JUDICIAL CONSIDERATION OF THE *INDIAN OIL AND GAS ACT* AND *REGULATIONS*

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Some 1.29 million hectares of land are under the control and management of the Government of Canada for the "use and benefit" of First Nations[1] (for ease of reference, "Indian reserves"). In the provinces of British Columbia, Alberta, Saskatchewan and Manitoba over 60 First Nations have oil and gas exploration and/or production on their lands.[2] This represents approximately 670 mineral agreements covering 612 thousand hectares of land.[3] To better gauge the scope of oil and gas production on First Nation lands, approximately 452 thousand cubic meters of oil and 2,175 million cubic meters of natural gas were produced in 2002-2003.[4] Given these statistics, it is not surprising that from time to time disputes arise in regard to royalties payable on oil and gas production from Indian reserves. What is surprising is the general lack of Canadian case law, to assist the parties in resolving these disputes.

I. RESERVE LANDS AND THE INDIAN OIL AND GAS REGIME

At law First Nations do not have the right to develop and exploit the oil gas resources underlying their reserve lands if this requires alienation or disposition of any portion of these lands to third parties.[5] As a result, First Nations must rely upon the Crown's trust and fiduciary obligations to

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[1] *Indian Act*, R.S.C. 1985, c. I-5, s.18.
[2] Online: Indian and Northern Affairs Canada <http://www.ainc.gc.ca/ps/lts/iogc_e.html>.
[3] Indian Oil and Gas Canada Annual Report 2002-2003, Minister of Indian Affairs and Northern Development, Ottawa, 2003.
[4] *Ibid.*
[5] [6]These restrictions have come about as a result of the following five sections of the *Indian Act*:
Section 18(1) states:

> "Subject to this Act, reserves are held by Her Majesty for the use and benefit of the respective bands for which they were set apart; and subject to this Act and to the terms of any treaty or surrender, the Governor in Council may determine whether any purpose for which lands in a reserve are used or are to be used is for the use and benefit of the band."

Section 28 states:

> "(1) Subject to subsection (2), a deed, lease, contract, instrument, document, or

them to administer these resources and to collect their royalties. These trust and fiduciary obligations have arisen from a number of sources including, among others, the inherent rights of First Nations, treaty rights, the *Royal Proclamation, 1763,* the Constitution of Canada[6] and, most importantly, the actual terms of the mineral "surrenders" to the Crown that are required before oil and gas leasing can take place.[7]

The Government of Canada has further defined its role in the administration of First Nations' oil and gas resources in the *Indian Act,*[8] the *Indian Oil and Gas Act*[9] and the *Indian Oil and Gas Regulations.*[10] The overall effect of this legislation is that a First Nation may not directly dispose to a third party any of its lands, any rights attached to its lands or any minerals located on its lands. Any disposition or grant of a First Nation's mineral interests to a third party, such as an oil and gas lease, requires that the particular right or interest in land that is being sought by the third party, must first be "surrendered"[11] to the Crown. Once the interest in the land or the specific

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> agreement of any kind whether written or oral, by which a band or a member of a band purports to permit a person other than a member of that band to occupy or use a reserve or to reside or otherwise exercise any rights on a reserve is void.
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> (2) The Minister may by permit in writing authorize any person for a period not exceeding one year, or with the consent of the council of the band for any longer period, to occupy or use a reserve or to reside or otherwise exercise rights on a reserve."

Section 37(2) of states:

> "Except where this Act otherwise provides, lands in a reserve shall not be leased nor an interest in them granted until they have been surrendered to Her Majesty pursuant to subsection 38(2) by the band for whose use and benefit in common the reserve was set apart."

Section 38(2) states that:

> "A band may, conditionally or unconditionally, designate by way of a surrender to Her Majesty that is not absolute, any right or interest of the band and its members in all or part of a reserve for the purpose of its being leased or a right or interest therein being granted."

And finally under section 93:

> "A person who, without the written permission of the Minister or his duly authorized representative,
> (a) removes or permits anyone to remove from a reserve
> (i) minerals, stone, sand, gravel, clay or soil, or
> (ii) trees, saplings, shrubs, underbrush, timber, cordwood or hay, or
> (b) has in his possession anything removed from a reserve contrary to this section,
> is guilty of an offence and is liable on summary conviction to a fine not exceeding five hundred dollars or to imprisonment for a term not exceeding three months or to both."

[6] *The Constitution Act, 1867* (U.K.), 30 & 31 Vict., c. 3, reprinted in R.S.C. 1985, App. II, No. 5.
[7] See *Blueberry River Indian Band v. Canada (DIAND*), [1995] 4 S.C.R. 344.
[8] *Supra* note 1.
[9] R.S.C. 1985, c. I-7
[10] S.O.R./94-753
[11] The term "designated" is now used under the *Indian Act.*

minerals has been surrendered to the Crown, the legislation obligates the Crown to deal with the surrendered lands or mineral interests for the "use and benefit" of the First Nation.[12]

