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Global Energy Industry Review

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Editors' Note

In this edition of Mayer Brown's *Global Energy Review*, we provide an overview of Latin America's increased focus on oil and gas exploration and how terms and conditions vary greatly from country to country. Additionally, in the United States, we look at the modifications of the oil and gas disclosure rules and the SEC comment letters pertaining to the updates.

We explore Southeast Asia's nuclear development in 2011 and what role the government, investors, public policy and bilateral cooperation play.

Lastly, in the United Kingdom, we look at the significant increase in tax applied to North Sea oil and gas producers as well as the UK government's cuts to funding for solar projects.

While this review is intended to look at trends in the energy industry, we regularly publish legal updates on timely issues. To view a complete list of our energy updates visit our Energy News and Publication page.

If you have any questions or comments on any of the articles in this edition, please contact us. ◆

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Latin America Offshore Roundup

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With significant gas reserves and oil reserves that are second only to the Middle East, Latin America has become a natural focus of oil and gas exploration in recent years. As the countries in this region increasingly turn their attention to their offshore prospects—which range from Brazil's massive fields to lesser known areas elsewhere—all are welcoming the technology, capital and expertise of foreign companies, but under terms and conditions that vary greatly from country to country.

Brazil[1]

With recently discovered offshore pre-salt reserves estimated to exceed 50 billion barrels of oil equivalent (boe) Brazil has the potential to become one of the world's leading oil producers. Petrobras, the giant state-run oil company, has announced plans to spend $224 billion over the next five years, with the goal of doubling its oil production and export capacity.

Brazil's oil and gas future is offshore. According to the Brazilian National Agency of Petroleum, Gas and Biofuels (ANP), about 92 percent of the country's proved oil reserves and 82 percent of its proved gas reserves are located offshore. About 90 percent of the country's current oil production is from offshore locations. Brazil currently hosts 33 percent of the world's fleet of floating production units.

Brazil has taken steps increase control over the pre-salt areas, which were discovered in 2007 as a result of drilling by Petrobras in the Tupi (now Lula) field. Through the recent enactment of a separate legal regime applicable to the development of "strategic areas"—a loosely defined term that includes the pre-salt regions—Brazil now mandates that private companies hold an interest in a production-sharing contract (PSC) under which Petrobras must serve as the operator and also hold a minimum 30 percent working interest. The award of these production-sharing contracts will be made competitively on the basis of the lowest bid for profit oil share. Petrobras itself may be awarded contracts without a competitive bidding process.

Brazil's traditional concession-contract regime will remain in place outside of the "strategic areas." Concessions granted in the pre-salt region prior to the 2009 enactment of the new law are grandfathered.

Brazil has recently announced its 11th bid round, which covers 174 blocks (87 of which are offshore) along the equatorial coast outside of the pre-salt region. As such, the areas will be subject to the concession contracts. The bid process is to commence in September 2011 and conclude in December.

Under the concession contracts, the contractor pays a signature bonus, a royalty at a rate of 5–10 percent, and various taxes; combined, these payments allow an operator to keep 25–30 percent of gross revenues. These contracts generally impose a schedule of minimum work obligations with an exploration phase lasting 3–7 years.

Concession contracts for the 11th round will likely require financial guarantees and will permit termination of the contract for failure to comply with the minimum exploratory program. Although payment of 1 percent of gross revenues from a field as a special participation has long been a part of these contracts, the ANP has indicated that, under the concessions to be awarded, half of this amount must be invested in previously approved projects in Brazilian accredited universities and institutes.

No bid rounds have been announced yet for the award of the production-sharing contracts in the pre-salt region. The government is reportedly still working on the model form PSC.

Mexico

Mexico, awash for decades in easily accessible oil, is grappling with declining oil production, particularly at the massive offshore Cantarell field, which now produces only a quarter of what it did in 2004. Many expect that Mexico's oil future lies in the deep waters of the Gulf of Mexico, where the expense and complexity of drilling operations has limited the ability of state-owned monopoly Pemex to expand its operations there.

Mexico has historically shunned international E&P companies, but now, in an effort to draw more foreign technology and know-how, it has sought to create a more friendly contract regime. However, this effort has been beset with political challenges: even the watered-down reform that was passed in 2008 has been subjected to protracted legal challenges. The ultimate result was a law permitting Pemex to enter into E&P contracts under which it would reimburse costs and pay a fixed fee in cash per barrel of delivered production. Incentive-based bonuses in cash may also be paid under specified circumstances. The law does not allow for ownership in Mexico of locally produced oil, nor does it allow compensation on the basis of the value of production. This precludes all forms of production-sharing arrangements and compensation in kind.

After delays due to legal challenges to implementing regulations, Mexico has been cautious in rolling out the new contracts. The first tender was announced last March, and it covers only three aging onshore fields in need of enhanced recovery methods. For those blocks, the contractor will be paid only a per-barrel fee, supplemented by a partial recovery of costs. No incentives are being offered. The Calderon administration remains optimistic that these contracts will successfully lure foreign companies, and the administration has announced plans to use them in other bidding rounds scheduled for next year.

