RECENT LEGISLATIVE AND REGULATORY DEVELOPMENTS OF INTEREST TO OIL AND GAS LAWYERS

LAURA M. DISANTO, FRANCES FERGUSON
AND PATRICIA H. FORREST*

The purpose of this paper is to provide a brief review of recent legislative and regulatory developments of particular interest to oil and gas lawyers. In addition to reporting on recent changes in statutes and regulations, recent decisions and published policy statements of administrative bodies, the paper also discusses a number of legislative and regulatory developments which are still evolving. In order to place some limit on the scope of the paper, federal and Alberta legislative and regulatory developments are reported and certain noteworthy developments in British Columbia, Saskatchewan and Ontario.

TABLE OF CONTENTS

I. LEGISLATIVE CHANGES

A. FEDERAL LEGISLATION

1. Statutes

(a) Federal Budget of February 26, 1991

It was announced in the budget that the Canada Oil and Gas Lands Administration will be disbanded and its responsibilities transferred to other departments. Also, the National Energy Board ("NEB") will move from Ottawa to Calgary.

(b) *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*, S.C. 1990, c.28

This Act establishes the Canada-Nova Scotia Offshore Petroleum Board and outlines its powers and function. It sets out the guidelines for exploration, production, royalties

* The authors are members of the law department of Esso Resources Canada Limited. The authors wish to express their appreciation to other members of the Law Department and of Esso Resources Canada for their assistance in the preparation of this paper.

and Canadian ownership and general operations for oil and gas development in the Nova Scotia offshore area. It also describes the application of federal and provincial laws to those operations and revenue sharing between federal and provincial governments. Division VIII of Part II was proclaimed in force October 1, 1990, the remainder was in force from December 22, 1989.

(c) *Hibernia Development Project Act*, S.C. 1990, c.41

This Act gives the Minister of Energy, Mines and Resources the authority to enter into agreements on behalf of the federal government relating to the Hibernia Development Project. It also contains an outline of the contents that may be included in those agreements and prescribes the federal and provincial laws to apply in the offshore area. In force November 9, 1990.

(d) *Act to Amend the Energy Supplies Emergency Act and to Amend the Access to Information Act in Consequence Thereof*, S.C. 1990, c.2

This Act amends the definition of "wholesale customer" and changes the requirements respecting Canada's representation within the International Energy Agency. The powers of the Energy Supplies Allocation Board with respect to controlled products, are extended. In force January 30, 1990.

(e) *Canadian Laws Offshore Applications Act*, S.C. 1990, c.44

This Act provides that in any area of sea not within a province, the seabed and subsoil below internal waters and territorial sea, as defined, are vested in the government of Canada. It describes the extent to which federal and provincial laws apply to offshore areas and extends the application of the *Coastal Fisheries Protection Act*,[1] *Criminal Code*,[2] *Canada Labour Code*,[3] and *Canada Shipping Act*,[4] among others. In force February 4, 1991, except section 7.

(f) *Excise Tax Act and Related Acts*, measure to amend, S.C. 1990, c.45

This Act which was reported in last year's paper, has become only too familiar to all Canadians. In force December 17, 1990 except Part VII which came into force March 1, 1991.

---

1. R.S.C. 1985, c.C-33.
2. R.S.C. 1985, c.C-46.
3. R.S.C. 1985, c.L-2.
4. R.S.C. 1985, c.S-9.

(g) *An Act to Amend the National Energy Board Act and to Repeal Certain Enactments in Consequence Thereof*, S.C. 1990, c.7

This Act amends the *National Energy Board Act*[5] by amending various definitions, providing the Board may make regulations imposing fees and charges on persons constructing or operating pipelines or powerlines, exporting or importing oil or gas or exporting electricity. The period for obtaining leave to appeal from a decision of the Board to the Federal Court of Appeal runs from the date of release of a decision or order. Part III.1 is added which deals with the construction and operation of power lines. In force June 1, 1990 except sections 13, 20, 25 and 27; sections 13 and 20 came into force January 1, 1991.

(h) *Oil and Gas Production and Conservation Act*, R.S.C. 1985, c.0-7

Section 28(1) of this Act amended by the enactment of the *Transportation Accident Investigation and Safety Board Act*.[6] The amendment provides that where a spill, debris or an accident to which the Act applies results in death, injury or danger to public safety or the environment, the Minister may direct an inquiry to be made under the *Transportation Accident Investigation and Safety Board Act*.[7]

(i) *Canadian Exploration Incentive Program Act*, R.S.C. 1985 (4th Supp.), c.27

This Act is amended by the *Government Expenditures Restraint Act*[8] which provides for a termination date of February 28, 1991 for eligible expenses under this Act.

2. Regulations

(a) *National Energy Board Part VI Regulations*, amendment, SOR/90-753

This amendment affects the import and export of natural gas. Parties exporting or importing natural gas can only do so under the authority of a licence or an order issued by the NEB. Licences authorizing exports or imports for a period not exceeding 25 years can only be issued, in accordance with subsection 24(1) of the *National Energy Board Act*,[9] after a public hearing is held. Orders to authorize such shipments can be issued without the necessity of holding a public hearing and are usually of a much shorter duration than licences (i.e. one to two years).

This amendment will authorize persons, pursuant to an order issued by the Board, to:

(i) import natural gas without volumetric restrictions for up to 24 months;

---

5. R.S.C. 1985, c.N-7.
6. S.C. 1989, c.3, s.46.
7. *Ibid.*
8. S.C. 1991, c.9, s.3 and 4.
9. *Supra*, note 5.

(ii) import not more than 30 thousand cubic meters per day of natural gas for a period exceeding 24 months but not more than 20 years; and
(iii) import for re-export and export for re-import natural gas without volumetric restrictions for up to 25 years.

In the case of direct imports of natural gas, paragraph 8(1)(b) of the Regulations currently authorizes the Board to issue orders permitting persons to import not more than 60 million cubic meters of gas for not more than 12 months. In view of the current volumetric restriction, parties must apply frequently to the Board in order to import gas, therefore, it is proposed that the volumetric restrictions be removed and, at the same time, the time period covered by short term import orders be increased from 12 months to not more than 24 months. Paragraph 8(1)(c) is also being amended to allow the Board to authorize imports by order for a period exceeding 24 months (currently it is 12 months) but not exceeding 20 years for the importation of not more than 30 thousand cubic meters per day. These changes would then put imports and exports of natural gas authorized by orders on an equal footing.

Parties exporting natural gas for re-import or importing for re-export usually apply for licences so that they can be authorized for extended periods of time and a licence can only be issued after a public hearing is held. However, given that these are routine applications which generally have no negative impact, convening a public hearing is often an unnecessary regulatory burden and expense. The amendment to the Regulations would permit the Board to authorize, by order, these types of shipments for up to 25 years. In this case a public hearing need not be held, unless the Board found it advisable to do so.

In effect November 1, 1990.

(b) *Canadian Exploration and Development Incentive Program Regulations*, amendment, SOR/90-96

This Regulations amends the *Canadian Exploration and Development Incentive Program Regulations*[10] as a consequence of the termination of the Canadian Exploration and Development Incentive Program (CEDIP). They provide the detailed rules on the coverage of the CEDIP termination and grandfathering regime. These amendments are retroactive to April 26, 1989 and were approved January 25, 1990.

(c) *Canada Oil and Gas Production and Conservation Regulations*, SOR/90-791

These Regulations, pursuant to the *Oil and Gas Production and Conversation Act*,[11] relate to safety, conservation practices and the prevention of pollution in operations undertaken for the production of oil and gas in the parts of Canada subject to the Act.[12] These Regulations establish the minimum requirements for all persons engaged in the development and production of oil and gas on frontier lands. The Regulations are

10. SOR/87-514.
11. R.S.C. 1985, c.O-7.
12. *Ibid.*

concerned with requirements for approvals and authorizations and with data requirements at the development stage as well as at the operations stage when a field is in production. Requirements with regard to conservation of resources, metering and testing of fluids produced from and injected into a well, design and construction of oil and gas processing facilities, production operations, environmental protection, safety and training of personnel and the reporting to the government of production, environmental and safety data are also specified in the Regulations.

The Regulations have been designed to identify the performance expected from the industry rather than set out how the performance is to be achieved. They will be complemented by a set of guidelines now being developed, which will establish performance parameters in key areas. The intent is to ensure that development of a field and subsequent operations are done in a manner consistent with resource conservation, protection of the environment and the safety of personnel.

The Regulations were approved November 22, 1990.

(d) *Energy Monitoring Regulations*, amendment, SOR/90-254 and SOR/90-731

Regulation SOR/90-731 repealed Regulation SOR/90-254, these Regulations prescribe the form and manner of returns for the Petroleum Monitoring Survey Questionnaire. The Questionnaire is regularly amended following an assessment of the data requirements of government and industry.

(e) *Hibernia Development Project Offshore Application Regulations*, SOR/90-774

These Regulations extend the laws of Canada relating to banking, bills of exchange, promissory notes, interest, bankruptcy, insolvency or the regulation of trade and commerce and the laws of Newfoundland relating to security interests for the purposes of the *Hibernia Development Project Act*.[13] This provides legislative authority for the preservation of investors' security and enforcement rights in a situation where project assets in which the security interests are taken, are located offshore. Regulations made November 9, 1990.

(f) *National Energy Board Cost Recovery Regulations*, SOR/91-7

These Regulations will allow the NEB to recover the cost of its operation imposing those costs on the companies being the main users of the NEB's services. The Regulations prescribe the charges payable by those companies, who are named in the schedules, and the method of calculation and payment of the costs.

Charges will be calculated using a two-tier system. First, an initial split is made among oil, natural gas and electricity, based on the amount of time spent by the NEB on each of them. Second, the split is then further allocated among the larger pipeline companies,

---

13. S.C. 1990, c.41.

on the basis of forecast deliveries from their pipelines and among the electric utilities who export, on the basis of the amount of their forecast exports.

These Regulations were effective January 1, 1991.

(g) *Frontier Lands Petroleum Royalty Regulations, 1987*, amendment, SOR/91-61

This Regulation extends the application of the *Frontier Lands Petroleum Royalty Regulations, 1987*[14] to December 31, 1991. A comprehensive royalty regime is being developed, together with the Frontier Energy Policy, that will replace the *Frontier Lands Petroleum Royalty Regulations, 1987*.[15]

(h) *Arctic Shipping Pollution Prevention Regulations*, amendment, SOR/90-628

These Regulations provide for ship construction standards and control the dates when ships may enter Shipping Safety Control Zones in the Arctic. Ships carrying more than $453m^3$ of oil are separated into classes. There are changes to entry dates for zones and in the time of operation in certain zones for shipping. Amendment made August 31, 1990.

3. Proposed Changes

(a) *Bill C-45, OSLO Oil Sands Project Act*, 2d Sess., 34th Parl., 1989

This Bill was reported in last year's paper. It died on the order paper at the end of the last session and likely will not be reintroduced unless the federal government changes its position to withdraw from the OSLO project.

(b) *Bill C-78, Canadian Environmental Assessment Act*, 2d Sess., 34th Parl., 1989-90
Status: Second Reading October 30, 1990

This Bill proposes the establishment of the Canadian Environmental Assessment Agency. It provides for an environmental assessment of projects for which the federal government holds decision making authority and provides for the creation of review panels to carry out assessments and guidelines for the review process. A public registry shall be maintained for every project for which an environmental assessment is conducted.

Regulations pursuant to the proposed Act are scheduled for publication in the Canada Gazette, Part I, in the third quarter of 1991 and in Part II during the fourth quarter of 1991. The government has proposed 12 sets of regulations under the following headings: Environmental Assessment Procedures; Exclusion Lists; Mandatory Environmental Assessment Study List and Report; Regulatory Statutes Provisions List; Crown Corporations and Harbour Commissions; Indian Act Lands; Domestic Financial

14. SOR/88-348.
15. *Ibid.*

Assistance; National Security; Projects outside Canada; Offshore Boards; International Agreements; and International Development.

