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Offshore decommissioning issues: Deductibility and transferability

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Abstract

Dealing with the decommissioning of petroleum installations is a relatively new challenge to most producer countries. It is natural to expect that industry's experience in building platforms is much greater than the one of dismantling them. Even if manifold and varied efforts are underway towards establishing international "best practices" standards in this sector, countries still enjoy rather extensive discretionary power as they practice a particular national style in the regulation of decommissioning activities in their state's jurisdiction. The present paper offers a broad panorama of this discussion, concentrating mainly on two controversial aspects. The first one analyses the ex-ante deductibility of decommissioning costs as they constitute an ex-post expense. The second discussion refers to the assignment of decommissioning responsibility in the case of transfer of exploration and production rights to new lessees during the project's life. Finally the paper applies concepts commonly used in project financing as well as structures generally used in organising pension funds to develop insights into these discussions.

Keywords: Decommissioning; Regulation; Petroleum installations

1. Introduction

One of the greatest and growing challenges of the offshore petroleum industry is guaranteeing a safe destination to exploration and production (E&P) structures after the termination of their productive phase. Different from most other productive activities, where the investment period takes place in the first years of project implementation, which are followed immediately by recovery years of positive cash flows, offshore E&P projects present an additional third period of unavoidable negative cash flow. This last period refers to all decommissioning expenses at the end of the life cycle of any well. These expenses occur precisely when no revenue is being generated any longer.

This peculiar characteristic of offshore E&P industry imposes an extra obligation upon government authorities in charge of regulating this sector's activities. It is fundamental for regulators to ensure that offshore production will not generate environmental damages as a result of badly managed licenses. If a government has to cope with this kind of liability, it will have to use funds that otherwise could be destined to other finality, and that like all government expense, in the end, it will have to be obtained from taxpayers. Due to the potential negative externalities portrayed in such a scenario, authorities of producer countries tend to scrutinise offshore E&P closely. Their aim is primarily to avoid decommissioning being undertaken by inexperienced and unscrupulous agents, with no technical or managerial abilities to deal with the end-of-leasing phase in a correct fashion.

Although this is a typical problem involving practically all of the more than 50 producer countries, interesting dilemmas arise from an analysis of offshore

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E&P in emerging economies, such as Brazil. The fact that this country (a) retains the record for deep-water completion, which precludes complex decommissioning processes; (b) boasts more than 105 producing offshore installations (ANP, 2003) in a wide range of depths; and (c) has recently liberalised its domestic sites to further international competition, makes Brazil a vivid laboratory of challenges for evaluation.

Nowadays Brazil carries out more than three-fourths of its production of petroleum and natural gas through offshore activities. Less than the one-fourth remaining (23%) is related to onshore production. The high percentage of offshore production exacerbates environmental concern with safeguard procedures since marine structures hold a potentially higher risk of pollution than onshore ones. In time, environmental issues regarding petroleum and natural gas exploration become more urgent as the more than one hundred producer installations in Brazil near the end of their respective life cycles. Another important recent development is that the market share of companies involved in E&P activities in the Brazilian continental shelf has changed since government-controlled Petrobras lost its monopoly power in the region. This change has demanded greater levels of modernisation and control in regulating decommissioning activities, marking the final episode of an era of relative ease for Brazilian authorities. In fact, it was much easier to control for the decommissioning when the government itself managed this activity through its monopoly holding state company.

Despite growing world-wide concern towards decommissioning, and the observed growth of legislation surrounding this subject, partly due to pressure from public opinion and environmental movements, this new regulatory framework, even in developed countries, is far from being complete, homogeneous and satisfactory. The majority of decommissioning regulations, especially those of the United Kingdom, Norway, United States and Canada establish fines and obstacles to access funding, as punishment for companies that do not follow safe standard procedures related to abandonment or cause negative externalities to explored sites. Some of these regulations suggest the creation of a compulsory contribution fund for all companies involved in E&P activities, aimed at covering bankruptcy cases during the validity period of their exploration licenses. This fund intends to avoid liabilities originating from the non-compliance with decommissioning obligations and will eventually be financed by the government. This paper highlights, among other issues, the inefficient and inequitable character of "socialising" these losses in a common fund.

Although the authors recognise several essential economic issues involved in the decommissioning process (i.e. optimum timing for initiating decommissioning activities, single or phased approach, removal and disposal options), the focus of this paper is on discussing deductibility of decommissioning expenses and transferability rights, especially in marginal fields. Even if manifold and varied efforts are underway towards establishing international "best practices" standards in this sector, countries still enjoy rather extensive discretionary power as they practice a particular national style in the regulation of decommissioning activities in their state's jurisdiction. This article also suggests the creation of a dedicated decommissioning account for each E&P project, similar to individual pension fund accounts.

