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Unitary Taxation in the Extractive Industry Sector

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International Centre for Tax and Development,
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Tel: +44 (0) 1273 91606261 Fax: +44 (0) 1273 621202
E-mail: info@ictd.ac
Web: www.ictd.ac

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Summary

This paper analyses whether a global unitary taxation approach to corporate income tax (CIT) can improve the ability of governments to design and administer efficient and effective tax and royalty policies for the extractive industries. Drawing upon experience with unitary approaches to corporate income taxation of the extractive sectors in subnational taxation systems of the United States (US) and Canada, this paper suggests that a unitary CIT should not be used in isolation, or be employed as the dominant source of revenue from the extractive sector. Instead, because of its informational and risk-aligning advantages, a unitary CIT may be best used in combination with other rent/profit-related levies on the extractive sector. At the same time the rent/profit-related levies may be assessed on a more limited base, such as source jurisdiction, in order to alleviate source entitlement concerns. Within this context a unitary CIT is recommended, because it enables more effective design and administration of all taxes in the extractive industries sector.

Keywords: unitary taxation; formulary apportionment; combined reporting; extractive industries; natural resource taxation; royalties; US state corporate income tax system; Canada provincial corporate income tax system.

Erika Dayle Siu is a Tax Research Consultant, and has worked for the United Nations on a project to exchange successful tax practices among developing countries. She holds an LL.M. from New York University School of Law.

Sol Picciotto is Emeritus Professor of Law at Lancaster University (UK), and a member of the Advisory Group of the International Centre for Tax and Development.

Jack Mintz is the Palmer Chair and Director of the School of Public Policy at the University of Calgary. He is widely published in public economics including taxation. He has consulted on corporate and resource tax reform with the World Bank, International Monetary Fund and the Organisation for Economic Co-operation and Development (OECD), as well as numerous governments. He chaired a business tax reform commission for the Canadian Minister of Finance in 1996-7.

Akilagpa Sawyerr is a Professor of Law and Head of the law firm, Laryea, Laryea and Co. He has led Ghanaian Government negotiations with multinational corporate investors. He holds a JSD degree from the University of California, Berkeley.

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Acronyms

BEPS	Base Erosion and Profit Shifting
BIT	Bilateral Investment Treaty
CbCR	Country-by-country reporting
CCCTB	Common consolidated corporate tax base
CIT	Corporate income tax
EI	Extractive Industry
EU	European Union
EITI	Extractive Industries Transparency Initiatives
FPT	Freehold production tax
GDP	Gross Domestic Product
IRC	Internal Revenue Code
LTBR	LIBOR (London Interbank Offer Rate) - Treasury Bank Rate
OECD	Organisation for Economic Co-operation and Development
MACRS	Modified Accelerated Cost Recovery System
PPT	Petroleum Production Tax
SE-ALP	Separate entity - arm’s length principle
TNC	Transnational corporation
US	United States
UT	Unitary Taxation

Introduction

The purpose of this paper is to assess the global unitary taxation (UT) approach as applied to taxation of the extractive industry (EI) sector.[1] Governments of resource-rich countries that own extractive resource deposits rely on resource revenue from the extractive industry to fund their public services. Transnational corporations (TNCs) or private producers that agree with governments to extract non-renewable resources seek profits from the development of resources. The relationship between private producers and governments is therefore akin to that of principal and agent, with the government as principal and the private producer as the agent.[2]

The aims of a government's fiscal design are threefold.

- As owner of the resource, the government is entitled to the economic rent, defined as the difference between revenue and the full economic cost of exploring, developing and extracting the resource.
- To attract the most efficient private producer to extract the resource, a rate of return, net of fiscal levies, should be offered that is comparable to opportunities elsewhere.
- The levy should be as efficient as possible with minimal distortions, to maximise the rent available to both the government and the producer.[3]

Governments raise resource revenue through a variety of EI levies, including company/corporate income tax (CIT), severance (or resource) taxes, royalties, bonus bids (payments on contract signing) and production bonuses (payments at certain levels of production), as well as rental payments, property, sales and capital gains tax, each of which affects incentives for private producers to invest in the jurisdiction.[4] The economic aims of CIT include backstopping personal income tax and ensuring that companies, which benefit from public services, contribute to their costs (Mintz 1996). Royalties, severance taxes and production bonuses, which are *ex post* payments and may be volume-based, revenue-based (*ad valorem*) or rent/profit-related,[5] are payments made by companies to governments for the right to extract resources. Bonus bids or rental payments are *ex ante* payments for the property right to explore for a resource.

Considerable research and policy debate is now attempting to improve the design of taxation, particularly of mining and extraction of hydrocarbons.[6] Unitary taxation as a basis for CIT is currently used to apportion company income across tax jurisdictions at the subnational level in several countries, such as Canada, Switzerland and the US, rather than

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1 This paper is a discussion of the use of a global unitary taxation approach to CIT and its effects on taxation of the entire extractives sector, including the mining and oil and gas subsectors. While acknowledging the major differences between these subsectors, the focus of this analysis is how a unitary approach to CIT affects the design and implementation of other resource taxes on extractives. Thus, case studies from Canada and the US will include both mining and oil and gas subsectors. An area of further research could include more specific treatment of these subsectors.

2 See Mintz and Chen (2012).

3 Here we use the term efficiency to denote allocative or economic efficiency. A tax system achieves economic efficiency if resources are put to their best use to maximise economic welfare or a standard of living. A company tax is efficient if capital is allocated to its most productive use.

4 A severance (or resource) tax is imposed by the state on the producer for the removal of a non-renewable resource, such as oil, gas or hard minerals. Most US states impose severance taxes in addition to royalties, while Canadian provinces impose royalties on the extraction of natural resources.

5 We use the term 'rent/profit-related' to refer to levies that take account of costs and revenue, while acknowledging that the rent levy is not the same as the tax on profits under a CIT or profit-based levy. Rent-based levies provide an explicit or implicit deduction for the full cost of financing including the imputed cost of equity financing and full loss offsetting, while profit-based levies only account for income and costs for the purposes of calculating company profits, which does not include all economic costs, such as the implicit cost of equity financing. See Section 1.2 and Mintz and Chen (2012) for further explanation.

6 See especially Daniel et al. (2010) and IMF (2012). The policy prescription currently favoured for developing countries is a combination of CIT, Rent Resource Tax (RRT) and *ad valorem* royalty (IMF 2012: 26 para. 48).

to rely on separate accounting and the arm's length principle (SE-ALP) to determine the tax base in the province or state.[7] Discussions continue to develop a common consolidated corporate tax base (CCCTB) at the regional level among European Union (EU) members, following a UT approach. In recent years, there has also been renewed interest in unitary taxation and formulary apportionment as an alternative to SE-ALP.[8] Yet to date, despite the existence of various models at the subnational level, there has not been analysis of how a UT approach would apply, particularly, to taxation of the EI sector. The purpose of this paper is to discuss whether a global UT approach to CIT can improve the ability of governments to formulate and administer optimally designed tax and royalty policies for the EI sector. We suggest that there are three reasons it could do so.

First, UT could assist governments not only to improve general CIT design but also to develop better rent/profit-related EI levies. Both CIT and rent/profit-related EI levies pose similar problems in relation to the determination of appropriate transfer prices for inputs, allocating overhead costs (general administration and other joint costs) and financing expenditure, with opportunities for what is now described as base erosion and profit shifting (BEPS). In addition, the use of UT based on a common global corporate group tax base for TNCs in the EI sector could reduce administration and compliance costs associated with both CIT and rent/profit-related levies.

Second, the development of new transparency rules under the Extractive Industries Transparency Initiative (EITI), implemented in over forty countries as of this writing, as well as new legislation in the EU and US, and wider G20 initiatives to improve transparency, will result in the reporting of payments to governments by EIs. Public information on tax payments will allow states to evaluate whether they are receiving appropriate revenue from EIs. To the extent that governments, under pressure from public opinion, feel that insufficient revenue is being raised, they may gravitate to less efficient forms of taxation that discourage investment in their jurisdiction. A UT approach, which requires country-by-country reporting on revenue, costs and tax payments, and the apportionment of global revenue based on that information, could assist in the development of better EI levy policies that are sensitive to the risks and costs incurred by private companies in extracting resources.

Third, a UT approach to CIT in the EI sector would better align the risks and rewards of natural resource extraction among governments and private producers. A unitary approach would allow global offsetting of company profits, as well as provide information for better-designed EI levies and reduce fiscal distortions affecting EI investment. TNCs invest until the return is sufficient to cover the cost of capital including depreciation, inventory cost and risk. A unitary approach to CIT in the EI sector would, thus, maximise the overall rent shared by the government and private producers.

Our full discussion of these issues follows below. The first section provides background on issues related to EI fiscal levies. The next sections look at how the UT approach to CIT, as developed in Canada and the US, is applied to the EI. Following that, we will consider whether and how a global UT approach to CIT could improve the design and implementation of rent/profit-related levies imposed on the EI.

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7 Some scholars use the term 'unitary' to refer exclusively to systems that define a corporate group according to the unitary business principle and then combine the tax base, and reserve the term 'formulary apportionment' to refer exclusively to systems that apportion the tax base regardless of the method of aggregation. See, e.g., Hellerstein (2005: 105): 'Formulary apportionment is compatible with - but by no means required by - consolidated reporting, at least as a matter of principle'. In this paper we treat the entire spectrum of cross-border aggregation of the tax base as unitary approaches, while specifying the methods used by each system in the discussion.

8 See, e.g., Weiner (2005); Roin (2008); Avi Yonah et al. (2009).

1 Background on fiscal regimes in the extractive sector

The exploitation of natural resources, especially extraction of oil, gas and hard minerals, is key to the economic development of many developing countries. Indeed, it has been central to their integration into the global capitalist economy. Large foreign-owned firms, often vertically-integrated, dominate natural resource extraction. However, there continue to be local small-scale miners in some countries, especially in hard minerals, although they often find it hard to survive competing in a sector that is capital-intensive and has important economies of scale, and may be either bought out or expropriated. Where they do continue, they may range from truly artisanal (usually alluvial) mining, to operations using increasingly sophisticated machinery, generally with small-scale foreign financing and technical leadership. Some apparently make more than a decent living, while remaining sometimes illegal and generally outside the tax net.[9]

Attracting foreign investment is generally considered necessary for large-scale exploitation, and beneficial for economic growth. However, apart from a few countries with a large local market and a sufficiently skilled workforce to provide services to the industry, minerals and hydrocarbons are usually exported with little or no local processing, so the economic spread effects are lessened. The capital-intensive nature of the sector also means that it does not create extensive employment in its operations. Although some policy measures to reverse both of these trends have been debated (Economic Commission for Africa 2011; Africa Progress Panel 2013), they are likely to remain characteristic of EIs in many developing countries, especially smaller ones.

Hence, revenue from EI levies is a significant benefit for host countries. Expectations have been high, especially in periods of relatively high world prices which help drive new investment and improved exploration technology. Yet the experience in many developing countries has been that government revenue from EI levies has been disappointingly low during boom years. Attention has focused especially on profit-based levies, and some have criticised the shift towards such taxes and away from volume-based levies (Lundstøl et al. 2013; Curtis et al. 2012).[10] Yet governments often introduce new tax incentives to encourage investment when profits are low or negative during downturns. Such instability in resource tax policy will discourage investment in the long run. A resource tax that recognises both revenue and costs is most efficient and fair to employ. However, profit measures can be difficult to assess unless prices and costs are determined independently, reflecting an appropriate market price for transactions.

Establishing an effective framework for fair and efficient taxation of the profits of large foreign-owned TNCs, which generally dominate the EI sector, has been especially challenging for smaller developing countries. A particular issue of concern is the widely-accepted separate entity principle applied in the assessment of profit-based levies – that is, for the purposes of calculating taxable income or profits, the affiliates of a TNC in different countries should be treated as if they were separate entities dealing at arm's length.[11] This paper results from a project that is part of a wider programme aiming to investigate the desirability and feasibility of a transition towards a unitary entity principle, which would treat an integrated TNC as a unitary firm and apportion taxable profits according to appropriate

9 e.g. the widespread practice described as 'galamsey' in Ghana.

10 There have also been inquiries and reports by governments, e.g. in Tanzania the Bomani Report (United Republic of Tanzania 2008). For an active public debate, notably involving the opposition shadow finance minister Zitto Kabwe, see <http://zittokabwe.wordpress.com/?s=mining>. For the legal framework of mining taxation in Tanzania, see Muganyizi (2012).

11 See Picciotto (2013).

criteria. The aim of this project is to investigate the implications of adopting a global UT approach for the EI sector. First, however, we will briefly discuss the related issue of transparency, which has been especially salient in the EI sector.

1.1 Complex governance and opacity

In many countries minerals are considered national assets, and are state-owned. To ensure their exploitation in the national interest, many countries nationalised concessions in the 1960s and 1970s with the establishment of state-owned firms (e.g. in hydrocarbons). However, even in countries where state-owned enterprises have become relatively powerful, they are still often dependent on foreign firms for capital investment, technology, management and market access. This results in various types of public-private joint ventures and production-sharing arrangements.

EIs entail large up-front investment resulting in sunk costs for exploration, development and setting up mining or drilling sites. The level of such investment has been rising fast, as exploitation has shifted to less easily-extracted deposits. Concessions are therefore often major projects, generally governed by detailed contracts between firms and investors with the government (OpenOil 2012, 2013). Overlaid on these contractual governance structures are national laws and regulations, as well as international treaties, forming a complex regulatory web. The resulting legal interactions can be surprising and contradictory, sometimes resulting in the creation of a specific regime for a firm and even for particular EI projects. In addition, tax treaties normally create preferential tax rules for foreign investors, such as reduced withholding taxes on dividend and interest payments. Bilateral Investment Treaties (BITs) also give foreign investors rights which can override national law, especially the prohibition of 'takings', and the obligation to give 'fair and equitable treatment', which may be interpreted to restrict actions such as the denial of tax exemptions or imposition of new or exceptional taxes.[12]

Special rights or privileges may also be given to investors under national mining/petroleum or foreign investment promotion laws, such as exemption from import duties for equipment, special depreciation rules, or 'standstill/stability clauses' that restrict the effects of subsequent changes in legislation. As a result, the contract or concession governing a particular project may insulate the investor from national law or regulation. However, as the recent *Tullow* ruling in Uganda illustrates, tax authorities have launched successful challenges against the application of preferential contract provisions that attempt to supersede tax laws enacted through a democratic process.[13] Such provisions often result in low government revenue from income and capital gains taxes on EI firms. Negotiation of these contracts is often the responsibility of mining ministries that regard their main role as attracting investment, disregarding the concern of tax authorities to ensure appropriate revenue to the state. Public concern about low EI revenue, especially in periods of high world prices, has led to renegotiation of contracts in a number of African countries, often focusing on revision of the taxation framework (Charlet et al. 2013).[14] In countries with extensive

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[12] e.g. hydrocarbon firm Occidental in 2004 was awarded US$71 million against the government of Ecuador under the US-Ecuador BIT, for denial of Value Added Tax refunds; the arbitral award was upheld by the UK High Court (*Republic of Ecuador v. Occidental Exploration and Production Co* [2006] EWHC 345 (Comm)). However, in 2006 Canadian energy firm Encana lost a similar dispute, partly because its investment in Ecuador had been through its Barbados affiliate (*EnCana Corporation v Republic of Ecuador*, London Court of International Arbitration, 3 February 2006).

[13] See *Tullow Oil v. Uganda Revenue Authority*, Uganda Tax Appeals Tribunal, Tax App. No. 4 of 2011 (16 June 2014). The *Tullow* case involved a dispute on the assessment of over US$400 million in capital gains taxes, which the private producer claimed were exempted through a provision in the production sharing agreement (PSA) contract. The Tribunal agreed that the exemption applied to the transfer that produced the tax assessment, but held that the exemption in the PSA signed by a government minister could not supersede tax laws passed by parliament. 'The framers of the 1995 Constitution of Uganda thought it wise that the people's representatives should be the most suitable persons to impose the taxes they should pay. So be it.' (Uganda Tax Appeals Tribunal, Tax App. No. 4 of 2011: 52).