Thus the Minister of Indian and Northern Affairs has a fiduciary or trust obligation to manage the exploration and development of First Nations' oil and gas resources in the best interests of the respective First Nations. In southern Canada this duty has in large part been delegated to a separate branch of the Department of Indian and Northern Affairs Canada ("INAC") known as Indian Oil and Gas Canada ("IOGC"). As a Special Operating Agency, IOGC's mandate is "to fulfill the Crown's obligations fiduciary and statutory obligations related to the management of oil and gas resources on First Nation lands and to further First Nation initiatives to manage and control their oil and gas resources".[13]

II. HER MAJESTY AS TRUSTEE: HELP OR HINDRANCE?

The Government of Canada, or more particularly INAC, is a very reluctant landlord of Indian oil and gas interests. The history and culture of INAC dictate that the department's mandate is to look after poor and destitute Indians. Oil and gas producing First Nations are not considered poor and destitute by INAC. Consequently, there is an underlying attitude at INAC that resents the fact the department must collect and manage oil and gas royalties for First Nations who, in the minds of some public servants, should not need their assistance. INAC has even taken the position that it is the responsibility of the affected First Nation to pursue and litigate the recovery of overdue, underpaid or unpaid royalties on the grounds that it is not part of the Government of Canada's fiduciary obligations to "collect" royalties let alone to litigate and recover overdue, underpaid or unpaid Indian royalties.

The ensuing reluctance of INAC to administer and collect Indian royalties manifests itself in a number of ways. Consider for example the fact that oil and gas have been produced from Indian reserves for 50 years now and that most of the larger oil and gas pools on Indian reserves were

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[12] *Supra* note 1.
[13] *Supra* note 3.

discovered in the 1950's and 1960's. Throughout the entire period that royalties have been paid there have been a multitude of gray areas in terms of how these royalties should have been calculated. With a reluctant landlord, however, many of these gray areas have never been addressed, let alone clarified. As a result, a number of issues have gone unresolved for many, many years.

Examples of some of the unresolved issues include: the length of lease terms and the continuance of leases; the continuance of leases without production; the applicability of revised Regulations to existing leases; IOGC's practice of allowing royalty deductions other than gas processing costs; the taking of royalties in kind; interest on royalties paid late; royalty sales below fair market value; the applicability of provincial legislation; and the jurisdiction of provincial regulatory agencies.

Another twist to this problem arises from the fact that Indian oil and gas royalties go into the Consolidated Revenue Fund, the same place all federal tax dollars go. Royalties are in fact payable to the Receiver General, the same person who collects our income taxes, Goods and Services Taxes, excise duties, etc. The Receiver General then deposits these payments into the Consolidated Revenue Fund along with taxes and other stipends paid to the Government of Canada. At any given point in time the Government of Canada is notionally holding and owing to First Nations upwards of a billion dollars in Indian royalties paid to the Government of Canada but not yet distributed to the beneficiary First Nations. Because the federal treasury enjoys the use of these funds, the Minister of Finance does not necessarily share INAC’s reluctance in collecting Indian oil and gas royalties.

In addition to royalty payments, all bonuses and rentals from oil and gas leasing on Indian reserve lands are deposited into the Consolidated Revenue Fund.[14] Rentals and other income are termed “revenue monies”, while bonuses and royalties are termed “capital monies”. These “capital monies” are released to the First Nation if and when the First Nation satisfies the Governor in Council, not just the Minister of Indian Affairs,[15] that they will be expended for the

[14] S*upra* note 1, s.62 and the *Financial Administration Act*, R.S.C. 1985, c. F-11.
[15] Although the Minister may authorize expenditures that fall within section 64 of the *Indian Act*.

use and benefit of the First Nation.[16] Thus there are no separate accounts holding bonuses and royalties from Indian reserves.

The Government of Canada agrees that it is holding these monies in "trust" for the respective First Nations.[17] However, the Receiver General has no segregated deposit trust accounts in the name of each First Nation. The Government of Canada instead only notionally owes these monies to the First Nations. Indian royalty monies are handled in a manner similar to, for example, Employment Insurance premiums and Canada Pension Plan payroll deductions. All of these payments to the Receiver General essentially become part of the national debt the day the Receiver General cashes the cheque from the oil and gas producer.

III. HINDRANCE

Historically, however, not all resource rents from Indian reserves have been paid to First Nations in the form of lease bonuses and royalties. One need only to turn the clock back to the 1970's and 1980's when the price of oil went from approximately $3.00 per barrel in the summer of 1973 to $35.00 per barrel by the beginning of 1986. The economy of Alberta was booming, a result of such phenomena as "windfall profits", "cartels" and "blue eyed sheiks". These terms were also used pejoratively to assess blame for skyrocketing oil prices, however they were never actually defined, nor was the causal connection leading to high prices explained.

Indian oil royalties too increased substantially in this time period. However, from 1973 to 1985 Indian oil royalties were calculated and paid on a domestic price that was below the market price for this oil. As a consequence, Canadian consumers and the Government of Canada (and to some extent the provincial governments) received a benefit of almost $2,000,000,000.00 that would otherwise have been paid to the First Nations from whose lands this oil was produced. The fact that the Government of Canada had such tight control of Indian oil and gas resources enabled this to occur. It remains to be seen whether such a wholesale appropriation of the value

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[16] *Supra* note 1, s. 61.
[17] See section 4 of the *Indian Oil and Gas Act, supra* note 9.

of Indian lands was in keeping with the Crown's fiduciary obligations to First Nations. It is no coincidence that oil and gas prices have increased substantially once again and the Government of Canada continues to retain control of these resources in order to "act" once more should it feel it necessary.[18]

Royalty disputes and arguments over resource rent sharing between governments and First Nations are front and center in a number of lawsuits currently before the courts.[19] However, the focus of this presentation is on royalty disputes between producers and the Government of Canada, as lessor and trustee for First Nations, as well as disputes between producers and First Nations directly.