(c) *Bill C-95, Bank Act*, 2d Sess., 34th Parl., 1989-90 — Status: First Reading December 19, 1990

This is a proposal to repeal and replace the *Bank Act*, R.S.C. 1985, c.B-1. The scope of those changes will not be discussed in this paper.

(d) *Canada Oil and Gas Installations Regulations* — Draft

In January of 1991 the Canada Oil and Gas Lands Administration (COGLA) circulated to industry a draft of Canada Oil and Gas Installations Regulations which are regulations to *The Oil and Gas Production and Conservation Act*.[16] These Regulations would govern all diving installations, drilling installations, production installations and offshore accommodation installations used in oil and gas operations on Canada Lands. The proposed regulations for Mobile Offshore Drilling Units (MODU's) differ from the International MODU Code which could cause compliance difficulties for offshore operators.

(e) *National Energy Board Part VI Regulations* — Draft

Amendments to these Regulations were required as a result of changes in the regulation of gas exports, particularly the implementations of the Market-Based Procedure. The Part VI Regulations will be restructured to provide for separate sections for natural gas, propane, butane and ethane and oil. Regulations regarding electricity are no longer included in the Part VI Regulations. Certain provisions respecting export and import reporting requirements will be removed and those requirements are now included in SOR/90-753, discussed previously in this paper. The Regulations contain special exemptions for propane, butane and ethane and also for Cold Lake and Peace River crude oils. Information sessions have been held to discuss the amendments and now require examination by the Department of Justice and approval by the Governor in Council.

(f) *Green Plan* (National Environmental Agenda)

The Green Plan: A National Challenge is the federal government's five-year environmental agenda which will address issues such as the greenhouse effect, thinning of the ozone layer, management of toxic chemicals, waste management, including recycling, carbon dioxide emission tax, environmental emergency response, energy conservation, reforestation, environmental assessment, and research funding. Various discussion documents are in public circulation and numerous specific legislative initiatives have been introduced.

16. R.S.C. 1985, c.O-4.

(g) Sulphur Reduction in Diesel Fuel

Transport Canada and Environment Canada have begun a study into the issue of reduced particulate emissions from heavy-duty diesel engines which is achieved through a reduction in sulphur levels in diesel fuel. The issue is whether Transport Canada will adopt the same HDVE standards as have been adopted in the U.S.A.

B. ALBERTA LEGISLATION

1. Statutes

(a) *Natural Resources Conservation Board Act*, S.A. 1990, c.N-5.5

This legislation, not yet proclaimed as of March 31, 1991, creates a Board to review certain projects that "will or may affect the natural resources of Alberta in order to determine whether ... the projects are in the public interest, having regard to the social and economic effects of the projects and the effect of the projects on the environment." Section 4 describes projects that are subject to the Board's review including forest industry, recreational or tourism, metallic or quarriable mineral, and water management projects, but perhaps just as significantly, includes "any other type of project prescribed in the regulations" and "specific projects prescribed by the Lieutenant Governor in Council." With respect to some of the specific types of projects, section 1 does limit application of the Act to those for which an environmental impact assessment has been ordered. It is clear from sections 3 and 5 that a project such as the Oldman Dam may not legally be commenced before the Board grants an approval. As no regulations were in force as of March 31, 1991, it is not possible to speculate how far-reaching this legislation might prove to be. However, for reviewable projects having a significant energy consumption component, jurisdiction of this Board would overlap with that of the Alberta Energy Resources Conservation Board ("ERCB") and it remains to be seen how review of such a project would be handled.

(b) *Personal Property Security Amendment Act*, 1990, S.A. 1990, c.31

This Act came into force on October 1, 1990 and amends the *Personal Property Security Act, S.A. 1988, c. P-4.05* (PPSA). Through this amending legislation, the PPSA is extensively revised. A detailed discussion of the changes is beyond the scope of this paper, but one must assume that the changes could be significant even though the basic structure of the PPSA may not be affected.

(c) *Metis Land Settlements Act*, S.A. 1990, c.M-14.3

This legislation will have significant impact on the oil and gas industry with respect to operations in the designated Metis Settlement Areas. A General Council and several Settlement Councils are established; jurisdiction over the land surface in the Settlement Areas is granted. With respect to rights of entry and compensation, this Act establishes a Land Access Panel and Existing Leases Land Access Panel with powers not only to grant but to deny access. New mineral leases within the Settlement Areas will be

dependent upon a bidding process in which the successful bidder will enter into a development agreement with terms benefitting Metis as well as the Crown. A broad range of Metis concerns may thus be addressed. In force on November 1, 1990.

(d) *Metis Settlements Accord Implementation Act*, S.A. 1990, c.M-14.5

This Act implements certain financial assistance elements of the Alberta-Metis Settlements Accord of 1989 and provides for transitional arrangements for local government of settlement areas. In force November 1, 1990 except s. 35(1)(b), (c) and (d).

(e) *Metis Settlements Land Protection Act*, S.A. 1990, c.M-14.8

This Act ratifies and confirms the letters patent granting patented land to the General Council, and prohibits alienation of the fee simple estate without certain consents. Further, any mortgage, charge or security given in respect of the fee simple estate is void. However, section 8 does provide for a limited time to file notice of existing rights to an estate in fee simple. In force December 20, 1990.

(f) *Petroleum Incentives Program Amendment Act*, 1990, S.A. 1990, c.32

This legislation provides for the transfer of any assets in the Alberta Petroleum Incentives Program Fund to the General Revenue Fund. Also, the *Petroleum Incentives Program Act*, S.A. 1981, c. P-4.1 will be repealed on Proclamation. In force May 30, 1990.

(g) *Mines and Minerals Amendment Act*, 1990, S.A. 1990, c.28

The Act amends the powers of the Minister to allow reinstatement of an agreement within 90 days after it has been surrendered, cancelled or forfeited. Any security notices registered against the agreement before its reinstatement will be effective against the agreement. If the annual rental in an agreement differs from the rental prescribed in the regulations, the regulations will prevail. A prosecution for an offence referred to in section 53(1) of the Act must be commenced within 60 months from the date that the subject matter of the prosecution arose. Also the definitions of "exploration" and "exploration equipment" are amended. In addition, it amends the *Builders' Lien Act*[17] to provide that when a lien attaches to an interest in minerals held directly from the Crown and the interest is not registered under the *Land Titles Act*,[18] the lien shall be registered with the Minister of Energy and not the Registrar. In force July 5, 1990 except sections 4 and 7 which were proclaimed in force July 12, 1990.

17. R.S.A. 1980, c.B-12.
18. R.S.A. 1980, c.L-5.

(h) *Alberta Corporate Income Tax Amendment Act*, 1990, S.A. 1990, c.4

This legislation amends the title of the *Alberta Corporate Income Tax Act* to the *Alberta Corporate Tax Act* and incorporates several technical amendments. The price sensitive Alberta Royalty Tax Credit ("ARTC") program, discussed in last year's paper, is incorporated with effect from January 1, 1990 until December 31, 1994. In addition to incorporating the price sensitive ARTC program, the legislation adopts certain of the technical amendments made to the *Income Tax Act, Canada*, S.C. 1970-71-72, c.63 (the "Federal Tax Act"), including the amendments to the rules for determining whether corporations are associated, and provides for the continued application of the anti-avoidance rules contained in subsections 245(1), 245(1.1) and 247(1) of the Federal Tax Act in lieu of the new general anti-avoidance rule which was incorporated into the Federal Tax Act with effect from September 13, 1988.

Among the technical amendments is a provision deeming a farmout of a resource property before a well is spudded where the farmor retains a gross overriding royalty which is convertible into a working interest after payout not to be a disposition for the purpose of determining whether the property is a restricted resource property. Effective April 1, 1990, the effective provincial income tax rate on the first $200,000 of active business income eligible for the small business deduction is 6%. The legislation also adds a penalty provision for late or deficient tax instalments to take effect from a date prescribed by regulation.

(i) *Oil and Gas Conservation Amendment Act*, 1990, S.A. 1990, c.30

This Act adds provisions to the *Oil and Gas Conservation Act*, R.S.A. 1980, c.O-5 giving the ERCB the power to designate a gas processing plant as a straddle plant so as to allow the extraction of a minimum volume of ethane from the gas stream going into that plant. The ERCB is given the power to order that a "threshold volume" of ethane remains in the gas stream going from a field ethane plant to a straddle plant. Unless a field ethane plant is exempt under the legislation, it is required to maintain, at a minimum, the threshold volume of ethane in the gas stream and reinject ethane into the gas stream if so required to maintain that level. This legislation was passed after a lengthy ERCB hearing in the fall of 1987 and subsequent statements made by the Alberta government respecting a guaranteed supply of ethane to straddle plants required to satisfy the demand of existing ethylene plants in Alberta. This legislation is repealed on June 30, 2008. Regulations[19] were also passed pursuant to this legislation and they are referred to in this paper. In force July 5, 1990.

(j) *Gas Utilities Statutes Amendment Act*, 1990, S.A. 1990, c.21

This legislation amends the *Gas Utilities Act*, R.S.A. 1980, c.G-4, by providing for municipal gas franchises for gas supply between a person and a municipality. Additional provisions regulate the gas supply obtained from direct sellers and consequential

19. Alta. Reg. 40/91.

amendments are made to the *Municipal Government Act*,[20] *Municipal Taxation Act*[21] and *Rural Act*.[22] In force July 5, 1990.

(k) *Public Utilities Board Amendment Act*, 1990, S.A. 1990, c.34

This Act gives the Public Utilities Board ("PUB") the authority to impose payment of an assessment on a person over whom the PUB has jurisdiction whether or not they have appeared before the PUB in the year to which the assessment relates. The assessment is to be used to pay the expenditures of the PUB. Interest and penalties will be imposed on any non-payment of an assessment. Assented to July 5, 1990.

(l) Provincial Budget of April 1, 1991

On April 1, 1991, the Provincial Treasurer presented his 1991 budget where it was announced that the provincial corporate tax rate would increase 0.5% to 15.5%. The effective tax rate for small businesses on the first $200,000 of active business income remains unchanged at 6%. In addition, corporations will be subject to higher fees for certain services, including a fee of $100 for filing annual statements with the registrar of corporations.

2. Regulations

(a) *Alberta Corporate Income Tax Amendment Regulations*, Alta. Reg. 230/90

This regulation amends the *Alberta Corporate Income Tax Regulations*[23] by adding new provisions for the Royalty Tax Credit under the *Alberta Corporate Tax Act*.[24] They describe the calculation of the average par price for a period and the specified rate for a period when calculating a royalty tax credit. Filed August 8, 1990.

(b) *Royalty Tax Credit Regulation*, Alta. Reg. 38/91

This regulation specifies the period, average par price and specified rate applicable to be used in the calculation of the royalty tax credit under the *Alberta Income Tax Act*, R.S.A. 1980 c.A-31. Filed February 7, 1991.

20. R.S.A. 1980, c.M-26.
21. R.S.A. 1980, c.M-31.
22. R.S.A. 1980, c.R-19.
23. Alta. Reg. 105/81.
24. R.S.A. 1980, c.A-17.

(c) *Freehold Mineral Rights Tax Amendment Regulation*, Alta. Reg. 29/91

This regulation amends the *Freehold Mineral Rights Tax Act*[25] by providing for interest to be payable on increases and decreases in the tax payable for a taxation year from that shown on the last tax statement issued for that taxation year. Filed January 31, 1991.

(d) *General Amendment Regulation*, Alta. Reg. 187/90
Oil Sands Amendment Regulation, Alta. Reg. 189/90
Petroleum and Natural Gas Agreements Amendment Regulation, Alta. Reg. 190/90

All these amendments amend the rentals payable for permits or leases to which they apply. They all came into force on July 12, 1990.