The true test will come when Mexico seeks bids for the deep-water areas on which much of its energy future depends. Pemex officials have said that they plan to announce the first tender for offshore blocks in the first half of 2012 and expect to use incentive-based contracts. It remains to be seen how the E&P offshore industry will respond to contracts with very limited upside to compensate for exploration risk.

Venezuela

Venezuela's proved oil and gas reserves dwarf those of other Latin American countries. Although the Chavez administration is widely regarded as unpredictable and less than friendly to foreign companies, several international oil companies have invested heavily in the country and taken the long view.

In Venezuela, separate rules apply to oil contracts and gas contracts. With large, well-developed crude oil reserves, Venezuela is generally more exacting in granting oil contracts. All oil projects must be carried out by a joint venture company majority-owned by Petroleos de Venezuela S.A. (PdVSA), the state-owned oil company. Historically, Venezuela affords little stability, with tax and royalty rates liable to jump, and the threat of nationalization looming when a licensee does not accept changes to its contract.

In contrast to Venezuela's oil reserves, non-associated gas fields are severely underdeveloped and are found largely offshore; in combination, these facts give foreign oil companies more leverage. The law relating to the development of non-associated natural gas is intended to provide more favorable terms to private companies. The government has reduced royalty and income tax rates on non-associated natural gas projects and allows private companies to own all of the interests in projects. However, PdVSA reserves the right to take up to a 35 percent carried-working interest.

While non-associated gas projects appear to offer some promise, there are distinct disadvantages to operating in Venezuela, in that PdVSA would constitute the only outlet for offshore gas production. As for exports, the government has advanced plans to build an LNG facility for which offshore producers would serve as dedicated feed gas suppliers. Plans for pipeline gas exports through Colombia have missed several target dates. Some plans through Brazil have been shelved. As for the domestic market, natural gas is heavily subsidized and available prices may not compensate for production costs and risks.

Argentina

Production from Argentina's onshore oil and gas fields has declined rapidly over the last few years, causing the country to assess its offshore potential. Argentina is a newcomer to deep water drilling. When the state-owned energy company, ENARSA, and YPF, the largest producer in the country, announced plans to drill exploration wells off the coast of Buenos Aires province in 2010, it was the first major new offshore exploration project for the country in more than 30 years. Argentina has announced that it will be licensing 31 offshore blocks this year in the hopes that they will result in discoveries similar to Brazil's.

Jurisdiction over the country's oil and gas resources has shifted to the provinces. However, offshore areas beyond 12 nautical miles from the coast are subject to federal jurisdiction and, unless an exploration permit was previously granted to a private holder, all permits in the area are held by ENARSA. Private companies must associate with ENARSA in order to carry out E&P operations in federal waters.

Argentina grants exploration licenses (with the acreage diminishing at intervals), which may be followed by a production concession lasting 25 years. A royalty rate of 12 percent, paid in cash (or in kind, if requested by the government entity), is typical, but depends on the location of the reserves, and it may be reduced to as low as 5 percent under some circumstances. In order to encourage development of crude oil reserves, Argentina adopted the "Oil Plus" plan in 2008, which provides export duty credits to companies that increase their production and reserves by a certain threshold. In turn, the "Gas Plus" plan offers to exempt production from certain new discoveries from local price controls.

Colombia

Colombia has devoted considerable effort to increasing oil and gas exploration and production by attracting foreign participation, and the results are impressive. The country is on target to achieve, in the short term, its goal of one million barrels of oil equivalent per day (boe/d) of production. E&P contracts are granted by a state licensing agency (ANH) pursuant to a competitive bidding process and there is no requirement for an association with a state-owned company. The fiscal regime consists of royalty and income tax. State-controlled Ecopetrol competes on an equal footing with private companies in bid rounds.

The government has recently finished signing contracts following the 2010 bid round, which included the most offshore blocks of any bid round. No new offshore drilling has taken place in Colombia since 2008. At present, offshore production in Colombia is limited to the Chuchupa gas field (Caribbean coast) operated by Chevron.

Peru

Peru is the only country in South America that exports liquefied natural gas (LNG). The feed gas comes from the Camisea field on the eastern side of the Andes mountains, on the southern region of the country. Much of Peru's proven oil and gas wealth is located onshore, but recent offshore activity suggests some potential for larger finds in the future. Although its current offshore production in the northwest is relatively small, some have speculated that, by attracting investment, the country could substantially increase production from offshore areas.

As in Colombia, E&P contracts are granted by a state licensing agency (Perupetro) pursuant to a competitive bidding process and there is no requirement for an association with a state-owned company. The fiscal regime consists of royalty and income tax. State-owned Petroperu competes on an equal footing with private companies in bid rounds. ◆

1 Observations in this article about Brazilian law are by Tauil &Chequer Advogados. They are not intended to provide legal advice to any entity; any entity considering the possibility of a transaction must seek advice tailored to its particular circumstances.