[14] In Tanzania existing mining development agreements restricted the applicability of the reforms introduced in 2010; see Muganyizi (2012).

natural resources the stark contrast between the large revenue flows generated, and the lack of any evident resulting benefits for the vast majority of the population, has generated debate about the ‘resource curse’.[15] The ad hoc nature of concession contracts and other structural features of EI investment make this sector particularly prone to corruption.

An important response has been the development of transparency obligations, in the form of country-by-country reporting (CbCR). The EITI has established a global standard for disclosure of company payments and government receipts, governed by a multi-stakeholder model.[16] This has now inspired formal legal requirements in the US and EU. The Dodd-Frank Act[17] introduced an obligation for any company subject to Securities and Exchange Commission (SEC) filing requirements to report on a country-by-country basis any payments made to government or public agencies in connection with development of oil, gas or mineral reserves, by project and business segment. Although the detailed regulations under Dodd-Frank have been the target of frequent legal challenge, as of this writing a little over half the required rules have been finalised.[18] Meanwhile, the EU Accounting and Transparency Directive was approved in July 2013;[19] this will require reporting (for financial years after 2016) by companies formed in the EU involved in oil, gas, minerals or logging of natural forests, of payments made to each government and per project.

These specific provisions for CbCR in the EI sector will apply in parallel with the more general arrangements being developed as part of the OECD BEPS project, resulting from the G8 Lough Erne Declaration and the G20’s St. Petersburg Declaration Tax Annex (OECD 2014). A significant difference is that the specific EI regulations aim at public disclosure, whereas the OECD envisions disclosure only to tax authorities. However, the information to be included in the CbCR tax-reporting template is likely to be more extensive.

The introduction of CbCR will have a major impact on TNC taxation. In the EI sector, where it has been spreading for some time due to the EITI, this impact is already becoming evident. The increased transparency resulting from EITI reporting has greatly contributed to the heightened public awareness and debate, fed by reports that have used the published data.[20] The standardised template for CbCR being developed by OECD could also be an important tool for tax authorities. At the same time, the development of this template should take into account both the characteristics of specific important industry sectors such as EI, and the ways in which tax authorities might wish to use it in applying UT approaches to such sectors. This project aims to begin to map out and examine such approaches. In the remainder of this section we will briefly analyse EI taxation and the implications for it of international tax rules, especially SE-ALP.

1.2 EI taxes and their treatment under international tax rules

Fiscal regimes for the extractives sector are distinctive in that, in addition to the usual CIT on business profits, states generally seek to tax the rent from natural resource extraction through levies, such as royalties and severance (or resource) taxes. Economic rent (sometimes called ‘above normal profit’) is defined as the excess of revenue over the costs of discovery, development and production, less a normal return to capital.

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15 Countries with better governance overcome the resource curse, with their resource sectors associated with above average Gross Domestic Product (GDP) growth rates (e.g. Canada, Netherlands, Norway and the US). Other countries experience a resource curse with a resource sector associated with lower GDP growth rates, in some cases negative growth rates. See Gelb (2014).

16 The EITI Principles were agreed at a conference in London in 2003, and the EITI Standard, extending to implementation, governance and management, was adopted in 2013; see <http://eiti.org/>.

17 Wall St Reform and Consumer Protection Act 2010, s.1504.

18 Davis Polk, *Dodd-Frank Progress Report* available at <http://www.davispolk.com/Dodd-Frank-Rulemaking-Progress-Report/> (last accessed 9 July 2014).

19 Directive 2013/34/EU, to be implemented by member states within two years.

20 Such as Mintz and Chen (2012).

Depending on the choice of base, each type of EI levy captures varying amounts of economic rent. Rent-based levies are specifically designed to capture economic rent, distinguishing it from other volume-, revenue- or profit-based levies. First, a rent-based levy differs from a profit-based levy because it provides an explicit or implicit deduction for the full cost of financing including the imputed cost of equity financing and full loss offsetting. A profit-based levy, however, typically only accounts for income and costs for the purposes of calculating company profits, which does not include the cost of equity financing. Revenue-based or *ad valorem* levies take account of market prices, but they do not explicitly incorporate costs into the base. Finally, volume-based levies are assessed on production output and do not explicitly incorporate costs or market prices. In early stages of exploration and production a rent-based levy will generate negative returns, which may be carried forward as losses under a Resource Rent Tax (RRT) or be refundable under an R-based cash flow tax.[21] However, once all economic costs are covered, rent-based taxes can be expected to produce significantly higher revenue than volume-, revenue- or profit-based levies.[22]

Although revenue- and (especially) volume-based levies are considered to be less precise instruments in capturing economic rent, there may be an inherent tension between the risk preference of the government and the private producer. This preference for risk will affect the timing of payout. Generally, governments with a low risk preference prefer earlier and continuous payout, and the private producer prefers payout at a later time after all economic costs have been covered. Hence, even though rent-based levies are more effective at capturing above normal profits from natural resource extraction, governments with lower risk tolerance may prefer early payments such as bonus bids as well as continuous payments such as rental payments and volume- or revenue-based levies. Another advantage of these types of early and continuous levies is that they are relatively easy to administer, since they do not require accounting of costs (or prices in the case of volume-based levies, bonus bids and rental payments).

However, volume-based levies (and revenue-based levies to some extent) used in isolation may have negative consequences for governments. First, because both levies disregard costs they may discourage investment, usually in the form of large up-front outlays for exploration, drilling, and construction of extraction and production facilities. Secondly, use of volume-based levies alone may result in less than optimal levels of rent at times of high prices. Given that revenue in the EI sector is notoriously volatile due to fluctuating commodity prices, capturing revenue on the upswing would be a distinct advantage for a government. Hence, such levies should be used in combination with other instruments that more precisely capture rent, and also such levies should be set at a relatively low rate so as not to discourage investment from private producers. By choosing a suitable mix of EI levies, a country may be able to optimise the advantages of each type.[23] These levies are outlined in Table 1.

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[21] See Daniel et al. (2010: 32-33).

[22] Government revenue may also be derived by other means, e.g. production sharing agreements, especially in petroleum; these are not considered here. However, similar issues may arise in that context - notably transfer pricing.

[23] Under rent-based tax, it is not unusual for governments to use a minimum tax based on revenue or volume to ensure payment early on when production begins to ramp up. If the minimum tax is fully credible against the rent tax, such as enabling any unused minimum tax payments to be carried forward at a rate of interest, the government receives more money up front and less in the future compared to relying on a rent tax alone. On a present value basis, the total rent collected by the government is the same in principle.

Table 1 EI levy classification and international tax implications

Timing of payout	Type of levy	Base	International tax treatment	Related party transaction issues
ex ante production	Bonus bids, rental payments*	Specific amount	Not eligible for credit, treated as expense	None
ex post production	Production bonus payments, volume-based royalty or tax	Generally unit of production	Not eligible for credit, treated as expense	None
	Revenue-based (*ad valorem*) royalty or tax	Generally price/revenue based	Unlikely to be eligible for credit, treated as expense	Need to benchmark product price
	Profit-based royalty or tax	Generally income minus costs (may include cost of capital)	Case by case determination	Must apply SE-ALP to related party transactions
	CIT	Profit-based: income minus cost of capital including depreciation, inventory cost and risk	Can be credited	Must apply SE-ALP to related party transactions
	Rent-based royalty or tax	Revenue and costs as in CIT plus costs of equity financing	May be eligible for credit	Must apply SE-ALP to related party transactions

* Rental payments can be *ex ante* or *ex post* payments, depending on contractual terms.

The choice of EI tax structure should also take account of the international tax implications. Formally, a country is only bound by international tax rules to the extent that it is party to treaties embodying them. Many developing countries have few such treaties (Lang and Owens 2014). Even without a treaty in place, however, a developing country may nevertheless be affected by international tax rules in two main ways. First, their governments may be advised of the desirability to abide by international tax norms, at least in general terms, to meet investor expectations. Secondly, recognition of the compatibility of a tax with international tax rules may have important implications: in particular, it may enable treatment of taxes paid as a credit against the tax liability of the parent company, rather than merely deductible as an expense. A tax that falls within those defined (and usually specifically listed) in a tax treaty is legally entitled to a credit, at least for countries which provide such credits. However, countries such as the US also grant a unilateral foreign tax credit in specified circumstances.[24] Eligibility for credit is limited to taxes that correspond or are equivalent to the income or profit tax against which they are to be credited.[25] Hence, they are unlikely to be available for taxes that are not profit-based, such as a volume- or revenue-based levy. In most circumstances, a credit is more beneficial to the company than expensing the payment (and, in any case, eligibility for credit usually allows the company to choose). Consequently, profit-based taxes are less likely to deter inward investment.

Table 1 shows that only non-profit and non-revenue-based taxes are free from the problem of evaluating related party transactions. The more a tax is profit-related, the greater the complexity of evaluation. A revenue-based levy poses the problem of pricing the revenue derived from sales of the product at the wellhead or pitmouth, since observed prices are at a market to which the product must be transported. However, in the case of a vertically-integrated firm, such sales will be to affiliates and the firm's revenue will ultimately come from sales of refined or processed products to third parties. The intra-firm contract price must therefore be evaluated against a suitable benchmark.[26] Although world market price benchmarks exist for some types of resource, such as crude oil and many minerals, they cannot be used directly without adjustments, especially for the quality of the specific product involved and its location. Even with adjustments, such prices may not reflect the real value to the company. Some parts of the EI sector are so dominated by large firms that market prices do not exist, or are clearly unsuitable. For minerals, such prices are often for refined product

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[24] In the UK under the Taxation (International and Other Provisions) Act (TIOPA) s.8, and in the US under Internal Revenue Code (IRC) ss. 901-908.

[25] Crediting is possible in the US for some rent-based taxes that are not typical CITs. See McLure et al (forthcoming).

[26] This poses fewer problems than for manufacturing firms, since raw material commodities are more widely traded.

and require complex ‘netback’ calculations to arrive at appropriate export prices (IMF 2012: 30).

Rent/profit-related levies directly pose the issue of compliance with international tax rules, especially SE-ALP, which requires the tax authority to assess the profits of the local affiliate by starting from its own accounts, and adjust intra-firm transaction prices using accepted transfer pricing methods. Related party transactions on the cost side may include intra-firm charges for joint costs such as management fees and technical services, and royalties for intellectual property rights. The latter have become increasingly significant, as technology has become more important for EIs. These rent/profit-related levies could provide a presumptive charge for joint costs (as well as intellectual property rights), and use standard available benchmarks for direct costs. Issues may still remain, such as pricing of equipment transferred from related parties that make such simplified methods unsuitable in evaluating costs from related party transactions. On the revenue side, as mentioned above, revenue may be evaluated using appropriate and easily available benchmarks, such as exchange traded prices (Charlet et al. 2013). However, these may not reflect the real value to the company, which is more important for profit-based levies. Even a slight variation may make a big difference for profitability. This variation is further magnified if the same benchmark is used for both revenue-based and profit-based levies, due to the high marginal rate resulting from accumulation.

Finally, probably most significant for rent/profit-related levies in the EI sector is dealing with opportunities for tax avoidance through financial engineering, since the high level of investment involved means that financing terms are very significant. Also specific financial techniques are available for EIs, notably the use of derivatives that can be designed to attribute losses to affiliates in high-tax countries and profits to those in low-tax jurisdictions (Aarsnes 2011).

2 Applying a unitary approach to the EI sector

The analysis above indicates that, unlike in other sectors, it is to some extent possible in EIs to avoid the problems posed by international tax rules, especially the challenges created by SE-ALP. Avoiding these problems requires reliance to a great extent on non-profit-based levies. However, economic analysis suggests that such taxes are suboptimal for capturing the highest level of economic rent. Indeed it was for this reason that advice, especially from the World Bank, led many countries to move towards greater adoption of rent/profit-related levies. However, for CIT and revenue-based and rent/profit-related levies, the related-party transaction issues have created difficulties for governments in administration and capturing revenue. Hence, it is important to evaluate how far, and in what ways, the adoption of a UT approach to aggregation and apportionment of the CIT base could provide helpful solutions for effective taxation in the EI sector, which would enhance the administration and design of rent/profit-related levies.

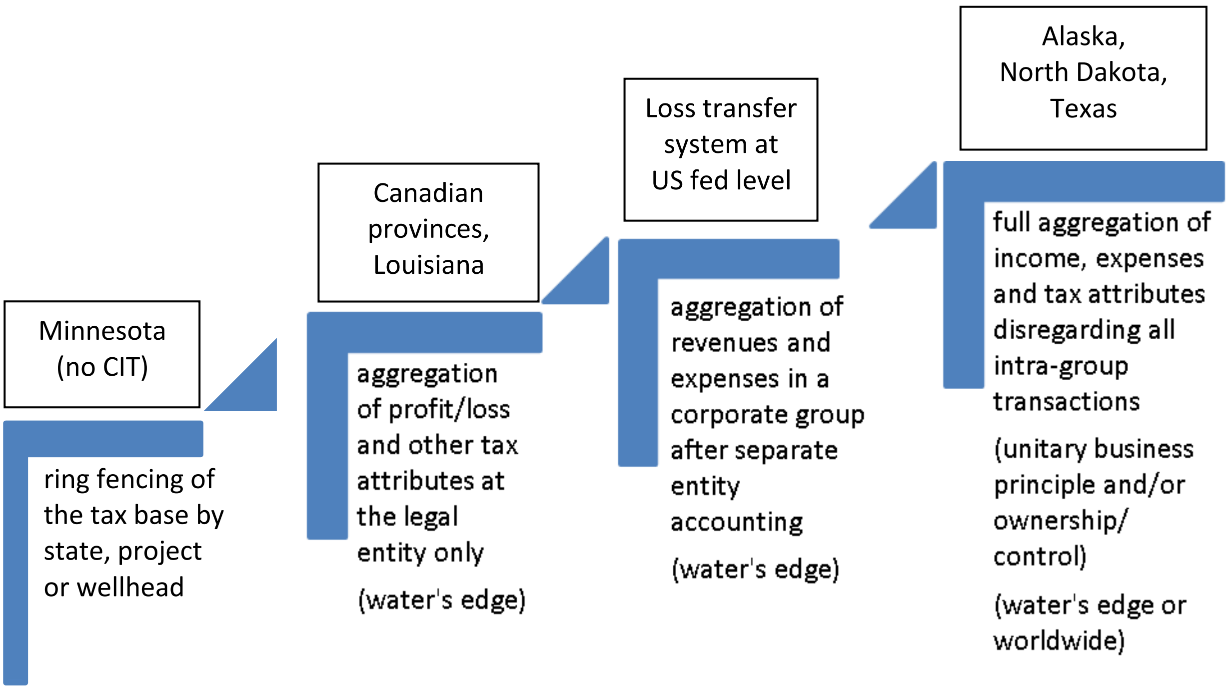
2.1 Defining the tax base

UT approaches define the tax base by aggregating income from a corporate unit, and then apportioning the tax base among the relevant jurisdictions through a formula. A formula is used as an approximation of the source of the income based on the location of economic value-creating activities, such as investment in labour and capital assets, as well as gross revenue.

In applying a UT approach to any tax instrument on profits, the scope of tax base aggregation should be clarified. Thus, for any instrument assessed on a base that incorporates expenses (such as overheads, transportation or intra-firm services), or capital costs (such as depreciation, inventory cost or risk), the scope of aggregation will have a significant effect on determination of the taxable base.

As Figure 1 below illustrates, the scope of aggregation may be envisioned along a spectrum. Ring-fenced or project-based tax bases lie at the far left (assuming the project is contained within only one state); aggregation of the cross-border tax base at the legal entity level is next; followed by aggregation within the corporate group after separate entity accounting;[27] and full aggregation of income, expenses and tax attributes within the corporate group at the far right. Under full aggregation the corporate group may be merged based on the unitary business principle, by an ownership test, or a hybrid of both. Additionally, apart from ring-fenced tax bases, the tax base may also be aggregated on a worldwide or water's edge basis.[28]

Figure 1 CIT base aggregation for the EI sector



We now turn to an examination of select UT approaches as currently applied to EI sectors in the Canadian and US subnational formulary apportionment systems. Each tax scheme will be examined in regard to the individual levies, their corresponding bases, the scope of tax base aggregation and apportionment formulas. Finally, based on these case studies, we conclude with an evaluation of the advantages and disadvantages of such approaches for the EI sector, with a focus on their potential application to EI sectors in developing countries.

