Exploring new waters

Chad Griffin and **James Terry** look at the first exploration and production administration to take place in the current cycle.

Prolonged weakness in the commodity price environment, particularly with respect to oil prices, has given rise to significant restructuring activity, and the start of a potential wave of insolvencies, with respect to exploration and production (E&P) companies operating on the UK North Sea Continental Shelf.

The first of these insolvencies involved the Iona Energy group, a Canadian-parented and listed group with oil and gas assets in the North Sea. FTI Consulting and Akin Gump had initially been retained in early 2015 by Nordic Trustee ASA, on behalf of senior secured bondholders, to negotiate a debt restructuring. Although a restructuring was substantially agreed and close to being implemented, further downward pressure on oil prices led to a key investor pulling out in late 2015 after a year of restructuring efforts, and in January 2016 joint administrators from FTI Consulting were appointed over the UK companies in the group.

We should expect to see more E&P restructurings and insolvencies over the near-term. This article highlights some of the key issues to be aware of for lenders and investors who are looking at contingency planning and potential insolvencies in distressed UK oil and gas situations.

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Background

Iona Energy ran into difficulties in late 2014, brought on by production problems at its main producing field (Huntington), a delay to the timetable for its key development project (Orlando), a need for additional development funding, a reduction in oil prices and looming decommissioning costs.

The focus of the restructuring efforts centred around the Orlando field, which was the principal asset in the group. Orlando was a development project, meaning that exploration test wells had been drilled, but various development steps were required to bring the project to ‘first oil’, originally hoped to occur during 2016. These development steps carried significant capex costs relating to the retention of a drillship to undertake further drilling, the purchase and development of the subsea infrastructure required to safely operate the wells, and the infrastructure required for the offtake and transport of the oil and gas hydrocarbons once the field became operational and went into production. Although the project had already received significant funding through equity raises and the bond issue, up to a further \$80m-100m (£55m–£68m) was required.

The company undertook fund-raising efforts, which might have involved any number of solutions from M&A, equity investment, new super senior debt »

financing and/or restructuring of the existing financial debt. Ultimately, an innovative restructuring was developed through a combination of capex savings, deferrals from key Orlando project suppliers (who in the current environment were highly incentivised to see the field becoming operational), a debt for equity swap to reduce the level of bond debt and future cash interest costs, and a farmout with an industry player. A farmout involves a new partner (typically another E&P company) coming into the field project and taking on a share of that project, usually by becoming responsible for an equivalent share of future costs (and by definition, future revenue once the field goes into production). This can be a very effective way to reduce costs (and associated risk) for existing field partners that are unable or unwilling to bear their current share of the future burden of concluding development of an oil field.

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However, in late 2015, the proposed farmout partner for the Orlando field pulled out after its parent elected to restrict capital allocation to its upstream operations. This had been a key component in the restructuring, and without it the restructuring could not proceed. The focus therefore shifted to preparing for an administration, and realising value through individual asset disposals.

The administration strategy involved effecting certain pre-packaged transactions for bids that had been negotiated during the M&A process, winding down operations and exiting from other licence interests where no bids emerged. A key question in this would be the impact of the administration on the continuation of the licence for the Orlando field.

Key issues

There are some significant industry, regulatory, operational and tax issues to be aware of in undertaking contingency planning for (and then administrations of) E&P companies, many of which have featured in the case of Iona Energy. We set out some of these below:

Understanding the assets

E&P companies range from large scale operators of producing oilfields to exploration focused companies, and their business models are vastly different. A thorough understanding and risk assessment is needed, as this will drive the appropriate strategy.

The assets themselves tend to comprise certain key components, each of which needs to be reviewed and understood. These tend to involve a government-issued oil licence; a joint operating agreement, and potentially also additional royalty entitlements and lifting entitlements (ie right to oil sales) that may have historically been negotiated between field partners. At the root of it all are the well inventories themselves, which dictate the expected production levels and life of the field, and therefore its ultimate value.

The joint operating agreement is usually the key contractual document. This regulates the rights and rules between the various field partners, and in particular the basis on which the field will be operated on a day-to-day basis by one of the joint venture partners who will act as the 'operator'. In the case of Orlando, Iona was the operator of the field. The insolvency of an operator can potentially be far more complex than the insolvency of one of the other partners whose involvement is principally financial. However, the level of complexity will depend on the extent to which the field is already operating, and the status of any wells that have been drilled.