SEC Staff Comments on Companies' Compliance with New Oil & Gas Reserves Disclosure Rules

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In December of 2008, the US Securities and Exchange Commission (SEC) adopted amended oil and gas disclosure rules. The adoption of these rules was a significant development for public reporting exploration and production (E&P) companies because it represented the first time in three decades that these rules had been substantially modified. According to the SEC's adopting release, the new rules were designed to better align SEC oil and gas disclosure standards with modern industry standards.[1]

After their adoption, however, questions began to arise regarding the application of the new rules in a number of critical areas. The SEC's Division of Corporation Finance issued Compliance & Disclosure Interpretations (Oil & Gas CDIs) in October 2009 in an attempt to clarify the new rules and address the industry's questions and concerns.[2]

Among the most significant changes under the new disclosure regime were two new "principles-based" rules: (i) a new "five-year rule" for proved undeveloped reserves (PUDs) and (ii) a broadened authorization that permits companies to prove their reserves by the application of "reliable technology."

Five-year rule. The five-year rule is a time-based limitation on reserves that a company can classify as PUDs. In order for PUDs to be booked for an undrilled location, the company must adopt a development plan indicating that the undrilled location is scheduled to be drilled within five years. PUDs that remain recorded on a company's books for more than five years should be removed from the proved category. There is an exception to this rule: PUDs may be booked for more than five years if "special circumstances" justify a longer interval before development will be initiated. In the Oil & Gas CDIs, the SEC staff identified some types of projects that may, depending on the situation, constitute candidates for these "special circumstances." These include development in urban areas, remote or environmentally sensitive locations and projects that involve the construction of offshore platforms. The Oil & Gas CDIs indicate that the ability to classify a location as a PUD location where development is scheduled to begin more than five years in the future "should be the exception, not the rule."[3]

Reliable Technology. Under the old rules, companies were generally confined to using flow tests or observing actual production in proving up their reserves. Given the technological advances in the industry over the past 30 years, the new rules now permit companies to use "reliable technology" in making their proved reserves determinations. The new rules define reliable technology as technology that has been field tested and demonstrated to provide "reasonably certain" results with consistency and repeatability in the subject formation or an analogous formation. By broadly defining reliable technology in this way, the SEC intended that companies may use their existing proprietary methods or develop new methods for determining their proved reserves.

Calendar-fiscal-year-reporting E&P companies were first required to comply with the new rules with respect to the disclosures contained in their Annual Reports on Form 10-K for their fiscal year ended December 31, 2009. This first round of reporting under the new rules provided the SEC staff an opportunity to analyze whether their application was congruent with the SEC's expectations. The views of the staff on the companies' compliance with the new rules in their SEC filings were expressed in comment letters issued by the staff in 2010 and early 2011.

The Comment Letters

Many comment letters dealt with (i) the extent of companies' compliance with the five-year rule and (ii) what constitutes sufficient support for booking new reserves that were added through the use of reliable technology.

Five-year rule. The staff generally took issue with descriptions of PUDs being converted to proved developed reserves at a rate that, mathematically, would take longer than five years.[4] If it did not appear to be possible to convert all existing PUDs to proved developed reserves within five years, the staff asked the companies to explain how they planned to accomplish the conversion. The staff sometimes asked companies to provide the amount and percentage of PUDs that had been converted to proved developed reserves during years prior to 2009.

The staff also took issue with PUDs that had been listed as such for longer than five years, and asked those companies to explain why these PUDs remained undeveloped. For some companies that had provided these explanations, the staff also wanted to know when the companies planned on drilling and producing from those locations, and emphasized that if those companies were not reasonably certain of developing the wells within the next five years, the reserves estimates attributable to those locations should be removed.[5]

- There were numerous comments dealing with insufficient explanations of material changes in PUDs, year-over-year, and the reasons for these changes.[6]
- Where PUDs attributable to a particular project or property were significant, the staff requested additional information about the development schedule and other factors regarding the project properties (e.g., whether there was one development project or multiple development projects, the terms of the relevant leases, etc.).[7]
- Where a company had disclosed that it expected to drill 90 percent of its undrilled locations within the next five years, but there had been no material conversions in 2009, the staff requested expanded disclosures to clarify the company's planned schedule for development of those reserves, and compliance with the SEC's new rule requiring disclosures of "investments and progress" made during the year to convert PUDs to proved developed status, including capital expenditures.[8]

Where a company had disclosed "special circumstances" to justify why certain PUDs would not be developed until year six or later, the staff asked for the total proved reserve figures for those particular PUD locations and the conditions that may prevent their initial development within five years of booking. There were other comment letters that dealt with field development and PUDs:

- The staff sometimes requested additional detailed information on how booked PUDs would be developed within the next five years.[9] If PUDs were expected to be developed and classified as proved developed reserves within five years due to special recovery methods, such as the use of compression techniques, the staff inquired whether the company had made a final investment decision on installing the requisite special recovery equipment and facilities in the field.[10]
- If it appeared that a company's liquidity to fund development plans was insufficient, the staff asked for additional information explaining how the PUDs could be developed within the time frame disclosed.[11]

