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US Gulf Offshore Oil: Petroleum Leasing and Taxation and their Impact on Industry Structure, Competition, Production and Fiscal Revenues

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FIGURES

ABBREVIATIONS

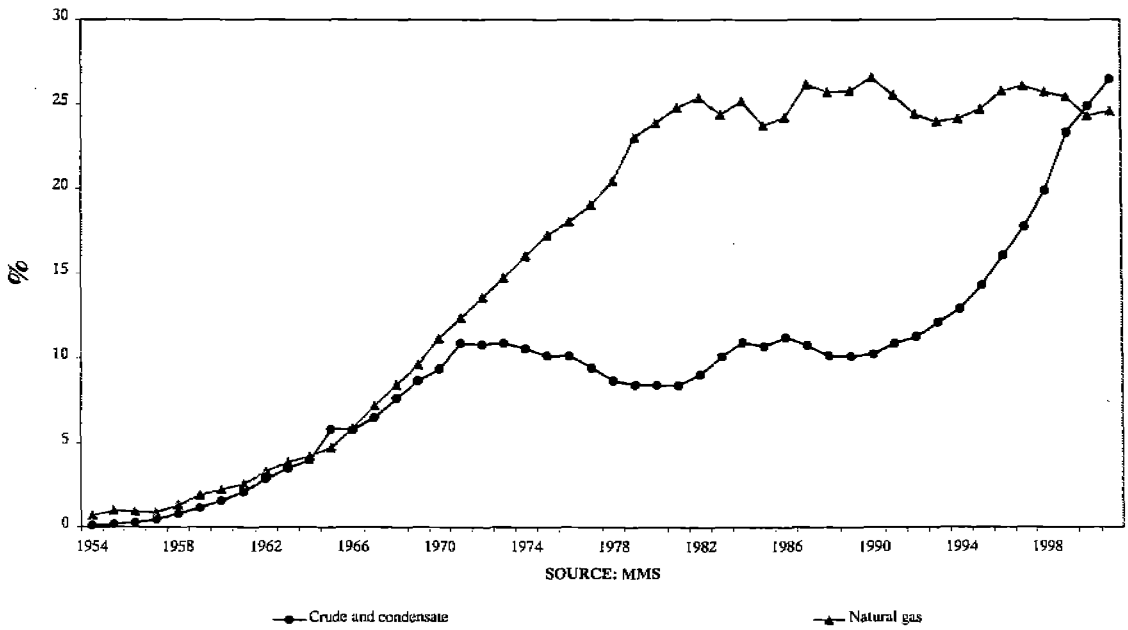
API	American Petroleum Institute
AWL	Area Wide Leasing
BD	Barrels per day
BCF	Billion Cubic Feet
BCFD	Billion cubic feet per day
BIT	Bilateral Investment Treaty
CBO	Congressional Budget Office
CZMA	Coastal Zone Management Act
DMROV	Discounted Mean Range of Simulation Values
DOE	Department of Energy
DOI	Department of the Interior
EEZ	Exclusive Economic Zone
EIA	Energy Information Agency
E&P	Exploration and production
EMPCO	ExxonMobil Pipeline Company
FERC	Federal Energy Regulatory Commission
FOGRMA	Federal Oil and Gas Royalty Management Act
FOIA	Freedom of Information Act
FPSO	Floating production, storage and off-loading
GAEOT	Geometric Average Estimation for Offshore Tract
GAO	General Accounting Office
GOM	Gulf of Mexico
HOOPS	Hoover Offshore Pipeline System
ICA	Interstate Commerce Act
IEA	International Energy Agency
IMF	International Monetary Fund
MBD	Thousand barrels per day
MBOED	Thousand barrels of oil equivalent per day
MMB	Million barrels
MMBD	Million barrels per day
MMBOE	Million barrels of oil equivalent
MMCFD	Million Cubic Feet per Day
MMS	Minerals Management Service
MMUSD	Millions of dollars
MOIP	Mandatory Oil Import Programme
MROV	Mean Range of Simulation Values
NERA	National Economic Research Associates Inc.
NOI	National Ocean Industries
OBRA	Omnibus Budget Reconciliation Act
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
OECD	Organisation for Economic Cooperation and Development
OPEC	Organisation of the Petroleum Exporting Countries
OTA	Office of Technology Assessment

PADD	Petroleum Administration for Defense District
PRT	Petroleum Revenue Tax
PSA	Production Sharing Agreement
RRT	Resource Rent Tax
SLA	Submerged Lands Act
SPR	Strategic Petroleum Reserve
tcf	Trillion Cubic Feet
TLP	Tension Leg Platform
TN	Tract Nomination
USD	US Dollars
USD/B	US Dollars per barrel
WTO	World Trade Organisation

1 INTRODUCTION

The Outer Continental Shelf (OCS) of the US Gulf of Mexico (GOM) is the most explored, drilled and extensively developed offshore petroleum province in the world. Since 1953 and up to 2000 inclusive, more than 35 thousand wells have been drilled offshore in GOM (including wells plugged and abandoned). Cumulative production of oil and gas to this date stands at 13 billion barrels of oil and 146 tcf of gas (9.7 per cent and 17.5 per cent, respectively, of cumulative US production to date since 1953). The prominence of this region as far as the US petroleum supply picture is concerned has grown markedly over the years, on the back of the output decline in traditional onshore basins (Figure F1.1). Currently, there are 39 million acres under lease in GOM, with 1585 producing leases and 4034 active production platforms tapping 662 active fields whose reserves represent around 13 per cent of the US total. GOM production already exceeds that of Texas (on an oil equivalent basis) and, in coming years, its crude oil output is bound to eclipse even that of Alaska (unless significant production occurs in the Arctic National Wildlife Refuge). Indeed, the prediction of some observers that GOM output will be responsible for as much as one third of US crude oil production by 2010 could turn out to be conservative.

FIGURE F1.1: GULF OF MEXICO OCS PETROLEUM OUTPUT AS A PROPORTION OF TOTAL US OUTPUT, 1954-2001



SOURCE: MMS

In recent times, GOM has also become one of the premier frontier exploration and production plays for the world oil industry, with large finds in deepwater zones that have more than compensated for declines in production in the mature shallow waters. Thanks to quantum advances in upstream technology, the prolific fields in this zone have made – and will continue to make – a major contribution to US oil and gas reserves and, more importantly, to US production. Between 1993 and 2000, overall US oil production declined by nearly 1.1 MMBD, but deepwater GOM production increased by 640 MBD over the same period (in 1999, deepwater GOM output surpassed shallow water output for the first time in history, accounting in the process for about 12 per cent of total US production). More than 150 deepwater discoveries have been announced in the deepwater GOM, with total reserves amounting to 12 MMBOE. Twenty-two of the fields discovered contain reserves in excess of 200 MMBOE. Although most of these finds have yet to enter production, there is no doubt that, as the US Minerals Management Service (MMS) puts it, "with 30 fields on production at the end of 1999, the deep water of the Gulf of Mexico can rightly claim to be America's new frontier and has truly emerged as a world class hydrocarbon province. Its future looks bright, as many new geologic trends are only now seeing the first exploratory drilling".[1] From 1993 onwards, upstream activities in deep waters in GOM, in short, have turned into the brightest star in the US oil industry firmament since the discovery of Prudhoe Bay.

Given the importance of GOM in the US supply picture, the study of the institutional framework (fiscal regime, acreage auctions, leasing conditions) that underpins oil activities in the region would appear to be an inherently worthwhile pursuit in itself. Further justification comes from the undeniable fact that practices in the oldest and most developed offshore petroleum province understandably exert a great deal of influence on policymakers in other parts of the world. Moreover, in recent times, the importance of this demonstration effect has been magnified by the remarkable revival of GOM production.

The conventional wisdom interpretation of this event is that it only occurred thanks to two major changes to the GOM institutional framework; namely, a radical overhaul of the leasing system undertaken in the early 1980s, on the one hand, and the granting of royalty relief for fields located in deep waters from 1995 onwards, on the other. The existence of a direct link between these institutional changes and the revival of an oil province that had derisorily come to be known by 1992 as the "Dead Sea"[2] is one of the many ideas that oil industry insiders and analysts take as read, but which are not "thoroughly argued and solidly established truths, merely preliminary statements which on close examination open a research agenda".[3] The self-evident status of this notion means that it has not really been the object of much academic interest or scrutiny. The literature on the subject is surprisingly sparse[4], and much of it tends to concentrate on issues that are of interest to a small number of lawyers.[5] Moreover, academic publications dealing with the leasing programme in the OCS tend to underutilise the wealth of relevant literature and statistical material put in the public domain by various agencies of the US government or legislature: MMS, the Congressional Budget Office (CBO), the General Accounting Office (GAO), the defunct Office of Technology Assessment (OTA), and so forth.

The objective of this paper is to discuss the evolution and performance through time of the institutional framework underlying oil activities in the GOM region. This region has accounted for the bulk of the hydrocarbons produced under the aegis of the offshore oil and gas leasing programme in Federal waters from the very moment that it got underway, with the passage of the Submerged Lands Act (SLA) and the Outer Continental Shelf Lands Act (OCSLA) in 1953.

The structure of the study is as follows. It is divided into six chapters, of which this introduction is the first. Chapter 2 gives background information on the overall institutional set-up of the GOM upstream sector, focusing chiefly on the constituent elements of the GOM fiscal regime. The thrust of our analysis is to highlight what the functioning of these various elements says about the approach of the US Federal government to a number of fundamental issues surrounding the ownership and development of petroleum resources; namely, the frequency and expediency with which it is prepared to grant access to such resources, the nature of the payments that it expects in return for such access, the means by which it goes about collecting such payments and, finally, the extent to which it has been ready to accommodate the demands for a share in these payments staked by political actors with a physical connection to the territory from which the resources are extracted.

We show that the equally prominent place assigned to signature bonuses and royalties in the GOM fiscal scheme is proof of the fact that, since its inception, the GOM institutional framework has striven – and largely managed – to follow a conciliatory path regarding these fundamental issues. The sole exception to this rule is paradoxical: even though the USA is a country with an exceptionally vigorous federalist tradition, the GOM fiscal regime does not incorporate any workable formula to provide for the equitable distribution between the Federal government and coastal states of the income derived from OCS petroleum resources. Finally, to conclude this chapter, we examine the contribution that royalties and cash bonuses for offshore acreage have made to US government revenues throughout the years. Our analysis of the relevant time series shows that GOM fiscal revenues have undergone a very significant (some would even say catastrophic) contraction. Moreover, the traditionally close link between these revenues, on the one hand, and GOM production volumes and international oil prices, on the other, seems to have disappeared. Crucially, the onset of both of these trends can be traced to 1983, a year which saw the introduction of radical changes in the GOM institutional framework.

Chapter 3 contains a chronological overview of the evolution of GOM leasing procedures. In this chapter, we provide a brief characterisation of the two systems that have defined the rules for offering and assigning GOM acreage: Tract Nomination (TN) from 1953 to 1982 inclusive, and Area Wide Leasing (AWL) from 1983 to the present. We also give an account of the circumstances and policy objectives that prompted the US government to replace the former system (which had proven phenomenally successful) with the latter, and of the unforeseen and acrimonious political conflicts that followed in the wake of this change of direction. In particular, we discuss the manner in which these conflicts gave rise to leasing and drilling moratoria that have effectively closed off the majority of the OCS to oil activities.

The arguments presented in the next two chapters of the study are very closely linked. Chapter 4 examines the question of whether or not there exists a link between the adoption of AWL and the increase in GOM output recorded from the early 1990s onwards. Taking as our point of departure assertions which claim that a case can be made to connect these events in a cause-effect chain, we argue that even though the bulk of the incremental GOM output has indeed come from fields lying in deep water blocks offered to the industry during the early years of AWL, the length of time that had to elapse before output reacted to the incentives provided by this programme suggest that the causal link joining them is tenuous to the point of irrelevance. We then show that the real driving force behind the renaissance in GOM production has been technological progress, as proven by the fact that not even very large oil companies were able to prevent a long time from elapsing before they could develop their deep water leases, simply because this was a task that lay beyond the possibilities of 1980s offshore technology. Thus, development of these blocks only got underway as the oil industry gradually acquired the capability of working in 2000 feet of water and beyond in places like the North Sea, a process in which AWL played no part whatsoever.

In Chapter 5, we discuss the effects that AWL has had on the structure of the offshore oil industry. In particular, we focus on the influence that the programme has had in terms of the way that oil companies compete among themselves for offshore oil and gas leases. Our aim is to show that AWL has sapped the vigour of competition in the offshore sector. Whereas TN was highly effective in inducing advantaged players into revealing their ideas about the prospects of different areas and then transmitting this information to other players, AWL destroyed the conditions under which such transmission of information could take place, thereby exacerbating the marked informational asymmetries prevalent in the market for offshore leases. Paradoxically, in seeking to reduce a certain type of entry barrier through the easing of restrictions on access to offshore acreage (namely, very large up-front signature bonus bids) AWL *raised* entry barriers overall, for the benefit of a few large oil companies (instead of the small and medium-sized firms that the programme was supposed to help). The main legacy of AWL, then, has been to relegate American independent producers to tidying up the scraps falling off the majors' table. This is a role that ill behoves a pioneering sector of the American oil industry, responsible not only for discovering most of the significant oil pools found in the lower 48 but also for opening up the GOM itself to oil activities.

We bring the study to a close by reflecting on the lessons that governments and policymakers in other petroleum provinces can draw from the GOM experience, concentrating in particular on whether policies similar to AWL might be of interest to those governments that wish to boost their oil revenues by achieving a higher oil output. Our main conclusion in this regard is that such governments would find the fiscal sacrifices that this approach entails to be crippling, and totally out of proportion to the results that a policy like AWL can bring about. That does not mean that the GOM experience is totally bereft of elements that might be worthy of imitation. However, if governments in producing countries want to open up access to their upstream sectors in a manner that is fiscally rewarding but at the same time promotes a competitive industry and efficient market outcomes, then they should focus on trying to devise licensing policies modelled after the tried and tested TN system but which make allowances for their own special circumstances.

NOTES

[1] Baud, Doyle, Peterson and Richardson 2000: ix.

[2] The year 1992 was the first in which the platforms removed in the GOM region exceeded the platforms installed. Ironically, the GOM output boom was just around the corner when this sobriquet was coined.

[3] Horsnell and Mabro 1993: 2.

[4] So much so that, in 1997, a doctoral thesis could still claim, with some justification, to have been the first "in-depth study ... of the history of the offshore petroleum industry" (Kreidler 1997: 13).

[5] See Fitzgerald 2001.

2 FISCAL ASPECTS OF GOM OFFSHORE PETROLEUM LEASING

The institutional framework that underpins offshore oil activities in the GOM region is deeply rooted in a tradition of private mineral governance in which ownership of subsoil resources is vested in the possessor of the surface,[1] rather than in an entity like the Nation or the Crown. The backbone of this institutional framework is a fiscal regime which, as is the case in other parts of the USA, is structured around lease contracts (specifying royalties and various other rent payments) rather than concessions or licences, which are legal constructs associated with the public mineral governance that holds sway in every other country of the world.[2]

Since leases on Federal lands are governed by private law, most of the revenues that the US Federal government obtains as a result of offshore petroleum activities are due to it in its capacity as the owner of the submerged lands on which such activities take place (as set out in the SLA). It is therefore convenient to refer to these OCS revenues – which, by the way, are the largest *individual* source of Federal government income after general income taxation – as lease payments, so as to distinguish them from genuine taxes (that is, compulsory contributions levied by a sovereign power). The only OCS payments that the Federal government receives in its capacity as a fiscal authority come from the federal income tax obligations that oil companies incur as a result of their profits from operations in the region.[3] However, since this tax is levied on corporations as opposed to ring-fenced fields, it is not possible to calculate the share of an oil company's Federal income tax bill that is attributable solely to its GOM operations (not least because the absence of a ring fence means that corporations can and do offset losses incurred in other activities against upstream income).

The constituent elements of the GOM fiscal regime (leaving aside federal income tax payments, for the reasons delineated above) are as follows: (1) signature bonuses for leases; (2) royalties; (3) surface rentals and minimum royalty payments; (4) shut-in gas payments and (5) sliding–scale royalties and profit–sharing mechanisms. In Appendix 1, we discuss the rationale, statutory evolution and behaviour through time of all these elements. In this chapter, however, our main objective is to characterise the GOM fiscal regime on the basis of the manner and means that it has used to approach the fundamental issues surrounding the ownership of petroleum resources. Such a characterisation will allow us to contextualise the GOM fiscal regime within the broad institutional continuum ranging from the liberal fiscal regime in force in the UK North Sea, at one end, to the restrictive and patrimonialistic fiscal regime that currently holds sway in Mexico, at the other. This contextualisation will also describe the way in which the position of the GOM fiscal regime has shifted over time, in response to developments in the international oil market (chiefly the so-called OPEC revolution and the relentless decline in US domestic oil production).

By way of conclusion to this chapter, we will consider the tangible results of the GOM fiscal regime: the revenues that the US government has obtained throughout the years as a result of the OCS leasing programme. Our examination, which will pay particularly close attention to the way in which royalties and cash bonuses for offshore acreage have been affected by changes in volumes and prices, will be based on the figures published by MMS in *Federal Offshore Statistics* and *Revenue Collection Activity on Public Lands*. For most of the fiscal indicators to be analysed, MMS makes no distinction between the various OCS regions (i.e. GOM, Pacific OCS, Alaska and the Mid-Atlantic). It is possible to disaggregate many of these indicators into their individual components, but we have not been able to do this for all of them (in particular, we have been unable to find statistics for the wellhead value of GOM natural gas production). This does not pose a serious problem, though, because the fiscal revenues from the GOM region dwarf those generated in others. Historically, GOM leases have attracted 77 per cent of all OCS bonus payments, and they have been responsible for 97 per cent of all oil and gas royalties, and 79 per cent of all rents received. For the sake of consistency, therefore, in this chapter we shall frame our discussion in terms of aggregate values for the whole OCS, even in cases when there are published figures that pertain only to the GOM region. We will separate GOM statistics only when it is both possible and instructive to do so.

2.1 Conceptual Considerations on the Characterisation of Fiscal Regimes

An oil fiscal regime is the tangible, institutional embodiment of the way in which individual political systems translate the views (often divergent) of internal and external actors regarding the key issues surrounding natural resource ownership. In broad terms, these issues can be said to be as follows:

— the manner and conditions under which the owner is prepared to grant access to these resources
— the patrimonial remuneration that the owner sees fit to exact in exchange for such access
— the means by which the owner collects such remuneration
— the degree to which the owner is ready to recognise *ex-ante* claims to a portion of this remuneration staked by other actors with a physical connection to the territory from which petroleum is extracted (and who can be private landowners, municipalities, provinces, departments, prefectures, federated states, or some other territorial entity).

There is a wide array of schemes and fiscal instruments that owners of petroleum resources can conceivably adopt in order to come to grips with these issues. However, if one distils the economically and politically relevant attributes of these apparently diverse measures, it is possible to fit all of them within either one of two ideal-typical categories of mineral governance: non-proprietorial (i.e. liberal), on the one hand, and proprietorial, on the other.[4]

2.1.1 Non-proprietorial Governance

This mode of mineral governance is predicated on the free and frictionless flow of investment into even the most marginal reservoirs, so as to allow for the greatest possible petroleum output at the lowest possible market price. It grants access to resources either in perpetuity or through licences that are renewable as a matter of course, and openly renounces any form of patrimonial compensation for extracted resources (which are therefore treated as a free gift of nature). It avoids oil-specific taxation, restricting its use to situations when oil activities are perceived as generating returns over and above those "needed to attract investment and production".[5] Such returns are unjustifiable in principle since "the existence of oil is not attributable to any activity or effort by the oil industry"[6] and, therefore, capturing them is the only option open to a fiscal authority that wishes to preserve a level playing field for genuine inter-firm competition to take place, as opposed to "granting privileges to some investors that would be difficult to justify *vis-à-vis* ordinary taxpayers".[7] In the non-proprietorial scheme of things, the preferred way to deal with Ricardian rents involves enacting *progressive net income levies,* which are in turn a superior alternative to signature bonuses, which are themselves superior to 'regressive' levies (like severance taxes). Signature bonuses are supposed to be neutral with regards to investment (after all, the size of the bonus a company is willing to pay for a tract in theory reflects the net present value of expected excess profits net of tax, so a bonus payment *in principle* should not alter the way in which a given project appears pre-tax versus its attractiveness post-tax). However, the fact that they have to be paid up front in an uncertain world means that bonuses can cause distortions (if the excess profits fail to materialise, for instance), so the more radical a non-proprietorial fiscal regime is, the more such bonuses – when used at all – will function merely as tie-breaking devices to aid in the transparent assignation of leases/licences, rather than as vehicles for the collection of Ricardian rents.[8]

Non-proprietorial mineral governance posits "an exclusive relationship between consumers and producing companies";[9] the crux of this relationship is the notion that "natural resources ... belong to ... *society as a whole* and should be developed for the benefit of *all* society".[10] Hence, this mode of governance does not recognise the legitimacy of any *ex-ante* claims to compensation associated to natural resource ownership that might be advanced by territorially-based political interests (a feature that the Scots, say, can only be too familiar with). Non-proprietorial forms of governance, in essence, approach the issues surrounding mineral exploitation purely in terms of *stewardship* (i.e. regulation) rather than *ownership*, essentially renouncing jurisdiction over any matter that does not entail the correction of competitive distortions or externalities.

2.1.2 Proprietorial Governance

The essence of proprietorial governance mechanisms is the erection of obstacles to the flow of investment, with the two-fold aim of obtaining the payment of a rent in exchange for every barrel of oil produced in a given area and of blocking the access to resources if their extraction does not generate a satisfactory fiscal income for their owner (regardless of whether it can generate a reasonable profit for investors). Proprietorial governance tries to levy tolls at every possible juncture: through signature bonuses when acreage is being assigned, through surface rental payments when exploration is ongoing, through gross income levies when production is taking place, through relinquishment and reversion clauses when E&P activities are winding down or undergoing a lull and, *in extremis*, through the assimilation of the management of the industry to that of the natural resource and the consequent transformation of concessionaires/lessees into mere production services providers for a nationalised industry. Proprietorial governance therefore will not grant access to resources in perpetuity, and it will seek to define a set of circumstances and triggering events under which such access may be forfeit and ownership of all rights on the land will revert to the original owner. The ultimate expression of this is the doctrine of 'permanent sovereignty over oil resources' embraced by OPEC member countries at the turn of the 1970s, and whose thrust was that the governments of these countries could, if it suited them, renege at will on whatever contractual obligations they had acquired with international oil companies and revise them in their favour (these companies, by the way, immediately understood that this doctrine made their position as concessionaires untenable).

Proprietorial governance relies on royalties and severance taxes rather than net income levies. In part, this is because these regressive levies entail low surveillance costs (only prices and volumes need to be monitored, and there is no need to define and calculate profits). Also, producers have to treat taxes on gross revenues as costs of production, and this has a discouraging effect on incremental supply (which, in turn, means that this type of levy might result in prices being higher than would otherwise have been the case). A third very important quality of royalties and severance taxes is that, even though they have distortionary effects on investment, they continue to be paid as long as production occurs, regardless of external contingencies. As the Department of Energy (DOE) acknowledges, "when there are production taxes, additional output made possible by investment in new development will give rise to tax liability whether the operation is profitable or not. In the case of an income tax, tax liability is incurred only in the presence of profits".[11] This non-contingent nature makes production taxes very attractive for actors (governments and Texas ranchers alike) who are not necessarily knowledgeable about the commercial aspects of the oil business and who tend to depend on oil extraction from their lands to generate the bulk of their income.

Proprietorial governance has one thing in common with non-proprietorial governance: in its pure form, it is also founded upon an exclusive relationship, which in this case involves consumers, on one side, and the governments that represent the ultimate owners of the natural resource, on the other. In this set-up, competition between the companies that are supposed to provide production services is harnessed for the benefit of the governments that control access to land (in the form of higher rents) rather than consumers (through lower prices). Naturally, there is no space for competing claims for territorially-based compensation, which means that landed interests or intermediate levels of government (state, local, provincial or otherwise) are unceremoniously excluded from any sharing of the spoils. To cite an example: whereas in Colombia or in Russia a set percentage of oil revenues is earmarked (*de facto* or *de jure*) for the governments of the jurisdictions in which oil extraction activities take place (municipalities in the former case, *oblasts* and autonomous *okrugs* in the latter), oil–producing states within Mexico are not entitled to any form of special statutory compensation from the central government.

In sum, proprietorial forms of governance approach the issues surrounding mineral exploitation in terms of custodianship, presupposing the active and constant intervention in industry affairs by governments who, to a lesser or greater degree, conceive of oil companies chiefly as administrators of national mineral assets. Thus, the interaction between companies and governments takes the form of a business rather than a regulatory relationship. To be sure, it is a *sui generis* business relationship, comparable in the eyes of operating companies to the silent partnerships that protection racketeers establish with their victims. The parallel can be extended further by saying that extreme proprietorial governance and racketeering, however retrograde or unsavoury they might appear to outside observers, are the expression of rather intractable 'facts on the ground' (in the first case, control of armed muscle in a territory where the rule of law cannot fully guarantee property rights and, in the second, control born of the eminent sovereign domain over those locations where Nature randomly chose to concentrate most of the world's oil resources).

2.2 Petroleum Governance in the GOM Region

The degree to which proprietorial or non-proprietorial mechanisms will predominate within a fiscal regime depends on a multiplicity of factors, like the balance of domestic political forces in a given country, the structures that underpin its political system, the mode of its insertion in the global economic and political scene and the influence of exogenous changes in the oil industry, the international oil market, and the world at large. It is therefore not surprising to see that, regardless of the fact that these modes of governance are at opposite poles from one another, most oil fiscal regimes combine disparate elements associated with both of them. Simply put, compromise lies at the heart of most oil fiscal regimes. Since "the public debate on mineral governance, by its very nature, is of political nature",[12] the variety of actors with views regarding the ownership of natural resources generally find it necessary to forge some sort of alliance or accommodation in order to solve the frictions, controversies and confrontations that the exploitation of these resources gives rise to.

The ultimate example of a conciliatory fiscal regime is to be found in the USA. In this country, the compromise was forged in the crucible of the courts at a very early stage in the development of the oil industry. Judicial decisions made it clear that, although landowners could demand however much rent they desired, they were not entitled to prevent their lessees from retiring their capital from a lease when its term expired. But having neutralised landed interests by decreeing that leases would remain in force as long as oil was produced in paying quantities, the courts then made it clear that satisfying the legal requirement of mutuality of contract required that this indefinite period of tenure be contingent upon an obligation to explore the land and achieve production during a specified period from the moment the lease was granted.[13] This historic compromise, which has proved extraordinarily stable, is reflected in the patrimonial retribution arrangements that took root in various parts of the USA (including the OCS after the passage of SLA and OCSLA). On the one hand, signature bonuses came to be accepted as the key instrument for landowners to obtain an income from petroleum resources lying under their property (and this ensured that their claims for compensation would induce as small a distortion as possible on the investment decisions of lessees). On the other hand, the preservation of royalties enshrined the rights of landowners (including the Federal government) to an ongoing participation in the benefits of any oil discoveries on their property.

The conciliatory nature of the GOM fiscal regime comes across quite clearly when one compares the contribution that non-proprietorial and proprietorial mechanisms have made to government revenues over the lifetime of the offshore leasing programme (up to 2000). Of the USD 129 billion that offshore petroleum leasing has generated for the US Federal government during this period, 46 per cent – or USD 61 billion – has corresponded to non-proprietorial mechanisms (signature bonuses), while 54 per cent – USD 71 billion – have come from proprietorial mechanisms (chiefly royalties, but also surface and other types of rentals).[14]

Interestingly, this balance used to be more heavily tilted in favour of signature bonuses: from 1953 to 1982, bonuses accounted for 67 per cent of the direct government revenues generated by offshore leasing. The reasons for this change will become apparent in a subsequent chapter, however. For the moment, we just want to explain the way in which the constituent parts of the GOM fiscal regime have functioned and adapted to changing circumstances over the years. This entails the discussion of three key issues. Firstly, the advantages, limitations and performance of signature bonuses (as well as alternatives to them) as vehicles for excess profit taxation. Secondly, the reasons for the abiding popularity of royalties in spite of their restraining effects on output, and the prospects for their eventual demise. Thirdly, the way in which the US federal system has dealt with (or more accurately, failed to come to terms with) the problem of the equitable distribution between the Federal government and coastal states of income derived from OCS petroleum resources.

2.2.1 Excess Profit Taxation in the GOM Region: the Role of Signature Bonuses

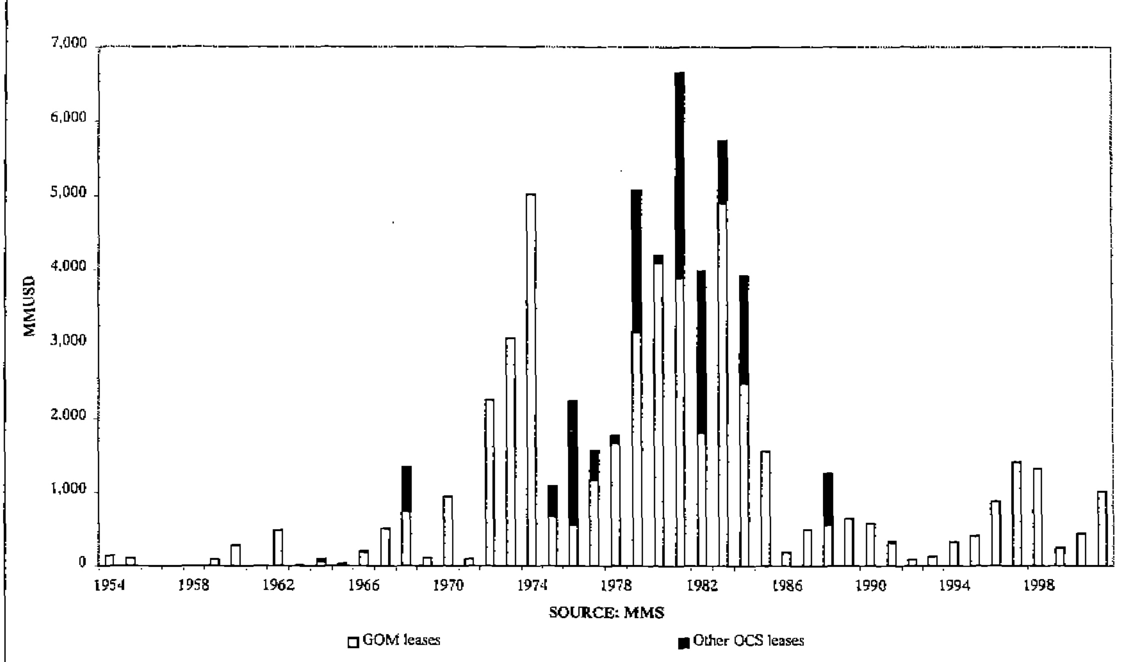
The popularity of bonuses in the USA as a means of granting access to public domain resources has had a lot to do with their transparency (memories of Teapot Dome die hard, after all), and their non-arbitrary nature (a feature well suited to a litigious society). However, it also reflects the fact that, in comparison with other forms of excess profit taxation – like the British Petroleum Revenue Tax (PRT) or the Australian Resource Rent Tax – signature bonuses possess the undeniable virtue of administrative simplicity. Excess profit taxation schemes presuppose ring-fencing, which prevents the dilution of upstream profits (through transfer pricing, outsourcing, subcontracting and cost imputation) but also makes the whole enterprise fiendishly complicated, as well as "economically and politically costly to administer, potentially litigious and requir[ing] strong political institutions as well as highly specialised accountants, economists and lawyers".[15] In contrast, capturing Ricardian rents through signature bonuses merely requires holding an auction in which prospective lessees announce how much they are willing to pay for tracts, keeping a ledger for submitted bids and, finally, having a bank account in which winning bids can be deposited.

High rates of excess profit taxation are also associated with serious incentive problems, which tend to make themselves manifest through over-investment and goldplating. As Mead puts it, in situations "where benefits accrue primarily to the lessee, but the costs are shared between the government and the lessee, some investments will be made because the benefits to the lessee exceed the cost-share borne by the lessee".[16] Thus, at high windfall tax rates, enterprises will take advantage of any possible loophole to increase their expenditure, so long as this generates a profit (even though the return associated to this incremental investment might be much lower than what would be acceptable on a standalone basis, and even negative on occasion).[17] This is merely symptomatic of the natural desire of capitalist enterprises to minimise their windfall tax obligations, just as they wish to minimise their payments of other taxes in general. Signature bonus payments also score highly on this account because, as will be explained in greater detail in the second part of this chapter, their use as a rent collection device allowed the take of the Federal government on GOM income to reach very high levels at certain times (during most of the 1970s, for instance), without giving rise to the perverse incentive investments that have been encountered in provinces like the UK North Sea.[18] The advantage of signature bonuses in this department is due in no small measure to the fact that 'conventional' resource rent taxes are predicated on the principle that Ricardian rents should only be collected *after* they have actually materialised, which opens a window for investors to increase expenditure and investment in order to dissipate them (even when in the presence of ring fences). In contrast, since signature bonuses are meant to capture *expected* Ricardian rents, they are payable in advance of any disbursements associated to investments and operations and are therefore not affected by these. Signature bonuses are in effect sunk costs, so they cannot but induce parsimony in lessees (because investment profligacy will only reduce the magnitude of their future cash flows from a lease).[19]

The major drawback associated with signature bonuses is that their efficiency and neutrality as rent collection devices depends on there being a competitive market for offshore leases. Unfortunately, the competition that does prevail in this market is in thrall to noise of all kinds. The risk that such noise may lead to the appearance of distortions is magnified by the cyclical nature of prices, output and investment in the oil industry. Cyclical patterns of behaviour are of course typical of industries that are intensive in their use of capital and raw materials, but they are particularly strong in the case of the oil industry, because of the weak linkage between production costs in major petroleum provinces and the international market price for crude. Thus, industry expectations (which determine the amounts of money that companies may be willing to risk in the form of bonuses) are subject to sudden and frequent adjustments, and only tend to reflect the conditions of the immediate past. From the point of view of a liberal licensing authority (i.e. one wishing to expedite access to, and development of, oil resources), potentially the most unwelcome amongst the gamut of distortions associated to noise in the cyclical market for leases is an increase in bonus payments in anticipation of a period of sustained high prices for oil. This is because, if future price scenarios are exuberantly bullish, signature bonus payments may have the effect of ultimately hindering the flow of investment, especially if smaller players become overcommitted financially, or else drop out of acreage auctions in order to avoid this danger.

In the USA, the frenzied lease sales that took place in the chaotic aftermath of the First Oil Shock led many policymakers and legislators to reach the justifiable conclusion that the oil companies were paying astronomical bonuses which they would never recoup (see Figure F2.1). By extension, they reasoned that the way in which the bidding system for offshore leases was working could be undermining the financial health of at least some of these companies, thereby compromising the country's future oil output. It is a well-attested finding in auction literature that "even modest bidding costs *may* be a serious deterrent to potential bidders ... [in much the same way] that the contestability of a market is nonrobust to even small costs of entry"[20] and, perhaps with this in mind, the US Congress decided to look for alternative mechanisms that would allow for a reduction in upfront bids, ostensibly "to increase company participation in offshore lease sales ... especially from smaller companies with limited financial resources",[21] but in a manner that would hopefully be compensated fiscally by a quicker receipt of royalties, rents and tax revenues.

FIGURE F2.1: TOTAL OCS SIGNATURE BONUS PAYMENTS, 1954–2001



The 1978 OCSLA amendments were a clear manifestation of a Congressional desire to "reduce the initial amount of money, in the form of bonus bids, required to obtain a lease", in a way that would "require the holder of the lease to pay the government a larger share of any follow-on production".[22] The amendments authorised the Department of the Interior (DOI) to explore alternatives to the traditional bidding system for leasing offshore tracts. They required the use of alternative systems for at least 20 per cent and no more than 60 per cent of the offshore acreage offered for lease each year over a 5-year test period, which would end in September 1983.[23] Thus, between 1980 and 1983, DOI leased 215 GOM tracts with profit–sharing provisions. However, the complex accounting and administrative requirements of profit-sharing mechanisms meant that DOI was very keen to discontinue their use, even though in its dealings with the public the department always maintained that it would "continue to consider and apply alternative bidding systems in future OCS lease sales". [24] The preliminary findings of a GAO investigation into alternative bidding systems suggested that more time was needed to evaluate their potential benefits, but DOI's view prevailed.

The main consequence of DOI's victory on the issue of alternative bidding systems was their disappearance from the radar screens in 1983. This outcome was not altogether surprising,[25] for two reasons. On the one hand, even advocates of these systems admitted that they posed far greater difficulties to administer (particularly from a fiscal point of view) than the traditional leasing approach based on cash bonuses and fixed royalties.[26] In particular, as Siegel and Smith pointed out in 1984, there was "no single setting for [profit-sharing] parameters that [could] be applied indiscriminately to all tracts and yield the desired results", so for the mechanism to work the government had to have the capability "to fine tune the system and apply its provisions across different tracts". Unfortunately, this capability was a function of information that only become available after leases had been sold, and it was further hamstrung by the fact that, for legal and political reasons, the government had to maintain "rigid and uniform profit sharing rules and conventions".[27]

On the other hand, the demise of the alternative bidding systems initiative was also related to the fact that the revenue objectives embraced by its political backers in Congress were at odds with the political winds that swept through the governmental circles of industrialised countries in the aftermath of the OPEC revolution and which, among other things, led to the formation of the International Energy Agency (IEA). For all of its non-proprietorial elements (notably its emphasis on ease of access), the fact is that the whole alternative bidding systems initiative was very much a creature of Congress and, as such, it had been crafted under the watchful eye of representatives from states in the US oil patch (still responsible at the time for the overwhelming majority of the country's oil output). For obvious reasons, these members of Congress supported wholeheartedly one of the key policy tenets pushed by the IEA; namely, that everything possible should be done to "encourage the timely development" of oil reservoirs in member countries, so as to "minimise declines in … [their] indigenous oil production".[28] However, they were downright unenthusiastic about pursuing this goal through the means that the IEA proposed: looser and more liberal oil governance and taxation schemes, based on gross income rather than net income levies, on the one hand, and on the assignation of acreage on the basis of bids for the highest marginal tax rate rather than up-front signature bonuses, on the other.[29]

Given the strength of private property rights in the USA, the overt advocacy of such radical liberal measures by any member of Congress hailing from the oil patch would have alienated not only politicians from their state but also the large number of their constituents who happen to be royalty owners.[30] The concern that legislators from traditional oil-producing states displayed with regards to safeguarding the revenue-raising dimension of offshore leasing meant that, in practice, GOM alternative bidding systems ended up by resembling the tried and tested royalty bidding mechanisms from Texas and Louisiana, whose main thrust has always been to maximise income from tract auctions by exploiting the intense competition between bidders that develops when acreage is offered on a *frequent* but *strictly limited* basis. It also meant that the alternative bidding systems initiative was always seen as tainted and woefully inadequate by the free-market zealots who were swept into power in 1980 on the crest of the political backlash let loose by long gasoline lines, brownouts and sundry other traumas associated in the minds of US consumers with OPEC's 1970s muscle-flexing. Upon taking office, they therefore wound down the alternative bidding systems initiative and proceeded to devise a radical overhaul of the offshore leasing programme, which was to change the whole orientation of the GOM fiscal regime even though it maintained the institutional framework intact in terms of its external appearance. Most of the remainder of this study will be dedicated to ascertaining the degree to which this overhaul achieved the objectives sought by its supporters.

2.2.2 The Place of Royalties in the GOM Fiscal Regime: Continuity and Change

When the oil industry was born, the lands where the bulk of US oil output would eventually occur (i.e. Oklahoma, Texas, California, Kansas) were mostly in the public domain, and as such subject to homesteading legislation that gave settlers the right not only to pre-empt tracts of land to prospect for and extract minerals but also to attain ownership of these tracts by investing a certain amount of money. However, oil production actually began in more populated regions where the private property of land (and the underlying subsoil resources) already was the rule. Thus, from the legal standpoint, the oil industry developed around the legal figure of the mineral lease. At its most basic, this type of contractual arrangement consists of clauses that confer "a sufficient grant and term to permit the operator to remove the minerals if discovered", and others that ensure that "the mineral owner shares in the production of the substances from his land ... by providing that a certain portion ... of the production shall be deliverable or payable to the lessor".[31] Thanks to the fact that, at the dawn of the oil age, around 80 per cent of E&P activity involved tracts held under lease, royalties came to occupy the place of privilege among the panoply of devices that landowners in the USA have used in order to derive an income from their property rights.