2. Decommissioning overview

The number of world petroleum installations currently surpasses 7500 units.[1] These installations are located in the continental shelves of 53 countries worldwide, of which 40 produce offshore oil and gas in significant quantities. The regional distribution of these structures among the different regions, seen in Fig. 1 below, calls attention to the Gulf of Mexico that stands out, with approximately 4500 installations. Retaining the record for deep-water completion, Brazil holds 105 producing offshore platforms (ANP, 2003).

By the end of the 1990s, around 50% of all Brazilian offshore platforms were installed in depths greater than 400 m (ANP, 2003). Since not many platforms of this size have been disposed of around the world, expertise in this field is limited and cost estimates vary within a wide range. As should be generally expected, removing floating installations in the Brazilian outer continental shelf is significantly less costly than removing fixed ones. The cost of plugging and disposing of wells in Brazilian deep and ultra-deep (over 1000 m) waters tends to pose, however, additional challenges. Complexities are also common in site-clearance activities. Well-plugging and abandonment constitute two of the most expensive activities within any decommissioning process. The balance of floating and fixed installations in offshore Brazil is illustrated below, in Table 1.

As a further noteworthy example, Norway accounts for approximately 35% of the total worldwide decommissioning expenditure, while holding only around 7% of total world offshore installations. The main reasons for this cost discrepancy lie in the high weight and structural complexity of Norwegian installations, the severe weather conditions common to that region (Ferreira et al., 2004) and the high environmental

[1]Numbers updated from data collected from Ferreira (2003) and various sources including government and industry reports and academic literature.

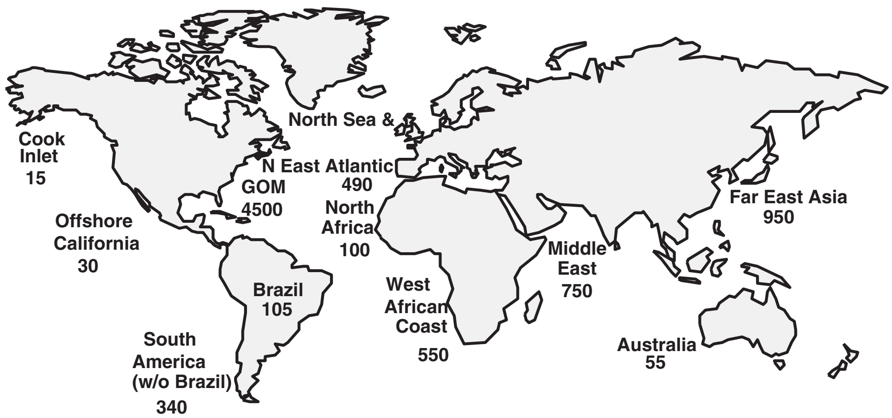

Fig. 1. Global Distribution of Platforms. Updated from Ferreira (2003) with numbers compiled from various sources, including government reports, industry reports and academic literature.

Table 1
Brazilian offshore production installations

Type of installation	March/2003
Floating production systems	2
Floating, production, storage and offloading	8
Fixed production systems (non-concrete)	77
Fixed production systems (concrete)	3
Semi-submersible	15
Total	105

Source: ANP, 2003.

standards imposed by Norwegian authorities (Osmundsen and Tveterås, 2003).

It is natural to expect that humans' experience in building platforms is much greater than in their dismantling or disposal. While the first offshore installations date from the early 1920s, the first disposal of platforms happened in the last quarter-century and the most complex structures began to be decommissioned around the 1990s (Athanassopoulos et al., 1999). In practice, the majority of these installations end up being reutilised in new projects or having their productive life extended through new techniques involving marginal field recovery.

Based on estimated costs, decommissioning may become one of the major issues facing the global offshore industry in the near future. Although offshore installations must be decommissioned at the end of petroleum projects, most offshore structures were not designed to be removed. According to Coleman (1998), in the coming two decades, up to 6500 installations are expected to be decommissioned at an estimated cost situated in the range of 20–40 billion USD. The fact that each installation is unique, due to the large variety of available structures and site specificity, associated with the existence of a wide range of different regulations world-wide to be complied with, makes the estimation of total decommissioning costs a rather complex task.