27 Consolidated reporting is allowed at the US federal level. See 15 USC § 1501 et seq.

28 Water's edge means that the scope of tax base aggregation is limited to the boundaries of the entire jurisdiction applying the unitary approach. Often the jurisdiction is a country, as in the states of the US or the provinces of Canada. However, the jurisdiction could be a larger economic community, such as member states of the EU, as proposed in the EU CCCTB. Conversely, a worldwide approach to tax base aggregation would combine the global taxable profits/losses of a taxpayer, as in the case of the EI sector in Alaska.

2.2 Case studies of UT approaches in the Canadian and US subnational formulary apportionment systems

There is considerable experience of a UT approach at subnational levels in Canada and the US, which are major natural resource producers. In the US there is greater variety due to the lack of a comprehensive tax harmonisation law among the states. For example, for CIT in the oil, gas and pipelines sector, Alaska requires aggregation of all the income and expenses of the entities that comprise a worldwide unitary business, and apportionment through a special formula that takes into account the amount of resource extracted. Moreover, a combined report of worldwide activities of the unitary business is required in a taxpayer's annual filing. In contrast, Minnesota exempts producers in the taconite industry from CIT, and instead assesses a tax on all the in-state mining revenue (with limited deductions) of the taxpayer. At the provincial level in Canada, income earned from corporations with permanent establishments in more than one jurisdiction is subject to allocation through a two-factor formula comprised of gross revenue and payroll. However, there is no aggregation of the tax base beyond the legal entity level, and no reporting requirements of subsidiary income (in other words no consolidation of corporate groups). Although there is a diversity of royalty, CIT rates and tax credits throughout the resource-producing provinces, the CIT base and allocation formula for the extractives industry follow the general rules set for other industries. The following sections describe these systems in more detail.

2.2.1 UT approaches in the EI sector in Canada

The Canadian constitution (originally the British North America Act of 1867 and renamed the Constitution Act of 1982) lays out the taxing powers of federal and provincial governments. The federal government has the power to tax according to any 'mode or system of taxation'.[29] The provinces were given the power to levy direct taxes 'within the province for provincial purposes',[30] which were interpreted as taxes paid by the person subject to tax (such as income taxes). The ownership of resources was also given to the provinces,[31] enabling provinces to levy royalties (royalties are broadly defined as payments made to governments for the right to extract resources from government-owned lands). By implication the federal government may levy CIT and other direct taxes on resource firms, but not royalties on provincial-owned resources. Provinces have not been given jurisdiction to levy indirect taxes and custom duties, as these are viewed as interfering with trade of goods and services across provincial boundaries. However, in 1982 the provinces were given the power to levy indirect taxes on resources produced from private lands. Only the federal government can assess withholding taxes on income paid to non-residents.

The federal government and provinces in Canada therefore share the major tax fields: income, sales and payroll taxation. Given the overlapping federal and provincial powers as well as a tax jungle created by non-harmonised provincial taxes,[32] the federal and provincial governments concluded 'tax rental' agreements in 1942 whereby the provinces agreed to vacate income and estate tax fields for rental payments, as well as debt and unemployment relief. After the Second World War, Quebec and Ontario adopted their own corporate taxes in 1947 at a 7 per cent rate, with other provinces agreeing to a rental payment equal to 5 per

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29 British North America Act (Constitution Act) 1867, Section 91(3).

30 British North America Act (Constitution Act) 1867, Section 92(2)

31 Section 109 states: 'All Lands, Mines, Minerals, and Royalties belonging to the several Provinces of Canada, Nova Scotia, and New Brunswick at the Union, and all Sums then due or payable for such Lands, Mines, Minerals, or Royalties, shall belong to the several Provinces of Ontario, Quebec, Nova Scotia, and New Brunswick in which the same are situate or arise, subject to any Trusts existing in respect thereof, and to any Interest other than that of the Province in the same'. Parallel sections were introduced when other provinces joined the Confederation, except for Alberta, Saskatchewan and Manitoba, which waited until 1930 when resource ownership was finally transferred to them.

32 Rowell-Sirois Commission prior to the Second World War recommended the federal government take over personal income taxation, corporate income taxation and estate taxation for equalisation payments, debt relief and unemployment relief (see Royal Commission on Dominion-Provincial Relations 1940).

cent of provincial corporate taxable income (and Quebec adopted a personal income tax in 1954). The allocation of corporate taxable income, which is quite relevant to the treatment of provincial corporate income, was developed at this time and is further detailed below.

In 1962 Tax Collection Agreements replaced the tax rental agreements for corporate income, personal income and estate taxes. For CIT, the agreeing provinces would assess tax on income as defined by federal tax law, and the federal government reduced its CIT rate by an abatement to make room for provincial rates. The provinces could therefore choose the tax rate, surtax rates and investment tax credits. As part of the agreement, the federal government agreed to cover the cost of administering the tax without charge.

Quebec and Ontario continued to operate their own provincial CITs in 1962. Alberta adopted its own CIT in 1980, in order to have better information and policy control over its corporate tax. Nevertheless, most base provisions under independent provincial corporate taxes were similar to the federal corporate tax, thereby providing significant benefits in terms of lower compliance and administrative costs (Technical Committee on Business Taxation 1997 Chapter 11). Ontario agreed to harmonise its CIT with federal tax from 1 January 2009 in order to reduce costs.[33]

The provinces collect their own capital taxes (most have now been phased out), payroll taxes and property taxes. Federal-provincial sales taxes have been harmonised with the federal Goods and Services Tax (a form of value-added taxation) in all provinces except for British Columbia, Saskatchewan and Manitoba (Alberta has no sales tax). Sales tax harmonisation has also reduced administrative and compliance costs in sales tax collection in Canada, and led to the removal of sales taxes on business inputs that is typical under retail sales taxes that continue in the aforementioned Western Provinces.

One further point of importance is the role of equalisation in Canada, and its impact on tax policy harmonisation. Equalisation payments to provinces have been made to ensure that provinces have comparable fiscal capacity to offer comparable public services.[34] The federal government makes payments to those provinces that have less fiscal capacity than the national average for five aggregated tax bases (personal income taxes, business income taxes, sales taxes, property taxes and resource revenue). Only one-half of resource revenue is subject to equalisation (although a province can exclude resource revenue if it improves their equalisation payment). 'Have-not' provinces with per capita tax bases below the national average receive equalisation payments equal to the difference between the national and provincial per capita tax base multiplied by the population of the province and national tax rate. A cap on total equalisation payments was introduced in 2007 to limit growth based on a three-year rolling average of GDP growth rates. Equalisation payments to provinces are limited to fiscal capacity including resource revenue that is no more than the poorest non-recipient of equalisation payments. This cap has resulted in new interactions among provinces, whereby policies adopted in one province that increase equalisation payments come at the expense of equalisation paid to other provinces.

The effect of equalisation has been to help harmonise tax policy in Canada by reducing the incentive to engage in tax competition, since tax reductions result in losses of equalisation revenue. If a province were to reduce its CIT rate the per capita tax base would grow relative to the national average, thereby reducing equalisation payments. On the other hand, recipient provinces have a financial incentive to increase tax rates, since the per capita base would decline relative to the national base and thereby increase equalisation payments. These financial incentives have been particularly important with respect to resource

33 It is estimated that harmonisation reduces compliance costs in Ontario by C$136.7 million per year <http://www.cra-arc.gc.ca/whtsnw/tms/ctao-airso-eng.html>.

34 For a description, see <http://www.parl.gc.ca/Content/LOP/ResearchPublications/2008-20-e.htm>.

development and have resulted in past policy initiatives to reduce the clawback of equalisation on revenue for resource developments. For example, if an Atlantic Province were to develop a new offshore oil and gas project, the province would lose one dollar of equalisation payments for each dollar of resource revenue. The 2005 Atlantic Accords included a provision of compensatory payment to Nova Scotia and Newfoundland and Labrador to offset the 100 per cent clawback. The policy was reversed, since it created inequities among provinces (Holden 2006). Resource revenue remains a constant source of debate in Canada, given its importance to differences among provinces in their overall fiscal capacity.

2.2.2 Extractive industries and provincial taxation

Extractive industries are subject to CIT as well as provincial royalties. The CIT in each province follows the federal base in determining revenue and costs. Specific to the industry, revenue is from the sale of product to the market as determined for a permanent establishment in the provinces. At the extraction stage, exploration is expensed and development costs are written off on a declining basis of 30 per cent. Post-production capital expenditure is depreciated according to the classification of asset (Canada primarily uses a pooled asset approach and declining balance depreciation for determining capital costs). A deduction is provided for resource royalties.

The federal and provincial governments have undertaken several reforms in the past few years to reduce CIT incentives for mining and oil and gas. The federal government has cut back incentives for oil sand development by phasing out accelerated cost recovery for new mine assets by 2015. Oil sand development expenditure that was classified as exploration and fully expensed will not be written off at a 30 per cent rate as in the case of development. The federal government is also phasing out the mineral corporate exploration tax credit for mining by 2015, and the 10 per cent Atlantic Investment Tax Credit for oil, gas and mining by 2015 (the credit will remain for agriculture, forestry and manufacturing in the Atlantic). The new mine accelerated cost provision (up to 100 per cent of a project’s income or at minimum of 25 per cent) is now being phased out for mining as of 2020.

In 2007 the federal government fully phased out the resource allowance, which was a 25 per cent deduction from ‘resource profits’ (these profits are defined gross of interest, exploration and development costs) in lieu of resource royalty deductions. This provision was introduced to discourage provinces from raising resource royalties that were partly borne by the federal treasury through lower corporate tax collection. The federal government has returned to royalty deductibility, although Ontario has maintained the resource allowance for mining, which provides an additional incentive for exploration and development.

With respect to the provincial royalties, most are profit-based in Canada except for conventional oil and gas, which historically began as a well-by-well royalty on sales. Under the revenue-based royalty system in Alberta, royalty rates vary by the volume and price for each well, which is a rough manner to account for costs that are not deductible from the base. With the development of non-conventional oil and gas projects, provincial governments have resorted to profit-based or rent-based regimes in recent years, applied on large projects or at the firm level.

On the other hand, mining royalties in Canada have been historically based on profits. In earlier years provinces applied royalties on gross profit (no deduction was provided for borrowing costs), and capital costs were depreciated. To encourage processing, the provinces provided a generous deduction for processing capital costs. In the 1980s British Columbia introduced a cash flow mining tax, whereby capital expenditure is expensed against mining income or carried forward, indexed at a government bond rate to preserve the value of the deduction written off future income. The Alberta government, with respect to oil sand developments, also adopted this cash flow approach to the British Columbia mining tax. The variation in CIT and royalty provisions related to mining and oil and gas is provided in Tables 2 and 3 below.

Table 2 Corporate income and royalty provisions for major oil- and gas-producing provinces in Canada as of 2013

Tax jurisdiction	Deductibility of other levies	Tax rate	Tax base	Special provisions
CANADA - Federal	Federal CIT rate is 15%, under which all provincial royalty payments are deductible.	Special tax provisions include: a 100% allowance for exploration cost, a 30% annual allowance for development and a 25% allowance for a special class of depreciable assets (Class 41), covering a broad range of assets used by the resource sector.	Federal government collects royalty only from oil and gas produced on the 'frontier lands,' including 'territorial sea' and 'continental shelf,' which regions are outside the scope of this study.	None
Alberta	Royalties are deductible for the purpose of CIT.	CIT rate is 10% and the tax base matches that of the federal government.	For conventional oil and gas, the royalty rate is based on gross revenue or production and is sensitive to both the market price and well productivity. For oil, the royalty ranges from 0% to 40%, and for natural gas 5% to 36%. There is also an initial 5% royalty that applies in the first 12 months with a volume cap. For oil sands, a progressive gross royalty ranging from 1% to 9% applies before payout.	For oil sands only, in addition to a pre-payout gross royalty, there is a net royalty of 25% to 40% after payout depending on the price level of the oil.
British Columbia	Royalties are deductible for the purpose of CIT.	CIT rate is 10% and the tax base matches that of the federal government.	For conventional oil and gas, the royalty is based on gross revenue. The royalty rate differs first by product category, such as density of oil or type of gas (i.e. conservation vs. non-conservation gas) and by well age (except for heavy oil and conservation gas). Then the formulation of the royalty rate for a given product category differs between oil and gas. For oil, the royalty rate is sensitive mainly to productivity; for gas, the royalty is sensitive only to price. For certain high-cost shale gas projects, there is a pre-payout 2% royalty on gross revenue (refer to next column).	For certain high-cost shale gas projects, a newly-introduced net profit royalty programme with four tiers of royalty rates applies: a pre-payout 2% royalty on gross revenue, and three post-payout tiers associated with a royalty that is the greater of 5% of gross revenue and a higher rate of net revenue (i.e. 15%, 20%, or 35%, depending on the tier order). To reach each of the three tiers of net royalty, a progressive return allowance applies.
Saskat-chewan	Crown royalties and freehold production taxes are deductible for CIT purposes. There is also a resource surcharge under the corporate capital tax regime, which is deductible	CIT rate is 12% and the tax base matches that of the federal government.	Crown royalty and freehold production tax (FPT) on oil and gas are determined using formulas containing parameters that are adjusted monthly by the government. Both royalty and FPT are sensitive to price and well productivity, and differ by product in terms of their	None

	for CIT purposes.		vintage and characteristics (e.g. type of product, well and location). The FPT is lower than the crown royalty by a production tax factor (PTF), which varies by the type of product and ranges from 6.9% to 12.5%.	
NF&L	Royalties are deductible for CIT purposes. The generic royalty regime consists of a basic royalty and a two-tier net royalty. Note that unsuccessful exploration expenditure is disallowed for the purpose of calculating royalty.	CIT rate is 14% and the tax base matches that of the federal government.	Under the generic offshore oil royalty structure: a basic royalty is charged on gross revenue at rates rising from 1% to 7.5% as cumulative production rises and before payout of all the project costs and the basic gross royalty and the compounded return allowance are exhausted. Basic royalty is payable over the entire production period. But after the payout, it is first creditable against the Tier I net royalty and further deductible from the base for Tier 2 royalty.	Two-tier net royalty (20% and 10%), along with a two-tier return allowance, applies after payout. Tier 1 net royalty applies after all the project costs and the basic gross royalty and the compounded Tier 1 return allowance are exhausted. Tier 2 royalty becomes payable after the payout of both gross royalty and Tier 1 net royalty along with the Tier 2 return allowance. The return allowance is 5 percentage points above LTBR for Tier 1 and 15 points above LTBR for Tier 2.
Nova Scotia	Royalties are deductible for CIT purposes. The generic offshore royalty regime consists of a two-tier gross-revenue royalty and a two-tier net royalty depending on the gross and net revenue levels respectively.	CIT rate is 16% and the tax base matches that of the federal government.	Revenue-based, or gross royalty is two-tiered - 2% before payout and 5% after payout - and deductible for calculating the base for the net revenue royalty. Note that regardless of the revenue and profit level being reached, the 2% gross royalty applies for a minimum of 24 months, and the 5% gross royalty applies for a minimum of 36 months. This implies that there is no net royalty, or rent tax payable for the first 5 years after the commencement of production.	Two-tier net royalty rate is 20% and 30% depending on the net revenue tier reached. Even after the net royalties become payable, only the greater rate of 5% of gross revenue and 20% or 35% of net revenue is payable. To reach each of the two tiers of the net royalty scheme, a progressive return allowance applies: 20 percentage points above LTBR for Tier 1 and 45 points above LTBR for Tier 2.

