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

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The purpose of this article is to provide a brief review of recent legislative and regulatory developments of particular interest to oil and gas lawyers. Part I deals with legislative developments. In addition to reporting recent changes in statutes and regulations, this part also discusses a number of legislative developments which are still evolving. Federal and Alberta legislative developments and certain noteworthy developments in British Columbia and Saskatchewan are reported. Part II of the article considers regulatory developments with respect to decisions made at both the federal and provincial levels. At the federal level, the authors examine recent decisions of the National Energy Board. The authors also examine decisions made by the Alberta Energy Resources Conservation Board and the Alberta Public Utilities Board.

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I. LEGISLATIVE DEVELOPMENTS

A. FEDERAL LEGISLATION

1. Statutes

a. *Canadian Environmental Protection Act*[1]

Sections 26 to 30 and ss. 147(2) of the *Act* have been proclaimed to be in force July 1, 1994.[2]

b. *Nunavut Act*[3]

This *Act* establishes a territory to be known as Nunavut, provides for its government and amends certain Acts in consequence thereof. For instance, "frontier lands" in s. 2 of the *Canada Petroleum Resources Act*[4] is now defined as the Yukon Territory, the Northwest Territories, Nunavut or Sable Island. Similar amendments recognizing

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1 R.S.C. 1985 (4th Supp.), c. 16.

2 SI/94-40.

3 S.C. 1993, c. 28 (assented to 10 June 1993).

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

Nunavut are made under the *Canadian Environmental Assessment Act*,[5] *Canadian Laws Offshore Application Act*,[6] *Energy Administration Act*,[7] *Federal Real Property Act*,[8] *Canada Oil and Gas Operations Act*,[9] and the *Territorial Lands Act*.[10] All but part III of this *Act* come into force on April 1, 1999 or on an earlier day fixed by order of the Governor in Council. Part III will come into force six months after the day on which this *Act* is assented to or on such earlier day as the Governor in Council may fix by order.

c. *An Act to amend the Canada Shipping Act and to amend another Act in consequence thereof*[11]

This *Act* amends the *Canada Shipping Act*[12] and the *Arctic Waters Pollution Prevention Act*.[13] The *Canada Shipping Act*[14] adopts the *International Convention on Salvage*[15] signed by Canada in London in 1989. The Commissioner of the Coast Council is appointed as the national authority responsible for the enforcement of the *Convention*.

The *Act* allows for the creation of regulations to govern pollution prevention and response procedures applicable to matters such as the shipping of oil and oil handling facilities.

d. *An Act to Amend the Income Tax Act*[16]

(i) Removal of Mandatory CCEE Deduction for Principal Business Corporations

While taxpayers are generally able to make an optional write-off of up to 100 percent of their cumulative Canadian exploration expenses ("CCEE") balance, principal-business corporations are required to deduct a portion of their CCEE balances. A recently proposed amendment to the *Income Tax Act*[17] will remove this mandatory CCEE deduction for such corporations. The amendment applies to taxation years after December 2, 1992.

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5 S.C. 1992, c. 37.

6 S.C. 1990, c. 44.

7 R.S.C. 1985, c. E-6.

8 S.C. 1991, c. 50.

9 R.S.C. 1985, c. 0-7; S.C. 1992, c. 35.

10 R.S.C. 1985, c. T-7.

11 S.C. 1993, c. 36 (assented to 23 June 1993; ss. 1-5, 6, 7(1), 7(2), 7(3), 9 12-22 in force 31 December 1993, SI/93-256).

12 R.S.C. 1985, c. S-9.

13 R.S.C. 1985, c. A-12.

14 *Supra* note 11.

15 28 April 1989, International Maritime Organization (London, 1989), Sales No. 450 89.12.E [hereinafter *Convention*].

16 S.C. 1993, c. 24. (assented to and in force 10 June 1993).

17 R.S.C. 1985, c. I-3.

(ii) Resource Allowance at Partnership Level

The resource allowance is designed to compensate for the non-deductibility of Crown royalties and similar Crown payments. The resource allowance is a deduction of 25 percent of certain resource profits, such that only 75 percent of these profits are subject to tax. Under the present structure of the *Act*, a partnership earning resource profits would calculate the resource allowance at the partnership level. In contrast, claims for Canadian exploration expense ("CEE"), Canadian development expense ("CDE") and Canadian oil and gas property expense ("COGPE") are made by partners. A recently proposed amendment to the Income Tax Regulations will result in the resource allowance being claimed by partners, rather than by a partnership.

(iii) Time Extended for Renunciating CDE Under the Flow-Through Share Rules

The flow-through share rules permit a principal-business corporation to renounce CEE, CDE and COGPE to a person who acquires flow-through shares. Pursuant to the rules, the expenses must be incurred on or after the date the agreement to subscribe for shares was executed and before twenty-four months from the end of the month in which such an agreement was executed. The actual renunciation must occur within thirty days after the end of the twenty-four month period. The amendments allow a renouncing corporation to renounce such expenses before March of the first calendar year commencing after the twenty-four month period. The draft provision relates to expenses incurred after February 1986.

(iv) Deemed Recharacterization of CDE

Draft amendments will allow a principal-business corporation to renounce specified CDE to a flow-through shareholder while that shareholder will be deemed to have received CEE rather than CDE. The recharacterization provision relates to CDE incurred after December 2, 1992. The renouncing corporation and corporations associated with it may not recharacterize more than a total of $2 million CDE in a calendar year.