(e) *Horizontal Well Petroleum Royalty Regulation*, Alta. Reg. 96/91

This regulation established the royalty scheme to apply to "qualifying crude oil" recovered by means of a horizontal drilling operation approved under this regulation. Filed March 21, 1991.

(f) *Natural Gas Royalty Regulation*, Alta. Reg. 246/90, amended by *Petroleum Royalty Amendment Regulation*, Alta. Reg. 33/91

Regulation 246/90 replaces Alta. Reg. 16/74 and in effect is a consolidation of all the changes made to Alta. Reg. 16/74 up to August, 1990. Filed August 9, 1990.

Regulation 33/91 adds new provisions to Schedule 1 relating to the Minister's determination of new gas specifying when such determination may be made only on application and when the determination is effective. Filed January 31, 1991.

(g) *Petroleum Royalty Regulation*, Alta. Reg. 248/90, amended by *Petroleum Royalty Amendment Regulation*, Alta. Reg. 31/91

Regulation 248/90 replaces Alta. Reg. 93/74 and consolidates all the changes made up to August 1990. In addition, it includes changes to the tertiary enhanced oil recovery (EOR) royalty relief program. Section 4.2 of Alta. Reg. 93/74 is now section 11 in this Regulation. The changes to the EOR royalty relief are:

(i) eligible EOR costs will now be defrayed only against incremental tertiary production instead of against all oil production from the project. The maximum relief for a given period is the Crown's royalty share of tertiary production. A "t" factor is applied to the production for a given period, the resulting volume is the production for which relief can be obtained. Different "t" factors are applied

25. S.A. 1983, c.F-19.1.

to New EOR projects and to Existing EOR projects. The "t" factor is based on reserves established by the ERCB for an EOR project. The operator of an EOR project may submit applications to the Department of Energy for "t" factors and they will be considered together with those established by the ERCB to establish the final "t" factor for a project;

(ii) royalty relief is allowed for gross volumes of injectants less breakthrough reproduced volumes of injectants. The elimination of relief for breakthrough injectants became effective June 1, 1990. The reduction of this relief is partially offset by an increase in the processing allowance when breakthrough hydrocarbons are reinjected; and

(iii) the overhead allowance for vertical EOR projects is 15 per cent.

Regulation Filed August 9, 1990.

Alta. Reg. 31/91 adds provisions relating to the Minister' s determination of a new oil entity or a co-existen oil factor, specifying when such determination may be made only by application and the Minister's determination is effective. Filed January 31, 1991.

(h) *Oil and Gas Conservation Amendment Regulations*, Alta. Reg. 19/90

This Regulation amends the provisions in the *Oil and Gas Conservation Regulations*[26] dealing with surface casing for a well and equipment on a well and procedure relating to blow-out prevention. Filed February 1, 1990.

(i) *Oil and Gas Conservation Amendment Regulation*, Alta. Reg. 321/90

This Regulation contains new provisions for the information required on a sign at wells and facilities and the fencing of wells in particular situations. Filed October 18, 1990.

(j) *Oil and Gas Conservation Amendment Regulation*, Alta. Reg. 40/91

This Regulation adds provisions to the *Oil and Gas Conservation Regulations* for the supply of ethane to straddle plants and they are related to the changes made by the *Oil and Gas Conservation Amendment Act, 1990*.[28]

The provisions set out the guidelines that apply if a processing plant is to be designated as a straddle plant and that apply to the calculation of threshold volume by the ERCB and the input that operators of field ethane plants may have to that calculation. The determination of the threshold volume by the ERCB is final. The ERCB is given the authority to order the operators of field ethane plants to inject ethane into the gas stream

26. Alta. Reg. 151/71.
27. *Ibid.*
28. S.A. 1990, c.30.

to straddle plants in order to maintain the threshold volume of ethane in that gas stream. The operators of field ethane plants are to be paid by either the operator of or the purchaser of ethane from a straddle plant for the ethane injected and if they cannot agree on a price the *Arbitration Act*[29] applies. The threshold volume in each of the four twelve-month periods following July 1, 2004 until repeal of this Regulation on June 20, 2008, shall be reduced by 20 per cent for each period. Filed February 7, 1991.

(k) *Oil and Gas Conservation Amendment Regulation*, Alta. Reg. 79/91

This Regulation contains amendments relating to flare equipment for facilities handling sour gas. Filed March 7, 1991.

(l) *Sulphur Emission Control Assistance Amendment Regulation*, Alta. Reg. 30/91

This amendment provides that the operator of the eligible plant who made application for credits under the *Sulphur Emission Control Assistance Regulation*[30] is liable to pay the Crown for any credits that have subsequently been reduced rather than it being the liability of the person for whose benefit the credits were applied. Filed January 31, 1991.

3. Proposed Changes

(a) *Bill 5, Mines and Minerals Amendment Act*, 1991, 3d Sess., 22d Leg. Alta., 1991 – Status: Committee of the Whole April 22, 1991

The proposed changes to the *Mines and Minerals Act*[31] are to add provisions describing the duties of a lessee relating to operations in road allowances and dealing with mineral accretion. Provisions relating to agreements for quarriable minerals and metallic minerals are deleted. The notice provisions for unit agreements is amended to provide that notice shall be published in the Gazette within 60 days after the Minister becomes aware that the unitization in the unit agreement has become effective.

(b) *Bill, Oil and Gas Conservation Amendment Act*, 1991, 3d Sess., 22d Leg. Alta., 1991 – Status: Second Reading March 25, 1991

The proposed changes are to add a definition for experiment and experimental scheme and repeal the definition of production spacing unit and amend sections relating to those terms. Section 22 of the Act[32] dealing with prorationing of oil is repealed and replaced by a provision that allows the ERCB to restrict the amount of oil and of gas produced in association with it, by determining the market demand for a stream of crude oil within a pipeline and allocating that demand among the wells supplying the pipeline.

---

29. R.S.A. 1980, c.A-43.
30. Alta. Reg. 275/89.
31. R.S.A. 1980, c.M-15.
32. R.S.A. 1980, c.O-5.

(c) *Bill 21, Rural Utilities Amendment Act*, 1991, 3d Sess., 22d Leg. Alta., 1991 — Status: Second Reading April 15, 1991

The proposed changes are to add provisions to the *Rural Utilities Act*[33] dealing with the removal of work placed on land by an association under the Act and with liens placed on the lands by an association.

(d) *Bill 23, Environmental Council Amendment Act*, 1991, 3d Sess., 22d Leg. Alta., 1991 — Status: Second Reading April 15, 1991

These proposed amendments add a definition for environment thus expanding the application of the *Environmental Council Act*, R.S.A. 1980, c.E-13, also the responsibilities and powers of the Council are expanded.

(e) *Bill 36, Safety Codes Act*, 1991, 3d Sess., 22d Leg. Alta., 1991 — Status: Second Reading June 20, 1991

This Bill was introduced as a result of the inquiry into the Mindbender accident at West Edmonton Mall which found that the laws in Alberta regarding technical and mechanical integrity are fragmented. The proposed *Safety Codes Act* will combine seven existing statutes which apply to fire protection, buildings, elevating devices, electrical, plumbing, sewage and gas systems, and pressure equipment. The important philosophical shift in the proposed *Safety Codes Act* is that it changes responsibility for enforcement, causing industry to self-police, while the role of government will be to test for compliance.

(f) *Alberta Environmental Protection and Enhancement Act* — Draft

On January 9, 1990, Alberta Environment Minister, Ralph Klein announced that the province is embarking upon a complete redrafting of its environmental legislation. An environmental review panel report was issued in January of 1991, making a number of recommendations for consideration during the redrafting process. A proposed bill has been circulated for public comment.

The proposed Act, will incorporate nine existing Acts into one comprehensive new piece of legislation. The Acts included are: *Agricultural Chemicals Act*;[34] *Beverage Container Act*,[35] *Clean Air Act*,[36] *Clean Water Act*,[37] *Ground Water Development*

33. R.S.A. 1980, c.R-21.
34. R.S.A. 1980, c.A-6.
35. R.S.A. 1980, c.B-4.
36. R.S.A. 1980, c.C-12.
37. R.S.A. 1980, c.C-13.

Act,[38] *Hazardous Chemicals Act*,[39] *Land Surface Conservation and Reclamation Act*,[40] *Litter Act*,[41] and portions of the *Department of Environment Act*.[42]

The *Environment Council of Alberta Act*[43] will remain as it is and the *Water Resources Act*[44] will be reviewed separately for later inclusion in the new Act. Twelve draft regulations are due for release in the summer of 1991 and public comment will be sought.

(g) *The Alberta Water Resource Act* — proposed

The judicial review of the Oldman River Dam Project exposed certain flaws in the existing Act[45] and in the administration of the Act which are now being corrected. Drafts of the new *Water Resources Act* and Regulations are to be tabled at the fall sitting of the legislature. The new Act will co-ordinate provincial activities with the federal jurisdiction outlined in the proposed *Environmental Protection and Enhancement Act*, and it will reflect the ruling of the Supreme Court of Canada arising out of the jurisdictional reference.

(h) *Oil Sands Regulations*

The draft Regulations circulated to industry in April, 1990 are still being discussed and a new draft has not been issued.

(i) Clean Air Strategy for Alberta

In June of 1990, the Ministers of Energy and Environment jointly announced the need to develop a Clean Air Strategy for Alberta. The strategy has, as its objective, the identification and clarification of possible impacts of energy-related emissions on the environment, and to outline practical and achievable actions that can respond to these impacts. The government report will be reviewed by the Alberta Round Table in the summer of 1991.

(j) Alberta Gas Cost Allowance

The recommendations made in February 1990 by a joint industry task force on changes to the Jumping Pound formula were rejected by the federal government. The firm of Deloitte Touche has subsequently been hired to consider changes to the Jumping Pound

38. R.S.A. 1980, c.G.11.1.
39. R.S.A. 1980, c.H.-3.
40. R.S.A. 1980, c.L-3.
41. R.S.A. 1980, c.L-19.
42. R.S.A. 1980, c.D-19.
43. R.S.A. 1980, c.E-13.
44. R.S.A. 1980, c.W-5.
45. *Ibid.*

formula. There has been no further progress on the other recommendations of the task force to changes in natural gas processing charges.

(k) Gas Royalty Simplification Project

This project has been initiated by the Department of Energy to address the increasing complexity in the calculation and reporting of the Crown royalty on natural gas. The consulting firm of Deloitte & Touche has been hired to review the existing process and formulate a simplification proposal. This project is being carried out in consultation with industry and completion was targeted for June, 1991.

C. BRITISH COLUMBIA LEGISLATION

1. Statutes

(a) *Natural Gas Price Amendment Act*, 1990, S.B.C. 1990, c.62

This Act allows for privatization of the marketing function of British Columbia Petroleum Corporation ("BCPC") and amends the formula for pricing natural gas acquired under an acquisition order. Regulations to be made under the Act will set the price payable by BCPC for gas it will continue to purchase under those contracts which have not been privatized. Natural gas wholesalers will be able to resell gas at prices approved by their wholesalers. This Act and the *Natural Gas Price Act*[46] were brought into force and the *Natural Gas Price Act*[47] was repealed, all effective August 1, 1990.

(b) *Waste Management Amendment Act*, 1990, S.B.C. 1990, c.74

This Act amends the *Waste Management Act*[48] and enhances the legislation for remediation of contaminated sites. In addition to sites contaminated by continuing operations, it is also directed at sites contaminated in the past but that are no longer being used for the same operation. The Act provides for the assessment of fees, remediation of contaminated sites and more effective control of underground storage. It came into effect on August 30, 1990.