In fact, offshore installations may have many distinct features. Beginning with shallow water structures comparable to 20-storey buildings, weighing less than 4000 tonnes each, they can reach, for medium deep water exploration, structures higher than the Eiffel Tower, with a concrete gravity base structure of more than 20,000 tonnes. Yet further, for deep and ultra-deep activities, one encounters floating structures larger than many sports fields, attached to a tension leg structure more than a kilometre long. There are also a variety of decommissioning options for entire or merely parts of an oil and gas installation, such as options for equipment carried aboard the platforms, connecting piping and the deck and jacket structures. Unlike the jacket portion of an installation, which is designed for a specific depth and is usually not reusable, the deck portion in the majority of decommissioning cases is recovered for use with a new jacket in another site.

Although a wide range of decommissioning options exists, none of them are in fact free of externalities. To begin with, all alternatives involve air emissions from decommissioned parts, which might represent a serious problem in areas like Santa Barbara in California which has been designated as a non-attainment area under the US Federal Clean Air Act (Athanassopoulos et al., 1999). For its part, even onshore disposal implies the existence of a landfill available to accommodate such massive structures. Deepwater disposal requires commuting with the platform throughout the continental shelf until sinking it, and is not a permitted option under many regulatory regimes like the North Sea and the Gulf of Mexico. Moreover, the conversion of installations into artificial reefs that became known as Rigs-to-Reefs programmes, and is largely accepted in regions like the Gulf of Mexico[2] requires a change in most other regulatory frameworks. Such programmes preclude protracted negotiations with other users of marine waters due to their impacts on navigation, military strategies, fishing and sports activities, among others.

Despite all difficulties involved in the decommissioning process, it is an inevitable development. Osmundsen and Tveterås (2003) refer to an average of 15–25 installations expected to be decommissioned annually in Europe over the next 10–20 years, representing 150,000–200,000 tonnes of steel per year among other materials.

3. Regulatory challenges for governments and agencies

The set of activities related to petroleum and natural gas E&P projects fall under a very dense regulatory framework worldwide. Decommissioning has become an all-inclusive, politicised and costly issue as underscored by Ferreira (2003). An ideal decommissioning assessment report, for instance, must take into consideration the effects of all decommissioning options. It should include energy use, biological and technological impact of discharges, secondary air emissions, physical and habitat matters, fisheries, waste management, littering, drill cutting deposits, free passage, personnel safety, national contents, employment, cost feasibility, and impacts on local communities, including visual interference, noise, odour and traffic. As the "public relation environment" may be looked at before the "physical and legal environment", a company may strictly follow all regulations and still be far from satisfying public expectations (Ferreira, 2003). Osmundsen and Tveterås (2003) call attention to the population's growing willingness to pay for keeping the oceans as close as possible to their "natural" state and also to the companies' growing concerns with the effect on their respective reputations as a consequence of their decommissioning choices.

All these variables have a strong influence on policy makers and regulation authorities to the extent that at least a part of them may consider requesting very high decommissioning standards as the best option to pursue. Many of these policy makers have noticed, however, that they need a frame of flexible rules as the excess rigidity may make offshore E&P activities less competitive in their territories. Being related to energy resources, the exploration of petroleum and natural gas represents an important source of strong currency and/or important savings in the trade balance, especially for developing and under-developed countries.

Although this picture has changed quite dramatically in Brazil in recent decades, during which this country became almost self-sufficient in petroleum and related products, this commodity represented more than 50% of the country's total imports in the 1970s and in the beginning of 1980s. Added to this is the fact that petroleum is very sensitive to periods of international instability in which it becomes even more indispensable. Although some governments believe it is safer to conduct strategic E&P operations exclusively through state-operated enterprises, the aforementioned constraints mean this may not be a viable strategy or even a plausible alternative to maximise offshore E&P results.[3]

When governments decide to abandon the state monopoly model, the next alternative to avoid liabilities is to open up the petroleum and gas sector to selective competition, among a few large and experienced enterprises. Selecting and attracting companies with such a profile is not, in practice, as easy a task as in theory. Theoretically, during the auction period, it should be sufficient to request that only companies above a certain size of assets and above a certain number of years of proven experience in the sector, among other requirements, are entitled to participate. Also to attract these enterprises, inducing a higher interest, regulation authorities can give up some percentage of government take (GT), translated into requesting less royalties, taxes and special government participation. In practice, what can be observed is that, by taking this alternative, governments facilitate a market structure dominated by larger players.