- Where a company had argued that PUDs in one field could not be developed in five years because of factors largely "out of its control," the staff disagreed, stating that the factors in question—a lack of access to hydraulic fracturing services, rental equipment (primarily completion rigs) and associated contract services—were all known factors at the time the reserves were estimated, and that those PUDs therefore should have been removed.[12]
- Where additional PUDs had been added and the additions were attributable to a number of different factors, the staff requested disclosures on which portions of the additional reserves had been attributable to (i) drilling, (ii) acquisitions and (iii) revisions.[13]

Reliable technology. A number of comment letters requested expanded disclosures of the specific technologies used to establish "reasonable certainty" for the additions to the companies' disclosed reserves estimates. The level of required detail was referred to in several letters as a description, a general discussion and an explanation of the methods used.[14] Under the new rules, reliable technology must have been field-tested and demonstrated to provide "reasonably certain" results with consistency and repeatability in the subject formation in order to establish the appropriate level of certainty. Thus, the staff requested disclosure on the actual technologies employed and why companies believed they were reliable in the geological environment in which they were applied. The staff also requested disclosure on how many proved reserves were determined by using alternative methods and technologies, including production flow tests. Still other comment letters dealt with reliable technology disclosures:

- Broad, imprecise descriptions of the technologies relied upon were found by the staff to not meet the reasonable certainty threshold.[15] Where there was only a general reference that technology had been employed (e.g., "the application of reliable technologies"), the staff asked the company to provide a detailed description of what those technologies were.[16]
- Where references to the use of certain specific technologies were made, the staff sometimes requested explanation in greater detail (e.g., information regarding the "microseismic operations and reservoir simulation modeling" used to estimate reserves).[17]

Conclusion

The SEC staff comments discussed above represent only a small portion of the types of shortcomings in oil and gas disclosures (in the staffs' view) that were addressed in other comment letters to E&P companies.[18] The staff will review filings of additional E&P companies in 2011 and beyond, which will deal with the same issues addressed in this article, but will also no doubt raise new areas of concern. Based on the staff's views to date, publicly reporting E&P companies should keep in mind the following:

- The staff maintains a strong presumption against companies' ability to maintain their PUDs on their books for more than five years, and
- Despite concerns that disclosures might be competitively harmful and not protective of their proprietary information, companies should be prepared to:
  - Disclose their development plans (including projected capital expenditures) for converting existing PUDs to proved developed reserves; and
  - Provide detailed descriptions of the specific technologies and methodologies employed if proved reserves are added on the basis of applying "reliable technology." ◆

Endnotes

1 "The amendments are designed to modernize and update the oil and gas disclosure requirements to align them with current practices and changes in technology." SEC Release No. 33-8995, "Modernization of Oil and Gas Reporting" at pg. 1 (December 31, 2008).

2 The Oil & Gas CDIs were addressed in a Mayer Brown Global Energy Industry Review published in March 2010. See "*Recent Staff Interpretations of the SEC's New Oil and Gas Disclosure Rules Leave Many Questions*," in Issue 1–2010 "Global Energy Industry Review" (March 2010) at pg. 16.

3 Question 131.03 of the Oil & Gas CDIs.

4 *See, e.g.*, Brigham Exploration Company (July 1, 2010); Petrohawk Energy Corporation (Apr. 27, 2010).

5 Range Resources Corporation (Aug. 25, 2010, Nov. 9, 2010). *See also* Nexen Inc. (July 2, 2010); Quicksilver Resources

Inc. (July 2, 2010); Stone Energy Corporation (June 30, 2010); EOG Resources, Inc. (June 25, 2010); Cimarex Energy Co. (June 21, 2010); Encore Energy Partners LP (December 30, 2010); Rex Energy Corporation (Feb. 16, 2011).

6 Daybreak Oil & Gas, Inc. (Feb. 28, 2010); Cubic Energy, Inc. (Feb. 7, 2011); Encore Energy Partners LP (Dec. 30, 2010).

7 Devon Energy Corporation (June 11, 2010).

8 Stone Energy Corporation (June 30, 2010); Item 1203(c) of SEC Regulation S-K.

9 *See*, *e.g.*, EOG Resources, Inc. (June 25, 2010).

10 Noble Energy, Inc. (Dec. 10, 2010).

11 FieldPoint Petroleum Corporation (Mar. 2, 2011); Mexco Energy Corporation (Mar. 9, 2011).

12 Swift Energy Company (Feb. 16, 2011).

13 EOG Resources, Inc. (June 25, 2010).

14 Quicksilver Resources, Inc. (July 2, 2010); EOG Resources, Inc. (June 25, 2010); New Concept Energy, Inc. (Apr. 19, 2010).