2. Regulations

(a) *Petroleum and Natural Gas Royalty Regulation Amendment*, B.C. Reg 112/90

This regulation provides an exemption from payment of royalty in excess of the royalty on new oil for oil that is classed as new oil but would be old oil if not for section 4(1)(c) of the Regulation.[49] Ordered March 23, 1990.

---

46. S.B.C. 1989, c.74.
47. S.B.C. 1985, c.53.
48. S.B.C. 1982, c.41, as am.
49. Petroleum and Natural Gas Royalty Regulation, B.C. Reg. 222/88.

(b) *Natural Gas Price Act Regulation No. 2*, B.C. Reg. 241/90

This Regulation introduces provisions governing minimum producer support for sale of netback gas and establishes a levy on the volume of gas produced by a producer holding an acquisition order from BCPC. Effective August 1, 1990.

(c) *Petroleum and Natural Gas Royalty Regulation Amendment*, B.C. Reg. 242/90

This amendment changes the calculation of royalty payable to the Crown for natural gas and natural gas by-products. The royalty share of natural gas is now multiplied by the acquisition order price rather than the gas price and the gas cost allowance received by the producer is included in the calculation of the weighted average royalty rate. Effective August 1, 1990.

(d) *Spill Reporting Regulation*, B.C. Reg. 263/90

This Regulation provides definitive guidelines for a person who is in possession, charge or control of one of the substances listed in the regulation if there is a spill of that substance. The substances listed are based in part on the *Transportation of Dangerous Goods Regulations*[50] under the *Transportation of Dangerous Goods Act (Canada)*,[51] the reportable amount of a spill is also listed. Ordered August 10, 1990.

(e) *Petroleum and Natural Gas Royalty Regulations Amendment*, B.C. Reg. 435/90

This Regulation amends the *Petroleum and Natural Gas Royalty Regulation*[52] by amending the definition of reference price and the provisions for the price at which the royalty share of oil and gas is to be sold. Ordered and approved November 1, 1990.

3. Proposed Changes

(a) *Bill M203, Spill Prevention and Reporting Act*, 4th Sess., 34th Parl. B.C., 1990
Status: First Reading May 23, 1990

This is a proposal to amend the *Waste Management Act*[53] by defining "spill," specifying to whom spills must be reported and requiring the Ministry to maintain a record of spills and prosecutions which will be available to the public.

50. SOR 85-77, as am.
51. R.S. 1985, c.T-19.
52. *Ibid.*
53. *Supra*, note 48.

(b) *Bill M206, An Act to Enforce Pollution Offences and Create Environmental Protection Fund,* 4th Sess., 34th Parl. B.C., 1990 Status: First Reading May 24, 1990

This is a proposal to increase the penalties under the *Waste Management Act.*[54]

(c) *Bill M209, Environmental Protection Act,* 4th Sess., 34th Parl. B.C., 1990 Status: First Reading May 25, 1990

This is a proposal to repeal and replace the *Environmental Management Act.*[55] It would require all major public and private projects to be subject to independent public environmental review.

D. SASKATCHEWAN LEGISLATION

1. Statutes

(a) *The Crown Minerals Amendment Act,* 1990 S.S. 1990, c.13

This Act provides that royalties payable under unit agreements or Crown leases shall be determined in accordance with the regulations under *The Crown Minerals Act*[56] and that those regulations will prevail over the terms of the unit agreement or the lease. A limit of $50,000 per production year was placed on compensation payable to any person under section 23 of *The Crown Minerals Act*[57] or *The Oil and Gas Conservation, Stabilization and Development Act,*[58] which right would have accrued prior to the repeal of that Act. There are also provisions relating to the registration of title or transfer of lands caught by that legislation. New provisions are introduced for trust lands: these include how they are to be handled, provisions for transfer, revenue allocation and appointment of an Administrator. In force June 22, 1 990 except section 23.1 which is retroactive to February 1, 1990.

(b) *The Land Titles Amendment Act,* 1990, S.S. 1990, c.21

This Act amends the provisions dealing with certain forms and the registration of caveats. In force June 22, 1990.

54. *Ibid.*
55. S.B.C. 1981, c.14.
56. S.S. 1984-85-86, c.C-50.2.
57. *Ibid.*
58. R.S.S. 1978, c.0-3, as rep. *The Minerals Resources Act,* 1985, S.S. 1984-85, c.M-16.1, s. 16.

2. Regulations

(a) *The Petroleum and Natural Gas Amendment Regulations*, 1991, Sask. Reg. 11/91

These Regulations amend *The Petroleum and Natural Gas Regulations, 1969*.[59] There are a number of amendments affecting the calculation of royalties as provided in the current Regulation,[60] the significant point to note is that the application is now to all wells and not only non-unit wells. There is a new method of calculating royalties on oil and gas production from unit operations. Commencing in January, 1991, the monthly production rate of each producing well in a unit will be used to determine the royalty rates applicable to the conventional production from each well. The total royalty liability of the unit will be determined by aggregating the amounts calculated with respect to each individual producing well. The Regulations came into force on February 20, 1991 but various sections are retroactive to earlier dates in 1991 and 1990.

(b) *The Freehold Oil and Gas Production Tax Amendment Regulations*, 1991, Sask. Reg. 12/91

These Regulations amend *The Freehold Oil and Gas Production Tax Regulations, 1983*.[61] The Regulations amend their application so they apply to all freehold oil produced from a well after January 1, 1991 rather than a non-unit well after 1986. The tax is payable on a taxpayer's proportionate share of production from a well either based on working interest or proportionate share in a unit. The method of calculating the tax is the same as the calculation of the Crown royalty under Sask. Reg. 11/91, discussed above. The Regulations came into force on February 20, 1991 but various sections are retroactive to earlier dates in 1991 and 1990.

(c) *The Petroleum and Natural Gas Amendment Regulations*, 1991 (No. 2), Sask. Reg. 25/91

The main amendments are to add provisions governing Crown leases in a heavy oil area. In force April 1, 1991.

59. Sask. Reg. 8/69 as am.
60. *Ibid.*
61. Sask. Reg. 11/83 as am.

II. REGULATORY DEVELOPMENTS

A. FEDERAL

1. National Energy Board

(a) Decisions

(i) *GH-10-88 — Esso Resources Canada Limited, Shell Canada Limited and Gulf Canada Resources Limited — Mackenzie Delta Gas Export Licenses*

The decision was reported in last year's paper but a further development of note was that in May 1990 the NEB denied a request by the Dene/Metis Negotiations Secretariat for a review of the decision to allow exports of natural gas from the Mackenzie Delta. The Dene/Metis Negotiations Secretariat disagreed with the conclusion of the NEB that it was not appropriate to include a condition in the export licenses relating to native training programs and employment. Although the NEB stated a belief that if the export project is to provide maximum benefits to the North and its people, there is a fundamental need for a good working relationship and understanding between the people of the North and Esso, Shell and Gulf, it decided that a condition requiring license holders to provide training programs and employment is not appropriate in an export license.

(ii) *GH-1-89 — Amoco Canada Petroleum Company Ltd. and Consolidated Edison Company of New York; Indeck Gas Supply Corporation; Western Gas Marketing Limited; Western Gas Marketing Limited as agent for TransCanada Pipelines Limited; ICG Utilities (Ontario) Ltd.; Direct Energy marketing Ltd.; ProGas Limited; Shell Canada Limited — Gas Export Applications*

The decision regarding the gas export licenses was reported in last year's paper. However, as a result of recent Federal Court decisions regarding EARP guidelines and also the request to Cabinet by the Canadian Environmental Law Association to conduct an environmental review in the matter of the Mackenzie Delta gas export application[62] the NEB decided to conduct environmental screening for all gas exports already approved by the NEB but not yet approved by Cabinet.

In June 1990 the NEB issued its first environmental screening report which related to these seven export applications. The NEB found that any potential adverse environmental effects and directly related social effects associated with the seven natural gas export licenses would be insignificant or mitigable with known technology.

Environmental screenings are now conducted for all natural gas export applications, the majority by written submissions.

---

62. GH-10-88.

(iii) *EH-3-89 — Hydro-Quebec — Two Applications for Electricity Exports*

This decision is of interest not because of the subject matter, but because of the conditions which the NEB placed on its approval of export licenses. Hydro-Quebec filed two applications for licenses to export firm power and energy to New York Power Authority and Vermont Joint Owners. In order to meet both domestic and export requirements Hydro-Quebec has plans to build new hydro-electric facilities mainly in the James Bay and Hudson Bay areas of northern Quebec. In September 1990 the NEB released its decision approving the applications, and issued seven export licenses, subject to the condition that they will remain valid only if any required production facilities for which construction had not been authorized at the completion of the hearing will be subjected, prior to construction, to the applicable federal environmental assessment and review procedures.

The NEB stated that at the time of making its decision it did not know the full environmental impact arising from the construction of Hydro-Quebec's future facilities, so was unable to determine whether the environmental consequences of these facilities are acceptable or mitigable. However, by placing conditions on the issued licenses, the NEB stated that it was satisfied that it fulfilled the requirements of the EARP.

This decision is being challenged as *ultra vires* by both Hydro-Quebec and the province of Quebec.

(iv) *GH-6-89 — Can States Gas Marketing and Transco Energy Marketing Company; Esso Resources Canada Limited; FSC Resources Limited; Ramarro Resources Inc.; Vector Energy Inc.; Western Gas Marketing Limited — Gas Export Licenses*

In September 1990, the NEB released its reasons for decision dated July, 1990. The hearing to consider six applications to export natural gas took place in March 1990 and is of interest because it occurred shortly after the release of the NEB decision to discontinue the use of the benefit — cost analysis as a component of the Market-Based Procedure for export licensing applications.[63] As a result, the applicants were not required to provide evidence on net social benefits.

In its decision, the NEB stated:[64]

The Market-Based Procedure includes consideration of the following:

1) complaints, if any, under the complaints procedure;
2) an Export Impact Assessment (EIA); and
3) any other factors that the Board considers relevant to its determination of the public interest.

---

63. GHW-4-89: NEB reasons for decision dated March 1990 in the matter of a review of certain aspects of the market-based procedure.

64. GH-6-89: NEB Reasons for Decision dated July 1990, at 2.

As a result of a review of Export Impact Assessment filing requirements conducted in the fall of 1989,[65] the NEB decided that, while it would continue to retain an EIA as part of its Market-Based Procedure, it would conduct its own assessment which would not be project specific, giving several projections of exports. Applicants would then have the option of using the NEB's analysis or of preparing and submitting their own analysis as a basis for arguing whether the proposed exports would result in adjustment difficulties in Canadian energy markets. All of the applicants, except Esso Resources and WGML, elected to use the NEB's EIA. In both instances the conclusions of the independent EIAs were similar to the NEB's – namely that the applied for export volumes would have little impact on Canadian production, consumption and prices of natural gas and Canadian users would not have any difficulty in meeting their future energy requirements as a result of the proposed exports.

The "other factors relevant to the public interest" considered by the NEB were gas supply, markets and transportation, and sales contract arrangements.

In the area of gas supply, it is of interest that FSC Resources Limited used as its gas supply, not its own reserves, but a fifteen year Gas Sales Contract with WGML. With regard to sales contracts, the NEB relied on its decision in GHW-4-89 that it would examine the sales contracts to ensure their commercial substance and durability. Further, it would operate on the presumption that contracts freely negotiated at arm's length would be in the public as well as the private interest and consequently, would only intervene in exceptional circumstances on the issue of flexibility of terms.

A screening of the environmental effects of the proposed exports in accordance with the EARP guidelines order was conducted by written submission.[66] The NEB found that any potential adverse environmental effects and directly related social effects would be insignificant or mitigable with known technology, except for new transmission facilities required on the TransCanada Pipelines Limited (TCPL) system to transport the exports of CanStates and TEMCO which were being addressed in hearing GH-5-89.