Governments and their regulators, however, naturally want the best of both worlds. This means the highest possible amount in GT, associated with the highest level of domestic E&P activity to increase the chances of higher production and income, embedded in a competitive environment to ensure lower prices, combined with the best standards of safety procedures during the recovery phase and mainly throughout the decommissioning of offshore installations. As time goes by, more economically viable sites are depleted, sub-optimal locations are developed, with lower productivity and more difficult exploration. These sites are generally operated by smaller sized companies, specialised in this niche of activity, which are able to obtain reasonable returns for themselves and for the region where they are active. The exploration of these depleted sites becomes economically unviable for larger enterprises which demands the entry of smaller companies with lower costs, so a new option for the regulators is to stimulate these enterprises to enter competition. Therefore the oil and gas offshore industry has to renounce being an

[2]According to Athanassopoulos et al. (1999) both Louisiana and Texas artificial reef programs comprise almost 100% of the offshore oil and gas installations within their respective jurisdictions.

[3]Viscusi et al. (2000) present a very complete discussion about public enterprises in Chapter 14.

exclusive ground for the same group of large companies, and become a ground for a diverse set of enterprises. One of the consequences is that regulating this new set of companies and activities poses an extra challenge to government authorities of producer countries.

In this way, the critical challenge of engendering a competitive and safe environment for the offshore industry has to reach a balance among several issues such as: (a) a realistic set of safety requirements; (b) response capacity of producer actors; and (c) cost-benefit analysis for society. One can observe that the petroleum and gas industry has already taken many steps in this direction. Regarding decommissioning activities, the acceptance of partial decommissioning, or the transformation of platforms into artificial reefs, or the acceptance of longer periods before installations dismantling takes place in a series of operations, or even deep sea disposal, are all examples of compromise solutions.

4. Deductibility and transferability issues

4.1. Fiscal planning and ex-ante decommissioning deduction

Fiscal planning becomes more important, as economic incentive mechanisms are increasingly adopted by regulatory agencies around the world. As competition increases, environmental regulations become more stringent and projects get marginal, companies are increasingly compelled to reduce, as much as legally possible, government revenues from projects. According to Young and McMichael (1998), the most significant negotiable factor that affects the performance of the project is income tax.

Future liabilities, such as costs of meeting decommissioning obligations, must be carefully considered in a company's financial statements. Lessees must consider how to anticipate such expenditures and how, whenever possible, to apply them in each year's accounts. Lower cost estimates to meet ex-post obligations may provide better results. Lower tangible ex-post costs may provide better profits. On the other hand, higher net present cash flow values lead to higher corporate taxes. In addition, higher decommissioning estimates may be conducive to higher financial assurance requirements.

Since decommissioning activities take place at the end of an offshore E&P project's lifetime, the ability to obtain deductions against taxable income becomes practically impossible in many countries. At that point there is no positive cash flow from operations available. In most countries, authorities find it hard to give permission to tax deductions based on future expenditures. Regulation authorities fear that not only the amounts of future decommissioning costs are unknown but also that in advance tax-deductions may give the wrong incentive to companies in the direction of overestimating end-of-leasing expenditures to obtain higher up-front benefits.

Answering the question whether ex-post expenditures should be tax-deductible is not easy. Different answers to this question are found among producers. If offshore E&P were to enjoy the same benefits of most other activities, equity would demand that not only incurred investments should have the right to be recovered during the lifetime of a project, but also all costs should be matched against earnings to indicate the taxable income. The problem appears if specific industries have peculiar cash flow profiles such as petroleum and natural gas E&P.

In an industry with a large number of stakeholders, companies are not the only parties affected by high ex-post costs. Such costs generate direct and indirect impacts on governments, taxpayers, and society as a whole. In many countries the current tax structure determines that governments, and consequently taxpayers, bear part of the cost for decommissioning, providing tax relief for oil companies. In some countries, where the debate on decommissioning related issues is more advanced, the matter of charging the taxpayer for decommissioning operations of private oil enterprises is being severely questioned. However, to some extent, many regimes do provide a legal basis for dividing the costs of meeting ex-post obligations between the state and the private sector.

Deduction rates also vary significantly among petroleum producer countries. In the UK, for example, oil companies are taxed on their earnings from oil and gas production but, since decommissioning expenditures are allowable against taxable earnings, the UK government loses revenues equivalent to 50–70% of ex-post costs (Prognos, 1997). In Norway, the government covers the largest part of platform removal costs and companies cannot deduct removal expenses in their corporate income tax according to the Norwegian Petroleum Directorate (NPD, 2000) and Phillips Petroleum Norway (Phillips, 1999b). In this country, decommissioning obligations are not subject to ordinary tax treatment: they are maintained outside the tax system. In any case, other costs involved in the decommissioning of installations are fully deductible.