(v) CDE in First Sixty Days of Calendar Year

The *Act* deems the renunciation of CEE by a corporation in the first sixty days of the calendar year to have been incurred by the corporation at the end of the preceding calendar year. The rules are to be amended to allow specified CDE to benefit from the same rule for expenses incurred after 1992.

e. *An Act to provide for the repeal of the Land Titles Act and to amend other Acts in relation thereto*[18]

This legislation provides that upon enactment of a land titles ordinance to replace the *Land Titles Act*[19] in the Yukon Territory and the Northwest Territories, the Governor in Council may repeal the *Land Titles Act*[20] in respect of such territory if such ordinance is established upon the principles of the Torrens system for land registration.

f. *An Act to amend certain petroleum-related Acts in respect of Canadian ownership requirements and to confirm the validity of a certain regulation*[21]

This *Act* amends the *Canada Petroleum Resources Act*[22] by eliminating the prohibition contained in s. 46 of the *Act* such that no production license shall be issued to an interest owner who has less than a 50 percent Canadian ownership rate. The only qualification for a production license will be contained in the new s. 44 which states that no corporation incorporated outside of Canada shall hold a production license. In addition, all of Part 5 of the *Canada Petroleum Resources* Act[23] which deals with the determination of the Canadian ownership rate will be repealed. Similar changes were also made such that the Canadian ownership requirements under the *Canada-Newfoundland Atlantic Accord Implementation Act*[24] and the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*[25] are consistent with those proposed for the *Canada Petroleum Resources Act.*[26]

This *Act* also confirms that the amendment to subparagraph 54(2)(c)(iii) of the *Canada Oil and Gas Land Regulations,*[27] which concerns qualifications for a production license, was validly made.

g. *Miscellaneous Statute Law Amendment Act*[28]

This *Act* amends the *Canada Petroleum Resources Act*[29] by repealing ss. 80(1) and substituting a provision which states that each Minister may, after considering recommendations by the Board pursuant to paragraph 79(1)(e), fix a rate for each prescribed region of frontier lands within the area under his administrative responsibility.

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18 S.C. 1993, c. 41.
19 R.S.C. 1985, c. L-5.
20 *Ibid.*
21 S.C. 1993, c. 47. (assented to 23 June 1993; in force 30 June 1993, SI/93-149).
22 *Supra* note 4.
23 *Ibid.*
24 S.C. 1987, c. 3.
25 S.C. 1988, c. 28.
26 *Supra* note 4.
27 C.R.C., c. 1518.
28 S.C. 1993, c. 34.
29 *Supra* note 4.

The *Canadian Environmental Assessment Act*[30] was also amended with revisions to certain words and provisions in the French language version.

The *Northern Pipeline Act*[31] was amended by repealing ss. 8(2), which allowed the Governor in Council to designate an acting associate Vice-Chairman of the Board. Section 29 was also repealed and substituted with provisions regarding the costs of the Agency that may be recovered and modifications to cost recovery regulations under the *National Energy Board Act*.[32]

2. Regulations

a. *Canada Labour Code*[33]
Oil and Gas Occupational Safety and Health Regulations — Amendment[34]

These amendments clarify and improve the wording of the existing regulations by correcting typographical errors, translation errors and other inconsistencies. They will give the public a better understanding of what is required and are necessary to ensure consistency. The underlying intent of the regulations is not altered.

b. *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*[35]
Nova Scotia Offshore Revenue Account Regulations[36]

These regulations prescribe the time and manner for the crediting of amounts by the Minister of Energy, Mines and Resources to the Nova Scotia Offshore Revenue Account, and the time and manner for the payment to Her Majesty in right of Nova Scotia of any amount credited to that account. They replace similar regulations made under the *Canada-Nova Scotia Oil and Gas Agreement Act of 1984*, which ceased to be effective once the new *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*[37] came into force.

c. *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*[38]
Nova Scotia Resources (Ventures) Limited Drilling Assistance Regulations[39]

These regulations pertain to the drilling fund established by Part VII of the *Act*. They provide a framework within which payments may be made from the Government of Canada to the Nova Scotia Resources (Ventures) Limited ("NSR(V)L") in respect of

30 *Supra* note 5.
31 R.S.C. 1985, c. N-26.
32 R.S.C. 1985, c. N-7.
33 R.S.C. 1985, c. L-2.
34 SOR/94-165 (registered 10 February 1994).
35 *Supra* note 25.
36 SOR/93-441 (registered 26 August 1993).
37 *Supra* note 25.
38 *Ibid.*
39 SOR/94-168 (registered 10 February 1994).

CEE and CDE incurred in the Nova Scotia offshore area. Upon application, the drilling fund will pay for 50 percent of certain costs incurred by NSR(V)L in the drilling and development of wells offshore Nova Scotia. The regulations also define eligible expenses. They only apply to one company, NSR(V)L, and are administrative in nature, so the impacts will be limited.

d. *Canadian Environmental Protection Act*[40]
Canadian Environmental Protection Act Omnibus Amendment Order, 1992[41]

This order amends certain regulations made under the *Act* including the *Asbestos Mines and Mills Release Regulations*,[42] the *Chlor-Alkali Mercury Release Regulations*,[43] the *PCB Waste Export Regulations*,[44] *Pulp and Paper Mill Effluent Chlorinated Dioxins and Furans Regulations*,[45] and the *Federal Mobile PCB Treatment and Destruction Regulations*.[46] In addition, Regulations SOR/93-213 and SOR/93-214 (both registered April 27, 1993) control the use and consumption of specific substances.

e. *Northern Inland Waters Act*[47]
Northwest Territories Waters Act[48]
Yukon Waters Act[49]
Northern Inland Waters Regulations — Revocation
Northwest Territories Waters Regulations
Yukon Waters Regulations[50]

The *Northern Inland Waters Regulations*[51] ("NIWR") are revoked and regulations respecting inland water resources in the Northwest Territories and the Yukon Territory are established under the *Northwest Territories Waters Act*[52] ("NTWA") and the *Yukon Waters Act*[53] ("YWA"). These new regulations are mainly simple amendments to the previous NIWR that reflect the changes in the new *Acts* and update certain provisions. (The NTWA and YWA were created in 1992 by amendments which essentially split and repealed the *Northern Inland Waters Act*).[54] Anyone who uses inland waters or deposits waste into inland waters will be subject to these regulations which include: a modified fee structure to bring the levels up to date and encourage conservation through

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40 *Supra* note 1.
41 SOR/93-231 (registered 11 May 1993).
42 SOR/90-341.
43 SOR/90-130.
44 SOR/90-453.
45 SOR/92-267.
46 SOR/90-5.
47 R.S.C. 1985, c. N-25.
48 S.C. 1992, c. 39.
49 S.C. 1992, c. 40.
50 SOR/93-303 (registered 8 June 1993).
51 C.R.C., c. 1234.
52 *Supra* note 48.
53 *Supra* note 49.
54 *Supra* note 47.

