ATLANTIC PETROLEUM ROYALTIES: FAIR DEAL OR RAW DEAL?

G. C. WATKINS

The AIMS Oil and Gas Papers (PAPER #2)

Brian Lee Crowley, Series Editor

June 2001

Atlantic Institute for Market Studies

Where Tomorrow's Public Policy Begins Today

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a) initiating and conducting research identifying current and emerging economic and public policy issues facing Atlantic Canadians, and Canadians more generally, including research into the economic and social characteristics and potentials of Atlantic Canada and its four constituent provinces

b) investigating and analysing the full range of options for public and private sector responses to the issues identified and to act as a catalyst for informed debate on those options, with a particular focus on strategies for overcoming Atlantic Canada's economic challenges in terms of regional disparities

c) communicating the conclusions of its research to a regional and national audience in a clear, non-partisan way

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The usual absolution applies: none of these individuals are responsible for any errors in fact or judgement that may remain.

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Foreword

The oil and gas industry offers the first real opportunity in quite some time for Atlantic Canada to lift itself out of the cycle of debt and dependency in which we have been stuck for several generations. The region's importance and potential as an energy producer has been underlined both by the presence of some of the world's largest petroleum companies, as well as by explicit recognition in U.S. Vice President Dick Cheney's recent report on his country's energy future.

It goes without saying that this region's fiscal and regulatory regimes will be major factors in whether this potential is realized. And that makes this area fertile territory for AIMS.

What led AIMS to commission this particular paper was the controversy surrounding the offshore royalty regimes in Newfoundland and Nova Scotia. Atlantic Canadians have increasingly seen the very foundations of the royalty regimes questioned. Had the international oil giants taken advantage of inexperienced provincial governments? Or had the regimes asked so much from the industry that investors would not bring their money to Atlantic Canada because of the lack of a reasonable return?

AIMS felt it was critical to compare our regimes to the best practices elsewhere if these questions were to find authoritative answers. We were extremely fortunate to be able to attract one of Canada's foremost oil and gas economists to explore this issue. Dr. G. Campbell Watkins is a distinguished international author and lecturer and a renowned expert on the economics of energy. His analysis is both clear and direct. He offers not only valuable comment on what has been accomplished to date but insightfully suggests areas for future attention. This paper lays important groundwork for understanding the offshore oil and gas industry in Atlantic Canada.

As the second paper in our newest series, *The AIMS Oil & Gas Papers*, it is a worthy complement to the first paper *Taking off the Shackles: Equalization and the Development of Nonrenewable Resources in Atlantic Canada*, by Ken Boessenkool. That paper talked about how Canada's federal fiscal arrangements create disincentives to the development of nonrenewable resources. We look forward to publishing further contributions by some of Canada's leading authorities on public policy in this vital area in the coming months.

Brian Lee Crowley, President
Atlantic Institute for Market Studies
Editor of *The AIMS Oil and Gas Papers*

STUDY HIGHLIGHTS

Summary

Since Atlantic Canadian offshore oil and gas production became a reality in the 1990s, criticism of the royalty regimes and associated agreements has been a regular occurrence in both the media and the respective provincial legislatures. As a result, the public is subject to considerable uncertainty and anxiety about whether returns from resource exploitation are fair. This paper is the first independent investigation to determine if the criticisms and anxiety are justified.

In the absence of a healthy and financially successful petroleum industry, the government cannot realize the full benefit of resource extraction. On the other hand, a government that agrees to terms that do not capture fair value for the resource betrays the trust of its citizens. It seems clear that we need some means of testing the local regimes against a set of criteria that reflect not only best practices elsewhere, but also economically and politically sound principles. The author, noted petroleum economist G. Campbell Watkins, develops such a set of criteria, which he then applies to the Newfoundland and Nova Scotia royalty regimes.

The paper concludes that, although there is room for improvement, the regimes in fact stand up to rigorous examination: they do provide a fair return to the provinces and citizens while not in themselves discouraging further development of the industry.

Offshore in Atlantic Canada: A new game

Having watched decades of oil and gas production from other parts of Canada and around the world, Atlantic Canadians are just now getting into the game. And they're wondering if they're doing it right.

This paper establishes the basis for evaluating the royalty regimes in Nova Scotia and Newfoundland, sets criteria for assessment, and applies those criteria to the two Atlantic Canada regimes. Royalty schemes such as Alberta's, which focus on wells, are not attuned to high-cost inhospitable regions such as the east coast offshore. Therefore, reliance on the Alberta royalty model would not be suitable.

In setting the criteria, the author draws on his extensive international experience. To help put the Atlantic Canada royalty regimes in perspective, he outlines regimes established under similar development conditions in Australia (offshore projects, 1984), Canada (federal frontier lands, 1987), and the United Kingdom (North Sea, 1975).

Establishing the basis for assessment

A resource endowment such as a petroleum reserve has value on which the owner has a claim. Where the owner is not the resource developer, or producer, fiscal instruments are used to capture that value. Payments made by producers to owners are termed *royalties*. Royalty instruments take various forms, such as lease bonuses, gross production shares, and profit sharing. Typically, more than one instrument may apply.

The resource value on which royalties are ultimately predicated is *economic rent* – the value at the point of sale less economic costs of production. Such costs comprise all payments required to sell the resource, including a suitable risk-adjusted return on capital.

The two main methods to acquire rents are up-front payments and a flow of payments over time. A distinction can be made between rents arising from variations in resource quality and those arising when prices and costs depart from anticipated values (unforeseen rents). Up-front payments can capture quality rents if competition is sufficiently intense, but cannot handle unforeseen rents – these require flow mechanisms. Of the various royalty instruments, the most relevant in the context of the Atlantic Provinces regimes are gross royalties and resource rent royalties.

A resource rent royalty (RRR) taxes resource profits above a stipulated floor level. It involves specification of a threshold return representing normal profits, no tax on returns up to the threshold, and a relatively high tax on returns in excess of it. The taxation unit is a project, not aggregate company income. Because a single threshold rate introduces bias in the presence of differential project risk, setting the appropriate threshold rate(s) is a major issue with an RRR. Various jurisdictions worldwide have adopted RRR-style regimes, including the three mentioned beforehand – Australia, Canada, and United Kingdom.

Assessing the regimes

Royalty instruments should be assessed in light of economic efficiency and public policy. A threefold distinction can be made between assessment criteria. *Basic* criteria cover legality, acceptability, severity, and interaction with other fiscal measures. *Efficiency and fairness* criteria include neutrality, horizontal and vertical equity among projects, cost recovery, risk sharing, and competition with other jurisdictions. *Administrative* criteria relate to administration cost, transparency, robustness, and consistency.

Both the Nova Scotia and Newfoundland generic royalty regimes, which are the focus of this paper, have reasonably similar structure and parameters. Newfoundland's gross royalties are more lenient at earlier stages and more severe at maturity. Nova Scotia's net royalty rates are higher at higher profitability levels, but are imposed after award of more generous return allowances. Cost eligibility is much the same, except that Newfoundland allows compounding of return allowances. But Newfoundland does not provide relief for high-risk projects as does Nova Scotia.

Qualitative application of 16 royalty assessment criteria to the two offshore schemes does not reveal appreciably different scores between the two. Both rely on a profit-sensitive component, while at the same time providing some returns to owners, irrespective of project profitability. Both satisfy the majority of adopted criteria, and neither posts flagrant violations. The schemes are not punitive. Deficiencies are disclosed, but they do not lead to fundamental distortions. Overall, the regimes are well founded.

The royalty regimes in both Nova Scotia and Newfoundland are competitive when compared with relevant international practice. Thus the regimes are not vulnerable to criticism that the governments are not getting fair value for the resources on behalf of their citizens. By the same token, the fact that industry has endorsed the regimes and is making investments under them suggests there is no compelling need for reductions. Governments are not trying to grab too much and producers are not enjoying a free ride.

Looking ahead

Royalties are not a tool for macroeconomic policy. Royalty schemes should be developed in the context of the overall fiscal system in which they are embedded. For producers, what is crucial is the overall tax burden imposed by governments. The two regimes examined should not be etched in stone because adjustments may well be required over time.

Royalties, of course, are only one part of the public policy puzzle. This paper lays important groundwork for understanding the offshore oil and gas industry in Atlantic Canada. The next logical step would be empirical analysis, which would include the impact of income taxes. Beyond that, analysis of the overall fiscal framework must take into account interaction with other programs, especially Equallization.[1]

[1] This subject is treated in another paper recently published by AIMS: *Taking Off the Shackles: Equalization and the Development of Nonrenewable Resources in Atlantic Canada*, by Ken Boessenkool (AIMS 2001).

About the Author

Dr. G. Campbell Watkins is an internationally recognized expert in energy policy and the application of economic analysis and statistical tools to the energy industry. Dr. Watkins has published extensively on the economics of the oil and gas industry, including demand, supply, market, pricing, taxation, regulation and policy issues. He has testified before numerous provincial, national, and international tribunals, courts, and regulatory agencies. He has worked overseas in Tanzania, Indonesia, and South America and is currently an Honorary Professor of Economics at the University of Aberdeen and last year was a Visiting Scholar at MIT. He is joint editor of *The Energy Journal,* a former President of the International Association for Energy Economics (IAEE), and a Consulting Principal with LECG Inc.

Introduction

Natural resources are oft called a free tribute of nature. A tribute, maybe – but not free. Their recovery requires expenditure of physical, technological, and human resources, as well as human ingenuity. And there is no natural resource for which this is truer than petroleum.

The Atlantic provinces have embarked on production from what hopefully will be the first in a series of offshore oil and natural gas projects. This prospect raises important issues, some already dealt with, others looming, and yet others lurking.

The initial taxation of resources upstream – that is, royalties levied on oil and gas as they emerge from the ground and are sold – stand at the apex of what can be viewed as a resource development pyramid. Are governments (representing owners) going to get a fair shake, and are developers going to receive sufficient returns on existing and prospective discoveries? How do the royalties react with general business taxes? What is the overall tax burden (industry's bottom line)?

How will new streams of resource revenues received by provincial governments affect public finances after account is taken of the impact on federal government transfers (equalization)? Does the equalization formula fairly handle resource revenues? How should provincial governments dispose of them? What macro impacts may be expected on provincial economies? Are there significant spin-offs? What opportunities will arise for participation by local businesses in resource development, and what is the scope for downstream processing – is there a role for governments to play here? All these issues are linked.

The way these questions are resolved will determine whether offshore resources will become a bounty for the provinces or whether they will create adjustment and other problems akin to what has been termed the Dutch Disease, where resource development was seen as squeezing other activities.

This paper, one of a planned series, looks at offshore petroleum royalties. Here in Atlantic Canada, royalty regimes are already in place. The regimes have attracted persistent criticism, with the petroleum industry portrayed as rapacious and governments as betraying the public trust.[2] This has created public unease about whether the distribution of returns from resource exploitation is fair. At the same time, independent assessment of the design of these regimes has been absent – a gap this paper attempts to fill.