The history of taxation on decommissioning activities has many highlights. In 1975, Phillips Petroleum Norway claimed deduction for future removal costs. During this period, the Norwegian Petroleum Directorate—which is administratively subject to the Ministry of Petroleum and Energy, and advises the Ministry on matters concerning the management of the petroleum resources on the Norwegian continental shelf—established its first special tax rule for decommissioning costs: "based on the principle of taxation, all costs are deductible but due to the uncertainties involving anticipating costs, no tax deduction for future costs are allowed'' (Phillips, 1999a,b; NPD, 2000). The Norwegian Removal Grant Act of 1986 stated that when installations were to be removed, the State should bear a share of the removal and disposal costs. Other ex-post obligations were not included in this cost sharing treatment. This Act was only applicable for expenses directly related to the removal and disposal of installations. Other ex-post costs such as preparation, assessments, well-plugging, among others, were still considered legitimate operation costs and were deductible (NPD, 2000).

A better way of understanding the Norwegian system, prior to 2004, is to keep in mind that [the] ''State's percent share is equal to the average tax rate for each lessee over the lifetime of an installation'' (Phillips, 1999b). The state's share for removal costs was based on each lessee's estimates, while considering that state contributions cannot exceed accumulated paid taxes. Under that regime, the payment of tax before 1975 was not included for sharing purposes. The final decision would not be taken by the NPD, but rather by the Ministry of Finance, which would define removal costs. This calculation used to include all years from the development of the platform up to its removal and disposal. It did not include taxes paid before the platform was installed. For instance, if the average corporate tax paid during the 20 years of operations of a platform was 75%, the Norwegian government would pay for 75% of disposal costs. Since averages usually do not work properly regarding cash flows, specially including long periods, some problems were raised with that methodology. One problem that could be anticipated under this regime was that if near the time of decommissioning of a specific platform the tax rate was, for instance, around 80% and the average was calculated at 75%, the company would lose 5%. In 2004, according to specialists, the Norwegian tax treatment of decommissioning costs was changed. After this change, 78% started to be refunded, regardless of the average tax rates of the licensees.

Parameters such as decommissioning options (total or partial platform removal) may also cause significant fiscal effects. According to some studies completed by Prognos in 1997, North Sea governments' expenditure, or the amount by which tax receipts are reduced as a result of decommissioning, could reach US$ 6.3 billion in the case of total removal and between US$ 3.8 billion and US$ 5.8 billion for partial removal. Consequently, possible ''savings'' offered by partial removal options are somewhere between US$ 1 billion and US$ 2.5 billion up to 2020, merely for North Sea projects. Income tax revenue generated by new jobs and related decommissioning activities reach approximately US$ 1.4 billion for total removal, which is between US$ 0.1 billion and US$ 0.3 billion higher than in the case of partial removal. According to these numbers, considering total and partial removal options, taxpayers from North Sea producer countries would save between 8% and 44% (US$ 15 million to US$ 95 million) per year, if partial removal options were adopted for all installations. If total removal is adopted, taxpayer from North Sea producer countries will be paying for decommissioning up to the year 2020 between US$ 400 million and US$ 2.2 billion.

The existing tax environment may also contribute to the adoption of even more improved practices. Kapoen (2001) suggests that in order to encourage the re-utilisation of redundant offshore installations and components, depreciation should not only apply to new business assets. In addition, he suggests that authorities should accept that remaining partners could roll over their tax book values. Thus, it is clear that fiscal incentives may help improve the market for used structures, mainly to be utilised in small and/or marginal projects.

For most tax regimes, ex-post environmental obligations, including decommissioning costs, are ordinary and necessary expenses. In general, such expenditures are tax-deductible only once services have been performed and payments have been made. When progressive abandonment is adopted, the same rule applies. Deductions are usually not allowed for decommissioning activities that are carried on during non-income years, once production has ceased. In such situations, companies are usually allowed to carry a ''credit'' towards a future project, as is the case in the current Brazilian fiscal regime. The approximate government take in the petroleum and natural gas industry in Brazil is around 65%, not including bond related expenditures (ANP, 2003), and carrying a ''credit'' towards a future project does not help much in reducing this government participation.

Some other regimes still offer provisions allowing some type of ''anticipated tax-deduction provision'' spread over a period during revenue-generating years. Despite it being a sector benchmark, the Norwegian regulatory regime relies on many assumptions that may not be appropriate to the reality of other economies. The fact that the Ministry of Finance becomes involved in decommissioning issues should not be neglected. Due to the large amounts needed for decommissioning activities, the latter can carry a strong side effect on government budgetary planning. It also implies that the government has to be conscious enough: not to overspend previously collected taxes, not to divert them to other budgetary demands, and thus having enough proceeds to honor its obligations towards decommissioning expenses.