IV. HOW SHOULD PRODUCERS DEAL WITH INDIAN ROYALTIES

As already stated, whether the royalty dispute is between producers and the Government of Canada or between producers and First Nations, there remains a significant lack of case law to assist the parties when it comes time to interpret the royalty provisions of the leases, the *Indian Oil Gas Act*[20] and the *Indian Oil and Gas Regulations*[21]. In part this is a function of the reluctance of the First Nations' trustee to pursue and collect overdue, underpaid and unpaid First Nation royalties. This is further exacerbated by the fact that the majority of the First Nations simply do not have the financial means to pursue litigation as against the producers. The result – royalty disputes remain outstanding and unresolved for many years – generally to the ultimate prejudice of the First Nation.

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[18] Conventional wisdom tells us that Canadian taxpayers support native peoples and First Nations to a great extent. Today's policy makers in Ottawa (and Edmonton?) are by and large from the same school as those who fought the energy wars with the western provinces in the 1970's and 1980's. Resource rents from oil and gas production are still looked upon as "windfalls" and as undeserved benefits to the owners of the resource. Just as myths were created in the 1980's that Alberta's streets were paved with gold, so today those First Nations having oil and gas production are labeled as "oil rich", regardless of the reality.

[19] For example, *Buffalo v. The Queen*, *Ermineskin v. The Queen*, and *Ear v. The Queen*, all currently before the Federal Court of Canada.

[20] *Supra* note 9.

[21] *Supra* note10.

Even where there is case law, bear in mind that the majority of the Indian royalty litigation[22] dealt with the *1977 Indian Oil and Gas Regulations*[23]*, which* have been superseded by updated regulations that came into effect on January 1, 1995.[24] The good news -- there are actions currently before the courts[25] that will consider the *1995 Indian Oil and Gas Regulations*[26]. The bad news – before these actions work their way through the courts it is anticipated that the Government of Canada will introduce a new set of regulations.

The following sections will discuss some of the Indian royalty litigation and how royalty payors might respond to these rulings.

A. MARKETING AND ADMINISTRATIVE COSTS

The case of *Imperial Oil Resources Ltd v. Canada (Minister of Indian Affairs and Northern Development)*[27] involved "deductions" made by Texaco Canada Resources Ltd. ("TCRL"), the predecessor corporation to Imperial, in the form of a 5% marketing fee. Texaco sold gas products from the Bonnie Glen field (part of which underlies Pigeon Lake Indian Reserve No. 138A) to its parent company, Texaco Canada Inc. ("TCI"). Under the terms of an agreement between TCRL and TCI, TCI undertook to market gas products acquired from TCRL and agreed to pay TCRL 95% of TCI's sale price. TCRL calculated its royalty obligation to IOGC on the 95% netted-back price for the period in question, August 1979 to the end of 1985.

The *1977 Indian Oil and Gas Regulations*[28] provided that royalties were to be calculated in accordance with Schedule I. That schedule stipulated that all *quantities* or *amounts* should be calculated at the time and place of production, free and clear of any deduction whatsoever. In

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[22] *Imperial Oil Resources v. Canada (Minister of Indian Affairs and Northern Development*), [1999] F.C.J. No. 1910, aff'g [1997] F.C.J. No. 1767 (T.D.) (QL) [***Imperial***]; *Shell Canada v. Canada* (A.G.), [1998] F.C.J. No. 1525 (C.A.) (QL), aff'g [1998] 3 F.C. 223 (T.D.) [***Shell***]; and *Stoney Tribal Council v. PanCanadian Petroleum,* [2000] A.J. No. 870 (C.A.), aff'g in part [1999] 218 A.R. 210 (Q.B.) [*Stoney*].
[23] S.O.R./77-330, C.R.C. 1978, c. 963
[24] *Supra* note 10
[25] *Chevron v. Her Majesty the Queen, et al.; Buffalo v. Imperial, et al.* and *Buffalo v. Amoco, et al.*
[26] *Supra* note 10.
[27] *Imperial, supra* note 22.

the case of natural gas, subsection 2(2) contained the additional qualifier "except as provided in subsection (4)." That subsection provided as follows:

> (4) Where gas is processed by a method other than gravity, the royalty of the gas obtained therefrom shall be calculated on the actual selling price of that gas, but such costs of processing as the Manager may from time to time consider fair and reasonable, ... shall be allowed.

In 1994, the Executive Director formed the opinion that the 5% deduction was impermissible and decided to audit the pre-1986 TCRL records.[29] On an application for review the Minister confirmed the Executive Director's decision to disallow the deduction. In reaching his decision, the Minister treated TCI and TCRL as if they were a single entity.[30] This allowed him to treat TCI's selling price as TCRL's selling price and therefore the deduction was an impermissible deduction. A further reason for the Minister's decision relied on the fact that the Alberta Crown did not allow the deduction of similar fees for its royalty share of production from the Bonnie Glen field, although there was evidence that this was the result of negotiations between Alberta and TCRL.