progressive fees; the introduction of criteria for a two-tiered system and of amended criteria for unlicensed water use and waste disposal; amended security provisions; expanded water register requirements; and expanded requirements for the submission of information. These regulations will reduce the number of public hearings required and the waiting period for a license to be issued. They will also protect the environment by requiring a license for any activity with potential impact on the environment.

f. *Northern Pipeline Act*[55]
Order Designating the Minister of Energy, Mines and Resources as Minister for Purposes of the Act[56]

The Minister of Energy, Mines and Resources, a member of the Queen's Privy Council for Canada, is designated as Minister for the purposes of the *Northern Pipeline Act*.[57]

g. *Transportation of Dangerous Goods Act, 1992*[58]
Transportation of Dangerous Goods Regulations — Amendment[59]

This amendment to the *Transportation of Dangerous Goods Regulations*[60] requires a person who is subject to an order of court under paragraph 34(1)(d), to provide a summary of the order to the Director General of the Transport Dangerous Goods Directorate within thirty days of the order. The amendment also provides the method and default time period of ninety days for payment to be made by the convicted person. It is anticipated that this amendment will have a positive impact on safety in Canada by providing funds for research into enhanced safety measures.

h. *Transportation of Dangerous Goods Act, 1992*[61]
Transportation of Dangerous Goods Regulations — Amendment[62]

This amendment schedule, marked Schedule No. 18, will align the *TDG Regulations* with international requirements. The amendment schedule concentrates on changes to Schedule II, Schedule III, and Part III and primarily affects the consignor. The two lists in Schedule II for explosives and for other dangerous goods are amended to align them with the seventh revised edition of the United Nations Recommendations. Consequently, these goods have new shipping names and classifications. Several other amendments reduce the need for permits and clarify the intention of the regulations by eliminating redundancies and by correcting oversights.

55 *Supra* note 31.
56 SI/93-237 (registered 15 December 1993).
57 *Ibid.*
58 S.C. 1992, c. 34.
59 SOR/94-146 (registered 3 February 1994), amending SOR/88-77 [hereinafter *TDG Regulations*].
60 *Ibid.*
61 *Supra* note 58.
62 SOR/93-525 (registered 2 December 1993; effective 1 October 1994), amending SOR 85-77.

i. *Transportation of Dangerous Goods Act, 1992*[63]
Transportation of Dangerous Goods Regulations — Amendment[64]

Amendment Schedule No. 19 revokes the requirement contained in the *TDG Regulations* to notify the Director General sixty days before the importation or exportation of a consignment or series of consignments of waste. This revocation is a result of Environment Canada's new regulations respecting the export and import of hazardous waste under the *Canadian Environmental Protection Act*.[65] The requirement to notify for inter-provincial shipments of wastes containing PCB's is being revoked since it duplicates existing communication between provincial governments and their clients. In addition, the definition of recyclable material in the *TDG Regulations* is being amended to reflect Environment Canada's regulations and to ensure consistency.

3. Evolving Matters

a. Statutes

(i) *An Act to Amend the Canada Oil and Gas Operations Act, the Canada Petroleum Resources Act, and the National Energy Board Act, and to make consequential amendments to other Acts*[66]

This *Act* transfers a number of advisory, regulatory and appellate powers to the National Energy Board ("NEB"). It provides for pipeline inspection officers and regulatory exemptions. It also repeals the *Canada Oil and Gas Act*.[67] This *Act* was at second reading March 11, 1994.

(ii) *Canadian Environmental Protection Act* — Amendment (Schedule III)[68]

These amendments would allow Canada to meet its international obligations under the amendments to the London Dumping Convention,[69] which address immediate and long-term disposal at sea issues. They will ban the disposal at sea of radioactive waste and the sea disposal or incineration at sea of industrial wastes. These amendments are consistent with ocean disposal practices in Canada where disposal at sea is permitted only for non-hazardous substances and where it is the environmentally preferable and practical alternative.

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63 *Supra* note 47.

64 SOR/93-203 (registered 20 April 1993), amending SOR/85-77.

65 *Supra* note 1.

66 Bill C-6, 1st Sess., 35th Parl., 1994.

67 R.S.C. 1985, c. O-6.

68 C. Gaz. 1994.I.1778, amending R.S.C. 1985 (4th Supp.), c. 16.

69 *Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter*, 13 November 1972, 2 I.L.M. 1291.

b. Regulations

(i) *Energy Efficiency Regulations*[70]

These regulations are made pursuant to the *Energy Efficiency Act.*[71] They will establish national minimum energy efficiency performance standards for equipment imported into Canada or traded interprovincially, and will provide a new regulatory basis for the EnerGuide Program. They are a component of the implementation process of the National Action Strategy on Global Warming and will encourage efficient use of energy that makes economic sense.

(ii) *Newfoundland Offshore Area Petroleum Diving Regulations* — Amendment[72]

These *Diving Regulations* under the *Canada-Newfoundland Atlantic Accord Implementation Act*[73] specify minimum standards of training and practical experience for personnel directly engaged in diving. They provide limits for depth and duration of diving operations based on the type of diving techniques used. They specify plant equipment and emergency back-ups used for different types of diving operations and for different environmental conditions. They also prescribe minimum testing and maintenance requirements for plants and equipment and lay down, in detail, the authority and responsibility of personnel directly involved in a diving program. The amendments will transfer decision-making responsibility on technical and administrative matters related to diving programs and operations from the Canada-Newfoundland Offshore Petroleum Board to the Chief Conservation Officer, a Conservation Officer, the Chief Safety Officer or a Safety Officer.