As the awareness within the US government regarding the great value of petroleum resources grew, its willingness to make those resources freely available for exploration and production, as per the provisions of Placer Law, gradually evaporated. As Mommer explains, "early in the twentieth century ... free access was restricted. More and more federal lands were withdrawn as soon as the existence of oil and gas became known ... and, finally, after the First World War, oil and gas on federal lands was subject to a new leasing law ...Everywhere the legislator essentially equalised the conditions on public lands with the ones prevailing on private lands",[32] especially as regards royalty rates. Once this equalisation had been achieved, the fiscal regime for oil activities in lands under Federal jurisdiction has varied very little, in spite of the radical structural transformation undergone by the international oil industry from the 1950s onwards.

One of the chief agents behind this change was the gradual but inexorable passage of the USA from a position of near self-sufficiency in oil to one of massive import dependence. This development started to bear its bitter fruit for consumers in the developed economies of the world during the mid-1970s, and amongst the policy responses that it elicited from the governments of IEA member countries were agreements to implement comprehensive programmes of upstream tax incentives aimed at boosting their domestic oil production. The US government was a prime mover behind these agreements but, paradoxically, found it very difficult to practise what it preached with such fervour. Thus, royalties in the Federal OCS were not reduced, much less phased out. The paralysis of the US government in this regard is especially noteworthy on two grounds. Firstly, there are no vested private property rights in the federal OCS to raise objections against the liberal principle that natural resources should be considered a gift of nature whose exclusive usufruct corresponds to whoever discovers and develops them.[33] Secondly, outsize benefits accrue to the US economy as a whole from every supply-induced fall (however small) in the international price of oil. Hence, the long-standing failure of the US government to whittle down royalties with the vigour displayed by some of its OECD peers speaks volumes not only about the aversion that this sort of liberal agenda arouses in a country where 40 per cent of total oil production still takes place on private lands, but also about how deeply ingrained in the American psyche is the idea that the "property" component of the concept "public property" is not just for show and that, as something that has an intrinsic value, mineral resources in the public domain (seen as a capital accumulated by Nature) should not be surrendered or conveyed to private parties without fair and proper compensation.

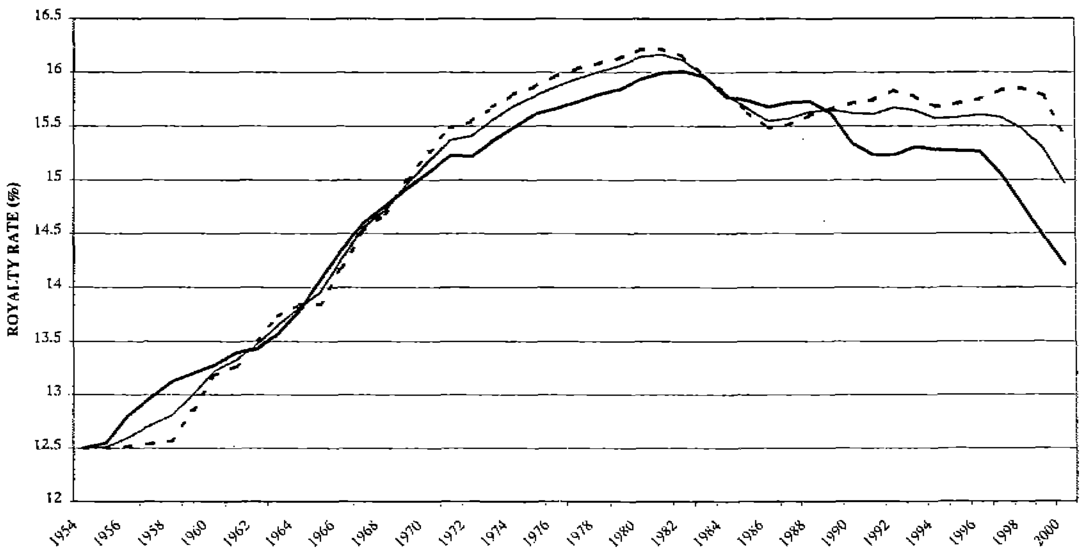
The historically-grounded robustness of the proprietorial strand in the GOM fiscal regime meant that, twenty years after the First Oil Shock, the best that the Federal government had been able to come up with in order to improve the profitability of marginal fields and fields in frontier areas (including the deep water) was to ensure that deepwater tracts would only attract the minimum royalty rate set by law (12 ½ per cent). This achievement appears derisorily modest, but when compared with developments in Louisiana, Texas and other oil–producing states, one can appreciate that it actually represented progress of sorts in terms of the advancement of the liberal oil agenda in the USA. In these states, politicians and landowners alike shared the Federal government's desire to increase oil output after the first oil shock. However, it never crossed the mind of these actors that the pursuit of this objective should mean lower royalties, severance taxes and bonus payments.[34] In fact, they reached the exact opposite conclusion. Thus, in 1972–3, Louisiana nearly doubled its severance tax rate to 12.5 per cent.[35] In the case of Texas, the state severance tax did not go up, but

> landowners drove harder bargains with oil operators. Terms of leases shortened, from five years to three or less ... Royalties rose from an eighth or a sixth to three sixteenths or even one fourth in many areas. As activity in the Austin Chalk area in central Texas [an area whose intractability had given it the reputation of being an oilman's graveyard] reached

fevered pitch in the mid-seventies, some landowners demanded and received 50 per cent royalties.[36]

The passage of the Deepwater Royalty Relief Act (which president Clinton signed into law in 1995, as Title III of the Alaska Power Administration Sale Act, S. 395) marks a dramatic change in the status of GOM royalties. This bill was meant to encourage production in deep waters by exempting new leases (issued after 28th November 1995) located in such areas from royalty payments until output had reached a certain amount, which varied according to depth.[37] Among other things, the Royalty Relief bill allows the Secretary of the Interior to waive royalty payments temporarily if it can be demonstrated that production would be uneconomic without the relief requested. It also empowers him/her to reduce or eliminate royalties to either promote development on non-producing leases or encourage primary, secondary or tertiary recovery from marginal GOM leases. Importantly, the legislation provides for automatic approval of any petition of royalty relief in the event that the Secretary of the Interior fails to act upon it within a certain time–frame (180 days).[38]

FIGURE F2.2: PRODUCTION-WEIGHTED ROYALTY RATE IN THE GOM REGION (1954–2001)



SOURCE: MMS

Even before the royalty relief legislation was passed, the move of GOM E&P activities towards progressively deeper waters, together with the rapid increase in deepwater oil and gas output, had already led to a decline in the weighted GOM royalty rate (Figure F2.2).[39] Currently, the nominal royalty rate is around 15 per cent but, in the near future, the effective GOM rate will slip below this figure, as a consequence of the royalty holidays that many deepwater blocks currently under development will enjoy. The symbolic significance of the royalty relief initiative cannot be stressed strongly enough. After all, by the time of the bill's passage, a string of major finds had already made it evident that the GOM deep waters, far from being a marginal exploration play whose prospects would be stunted if it were not carefully nurtured with tax breaks, was set to become nothing less than "America's new frontier and ... a world class hydrocarbon province".[40] In other words, royalty relief was enacted for the benefit of fields lying in what is certain to be the most prolific and profitable producing area in the USA in the foreseeable future.

It is particularly instructive to consider this fact in the context of the fate suffered by the statutory right granted to the Secretary of the Interior to reduce the royalty rate for a field if its abandonment was imminent, which was enshrined in the 1970s OCS legislation. As Mead explains, no Secretary ever dared to exercise this authority because of their fear that "the public might not understand the economic reasoning indicating that society would benefit by such action and might instead see it as a 'give away' to oil companies".[41] Thus, it is no exaggeration to say that the GOM royalty relief initiative marks a paradigmatic shift in both US oil politics and governance.[42] In essence, royalty relief embodies the abandonment of the deep-seated principle that it is always best for a royalty owner to wait for favourable circumstances and new technology to develop, rather than granting access to the minerals in his land for anything less than what is seen as the habitual rent at a wider level in society.

This principle is not as retrograde as its detractors would have it, and is actually justified by one of the most salient characteristics of technological progress: the fact that "over time, what had been once frontier becomes routine, and the tasks involved seem simple in retrospect. Indeed, the passage of time almost confers an air of charming naivety ... A few decades on, the industry's current achievements might also appear rather twee, although the idea of a future engineer using the phrase 'only

10 thousand feet of water' still stretches the imagination".[43] By the time this last phrase becomes common currency in the oil industry, proprietorial governance mechanisms in the USA will almost certainly have been rolled back further. Already, royalty holiday measures to incentivise drilling for deep gas deposits in shallower areas of the continental shelf[44] have been passed. Moreover, oil companies have put in motion a strong lobbying effort aimed at obtaining a radical overhaul of the whole federal royalty system on the back of a legal challenge to new MMS royalty assessment rules, and there are ongoing efforts to extend the benefits of royalty relief to all mature fields in the shallower parts of the continental shelf.[45] Supporters of these initiatives allege that the number of deepwater blocks receiving bids since 1995 has increased markedly, a development that they put down largely to the effects of the relief measures.[46] Also, some of them suggest that, in the absence of further royalty relief, the contribution of GOM natural gas to future US supply will fall short of requirements, and serious imbalances in the Yukon-to-Yucatán market for this fuel will develop.[47] But even with such a potential supply crunch looming in the background, the experience of the steering of the deepwater royalty relief initiative through the halls of Congress (which took the best part of four years) suggests that widening the beachhead established by the 1995 royalty relief initiative will be a protracted, convoluted and eventful affair.[48]

2.2.3 The Division of OCS Revenues between Different Levels of Government

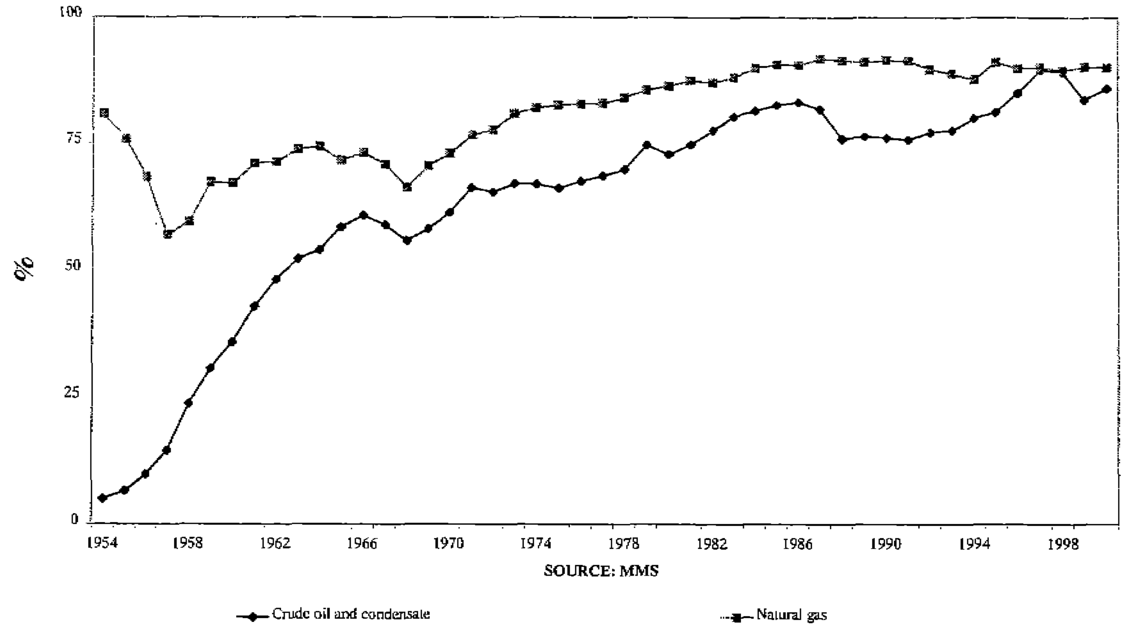
Consider the following propositions. Firstly, the various aspects of the OCS fiscal regime examined so far have underscored its essentially conciliatory nature. Secondly, the USA is, without a doubt, the country with the strongest federalist tradition of all. Thirdly, this federalist tradition finds expression in the rules governing the collection of bonuses and production royalties "to compensate the general public for the market value of the resources that businesses remove from public lands", and which enjoin the Federal government to distribute "a share of those receipts to the states to help state and local governments meet their costs of supporting development activities on public lands".[49] Fourthly, states harbouring Federal leases within their territories have derived substantial benefits from the revenue-sharing arrangements covering royalties from such leases (states receive 50 per cent of such royalties from the Federal government, with the exception of Alaska, which gets 90 per cent). On the strength of the above, and given that issues related to taxation by different levels of government lie at the very centre of any federal pact, one would expect the GOM fiscal regime to incorporate some form of revenue-sharing mechanism. And yet, paradoxically, the exact opposite is true: OCS oil leasing is the *sole* federal programme authorising the leasing, sale or disposal of public resources in which no provision is made for the sharing of revenues with states in whose territory the land from which these resources were extracted is located or with states affected by the development of these mineral resources.

Admittedly, OCS oil activities take place within territory under the exclusive jurisdiction of the US Federal government. However, coastal states like Louisiana and Texas not only face a substantial part of the risks associated to such activities (i.e. oil spills, pollution with drilling fluids and so on) but also have to foot the bills for providing onshore infrastructure and services in support of them. And yet, state and local governments have never been able to tax OCS facilities, and the levies that they can impose on onshore facilities simply do not have the potential for raising the amount of money necessary for the remediation of problems related to offshore oil development. Even today, after fifty years of OCS petroleum leasing, coastal states are only entitled to receive revenues from OCS oil activities in the form of congressional appropriations under the Coastal Zone Management Act (CZMA) and/or the environmental clauses of OCSLA amendments.

Not surprisingly, this unequal division of the OCS spoils and costs has given rise to much acrimony in the affected states. In the case of Louisiana, for instance, the way in which this state's shifting coastline was defined in court in 1969 cost it "over $10 billion; overburdened the infrastructure, decreased the tax base; and caused environmental damage".[50] If one bears figures like these in mind, it comes as no surprise to see that public officials in these states have long believed that their interests were "ill served by the federal government in the allocation of the overall wealth of the Continental Shelf", and that the only thing that could "salve the continuing sense of injustice"[51] they feel would be a revenue–sharing mechanism that would lessen the imbalance between the benefits attached to GOM petroleum production – which are experienced nationally – and its very local costs and consequences. Nevertheless, coastal states' calls for revenue sharing have gone unanswered since 1953, not least because of the remarkable rapidity with which erstwhile staunch defenders of states' rights – like Texas senator Lyndon Johnson or California governor Ronald Reagan – have gone cool on the idea of revenue sharing almost as soon as they entered the Oval Office. Also, as discussed above, the way in which OCS revenues are divided between different levels of government is in sharp contrast to the arrangements governing the sharing of royalties collected from *onshore* leases on Federal lands, which can only have added insult to the already considerable injury suffered by coastal states.

The financial exclusion of states from the OCS programme was the ultimate expression of the profound misgivings that Federal policymakers, jaded by the lessons of flush petroleum production in places like Oklahoma and Texas, harboured with regard to the likelihood that coastal states that stood to receive large amounts of money from offshore oil leasing (mainly via royalties) would exercise restraint and moderation in the development of these resources. After 1937, these misgivings crystallised in a concerted, sustained, exceedingly unpopular but ultimately successful attempt by the Federal government to wrest the control of as yet untapped offshore resources away from these coastal states, in order to safeguard the nation-wide control of petroleum production that had been so painstakingly put in place throughout the 1930s. This effort became even more intense with the end of the Second World War, which coincided with the exhaustion of the natural drive in some of the great southeastern flush fields (notably East Texas) and the appearance of localised products shortages as civilian demand expanded vigorously.[52] Events like these convinced policymakers that the recklessness that had characterised the development of onshore oil resources would not be repeated in the offshore continental shelf (for national security reasons, if nothing else).

FIGURE F2.3: FEDERAL OCS CRUDE AND NATURAL GAS PRODUCTION AS A PERCENTAGE OF TOTAL US OFFSHORE PRODUCTION, 1954–2000



The comparison between offshore oil production in state and Federal waters shows that these concerns were by no means groundless: OCS oil resources turned out to be prolific enough to have caused a major upset in the US oil market had they been exploited in a manner even remotely similar to that which characterised the development of onshore oil pools in the oil patch (Figure F2.3).[53] In a maritime environment, moreover, such an environmentally negligent mode of exploitation would have been particularly unacceptable.[54] Crucially, during the early 1950s, the Federal government decided that the best way of ensuring that coastal states would not disrupt the pace and nature of OCS development over questions of money was not to give them any (see Appendix 3). On the basis of its previous leasing experiences involving other minerals, as well as the long history of private oil leasing, the Federal government concluded that coastal states would tend not to behave as "silent partners" if given a financial stake in the offshore leasing programme, and would instead seek to accelerate the rhythm of extraction of OCS resources in order to increase their fiscal income. That is why Everette DeGolyer (who as assistant deputy petroleum administrator during the Second World War made crucial contributions to the drafting of various – unsuccessful – Tidelands bills), held the opinion "that he preferred federal development of the tidelands if that meant a more gradual development".[55] With the passage of SLA and OCSLA, the achievement of this objective of gradual development became easier (and the pace with which DOI made OCS tracts available for leasing up to the early 1980s reflected the agency's concerns in this regard). However, as we will show in the next chapter, the long-term price that both the Federal government and the oil industry have had to pay in exchange for this victory has been prohibitively high.

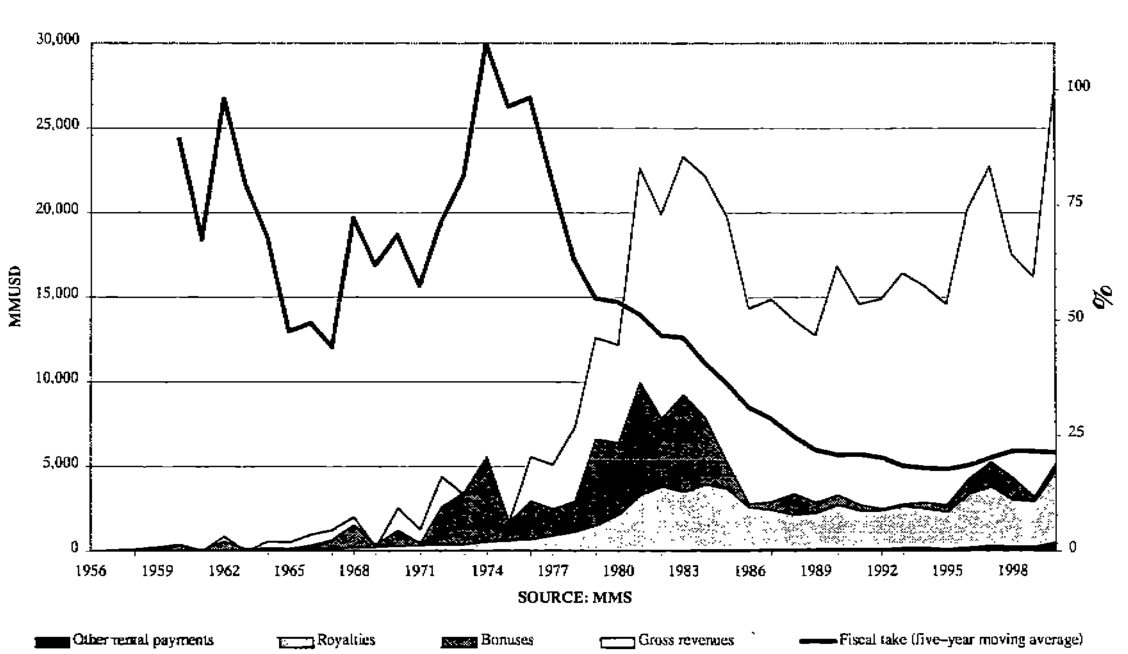
2.3 The Behaviour of Fiscal Revenues from OCS Oil Activities

Although the GOM institutional framework proved to be impervious even to the oil market dislocations that forced customary royalty and severance tax arrangements in other parts of the USA to give way "to whatever the market would bear"[56] during the early 1970s, this stability never did insulate GOM lease payments either from the whipsaws in the international price of oil or from variations in GOM production volumes. Total GOM lease payments did more than track the fortunes of the oil market closely, though. From the late 1960s up to the early 1980s, they actually tended to run slightly ahead of price developments, mainly because the magnitude of bonus payments reflected very bullish expectations of future price behaviour and output (rather than the real market value of oil and production levels at the time these lease sales were held).[57] Moreover, because bonuses need not be paid out of operating revenues (unlike other upstream levies), there were actually a few years (1960, 1962, 1968, and 1972–4) when total lease payments actually exceeded OCS gross income (i.e. the sales value of crude, condensate and natural gas production), sometimes by a sizeable margin.

The traditionally close link between lease payments, on the one hand, and GOM production volumes and international oil prices, on the other, has undergone significant changes since 1983. From that point onwards, the degree of sensibility of total lease payments to high prices and high production volumes has become attenuated. In other words, even during spells characterised by relatively high prices (and, from 1993 onwards, very favourable output perspectives), total lease payments have failed to rise above levels that look very modest indeed by pre-1983 standards.

Up until 1982 inclusive, total lease payments by oil companies came to about 55 per cent of a GOM cumulative gross income of USD 105 billion. After 1983, the ratio of total lease payments against GOM gross income has never again come close to such percentage. It declined to its lowest point yet (16.41 per cent) in 1992, and even during the banner year that was 2000, it only managed to reach 19 per cent. Indeed, for the 1983–2000 period as a whole, total lease payments represented only 22 per cent of a GOM cumulative gross income of USD 322 billion. The Federal government's fiscal take on GOM gross income, as measured by a five-year average (which dampens the effects of fluctuations in bonus payments and oil prices) has declined dramatically: having been close to 70 per cent during the late 1970s, as Figure F2.4 shows, it is currently down to approximately 20 per cent.

FIGURE F2.4: US FEDERAL OCS GROSS REVENUES AND FISCAL INCOME, 1956–2000



Gross income from OCS production activities first peaked in 1984 at USD 24 billion. Total lease payments peaked three years earlier (at USD 9.97 billion), when the wellhead price for OCS crude reached its all-time high (USD/B 33.43). As conditions in the international oil market deteriorated and crude oil prices entered into a period of acute decline, lease payments followed suit, falling by no less than USD 7.2 billion between 1983 and the *annus horribilis* of 1986. The stabilisation of oil prices after the netback crises did not lead to any improvement in terms of OCS fiscal revenues, which reached their nadir of USD 2.49 billion in 1992. After this date, total lease payments have increased markedly although, once again, they have never approximated the figures observed during the early 1980s (notwithstanding the healthy oil prices that have prevailed at times during the 1993–2000 period).

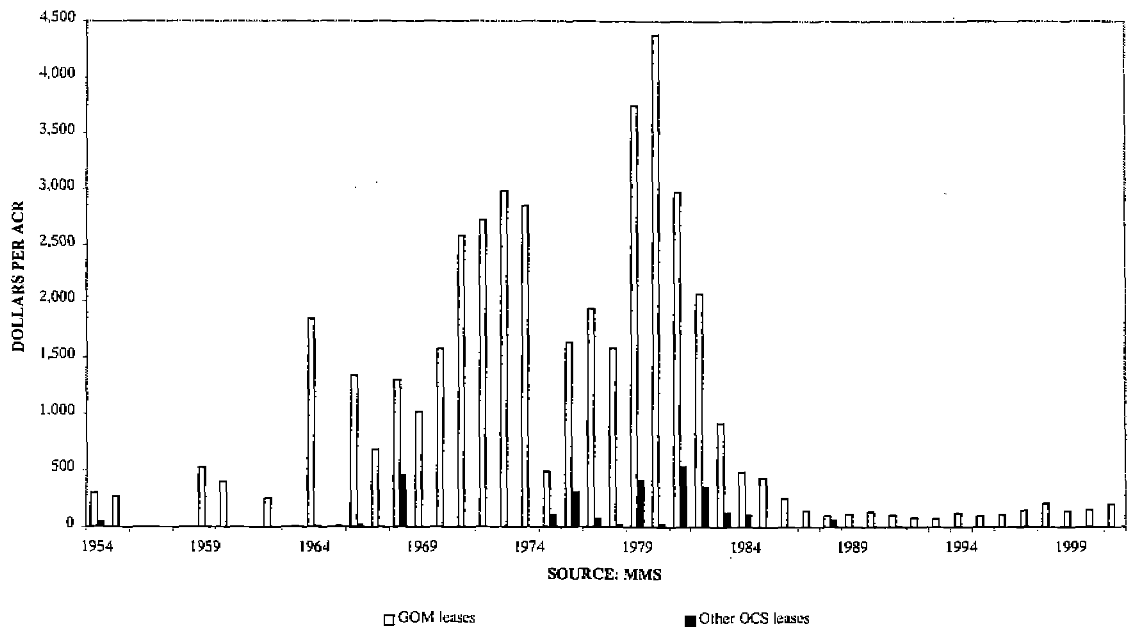
The extent to which lease payments have become increasingly decoupled from both production volumes and prices becomes readily apparent when one examines the behaviour of these variables during 2000. In that year, OCS gross income posted a new record of USD 27.1 billion, as the boom in deepwater production continued to gather pace, and international oil and gas prices exploded. Nevertheless, the phenomenal increase in the value of OCS hydrocarbons output did not herald a new peak in fiscal revenues: the figure for total lease payments for that year – USD 5.21 billion – was USD 4.76 billion short of the all-time peak. Admittedly, the sum of oil and gas royalty payments during 2000 (USD 4.1 billion) did manage to exceed the previous record, set back in 1984 (USD 3.9 billion). However, this *8* per cent difference between royalty payments in 1984 and 2000 stemmed from a *23* per cent difference in total output (itself the product of a 10.4 per cent increase in natural gas output and a 50 per cent increase in crude oil output).

Throughout the period of time under consideration, royalty payments have varied in harmony with changes in prices and volumes (although, as we have pointed out above, this is bound to change in the future). Thus, the abrupt decline in fiscal revenues from the early 1980s onwards is almost exclusively due to the behaviour of signature bonus receipts, which peaked in 1983 at USD 6.65 billion but plummeted afterwards. The oil price collapse of 1986 did nothing to help bonus payments out of the doldrums and in fact, since this date, yearly proceeds from OCS lease sales have only exceeded the USD 1 billion mark on three occasions – 1988, 1997 and 1998 – after having averaged USD 5.3 billion over the 1979-81 period. All the same, the fall in bonuses after 1983 has greatly exceeded the degree to which international oil prices have declined since that year.

Bonus payments were actually at their lowest ever (84 MMUSD) in 1992. In subsequent years, proceeds from lease sales have been much better, but their recovery appears distinctly unimpressive when measured on a per acre basis. Indeed, the extent to which per acre bonus payments have failed to respond to sharply increasing oil prices and significantly improved upstream prospects in the GOM is remarkable

(Figure F2.6). Even the large bonus payment receipts from auctions held during the mid-1990s were a function of the vast acreage leased. More importantly, bonus payments have remained relatively static even as activities in deep waters have become an everyday – indeed, an essential – part of the remit of more and more oil companies. Thus, even though a lot has been made of the record-breaking nature of the GOM acreage auctions that took place during the middle to late 1990s, this success is palpable only if it is measured in non-monetary indicators (like the total number of bids submitted or the total number of tracts bid upon).[58] Even after being deflated, the USD 1.4 billion in GOM bonus payments that the Federal government obtained in the much vaunted lease sales of 1997, for instance, compares rather unfavourably (especially on a per acre basis) with the USD 4.9 billion figure recorded during 1981.

FIGURE F2.5: OCS BONUS PAYMENTS BY UNIT OF SURFACE, 1954–2001



In oil provinces where licensing rounds are relatively rare occurrences, proceeds from acreage auctions actually constitute a form of extraordinary income, and the fiscal impact of the amount of acreage that the licensing/leasing agency might be willing to lease, on the one hand, and the manner in which it offers this acreage (i.e. bidding and adjudication procedures), on the other, will depend almost exclusively on the hydrocarbons production profile that their interaction gives rise to (i.e. whether they induce a faster rise to peak production and a commensurately quick production decline, for instance). In the GOM region, of course, the situation is altogether different: given the frequency of tract auctions, it follows that changes in the way in which the Federal government assigns offshore oil exploitation rights to companies should be expected to have an immediate and very perceptible fiscal impact. And, as it happens, the year which saw the onset of a precipitous fall in the percentage of GOM revenues that ended up in the coffers of the Federal government (1983) coincides with the moment when DOI, drawing directly from the example of the British North Sea[59], adopted major changes in its overall leasing policy, auction rules, bidding practices and parameters, and the whole mechanics underlying the offshore leasing process. What these changes were is the subject of the next chapter.

NOTES

[1] The only exception to this rule is the state of Louisiana, where oil and gas beneath the surface of the earth is regarded as not susceptible to private ownership and is therefore not a part of the land through which it flows.

[2] Inexcusably, Susan Strange makes constant references to 'concessions', 'governments' and 'concessionaires' in her overview of the evolution of American oil in the greater context of the international oil industry (Strange 1998: 198). No mineral concession as such has ever been granted in the USA, of course, and governments (whether at a local, state or federal level) only figure in lease contracts in their capacity as lessors.

[3] This legalistic distinction is of no consequence whatsoever to the companies that exploit oil resources located in Federal lands.

[4] See Mommer 2002.

[5] Van Brauman and Mangano 2000: 21.

[6] *Ibid.*: 25.

[7] Mommer 2002: 90–91.

[8] Signature bonuses have on occasion been used in the UK, but their magnitude has always been negligible.

[9] Mommer 1999: 25.

[10] Van Brauman and Mangano, *op. cit.*: 25. Italics ours.

[11] Quoted in Deacon *et. al.* 1990: 22.

[12] Mommer 2002: 106.

[13] Sullivan 1955: 69 ff.

[14] Surface rentals, minimum royalties and shut–in gas payments have generated USD 3.1 billion over the 1953–2000 period.

[15] Mommer 2002: 91-92.

[16] Mead 1993: 245.

[17] "The nation learned this lesson during the Korean War when an excess profit tax was levied on corporate income with the result that the highest tax bracket became 82%. Under such conditions, leasing a corporate jet, business conferences in Hawaii and similar 'perks' ... were commonplace for the reason that they cost only 18 cents on the dollar after taxes" (*ibid.*).

[18] PRT, for instance, was calculated on the basis of rules that made no distinction between investment and current expenditure, and which gave all producing companies the option to plough any excess profits generated back into E&P activities in the North Sea, thereby reducing their PRT liability. Thus, PRT effectively functioned as an exploration subsidy.
[19] Thus Mead (1993: 234): "upon payment of the bonus, the economic rent becomes a 'sunk cost' and thereafter has no effect on output or investment decisions. These decisions will then be made on the basis of incremental private costs and benefits. This result is optimal because economic rent is not a social cost. Rather it is a transfer payment to the government and as such it should not be allowed to affect investment or output decisions."
[20] Klemperer 2002: 186. Italics ours.
[21] GAO 1984: 1–2.
[22] *Ibid.*
[23] *Ibid.*
[24] *Ibid.*
[25] Profit–sharing systems have numerous intrinsic disadvantages, the most serious of which is that "the benefits of [a] project may accrue primarily or entirely to the lessee firm" (Mead 1993: 244) because of their administrative and accounting complexity. In the light of these handicaps, what comes as a surprise is not so much DOI's hostility towards profit–sharing mechanisms as their popularity outside the USA, especially amongst governments and agencies whose capabilities for administering them successfully are more limited by orders of magnitude than those of the US Federal government.
[26] "The design of sliding scale royalty and profit sharing systems is based on certain types of tract-specific information that is difficult for the government to achieve. Post-production accounting in these systems often involves complex procedures for verifying costs, profits, and/or flow rates associated with individual leases. Work commitment bidding systems have administrative costs in negotiating terms and conditions and monitoring industry compliance. There has also been concern about potential government intervention into industry accounting and operational practices in the implementation of these bidding systems" (OTA 1985: 157).
[27] Siegel and Smith 1984: 152.
[28] Scott 1995, v. 2: 169.
[29] See Scott 1994–5.
[30] As Mommer (2001: 27) puts it, when public and private mineral ownership (not only of oil, but also other minerals) co-exist, "it is difficult to argue that natural resources should be considered a free gift of nature in one case but not in the other. To be able to treat oil as a free gift of nature on public lands, one would need to abolish private ownership of minerals, which is politically inconceivable" in a place like the USA.
[31] Ballam 1999: 153.
[32] Mommer 2002: 58.
[33] Paradoxically, only the libertarian right has ever dared question the institution of private mineral ownership in the USA (see Bradley 1996, v.1: 59–74).
[34] See MMS 1997.
[35] In true petro-state fashion, the state also reduced personal income taxes and repealed the state occupational licence tax.
[36] Olien and Olien 1984: 145. Such rapacity, of course, did not then and has not since made any great difference to output decline in either state, a trend that began in 1971 and has accelerated regardless of the vast amounts of money thrown at it. And yet, even though today 39 per cent of wells in Texas produce less than 25 BD, no politician from that state would ever dare suggest that royalty rates be adjusted downwards, and much less entertain the notion that royalties be abolished altogether in the interests of greater output, lest he develop an unhelpful reputation as a communist agitator.
[37] The original provisions in the bill, which expired on 28th November 2000, exempted companies from paying royalties on the first 17.5 MMBOE produced in leases lying at water depths between 600 and 1200 feet, 52.5 MMBOE for leases lying between 1200 and 2400 feet, and 87.5 million barrels for leases located beyond 2400 feet. From the 2001 lease sales onwards, MMS has adopted a slightly less generous system that limits royalty relief to 9 MMBOE in water depths between 2400 feet and 4800 feet, and 12 MMBOE in water depths greater than 5300 feet.
The reason why the royalty relief bill only applies to new leases is that this was the only way in which it could achieve budget neutrality for purposes of the five-year budget window that the CBO uses to assess the cost of legislation (the lead times for exploration and development for new leases effectively meant that the budgetary impact of royalty relief would only be felt beyond this crucial window). Royalty relief for *existing* leases would have triggered the pay-as-you-go provisions of the Budget

Enforcement Act that allow a point of order to be made against legislation that increases federal mandatory spending or reduces mandatory offsetting receipts (like royalty and bonus payments), unless these changes are paid for either by cuts in entitlement programmes or by tax increases. This would almost certainly have caused it to be stillborn.

[38] No royalties will be due for any new production achieved after the date of enactment, pursuant to a Development Operations Coordination document approved by the Secretary of Interior (Davis and Neff 1996: 46).

[39] Thus far, the deepwater province has turned out to be more prospective for crude than for gas, which is why the weighted royalty rate for crude has declined more.

[40] Baud, Doyle, Peterson and Richardson, *op. cit.*: ix.

[41] Mead 1993: 239.

[42] A shift that has also been gathering pace in Alaska. Although this state resembles a Persian Gulf country both in its small population and its overwhelming fiscal dependence on oil exports (in this case, to other parts of the USA), it is nonetheless happy to put its name to position papers discussing 'Petroleum Fiscal Systems' in which gross revenue levies are summarily dismissed as 'regressive' and net revenue levies extolled as 'progressive' (see State of Alaska 2000: 19–21). For a lucid explanation of why the alleged drawbacks of royalties and similar gross income levies are much less serious in the real world than what economics textbooks might suggest see Berman 1997.

[43] Horsnell 1999: 62.

[44] Leases located in up to 330 feet of water will enjoy a royalty holiday on the first 20 BCF of production from any well drilled at least 15,000 feet below sea level.

[45] Supporters of these initiatives will have to surmount seemingly intractable procedural obstacles before they can be enacted into law (see Appendix 1).

[46] According to consultants from the defunct Arthur Andersen, "after 1995, when Congress reduced royalties on certain deep water leases, the pace of leasing reached fever pitch ... [again setting] records for the number of tracts bid on and the number of bids submitted as energy companies battled for the right to exploit the deep waters of the Gulf" (Riddle, Snyder and George 2001: 4).

[47] The National Petroleum Council estimates that US natural gas demand will increase to more than 29 tcf by 2010 (from a level of 22.5 tcf in 2000), and it is hoped that incremental GOM output will satisfy more than half of this increase in demand. Annual gas production in the area has been predicted to increase – with an optimism bordering on the irresponsible, according to some experts (see Nehring 2001) – from less than 0.9 tcf in 1998 to more than 4.5 tcf by 2010.

[48] The account of this process is certainly a salutary lesson into the tortuousness of the legislative process in the USA (see Davis and Neff, *op. cit.*). Supporters of the bill had to put into play all of their legislative wiles to secure its passage and, even then, the bill survived mainly because it was appended to another legislative vehicle that enjoyed quite broad support: the repeal of the ban on Alaskan oil exports.

[49] CBO 2000: 3.

[50] Fitzgerald, *op. cit.*: 42.

[51] *Ibid.*: 44.

[52] In an especially embarrassing incident, the battleship Missouri (where Japan had signed its capitulation) was immobilised in New York harbour through lack of fuel.

[53] The Rule of Capture was never a problem on public lands because, by law, lessees were always obliged to unitise fields.

[54] In 1947, for instance, oyster fishermen in Louisiana filed 64 suits alleging that oil industry activities had completely destroyed oyster beds in the area. An investigation of these claims found that GOM was indeed heavily polluted with oil, although the companies were at least exonerated from culpability in oyster mortality, which was attributed to a parasitical infestation (Kreidler, *op. cit.*: 177–180).

[55] *Ibid.*: 99.

[56] Kuntz *et. al.* 1998: 288.

[57] In addition, OCS bonus figures for the late 1970s and early 1980s include substantial payments collected on lease sales covering regions which, for political reasons, have never produced any petroleum (notably the Mid-Atlantic OCS).

[58] Riddle, Snyder and George, *op. cit.*: 4.

[59] The desirability of imitating certain aspects of the North Sea model had been well established by the time Watt occupied the Interior portfolio. Consider the following lines, written in the immediate aftermath of the First Oil Shock: "the primary initial objective of the North Sea governments was to get exploration and development activity underway. In the U.S., on the other hand, a major objective has been to produce the maximum initial government revenue. It is no longer clear that this objective ranks

so high, and it now seems that U.S. policy emphasizes rapid exploration and development. U.S. objectives need to be reviewed and ranked, and the effectiveness of the current leasing system in achieving these objectives assessed. The results produced by the licensing systems used in the North Sea suggest that features of those systems could be used beneficially in the U.S. (White *et. al.*, 1974: 143-4).

3 THE EVOLUTION OF GOM LEASING PROCEDURES: FROM TRACT NOMINATION TO AREA WIDE LEASING

The supply to investors of land with oil potential is the essential function of any oil fiscal regime, be it proprietorial or non-proprietorial in character. This function presupposes the existence of procedures for discriminating between potential investors in order to assign oil exploitation rights to just some of them, on grounds of their technical, economic, even political, suitability. Such procedures, in turn, can be based on a variety of decision-making parameters, which need not involve monetary transfers to the leasing/licensing agency. For instance, agencies can resort to investment-related bidding parameters (the length of seismic lines to be shot, the number and depth of wells to be drilled, the total amount to be spent in exploration activities, and so on). Alternatively, as happens in the UK, licences can be awarded after a bureaucratic process of negotiation centring on the work programme and past performance of prospective licensees. A major weakness that these parameters have is that, "without knowing how much oil or gas will be produced, there is no way to identify the high bidder"; thus, even in situations where "a single bid variable is mandated, if the rules allow renegotiating after the award has been made, the apparent initial high bid may turn out to be an illusion".[1] In addition, these parameters have other drawbacks attached that make them neither popular nor viable in most parts of the world (investment-related bidding can easily lead to distortions in the investment programmes of firms, while discretionary assignation of acreage is clearly vulnerable to corruption).