On its application for judicial review to the Federal Court, Imperial argued that the Minister had erred in disallowing the marketing fee and also argued that IOGC had no authority to conduct an audit. Justice Rothstein of the Federal Court, Trial Division quashed the Minister's decision. Justice Rothstein ruled the Executive Director had no right to audit and went on to say that the Minister committed an error of law by treating TCRL and TRI as a single entity.[31] There was nothing in the *Indian Oil and Gas Act*[32] or the *1977 Indian Oil and Gas Regulations*[33] to permit this and thus the common law rule to the effect that a corporation is a separate and distinct legal entity from its shareholders prevails.

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[28] *Supra* note 23.
[29] IOGC had previously audited the 1986-88 period and Imperial "submitted corrected royalties" for that period.
[30] This is Justice Rothstein's characterization, *Imperial supra* note 22 at 10.
[31] *Ibid*. at 18 - 22.
[32] *Supra* note 9.
[33] *Supra* note 23.

As a result of this decision it is clear that the Minister cannot disallow the deduction of a marketing fee *where the Minister's reasoning depends upon piercing the corporate veil*. Contrary to Imperial's current contention, Justice Rothstein did not rule that Imperial is entitled to reduce its royalty obligation by deducting a marketing fee. Presumably, it is still open to the Minister to say that he has other good and sufficient reasons for denying the deduction of the marketing fee, which reasons do not depend upon piercing the corporate veil. For example, he might reason that since the contract between TCRL and TCI required TCI to sell products "at competitive market values",[34] the actual sales prices achieved by TCI must be the best evidence of actual price, not just for TCI but also for TCRL as the party obliged to pay royalties. The Minister might also be able to reason with some conviction, that while allowable processing costs can be deducted, the marketing fee claimed does not amount to a processing cost.

Nevertheless, Imperial is utilizing a scheme whereby marketing and perhaps other costs are isolated in an affiliate company. This method to date has been successful in enabling these costs to be deducted from selling prices prior to the calculation of Indian royalties.[35]

Contrast this situation with that arising as a result of the decision in *Stoney v. PanCanadian*[36] in which the Alberta Court of Appeal confirmed that marketing fees, in the form of OMAC charges[37], are not processing costs and thus not deductible for the purposes of calculating Indian royalties, even though the marketing costs were ostensibly incurred by a party other than the royalty payor. The ability of an Indian royalty payor to deduct marketing and administrative fees would therefore seem to depend on how successfully these fees can be isolated in a party other than the royalty payor.

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[34] *Imperial, supra* note 22 at 6. How much room the Minister has here depends very much upon the terms of the formal order. The order is reproduced in [1998] FCJ 1708. Paragraph 1 of the order quashes the actual decision of the Minister, but then goes on to make certain declarations including the declaration that there was no evidence on the record of the improper deduction of a marketing fee.

[35] Since this judgment was rendered the Minister directed Imperial and the Executive Director of IOGC to resolve this outstanding matter. To date there has been no resolution of any of the issues that led to the judicial review application.

[36] *Stoney, supra* note 22.

[37] Operating, marketing and administrative charges.

B. THE USE OF AFFILIATE CORPORATIONS

In *Imperial*[38] Justice Rothstein was also troubled by what he perceived to be an unusual and unfair aspect of the Indian oil and gas regime. The *1977 Indian Oil and Gas Regulations*[39] provided that the value of the gas for royalty purposes is the "gross proceeds" of the sale free and clear of all deductions, other than processing costs. If gas is sold at a price lower than market value, the *Regulations* provided a mechanism whereby the lessee must then pay royalties based on the higher, fair market value of the gas.[40] However, if the gross proceeds accruing to the lessee are higher than the fair market value, royalties are still based on the higher, gross proceeds. The lessor gets the best of both worlds in Justice Rothstein's eyes.

Justice Rothstein felt that this mechanism was specifically designed for non-arm's length sales of royalty oil and gas. An arm's length transaction is one arrived at in the market place between independent, non-affiliated persons with opposing economic interests regarding that contract.[41] The TCI/TCRL relationship was clearly not arm's length.

Imperial's own evidence indicated that TCI's sales directly from the plant gate were 5% higher than the price used by TCRL to calculate the royalties it paid to IOGC. The gas products sold by TCI to third parties were identical to the gas products purportedly sold by TCRL to TCI and were sometimes sold at the same location.

Evidence of the fair market value of TCI's products should logically also have been evidence of the fair market value of TCRL's products. Since both TCRL's purported sales to TCI and some of TCI's own sales to third parties were at the processing plant gate, the marketing fee could not

[38] *Imperial, supra* note 22.
[39] *Supra* note 23.
[40] *Supra* note 23, s. 21(7):
21(7) Where oil or gas that is the royalty payable under these *Regulations* ... is sold or to be sold and, in the opinion of the Manager, the sale was or will be at a price that is less than the fair market value of the oil or gas, the Manager shall, by notice in writing addressed to the lessee, specify the dollar value of the oil or gas that would be realized if it were sold in a business-like manner, at the time and place of production in an arm's length transaction; and the lessee shall, in his royalty payment next following the receipt by him of the notice, account for and pay to the Manager the deficiency between the dollar value specified in the notice and the actual dollar value obtained by the lessee on the sale of the oil or gas.
[41] For a definition see for example US Regs at 30 CFR 206.101.

have been a deduction "downstream" of the processing plant. Or, looked at another way, sales by TCI, after it had purchased the gas products from TCRL, were sometimes f.o.b. the plant gate. Since the price of these sales was 5% higher than the price on the sales from TCRL to TCI, these sales themselves are evidence that the latter sales were less than fair value.