(iii) *Newfoundland Offshore Area Petroleum Diving Regulations* — Amendment[74]

These amendments, made under the *Canada-Newfoundland Atlantic Accord Implementation Act,*[75] are part of a comprehensive package of regulatory initiatives which include the *Newfoundland Offshore Petroleum Installations Regulations,*[76] the *Newfoundland Offshore Certificate of Fitness Regulations,*[77] and amendments to the *Newfoundland Offshore Petroleum Drilling Regulations.*[78] The amendments are being made to reference certain sections of the *Newfoundland Offshore Certificate of Fitness Regulations*[79] dealing with diving equipment. They include the requirement in the *Diving Regulations* for an operator to obtain a certificate of fitness in cases where work is to be carried out in the Newfoundland offshore area.

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70 C. Gaz. 1994.I.1715.
71 S.C. 1992, c. 36.
72 C. Gaz. 1994.I.1765, amending SOR/88-601 [hereinafter *Diving Regulations*].
73 *Supra* note 24.
74 C. Gaz. 1994.I.1168, amending SOR/88-601.
75 *Supra* note 24.
76 C. Gaz. 1994.I.1188.
77 C. Gaz. 1994.I.1171.
78 SOR/93-23.
79 *Supra* note 77.

(iv) *Newfoundland Offshore Area Petroleum Geophysical Operations Regulations*[80]

These regulations, made under the *Canada-Newfoundland Atlantic Accord Implementation Act,*[81] would establish a standard set of procedures which operators and contractors must follow prior to, during and following geophysical operations. The primary objective of the regulations is to ensure safe geophysical operations with minimum environmental impact. A secondary objective is to ensure that geophysical data obtained during operations are reported in a standard format and that the basic field data are neither destroyed nor removed from Canada for a reasonable period of time.

(v) *Newfoundland Offshore Certificate of Fitness Regulations*[82]

These regulations, made under the *Canada-Newfoundland Atlantic Accord Implementation Act,*[83] will require an independent third party known as a Certifying Authority to confirm to the Canada-Newfoundland Offshore Petroleum Board that an oil and gas installation or structure has been designed, constructed and installed in accordance with recognized standards. The confirmation will be in the form of a Certificate of Fitness. Every offshore installation operating in the Newfoundland offshore area will require a Certificate of Fitness. The responsibility of the Certifying Authority will continue until the installation is abandoned or removed, or until a new Certifying Authority has sufficient time to assume responsibility. The intent is to ensure the integrity of the installation, the safety of personnel and the prevention of pollution.

(vi) *Newfoundland Offshore Petroleum Installations Regulations*[84]

These regulations made pursuant to the *Canada-Newfoundland Atlantic Accord Implementation Act*[85] will establish the minimum safety requirements which must be met by all persons engaged in the exploration, development and production of oil and gas in the Newfoundland offshore are. They ensure that the various components of an installation function according to specifications. The technical requirements in the regulations are designed to protect the safety of workers, the operations, and the environment.

(vii) *Nova Scotia Offshore Area Petroleum Diving Regulations*[86]

These regulations are based on the *Newfoundland Offshore Area Petroleum Diving Regulations*[87] and the *Canada Oil and Gas Diving Regulations,*[88] promulgated

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80 C. Gaz. 1994.I.1947.
81 *Supra* note 24.
82 *Supra* note 77.
83 *Supra* note 24.
84 *Supra* note 76.
85 *Supra* note 24.
86 C. Gaz. 1994.I.640.
87 SOR/88-601.
88 SOR/88-600.

pursuant to the *Canada Oil and Gas Operations Act.*[89] They specify minimum training standards and practical experience for personnel directly engaged in diving operations and specify the types of plant, equipment and emergency back ups to be used for the different types of diving operations and various environmental conditions encountered during these operations.

(viii) *Nova Scotia Offshore Area Petroleum Geophysical Operations Regulations*[90]

These regulations parallel the *Newfoundland Offshore Area Petroleum Geophysical Operations Regulations* discussed above.

(ix) *Nova Scotia Offshore Certificate of Fitness Regulations*[91]

These regulations are made pursuant to the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act.*[92] They parallel the *Newfoundland Offshore Certificate of Fitness Regulations* above, requiring an independent third party known as the Certifying Authority to confirm that oil and gas installations or structures comply with recognized standards.

(x) *Nova Scotia Offshore Petroleum Drilling Regulations* — Amendment[93]

These drilling regulations, under the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act,*[94] are being amended in order to reference certain sections of the *Nova Scotia Offshore Petroleum Installations Regulations* and the *Nova-Scotia Offshore Certificate of Fitness Regulations*. The amendments will also transfer the cover design requirements for offshore oil and gas drilling installations to the *Nova Scotia Offshore Petroleum Installations Regulations*. In addition, there will be requirements added to the drilling regulations for an operator to obtain a Certificate of Fitness in cases where work is to be carried out in the Nova Scotia offshore area.

(xi) *Nova Scotia Offshore Petroleum Installations Regulations*[95]

These regulations, which are made under the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act,*[96] parallel the *Newfoundland Offshore Petroleum Installations Regulations* discussed above. They establish minimum safety requirements for people engaging in exploration, development and production of oil and gas in the Nova Scotia offshore area.

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89 R.S. 1985, c. O-7.
90 C. Gaz. 1994.I.1962.
91 C. Gaz. 1994.I.1254.
92 *Supra* note 25.
93 C. Gaz. 1994.I.1267.
94 *Supra* note 25.
95 C. Gaz. 1994.I.1271.
96 *Supra* note 25.

(xii) *Ozone-depleting Substances Regulations*[97]

The proposed *Ozone-depleting Substances Regulations* under the *Canadian Environmental Protection Act*[98] would amend the controls on production and consumption of chlorofluorocarbons, halons, and methyl chloroform to conform with the accelerated Canadian phase-out schedules. They would also incorporate the three regulations related to domestic production and consumption of bulk ozone-depleting substances ("ODS") into one (*i.e.* the controls in the *Ozone-depleting Substances Regulations No.1*[99] and *No.2*[100] will be added to those in the *Ozone-depleting Substances Regulations No.4*).[101] The substances formerly controlled under the four ODS regulations will now be covered by two regulations: the *Ozone-depleting Substances Regulations* will regulate bulk ODS substances, and the *Regulations on Products Containing Ozone-depleting Substances* will regulate products containing ODS. The new regulations would also add hydrobromofluorocarbons to the list of controlled substances.