(v) *GH-5-89 – TransCanada Pipelines Limited – 1991/92 Expansion Project – Tolling and Economic Feasibility and Partial Facilities Certificate Application*

This decision addressed an application by TCPL for a certificate under Part III of the *National Energy Board Act*[67] for new facilities to increase deliveries to domestic markets in Eastern Canada and to export markets in the Eastern United States. The hearing considered the facilities application, the appropriate toll treatment of the proposed facilities and economic feasibility tests, and finally the application for 15 gas export licenses.

The significant issue before the NEB related to toll design. Since the greater part of the expanded capacity would go to service export sales, there was argument from the

65. NEB Reasons for Decision in the Matter of the Proposed Amendment to Export Impact Assessment Filing Requirements, November 1989.
66. GHW-3-90.
67. *Supra*, note 5.

domestic toll payers that the cost of the expansion should be tolled on an incremental basis, so that the users of the expanded capacity would bear the cost of the expansion through higher tolls. All previous expansions of the TCPL line have been tolled on a rolled in basis.

The decision was released in three volumes, Volumes 1 and 2, issued in November 1990, dealt with tolling and economic feasibility and a partial certificate for construction of a portion of the facilities, worth $546M, and Volume 3 issued in April 1991 dealt with the remainder of the facilities and the gas exports.

Volumes 1 and 2: Tolling and Economic Feasibility

The decision of the NEB was a landmark decision in that it decided that all facilities in the GH-5-89 proceedings will be rolled into TCPL's rate base for toll purposes. In addition, with respect to future expansions, while the NEB did not make its finding respecting rolled in methodology to be generic, it indicated that there would have to be a clear demonstration of radically changed circumstances before the issue of tolling methodology would warrant re-examination. This effectively endorsed the methodology of rolled in tolls for future expansions and should shorten future hearings.

The second segment of the decision related to the assessment of economic feasibility, and the decision is of interest because it contains a comprehensive economic feasibility review. The NEB did not accept proposals for quantitative tests of economic feasibility, nor a form of incremental tolls as a test of economic feasibility.

The NEB decided that the economic feasibility of the proposed pipeline facilities would be determined by having regard to evidence on all relevant factors which impact the likelihood of the facilities being used at a reasonable level over their economic life and the likelihood of the demand charges being paid. The decision contains, at page 26, a comprehensive statement of the factors which, if considered, would provide a good indication whether this would be likely to occur.

Volume 3: Facilities, Gas Exports and Section 71 Applications

This decision approved the construction of the remainder of the facilities expansion program for a capital cost estimated at $1.8 billion, and also fifteen export licenses. In addition to using the complaints procedure and the Export Impact Assessment the NEB as required by s.118 of the *National Energy Board Act*, continues to have regard for all other factors it considers relevant in determining if a proposed export is in the public interest. The NEB stated, "[i]n general, these factors can be placed in two categories: a) gas supply and b) market and commercial arrangements and regulatory status."[68]

This decision points up the fact that the NEB's assessment of export applications is mainly directed towards supply and markets. As long as the commercial arrangements

---

68. GH-5-89 Volume 3 at 10.

meet certain criteria, the NEB operates on the presumption that, where contracts are freely negotiated, they are in the public as well as private interest. If removal permits have been granted by the province of Alberta, this leaves U.S. regulatory approvals to be considered. If the gas is coming from British Columbia, with the introduction of relaxed removal permits, the NEB may wish to conduct more of an in-depth examination. This leaves supply and markets to be considered. Increasingly, supply is from corporate supply pools, rather than specific contracts, or reserves, and market is to local distribution companies, cogeneration facilities or independent power producers (i.e. the electric utility's own generating facilities). This decision is an example of the changes in industry which impact on the matters considered by the NEB.

(vi) *GH-4-90 — TransCanada Pipelines Limited — Gananoque Extension*

Last year's paper reported on the denial of TCPL's request for a certificate for the Gananoque extension, a short lateral from Gananoque to the Canada/U.S. border near Wolfe Island in the St. Lawrence River, to be used to transport exports to Niagara Mohawk Power Corporation.[69]

In March 1991 the NEB issued a decision again denying an application by TCPL to construct the Gananoque extension. The decision was released with reasons to follow, because the gas, which would have been supplied by TCPL, would have displaced Niagara Mohawk's system gas supplied entirely by CNG Transmission Corporation, and Niagara Mohawk was obliged to inform CNG, by April 1, 1991 of its intention to purchase Canadian gas. The NEB expects to issue its reasons for decision in May 1991.

(vii) *GHW-5-90 and RH-3-90 — Interprovincial Pipeline Company, a division of Interhome Energy Inc. — Application for a Natural Gas Liquids Storage Facility*

Interprovincial Pipeline Company (IPL) was approached by a group of prospective shippers with a request to construct and operate NGL storage and injection facilities. The prospective shippers entered into a Facilities Support Agreement ("FSA") whereby they would for a fifteen year term provide certain financial support to IPL in the event their NGL shipments failed to meet stipulated volumes. The prospective shippers requested to include in any order approving the facilities, a condition that nominations by the prospective shippers, for volumes up to the volumes specified in the FSA, not be subject to apportionment as a result of nominations made by shippers not a party to the FSA.

The NEB conducted a hearing to address the need for the proposed facilities as well as access issues and toll design. Other facilities matters and an environmental screening were dealt with by written submission.

The NEB released its decision dated February 1991. The NEB granted the prospective shippers' request for unapportioned access up to the volumes committed for in the FSA, in view of the obligations imposed on them by the FSA. Any changes to the FSA must

---

69. GH-1-89.

be filed with the NEB which would then decide whether the amended FSA would provide justification for the prospective shippers continuing to receive unapportioned access.

IPL proposed a rolled in toll with a surcharge for NGL's, on the basis that it followed the most recent methodology for IPL in RHW-1-89 and that it would also satisfy toll design objectives such as fairness, economic efficiency, understandability and acceptability, ease of administration, and toll stability. The proposal was opposed by the Independent Petroleum Association of Canada, Amoco Canada Petroleum Company Ltd. and the Alberta Petroleum Marketing Commission who argued that the proposed facilities were physically unique and favoured a stand-alone toll. The NEB rejected IPL's proposed toll design and approved a stand-alone toll design whereby the cost of all of the facilities would be borne by the users.

Several of the prospective shippers have withdrawn from the FSA.

(b) Evolving Matters

(i) *RH-1-91 — TransCanada Pipelines Limited — Toll Application*

A public hearing commenced on May 14, 1991 to consider an application by TCPL for new tolls effective January 1, 1991.

The outcome of this hearing should be of interest because TCPL requested tolls averaging 19.6 percent higher than in 1990, a 30.9 percent increase in its revenue requirement, and an increase in the rate of return on common equity from 13.25 percent to 14.50 percent. This is a rare occasion when the Industrial Gas Users Association, the Canadian Petroleum Association, the Independent Petroleum Association of Canada and the Alberta Petroleum Marketing Commission are co-operating to oppose the toll increases.

(ii) *California Gas Markets — California Public Utilities Commission*

Since September 1990 the California Public Utilities Commission (CPUC) has attempted to increase sales competition for gas supply into the core California markets, and thereby reduce prices. Under an "Access Agreement" with the Alberta government, CPUC and Alberta have agreed that 25 percent of the capacity of the Pacific Gas Transmission (PGT) pipeline should be opened up for direct sale. PGT is a subsidiary of Pacific Gas & Electric Co. (PG&E) whose Canadian buying arm is Alberta & Southern Gas Co. (A&S). Currently, the gas flowing through the PGT pipeline to California is from the A&S pool of long term gas contracts.

This means that A&S long-term contract holders will have a portion of their contracted gas made available for "direct" sales, so gas producers and aggregators must make arrangements to market this gas in California at competitive prices. Recent CPUC decisions threaten the Alberta producer support mechanism and have caused the Alberta

Minister of Energy to consider amendments to the *Natural Gas Marketing Act*[70] which could result in partial reregulation of gas prices.

There are many other issues raised by the CPUC commission decisions and this matter will no doubt receive much attention in the next year.

2. Competition Tribunal/Bureau of Competition Policy

(a) Decisions

There were no new decisions relating directly to the oil and gas industry.

(b) Published Policy Statements

(i) *Price Discrimination*

In July 1990 the Director issued a Discussion Paper on price discrimination. The document is intended to provide guidelines for business and legal communities as to the approach proposed by the Director with respect to alleged practices of price discrimination prohibited by section 50(1)(a) of the *Competition Act*.[71] The proposed approach differs from the position that the Bureau has historically taken in determining justification for granting a price concession or other advantage to a purchaser of articles.

(ii) *Mergers*

In November 1990 the Director circulated a draft of its proposed Merger Enforcement Guidelines for comments; the final version was released in April 1991. The purpose of this document was described in a recent speech by the Director:

> First, the Guidelines should promote a high level of public confidence in the Bureau's merger review process. In this regard the Guidelines are not a restatement of the law. Rather, they provide a description of the Bureau's enforcement policy in sufficient detail to guide to the maximum extent possible without compromising flexibility and discretion. Second,... promote a better understanding of the Bureau's merger review process, and so will reduce any uncertainty or unpredictability that is associated with, or perceived to be associated with, Bureau merger review.... Third,... facilitate and influence business planning and practices.... We anticipate that a further important benefit ... will be to improve the quality and predictability of information provided to the Bureau for our assessment of particular transactions.[72]

70. S.A. 1986, c.N-2.8.
71. R.S.C. 1985, c.C-34.
72. Howard I. Wetston, Speech to 17th Annual Conference of the Fordham Corporate Law Institute, New York, October 19, 1990.

3. Investment Canada Guideline – Acquisitions of Oil and Gas Interests

The office consolidation of the *Investment Canada Act*[73] issued in April 1991 contains new Guidelines – Acquisition of Oil and Gas Interests to assist investors in determining whether various transactions involving the acquisition of interests in oil and gas properties are subject to either notification or review under the Act. The guidelines provide a more comprehensive and practical description of what constitutes the acquisition of an interest in a "business" and the acquisition of "control." Guidelines are also given for "control" of unitized and non-unitized assets and for assessing the value of the entity.

4. The Oil & Gas Committee Under The Canada Petroleum Resources Act

A long standing issue with respect to the determination of frontier significant discovery areas under the *Canada Petroleum Resources Act*[74] (CPRA) may be moved closer to resolution by the first decision of the Oil & Gas Committee[75] which is fixed, under section 106 of the CPRA, with hearing appeals of SDA's proposed for declaration by the Minister (DIAND). In its thoroughly reasoned recommendation to the Minister on an appeal of the SDA proposed for the Esso-PCI-Home et al Minuk I-53 well, the Committee cited a test from the Federal Court decision in *Mobil Oil Canada Limited* v. *Minister of Energy Mines and Resources*[76] and its own analysis or the legislative intent of the CPRA to conclude that a significant discovery area may extend, on reasonable grounds taken from geological and engineering factors:

(a) to areas within the geologic feature which are laterally adjacent but not in communication with zones flow tested in the discovery well, and

(b) to zones within the geologic feature which, while intersected by the well, were not actually flow tested.

It was common ground in the application that a significant discovery had been established with respect to zones which had been tested by the Minuk I-53 well. The Minister' s decision on the Oil & Gas Committee recommendation is pending.

---

73. R.S.C. 1985, c.28.

74. R.S.C. 1985, c.36 (2nd Supp.).

75. Report and Recommendations of the Oil and Gas Committee to the Minister of Indian Affairs and Northern Development in the Matter of the Application of Esso Resources Canada Limited under section 106 of the Canada Petroleum Resources Act with respect to the Proposed Declaration of Significant Discovery for Esso-PCI-Home et al Minuk I-53 Well, January 9, 1991.

