and untested "additional compensation" scheme, create a certain degree of uncertainty which will need to be resolved if the ambitious goals set by the Energy Transition Law are to be achieved.

8 Decision of the Commission C(2014) 1315 final, State Aid SA.36511 (2014/C) (ex 2013/NN) France.

A renewed framework for hydroelectric concessions

The Energy Transition Law finally sets out a revised regime for the award and operation of hydroelectric concessions in France. After having formally announced the retendering of several existing concessions in 2010,[9] French authorities have finally taken some tentative steps towards the opening up of the French hydroelectric market.

9 Jean-Louis BORLOO décide des modalités de renouvellement des concessions hydroélectriques : 10 concessions d'une puissance cumulée de 5.300 mégawatts seront renouvelées entre 2010 et 2015, 22 April 2010, developpement-durable.gouv.fr.

It is clear, however, that the Parliament (upon the instigation of the Government) has not given in to pressure from private operators, many of them foreign, that have been requesting for years that France complies with its obligation to liberalise the sector. The revised framework is unlikely to meet their expectations. Rather than genuinely opening up the French hydroelectric sector to new French and international private sector operators, the Energy Transition Law instead provides for a new organisation of the French hydroelectric sector in which the State will maintain strong control. There exists a broad consensus across the political spectrum in favour of the status quo in this sector.

The renewed framework is primarily based on:

- the restructuring of a number of concessions by combining existing individual concessions located in the same valley into a single "cascade", and
- the "opening up" of the hydroelectric sector through the creation of a new form of public-private entity to operate concessions.

The measures adopted for the regrouping of concessions allow, in practice, for the extension of the duration of the new concession resulting from the combination of the existing concessions and therefore maintain the existing concessionaire in place. It is clear from the Parliamentary debate and the provisions of the law that, despite the stated objective of regrouping existing concessions with a view to retendering them, the actual intention is rather to further postpone the opening up of the hydroelectric sector to effective competition.

The provisions of the Energy Transition Law dealing with the establishment of a new form of public-private entity reflect the need for the Government to find a balance between public control over hydroelectric concessions and the right of private operators to operate those concessions. Specifically, where a hydroelectric concession is to be retendered, the State is now allowed to create special public-private companies, referred to as "hydroelectric SEM" (SEMH) (*société d'économie mixte hydroélectrique*), whose single purpose shall be to operate a hydroelectric concession. In line with the principles stated by the Commission[10] and the European Court of Justice in the *Acoset Spa* decision,[11] the selection of the private partner in the SEMH and the award of the concession contract to the SEMH are subject to a single public tender launched by the State in accordance with the terms and conditions that will be set out in a future decree.

10 Interpretative communication on the application of Community law on Public Procurement and Concessions to institutionalised PPP (IPPP) 2008/C 91/02, Official Journal C 91 dated 12 April 2008.

11 EUCJ 15 October 2009, *Acoset Spa*, case C-196/08. According to this decision, a public service can be directly awarded to a public-private company dedicated to providing that service, on condition that the private partner is selected through a tender process in accordance with the rules of the EU procurement directives or, as the case may be, with the principles of free competition, transparency and equality of treatment as set out in the EU Treaty.

The complexity and the cost of establishing such public-private entities are very likely to mean that, in practice, the recourse to SEMH will be limited to only major hydroelectric concessions.

In addition, the State will exert tight control over the SEMH in the following ways:

- the decision to create a SEMH rests solely with the State;
- it can decide to open the shareholding of the SEMH to other public sector entities (local authorities and other public bodies or public-owned companies);
- the State and, as the case may be, the other "public" shareholders must hold between 34 per cent and 66 per cent of the share capital and the voting rights at the board of the SEMH and, therefore, will always keep at a minimum a blocking minority in the SEMH; and
- the terms and conditions of the tender terms will be determined by

the State. These will include the agreement concluded between the "public" shareholders prior to the tendering process (i.e. percentage of the share capital to be held by public entities, rules governing management and control of public entities over the SEMH, etc.), the draft articles of association of the SEMH as well as other documents governing relationships between "public" and private shareholders, and last, but not least, the main terms of the concession contract.

Since the adoption of the Energy Transition Law, we note that the Energy Minister has moved unusually quickly and has already published various draft implementing regulations subject to public consultation.

These additional regulations include:

- the draft implementation decree which, among other things, specifies the conditions pertaining to the regrouping of existing concessions, sets out the process for the setting up of a SEMH, authorises the State to tender new hydroelectric concessions and, above all, reorganises the tendering process for hydroelectric concessions including, in particular, some specific provisions regarding the termination and renewal of existing concessions (e.g. information due by the concessionaire before the expiry of the concession, the formula for the (highly complex) calculation of the entrance fee (*droit d'entrée*) to be paid by the new concessionaire to the State in order to compensate the outgoing concessionaire, etc.);
- a draft of the model tender terms (*cahier des charges*) appended to the decree, which will be used in the tendering or retendering of hydroelectric concessions. This model needs, however, to be completed and amended to take into account the characteristics of each specific concession; and
- two draft orders, one clarifying the revenues (other than the revenues from energy sales) taken into account for the calculation of the concession fee (*redevance*) owed by the concessionaire to the State, and the other specifying the content of the concession-end report (*dossier de fin de concession*) that must be submitted by the outgoing concessionaire to the State at least five years before the expiry of the hydroelectric concession.

The publication of these draft regulations is probably not unrelated to the formal notice which, according to press releases, was sent on 22 October 2015 by the European Commission to the French Government requesting that after years of foot-dragging, France opens up its hydroelectric concessions market at last.

The above-mentioned draft orders in relation to *redevance* and *dossier de fin de concession* have recently been published (i.e. on 10 December 2015). Once the other implementing regulations are published, the new legal framework applicable to hydroelectric concessions will be complete. Then, subject to political will, the Government will be in a position to retender the hydroelectric concessions that have already expired and those which will expire in the coming years. According to press releases quoting a statement by the Energy Minister of July 2015, first calls for tenders are expected to be launched in early 2016.

Conclusion

With the Energy Transition Law, the French electricity market is entering into a new phase. Renewable energy is now given a pre-eminent role at a time when the Government has formally pledged a reduction of the share of nuclear energy in the energy mix to 50 per cent. Renewable energy shall no longer come at any price, however: renewable energy will continue to be subsidised but no longer at levels disconnected from market prices, and it shall progressively become a constitutive part of the regulated energy market. At the same time, the Energy Transition Law allows for the perpetuation of tight public control over hydropower, which is still today the main source of renewable energy in France. The French electricity market is indeed in transition but key structural changes are taking place at different paces so that it remains to be seen whether such transition will effectively result in a "greener" and more competitive market.

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DEMOBILISING OFFSHORE DRILLING RIGS:

Shifting costs

by Peter Voss and Harriet Lenigas

Efficiency and cost reduction are an essential priority for oil and gas companies in the current period of low prices. In the context of drilling services, careful drafting of demobilisation clauses in offshore drilling contracts can improve the prospects of reducing demobilisation costs when a rig has work after the completion of a campaign.

In a market where there is reduced demand for rigs, there may be more opportunity to mitigate risks than in a market where demand for rigs is strong.

This article examines ways in which a charterer can mitigate the risk of a rig owner taking steps to prevent the rig from being in direct continuation for its own commercial purposes where the rig has ongoing employment.

A major cost

An outgoing charterer's contractual obligations end on "rig release" at the "point of demobilisation". When there is another charter immediately following, a rig is said to be in "direct continuation".

When a rig is not in direct continuation, the outgoing charterer usually has an obligation to transport the rig to a major port. The cost can be significant and avoiding it a significant saving.

What is "direct continuation" and how is it defined?

The term "direct continuation" is a term widely used in the offshore drilling industry. For example, rig owners frequently make announcements to the market and their shareholders that their rigs have secured employment in direct continuation of a previous charter. Operations personnel also use the term, as it determines the operational obligations of each party to a drilling contract on demobilisation of a rig. Sometimes where a rig has a contract in direct continuation, it is referred to as "follow-on work".