Again, the ramifications arising from *Imperial*[42] make for interesting possibilities in terms of how a royalty payor might use affiliate companies in order to retain for itself a greater share of the value of the royalty oil and gas. Imperial and other large producers on Indian lands utilize affiliates in this manner.[43]

Caution is warranted however, as the *Regulations* still include provisions whereby IOGC can dictate that royalties be paid on a fair market value that is higher than the sales prices between affiliates.[44] The only question is whether IOGC is willing to use these powers.

C. RETROSPECTIVE REGULATION

Shell Canada Ltd v. Canada (Attorney General)[45] is a decision that dealt with the issue of gas processing deductions for royalty gas, commonly known as Gas Cost Allowance ("GCA"). Shell had been producing gas from the Jumping Pound field, a portion of which underlies the Stoney Indian Reserves. Between 1983 and 1988, and pursuant to the guidelines for calculating gas cost allowance, Shell included the capital costs of its relevant capital assets in calculating GCA deductions. Shell did not deduct the value of investment tax credits ("ITCs") earned by it under the *Income Tax Act* when it included its capital costs in the GCA formula. The guidelines were silent on this question and it was not until 1991 that IOGC informed industry that it would require Indian lessees to deduct ITCs in calculating capital costs for GCA purposes. In 1995 the Executive Director of IOGC decided to claim additional royalties from Shell for the period from 1983 to 1988 on the basis that ITCs should have been deducted from the capital costs included in

[42] *Imperial*, *supra* note 22.
[43] Shell Canada Ltd. has also used an affiliate, Coral Energy Ltd., for the purposes of marketing natural gas from Indian reserves
[44] *Supra* note 10, s. 33(6).

the GCA formula. Shell appealed that decision to the Minister who confirmed the Executive Director's decision. Shell was successful on its judicial review application to the Federal Court and the Federal Court of Appeal confirmed the trial decision.[46]

The Federal Court of Appeal gave two reasons for confirming the trial decision. First, the Court held that the Executive Director and the Minister had no authority to apply the Regulations retrospectively, which is what the Court held had in fact been done:[47]

> "A statute is said to be retrospective not only when it takes away or impairs a vested right, but also when it creates a new obligation, imposes a new duty or attaches a new disability with regard to events already past.
> From 1983 - 1988, Shell's royalty returns were filed according to the known guidelines. By adding a new component to those suggested by the guidelines for the purposes of computing GCA, the Manager imposed a new liability on Shell which neither the *Act* nor the *Regulations* contemplated."

In coming to this conclusion, the Court presumably must also have decided that the former guidelines could not reasonably have been interpreted as requiring the deduction of ITCs from capital costs.[48] On this interpretation, when the more specific guidelines were announced in 1991, they had the effect of changing the previous guidelines in a retrospective manner.

Although the Act required lessees to pay royalty in accordance with the *Regulations* "as amended from time to time", and although the Schedule to the *1977 Indian Oil and Gas Regulations*[49] allowed deductions for such processing costs as the Executive Director "from time

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[45] *Shell, supra* note 22.
[46] *Ibid.*
[47] *Ibid*, at13 and 14.
[48] The court's decision turns very much upon the idea that the Executive Director was making a new decision with retrospective effect rather than simply asserting that this was the proper interpretation of the original guidelines. The point is of dual significance since the Executive Director is presumably entitled to some deference as to the proper interpretation of the guidelines. The Executive Director did have advice from Peat Marwick that Shell's treatment of ITCs was not in accordance with the guidelines: *Shell* (F.C.A.), *supra* note 22 at 8.
[49] *Supra* note 23.

to time" considered reasonable, the Court held that both provisions should be interpreted to be prospective in nature.[50]

Inconsistent or changing application of the GCA rules by IOGC, if this can be characterized as retroactive or retrospective in its effect, can therefore be successfully attacked. Producers should keep this in mind given that in the past IOGC has been notoriously slow in approving final GCA rates.[51]

D. TIME IS ON YOUR SIDE: LIMITATIONS OF ACTIONS

Lessees who have been producing from Indian reserves for a number of years are by now aware that IOGC is very reticent to issue default notices for unpaid royalties.[52] This, combined with IOGC's proffered inability to charge interest on overdue royalties, means that lessees are usually in little danger of suffering dire consequences should issues remain unresolved and royalties go unpaid. Moreover, it appears to be the position of the Government of Canada that the commencement and pursuit of legal proceedings to collect oil and gas royalties is not part of the fiduciary or trust obligations of the Government of Canada to First Nations. Obviously, the "full weight" of the Government of Canada is fairly light when it comes to collecting Indian oil and gas royalties. Producers should not become sanguine however, as these positions taken by IOGC could of course change.