It is important to consider that from the government's point of view, even while losing considerable revenue by allowing tax relief for ex-post expenditures, governments will earn tax revenues from workers' income taxes and other levies imposed on companies involved in offshore E&P activities. In addition, by allowing fiscal incentives regulatory authorities may significantly reduce the risk of non-compliance and undesirable environmental liabilities.

4.2. Dedicated account mechanism and transferability

Two issues, one concerning the fiscal treatment of end-of-lease expenses and another, the tracking of responsibilities in the event of offshore projects changing hands, are among the most controversial regarding the decommissioning of petroleum and natural gas installations. The first one refers to ex-ante tax deductibility in the event of ex-post decommissioning costs. The second one is concerned with the demarcation of potential liabilities if an offshore E&P project changes lesseeship during its lifetime.

The ability to approach these fiscal concerns varies across countries, as seen in Section 4.1. In some countries, the government bears the majority of the financial responsibility, as is the case in Norway. The Norwegian government, for instance, is committed to participating in a large share of decommissioning costs. In most cases, government contribution towards end-of-leasing expenditures may surpass 50% of total closure costs. Actually the funds for these contributions originate from the same tax revenues collected during the lifetime of each of these projects. This system is equivalent to the government returning part of the taxed proceeds, by the end of the taxed phase. According to specialists, as for necessary proceeds to honour its obligations, Norway kept a petroleum fund invested abroad of 150 billion dollars, as of 2004.

For many other countries, the company managing a certain project can accumulate credits to be deducted during the lifetime of another future project. This may not be a fair proposition since it assumes in advance that there will always be a future project able to recover the benefits of the former project through the use of the accumulated credits. Also, it appears that larger companies, with many ongoing projects, are able to profit more from this system than other industry participants are.

Within other financial assurance regimes, companies are requested to deposit funds into escrow accounts pledged to the government and no deduction is generally available until the company loses ownership of the funds. However, within most financial assurance regulatory frameworks, such expenditures can be amortised over the time period covered by the bond, if a lessee pays fees or premiums to keep surety bonds or environmental insurance policies. In other words, the issue of deductibility is a main driver for selecting the specific financial instrument to cope with closure expenses.

In general, the rule for deductibility is that the expense has to be an ordinary and necessary business expense and not a capital expenditure (IRS, 1999). The fact that a lessee is contractually liable for ex-post expenditures or provides anticipated funds to guarantee such obligations, in most cases does not entitle it to deduct the cost of such services before they have in fact been performed.

In Canada, Japan and South Africa, collateral bond instruments, such as escrow accounts that allocate up-front capital, are also conferred with deductions. Nevertheless, any revenue gained from the financial application of allocated funds (i.e. interest from escrow accounts) is subject to ordinary taxation. Under more mature bond regimes, such as in Canada, there is a common notion among specialists and regulators that offering a net fiscal incentive is better than risking inheriting ex-post environmental liabilities from the mining and oil sector.

Regulators are also concerned whether further fiscal incentives reduce or eliminate the main motivation for compliance with ex-post obligations. However, the rationale behind this thought lies in the fact that if deductions are extended to cash collateral accounts, for instance, the main motivation for compliance, which is "doing it right in order to get the bonded money refunded", may be annulled. As a result, if a company can obtain its allocated capital through tax deductions before the end of the project, the remaining incentive to comply might disappear. It is evident however, that other factors besides financial incentives keep a lessee aware of its responsibility. As seen in previous sections, companies do worry increasingly about their reputation, and track records are fundamental to remaining in this business area.

Three variables can act as catalytic factors within regulatory regimes: (1) flexible rules[4] demanded by the industry, (2) requirements established by regulators, and (3) risks offered by flexible rules. Providing fiscal incentives could be considered a form of flexibility. This illustrates the dynamics of regulatory regimes where, due to public pressure, regulatory authorities establish stringent bond requirements generating direct and indirect economic impacts on the profitability of petroleum projects. Industry demands flexible rules that may come in the form of softer instruments, fiscal incentives, or lower bond estimates. These flexible rules increase the risk of non-compliance, thus triggering public concern and involvement, which closes a common negative cycle.

[4]Providing fiscal incentives, allowing deductibility, giving extra time before decommissioning takes place, allowing rigs-to-reef programmes, etc.