Direct continuation *normally* refers to a situation where there is effectively no break between contracts for the charter of a rig. The rig will have constant uninterrupted employment enabling the rig owner to charge a day rate without any down time between drilling contracts.

As mentioned, it is standard practice that where the rig has not been able to secure future employment, the outgoing charterer pays the cost of demobilising the rig to a port where it can be safely anchored and marketed until it obtains future employment. Depending on the contractual obligations and the remoteness of the location of the charterer's drilling campaign, it can take weeks to transport a rig to the agreed port or location on demobilisation before rig release occurs.

Although there is a general understanding in the industry as to the

> “This shifting cost allocation is reflected not only in contracts for the charter of rigs, but also in other industry documents and accounting procedures.”

meaning of direct continuation, the term is often not defined in drilling contracts or drilling lexicon. This means that there is significant scope for ambiguity and misunderstanding as to the rights and obligations of the parties concerning demobilisation when the rig has work following the completion of the charterer's campaign. Given the high costs at stake, in the absence of a precise definition, the parties may find themselves in a dispute about direct continuation as a result of attributing different or nuanced meanings to the term.

Allocation of the costs of demobilisation

Once a rig reaches the point of demobilisation, the drilling contract comes to an end and the charterer's obligation to pay applicable day rates for the rig generally ceases.

The cost of demobilising a rig is either:

- accounted for as a pre-agreed fixed sum payable by the charterer to the rig owner on pulling anchors and/or other specified demobilisation activities being completed, such as the removal of the charterer's equipment from the rig; or
- calculated after the drilling contract has terminated by applying a day rate, usually a standby rate which is less than the operating rate, to the number of days taken to transport the rig to the point of demobilisation specified in the contract.

The point of demobilisation will change depending on whether the rig is in direct continuation or not.

No direct continuation

When a rig has no work in direct continuation, the point of demobilisation is usually a port that is a convenient location for the owner to market the rig, or a port where there are suitable facilities (for example, dry docking facilities), which will allow the rig owner to conduct any required periodic surveys, repairs or maintenance works. The charterer is usually required to pay a day rate while the rig is being moved. For a tow or demobilisation of one month, the day rate can be anywhere between US$8m for a semi-submersible to US$15m for a drillship.[1] In addition to this, if a rig is not self-propelled, the charterer will be required to charter support vessels and crew to tow the rig to port or to charter a heavy lift vessel to do so.

Direct continuation

Where a rig has been able to secure work in direct continuation, the point of demobilisation is usually in open waters with the rig on tight tow approximately one nautical mile from the outgoing charterer's last well location with all of the charterer's personnel and equipment offloaded. Sometimes, returning the rig owner's equipment from the charterer's supply base to the rig is also included as part of the demobilisation activities.

In a direct continuation situation, the financial burden then shifts to either the

1 See rigzone.com/data/dayrates.

incoming charterer or the rig owner, as they bear the cost of moving the rig to the incoming charterer's area of operations from (or close to) the outgoing charterer's area of operations.

It is important that the point of handover be clearly defined.

Clearly, it is in the outgoing charterer's commercial interests that a rig is in direct continuation at the end of a charter, because the charterer's obligation to pay the applicable day rate will effectively cease within a few hours of pulling anchors at its last well location. The charterer is also relieved of the attendant risk of moving the rig in open seas and into port. Ideally, charterers should try to have the rig owner charter the tow or heavy lift vessels to reduce the risks associated with moving the rig.

This shifting cost allocation is reflected not only in contracts for the charter of rigs, but also in other industry documents and accounting procedures. For example, the concept of direct continuation is reflected in the Norwegian Oil and Gas Recommended Guidelines for Joint User Costs for Mobile Rigs/Drill Ships (NOGR Guidelines).[2]

The NOGR Guidelines state that demobilisation costs vary from case to case depending on the contractual clauses that apply to demobilisation. In some cases, the rig is considered to be demobilised near the location of the last well when the anchors are stowed and the rig is on tight tow, whereas other contracts require that the charterer cover the day rate and other associated costs until the rig has been demobilised to a port. Where a rig is required to be demobilised to a port, the NOGR Guidelines provide that *"demobilisation costs may nevertheless be low if the rig moves directly from the last location to a new operating company"*.

Example demobilisation clauses

Despite the wide usage of the term "direct continuation", there is inconsistency in the way in which the concept is expressed in drilling contracts.

Set out below are some examples of demobilisation clauses. Example 1 does not provide for a direct continuation situation. Example 2 provides for a situation where the parties may reach a later agreement without expressly referring to a direct continuation situation. Example 3 may provide for a direct continuation situation, but it is ambiguous. Finally, example 4 provides for a situation of direct continuation, with direct reference to the concept.

None of the examples define what direct continuation is and provide limited certainty in respect of the trigger points that will determine whether the rig will be in direct continuation or not. Direct continuation is a term that is rarely explicitly defined in drilling contracts.

Example 1: Lump sum demobilisation fee – no direct continuation option

The demobilisation provision in one of the most widely used standard form drilling contracts, the International Association of Drilling Contractors (IADC), International Offshore Daywork Drilling Contract, provides for a lump sum demobilisation fee. It does not contain a clause allowing for a change in the payment obligation where a rig is in direct continuation.[3]

Termination
This Contract shall terminate:

(b) *after the number of wells ... are completed, and the Drilling Unit has been safely jacked up or moored, whichever is applicable, at the demobilisation location specified [in the drilling contract] (unless some other location or port is mutually agreed) and all of [Charterer's] Items have been offloaded, whichever is latest; or*

Demobilisation Fee
In addition to [Charterer's] obligation to pay the Stand-by Rate ... [Charterer] shall pay [Rig Owner] a demobilisation fee as specified in [the drilling contract] which shall be earned on the date of termination of this [drilling contract].[4]

2 Norwegian Oil and Gas Recommended Guidelines for Joint User Costs for Mobile Rigs/Drill Ships, Norsk olje & gass, No. 077/02, Rev. No. 1; Rev. date: 01.01.2009, part 4.4, Demobilisation and Oil & Gas UK, Standard Oil Accounting Procedures, Minimum Standards for Well Cost Reviews and Recommended Well Accounting Policies, revision 4, August 2014, SOAP 3.

3 Clause 203, Termination, of the International Association of Drilling Contractors, International Offshore Daywork Drilling Contract, November 2007.

4 IADC Standard form contract, clauses 203 and 703.

Examples 2, 3 and 4 are taken from drilling contracts available as public records online.

Example 2: Direct continuation option – no use of term

Demobilisation Fee

The [Charterer] shall pay the owner/operator a lump sum [for demobilisation] within thirty days of receiving the owner/operator's invoice bearing the date the rig, ancillary equipment and supplies departs the [Charterer's] last wellsite. If the owner/operator has received another contract for this rig, to commence with release of this rig from the charterer's last well, then the demobilisation will be reduced by [various percentages in accordance with the distance].

Example 3: Ambiguous direct continuation option – no use of term[5]

[Charterer] shall pay Owner a Demobilisation Fee as specified in Appendix A to cover all Owner's costs of demobilising the Drilling Unit. [Charterer] shall have no further demobilisation obligations other than the payment of the Demobilisation Fee. The foregoing notwithstanding, the Demobilisation Fee shall not be payable ... if the Drilling Unit is demobilised to any other location than directly to the point of demobilisation on the termination of the contract.

Example 4: Direct continuation option – use of term[6]

"Demobilization Point" means a location within the Host Country agreed by the Parties, except that, if the Rig is committed to another party in direct continuation after the completion of all Work for Operator on the last Designated Well, the Demobilization Point shall be one thousand feet (1000') from the location of the last Designated Well.

[Charterer] shall demobilise the Rig and [Charterer's] personnel from the last well location upon the expiration of the term. [Charterer] shall pay and be responsible for all risks, costs and expenses ... necessary to move and demobilise the Rig from the last designated well location upon operator's notification to [Charterer] of Rig Release. Operator shall pay the Demobilisation Fee to [Charterer] on or after the date that the Drilling Contract terminates ... Operator shall also not be required to pay the demobilisation fee if, upon the termination of this drilling Contract, [Charterer] has committed the Rig to another party in direct continuation after the completion of all work for operator on the last designated well.