By far the most widespread procedure for the award of leases/licences involves the payment of cash bonuses by prospective investors in bidding rounds for acreage. Auctioning land in this fashion makes it possible for the leasing/licensing authority to identify high bidders *unambiguously* and, just as importantly, *at arm's length* (obviating the need for any discretionary or subjective judgements). In the context of liberal institutional frameworks, where signature bonuses are meant to function purely as decision-making tools for acreage assignment, this type of auction entails particularly low administrative costs. When acreage auctions are also deployed as a form of excess profit taxation, they place heavier demands on their users, although in terms of administrative simplicity they still compare favourably with other forms of excess profit taxation (like Resource Rent Taxes and Production–Sharing Agreements). These demands stem from the need to draw up bidding rules and other key features (like reserve prices, say) in a way that will make the auction attractive to bidders while, at the same time, discouraging collusion, predation and entry deterrence attempts on the part of some or all of them. Thus, auction design for Ricardian rent collection purposes can be a very knowledge-intensive enterprise indeed.

It is intuitively obvious that, if an acreage bidding round is to function as a vehicle for collecting expected excess profits, the leasing authority has to have some way of independently calculating the likely magnitude of these profits. In practice, of course, leasing authorities are rarely in a position to do this, which means that there is a great deal of informational asymmetry between themselves and their prospective lessees. Acreage auctions, in other words, ordinarily take place under conditions of acute adverse selection[2] (because a good is offered for sale when only purchasers can have an idea of its potential value). As a result of this, the leasing authorities will have to avail themselves of competition between prospective lessees in order to loosen these informational constraints, and thereby increase their capability to extract higher rents from lessees.

An excess profit taxation scheme based on bonuses therefore requires a reasonably sophisticated leasing authority that is able to dedicate resources not only to controlling and auditing prospective lessees but also to evaluating the informational content of submitted bids (to ascertain whether bids are being used as signalling devices for collusion between players, for instance).[3] As Macho-Stadler and Pérez-Castrillo point out, "even though this activity implies a wasteful cost, it may make the ... information [that only some firms possess] *less important*",[4] thereby increasing the probability that such firms will find it in their interest to reveal this information to the leasing authorities through high bids for acreage. Absolute *laissez faire*, therefore, is largely incompatible with what one can call the first cardinal principle of auction design; namely, that sellers will always be better off to the extent that they design auction schemes where bidders that bid high will face a low risk of not getting what they want, and bidders that bid low will face concomitantly high risks.[5]

A second golden rule of auction design is that sellers will always be better off to the extent that they adopt mechanisms intended to prevent collusion between bidders. In terms of the case at hand, this again presupposes a leasing authority that is fully conversant not so much with welfare economics as with game theory and strategic bargaining (or that is at least able to select, hire and digest the recommendations of consultants in auction design).

The third golden rule is that "the structure of the industry that will be created cannot be ignored by the auction designer".[6] However tempting – especially at an ideological level – it might be for leasing authorities to let the outcome of auctions be decided solely by "The Market", they should be discerning enough to realise that a radical hands-off approach will almost inevitably cause a host of competitive distortions, "the most obvious ...[of which] is that ... too few firms may win a share ... and these winners may each win too much, in just the same way as a 'hands-off' policy to merger control will tend to create an overly concentrated industry".[7] Such an outcome is especially regrettable in an extractive industry like oil, because it gives rise to entry barriers associated to the tenure of – and access to – land, which are much more intractable than barriers associated to the access to technology and capital (hence the Texan adage: "hold on to land, because God is not making any more").

Finally, if an auction is to be truly successful, its designer has to find ways of counteracting the inhibiting effect that the so-called winner's curse can have on the willingness of certain types of prospective bidders to participate in auctions. The winner's curse "reflects the danger that the winner of an auction is likely to be the party who has most greatly overestimated the value of the prize", a danger that looms all the more menacingly in circumstances "when bidders have the same, or close to the same value for a prize, but they have different information about that actual value".[8] Although the winner's curse preys on the minds of large and small bidders alike, it affects them asymmetrically: the latter are especially wary of it because they "recognize that they are only likely to win when they have overestimated the value by more than usual", whereas the former can afford to be less cautious, "since beating very cautious opponents need not imply one has overestimated the prize's value".[9] Moreover, since the effect of the winner's curse is "self-reinforcing, the advantaged bidder wins most of the time ... and because its rivals bid extremely cautiously [or not at all], it also generally pays a low price when it does win".[10]

In the following sections of this chapter, we will delineate the way in which DOI translated these four cardinal rules into policy up to 1983. Next, we shall explain the nature of the major changes that the agency decided to introduce after this date. Lastly, we will discuss some of the economic and political consequences that followed from this change of tack.

3.1 The Tract Nomination System

Up until 1982 inclusive, the mainstay of OCS offshore acreage auctions was a procedural system commonly referred to as Tract Nomination (TN). Under this system, DOI issued a call for nominations, in which it requested oil companies to identify promising tracts within an OCS region. After evaluating these nominations, DOI would decide which tracts to offer, on the basis of "the past leasing history of the area, economic and environmental considerations, multiple-use conflicts, and the estimated potential of the sale area".[11] Importantly, the mere fact that a tract had been nominated by industry did not make it obligatory for DOI to offer it in a tract sale (five of which were usually held every year). DOI had the right to withhold from offer any tracts lying in areas about which the department felt that it had insufficient knowledge, for instance (a faculty that gave oil companies interested in obtaining such tracts a strong incentive to remedy DOI's ignorance).

Except in the relatively small number of tracts involved in the alternative bidding systems initiative, the sole bidding parameter in lease auctions carried out under the TN system was a cash bonus payment. However, the *primary criterion* for the acceptance or rejection of individual bids received was DOI's independent estimate of the value of each tract, and *not* the magnitude of the highest bid or the amount by which it exceeded the second highest bid.[12] This did not translate into extortionate reserve prices for acreage. GAO noted that, under the TN system "high bids usually substantially exceeded Interior's estimates of tract value",[13] but a 1980 study carried out by the Los Alamos National Laboratory, in which DOI's estimated values were considered under the light of the number and magnitude of bids received and the levels of production achieved after lease, found that the simulation methodology on the whole rendered quite conservative estimates of the fair market value of tracts.[14]

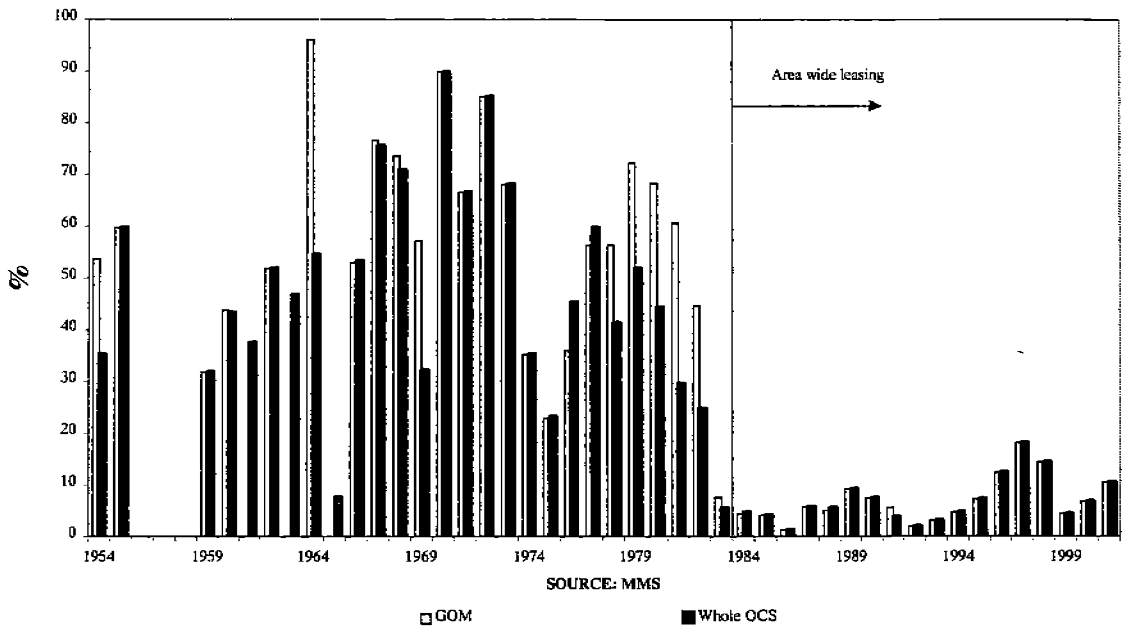
When the TN system is viewed under the light of the golden rules of auction design outlined earlier, there is little that one can find fault with. Firstly, the leisurely pace at which tracts were offered had the effect of keeping the demand for offshore leases high, which made up for lively and competitive auctions whenever sales were held. This, in turn, had a very beneficial effect on government revenue: GAO's statistical analysis established that, throughout the life of the TN system, each additional bid that DOI received for a given tract had, on average, translated into an increase of USD 1082 USD per acre in the amount of the high bid submitted for that tract (i.e. USD 6.2 million for a typical tract).[15]

Secondly, the preparation of independent estimates of the value of tracts undoubtedly offered an effective way of curbing the incentive for underbidding on the part of players, especially advantaged ones (i.e. larger companies). This procedure amounted to a credible threat signalling that companies submitting lowball bids would face a greater risk of not obtaining the acreage they desired, whereas the more closely that these bids reflected their true estimate of the tract's worth as well as their cost advantages, the lower this risk would be. For instance, in the legendary GOM sale of March 1974 (which saw the second highest bonuses per acre ever recorded, and the fourth highest total bonus payment[16]), Shell paid USD 65.8 million for South Timbalier Block 26, a drainage tract adjacent to an area where it had substantial production. Shell faced no competition for the block (the only other bid submitted was a lowly USD 834,000) but, as the *Oil and Gas Journal* remarked at the time, Shell submitted what turned out to be the second highest per-acre bid of the whole sale (USD 26.3 million) in order to meet what it considered would be DOI's estimate of the value of this block.[17]

Thirdly, the system neutered collusion and its negative effects, largely through elegant prophylactic measures. After all, even if bids for different tracts were the outcome of inter-firm agreements, the colluded bidders would have had, at a minimum, to exceed DOI's independent estimate of the value of the tract in order to obtain the lease. In addition, the fact that this estimate of value was unknown to bidders introduced an element of uncertainty that, again, encouraged companies to submit bids that genuinely reflected their ideas about the prospects of a tract (see above). Members of a bidding ring could never be sure that companies that were not part of it would not submit higher bids; what is more, they could not even be sure that companies who were part of the ring would not try to convince the others to submit a lowball bid, only to submit – on their own – a higher bid reflecting information obtained on occasions when a collusive bidding strategy might have been agreed upon. Indeed, because DOI was fully within its rights to refuse to lease any acreage at all if it was dissatisfied with the bids received, the TN system offered reasonable protection even against the remote possibility that *all* prospective lessees might become part of a bidding ring.

Thirdly, the nomination procedure created a positive informational externality, by making it possible for smaller companies to concentrate their resources on evaluating the resource potential of a limited number of tracts. Thus, TN created a more level playing field than would have otherwise been the case. Tracts were subjected to intense scrutiny and examination before coming up for auction, and this lowered the exploration risks that independents faced. After all, the mere fact that a tract had come up for auction in the first place was an indication to a company that someone else had good reasons to believe that oil would be found there (as discussed above, the system also fostered the diffusion of information about areas that had been subject to limited exploration or surveying). This gave even smaller actors the chance of bidding on tracts for which they had no independent data, in the expectation rather than the hope "that resources would be found later".[18] This largely explains why a significant proportion of the areas offered in each sale under TN were leased (Figure F3.1). But even though TN effectively opened up bidding, leasing and drilling to many producers who would otherwise have stayed sidelined because of their limited capabilities to manage offshore geological risk, it should not be thought that this amounted to an unjustifiable policy bias in favour of small firms that were somehow less technically competent and efficient than the majors. Mead, for instance, found in an analysis of 1223 OCS oil and gas leases issued from 1954 through 1969 that majors were actually more prone than smaller firms to acquire dry leases and that, conversely, small firms earned higher rates of return on their lease investments than did majors.[19]

FIGURE F3.1: OCS ACREAGE LEASED AS A PROPORTION OF ACREAGE OFFERED, 1954–2001



SOURCE: MMS

Notwithstanding the apparent soundness of the key elements of the TN system, changing circumstances during the late 1960s and early 1970s (notably the relentless tightening of the international oil market and the first fleeting glimpses of Hubbert's peak in the Lower 48) revealed that it was not entirely without shortcomings. During the Johnson administration, the way in which the TN system was handled probably did become too obstructive and focused on wringing every penny out of prospective lessees, but chiefly because the Federal government was desperate for cash to pay for its misadventures in Vietnam (as we have seen, total lease payments during several of those years managed to exceed OCS gross revenues, often by a considerable margin). This was not a terminal condition, though, as proven by the fact that between 1973 and 1979 (i.e. during the Nixon, Ford and Carter administrations), the amount of OCS acreage offered and leased increased by 238 per cent and 197 per cent, respectively, with nothing but beneficial effects in terms of overall fiscal revenues.[20]

A related (and very serious) problem was that posed by the inflated bidding that became the norm in OCS auctions as a result of the frenzied atmosphere whipped up by the OPEC revolution, on the one hand, and the pervasive obsession that more oil had to be found in politically reliable areas of the world, on the other. As we have seen, the prospect of domestic oil firms bidding themselves into financial oblivion became a cause of grave concern in the USA. Still, it would appear that the alternative bidding systems initiative that US policymakers devised to address this problem was unnecessarily complex. Quite effective results could have been achieved with less all-round aggravation through the simple expedient of conducting lease auctions on a *second price* rather than a *first price* basis,[21] always in the presence of reasonable safeguards to prevent signalling between firms, and perhaps incorporating mark-up or reservation price elements in case the two highest bids were too far apart.[22] In any case, the increase in the supply of land that occurred during the final years of TN meant that, by the beginning of the 1980s, payments per unit of surface had come down to much more reasonable values than those observed during the early 1970s (even though the price of oil had gone up in the meantime).

It is therefore not far fetched to suggest that tinkering at the margins of the TN system by means of quite straightforward and *market-centred* mechanisms like those mentioned above might have sufficed to protect American oil companies (especially smaller ones) from compromising their viability through overenthusiastic bidding for offshore leases. Importantly, had the US government followed such a course of action, it would have ensured the continuity of a system that, for more than thirty years, had proven to be smooth running, resilient and, above all, enormously successful in fiscal terms. As things turned out, though, the US government went for the option of jettisoning the TN system *in toto* and introducing in its stead a system that before long came to be known as area wide leasing (henceforth AWL).

3.2 The Area Wide Leasing System

Up until 1982, the various functions associated to OCS had been scattered throughout DOI and its dependencies (like the US Geological Survey). The Reagan administration centralised most of these functions in a new agency, the MMS, with the Secretary of Interior retaining sole authority over a number of critical steps in the process, notably the preparation of the leasing programmes, the sharing of information with affected coastal states, the approval of the final notice of sale, the right to reject high bids and the right to cancel leases. In addition, DOI mounted an all-out effort to increase the frequency of lease sales, to offer more tracts for lease in each sale, and to streamline the bid acceptance and presale planning processes.[23] These efforts crystallised into an extraordinarily ambitious five-year leasing programme that hinged upon offering nothing less than the entire OCS, by means of 41 lease sales[24] that would put to the consideration of the oil industry entire offshore planning areas[25] at a time (hence the area wide moniker).

The AWL programme contemplated putting into play planning areas which could cover up to 50 million acres in extension, as opposed to specifically identified tracts (as had been the case with TN). Nevertheless, under AWL, individual tracts would continue to be limited to an area of nine square miles – 5670 acres – unless the MMS determined that a larger area was necessary to put together a reasonable economic unit. However, leasing terms would no longer be limited to 5 years. Instead, 10–year leases in the GOM region[26] would be offered for tracts lying at depths of 3,000 feet or greater, while blocks in water depths between 1300–3000 feet would enjoy 8–year terms.[27] AWL also increased the minimum acceptable bid from USD 25 to USD 150 per acre. This proviso was a casualty of the 1986 oil price collapse,[28] but its demise has been inconsequential in fiscal terms because, as explained below, the bid adjudication process underlying AWL largely negated even the modest protection afforded by the USD 150 per acre minimum bid.

Under AWL, assignation of acreage still took place following a competitive bidding process, thereby maintaining the tradition whereby the USA is one of the few countries where leases are granted solely on the basis of cash bonus payments. However, given the acreage involved in AWL offerings, the primary assignation parameter could no longer be an estimate of tract value, as MMS lacked the resources to subject many hundreds of individual tracts to a detailed examination.[29] Instead, high bids would automatically be accepted for tracts receiving three or more bids, regardless of how low the highest bid might appear. Likewise, a high bid would automatically be accepted for any tract that MMS had reasons to believe harboured too little oil or gas for commercial production to take place. These reasons did not have to be particularly *good ones*, though: the mere "lack of Interior maps on [a] tract",[30] for instance, was justification enough to classify it as non-viable.

The AWL adjudication procedures still contemplated estimating the fair market value (through Monte Carlo analysis, as under TN) for tracts that were deemed viable but which had not received three or more bids. In such cases, MMS would accept any high bid that exceeded both the minimum acceptable bid value and the geometric average of its estimated value and the bids it had received. Of course, in averaging multiple bids with its own single estimated value in this fashion, MMS in effect gave "more importance to a relatively few bids ... than to ... good supporting data and estimates of tract value",[31] thereby providing companies with a powerful incentive to bid against procedures and criteria that signalled that MMS was prepared to assign leases even if bonus payments came in below its traditionally conservative estimates of fair market value.[32]

The foundations upon which the whole AWL policy was built appear shaky when one examines them in the light of the golden principles of auction design. For instance, few if any auction designers would concur with the simplistic assumption that the receipt of multiple bids for a tract is evidence in itself of sufficient competition, and that the possibility of collusion can therefore be discarded without further ado.[33] Therefore, it is fair to assume that auction experts would have taken a dim view (as GAO, in fact, did) in connection with the 305 tracts that MMS summarily leased (with no knowledge of their potential value[34]) on the basis of this criterion during the first ten AWL sales.[35] Likewise, they would probably have been unimpressed by MMS' claims that most of these winning bids would have been accepted anyway had detailed examinations been carried out, since the agency confessed it was unable to rule out the possibility that it might have accepted high bids that were too low given the prospects of individual blocks.[36] Finally, they would also have had reservations about the soundness of the out-of-date data that MMS used to diagnose many tracts as being non-viable, given that a significant proportion of the discoveries made on blocks leased in the early area wide sales involved tracts that fell within this category.[37]

The whole AWL policy was predicated on the assumption that lease offerings would attract many knowledgeable prospective buyers, and that a number of them would bring to bear *comparable* analytical, scientific and financial capabilities on the evaluation of each *individual* block. However, this assumption was really meant to safeguard MMS' peace of mind (rather than the economic interests of the Federal government), mainly because it enabled the agency to rule out on an *a priori* basis, four very real problems that could threaten the success of the whole accelerated offshore leasing programme as conceived out by James Watt, President Reagan's first Secretary of the Interior. The first problem was that the territorial interests of individual companies might not overlap (whether due to collusion or because of the large areas offered, or both) and that, as a result, competition for tracts might fail to develop at all. The second one was that the more knowledgeable and capable players might submit lowball bids to take advantage of the extent to which other players (competitors as well as the MMS) were in the dark about the potential of certain blocks, especially since the adjudication procedure "made strategic bidding practices ... more attractive ... [by ensuring] that the right combination of two or three bids could guarantee the high bidder the lease to any tract".[38] The third was that an overwhelming percentage of the acreage on offer might somehow end up in the hands of these more capable players. And the final problem that MMS chose to ignore was that the winner's curse might exert its well-attested and potentially decisive influence on the structure of an industry powered by auctions by inhibiting smaller players from submitting anything but very conservative bids, thereby reinforcing the position of advantaged players.

In its political dimension, AWL was predicated on the notion that coastal states that had never had any direct share in the proceeds from OCS leasing would act as silent and passive bystanders as the amount of OCS acreage on offer increased exponentially, as their participation in the whole leasing (and development) process became increasingly irrelevant (*de facto*, if not *de jure*), and as the estimated magnitude of the open-ended liabilities that their support and provision of infrastructure for OCS development would entail skyrocketed. In exchange for all this, coastal states were to be compensated in a rather peculiar manner: there would be no OCS revenue sharing, thereby leaving states with an identical revenue entitlement to the one they had come to resent so much under TN (that is to say, zero).

As argued above, there was a certain leap of faith quality to the economic dimension of the whole AWL enterprise (specifically, faith in the ability of *laissez faire* to sort out the issues of collusion, entry deterrence, informational asymmetries and buyer market power that are central to the correct functioning of auction markets). The economic policy tenets underlying AWL could be considered ill-advised by someone subscribing to the idea that auction design is largely a practical application of standard antitrust theory.[39] However, these tenets were not inherently implausible, which is far more than can be said for the assumption that the one-sidedness of AWL would not lead to a flaring up of the long-standing federal/state conflict over OCS oil development.

The gravity of this political misjudgement was driven home to the designers of AWL as soon as the programme got officially under way (see Appendix 3). Politicians in the East Coast, Florida and California were deeply incensed at the way in which Secretary Watt was prepared to ride roughshod over the environmental concerns of their constituents in order to achieve a higher domestic petroleum output, but without offering their states anything by way of compensation. A flurry of lawsuits and sniping in Congress ensued, enveloping the whole OCS leasing programme in controversy and acrimonious litigation.[40] AWL provoked umbrage even in Texas and Louisiana, as their governments complained that AWL would not allow the maximisation of the price for acreage straddling state/federal boundaries in the way that the tract nomination system had done. These states considered that they had to be compensated for drainage of their resources according to the value that the tracts would have fetched in restricted auctions (and not according to what the MMS had managed to obtain for these tracts in what they saw as fire sales), and they proceeded to take the Federal government to court to obtain compensation.[41] The opposition of these states with regard to AWL received considerable reinforcement from the contents of a study that the Texas government commissioned from National Economic Research Associates Inc. (NERA), which indicated that the introduction of AWL had coincided with a collapse in the amount of money paid per OCS area unit. The study explained this development in terms of a number of intuitive factors: reduced competition through an oversupply in offered acreage, poor information on the available acreage, fixed company budgets for lease acquisition, and, finally, the inadequacy of the capital and equipment that many companies as well as the MMS itself had at their disposal to evaluate tracts.[42]

The intense opposition to AWL by coastal state governments and members of Congress crystallised in the enactment of restrictive leasing moratoria on ever more extensive swathes of the OCS. Up to 1982, moratoria covered only 736,000 acres offshore California, but by 1983 they already blanketed 35 million OCS acres.[43] One year later, the DOI appropriation bill had slapped moratoria onto no less than 52.2 million OCS acres (36.6 million in California, 8.2 million in the North Atlantic and 7.4 million in the Eastern Gulf, off Florida). Thus, notwithstanding Ronald Reagan's virulent distaste for any sort of disposition that might interfere with hydrocarbons production (and his readiness to deploy his presidential veto against such dispositions), the "antiquated hierarchical approach to decision making"[44] that his administration pursued led to the almost complete breakdown of the offshore leasing programme outside the GOM region within a very short time–span.[45]

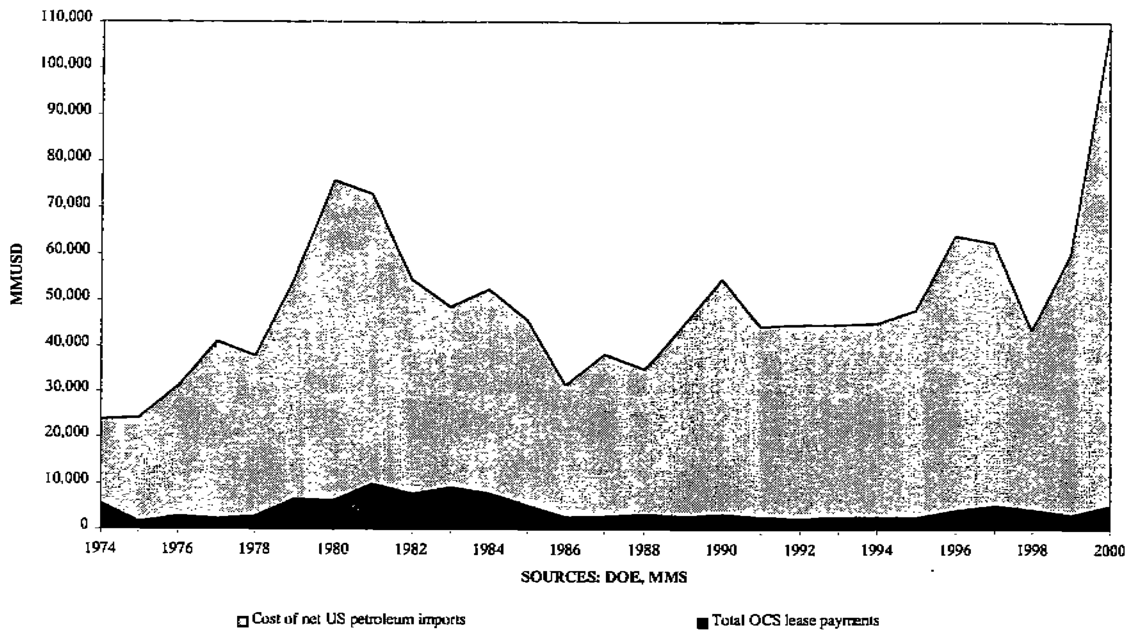
3.3 Conclusions

AWL cannot be said to have got off to an entirely auspicious start, given the severity of the unintended political side effects that it provoked: to wit, inflaming the hitherto low-intensity Seaweed Rebellion (see Appendix 3) into a full-scale Federal/state conflagration across several fronts: California, Florida, the Mid-Atlantic OCS. What is more, the fiscal sacrifices that the designers of the policy incorporated into their cost/benefit calculations turned out to be more unpalatable than originally planned. When AWL was introduced, DOI estimated that by 1985–6, bonuses would have declined to a level of USD 2–3 billion per year, while royalties would have increased substantially, surpassing bonus payments more or less at the same time and eventually stabilising at a level of USD 3–4 billion per year. In fact, as shown in Chapter 2, the decline in revenues from bonus payments exceeded these expectations by an order of magnitude. According to GAO, the "significant negative relationship between area-wide leasing and the number of bids received for each tract" meant that the USD 8.9 billion that the Federal government received in bonuses in the first ten area wide sales was – in nominal terms – USD 7 billion less than what it would have received had "the slower pace of the prior tract-selection programme ... been followed".[46] By 1985 proceeds from lease sales had slipped well below the USD 2 billion mark, to USD 1.56 billion, and they have only exceeded USD 1 billion (i.e. half the predicted minimum) twice since then, during 1988 and 1997. Unsurprisingly, the estimates of royalty receipts also proved too rosy: royalty payments surpassed the USD 3 billion mark for the first time only in 1996 and, since then, they have only managed to repeat this feat twice (during 1997 and 2000).

The above factors notwithstanding, AWL has been garnering accolades from consultants, analysts and oil companies alike for the best part of twenty years now, chiefly because these actors are sceptical regarding the connection between the modest bonus payments received for OCS tracts after 1983, on the one hand, and AWL, on the other. The many admirers of AWL stress that the downward trend in GOM bids began under the TN system in 1980, and merely intensified under its successor. This is seen as a straightforward response to the readjustment of oil price expectations after the Iranian revolution and the netback crisis. Furthermore, supporters of AWL also point out that lower bids are a natural consequence of the fact that, from the early 1980s onwards, exploration in GOM had to move to much riskier areas because of the maturity of the region. In the GOM areawide sales of 1983–4, for instance, more than 26 per cent of the tracts leased were located in water depths beyond 2000 feet and 18 per cent lay in water depths beyond 3900 feet; in contrast, prior to 1983, leasing in water depths beyond 2000 feet seldom exceeded 5 per cent of total acreage.[47] These are very important points, and we shall be returning to them later on.

GAO carried out an in-depth evaluation of AWL early into the life of the programme (it reviewed the first ten area wide leasing sales, spanning the period from April 1983 to September 1984). While not in itself predisposed against AWL, GAO encountered enough disquieting signs for the whole report to be permeated with the cautionary notion that, given some of the apparent drawbacks of AWL, its proponents had better be right as regards the abundant long-term benefits that they insisted would derive from its adoption (the study was drafted as the political backlash against AWL in California, Florida and other coastal states was gathering an unstoppable momentum, but the agency did not dwell on this point at all). In a related study, GAO also disqualified the methodology that DOI had used to calculate the benefits that would supposedly be generated by the early receipt of corporate federal income tax on incremental oil and gas output. Strictly speaking, the magnitude of these benefits would have been given by the extent to which offshore production yielded tax revenues greater than what would have been received from taxing revenues generated by other investments. But in its calculations, DOI simply included the whole of the future income tax payments as a fiscal benefit even though, as GAO explained, this was tantamount to assuming that "capital not invested in offshore development [would] produce no taxable income".[48] This accounting sleight of hand generously overstated the tax advantages of area wide leasing and the gains from early receipt of revenues, mainly by inflating the ratio between revenues from taxes and royalties, on the one hand and revenues from bonuses, on the other.

FIGURE F3.1: OCS LEASE PAYMENTS AND COST OF NET US PETROLEUM IMPORTS, 1974–2000



Notwithstanding its misgivings regarding DOI's accounting tricks, as well as its concern over some unfortunate consequences of AWL that were already in evidence by 1985, GAO refrained from concluding on this basis that AWL was an inferior policy alternative to TN. The agency was surely right in doing so. After all, these drawbacks were primarily fiscal in nature, and for a country with the petroleum consumption profile of the USA, the fiscal dimension of oil leasing simply cannot be the yardstick used to judge the soundness of a policy like AWL. To appreciate why this is so, one need not look beyond Figure F3.2, which shows that the admittedly enormous sums the US Treasury has foregone as a result of the collapse in total lease payments nonetheless represent but a fraction of the yearly US oil import bill. Thus, it is clear that the cost/benefit balance on the AWL account would be very positive if US domestic production had indeed increased – and the country's dependence on crude imports decreased – in the way that the designers of this policy intended. In the following chapter, we shall try to ascertain whether this was in fact the case.

NOTES

[1] Mead 1993: 224.

[2] This transactional problem arises when parties want to trade in the presence of "asymmetric information regarding any variable relevant to the contractual relationship", or when one of them has an "informational advantage concerning his personal characteristics" (Macho-Stadler and Pérez-Castrillo 1997: 103).

[3] *Ibid.*: 157.

[4] *Ibid.*

[5] Maskin and Riley 1984.

[6] Klemperer 2002: 177–8.

[7] *Ibid.*

[8] *Ibid.*: 173.

[9] *Ibid.*

[10] *Ibid.*

[11] GAO 1986: 9.

[12] Details on the methodology that DOI followed to estimate the value of tracts can be found in Appendix 1.

[13] GAO 1985: 30.

[14] Indeed, so conservative were they that DOI was on occasion accused of "radically underappraising the land" in order to clear the way "for accepting just about any bid that came along" (Sherrill 1983: 238). In support of this accusation, Sherrill mentioned the case of 35 tracts whose value was appraised at USD 146 million, but which were leased for USD 1.49 billion (with two individual tracts valued at USD 144,000 going for USD 91.6 million and 76.9 million, respectively). What Sherrill never explained was why bidders found it necessary to pay such sums if DOI was indeed ready to accept any offer that came along.

[15] GAO 1985: 18.

[16] The average bonus per acre in this sale was USD 4.96 million (against the USD 5 million recorded in lease sale 19, held in 1968). Total bonus payments for this sale came to a staggering USD 2.1 billion.

[17] *O&GJ*, 8 April 1974: 40. According to the Small Business Committee of the US Congress, on those occasions when DOI rejected a high bid for a block, it obtained an average of 13 times more for it the next time it came up for auction (Sherrill, *op. cit.*: 238).

[18] Gramling 1996: 160.

[19] Mead 1993: 226.

[20] During the Nixon administration, about 10 million OCS acres were leased, an amount equivalent to that leased from 1953 to 1973. Naturally, the amount of bid money obtained per acre went down as a result of this (prompting predictable accusations that OCS acreage was being given away).

[21] In both types of auction the good is sold to the highest bidder, but whereas in the latter he has to pay the amount bid, in the former he pays the amount of the second highest bid.

[22] Auction mechanisms of the type that Klemperer (*op. cit.*: 181–2) calls Anglo-Dutch might have also have done the trick as well if not better, at least on paper (in practice, US procedural requirements would appear to render them unsuitable for offshore oil leasing). This is an ascending auction in which price is raised continuously until all but two bidders have dropped out, whereupon both have to submit final sealed bids.

[23] Comparison between the planning processes for TN and AWL can be found in GAO 1985: 45. The whole AWL procedure, pre-lease and post-lease, is explained in great detail in OTA 1985: 205–210.

[24] 16 offerings would involve tracts located offshore Alaska, 12 in the GOM, 8 in the Atlantic Coast, 4 off California and one reoffering sale.

[25] For leasing and administrative purposes, the US Exclusive Economic Zone (EEZ) is divided into 26 planning areas that cover nearly 1.1 billion acres out of the total 1.9 billion acres within the OCS. The planning areas are: North Atlantic, South Atlantic, Mid-Atlantic, Eastern Gulf of Mexico, Central Gulf of Mexico, Western Gulf of Mexico, Southern California, Central California, Northern California, Washington and Oregon, Florida Straits, Gulf of Alaska, Kodiak, Cook Inlet, Shumagin, North Aleutian Basin, Aleutian Arc, St. George Basin, Bowers Basin, Navarin Basin, St. Matthew Hall, Norton Basin, Hope Basin, Chukchi Sea and Beaufort Sea. Each one of these areas encompasses one or more sedimentary basins, but only about 17 per cent of the acreage (179 million acres) in the planning areas is considered to be underlain by 'promising geological structures' with significant potential for accumulated oil and natural gas (OTA 1985: 33). Over half of this promising acreage

(110 million acres) is adjacent to Alaska, and a further 15 per cent (27 million acres) is located in the Atlantic planning areas.

[26] Longer leasing terms had been introduced in other OCS regions before 1983. The first time that DOI offered tracts with 10-year leases was in the 1979 joint Federal/State sale in the Beaufort Sea, and 10-year leases more or less became the rule in Alaskan/Arctic waters thereafter. In the Mid-Atlantic OCS, starting in 1981, all tracts lying in 1320 feet of water or greater were offered with 10-year lease terms.

[27] Leasing terms have gradually been relaxed in other aspects as well. For instance, up until 1996, holders of 5- and 8-year leases had to submit either exploration plans or statements of intention to explore by the end of the fourth or fifth year of the lease term, respectively. This blanket requirement has now been dropped, although MMS reserves the right to identify cases in which exploration activities do have to adhere to the previous milestone schedule. Holders of 10-year leases, in contrast, have never had a set milestone for submission of exploration plans. In general, production still has to begin within the primary period if the lease is not to be forfeit, although the MMS has great leeway in defining exceptions and extensions to this rule.

[28] *Federal Register*, 20 July 2000: 45103. The previous minimum figure was reinstated in 1987 and it has remained unchanged for blocks located in 2600 feet or less of water ever since. As a result of the deep water boom, the minimum bid for blocks in waters deeper than these has been raised to USD 37.50 per acre. In principle, MMS has the faculty of changing the minimum bids every time it conducts a lease sale, although it must announce the figure well in advance of it.

[29] DOI's Monte Carlo simulations required at least 1000 iterations per tract.

[30] GAO 1985: 94. A tract could also be pronounced non-viable if it met one or more of the following criteria: "lack of an oil or gas structure; structure too small to be economical to produce; adverse stratigraphic conditions" (*ibid.*).

[31] GAO 1985: 43.

[32] This weighting method fatally undermined the role that tract value estimates played under TN as indicators of DOI's reserve price for tracts. As Klemperer (*op. cit.*: 177) observes, "the credibility of reserve prices is of special importance. If a reserve price is not a genuine commitment to sell an object if it does not reach its reserve, then it has no meaning, and bidders will treat it as such".

[33] Especially given the repetitive nature of offshore leasing: "a frequently repeated auction market . . . is particularly vulnerable to collusion, because the repeated interaction among bidders expands the set of signalling and punishment strategies available to them and allows them to learn to cooperate" (Klemperer, *ibid.*: 172).

[34] GAO 1985:34. Their disparagement might have turned into disbelief upon hearing that MMS considered that it had good or excellent data for 97 tracts which it could have evaluated "with little additional effort", but instead chose to lease them sight unseen for USD 638 million.

[35] GAO pointed out that, if the three or more bids criterion had been in operation before 1983, 11 per cent of the high bids rejected under TN would have been accepted, netting USD 826 million less than DOI's value estimates for these tracts (some of the bids that would have been accepted would have been lower than the tract value estimates by up to 40 per cent; GAO 1985: 34).

[36] GAO 1986: 21.

[37] Early on in the history of AWL, GAO pointed out that "in the first two Gulf area-wide sales, 285 of the 610 tracts with poor supporting data were classified non-viable and leased without further evaluation for $1 billion", even though some tracts attracted multiple bids, thus indicating that more than one company considered the tracts to be potentially valuable (GAO 1986: 21). For instance, 18 of the tracts in the second Gulf areawide sale that the MMS had classified as nonviable received at least three bids each.

[38] GAO 1985: 39. The submission of three bids of USD 1 million, USD 2 million and USD 5 million would have guaranteed that the high bid would win the lease to any drainage or development tract valued up to USD 62.5 million, for instance.

[39] Klemperer, *op. cit.*: 186.

[40] As a result, out of the 21 lease sales planned to have taken place through the end of 1984, only 7 were held on their scheduled dates (although all but four of the sales scheduled for the 1982–4 period had been held by the end of the latter year). Litigation in California was particularly intense, and it eventually engulfed projects located in areas not covered by moratoria (the development of the giant Point Argüello field was the highest profile casualty amongst these); see Sollen 1998. For Florida, see Gramling *op. cit.*: 135–150.

[41] The lawsuits were only resolved with the passage of the Omnibus Budget Reconciliation Act (OBRA) of 1985. OBRA determined that states would receive 27 per cent of the rents, royalties and bonuses derived from leasing in areas lying wholly within six miles of their coastlines (i.e. three miles seaward from the edge of their territorial waters). Rents from leases only partially located within this zone would be shared according to the percentage area of the tract lying within three miles of the boundary of the state's territorial waters (Fitzgerald, *op. cit.*: 153). The Federal offshore revenues that the GOM coastal states (Alabama, Florida, Louisiana, Mississippi and Texas) have received from 1986 to 2000 under section 8(g) of OCSLA, as amended, amounts to USD 1.7 billion (of which Louisiana has received 50 per cent and Texas 39 per cent), an insignificant figure when compared to the USD 51 billion that the Federal government has received over this period.
[42] GAO 1985: 21.
[43] OTA 1985: 144.
[44] Fitzgerald, *op cit.*: 274.
[45] Gurney (1997: 31) mistakenly says that "areawide leasing was devised only for the Central and Western Gulf planning areas and the government did not use it in other US OCS regions". In practice, area wide leasing has not been used much in other areas, but it has certainly not been for lack of trying.
[46] GAO 1985: 18. GAO estimated that DOI challenged these calculations in a response to Congress, which was turned over to GAO for consideration. GAO showed that DOI's critique was methodologically flawed, and insisted that its own calculations continued to provide the best estimate of the fiscal effects of area wide leasing (GAO 1986: 13–7).
[47] Currently, 50 per cent of existing GOM leases lie at water depths of 1300 feet or greater.
[48] GAO 1984: 17.