Table 3 CIT and metallic mining royalty provisions by province as of 2013

	BC	AB	SK	MB	ON	PQ (6)	NB	NS	NFLD
Corporate Tax provisions									
Federal Rate	15%	15%	15%	15%	15%	15%	15%	15%	15%
Prov Rate	10% (3)	10%	12%	12%	10%	11.9%	10%	16%	14%
Special Provincial Tax provisions	Prov. exploration tax credit: 20% (30% in pine beetle areas)			10%	Resource allowance 25% of profits Corporate minimum tax.	Develop-ment costs expensed. Refundable tax credit of 15-38.75% for Quebec exploration expenses.			
Mining royalty provisions									
Tier 1	2% on net current proceeds (fully	1% of pre-payout sales	N/A	N/A	N/A	N/A	2% revenue net of processing and transport	2% of net revenue	15% of profit with deduction of 20% before

	credited)						costs (exempt first two years)		allowance if greater than non-Crown royalties.
Tier 2	13%	12% on revenue net of accumu-lated costs	10% (5% on sales up to C$1 m oz or 1 m mt)	17%	10% (5% remote areas)	16%	16% in excess of C$100 k	15% of net income (if greater than first tier)	20%
Depreciation	Additional super allowance of 33% for new mine expansion until 2016.	15% SL	100%	20%	30% SL or 100% new mine assets. Processing assets: 15% SL	30%	New mine expansions (5% minimum) and 33% other assets.	100% first 3 years, then 30%	25% (100% for new or expanded mine assets) Half yr convention
Development expenses	Expensed	Expensed	150%	20%	Expensed	Expensed	Expensed	100% first 3 years, then 30%	Over life of mine
Exploration	Expensed	Expensed	150%	Expensed Offsite exploration given 150% write-off of expenditure over 3-year average.	Expensed	Expensed (125% for north)	150% (except mineral rights that are expensed)	100% first 3 yrs, then 30%	Expensed
Processing allowance	Expensed	None	N/A	20% of original cost of assets (milling, smelting and refining) Up to 65% of profits	Asset original cost - 8% milling - 12% smelting - 16% refining - 20% North Ont. Up to 65% of profit	Asset original cost - 7% milling - 13% smelting - 13% refining Up to 55% of profit	Asset original cost - 8% milling - 15% smelting - 15% refining Up to 65% of profit	Asset original cost - 8% milling - 10% smelting - 8% refining Up to 65% of profit	Asset original cost - 8% milling - 15% smelting - 8% refining Up to 65% of profit
Financing allowance for carry forwards	125% of bank rate to cumulative expenditure account balance	None	None	None	None	None	8% of un-depreciated base	None	None
Reclamation contributions	Deductible	Deduct-ible	Deduct-ible	Deductible	Deductible	Deductible	Deductible	N/A	Deductible
Other provisions		10% allowance in lieu of over-heads	10 yr holiday 150%pre-prodn. expenses recovered before royalties paid	New mine holiday until payback is achieved.	No tax for first 3 years or C$10 million (10 yrs for remote locations	Mine-by-mine approach for duties. Cash refund of 16% of non-capital losses and credit of 8% for exploration and develop-ment costs	15% R&D tax credit		Max C$2 m/yr credit for 10 years

Notes:

1. Federal CIT provisions include royalty deductibility, capital cost deductions for post-production investment (most important for tangible assets is class 41 and 41a which provides a minimum 25% Capital Cost Allowance (CCA) rate and up to 100% for pre-production expenditure and mine expansions in excess of 5% of sales and also ring-fenced – this provision is being phased out by 2020). A 10% investment tax credit for pre-production mining expenditure, including both exploration and development expenses that involve base or precious metals, is also being phased out by 2015 (refer to section 127 of the Income Tax Act) as well as an Atlantic Investment Tax Credit of 10% being phased out for mining and oil and gas. Canadian development expenses are written off at a 30% rate (includes mine shafts after commercial production).
2. Tax rates used are those fully adopted by 2013.
3. British Columbia: corporate tax rate may increase depending on Harmonised Sales Tax referendum outcome.
4. SL signifies straight line depreciation. Otherwise, declining balance.
5. Flow-through shares enable exploration and development deductions to be flowed through to shareholders. A federal investment tax credit is provided equal to 15% of exploration expenditure. Credit rates by province are BC (20%), Manitoba (20% or 30%), Ontario (5%) and Saskatchewan (10%). Credits reduce exploration deduction available.
6. Quebec has undertaken a significant reform of its mining royalty effective 1 January 2014.

CIT and extractive industry levies are reported for the years 2008 to 2012 in Tables 4 and 5. Data on CIT payable by sector is not available at the provincial level. However, royalties, which include cash flow or profit-based levies, are available in provincial budget documents. In Canada the primary source of collecting levies on resource rents is through provincial royalties and bonus bids, which is consistent with provincial ownership of resources in the Canadian constitution. CIT levies are smaller than royalties in part because corporate tax policy is focused, at least in principle, in a neutral treatment of different activities, especially following the proposals of the 1997 federal Technical Committee on Taxation, which recommended the removal of special preferences for certain industries along with corporate rate reductions. This reform process has evolved since 2000 with the removal of several preferences in extractive and other industries, and a reduction in the average federal-provincial CIT rate from 43 per cent to 26 per cent. The revenue below reflects both business cycle impacts as well as policy changes.

Table 4 CIT payable by extractive resource industry in Canada (federal and provincial), 2008-2012 (C$ million)

	2008	**2009**	**2010**	**2011**	**2012**
Oil and gas extraction and support activities					
Federal	3101	3928	1710	1463	1349
Provincial	1722	2194	1027	987	1069
Total	4823	6122	2737	2450	2418
Mining and quarrying (except oil and gas)					
Federal	909	321	644	678	280
Provincial	636	220	497	571	246
Total	1545	541	1141	1249	526
TOTAL	**6368**	**6663**	**3878**	**3699**	**2944**

Source: Statistic Canada

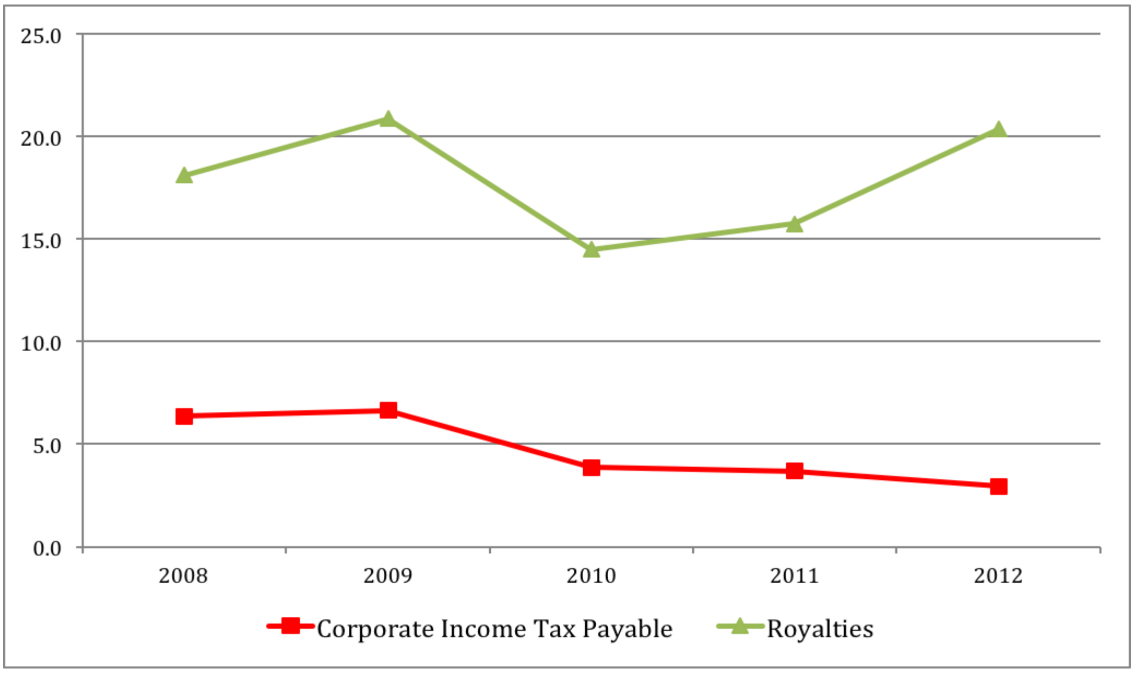
Table 5 Royalty payments received by Canadian provinces from the extractive resource industry, 2008-2012 (C$ million)

Year/Province	2007/8	2008/9	2009/10	2010/11	2011/12
Alberta[1]	11271	12176	6892	8555	11802
British Columbia[2]	2601	2755	1800	1787	1874
Saskatchewan[3]	1515	2273	3369	2108	2829
Manitoba[4]	117	137	20	47	57
Ontario[5]	193	197	228	145	201
Newfoundland and Labrador[6]	1835	2808	1965	2607	3088
Nova Scotia[7]	512	458	154	176	113
New Brunswick [8]	13	37	13	19	20
Quebec[9]			42	305	365
Total	**18099**	**20883**	**14483**	**15749**	**20349**

Source: Provincial Government Budget (Alberta, British Columbia, Saskatchewan, Manitoba, Ontario, Newfoundland and Labrador, Nova Scotia, New Brunswick, and Quebec), various years.

Notes:
1. Royalties for the province of Alberta include natural gas and by-products royalty, crude oil royalty, synthetic crude oil and bitumen royalty, bonuses and sales of crown leases, rentals and fees, coal royalty, and freehold mining rights. For 2007/8, Royalties are Net Royal Tax Credit; 2008/9: Royalties are Net Royal Tax Credit; 2009/10 Royalties are Net Energy Industry Drilling Stimulus Program; 2010/11: Royalties are Net Energy Industry Drilling Stimulus Program; 2011/12: Royalties include Net Energy Industry Drilling Stimulus Program.
2. Royalties for the province of British Columbia include natural gas royalty, bonus bids, fees and rentals, petroleum royalty, bonus bid revenue, coal, minerals, metals and other, sale of crown land tenures, oil and gas commission fees and levies.
3. Royalties for the province of Saskatchewan include crown land sales, natural gas, oil, potash, resource surcharge and others.
4. Royalties for the province of Manitoba include mineral and petroleum fees and royalty, mining tax and mining claim lease.
5. In the Ontario Budget 'Royalties' line include royalties collected from diamond and some revenue from quarries, but it can also include royalties from another sector (such as water and stumpage fees). There is no detailed breakdown of extractive resource revenue royalty in the Ontario budget. The mining tax in Ontario Budget is clubbed (rolled in) with the category 'other Taxes'. Royalty data for the province of Ontario excludes mining tax.
6. Royalties for the province of Newfoundland and Labrador include mining tax and offshore royalty, and mining and petroleum permits and fees.
7. Royalties for the province of Nova Scotia include offshore licences, forfeitures, rentals, petroleum licences, royalties - petroleum, prior years' adjustments in respect of other royalties, coal royalty, mineral rentals, lease and grant resources, gypsum tax, explorations claims, and other.
8. Royalties for the province of New Brunswick include royalties on coal, natural gas, oil, potash, and salt.
9. Royalties for the province of Quebec include mining royalty and credits for losses. The royalties for the period 2006 to 2010 are the average value as reported in the Quebec provincial budget of 2012/13.

Figure 2 Comparing royalties and CIT payable by Canadian extractive resource industry, 2008-2012 (C$ billion)



Source: Authors' estimate based on Statistic Canada data and Canadian provincial budgets, various years.

2.2.3 Corporate allocation formula in Canada

Canada's corporate allocation formula has been an important part of its overall approach to tax harmonisation. Provinces initially operated their own CITs with income allocated to the province according to headquarter permanent establishment, with a tax credit provided for any taxes paid in other provinces (Smith 1976). Under the 1942 Tax Rental Agreements, gross receipts were initially used as a single apportionment factor to divide income of a permanent establishment operating across provincial boundaries (Weiner 2005). With new tax rental agreements after the Second World War (1947-52), corporate allocation became even more important to businesses as Quebec and Ontario wished to levy independent corporate taxes. In 1946 the provinces adopted a common approach based on two factors: payroll and gross receipts.

Canada considered the use of physical capital as a factor similar to the US Massachusetts formulary apportionment system.[35] However, it was felt that a three-factor approach would allocate more revenue to the dominant manufacturing provinces (Ontario and Quebec) and less to the Atlantic and Western provinces, since the sales factor was based on consumer purchases (destination-based) as opposed to production (origin-based) (Technical Committee on Business Taxation 1997). However, in later years resource-rich provinces were concerned that the corporate allocation formula resulted in too little profit allocated to them, given that the destination-based sales factor resulted in the allocation of resource profits to consuming provinces like Quebec and Ontario. However, given that difficult negotiations over the common formula take place in a zero-sum game, the formula has not been changed.

Indeed, the common two-factor approach in Canada has not changed in seventy years. Its virtue is that the provinces agree to a common formula, unlike the US where states can choose their own weights. Thus, Canadian weights add up to one across provincial and

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35 The Massachusetts apportionment formula is comprised of three factors: property, sales and payroll.

territorial jurisdictions, with no over- or under-taxation of income. It has resulted in lower compliance and administrative costs, as well as fewer economic distortions. However, because Canada does not have corporate group taxation, businesses could avoid allocating revenue across jurisdictions by setting up separate entities in each province, subject to separate accounting rules. Businesses thus have some discretion to avoid corporate allocation if it helps reduce tax payments.[36] Nonetheless, in 1997 about 45 per cent of corporate taxable income was allocated across provinces (with roughly half of non-allocated income being represented by small corporate businesses).[37]

2.2.4 Mechanics of the Canadian approach to corporate allocation

The Canadian allocation approach begins with identifying whether there are permanent establishments operating in more than one province. A permanent establishment is a fixed place of corporation, which includes an office, branch, oil well, farm, timberland, factory, workshop, warehouse or mine. If there is no permanent establishment, the corporation's principal place is where its business is normally conducted. Newfoundland and Labrador and Nova Scotia offshore are treated as part of the provinces.

The general formula requires the company's domestic income to be allocated to each province according to an equally-weighted sum of the share of payroll and gross revenue by province (specific cases are discussed below):

$$Y[p] = Y \times 1/2\,[w(p) + GR(p)]$$

$Y(p)$ = corporate income allocated to the province p.

Y = national corporate taxable income

$w(p)$ = share of national payroll in province p.

$GR(p)$ = share of national gross revenue in province p.

To determine tax in each province, taxable income is multiplied by the provincial CIT rate. Provincial tax credits are subtracted from tax payable to arrive at the final amount.

The gross revenue weight is calculated by excluding interest, dividends, rent and revenue from gross revenue. Gross salaries and wages only include employee compensation at the permanent establishment, and not contract labour. Benefits are not included.

Special weights apply for specific industries, especially transportation and finance, substituting for one or both factors depending on the case. These include insurance (net premiums only), banks (loans and deposits instead of gross revenue), trust and loan companies (gross revenue only), railway companies (equated track kilometres and gross ton kilometres), airlines (capital cost of fixed assets and revenue plane kilometres), grain elevators (bushels of grain instead of gross revenue), bus and truck operators (kilometres driven instead of gross revenue), ships (port-call-tonnage instead of gross revenue), and pipelines (kilometres of pipe instead of gross revenue).

Given the federal role in administering CIT, the issues arising with respect to transfer pricing, financial structures and other profit shifting among provinces are of far less consequence

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36 Allocation minimises taxes if the weights allocate more income to low-tax rate jurisdictions; e.g. Quebec had a much lower CIT than other provinces in the 1980s – companies with sales and payroll primarily in Quebec would prefer allocation rather than setting up separate companies in each province.

37 Technical Committee on Business Taxation (1997: 11.9).

compared to international tax planning. Nonetheless, the ability of companies to set up subsidiaries in different lines of business provides opportunities for tax planning, although transfer pricing is more difficult to use to shift prices due to the federal auditing of tax bases on behalf of the provinces.

Income earned by mining and oil and gas companies is allocated across provinces in accordance with the general formula. Extractive industries in Canada are therefore treated similarly to other industries with respect to extraction, refining or processing, and retail operations. The income is allocated across provinces according the payroll and gross revenue shares. If separate subsidiaries are established for different operations, allocation only applies to those subsidiaries with permanent establishments in multiple provinces.

As for provincial royalties, the corporate income allocation rules are irrelevant in the sense that income or sales are typically measured on a project or well basis, and administered by energy or mining departments at the provincial level.