All of the above example definitions have varying levels of ambiguity as to the parties' obligations on demobilisation. None of them specify with certainty the factual matters that will determine whether a rig is in direct continuation, nor do they provide a means by which the charterer can independently verify whether the facts satisfy the definition of direct continuation.

The balance of power lies with the rig owner

Quite often, when the initial negotiations for the charter of a rig are conducted, the details of the next charter are not known or agreed. A rig owner may seek to obtain a windfall by requiring the outgoing charterer to pay full demobilisation costs. There is the potential for double recovery if the rig owner can negotiate mobilisation costs from the location of the prior charterer's campaign. Accordingly, they are unlikely to volunteer much (or any) information about the incoming charterer due to the commercial benefit the rig owner is likely to achieve if he can create a deliberate break between contracts to ensure that there is no direct continuation where, for all intents and purposes, the rig has continuing employment. This means that the owner of the rig usually holds the balance of power in respect of demobilisation, because the outgoing charterer is likely to have little precise knowledge of the incoming charterer's contractual obligations due to confidentiality obligations even if drilling crews and management are aware of general details of the rig's future work programme.

5 Daywork Drilling Contract, techagreements.com.

6 Offshore Drilling Contract between CIE Angola Block 21 Ltd and Universal Energy Resources Inc. for the newbuild semi-submersible drilling rig SSV Catarina, 30 July 2012, sec.gov.

How can a charterer disrupt this balance of power?

Charterers do not have to accept standard form clauses concerning demobilisation which may not adequately address direct continuation situations. Charterers may have the opportunity to broaden the scope of the ordinary meaning of direct continuation through contract. The following are some steps that may be taken by charterers to protect their position:

- ensure that the points of demobilisation and demobilisation activities are defined in the contract. In the event of an unforseen situation, there should be a way in which the parties may agree an alternative demobilisation point without having to amend the contract. For example, the point of demobilisation is port "A", unless mutually agreed otherwise;
- ensure that the contract provides that, where the rig has ongoing employment, the rig will be deemed to be in direct continuation and handover will occur close to the outgoing charterer's area of operations, usually one nautical mile from the last well;
- explicitly define the term "direct continuation" to minimise the risk of a dispute concerning its meaning; and
- define the triggers that will determine whether a rig is in direct continuation. For example, charterers should consider:
    - the time at which the subsequent contract must be agreed;
    - whether the agreement must be executed prior to the completion of the outgoing charterer's contract or whether a memorandum of understanding or some other such document is sufficient;
    - whether the rig is required to proceed "immediately" to the incoming charterer's area of operations or can the rig be taken to a port or be otherwise diverted or delayed;
    - whether a lump sum demobilisation fee will be payable on rig release; and
    - whether to include a contractual obligation that requires a rig owner to immediately notify the charterer when the rig owner executes a contract in direct continuation.

A charterer may also wish to include an audit clause that enables the charterer to conduct an audit of the rig owner's records to ascertain the factual basis for the rig owner's assertion that the rig does or does not have work in direct continuation. This can greatly assist the charterer to clarify the true position in a timely manner.

A charterer may also consider a claw-back clause where a demobilisation fee has been paid and the rig owner subsequently secures work in direct continuation.

To ensure there is sufficient information to make an assessment of exactly how direct continuation should be defined in a particular drilling contract, those involved in the negotiations for the charter of the rig (on a contractual, operational or technical level) should attempt to gain an understanding of the rig owner's future plans for the rig and whether any works on the rig are scheduled or contemplated by the owner. If charterers obtain this information during the negotiating phase, it is possible to seek to negotiate specific carve-outs in the direct continuation definition so that delays caused by known future works or other diversions do not prevent the rig from being in direct continuation. This may mitigate or eliminate the risk of the rig owner taking steps to create a deliberate break between two charters for his commercial benefit.

Example carve-outs

The following are various circumstances that a charterer may wish to set out in the contract as being ones that do not prevent the rig from being in direct continuation:

- where works (or a significant proportion of works) are undertaken on the rig between charters for the benefit of the owner or subsequent charterer(s) and such works are not primarily undertaken as a result of damage caused during the outgoing charterer's drilling operations;
- where a subsequent third party drilling contract is contingent upon rig inspection and/or acceptance if that drilling contract was entered into during or prior to this charter;
- where a subsequent third party drilling contract is contingent upon regulatory or legislative consents or approvals being granted;
- where the rig diverts from a direct course to the subsequent charterer's area of operations and stops at port for fewer than 30 days in

circumstances where the rig has entered the subsequent drilling contract during this charter;

- where the rig is diverted and/or delayed due to specified types of work or specified scheduled works of fewer than 30 days in circumstances where the rig has entered into the subsequent drilling contract during this charter; and
- where the rig is diverted and/or delayed due to inclement weather or other events which are not unforeseeable or within the control of the outgoing charterer.

When referring to terms such as "works", "maintenance works", "upgrade" or "repair", it is important to note that these are common English words and can be used quite loosely. Courts will very rarely give a word in common usage some specialised industry meaning.[7] If a charterer is aware that the rig owner intends to perform particular works, they should ensure that both parties have a common understanding as to the nature of the work and whether it will be captured by a carve-out or not.

Dispute resolution mechanisms

Charterers may also wish to consider what dispute resolution mechanisms will apply if there is a dispute about demobilisation and/or direct continuation. Given the high-risk nature of the demobilisation process, it may be prudent to include a clause whereby, upon notice of such a dispute, the parties agree that the rig will be towed to the required destination. The clause should specify who bears responsibility of the tow in those circumstances, pending determination of the dispute.

It will also be important to ensure that there is a contractual mechanism which will enable the charterer to gain access to relevant and necessary documents in order to verify the rig owner's position.

7 *Cunliffe-Owen -v- Teather and Greenwood* [1967] 1 WLR 1421 at 1438. The test for proving such usage is demanding. See also *Nelson -v- Dahl* (1879) 12 ChD 568 at 575 Jessel MR.

Conclusion

Clearly defined demobilisation and direct continuation provisions do not only provide commercial benefit to a charterer, but also operational and safety benefits, as mobilisation and demobilisation are generally considered to be high-risk phases in a drilling programme. Contractual disputes as to which party bears certain demobilisation costs can distract the management and operations teams from carefully planning and executing the demobilisation.

It is important to remember that the obligations surrounding demobilisation can be established and modified by contract in order to accommodate unique situations applicable to each drilling programme.

Through careful drafting, charterers have the ability to reduce commercial exposure to demobilisation costs by limiting or removing ambiguity surrounding a charterer's obligations on demobilisation. They can also take steps to ensure that the rig owner has less control over the trigger points that determine whether a rig is in direct continuation.

Obviously, these issues will be a matter for commercial negotiation, but the more fully the parties consider and record their obligations in writing, the less likely it will be that questions about the parties' obligations on demobilisation will result in a legal dispute.

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AUSTRALIAN MINING:

Securing rehabilitation obligations

by Adam Conway and Christopher Barry

The global resources boom that has dominated recent decades has seen a strong focus from government and industry on how best to promote mining development. Less attention has been paid to the question of mine site rehabilitation when mining operations come to an end. This is an important issue, as the cost of rehabilitating a mine site can run to tens of millions of dollars. It is also a question that will become increasingly pressing as falling commodity prices place mining companies under financial pressure, leading to more mine closures and more companies entering administration or liquidation. This article considers whether the existing legal regimes for securing mine rehabilitation obligations are up to the challenge.