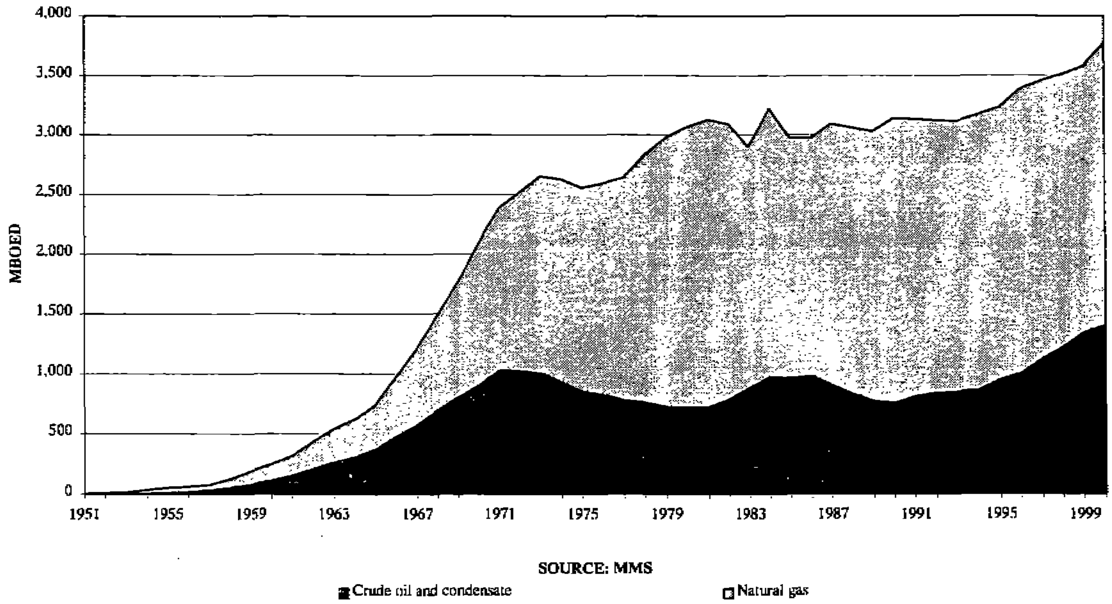
4 THE EFFECTS OF AREA WIDE LEASING ON GOM OUTPUT

In the oil industry at large, AWL is usually singled out as a particularly farsighted policy initiative. According to consultants Arthur Andersen, for example, the resurrection of GOM as a world-class hydrocarbons province would not have come about in the way it did without AWL, because it was chiefly "as a result of this new leasing system that interest in the GOM really grew".[1] Stouffer and Knight, for their part, praise it for having made it possible for firms "to begin amassing tracts in deeper waters, which in turn provided an incentive for technological development".[2] These statements (and similar ones to this effect) are eminently plausible. However, in spite of the wealth of relevant material scattered through publications issued by various agencies of the US executive or legislature, they have not been subject to any rigorous examination, and hence should not be accepted at face value.

Much has been made in this study concerning the abundance both of data and official publications regarding the offshore leasing programme. It is therefore somewhat surprising to see that, when it comes to the evaluation of the long-term effects of AWL, there is actually not a great deal available, whether from academic or official sources. On of the most glaring omissions in the literature can be ascribed to GAO's decision never to update its thorough and extensive 1985 study, quoted in the previous chapter. At the time that investigation was published, the agency explained that it felt unable to reach even tentative conclusions regarding the long-term effects of AWL. In GAO's words, "insufficient time [had] elapsed for exploration to be completed and production to occur", which doomed to failure any serious attempt "to estimate the number and size of potential discoveries from the area-wide programme, and to determine the effects on overall domestic production, imports and prices".[3] Twenty years have gone by since the lines above were written, during which time more than 2200 production platforms have been installed in GOM waters. Thus, lack of data can no longer be considered to be an obstacle in the way of an assessment of the effects of the programme, and whether or not it has lived up to its promises, especially in terms of its impact on offshore petroleum production.

At first glance, the way in which GOM output has evolved since 1983 would appear to vindicate the promises of the designers of AWL, and to disprove the strong objections raised by the governments of Texas and Louisiana (amongst others) in the sense that AWL would "not accelerate energy production, because development is determined by the profitability of individual leases and not the rate and number of lease purchases".[4] It is true that AWL failed to elicit any output response whatsoever from the industry during the first twelve years after its adoption. Nevertheless, as Figure F4.1 shows, current GOM output (for both oil and gas) is much higher than what it was during the 1980s (and even during its 1970s peak). Just as importantly, the declining trend in GOM production has not only been arrested but actually reversed, notwithstanding the harsher economic conditions that the industry has encountered as it moved into ever deeper waters. But still, given AWL's rather lackadaisical beginnings the question remains: just how much of the credit for the astonishing recovery in GOM output ought to be laid at its door?

FIGURE F4.1: USGC OFFSHORE OIL AND GAS PRODUCTION, 1951–2000



SOURCE: MMS

4.1 Ease of Access or Technology?

In the GOM region, from the mid-1950s onwards, the American oil industry pioneered a series of major innovations across the whole spectrum of E&P activities that quickly established standards and patterns that offshore operations the world over follow to this day.[5] By the early 1960s, as Gramling notes,

> a growing demand for improved technology ... [for] greater numbers of exploratory rigs, more efficient ways to bring development platforms on line, pipelines to transport offshore production, and a massive support sector to support these other demands ... [had] brought about integrated changes in the technology, infrastructure base, and physical environment and concomitant changes in the social and economic environments of the coastal Gulf of Mexico ... to produce a massive offshore-onshore system in a remarkably short period of time.[6]

This massive system was required to handle a wave of discoveries that averaged 1 billion barrels per year for around 30 years. However, by the late 1970s, GOM reserve addition rates had tailed off and output started falling soon after. This declining trend continued unabated until the early 1990s, when a number of world-class fields located in very deep waters started to come on stream.

FIGURE F4.2: WEIGHTED AVERAGE WATER DEPTH OF GOM PRODUCTION, 1953–2000

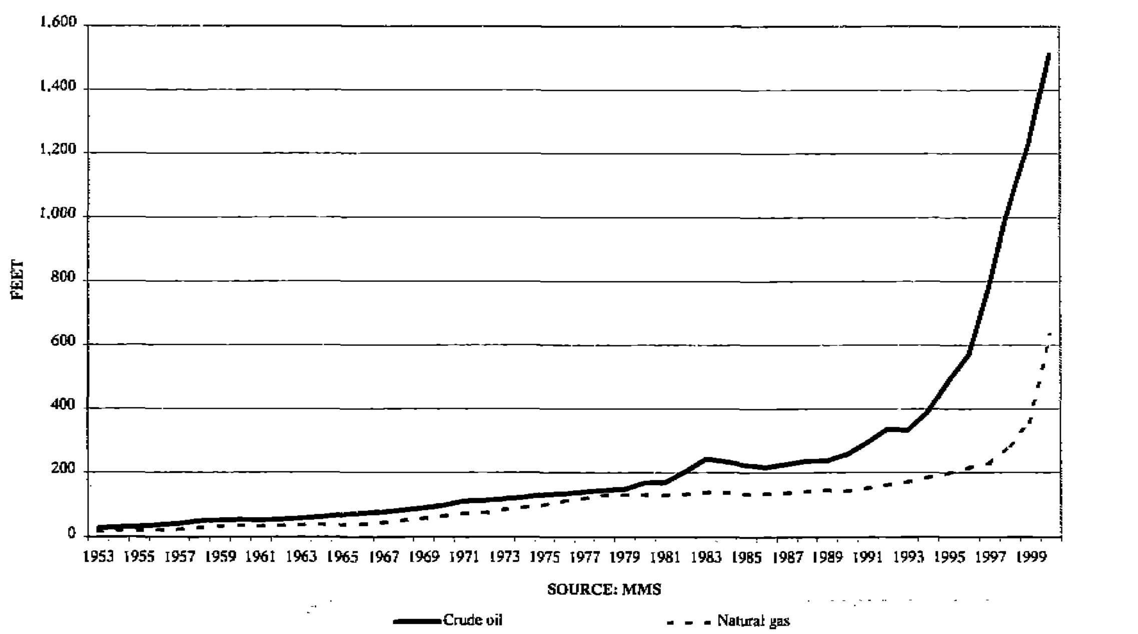
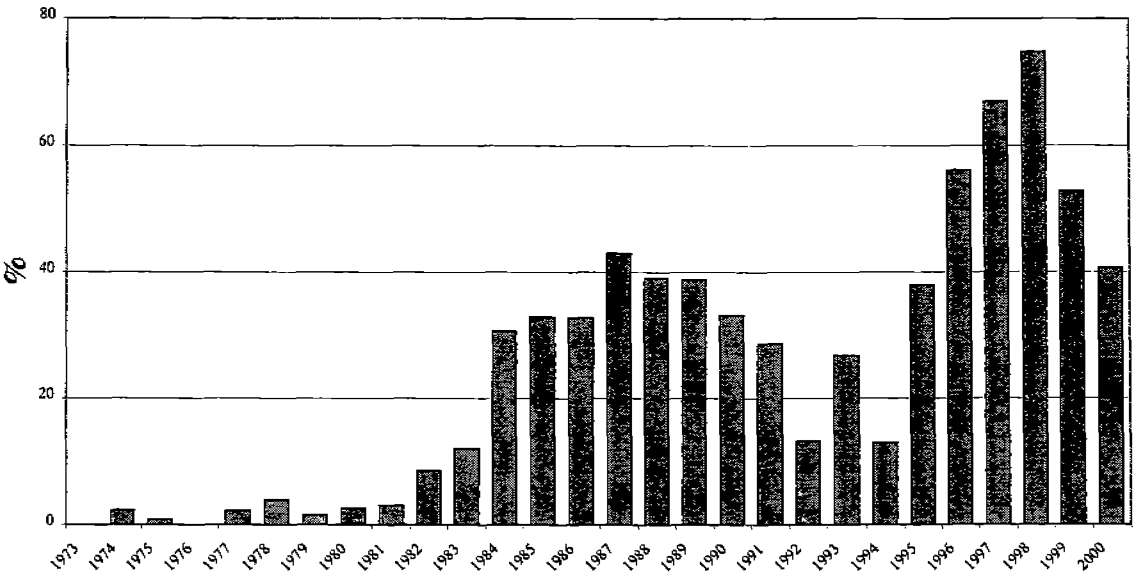


Figure F4.2, which plots the average depth of producing fields weighted by annual production levels, makes it easy to gauge the impact that these new fields have had not only as far as overall output goes but also in terms of the very character of offshore oil activities in the GOM region. As can be appreciated, in 1970 the average production weighted depth for crude oil was just 100 feet, and had only reached 250 feet by 1990. This indicator began to increase rapidly as soon the first deepwater fields came on stream during the mid-1990s, reaching 1500 feet (i.e. a sevenfold increase on the figure posted ten years before) in early 2000. Indeed, according to the commonly accepted definition of the deepwater threshold (1000 feet of water or more), deepwater production actually became the norm rather than the exception in GOM in 1998. This is a logical consequence of the fact that deepwater tracts began to account for a very significant proportion of the leases allocated from 1983 onwards (Figure F4.3), due to the extent to which acreage in the shallow GOM waters had been thoroughly picked over by then.

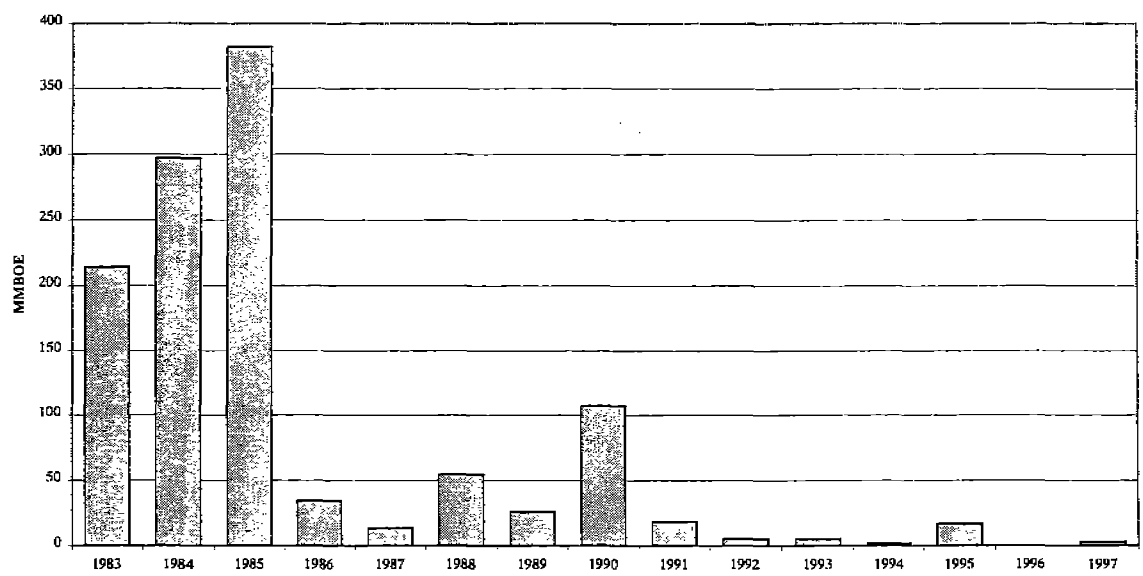
FIGURE F4.3: DEEPWATER TRACTS (1000 FEET OR MORE) AS A PROPORTION OF TOTAL GOM LEASED TRACTS, 1973–2000



SOURCE: MMS

As Figure F4.4 shows, the bulk of the incremental GOM output has come from fields lying in blocks offered to the industry after the adoption of AWL, and particularly during the early years of the programme. Is this not suggestive of the existence of a direct – albeit lagged – link between AWL and the surge in deep water output, a link which would implicitly justify the fiscal sacrifices that AWL entailed? The answer to this question is negative: the nature of this apparent link is *sequential* and not *consequential*, because the real driving force behind the renaissance in GOM production has been technological progress, rather than ease of access to prospective acreage. After all, even large oil companies (which amassed impressive deepwater lease portfolios during the 1980s) were unable to prevent a long time from elapsing between the dates of lease assignment and first oil, simply because developing their deepwater prospects profitably was a task that lay beyond the possibilities of 1980s offshore technology (Figure F4.5). Thus, development of these blocks only got underway as the oil industry gradually acquired the capability of working in 2000 feet of water and beyond, in other offshore provinces (like the North Sea) where, as was not the case with GOM, there was enough attractive acreage to be found at these depths.[7]

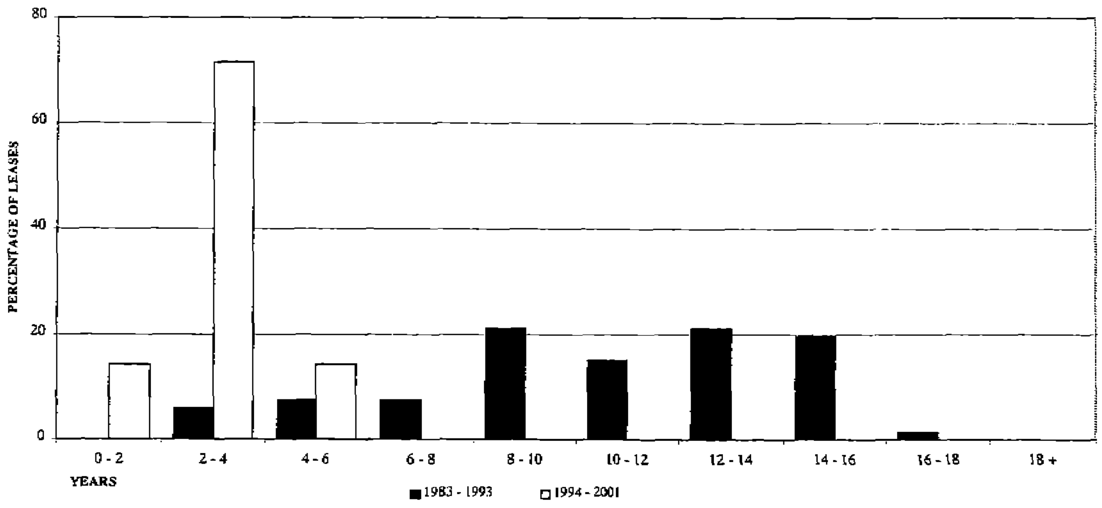
FIGURE F4.4: CUMULATIVE GOM PRODUCTION BY YEAR OF LEASE ASSIGNATION, 1983–2000



SOURCE: MMS

One might argue that, notwithstanding the central role that technological progress played in opening up the deepwater province, AWL might still have made a decisive contribution to the development of these blocks because oil companies would not have invested as much as they did in deepwater R&D had these efforts not been backed up by the exciting drilling prospects that the companies discovered in leases acquired relatively cheaply (a factor, which, among other things, might have increased their willingness to accept higher dry hole risks). In other words, could it be that these tangible prospects were the spur that prompted companies to find a way of getting deepwater oil to market (a search that, moreover, did not have to run against a tight five-year schedule, thanks to the relaxation in leasing terms that AWL also brought about)?

FIGURE F4.5: TIME ELAPSED BETWEEN THE DATE OF FIRST ASSIGNATION FOR GOM DEEPWATER LEASES (1000 FEET OR MORE) AND FIRST OIL, BY PERIOD, 1983–2001



SOURCE: MMS

GAO, for one, subscribed to this hypothesis, which also came quite handy for explaining the relatively low bids that deepwater leases attracted in area wide sales (after all, if an oil company knows that production from a lease will be quite long in coming, then it will reduce its bid so as to offset the time value of the money paid for the acreage). In its comments regarding Mid-Atlantic OCS Sale 59, for instance, GAO asserted that its own preliminary analysis showed that even though oil companies were "capable of *exploring* the deep waters of Sale 59 ... production technology [had] yet to be developed [to produce] ... hydrocarbons in the water depths which face them in the Sale 59 leases".[8] GAO accepted the suggestions of "industry officials" in the sense that they could "develop the required *technologies if something worth producing [were] found*". It also went along with the idea that a "longer than the normal 5-year term [*sic.*] was needed in order to explore and to achieve production if hydrocarbons [were] found", and therefore wholeheartedly agreed with the decision to grant "a 10-year lease ... for all of the accepted high bid tracts".[9] In other words, GAO believed that development of the Sale 59 leases would eventually occur but only because, in taking a long-term view in its tract offerings, MMS had spurred the development of deepwater technology in a way that a more restrictive (i.e. revenue-maximising) leasing system — like TN — could never have done.[10]

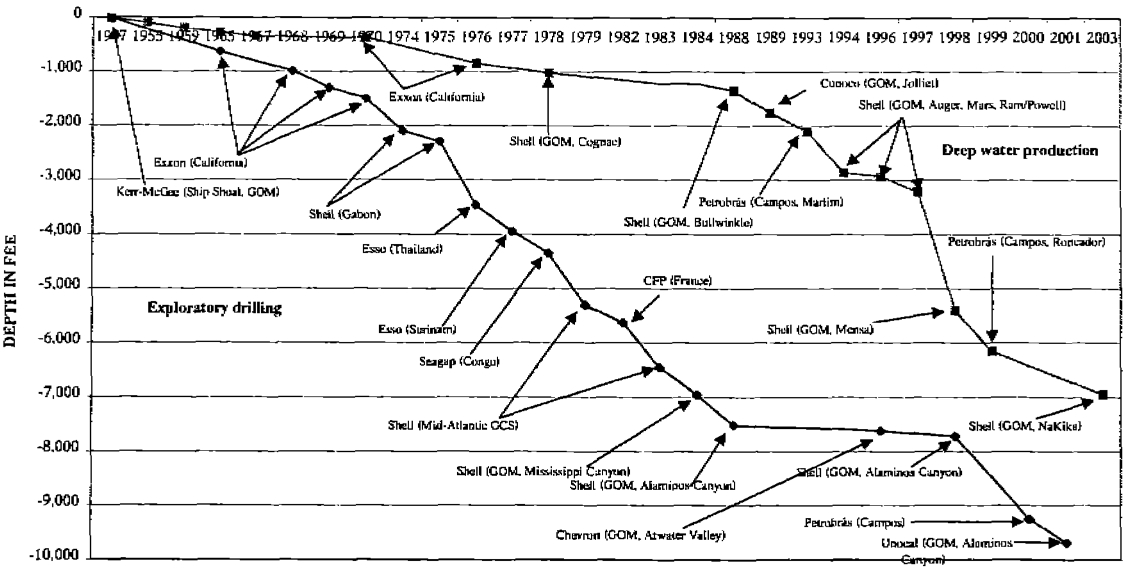
This syllogism, though, is again invalidated by the empirical evidence from oil industry operations throughout the world, which suggests that oil companies are quite willing to take the plunge in very challenging plays even if they do not count with the additional security that an already identified discovery represents. This is hardly surprising, of course, as tackling this kind of risk is the very essence of an oil company's entrepreneurial being. Simply put, oil is where you find it, and given that most of the places where it is found in greatest abundance have been out of bounds to international oil companies (large and small) since the early 1970s, the mere prospect of there being oil aplenty in deep waters would have provided a sufficiently strong incentive for companies to invest in ways of locating it and, in due course, extracting it at a profit. As Horsnell explains,

> when oil companies had access to the easy acreage, there was really no great incentive to make quantum leaps in technology. You could of course have invested in a research programme to allow you to drill in ten thousand feet of water, but there was no earthly reason to do so ... [It is] a measure of the extent to which opportunities for developing new oil provinces in the world have narrowed, that such a surge in interest in deep water oil occurred in the late 1990s. Over that period oil prices were more often weak than strong, and companies continued to stress that they would achieve growth in profitability by constant reduction of costs. These are hardly the optimal conditions to launch oneself in frontier projects, involving far greater than usual technical cost, risk and managerial attention.[11]

Hardly optimal these conditions might have been, but given an overall lack of prospects, oil companies were forced to try their luck, or resign themselves to eventual extinction.

Figure F4.6, which plots the progress of deepwater exploratory drilling activities worldwide during the past 35 years, should put to rest any residual doubts regarding the fundamental unsoundness of the idea that firm prospects in hand are a *sine qua non* for oil companies to commit to exploration in frontier areas. This graph clearly shows that the quest for oil had been pushing companies to explore progressively deeper waters long before AWL was even a twinkle in some policymaker's eye. Thus, it appears inevitable that oil companies would eventually have come to the deep water GOM to drill and develop, even without the benefit of AWL. Under such conditions, however, they would have had to pay the Federal government much more for the privilege.

FIGURE F4.6: WORLDWIDE PROGRESSION OF OFFSHORE EXPLORATORY DRILLING AND PRODUCTION, 1947–2003

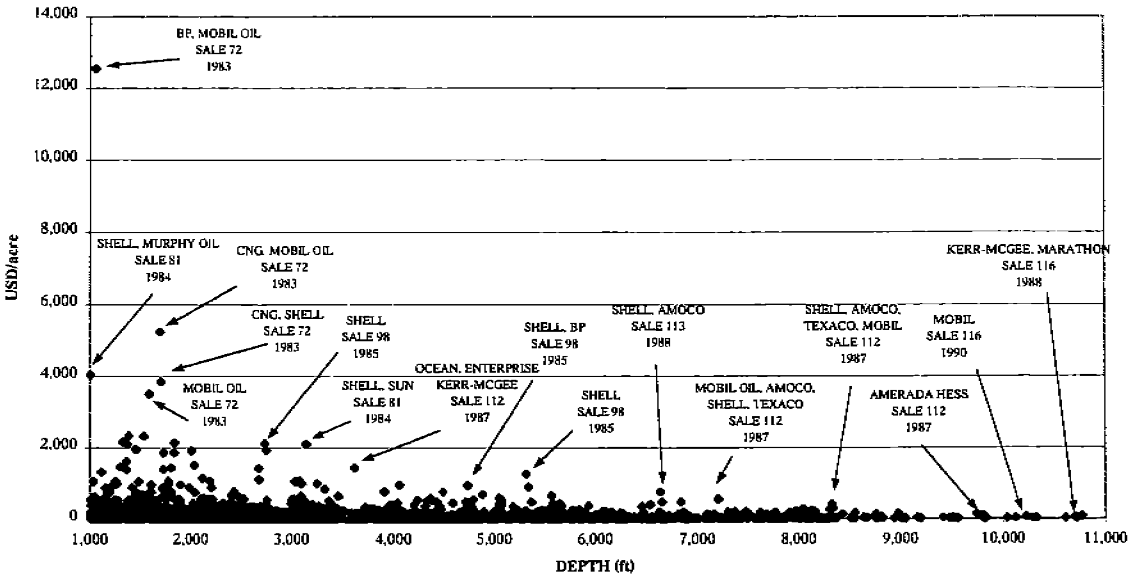


SOURCES: MMS, OTA 1985, Shell, Petrobrás

4.2 The (Foregone) Wages of Patience

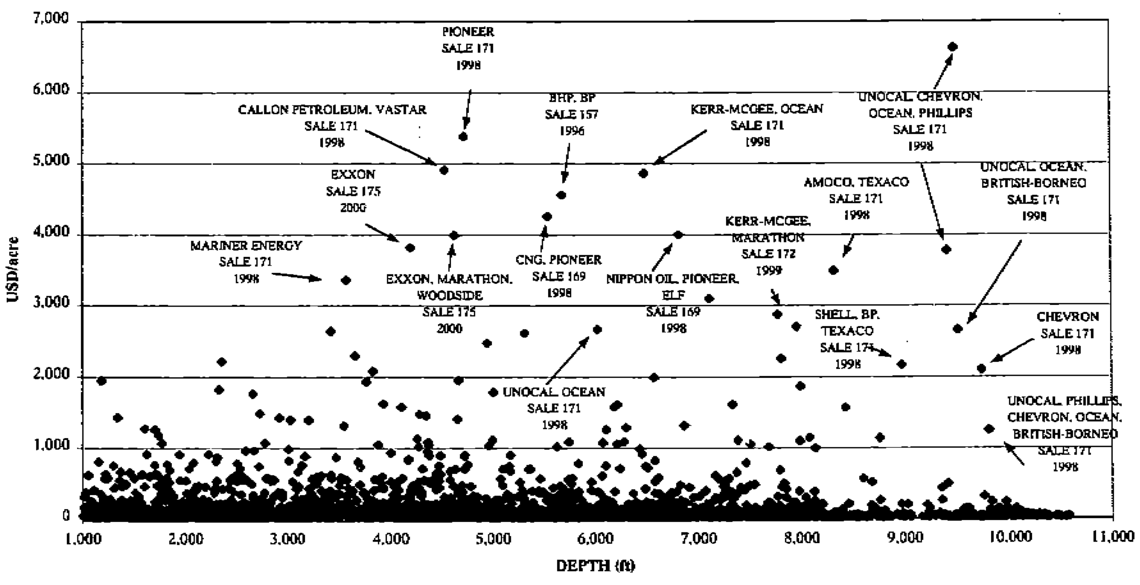
The concept of user cost (defined as the potential for change in the value of the landowner's wealth associated with changes in mineral prices or the costs of factors necessary to exploit them) is of considerable assistance when trying to understand the motivations of such landowners to act in certain ways. As Brannon observes, "from a landowner's point of view, if he sells the right to drill on his property this year, he will not be able to sell them next year. If there is a strong prospect that oil and gas prices will rise, it would be a good tactic for the landowner to hold out for higher current payments for drilling rights to compensate himself for the loss of future income".[12] The same holds true, of course, if there is a realistic prospect that costs will decline (as was clearly the case for deepwater production technology during the 1980s). Of course, even in situations when the outlook for technological progress is encouraging, if expectations about future oil prices are sufficiently gloomy (as they were after the 1986 crisis), user costs might nevertheless become negative, in which case landowners may be very eager to offload their acreage. Seen from this angle, the decision by MMS to offer, throughout much of the 1980s, vast amounts of acreage at fire sale prices in blocks where no operator appeared to stand a chance of generating profits of any kind (let alone excess profits) seems to make sense. Indeed, more than an opportunity foregone, it takes on the appearance of a reprieve at the last chance saloon.

FIGURE F4.7: DISTRIBUTION OF WINNING BIDS FOR GOM DEEPWATER (1000 FEET OR MORE) ACREAGE, 1983–1993



SOURCE: MMS

FIGURE F4.8: DISTRIBUTION OF WINNING BIDS FOR GOM DEEPWATER (1000 FEET OR MORE) ACREAGE, 1994–2000



SOURCE: MMS

With the benefit of hindsight, though, one can see that what MMS really achieved by leasing deepwater acreage prematurely was to forego the chance to collect massive excess profits when these in fact materialised (from the mid 1990s onwards). Consider Figures F4.7 and F4.8. These graphs plot the winning bids submitted for individual deepwater blocks in the years before and after Shell's announcement of the discovery and development of the giant Mars field (1993). As can be appreciated, the highest overall bids registered after this key watershed were submitted in lease sales held toward the end of the period under scrutiny, by which time offshore technology had caught up with GOM deepwater conditions, and its use had become widespread outside the circle of the large oil majors. Also, many of these high bids were submitted by large independent producers, who had tended to stay on the sidelines during the deepwater auctions held in the 1980s. Needless to say, bonus payments would most probably have been even higher had MMS bided its time, and then offered promising acreage on the basis of a mechanism similar to tract nomination. In such circumstances, even smaller companies, more risk averse and less capable of handling overseas operations, would probably have participated in the bidding process very enthusiastically, as this would have given them the chance of securing challenging but highly prospective acreage only a couple of hundred miles away from home.

Comparisons at the level of individual leases or prospects are especially instructive in highlighting the monetary difference that *laissez faire* licensing policies made in the GOM region. Consider two landmark deepwater projects: Cognac and Mars, both operated by Shell (the company's working interest is 34.87% in the former and 71.5% in the latter).[13] Cognac (which came on stream in 1979) was the first genuine deepwater development in the world. The project set a number of records at the time of its completion: it was the offshore structure installed at the greatest water depth (1025 feet), with the largest number of wells (62), and the heaviest steel platform (59,000 tons). At a total cost of MMUSD 464[14] (exclusive of leasing and exploration costs), it was not the most expensive offshore development to that date, but it was not far off the mark either, especially on a per barrel of output basis. The development of the Mars field, for its part, was the event that confirmed to the oil industry at large that, "in terms of potential, raw barrel numbers, the fiscal terms of the play and the available technology, including infrastructure available, the Gulf is the place to be".[15] Like Cognac, Mars was also a record-breaker, in physical as well as in financial terms: the Mars tension–leg platform (TLP) was installed in May 1996 at a water depth of 2940 feet, breaking the GOM record for a permanent drilling and production platform by around 100 feet, at an initial development cost of approximately USD 1.1 billion.[16]

The working interest owners of Cognac (quite a few of which were independent producers) acquired the four blocks where the field is located in the March 1974 OCS lease sale, for a total bonus of USD 295.3 million. Mars is much larger than Cognac: initial recoverable reserves for the former were estimated at more than 500 MMBOE against 200 MMBOE for the latter. Nevertheless, in 1985 and 1988, Shell paid only USD 5.3 million in bonuses for the six blocks that straddle the Mars field. The development of Mars was more expensive than that of Cognac, but not by a great deal when measured in real terms (Mars would have cost 490 MMUSD to develop in 1975 money, the year when the decision to proceed with Cognac was taken). Moreover, at USD 1.59 billion (in 1996 money), Cognac's full costs (i.e. development plus exploration plus lease acquisition) were considerably higher than Mars' own USD 1.3 billion. To be sure, oil prices at the time the projects received their respective go-ahead were very different[17], as were oil price forecasts (although in 1975 there was not too much talk about 100 dollar oil; that would only come later). But however long one chooses to dwell upon these and other – subtler – differences, one is hard pressed to come up with a reason that can explain how it was that the Mars leases cost Shell only 2.2 MMUSD (USD 64.6 per acre) in 1974 money, an astonishing 134 times less (or 201 times less on a per acre basis) than the amount that the company and its partners paid for the considerably less prolific (and in many ways equally challenging) Cognac blocks.

The conventional interpretation for this disparity would focus on the fact that the amount of money paid for an offshore lease depends on the level of interest that it manages to arouse in competing bidders, a factor that in its turn "is more directly related to an area's resource potential than to the method of leasing".[18] This proposition implies that Mars went for peanuts because no one besides Shell could see any sense in tying down money in leases whose odds for profitable development seemed infinitesimal, given the costs involved and the prevailing oil price expectations at the time the blocks were being offered. By the same token, notwithstanding the steepness of its costs, Cognac attracted much more bidding interest than Mars because the expectations for the oil price in 1974 were very bullish (indeed, there is little reason to doubt that the bonuses paid for Cognac would have been lower had they been offered during the middle to late 1980s). These are fair points, but they do not address one crucial issue that lies at the heart of the enormous fall in value of OCS acreage, and which we will explore at length in the next chapter; namely, the way in which the different methods for holding acreage auctions influence the nature and intensity of competition to obtain offshore oil and gas leases by allowing players with differing capabilities (technological, managerial and financial) to form an idea about an area's resource potential, and tailor their bids accordingly.

4.3 Conclusions

It appears reasonable to postulate that throughout the 1980s, GOM production would not have been very different from what it actually was had the supposedly "out-dated"[19] TN system continued in use: little production would have been forthcoming from deepwater blocks anyway. However, critics of TN suggest that this mechanism would nonetheless have acted as an obstacle to the discovery of prolific GOM deepwater fields because fiscal revenue considerations would have prompted DOI to continue offering exhausted shallow-water acreage instead of more prospective deepwater tracts (as this course of action would have held the promise of attracting higher bids). This criticism rings true to the extent that, especially up to the early 1970s, DOI made TN somewhat more restrictive than it need have been by its penchant for often failing to include in lease sales many of the tracts nominated by the oil industry. However, a TN system in which industry nominations were invariably respected would certainly have seen GOM deepwater tracts come into play and bid upon as soon as the 2000 foot barrier had been comprehensively overcome in some other oil province. Such a system might have offered a reasonable compromise between fiscal revenues, on the one hand, and the timely and opportune access to prospective acreage for the industry, on the other.

The economic relevance of licensing and leasing policies is generally seen as a function of their "influence on long-term supply patterns, whether or not they reflect a coherent depletion policy", since "their effects on the day-to-day operation of markets tend to be indirect and not very significant".[20] In the specific case of GOM, though, the Federal government's aggressive leasing and depletion policies post-1983 (both embodied in AWL) had virtually no impact on output, either on a medium- or a long-term basis (deepwater production would have come about in its own time, with or without it). What they did have was a great impact on government revenues but, as we have repeatedly reiterated, fiscal considerations have long been a secondary priority of US energy policy. This makes it appear as if the worst thing that could be said about AWL was that the fiscal sacrifice that lay at its core was well-intentioned, but ultimately availed the Federal government for nought. Unfortunately, when AWL is examined from the standpoint of the industry structure that it gave rise to, as we do in the next chapter, it becomes clear that this fiscal sacrifice, more than futile, has proved to be positively counterproductive.

NOTES

[1] Riddle, Snyder and George, *op. cit.*: 4.
[2] Stouffer and Knight 2002: 3.
[3] GAO 1985: 143.
[4] OTA 1985: 136. The misgivings regarding AWL that the Texas government expressed after reviewing the conclusions of the NERA study were reiterated very strongly by the Louisiana Department of Natural Resources in 1991 (see Gramling, *op. cit.*: 129).
[5] On the exploration and development front, there was the introduction of jackup rigs, drillships and submersible and semi-submersible drilling rigs, as well as the relocation of the major construction activities to onshore facilities, where large support structures (jackets) were built on the basis of templates. The great expansion in the size and weight of production platforms also necessitated advances in the ancillary processes used in the installation (and later, the launching or flotation) of offshore structures. The sturdiness of steel platforms opened the possibility of incorporating living quarters and this, in turn, led to the appearance of the peculiar pattern of shiftwork that is characteristic of the offshore oil industry, as well as to the consolidation of the helicopter as the ubiquitous offshore workhorse. As far as transportation was concerned, there was a rapid move towards submarine pipeline infrastructure, and the rapid expansion in the number, extension and size of pipelines prompted advances in related areas, notably materials and underwater pipelaying. See Veldman and Lagers 1997.
[6] Gramling, *op. cit.*: 72.
[7] The Northern Gulf of Mexico covers an extremely large area of shallow waters. Particularly in the area close to the Texas and Louisiana border, water depths can be below 500 feet more than 120 miles out from shore. Beyond 500 feet of water, however, the Gulf moves fairly sharply down an escarpment, and as a consequence of this, the area lying at water depths between 500 and 2000 feet is very small.
[8] GAO 1982: 8.
[9] GAO 1982: 8; italics ours.
[10] Sale 59 leases, of course, were never developed due to a drilling moratorium.
[11] Horsnell 2000: 78–9.
[12] Brannon 1974: 66.
[13] BP holds the remaining interest in Mars. Shell's current partners in Cognac are: BP with 21.8%; Agip with 16.5%; Sonat with 10.7%, Texaco with 6.9%, Unocal with 4.7%, Murphy with 2.4%, Conoco Phillips with 1.2% and Koch with 1.1%.

[14] The costs breakdown was as follows: USD 265 million for the platform, USD 16 million for the pipeline, USD 154.5 million for the production wells and USD 28.5 million for other production facilities (*O&GJ*, 30 April 1979: 162).

[15] Stouffer and Knight, *op. cit.*: 2. The words are those of an official in charge of deepwater activities at Unocal.

[16] About 55 per cent of the project costs involved the fabrication and installation of the hull, deck, facilities, and pipelines. The other 45 per cent was spent on drilling and completion of the wells. In the case of Cognac, well drilling and completion were responsible for only 33 per cent of that project's costs (this relative difference is a good indicator of the greater difficulties encountered in drilling in very deep waters, particularly since Mars will be developed with only about a third of the wells drilled for Cognac).

[17] In real terms, 1993 oil prices were equivalent to 45 per cent of those from 1975.

[18] OTA 1985: 154.

[19] Riddle, Snyder and George, *op. cit.*: 1.

[20] Mabro *et. al.* 1986: 93.

5 AREA WIDE LEASING AND INDUSTRY STRUCTURE IN THE GOM UPSTREAM SECTOR

The main priority for energy policy during the Reagan era was "to advance the consumer", as was made clear with the bluntness and questionable syntax so characteristic of James Watt. Advancing the consumer was more or less synonymous with breaking the perceived stranglehold of OPEC on the economic prosperity of the OECD, in general, and the USA, in particular. The policy prescription for achieving this end had been outlined long before Watt's time, during the Nixon and Ford administrations. In the words of Henry Kissinger, this prescription rested "not only [on] economic analysis but – even more – [on the] political, indeed moral, conviction" that it was necessary "to bring about a reduction in oil prices by breaking the power of OPEC", through an ambitious and wide–ranging programme consisting of "emergency sharing; energy conservation; active development of alternative energy sources; [and the] creation of a financial safety net".[1] President Reagan and his acolytes took to implementing the Kissinger agenda with a degree of relish that bordered on ferocity.[2]

As Watt saw it, the offshore leasing programme had played no small part in the political debacle leading to the Energy Crisis, chiefly because it had unwisely been used "to meet short-term budget needs rather than focusing on the consumer". Watt pilloried his predecessors at DOI for forgetting the golden rule of the energy game in America; namely, that "if you are interested in consumers, you want to deliver energy to them. If you are interested in national security, you want energy, and energy comes about through competition, not through restricting supply".[3] In other words, Watt believed that the way in which DOI had handled access to prospective acreage in Federal hands was fatally flawed and actually more pernicious than successful: while it did manage to keep up bid prices, it also stunted competition, thereby shackling the endless ingenuity of the American oil industry and making the country's economic prosperity a hostage to the intolerable whims of OPEC. The high bonuses paid for OCS acreage were therefore conceptualised as being symptomatic of an underlying pathology in the offshore oil industry, a pathology that constituted an important obstacle in the path of the all-out exploration effort required if US dependence on oil imports was to be reduced and the impact of the 1973–81 oil price increases mitigated.

Watt did not consider that any part of the TN system was worth salvaging because, to him, the economic outcomes that it generated were tangible proof that "the power to license" all too easily becomes "the power to exclude", chiefly because regulatory entities cannot resist "the imposition and administration of restrictions on entry, and on what might otherwise have been independent and competitive price and output decisions",[4] for the benefit of the firms that they are supposed to oversee. Watt saw these restrictions on entry as taking the form of unjustifiable limitations on both the number and location of tracts that were offered to the oil industry and, by extension, on the amount of acreage that could be opened up to exploration and development activities. And he saw his mission (in the evangelical sense of the word) as the restoration of competitive discipline to this vital sector of the American economy.