2.2.5 UT approaches in the EI sector in the US

The US constitution governs federal and state laws, and federal and state governments share taxation powers with the exception of import duties and duties of tonnage which are assessed exclusively at the federal level. Within these bounds, the states levy both direct and indirect taxes according to their constitutions, laws and regulations. In all the US states mineral resources are either owned by the federal government, the state government or by private persons. Generally the landowner owns the right to subsurface minerals as well as the surface, unless the title has been previously severed. However in some US states, such as Louisiana, the state retains title to all water bottoms.[38]

The US is rich in mineral resources, both fuel and nonfuel. The country is a net exporter of nonfuel mineral raw materials, and in 2012 the US mining industry contributed US$15.7 billion to US GDP (US Department of the Interior/USGS 2013).[39] The State of Nevada produces nearly 15 per cent of total nonfuel minerals from the US.[40] Other significant nonfuel mineral-producing states include Arizona (11 per cent), Minnesota (6 per cent), Florida (5 per cent) and California (5 per cent) (US Department of the Interior/USGS 2013: 9-10). With the exception of coal, the US is a net importer of fuel minerals.[41] Crude oil, natural gas and coal are produced in more than half the US states, as well as offshore in the Pacific Coast and Gulf of Mexico. The top oil-producing states are Texas, Alaska, California and North Dakota; the top natural gas-producing states are Texas, Wyoming, Louisiana, Oklahoma and Pennsylvania; and the top coal-producing states are Wyoming, West Virginia, Kentucky, Pennsylvania and Texas.[42]

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38 La. Rev. Stat. 41:14.

39 Primary mineral commodities include gold, crushed stone, copper, cement, construction sand and gravel, iron ore, molybdenum concentrates, phosphate rock, lime, industrial sand and gravel, soda ash, clays, salt, zinc and silver.

40 US Department of the Interior/USGS (2013: 9 Table 3). 'In 2012, 11 States each produced more than US$2 billion worth of nonfuel mineral commodities. These states were, in descending order of value - Nevada, Arizona, Minnesota, Florida, California, Alaska, Utah, Texas, Missouri, Michigan, and Wyoming. The mineral production of these States accounted for 64% of the US total output value'.

41 In 2011 the country imported twice as much oil as it produced domestically, while net imports of natural gas amounted to 6% of the total natural gas consumed during the same period. The US imported over four billion barrels of oil, while domestic production was a little over two billion barrels. Gross natural gas imports decreased by about 10% to 3,135 Bcf in 2012, the lowest level since 1998. US Energy Information Administration, *US Imports by Country of Origin (2011)*; *US Natural Gas Exports & Imports 2012* (July 2013). During the same period, however, US net exports of coal totaled 94.2 million short tons. US Energy Information Administration, *Annual Energy Review 2011*, Coal Overview, Table 7.1.

42 US Energy Information Administration, *US Crude Oil and Natural Gas Proved Reserves 2011* (August 2013); National Mining Association (2012). The largest fuel mineral deposits in the US are located in the North Slope of Alaska; the Gulf of Mexico; the Williston Basin, which covers parts of the State of Montana, North Dakota and South Dakota; Southwestern Wyoming; the Great Eastern Basin, which covers parts of Nevada, Utah and Idaho; and the Appalachian Basin and Marcellus Shale along the Northeastern US (US Department of the Interior/USGS *National Assessment of Oil and Gas Resources Update* March 2013).

For federally-owned lands, such as the National Petroleum Reserve in Alaska and the offshore Gulf of Mexico, oil and gas leases are obtained through auction, after which a royalty applies to 12.5 per cent of the value onshore production and 16.67 per cent of the value offshore production. Coal mining on federal lands is subject to a 12.5 per cent royalty on gross value for surface mining and 8 per cent royalty on gross value for subsurface mining, while nonfuel mining operations are exempt from federal royalties.[43] There is also a federal excise tax assessed on coal production at 4.4 per cent of the sales price.[44]

Under current federal CIT laws, there are various tax preferences for domestic oil, gas and coal production.[45] Income from oil, gas and coal domestic production benefits from a six per cent deduction from income, resulting in a reduced effective CIT rate of 31.9 per cent. Exploration and development expenditure, such as intangible drilling and completion costs, may be expensed;[46] either cost or percentage depletion may be deducted from gross income;[47] geological and geophysical expenditure may be amortised over two years; royalties from coal mining are not treated as ordinary income but instead as capital gains, which are subject to a reduced tax rate of 20 per cent; and many of the major oil and gas producers have adopted the Modified Accelerated Cost Recovery System (MACRS) for claiming depreciation deductions for tangible assets.[48] The US also has an elective loss transfer system for CIT, which allows consolidation of the tax base of a corporate group in which the parent owns, directly or indirectly, at least 80 per cent of the total voting power and value of the stock of its subsidiary.[49] As a result, profits can offset losses from various projects as well as up/downstream activities within the corporate group.

2.2.6 Extractive industries and state taxation

Unlike Canada, there is no comprehensive federal harmonisation of state taxation. Hence, the states have enacted a wide variety of CIT and other EI levies. The states collect royalties (usually 12.5 per cent but increasingly higher, up to 18.75 per cent depending on extractive capacity) from oil, gas and coal extraction on state-owned lands and water bottoms. In all the US states where land is privately-held, extractives royalties are payable to the owner of the mineral interest. Some states have minimum royalty statutes, which typically follow the 12.5 per cent royalty of the federal government, but in many cases there is no statutory minimum. In addition to these royalties, states generally assess two additional levies: a CIT or franchise tax, and a severance tax. Both the royalty and severance taxes are generally based on the gross revenue or production value net of transportation and gas compression costs, but many levies remain volume-based. Royalties and/or severance taxes are often deductible for federal and state CIT purposes. Because state taxation regimes on the EI sector vary widely, two contrasting case studies will be examined – Alaska and Minnesota. Case studies of EI taxation regimes in Louisiana, North Dakota and Texas are provided in the Appendix.

2.2.7 Case study: Alaska's oil and gas sector

The state of Alaska is a leading oil- and nonfuel mineral-producing state – both in terms of crude oil, at over 190 million barrels produced annually, and nonfuel minerals such as gold, zinc, silver, lead, sand and gravel, valuing over US$3.5 billion and 5 per cent of total US

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43 Coal mining operations are subject to a 12.5% royalty for surface mining and 8% for underground mining. There have been increasing efforts to change the law exempting certain nonfuel mineral extraction from royalties. See Snyder (2013).

44 IRC Sec 4121.

45 See US Office of Management and Budget, *Analytical Perspectives, Budget of the United States Government, FY 2013*, Table 7-1, 249.

46 IRC Sec. 263(a), (c). Under this section, IDC may be capitalised or expensed by irrevocable election.

47 IRC Sec. 612-613.

48 IRC Sec. 168; MACRS allows for five years for oil and gas well drilling; off-shore drilling assets; seven years for assets used in oil and gas exploration; see also IRS Pub. 946 (2012) Table B-2; IRS Oil and Gas Handbook, 4.41.1.3.2.4 (10-01-2005) – Depreciation.

49 15 USC § 1501 et seq.

nonfuel mineral production.[50] Companies in the extractives industry of Alaska are subject to three primary levies in addition to municipal property taxes: royalty payments, severance taxes and conservation charges, and CIT. The statutory minimum for royalty payments for the oil and gas extraction on state-owned lands is 12.5 per cent. In addition, minimum royalty rates exist for coal and certain nonfuel minerals.[51]

Severance taxes/charges for oil and gas

Special taxes/charges for the oil and gas sector include the Oil and Gas Petroleum Production Tax (PPT); Oil and Gas Property Tax at the rate of two per cent of the market value of exploration, production and pipeline production property in the state;[52] and Oil Conservation Charges totalling 5¢ per barrel produced in the state.[53]

From 2014 PPT is set at 35 per cent of net value of production (or production tax value) in the state.[54] The net value of production is determined by the gross value at point of production, less deductions for lease expenditure and adjustments to lease expenditure.[55] Gross value at the point of production includes a deduction for the actual costs of transportation, except when the shipper of the oil or gas is affiliated with the transport carrier; or the contract is not at arm's length; or there are other reasonable methods of transport.[56]

Lease expenditure is then subtracted from the gross value. Lease expenditure includes ordinary and necessary direct costs upstream of the point of production, and overhead expenses for exploring, developing and producing oil or gas deposits in the state.[57] Lease expenditure does not include depreciation, depletion or amortisation; royalty or production payments; taxes measured by net income; interest or financing charges for raising equity or debt capital; fines, penalties, arbitration or indemnity costs; acquisition or organisation costs; abandonment or clean-up costs; or political lobbying costs. Any other expense incurred through internal transfer must be demonstrated by the producer as not exceeding fair market value.[58] Lease expenditure must then be adjusted by subtracting payments or credits received by the producer for other leasehold or management payments; insurance and other production-related reimbursements; and amounts received from the sale or transfer of assets acquired as a result of the leasehold and oil or gas.[59] There are also gross revenue exclusions of 20 per cent for certain new production, with an additional credit of US$5 per barrel produced.[60] For all other production there is a sliding scale, non-transferable tax credit of up to US$8 per barrel based on oil prices.[61]

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50 A severance tax for the mining industry applies as provided in AS 43.65; however, this analysis will focus on the oil and gas sector.

51 The minimum royalty for coal is 5¢ per ton. AS 38.05.150.

52 AS 43.56. Oil and gas reserves, leases and other rights to explore and produce, as well as intangible drilling and exploration expenditure, are exempt from taxation. A non-refundable credit is given for municipal property taxes paid. See also Alaska Tax Division (n.d: 60).

53 AS 43.55.201; 43.55.300.

54 See More Alaska Production Act, Ch. 10, S.B. 21, Laws 2013. Before 1 January 2014, the Alaska's Clear and Equitable Share (ACES) tax system applied with a 25% tax rate and an additional progressive tax based on oil/gas prices under AS 45.55.011(e). For a comparison of both taxes, see Goldsmith (2014).

55 AS 43.55.160.

56 In such cases the Department of Revenue will use the lower of the actual and reasonable costs (based on fair market value) to determine the gross value. Reasonable costs are determined by the Department of Revenue using the fair market value of like transportation, the fair market value of equally efficient and available alternative modes of transportation, or other reasonable methods. Transportation costs fixed by tariff rates that have been adjudicated as just and reasonable by the Regulatory Commission of Alaska or another regulatory agency and transportation costs in an arm's length transaction paid by parties not affiliated with an owner of the method of transportation shall be considered prima facie reasonable. In any case transportation costs do not include charges related to loss or damage of vessels in connection with a catastrophic oil discharge. AS 43.55.150.

57 AS 43.55.165.

58 AS 43.55.165(e)(12).

59 AS 43.55.170.

60 AS 43.55.160(f); A.S. 43.55.024(i).

61 AS 43.55.024(j).

CIT for oil, gas and pipelines sector

For all extractives sectors Alaska's CIT applies, with a payment of US$10,830 on the first US$222,000 of taxable income, and the remaining taxable income subject to a tax rate of 9.4 per cent.[62] Under this regime the CIT base is aggregated based on the unitary business principle.[63] The unitary business determination is a factual case-by-case analysis: where entities are under common control either directly or indirectly, and the activities of the entities are contributory and complementary, there is a unitary business.[64] Furthermore, if the activities of the entities are in the same line of business, if the entities are performing different steps in a vertical process, or if there is strong centralised management, there is a presumed unitary business.[65] Mining companies are cited as an example of a vertically-integrated business in the *Alaska Guide to Returns Based on a Combined Report* (Alaska Department of Revenue n.d.(a)). The tax base of affiliated groups must also be consolidated if they are part of a unitary business.[66]

For all such taxpayers engaged in a unitary business that derive income from sources within and outside of the state, a combined report is required. The oil, gas and pipelines sector is subject to worldwide combined reporting, and all other sectors file returns based on water's edge combined reporting.[67] In addition to a combined report, consolidated returns are allowed and required when filing a federal consolidated return; separate combined reports are required for each unique combined (unitary) group represented in the consolidated return.[68]

The tax base is then apportioned based on the proportion of economic factors located within the state vis-à-vis outside the state. The mining sector apportionment follows the general three-factor formula of sales, property and payroll, while the oil, gas and pipeline sector tax base is apportioned by a formula based on sales (including tariffs), property and an extraction factor, consisting of total production of barrels of oil plus ⅙ Mcf of natural gas. If the taxpayer is engaged in all three subsectors (oil, gas and pipelines), the formula factors are sales, property (including intangible drilling and development costs) and the extraction factor. If the taxpayer is not involved in the production of oil and gas or gas only, the formula factors are property and sales.[69] If the taxpayer is not involved in the pipeline transport of oil or gas, the formula factors are property and extraction.[70]

Although Alaska adopted the Uniform Division of Income for Tax Purposes Act (UDITPA) in 1959 and has used the three-factor property, payroll and sales formula since that time, it was not until 1978 that the legislature found that the standard formula did not fairly reflect Alaska

62 This bracket and rate applies from 1 January 2014, signed into law on 28 May 2013. See AK S.B. 7, Laws 2013.

63 See 15 AAC 20.310; Alaska Department of Revenue (n.d(a): 1).

64 A business is unitary if the entity or entities involved are owned, centrally managed, or controlled, directly or indirectly, under one common direction which can be formal or informal, direct or indirect, or if the operation of the portion of the business done within the state is dependent upon or contributes to the operation of the business outside the state. 15 AAC 20.310(a).

65 15 AAC 20.310 at 2.

66 An affiliated group is defined as a group of two or more corporations in which 50 per cent or more of the voting stock of each member of the group is directly or indirectly owned by one or more corporate or non-corporate common owners, or by one or more of the members of the group. Foreign affiliates are included when 20% or more of affiliate's average property, payroll and sales factors are assigned to a location within the US; the affiliate is a domestic international sales corporation; a foreign sales corporation; a corporation that is registered or does business in a country with no income tax or 90% less than the US tax rate if 50% or more of the sales, purchases, or payments of income or expenses are made to members of the combined group and the corporation does not conduct significant economic activity. AS 43.20.073.

67 AS 43.20.144; 43.20.145. One exception is provided through Alaska Stranded Gas Development Act, which provides that a company that develops Alaska's gas under that framework could have a negotiated payment in lieu of other taxes (PILT). See A.S. 43.82. The PILT under the terms of the contract would exempt the payer from CIT (as well as other taxes).

68 See Alaska Department of Revenue (n.d.(b): 3).

69 AS 43.20.072(c)(1).

70 AS 43.20.072(c)(2).

income for oil and gas corporations. In response, the legislature adopted a law requiring oil and gas companies to calculate Alaska taxable income using separate accounting. This change was met with such a high level of litigation from taxpayers that three years later the legislature modified the apportionment formula for the oil, gas and pipelines sector to include an extraction factor. Moreover, it was only in 1991 that the legislature allowed companies to use water's edge apportionment; before 1991 all companies were required to report on a worldwide basis. However the oil, gas and pipelines sector was allowed to continue to report on a worldwide basis after the change to water's edge apportionment in 1991 (Alaska Tax Division n.d: 26-27).

Recently, the Alaska Supreme Court issued a decision in *Tesoro Corp. v. Alaska* solidifying the application of worldwide combination of a unitary business and formula apportionment with respect to oil and gas companies.[71] Tesoro Corporation is a petroleum company, headquartered in Texas, and comprised of thirty-three subsidiaries organised into five business segments, one of which is based in Alaska. The remaining segments are based in Bolivia, Louisiana and Texas. When the exploration and production business segment (located in Bolivia and Texas) realised profits of approximately US$200 million from the sale of an interest in a gas field and sums from a successful breach of contract claim (which were far greater than those of the Alaska retail and marketing segment), Tesoro sought to isolate this profitable segment from the Alaska unitary business in order to avoid bringing this income into the combined tax base.[72] Upon examination of the unitary nature of the business, the Court ruled that the exploration and production segment belonged to the Alaska unitary business, and, as a result, all the income from the business segment was correctly included in the unitary tax base and apportioned to arrive at the Alaska taxable income.