Introduction

Until the 1980s, Australian States had either weak or non-existent regulations for the rehabilitation of mines. Now, States have comprehensive regulatory schemes to ensure the costs of rehabilitation are met by mining companies. Performance bonds, which are designed to secure performance of rehabilitation obligations, sit at the heart of the regulatory system in Australia, and in a number of jurisdictions around the world. One Australian State has, however, recently moved away from the performance bond system and adopted a "pooled fund" model, which is seen as offering a more flexible and sustainable way of securing mining rehabilitation obligations. This new system has been seriously tested in its first years of operation by the shutdown of the Ellendale Diamond Mine in Western Australia that has left the State facing a rehabilitation liability of up to AU$40m. In this article, we explain how the existing performance bond systems operate and contrast that with the new pooled fund model introduced in Western Australia. We also highlight the benefits and risks of pooled funds and examine how the implementation of the Western Australian scheme presents a cautionary tale for other jurisdictions considering moving to a pooled fund model.

Rehabilitation liabilities

In Australia, the States have the power to regulate the minerals situated within their boundaries. While there are differences between each State,[1] there are a number of common features between each of the regimes for mining rehabilitation obligations. In each State, companies that own mining tenements and conduct exploration and extraction activities have primary liability for the rehabilitation

1 Land (Planning and Environment) Act 1991 (ACT); Mining Act 1980 (NT); Mining Act 1992 (NSW); Mineral Resources Act 1989 (Qld); Mining Act 1971 (SA); Mineral Resources Development Act 1995 (Tas); Mineral Resources Development Act 1990 (Vic); Mining Act 1978 (WA).

of their mines. Mining rehabilitation obligations are primarily enforced by a system of ongoing mine closure planning and reporting, commencing at the grant of the tenement and continuing throughout the life of the mine. The content of those obligations is prescribed either under mining and environmental legislation or as conditions on mining leases.

For example, in New South Wales, it is a condition imposed on the grant of every mining lease under the Mining Act 1992 (NSW) that the applicant submit a Mining Operations Plan prior to the commencement of any operations, as well as Annual Environmental Management Reports.[2] These reports must explain how a mine will be developed and must specifically address progressive and end-of-mine rehabilitation. Similarly, in Western Australia, the Mining Act 1978 (WA) obliges every mining lease applicant to lodge a Mine Closure Plan for approval by the Department of Mines and Petroleum (DMP), detailing plans for the closure, decommissioning and rehabilitation of the mine. The Mine Closure Plan must be updated and reapproved every three years. In Queensland, mine rehabilitation plans are required as part of the environmental approval process under the Environmental Protection Act 1994 (Qld) rather than as a condition of a mining lease.

These regimes illustrate that the primary means of enforcing mine rehabilitation obligations is through a system of reporting and planning that commences when a tenement is first granted and continues throughout the life of the mine.

Financial assurance systems

While mine closure planning is the first line of regulation used by States, the potentially heavy financial burden of rehabilitation has led States to impose additional measures compelling companies to meet their rehabilitation obligations. In most States, mining tenement holders are required to provide a security payment, usually in the form of a bank guarantee or cash, that covers the estimated cost of rehabilitating the tenement. The security can be used to fund the cost of rehabilitation if the tenement holder is unable or unwilling to rehabilitate the land. Securities are held by the State until it is satisfied that the tenement holder has met its rehabilitation obligations.

For example, under the Mining Act 1992 (NSW), any authorisation to conduct mining or exploration may be accompanied by a condition requiring the holder to provide a security deposit that covers all estimated rehabilitation costs. As a matter of policy, the State requires a security deposit for all coal, mineral and petroleum exploration and production activities.[3] The titleholder must provide the Department of Resources and Energy with an estimate of rehabilitation costs, which the Department considers when determining the amount of the security deposit. In deciding whether to release a security deposit, the Department will consider whether the requirements of the rehabilitation and closure plan have been met, whether environmental and safety obligations have been met, and who is responsible for ongoing management of the site.[4] If the rehabilitation obligations have not been met to the satisfaction of the Minister, then part or all of the security deposit may be forfeited under the Mining Act 1992 (NSW).

Similarly, in Queensland, the Department of Environment and Heritage Protection has the power under the Environmental Protection Act 1994 (Qld) to impose a condition on an environmental authority requiring that financial assurance be provided before any mining operations are carried out and, as a matter of policy, imposes such a condition wherever there is "resource activity" that may result in "significantly disturbed land" under a mining lease.[5] Uniquely, Queensland allows a mining company to discount its financial assurance below 100 per cent of the estimated rehabilitation liability in recognition of good environmental performance and a low risk of default.

A large number of countries outside Australia also use the financial assurance model to secure rehabilitation obligations. To give some idea of the scale, a World Bank Report in 2009 conducted case studies of ten different jurisdictions that operated a financial assurance system – Ontario, Nevada, Queensland, Victoria, Botswana, Ghana, Papua New Guinea, South Africa, Sweden and the European Union.[6] While there are variations between these jurisdictions about the type of security that is accepted, the amount of security that is required, whether administration costs are included in the liability estimate and whether the security is applied by tenement or by project, the core aspects of the schemes are similar.

Pooled fund model

In 2013, Western Australia became the first Australian jurisdiction to introduce a pooled fund for its mining industry. The Western Australian Mining Rehabilitation

2 *ESG3: Mining Operations Plan (MOP) Guidelines*, 3, Department of Trade and Investment, Government of New South Wales, September 2013.

3 *EDP11 – Rehabilitation Security Deposits*, Department of Industry, Resources and Energy, Government of New South Wales, January 2012.

4 Ibid.

5 *Guideline: Financial assurance under the Environmental Protection Act 1994*, Environmental Protection Act 1994 (Qld), Department of Environment and Heritage Protection, May 2013.

6 *Guidance Notes for the Implementation of Financial Surety for Mine Closure*, Oil, Gas and Mining Policy Division, The World Bank Group, 2009.

Fund (MRF) requires tenement holders to make regular contributions into a central fund administered by the State. The MRF operates in accordance with the Mining Rehabilitation Fund Act 2012 (WA) (MRF Act) and Mining Rehabilitation Fund Regulations 2013 (WA) (MRF Regulations).

The reform of Western Australia's security bond system was driven by State and industry concerns.[7] The State's main concern was that bonds were inadequate to cover its potential rehabilitation liability. In a 2011 policy paper, the State estimated that bonds secured less than 25 per cent of the total potential rehabilitation liability for mines in Western Australia. As a result, the State increased the minimum amounts bond holders were required to pay, leading to industry complaints that the bonds were too onerous. Industry also expressed concern that the system was inflexible, particularly because a bond could only be applied to the rehabilitation costs of the specific tenement to which it related, as opposed to the rehabilitation costs of a whole mining project.

The MRF Act imposes an obligation on all holders of a mining tenement to pay an annual levy. A miner's rehabilitation liability is determined by multiplying the size of the tenement by a "rehabilitation rate", which reflects the likely rehabilitation cost of a project based on the intensity of the mining operations. Holders of tenements with a rehabilitation liability of AU$50,000 or above are required to make an annual, non-refundable payment into the fund at the contribution rate of one per cent of the calculated rehabilitation liability. MRF funds can be used to rehabilitate any tenement in respect of which the levy was payable. Additionally, income earned from the MRF can be used to rehabilitate any abandoned mine site in the State.

After the introduction of the MRF, it was unclear how it would interact with the existing security bond system. Initially, the Western Australian Government began releasing performance bonds on the basis that rehabilitation liabilities would be covered by the MRF. However, in July 2014, the State announced that, regardless of whether a levy payment is required under the MRF Act, it would still impose performance bonds on tenements where there is a high risk of the rehabilitation liability reverting to the State.[8] This includes where the tenement holder is in administration or liquidation, has breached its environmental obligations or its reporting and payment obligations under the MRF Act, or has failed to make royalty payments to the State.

The pooled fund model illustrated by the MRF is seen as a more flexible and sustainable way of securing environmental performance and is likely to be examined closely by other Australian jurisdictions. For example, Queensland is currently considering replacing its performance bond system with a pooled fund model.[9] Despite this, serious questions about the effectiveness of the MRF have emerged following the shutdown of the Ellendale Diamond Mine in Western Australia.