Prima facie, it is not difficult to accept the notion that the actions and omissions of a regulatory agency like DOI may indeed contribute to the cartelisation of the industry that it is supposed to oversee. There is after, all, plenty of evidence from all over the world that such occurrences are not exactly rare. By the same token, though, only those wholly in thrall to neoclassical dogma (amongst whom one can certainly count Watt) would hold that 'cartelisation through regulation' has to be the *inevitable* outcome of any governmental interference with the market mechanism.[5] Less biased observers would tend to agree that "the question of whether agencies favour or discourage entry ... cannot be resolved on purely theoretical grounds ... [since] only a detailed industry study can indicate the relevance of [the factors that determine] ... whether cartelisation or excessive entry occurs ... [namely] the pro- or anti-competition nature of the agency's information ... whether the political principal is active or passive and whether competition destroys industry rents".[6]

In this chapter, we undertake just such a detailed industry study. Building chiefly on the foundations laid in Chapter 3, we show that, under TN, the DOI (as political principal) was very active indeed, with the crux of its activity consisting in coaxing advantaged players into revealing their ideas about the prospectivity of different areas, and then signalling the relative attractiveness of the areas to the industry at large.

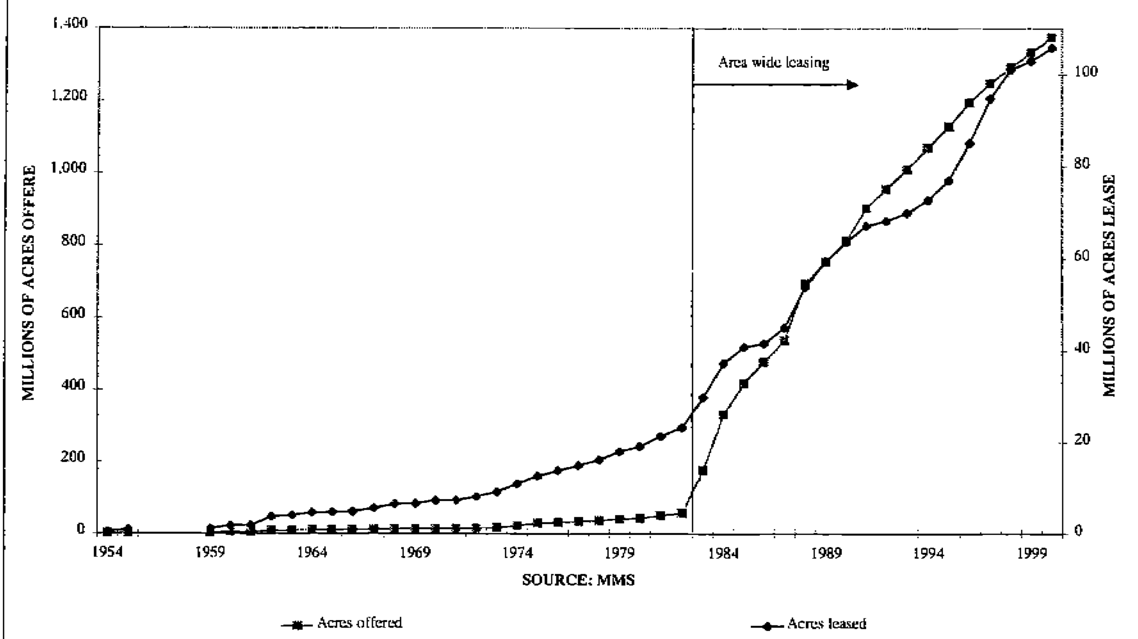
This information had a very salutary impact on competition, as it shifted substantial surveying and exploratory risks and costs onto the shoulders of more affluent players. Rivalry between bidders in acreage auctions, in turn, was highly effective in eliminating industry rents and delivering these into the pockets of the Federal government.

AWL, in contrast, transformed DOI into a passive principal, by turning the responsibility of deciding which acreage would come into play over to the companies. As a result of this, DOI was no longer able to convey valuable information to risk averse players (who happened to constitute the majority of the universe of bidders), a development that exacerbated informational asymmetries in the market for offshore leases and hamstrung competition. Paradoxically, AWL was presented as a measure that would give a helping hand to small and medium-sized companies, allowing them to compete in the increasingly demanding offshore big leagues. But in actual fact, AWL loaded the dice against its supposed beneficiaries, marginalising them from the crucial formative stages of the opening of the GOM deepwater province – the only world-class source of long–term growth for the US domestic oil industry found since Prudhoe Bay – to a far greater extent than appears warranted by the admittedly daunting technological nature of operations in this region. In all, the disregard of the designers of AWL for sound auction design, elementary anti-trust economics and information economics annulled the beneficial effects which in theory were to have accrued both to the Federal government and the American oil industry as a result of it, and in the process dealt the independent oil producers a crippling blow from which, as a group, they have never really recovered.

5.1 Competition in the GOM Offshore Sector after 1983: Some Problematic Indicators

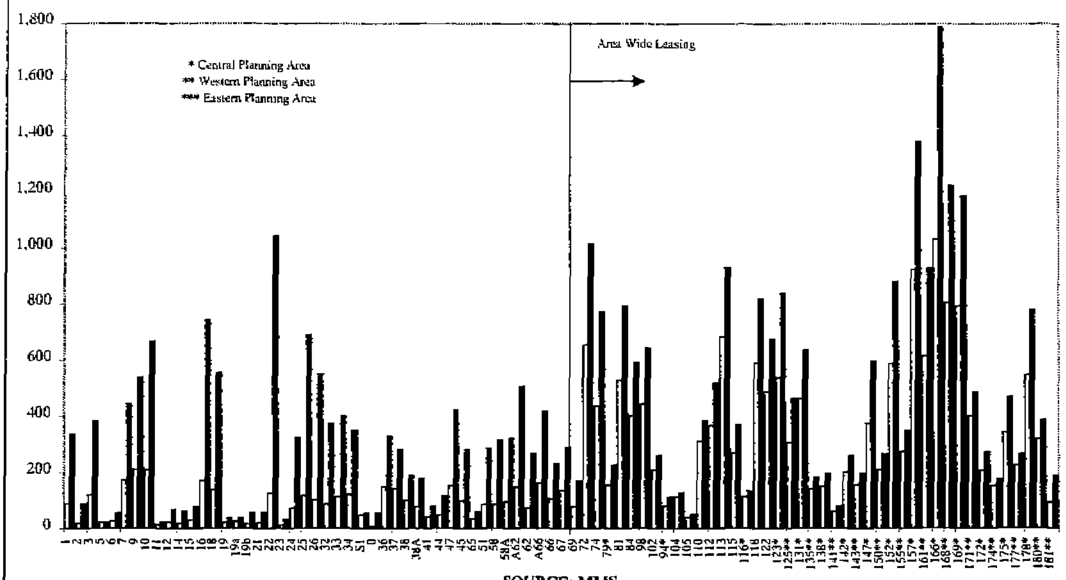
If measured solely by the acreage that it has made available to the oil industry since 1983 (Figure F5.1), AWL cannot be considered anything but a roaring success, notwithstanding the vast areas of the OCS that have been put out of bounds by leasing moratoria. However, the amount of land offered and leased was never supposed to be an end in itself, but merely the means to achieve ambitious output goals, on the one hand, as well as a clearly defined (in terms of an overall increase in the number of participants bidding for offshore leases) competition target, on the other. As we have seen, the first goal proved rather elusive, and when it finally did come about, it was not really as a consequence of the incentives supposedly provided by AWL. What about the second one?

FIGURE F5.1: CUMULATIVE OCS ACGREAGE OFFERED AND LEASED. 1954–2000



There has not been all that much written about the way in which AWL might have affected competition in the market for offshore leases. The last major study to consider this issue in any detail (published back in 1993 by Walter Mead, an admirer of AWL) analysed bids submitted, production profiles and estimated rates of return for thousands of GOM blocks, and reached the conclusion that competition was alive and well in the market for offshore leases, and that there was no need of any further involvement by the government to nurture it.[7] However, the cut-off point for Mead's analysis was 1981, which effectively meant that it included no results from lease sales conducted under AWL. So it seems legitimate to ask how different this study's findings would have been had its cut-off point been in the late 1990s, instead of the early 1980s.

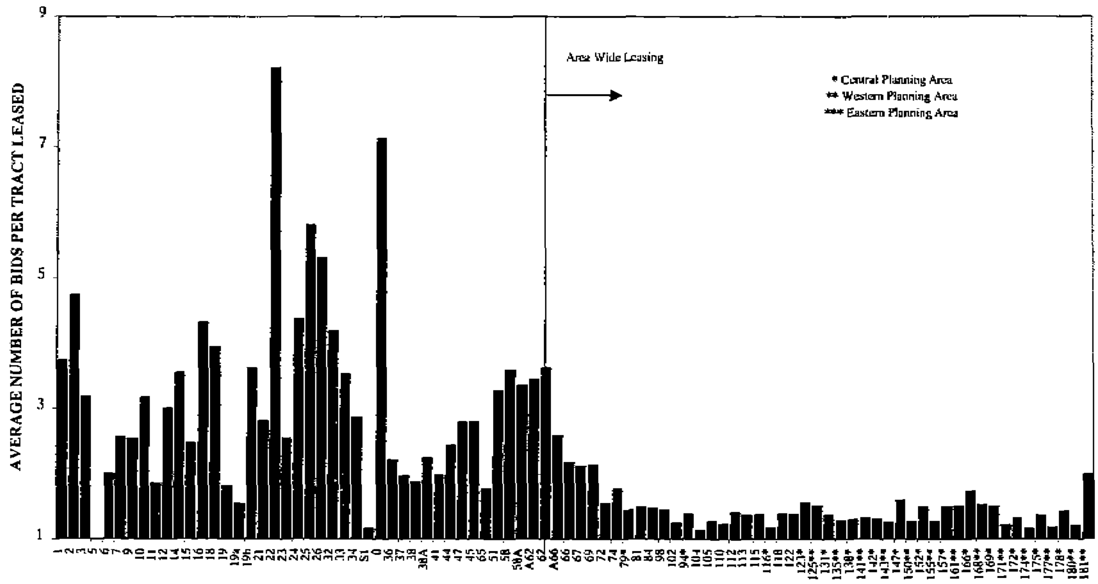
FIGURE F5.2: BEHAVIOUR OF KEY INDICATORS IN GOM LEASE AUCTIONS. BY SALE NUMBER (1954–2001)



SOURCE: MMS

Figure F5.2 shows that the introduction of AWL clearly had a beneficial effect on both the number of bids submitted and the tracts receiving bids when compared to the equivalent figures recorded in the last sales held under TN rules. Thus, it would appear that extending the chronological scope of Mead's study beyond OCS sale 69 corroborates its conclusions regarding the health of the competitive environment. After all, in the minds of many analysts and consultants, these two parameters are good proxies for the degree of industry interest and participation in GOM acreage auctions[8] and, ultimately, for the degree of competition prevailing in the market for offshore leases. However, quite aside from the fact that the gains made look less impressive when compared to the level of participation achieved during sales held in the early 1970s, the suitability of these parameters for the purpose of measuring the intensity and effectiveness of competition leaves a lot to be desired.

FIGURE F5.3: BEHAVIOUR OF KEY INDICATORS IN GOM LEASE AUCTIONS, BY SALE NUMBER (1954–2001)



SOURCE: MMS

Competition is the rivalry that arises whenever two or more parties strive for something that not all of them can obtain, and the submission of a large number of bids for a large number of tracts says nothing about whether an auction was genuinely driven by such rivalry or not. An equally simple but more reasonable indicator for gauging the intensity of rivalry is to count the number of bids that each item in an auction drew. *Grosso modo*, it is safe to say that the greater the number of bids that a leasing authority receives for each tract, the more justified will be any confidence on its part that competition between bidders will indeed eliminate Ricardian rents. Thus, Mead cited the fact that each tract leased over the 1954–81 period drew an average of 3.3 bids as strong evidence of the vigour of competition in the market for offshore petroleum leases. However, the equivalent figure for the leases held under AWL rules is a considerably lower 1.4 bids per tract leased (Figure F5.3). Moreover, if one looks in greater detail at the lease sales covering the deepwater boom (as is done Table T5.1), it is difficult not to conclude that the bulk of the blocks assigned in such sales were not really subject to any competitive bidding.

Table T5.1: Number of Bids Received per Leased GOM Block, by Sale Number (1993-2000)

Sale number	*Total blocks leased*	*Bids received* 1	2	3	4 or more	*Average bids per tract*
157	924	647	174	64	39	1.49
161	617	444	89	56	28	1.51
166	1032	637	209	95	91	1.73
168	804	563	137	66	38	1.52
169	794	596	120	36	42	1.50
171	402	347	40	5	10	1.21
172	207	166	27	7	7	1.31
174	153	135	15	1	2	1.16
175	344	262	59	16	7	1.36
177	226	197	21	6	2	1.18
178	547	398	93	35	21	1.43
180	320	272	38	6	4	1.21
181	95	48	19	14	14	2.00

Source: MMS

Mead might also have been impelled to revise his conclusions had he scrutinised the behaviour of the variable that MMS calls "total monies exposed", which consists of the sum of all the bids (successful and unsuccessful) drawn in an acreage auction. As a rule of thumb, one can say that the greater this interest and participation are, the greater the number of bids received per tract will tend to be and the lower the proportion of total monies exposed that will be accounted for by winning bids. Figure F5.4 makes it clear that, since the introduction of AWL, the winning bids against total monies exposed ratio has increased markedly, approaching 90 per cent on occasion (in those years, winning bids were pretty much the *only* bids that MMS received). After 1983, for instance, there has never been a repeat performance of a situation like the one recorded in the lease sale of March 1974 (to cite but one random example), when a block that received a record bid USD 168.9 million also drew a further nine bids, three of which exceeded the USD 100 million mark.[9] Indeed, as Figure F5.5 shows, the vast majority of deepwater tracts assigned under AWL have attracted bids of only USD 100 per acre or less, even after the province "came of age" during the 1990s.

FIGURE F5.4: BEHAVIOUR OF KEY INDICATORS IN GOM LEASE AUCTIONS, BY SALE NUMBER (1954–2001)

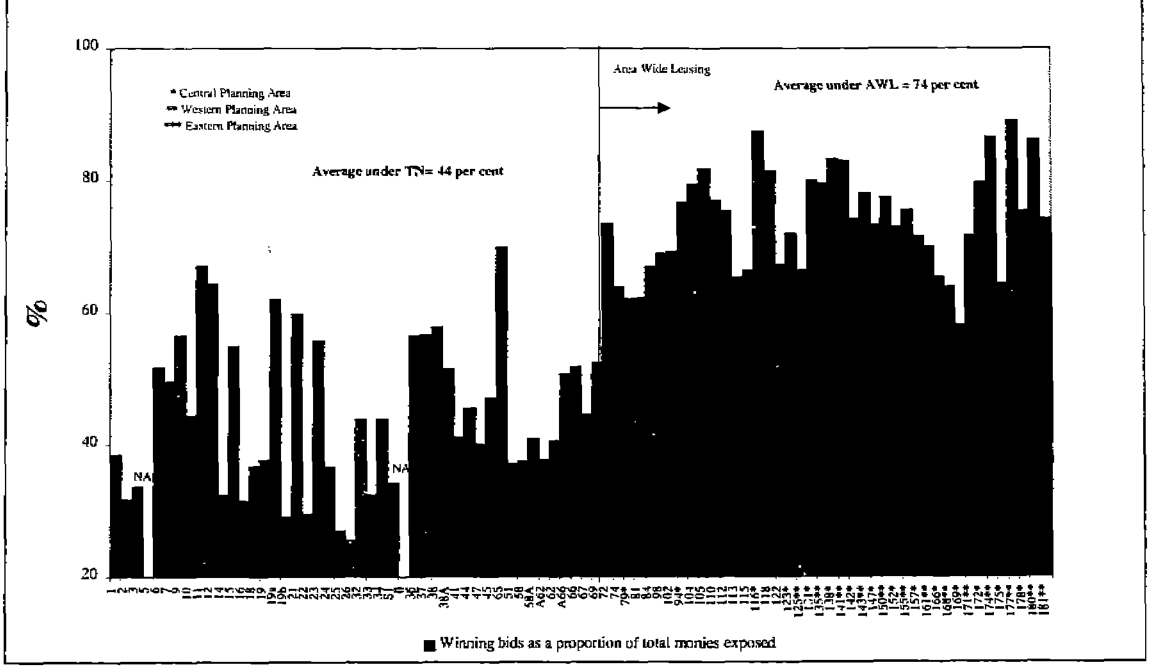
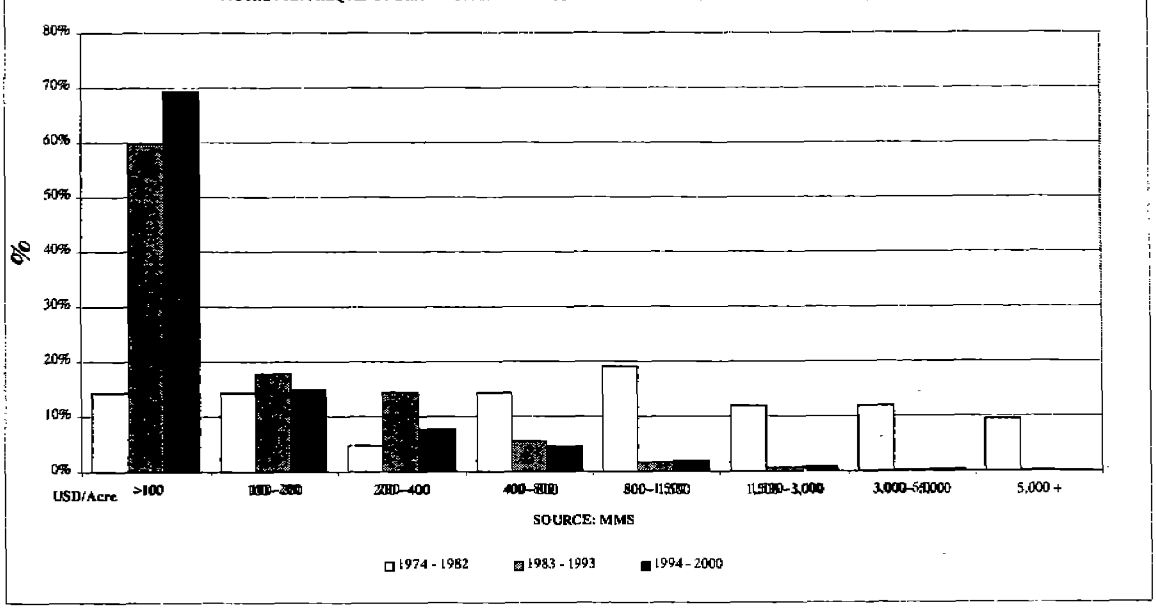
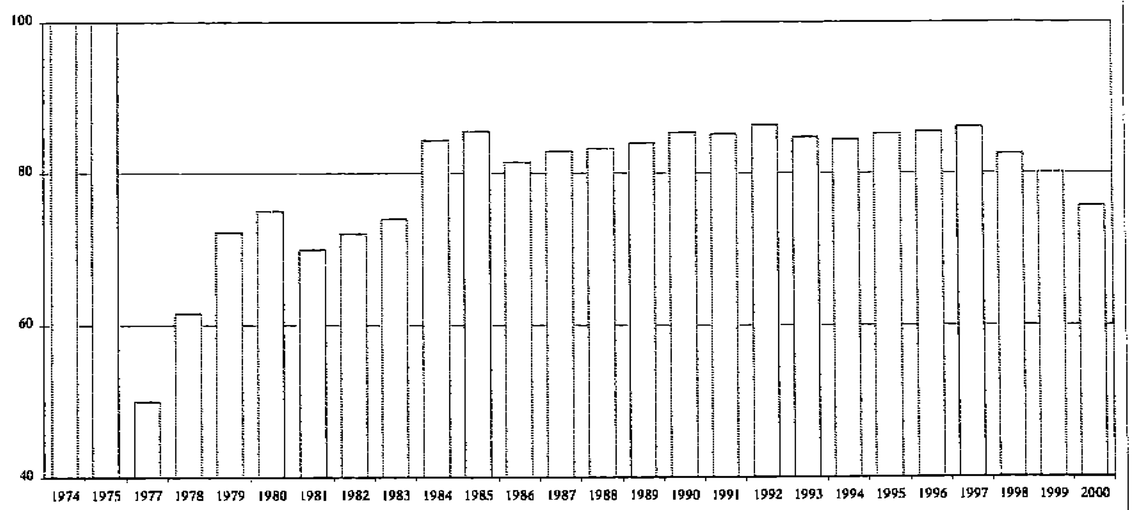


FIGURE F5.5: FREQUENCY DISTRIBUTION OF BONUS PAYMENTS FOR GOM ACREAGE BY PERIOD, 1974–2000



Of course, determining whether competition in a given auction market has been effective cannot simply be a matter of counting heads or the total amount of money that bidders have put into play, since both are essentially *ex ante* measures. Even if a great number of actors participated in repeated auctions, it would be pointless to call these competitive if a couple of players consistently managed to walk away with all the prizes. Thus, *ex post* outcomes necessarily have to play a part in any assessment of the effectiveness of competition. Figure F5.6 shows that about 80 per cent of the deepwater tracts assigned between 1983 and 2000 ended up in the hands of major oil companies (with Shell accounting for a sizeable chunk of this). This might sound like an inordinately high figure, but it is actually comparable to the proportion of offshore leases assigned to the 20 largest oil firms between 1954 and 1969 (84 per cent[10]). Thus, AWL appears not to have made any difference in terms of this particular parameter. Indeed, the percentage of deepwater leases held by majors has been declining in recent years and, at the moment, the number of equivalent sized firms in the GOM deep waters (i.e. the inverse Herfindahl Index) *when measured on the basis of lease holdings*, stands at a reassuring 9.5. This index is bound to keep going up in coming years, as non-major oil companies who are keen not to be left out of the deep water bonanza expand their leasing programmes.

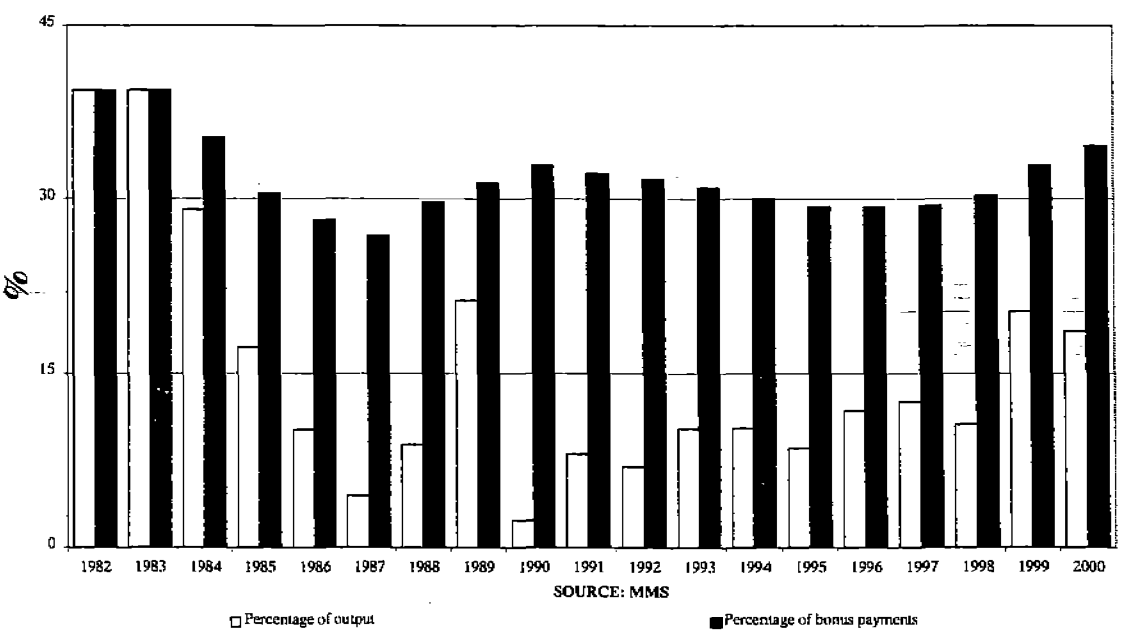
FIGURE F5.6: PERCENTAGE OF GOM DEEPWATER LEASES (1000 FEET OR MORE) HELD BY MAJOR OIL COMPANIES, 1974–2001

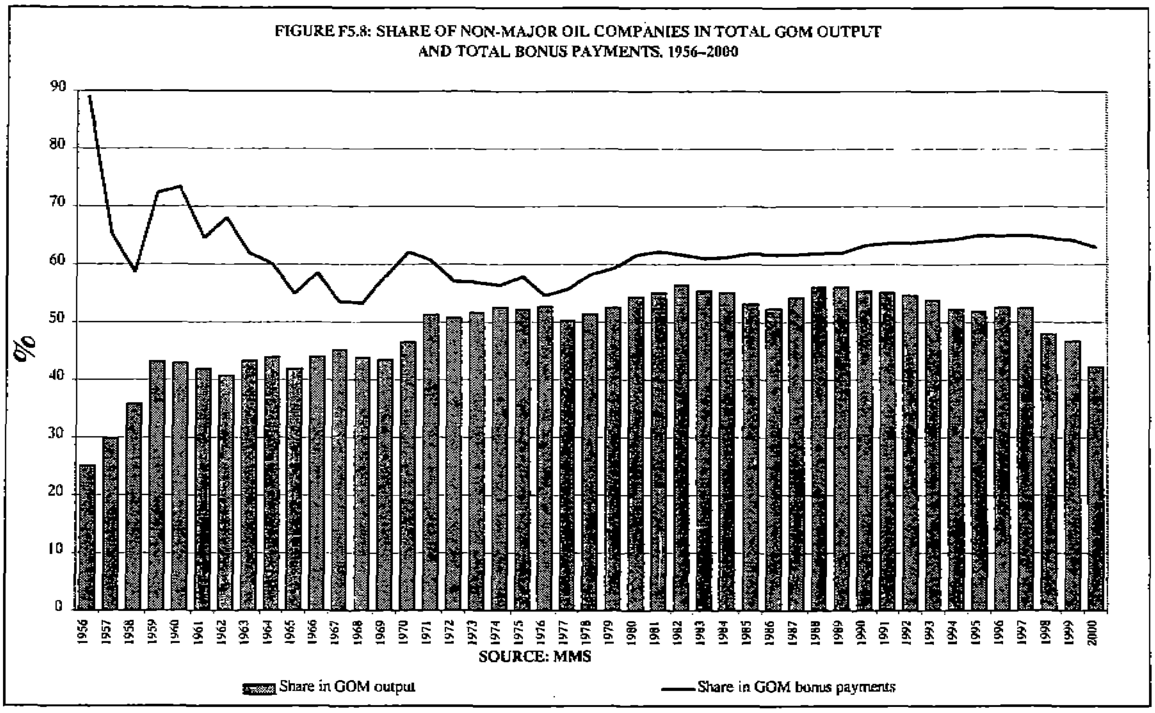


SOURCE: MMS

On the output front, things look very different, though: in the years that have passed since the introduction of AWL (but especially during the 1990s), the degree of concentration in the US offshore upstream has increased markedly. This sector may never have been the mirror image of the ultra-atomised onshore upstream, but it was nonetheless characterised by a degree of concentration that was much lower than that prevailing in offshore provinces outside the USA. Nowadays, GOM concentration is still less than that of the North Sea, for instance, but the two provinces are drawing closer in this respect, and at an accelerating rate. This is primarily a reflection of the disproportionate share of deepwater output accounted for by a handful of major oil companies: for the past six years or so, the inverse Herfindahl Index in the deep water province, *measured on the basis of output*, has barely exceeded 2. The share of non-major oil companies in deepwater production has not only been rather modest (Figure F5.7), but also out of proportion to their share of bonus payments for deep water acreage and their (rapidly declining) share in *overall* GOM output (Figure F5.8). And although quite a few of them have mounted aggressive leasing and exploration campaigns from 1996 onwards, the significant rise in bonus outlays that this has entailed is unlikely to translate into a commensurate increase in the non-majors' share of total deepwater output. This is because, in the near future, the bulk of incremental deepwater output will come from very large development projects held primarily by majors (above all Thunder Horse).

FIGURE F5.7: SHARE OF NON-MAJOR OIL COMPANIES IN TOTAL GOM DEEPWATER (1000 FEET OR MORE) OUTPUT AND TOTAL DEEPWATER BONUS PAYMENTS, 1982–2000





In sum, it is clear that, *pace* Mead, competition for GOM offshore oil and gas leases underwent a serious decline after the demise of TN. It is also clear from the previous chapter that this outcome cannot be explained purely in terms of lower price expectations and/or increased exploration and development risk. What is *not* clear at all, regardless of these chronological coincidences, is whether AWL should in any way be held responsible for this. After all, the ultimate reason behind the collapse in the traditionally healthy levels of entry and competition in the GOM offshore lies in the very limited participation in post-1983 lease sales by a readily identifiable group of players (the non-major oil companies). Their reluctance to enter the leasing fray during this period is puzzling, for a number of reasons. Firstly, the GOM offshore had always been a magnet for these companies, and for a long time their share of output actually exceeded that of the majors (see Figure F5.7 above). Secondly, these companies had repeatedly demonstrated that they were quite capable of holding their own as far as the payment of bonuses was concerned, and also that they were capable of punching above their weight in the project management and technology league. Finally (and most importantly), these companies were as free as the majors to bid on deepwater acreage, *but chose not to do so until well into the 1990s*. Through their own volition, then, non-majors effectively sidelined themselves from what has turned out to be one of the hottest exploration plays worldwide in the past decade. In the following section, we will argue that their actions were an entirely predictable consequence of AWL, whose impact on the way that the market for offshore leases operated dramatically decreased the relative fitness (competitiveness) of non-major oil companies. Our contention is that, in seeking to reduce a certain type of entry barrier through the easing of restrictions on access to offshore acreage, AWL paradoxically *increased* overall entry barriers, thereby exacerbating the strong and ever-present propensity towards oligopolisation typical of an industry that is as capital-intensive as oil.

5.2 The Role of Informational Externalities in Promoting Competition for Offshore Leases

The notion that even modest bidding costs may constitute a serious deterrent for entry is a recurring one in auction theory and design literature.[11] Moreover, because of the asymmetrical nature of the winner's curse, the negative effect of bidding costs will make itself felt more strongly among smaller players. That being the case, how can we maintain that the dramatic scaling down, at the stroke of a pen, of a factor acknowledged to affect entry very negatively was accompanied by an even more dramatic fall in competition (and a concomitant increase in concentration) from what had traditionally been very healthy levels? In a nutshell, this outcome can be traced to the blatant disregard of AWL's designers for some of the key insights of the economics of imperfect information, a disregard made all the more inexcusable by the fact that, when this policy was formulated, this theoretical furrow was already very well ploughed.[12]

Under conditions of perfect information, the lot of a leasing authority is an enviable one (amounting, quite literally, to the quiet life that all monopolists are supposed to aspire to). When acreage is offered, bidders calculate the magnitude of expected revenue streams from specific tracts and the ones with the lowest costs among them signal this fact to the lessor by submitting bids that higher-cost competitors find daunting. Thus, the leasing authority assigns each tract to the most efficient operator while neutrally collecting all Ricardian rents, and the story has a happy ending.[13] In a situation of adverse selection, however, the plot thickens considerably. Efficient firms can take advantage of the ignorance of the leasing authority to pretend that they are inefficient (or that the acreage is not very prospective), thereby forcing the lessor to provide them with income (a share of the excess profits to be generated by the tract).[14] In other words, under such conditions, *laissez faire* inevitably means "*the most efficient agent receives utility greater than his reservation level due to his private information*".[15] And, of course, prospective lessees will not be interested in revealing private information if they are in a position to obtain greater gains by keeping it secret (an unavoidable fact that lies behind Stiglitz's remark that "markets do not provide appropriate incentives for information disclosure"[16]).

Asymmetric information, we reiterate, "forces principals to give up costly rents to their agents".[17] Thus, a leasing authority that has to operate under conditions of adverse selection while still expecting to capture excess profits through signature bonuses has two choices open to it. On the one hand, it can take "the regulatory response to ... asymmetry of information", which consists in "allocations [being] distorted away from first-best allocations and toward low-powered schemes".[18] For the most part, these distortions affect the contract of the least efficient firm, which therefore receives breaks that it does not apparently deserve. Crucially, however, this is only done in order to make "this contract ... less attractive to the efficient firm, *thereby reducing its informational income*".[19] Regulatory interference in offshore oil leasing can take many forms, of course, ranging all the way from the discretionary assignation of acreage (which on the whole provides a poor antidote against creeping oligopolisation, due to the pervasiveness of regulatory capture[20]) up to the elegant market-centred mechanisms underlying the TN system.

If intrusive regulation is unacceptable, for whatever reason, leasing authorities that find themselves at the short end of the informational stick can always go for the self-delusion option, which consists in pretending that these informational problems are either of no consequence or else easily remedied by the 'natural' rivalry that is supposed to exist between all firms. This approach, which lies at the heart of AWL, in effect ignores the key insight that an economy in the real world necessarily "has to choose between two different imperfections: imperfections of information or imperfections of competition".[21] It also assumes that even the presence of both forms of imperfection will not pose a problem to the operation of a market, although there is "no particular reason [to think] that these imperfections will be 'balanced' optimally".[22]

The empirical evidence examined thus far in this study suggests that, in the case of GOM, these imperfections did not balance themselves at all. On the one hand, signature bonuses ceased to bear any relationship whatsoever to the prospectivity of offshore tracts after 1983. On the other hand, the benefits from this decline in bonuses, in terms of both acreage leased and output, accrued overwhelmingly to major oil companies, chiefly because their smaller peers did not play any meaningful part in deepwater lease sales. At first glance, it is not immediately apparent why smaller players should have chosen to leave the field in the hands of majors for more than a decade. After all, *just as long as they were in a position to form reasonable estimates of tract profitability*, non-majors could conceivably have become just as adept as majors at lowballing the leasing authority.

In order to understand why this did not happen, one should bear in mind that the informational asymmetries that can impinge on the efficiency of the market for offshore leases are not only those that separate lessor from prospective lessees, *but also those that set the latter apart from one another.* And the key to the enormous success of the TN system lay in the fact that it addressed *both* types of asymmetries in a highly effective way. On the one hand, the nomination procedures induced advantaged players into revealing their ideas about the prospects of different areas, thereby rendering DOI much less ignorant than it would otherwise have been. On the other hand, the offering procedures created an informational externality that largely negated the significant asymmetries between potential bidders.

The way in which the TN operated made it almost impossible for advantaged players to appropriate the returns inherent to the valuable information that they created when they surveyed areas in order to nominate tracts for inclusion in future lease sales. The mere fact that a tract was being offered signalled less advantaged players that some other company had seen something sufficiently interesting to submit proprietary geological, geophysical, engineering and economic data to DOI, in order to ensure the inclusion of the block in a lease sale. With the advent of AWL, however, smaller players saw their limited resources swamped by the sheer abundance of acreage, and this biased the bidding process in favour of major oil companies. As Gramling says, in the wake of AWL, "only those with independent data (i.e., data they have gathered) have real knowledge as to the potential of most tracts, and only the major oil companies can afford the type of extensive surveys necessary to examine even a portion of the entire central Gulf".[23]

DOI's value estimation procedure also showed less advantaged players that the agency had formed reasonably positive impressions about the prospectivity of a tract on the basis of the data it had collated prior to the sale. In effect, this procedure made it difficult for more advantaged players to nominate dud blocks as a way of distracting the attention of potential competitors for prime acreage. In contrast, AWL gave more capable players plenty of scope to develop effective strategies to minimise the informational trickle from their bids. Confirmation of this can be found in a plea by William Clark (Watt's immediate successor at DOI) in the sense that companies should only "target those tracts in which they are seriously interested and reduce 'scenery' selections (those intended to mask bidding strategy)".[24] Notwithstanding Clark's efforts to back up this request with revised procedures in which oil companies were expected to make specific recommendations on selected tracts at the call for information stage, scenery selection is still a widespread practice.

In sum, the concrete allocative distortion that the TN regulatory entailed was that players with limited resources were given a *free ride* on the ample financial and technological coat-tails of the more capable players, who were consequently deprived of the fruits of their *recherche* as a price for being able to participate in lease auctions. As Kreidler notes, the very high costs of offshore operations dampened the wildcat spirit that had traditionally driven non-major participants in the onshore basins, making them very "cautious about expensive and unproductive experimentation".[25] The abiding merit of the TN system resides in that it was able to counteract the risk aversion of relatively smaller operators. In contrast, AWL accentuated their risk aversion to the point of paralysis, rendering them unable to compete and, in the process, needlessly sacrificing their enterprising dynamism on the altar of ideology.

5.3 Are High Technology and Low Concentration Necessarily Antithetical?

In a previous chapter of this study, we stated that the real driving force behind the renaissance in GOM production has been technological progress. That being the case, some readers might ask why the trend towards greater concentration (and consequently diminished competition) in the GOM upstream should be greeted with surprise, or why AWL should carry the can for this trend. After all, it is normally taken as read that only oil companies at the top of the size rankings are in a position to marshal the enormous financial, and human resources necessary to tackle the development of projects that are fraught with all kinds of uncertainties and technological exigencies, as the early GOM deepwater projects were. The problem with this viewpoint is that it is too simplistic, in that it rather overstates the degree of technological and project-management superiority that the largest oil companies are supposed to enjoy.

In order to appreciate this, one need only look at the many offshore upstream projects posing unique and enormous challenges (often at the cutting edge of technology) which medium–sized companies or first–tier independents have managed to tackle successfully nonetheless. Consider but one case: the Ekofisk field. In the words of a Phillips manager intimately involved with this project, "it is hard to comprehend the amount of risk, energy, engineering skill, and money involved in ... operating at the limit of knowledge at that time ... in the face of tremendous odds and against the advice of many pessimists".[26] Total disbursements on Ekofisk (around USD 6.5 billion) have exceeded by a factor of three Phillips' original expenditure estimates.[27] Yet Phillips, a largish but by its own reckoning "domestically oriented US oil company", was happy to bet the house on Ekofisk, knowing that this discovery alone would be enough to transform it "into a truly international competitor".[28] For all its challenges, Ekofisk proved to be a company-building elephant (since its discovery, and up until the moment when the intricacies of US anti-trust policy allowed Phillips to buy into Prudhoe Bay, this field was Phillips' most important upstream asset by a long distance). And, as things turned out, Phillips was able to conquer this challenge, breaking a lot of new ground in the process.

The highly successful development of the Campos basin by Petrobrás also appears to disprove the notion that success in the deepwater frontier is an exclusive preserve of the multinational majors. After all, the Brazilian national oil company has developed a top-drawer deepwater expertise, as proven by its being the record holder for the deepest offshore producing well (at the Roncador field, in 6157 feet of water) and, until quite recently, for exploratory drilling in deep water (9111 feet). In recent years, the company's deepwater reserves have increased at a compounded annual growth rate of 5 per cent, making it the most important player in this niche after Shell, a company that is nearly four times its size.

Admittedly, an argument could be made that the successes of Petrobrás are not good indicators of the capabilities of non-major oil companies to prosper in frontier areas, on two grounds. The first one is that Campos is geologically more tractable than GOM, there being no massive salt sheets and extrusions (and sundry related complications) to contend with. This is true, but the absence of salt in Campos does not make this anything less than a thoroughly inhospitable environment in which to operate, by any reasonable standards. The second reason is that the legal monopoly that Petrobrás used to enjoy over all Brazilian upstream activities for a long time protected the company from international competitors, which under equal circumstances might have done the same job for less money. Again, it is undeniable that its cosseted and isolated position was certainly a help rather than a hindrance for Petrobrás, as was the fact that successive Brazilian governments did not balk at bankrolling a distressingly expensive and – for a long time – unsuccessful long-term exploration and development effort (which has cost an estimated USD 35 billion thus far[29]). Still, this does not invalidate our contention that there is nothing in putting together and managing very demanding deepwater projects (like the development of the Marlim field, say) that is *intrinsically* beyond the capabilities of a medium-sized company like Petrobrás. The production infrastructure in Campos, the significant recent increases in Brazilian deepwater output and, perhaps more important of all, the willingness of international investors to underwrite Petrobrás' E&P projects,[30] all bear eloquent witness to this.