76. (1990), 35 F.T.R. 50.

5. The Environmental Impact Review Board

The Environmental Impact Review Board (EIRB) established under the *Inuvialuit Final Agreement*[77] conducted a public review in June 1990 of the drilling program proposed in the Beaufort Sea for 1990-1992 by Gulf Canada Resources Limited using its Kulluk drilling vessel. Based, *inter alia*, on an absence of evidence as to a potential worst case scenario for an oil well blowout in the program and on concerns as to the applicant's financial capacity to respond to a major environmental incident, the EIRB recommended that the application not be approved and that government authorities work to resolve uncertainty on a number of issues including those relating to standards for oil spill contingency plans, to determination of a worst case scenario, to financial responsibility and liability for cleanup and compensation and to measurement of the impacts of an oil spill.[78] Following on the recommendations of the EIRB, the Minister of Indian Affairs and Northern Development constituted a joint task force chaired by an independent consultant and composed of representatives of industry, government and the Inuvialuit to develop recommendations to deal with the identified issues. The task force report was given to the Minister in April 1991 and steps are currently being taken to see that the recommendations are implemented.

B. ALBERTA

1. Alberta Surface Rights Board Decisions

(a) Decision 91/0004[79]

The Alberta Surface Rights Board (the ASRB) usually awards costs for a matter brought before the ASRB in favour of the landowner. This decision is not consistent with that unstated policy. At issue was the rate of compensation payable by an operator under a surface lease; the landowner also claimed costs. The compensation was increased, but the ASRB stated that when adjudicating costs, those costs must be reasonably incurred. In this situation the costs claimed by the landowner were considered to be "unreasonable in the extreme" and were excessive considering that resolving disputes before the ASRB is intended to be a simple and expedient process. The operator did not claim costs and the parties were found to be responsible for their own costs.

77. June 5, 1984 and confirmed as binding in the *Western Arctic (Inuvialuit) Claims Settlement Act*, S.C. 1984, c.25, s.3(1).

78. Decision of the EIRB on Public Review of the Gulf Canada Resources Limited Kulluk Drilling Program 1990-1992, June 29, 1990.

79. Alfred Kestutis Opanavicius v. Murphy Oil Company Ltd., January, 2, 1991.

(b) Decision 91/0064[80]

The issue for consideration by the ASRB was the rate of compensation for a surface lease. In determining the appropriate compensation, the ASRB usually considers loss of use and adverse effect to normal use of the land. However, in calculating the compensation the ASRB calculated a value for the land and applied a 10% rate of return to determine the annual compensation to be payable under the lease rather than considering loss of use and adverse effect. No reason was given in the decision as to why the ASRB applied the "rate of return" concept.

2. Energy Resources Conservation Board

(a) Decisions

(i) *Decision D9O-2*[81]

Victor Durish and Seascape Oil & Gas Ltd. (Seascape) brought competing applications for an assignment of pipeline licence and a compulsory pooling order, and Durish applied for transfer of a gas well licence. Durish was a mineral owner as to 454 acres of the section spacing unit, and after failure of the lease (due to interruption of production) sought to resolve issues relating to operation and production of the well. Seascape took the position that it should retain the well licence transferred to it in 1987, as the mineral holdings held at the time of the transfer gave the transferor the right to transfer the well licence to Seascape. In addition, Seascape held leases covering at least 160 acres. Also at issue was whether any reimbursement or allocation of a penalty to drilling and facilities costs was required upon pooling: the original payors of the costs were no longer involved. Seascape contended that it was the owner of the pipeline, although the assignment of the pipeline licence was never registered with the Board.

The ERCB stated that had it been aware in 1987 of litigation in progress regarding validity of the leases, it might have deferred its decision on the well licence transfer to Seascape. Based on the fact that Durish was owner of the minerals in the quarter section containing the well and thus would have the right to produce oil or test gas production without any agreement with any other mineral owners in the section, the Board directed transfer of the well licence to Durish.

Despite Seascape's contention that there was no dispute as to lease ownership for one quarter section and its argument that Durish's interests in that quarter section were only top leases, the Board stated that a pooling order pursuant to section 78 of the *Oil and Gas Conservation Act*[82] was appropriate pending settlement of the ownership dispute. The Board also discussed the drilling and completion costs that may appropriately be subject

80. Edward Muntean and Bradley David Muntean v. GNE Resources Ltd., March 5, 1991.

81. Energy Resources Conservation Board Decision D 90-2 dated 29 March 1990, in the Matter of an Application for Assignment of Pipeline Licence, Compulsory Pooling, and Transfer of Well Licence – Malmo Field.

82. *Supra*, note 32.

to reimbursement upon pooling and stated that these may include costs required to allow production to resume, as well as costs already incurred by Seascape for maintenance of the shut-in well.

(ii) *Decision D90-3*[83]

Chesapeake Resources Ltd. applied for a licence to drill a well near a rural subdivision and 150 meters from the boundary of an alpaca ranch. The ranch owners submitted that the value of its alpacas and revenues from a growing business would exceed the value of the proposed well, and stated the belief that need for the proposed well did not outweigh its impacts.

The ERCB discussed the rights of the various parties, including those owning the surface, and stated that the proposed well would generate significant economic benefits. This decision illustrates the considerations addressed by the Board when there is no direct scientific evidence available with respect to adverse effects of drilling activities on extremely valuable animals. The impact of noise was discussed at some length.

The applicant committed to detailed mitigative measures to reduce potential impacts, including consultation with the ERCB in selection of its drilling rig and noise attenuation equipment, and on that basis the well licence was granted. The ERCB stated its intention to ensure compliance by the applicant with the conditions.

(iii) *Decision D90-6*[84]

Altex Resources Ltd. applied for approval to modify an existing sweet gas plant for processing raw gas. Northstar Energy Corporation contended that processing needs of Altex could be met at Northstar's existing gas plant; however, the parties had been unable to agree on processing fees. The Board agreed with Altex's assessment of reserves available for processing in the area and thus the decision to grant Altex's application was at least partially founded on predicted requirements for capacity that would be served by the proposed modification.

Economic considerations centred around distribution requirements not presently met by the Northstar plant and the feasibility of processing other reserves that would result in higher transportation and processing fees if that gas were brought to the Northstar plant. With respect to the issue of plant proliferation, the Board stated:

> ...the Board's objective is to avoid unnecessary duplication of processing facilities, to encourage the use of existing facilities and infrastructure wherever practical, and to ensure that new facilities are appropriately sized having regard for the needs of all area producers. The policy is not specific to sour gas processing plants and should not be construed as an attempt to alter the ratio of sour versus sweet

---

83. Energy Resources Conservation Board Decision D 90-3 dated 4 June 1990, in the Matter of an Application for Well Licence – Whitemud Area.

84. Energy Resources Conservation Board Decision D 90-6 dated May 1990, in the Matter of an Application for Approval of Modification of Gas Plant - Bittern Lake.

processing schemes. Additionally, the policy is not intended to create processing monopolies or prevent the construction of new facilities without regard for economic impacts.[85]

Further, the Board noted that both the Altex and Northstar processing alternatives would make use of existing facilities. Altex argued that its proposal was superior because third-party processing fees would be lower than those proposed by Northstar.

The City of Camrose expressed concerns regarding emissions from the proposed plant expansion, especially with respect to the water quality at the City's water supply source. Altex stated that it would meet or exceed all current guidelines and noted that the Northstar proposal would require a pipeline crossing of the Battle River, which would result in greater environmental impact. The ERCB accepted the position of Altex, as it found no evidence to suggest adverse environmental impacts on water quality would result.

(iv) *Decision D 90-8*[86]

The ERCB received competing applications from each of Shell Canada Limited and Husky Oil Operations Ltd. to develop the sour gas reservoir known as Caroline Beaverhill Lake. Shell's proposal had the support of the larger share of working interest owners in the area. This significant decision is only briefly summarized here.

The two proposals were generally similar with respect to field facilities to produce and gather production. With respect to processing, however, Shell proposed to build a new plant in the relevant area, while Husky proposed to expand its existing Ram River plant to accommodate new volumes and to upgrade the plant's total sulphur recovery level. Each proposal thus involved different configurations of pipelines and other transportation and operation requirements. The Board was of the view that both projects were well planned and would meet provincial standards and regulations. Consideration was given to a number of public interest criteria and the ERCB concluded that, while both projects offered substantial benefits, the Shell proposal was the most desirable in terms of overall public interest. In the decision the Board enumerated the advantages offered by each of the proposals, as well as the criteria met equally well by each.

(v) *Decision D 90-9*[87]

Gulf Canada Resources Limited applied, pursuant to section 72 of the *Oil and Gas Conservation Act*, for six compulsory pooling orders that would combine all tracts within each of six gas drilling spacing units (DSU) as a unit to permit the production of gas from all formations to the base of the Belly River Formation through wells currently existing in each of the DSUs. Shaman Energy Corporation, which held varying percentages of ownership in the six DSUs, intervened. Gulf and Shaman were unable to agree on the

85. *Ibid.* at 12.

86. Energy Resources Conservation Board Decision D 90-8 dated August 1990, in the Matter of an Application for Caroline Beaverhill Lake Gas Development.

87. Energy Resources Conservation Board D 90-9 dated 24 August 1990, in the Matter of an Application of an Application for Compulsory Pooling – Fenn-Big Valley Field.

appropriateness of well costs for five wells to be shared, as Shaman considered drilling and completion costs to be excessive. Shaman further maintained that pooling orders should not name the producing formations as all formations to the base of the Belly River. Shaman claimed that the sixth well drilled by Gulf ("7-27") was incapable of efficient and effective gas production from the Belly River formation and proposed that it drill a new well that would be a better and less expensive producer from that formation.

The Board noted that except for the 7-27 well, Gulf and Shaman agreed on the need for pooling, and the Board was prepared to issue pooling orders for all wells since Shaman did not prove to its satisfaction that the 7-27 well could not produce from the Belly River formation. In its decision the Board stated:

> In naming the applicable producing formations in any pooling order, the Board believes that it has legislated authority to name only those formations that have been shown to require compulsory pooling and are believed to be capable or being made capable of commercial production.[88]

With respect to well costs to be shared, the Board noted that for five wells the disagreement was based on differences in operating practices. In the case of the 7-27 well, the ERCB looked at Gulfs purpose in drilling the well – to evaluate formations below the Basal Belly River, and held it appropriate to first discount the avoided cost (what it would have cost Gulf to drill a well to the Belly River if the 7-27 well were not available) by one-half and then calculate cost share on an acreage basis. The avoided cost would be based on an average of Gulf s actual costs for the other five wells. The penalty applied was that existing at the time the application was heard, rather than that in effect pursuant to subsection 72(5) of the Act.

Two clarifying addenda to this decision have been issued.[89] In the first, the Board clarified how it intended the parties to determine applicable drilling and completion costs for the 7-27 well, and when the penalty provision is applicable. In the second, the Board directed Gulf as to a fair and equitable method of allocating drilling costs to horizons producing through the same wellbore on certain wells so that it could properly invoice drilling costs to tract owners within their respective DSUS.

(vi) *Decision D 90-10*[90]

Mobil Oil Canada applied for drilling spacing units (DSU) of two legal subdivisions for production of Nisku oil from the SW quarter of section 22, Township 29, Range 20, West of the Fourth Meridian. Passburg Petroleums Ltd. applied for DSUs of one legal subdivision for production of Nisku oil from certain quarter sections of sections 15, 16, and 21 in the same township. There was no disagreement between the applicants

---

88. *Ibid.* at 6.

89. Addendum to Energy Resources Conservation Board Decision D 90-9 dated 14 December 1990, and Second Addendum to Energy Resources Conservation Board Decision D 90-9 dated 27 March 1991, in the Matter of an Application for Compulsory Pooling – Fenn-Big Valley Field.