15 Brigham Exploration Company (July 1, 2010).

16 Petrohawk Energy Corporation (Apr. 27, 2010).

17 Rex Energy (Jan. 27, 2011).

18 *See*, *e.g.*, inadequate disclosures regarding PUDs attributable to drilling locations not directly offsetting the producing well (Petrohawk Energy Corporation (Apr. 27, 2010, June 23, 2010) ("Tell us how many locations away from a producing well you determined met the definition of proved reserves and the evidence that supports it."); see also Brigham Exploration Company (July 1, 2010, Sept. 1, 2010)); failures to adequately provide the required disclosure of fields that contained 15% or more of a company's total proved reserves (Cimarex Energy Co. (June 21, 2010); Gulfport Energy Corporation (Mar. 4, 2011)); failures to properly disclose the 12-month average pricing methodology (Pyramid Oil Company (June 22, 2010); Cimarex Energy Co. (June 21, 2010)); failure to disclose the extent to which the proved reserves are attributable to enhanced recovery techniques (QR Energy, LP (Oct. 27, 2010); failure to include effects of foreign taxes (Ghanian) relating to oil and gas producing activities derived from proved oil and gas reserves (Kosmos Energy Ltd. (April 19, 2011)).

Southeast Asian Nuclear Development for 2011

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The Atomic Age

There is a paradigm shift in nuclear development: developing Southeast Asian countries such as Vietnam, Indonesia and the Philippines are at the forefront of harnessing nuclear power into a safe, efficient and sustainable energy source. In this article, we consider these three countries in relation to their legal development, official plans to build reactors and investment opportunities in order to determine their positions in the Southeast Asian nuclear development.

History of Nuclear Development in Southeast Asia

Since March 2010, Vietnam has taken significant measures to develop the legal framework upon which to build its nuclear capabilities. The country's first four projects are estimated to have a life expectancy of 60 years, and its energy development plan to build 14 nuclear reactors by 2030 should be celebrated as an encouraging sign for both foreign and domestic investment.[1]

Indonesia's nuclear history began well before Vietnam's, and with 40 years of infrastructure experience behind it, it may soon start to show its potential. For example, in 2010, Indonesia introduced Presidential Regulation No. 5 to implement a policy for the mid-term national development plan relating to nuclear power plants (NPP) during 2010-2014, and has designated three nuclear sites in Banten, Bangka and the Muria Peninsula.[2] However, Indonesia is still in the early stages of developing NPP's in comparison to Vietnam.

The Philippines having built the Baatan plant in 1984, which fizzled out after political conflict, is a prime example of the importance for promulgating governmental support and action in developing nuclear programs.

The question is, what has sparked the renewed interest in these countries, and will there be a race to the top? All three are members of the World Trade Organization (WTO), with Vietnam only recently acceding in 2007, and all three are committed International Atomic Energy Agency (IAEA) members. Asia is one of the fastest growing regions for nuclear development so it comes as no surprise that emerging countries such as Vietnam, Indonesia and the Philippines, which rely heavily on foreign investment, are eager to have a slice of the pie.

The Role of Governments

Governments should be significantly involved in the process of nuclear development, so that energy policy grows in tandem with the development of NPPs.

Statistically, emerging markets have a high energy output; Southeast Asia is currently experiencing deficits in its energy capacity, with Vietnam expecting a power shortage of approximately 128bn kWh in 2020. As a result, emerging countries are spending a higher percentage of their GDP on funding for alternative energy sources. Even with their high initial capital costs, NPPs can generate cheaper electricity on a long-term basis than more conventional energy generation, depending on the reactors employed. Operating NPPs in Vietnam would ensure that 10 percent of the total national electricity capability by 2030 would derive from 15,000 MW of nuclear power.

Ultimately, the responsibility will fall on each country's government to ensure that the financial risk involved in nuclear investment will be reasonable. Vietnam is currently experiencing financial drawbacks from the devaluation of its currency, high inflation and reduced credit rating resulting from recent poor investments. The International Nuclear Energy Development of Japan Company (JINED) has expressed an interest in providing the Vietnamese government loans for its Ninh Thuan Power Project, yet details of the loan facility are currently unknown.

Public Policy Concerns

Significant public policy concerns still need to be addressed. For example, it remains to be seen whether future NPPs in Southeast Asia will develop plans for the safe handling of uranium and for confining nuclear usage to peaceful means.

Between Indonesia, Vietnam and the Philippines, Vietnam has the only official plan to build an NPP that has secured foreign partners for development—the "Ninh Thuan Project." Indonesia is struggling with seismic activity in the proposed vicinity for building NPPs as well as the souring of public opinion, causing it to abandon its plant in the Muria Peninsula.[3] Indonesia's temperamental public attitude is at odds with the government's stance on developing nuclear plants. The Philippines' plans to build an NPP near earthquake fault lines and dormant volcanoes were abandoned after officials deemed construction to be unsafe.

The safe storage of uranium and nuclear rods as a main public policy concern has recently been highlighted by the explosion at Japan's Fukushima Daiichi plant. Despite the events in Japan, both the Indonesian government and Ministry of Foreign Affairs in Vietnam issued statements declaring continued advancement with their respective nuclear development plans.[4]

Vietnam's Law on Atomic Energy stipulates a financial cap on liability in the event of a nuclear disaster (XDR 150 million for NPP accidents and XDR 10 million for transporting radioactive materials), and the country's Master Plan, governed under Decision 906, sets out three main objectives of the nuclear reactors—one of which emphasizes safety by establishing a nuclear safety agency. Furthermore, Vietnamese and foreign organizations involved in nuclear-related activities in Vietnam are regulated under Decision 45, listing the prohibited uses of such activities that are subject to criminal and civil liability.