[2] The following is a representative cross-section of criticism: Brian Flinn's "N.S. 'easy mark' for oil firms – Liberals" in the Halifax *Daily News* (May 18, 2001); "Nova Scotia – Bad Timing", by industry watcher Ian Doig in *Doig's Digest* (DeWinton, February 2001); "Hibernia raw deal – Nfld.", a CP story in the *Daily News* (April 11, 2000); Nova Scotia opposition member John Holm ("Patsies, Mr. Speaker . . .") in *Hansard*, p. 4824 (December 21, 1998); *Submission to the Joint Review Panel on the Sable Offshore Energy Project*, prepared for the Ecology Action Centre by ATi Consulting Corporation Inc., Halifax (February 28, 1997).

Crown ownership of Atlantic provinces onshore resources is vested in provincial governments, representing citizens. The provincial governments also act as joint managers of offshore petroleum resources with the Government of Canada.[3] Owners seek compensation for rights awarded to recover and market the resources to which they hold title. Payments made to owners for these rights are often called *royalties*, to distinguish them from other taxation instruments.

Royalties can be levied in various ways. The most common are some form of *ad valorem* levy on production and some form of levy on net income, supplemented by a bidding process for allocating production rights. All are fundamentally predicated on resources having some net market value in the hands of the owner. Economists often refer to these net resource values as *economic rents*.

The purpose of this paper is to examine the nature of economic rent, to look at various instruments used to lay claim to it, to develop a menu of criteria with which to evaluate royalty schemes, and then to apply those criteria to the Nova Scotia and Newfoundland generic offshore petroleum regimes. Particular attention is given to resource rent royalty (RRR). Apart from more traditional levies, RRR-style schemes constitute the main vehicle adopted by the two provinces.

To anticipate: the royalty regimes adopted by Nova Scotia and Newfoundland are similar, both consisting of a combination of levies on gross revenues and on deemed profits. I find the schemes are for the main sensibly designed and targeted; they are sensitive to variations in costs and revenues, yet they afford governments some basic returns as soon as production commences. However, the regimes are deficient in their treatment of exploration costs and may not be well integrated with other taxes for which producers are liable, especially corporate income tax. The combination of royalties and full income tax rates generate quite high marginal tax rates on profitable projects. And the royalty flows generated by projects could be erratic. More heed should be given to cash bids than to work expenditures in awarding licences.

The paper is organized in six sections. Section 1 sets the stage by discussing economic rent in the context of natural resources. Section 2 outlines various instruments that have been used to capture resource rents. Section 3 focuses on the resource rent royalty (RRR) instrument, dealing first with a tax on net cash flow (the Brown Tax) before outlining its approximation by the RRR, then looking at examples of resource-rent-style regimes in three jurisdictions (Australia, Canadian Frontier Lands, and the United Kingdom). Section 4 develops and discusses a menu of royalty regime evaluation criteria. Section 5 applies the criteria developed in Section 4 to the current generic Nova Scotia and Newfoundland offshore petroleum tax regimes. Closing remarks are made in Section 6.

Two appendixes and a reference list complete the paper. Technical details relating to the discussion of RRRs in Section 3 appear in Appendix A. Appendix B provides details on RRR-style regimes in Australia, Canadian Frontier Lands, and the United Kingdom.

[3] The courts have awarded ownership of offshore Newfoundland resources to the federal government; ownership of offshore Nova Scotia resources has yet to be resolved.

SECTION 1
ECONOMIC RENT AND NATURAL RESOURCES

In most countries, mineral resources as they exist in situ are publicly owned. A major exception is the United States, where resources outside of federal lands are in private hands.[4] However, in both instances exploration, development, and resource extraction are normally carried out by companies, not owners. Whether resource ownership is vested in a government (on behalf of its citizens) or is private, resource levies are equivalent to an equity share in mineral development.

In this paper, I term payments to mineral resource owners for exploitation rights a *royalty*.[5] Payments can accrue under various guises, including auctions of land rights, shares of production volumes or gross revenues, and profit shares. Such techniques are often used jointly – the Nova Scotia and Newfoundland royalty regimes described later are no exception.

The value of a resource at the point of production is its value at the point of sale less all prior costs incurred, including a suitable return on investment. A royalty is a claim against this net resource value. The net resource value itself is termed *economic rent*. The in situ value of the resource to the resource owner is the capitalized value of the future stream of rents.

This definition of rent as a surplus over costs is beguilingly simple. Unfortunately, simplicity evaporates when one attempts to quantify rent – the devil is in the details.

The essence of discovered petroleum resources is that they are limited in total supply and vary in quality and cost. Such variations entail a quite sophisticated technology to identify economic rent. And while rents, as a surplus, offer the prospect of relatively painless and efficient extraction, this seldom proves to be the case.

In what follows, I look at natural resource rent in more detail, starting with the Ricardian notion from 18th-century agriculture.[6] I then develop an operable definition of rent in the context of petroleum, and discuss the timing dimension.

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[4] In Canada a few companies (e.g., Canadian Pacific and Hudson's Bay Company) enjoy freehold title to some lands.

[5] The Alberta government draws a distinction between payments made to the owner for the right to produce oil and gas (usually revenue from land sales) and payments made related to the flow of production itself. This illustrates a distinction between collecting revenue from the sale of options to explore and develop prospects, and revenue collected by a levy on the realized return from developed prospects. The Alberta legislation specifically refers to a royalty as being reserved to the Crown on any mineral recovered (*Mines and Minerals Act*, Chapter M-15, clause 34).

[6] The English economist David Ricardo (1772–1823) is best remembered for his theory of rent and comparative cost.

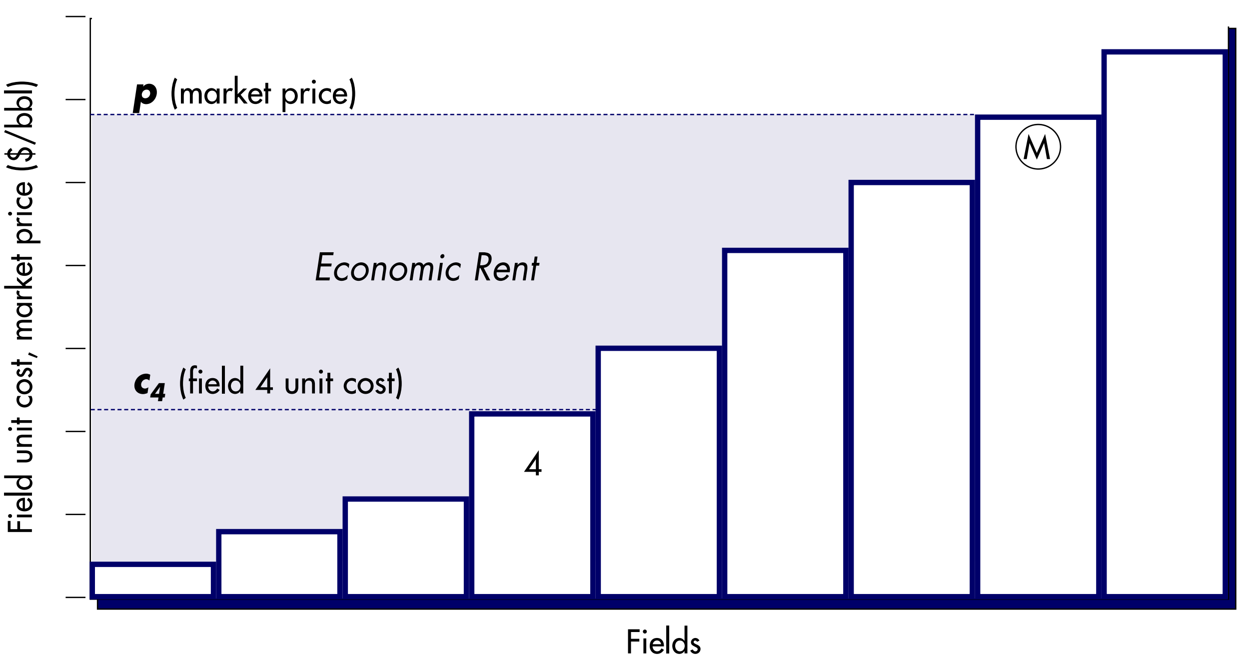
Ricardian Rent

The point of departure for the discussion of economic rent – especially in the context of natural resources – is the Ricardian notion. Pure Ricardian rent refers to payments for the use of the "original and indestructible powers of the soil" (Ricardo 1951, 67). These powers are non-depletable (maintainable forever at no cost) and non-augmentable. Supply is fixed irrespective of price.[7] But mineral deposits are both depletable and renewable by development and exploration. Hence, royalty incomes received from mineral exploitation are not pure Ricardian rents; rather, they are quasi-Ricardian rents.

Mineral deposits such as oil fields can be arrayed by ascending cost of production. The difference between a field's unit cost of production and the market price is the field's unit rent, the surplus over and above unit cost. Fields with unit costs below market prices – because of efficiencies or favourable physical properties such as prolific well production rates – enjoy *quality* rents, reflecting greater profitability. The marginal field is the field with a unit cost equal to the market price; it has no rent. Rents are market price determined, not price determining.

Chart 1 illustrates these concepts. Wellhead prices and unit costs are measured on the vertical axis; field production is arrayed on the horizontal axis in terms of ascending cost. The field designated "4" has unit cost c_4, and a unit rent of $p - c_4$, where p is the market price. The field "M", with a unit cost equal to price p, has no rent.

Chart 1: Field Economic Rents



[7] In the jargon, supply is completely price inelastic.

In contrast to pure Ricardian rent, the quality rents depicted in Chart 1 would not be received in perpetuity, even if the price were fixed, because supply from a field is depletable, not inexhaustible. As Steele observes, mineral resource rents represent a sort of liquidating dividend. Each installment reduces the stock of existing resources, ultimately yielding a determinate total quasi-Ricardian rent (Steele 1967, 236).[8]

An *operable* definition of economic rent is the profit over and above that necessary to obtain production from a project, a sort of superprofit. More technically, economic rent can be defined as the difference between market value of a commodity and the *supply prices* of the economic inputs (plant, equipment, fuel, labour) employed in its production. A supply price is the minimum price that will entice supply of an economic input.

This definition partitions project revenues into two elements. The first consists of the revenues necessary to attract economic inputs to a project – a project's total economic cost.[9] The second is the difference between revenues generated and total economic cost. These two elements can be written as

total economic cost = quantity of economic inputs used x *respective supply prices*

economic rent = total revenue – total economic cost.

Timing Aspects

There is a timing dimension to economic rent. In the short run, a fixed input such as capital represented by a producing well is a sunk cost; it does not have an alternative use and its (short-run) supply price is zero. Short-run rent, then, is the difference between the market price and the supply prices of variable inputs (labour, power, and the like). In the long run, the supply prices of fixed inputs enter the equation. Normally, short-run rents exceed long-run rents.