Ellendale Diamond Mine[10]

In 2015, the Kimberley Diamond Company Pty Ltd (KDC), a subsidiary of Kimberley Diamonds Ltd (KDL), shut down its Ellendale yellow diamond mine after it was unable to find a buyer for the mine. KDC was put into liquidation after the mine closed with a number of outstanding liabilities, including unpaid wages, more than AU$10m in creditor debts, AU$1.5m in unpaid royalties and an estimated rehabilitation cost of AU$28m–40m. With KDC in liquidation, it was revealed that the State had released AU$12.1m in performance bonds to KDC when it signed up to the MRF in 2013. KDC contributed a total of AU$818,826.40 to the MRF, leaving a significant gap between its rehabilitation liability and money contributed to the fund.

KDC's liquidator initially sought to find a buyer to take on the mine and the rehabilitation liability. When this failed, the liquidator lodged a "disclaimer of onerous property" with the Australian Securities and Investments Commission. It seems that this is the first time this provision of the Corporations Act 2001 (Cth) (Corporations Act) was used in relation to a mining tenement in Western Australia. The effect of the disclaimer of onerous property provision is the company's rights, interests and liabilities in the disclaimed property are terminated from the day the disclaimer takes effect. The purpose of this provision has traditionally been to enable a liquidator to rid a company of burdensome financial obligations which might otherwise continue to the detriment of those interested in the liquidation. The DMP did not exercise its right to challenge the notice and, as a result, the cost of completing the rehabilitation now falls on the State, rather than on the liquidator of KDC.

The interaction between restrictions on the surrender or transfer of mining tenements and the power to disclaim onerous property has not been considered in Australia. The Mining Act regime in Western Australia is designed to prevent tenement holders from simply walking away from their rehabilitation obligations. A mining lease can only revert to the State where the holder applies to surrender it, the Minister orders that it be forfeited for breach of a covenant in the lease, or the Mining Warden orders that it be forfeited (on application by a third party) for non-compliance with the prescribed expenditure conditions. Similarly, mining leases cannot be transferred without the Minister's consent. The liquidator of KDC effectively avoided these restrictions by using the power to disclaim onerous property under the Corporations Act.

A similar issue has, however, been considered in the UK, which has a similar provision for the disclaimer of onerous

7 See *Western Australia's Mining Security System – Preferred Option Paper*, Department of Mines and Petroleum, March 2011 and *Preliminary Discussion Paper – Policy Options for Mining Securities in Western Australia*, Department of Mines and Petroleum, December 2010.

8 *The administration of mining securities for mine sites by the DMP*, Department of Mines and Petroleum, Government of Western Australia, July 2014.

9 *Reform of Queensland's financial assurance system: Discussion paper*, Department of Environment and Heritage Protection, Government of Queensland, June 2014.

10 The facts relating to the closure of the Ellendale Diamond Mine are taken from the following sources: Peter Williams, "State picks up $40m Ellendale bill", *The West Australian*, 3 November 2015; Nick Evans, "Bit-by-bit sale for Ellendale", *The West Australian*, 3 September 2015; Ben Hagemann, "Kimberley Diamonds leaves a poor legacy", *Australian Mining*, 6 July 2015; Jessica Kidd, "Former Kimberley Diamonds boss arrested for allegedly misleading stock market over yellow diamond prices", *Australian Broadcasting Corporation*, 15 September 2015; Hon. Robin Chapple, Parliamentary Debates, 3290, Western Australia, Legislative Council, 11 August 2015.

property.[11] In *Re Celtic Extraction Ltd*,[12] an official receiver sought to disclaim waste management licences under the Environmental Protection Act 1990 (UK), under which the companies would have been liable for over £300,000 in clean-up costs. The Court of Appeal found that the receiver was entitled to use the power to disclaim onerous property to dispose of the waste licences. The Environmental Protection Act 1990 (UK) provided that a waste management licence would continue in force until it was revoked or surrendered in accordance with the Act, and the Environment Agency argued that this excluded the operation of the power to disclaim. The Court of Appeal rejected this argument and held that the Environmental Protection Act did not exclude termination of a licence by external statutory force, including by the power to disclaim. In reaching this conclusion, the Court of Appeal said that the "polluter pays" principle, which underpins the waste management licence scheme, should not be applied where the polluter cannot pay. Applying polluter pays to a company in liquidation would undermine the principle that the property of insolvent companies should be divided equally among unsecured creditors and not entirely to a creditor who holds the rights to onerous property.

Although the issue has not been considered in Australia, the reasoning of the Court of Appeal could be applied to a mining lease. As discussed, the Mining Act 1978 (WA) has a number of provisions which prescribe the circumstances in which a company can surrender, forfeit or transfer a mining lease. Following the reasoning in *Re Celtic*, the existence of such provisions would not stop a company from invoking the power to disclaim onerous property, as was done by the liquidator of the Ellendale Mine. In fact, the conclusion would be even stronger under the Mining Act 1978 (WA) because, unlike the Environmental Protection Act 1990 (UK), the Mining Act does not contain any provision that expressly provides that a mining tenement shall continue in force until it is terminated under the Mining Act. The UK's experience provides a strong argument that could be made in Australian courts if the DMP sought to challenge the validity of the exercise of a disclaimer of onerous property in relation to a mining lease.

Lessons

Given the prevalence of financial assurance systems around the world, Western Australia's early experience with a pooled fund system provides an insight into the benefits and challenges it presents as an alternative model.

The pooled fund model provides a

11 Insolvency Act 1986 (UK) s 436.
12 [2001] Ch 475.

number of advantages over financial assurance systems. First, it imposes a much less onerous obligation on tenement holders because they are only required to contribute a small percentage (one per cent in Western Australia) of the estimated rehabilitation cost on an annual basis, rather than 100 per cent of the estimated liability. Second, it addresses concerns that financial assurance systems are not able to keep up with the rehabilitation bill that different States have accumulated. For example, Queensland currently holds AU$5.38bn in rehabilitation securities in the form of cash or bank guarantees and New South Wales holds AU$1.8bn. However, estimates suggest that the actual rehabilitation costs will be three to ten times that amount,[13] with one study putting the combined bill for New South Wales and Queensland in excess of AU$17.8bn.[14] Third, pooled funds can be used for a wider range of purposes rather than simply securing the rehabilitation commitments of one holder of one tenement. In this way, a pooled fund provides a way of meeting the cost of rehabilitating abandoned mines that escaped the obligations imposed under mining or environmental legislation.

On the other hand, the pitfalls of moving to a pooled fund model are illustrated by the Ellendale Diamond Mine case. The State's decision to release the AU$12m performance bonds it held over the Ellendale Mine has left it with little recourse to recover the costs of rehabilitating the site. For Western Australia, the problem extends well beyond the Ellendale Mine because, as part of transition to the Mining Rehabilitation Fund, 4,581 performance bonds have been retired and only 201 remain in effect across the State.[15]

While the Ellendale case raises questions about the pooled fund model, it also invites scrutiny of the DMP's implementation of the MRF. Under the DMP's policy, performance bonds were to be retained for mines with a "high risk of the rehabilitation liability reverting to the State", including where there had been a failure to pay royalties. Arguably, KDC's performance bonds should not have been released under this policy, given that it had fallen behind on its royalty payments. However, it is unclear what information was provided to the DMP prior to the release of the performance bonds, and the Chairman of KDL has subsequently been charged with four offences relating to making false and misleading statements to the Australian Securities Exchange. This illustrates some of the challenges that need to be addressed in the transition from a financial assurance system to a pooled fund model.

Conclusion

Ultimately, performance bonds provide States with the greatest level of security for the performance of mine rehabilitation obligations. However, performance bonds are facing increased scrutiny as questions are raised about whether they impose too much of a burden on companies and whether they can meet the true cost of rehabilitation. Pooled fund models offer a potential solution to these problems but, as the Ellendale case demonstrates, will not be effective unless regulators can accurately estimate potential liability and raise a sufficient amount of funds to cover that liability. The Ellendale case, which could cost Western Australia up to AU$40m, illustrates the cost of getting it wrong and provides a cautionary tale for other jurisdictions considering a pooled fund model.