Importantly, to promote international compliance due to Vietnam's WTO commitments, Decision 906 ensures that Vietnam's nuclear energy will be used solely for peaceful purposes. In line with Decision 906, the Philippines, Indonesia and Vietnam are all signatories to the Southeast Asian Nuclear Weapon Free Zone treaty (SEANWFZ) and Non Proliferation Treaty (NPT) ensuring peaceful use of nuclear power.

Investors

Financing NPPs is undoubtedly one of the most challenging aspects for project implementation. The technological know-how, raw material and personnel may exist, but without investor funding, development of NNPs is not a viable option for most developing countries. The pressure of adhering to timelines and costs is tight, especially in an industry that has a history of delays and tendency to run over budget. The costs of the Ninh Thuan project were estimated in 2008 to be $3.4 billion but this estimate has since escalated to $10.5 billion The Philippines took nearly 30 years to pay off its debts from the political collapse of the inoperable Baatan plant.[5] With these experiences in mind, a clear financial strategy is required.

The commercial question on investors' minds is "who will 'assist' the Southeast Asian enthusiasm to develop nuclear power?" China's Guangdong Nuclear Power

Group, the United States' Westinghouse, Russia's AtomStroyExport and France's nuclear giant Areva have all approached Vietnamese officials looking for the opportunity.

For foreign investors, concern will arise regarding the ability of Southeast Asian governments to liberalize the nuclear markets. Indonesia is ahead of the trio, encouraging an open market subject to the State having a right of first refusal to buy all power. Vietnam is still a question mark in terms of opening its doors to more private investment in this sector. China's Guangdong Nuclear Power Group recently signed a memorandum of understanding with the Vietnam Atomic Energy Commission for cooperation in its nuclear power sector and to aid Vietnam in nuclear technology transfer. The Vietnamese government's Master Plan, issued in June 2010,[6] aims to achieve self sufficiency for the future maintenance of NPPs. For this to be realized, foreign investment must play a key role in the manufacture and supply of modern and tested technology, which local manufacturers can source at a later date. According to government policy, foreign organizations will directly contribute to sourcing the fuel needed for the nuclear plants until 2030.

Currently, the financing of the Ninh Thuan Project is based on a sovereign model where funding originates from governmental sources, in this case the state-owned utility EVN. Russia's Rosatom has agreed to construct the first plant under the Ninh Thuan Project with two 1,200 MWe pressurized water reactors.[7] The second plant will be commissioned by JINED. In accordance with Vietnam's Master Plan, the Vietnamese government has a target of issuing 20–30 percent of construction contracts to be sourced locally, increasing to 30–40 percent by 2030, encouraging further domestic participation.

It remains to be seen whether nuclear financing will become more commercially focused with increased participation from private investors via an Export Credit Agency or providing actual commercial debt that may be more cost effective.

Bilateral Cooperation

The IAEA suggests that, because of the volatile nature of nuclear development, emerging economies should closely cooperate with nations having relevant technical know-how.[8] It also recommends bilateral assistance for dealing specifically with spent fuel and radioactive waste. The results of previous successful performers such as Brazil, Argentina and Sweden demonstrate a plausible argument in favor of approach. In this context, it might be beneficial for countries like Vietnam to seek advice from experienced countries with already operating NPPs such as Japan or Russia.

One potential area of bilateral assistance to Vietnam, as evidenced in Decision 1558, is the established training facilities in nuclear advanced countries. Recognizing its lack of skilled technicians for nuclear energy operation, Vietnam has now injected VND 3 trillion (about USD 150 million) to facilitate training. Further demonstrating its commitment to develop its nuclear capabilities, the Vietnamese government has agreed to provide large financial incentives for "senior experts" to join the training program.

Indonesia also has shown an interest in its human resources preparation and has recognized the need to cooperate with countries developed nuclear programs, such as Japan, Korea and France.

Vietnam's Decision 1558 is meant to establish favorable conditions for foreign investment as the government aims to send a large number of trainees overseas for education and employ foreign experts to train technicians in Vietnam. The legislation highlights, in particular, investment in training at universities and training of professional engineers and experts in nuclear power, nuclear power management, application and security.

Summary

The three Southeast Asian countries addressed in this article have each expressed an interest in developing their nuclear capabilities with the aim of sourcing renewable energy. Although faced with many challenges, three are particularly significant. The first challenge is concerned with employing skilled technicians—addressed in Vietnam by implementing a training program in accordance with its Decision 1558. The second challenge is public policy concerns relating to geographical challenges in locating NPPs away from seismic zones and potential natural disasters. The third challenge is the availability of funding for NPPs, focusing on encouraging foreign investment with previous NPP construction experience. How these challenges are met and overcome will determine the pace and breath of development of NPPs in these countries. ◆

Endnotes

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Legal Challenge Announced as UK Government Confirms Cuts to Solar Projects

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The UK Government last week confirmed new funding tariffs for large-scale Solar PV projects under its green electricity initiative, the Feed-In Tariff ("FiT") scheme. From 1 August 2011, new entrants for solar projects into the FiT scheme will receive amended tariffs amounting to up to a 70% cut to current levels of funding. Schemes under 50kW are unaffected by the changes.