In the context of petroleum, short-run rents for an already discovered and developed field – the difference between wellhead revenues and extraction costs – would typically be large, since extraction costs tend to be relatively small. Rents on discovered but undeveloped resources entail deduction of development costs in addition to extraction costs. Rents on unexplored lands involve deduction of finding costs, as well as development and extraction costs.

To put it another way: economic rents distinguish among costs and returns necessary to sustain ongoing production from existing fields, development of discovered fields, and new exploration. Estimates of economic rent depend on the development stage of a petroleum property. This has implications for the design of royalty regimes, as will be seen later.[10]

I now turn to various instruments of resource taxation.

[8] The unit extraction cost of production for any oil field rises until it exceeds the wellhead price, at which point wells would be abandoned.

[9] For a similar formulation, see Kemp (1987, 5).

[10] Full-cycle, or eventual, rents accruing normally are considerably less than half-cycle, or initial, rents.

SECTION 2
TYPES OF ROYALTY INSTRUMENTS

Broadly speaking, there are two methods to acquire rents: *stock* (up-front) payments and *flow* payments (streams of payments over time). A useful distinction can be made between rents arising from variations in quality (expressed by unit costs) and those arising as a result of departures from anticipated prices and costs.

Stock payments could capture quality-type rents if the bid process were sufficiently competitive. But they can't handle variations in rents associated with unanticipated changes in prices and costs – up or down. Hence the importance of flow payments that reflect realized revenues and costs.

The spectrum of royalty instruments embraces
- bids for rights to explore, develop, or produce;
- percentages of production volumes;
- percentages of gross revenues;
- percentages of net revenues (profit sharing);
- production sharing agreements (PSAs);
- corporate income taxes; and
- resource rent royalties (RRRs).

The feasibility of these instruments cannot be divorced from the terms and conditions under which resources are held – the *resource-tenure* system. For example, if the period for which a resource licence is held were seen as too short to allow a reasonable chance of cost recovery, schemes relying heavily on percentages of gross revenues would be unattractive to developers.

Bids

Governments can auction off rights to explore tracts, and they can award rights to production leases in the event of success. Sealed bids are the usual mechanism. If foresight and competition were perfect, the bidding process would cream off any foreseeable rent. If competitive bids were one of several instruments employed to obtain rents, they would tend to mop up any outstanding rent. Outstanding rent refers to the residual after deduction of expected taxes and flow royalties – deductions treated as costs in bid determination. However, bidders seldom have equivalent information about a property – data are jealously guarded, and participants in adjacent properties will probably enjoy superior insights. Moreover, rivalry may lack sufficient intensity. And deficient foresight will ensure discrepancies between anticipated and realized rents.

The most mature petroleum province in Canada is Alberta, where land rights fall into two main types: licences (for exploration) and leases (for production). An exploration licence grants exclusive rights to conduct exploration in a defined area; the licence term (two to five years) and maximum area licensed depend on location. A production lease, which confers exclusive rights to sell oil and gas, can be obtained by exploration licence conversion or by bid. Conversion arises in the event of exploration success, with the converted area generally depending on exploration footage drilled. The remaining portion of the exploration tract reverts to the government, which in turn may put it up for resale. Evidence on areas subject to bid suggests that competition in Alberta has been sufficiently strong to allow the government to capture a large portion of foreseeable rents (Watkins and Kirkby 1981; Watkins 1975).

Recently, the Venezuelan authorities employed a sealed-bid auction to lease blocks, many of which related to existing fields thought propitious for resuscitation. The third-round auction in 1997 saw 20 blocks put up for bid sequentially over consecutive days. After each day, all bids were announced. Forthcoming bids could be revised based on results the previous day. More than 100 international companies were involved in the auction. Generally, the winning bids exceeded expectations.

Volume Percentages

A royalty expressed as a straightforward fraction of production volumes is a traditional instrument. One eighth (12.5 percent) would be a representative levy in North America. And royalties could be taken in kind. Unless owners market royalty oil themselves, producers in effect buy back the oil at the prevailing market price. Provision is often made for reducing the original royalty fraction if it leads to premature well abandonment.

Volume percentages can be expressed in a form that is sensitive to well or project output, price, and time of discovery. Before the OPEC-inspired price rises in the early 1970s, Alberta (flow) royalties were a percentage of well production, rising as well productivity increased. Well productivity acted as proxy for resource quality.

Unanticipated oil price rises in the 1970s inspired a restructuring of traditional royalty formulas. Nowhere is this more evident than in Alberta, where a new system in 1974 treated royalties as a function of well production volumes (as before) but also introduced price and time of discovery to the royalty formula. A base royalty was augmented by a fraction of the spread between an average realized price and a reference price, and by a factor that distinguished between new and old oil, where old oil referred to oil discovered before 1974.[11]

[11] For further details on, and analysis of, these Alberta formulas, see Watkins and Scarfe (1985).

Gross Revenue Percentages

Rather than treating royalties on a volume basis, royalty percentages can be expressed in terms of gross revenues. This is the instrument used for initial royalties in Canadian frontier regimes, for example.

Net Revenue Percentages

Deduction of some kind of cost allowance from gross revenues allows royalty percentages to be expressed as a fraction of net revenues or notional profits. This is tantamount to profit sharing and is a component of RRR-style schemes, discussed in Section 3 and later.

Production Sharing Agreements

PSAs have been popular in many oil-producing countries, especially in the third world; a country will take title to a share of petroleum – at the wellhead or processing plant – that will be marketed through its national oil company. In essence, this is a variant of a gross production royalty, but one with many terms and conditions that mark a departure from a conventional gross royalty system.

Income Taxes

Corporate income tax is levied on the income of firms, not on resource properties. Nevertheless, income taxes can also act as royalty-collecting devices, and are often tweaked to deal with income from natural resources. For example, disputes over resource revenues between Canadian provinces and the federal government in the 1970s led the federal government to disallow the income tax deductibility of royalties paid to provincial governments. Subsequently, in partial compensation, the federal government inserted a resource allowance as a deduction from federal taxable income.

Resource Rent Royalty

The resource rent royalty (RRR) approximates to a levy on project net cash flow, and is a key component of the regimes adopted in Nova Scotia and Newfoundland. In this light, and since it is a quite convoluted instrument, the RRR is treated in detail in the next section.

SECTION 3
RRR-style Instruments

To recapitulate, Section 1 provided a definition of economic rent in the context of natural resources as the value at the point of sale less the economic costs of production. Production cost is used in the broad sense of *all* economic factor payments required to bring the resource to the point of sale (not just extraction cost). Such payments would include a suitable risk-adjusted return on capital. It is this net resource value – the economic rent – at which a royalty tax ideally should be directed. Section 2 outlined the main royalty instruments, except for resource rent royalty, which I deal with here.

The following discussion first examines the idea of what has been termed a *pure* profit tax and how such a tax might be adjusted to a form more suitable for taxing authorities – the resource rent royalty (RRR). The royalty level set by the government, though critical to those whose ox is being gored, is not critical to this analysis. A pure profit tax is a straightforward tax on net cash flow that would take account of all costs as incurred, with the tax authority making payments if net cash flow were negative. It is a suitable point of departure in looking at levies on resource rents.

Cash Flow Tax

The Brown Tax (Brown 1948) has been called a pure profit tax. The structure is simple. It is levied as a stipulated fraction of net cash flow and applies irrespective of sign. Negative net cash flows are subsidized by the government at the same rate as positive cash flows are taxed. No distinction is made between capital and other costs. If the Brown Tax (BT) rate were set at 50 percent, the government would supply half of the project cash outflows and obtain half of all cash inflows.

In the absence of the Brown Tax (and excluding any other taxes imposed), the company pays all project expenses and collects all the revenues. With a 50 percent tax rate, the company's share has been halved: the government has become an equal project partner. The Brown Tax can be seen as an implicit government equity share equal to the tax rate (Smith 1982, 2).

A fully competitive bid auction (with bidders enjoying perfect foresight) and a Brown Tax in conjunction with a bid would be complete substitutes, as long as the auction cash bid were not allowed as a deduction (Fane and Smith 1986, 5); for derivation, see Appendix A.

The significance of this result is that the government enjoys the whole net resource value irrespective of the level at which it sets the BT rate. With a high rate, the government gets most of the return through the tax, and bears most of the risks associated with the actual success or otherwise of a project. With a low BT rate, the government would obtain most of its revenue via the auction, and the private shareholder would bear most of the realized risk.

Given its simplicity, why hasn't the Brown Tax been adopted in preference to a resource-rent-style tax? The main reason is the reluctance by governments to become effectively full participants in front-end risks by providing funds directly to firms when negative tax liabilities occur.[12] The resource rent royalty can be viewed as an attempt to implement a more acceptable version of the Brown Tax.

Resource Rent Royalty

Garnaut and Clunies-Ross (1975) set the style of the resource rent royalty (RRR) levy.[13] Its rationale rests on the notion that if a company with rights to exploit mineral resources is not subject to further tax, it will enjoy profits in excess of the return required on the investment made to develop and produce the property. The intent, then, is to tax company profits in excess of some floor level (ibid., 276, 280). The RRR was designed to capture such supernormal profits without encroaching on normal profits and discouraging investment. The tax involves specification of a threshold rate of return representing normal profits, no tax on returns up to the threshold level, and a relatively high tax rate on returns in excess of the threshold.

The unit of taxation for the RRR is a *project*, rather than aggregate company income. Conceptually, the appropriate threshold rate would vary across projects by virtue of differential project risks. But in practice a uniform threshold rate often applies.

The RRR is structured as a tax on net cash flows: any initial negative cash flows that arise are accumulated at the threshold rate and subsequently deducted from future positive cash flows in calculating RRR liability. If accumulated RRR-style assessable income never became positive, the government would get no tax, and the company would have suffered apparent uncompensated losses unless they were transferable to successful projects.[14]

The government makes no direct contribution to a project's capital costs. Its contribution is effectively deferred until such time as positive cash flows emerge, the project investment is recovered, and a threshold return on the investment is made. Only after that does the tax kick in.

[12] See also comment by Kemp (1987, 10).

[13] Garnaut and Clunies-Ross refer to their scheme as a resource rent tax (RRT). To maintain emphasis on the term *royalty*, I call it a resource rent royalty.

[14] The "apparent" qualification is to accommodate the case where the threshold rate exceeds the company hurdle rate.

What, then, are the main differences between the generic RRR tax as outlined and the Brown Tax (BT), which the RRR is intended to mirror?[15] When a project yields a negative cash flow under the BT, the government reimburses the company to the tune of the product of the rent tax rate and the negative cash flow. Under the RRR, the project has a credit of this amount carried forward at the threshold rate. It is offset against RRR liabilities when net cash flows turn positive. Companies only make RRR payments when all credits from earlier years, compounded at the threshold rate, have been exhausted.