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13 Lisa Main and Dominique Schwartz, "Industry insider warns taxpayers may foot bill for mine rehabilitation unless government, industry step up", *Australian Broadcasting Corporation*, 19 September 2015.

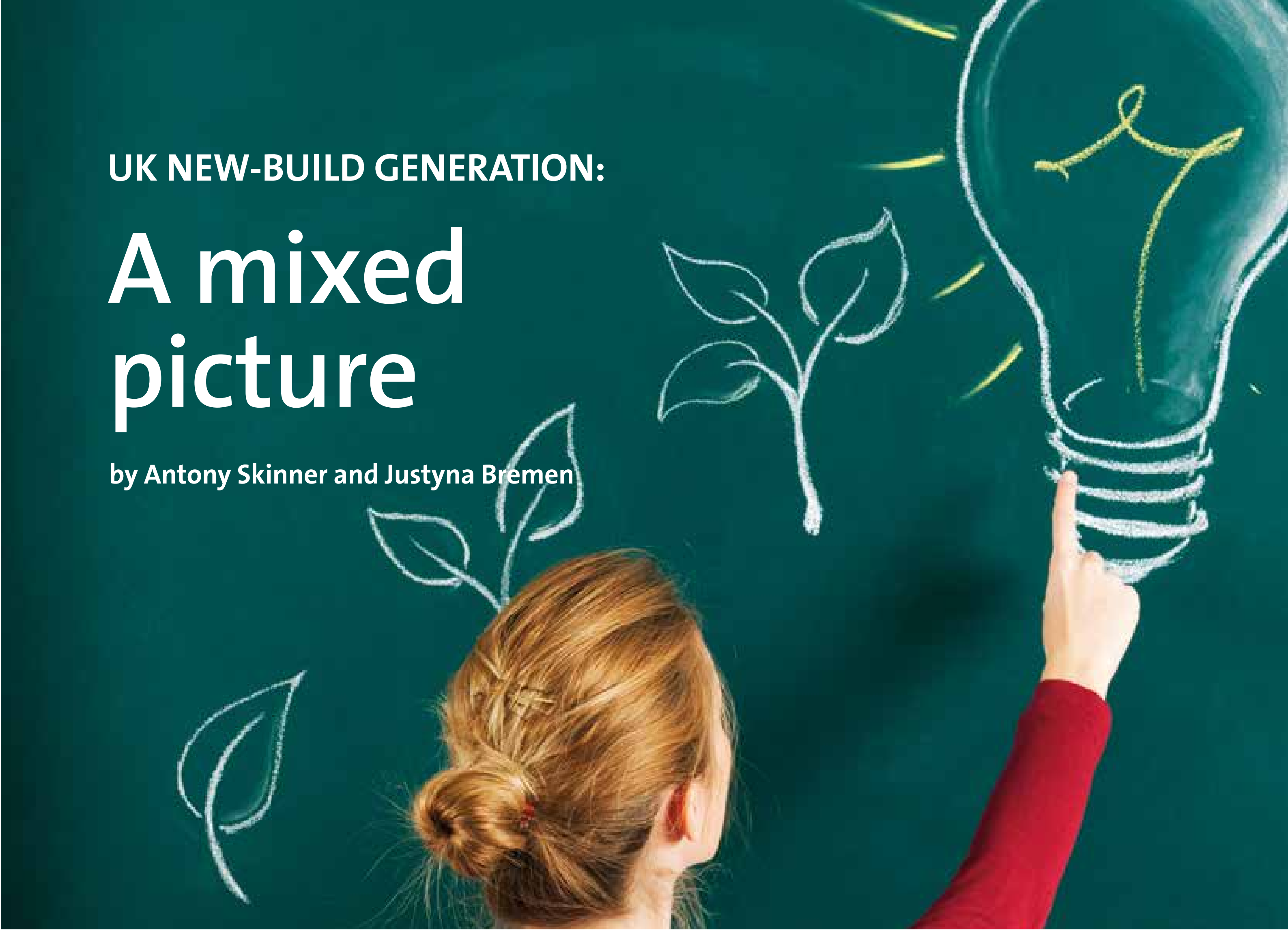
14 Lachlan Barker, "Who will pay the more than $17.8 billion mining rehabilitation bill?", *Independent Australian*, 1 June 2015.

15 Hon. Robin Chapple, *Parliamentary Debates*, 3290, Western Australia, Legislative Council, 11 August 2015.

UK NEW-BUILD GENERATION:

A mixed picture

by Antony Skinner and Justyna Bremen



Since the new UK Government took office in May 2015, there has been a degree of uncertainty about some aspects of its energy policy. In particular, while it is an inescapable fact that significant investment in new-build generation is needed, there have been indications of a change in policy direction in relation to which generation technologies should be supported and how. As at the end of 2015, some issues have been clarified, while others are still unanswered, as summarised in this article.

Background: it's all about the money

In 2014, in response to a growing energy "trilemma" – energy security, rising electricity costs and the need to reduce emissions – the former coalition Government implemented Electricity Market Reform: a complex and radical set of new measures to incentivise investment in new-build generation. In particular, the new Contracts for Difference (CfD) regime is intended to support investment in new-build low-carbon generation (primarily nuclear and renewables), replacing, over time, the existing Renewables Obligation (RO) regime. The new Capacity Market (CM) mechanism, on the other hand, offers payments to generators (both existing and new-build) for the provision of capacity.

However, the difficulty faced by the Government is that while a sophisticated and complex framework is in place to procure private sector investment in new-build generation, the costs of the old and new support mechanisms have risen to a level not originally anticipated. Other factors have also played a role in shifting government policy – such as local community opposition to onshore wind farms and concerns about the sustainability of biomass as an energy source – but cost has, overwhelmingly, been a major policy driver.

In the UK, the cost of supporting renewable energy projects is passed down to electricity consumers. However, the Government is obliged to control that cost under the so-called "Levy Control Framework" (LCF). The LCF was established by the Department of Energy and Climate Change (DECC) and HM Treasury in 2011 in order to cap the cost of levy-funded schemes and ensure that DECC "*achieves its fuel poverty, energy and climate change goals in a way that is consistent with economic recovery and minimising the impact on consumer bills*". The LCF caps spending at £7.6bn to 2020. However, DECC modelling carried out in 2015 indicates that this has already been exceeded by £1.5bn: total spend is estimated at £9.1bn (in 2011/12 prices – equal to £11.4bn in nominal prices). The budget blowout is attributed to factors such as low wholesale electricity prices and a high take-up of support under the various schemes.

It should be noted that the LCF allows for 20 per cent headroom on top of the cap, so some industry analysts have suggested that the situation may not be as dire as may appear at first glance. Nonetheless, the Government's response has been to cut the level of support offered to various technologies under the RO and the small-scale Feed-in Tariff (FIT) scheme, and postpone the second CfD allocation round, which was originally scheduled for October 2015. The situation has left developers trying to second-guess what may be the Government's next move.

On 18 November 2015, in a speech described by the Government as a "reset" of Britain's energy policy, the Secretary of State for Energy and Climate Change, Amber Rudd, provided the first comprehensive update on the Government's energy policy since the Conservative Party's election manifesto. The speech, together with November's Spending Review and Autumn Statement 2015, and the second CM auction of December 2015, paint a picture of some losers, some winners and some unknowns. We consider this further below.

Coal-fired generation

The Government has confirmed that all unabated coal-fired generation is to be phased out by 2025. The details are to be provided in a consultation document to be published in spring 2016, setting out proposals to close unabated coal-fired power stations by 2025 and restrict their use from 2023. Coal-fired power stations will only be able to continue generating beyond 2025 if they are carbon capture and storage (CCS) enabled. The UK's Emissions Performance Standard already means that no new-build coal-fired power stations can be constructed unless they are CCS enabled.