According to Government sources, the changes are aimed at achieving a "sustained growth path for the solar industry", although the announcement comes as a crushing blow to many within the UK's fledgling solar industry who had pinned their hopes on continuing Government subsidy. A major review of renewable energy published last month by the Government's advisory body on climate change — the Committee on Climate Change — noted the significant potential for solar PV generation in the UK, although its development is generally thought to have been hampered by the high costs associated with this technology.

The FiT scheme was introduced in April 2010 and is one of the ways in which the UK proposes to meet its ambitious climate change and renewable energy targets. Under the scheme, financial incentives are provided for the generation of electricity and heat on a small scale using renewable sources (known as microgeneration).

Last week's announcement followed a "fast-track" review launched by the Government earlier in the year following initial evidence showing the number of large-scale solar projects in the planning system to be much higher than anticipated.

A group of solar developers and investor organisations has been given permission to proceed with a Judicial Review action against the Secretary of State for Energy and Climate Change in relation to the handling of the review. A full hearing is expected before 29 July 2011, the outcome of which may have important implications for the solar industry in the near term future. ◆

UK Oil and Gas Tax—A Shock to the System

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The UK Budget 2011 delivered something of a shock to the UK oil and gas sector. In an effort to help balance the books, the UK government announced a significant increase in the tax applied to North Sea oil and gas producers, effective from 24 March 2011. This article is a short summary of the tax changes that were announced in the UK Budget 2011, the market reaction and the status of the changes at the time of writing. References to oil should be read as including gas, and references to the United Kingdom include the UK continental shelf.

UK Oil and Gas Tax—a Brief Summary

The taxation of profits derived from the extraction of oil in the United Kingdom is quite complex. Companies can be subject to some or all of petroleum revenue tax (PRT), corporation tax and the supplementary charge.

PRT is applied at 50 percent to the profits derived from the production of oil from specific oil fields (broadly, those licensed prior to 16 March 1993). It has its own basis for calculating profits and expenses, which is different from the basis used for corporation tax and the supplementary charge. Further, PRT is allowed as a deductible expense for the purposes of calculating profits for corporation tax and the supplementary charge.

Corporation tax is applied to the profits of all companies which are tax resident in, or have a permanent establishment in, the United Kingdom. For oil companies, in broad terms, any oil extraction activities in the United Kingdom, or any exploitation of oil rights related to the United Kingdom, are treated as a separate trade (they are "ring-fenced"). Ring-fenced profits are taxed at 30 percent; companies subject to the corporation tax ring-fence regime do not benefit from the reductions in the main rate of corporation tax announced at the Budget (decreasing from 28 percent to 23 percent over the next 4 years), except to the extent that they are also involved in taxable activities that are not taxed under the ring-fence rate, but instead are taxed under the main corporation tax rules. Ring-fenced profits cannot be reduced by losses arising from other (non-ring fence) trades. Again, there are numerous specific rules that relate to the calculation of deductible expenses, in particular in relation to capital allowances (the United Kingdom's tax depreciation rules).

In addition to the UK corporation tax ring-fence rate, companies falling within that regime are subject to a supplementary charge that is applied to their adjusted ring fence profits in the relevant accounting period. These are the profits that would be subject to the main ring-fence corporation tax charge, assuming that financing costs and loss relief are left out of account in computing the profits and losses of the ring fence trade for the accounting period in question. Until 24 March 2011, the rate of the supplementary charge was 20 percent.

The Budget Tax Grab

It was announced at the Budget that the supplementary charge will increase to 32 percent, effective from 24 March 2011. As a result, those subject to the UK corporation tax ring-fence regime and supplementary charge now face a combined 62 percent rate of tax (rising to 81 percent for companies whose older fields are subject to petroleum revenue tax); however, the complex system of allowances and reliefs can reduce the profits that are subject to that tax rate. This rate change made all the headlines, but there were some other, more subtle changes:

- Legislative changes will ensure that the "intangible fixed assets" tax regime (which broadly taxes intangible assets, including goodwill, on an income basis in accordance with accounting entries) does not permit a company to obtain a debit in calculating its profits where it acquires an oil licence or an interest in an oil licence from another company. Oil licences and interests in them are already excluded assets under the intangible fixed assets rules—this exclusion is now being extended to cover all goodwill and any other intangible asset which relates to, derives from or is connected with an oil licence or an interest in an oil licence. This is being introduced because HM Revenue & Customs became aware of oil companies interpreting accountancy practice in such a way as to recognise goodwill on the acquisition of an oil licence or an interest in an oil licence. This was considered to be contrary to the intention of the intangible fixed assets rules. This change is effective from 23 March 2011.
- The government announced its intention to introduce rules in Finance Bill 2012 (with effect from the 2012 Budget) to restrict tax relief for decommissioning expenses to the 20 percent rate of the supplementary charge. The government said that it will work with the oil industry with the aim of announcing "further, longer term, certainty" on decommissioning at Budget 2012.
- An interesting feature of the new rate of supplementary charge will be the linking of the rate to a "fair fuel stabiliser." The effect of this will be to reduce the rate of supplementary charge back down towards 20 percent "on a staged and affordable basis" where the oil price falls below a set "trigger price." The trigger price was initially announced as US$75 per barrel (subject to ongoing consultation with affected parties).
- One small crumb of comfort for the industry was confirmation (more than one year after they were first announced) that changes to reinvestment relief would be enacted in Finance Bill 2011 (but with effect from 24 March 2010) that extend reinvestment relief to exploration and development expenditure.