Many royalty related issues in dispute are old issues that could have been resolved much more easily had they been addressed on a timely basis. Unfortunately, they have not been addressed, let alone resolved, and many are still not being addressed. If lessees do not address current Indian royalty issues on a timely basis, chances are they may be relying on limitations defences

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50 *Shell, supra* note 24 at 15 relying on *AG Alberta v. Huggard Assets Ltd*, [1953] A.C. 420 (P.C.).

51 *Quaere* whether a retrospective application of the GCA rules in favour of a royalty payor could be challenged by the First Nation beneficiary

52 "You suggest in ... your letter that if all royalties owing are not paid in full, IOGC should issue a default notice under section 46 of the *IOG Regulations*.... In general, it is our position that defaulting the leases is not the most prudent or responsible approach." Extract from a letter from the Executive Director of IOGC to the author, November, 2000.

down the road should the substantive issues not be decided in their favour. Such reliance is not necessarily a bad thing if you are an Indian lessee.

Recent decisions have held that limitations of actions statutes do serve to limit the damages a defendant is liable for when sued for unpaid Indian royalties.[53] While limitations defences may be good defences, it is important to keep in mind that the applicability of provincial limitations statutes to Indian lands may still be problematic. Key questions remain outstanding. For instance, while *Wewaykum Indian Band v. Canada*[54] suggests that provincial limitation statutes are incorporated by reference through the *Crown Liability and Proceedings Act*[55], and therefore may apply when First Nations pursue claims against the Government of Canada, no such legislation comes into play in actions as between First Nations and producers. In fact, both the Government of Canada and producers forget that the Court of Appeal in *Stoney*[56] did not hear any arguments or render a judgment as to the constitutional applicability of provincial limitation periods as between First Nations and producers or whether there are applicable limitations periods as between the Government of Canada and producers.

As well, since producing oil and gas leases are executory in nature, actions of a lessee can be interpreted as restarting any applicable limitations periods. For instance in considering the 10 -year limitation period set out in section 3(1)(a) of the *Limitations Act*[57] and whether or not section 3(3) suspends the commencement of the limitation period, Justice Lovecchio recently held that:[58]

> "The Applicants submit the failure by Imperial to pay the Meek Royalty each month constitutes "a continuing course of conduct" or amounts "to related acts or omission". As a result the ten year period has not commenced to run.

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[53] For example, *Stoney, supra* note 22.
[54] [2002] 4 S.C.R. 245.
[55] R.S. 1985, c. C-50.
[56] *Stoney, supra* note 22.
[57] R.S.A. 2000, c. L-12.
[58] *Meek Estate v. San Juan Resources Inc.*, [2005] A.J. No. 13 at 89, 93-95.

> As stated, the rationale for the section is to give a defendant peace of mind for "ancient obligations". When a course of conduct is continuing, it has not yet become "ancient" conduct. Only when that conduct ceases will it become a historical fact from which a defendant should at some point be given peace of mind.
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> There is no policy basis on which to give a defendant who continues to misbehave in the same fashion peace of mind for their prior acts of a similar nature.
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> As a conduct has not terminated nor the last act occurred, the ten year limitation period has not commenced to run. Stated another way, using the vernacular of the section – as the need to assert the claim has not yet "arisen", the 10-year limitation prescribed by section 3(1)(b) does not apply so as to statute bar part of the claim."

To avoid having to rely upon limitations defences and to avoid the expense and uncertainty associated with litigation, producers with interests on Indian reserves should take steps to ensure that their royalty administration people are familiar with the *Indian Oil and Gas Regulations*[59] and that Indian royalties are calculated and paid in accordance with lease terms and these *Regulations.* For better and for worse, the *Indian Oil and Gas Act*[60] and *Regulations* constitute a unique regime that must be treated as such, even if to do so is inconvenient. In the past, Indian royalties have often been treated by lessees like Alberta Crown royalties or freehold royalties. They are neither. Policy and administrative positions taken by Alberta Energy cannot automatically be applied to Indian lands, no matter how convenient this is for royalty administration.[61] Furthermore, it is not prudent to rely upon the acquiescence of IOGC to a procedure or a method if that method clearly is not in compliance with the Regulations.[62]

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[59] *Supra* note 10.
[60] *Supra* note 9.
[61] See the comments of McIntyre, J. in *Stoney, supra* note 22.
[62] For example, the deduction of gathering costs prior to 1995.

V. THE FIRST NATION PERSPECTIVE

When problems arise, First Nations who beneficially own royalty interests are at an inherent disadvantage in that they may have no privity with the oil and gas lessees operating on their reserve lands. While traditionally First Nations have relied on their trustee, the Government of Canada, to enforce mineral lease terms and to collect their royalties, there are serious limitations to wholesale reliance on the Government of Canada. While IOGC is obviously cost effective[63] and while IOGC has competent and diligent people, their hands are often tied by the "reluctant landlord" attitude described earlier. So if a First Nation feels that a particular royalty issue is going unaddressed by IOGC, what are its options?