Of course, this does not mean that the question of whether relatively smaller companies can beat the large majors on the cost front is irrelevant. However, as we have explained above, even in a superficially competitive bidding environment, host governments will find it very difficult to extract rents from bidders that reflect accurately the prospectivity of tracts and the undeniable cost advantages that majors enjoy *unless* they take proactive steps that dissipate and negate some of these advantages, for the benefit of relatively smaller players.

The fixation that many oil industry commentators have with regard to the major's supposedly unassailable technological lead, on the one hand, and these companies' self-congratulatory tendency to "bask in the glow of the technological strides made", on the other, has rather obscured the crucial fact that "the real innovators in [the] story [of deep water exploration and production] have perhaps been the service companies".[31] Engineering and services contractors have made a vital contribution to the overall expansion of the industry's operational envelope and capabilities, partly by developing technology able to cope with progressively more demanding environmental conditions (like those encountered in deep waters), and partly by taking on the role of systems integrators (a function comparable in many ways to the one that prime contractors play in other high technology industries like aerospace).[32]

Customers of service companies can expect the latter to orchestrate "alliances and contractual relationships involving suppliers, service providers, and even other operating companies ... to reduce overall system costs and cycle times and to ensure access – sometimes pre-emptively – to crucial technology and inputs".[33] These networks, which "are most relevant in technologically complex frontier regions ... where exploration and development are expensive and risky",[34] have underpinned the efforts of many of those players that seem to be punching way above their weight (like Petrobrás), and have even been behind the frontier success stories of some of the very largest oil firms.[35] Furthermore, as the oil industry moves into ever more difficult operating environments, the importance of these service companies will increase rather than diminish. After all, as Horsnell points out, "given the large-scale run down of the internal capabilities of most major oil companies, and the apparent, and almost certainly short-sighted, downgrading of the importance of engineering and research within company budgets", it is increasingly clear that "the bold predictions that the industry makes for its own future capabilities will be primarily delivered by the contractors and not the oil companies".[36]

There is an undeniable logic to the hypothesis that rationalises the foreclosure of GOM deepwater acreage by a few players in terms of a simple technological race: these were companies that spent vast sums on developing leading edge production technology and were therefore able to stake claims for the best deepwater acreage first, to carve out a dominant position for themselves and to pre-empt players who had to wait for the technology to become available in order to buy it.[37] However, what cannot be stressed strongly enough is that these companies were only able to leverage their technological leadership *to the extent they have* thanks to the manner in which MMS granted access to OCS resources after 1983. Had MMS not been in the market frantically offering acreage at distress prices, those companies which, after 1986, still had enough disposable income to carry the costs of very long-term speculative investments would not have managed to establish a corner on the most prospective deepwater acreage.[38]

Simply put, had leasing continued to take place as per the TN rules after 1983, successful deepwater explorers would have been unable to cover their tracks, and this would have attracted the unwelcome attention of other players who, in turn, would have tried to get into the deepwater action earlier, seeing it as much less of a long shot. At the very least, the interest of these opportunists in the bidding proceedings would have forced the party that had obtained encouraging information from proprietary surveying or drilling to pay top value for any adjacent tracts. Instead, all throughout the 1980s and early 1990s, one comes across stories like that of two Garden Banks blocks located in 2900 feet of water, which Shell won in a bidding round held in early 1984 (for a bonus payment of USD 8.9 million). After having shot a proprietary grid of seismic over all its blocks around the zone, Shell decided that the prospect with the greatest potential was a large salt dome that it had located in the aforementioned blocks. Having acquired the adjacent blocks in 1985 in the face of no competition (for a bonus payment of only USD 2.4 million), Shell drew up a drilling programme and sank its first exploratory well in 1987. In 1989, Shell announced its decision to develop the project (by then baptised as Auger) by means of a tension leg platform, inaugurating the deepwater boom in the process.

Even if one acknowledges the very different nature of the challenges posed by the deepwater GOM and the early Norwegian North Sea,[39] there is no *a priori* reason to doubt that the likes of Pennzoil, Amerada or Kerr-McGee would have been able to rise to the occasion pretty much as Phillips did in 1969, and for much the same reason: the colossal magnitude of the potential rewards. That is not to say that relatively smaller oil companies (still quite large in market capitalisation terms, of course) would have found the going easy. Still, there is no misplaced optimism in the technological capabilities of such players in saying that they would certainly have been willing and able to undertake large projects, even at a relatively early stage in the development of the deep water province. Of course, this capability would have expanded enormously as the more esoteric elements of offshore technology gradually became more widely available, as they are today. Indeed, under conditions of restrictive access to acreage, advantaged players would probably have been impelled to disclose their proprietary advances in production technology more readily, partly to secure rights of ownership on these advances through patenting with a view towards licensing (which would have helped defray R&D costs), and also to promote the further development of these innovations by parties who would be in a position to become specialists in them and hence offer them at a lower cost in the future.[40]

The negative effects of a greater involvement at the early stages of deepwater development in the GOM by relatively smaller companies would probably have been nothing more serious than slightly longer lead times for projects in which such companies assumed the leading role. However, the resurgence in GOM output would still have taken place, most probably along broadly similar lines. Indeed, it is conceivable that this resurgence might have occurred slightly faster, for the simple reason that lease portfolio management by major oil companies has meant that many of the leases obtained during the early days of AWL have only been subjected to exploration and drilling efforts as their ten-year primary (exploration) period neared expiry. Recently, a spokesperson for BP indirectly highlighted the magnitude of the fallow acreage in the hands of the majors when, upon being asked whether his company was considering scaling back its deepwater activities in view of the disappointing results that the industry was posting province-wide, he replied that BP remained "committed to the area", not least because it "has not even had a chance to look at the vast majority of its leases".[41]

Finally, it should be noted that even if non-major companies had indeed been incapable of taking on the operating leadership of early deepwater projects, they could still have carved out a respectable position for themselves in the deepwater production *provided that access to acreage had been expensive enough* (as was the case under the TN system). Once again, we can look at the example of the Cognac development for confirmation of this paradoxical insight. Originally, three of the four blocks where this field was found were acquired by a Shell-led consortium that included another major (Conoco) but also a number of independents (Sonat, Drillamex, Barber Oil, Florida Gas Exploration and Offshore Co.) whose combined stake came to 25 per cent. An Amoco-led consortium that also included Ocean Oil and Gas, General American, Murphy, Ocean Production, Koch and Unocal acquired the fourth block. And why did the big names bring all of these small fry on board? Because of their need to spread around the very high costs attendant to the acquisition of the leases, a purpose for which the money of a small company was as good as anybody else's.

It is typical of the confusion that surrounds the whole issue of offshore leasing in the USA that the stakes that smaller players received as a result of this process were perceived at the time as evidence of the impossibility of their competing with the majors. This, for instance, is how Sherrill summed up the auction at which the Cognac blocks were leased: "look at the winning bidders...Gulf Mobil and Texaco teaming up for one tract, Exxon bidding alone on another. It was the same old crowd. Where were the smaller companies, the independents? Shut out by the prices".[42] But actually, if one looks at the list of winning bids in this auction,[43] one can see that hundreds of independents were able to acquire blocks (if not on their own then as part of consortia), ending up with around a quarter of the net acreage leased (this percentage was marginally higher in the case of the small number of deepwater blocks offered). And while this proportion may not seem like a lot, for most companies it compares very favourably with the acreage (and, more importantly, output) positions that they have been able to build in sales held under the auspices of AWL. Had Sherrill rephrased his account to cover a GOM lease sale held during the late 1980s, it would have read something like this: "look at the winning bidders. Always the same old crowd of four. And where were the smaller companies, the independents? Shut out, of all things, by low prices and the policy that begat them."

5.4 Living with the Long-Term Effects of AWL: New Entrants, Incumbents and Third-party Access to Processing and Transportation Infrastructure in GOM

There has been no shortage of observers who have tried to put a gloss on the marginalisation of non-major oil companies from the deepwater province by saying that it is becoming irrelevant in any case, as

> independents are slowly gaining more of a foothold as primary leaseholders, particularly in the shallower sections of the deepwater. Increased activity from the independents in deepwater is expected in the future as a result of the recent mega-mergers ... [as the merging companies] decide which assets to keep and which to let go. When decisions have been made and some of the properties are dropped it seems likely that more independents will move in.[44]

It is true that entry into the deepwater sector via the exploration route has greatly increased in recent years as technological entry barriers have diminished (and that some of the larger independents, like Anadarko and BHP, are doing quite well in the deep water, notwithstanding their relatively late entry). This does not mean, though, that competition in the GOM deep waters is going to become any less lopsided than it is at the moment.

The profitability of the development projects of late entrants is bound to be curtailed by their need to come to terms with incumbents regarding tie-ins to existing pipelines, on the one hand, and to processing facilities, on the other. The price that such access commands is very high (particularly for natural gas gathering and processing[45]): according to a McKinsey study, Shell has managed to add more than 60 per cent to its original field development values in some GOM fields through third–party pipeline and processing fees.[46] To a certain extent, this situation is a consequence of the costs and myriad difficulties inherent to operating in the deep water. However, it also reflects the fact that the commanding logistical position of incumbents has translated into significant market power, which is further reinforced by the sensitivity of deepwater economics to the presence of infrastructure in the vicinity of a project. And, lest it be forgotten, this commanding logistical position is the product of these companies' effective leveraging of infrastructure in the new province with their extensive assets lying in the shallower parts of GOM and, more importantly, of their earlier start to the leasing and development race in the deep water.

The scope that deepwater incumbents have to augment their production revenues significantly by processing and transporting hydrocarbons for third parties gives them an obvious competitive advantage over new entrants. The competitive vulnerability of new entrants is heightened by the possibility that incumbents may choose to ration, via prices, the access to their transportation, storage and processing facilities in a way that limits competition for outlets in the market for domestic pipeline crudes. This course of action is possible because the tariffs on many of the key transportation systems in the deepwater GOM were calculated purely on the basis of throughputs from the fields that they were initially meant to serve, even though the lines themselves were built to handle considerably larger volumes (Table T5.2). Thus, owners of such lines can in principle achieve a reasonable return on their investment *without having to accommodate oil or gas produced by competitors*. And, of course, it is not difficult to conceive of situations in which this may inhibit any need, want or desire on the part of a transportation company affiliated to a producer to reduce tariffs to increase the throughputs of third party volumes.

Table T5.2: Comparison of Key Parameters of GOM Crude Oil Pipelines (MBD)

Name	*Type*	*(A) Design capacity*	*(B) Throughput**	*B/A (%)*
Bonito Pipeline	Vintage line serving depleted fields	85	70	82
Eugene Island	Vintage line serving depleted fields	215	180	84
Mars/Amberjack	New system serving deepwater fields	550	250	45
Poseidon	New system serving deepwater fields	300	120	40
HOOPS	New system serving deepwater fields	200	100	50

* In the case of deepwater pipelines, throughput refers only to volumes from the fields that they were initially designed to serve

Tangible proof that such a scenario does not just amount to far-fetched speculation comes from the proceedings of a recent Federal Energy Regulatory Commission (FERC) hearing in which BP Exploration & Oil Inc. protested against a tariff filed by the ExxonMobil Pipeline Company (EMPCO), in which rates for the shipment of crude on the latter company's Hoover Offshore Pipeline System (HOOPS) were proposed.[47] In this hearing, BP (a full partner in the project served by the line) argued that the proposed tariff structure would result in HOOPS receiving revenues well in excess of its cost of providing service, to the detriment of shippers whose delivered prices would consequently be higher than they need have been. BP convinced the regulator that there was no good reason for the HOOPS tariffs to be calculated solely on the basis of Diana/Hoover production, as there was every likelihood that substantial volumes of crude oil would be produced (not least by BP) in fields located within the catchment area of HOOPS, throughout this pipeline's useful life.

But does not the positive outcome of this hearing – FERC decreed the suspension of EMPCO's proposed tariff, and enjoined the parties to negotiate alternative rates – demonstrate precisely that existing regulation is adequate to prevent anticompetitive outcomes like the ones we delineated above? The answer to this is: not necessarily. For one thing, it is legitimate to wonder what would have happened with this tariff had the aggrieved party not been the formidable BP; after all, as a recent US Senate report on the workings of the American oil market warns, "the laws and regulations governing access and control to ... [pipelines] are complicated and often not well understood – even by the parties most affected by them".[48] For another, FERC's observance in such matters has been known to slip and its enforcement record is not entirely without blemish.[49] Much more worrying in its anti-competitive implications, though, is the fact that FERC is not in a position to do anything about the rates of the majority of the pipelines located in deep water, because the commission lacks jurisdiction to enforce the Interstate Commerce Act (ICA) with respect to lines located *wholly* on the OCS

5.4.1 The Problem of FERC Jurisdiction over OCS Deepwater Pipeline Rates

In 1992, FERC determined that intra-OCS pipelines did not engage in interstate commerce, and therefore did not need to comply "with any of the requirements of the ICA with respect to their facilities on or across the [OCS]",[50] being bound only not to contravene the access provisions of OCSLA. This legalistic distinction is of enormous significance. ICA expressly stipulates that rates must be "*just and reasonable*" as well as nondiscriminatory, and these provisions clearly protect shippers against price gouging. In contrast, aside from not making it obligatory for pipelines to file any tariffs specifying the terms and conditions of transportation services, OCSLA only requires that access to OCS pipeline facilities be "*open and nondiscriminatory*". Thus, in the case of an offshore pipeline crossing a state boundary (i.e. HOOPS), it lies within FERC's attributions under the ICA to decree a downward adjustment in a tariff that appears unreasonable in the context of likely throughput scenarios. However, it is beyond FERC's competence to do the same in the case of an intra-OCS pipeline, so long as there exists one shipper willing to pay the tariff (as ExxonMobil would have been in the case of HOOPS). In other words, FERC's disclaimer of ICA jurisdiction for pipelines lying entirely within the OCS makes shippers on such lines "vulnerable to the risk that [their] owners will impose transportation rates *that are unreasonable under the ICA but nondiscriminatory under the OCSLA*".[51] Shell, for instance, perceived this risk to be both tangible and high enough for it to take the highly unusual (but ultimately fruitless) step of appealing *against* a verdict that FERC had reached *in Shell's favour* regarding Pennzoil's obligation under § 5(f) of the OCSLA to connect the Bonito pipeline system with the pipeline transporting crude from the Auger platform.[52]

There are many ramifications to the issues surrounding FERC's regulatory jurisdiction in the OCS, not least because *the great majority of deepwater pipelines do not cross any state lines*. This makes it difficult to derive any comfort from the positive outcome of the HOOPS hearing, for instance. In this case, FERC was only able to intervene in the way it did because HOOPS crossed a state boundary and this, in turn, was a consequence of the fact that the Hoover and Diana fields are located offshore Texas, where infrastructure is much thinner on the ground than offshore Louisiana. Crucially, had HOOPS terminated at one of the many hubs that lie beyond the Louisiana state boundary (Ship Shoal, Eugene Island, Mars), FERC would have had no legal grounds for rejecting the tariff, and BP would have had no option but to cough up. Unfortunately, the same would hold true for a player seeking to bring on stream a much smaller field than Hoover or Diana, but prevented from doing so by the steepness of the tariff. This means that the ruling determining that the ICA does not apply to many OCS oil pipelines may make a negative contribution towards the ultimate recovery of oil in the GOM deep water, *but only because of the highly concentrated industry structure that developed in this basin as a consequence of AWL*.[53] The potential fate of small pools in the deepwater GOM is particularly paradoxical when one considers that the whole point behind the fiscal sacrifices underlying AWL was to make sure that even the most marginal oil accumulations were brought into production.

5.4.2 The Anticompetitive Potential of Deepwater Hubs

The more serious anti-competitive effects of the fact that intra-OCS pipelines are not bound by the rate reasonableness, nondiscrimination, or tariff filing provisions of the ICA can probably be defused through legislation. But, again, the GOM deep water would still not be a paradise for competition even if such legislation were to materialise, for the simple reason that high tariffs do not necessarily constitute the most serious threat to competition in the offshore upstream. This is because the GOM deepwater transportation system, with its reliance on hubs controlled by a few "basin masters"[54] providing transportation services lends itself particularly well for such players to circumvent common carriage duties through the imaginative use of a mix of regulated (i.e. pipeline) and non-regulated (i.e. storage, processing and gathering) facilities. As the US Senate recently warned,

> control of critical transportation and storage facilities are a less visible and very effective way to influence cost, supplies and market competition ... Although on the surface common carriage appears to be a neutral means of transporting supplies ... [the] parties who control the transportation and storage facilities *can* take advantage of the complexity of the laws and regulations to circumvent the requirements of the law and limit competition in the market.[55]

The Senate unearthed plenty of evidence about how transporters *do* take advantage of these factors in order to limit competition. For instance, one products pipeline in Michigan (Wolverine) was found to have withheld common carrier service from shippers by claiming that it did not have control over tankage which was "essential for transportation movements into its ... line"[56] and was owned by a party affiliated to the line. It is important to note that, quite apart from its objections regarding the magnitude of the proposed HOOPS tariff, BP specifically complained about two factors that bring the Wolverine case to mind: the conditions under which HOOPS shippers were to be granted access to ExxonMobil tankage facilities at the pipeline's landfall in Quintana (Tx.), on the one hand, and EMPCO's agreements covering the lease of certain SPR lines through which crude shipped in HOOPS was to be taken to markets in the Gulf Coast and beyond,[57] on the other.

5.4.3 Are Floating Production Storage and Offloading Vessels a Solution?

On the whole, the expense and potential risk of relying on other peoples' facilities in GOM deep waters are so high that, given certain circumstances (notably a large enough strike), it appears to make sense for players to build their own transportation and processing infrastructure. This course of action, though, presupposes pockets of a depth exceeding even that of the waters that most GOM players are likely to find themselves drilling in, and hence is only really open to a late entrant like BP.[58] Thus, it is hardly surprising that many companies (generally small to medium-sized producers) have pinned their hopes on being able to use FPSOs to bypass trunkline tolls and avoid the prospect of being left with stranded pipeline segments.

In late 2001, MMS approved in principle the use of this production method in certain GOM areas, and this was heralded as a development that would "open up bidding, leasing and drilling to many more producers, who would otherwise have stayed out because of the cost stranding situation".[59] Unfortunately, the high expectations attached to FPSOs are unlikely to be realised in full, because even in those GOM locations that seem ideally suited for FPSO operations, (i.e. where oil strikes lie at a considerable water depth, at a long distance from shore and in areas lacking in infrastructure), the minimum profitability threshold for projects developed on the basis of this production method is likely to be rather higher than in other offshore provinces.

FPSOs in GOM have to comply with legal requirements and guidelines (notably the Jones Act) that will make their operations more expensive than is the case elsewhere.[60] In particular, MMS' stated intention to discourage FPSO operators from re-injecting any produced gas (even if this requires the construction of a dedicated gas pipeline or the adoption of commercially unproven and expensive technologies, like gas to liquids, in order to dispose of produced gas) will have, if it is applied to the letter, quite a negative impact on the economic prospects of FPSOs (one of the main attractions of these vessels lies precisely in their ability to operate remotely from any such infrastructure, after all).[61] Thus, it is likely that FPSOs may end up by providing a few smaller players with a palliative, never a remedy, against some of the insidious manifestations of the highly concentrated industry structure that constitutes AWL's long-term legacy.

5.5 Conclusions

In 1984, National Ocean Industries (NOI), a prominent oil industry lobbying organisation, published a position paper prompted by the radical changes in Federal leasing policy that the Reagan administration introduced. NOI gave this paper a colourful title: "*Area-Wide Leasing: National Boon or Industry Boondoggle?*"[62] Predictably (not to say self-servingly), NOI answered this question by announcing that AWL would prove to be a harbinger of bonanza in the OCS for all parties concerned. This prediction, as we have shown, has turned out to be hollow (in fiscal, output, and competition terms), as has James Watt's boast that his policies had "demonstrated that the marketplace is the right place for decisions to be made regarding the allocation of natural resources". Indeed, it is difficult to disagree with Sherrill when he summarily dismisses these claims by saying that "actually, he [Watt] had only demonstrated that oilmen know a sucker when they see one".[63]

It would be both unfair and inaccurate to say that AWL was an industry-wide swindle, however. After all, this would imply that all oil companies shared equally in the loot, which was patently not the case (because not all companies were in a position to take advantage of the 'great acreage giveaway'). As we have shown, AWL has been inimical to the collective long-term interests of non-majors. Given the support that these companies have always expressed for this policy, it would be tempting to dismiss this conclusion as fanciful, were it not for the precedent of the Mandatory Oil Import Programme (MOIP), a programme which independent oil companies tenaciously defended even though, like AWL, it benefited the majors far more than them.[64]

The anti-competitive effects of AWL were such that, by the time deepwater technology was reasonably mature, the large oil majors had long ago cherry-picked the choicest acreage. More than anything else, this ensured that medium-sized companies would not be in a position to repeat in the deepwater province the pioneering role that, for instance, Pennzoil played in the development of the giant

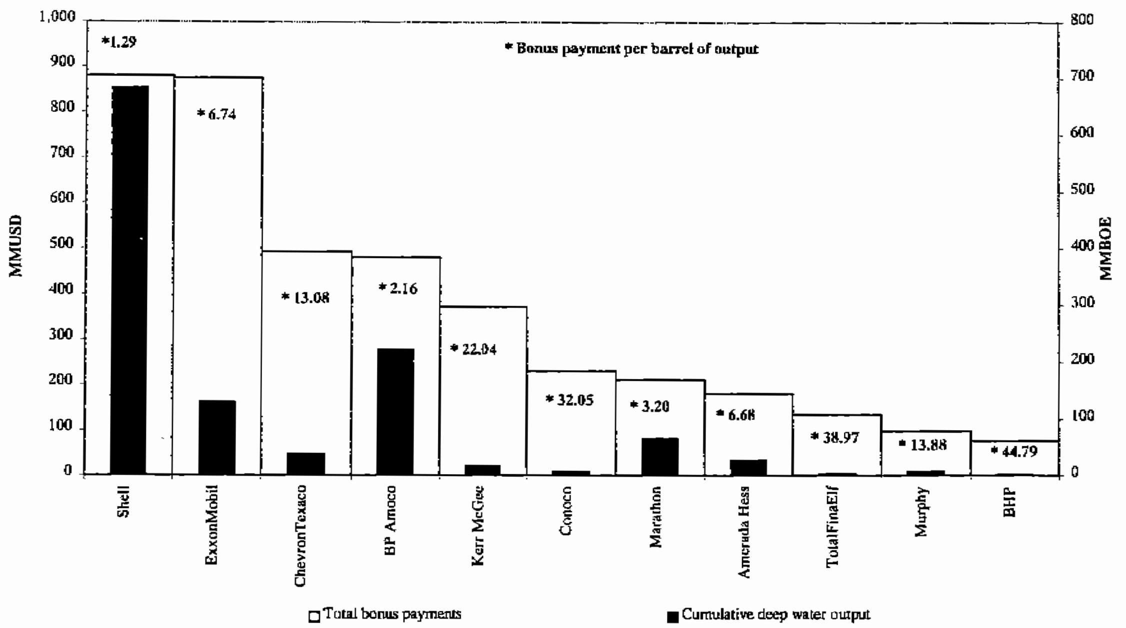
Eugene Island Block EI 330 or, for that matter, the one that Kerr-McGee played in opening up the whole of GOM to oil activities (to name but two examples).[65] It is true that, thanks to AWL, non-majors have not had to worry about the "inordinately high lease-bonus costs" that they began to find so "puzzling"[66] (i.e. objectionable) once the majors got involved in the GOM offshore sector in earnest, from 1962 onwards. Unfortunately for them, the high bonuses that small and medium-sized players used to pay under the TN system were precisely what gave them a chance to compete head-on with the majors for tracts, and were not really a reflection of any avowed policy objective on the part of DOI to maximise OCS fiscal revenues at their expense. As we have explained, the main concern of Harold Ickes and his immediate successors at DOI was that OCS oil resources be developed in an orderly fashion (i.e. in a way that did not lead to physical waste), and that the pace of OCS leasing be tailored accordingly. The revenues that the Federal government obtained from offshore oil were a welcome by-product of this policy, to be sure, but they were not responsible for the timing of DOI's lease sales or, more importantly, for the peculiarities of its leasing practices.

The very high bonuses paid by prospective lessees were a consequence of the fact that the market for offshore leases was working with reasonable efficiency (even during the period of maximum agitation in the world oil market (1973–1981), and that competition between bidders was eliminating Ricardian rents. In other words, strong bonuses were evidence of the fundamental soundness of the market for offshore oil and gas leases, which Watt compromised with ideologically blinkered policies. The pernicious effects of AWL could only have been worse had Watt been in a position to heed the recommendation that OCS leases be granted in perpetuity, "eliminating the five-year rule and diligence requirement" for the primary term.[67] Such a course of action would have been equivalent to privatising offshore oil and gas resources, but for the benefit of only a handful of companies who would have had to pay a pittance for the privilege.

The foregoing notwithstanding, it would be unfair to say that AWL was foisted upon an unwary government by the devious majors. After all, policymakers like Watt were only too eager to jump on this particular bandwagon of their own accord. Indeed, even if one does not extend the benefit of hindsight to the majors, one suspects they might perhaps have preferred a more accommodating approach to OCS leasing, as this would have forestalled a lot of litigation and conflict, thereby opening up to exploration activities a larger area than the one that eventually materialised from Watt's radically ambitious plan. Nevertheless, the long-term results of AWL so much resemble a boondoggling outcome (to use NOI's technical term) that MMS should probably be grateful for the protection that a US Court of Appeals judgement gives it against possible claims of dereliction of duty. This judgement upheld the legality of AWL against suits brought by the Texas and Louisiana state governments, on the grounds that the OCSLA Amendments of 1978 did not require the maximisation of revenues, merely the "receipt of fair market value for the lands leased and the rights conveyed by the Federal government". More importantly, the judgement accepted MMS' definition of fair market value, which sees this as "the amount in cash ... for which in all probability the property would be sold by a knowledgeable owner willing but not obligated to sell to a knowledgeable buyer who desired but is not obligated to buy ... This market value which is sought is not merely theoretical or hypothetical but it represents, *insofar as it is possible to estimate it, the actual selling price*".[68] This helpfully tautological formulation makes it difficult for anyone to argue that the Federal government might have been short-changed at any point in its offshore dealings.

Finally, even though we hope to have made it clear that AWL was a profoundly misguided and flawed policy, plenty of credit should be given to those companies that were able to press home to the greatest effect the many advantages that AWL gave them. While it is indisputable that AWL fostered the appearance of basin masters in the GOM deep water, the fact that Shell has managed to turn AWL to the greatest advantage is a testament not to bureaucratic incompetence but to the excellence of this company's applied geosciences, on the one hand, and its unflagging commitment to research and development, on the other.[69] To a far greater extent than other majors, Shell was able to translate its R&D efforts into deepwater output, in the process achieving an enviable figure for acreage acquisition cost per barrel of oil equivalent produced. As can be seen in Figure F5.9, Shell's dominant acreage position has entailed significant disbursements in the form of bonuses, but the fruits of this expenditure exceed those of other companies by orders of magnitude.

FIGURE F5.9: DEEPWATER (1000 FEET OR MORE) BONUS PAYMENTS AND CUMULATIVE PRODUCTION BY COMPANY (UNTIL 2000)



Looking at this graph, incidentally, it is easy to see the reason behind Lee Raymond's opinion that "the best thing ExxonMobil could have done after it drilled its first well in the Gulf was to never drill another again".[70] Doubtlessly, there are plenty of CEOs from other companies who share Raymond's feelings, although none has been quite as candid. But at least MMS can take some consolation from these companies' dismal showing in the deep water, because it demonstrates that the current pattern of lease ownership in this province is not the product of an explicit collusive agreement between bidders. Simply put, it is inconceivable that any party to such an agreement would have idly stood by while Shell took it to the cleaners in the manner implied by the graph above.

The other dominant player in the GOM deepwater province is BP, whose success can be traced to its bold decision to abandon the proven Shell strategy of looking for complex stratigraphic traps adjacent to salt bodies. Taking advantage of advances in imaging and drilling technology, BP undertook the very risky and costly exploration of what appeared to be simpler and much larger traps under the mammoth salt sheets that cover vast swathes of the northern GOM. In one of those traps, BP found the largest field uncovered yet in the deepwater province, with around 1.5 billion barrels of estimated recoverable reserves, including oil in related structures.[71]

BP's success story appears to go against the hypothesis that sees AWL as a mechanism that stifled competition in the deep water, essentially by placing the choicest deepwater plums in the hands of a few companies in exchange for paltry sums of money. BP itself pushes the line that says that the way in which "the mobile salt, trapping complexities generated by the mobile salt and imaging problems created by the salt" complicated exploration activities actually worked out in the company's favour, allowing it to "carve out a position in the region ... [even] as a late entrant into the Gulf of Mexico". [72] According to a BP official, less exacting conditions would actually have been more conducive to foreclosure, as they would have enabled first movers to monopolise the action. Indeed, the company rationalises its own towering presence in Alaska in precisely these terms, suggesting that things might have turned out differently had this not been a "geologically relatively simple" province "where exploration was essentially over in three years ... and the life of the play was shorter than the lease term".[73]

As far as explanations go, this one is unexpected in its sincerity and forthrightness, but is unsatisfactory all the same. Put quite simply, BP's position in Alaska is a reflection of the remoteness of the area, the extraordinarily inclement operating conditions and the colossal expenditure required to build the TransAlaskan Pipeline System, rather than the simplicity of the geology. As far as the GOM is concerned, while it may be true that BP was able to carve out a position for itself in the deep water as a late starter, it is also true that it did so taking risks and running bills that only a handful of very large companies would have been in a position to imitate. Most importantly, one should not forget that BP has at least in part underwritten its ambitious deepwater exploration and development programme with the cash flows generated by its highly profitable natural gas operations in GOM. Output for these operations, which were part of Amoco's dowry, came from the most part from blocks leased under the auspices of AWL. BP's case, therefore, tends to reinforce rather than undermine the case regarding the anti-competitive effects that AWL has had on the structure of the offshore upstream sector. Thus, one cannot help but think that it would not be entirely inappropriate if, in one or more points of the far-flung Shell and BP empires, statues were to be erected to commemorate the day that James Watt took office as Secretary of Interior.

NOTES

[1] Kissinger 1999: 668–9.

[2] Watt's zeal in aligning "his department's activities with its statutory requirements ... [in order to] fulfil the president's political commitments" was seen even by admirers in the oil industry as bordering on "fanaticism" (*O&GJ*, 17 October 1983: 43). In the end, Watt succeeded in alienating even natural supporters in the Western states and the oil patch, and he was forced to resign in 1983 after making spectacularly ill-judged comments that had very disagreeable racist and discriminatory undertones.

[3] Bradley, *op. cit.*, v.1: 306.

[4] Laffont and Tirole 1993: 538.

[5] See Bradley, *op. cit.*

[6] Laffont and Tirole, *op. cit.*: 537.

[7] Mead 1993: 236.

[8] Riddle, Snyder and George, *op. cit.*: 4.

[9] *PON* 20 March 1974: 1.

[10] Mead 1993: 229.

[11] Klemperer, *op.cit*: 186.

[12] The seminal article for this *problématique* is Akerlof 1970.

[13] Typically, Mead accepts that in pure bonus bidding there is "a *theoretical* case for asserting that, in the long run, high bidders are the most efficient operators" (1993: 236; italics ours). However, he then goes on to assume that this situation effectively obtains in practice.

[14] Macho-Stadler and Pérez-Castrillo, *op. cit.*: 157.

[15] *Ibid.*: 113; italics in original.

[16] Stiglitz 2002: 472.

[17] Laffont and Tirole, *op. cit.* 59.

[18] *Ibid.*: 60. In an oil industry context, Osmundsen (1995: 372) concludes that the best way of reducing informational rents even while distorting "the level of petroleum extraction for the efficient producers" involves "a menu of linear tax contracts, composed of a licence fee and a distortive royalty".

[19] Macho-Stadler and Pérez-Castrillo, *op. cit.*: 157; italics ours.

[20] The history of the British North Sea, for instance, shows that having a discretionary licensing regime in place is actually a very good way of ending up with a highly oligopolised industry structure. Discretionary assignation, in any case, is not feasible in places where – as would be the case of the USA – it inevitably becomes the object of spirited legal challenges by parties disagreeing with whatever form it takes.

[21] Stiglitz, *op. cit.*: 471.

[22] *Ibid.*: 471.

[23] Gramling, *op. cit.*: 160.

[24] OTA 1985: 135; italics ours.

[25] Kreidler, *op. cit.*: 197.

[26] Dunn 1995: 47.

[27] Indeed, Ekofisk was in the end affected by those "two immutable laws operating on the Norwegian continental shelf" that became infamous after the Statfjord project ran into major delays and cost overruns; namely that "regardless of how much has been invested, the amount still to be invested remains constant", on the one hand, and that "regardless of how far the project has advanced, completion is still six months ahead" (Richardson 1982: 46).

[28] Dunn, *op. cit.*: 47.

[29] Stouffer and Knight, *op. cit.*: 7.

[30] See the prospectuses for the bond issues of Companhía Petrolífera Marlim 1999–2000.

[31] Horsnell 2000: 78. This, incidentally, was also true during the formative years of the offshore sector. As Kreidler (*op. cit.*: 203–4) notes, "the willingness of drilling contractors to invest in new equipment contributed to the offshore rush. Such interest was crucial since operators shied away from experimenting with technology and handling their own drilling operations ...[while] the majors had avoided capital investment in drilling equipment and personnel".

[32] These roles, incidentally, are as old as the offshore sector itself: "drilling contractors ... led the way for the rest of the industry into the Gulf ... Owing to the increasing complexity of offshore operations, drilling contractors became data clearinghouses for various disciplines and fields of expertise, and took on a technological sophistication that often surpassed their land-based cousins" (Kreidler, *op. cit.*: 205).

[33] Ernst and Steinhubl 1999: 153.

[34] *Ibid.*

[35] As can be readily appreciated by examining in detail the various technological components that have to come together to bring to fruition a development like the ExxonMobil-led Hoover/Diana in the GOM deep waters (see the special supplement that *Hart's E&P*, March 2002, dedicated to this project).
[36] Horsnell 1999: 62.
[37] As a Research Coordinator of the Shell Group put it, "if you decide to buy this know-how, you will find yourself in the same queue as your competitors. Much of our research is done to keep ahead of our competitors"(Conn and White 1994: 63).
[38] During the first ten years of AWL, Shell, for instance, amassed 600 GOM deepwater tracts which allegedly covered 60 per cent of the deepwater area accessible to traditional 2-D seismic techniques.
[39] Ekofisk, for instance, was located in only 200 feet of water.
[40] In 1963, Shell's lead in offshore activities was considerably greater than it is today. As Valdeman and Lagers (*op. cit.*: 84–5) point out, "Shell held a special position in the otherwise young and still rather unstructured offshore sector ... [as] the main contributor to the development of offshore technology". Nevertheless, Shell (at the behest of its patents and licensing department) took the remarkable decision to hold, in 1963, a three-week course dealing with floating, drilling and underwater well completions for all of its contractors *and* its competitors. This course has gone down in oil lore as "the million dollar school of offshore technology": each participant had to pay a staggering USD 100,000 for the privilege of attending (about USD 460,000 in money of 2000); the SONJ (now Exxon) affiliate Humble sent ten delegates and SOCONY (later Mobil) twelve.
[41] *FT*, 25 April 2002: 29.
[42] Sherrill, *op. cit.*: 239.
[43] *O&GJ*, 8 April 1974: 38–39.
[44] Riddle, Snyder and George, *op. cit.*: 13.
[45] Gas gathering facilities, under 1(b) of the Natural Gas Act (15 U.S.C. 717), are free from FERC's regulatory jurisdiction. The agency considers that any facility collecting gas at depths of 200 metres or greater is a gathering facility, "up to the point or points of potential interconnection with the interstate pipeline grid" (Shell Gas Pipeline 74 FERC 61,896). From that point, the Commission applies a so-called 'primary function' test to determine (on the basis of a sliding scale that broadens the definition of gathering pipelines in terms of length and diameter as a function of the distance from shore and the water depth of the offshore production area) whether a given facility falls within its regulatory jurisdiction or not. The tests are explained in *Williams Gas Processing-Gulf Coast Company, L.P v. FERC*, 1998; the sliding scale in Amerada Hess, 52 FERC 61,268.
[46] Conn and White, *op. cit.*: 66. Shell operates deepwater hubs at Bullwinkle, Mars and Auger, and will have hub operations at Ursa and Brutus in the near future. Bullwinkle (whose location at the edge of the deep water was particularly favourable) was turned into one of the first major hubs built around subsea production in 1997, when it was expanded to handle 200,000 MBD of oil or 320 MMCFD of gas.
[47] Hearing order: 91 FERC 61,182 (2000) for ExxonMobil Pipeline Co.
[48] US Senate 2002: 187–189
[49] In its investigation on the US gasoline market, for instance, the US Senate reported that it was only as a result of a fortuitous challenge on a rate request of a regulated products pipeline in Michigan (Wolverine) that FERC discovered not only that this pipeline and its affiliates had engaged in practices that "violated the Interstate Commerce Act [ICA], *some for over twenty years*" but also that "had not the rate request been challenged, it is likely these discriminatory practices would have continued, and it would have been more difficult for independents to compete" (US Senate, *op. cit.*: 16; italics ours). Tariffs can be long-lived, but they are not set in stone (in 1930, the US Supreme Court said that a rate order can never be *res judicata*). FERC itself has made it clear that "[t]he fact that a rate was once found reasonable does not preclude a finding of unreasonableness in a subsequent proceeding" (*OXY USA, Inc. v. FERC*, 64 F.3d at 690, 1995).
[50] Hearing order: 61 FERC 61,051 (1992) for Oxy Pipeline, Inc.
[51] Shell Oil Company v. FERC (1995).
[52] Hearing order: 61 FERC 61,050 (1992) for Bonito Pipe Line Company. Shell's objections were dismissed by the Court of Appeals for the District of Columbia Circuit (see note above).
[53] Such a situation is currently unfolding in the UK sector of the North Sea, where independent operators are alleging that many small oil pools (10 million barrels or so) are in danger of being left stranded as production facilities located nearby are abandoned and decommissioned by large companies who nonetheless refuse to mark down tariffs in a way that might allow these companies to tap such pools (Arnott 2002).
[54] Ernst and Steinhubl, *op. cit.*.

[55] US Senate, *op. cit.*: 187–189; italics ours.

[56] *Ibid.* As a consequence of this gambit, independent shippers in the line were not in a position to acquire an "assured commitment ... to access the tankage storage [*sic.*]" and this "preclude[d] the use of the through rates posted in the tariff and discourage[d] shippers not affiliated with Wolverine from entering into long term purchases of commodity products which could lower procurement costs" (*ibid.*).

[57] EMPCO has leased the lines that connect the SPR site at Bryan Mound (located in the vicinity of Quintana) with refineries in the Texas City area, on the one hand, and to the Jones Creek SPR site (itself connected to a major pipeline running to the Midcontinent), on the other. BP extricated the details of the lease agreement from SPR through a series of Freedom of Information Act (FOIA) requests and appeals lodged at DOE (see Case No. VFA-0503, 27 DOE 80,216 and Case No. VFA-0522, 27 DOE 80,236).

[58] BP has made transportation issues the centrepiece of its current GOM deepwater development strategy, entrusting a special task force with delivering "options to bring to shore the company's significant oil and gas reserves in the southern Mississippi Canyon, the southern Atwater Valley and the Green Canyon areas of the Gulf on a 100% BP Amoco funded basis" (*Offshore*, June 2000).

[59] *Offshore*, June 2000.

[60] FPSOs will not be considered Jones Act vessels or be required to be coastwise qualified, unless they are actually used to deliver oil to US ports (which is unlikely). However, all shuttle tankers carrying oil produced at FPSOs will have to comply with Jones Act requirements (i.e. be US built and crewed) and be coastwise qualified, and this will significantly increase the costs (fixed and variable) of the shuttle tanker fleet (which, in any case, still has to be built).