(xiii) *Ozone-depleting Substances Regulations No.1 (Chlorofluorocarbon)* — Revocation[102]

This is a proposal to revoke the *Ozone-depleting Substances Regulations No.1* made by Order in Council P.C. 1989-1315 of June 29, 1989.[103]

c. Minister's Advisory Panel on Regulatory Review

The Minister of Energy, Mines and Resources ("EMR") established an advisory panel to review the regulations administered by the department and by the NEB and the Atomic Energy Control Board. The panel's concerns included regulatory overlap, regulatory costs/cost recovery programs, the process of developing legislation and regulations, and the management and administration of regulations. A summary of their recommendations on specific regulations follows.

(i) Energy, Mines and Resources Regulations

A variety of regulations administered by EMR relating to the National Energy Program, the single oil pricing policy and a number of other government programs, all of which have been either terminated or completed were recommended to be revoked. A wide range of regulations which are required to implement government policy objectives were recommended to be retained without further study since they are functioning effectively. The exceptions to this latter category include recommendations

97 C. Gaz. 1994.I.1805.
98 *Supra* note 1.
99 SOR/89-351.
100 SOR/90-583.
101 SOR/93-214.
102 C. Gaz. 1994.I.1804.
103 *Supra* note 100.

that the *Energy Administration Act*[104] be amended so that it does not require that regulations be retained to maintain a free market for natural gas prices in Canada; that the regulations relating to the *Arctic Waters Pollution Prevention Act*[105] be reviewed since they appear dated; and that the requirements under the *Newfoundland Offshore Area Oil and Gas Operations Regulations*[106] and the *Canada Oil and Gas Operations Regulations*[107] to license parties as eligible to operate offshore be considered for revocation since licenses and approvals must be obtained before parties can actually operate offshore.

There were further recommendations on other regulations administered by the department. Reviews should be conducted of the *Canada Oil and Gas Drilling Regulations*,[108] the *Declarations of Significant Discoveries Orders*,[109] the legislation requiring the establishment of the *Environmental Studies Research Fund Regions Regulations*,[110] and the *Canada Oil and Gas Lands Regulations*.[111] The consultation process related to the proposed *Energy Efficiency Regulations*[112] should continue with consideration given to harmonizing regulation substance and wording with similar provincial regulations.

(ii) National Energy Board Regulations

The panel concurs with a recommendation by the NEB staff to revoke the *Pipeline Companies Records Preservation Regulations*[113] on the basis that it is duplicated by other NEB reporting requirements. A number of regulations were recommended for retention including the NEB's *Rules of Practice and Procedures*[114] and *National Energy Board Cost Recovery Regulations*.[115] The panel also endorsed the NEB submission that pipelines should be deleted from the mandate of the Transportation Safety Board in order to eliminate duplication. All other regulations administered by the NEB were the subject of a detailed internal review. Some of the panel's decisions include: review of the guidelines for the preparation of regional socio-economic impact assessments of gas or oil pipeline projects; further revisions to the *International Power Line Crossing Regulations*;[116] review of the *Toll Information Regulations*;[117] review of the Guidelines for the Filing of Information by Oil Pipelines and Gas Pipelines

104 *Supra* note 7.
105 *Supra* note 13.
106 SOR/88-347.
107 SOR/83-149.
108 SOR/79-82.
109 SI/85-161; SI/85-162; SI/89-88; SI/85-163; SI/85-176; SI/85-177; SI/85-178; SI/85-179; SI/86-134; SI/86-135; SI/86-156; SI/86-136; SI/87-53; SI/87-207; SI/87-208; SI/89-68; SI/89-107; SI/89-216.
110 SOR/87-641; SOR/90-108.
111 *Supra* note 27.
112 C. Gaz. 1994.I.1715.
113 C.R.C., c. 1059.
114 C.R.C., c. 1057, as rep. by SOR/93-241 (filed 11 May 1993).
115 SOR/91-7.
116 C.R.C., c. 1054.
117 SOR/79-319.

Applying for an Order Fixing Tolls and Tariffs; and review of *National Energy Board Pipeline Crossing Regulations.*[118]

B. ALBERTA LEGISLATION

1. Statutes

a. *Alberta Corporate Tax Amendment Act*[119]

This *Act* makes a number of highly technical amendments to ensure compatibility with the federal *Income Tax Act*. It also authorizes an agreement for Alberta tax to be collected by the federal government.

b. *Alberta Energy Company Act Repeal Act*[120]

Section 1 of this legislation repealed the *Alberta Energy Company Act.*[121]

c. *Alberta Environmental Protection and Enhancement Act*[122]

The amendments made pursuant to this statute were summarized in last year's legislative developments article. They became effective on September 1, 1993.

d. *Natural Gas Marketing Amendment Act, 1994*[123]

In addition to broadening the Lieutenant Governor's regulation-making authority, this *Act* makes directors liable for offences under the *Act* regardless of whether the company has been prosecuted or convicted. The offence prosecution limitation is set at thirty-six months.

2. Regulations

a. Regulations Enacted Pursuant to the *AEPEA*[124]

(i) *Air Emissions Regulation*[125]

This regulation sets maximum limits on a variety of substances released into the atmosphere. It deals with the opacity of visible emissions from any stationary source, the concentration of particulate emissions from identified sources (including secondary

[118] Part I, SOR/88-528; Part II, SOR/88-529.
[119] S.A. 1993, c. 9 (assented to 15 November 1993).
[120] S.A. 1993, c. 10, s. 1 (effective 29 October 1993).
[121] R.S.A. 1980, c. A-19.
[122] S.A. 1992, c. E-13.3 (effective 1 September 1993) [hereinafter *AEPEA*].
[123] Bill 3, 2d Sess., 23d Leg., Alberta, 1994 (assented to 2 May 1994).
[124] *Supra* note 122.
[125] Alta. Reg. 124/93 (filed 22 April 1993).

lead smelters), and gaseous emissions from vinyl chloride and polyvinyl chloride plants.