If the approach of project finance is adopted to deal with this issue, it should be expected that each E&P project is self-contained. This means that the proceeds to cope with decommissioning expenses should be generated during the lifetime of each project. Even if regulatory authorities request a certain financial guarantee—in the shape of any bond instrument, reinforced by a third party that could be an insurance company or bank—the proceeds for closure and post-closure activities should come from the project's positive cash flow phase. Banks and insurance companies select clients expecting that the insurance policy will not be withdrawn. Actually, the use of the insurance policy or bank coverage, such as a bond or a letter of credit, constitutes part of the bankruptcy scenario to be avoided.

Under this circumstance, offshore project lessees should enjoy incentives that incite them to provide for these funds, which are aimed at covering decommissioning expenditures. In this scenario, tax deductibility should not be excluded from the set of possible incentives. A suggested option that has not yet been sufficiently explored intends to illuminate the amount set aside to cope with end-of-lease expenses through an independent dedicated decommissioning account. In the same way that pension fund accounts are organised for future pensioners, the project administrator would receive incentives to provide funds for the end-of-leasing activities. The access to this independent and dedicated account would be permitted only at the end-of-leasing moment and just for decommissioning coverage purposes.

In contrast with usual practice, any revenue gained from financial application of proceeds allocated in this fund (i.e. interest from decommissioning dedicated accounts) could be reinvested instead of being subjected to ordinary taxation. Fig. 2 shows a breakdown diagram, modified from the fiscal regime currently adopted by Brazil, to exemplify the new possible position of decommissioning expenses. These expenses can be removed before indirect taxes and taxable profit are paid. It also illustrates the creation of a dedicated decommissioning account (see Fig. 2).

A visible advantage of an account with these characteristics is that it may reduce expenses with part of the insurance and/or performance bond instruments. In fact, traditional expenses with bond instruments could be reduced at the same pace as the contributions to decommissioning funds were increasing (see Fig. 3). Only accidental damage coverage would have to remain unchanged throughout the project's lifetime, in order to finance premature and unplanned closure.

The issue of transferability also deserves attention. One of the most complex problems to deal within the offshore industry is the tracking of responsibilities for environmental damages. Since there is a potential higher risk at the end-of-leasing phase, this becomes a rather critical moment in terms of environmental care. In theory, a petroleum and gas installation project can potentially change ownership innumerable times until the end of its productive life. This practice is generally discouraged as it implies extra costs for the regulatory authority to check and control new lessees. Specially in the event of any environmental damage, it becomes rather costly to investigate and assign responsibilities without facing long law suits. This explains why, in some cases, the government decrees that the original project lessee remain responsible for end-of-lease activities even if exploration and production rights are transferred. The disadvantage of this method is that in practice it discourages the optimisation of E&P

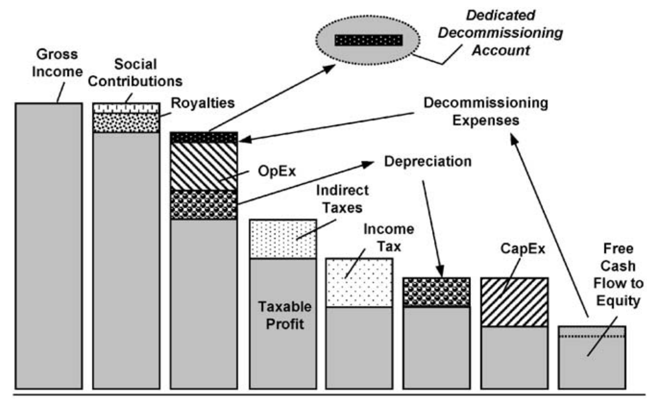

Fig. 2. Fiscal regime currently adopted in Brazil: breakdown diagram of taxes and other government takes indicating new position of decommissioning expenses to be collected into a dedicated decommissioning account. "OpEx" represents operational expenditures and "CapEx" stands for capital expenditures. Starting from gross income, each component is subtracted until indirect taxes and taxable profit are calculated. Since depreciation is not a cash out flow, it returns to reintegrate the free cash flow to equity. (Schiozer, 2002—modified).