If companies were able to transfer RRR credits between projects and sell unused credits to companies having RRR payments to make, this would be tantamount to a full loss offset.[16] When such transfers are not allowed, full loss offsets are denied. This is an important difference between a BT and an RRR. Under the BT, of course, the loss offset is paid directly. One way of compensating for any lack of full loss offset is to set the threshold rate higher than it would be set with guaranteed full loss offsets.[17]

If the threshold rate were set equal to the bond rate, the denial of full loss offsets under an RRR would convert it from a tax on project net cash flow to a tax discriminating against risky projects (Fane and Smith 1986, 9). In this light, threshold rates above the bond rate offer some compensation. But a single threshold rate would still introduce bias in the presence of differential risk among projects. However, if all exploration expenditures were taken into account, the burden of risk compensation via the threshold rate would be markedly reduced (Bradley and Watkins 1987, 286). *Setting the appropriate threshold rate is a major issue with an RRR.*

Smith (1982, 10) discusses mineral rent taxation in the context of optimal investment portfolio behavior by government when the private sector has the capacity to spread risk. Administration of an RRR on a company (rather than project) basis would allow a threshold rate to reflect the probability distribution of the outcomes for an average project, avoiding any need for threshold rates to vary by project.

An RRR that defers tax until after project payout, including a return on capital, does not treat capital inputs as providing a flow of services over an asset's life. Another way of treating capital costs is to define them over the effective life of the capital asset (the project life, in the context of resource taxation). Capital costs allocated over a project life – represented, for example, by the term of a production lease – would result in a rent trajectory that would commence earlier and become more even than one in which apparently no rent emerges until after payout and enjoyment of a threshold return (front-end loading of costs), followed by chunks arising later on (back-end loading of rent).

RRR-style regimes have been employed in several jurisdictions. And the World Bank has endorsed the RRR kind of approach (McPherson and Palmer 1984). As a prelude to later examination of the Atlantic

[15] See also discussion in Fane and Smith (1986, sec. 3).

[16] As discussed later, this was not what emerged in Australia.

[17] Fane and Smith (1986, 7) suggest that this was precisely what the Australian Government intended in setting a generous threshold rate.

regimes, I look at schemes in three jurisdictions: Australia, Canada (federal government), and the United Kingdom. The schemes are briefly described in this section; fuller details are provided in Appendix B.

Australia

The Resource Rent Tax (RRT) was inaugurated in 1984. The tax is levied on offshore projects, and applies a tax rate of 40 percent to net cash flow *after* projects have achieved a specified rate of return (the threshold rate); unsuccessful projects are denied full loss offsets. To compensate, the threshold rate was originally set at 15 percentage points above the bond rate for carry forward of most RRT credits. Pre-tax losses are compounded at the threshold rate.

Canadian federal government frontier royalty regime

This regime is similar in structure to the Alberta Cold Lake agreement, a regime that has pretty well provided a model of royalty structures for Canadian offshore and frontier lands.

The basic royalty formula combines a low gross royalty in the early years of the project with a relatively high net profits royalty following recovery of invested capital plus current costs. *It is imposed on a project basis.* Gross royalties start at 1 percent of gross revenues, rising to 5 percent after six years. After investment payout, royalties are the greater of 30 percent of before-tax project profits or 5 percent of gross revenues. Investment payout includes a (compounded) return allowance on capital of 10 percent above the long-term bond rate.

United Kingdom

Special taxation of petroleum dates to 1975. Three different taxes are levied on North Sea oil: a traditional royalty, normal corporation tax, and the Petroleum Revenue Tax (PRT). Here, I focus on the latter.

The PRT is levied on a field-by-field basis. The original rate of 45 percent applied to a base consisting of gross revenue less a number of allowances, including a substantial uplift to field capital costs, intended to compensate for interest on loans not being deductible and to assist small fields. The PRT was mitigated if gross field profits fell below certain levels, and a PRT ceiling was set. The PRT does not include a return allowance.

Over the years several changes were made to the PRT rates and regulations, all basically intended to increase taxes when oil prices were high, and reduce them when prices fell.

Commentary

How do these three tax regimes relate to the generic RRR type of tax described earlier in this section? It is obvious that the Australian RRT is an RRR-style levy. The Canadian frontier tax regime is also obviously in the RRR style, although it does have an interesting nuance – its provision for relatively modest floor royalty payments once production starts and revenue is generated, with more substantial minimum royalties after payout.

The initial Canadian floor royalty payment is tantamount to a transfer of risk from the government to the developer. It avoids a company preempting all revenue before project payout is achieved. The provision was probably provoked by the high costs of frontier development and a propensity for cost overruns that would tend to result in a lengthy deferral of any return to the owner. The initial floor royalty is a way to ensure that any project on stream does pay some amount to the resource owner – to compensate for administrative costs, to protect the owner against any overly generous accumulation rate, and to better reflect economic depreciation over the entire life of an asset.

The UK Petroleum Revenue Tax is a more convoluted taxation instrument, not so easily seen as an obvious RRR-style tax. However, it is clear that the PRT is designed to obtain a share of profits generated by North Sea oil resources. It is also clear that since the PRT is imposed on a field basis, with only limited transfer of any excess allowances, it is intended to reflect differences in field quality.

The major difference between the PRT and an RRR is the failure of the former to allow any return on capital expenditures, an exclusion that extends even to debt interest. But the heavy uplift fraction in the original version of the tax can be interpreted as a surrogate return allowance. If so, while the PRT does not identify a return on capital and thus only imperfectly defines economic rent, it does remain a tax directed at economic rents *by project*. The way the rate of PRT was effectively ratcheted up or down as the price of oil fluctuated also confirms its status as a rent-style tax. However, the kinds of modifications to which the PRT has been subjected are testimony to its clumsiness.

The Nova Scotia and Newfoundland regimes – described and appraised in Section 5 – are patterned in part on the RRR (and are similar to the Canadian frontier regime). The following section develops a set of royalty regime evaluation criteria.

SECTION 4
A ROYALTY EVALUATION MENU

Royalty instruments should be appraised in light of economic efficiency and public policy objectives. Economic rent was defined as what can be extracted without impairing an industry's ability to earn the minimum return required to attract investment. Ideally, neither the pace nor level of industrial activity will be affected by rent extraction. But, for all practical purposes, such neutrality is a pipedream. Because rent extraction affects industry profitability and cash flow, it will inevitably affect the rate of investment, even if minimum project returns are preserved. It would be rare indeed for rents to be appropriated without introducing some inefficiencies and distortions.

The architecture of a royalty scheme can be evaluated against a suitable checklist. The following discussion makes a distinction between basic criteria, efficiency and fairness criteria, and administrative criteria. The criteria advanced are neither exhaustive nor independent. Interrelationships and indeed some potential conflicts exist. The order of the listing is not intended to represent rank.

Basic Criteria

Four such criteria come to mind.

1. *Legality*. The form and structure of the royalty must either satisfy existing statutes or entail new legislation. This criterion may seem trite, but traditionally many royalty provisions had to be couched in terms of a levy in kind, or a levy on production from individual wells. This tends to make profit-sensitive royalties legally elusive. Bridging any legislative gap is important, given the argument in this paper that royalties should be directed at economic rent.

2. *Tolerability*. A punitive policy to appropriate all perceived rent would not be acceptable to producers and would discourage efficiency by making producers indifferent to costs. Maximization would leave little margin for error – unraveling rents from hurdle rates of return is difficult, and information on costs can lack precision, especially in terms of assigning indirect costs and full exploration costs to projects. An even more severe policy of maximum appropriation directed at short-run rents would kill the goose that lays the golden eggs. Leaving some apparent rent in the hands of producers also has the virtue of possibly offsetting any capital market distortions.[18]

[18] The upstream petroleum industry has traditionally relied heavily on internal cash flow in light of such distortions.

3. *Floor levies.* While royalties should focus on economic rent, there is a case for imposing minimum royalties as a basic "cover charge". A floor levy can be seen as compensation to owners for costs they incur, including administrative costs and social infrastructure, as well as providing a minimum return. Floor levies help smooth royalty flows and are more consistent with the view that economic rent accrues over an asset's life. But too high a floor royalty could inhibit activity.

4. *Fiscal interaction.* A royalty regime should not be conceived in isolation either from the resource tenure system or from other fiscal instruments. To give an example: bidding for production leases could afford a more lenient attitude toward gross royalties, since bids could mop up some rents that gross royalties might miss. And the impact of corporate tax influences the scope for setting royalty levels. For the producer, the overall government take is what matters most, irrespective of its derivation – from government's role as owner, or as general tax authority.

Efficiency and Fairness Criteria

I list eight criteria under this heading.

1. *Neutrality.* Royalties should not distort the market mechanism, especially since they are not levied to compensate for side effects (e.g., pollution impacts not already covered by charges). Royalties should not deter exploitation of the full range of fields and should not influence price or production decisions. Neither should they interfere with project rankings. If project A is more attractive than project B before royalty, it should remain so after royalty. Royalties that focus on rents tend to avoid these problems by entailing sensitivity to costs and prices.[19]

2. *Mitigation at the margin.* Royalties should leave the return on marginal investment and on marginal output unimpaired. The intention is to ensure that royalties do not inhibit development of high-cost fields that are economic pre royalty; nor should they lead to premature abandonment of already developed fields. That is, the royalty scheme should not influence recovery at the economic margin.[20]

3. *Horizontal equity.* Horizontal equity can be viewed as equal treatment of resources of equal quality. The relevant measure of quality is economic rent. Thus, fields with equivalent cost structures should be treated in the same way.

[19] For the way the Russian tax regime significantly violated neutrality, see Smith (1997).

[20] Transfer payments such as royalties are (private) costs to the developer, not to the owner. In the presence of transfers, an abandonment decision based solely on private costs could be premature from the owner's perspective. When marginal costs approach market prices, royalties that do not compress are inefficient: resources would be lost to the economy. For an illustration of this point, see Chart 1 – royalties should not preclude production from the field labeled "M" that has a cost equal to the price p.

4. *Vertical equity.* Vertical equity refers to equivalent treatment of resources of different quality. The better the quality (profitability of the field), the greater the amount of economic rent transferred to the owner. This might be simply handled by applying fixed percentages, but the principle of progressive taxation could suggest royalty rates rising with resource quality.[21] Often, well productivity is used as a surrogate measure of quality (see the earlier mention of Alberta well royalties), but lack of a cost dimension makes this an imperfect proxy. In broader terms, the criterion suggests that royalties should be consistent between different types of fields and different price levels. The proportion of rent paid by a high-cost field should be at least the same as that paid by a low-cost field; the proportion paid when prices are low should be no more than when prices are high.[22]

5. *Cost recovery.* Producers seek recovery of full-cycle costs, which entails a focus on long-term rents. Development and operating costs are usually easy to identify and assign to a project. Exploration costs are more ambiguous to allocate, especially the costs of unsuccessful efforts and of activity located beyond project contours. Cost deduction rules that do not make sufficient allowance for all exploration costs (direct or indirect) can lead to underinvestment in risky ventures.