(ii) *Conservation and Reclamation Regulation*[126]

This regulation governs the conservation and reclamation of land affected by industrial activities. It also contains provisions related to the jurisdiction and operation of the Conservation and Reclamation Council, including those dealing with Council activities in the area of reclamation inquiries, environmental protection orders and reclamation certificates. This regulation also provides for the granting of security by operators in relation to anticipated costs of conservation and reclamation, and sets out the procedures for requiring security, the form of security, and provisions for the return and forfeiture of security.

The regulation identifies "specified land", which incorporates the list of activities which are required to be reclaimed upon abandonment, and adds to the list land used for the "construction, operation or reclamation of a plant." The regulation outlines the required contents of environmental protection orders and applications for a reclamation certificate and allows for an environmental protection order to be issued for a specified period of time after a reclamation certificate has been issued. This period will be up to five years for activities on specified land that do not require an approval under the *Act* and up to twenty-five years for plant sites. Operations which require an approval will not normally be subject to environmental protection orders after a reclamation certificate has been issued. This regulation allows security to be collected with respect to activities on specified land which do not require an approval under the *Act*. This provision will provide an incentive for parties to undertake reclamation activities and protect the government from liability for reclamation costs.

(iii) *Disclosure of Information Regulation*[127]

This regulation provides the public with increased access to environmental information, including information relating to the Environmental Assessment Process, any reports or studies provided to the Department of Environmental Protection pursuant to an approval, and any information generated by the department for the purposes of administering the *Act*, such as approvals, reclamation certificates and various types of orders. The Minister maintains the discretion to disclose other information to the public. Information relating to an investigation or proceeding under the *Act* may not be disclosed.

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[126] Alta. Reg. 115/93 (filed 22 April 1993).

[127] Alta. Reg. 116/93 (filed 22 September 1993).

(iv) *Environmental Assessment Regulation*[128]

The Environmental Assessment Process provides a means of reviewing projects to assess their potential impact on the environment, allowing for full public participation and ensuring that economic development occurs in an environmentally responsible manner. There are four stages to the Environmental Assessment Process. The first involves an initial review and screening to determine if an Environmental Impact Assessment ("EIA") is required. If an EIA is not required, the applicant may request an approval to proceed. If an EIA is required, a report must be filed which contains the proposed activity's location, purpose and potential impact on the environment and it must be made available to the public. Public comment may be submitted and reviewed during the preparation of the EIA (Stage 3). Additionally, the report must contain: a brief description of the potential positive and negative environmental impacts of the proposed activity; cultural, economic and social impacts of the proposed activity; plans for mitigating potential negative environmental impacts; and a description of all public consultation and participation that is, has been, or will be occurring with respect to the environmental assessment of the proposed activity. Once complete, the report must be submitted to the director for review. The completed EIA is made available for any public hearings held as part of reviews by the Energy Resources Conservation Board ("ERCB") or the Natural Resources Conservation Board ("NRCB"). The Minister may request additional information or recommend further review by the NRCB.

(v) *Environmental Assessment (Mandatory and Exempted Activities) Regulation*[129]

Large projects to be subject to the Environmental Assessment Process include the construction, operation or reclamation of:

(1) an oil sands mine;
(2) a commercial oil sands, heavy oil extraction, upgrading or processing plant producing more than 2000 cubic metres of crude bitumen or its derivatives per day;
(3) an oil refinery;
(4) an ethylene or ethylene derivative manufacturing plant; and
(5) a benzene, ethyl benzene or styrene manufacturing plant.

For other projects, the *AEPEA* provides steps to determine if the assessment process should be applied. This regulation also identifies routine or smaller projects, which will generally be exempt from the Environmental Assessment Process.

(vi) *Approvals Procedure Regulation*[130]

This regulation sets out the details of the process for certain activities which require an approval, which include waste management, substance release, conservation and reclamation, miscellaneous (pesticides, designated materials, water well drillers), and

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128 Alta. Reg. 112/93 (filed 22 April 1993).
129 Alta. Reg. 111/93 (filed 22 April 1993).
130 Alta. Reg. 113/93 (filed 22 April 1993).

potable water. The approval process includes five stages: (1) filing of an application; (2) notice of requirements for completed applications; (3) review of application; (4) decision to issue or refuse to issue approval; and (5) provisions for appeal. Approvals are generally issued for a term of ten years, but may be made for a specified time period. Approvals can be amended, suspended and cancelled.

(vii) *Environmental Appeal Board Regulation*[131]

The Environmental Appeal Board has been established to provide for the independent review of decisions made under the *AEPEA*. This regulation gives the Board the power to make recommendations to the Minister on matters before it, with the exception of requests for confidential information and administrative penalties which the Board handles directly. The Board has all the powers of a commissioner and members are appointed by cabinet. The regulation sets out the process for initiating, filing and resolving an appeal.

(viii) *Environmental Protection and Enhancement (Miscellaneous) Regulation*[132]

This regulation sets out a number of areas which are subject to regulations within the authority of the Minister, which contain requirements that can only be included in regulations made under the authority of the Lieutenant Governor in Council. In addition, this regulation sets out the penalties which may be assessed for various offences under the *AEPEA*.

(ix) *Industrial Plants Regulation*[133]

This regulation pertains to facilities handling industrial waste water and storm runoff from industrial facilities. The regulation sets out reporting requirements and prohibitions respecting releases which may affect industrial facilities.

(x) *Ozone-Depleting Substances Regulation*[134]

This regulation is a new initiative which regulates ozone-depleting substances. It contains prohibitions with respect to the production and use of ozone-depleting substances and products produced using these substances. The regulation includes provisions related to the servicing of equipment which may contain ozone-depleting substances. A schedule to this regulation sets out those substances which are regulated as ozone-depleting substances. There is a general prohibition against the release of these substances, but exemptions are made with respect to fire-fighting equipment and applications for human and animal health care. Regulatory offences and penalties carry a maximum fine of $500,000 for corporations.