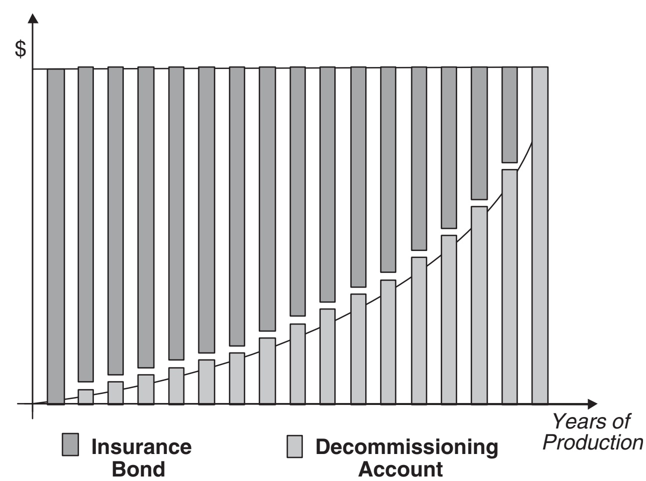

Fig. 3. Diagram illustrating accumulation in the decommissioning account and decrease in bond insurance requirements.

activities, especially in marginal fields. Since many former companies are afraid of being held responsible in case of malpractice by future lessees, the optimisation may not be reached since these fields are not transferred for specialised companies that could carry on the E&P at lower costs.

If marginal fields are left under-recovered, overall production may not reach its optimum level. In many cases, marginal field operation can improve the whole productivity of an exploration site. If some small and specialised niche companies can carry out offshore E&P in marginal fields, regulatory authorities need to establish a systematic approach to deal with them. There are also other companies that have been developing expertise in top decommissioning technologies. Few of these companies have extensive track records to offer either to regulatory authorities or to insurance companies.

In fact new lessees that take over ongoing projects could also profit from pre-existing dedicated decommissioning accounts linked to the offshore projects they intend to explore. It is important for regulators to offer new types of fiscal incentives for direct investment in innovative technologies and processes aimed at improving environmental performance of end-of-leasing activities and reducing ex-post expenditures. One of the major concerns regarding transferability is the crucial moment of decommissioning. If a dedicated decommissioning account accompanies the project until the end of the latter's productive life, belonging to the project itself and not to the lessee, part of the risk associated with end-of-leasing activities, especially the credit risk, is minimised.

It is worth highlighting a further kind of fund designed to indemnify governments against failures in complying with end-of-leasing obligations. Some of these funds are common to the whole sector and cover different companies operating in a certain region. Even if from one standpoint these funds may guarantee funding to deal with inherited liabilities from lessees, from another perspective they reveal the disadvantage of socialising losses amongst all companies including those that follow good practices. In other words, these funds extend the same treatment to well- as well as mismanaged companies.

There are many similarities between a dedicated decommissioning account and an escrow account, but there are also major differences. Escrow accounts are generally established with proceeds that flow directly from the buyer of goods or services to a third party account, without passing through the cash account of the company selling these goods or services. Although a lessee does not have the power to perform withdraws from a dedicated decommissioning account, unless for decommissioning purposes at the end of the license period, the lessee keeps discretionary power to accumulate this account in the rhythm that most suits its fiscal planning and cash management.

Furthermore, there are also major differences between a dedicated decommissioning account and an ordinary collateral bond instrument since, in the former case, the lessee does not have to allocate the whole amount of capital necessary to meet end-of-leasing obligations up-front. It can control periodic deposits, taking into consideration fiscal incentives it may receive and savings for dismissing other bond instruments. Although studies show that cash collateral like instruments may present a smaller preference when compared to other bond instruments like surety bonds and letters of credit (Ferreira et al., 2003), preferences may shift due to deductibility incentives authorised by regulators which might extend these payoffs to dedicated decommissioning funds.

5. Conclusions

A project finance approach to offshore E&P projects helps to clarify that each project, if seen from the perspective of a self contained unit, should provide funds for its own decommissioning phase. Incentives for creating a dedicated decommissioning fund for each license extended to E&P activities may be a possibility to pursue as it reinforces the concept of self-contained projects, diminishing credit risks during the end-of-lease period. This project finance approach also helps to illuminate the issue of deductibility since closure expenses are part of every offshore project, even though these costs are incurred at a project's ultimate stage.

The issue of transferability is also a challenge that has to be faced by producer countries, as there is a growing trend for marginal field exploration. Generally, these activities are performed by smaller and specialised companies, which require the existence of a robust regulatory framework to control such operations. A dedicated decommissioning fund that accompanies the offshore project, regardless of the new lessee's identity, may indemnify authorities and society against failure to comply with lease contractual obligations.

Although some studies have shown that cash collateral-like instruments, such as dedicated decommissioning accounts, may present a lower preference when compared to other bond instruments, preferences may shift with deductibility incentives authorised by regulators. In fact, preferences may vary if further incentives were provided to reduce financial impacts on project cash flows. Indeed, a very interesting study proposal would be the assessment of potential fiscal incentives for financial assurance instruments that fulfil these objectives.

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