6. *Inflation adjustments.* Investor returns are sensitive to inflation. Higher nominal returns resulting from general inflation should not induce greater government takes of what is simply a money illusion.

7. *Risk sharing.* Risk sharing is a complex issue. The various royalty instruments embody different risk characteristics. High gross royalties shift risk to producers. RRRs with generous return allowances shift risk to owners. Limitations on the transfer and carrying forward of losses among projects increase investor risk and place more emphasis on compensating devices. Marginal tax rates are an important determinant of how unexpected changes in prices or costs affect returns to producers and owners. And for producers, the relevant marginal rate is the total rate, the sum of the marginal royalty rate and the marginal income tax rate.

8. *Competition with other jurisdictions.* Setting royalty parameters requires some degree of sensitivity to regimes in competing jurisdictions, both domestically and internationally. If greener pastures beckon elsewhere, too severe a regime could stultify activity. However, comparisons among regimes are usually not easy, requiring adjustments to account for differences in resource endowments and other elements of the overall tax and resource tenure system that, if unrecognized, would undermine the analysis.

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[21] And there are grounds for suggesting that the poorer the deposit the lower the government share should be to better compensate for finding costs that do not vary with field size. However, perverse incentives can arise when expenditures are made simply to avoid triggering a higher tier of profit sharing.

[22] In more technical terms, the elasticity of royalty revenue with respect to price, to field or well productivity, and to cost, should equal or exceed unity (absolute). This assumes that increases in price and well productivity accelerate rent at a rate in excess of price or production, and that such additional rent is a legitimate target for the owner. If royalties are progressive (as rent increases, the proportion accruing to the owner increases), care must be taken to avoid disincentives: investor returns from large, prolific fields (elephants) should not evaporate.

Administrative Criteria

I identify four such criteria.

1. *Cost.* The proportion of royalty revenues dissipated by collection costs should be modest. And collection expenses are borne not only by tax authorities – producers also incur them. Hence the importance of relative simplicity and intelligibility for any royalty regime. Administrative costs are also affected by certainty of incidence and liability, and by the evasion ratio. *Certainty of incidence* refers to authorities' knowing on whom the royalty is visited; normally this poses few problems. *Certainty of liability* concerns the ease with which the liability can be assessed; unless the scheme is very intricate, this should not be difficult. The *evasion ratio* – indicating the ability of authorities to extract royalties from those liable – should be small, irrespective of royalty design.

2. *Transparency.* The more transparent the means by which governments obtain revenues, the better informed the investors and the general public. For contributors, royalties determine bottom-line profitability, and awareness of them is seldom a problem. But for the public, a complex scheme shrouded in deductions and different royalty tiers is more difficult to comprehend than, say, straightforward percentages of production. And the more transparent the scheme, the less the scope there is for manipulation and administrative discretion – behavior that increases industry's perception of risk.

3. *Robustness.* Royalty schemes unable to withstand changes in the economic environment make life difficult for both industry and government. It may be too much to hope that a single regime can accommodate violent changes. Nevertheless, it should be capable of tolerating reasonable oscillations in underlying conditions and be seen as self-adjusting. Frequent legislative changes compound sovereign risk perceived by industry. This suggests that a regime should enable participants to see how royalties would vary as prices, costs, and market conditions change. It may well also entail reliance on more than one instrument, especially given the distinction between anticipated and realized rents often caused by price fluctuations.

Another aspect of robustness is provision for resource owners to refuse sales at prices or returns below certain levels. This can be accomplished by setting a reservation price on land sales, by setting floor values on royalties, or on prices, if consistent with resource-tenure conditions. Alternatively, owners should be able to take royalties in kind and dispose of such volumes as they see fit.

4. *Consistency.* While external conditions will strongly influence royalty payments, system design should be directed toward achieving reasonably consistent and predictable flows. Predictable flows – an aspect of fiscal *marksmanship* – ease government and industry's financial planning. Moreover, lumpy royalty flows can place too much discretion in the hands of the government of the day. This criterion suggests avoidance of sole reliance on up-front bidding, or deferral of any royalty collection at all until after investment payout (as typified by RRR schemes).

The next section applies these evaluation criteria qualitatively to the generic offshore petroleum royalty regimes promulgated in Nova Scotia and Newfoundland. The scope of this paper does not extend to quantitative simulations necessary for full appraisal.

SECTION 5
HOW DO THE NOVA SCOTIA AND NEWFOUNDLAND REGIMES STACK UP?

In this section, I first describe the generic offshore oil regimes adopted by Nova Scotia and Newfoundland. Not surprisingly, given proximity and joint management with the federal government, they have much in common. Next, an attempt is made to evaluate both regimes qualitatively by applying the criteria developed in Section 4. I emphasize again that the evaluation does not embrace empirical analysis that would disclose in detail how the regimes perform under changing conditions.

Nova Scotia Offshore Regime

The Canada–Nova Scotia Offshore Petroleum Resources Accord of 1986 treated receipt of offshore resource revenues by Nova Scotia as if the resources were onshore; that is, as if they were totally under provincial jurisdiction. Hence, there is no intended sharing of royalty revenues with the federal government, although such revenues will affect federal government transfers to Nova Scotia under the Equalization program.

A regime specific to the Sable Offshore Energy Project (SOEP) was established in May 1996, and a generic offshore oil and natural gas regime was announced in August 1998. My concern here is with the latter. The generic regime is structurally similar to that for Newfoundland, in essence combining gross royalties and an RRR-style levy, assessed on a project basis; however, Newfoundland's applies just to oil.

A *floor* gross royalty is payable, with the floor increasing as a project records notional profits (profits defined by the royalty formula) above a stipulated threshold level. When deemed project profitability exceeds another threshold, a net revenue royalty kicks in and escalates if project profitability rises above yet another threshold tier. Once the net royalty applies, project royalties become the greater of the net or gross revenue levy.

Details

Floor royalty. The floor royalty consists of two royalty levels as a fraction of gross project revenues:

- 2 percent of gross revenues until simple project payout and a project return allowance of 5 percent above the long-term bond rate (LTBR) is achieved;
- 5 percent of gross revenues until simple project payout and a return allowance of 20 percent above the LTBR is achieved.

Thereafter, the 5 percent of gross revenue acts as a minimum royalty, irrespective of project profitability.[23]

Net Royalty. A percentage of net revenues is levied once a project has enjoyed payout plus a threshold return allowance; the royalty rate increases once stipulated returns exceed another, higher threshold level, as follows:

- 20 percent of net revenues after simple project payout and a return allowance of 20 percent above the LTBR, and before simple project payout and a return allowance of 45 percent above the LTBR, is achieved;
- 35 percent of net revenues after a return allowance of 45 percent above the LTBR is achieved.

If the net-revenue-based royalty were less than 5 percent of gross revenue, the 5 percent gross royalty would apply in its stead.

Eligible costs. Approved costs in the computation of project payout consist of certain exploration costs, cumulative project capital, and operating costs plus cumulative royalties paid. A 1 percent *uplift* is applied to capital costs; a 10 percent uplift applies to operating costs excluding royalties. These uplifts are intended to account for company overheads that cannot be treated as approved project-specific costs. Project costs are reduced by any associated federal investment tax credits. Income and capital-related taxes do not qualify as eligible costs.

Simple payout. Simple payout holds when cumulative project revenue exceeds cumulative eligible costs.

Return allowances. Return allowances are awarded monthly on the (positive) difference between cumulative eligible costs (including allowed royalties) and cumulative revenues.[24] These allowances are accumulated in determining profitability tiers, but no return allowance is allowed on accumulated return allowances (i.e., there is no compounding).[25]

[23] There is no reversion to lower gross revenue royalty rates if subsequent costs incurred are such as to reduce overall project returns to below threshold levels.

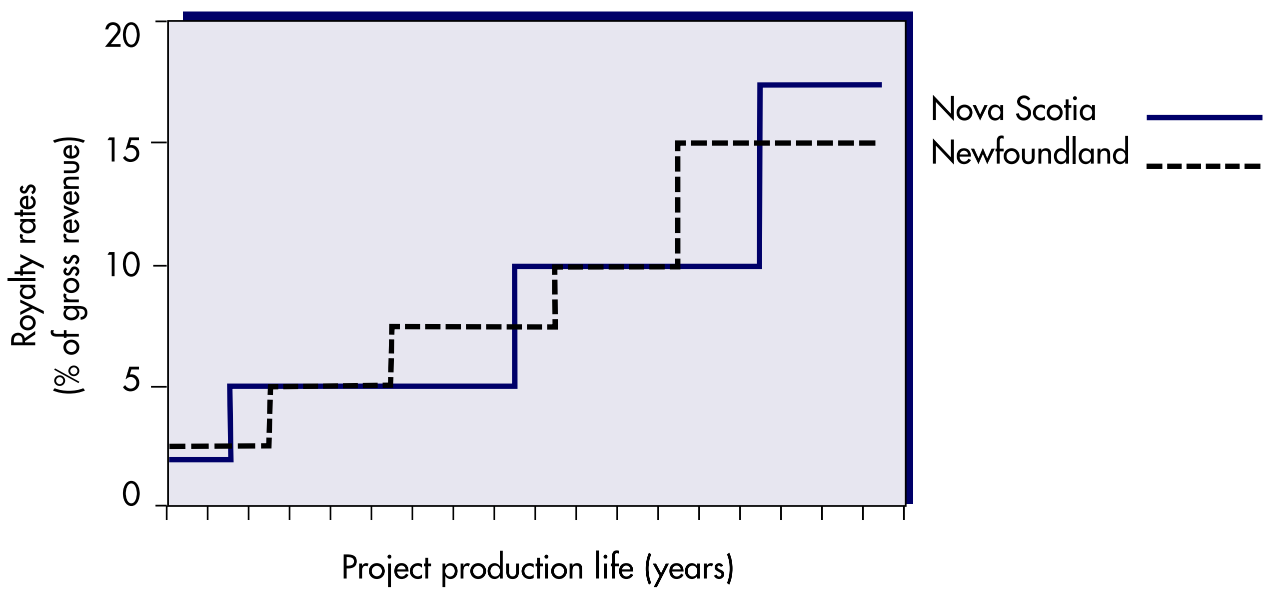
[24] To avoid circularity, approved royalties in the current month are treated as royalties paid in the previous month. The monthly LTBR is the annual LTBR/12.

[25] Thus the return allowance differs from a DCF return on investment – it is calculated as equivalent to simple interest.