This ruling illustrates the sometimes disadvantageous position of taxpayers whose out-of-state income is included into the Alaska tax base – but only in proportion to the worldwide factors of production which are located in the state. On the other hand, if a taxpayer experiences a corollary loss, this loss will also offset the Alaska tax base – but only in proportion to the worldwide factors of production which are located in the state. When the Alaska worldwide combined reporting system converges with other tax systems in third jurisdictions, both of these instances may result in either double taxation or double non-taxation, but only to a limited extent: if a taxpayer in a third jurisdiction experiences a loss, thus offsetting taxable income in the third jurisdiction, the taxpayer can also offset the loss against the Alaska tax base. However, the amount of this offset is limited to the proportion of worldwide factors of production located in Alaska (and vice versa with profit). Apparently from the *Tesoro* ruling, this 'convergence aspect' of worldwide combination is a tolerable consequence in comparison to the benefit of combining the worldwide tax base of the unitary business in the oil, gas and pipelines sector.

In summary, along with CIT, there are three distinct severance taxes for oil and gas extraction: a small unit-based conservation charge; an *ad valorem* property tax; and a net value-based production tax, which yields the greatest amount of revenue. Revenue collection statistics are shown in Table 6. A comparison of PPT and CIT is shown in Table 7. Although both taxes incorporate costs at some level, the bases and scope of consolidation are very different. The base of PPT is the net value of in-state production only, while the base of CIT is the global profit/loss of the entire unitary business. Thus, PPT operates from the bottom-up and requires attribution of costs to in-state operations, while CIT operates from the top-down by removing all intra-group transactions to determine the overall profitability of the consolidated corporate group. With both perspectives, the tax administration has more

[71] Case No. 6838, Alaska Supreme Court (25 October 2013).

[72] Case No. 6838, Alaska Supreme Court (25 October 2013) at 3.

information to ensure consistency in cost reporting. In addition, the understanding of in-state costs in relation to overall profits can inform the design of more efficient production taxes.

Table 6 Tax revenue from EI sector in Alaska

Revenue source	Revenue collection (FY 2012 US$ million)
Petroleum Production Tax[73]	6,146.1
State oil and gas rents, royalties, bonuses and interest	2,031.7
Oil and gas CIT	568.8
Oil and gas Property Tax	111.2
Mining License Tax	40.7
State mining rents and royalties	12.3

Source: Alaska Department of Revenue (2013)

Table 7 Alaska oil and gas CIT and PPT comparison

Tax type	Base	Rate	Consolidation scope	Deductions	Excluded deductions
PPT	Net value of production = gross value at point of production less (deductions for lease expenditure less adjustments)	35%	In-state production only	**Gross value deductions** = lower of the actual or reasonable costs of transportation **Lease expenditure** = ordinary and necessary upstream costs as well as direct costs and overhead expenses for exploring, development and production in the state **Lease adjustments** = subtract payments or credits received by the producer for other leasehold or management payments; insurance and other production-related reimbursements; and amounts received from the sale or transfer of assets acquired as a result of the leasehold and oil or gas	Depreciation, depletion or amortisation; royalty or production payments; interest or financing charges for raising equity or debt capital; fines, penalties, arbitration or indemnity costs; acquisition or organisation costs; abandonment or clean-up costs; political lobbying costs; taxes measured by net income
CIT	Net income	US$10,830 on first US$222,000; remaining subject to 9.4%	Worldwide net income of consolidated business apportioned by in-state sales and tariffs, property + intangible drilling and exploration costs and extraction	Same as federal taxable income expenses and deductions except those in the next column	Taxes based on or measured by net income; intangible drilling and development costs should be capitalised and depreciated (not expensed); depletion deducted on a cost basis only (not percentage); accelerated or bonus depreciation not allowed

2.2.8 Case study: Minnesota

While Minnesota does not produce fuel minerals, the state is the third largest nonfuel mineral producer in the US and produces 75 per cent of total US iron ore totalling 40 million tons annually. There are six iron ore operations in the state, which are owned by only three companies. These operations extract iron ore from the ground, crush it into a fine powder, remove impurities, and then compress it into marketable pellets. The government owns the largest share of mineral rights in the state, followed by private owners. The statutory

73 Includes Oil and Gas Conservation Charge receipts.

minimum for royalties on leases on state-owned lands range from 3.95-20 per cent for metallic (nonferrous) minerals[74] and from 11-18¢ per ton for ferrous minerals, depending on form, such as ore or pellets, and content.[75]

Along with royalties, there are five primary levels of tax assessed on mineral production in the state: Mining Occupation Tax; Taconite Production Tax; Sales and Use Tax; and *Ad Valorem* Property Tax. In 2011, the state collected US$3.07 in total taxes per ton of taconite (Minnesota Revenue (2012: 4). Table 8 describes total revenue to the state from mining.

Table 8 Tax revenue from EI sector in Minnesota

Tax type	Revenue collection (2011 US$ million)
Mining rents and royalties (state-owned lands)	156.57
Taconite Production Tax	79.97
Sales and Use Tax	24.67
Mining Occupation Tax	22.05
Ad Valorem Property Tax	0.898
Income Tax on mining royalties (6.25% withholding)	0.373

Source: Minnesota Revenue (2012).

Mining Occupation Tax

The Mining Occupation Tax is levied in lieu of CIT and is assessed at the rate of 2.45 per cent of taxable income.[76] There is a separate calculation of taxable income for ferrous minerals or taconite, and all other nonferrous minerals. For nonferrous minerals, taxable income equals gross proceeds less deductions. Gross proceeds includes any gain or loss recognised from the sale or disposition of assets used in the business in this state. When the metal product is used by the producer or sold in a non-arm's length transaction, for example, to an affiliate or wholly-owned smelter, the Department of Revenue determines the gross proceeds by reference to published prices.[77]

For ferrous materials, taxable income is determined by the mine value less allowable deductions.[78] Mine value is the selling price of iron ore or taconite concentrates at the mine. Mine values are published by the Department in an annual Directive. For both ferrous and nonferrous materials, deductions are only those expenses necessary to convert raw ores to marketable quality. Such expenses include costs associated with refinement, but do not include expenses such as transportation, stockpiling, marketing or marine insurance that are incurred after marketable ores are produced.

For both minerals, the taxable base comes from only the Minnesota mine and plant. Thus, the Occupation Tax is non-unitary. All transfers of minerals are deemed by law as Minnesota sales, and, thus, there is no apportionment of the tax base.[79] Instead taxpayers are required to carve out all gross proceeds and deductions which apply to the state. Moreover, gross income and deductions from iron/taconite and other minerals mined and processed at the same mine and plant must be calculated separately first, before being combined to render profit and loss on the Occupation Tax return. For both ferrous and nonferrous minerals, there is a deduction for percentage depletion of 15 per cent for iron ore gross income from the

74 Minn. Stat. 93.25.
75 Minn. Stat. 93.20.
76 Minn. Stat. 298.01.
77 Minn. Stat. 298.016.
78 Minn. Stat. 298.01, subd.4.
79 Minn. Stat. 298.01, subd. 4a(c).

property (but not exceeding 50 per cent of net income), excluding rents or royalties paid or incurred by the taxpayer in respect of the property.

Taconite Production Tax

Taconite Production Tax is assessed in lieu of *Ad Valorem* Property Tax on taconite land and structures used in the production of taconite.[80] As of 2013, the tax is assessed at the rate of $2.56 per gross dry ton of taconite concentrate. The annual tax rate changes based on GDP Implicit Price Deflator. 'Taxable tons' are the average tons produced during the current year and the previous two production years. There is an additional tax of 10¢ per 2,000 lb on tailings.[81] 'Tailings' refers to the solid and liquid waste materials resulting from the beneficiation process.

Sales and Use Tax

Sales and Use Tax is assessed at 6.875 per cent on the sale of tangible personal property or services. For the mining industry, exemptions such as industrial production exemption, taconite production material exemption, minerals production facilities exemption, and capital equipment refund decrease the taxable base.[82]

Ad Valorem Property Tax

Although the Taconite Production Tax is assessed in lieu of *Ad Valorem* Property Tax on taconite land and structures used in the production of taconite, there are other types of *ad valorem* taxes assessed on the industry, including on auxiliary mining lands for taconite operations,[83] on unmined taconite,[84] on unmined natural iron ore,[85] on taconite railroads,[86] and on severed mine interests.[87]

As Table 8 illustrates, the majority of revenue generated from mining in Minnesota arises from volume- or unit-based royalties. Taconite Production Tax – a volume-based tax – yields about half the amount generated by royalties. Despite numerous exemptions for the mining industry, Sales and Use Tax brings in more than Mining Occupation Tax, which is levied in place of CIT. Mining Occupation Tax is the only levy which allows for deductions for production costs and percentage depletion. Similar to the other tax instruments, the Mining Occupation Tax base only includes in-state income/assets. In this sense, it is a non-unitary tax base, confined to Minnesota mine and plant.

3 Assessing the unitary approach for the EI sector

This paper has described EI tax structure variations at the US and Canadian subnational levels to explore whether a UT approach could enhance design and implementation of other EI levies. On one hand it has been observed that, although the scope of aggregation varies

80 Minn. Stat. 298.24.

81 Minn. Stat. 298.24, subd. 2.

82 Minn. Stat. 297A; See also Minnesota Department of Revenue, *Mining – Metals, Minerals, Ores, and Taconite*, Sales Tax Fact Sheet 147, which provides a list of exempt and taxable items used in the taconite and iron mining industry.

83 Minn. Stat. 272.01.

84 Minn. Stat. 298.26.

85 Minn. Stat. 272.03 et. seq.

86 Minn. Stat. 270.80 et. seq.

87 Minn. Stat. 272.039 et. seq.

widely, the US and Canadian subnational CIT regimes employ a UT approach by aggregating the tax base across jurisdictional borders. However, for other EI levies the base is restricted to the source jurisdiction – and sometimes even ring-fenced to the project or well. In this section we assess the suitability of a global UT approach in terms of aggregation and apportionment of the tax base. We conclude with recommendations in the final section.

3.1 Tax base aggregation

Despite the comparatively smaller contribution to revenue from CIT in the US and Canadian subnational tax systems, tax base aggregation and combined reporting present the advantage of providing a clearer picture of global investment, production, revenue and corporate structures, which aids in understanding the true income and costs borne by private producers. These costs are a factor in all types of extractive revenue collection instruments – even those that are volume-based, as the royalty rate per unit of production should reflect a sharing of profits that accounts for production costs. When governments have a clearer understanding of costs, revenue and risks involved in exploiting their natural resources, they are able to design more effective EI levies that reflect these costs, revenue and risks without deterring investment. Likewise, under rules that aggregate the tax base separate business structures no longer offer a tax benefit, either because of the redefinition of the tax base or because companies must now combine their business operations onto a single combined tax return.[88] Hence, private producers can also allocate resources in more efficient ways.

It is important to consider carefully the level at which accounts are aggregated to define the tax base. When tax base aggregation and reporting is limited to the legal entity, as in the case of the Canadian provinces, the scope of this informational advantage drastically decreases. On the other hand, a worldwide system of combined reporting, as in the case of the oil, gas and pipeline sector in Alaska, may increase the information and reporting requirements for firms – however note that all intragroup transactions and their related reporting would be eliminated. Worldwide tax base aggregation allows global offsetting of losses, which is significant due to the large upfront costs in the EI sector. This could enable countries to tax an apportioned share of worldwide profit when the firm's local projects are still in a start-up phase, but by the same token would mean accepting a lower tax base in a period when local production might be booming. Where the firms concerned are large and internationally diversified this may help the source country ensure more stable revenue, as tax revenue more directly linked to world market prices is vulnerable to the often severe fluctuations in those prices. However, companies may find this difficult to accept and, as the *Tesoro* case from Alaska illustrates, they may contest the consolidation of gains made in other jurisdictions on the grounds that they are not part of an integrated or unitary business.[89] Therefore, a unitary approach based on worldwide consolidation may be more suited to CIT alone and not applied to all EI levies, and might be considered as an alternative to a pre-production levy such as a signature bonus.

A rent/profit-related EI levy could be ring-fenced and all transfers of the extracted mineral taxed at source. This system would satisfy source entitlement concerns and perhaps involve a simpler reporting scheme. However, ring-fencing may introduce more complexity since costs (which are usually incurred at higher levels in a vertically-integrated firm) must be segregated and an appropriate proportion attributed to a specific project. This complexity would incur increased compliance costs for private producers, as well as require increased administration and expertise by a government to establish appropriate prices and costs. Moreover, without an understanding of overall costs and revenue generated by the firm as a whole, the government may not be able to establish appropriate prices and costs accurately.

88 This observation has been made regarding the Revised Texas Franchise (Business Margin) Tax. See Texas Taxpayers and Research Association (2011).

89 See Section 2.2.7.

In this regard, a unitary CIT used in combination with a ring-fenced EI levy could compensate for such informational deficits.

If used in combination with other source-based EI levies a unitary CIT alters the balance of *ex ante* risk between the government and the private producer, because it allows global loss offsetting. This advantage of a UT approach to CIT may have important effects on investment decisions. Given the volatility of world prices, variability of mineral quality and high potential of profit, a ring-fencing approach to all EI levies may be more successful in a smaller and more stable extractives subsector, such as iron in the case of Minnesota, where the Taconite Occupation Tax is restricted to Minnesota mine and plant. In most other cases where the above factors typically dominate, a ring-fenced EI levy complemented by a worldwide unitary CIT could serve better in more efficient design and administration of EI levies.

3.2 Tax base apportionment

When a government adopts a global unitary approach to company taxation of the EI sector, another important consideration is apportionment of the tax base. The unitary approach used in Canada allocates corporate income through a formula of two factors: sales by destination and payroll. Although there are special formula rules for certain industries, the EI sector falls under the general allocation formula – the effect is to spread EI tax revenue among the provinces. As applied to resource-rich provinces this formula is not very advantageous: sales by destination attributes the revenue from minerals to other consuming provinces (away from the source state), and, due to its capital-intensive nature, the EI sector requires comparatively fewer human resources than most other industries. The single-sales by destination formula, now adopted by sixteen US states, would attribute away all revenue of minerals sold to consumers outside of the state. The Massachusetts three-factor formula, once dominant in the US states but now only used by twelve states, incorporates a factor for tangible assets which would include tangible assets used in the EI sector but would continue to attribute sales of the minerals away from the state of production when the mineral is sold to out-of-state consumers. This is often the case with integrated economies where minerals may be extracted from the source state and shipped out-of-state for processing, refinement and manufacturing. It is also the case in some developing countries where minerals extracted from the source state are generally shipped abroad for processing.

In response, some US states have used more aggressive means to capture mineral revenue in the CIT tax base. Louisiana attributes all mineral revenue to in-state sources by excluding mineral revenue from all other apportionable corporate income. Before repealing its CIT for the taconite industry, Minnesota deemed all sales (regardless of the location of the purchaser) as Minnesota sales in its apportionment formula. For the past three decades, Alaska has used a special formula for the oil, gas and pipelines sector that includes an extraction factor, consisting of total production of barrels of oil plus ⅙ Mcf of natural gas. If the taxpayer is engaged in all three subsectors (oil, gas and pipelines), the formula factors are sales (by destination), property (including intangible drilling and development costs) and the extraction factor. If the taxpayer is not involved in the production of oil and gas or of gas only, the formula factors are property and sales by destination. Another way for source-states to capture mineral revenue under a formulary apportionment scheme would be to adopt an origin-based sales factor, as used in the apportionment formulas in the Swiss cantons (Siu et al. 2014). Due to the prominent source entitlement concerns in the EI sector, a modification of the general apportionment formula may be necessary – especially as regards the sales factor, because a destination-based sales factor shifts tax base from EI away from the source state. Global agreement on such a formula would be ideal in reducing competing claims on tax jurisdiction.

4 Summary of recommendations

Given the advantages and limitations of a UT approach as applied to the EI sector, including the very real concerns of developing country source jurisdictions with potential abuse of global offsetting of company profits, a unitary CIT should not be used in isolation or be employed as the dominant source of EI revenue. Instead, a unitary CIT is best used in combination with other rent/profit-related EI levies, because of its informational and risk-aligning advantages. At the same time, the rent/profit-related EI levies should be assessed on a more limited base, such as source jurisdiction, in order to alleviate source entitlement concerns. Within this context, a unitary CIT is recommended because it enables more effective design and administration of all taxes on the EI sector in the following ways:[90]

- A unitary CIT enables better design of other rent/profit-related EI levies that require a clearer picture of revenue, costs and risks borne by the industry.
- A unitary CIT increases the effectiveness of implementation and enforcement of all EI levies because the information from the worldwide combined report, which is top-down, can serve as backstop to cost and revenue reporting under other EI levies that require separate accounting, which is bottom-up.
- A unitary approach to CIT can be more favourable for investment because it allows global offsetting of corporate losses.
- Worldwide combined reporting under a global unitary approach aligns with current reform initiatives such as EITI and CbCR.
- Finally, a specialised 'production volume' factor or a source-based sales factor could be used in the apportionment formula to measure business activity in the extractives sector more accurately, as well as to satisfy source entitlement concerns.