A. FILE NOW, NEGOTIATE LATER

First Nations with legitimate claims and a belief that royalty monies are owing, have no other choice but to claims in the courts. For instance, limitation periods in Alberta may be as short as two years[64] and First Nations that wait to see if negotiations will come to fruition may very well prejudice their ability to use legal means to resolve their claims.

While some may feel that such advice coming from a lawyer is self-serving, we need only point out the millions of dollars that have already been left behind by First Nations who waited too long to pursue their claims in the courts.[65] No amount of negotiations or political lobbying will ever recover these foregone royalties.

First Nations should also be prepared to meet other defences that IOGC does not have to deal with. For example, the standing of an individual First Nation to pursue royalty issues may be

[63] IOGC charges no direct fees to First Nations.
[64] *Limitations Act, supra* note 37.
[65] See for example *Blueberry River, supra* note 7 and *Stoney, supra* note 22.

challenged. In general, the longer a royalty owner waits to collect royalties owing to him, the less sympathy the courts will have for that royalty owner.[66]

B. TRANSPORTATION DEDUCTIONS

The *1977 Indian Oil and Gas Regulations* did not expressly allow any transportation deductions in the calculation of royalties, nor did they contemplate a "net back" method of pricing for the purposes of royalty calculation. Royalties were to be calculated on the actual selling price (arguably wherever that sale took place), less only gas processing costs. In spite of this, IOGC generally allowed the deduction of additional costs, such as transportation or gathering system costs that were incurred between the wellhead and the point of sale of the royalty gas or oil.[67] The *1995 Indian Oil and Gas Regulations*[68] expressly allow gas gathering system deductions.[69]

In *Imperial*[70], Justice Rothstein noted that the Executive Director had attempted to disallow one type of deduction, namely marketing fees, while allowing or "netting back" other deductions downstream from the wellhead, namely transportation costs. Justice Rothstein pointed out that if the Executive Director had consistently interpreted the *1977 Indian Oil and Gas Regulations*[71], he should also have disallowed these transportation deductions:

> "The purported basis for disallowing the marketing fee charge is that it is not a cost of processing which is the only type of cost that may be deducted under subsection 2(4) of Schedule I of the *Regulations*. However, the respondents do not take the same position with respect to transportation charges or taxes incurred beyond the plant gate. In essence, the respondents for marketing fee purposes, treat TCRL and TCI as one entity, but treat them as separate entities for other charges. If indeed the respondents had the authority under the Regulations to

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66 See *Imperial, Shell and Stoney, supra* note 22.
67 See *Imperial, supra* note 22 at 22.
68 *Supra* note 10.
69 *Supra* note 10 at Schedule I, s. 4.
70 *Imperial, supra* note 22.

> pierce the corporate veil and did so, they would be obliged to disallow all non-processing costs. They do not have the power to allow or disallow costs in their discretion."[72]

The conclusion is that if transportation or gathering system costs were deducted from royalties payable prior to January 1, 1995, these deductions may be challenged.

C. TOPGAS INTEREST CHARGES AND RELATED DEDUCTIONS

Even if the Regulations are interpreted to permit the adoption of the netback methodology to move from the first point of sale to arrive at a wellhead price, it does not follow that all of the costs incurred by a producer can be considered as part of this net-back arrangement. The decision in *Stoney*[73] supports this proposition. The issue is not "are the proposed costs fair and reasonable" but rather, as a matter of law, are they essential to determining a netback price.

The Stoneys claimed that PanCanadian had underpaid its royalty obligations by making two types of deductions, first, a deduction for TOPGAS financing charges that were chargeable to and paid by PanCanadian, and second, operating, marketing and administration charges ("OMAC") that were paid by PanCanadian to TransCanada Pipelines Ltd. to whom PanCanadian sold the gas produced from the Stoney reserves.

The original leases both provided that the royalty was to be payable "free and clear of all rates and taxes and assessments and from all manner of deductions whatsoever." The lease renewals both provided that the lessee was to pay the lessor the royalty from time to time prescribed by the Regulations. The *1977 Indian Oil and Gas Regulations*[74] provided that a lessee must pay a basic and a supplementary royalty with "all quantities to be calculated at the time and place of

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[71] *Supra* note 23.
[72] *Imperial, supra note 22* at 22. Justice Rothstein however seemed to think that the deductibility of these costs had something to do with whether the costs were deducted by the royalty payor or by a third party. Respectfully, he was mistaken in this regard. See Justice McIntyre's comments in *Stoney, supra* note 22 at 98.
[73] *Stoney, supra* note 22.

production free and clear of any deduction whatsoever" except as provided under subsection (4). Subsection (4) as we have seen, is confined to such fair and reasonable processing costs as are allowed by the Manager. As Justice McIntyre noted, "The Manager did not allow costs relating to TOPGAS or OMAC, which costs are not, in any event costs of processing."[75]

The Regulations prohibited any deductions except allowed processing charges. The charges in question do not fall into that category and neither the TOPGAS charges nor OMAC was an essential or integral part of determining a netback price. The fact that the lessee had to make a payment to a third party in respect of gas produced on Indian lands did not in and of itself make that payment an essential element of the netback.

TOPGAS interest charges were deducted from 1982 to 1995. However, OMAC charges, in the form of a component of the "Alberta Cost of Service",[76] continue to the present. Therefore, First Nations should continue to investigate whether their gas royalties have had OMAC deducted prior to the calculation of the royalty.