Also relevant is the creditworthiness of other field partners. If one of the field partners fails, the other partners need to decide whether to abandon the field venture in its current form, or whether to take on the non-performing partner's share of the field. While in the long run this route will provide access to an increased share of revenue, prior to production it also involves the performing partners bearing an increased level of the development costs, for which they may not have budgeted. Although joint operating agreements are often based on an industry standard form, there has been little track record to date of distress in the E&P industry and therefore many of the default provisions in joint operating agreements have not actually been tested in practice. It should be assumed that major oil companies in particular will be keen to adhere strictly to the provisions of the agreement, not least given the concern to establish a strict precedent across all of their other field ventures.

All of these items need to be reviewed in detail to understand entitlements, the impact of operational and financial defaults, and points of leverage.

Particular focus is needed on decommissioning – the requirement once a field becomes operational to post security for the ultimate close-down of the field at the end of its life. Decommissioning liabilities can involve significant up-front payments. They will be of significant importance to regulators, as well as potential bidders. An in-depth understanding of the development

infrastructure in place on the seabed, including suspended wells, is crucial.

Health and safety and emergency response arrangements

Membership of the Offshore Pollution Liability Association (OPOL), an industry organisation that administers a voluntary strict liability compensation regime, is mandatory for operators of oil licences. This imposes certain obligations on members including financial and operational capability in the event of an emergency pollution incident.

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It is important to review insurance arrangements. Specialist energy policies are not covered by standard open cover and it will be important to liaise with the insurers to ensure continuity and availability of cover.

A risk assessment should be undertaken for health and safety executive (HSE) issues. This is not an area to be overlooked, however low the perceived risk. Key staff with health and safety and emergency response responsibilities should be identified and retained. Certain standby contracts may also be needed to ensure appropriate incident readiness.

Role of the regulators

From April 2015, UK North Sea oil and gas companies have been regulated by the Oil and Gas Authority (the OGA). It is an executive agency of the Department of Energy and Climate Change (DECC) and is principally focused on licensing. Early engagement with the OGA is important in distressed situations given licence defaults upon insolvency, development obligations and the OGA consent requirements for disposals. It should be remembered that prior to 2016 there has only been one formal insolvency of an E&P company operating in the UK North Sea, namely Oilexco. To that end, recent events are making yet new ground, and requiring the OGA to consider their strategy in an environment where multiple licensees could be in financial distress. It is important to have an open and constructive dialogue with the OGA. The OGA is acutely aware of the difficulties facing many struggling oil and gas companies and can play a key role in providing flexibility and support where needed.

Experience to date has shown the OGA to be practical and commercial.

The Petroleum Act 1998 affords the secretary of state for the DECC wide ranging powers to serve notices on parties in connection with decommissioning and well abandonment. These parties can include group companies, shareholders owning in excess of 50 per cent, former owners and potentially directors and officers.

Specialist E&P legal advice is important in this area. Insolvency practitioners will wish to make appropriate arrangements with the OGA and DECC ahead of any insolvency, in particular in relation to managing potential risks of claims against them for decommissioning and abandonment.

Asset realisation and the importance of tax

With depressed oil prices, disposal processes will prove challenging. It must be recognised that purchasers interested in development assets, or operating assets with capex requirements, will face significant funding requirements. It is important to explore creative payment structures on the sale of assets, including the possibility of upside sharing through deferred consideration to drive superior recoveries.

Most distressed oil and gas companies have significant pools of tax losses. These are typically available to shelter future trading profits on licences but are not capable of being sold separately. It is also key to drive value from these attributes.

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Given high corporation tax rates for UK North Sea oil companies, most interested parties look for an acquisition of companies to preserve the tax loss pools, rather than business and assets, which would result in the tax losses being unavailable.

Consequently, efforts should be taken to achieve a financial restructuring that enables the sale of companies as going concerns, meeting the administration first purpose. This may involve a company voluntary arrangement (CVA) to restructure unsecured creditors' claims in an efficient way. The recent introduction of the corporate rescue exemption may also be of benefit in restructuring secured debt in a tax efficient manner.

With tax being such a large value driver for bidders, it is important to seek tax advice early, to develop a value maximising approach to disposals.

Optimising the overall outcome

E&P restructurings and insolvencies present a unique set of challenges. Given the benign oil environment in recent years, there are few precedents to follow. It is important to assemble the right team with the requisite experience, who can step up immediately and drive an optimal recovery. ◻

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