[61] MMS argues that a number of emerging technologies (converting gas to liquids, gas compression for ship-borne transport, etc.) have been identified in industry studies as technically and economically feasible, and that potential FPSO operators should consider these alternatives in their decisions about gas disposition. This might be true, but the enforced adoption of any of these alternative technologies will significantly increase the costs of any FPSO project in GOM.

[62] NOI 1984.

[63] Sherrill, *op. cit.*: 485.

[64] The main effect of MOIP was to increase US crude oil prices relative to world prices, which greatly increased the value of the output of independent oil companies. MOIP benefited the integrated majors in the same way, of course. In addition, it safeguarded the value of their extremely large investments in higher-cost oil in North America, which would have had to be written down had competition driven down the price of oil to the levels warranted by the very low production costs of the Middle East. Also, it brought about an increase in the differential rent element for oil produced in the Middle East or Venezuela, which majors could monetise by means of their extensive captive downstream systems. Finally, MOIP shifted the costly burden of domestic prorationing – which forced all oil producers to idle a certain proportion of their production capacity – onto the shoulders of companies that did not have access to oil reserves outside the USA (and the main reason why independent companies lacked such reserves was that they had been excluded from some of the most prospective zones by the restrictive agreements struck between the Seven Sisters).

[65] As Kreidler (*op. cit.*: v) observes, "though large oil companies eventually placed its [*sic.*] indelible stamp upon the industry, the smaller, independent oil operators set the initial pace to establish the offshore frontier".

[66] The expressions are those of a Conoco official, quoted in *O&GJ*, 1 April 1963: 78–9.

[67] Mead 1994: 17.

[68] GAO 1985: 34; italics ours.

[69] During the early 1990s, Shell was spending 40 per cent more on R&D than Exxon, its closest follower in this department, and it had already drilled 57 deepwater wells, against 34 by its nearest competitor (Conn and White, *op. cit.*: 63).

[70] *FT*, 25 April 2002: 29.

[71] BP has a participation in 8 out of the 13 major discoveries made thus far in GOM water depths beyond 5,000 feet.

[72] Rainey 2002.

[73] *Ibid.*

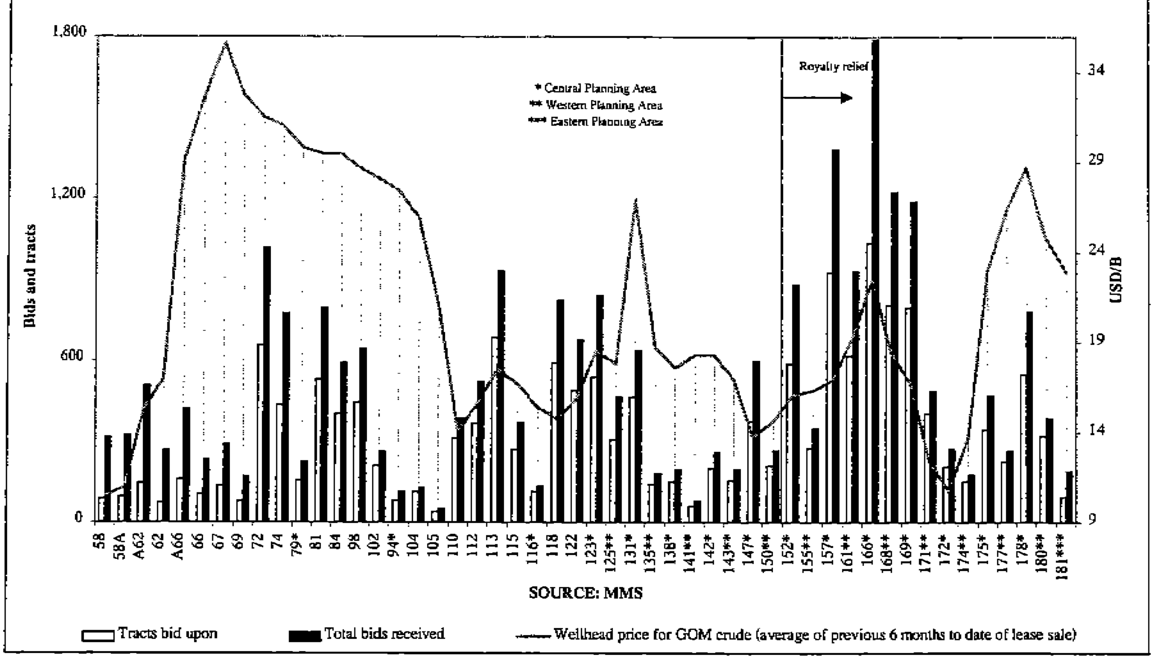
The first GOM well drilled out of sight of land (by Kerr-McGee, in 1947) was a full ten miles away from shore, although it was actually sitting in just 18 feet of water. GOM upstream activities have come a long way since these (shallow) beginnings, as production now routinely takes place in 5000 feet of water, and drilling in 9000 feet and beyond. At the time of writing, the GOM record for deepwater drilling stands at 9727 feet, which Unocal achieved in an exploration well drilled in Alaminos Canyon block AC903.

Throughout the time-span circumscribed by these two milestones, cutting-edge technology has been a key driver for oil activities in this province, much more so than in others (where oil companies have been content to apply the innovations originally pioneered in the GOM region). GOM was a logical and in many ways ideal place for the offshore oil sector to take off, and for offshore technology to mature. Quite apart from its proximity to what was the epicentre of the world petroleum industry until the 1950s, its gentle slope meant shallow water far out from shore and a relatively flat bottom (particularly in the area close to the Texas and Louisiana border, water depths can be below 500 feet more than 120 miles out from shore). Its waters were often calm, and it was only a short way from major centres of oil related activity, where specialised construction and services could emerge from existing companies. Admittedly, not everything was a piece of cake. Oil companies active in the GOM offshore had to contend with unstable sediments on the sea floor, active faults, a treacherous underlying karstic topography, colossal submarine mudslides in the Mississippi delta and, above all, hurricanes. These factors made it impossible for them to go for the relatively undemanding "onshore operations offshore"[1] (i.e. the recreation of land-like drilling sites in water, mainly through the use of piers and trestles) approach to exploiting submarine oil deposits that had been very successfully applied for a long time in places like California, Lake Maracaibo, Lake Caddo, Baku and the Louisiana bayous.

Prima facie, the current GOM output bonanza is the latest instalment in a long-running and fruitful relationship between technology and oil entrepreneurship. The stock interpretation given to the development of the deepwater province is that it proves yet again that, regardless of how daunting the technological challenges might appear, the collective ingenuity of the industry will in the end win the day provided that, as was the case in the GOM deep waters, the geological as well as the investment conditions are right. In this context, AWL and royalty relief are constantly put forward as models that other governments should strive to imitate, by rising above pressing short-term financial considerations and putting in place flexible fiscal mechanisms, based on gross income rather than net income levies and back- rather than front-loaded (with acreage being assigned on the basis of bids for the highest marginal tax rate rather than up-front signature bonuses). Only thus, they have been told, will the long-term interests (and revenue-generating power) of their respective oil industries be properly safeguarded.

There are a number of conceptual and practical problems with this "no jam today but jam tomorrow" trade-off scenario, though. First of all, as John Mitchell observes, "fiscal terms affect supply only marginally ... They do not greatly affect the general level of activity, which is more influenced by overall price levels and exploration attractiveness".[2] There are plenty of observers who suggest that the increase in the number of deepwater blocks receiving bids since 1995 would not have been quite so marked in the absence of the relief measures.[3] However, this is a hard proposition to swallow, in view of the effective exhaustion of exploration prospects in shallow water blocks (as Gramling notes, up to a depth of 1300 feet, the "overwhelming majority" of tracts in the central and western planning areas are under lease "or were leased in the past and have expired or been relinquished"[4]). The upwards and downwards variations in bids submitted and tracts bid upon since 1995 can be explained much more straightforwardly in terms of the behaviour of oil prices during the period preceding acreage auctions (see Figure F6.1). Indeed, in moments of candour, companies themselves downplay the importance of royalty relief. As an official in a large independent company pointed out, "the discoveries that you are likely to make [in deep water] are much larger than in shallower waters. That's the real attraction. The royalty holiday is an enhancement, but it's not the reason for deep water drilling."[5]

FIGURE F6.1: BEHAVIOUR OF KEY INDICATORS IN GOM LEASE AUCTIONS, BY SALE NUMBER (1979-2001)



Secondly, fiscal revenues associated to increases in production have displayed a worrying tendency of failing to materialise, partly because greater output sometimes translates into lower prices and partly because "progressive" net income levies lend themselves quite well to tax optimisation practices.[6] A developed country can probably afford to gamble and lose vast sums (as the USA did with AWL) in the pursuit of the overriding objective of lessening its dependence on oil imports. However, governments for whom (as Silvan Robinson once quipped) the real costs of oil production include the costs of running their countries[7] are in a very different position. Before succumbing to the entreaties of the liberal brigade, such governments should dwell on the example of a number of their counterparts in oil-producing states within the USA, who have looked long and hard at the use of tax breaks as a way of maximising ultimate recovery within their territories, only to decide that the game is not worth it.[8]

Thirdly, simply scrapping restrictions on access to the upstream sector across the board can bring about undesirable changes in industry structure, specifically a greater degree of concentration. Imitating AWL, on the whole, seems like a good way of ensuring that certain types of players are discouraged from investing while other players can take advantage of this apparent lack of interest to drive acreage prices (and fiscal revenues) down, that future entry into the upstream is compromised, that fiscal dependence on a reduced number of operators is increased and even that the ultimate amount of oil to be recovered from an offshore basin may turn out to be lower than what it would otherwise have been.

Finally, it has been argued that "low cost producers . . . [wishing] to open their oil reserves ... to long-term equity investment by the companies which are currently investing in expanding capacity elsewhere", will only be able to lure these companies by offering fiscal terms that are as attractive and flexible as possible. However, as John Mitchell points out, the arithmetic underlying this assertion is flawed.[9] According to this author, for instance, a duplication of investment by private oil companies in OPEC countries would only divert about 14 per cent of the estimated oil industry funds available for investment each year. Moreover, if the funds available for upstream investment worldwide were not limited to current levels of spending (and there is no reason on earth why they should be), economic opportunities outside the circle of low cost countries could still be developed even if multinational oil companies were investing truly massive amounts within such countries. All of which goes to show that international oil companies have far more funds available for investment than attractive prospects to plough them in (especially now that local oil companies have ensconced themselves in the driving seat in Russia), which means in turn that low cost producers should not really be competing with each other on fiscal terms. The fact that some of them do is primarily a testament to the effectiveness of "the well-designed strategy of the developed consuming countries, their international organisations, companies and consultants",[10] as opposed to an alleged imperative to compete for investment.[11]

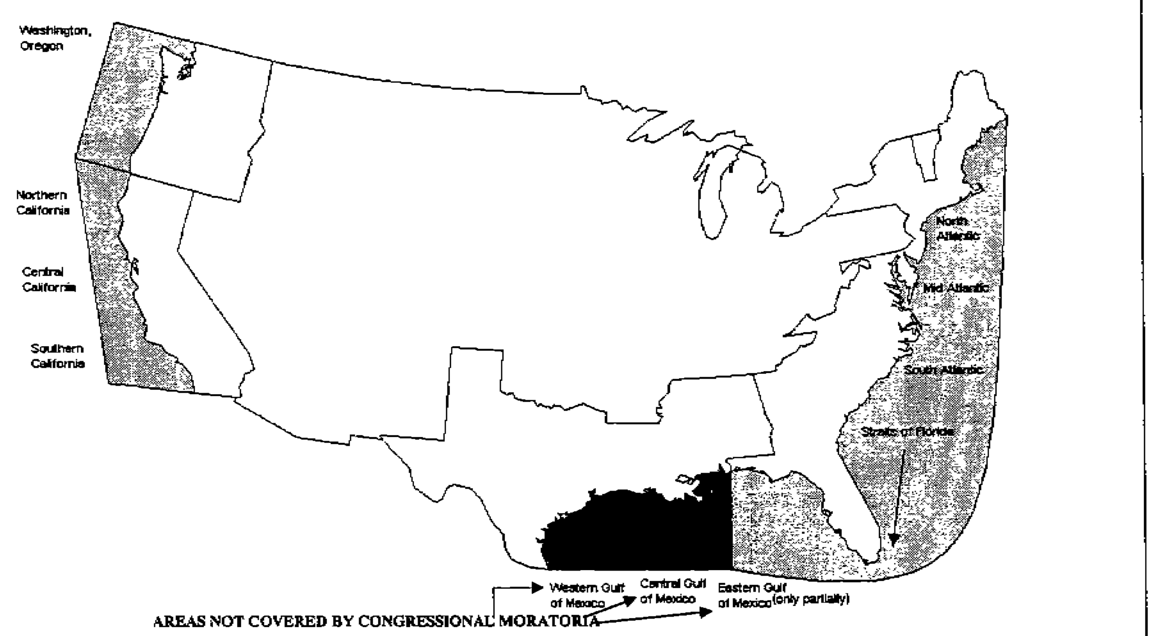
There are many governments that need to digest the lessons of AWL before adopting policies that may affect their oil lifelines but, at this moment in time, Mexico's is probably the one that has to do it with the greatest degree of urgency. Even though the prospect that the Mexican oil sector might open up to private investment as a result of a constitutional amendment still appears rather remote, the activities of oil companies in the GOM deep water have been creating "facts on the ground" that might very well lead the Mexican government's hand in this direction. Specifically, the sinking of a couple of discovery wells in the Alaminos canyon area of the Western

Gulf (Shell's Baha, and Unocal's Trident), very near to the US–Mexican border (and only about 4–5 miles away from the area where both countries have agreed to a 10-year drilling moratorium as part of the treaty delimiting the boundaries between their respective EEZs) has raised the prospect that reserves straddling this border might be developed in the short to medium term.[12]

Given that PEMEX has a portfolio of relatively cheap exploration and development prospects in shallower waters, and in light of the company's constrained investment budget, it is conceivable that a future Mexican administration may have to find a way of opening up this deepwater area to foreign companies in haste, in order to mount an offset drilling programme aimed at preventing the drainage of reserves from under the Mexican side of the border. Under such circumstances, it would be understandable for a government that is totally unaccustomed to the practicalities of granting production licences or concessions to look northwards for an example of how to go about things. But, by the same token, it would be inexcusable if, in their quest for instruction and guidance, the Mexican fiscal authorities did not make it their business to compare the relative merits of the TN system, on the one hand, and the AWL system, on the other. In our view, such a comparison would significantly narrow down the array of licensing policy options that the Mexican government might be prepared to entertain. This is, after all, a government that, over the past decade, has derived at least a fourth of its fiscal income from oil export revenues.[13] One could logically expect a Mexican licensing authority to greet the fiscal outcomes of an AWL-like policy with dismay, which might leave the field clear for a licensing system patterned after TN.

Quite apart from its failure to deliver on its economic promises, AWL has been a colossal flop on the political front: its enduring legacy, after all, is the closing off to exploration and production activities of a vast area of the US OCS, potentially very rich in hydrocarbons (Figure F6.2). As far back as 1985, the DOI observed that "the only apparent solution to reducing the cost of opposition to the OCS programme" would involve providing "the States and localities with an incentive to support leasing which is perceived by the States and localities as sufficient to counterbalance their perception of the potential harm and risk to which they are subject. OCS revenue sharing is the best incentive to achieve that balance".[14] When they were penned, these lines were probably a reasonable diagnosis of the federal/state impasse on offshore oil activities, and revenue sharing might conceivably have broken the deadlock then. Indeed, Fitzgerald is still of the opinion that, with revenue sharing, even "green" states would support the lifting of the moratoria and the volume of litigation would dwindle to a trickle.[15] This situation is now very unlikely to materialise, though, not least because the share of the mineral revenues that coastal states would be entitled to are minimal in comparison to the amounts of money that a state like Florida makes from tourism, say.

FIGURE F6.2: CURRENT LEGAL STATUS OF OCS LEASING PROGRAMME IN THE LOWER 48



~~SOURCE: After OTA, 1985: 37~~

The mobility of OCS operations and their suitability to a remote form of operation means that job creation will not even function as inducement for recalcitrant coastal states to sign on to the programme. As Gramling notes in the case of Florida, "few, if any, jobs, or other economic benefits would go to residents of the state. The rigs, support vessels, and crews would come from southern Louisiana, and local purchases would be limited to such items as potable water, which is already in short supply in south Florida, and diesel fuel".[16] The exact opposite is true in the central and western planning areas of GOM: according to a study commissioned by the Louisiana Mid-Continent Oil and Gas Association, GOM oil and gas operations contribute USD 6 billion per year to this state's economy.[17] That, of course, is why OCS development in Texas and Louisiana "is supported as strongly ... as it is opposed elsewhere".[18]

As if this were not enough, a lot of water has gone under the environmental bridge since 1985. In the wake of events like the *Exxon Valdez* disaster and the polarisation of environmental politics in key states, it appears that, regardless of the frustration of US oil companies and a steadily growing dependence of the USA on imported oil, the whole of the Pacific OCS, Florida and the Eastern seaboard will remain out of bounds to the drill bit in the foreseeable future, even in the event that some future president were to decide to support the incorporation of reasonable revenue sharing amendments to extant OCS legislation. This being the case, it is highly unlikely that any future administration will pursue this course of action. Oil companies seem to subscribe to this view, as witnessed by their cautious endorsement of the proposals put forward by Federal senators from California and Louisiana whereby DOI would reacquire all leases off California in exchange for credits that could be used for paying bonuses in GOM lease sales or for liquidating royalty obligations.[19] A small number of legislators in the Louisiana state senate have likewise concluded that revenue sharing is as unlikely to happen now as it ever has been in the past. Thus, they are once again seeking to redress the historical injustice represented by their state's exclusion from the bounty generated just off its coasts through a proposed oil and gas processing levy that would tax every barrel of oil and petroleum products and every cubic foot of natural gas processed (i.e. produced, transported or refined) in Louisiana,[20] in exchange for a repeal of the severance tax currently collected on oil and gas produced within the state. This processing tax, which is almost certain to be stillborn, would supposedly generate more than USD 2.1 billion annually for the state, compared to the USD 400 million that severance taxes currently raise.[21]

That the USA is failing to tap significant domestic energy resources notwithstanding widespread concerns within its political system that a rising tide of oil imports may be undermining the foundations of the country's national security is a paradoxical state of affairs, as well as a poignant reminder of the failure of the OCS institutional framework and fiscal regime to achieve the equitable distribution of the fruits of developing US offshore petroleum resources. For international oil companies, the governments of major consuming countries and supranational organisations (EIA, IMF, World Bank, WTO), however, it should also be a clear warning about the political limitations of their aggressively liberal oil agenda, which in recent years they have succeeded in imposing in a growing number of oil–producing countries. This agenda is predicated on acknowledging the sovereign right of oil-rich albeit underdeveloped countries to grant access to their resources, while at the same time stripping these countries of all other meaningful attributions of sovereignty and eminent domain (notably the power to tax their extractive industries in any way that they see fit) by means of legal fetters incorporated into bilateral investment treaties (BITs) and multinational investment agreements (like the Energy Charter Treaty).[22]

The way in which SLA and OCSLA effectively barred coastal states from having any meaningful say in the development of OCS resources (especially after the adoption of AWL) and denied them any financial compensation in return seems similar to the intended effects of this liberal agenda. Thus, it would be logical to expect that the consequences of this agenda might end up to be crippling political paralysis and endless conflict and litigation (it can probably be said – and only half in jest – that every barrel produced in the Federal OCS has generated around 10 cents in legal fees). Certainly, the evolution of foreign direct investment in Russian oil after 1990, or the way in which the Venezuelan *Apertura* has ground to a halt after the electoral success of Hugo Chávez are developments that point in this direction. These also suggest that it is the fundamental imbalance embodied in the liberal agenda which is more likely to hamper investment, and prevent capacity from coming on stream when needed, rather than the legitimate claims for compensation on the part of natural resource owners.

The liberal oil agenda is part of the same approach promoted by the Washington consensus, whose central characteristic (in the words of its critic Joseph Stiglitz, joint winner of the 2001 Nobel Prize in Economics), is its "market fundamentalism – the simplistic view of competitive markets with perfect information, inappropriate even for developed countries, but particularly inappropriate for developing countries".[23] Despite its predominance "in the policy advice of the international financial institutions over the past quarter century",[24] the Washington consensus policies have consistently fallen short of expectations in general development terms, in managing the transition from centrally-planned to market economies and in preventing and managing economic crises. The liberal oil agenda has similar effects, as the accelerated institutional and economic collapse of the post-*Apertura* Venezuela illustrates. But then, as Stiglitz disparagingly observes, "it is not surprising that policies based on models that depart as far from reality ... [should] so often lead to failure".[25]

So how is it that these frequent and spectacular failures have nonetheless failed to dent the popularity of these policies? One plausible explanation for this may lie in the counterproductive fixation that most practitioners of the dismal science have for long had regarding the concept of "optimality", and the way in which this leads them to confuse actual with ideal modes of organisation in the regulatory arena. As another Nobel laureate in economics once put it,

> contemplation of an optimal system may provide techniques of analysis that would otherwise have been missed out and, in certain cases, it may go far to providing a solution. But in general the influence has been pernicious. It has directed economists' attention away from the main question, *which is how alternative arrangements will actually work in practice*. It has led economists to derive conclusions for economic policy from a study of an abstract of a market situation.[26]

Unrealistic conclusions have produced unrealistic policies, which is why one hears so much in oil policy making circles about *ex ante* variables like optimal rates of taxation or resource extraction, optimal allocation of risk, perfect foresight in the calculation of excess profits and *expected* fiscal revenues,[27] while there are very few *ex-post* analyses of actual outcomes, in terms of the amounts that reached a given government's coffers or the tangible consequences of fiscal shortfalls.[28] One can only hope that, at some time in the not–too–distant future there will be a change of tack on the part of oil policymakers who are more in touch with political realities in their respective countries. But until that happens, the apologists of the liberal oil agenda will still be able to draw much comfort from Mark Twain's savage aphorism: "hain't we got all the fools in town on our side? And ain't that a big enough majority in any town?"[29]

NOTES

[1] Pratt, Priest and Castaneda 1997: 13.

[2] Mitchell *et. al.* 2001: 49–50. The resurrection of the UK North Sea is commonly cited as the prime example of the power of more flexible taxation schemes to coax higher output from maturing fields. Production of liquid hydrocarbons in the UK peaked (for a second time) in 1999 at 2.82 MMBD, after having languished at 1.88 MMBD during 1988–89. A detailed study on this resurgence concluded that, out of a total production of 2.676 MMBD in 1995, only about 355 MBD would not have been produced without the modifications in the British fiscal regime introduced in 1983 and subsequent years (Martin 1997: ii–iv).

[3] Riddle, Snyder and George, *op. cit.*: 10. As these authors see it, "after 1995, when Congress reduced royalties on certain deep water leases, the pace of leasing reached fever pitch ... [again setting] records for the number of tracts bid on and the number of bids submitted as energy companies battled for the right to exploit the deep waters of the Gulf" (*ibid.*: 4).

[4] Gramling *op. cit.*: 156–7.

[5] *Inside F.E.R.C.'s Gas Market Report*, 4 October 1996: 4.

[6] Martin estimated that the fiscal revenue from incremental production in the UK North Sea deriving from tax rebates would be £2 billion, while the rebates themselves would cost the Treasury £5.3 billion, for a net loss in fiscal revenues of £3.3 billion (Martin, *op. cit.*: iv). The main conclusion of the 1979 white paper on *Taxation and Revenue Sharing* undertaken by Canada's Department of Energy, Mines and Resources regarding the convenience of tax breaks like those adopted in the UK was that the net present value of future tax receipts was likely to be "less than the tax savings provided" (quoted by Fossum 1997: 127).

[7] Robinson 1989.

[8] An exemplary study is that of Gerking *et. al.* 2000. Graves (2001) spells out the case for Texas.

[9] Mitchell 1996: 27.

[10] Mommer 2002: 226.

[11] Paradoxically, as Mitchell observes, it would seem that the only truly effective way in which low cost producers "could limit the private-sector funds available for upstream investment elsewhere would be for them to compete so intensely that the oil price falls for a long period" (*op. cit.*: 28). This is an example of a situation where the remedy is worse than the malady, though, as 1998 so clearly proved.

[12] The drilling of the Baha well drew protests from the Mexican government, on the grounds that extraction from this prospect could result in the drainage of oil lying in the Mexican side of the border. Probably as a result of President Fox's electoral victory, no such protest accompanied the drilling of the Trident well.

[13] The usual figure quoted for the Mexican government's dependence on oil taxes is slightly over a third. However, this proportion includes not only direct upstream taxes but also gasoline and diesel excise taxes and the value added tax paid by the oil industry.

[14] Fitzgerald, *op. cit*: 158.

[15] *Ibid.*: 276.

[16] Gramling, *op. cit.*: 147.

[17] See http://www.lmoga.com. More than USD 1.2 billion of this impact comes in the form of salaries and wages paid to offshore workers. The remainder results from the business the offshore industry does with onshore vendors located in Louisiana. More than 21,000 producing company jobs are said to exist as a direct result of GOM oil and gas activities, of which Louisiana residents take 16,725. The estimated payroll for them is USD 1.2 billion (an average of USD 74,000 per employee). Nearly USD 6 billion was paid by producing companies to vendors and contractors in support of GOM offshore activities, with more than $3.7 billion of that amount (58 per cent) spent in Louisiana. Also, approximately 45 per cent of vendors in Louisiana derive more than half of their income from OCS activities in the GOM.

[18] Gramling, *op. cit.*: 166. See also Keithley 2001 and Hughes *et. al.* 2002.

[19] As envisaged, the credits would be in an amount equal to the total sum paid by leaseholders for bonuses and rentals, as well as the amount spent on exploration and related expenses. Holders of the Californian leases suggest that the total amount involved would be between USD 1.9 billion and USD 3 billion (see *O&GJ*, 18 March 2002: 50).

[20] The tax would apply to hydrocarbons produced in the state as well as in the Federal OCS, and to imported crude or imported products landed in Louisiana for refining or consumption there, and to all crude oil, natural gas and refined products transported through the state to other destinations.

[21] This tax is an offshoot of the First Use Tax (see Appendix 3), found to be unconstitutional in 1981 by the U.S. Supreme Court (*Maryland v. Louisiana*). The Coastal Wetlands Environmental Levy of 1982 sought to tax all oil and gas passing through the coastal area of the state as a way of paying for the alleged environmental damage caused by the industry, but was never enacted. The current oil and gas processing tax was first proposed in 1992 during a state constitutional convention called for the purpose of revamping the state's tax structure.
[22] Mommer 2002: 168–83; 228–35.
[23] Stiglitz *op. cit.*: 485.
[24] *Ibid.*: 461.
[25] *Ibid.*: 485.
[26] Coase 1964: 195; italics ours.
[27] The reader is referred to any one of the copious works by Alexander Kemp, for instance.
[28] Mommer 2001: 33.
[29] *The Adventures of Huckleberry Finn*, chapter 26.

APPENDIX 1: CONSTITUENT ELEMENTS OF THE FISCAL REGIME FOR OIL ACTIVITIES IN THE GULF OF MEXICO OFFSHORE CONTINENTAL SHELF

Signature bonuses: Signature bonuses in the OCS fiscal regime have traditionally played a role quite unlike the one they play in other oil provinces where acreage auctions are infrequent, and where proceeds from acreage auctions actually constitute a form of extraordinary income. The very prominent role of bonuses means that they can be neither ignored nor isolated for the purposes of calculating government take on GOM oil industry revenues, even though grouping together bonuses with royalties and other rentals to calculate the fiscal burden on the GOM oil industry can generate values that might appear aberrant (as when total lease payments exceed industry gross income).

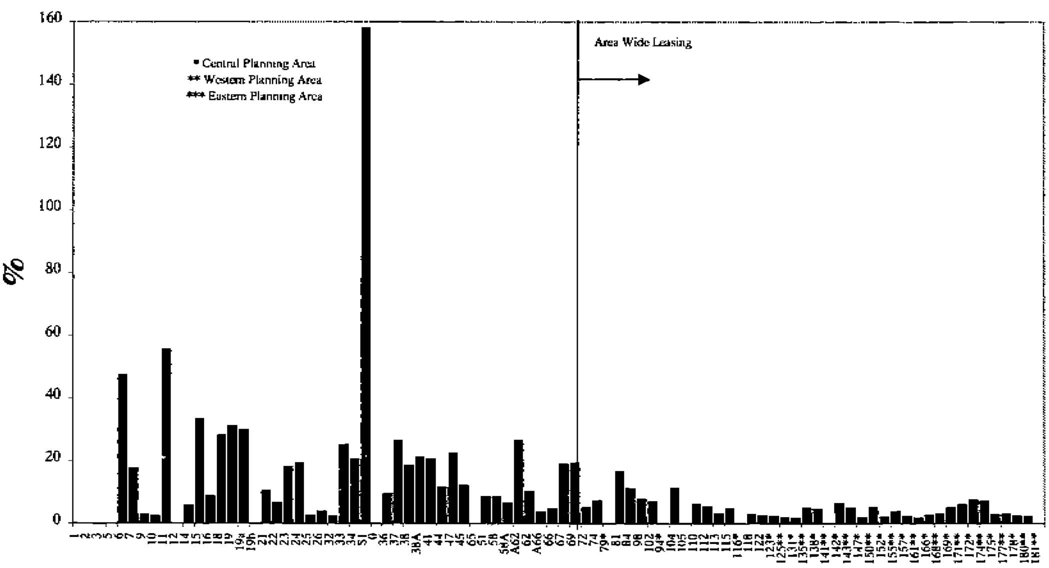
Under TN, the main tool used to evaluate bonus bids was the estimate of tract value which DOI prepared on the basis of a Monte Carlo simulation supported by geological, geophysical, engineering and economic data collected from industry and collated prior to each sale.[1] This simulation produced two decision parameters: the so-called mean range of simulation values (MROV) was the estimated value of a tract at the time a lease sale was held, while the discounted mean range of values (DMROV) was equivalent to the present value of the revenue delays that would occur if a high bid were rejected and the tract for which such bid was submitted were to be leased at the next scheduled sale. DOI would accept a high bid only if it exceeded the lowest of either MROV or DMROV. Throughout the time that the TN system was in place, DOI rejected about 17 per cent of all high bids for GOM tracts as unsatisfactory. According to a study which the Small Business Committee of the US Congress conducted in 1974, on those occasions when DOI rejected a high bid for a block, it obtained an average of 13 times more for it the next time it came up for auction.[2]

Under AWL, high bids are automatically accepted for tracts receiving three or more bids, as well as for tracts that MMS has classified as nonviable. MMS can classify a tract as non-viable on account of any one of the following four conditions: lack of an oil or gas structure; structure too small to be economical to produce; adverse stratigraphic conditions; and finally, "lack of Interior maps on the tract".[3]

Tracts that are supposed to be commercially viable but have not received three or more bids can fall into any of the following categories: wildcat tracts (i.e. unexplored), proven tracts (previously leased tracts with known oil or gas reserves), drainage tracts (tracts that have nearby productive wells on common reserves) or development tracts (tracts that have nearby productive wells on the same general structure). In order to assign these various types of tracts, MMS is supposed to estimate fair market value through Monte Carlo analysis as under TN. However, the adjudication methodology has changed in one crucial respect: in situations where a tract received at least two bids but the high bid was lower than MROV, the MMS combines the bids received with its estimate of fair market value and computes a geometric average estimation for the tract (GAEOT). High bids are accepted if they exceed GAEOT and the minimum acceptable bid value, which currently stands at USD 25 per acre for blocks located in 2600 feet or less of water and USD 37.50 per acre for blocks in waters deeper than these.[4] In principle, MMS has the faculty of changing the minimum bids every time it conducts a lease sale, although it must announce the figure well in advance of it. However, the agency has not exercised this prerogative thus far. The likelihood that MMS will reject a high bid for a tract has fallen by around than three quarters, to 4.6 per cent (Figure FA1.1)

Royalties: GOM royalty payments are determined as a percentage of the value of production less allowable deductions. The value of production is determined by multiplying the volume of oil and gas produced by their respective sales prices and the applicable royalty rate. The standard royalty rate on GOM production is still $16^{2/3}$ per cent, although as a result of the testing of alternative bidding systems (including royalty bidding), there are few tracts that pay much higher rates ($33^{1/3}$ per cent royalties or higher). Most of the deepwater tracts currently producing oil enjoy what used to be the minimum royalty rate set by law of $12^{1/2}$ per cent (see Table TA1.1). As a result of the 1995 Deepwater Royalty Relief Act, this minimum rate has been effectively reset at zero, for the early life of new deepwater fields. Royalty relief will translate into a reduction in the effective GOM royalty rate, which was already on a declining trend as a result of the growing importance of deepwater production. The decline in royalty rates has been steeper in the case of crude oil than natural gas, which reflects the oil-prone nature of the deepwater province.

FIGURE FA1.1: BEHAVIOUR OF KEY INDICATORS IN GOM LEASE AUCTIONS, BY SALE NUMBER (1954–2001)



SOURCE: MMS

■ Bids rejected or withdrawn as a proportion of high bids accepted

Table TA1.1: Royalty Rates for GOM Federal Leases, by Tract and Type of Company

Rate (%)	*Producing tracts*	*All tracts held by independents*	*Of which: in deep waters*	*All tracts held by majors*	*Of which: in deep waters*
12 1/2	6,673	4,378	3,986	5,800	5,584
16 2/3	13,202	16,034	123	5,944	115
33 1/3	26	35	0	13	0
Other	454	-	-	-	-
Sliding Scale		211	0	112	5
Profit Sharing		137	25	142	20
TOTALS	20,355	20,795	4,134	12,011	5,724

Source: MMS

FIGURE FA1.2: OCS CRUDE OIL OUTPUT AND UNIT PRICE OF OCS CRUDE, 1953–2000

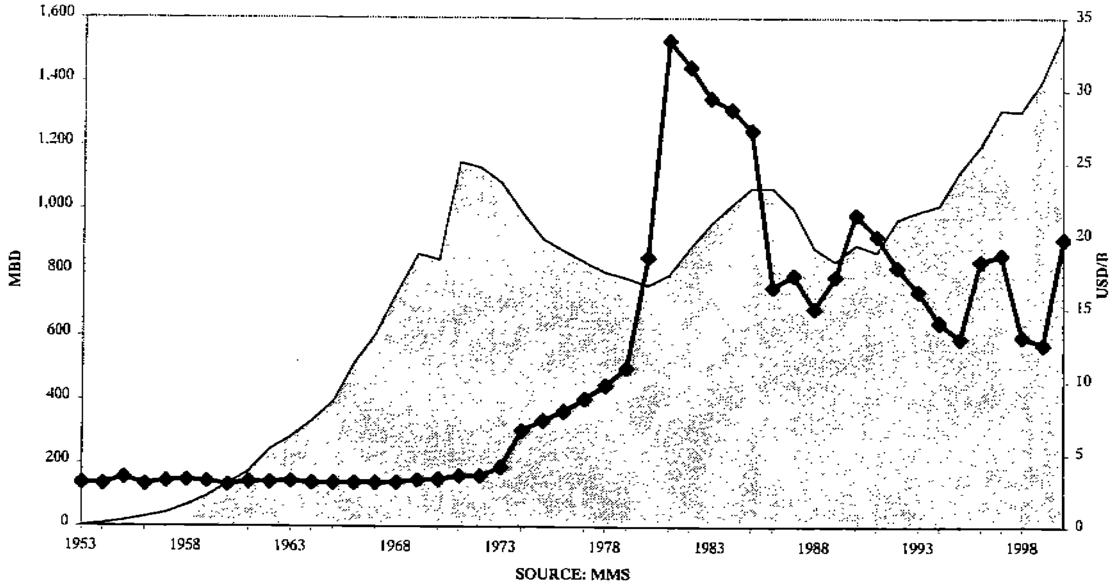


FIGURE FA1.3: FEDERAL OCS. GROSS REVENUES AND ROYALTIES FROM CRUDE OIL SALES, 1953–2000

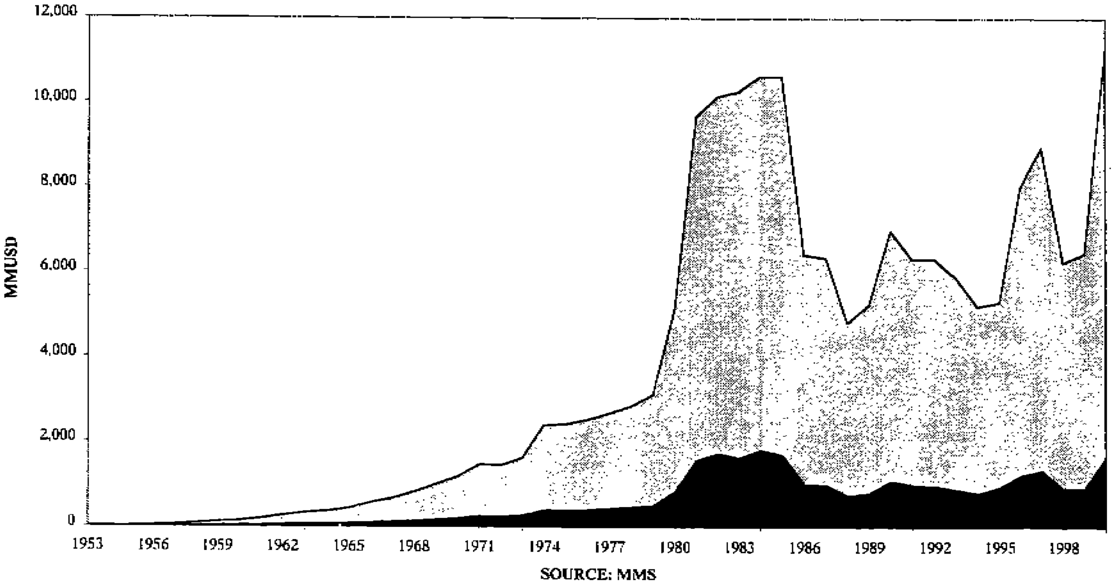


FIGURE FA1.4: OCS NATURAL GAS OUTPUT AND UNIT PRICE OF OCS NATURAL GAS, 1953–2000

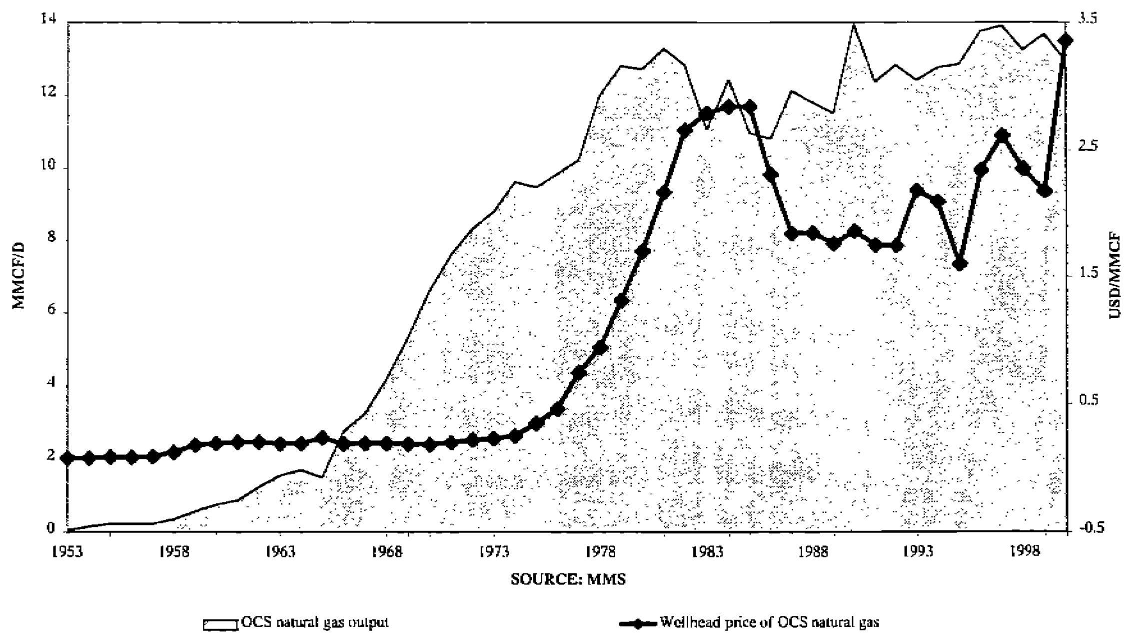


FIGURE FA1.5: FEDERAL OCS. GROSS REVENUES AND ROYALTIES FROM NATURAL GAS SALES, 1953–2000

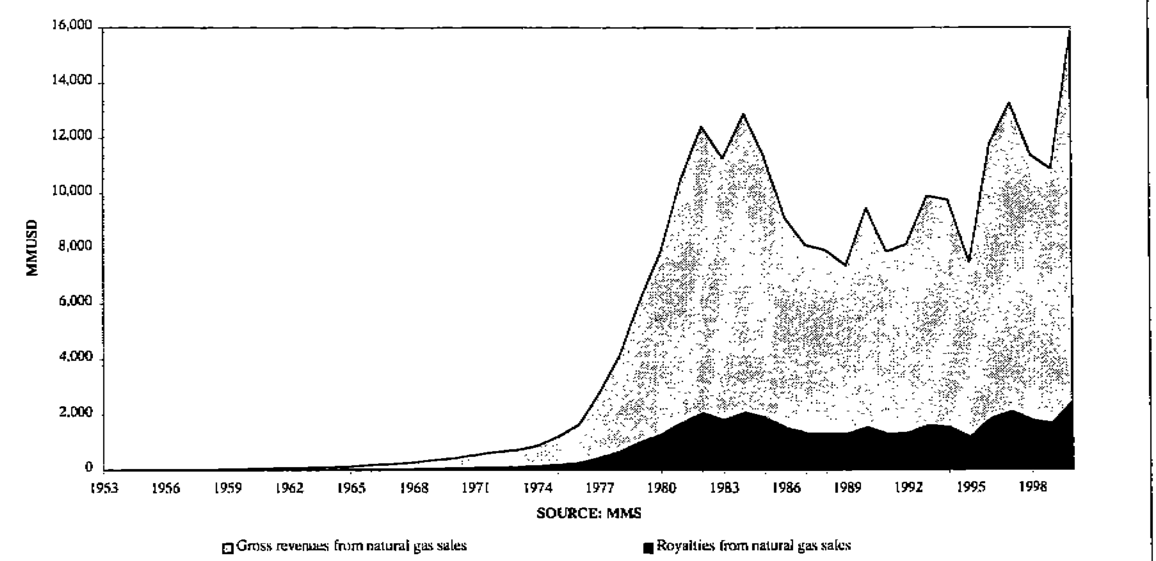
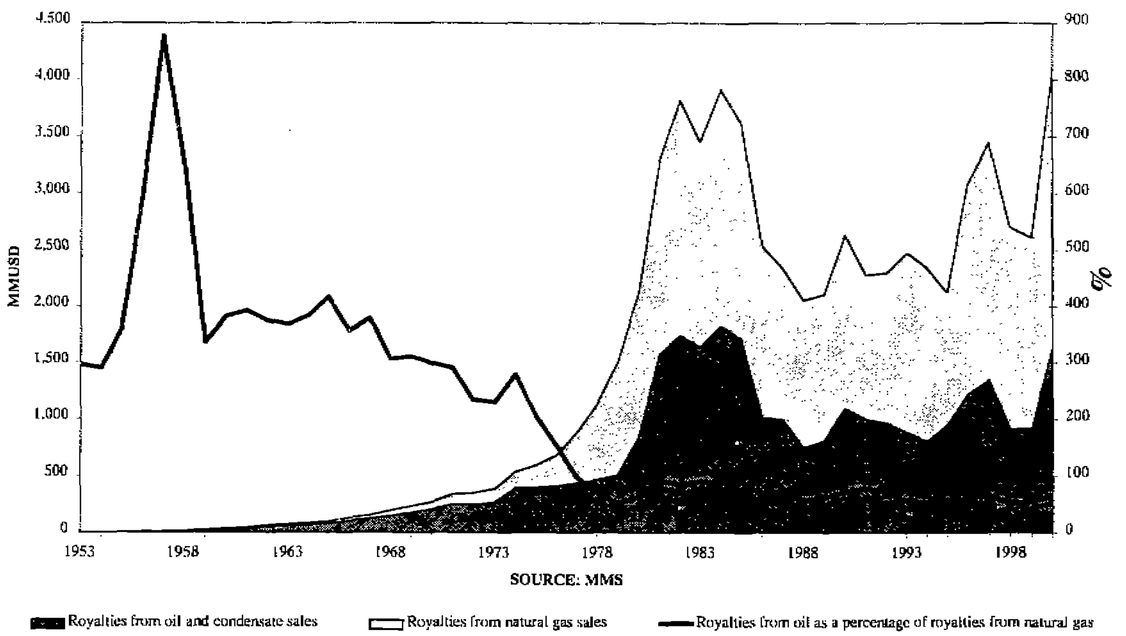