90. Energy Resources Conservation Board Decision D 90-10 dated 20 September 1990, in the Matter of an Application for Reduced Drilling Spacing Units – Drumheller D-2 B Pool.

regarding reservoir characteristics and neither opposed the other's application. The ERCB approved both applications and stated:

> The Board accepts that reduced well spacing which allows flexibility in the location of wells would result in improved oil recovery from this pool. The Board recognizes that the adoption of a uniform spacing within a pool would normally be desired to address equity and drainage concerns. However, in this case it is satisfied that equity concerns can be accommodated by appropriate set-back and interwell distance provisions.[91]

(vii) *Decision D 90-11*[92]

The Department of Energy, government of Alberta, applied for an order rescinding nine existing two-section drilling spacing units (DSUs) and establishing DSUs of one section. This decision reviews the Board's reasons for establishing special DSUs and the basis for rescinding them.

The Board stated that establishment of special DSUs is to be based upon the following considerations: resource conservation, economics and efficiency, equity, land use, and land tenure policy.[93] The Board's view was that established spacing rules, whether special or normal, should not be changed without sound reasons, but an uncontested application to rescind special DSUs might be approved if generally acceptable with respect to resource conservation and other relevant issues. Where such an application is contested, the Board's view was that the onus would be on the contesting party to justify the maintenance of the special DSU.

In the present decision the ERCB stated:

> The Board considers the issue to be whether the rescission of the special DSUs involved would have an unacceptable net impact on the criteria set out above: resource conservation, efficiency, equity, land use, and land tenure policy.[94]

The decision illustrates the various arguments that might be made with respect to the criteria. One intervener argued that the onus was very high on anyone wanting to rescind a special DSU, to present justification in support of that position. The Board was prepared to rescind the special DSUs, as it was satisfied that there would be no unacceptable effects on the criteria it had earlier set out. However, with respect to one DSU there was an equity issue that needed to be addressed but that could be resolved if a request from the mineral interest holders were received.

---

91. *Ibid.* at 3.
92. Energy Resources Conservation Board Decision D 90-11 dated 30 October 1990, in the Matter of an Application for Rescission of Special Gas Drilling Spacing Units – Pembina and Westerose Areas.
93. *Ibid.* at 2.
94. *Ibid.* at 3.

(viii) *Decision D 90-13*[95]

Corvair Oils Ltd. applied for well licences for five wells to be directionally drilled from a site containing three wells, battery modification at the existing production facilities, and reduced oil well spacing. Mr. Bruce Cook, the surface owner of the site, sought to obtain cancellation of existing well licences at the site pursuant to section 42 of the *Energy Resources Conservation Act.*

As to the status of the existing wells, the landowner was concerned that his expectations regarding his ability to use the land for residential purposes were not being met. Mr. Cook submitted that the ERCB allowed the drilling of the original well on the basis of an estimated life of ten years and claimed that he had not been given notice prior to the drilling of the two subsequent wells. In rejecting Mr. Cook's application, the Board noted that Mr. Cook had notified neither the ERCB nor the Surface Rights Board regarding desired mitigative measures or additional compensation.

The ERCB granted Corvair's applications except with respect to battery modification. With respect to future production facility requirements, the existing facilities could accommodate the production testing of the first and possibly second new wells. If any of the new wells prove productive and are completed, Corvair would be required to flowline the total production from all wells to another suitable location. Testing of subsequent wells could be done through the flowlines. This decision is an example of a practical approach where expansion at one site must be curbed to allow for co-existence of resource and residential development of the surface lands.

(b) Published Policy Statements

(i) *Information Letter IL 90-9*

This Information Letter, entitled "Government of Alberta Ethane Policy Implementation Procedures," was issued July 16, 1990. In addition to obtaining the Information Letter, interested parties may refer to the Alberta legislation, discussed previously in this paper.

(ii) *Information Letter IL 90-17*

In September 1990, the ERCB issued B 90-17 entitled "Emergency Procedure Plans for Sour Gas Facilities – Biennial Meetings" in which it revised the requirement that operators review emergency response procedures for sour gas facilities at least every two years. The Board provides details of several requirements, including an annual internal exercise for each facility that has an emergency procedure plan filed with the Board, establishing review procedures for new or modified facilities and clarifying responsibilities of various agencies, and communicating effectively with local authorities and the general public in the emergency planning zones.

---

95. Energy Resources Conservation Board Decision D 90-13 dated 20 November 1990, in the Matter of Applications for Well Licences, Battery Modification and Reduced Oil Well Spacing – Armisie Field.

(iii) *Information Letter IL 90-20*

This document, entitled "Well Site and Access Road Construction prior to the Issuance of a Well Licence, was issued November 23, 1990. The Board states that, because of concerns regarding environmental impacts, operators are expected to delay well-site and roadway lease construction until a well licence has been issued so that all potential concerns have been adequately addressed.

(iv) *Information Letter IL 91-1*

This Information Letter, dated 29 January 1991 and replacing IL 90-5, is entitled "Applications for Approval of Gas Processing Schemes – Policy on Plant Proliferation." It discusses the Board's current position on the development of new gas plants and the need to avoid plant proliferation. With respect to applications for approval of gas processing schemes, the Board's intention is to achieve optimum use of facilities. This document describes the process required of a proponent prior to making an application:

> ...the Board expects operators will vigorously explore all reasonable options to use existing gas processing plants in the area and expects these efforts to be documented in support of an application to expand or add new facilities. The Board appreciates that there can be many factors which make a new plant preferable to using an existing one and will not preclude its development if the circumstances warrant a new facility. Each application will continue to be evaluated on its own merits.

(c) Evolving Matters – Orphan Wells

> Of the some 129,000 wells which have been drilled in Alberta since the early 1900s approximately 25,000 are currently inactive; they are neither producing nor are they properly abandoned. Up to about 1,600 of these may not have traceable owners (and are, therefore, referred to as 'orphan wells'), although our current information suggests that the actual number is between 17 and 243.[96]

> However, it should be noted that the problem is dynamic – all of the existing 90,000 or so wells will eventually have to be abandoned, as will the many of thousands of wells yet to be drilled.[97]

The issue of orphan wells was the December 1989 Christmas present to the petroleum industry from the ERCB which indicated that the problems of orphan wells must be addressed and also that the "present" was expected to be paid for by the petroleum industry! The cost of the present, in addition to the cost of technically abandoning the well, was also expected to include costs to reclaim the surface of the wellsite and any access roads. Those familiar with surface reclamation are aware that the costs of reclamation can exceed, many times, the costs to technically abandon a well. Compliance with increasingly stringent criteria relating to soil reclamation and replacement, and water, both underground and surface, coupled with liability under the proposed Alberta *Environment Enhancement and Protection Act*, indicates the traditional funding

---

96. Recommendations to limit the public risk from corporate insolvencies involving inactive wells – Alberta Energy Resources Conservation Board, December, 1989 – Executive Summary, at 1.

97. *Ibid.* General Discussion, at 1.

relationship between the petroleum industry and government will change because petroleum industry is being asked to bear the cost of abandonments when the licensee does not perform its obligations.

The ERCB budget is funded 50% by the petroleum industry and 50% by the Alberta government. Where surface reclamation is required and no viable licensee can be found, costs of abandonment are paid 100% by the Department of the Environment.[98] It is proposed that the petroleum industry pay 100% of these costs as part of the well-abandonment process. Can the petroleum industry, alone, afford to pay those costs out of its ever-shrinking share of economic rent from petroleum operations? What about the public which benefits from the economic activity generated by the petroleum industry?

Orphan wells are described by the ERCB as wells which:

(a) have little or no value;
(b) have not been properly abandoned; and
(c) have no traceable owners — mainly due to bankruptcies.

These wells must be abandoned properly to avoid situations which might cause problems with cross-flow between formations, conservation losses, possible contamination of fresh-water aquifers, and possible hazards to public safety at the surface. To put the matter in a clear perspective, ERCB statistics indicate that there are:

2,600 licensees,
1,350 inactive licensees,
1,250 active licensees,
514 licensees with no production,
68% control 3% of production, and
32% control 97% of production.

As the Alberta royalty tax credit is phased out, concern has been expressed that there may be more licensees who are financially unable to abandon wells.

To highlight the difficulty the ERCB perceives in enforcing its regulatory and supervisory rights over well licence transfers, the case of *Panamericana de Bienes y Servicios S.A.* v. *Northern Badger Oil & Gas Limited*[99] (popularly known as the "Northern Badger" case) is interesting. The plaintiff, Panamericana, was a secured creditor of Northern Badger. In May 1987, the court appointed a receiver/manager of the assets and undertakings of Northern Badger. In July 1987, a receiving order was made under the *Bankruptcy Act* against Northern Badger and a trustee was appointed. The receiver, after realizing on most of the assets, except certain well licenses and a fractional interest in the seven wells which had been suspended for a considerable length of time, moved for discharge. The request for discharge included permission to pay money to the

98. *Supra*, note 40, ss. 51 and 54.
99. (1989), 75 Alta L.R. (2d) 185 (Q.B.).

secured creditor after payment of its fees and disbursements, and leave to deliver the remainder of the unrealized property, including the suspended wells, to the trustee in bankruptcy.

In June 1989, the ERCB made orders under the *Oil and Gas Conservation Act*[100] ("OGCA"), directed to the receiver/manager, to abandon the wells at a cost of approximately $200,000. The ERCB orders were sanctioned by Orders in Council of the government of Alberta and were treated by the judge as the law.

The practical issue was whether the cost of abandoning the wells could be ordered by the ERCB to be paid out of funds held by the receive/manager for secured creditors or funds payable to the trustee in bankruptcy. Mr. Justice MacPherson reasoned:

(a) Sections 4(b) and (f) of the OGCA which provide:

4. The purposes of this Act are ...

(b) to secure the observation of safe and efficient practices in the locating, spacing, drilling, equipping, completing, reworking, testing, operating and abandonment of wells and in operations for the production of oil and gas;

(f) to control pollution above, at or below the surface in the drilling of wells and in operations for the production of oil and gas and other operations over which the Board has jurisdiction.

together with Section 7 which provides:

7. The Board, with the approval of the Lieutenant Governor in Council, may make any just and reasonable orders and directions the Board considers necessary to effect the purposes of this Act and that are not otherwise specifically authorized by this Act,

gave the ERCB ample jurisdiction to make the order.

(b) The ERCB was a creditor seeking to have its claim to abandon the seven wells preferred to the claim of the secured creditor and the scheme for distribution in the *Bankruptcy Act*.

(c) The *Bankruptcy Act* has not been amended to deal with modern social problems of abandonment of contaminated property. Abandonment and securing of potentially dangerous wellsites would be at the expense of secured creditors if the ERCB were to succeed.

Mr. Justice MacPherson ruled that the receiver/manager could not abandon the wells from money held for secured creditors. The case was appealed and argument was heard

---

100. *Supra*, note 32.

by the Alberta Court of Appeal in December 1990. We await the decision with interest.[101]

The case raises, again, the issue of priorities under the *Bankruptcy Act* where, as has been stated many times, a provincial statute cannot affect the priorities created by a federal statute; consistency in the order of priority in bankruptcy situations is required from one province to another.[102]

In response to the ERCB's recommendations of December 1989, the Canadian Petroleum Association, the Independent Petroleum Association of Canada and the Small Explorers and Producers Association of Canada formed a petroleum-industry task force to work with the ERCB to develop an appropriate methodology to address the issue of orphan wells. This task force is addressing how to reduce the number of orphan wells and how to deal with new orphan wells which arise. Specific areas being addressed include the following.

(a) The ERCB proposed a descending order of responsibility for well abandonment as follows:

(i) a licensee;
(ii) receiver or other representative of a licensee;
(iii) other working interest owners;
(iv) previous licensees of the well;
(v) lessee of the mineral rights;
(vi) previous holders of the lease of mineral rights; and
(vii) owners of the mineral rights.