Market (and Political) Reaction

The Budget announcements provoked a considerable amount of reaction from industry players and commentators, with some estimating that almost £2bn was wiped off the market values of North Sea oil and gas producers immediately following the Budget.

Many commented on the fact that the industry is subject to regular changes of fiscal policy (leading to difficulties in assessing the future returns on investment) and that the oil and gas industry is already subject to high tax rates, and that, as a result, further increases damage investment. In a press release after representatives from Oil & Gas UK (the trade association for the UK offshore industry) gave evidence to the Energy and Climate Change Committee (a cross-party committee — not part of the UK government) on 4 May 2011, Malcolm Webb, Oil & Gas UK's chief executive, said:

> We need to find means to re-incentivise investment in the UK's oil and gas developments.... Doing so will reduce the risk that these fields will be decommissioned in the near future and their infrastructure removed, limiting the industry's ability to recover small remaining reserves of oil and gas nearby.

The treatment of gas in the proposals is also arguably unfair. First, the price of gas has (as a broad generalisation) increased significantly less than has the price of oil in recent years. Yet, because the United Kingdom generally taxes gas in the same way as oil, gas is subject to the same increase in the supplementary charge. Second, the fair fuel stabiliser (see above) is linked only to the price of a barrel of oil, which is currently considerably in excess of the price of an equivalent amount of gas. Thus, in some sense, gas extractors are unfairly pegged to the price of oil. Furthermore, in relation to oil, the trigger price has arguably been set too low, given that most industry observers would predict the price of oil will be well above the proposed US$75 per barrel in the short to medium term. If that turns out to be true, the "fair fuel stabiliser" won't stabilise anything.

The increase in the supplementary charge is uniform across all oil and gas fields. This is likely to have a greater impact on those fields where the profitability (before tax) is already considered marginal. In a publication titled "UK Continental Shelf Tax Regime—Options for Reform" released on 10 June 2011, the Scottish government suggested that the higher tax rates should be linked to some form of investment rate of return (so that the higher tax rates only apply once a certain rate of return has been reached).

A number of companies also publicly stated that they would review their UK Continental Shelf operations given the changes. In a press release on 14 July 2011, Deloitte revealed a survey showing that UK oil and gas drilling had fallen by as much as 52 percent in Q2 2011 when compared to Q2 2010. It is too early to say how much of that drop results from the Budget 2011 changes.

The First Step Back from the Cliff?

On 5 July 2011, the UK government announced a change to help mitigate the increased taxes as a result of the Budget. The industry hopes that this is the first of a number of steps to help mitigate the tax changes.

The government announced that with effect from 1 January 2012, the annual rate of the ring-fence expenditure supplement (RFES) will increase from 6 percent to 10 percent. The RFES is a special allowance for companies within the ring fence, and it allows such companies to increase the value of certain losses carried forward by a certain percentage on an annualised basis. In broad terms it increases the value of the losses over time (and thus to some extent recognises the time value of money). It is helpful in an industry where early stage expenditure can often outstrip income for many years.

The government also announced that it will "continue to engage with oil and gas companies on the case for new categories of field qualifying for field allowance." While not a concrete measure, any increase in the categories of field allowance would also be welcome by the industry. The reason is that field allowances are a special form of allowance that are specific to the supplementary charge (and, in broad terms, can reduce the amount of profits that are subject to the supplementary charge until such allowance is used up). At present, field allowances are only available to certain types of fields, including ultra heavy oil fields, ultra high pressure/high temperature fields, and certain small fields.

Industry response to the announcement has been positive, albeit guarded. A number of large producers that had indicated that they would shut down or reduce investment in the UKCS as a result of the Budget increase, responded to the government's announcement by saying they would now reappraise their positions in the UKCS. However, there is a feeling that the government has not gone far enough in repairing the damage done as a result of the Budget announcements. In a press release, Malcolm Webb, Oil & Gas UK's Chief Executive, said:

> This is a first step in the right direction. We made it clear after the Budget that Government actions and not just words would be required to begin to rebuild trust and restore the confidence of investors. This will help some new players but much more action is needed including on other reliefs and on the important decommissioning problem in the light of the Budget. However this has to be seen as an encouraging first sign of some real progress.

It is unclear if or when the UK government will issue further announcements, so Oil & Gas companies should continue to "watch this space." ◆