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131 Alta. Reg. 114/93 (filed 22 April 1993).
132 Alta. Reg. 118/93 (filed 22 April 1993).
133 Alta. Reg. 121/93 (filed 22 April 1993).
134 Alta. Reg. 125/93 (filed 22 April 1993).

(xi) *Pesticide Sales, Handling, Use and Application Regulation*[135]

This regulation classifies pesticides, deals with certification of pesticide applicators and deals with approvals for pesticide vendors and businesses offering pesticide application services. It also establishes requirements for the storage, use, application, transportation, mixing, loading and disposal of pesticides. An offence for corporations may carry a fine of up to $500,000.

(xii) *Potable Water Regulation*[136]

This regulation deals with the operation of waterworks systems and establishes standards for such facilities and their operators. This regulation also establishes requirements for potable water quality, including matters such as disinfection and fluoridation.

(xiii) *Release Reporting Regulation*[137]

This regulation consolidates reporting provisions found in previous environmental legislation to provide consistent requirements for all types of releases and provides greater detail with respect to reporting requirements in the *AEPEA*. The minimum reportable quantities of substances as referenced in the *Transportation of Dangerous Goods Act*[138] and in the lists of toxic substances are clearly set out, in addition to prohibited substances, under the *Canadian Environmental Protection Act*.[139] Requirements for written release reports have been modified to ensure consistency in all situations where such reports are provided. The submission deadline for reports is extended from forty-eight hours to seven days. Exemptions from reporting are also clearly provided in this regulation.

(xiv) *Waste Control Regulation*[140]

This regulation addresses the handling, storage and disposal of hazardous waste. Part 1, Division 1 deals in detail with the identification of hazardous wastes, as well as setting out the requirements related to the handling, storage and disposal of such wastes. Part 9, Division 1 deals with waste minimization and regulates the handling and recycling of hazardous recyclables. Part 1, Division 2 controls the treatment, storage and recycling of hazardous recyclables. Part 9, Division 2 of the regulation deals with the control of waste (litter) and incorporates much of the existing litter control legislation. Part 2 deals with the types of orders which may be for the control of waste, and addresses the review of such orders once issued.

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135 Alta. Reg. 126/93 (filed 22 April 1993).

136 Alta. Reg. 122/93 (filed 22 April 1993).

137 Alta. Reg. 117/93 (filed 22 April 1993).

138 *Supra* note 58.

139 *Supra* note 1.

140 Alta. Reg. 128/93 (filed 22 April 1993).

This regulation repeals the *Hazardous Waste Regulation*[141] and the *Litter Control Regulation.*[142]

(xv) *Wastewater and Storm Drainage Regulation*[143]

This regulation sets out the requirements for the construction and operation of municipal plants for the handling of stormwater drainage and wastewater.

(xvi) *Water Well Regulation*[144]

This regulation deals with groundwater and related drilling, and seeks to protect groundwater from actual and potential adverse effects. It sets out in detail the requirements in relation to the construction and testing of water wells, and provides for approvals for drillers involved in the development of water wells.

b. Regulations Enacted Under the *Mines and Minerals Act*[145]

(i) *Natural Gas Royalty Regulation, 1994*[146]

Effective January 1, 1994, the Department of Energy implemented a new and simplified natural gas royalty regime. The highlights are as follows:

(1) Royalty liability will be triggered at the plant gate (except where gas is sold on process).

(2) Royalty credits will be established monthly to defer liability relating to qualifying injection. Royalty paid banking will be eliminated and current banks paid out.

(3) The royalty share of gas (raw gas, residue gas and ethane) and liquids (propane, butane and pentanes) will be valued at a monthly reference price. Royalty payers may instead elect to use an annual corporate average price to value gas. Sulphur will be valued at an annual corporate average price.

(4) The Crown will pay a standard operating cost for the gathering, compression and processing of each of its volumes. The rates will be determined annually.

(5) The Crown will recognize an allowance for each royalty client's total actual corporate capital costs of gathering, compression, processing and actual corporate custom processing fees paid.

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141 Alta. Reg. 505/87.
142 Alta. Reg. 88/73.
143 Alta. Reg. 119/93 (filed 22 April 1993).
144 Alta. Reg. 123/93 (filed 22 April 1993).
145 R.S.A. 1980, c. M-15.
146 Alta. Reg. 351/93 (filed 16 December 1993).

(6) The department will invoice royalties monthly.

The royalty rates for raw gas, residue gas and ethane in any month, expressed as a percentage of the Crown's ownership share are determined in accordance with the following formulae:

OLD GAS

$$R\% = \frac{15\,G + 40\,(PP - G)}{PP}$$

NEW GAS

$$R\% = \frac{15\,N + 40\,(PP - N)}{PP}$$

where: R% = the Royalty Rate

PP = Par Price equal to the previous month's Gas Reference Price

G = the old gas select price set annually before the first production month in the calendar year

N = the new gas select price set annually before the first production month in the calendar year

The minimum royalty rate for old and new gas is 15 percent and the maximum royalty rates for old and new gas are 35 percent and 30 percent respectively. The Gas Reference Price is a monthly weighted average of the intra-Alberta consumers' price and ex-Alberta border price, reduced by allowances for transporting and marketing gas.

Previous royalty holidays and exemptions have been brought under the new *Natural Gas Royalty Regulation, 1994*, such as exemptions for exploratory gas wells and qualifying intervals in deep gas wells. In addition to providing for certain royalty exemptions, the new regulation also provides for the proportionment of royalty liability, and enhanced administration and enforcement provisions.

Each royalty client must elect the method by which Alberta's gas royalty share is valued. Typically, the gas will be valued according to the Gas Reference Price, calculated and reported by the Alberta Petroleum Marketing Commission. Certain adjustments may be made for raw gas sales and sales related to long-term co-generation contracts. Alternatively, royalty clients may have, prior to April 15, 1994, chosen to use their Corporate Average Price. That price is based on actual sales by the royalty client.