Royalty patterns

A typical pattern of royalty rates for a profitable Nova Scotia project – one in which both net royalty tiers apply – is illustrated by the solid line in Chart 2. For convenience, net revenues are assumed to be half of gross revenues after the project becomes subject to net royalties. This assumption enables the effective royalty rate to be expressed throughout the project life as a share of gross revenues. Hence, once the first tier of net royalties kick in, the effective royalty rate becomes 10 percent of gross revenues, rising to 17.5 percent of gross revenues when the second tier of net royalties applies. The chart shows the royalty rate as being higher in the later stages of a project than in the earlier stages (*back-end* loading).[26]

Chart 2: Illustrative Royalty Trajectories, Nova Scotia and Newfoundland



Adjustments for high-risk projects

Two kinds of concessions are made for projects treated as high risk: lower royalty rates and higher eligible exploration costs. Increased eligible exploration costs include the cost of unsuccessful exploration efforts (plus seismic costs) incurred on relevant tracts under licence. In contrast, eligible exploration costs for projects with access to existing infrastructure (sweet spots) are confined to the successful well and associated expenditures (such as seismic costs).

A distinction is made between projects with small reserves and short lives and *greenfield* projects (projects seen as being located in high-risk areas). Projects with small reserves and short lives may also qualify as greenfield projects.

[26] This is only an illustration of royalty patterns over time for a profitable project – once the net royalty applies, royalties are not defined as a fraction of gross revenues.

Royalties for projects with small reserves and abbreviated lives are confined to gross royalties over the first five years of operation. Net royalties can apply after five years if threshold return allowances are achieved. In particular, such projects would pay a gross royalty of 2 percent for the first two years and 5 percent for the next three years of operation irrespective of project profitability. Thereafter, the 20 percent and 35 percent net revenue royalty tiers apply once payout plus the respective return allowances have been achieved; the 5 percent of gross revenue remains as a floor royalty. Small projects, or those with short lives, also qualify for the broader attribution of exploration costs.

Greenfield projects enjoy the more generous assessment of eligible exploration costs in the computation of payout, with the allowance for unsuccessful exploration efforts embracing all such costs incurred over the entire licensed exploration tract. However, a subsequent project in a greenfield licence area would revert to the conventional narrow definition of eligible exploration costs. The net royalty for a greenfield project is capped at the 20 percent tier. A small reserve or short-lived project in a greenfield area may qualify for the 20 percent royalty cap as well as for the five-year gross royalty provision.

Resource tenure

The Canada–Nova Scotia Offshore Petroleum Board (CNSOPB) puts up exploration tracts for competitive bid, with bids expressed in terms of work expenditures. Tracts are awarded to bidders with the biggest proposed spending. The initial term of an exploration licence is five years, with possible extension for another four. The winning bidder has to deposit 25 percent of proposed expenditures with the CNSOPB. The deposit is returned to the licence holder in proportion to the degree to which work commitments are fulfilled. For example, if only 50 percent of the bid expenditure were spent, the holder would recoup only half the 25 percent deposit.

A licence holder making a non-commercial (non-economic) discovery can convert the relevant area of the exploration tract to a *significant discovery* licence, which can be held in perpetuity. In the event of a commercial discovery, all of the area within the contours of the discovery can be converted to a 25-year production licence after the operator receives approval for a development plan.[27]

Newfoundland Offshore Regime

In 1996 Newfoundland announced a generic oil royalty regime for the Newfoundland and Labrador offshore area, excluding the Hibernia and Terra Nova projects. In essence it combines a gross revenue royalty and an RRR-style levy, applied on a project basis.

A basic royalty is payable on every barrel produced. The percentage appropriated increases mainly as a function of cumulative production. In addition, a profit-related royalty is levied, applied in two tiers.

[27] By way of contrast, under similar conditions in Alberta 50 percent of the lands relating to a commercial discovery would revert to the Crown.

The Tier 1 royalty kicks in once a deemed level of approved project profitability has been achieved, with royalties payable becoming the greater of the Tier 1 royalty or the basic royalty. The Tier 2 net royalties become payable when project profitability reaches a higher stipulated threshold level.

Details

Basic Royalty. The basic royalty is imposed on gross sales revenues less deemed transportation costs between the field and the point of sale. In other words, the price component of gross revenue is the price attributed to the field. The basic royalty layers are:

- 1 percent until the earliest of (1) extraction of 20 percent of reserves, (2) accumulation of 50 million barrels of project production, or (3) simple payout;
- 2.5 percent until the earlier of (1) 100 million barrels of cumulative production or (2) simple payout;
- 5 percent on the next 100 million barrels; and
- 7.5 percent on any additional production thereafter.

Net Royalty. Net royalties are payable once a project is deemed to have recovered all eligible costs plus a specified return allowance. There are two return allowance thresholds: Tier 1, at 5 percent above the prevailing long-term bond rate (LTBR), and Tier 2, at 15 percent above the LTBR. The threshold returns are accumulated and, in contrast with Nova Scotia, compounded. The royalty rate for Tier 1 is 20 percent of net revenue; the rate for the Tier 2 threshold is 10 percent of net revenue.

The basic royalty is credited against the Tier 1 royalty. If, for example, a project were in the basic royalty band of 5 percent and the 20 percent net revenue royalty yielded less revenue, the 5 percent basic royalty would apply. If the Tier 1 net royalty exceeded the basic royalty, the net royalty would prevail. Thus, in the Tier 1 band of application, royalties levied are the greater of the base or the Tier 1 royalty.

The Tier 2 royalty of 10 percent of net revenue imposed after the project return allowance of 15 percent above the LTBR has been achieved is strictly incremental. For example, if the basic royalty exceeded the Tier 1 royalty revenue, the difference between the Tier 1 royalty and the basic royalty would not be credited against the Tier 2 royalty: the 10 percent net royalty would apply in full as an addition to the basic royalty.[28] If the Tier 1 royalty prevailed over the basic royalty, total royalties payable would be 30 percent of net revenue.

Eligible Costs. Costs allowed in computing project payout, and on which the return allowance applies, consist of approved operating and capital costs, including successful exploration costs. Operating costs include a markup, or uplift, of 10 percent to allow for overhead costs; capital costs are uplifted by 1 percent. Basic royalties paid are treated as allowed costs, but are not uplifted.

[28] Because the basic royalty increases as a function of cumulative production, it doesn't necessarily follow that when the Tier 2 royalty kicks in the Tier 1 royalty revenue will exceed the basic royalty revenue.

Simple Payout. Simple payout is the point in time when all allowed costs attributed to the project have been recovered. Such costs do not include the return allowances.

Royalty patterns

A typical pattern of royalty payments for a profitable Newfoundland project – one to which both net royalty tiers apply – is illustrated by the broken line in Chart 2 (page 21). As in the Nova Scotia example, net revenues are assumed to be half of gross revenues after the project becomes subject to net royalty revenues – an assumption of convenience. Hence, once the Tier 1 net royalties kick in, the effective royalty rate becomes 10 percent of gross revenues, rising to 15 percent of gross revenues when the second tier of net royalties apply.

The lines sketched in Chart 2 for Nova Scotia and Newfoundland respectively are not strictly comparable. Differences in cost eligibility and treatment of basic royalties in the case of Newfoundland in part as a function of cumulative production make any comparisons indicative, not precise.

Resource tenure

Exploration licences are put up for competitive bid on the basis of cash or work expenditure. For offshore licences, work expenditure is the preferred determinant. An exploration licence is initially awarded for five years, with the possibility of extension. With a significant discovery, the relevant portion of the exploration tract can be converted to a *significant-discovery* licence, which could last in perpetuity. For a commercial discovery, a production licence would be sought for the field contours. It would have a term of 25 years, or beyond if production were sustained.

Nova Scotia and Newfoundland Regimes Compared

Both the structure and parameters of the respective regimes are reasonably similar. Such convergence is not surprising among adjacent jurisdictions occupying similar offshore territories.

The gross royalty rates cross over, the Newfoundland regime being more lenient at earlier stages of production but more severe at maturity. Nova Scotia's net royalty rates are higher at higher profitability levels, but kick in at a later stage (other things being equal) since Nova Scotia's threshold rates are more generous than Newfoundland's, although Newfoundland allows compounding of return allowances. Cost eligibility for computing payout is much the same. Resource tenure conditions are comparable. However, in contrast to Nova Scotia, Newfoundland does not single out high-risk projects for relief.

Overall, it would be difficult to disentangle the net impact of these regimes on royalties generated if they were applied to identical projects. This would require a simulation exercise beyond the scope of this paper. And differences in regime design may reflect perceived differences in typical prospects in the respective territories.

Regime Evaluation

Both regimes are a mix of a traditional gross royalty and a profit-sensitive levy; both clearly owe much to the RRR schemes discussed in Section 3. In evaluating these two regimes by the criteria developed in Section 4, I assign qualitative ratings according to how well each one meets each criterion. Table 1, which summarizes the findings, is followed by discussion of each entry. With few exceptions, the entries are much the same for each regime, again indicating their similarity.

Table 1: Satisfaction of Royalty Criteria

Criteria	Nova Scotia	Newfoundland
Basic		
1. Legality	Y	Y
2. Tolerability	Y	Y
3. Minimum royalties	Y	Y
4. Fiscal interaction	A	A
Efficiency, fairness		
1. Neutrality	Y	M
2. Mitigation	P	N
3. Horizontal equity	Y	Y
4. Vertical equity	Y	Y
5. Cost recovery	M	P
6. Inflation adjustment	M	M
7. Risk sharing	P	P
8. Competitiveness	M	M
Administrative		
1. Cost	M	M
2. Transparency	Y	Y
3. Robustness	M	M
4. Consistency	M	M

Legend
Y: yes
M: mainly
P: partly
N: no
A: ambiguous

Basic

1. *Legality.* Appropriate legislation is in place: the test is met.

2. *Tolerability.* The provision for the bulk of royalties to be collected after payout (for profitable fields) and the fact that post-payout royalties take less than one-half of deemed net revenues preempt any concern

that the schemes are designed to extract all the economic rent, unless the relatively low gross royalty prevails throughout a project's life. The return allowances in both schemes are quite generous (especially Nova Scotia's), although in the absence of compounding, return allowances in Nova Scotia should not be confused with discounted cash flow (DCF) hurdle rates employed in industry feasibility assessments.

The structure of the Nova Scotia and Newfoundland regimes are predicated on Alberta's Cold Lake 1-5-30 scheme and the one for federal frontier lands (see Section 3). Industry has had the opportunity to make representations and has in large measure endorsed the regimes, suggesting that they are not seen as punitive.

I conclude that the regimes do not erect difficult hurdles and that their structure and parameters are broadly acceptable to industry. There remain legitimate concerns for lessees in terms of ability to recover full-cycle costs, the total tax take once income taxes and other imposts are included, loss carryovers among projects, and, in the case of Newfoundland, the absence of any recognition of differential risks among projects.

3. *Floor royalties.* The gross royalties imposed provide a tangible floor, and do not seem sufficiently high as to inhibit activity. And again, industry has endorsed the structure. The test is met.