[90] A unitary approach to CIT requires international cooperation to make it work as efficiently and fair as possible. See Siu et al. 2014: 83).

Appendix

A1 Case study: Louisiana

Louisiana is ranked second nationally in gas production, and seventh in oil production. In 2013 the state received approximately US$1.5 billion in revenue from its mineral wealth.[91] For state-owned lands and water bottoms, there is a minimum royalty of one-eighth (or one-sixth for school boards only).[92]

Natural Resources Severance Tax

A Natural Resources Severance Tax is levied on the extraction of all natural resources, with oil and gas collection accounting for almost 92 per cent of all severance tax collection. Tax rates vary by production capacity of the well, but the large majority (approximately 85-95 per cent) of oil and gas severance tax collection are generated from capable wells. The full rate for gas for 2013/14 is 11.8¢ per thousand cubic feet (Mcf).[93] This rate is adjusted annually against a base rate of 7¢ per Mcf.[94]

The full rate for crude oil as well as condensate is 12.5 per cent of value at the time and place of severance, less a 25¢ per barrel deduction for transportation.[95] The value is determined by the higher of the gross receipts from the first purchaser less any transportation fees received, or the posted field price. If there is no posted field price or the first purchase is not an arm's length transaction, the value of gross income must be consistent with gross income declared for percentage depletion purposes on the taxpayer's CIT return.[96] Severance taxes paid on royalty shares are also deductible against royalty payments for mineral leases on state-owned lands and water bottoms.

Corporation Income and Franchise Taxes

All corporations in Louisiana are subject to Corporation Income and Franchise Taxes. Under CIT, taxpayers with net incomes over US$200,000 are taxed at the rate of 8 per cent.[97] For multistate businesses separate reporting at the legal entity level is required, and no consolidated returns are allowed even if filing a federal consolidated return.[98] As a result, Louisiana law does not refer to the concept of a unitary business in its laws or regulations. Thus, much like the Canadian provinces, the level of tax base consolidation for CIT is limited to domestic cross-border business activities within the corporate entity. Moreover, income from mineral interests and oil payments is allocated to in-state income through allocation rules as described below.

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91 State of Louisiana, Department of Natural Resources, Technology Assessment Division, *Energy Facts and Figures*, 2013.

92 La. Rev. Stat. 30:127.

93 La. Rev. Stat. 47:633(9).

94 The Department adjusts a base rate of 7¢ per Mcf annually based on a fraction, the numerator of which is the average of the New York Mercantile Exchange (NYMEX) Henry Hub settled price on the last trading day for the month, as reported in the Wall Street Journal for the previous 12-month period ending on 31 March, and the denominator of which is the average of the monthly average spot market prices of gas fuels delivered into the pipelines in Louisiana as reported by the Natural Gas Clearing House for the 12-month period ending 31 March 1990 (1.7446 US$/MMBTU). La. Rev. Stat. 47: 633(9).

95 LAC 61:1.2903A(h). Charges for trucking, barging and pipeline fees actually charged the producer may be deducted. However, where the producer transports the oil and/or condensate by his own facilities, US$0.25 per barrel shall be deemed to be a reasonable charge.

96 See La. Rev. Stat. 47:158(c).

97 La. Rev. Stat. 47:287.12(5). 'Louisiana net income' is defined as net income earned within or derived from sources within Louisiana. La. Rev. Stat. 47:287.67.

98 La. Rev. Stat. 47:287.480.

'Louisiana net income' is determined by allocation and apportionment of gross income and allowable deductions.[99] First, certain items of gross income are directly allocated to the state in which they are earned. Income from (or gains from the sale of) in-state mineral lease rents and royalties, oil payments or other mineral interests, as well as income from construction on in-state mineral properties, is directly allocated to Louisiana gross income.[100] All losses, expenses and deductions, including intangible drilling and development costs as well as a deduction for depletion (the greater of cost or depletion at 22 per cent of gross income),[101] which are directly attributable to allocable gross income, are then subtracted.

The remaining amount is gross apportionable income. All losses, expenses and deductions are then subtracted to arrive at net apportionable income.[102] The apportionment rules explicitly exclude taxpayers whose income is primarily derived from the production or sale of unrefined oil or gas and integrated oil companies as defined by the IRC.[103] Thus, despite the cross-border merging of the apportionable corporate tax base, mineral profits avoid apportionment because they are allocated to the source state before apportionment.

Corporation Franchise Tax is also assessed at a rate of 0.3 per cent on corporations whose total capital stock, surplus and undivided profits exceed US$300,000.[104] If business is conducted in other states, allocation and apportionment rules apply; however, as with CIT, in-state mineral lease rents and royalties, oil payments or other mineral interests are directly allocated to Louisiana,[105] and taxpayers whose income is primarily derived from the production or sale of unrefined oil or gas and integrated oil companies as defined by the IRC are excluded from apportionment.[106] Thus, again, mineral interests in the Corporate Franchise Tax base avoid apportionment and are allocated to the Louisiana tax base.

As Table 9 below illustrates, the majority of mineral revenue arises from severance tax collection from oil extraction. Because data on CIT and Franchise Tax collection for the oil and gas industry are not segregated from overall collection, comparability analysis on the basis of revenue collection is not possible in this case study.[107] However, total CIT and Franchise Tax collection for 2013 was approximately three-quarters of Oil Severance Tax collection for the same period. Despite the use of formulary apportionment in the overall CIT and Franchise Tax, all mineral revenue is attributed to in-state sources by excluding mineral revenue from apportionable income. As a result, there is no aggregation of the mineral revenue tax base. This feature of the tax system appeals to source entitlement concerns and eases administration.

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99 La. Rev. Stat. 47:287.77.

100 Rents and royalties from immovable and corporeal movable property are allocated to the state where the property is located when the income is derived. La. Rev. Stat. 47:287.93. Under this provision, income from (or net profit from the sale of) a mineral lease, royalty interest, oil payment, or other mineral interest is allocated to the state or states in which the property subject to such mineral interest is situated. La. Rev. State. 47:287.92B(1); La. Admin. Code 61:I, Sec. 1134D(4)(b). Income from construction, repair or other similar services is also directly allocated to the state where the work is done. La. Admin. Code 61:I, Sec. 1130A(3)(b). Under this provision, 'other similar services' means any work that has as its purpose the improvement of immovable property, and includes the drilling of a well on a mineral property, whether under lease or not. La. Rev. State. 47:287.92B(4); La. Admin. Code 61:I, Sec. 1130A(4)(b).

101 La. Rev. Stat. 47:287.743-745.

102 La. Rev. Stat. 47:287.94.

103 La. Rev. Stat. 47:287.95(2)(c)(ii)-(iii).

104 La. Rev. Stat. 47:601.

105 La. Admin. Code 61:I, Sec. 306A(1)(e)(i).

106 La. Rev. Stat. 47:606A(3)(c)(i), (iii).

107 Louisiana Corporation Income Tax collection in 2013 was US$427,493,441.86, and Corporation Franchise Tax collection for the same period was US$142,036,814.39, for a total of US$569,530,256.25. See Louisiana Department of Revenue, *Statistical Reports, Monthly Statements of Net Collections and Distributions* (2013). Segregated data for oil and gas companies was not made available by the Department.

Table 9 Louisiana oil and gas revenue

Revenue source	Revenue (FY 2013 US$ million)
Oil Severance Tax	761.75
State oil royalties	384.28
State gas royalties	159.47
Gas Severance Tax	99.45
Bonuses, rentals and royalty overrides	38.89

Source: State of Louisiana, Department of Natural Resources, Technology Assessment Division, *Energy Facts and Figures, 2013*.

A2 Case study: North Dakota

North Dakota is the second largest producer of oil in the United States, the tenth-ranked producer of coal, and eighteenth in gas production. The state produced 243.1 million barrels of oil in 2012, along with 27.5 million tons of lignite coal and 258 billion cubic feet of natural gas.[108] Currently the state leases over 800,000 acres of land for gas and oil production, with state royalty rates varying between 16.67 per cent and 18.75 per cent based on the county of the lease.[109] Over 700 acres of state land is also leased for coal mining. Mineral extraction is subject to three primary levels of taxation in the state: Severance Taxes, a Sales and Use Tax and the CIT.

Oil and Gas Gross Production Tax

Oil and Gas Gross Production Tax is assessed in lieu of the *Ad Valorem* Property Tax.[110] For oil production the tax rate is 5 per cent on gross value at the well.[111] Gross value at the well is the price paid for the oil under an arm's length contract between the producer and the purchaser, less, when applicable, transportation costs associated with moving the oil from the point of production to the point of sale under the contract.[112] For gas production, the tax is assessed on each unit of one thousand cubic feet (Mcf).[113] The gas tax rate is set each June by the State Tax Commissioner on the basis of the gas fuels producer price index. For the fiscal year beginning 1 July 2013, through 30 June 2014, the gas production rate is 8.33¢ per Mcf.[114]

Oil Extraction Tax

The Oil Extraction Tax is an excise tax assessed on oil extraction at the rate of 6.5 per cent of gross value at the well. A lower rate of 4 per cent of gross value at the well applies to certain new wells and recovery projects, where the average price of a barrel of crude oil for any consecutive five-month period of any year is lower than the stated trigger price.[115] The

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108 US Energy Information Administration, *Annual Energy Review, Coal Production and Number of Mines by State and Coal Rank, 2012*, Table 6.1; North Dakota Petroleum Council, *North Dakota Oil and Gas Industry Facts and Figures* (2013).

109 See ND Department of Trust Lands (2013); ND Department of Trust Lands, *ND Oil and Gas Lease Auction*, November 05, 2013, at 9.00 am CT, North Dakota State Capitol House Chambers.

110 NDCC Sec. 57-51-03.

111 NDCC Sec. 57-51-02. The tax is also assessed on royalty interests.

112 NDCC Sec. 57-51-02.3. In the absence of an arm's-length contract, the gross value at the well for oil is established by other arm's length contract prices paid for oil, either with the taxpayer or other parties for like kind oil; if none is available, the price is based on the posted field price of like kind oil with adjustments for transportation costs. In addition, transportation costs are the actual costs incurred in an arm's length contract or an established common carrier rate with the North Dakota public service commission. See NDCC Sec. 57-51.01(12).

113 NDCC Sec. 57-51-02.2. The tax is also assessed on royalty interests.

114 North Dakota, Office of the State Tax Commissioner, *Gas Tax Rate Notice*, 1 June 2013.

115 NDCC Sec. 57-51.1-02.

trigger price is determined by a base rate of US$35.50 adjusted annually for inflation.[116] For calendar year 2014, the oil trigger price is US$52.06.[117] Exemption categories include stripper oil wells, initial production periods and various oil recovery projects.[118]

Sales and Use Tax

A Sales and Use Tax of 5 per cent is assessed on all taxable purchases and sales within the state.[119] However, the sale of natural gas, coal and other heating fuels, along with the purchase and sale of property used to compress, process, gather or refine natural gas, is exempt from Sales Tax.[120] Additionally, initial sales of beneficiated coal, along with machinery and equipment used to produce coal from a new mine and materials used to construct a facility for coal gasification by-product processing, are also exempt from Sales Tax.[121] Despite these exemptions, almost 20 per cent of all taxable sales and purchases occur in the mining and oil extraction industry.[122]

Coal Severance Tax

In FY 2013, almost 28 million tons of coal were produced in the state. The Coal Severance Tax rate is 37.5¢ per ton of coal extracted, and is imposed in lieu of all Sales and Use Taxes.[123] An additional tax of 2¢ per ton for a special lignite research fund also applies.[124] There are exemptions and reductions on coal used for heating purposes, coal used in certain types of cogeneration and agricultural plants, and coal mined for out-of-state shipment.[125] There is also a special Potash Tax scheme, but as there are no active mining operations this tax will not be discussed.[126]

Coal Conversion Facilities Tax

Facilities that process or convert coal and electrical generating plants are subject to a Coal Conversion Facilities Tax.[127] For coal conversion facilities, the tax is assessed at the rate of 4.1 per cent of gross receipts, except for amounts received for the sale of a capital asset and production of synthetic natural gas in excess of 110 million cubic feet per day. For electrical generating plants that have a single generating unit with the capacity of 10,000 kw or more, two levies apply. One levy is .65 millionths times 60 per cent of installed capacity times the number of hours in the taxable period. The other levy is .25 millionths per kwh of electricity produced for sale.

Corporate Income Tax

All companies in the extractives sector in North Dakota are subject to CIT. A top rate of 4.53 per cent applies to net income of US$50,000 or more.[128] Corporations engaged in business within and without the state may be taxed only on such income as is derived from business transacted and property located within this state.[129] The determination of whether the

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116 NDCC Sec. 57-51.1-01 (12).
117 ND Office of the State Tax Commissioner, *Annual Oil Trigger Price Adjustment Notice*, 31 December 2013.
118 NDCC Sec. 57-51.1-03.
119 NDCC Sec. 57-39.2-01.
120 NDCC Sec. 57-39.2-04; 57-39.2-04.5
121 NDCC Sec. 57-39.2-04.8; there is a limitation of US$5 million; NDCC Sec. 57-39.2-04.11.
122 See ND Office of the State Tax Commissioner (2013: 18).
123 NDCC Sec. 57-61-01.
124 NDCC Sec. 57-61-01.5.
125 NDCC Sec. 57-61-01.1; 57-61-01.4; 57-61-01.4; 57-61-01.7.
126 See NDCC Sec. 57-65; ND Department of Trust Lands (2013: 9).
127 NDCC Sec. 57-60-02.
128 NDCC Sec. 57-38-30.
129 NDCC Sec. 57-38-14.

activities of the taxpayer constitute a single trade or business is a factual, case-by-case analysis; however, a single trade or business will be deemed if there is evidence to indicate that the business segments are integrated with, dependent upon, or contribute to each other and the operations of the taxpayer as a whole.[130] A worldwide combined report is mandated for the entire business income of such trade or business if more than 50 per cent common ownership exists, and is apportioned according to a three-factor formula of property, payroll and sales. Intangible drilling and development costs incurred by oil and gas producing companies in connection with oil and gas properties must be included in the property factor.[131]

A water's edge election may be made by taxpayers, in which only US-based companies, with the exception of certain corporations, combine income or loss to establish the tax base.[132] The apportionment factors are the same as for the worldwide combined report, except that the denominators of the factors are only those factors of all the companies included in the water's edge group. The water's edge election is binding for five consecutive years. If the election is made, a corporation is subject to a 3.5 per cent surtax on its North Dakota taxable income.[133] Moreover, two or more North Dakota domestic corporations affiliated as a parent and a subsidiary that file a federal consolidated return must file a combined report and a consolidated return.

Table 10 illustrates that collection from Oil Extraction Tax and the Oil and Gas Gross Production Tax compromise the majority of mineral revenue. CIT and Sales Tax is assessed on companies in the extractive industries; however, because data on CIT and Sales and Use Tax collection for this sector is not segregated from overall collection, comparability analysis on the basis of revenue collection is not possible in this case study. Nevertheless, total CIT collection for all industries for the same period as collection in Table 10 does not exceed US$386 million. Thus, despite the broader degree of consolidation of the CIT base, in terms of overall mineral revenue CIT collection from the mineral sector is not substantial. The system of worldwide combined reporting employed by North Dakota may be more useful in terms of its provision of information on in-state costs as they relate to the unitary business. Moreover, the surtax of 3.5 per cent (in addition to the top rate of 4.53 per cent), imposed on taxpayers reporting at the domestic level only, may incentivise a broader scope of consolidation and reporting.