In a paradoxical turn of events, the CCS industry suffered a significant setback as a result of the Spending Review, with the Government withdrawing £1bn of funding previously set aside for investment in two CCS projects selected through a CCS commercialisation competition originally launched in April 2012. The two projects are the White Rose project, involving capturing around 90 per cent of the carbon dioxide from a new super-efficient coal-fired power station at the Drax site in North Yorkshire, and the Peterhead project, involving capturing around 85 per cent of the carbon dioxide from an existing combined cycle gas turbine (CCGT) power station at Peterhead.

On a positive note, the House of Lords has called for a new clause to be included in the Energy Bill 2015-16, currently before Parliament, which will oblige the Secretary of State to prepare a CCS strategy.

Nuclear generation

The Government has confirmed its commitment to new-build nuclear projects, which rely on financial support under the new CfD regime. Not only was this commitment expressed in the Secretary of State's "policy reset" speech, but at the time EDF Energy and China General Nuclear Corporation signed a Strategic Investment Agreement in relation to the Hinkley Point C nuclear power project, the Government expressly stated that "*it is not continuing the 'no public subsidy policy' of the previous administration*" in relation to nuclear.

The Government appears to have recognised that strong policy support is needed to incentivise nuclear developers to commit to the significant early stage development costs associated with new-build nuclear.

Gas-fired generation

The previous Government's Gas Generation Strategy envisaged that gas-fired generation is to play a key role in the UK's energy generation mix. The new Government has now confirmed its commitment to supporting gas-fired generation, saying that it is "imperative" that new gas-fired power stations are built in the next ten years.

However, the new CM mechanism, which is the key policy instrument designed to achieve that objective, has so far failed on that front. The first CM auction resulted in only one new-build CCGT plant being awarded a capacity agreement. The reason for this is that the first auction ended with a clearing price of £19.40/kW, which is much lower than is needed to incentivise CCGT investment. Indeed, the Net CONE (Cost of New Entry), which was estimated by the Government for the purposes of the auction and was based on the estimated level at which new-build CCGT will bid into the Capacity Market, was set at £49/kW. Therefore, nearly all the potential new-build projects which participated in the auction exited the auction as the clearing price went down. The Trafford project, which was awarded a capacity agreement, is reportedly struggling to secure finance due to the low CM clearing price.

More recently, the second CM auction, held in early December 2015, achieved an even lower clearing price of £18/kW, over £1 cheaper than the first auction. As had been predicted by industry analysts, small-scale gas and diesel generators were the most successful in this auction and, once again, the auction failed to support large-scale CCGT – the Carrington CCGT project, the only new-build successful in this instance, is already under construction. Therefore, the CM mechanism has failed to support potential investors in new projects which may still be in the planning and development stage.

The Government has said that it will review the CM mechanism following the second auction. It is clear that some significant changes are required to the design of the mechanism to ensure that it

offers the right support to developers of new CCGT plants, rather than just rewarding existing capacity or small, inefficient generators. The Government is already implementing some changes to the CM to ensure, primarily, that projects awarded a capacity agreement do actually deliver the capacity promised.

Renewable energy

There has been concern that the Government is distancing itself from support for renewable energy. Cuts to support for solar PV projects, under the RO regime and the small-scale FIT scheme, cuts to support for onshore wind under the RO, as well as the postponement of the next CfD allocation round, have all given rise to uncertainty for the renewables sector.

Offshore wind

The Government has confirmed that it considers that new-build offshore wind projects have a role to play, but on the condition that the offshore wind industry can make cost savings. It seems likely that what this will mean in practice is that the strike price, which sets the level of support under the CfD regime, will be capped to a lower level.

The Government has also confirmed that a CfD allocation round will take place by the end of 2016. While it may not be wise to speculate until the Government announces further detail, offshore wind is likely to be eligible for participation in that round.

Offshore wind is also currently eligible for support under the existing RO regime, provided a project can achieve accreditation by 31 March 2017 (or by 31 March 2018, where certain "grace periods" apply).

Onshore wind

It seems that in the UK, onshore wind has been the victim of its own success. It is one of the most established and proven renewable energy technologies and, in 2014, onshore wind had the highest share of all UK renewable energy capacity, at 35 per cent. However, as mentioned above, there has been some public opposition to the growth in onshore wind farms. For that reason, it was part of the Conservative Party's manifesto that it will end "*any new public subsidy*" for onshore wind and that it would also change the planning consent regime so that "*local people have the final say on wind farm applications*".

Being true to its word, in June 2015, the Government announced that it would be closing the RO scheme to new projects from 1 April 2016, subject to various grace periods for projects currently in development. The Government's decision has been subject to some criticism because, until now, onshore wind has been seen as an important means of delivering the UK's renewable energy targets at the lowest cost. Indeed, the Energy Bill 2015-16, which (among other things) sets out the statutory provisions for the early closure of the RO for onshore wind, is currently before Parliament, and there is some possibility that the Government may be forced to rethink its position, because the House of Lords has objected to the relevant statutory provisions. However, the fact is that the RO will be closing soon in any case, and all future renewable energy projects will need to rely on CfD support.

In the recent "policy reset" speech, the Government has reiterated that there should be no new public subsidy for onshore wind, on the basis that its costs have come down. It therefore appears possible that the Government is contemplating making onshore wind projects ineligible for participation in future CfD allocation rounds. This raises questions from a state aid clearance perspective if the Government is seen to be excluding the most price-competitive technology.

Solar PV

The solar PV industry has suffered significant ups and downs in recent years. Ground-mounted solar PV farms became very successful under the small-scale FIT scheme, but support for them was significantly cut to control cost. More

recently, in October 2014, the Government confirmed its decision to close the RO to new solar PV generating stations above 5 MW in scale from 1 April 2015 (subject to some grace periods), and to additional capacity added to existing accredited stations from that date, where the station is, or would become, above 5 MW. Similarly, in December 2015, the Government confirmed that it will be closing the RO for solar PV projects of 5 MW and below from 1 April 2016 (also subject to some grace periods). In addition, in December 2015, the Government launched a consultation proposing a reduced level of support of 0.8 ROCs/MWh (a "banding review") for solar PV projects of 5 MW and below to apply from 1 June 2016. Significantly, the current level of support is not being grandfathered, which means that even projects that are accredited before 1 June 2016 will be affected by the banding review, if they are accredited after 22 July 2015. Only projects which can demonstrate that a significant financial commitment had been made on or before 22 July 2015 will receive protection against the reduction in support proposed under the banding review.

There has also been a high degree of uncertainty about the extent solar PV projects, including building-mounted panels, will be able to continue to rely on support under the small-scale FIT scheme. In August 2015, the Government published proposals to significantly cut the levels of support available. It had been proposed that tariffs may be reduced by up to 87 per cent, and the Government even indicated that the scheme may be withdrawn completely. The proposals have come as a shock to the industry because, while it was clear that large-scale solar PV projects and particularly ground-mounted ones were out of favour, the previous coalition Government had been very much in support of rooftop panels. In December 2015, the Government published the outcome of its small-scale FIT scheme consultation. There is some good news for the industry. In particular, the Government has confirmed that the scheme will not be scrapped, for the time being at least. Instead, the budget being made available for the small-scale FIT scheme will be capped, with a maximum of £100m a year being made available for new installations between February 2016 and April 2019, divided between technologies and subject to quarterly deployment caps. In addition, the generation tariff for domestic-sized rooftop panels will now only be cut by approximately 63.5 per cent, as opposed to the 87 per cent originally proposed. However, as noted by the Solar Trade Association, for rooftop and ground-mounted projects above 1 MW in size, there will in effect be no support at all, with a tariff of just 0.87p/kWh. While the FIT scheme may have received a partial reprieve, the Secretary of State, in announcing the consultation outcome, reiterated that subsidies for renewables should only be temporary.

In the same vein as for onshore wind, the Government has now confirmed that its "no new public subsidy" stance also applies to solar PV. Therefore, it is also questionable whether solar PV projects will be eligible for participation in future CfD allocation rounds.

Biomass

It's a mixed picture for biomass projects. It seems that dedicated biomass plant with CHP are one of the project types still "in favour", while support for dedicated biomass plant without CHP is gradually being withdrawn. Biomass conversion and co-firing projects are also considered as less desirable. All biomass projects are required to comply with new mandatory sustainability requirements introduced from 1 December 2015.