D. ROYALTY DEDUCTIONS VS. VALUATION OF PRODUCT FOR ROYALTY PURPOSES

In attempting to interpret and decipher the royalty provisions in the *Indian Oil and Gas Regulations*[77], it may sometimes be more rewarding for a First Nation to concentrate on the pricing or valuation of oil and gas for royalty purposes, rather than attempting to determine the legitimacy of any deductions taken in arriving at a royalty price.[78] Regardless of how the selling price of royalty products is determined, the Regulations provide that a determination of fair market value of such products must be carried out in any event.[79] Given that the Indian royalty

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74 *Supra* note 23.
75 *Supra* note 20 at 15.
76 The "Alberta Cost of Service" is determined pursuant to the *Natural Gas Marketing Act*, R.S.A. 1980, c. N-2.8.
77 *Supra* note 10.
78 See the reasoning of Rothstein, J. in *Imperial, supra* note 22.
79 In order that the Executive Director is able to make the determination required of him under s.33(6) of the *Regulations*.

recipient is entitled to a royalty based on the greater of the selling price or fair market value,[80] his efforts should perhaps be focused on the latter.

As noted earlier, Justice Rothstein in *Imperial*[81] seems to have had difficulty with the proposition contained in the *1977 Indian Oil and Gas Regulations*[82] that royalties could be made to be payable on the price at which the gas was sold or fair market value, whichever was greater. In fact, such a provision is not entirely unusual. One well known form of freehold lease provides that the lessor's royalty share is paid on "the greater of the actual price received (including payments from any source whatsoever in respect thereof) or the current market value of such substances or any of them, at the time and place of sale in respect of such substance ...”.[83] Typically in an oil and gas lease the lessor is not prohibited from benefiting from his lessee's marketing acumen.[84]

Furthermore, if the selling price of the lessor's royalty share is in fact higher than someone's determination of fair market value, then by definition that determination of fair market value may be incorrect and should be raised to the level of the selling price, since the selling price was presumably paid by a willing buyer in an arm's length situation. Oddly enough, in *Imperial*[85] IOGC appeared to take the position that arm's length sales did not necessarily establish the fair market value of the products.[86]

Market price was not raised directly in any of the cases discussed in this paper and in none of them did IOGC make any attempt to use its price-deeming power under the Regulations. However, there are hints of larger questions. For example, in *Imperial*[87] Mr. DeSorcy, a

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80 *Supra* note 10 at s.4 of Schedule I.
81 *Imperial, supra* note 22.
82 *Supra* note 23.
83 See PanCanadian's standard form freehold petroleum and natural gas lease at clause 5.
84 See also C.A. Rae, "Royalty Clauses in Oil and Gas Lease" (1965 - 66), 4 Alta. L.Rev. 323 at 327. Rae discusses the situation in which the lessee sells on a long-term contract at the prevailing price only to find that the price of gas increases at the wellhead faster than the escalation clauses of the sales contract. Can the lessee be compelled to pay royalty at the market price prevailing from time to time? Rae notes that the point is not settled in Canadian law. That continues to be the case.
85 *Imperial, supra* note 22
86 See the reply of IOGC to the Minister's reviewer dated June 7, 1996 at 44. Exhibit to the affidavit of W. Muscoby, part of the applicant's record, January 16, 1997.
87 *Imperial, supra* note 22.

reviewer engaged by the Minister, in his report alluded to the fact that IOGC did not necessarily accept that Imperial's posted field price was a market price. This issue was not pursued in Federal Court and to the best of the authors' knowledge has not been pursued by IOGC outside of the court process. Unless IOGC adopts its own procedures for deeming prices based on, for example, AEC-hub prices, IOGC or the affected First Nations perhaps should determine whether posted prices, reference prices and other such non-arm's length valuations do in fact produce fair market values.

VI. CONCLUSION

Both the lessor and the lessee always have some legitimate gray areas in the calculation of oil and gas royalties. The time and place of production of particular products is not always easily ascertainable and how to value petroleum and natural gas that are not sold until they are refined into other products can be a difficult exercise. Usually these types of issues are resolved at the administrative level (e.g. Alberta Crown royalties) or they are resolved through litigation (freehold royalty disputes). Unfortunately, with Indian oil and gas royalties many of these issues have never been formally addressed. What originally might have been a relatively minor dispute, with the effluxion of time, becomes more intractable and oftentimes the stakes increase.

The oil and gas industry is an inherently risky business. However, it is a business where risks are quantified, then minimized. Additional risks that cannot be quantified are not appreciated. It must be acknowledged that there may in fact be additional risks for the oil and gas developer operating on First Nation lands. However, with due diligence, an appreciation of the mutual interests involved and a good measure of patience, these additional risks can be quantified, minimized and even eliminated. Given the potential geological and economic advantages to be found on First Nations lands, proper attention to dealing with these risks could in the end prove to be a profitable investment for the oil and gas developer and the First Nation.

*For a more detailed discussion of the royalty cases addressed herein, please see Nigel Bankes and L. Douglas Rae, "Recent Cases on the Calculation of Royalties on First Nations' Lands", 38 Alta. L. Rev. 258.