4. *Fiscal interaction.* There is no overlap in the royalty schemes themselves that involves governments taking two dips into the same pot. However, the federal government revenues obtained via income taxes can loom large in prospective revenue flows. Income taxes (along with non-deductibility of royalties, albeit mitigated by the resource allowance) can be seen as a double dip. This suggests that the royalty regime may not be too well integrated with the overall fiscal system confronting the industry. For companies with marginal income tax rates of around 45 percent, the overall incremental tax burden of a project attracting upper-tier net royalties would be some 75 percent in the case of Nova Scotia, 65 percent in Newfoundland.[29] Such high rates encroach on any costs ineligible in payout calculations, such as some finding costs. They also undermine incentives for producers to control and reduce costs.

Efficiency and fairness

1. *Neutrality.* By and large, the schemes satisfy neutrality by not deterring exploitation of economic fields; nor do they interfere with project ranking or with price and production decisions. Since the regimes do have a focus on rents, they are sensitive to both prices and costs. However, employment of the same return allowance for all projects within the respective regimes introduces a bias against riskier ones. Nova Scotia does provide compensation for higher risk in the form of extended gross royalties, caps on net royalty rates, and more generous allowed exploration costs; Newfoundland provides no such offset.

[29] After allowing for the 25 percent resource allowance in the income tax provisions.

2. *Mitigation at the margin.* Except for the relatively minor possible impact of initial gross royalties, the schemes allow development of poorer quality high-cost fields, more so in the case of Nova Scotia than Newfoundland. But later in the life of a field, the apparent absence of any legislated reduction of gross royalties could lead to premature abandonment, again especially in Newfoundland, given its gross royalty of 7.5 percent. In Nova Scotia, mitigation is contemplated in the SOEP agreement. This suggests the generic regime may give parallel treatment.

3. *Horizontal equity.* There is no discrimination in the royalty schemes among fields of equivalent quality, except for the treatment of greenfield projects in Nova Scotia compared with fields in established areas. But here the intent is to equalize for project risk.

4. *Vertical equity.* Since royalties are profit sensitive, the amounts extracted will tend to be correlated with field quality; therefore, vertical equity is served. The provision for an increasing incremental share of deemed profits for an individual project does mimic a progressive income tax, but the maximum government royalty share of deemed net profits does not exceed 50 percent.

5. *Cost recovery.* Both schemes permit full recovery of direct project development and operating costs. However, it is not clear that sufficient recognition is given to all exploration expenditures and hence to recovery of full-cycle costs. Industry may not be able to recoup full-cycle costs from risky prospects, and to that extent interest in higher-risk areas could be undermined, although Nova Scotia's enhancement of cost eligibility by allowing additional exploration expenses is a significant offset. The point is even more apparent in the case of Newfoundland, where there is an implicit assumption that the returns remaining with investors from more profitable projects will provide sufficient compensation.

6. *Inflation adjustment.* Provision for recovery of expenditures as incurred (money-of-the-day terms) protects the investor from cost inflation. As long as shifts in long-term bond rates properly reflect general inflation, the return allowances move in the right direction.

7. *Risk sharing.* Because royalty flows do reflect economic rents, while at the same time providing for minimum royalties once production starts, the division of risks between owners and producers seems reasonable. However, the regimes have not been subjected to full risk analysis in this paper, and therefore this conclusion can be only tentative. And an absence of up-front cash bids for licences in either scheme precludes any further shift of risk from governments to producers, shifts that occur in other jurisdictions. The most important determinant of risk for the producer is the amount of exploration required for a given venture. The higher the proportion of exploration costs entering payout calculations, the lower the required threshold return allowance. The generally more lenient Newfoundland net royalty rates could be seen as compensation for constraints on eligible exploration costs.

8. *Competition with other jurisdictions.* Both schemes have been developed over a period of time, have had input from industry groups and the federal government, and are patterned on regimes for comparable resource endowments. Their evolution suggests that from a private industry standpoint the schemes do not suffer by comparison with those in other offshore regions, such as the North Sea and Australia. Recent exploration licence activity in Nova Scotia attests to the competitiveness of that regime.

Administrative criteria

1. *Cost.* No assessment of the cost of resource administration has been made. But there is little reason to assume the schemes will not be efficiently administered. Their design, while certainly not simple, is not so convoluted as to induce bureaucratic overload for both payers and payees.

2. *Transparency.* The schemes are transparent and their provisions leave little scope for manipulation and discretion by administrators. However, although I have entered a response of "yes" in the table, the tiered structure of both schemes can inhibit public perception of how royalty payments will evolve.

3. *Robustness.* Given the payout provisions and the treatment of royalties as a function of net profits after payout, the schemes are able to handle unanticipated fluctuations in prices and costs. Unless net profits emerge, project royalties will be confined to the relatively low gross royalty percentages. This is all well and good, since substantial royalties should not be inflicted on marginal (low-profit) projects. Provision has been made for the respective governments to take royalties in kind and withhold production if, as owners, they view prevailing prices as unfavourable.

4. *Consistency.* Over the initial project years, the flow of royalties should be quite consistent and predictable, though affected by the variability of prices. However, after payout the level of royalties payable by an individual project could be subject to quite considerable fluctuations over time, and in that way the schemes are not well calibrated to achieve even flows. But their transparency does assist prediction of the impact of changing conditions.

Summary Comment

Application of royalty evaluation criteria to the generic offshore oil regimes of Nova Scotia and Newfoundland does not reveal appreciably different "scores" between the two. Both rely on a profit-sensitive component that attempts to approximate a tax on economic rent; at the same time, returns accrue to governments, irrespective of eventual project profitability. Both satisfy the majority of the adopted criteria; neither posts flagrant violations. The schemes are not punitive. Some deficiencies are disclosed, but they do not lead to fundamental or corrosive distortions. Overall, then, the regimes are sensible. But my earlier caution that the evaluation excludes empirical analysis remains germane. And the relative weight placed on the evaluation criteria can vary by project, and also over time as markets fluctuate.

SECTION 6
CLOSING REMARKS

One dictionary definition of tax is a "contribution levied on persons, property, or business for support of government." Although royalties may be used to support government, that is not their raison d'être. Rather, royalties derive from ownership of resources by the Crown. Thus, a functional distinction can be made between royalties and general tax revenues. In this light, the principles governing taxation do not apply in equal measure to royalty incomes.

It also follows that royalties, if properly conceived, should not be viewed as a tool for macroeconomic policy – that is, for management of aggregate demand and supply. Neither should royalties be viewed as a correction for side effects as, say, a tax on cigarettes might be seen as reducing the perceived and unperceived social costs of tobacco addiction.

Royalty schemes should not be developed in a vacuum, without reference to the overall fiscal system in which they are embedded or in isolation from other government objectives. A key feature for both provincial governments is how resource royalties interact with the Equalization program, a topic not broached in this paper. What is crucial for producers is the overall burden imposed by the federal and provincial tax and royalty systems in tandem.

The Nova Scotia and Newfoundland regimes have not been designed in isolation; they rely on those adopted earlier in jurisdictions facing large discrete projects with long lead times. Such reliance suggests that prospective returns to governments and producers are seen by both parties as reasonable, that the schemes are competitive, and that they will not deter continued investment. In the case of Nova Scotia, recent applications for, and awards of, licences on the Scotia shelf attest to competitiveness by promising exploration of riskier prospects. In short, producers are not enjoying a free ride, and governments are not trying to grab too much.

Empirical analysis of the regimes may reveal some discontinuities and limitations. But there is nothing obvious to indicate that such analysis would disclose fundamental flaws. I believe my conclusion – that the two generic royalty systems examined are well founded – would be sustained. That said, concerns remain about the ability of producers to fully recover costs in the context of the overall tax burden confronted, the magnitude of the total tax take on incremental project income, and the transferability of losses between projects. These residual concerns suggest the regimes should not be etched in stone. Adjustments may well be required not only in response to revisions in competing jurisdictions but, as exploitation of a basin matures and the typical size and costs of new discoveries change, with a need to encourage full resource recovery.

It appears that unless project timing is such that fluctuations in individual project royalty flows are smoothed by project aggregation, total royalty receipts could be volatile. This emphasizes the need for governments to husband royalty income wisely and to avoid expenditure obligations that rely on a continuation of what may prove to be peak receipts.

The award of exploration licences on the basis of proposed expenditures (work bids) adopted by Nova Scotia and Newfoundland enjoys some rationale early in the development of a basin, with the incentive provided to garner information on physical features. But enthusiasm for work bids should be tempered by the perverse incentives provided for spending rather than efficiency. More consideration should be given to awarding licences by cash bids, thereby providing early cash flow for governments, an offset to the back-end loading of royalty flows inherent in RRR-style provisions.

More generally, a combination of cash bids, modest gross royalties that commence at production start up, and RRR-style taxes offers the best hope of collecting a suitable share of rents for governments without introducing distortions. The royalties so generated would offer governments early cash flows followed by additional cash flows in later years, as projects mature. The cash bid element is as yet missing from the offshore resource tenure arrangements for both regimes. It would reduce any need for high rates of profit-related royalties, thus helping to avoid possible efficiency losses.

Finally, some commentators have suggested that, in preference to the schemes adopted, Alberta's system of sliding-scale well production royalties provides a suitable template for the Atlantic provinces. But the circumstances in Alberta – a mature petroleum basin with a finely subdivided land tenure system predicated primarily on wells, not large-scale projects – are very different from the east coast offshore. Shrinking the royalty unit to an individual well would aggravate the problem of cost attribution and rent identification. Alberta attempts to overcome this problem by the quite rustic technique of linking royalties to well output and wellhead prices, but not to profits. Such mechanisms would be especially inappropriate for large-scale projects in high-cost inhospitable regions – precisely the conditions confronting east coast offshore developers. Notably, high cost megaprojects in Alberta (such as at Cold Lake) have attracted RRR-style schemes that preceded, and have much in common with, those in Nova Scotia and Newfoundland.

APPENDIX A
TECHNICAL DETAILS ON THE RESOURCE RENT ROYALTY (RRR)

This appendix deals with some technical aspects relating to the discussion of RRRs in Section 3.

Equivalence of Brown Tax and Lease Auctions

A fully competitive standalone lease auction yields the same results as the combination of a Brown Tax (BT) on cash flow and a lease auction with the cash bid not allowed as a tax deduction. To illustrate this statement, suppose the tax were set at the rate α. If the capitalized value of the property (its net present value) in the absence of the Brown Tax were V_o, the net present value of the property at auction in the presence of the Brown Tax, V_α, would be

$$V_\alpha = V_o(1 - \alpha)$$

With a fully competitive auction, the winning bid in the absence of the Brown Tax would be V_o. In the presence of the Brown Tax it would be V_α.