In 2013, the Government decided to introduce a cap on new dedicated biomass plants receiving support under the RO. The cap has been set at 400 MW of capacity. This means that only projects that fall within that cap will be guaranteed support under the RO for the life of the project, at 1.5 ROCs/MWh, until 31 March 2016, with a slight reduction to 1.4 ROCs/MWh for projects accredited from 1 April 2016. The cap does not apply to dedicated biomass plant with CHP. Consistently with that approach, dedicated biomass plant are also not eligible for support under the new CfD regime unless they are dedicated biomass with CHP. The initial reaction to this cap was that there would be a race to obtain an allocation within the cap, but the reality is that only 255 MW has been used up. This has been due to regulatory uncertainty and limited availability of bankable fuel supplies.

Dedicated biomass plant with CHP are currently eligible for support under the RO or the CfD regime. However, no dedicated biomass with CHP projects were awarded a CfD as a result of the first allocation round.

The Government originally stated that it would be following advice received from the UK's Committee on Climate Change that support for biomass power generation under the RO should be focused on co-firing and conversion of existing coal power plants. Co-firing and conversion projects are considered to be better value for money. However, more recently, the Government has taken a "policy U-turn" on support for biomass conversion and co-firing projects. As a means of controlling the cost arising from the large number of plant co-firing or converting to biomass, in July 2015, the Government confirmed that, subject to some exceptions, the support rates under the RO for new biomass conversion and co-firing projects will no longer be covered by the Government's grandfathering policy. This also applies to generating stations that are already receiving support under the RO and move for the first time into the mid-range co-firing, high-range co-firing or biomass conversion bands. This is a considerable disincentive to any plant owner considering biomass conversion or co-firing on the basis of support under the RO, and in our view means that third-party finance for these projects will be very difficult to raise.

While cost control is the main factor driving this decision, the Government has also said that, while biomass conversion and co-firing are cheaper means of producing renewable electricity compared to new-build generation, they should only be seen as a transitional technology because they have a lower efficiency than new-build generation and are unlikely to be able to generate CHP.

Under the CfD regime, no support is offered for co-firing plants because the Government's preference is for full biomass conversions. Moreover, while other renewable energy projects, including dedicated biomass with CHP, are eligible for 15-year term CfDs, any CfDs granted to biomass conversion projects are to end in 2027 – resulting in a shorter contract term. Biomass conversion projects are intended to be covered by a separate pot of money – so-called "pot 3". However, no money was made available by the Government for biomass conversion projects as part of the first allocation round. One of the reasons for this is that, in April 2014, two biomass conversion projects and one dedicated biomass with CHP project were awarded investment contracts – an early form of CfD.

Energy from Waste

Standard combustion Energy from Waste projects are only eligible for support under the RO and CfD regimes if they are CHP projects. This technology has been relatively free of controversy, but a big challenge ahead for this technology is the need for the industry to develop innovative solutions to reduce costs. Currently, under the CfD regime, the strike price being offered is already low.

Advanced Conversion Technologies (ACT), which are eligible for support under both the RO and CfD without the need for CHP, are currently being deployed on a relatively small scale. It seems likely that Government support for ACT projects will continue, and the UK may see an increased rate of deployment, as ACT projects are "banked" and confidence in viability and robustness of the technology increases.

Tidal lagoon

While the Government's appetite for subsidising renewable energy may be waning, one significant exception to this is tidal lagoon projects. Tidal lagoon projects are eligible for CfD support but currently that support must be applied for, and negotiated, on a case-by-case basis, outside the generic allocation round process for other renewables, similarly to nuclear power projects. The Government has expressed support for the Swansea Bay Tidal Lagoon Project and possibly several other tidal lagoon projects. The developers of the Swansea Bay Tidal Lagoon Project commenced negotiations with the Government for a CfD in March 2015.

Low-carbon heat

The Secretary of State has said that low carbon heat is to play a role, but it is not clear at this stage what approach the Government will take. The Government's approach is to be unveiled in 2016, as part of its strategy to meet the UK's carbon budgets. In particular, it is uncertain to what extent support will continue to be available for heat from renewable energy sources under the Renewable Heat Incentive (RHI) scheme. The RHI scheme is important, not just for renewable heat installations, but also for CHP plant, which rely on the RHI for support for their heat output. So far, as part of the Spending Review, the Government confirmed that it will increase funding for the RHI to £1.15bn by 2020-21. However, the Government also said that it would be "*reforming the scheme to deliver better value for money*".

Next steps

There had been an expectation that, in delivering its Spending Review and Autumn Statement 2015 in November 2015, the Government would provide some clarity about the future budget for spending on renewables under the Government's Levy Control Framework, as well as the exact time of the next CfD round. This did not happen. As mentioned above, the Government has confirmed that the next CfD allocation round will take place by the end of 2016, but more information about the timing, what technologies will be eligible to participate and the budget available is vital and has not yet been released.

There are also a number of changes that are currently being implemented, as well as other changes signalled for 2016, creating uncertainty for the industry while the final outcome is uncertain – for instance, the provisions under the Energy Bill 2015-16, currently before Parliament, dealing with closure of the RO scheme for onshore wind, and future changes to the Capacity Market mechanism.

The Government is clearly conscious of the need to attract investment in new-build generation. It is therefore hoped that, in the next few months, the Government will smooth out the road for investors, filling in any gaps, to ensure that the work that went into implementing the Electricity Market Reform framework is not in vain. It may also be that the new climate change deal agreed at COP21 will compel the Government to refocus its policy on renewable energy. However, driving costs down remains at the forefront of the Government's policy and they appear to be of the view that subsidies for more mature technologies, like onshore wind and solar, are distorting the market and preventing costs from reducing.

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Stop press

Ashurst strengthens resources and infrastructure team

Ashurst is pleased to announce the appointment of two new partners, Michael Harrison and Richard Guit, to its resources and infrastructure team.

Michael is based in Ashurst's Sydney office and Richard is based in Perth.

Michael is one of Australia's leading energy and resources, projects and transactional lawyers. His industry focus spans all aspects of the energy and resources sectors, from power to mining to oil and gas. Many deals on which he advises are cross-border matters throughout the Asia-Pacific region, including Indonesia, South Korea, Papua New Guinea and Western Australia.

In addition, Michael works for clients (including government clients) in the transport (ports, shipping, rail and road), waste and water industries (including PPPs). Michael advises on the development and finance, commercial, corporate, construction and engineering, licensing and regulatory aspects of projects and transactions.

Richard is a leading lawyer in infrastructure transactions and the energy and resources sector. He advises on infrastructure development, operation and divestment – acting for governments, sponsors, lenders and investors on all aspects of these transactions. He specialises in project documentation, financing, credit enhancement and security packages. He is active across all sectors and has extensive experience in PPPs, having advised on major economic and social PPPs in both the UK and Australia.

Energy and Resources Financing: A Practical Handbook

Ashurst has contributed to a large number of sector-focused books published by Globe Law and Business.

Energy and Resources Financing: A Practical Handbook is the latest such book, co-edited by oil and gas financing expert Huw Thomas and renewables and conventional power expert Antony Skinner, both of whom are partners in our London energy team.

The book covers financing across the energy and natural resources spectrum, from upstream oil and gas, pipelines and liquefied natural gas through to refineries, and from conventional power and renewable energy to nuclear power and mining. It discusses the most important financing techniques, including reserve-based lending, project finance and high yield bonds.

The book can be purchased from the Globe Law and Business website at globelawandbusiness.com/ERF/.

Awards and industry recognition

In Chambers and Partners UK 2016 directory, Ashurst once again retained its impressive ranking as Band 1 for both its Energy & Natural Resources: Oil and Gas practice and its Energy & Natural Resources: Renewables practice. The Ashurst team has been described by Chambers as *"very flexible and adapt to each transaction"* and its clients have expressed *"every confidence in their* [Ashurst's] *ability"*.

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