The petroleum-industry task force has serious problems with this descending order and are working at limiting the liability to the first three categories set out above.

(b) ERCB Informational Letter IL 89-22 sets out certain criteria which the ERCB considers in approving well licence transfers under section 18(1) of the OGCA.[103] A transferee is required to provide documentation respecting its ability to carry out financial, technical and operating responsibilities. Questions raised include:

(i) how are the financial obligations quantified?
(ii) what financial criteria should accompany have to meet? and

---

101. Since this paper was written, the Alberta Court of Appeal has upheld the validity of the ECRB actions; (1991), 81 D.L.R. (4th) 280.

102. *Federal Business Development Bank* v. *Commission de la santé et de la sécurité du travail*, [1988] 1 S.C.R., 1061.

103. A licence shall not be transferred without the consent in writing of the Board.

(iii) who pays the cost to continually update the data base and determine if the transferee continues to be able to meet its obligations in the future?

(c) The suspended well guidelines were developed by the Drilling and Completions Committee, an industry-ERCB committee, to reduce risk by having all inactive wells comply with stringent guidelines before they can be transferred or considered properly suspended.

(d) With respect to funding, the ERCB has presented the petroleum industry task force with a budget for 1991-92 to deal with activities the ERCB considers necessary for orphan wells identified in the budget. There is currently approximately three million dollars, mainly from ERCB past-budget surpluses, in what has been labelled an "abandonment fund" and the petroleum-industry task force process will include how much the abandonment fund should pay and how the fund will be replenished by the petroleum industry and the government.

(e) Amendments to legislation to more clearly define ERCB powers to control well licence transfers and abandonment orders are proposed, which include the following changes to the OGCA:

(i) amending subsection 10(g) which reads "prescribing the methods to be employed in any drilling or abandonment operations" to read "prescribing the methods to be employed in drilling, suspension or abandonment operations and prescribing the timing for abandonment of wells;" and

(ii) amending section 18(1) which reads "a licence shall not be transferred without the consent in writing of the Board" by adding the words "which consent may be refused" after the word "Board."

(f) "Reabandonment costs" which are costs associated with wells or wellsites that, once abandoned, require additional work.

(g) Perhaps the most contentious area, when considering environmental implications, is the role of receivers/trustees who are appointed either privately by contract, or by court order. Legislation affecting priorities includes:

(i) federal legislation such as the *Bankruptcy Act*,[104] *Companies' Creditors Arrangement Act*,[105] and the *Bank Act*;[106] and

104. R.S.C. 1985, c.B-3.
105. R.S.C. 1985, c.C-36.
106. R.S.C. 1985, c.B-1.

(ii) provincial legislation such as the *Business Corporations Act*[107] and the *Judicature Act*.[108]

Issues that immediately arise include:

(i) should a receiver/trustee, however appointed, who takes over and operates the assets of a licensee or working interest owner, be personally liable for abandonment costs; and
(ii) should a receiver/trustee who takes over assets simply to dispose of them not be personally liable for abandonment costs but should funds from the disposition be available first to pay or be designated as security for abandonment costs in priority to all other claims?

The petroleum industry, the Alberta government and the financial institutions will all be affected by the evolving program to manage the abandonment of existing orphan wells and to reduce the risk of future orphans.

3. Alberta Public Utilities Board Decisions

(a) E89004 — Alberta Power Limited, Transalta Utilities Corporation and the City of Edmonton — Rates

The decision of the PUB to impose the test, in section 82 of the *Public Utilities Board Act*,[109] to determine whether an asset is "used or required to be used" to provide service to the public within Alberta, upon facilities which had already received approval from the ERCB, was upheld by the Alberta Court of Appeal,[110] as reported in last year's paper. Leave to appeal to the Supreme Court of Canada was denied on September 13, 1990.

4. Alberta Environment Policies

(a) Ground Water Allocation Policy

In March 1990 a policy was announced to give users better access to water allocated for oilfield injection. New quantity limitations have been imposed and injection companies will be given licenses only on a rolling five-year basis. The injection company will have between four and five years to find an alternate source of water for injection when another user applies for a water license. The policy applies only to agricultural zones of Alberta.

107. S.A. 1981, c.B-15.
108. R.S.A. 1980, c. J-1.
109. R.S.A. 1980, c.P-37.
110. *Alta. Power Ltd.* v. *Alta. (Pub. Utilities Bd.)*, [1990] 10 A.W.L.D. 8.

C. BRITISH COLUMBIA

1. B.C. Ministry of Energy, Mines and Petroleum Resources Policies

(a) Natural Gas Removal Policy

In May 1990 the Ministry of Energy, Mines and Petroleum Resources issued for comments a policy paper entitled British Columbia Natural Gas Removal Policy. After some changes the Policy was made effective November 1, 1990 and applies to all new applications for Energy Removal Certificates and to current applications which do not satisfy the pre-November 1, 1990 policy.

The highlights of the policy are the elimination of the mandatory surplus test, the elimination of the border price test, flexible reserves determination, no reserves dedication for short term removals (less than two years), minimum price for royalty purposes, British Columbia Utilities Commission review of domestic local distribution companies' purchases, complaints procedure.

The result of the B.C. "relaxed" removal certificate provisions is that the requirements for a removal certificate from B.C. are significantly different from the Alberta requirements. The most significant difference is that the reserves requirement is 50% established reserves and the remaining reserves supported by a prudent development program (ie. potential reserves). The NEB has yet to decide an application for an export license where the applicant has a "relaxed" B.C. removal certificate.

D. ONTARIO

1. Ontario Energy Board Decisions

(a) E.B.R.L.G. 35; E.B.R.L.G. 35-1; E.B.R.L.G. 35-3 — British Gas plc. — Proposed Acquisition of the Common Shares of The Consumers Gas Company Ltd.

In October 1990 the Ontario Energy Board (OEB), reported on a reference from the Lieutenant Governor, who requested that OEB examine an application of British Gas to purchase 83% of the common shares of Consumers Gas, held indirectly by the Reichman family.

In making its decision that the purchase should be approved subject to certain conditions and undertakings, the OEB interpreted its role to be the examination of the effects of change of control of Consumers Gas on the public interest stakeholders, including the consequences for these stakeholders if the transaction were not to proceed.

In this decision, the OEB determined the public interest stakeholders to be the same as in the E.B.R.L.G. 34 report dealing with the Westcoast/Inter-City transaction except for the shareholders of the acquiror company. The OEB was of the view that the impact on the shareholders of British Gas did not fall within the scope of its examination.

At page 46 of its report, the OEB listed the matters which it considered relevant to the public interest. The following statement was also made:

> In previous cases the Board has made it clear that there are no firm criteria for determining the public interest that will hold true in every situation and, generally speaking, it is preferable not to attempt to define these criteria too closely. The public interest is dynamic, varying from case to case and the criteria by which the public interest is judged by the Board may also change according to the circumstances. In considering the criteria, the Board must use its best judgement as to the particular values of conflicting interests.[111]

Two matters of public interest were the issue of foreign ownership and the elimination of the public float of common shares. The OEB found that, because the physical gas distribution system must continue to be in Ontario, and the regulatory regime will continue to function unaffected by the British Gas transaction, denial of the takeover of Consumers Gas, solely because British Gas is a foreign company, would be contrary to the public interest. Having weighed the evidence, the OEB found that the elimination of the public float of shares would be contrary to the public interest and recommended re-instatement of the public float as a condition of the takeover. The view of the OEB was that:

> ... the residents of Ontario and other Canadians have become accustomed to the opportunity to invest in Consumers' common shares. If the common shares of Canada's largest natural gas distributor were to be removed from public trading, it is the opinion of the Board that that segment of the public interest would be unnecessarily deprived of this opportunity in the future.[112]

(b) E.B.R.O. 465 — The Consumers Gas Company Ltd. — Rates

In a decision dated March 1, 1991 the OEB considered the 1991 gas supply costs. The contract year beginning November 1, 1990 was the first year that the original WGML supply contracts with local distribution companies (Consumers Gas, Union Gas and ICG (Ontario)) were open for renegotiation. Consumers Gas negotiated a price of $2.02 per gigajoule for the contract year beginning November 1, 1990 and requested that these gas costs be accepted for ratemaking purposes on the basis that the $2.02 price was prudent and reasonable. Consumers Gas testified that the redetermined price was linked by agreement to the outcome of the arbitration proceeding between WGML and Union. The outcome was a price to Union of $2.04 per gigajoule. ICG (Ontario), now Centra Gas, Ontario Inc. negotiated a price of $2.10, $2.20 and $2.30 per gigajoule for the first, second and third contract years respectively.

The OEB staff concluded that "$2.02 per gigajoule was within the range of reasonableness, albeit at the high end of the range."[113]

---

111. E.B.R.L.G. 35, 35-1, 35-3 at 66.
112. *Ibid.* at 68.
113. E.B.R.O. 465 at 31.

The OEB found that, based on the evidence presented and the conditions that prevailed at the time of the re-negotiation, the purchase prices for the test year gas supplies from WGML and other suppliers were arrived at in a prudent manner, with due regard for the needs of the ratepayer.

(c) E.B.R.O. 470 – Union Gas Limited – Rates and Cost of Gas – 1992 Test Year – Phase I and Phase II

In this decision dated April 2, 1991 the OEB considered, *inter alia*, the cost of gas and the cost allocation of expansion facilities. In the comment in last year's paper on the decision in E.B.R.O. 462 it was noted that the matter of cost allocation for facility expenditures for new and distinct markets in order to recover costs from those markets (incremental tolling) would be reviewed at Union's next rates hearing. Having studied three cost allocation studies and rate proposals associated with the expansion of Union's Dawn – Trafalgar system and taking note of the NEB decision in the GH-5-89 hearing that the TCPL expansion facilities will be tolled on a rolled in basis, the OEB made the following finding:

> While the Board is cognizant of the Decision of the NEB in the GH-5-89 proceeding, it has approached its review of the Union system on a de novo basis. It finds that the Dawn-Trafalgar system is designed for the joint demands of both Union's M12 and in-franchise customers and therefore a rolled-in approach is appropriate for the allocation of DawnTrafalgar transmission costs. This does not preclude incremental cost allocation in other circumstances in which facilities are built specifically for incremental volumes.[114]

As a result of the WGML/Union price arbitration, a focus of attention in the hearing was on the commodity cost of gas for 1992 particularly gas purchased from WGML. Union's evidence was that it was necessary for the redetermined price to be decided by the British Columbia Commercial Arbitration Tribunal because the parties were so far apart in their positions. The arbitrator arrived at a "fair price" of $2.04 per gigajoule. Union's position was that, although the price was higher than it had argued for, it had acted prudently in taking the matter to arbitration and that the OEB should approve the gas cost consequences of the redetermined price and also Union's cost of the arbitration proceedings for recovery in the 1992 rates. The OEB took issue with criteria applied by the arbitrator but finally found that:

> ...although the arbitrated price for gas purchased from WGML may result in gas costs at a premium over those in the competitive market, it is within the range of reasonableness. The Board also finds that Union acted prudently, within the terms of the 1988 Agreement, in its conduct of negotiation and in the arbitration process. Accordingly, the gas cost consequences of the redetermined price for WGML Block A and Block B gas are approved for inclusion in the test year WACOG.[115]

---

114. E.B.R.O 470 at 106, 107.
115. *Ibid.* at 48, 49.

The fact that Union arbitrated the price for gas purchased from WGML, and the arbitration arrived at a price which was $.02 per gigajoule above the price negotiated by Consumers Gas contributed to alleviate the concern of the OEB regarding the pass-through of rates and assisted in establishing that the local distribution companies had acted prudently in negotiating contacts and pricing. As a result, the hearing was less confrontational.