Table 10 North Dakota oil and gas revenue

Revenue source	Revenue (US$ million 2011-2013 FY biennium)
Oil Extraction Tax	2,142.49
Oil and Gas Gross Production Tax	1,926.05
State oil and gas royalties	340.36
Oil and gas bonuses	192.75
Coal Conversion Tax	50.37
Coal Severance Tax	21.98

Source: ND Office of the State Tax Commissioner (2013); ND Department of Trust Lands (2013).

130 NDAC Rule 81-03-09-04.

131 Intangible drilling and development costs include such elements as wages, fuel, repairs, hauling, draining, road building, surveying, geological works, construction of derricks, tanks, pipelines and other physical structures necessary for the drilling of wells and their preparation for the production of oil and gas, and supplies incident to and necessary for the drilling of wells and clearing of ground. NDAC Rule 81-03-09-21.1.

132 This election generally requires that corporations with more than 50% of their stock owned or controlled by the same interests (directly or indirectly) are in the water's edge group, along with domestic international sales corporations, foreign sales corporations, export trade corporations, foreign corporations deriving gain or loss from disposition of a United States real property interest, and any foreign corporation where more than 20% of the average of its property, payroll, and sales factors are located in the US.

133 North Dakota, *Corporate Income Tax Return*, Form 40, Instructions.

A3 Case study: Texas

Texas is the top-ranked oil- and gas-producing state in the US. The state is also ranked fifth in coal production and eighth in nonfuel mineral production. State revenue from oil and gas production taxes reached nearly US$4.5 billion for FY 2013.[134] Although much of the oil and gas interests in the state are privately owned, royalties, bonuses and rentals from oil and gas leases on state lands generate approximately US$1.4 billion per year (see Table 11). The minimum royalty rate for oil and gas leases is 12.5 per cent of gross production or market value;[135] and for coal the minimum rate is 6.25 per cent of value.[136]

Natural Gas Production and Regulation Taxes

In 2011, Natural Gas Tax collection was US$1.1 billion, making up 2.9 per cent of total state tax collection (Legislative Budget Board 2013: 73). An Oil Production Tax is assessed on the production of natural gas at the rate of 7.5 per cent of market value.[137] For many drilling operations the tax rate on natural gas production is reduced to zero during the first ten years of production, or until the site recovers half its drilling and completion costs due to the high-cost gas rate reduction.[138] Condensate recovered from gas is taxed at 4.6 per cent of market value or 4.6¢ per barrel, whichever is higher.[139]

The market value of gas is its value at the mouth of the well, and is determined by subtracting actual marketing costs from gross cash receipts from the sale of the gas. Gross cash receipts include payments made to the producer and any other payments in connection with any judgment, compromise or settlement agreement relating to the recovery of the contract price of gas produced.[140] However, gross cash receipts do not include payments for gas if the gas is never produced and delivered, reimbursement for litigation-related expenses, and contract termination or amendment fees except for provisions affecting the purchase price.[141] Marketing costs are expenses incurred by the producer to get the gas from the mouth of the well to the market, including compressing, dehydrating, sweetening and delivery costs. However, marketing costs do not include production costs, costs incurred in normal lease separation of the oil or condensate, or insurance premiums on the marketing facility.[142]

In addition to the Natural Gas Production Tax, an Oil Field Clean up Regulatory Fee of $^{1}/_{15}$ of 1¢ on each Mcf of natural gas is levied.[143]

Oil Production and Regulation Taxes

An Oil Production Tax is assessed on the production of oil on the greater of 4.6 per cent of market value of the oil produced in the state, or 4.6¢ per barrel of oil produced in the state.[144]

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134 Texas Comptroller of Public Accounts, *Annual Cash Report*, 2013, p. 5.

135 Tex. NRC Sec. 52.022.

136 Tex. NRC Sec. 53.018.

137 Tex. TC Sec. 201.051-.052. Both producers and holders of royalty interests are liable for this tax.

138 Tex. TC Sec. 201.057. Government reports indicate that from 2010/11, the value of the rate reduction was worth close to US$1.0 billion per year and resulted in a loss of over half of potential total natural gas production tax revenue, making it the single largest exemption from either the oil or gas severance tax (Legislative Budget Board 2013: 80).

139 Tex. TC Sec. 201.055.

140 Tex. Admin. Code, Title 34, Part 1, Ch.3, Sub.B Rule §3.20(b).

141 Tex. Admin. Code, Title 34, Part 1, Ch.3, Sub.B Rule §3.20(b)

142 Tex. TC Sec. 201.101. In addition, marketing costs are determined by adding a reasonable charge for depreciation of the marketing facility being used, provided that, if the facility is rented, the actual rental fee is added; a return on the producer-owned investment equal to 6% per year on the average depreciable balance; costs of direct or allocated labour associated with the marketing facility; costs of materials, supplies, maintenance, repairs and fuel associated with the marketing facility; and *ad valorem* taxes paid on the marketing facility.

143 Tex. NRC Sec. 81.117.

144 Tex. TC Sec. 202.051-.052. Both producers and holders of royalty interests are liable for this tax.

For enhanced oil recovery projects, there is a reduced rate of 2.3 per cent on oil produced from a new enhanced oil recovery project.[145] The market value of oil is the actual market value plus any bonus, premium, or other thing of value paid for the oil.[146] In addition to Oil Production Tax, an Oil Regulation Tax is assessed at $^{3}/_{16}$ of 1¢ on each barrel of oil,[147] as well as an Oil Field Clean-up Regulatory Fee of $^{5}/_{8}$ of 1¢ on each barrel of oil.[148]

Sales Tax

The Texas state Sales and Use Tax rate is 6.25 per cent, but local taxing jurisdictions, including cities, counties, special purpose districts and transit authorities may also impose Sales and Use Tax up to 2 per cent for a total maximum combined rate of 8.25 per cent. For the oil and gas industry there are a number of exemptions from Sales Tax. Crude oil, which is taxed under the Oil Production Tax, is exempt.[149] Other Sales Tax exemptions include: natural gas, which is taxed as a motor fuel;[150] equipment used out-of-state for mineral exploration or production;[151] equipment used to capture, transport and sequester carbon dioxide as part of an enhanced oil recovery project;[152] and equipment used to process, reuse, and recycle wastewater that will be used in fracturing work at an oil or gas well.[153] Despite these exemptions, much of the equipment purchased by oil and gas companies, such as drilling and pumping equipment and storage tanks, is subject to Sales Tax. In 2011, Sales Tax revenue related to oil and gas extraction generated the state an additional US$489.1 million, or 2.3 per cent of all Sales Tax revenue (Legislative Budget Board 2013: 76).

Property Tax

Oil and natural gas producers are also subject to Property Taxes on all real and tangible property located, used or owned by taxpayers residing in the state.[154] There are exemptions for all mineral interests on public property,[155] as well as for offshore drilling equipment not in use.[156] However, despite these exemptions, in FY 2011 taxable values of oil, gas and other mineral property (including the value of minerals in the ground) exceeded US$1 trillion (Texas Comptroller of Public Accounts (2012: 4-5).[157] Because Property Taxes, which are often assessed at the local levels, vary, and the statewide average local Property Tax rate is roughly 2.1 per cent, we estimate a total maximum Property Tax levy of US$2.25 billion.[158]

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145 Tex. T.C. Sec. 202.052. There are exemptions for oil and gas from previously inactive wells, hydrocarbons from terra wells, oil and gas from reactivated orphaned wells, oil incidentally produced from the production of geothermal energy. Additionally, there are credits for incremental production techniques, low-producing oil leases, and enhanced efficiency equipment.

146 Tex. T.C. Sec. 202.053.

147 Tex. N.R.C. Sec. 81.111.

148 Tex. N.R.C. Sec. 81.116.

149 Tex. T.C. Sec. 151.308.

150 Tex. T.C. Sec. 151.308.

151 Tex. T.C. Sec. 151.324.

152 Tex. T.C. Sec. 151.334.

153 Tex. T.C. Sec. 151.355.

154 Tex. T.C. Sec. 11.01.

155 Tex. T.C. Sec. 11.11.

156 Tex. T.C. Sec. 11.271.

157 Oil, gas and minerals property includes producing and non-producing wells, all other minerals and mineral interests and equipment used to bring the oil and gas to the surface.

158 However, this amount may be slightly overstated, as most oil/gas production takes place in rural areas where property taxes are lower.

Revised Franchise (Business Margin) Tax

The Revised Franchise (Business Margin) Tax is not a traditional CIT: it is a hybrid between a tax on gross receipts and a tax on net income. The base of the Business Margin Tax is total revenue[159] less the greater of US$1 million, 30 per cent of revenue, cost of goods sold or employee compensation.[160] The rate for Business Margin Tax is 0.5 per cent for wholesalers and retailers, and 1 per cent for all other taxpayers.[161] However, for the tax years 2014 and 2015 the rates have been reduced as a result of a tax relief measure to 0.4875 per cent and 0.975 per cent respectively for 2014, and 0.475 per cent and 0.95 per cent respectively for 2015.[162]

Cost of goods sold includes expenses related to raw materials, production labour, depreciation, depletion, and amortisation costs. Intangible drilling and dry hole costs as well as geological and geophysical costs incurred to identify and locate property that has the potential to produce minerals are also included in cost of goods sold.[163] However, cost of goods sold does not include distribution costs, outbound transportation costs, contract bidding expenses, interest expenses or income taxes. If a taxpayer elects to subtract compensation from total revenue, the compensation amount must equal total salaries paid, limited to US$300,000 per employee plus certain fringe benefits.[164]

The resulting margin is then apportioned to Texas, based on the proportion of gross receipts in the state vis-à-vis the entire unitary business.[165] The unitary business is comprised of either separate parts of a single entity, or separate parts of an affiliated group of entities that are sufficiently interdependent, integrated and interrelated so as to provide a synergy and mutual benefit .[166] Relevant factors include vertical integration, 'such as the steps involved in the production of natural resources, including exploration, mining, refining, and marketing'.[167] For each unitary business, a combined report is required.[168] The combined group does not include taxable entities that conduct business outside of the US if at least 80 per cent of the entity's property and payroll are assigned to locations outside the United States.[169]

The combined group determines total revenue by combining the individual revenue of each member, then adding the total revenue of the members, and, finally, subtracting items of total revenue received from a member of the combined group.[170] In determining the margin, the entire combined group must elect to subtract either cost of goods sold,[171] or compensation;

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159 Revenue from very low-producing oil (10 barrels per day) and gas (250 Mcf per day) wells may be excluded from total revenue. See Tex. TC Sec 171.1011.

160 Acts of 83rd Legislature, Regular Session, HB 500, Sec. 6 Tex. TC Sec. 171.101(a), (b). Sole proprietorships and general partnerships with no limitation of liability are not taxable entities under the Revised Franchise Tax law. Tex. TC Sec. 171.0002. Taxpayers with total revenue of less than US$10 million may also elect to be taxed at a rate of 0.575% on total in-state revenue from the entire unitary business. Tex. TC Sec. 171.1014.

161 Tex. TC Sec. 171.002.

162 These changes are part of a larger package of tax relief enacted in June 2013. Acts of 83rd Legislature, Regular Session, HB 500, Sec. 2, Tex. TC Sec. 171.0022-171.0023.

163 Tex. TC Sec. 171.1012.

164 Tex. TC Sec. 171.1013. This includes workers' compensation benefits, health care, employer contributions made to employees' health savings accounts and retirement. The salary cap is also adjusted for inflation.

165 Tex. TC Sec. 171.106.

166 'Affiliated group' means a group of one or more entities in which a controlling interest is owned by a common owner or owners, either corporate or non-corporate, or by one or more of the member entities, or a corporation, either more than 50% owned directly or indirectly of the total combined voting power of all classes of stock of the corporation, or more than 50% owned directly or indirectly of the beneficial ownership interest in the voting stock of the corporation. TC Sec. 171.0001(1).

167 Tex. TC Sec. 171.0001(17).

168 Tex. TC Sec. 171.1014.

169 If the entity has no property and payroll, the gross receipts factor is used.

170 Tex. TC Sec. 171.1014(c).

171 Any payment made by one member of an affiliated group to another member of that affiliated group not included in the combined group may be subtracted as a cost of goods sold only if it is a transaction made at arm's length. Tex. TC Sec. 171.1012(l).

and in either case the taxable margin may not exceed 70 per cent of the group's total revenue.[172] If the group elects to subtract cost of goods sold, each member first calculates its cost of goods sold as if it were an individual taxable entity; these amounts are then combined; and, finally, any amounts paid from one member of the combined group to another member of the combined group are subtracted, but only to the extent the corresponding item of total revenue was subtracted in determining total revenue.[173] The process is the same for compensation.[174] As a result, intra-group transactions are excluded in determining the taxable margin of the combined group. As with single taxpayers the resulting margin is apportioned to Texas, based on the proportion of gross receipts in the state vis-à-vis the entire unitary business.[175]

The Business Margin Tax represents a middle way between a gross receipts tax and a net income tax. It is an attempt to simplify tax administration, especially for small and medium enterprises, and at the same time increase revenue by broadening the taxable base through elimination of deductions for distribution costs and interest expenses, and aggregating income from the unitary group while substantially lowering tax rates.[176] A stated purpose of the tax was also to align the Franchise Tax with the modern economy better (Texas Comptroller of Public Accounts 2013: 12). Evaluations have indicated that, since its adoption in 2008, the tax has been moderately successful in reducing tax planning by avoiding profit shifting through corporate restructuring and transfer pricing (Texas Comptroller of Public Accounts 2013:13).[177] However, the amount deducted through the cost of goods sold has been much higher than expected: taxpayers have deducted 82 per cent or more each year through this election. Among other sectors, the mining industry pays less Business Margin Tax than its share of the economy ((Texas Comptroller of Public Accounts 2013: 4), and compared to the pre-2008 Franchise Tax (4.5 per cent on earned surplus and 0.25 per cent on capital less debt with separate entity reporting), the mining sector Business Margin Tax collection share has decreased by 6 per cent (Texas Comptroller of Public Accounts 2013: Tables 5, 7). This may be due in large part to the fact that the mining sector has retained many of its traditional deductions, such as intangible drilling costs, depletion, and geophysical costs through the cost of goods sold election, while subject to a much lower rate of 0.5 per cent.

Table 11 illustrates the comparative relationship between mineral revenue in Texas. Oil and Gas Property Taxes dominate mineral revenue collection, followed by Oil Production and Regulation Taxes. Natural Gas Production and Regulation Taxes follow, with royalties, bonuses and Sales Tax next. The Business Margin Tax yields the smallest portion of revenue from the industry. Furthermore, the ability of the Business Margin Tax to provide information on marketing costs under the Oil Production Tax is limited, because the cost of goods sold does not include distribution costs, which include outbound transportation costs.

172 Tex. TC Sec. 171.1014(d).

173 Tex. TC Sec. 171.1014(e).

174 Tex. TC Sec. 171.1014(f).

175 Tex. TC Sec. 171.106.

176 The Business Margin Tax was created as a compromise to replace part of the revenue lost from a one-third reduction in school district property taxes . However revenue from the tax has not met expectations, due in large part to the economic recession, but also due to high cost of goods sold deductions. In the past three years, however, revenue has increased due to the economic recovery, coupled with a rapid increase in production from shale formations in several parts of the state.

177 See also Texas Taxpayers and Research Association (2011).

Table 11 Texas mineral revenue

Revenue source	Revenue (FY 2011 US$ million)
Property Tax for oil, gas and other minerals	2,252.12[178]
Oil Production and Regulation Taxes	1,472.85
Natural Gas Production and Regulation Taxes	1,109.72
Oil and gas bonuses and rentals	763.82
Oil and gas royalties	638.59
Oil and Gas Extraction Sales Tax	489.1
Business Margin Tax	320.26

Source: Texas Comptroller of Public Accounts (2013: Table 1); Texas Comptroller of Public Accounts, *Texas Transparency*, *State Revenue by Category*; Texas Comptroller of Public Accounts, *Quarterly Sales Tax Historical Data*; Texas Comptroller of Public Accounts (2012)

[178] Assumes average property tax rate of 2.124% (may be slightly overstated as most oil/gas production takes place in rural areas where property taxes are lower).

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International Centre for Tax and Development
at the Institute of Development Studies
Brighton BN1 9RE, UK
T: +44 (0)1273 606261
F: +44 (0)1273 621202
E: info@ictd.ac
www.ictd.ac