The present value of the government's stream of payments and receipts from the Brown Tax, R_α, would be

$$R_\alpha = \alpha V_o$$

Hence the total value to the government, T_α, of expected revenue from the combination of the auction and the tax is

$$T_\alpha = R_\alpha + V_\alpha = V_o$$

precisely the same as the winning bid without the Brown Tax, namely the present value of the flow of economic rent generated.

Expected Values to Investors under a Brown Tax

Suppose a project comprises exploration expenditure E and development expenditure D. Exploration precedes development, but for simplicity no allowance is made for a time interval between them. The probability of exploration success, p, initially governs whether development takes place. If development were successful, with probability w, an ongoing return of $R - C$ would be received (revenue R net of operating cost C). Although the return will accrue over an interval of time, assume it accrues at one point in time, T. As before, the rate set under the Brown Tax is α.

With a Brown Tax the expected net present value to the project developer is

$$V_D^{\mathrm{BT}} = -(1-\alpha)(E + pD) + (1-\alpha)pw(R - C)e^{-rT} \qquad (1)$$

where r is the opportunity cost of capital *unadjusted for risk*. The first term on the right-hand side of the equation represents the net investment cost to the developer; the second term represents the present value of the future expected net cash flow (Bradley and Watkins 1987, 280–1).

Expected Values to Investors under an RRR

Using the previous nomenclature and simplifying assumptions, the expected net present value for the developer subject to an RRR can be written as

$$V_D^{\mathrm{RRR}} = -(E + pD) + pw(R - C)e^{-rT} - \alpha pw[(R - C) - (E + D)e^{r^*T}]e^{-rT} \qquad (2)$$

where, as before, r is the opportunity cost of capital unadjusted for risk, and r^* is the deemed threshold rate. The first term of this expression is the expected cost of the up-front investment; the second term is the present value of the net revenue; and the third term is the present value of the RRR (ibid., 281).

Comparison of an RRR and a BT

The RRR can be compared with a BT by combining equations (1) and (2):

$$V_D^{\mathrm{RRR}} = V_D^{\mathrm{BT}} - \alpha(E + pD) + \alpha pw(E + D)e^{(r^* - r)T} \qquad (3)$$

Equation (3) shows the expected net return for the developer with the RRR as the net return under a BT, less a tax on investment, plus a subsidy (ibid.). In a world of certainty (where $p = w = 1$), if the threshold rate r^* were set at the company opportunity cost of capital r, it follows that the expected company net return would be the same under the RRR and the BT. Otherwise, equivalence depends on equating the value of the "subsidy" with the value of the "tax" on investment. Again, a single threshold rate across all projects will introduce a bias against risky ones because the spread between r^* and r will compress when r increases on account of higher risk. Equation (3) also shows how a generous threshold rate can provide a full loss offset to the tax on investment represented by $\alpha(E + pD)$.

Given full loss offsets, an RRR can be exactly equivalent to a BT if the threshold rate for compounding nominal RRR credits are set equal to the nominal interest rate, before tax, on government bonds. This holds even if project risk is such that an investor's expected return on equity is far above the government bond rate. The details are given in Fane and Smith (1986, 8–9). The intuition is that as long as companies are able to use their RRR credits, project risk is irrelevant in their valuation because the credits are equivalent to loans from the company to the government, which the company can neutralize by lending less (or borrowing more) in the bond market.[30] More generally, if the threshold rate were the same as the company's after-tax cost of capital, and as long as credits carried forward at the threshold rate are eventually redeemed, a project subject to a BT or an RRR would show no difference in terms of net present value.

[30] The demonstration assumes that a company actively participates in the government bond market.

APPENDIX B
RRR-STYLE REGIMES IN AUSTRALIA, CANADIAN FRONTIER LANDS, AND THE UNITED KINGDOM

This appendix provides the details underlying summaries in Section 3 of the Australian, Canadian Frontier Lands, and UK North Sea royalty regimes.

Australia

The following is mainly drawn from Kemp (1987, 28–9) and Fane and Smith (1986, 10).

In Australia, the Crown owns all petroleum in situ. The Resource Rent Tax (RRT) was proposed on July 1, 1984, to apply to greenfield offshore projects, for which production licenses were awarded after July 1, 1984. Certain areas were excluded from the new tax.

The RRT is levied on net cash flows, before company income tax, for projects that have achieved a specified return. The return is 15 percent plus the long-term pre-tax bond rate. When the tax was introduced, the latter was around 14 percent. Hence the total threshold rate was about 30 percent. The threshold rate compounds pre-tax (negative) cash flows until a positive cumulative cash flow emerges. At this stage a tax rate of 40 percent is levied. All relevant exploration, development, and operating costs are allowed as immediate deductions. Payments and receipts related to financing are excluded.

The RRT is assessed on a *project* basis, with the project defined to include the production area licence plus facilities outside the licence area necessary to obtain marketable petroleum. Thus the tax base could include a number of proximate fields. For income tax purposes, the RRT is deductible.

A subsequent RRT-style tax was imposed on an offshore field (Barrow Island). The main difference between it and the original RRT was that the threshold rate was to be set by arbitration, predicated on the cost of capital.

In summary, the Australian RRT employs a tax rate of 40 percent, the tax is applied on a project basis, and unsuccessful projects are denied full loss offsets. To compensate, the threshold rate was originally set at 15 percentage points above the bond rate for carry forward of most RRT credits. Pre-tax losses are compounded at the threshold rate.

Canadian Federal Government Frontier Royalty Regime

The following description is partly drawn from Natural Resources Canada (1998, 131–2).

The *Canadian Petroleum Resources Act* (CPRA) royalty regulations are similar in structure to the Alberta Cold Lake agreement, a regime that has pretty well provided a model of royalty structures for Canadian offshore and frontier lands. The Cold Lake type of royalty – a fixed share and profit-based share – recognizes the right of the Crown, as owner of the resource, to a portion of production, yet is sensitive to profitability.

The development of offshore and frontier resources requires long lead times for exploration, delineation, and project construction, during which no revenue would be generated. High financial risks associated with such projects encourage recovery of capital costs as quickly as possible once the project starts to generate cash flow. Thus, a fiscal regime sensitive to these factors would collect minimal returns during the initial production years; substantial returns would be garnered after capital recovery.

The basic royalty formula combines a low gross royalty in the early years of the project and a relatively high net-profits royalty when invested capital (including a return on it) plus current costs have been recovered. It is imposed on a project basis. Pre-payout royalties are 1 percent of gross revenues for the first 18 months, rising by single percentage point increments to 5 percent after six years. Post-payout royalties are the greater of 30 percent of before-tax project profits or 5 percent of gross revenues. Provision for upfront floor royalties ensures an initial, basic flow of government revenue, irrespective of project profitability.

Gross revenues are revenues from sales netted back to the oil loading point. Project payout occurs when cumulative gross revenue first equals the sum of total allowed capital costs, operating costs, overhead allowances, royalties paid, and a cumulative return allowance.

Eligible costs are confined to those occurring on project lands. *Capital costs* include costs of exploration, discovery and delineation, development drilling, and extraction. These costs are net of any direct government assistance. *Operating costs* cover direct costs plus an overhead allowance for costs incurred beyond the project.

The federal government *return allowance* consists of a nominal rate of return on outstanding capital of 10 percent above the long-term bond rate. The allowance commences only after development plan approval. It is calculated monthly and compounded. When the scheme was put forward in 1987, the effective return allowance was some 20 percent.

An Investment Royalty Credit (IRC) is available for new exploration wells on frontier lands. Such credits could be used to reduce royalties payable on another project under the jurisdiction of CPRA. Effectively, there is a *frontier* ring fence for these credits, but not a project ring fence. However, the credits are deductible from eligible exploration costs in calculating payout.

United Kingdom

Much of the basic description here is drawn from Kemp (1987, 30–4).

UK petroleum rights are vested in the state (*Petroleum Production Act* of 1934, extended to the UK continental shelf in 1964). Special taxation of petroleum dates to 1975. The *Oil Taxation Act* was passed, ensuring that three different taxes would be levied on North Sea oil: a traditional royalty linked to the role of the state as property owner; normal corporation tax; and the Petroleum Revenue Tax (PRT). Here, we focus on the PRT.

The PRT is a special tax on North Sea oil exploitation, levied on a field-by-field basis. The original rate of 45 percent applied to a base consisting of gross revenue less a number of allowances. The allowances comprised any accrued field losses, operating costs, royalties, 175 percent of the main field capital costs (the extra 75 percent was the called *uplift*), field related exploration costs, and an oil allowance (the value of a stipulated absolute volume of oil). The capital cost allowance deduction was fully expensed. Interest on loans was not deductible – the substantial uplift allowance was seen as compensation for this. The uplift allowance was also seen to give help to small fields, as was the oil allowance. Both of these adjustments can be viewed as an attempt to better target economic rent: smaller fields tend to be less profitable on a unit basis. Some older fields were exempt, and there was provision for refunding, or waiving of, the PRT (Devereux and Morris 1983, 15). PRT is deductible from corporation tax (Bland 1991, 11).

A one-way ring fence was established around petroleum exploitation: losses and capital allowances emanating outside the ring fence cannot be used against income arising within the ring fence. But losses arising within the ring fence can be set against other non-ring-fence income.

Further adjustments were made via *safeguard* and *tapering* provisions. In broad terms, these provisions stipulated that if gross field profits for any year were less than 30 percent of accumulated field investment (an accumulation that does not include a return), the PRT would be zero, and the maximum PRT in any year would be 80 percent of the excess of gross profits over 30 percent of total field investment.

Both of these adjustments, and the uplift allowance, can be interpreted as compensation for the fact that *the PRT does not incorporate a threshold return.* In effect, the PRT becomes payable after simple payback, subject to the safeguard provisions (Bland 1991, 36; Peat Marwick 1986, 7).

After 1975 several changes were made to the PRT. In 1979 the rate was increased to 60 percent, and both the uplift and the oil allowance were significantly reduced. A further increase in the PRT (to 70 percent) was made in 1980. In 1981 the safeguard and tapering provisions became more restrictive. And in 1981 a new tax, the Supplementary Petroleum Duty (SPD), was imposed on a field basis. The rate was 20 percent of gross revenues less an allowance of a fixed output quantity. The duty was deductible from the PRT and corporation tax. It was abolished in 1983. But, at the same time, the PRT rate was raised, and an advanced PRT (APRT) was introduced, similar in form to the discarded SPD but credited against PRT (Kemp 1987, 31–2).

This bevy of changes to the PRT (and the introduction of the SPD) during the period 1979–82 covered the second world oil price shock. The new measures were clearly intended to garner more economic rent for the government as resource owner.

In 1983, PRT concessions were made: exploration costs could be applied more generally across fields against income subject to PRT, and the oil allowance was increased. In 1987 further PRT concessions were made: some across-field allowances for development costs were introduced, and certain R&D costs were allowed as a deduction. These changes reflect perceived declines in rents available to attract tax.

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