FIGURE FA1.6: COMPARISON BETWEEN OCS OIL AND GAS ROYALTIES, 1953–2000



The relative weight in OCS fiscal revenues of royalties from sales of natural gas, on the one hand, and oil, on the other, has varied significantly over the years, but the former have been larger in absolute terms since 1977.[5] After 1987, this difference became greater, mainly because GOM natural gas held its own better than crude oil in both output and price terms (Figures FA1.2 to FA1.5). Between 1995 and 2000, the value of royalties from oil sales represented about 65 per cent of the value of royalties from natural gas sales (Figure FA1.6), notwithstanding the remarkable resurgence in GOM crude oil output recorded over this period.[6] Moreover, the growth in crude oil royalties in recent years has not kept pace with the phenomenal expansion in gross income from crude. This is a consequence of three factors. Firstly, the deepwater crudes that have been largely responsible for the resurgence in GOM output are rather heavy and sour, and this has a negative incidence on their market value. Secondly, transportation and processing costs in the deepwater province are high, and this makes for markedly lower wellhead prices. Finally, the prevailing royalty rate in most deepwater tracts is the legal minimum of 12 ½ per cent, which is appreciably lower than the standard GOM royalty rate of 16 2/3 per cent (in future, the effective royalty rate for new deepwater developments will be lower still).

DOI's authorities and responsibilities as pertains to the collection of royalties in Federal (and Indian) lands and the OCS were most recently laid out in the Federal Oil and Gas Royalty Management Act (FOGRMA) of 1982. The Federal government calculates outstanding royalties as if buyers had physically taken oil at the geographic location of individual leases. Leases are seldom the true points of sale (oil is usually transported by gatherers, marketers and traders to market centres where it fetches a higher price). Nevertheless, this method for calculating royalties is still in use because lessors of oil-bearing lands do not have the need nor, more importantly, the capability to trace to market every barrel that leaves their territory (not even if that lessor is the US government).[7] For oil not sold at lease, there are regulations stipulating that the price paid at the actual point of sale has to be adjusted to approximate the price that would have been paid had the oil been sold at the lease. Lessees have a "duty to market" the government's royalty share, and this entails their bringing the product up to minimum marketable quality, getting it to the delivery point and paying all the attendant costs. Lessees may deduct certain costs for moving oil and gas beyond the lease site as well as for processing them before determining their payments,[8] but oil companies consider that these deductions are not enough to compensate them for their real expenses.

The DOI/MMS oil valuation regulations have always made a clear distinction for price determination purposes between oil exchanged in internal transfers, on the one hand, and genuine arm's-length sales, on the other. The fiscal treatment of crude involved in arm's-length sales has remained pretty much constant through time: the quoted sales price plus any premia that the seller might have received or granted multiplied by volume gives the gross proceeds, and these are multiplied in turn by the applicable royalty rate to obtain the sum owed to the government. The treatment given to internal transactions, which involve around two-thirds of all oil extracted from federal leases (onshore and offshore), has changed very significantly in recent times, however. According to the regulations in effect from 1988 to June 2000, royalties on this type of transaction had to be assessed on the greater of either gross proceeds or "the amount arrived at by the first applicable valuation method from the following list of five alternatives: (1) the lessee's posted or contract prices, (2) other's posted prices, (3) other's arm's-length contract prices, (4) arm's-length spot sales and (5) a netback or any other reasonable method".[9] The choice between any of these benchmarks was up to individual companies and, moreover, different companies could use different benchmarks even if they were producing in the same lease area.

As can be appreciated, these regulations placed a high degree of reliance on posted prices: market value in the first two alternatives (and to a lesser extent the third) depended on posted prices, and these alternatives were by far the most popular amongst lessees. MMS was persuaded to take a long hard look at this system in the wake of a series of lawsuits that seemed to indicate that oil companies in various jurisdictions had manipulated posted prices to diminish their royalty payments[10] while conducting most of their trade of physical oil on either a spot or a "postings plus" (P-plus) basis. In particular, the "common practice of oil traders' and purchasers' quoting a posted price plus a premium" was taken as strong evidence that posted prices were equivalent to "less than market value".[11]

The MMS royalty assessment rule currently in vigour divides the USA into three separate regions: Alaska and California (including the Pacific OCS), the six Rocky Mountain states, and the rest of the country (including the GOM). Royalties in each region are assessed differently. In the GOM, the basis for royalty calculation in non-arm's length transactions will be an index of local spot prices, adjusted for individual leases according to their location and the quality of the oil produced there. According to MMS, this assessment rule was to generate USD 67.3 million in additional royalty receipts a year when compared to the one that it superseded in June 2000.[12] However, the operation of the new royalty assessment rule has been blocked by a legal challenge brought by oil companies objecting to their statutory "duty to market" obligations.[13] In particular, they argue that these obligations inflate the value of production and hence of royalties by including in the assessed sales price some of the value added downstream from the lease, including aggregation, marketing, storage and transfer fees.[14]

Besides this latest lawsuit, oil companies have also put into motion a strong lobbying effort aimed at obtaining a radical overhaul of the whole federal royalty edifice. Their proposed reforms centre around three key points. Firstly, lessees argue that the Federal government should bear a greater share of the costs (especially for marketing) that enhance value at the royalty site. Secondly, they suggest that the fairest and least complicated method to achieve this involves the government taking its royalties in kind and selling the oil or gas itself. Finally, lessees think that the government should abandon its process of audits and revaluations that they see as greatly increasing their uncertainty as regards their royalty obligations, quite apart from their being both onerous and time-consuming.

At the moment, it is unclear what the fate of these proposals for reform might be. They will almost certainly face a torrid passage through the legislature. Moreover, the reforms will only be adopted if they are budget neutral, but it is unclear how this status can be achieved, especially in the light of the inevitable decrease in receipts that will follow if the government were to increase deductible costs on royalty obligations. There are other aspects making things look distinctly complicated for the reform proposals on the budgetary front. For instance, the discontinuation of audits would certainly have a negative budgetary impact, because around USD 2.2 billion in royalty underpayments have been collected from 1982 through 1999 (i.e. around USD 120 million per year) thanks to the MMS audit programmes.[15] Also, as regards payment in kind, MMS has traditionally resisted this form of liquidation on grounds of cost effectiveness, arguing that "the federal government does not currently have relatively easy access to pipelines, has thousands of leases that produce relatively low volumes, has many gas leases for which competitive processing arrangements do not exist, and has limited experience in oil or gas marketing".[16] Furthermore, the pilot schemes in which MMS has accepted payments of royalties in kind have almost invariably ended in the red.

Sliding–Scale Royalties and Profit–Sharing Mechanisms: The 1978 OCSLA amendments defined six possible alternative bidding systems: (1) variable cash bonus payments with sliding scale royalties, (2) variable cash bonus payments with a fixed net profit–sharing mechanism, (3) fixed cash bonus payments with royalty rate bidding, (4) fixed cash bonus payments with net profit–share bidding, (5) variable cash bonus payments with fixed royalty rates and a fixed net profit–sharing mechanism and, finally, (6) fixed cash bonus payments and royalty rates with work commitment bids. These combinations of variables were not meant to be exhaustive, and the Secretary of the Interior was specifically allowed by the legislation to use "any bidding system he determine[d] to be useful",[17] thereby opening the field for other novel ideas like deferred bonus payments or cash bonuses payable only upon commercial discoveries. In practice, though, DOI only ever tested the first three of the combinations specifically identified in the amendments (i.e. combinations where the magnitude of the upfront cash bid was still the main selection criterion). On the whole, DOI's preferred alternative bidding system was the one that combined cash bonus bids with sliding scale royalties.[18]

Independent oil companies, meant to be the main beneficiaries of the OCSLA amendments, were clearly quite interested in bidding for tracts in a way that did not entail large up–front cash payments. As Table TA1.2 shows, these companies obtained close to 60 per cent of the leases offered on the basis of alternative bidding systems. Indeed, DOI came to believe that, sometimes, their enthusiasm for these systems meant that they could not really be trusted to make sensible bids. In the two acreage sales where royalty bidding was tested, eight tracts were assigned but the department concluded that unrealistically high bids had been put forward (the bids ranged from 51.8% to 82.2%). DOI concluded that these rates would have a deleterious effect on future investment in the tracts, not least because they would make economical production impossible unless a mammoth field was discovered.[19] Thus, DOI decided not to use royalty bidding system again and, for good measure, not to put the profit-share bidding system to the test. Likewise, the work commitment bidding system was discarded as an option for testing because, quite aside from its negative effects as far as bonus payments were concerned, DOI feared that it might promote inefficient exploration efforts by over-eager independents.[20]

Surface rentals and minimum royalties: GOM leaseholders pay annual rents of USD 5-10 per acre for the duration of the primary term of the lease (see Table TA1.3). Once production starts, royalties supersede rentals. However, if royalty payments amount to less than the previous yearly rental, the lessee has to continue paying this amount at the agreed rate as a minimum royalty.

Table TA1.2: Number of GOM Tracts Assigned Under Alternative Bidding Systems, by Type of Company*

Bidding system	*Majors*	*Independents*
Fixed net profit and capital recovery factor	142	137
Fixed bonus, variable royalty	4	2
Sliding scale royalty	108	209

*Includes partial and full shareholdings

Source: MMS

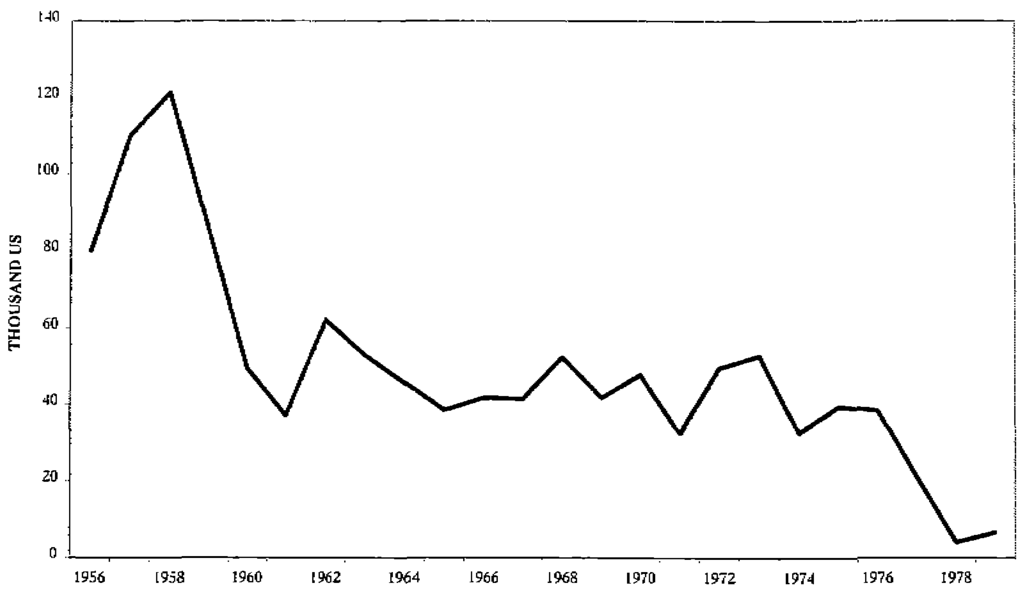
Table TA1.3: Surface Rent Payments for GOM Federal Leases, by Amount Charged

Rent (USD/acre)	*Number of tracts*
3	12,278
5	4,034
7.5	4,039
10	4
TOTAL	20,355

Source: MMS

Shut-in Gas Payments: The purpose of this levy was to give the government some compensation for revenue foregone on account of natural gas that had to be reinjected into the reservoirs because there existed no market for it.[21] Shut-in gas payments were always very small, but they had a certain symbolic importance, in the sense that they were an embodiment of the principle that the Federal government had to be compensated for any action that affected adversely the value of public property, no matter how small the negative impact was. As a result of both the deregulation of the US natural gas market and its growth, shut-in gas payments ceased in 1979 (Figure FA1.7).

FIGURE FA1.7: SHUT-IN GAS PAYMENTS BY OCS LESSEES. 1956–79



SOURCE: MMS

Fiscal Regime for Oil Activities in the Territorial Waters of Louisiana and Texas: These two states use different bidding systems in order to assign offshore acreage to prospective lessees. Louisiana relies on a hybrid system in which both the upfront cash bonuses and the royalty rates for individual tracts are open to bid. Minimum bonus amounts vary from sale to sale and there is a minimum royalty of 12.5 per cent (although, in practice, Louisiana has not signed any leases with less than a 20 percent royalty). Companies are allowed to submit multiple bids (i.e. combinations of these two elements) for the same acreage. The average royalty rate in Louisiana is around 21–26 per cent. On top of this, Louisiana levies a rental fee (equivalent to one half of the cash bonus paid for each tract) and a severance tax of 12.5 per cent on oil output. Louisiana conducts monthly lease sales of offshore tracts, and proceeds from such sales have traditionally made a very important contribution to the fiscal revenues of the state government.

Texas also continues to hold lease sales regularly (on a quarterly basis), although nearly two thirds of this state's offshore area is currently under lease. In Texas, most offshore tracts are offered on the basis of cash bonus bidding, with a fixed royalty (set at 25 per cent). However, tracts with especially favourable prospects have on occasion been offered on the basis of a mixed cash/royalty bidding system, similar to that used in Louisiana (but with the minimum royalty rate set at 25 per cent). Texas also levies a rental fee that increases with the number of years that acreage is held up to a maximum of 1 USD/acre after four years, as well as a 4.6 per cent severance tax on oil production (7.5 per cent for natural gas). Just as in Louisiana, the primary (i.e. exploration) term for lease contracts in Texas is five years.

APPENDIX 2: HYDROCARBON PRODUCTION IN LOUISIANA AND TEXAS STATE WATERS

Prior to the definition of offshore boundaries between coastal states and federal territory in 1953, three states (California, Louisiana and Texas, in that chronological order) had taken the lead in leasing offshore tracts for petroleum production. By the time the Tidelands controversy erupted, leases in the territorial waters of Louisiana and Texas had already produced 20 MMB and 0.6 MMB of oil, respectively. Activity in the area was affected by the uncertainty generated by this dispute, but it picked up very rapidly after 1954, in response to a flurry of lease auctions in both states and to the favourable economics of offshore production (good discovery rates, generous production allowables, and relatively low field development costs).[22] From the early 1950s to the early 1980s, the output recorded for leases in Louisiana and Texas state waters accounted for 39 and 19 per cent per cent of the total US offshore oil and gas production, respectively. Since then, however, the overall significance of output from state waters in the US supply picture has dwindled and nowadays, production in Federal waters accounts for upwards of 95 per cent of total offshore oil and gas production in the USGC area.

Louisiana has always accounted for most of the wells drilled and total hydrocarbons produced in state waters in the USA. Texas leased its first offshore tract in 1922, but had to wait until 1940 to see the first commercial production from its territorial waters. The leading position of these two states in domestic offshore production became unassailable after 1969 with the moratorium on leasing in California state waters (imposed as a result of the Santa Barbara Channel blowout). Currently, wells in Louisiana waters produce about 35 MBD of oil and 0.4 BCFD of natural gas. Output in Texas state waters is much more highly skewed towards gas (0.1 BCFD versus 1.6 MBD of oil). Production in the territorial waters of both states has been declining steadily (Figures FA2.1 and FA2.2), but proved reserves in both states have remained relatively stable, probably thanks to their continuous and energetic leasing efforts.

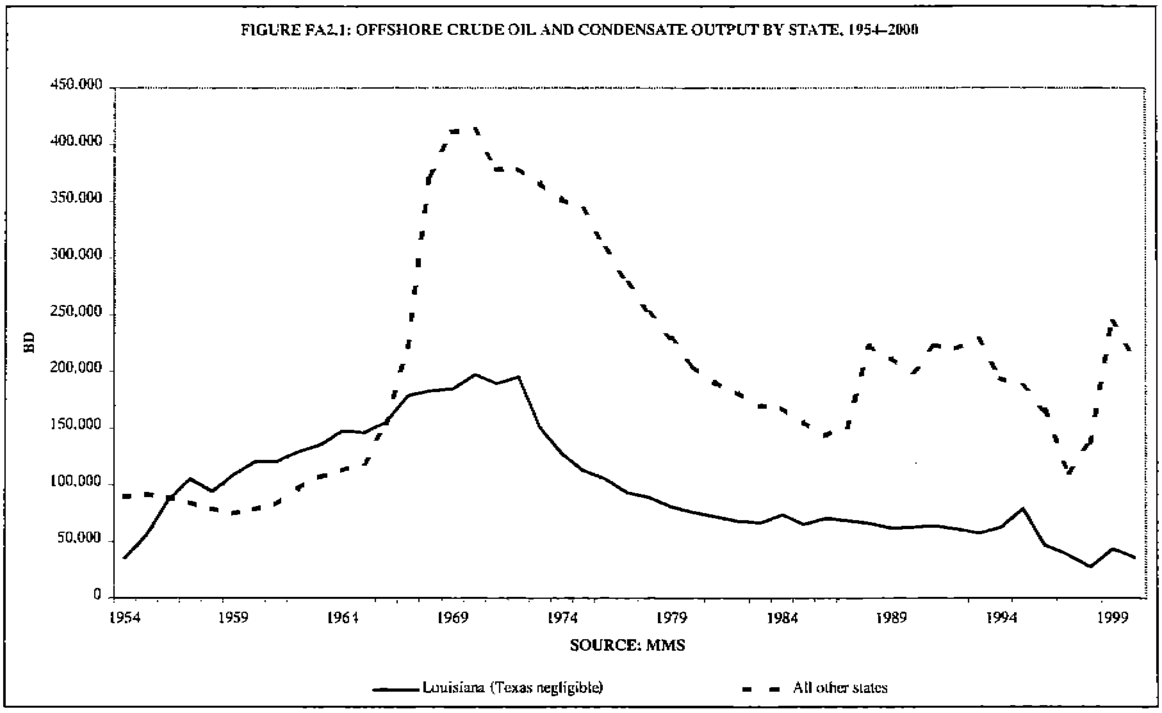


FIGURE FA2.1: OFFSHORE CRUDE OIL AND CONDENSATE OUTPUT BY STATE, 1954–2000
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
BD
1954
1959
1964
1969
1974
1979
1984
1989
1994
1999
SOURCE: MMS
Louisiana (Texas negligible)
All other states

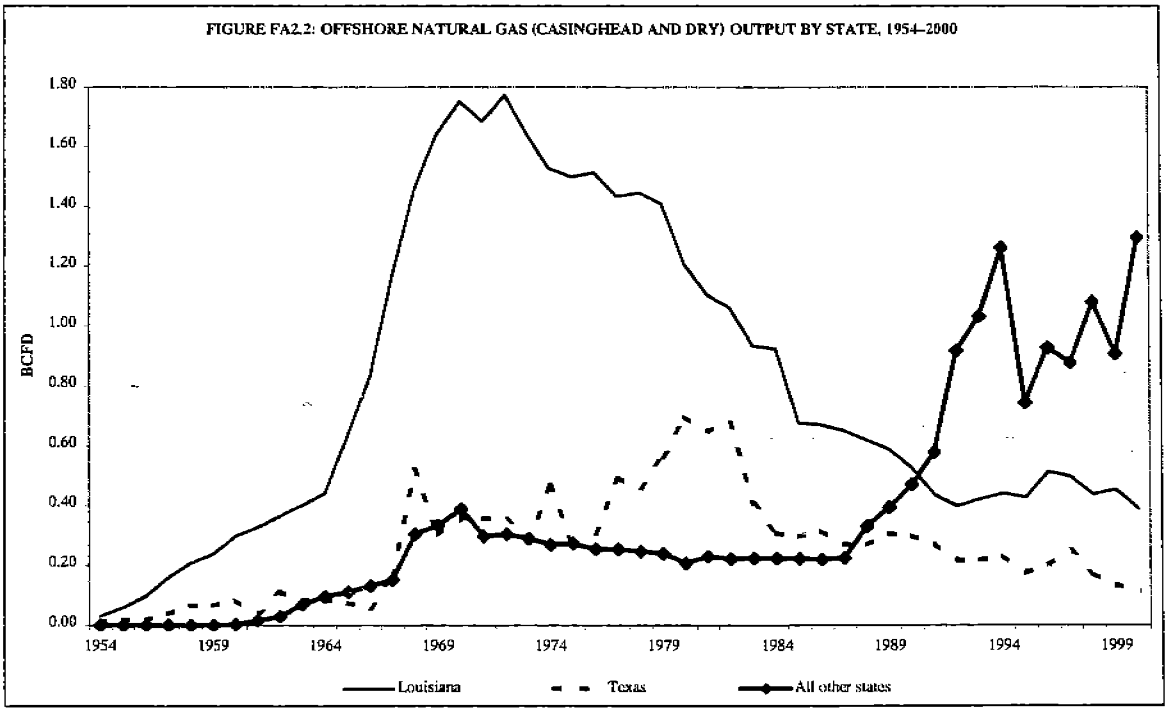


FIGURE FA2.2: OFFSHORE NATURAL GAS (CASINGHEAD AND DRY) OUTPUT BY STATE, 1954–2000
1.80
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
BCFD
1954
1959
1964
1969
1974
1979
1984
1989
1994
1999
Louisiana
Texas
All other states

APPENDIX 3: A *PRÉCIS* OF THE TIDELANDS OIL CONTROVERSY AND THE SEAWEED REBELLION (1937–2000)

The issue of state/federal OCS revenue sharing is inextricably bound to thorny jurisdictional questions that have plagued the development of US offshore oil resources since the late 1930s. In order to get an idea of the myriad political twists and turns that these questions have given rise to, one just needs to consider that during the first ten years after the end of the Second World War, when the definition of the maritime boundaries of federated states became an issue of national prominence, there were three Supreme Court decisions against the states, three acts of Congress in favour of the states, two presidential vetoes against the states, the resignation of the most powerful secretary in the history of the department of Interior (Harold Ickes), the "voluntary" withdrawal of Edwin Pauley to the nomination of Undersecretary of the Navy, and a heated and divisive electoral debate during the presidential campaign that would eventually take Dwight Eisenhower to the White House. To make matters worse, these jurisdictional questions have been couched in terms of US common law arcana that have a very limited resonance outside a small audience of lawyers. This is regrettable, not least because it obscures the economic issue at the heart of the Federal/state controversy over offshore territorial jurisdiction; namely, the desire on the part of the Federal government to prevent the multi-layered national scheme for the control of production that had come into being during the 1930s from being undermined by offshore oil flows whose magnitude could be expected to be much greater if the leasing process were in the hands of revenue-hungry coastal oil states than if it were in the steadier hands of the Federal government.

The Roosevelt administration and the Democratic congressional fraction first tried to introduce bills granting the Federal government title to all submerged coastal lands lying beyond the low water mark in 1937. Coastal states had long believed that they held title to these lands, and they had undertaken a number of positive acts in consequence: the regulation of fisheries, the building infrastructure and sewage disposal facilities, and, crucially, the leasing of offshore tracts for petroleum exploration and development in California, Louisiana and Texas (in that chronological order). Thus, the administration stance represented a radical break with the past because, before that year, neither Congress, nor the General Land Office nor the DOI had ever given any indication that they regarded the areas below the low-water mark as constituting a part of the public lands belonging to the Union. Indeed, in 1933, Secretary of Interior Harold Ickes, who was later to become the main instigator behind the Federal territorial claims, expressly denied a petition for an offshore lease by asserting that "title of the soil under the ocean within the 3-mile limit is in the State of California, and the land may not be appropriated except by authority of the State".[23]

Ickes' posture on that occasion was very much "at odds with the thoughts which [Ickes] was to nourish and support in the later thirties",[24] and would eventually come to haunt him. According to Bartley, "it is difficult to determine just when Ickes began to change his mind or for precisely what reasons",[25] although it is certain that by 1936, he was personally asking a North Dakota senator to introduce a bill declaring that the lands under the marginal seas of all coastal states (i.e. lands lying *within* the 3-mile limit that Ickes had mentioned in 1933) were part of the US public domain.[26] Bartley came close to putting his finger on the factor that set Ickes on the road to Damascus when he said that "there is no doubt ... that Ickes was altruistically interested in one thing: the conservation of oil".[27] Whether Ickes was ever interested altruistically in anything is debatable. But there can be no doubt either of his commitment to the cause of bringing order (i.e. price stability) to the American petroleum market through the control of production, or of his undying belief that conservation (the politically acceptable term used to justify such control) was a goal that "could best be accomplished under national administration".[28] It is no coincidence that, by the time Ickes' *volte face* came about, Congress had passed the Connally Hot Oil Act, the Interstate Oil Compact had been ratified and the Texas Railroad Commission had to a considerable extent succeeded in imposing its will on producers in that state, especially the mavericks in the East Texas field.

During the Second World War, the conflict around the Federal claims to submerged coastal lands was relegated from the limelight, only to resurface again in 1946 when Republicans and Dixiecrats tried to pass a bill granting states title over offshore submerged lands up to their historic boundaries. President Truman vetoed this bill, and his administration (with Ickes at the forefront) decided to press the claims of the federal government through the judiciary, rather than run the gauntlet of a hostile legislature. Thus began in earnest one of the most contentious episodes in the history of state/federal relations: the so-called Tidelands Controversy. In theory, this controversy was merely about state/federal boundaries, and the drawing thereof. In reality, though, the real motive behind the dispute was the question of whether control over development of oil resources in submerged lands would be in the hands of the Federal government or in those of the governments of coastal states. Ickes, who proclaimed himself "an advocate of legitimate States' rights", would forever insist that this was a contest over oil, and over oil only.[29]

The US Supreme Court rendered the first Tidelands decision stemming from a suit brought by the Federal government challenging California's title to submerged lands beyond the low water mark (*U.S. v. California*) in 1947. The decision was favourable to the Federal government, which appeared to vindicate the court-centred strategy of the Truman administration. Immediately, bills were introduced in the Republican Congress to overturn the decision, but they ran afoul of presidential vetoes. Subsequent Supreme Court decisions rendered in 1950 (*U.S. v. Louisiana* and *U.S. v. Texas*) strengthened the position of the Federal government, by dismissing claims that both Louisiana and Texas had unilaterally staked in 1938 and 1947 (respectively), the former state to a twenty–seven mile seaward boundary, the latter to all submerged lands on the continental shelf off its coastline.

The three judicial Tidelands decisions established that all submerged lands lying beyond the low water mark would henceforth be under Federal jurisdiction. However, in 1953 a Republican Congress (with the full backing of the Eisenhower administration) enacted legislation – the SLA – that overturned these verdicts and established a three-mile seaward boundary for coastal states. In addition, Congress also passed OCSLA, "a simple piece of legislation which established a framework for oil and gas leasing; granted the Secretary of Interior broad discretionary authority; ratified existing leases; and extended US jurisdiction and law to the OCS".[30] These two Acts clearly stipulated that the broad discretionary authority of the Federal government would only start beyond historical boundaries that had been claimed all along by coastal states. Even though they vested all authority for administering the OCS on the Federal government, they were seen at the time of their passing as being favourable to states' interests (after all, they apparently gave states everything the Federal government had been asking for since 1937). In actual fact, through, SLA and OCSLA came nowhere near meeting the expectations of defenders of states' rights in one critical aspect: this legal framework did not provide for any OCS revenue sharing between the Federal government and coastal states.

Throughout the 1950s and 1960s, outstanding state/federal boundary disputes were finally settled, thereby drawing down the curtain on the Tidelands controversy.[31] However, the conflict between the Federal and coastal state governments regarding petroleum activities in the OCS did not go away. Indeed, despite the federal-state partnership supposedly enshrined in the OCSLA, the exact opposite was true. But, the thrust of this renewed state/Federal conflict – which, under the name of the Seaweed Rebellion, continues to this day – was different, as it focused on issues of developmental impact rather than territorial jurisdiction. Specifically, the Seaweed Rebellion has been the expression of the enduring resentment that coastal states have felt at the lack of OCS revenue sharing between themselves and the Federal government, regardless of the fact that it is they who have faced most of the risks of offshore petroleum activities and have also had to foot a large part of the bills associated with such activities. When the fire of this resentment was stoked by the introduction of AWL, the Seaweed Rebellion exploded in a way that has led to the total breakdown of the OCS leasing programme outside GOM.

Revenue sharing might have mitigated the enduring indignation that existed within state governments as well as the Federal legislative power regarding the way in which "presidential directives to meet national energy development goals ... minimized congressional determinations ... [in a way] contrary to the text, intent and purpose of the statutes".[32] But since revenue sharing never materialised, state and local governments sought alternative redress for their grievances through litigation and unilateral actions (taken even in quintessentially "oil-friendly" quarters, like Gulf Coast states[33]). The US Congress, for its part, reacted by placing moratoria on OCS leasing and drilling, by means of budgetary restrictions. Thus, the existence of leasing and drilling moratoria that effectively close off the majority of the OCS to oil activities is a by-product of an institutional set up that never gave coastal states any fiscal stake in OCS development.

NOTES TO APPENDICES

[1] The details of the Monte Carlo simulation methodology can be found in GAO 1985: 94–5.
[2] Sherrill, *op. cit.*: 238.
[3] GAO 1985: 94.
[4] *Federal Register*, 20 July 2000: 45103.
[5] Currently, royalties on offshore gas production account for 46 per cent of all mineral – i.e. petroleum and non-petroleum – royalties paid to the Federal government (GAO 2000: 11).
[6] GOM natural gas output, which has been responsible for 25 per cent of total US domestic output for the last 20 years or so, also overshadows crude oil output in market terms, since it accounts for a much larger percentage of the US domestic demand for this fuel than does GOM crude production (GOM crude output as a proportion of total US output only surpassed the 20 per cent mark in 1998). GOM natural gas output is also more difficult to replace with imports when compared to crude, for logistical reasons.
[7] A good illustration of the Federal government's limitations in this sense can be found in OTA 1990. At the time this report was written, MMS had accounting responsibility for over 93,000 mineral leases, of which 23,200 were in production (19,000 in Federal lands and 4,200 in Indian lands). Extraction activities involved around 80,000 different combinations of leases, products and selling arrangements (*ibid*: 8).
[8] The rules allow the lessee to deduct the actual cost to transport natural gas from the lease point to the sales point or the point of value determination, up to a limit of 50 per cent of value at each sales outlet (although exceptions can be approved by MMS). Deductible processing costs for gas plant products are actual costs, but with an upper limit of 66.67 per cent of tailgate value of each gas plant product (again, exceptions are at the discretion of MMS). For crude, allowable transportation costs may be the actual charges for transactions with unaffiliated parties; in the case of internal transfers, complex federal regulations describe how allowances are to be determined. The movement from certain older offshore leases to treatment facilities onshore is allowed a full deduction. Crucially, the regulations do not allow "lessees to deduct costs for any actions they might take ... to make their product available and acceptable to buyers . . . include[ing] finding buyers (whether through brokerage firms or their own advertising), providing short-term financing, and paying for such ancillary services as product transfer (say, from truck to pipeline) and temporary storage (CBO, *op. cit.*: 14). MMS estimates brokerage fees alone to be worth around 0.15 USD/B.
[9] GAO 1998: 5–6.
[10] MMS's decision to revise its regulations "relied on the findings of an interagency task force that examined whether the use of posted prices for the purpose of determining federal royalties was appropriate" (GAO 1999: 4). The task force was convened as a result of a 1991 agreement between the city of Long Beach and six major oil companies by which the city dropped a suit it had filed years earlier alleging royalty underpayments of up to MMUSD 856, in exchange for a settlement of MMUSD 345. As the investigation was proceeding various states supplied MMS with information on legal settlements they had reached with companies concerning disputes revolving around the "undervaluation of oil from leases on state lands ... [due to] the oil companies' use of posted prices as the basis for determining royalties" (*ibid.*: 5). Alaska reported settling a lawsuit filed against three major oil companies for about USD 1 billion. Texas, Louisiana and New Mexico reported much smaller settlements totalling USD 23.5 million.
[11] GAO 1998: 9.
[12] CBO, *op. cit.*: 7.
[13] From December 1995 to March 1999, MMS published seven *Federal Register* notices soliciting public comments on proposals to change the way oil from federal leases is valued for royalty purposes, in the light of evidence indicating the unsuitability of posted prices for this purpose. Oil industry response was overwhelmingly against any changes in the regulations. Rearguard actions in Congress greatly delayed the introduction of a new system for valuing oil not sold at arm's length (for instance, the 1998 Emergency Supplemental Appropriations Act for the Department of Defense directed MMS not to publish any final oil valuation regulations before 1 October 1998). It should be noted that opposition to the new rules comes mainly from the quarters of the oil majors, as independent producers move a relatively small proportion of their output through integrated channels (except in the Rocky Mountain states).
[14] *PON*, 7 January 2002: 5; CBO, *op. cit.*: 8.

[15] GAO 1999: 15.
[16] GAO 1998: 14.
[17] GAO 1984: 8.
[18] However, the attraction of this system in the eyes of the oil industry was compromised by the fact that royalties could not slide to zero but only the legal minimum of $12^{1/2}$ per cent. In their eyes, this made this alternative system no better than the traditional one in terms of improving the profitability of small or marginal fields.
[19] Only one of these leases ever produced any petroleum, and then only because the royalty rate was adjusted downwards, from 73.4 per cent to 25 per cent (Mead 1994: 5), when the field was unitised with an adjacent lease bearing a 16 2/3 royalty. Very high royalty bids in reality are "low-cost options to produce oil or gas at the option of the lessee" (Mead 1993: 217).
[20] For a full *theoretical* discussion of bidding systems for offshore leases, see Mead 1993.
[21] Shut–in gas payments "are generally provided ... as a remuneration to the lessor to keep the lease in full force and effect for periods of time after production is found and before a market is obtained for the gas or gaseous products" (Burk 1983: 58).
[22] Around 26 per cent of the wildcat wells drilled in the USGC offshore until 1956 were productive, compared to a US onshore average at the time of 11 per cent. The production allowable for a 10,000 ft. deep well offshore (242 barrels) was nearly double the allowable for a comparable well onshore (132 barrels). By encouraging a greater spacing of development wells, this reduced field development costs in a way that compensated for the higher costs of individual wells (Pratt, Priest and Castaneda, *op. cit.*: 39).
[23] Bartley 1953: 129.
[24] *Ibid.*
[25] *Ibid.*: 133.
[26] *Ibid.*: 101.
[27] *Ibid.*: 136.
[28] *Ibid.*
[29] *Ibid.*: 136–7.
[30] Fitzgerald, *op. cit.*: 34.
[31] In the years immediately following the passage of SLA and OCSLA, Texas managed to obtain a three marine league boundary for itself, which the court accepted in recognition of the fact that it had entered the Union as an independent sovereign state (Florida was given the same privilege, on somewhat murkier grounds). The last unresolved state/federal boundary dispute (which centred upon the exact geographical definition of Louisiana's coastline) was settled in 1969.
[32] Fitzgerald, *op. cit.*: 274.
[33] Like Louisiana's abortive attempt to impose on pipeline companies a "first use" tax on OCS gas landed in the state and then shipped to out–of–state customers, or the enactment in a number of Californian cities and counties – after Congress lifted the moratorium on leasing off the coast of this state in 1985 – of ordinances that either banned the siting of onshore support facilities like pipelines, refineries or storage and processing facilities, or required their approval by popular referendum (see Fitzgerald, *op. cit.*: 156–7).

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Minerals Management Service, Gulf of Mexico Region (www.mms.gomr.gov)
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