Alberta's share of the cost of gathering, compressing and processing natural gas is taken into account through Annual Capital Cost Allowances, Monthly Operating Cost Allowances, and Annual Custom Processing Cost Allowances. The Annual Capital Cost Allowance is based on the total capital allocated to each royalty client in a year, including a 15 percent return on investment. Capital costs are allocated at a facility cost centre, which is a gathering system, processing plant, or compressor or at any combination of these facilities, having common ownership and one operator. Included in the Capital Cost Allowance are calculations to adjust for capital cost sharing by facility owners and designated royalty payors and adjustments for custom processing. The Monthly Operating Cost Allowance is calculated at an operating cost centre (a Gas Cost Allowance facility). Operating cost rates are expressed in terms of gas equivalent volumes. The rate is calculated on a "base rate" founded on previous years' operating costs, adjusted to 1994 dollars. Operating cost rates are adjusted for plant types to account for volume and cost differences in subsequent years. The Annual Custom Processing Cost Allowance is based on net custom fees paid by the royalty client each year. Only arm's length fees for gathering, compressing or processing service are eligible custom fees.

From a legal standpoint, it is notable that the regulation expressly provides for the Crown's title to its royalty share of natural gas to be transferred at the point immediately downstream from the place where the royalty was calculated. The royalty is calculated at the plant gate, unless the gas is sold as raw gas. Further, if gas is injected into an injection facility, the royalty client receives an "injection credit". The injection credit is calculated as a credit against the royalty client's royalty account.

(ii) *Natural Gas Royalty Amendment Regulation*[147]

As part of the natural gas royalty simplification program, the old *Natural Gas Royalty Regulation*[148] was amended. The title was changed to *The Natural Gas Royalty (Pre-1994) Regulation.* This regulation is now applicable only to natural gas recovered or gas products obtained before January 1994. Sections 3-15 of the *Natural Gas Royalty Regulation* are replaced with a provision in s. 3 exempting natural gas from payment of a royalty as described in Schedule 6 of the *Natural Gas Royalty Regulation, 1994.*[149]

The regulation also provides reporting requirements for every royalty client and for operators of a gathering system or plant. Where discrepancies between the costs and allowances set out in the report of the operator of a gathering system or plant in respect of a royalty client and those set out in the royalty client's reports are not corrected within four months of continuous notification by the Minister of the discrepancy, the royalty client will be required to pay the Crown a penalty of $25 or an amount equal to 0.00175 times the discrepancy. Where a discrepancy is not resolved, the royalty client may not deduct, and the Minister may not consent to liability for, any costs or allowances incurred by or on behalf of the royalty client in gathering, compressing or processing the Crown's royalty share of natural gas at the gathering system or plant.

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147 Alta. Reg. 352/93 (filed 16 December 1993).

148 Alta. Reg. 246/90.

149 Alta. Reg. 351/93.

(iii) *Enhanced Recovery of Oil Royalty Reduction Regulation*[150]

This regulation came into force on January 4, 1994 and applies to crude oil obtained in 1994 and later. The regulation entitles an operator of an enhanced recovery scheme or a proposed enhanced recovery scheme to apply to the Minister for a reduction of royalty payable under the *Petroleum Royalty Regulation*[151] in respect of crude oil obtained under the scheme. Eligible enhanced recovery schemes include projects where more crude oil is likely to be obtained from the pool under the enhanced recovery scheme than under the pool's base recovery scheme, and where the costs estimated for implementing and operating the enhanced recovery scheme are significantly more than those if the crude oil were obtained under the base recovery scheme.

The royalty payable to the Crown under the *Petroleum Royalty Regulation*[152] on crude oil obtained on an approved scheme is reduced by the quantity of crude oil determined by the following equation:

> Quantity of the royalty reduction for the month in cubic metres (Q) = relief of the approved scheme for the Year (R) divided by the product of the par price for the month (P) and the number of months in the Year (N). Q=R/P*N.

Relief for an approved scheme is the sum attributable to all Crown reporting interests of the approved scheme for that year. The operator of such a scheme is required to meet reporting requirements to calculate the initial actual relief. In addition, allowances may, for the purposes of calculating relief, be established by the Minister for costs incurred in an approved scheme that fall within a category of costs in an approval. However, no allowance in respect of crude oil obtained from a pool may be established for costs that would have been incurred under the base recovery scheme for the pool.

(iv) *Experimental Project Petroleum Royalty Amendment Regulation*[153]

This amendment replaces s. 3 with a new method of proportioning of royalty liabilities.

(v) *General Amendment Regulation*[154]

This regulation adds a new s. 7.1 to *The General Regulation*[155] which determines the interest on the amount of compensation payable to the Crown for an unauthorized taking of a mineral which is the property of the Crown as set out in s. 53.1 of the *Act*. The interest is payable in respect of each month in which the mineral was won, worked

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150 Alta. Reg. 348/93 (filed 16 December 1993).
151 Alta. Reg. 248/90.
152 *Ibid.*
153 Alta. Reg. 349/93 (filed 15 January 1994).
154 Alta. Reg. 347/93 (filed 15 January 1994).
155 Alta. Reg. 163/84.

or recovered in contravention of s. 53 and commencing on the first day of the month following the month in which such activity took place.

(vi) *Oil Royalty Incentive Amendment Regulation*[156]

This regulation extends the spud day for an "eligible well" (an oil well or oil sands well), such that the spud day now extends from October 31, 1991 and August 1, 1993. If the spud day occurred in August 1993, the well is eligible if the ERCB received a substantially complete application for the license for the well on or before July 30, 1993.

A new provision pertaining to "ineligible wells" has been added. An ineligible well is one which has been approved as a horizontal extension under the *Horizontal Well Petroleum Royalty Regulation,*[157] one from which a royalty has been prescribed under s. 10 of the *Petroleum Royalty Regulation,*[158] or certain eligible deep gas wells under the *Natural Gas Royalty Regulation, 1994.*[159] The regulation also expands the approval date for scheme boundaries.

(vii) *Oil Sands Royalty Regulation, 1984 Amendment Regulation*[160]

This regulation updates the current regulation, but does not make substantive changes.

(viii) *Petroleum Royalty Amendment Regulation*[161]

This regulation clarifies certain definitions including "finished drilling date", "heavy oil", "non-heavy oil", "production entity", "well event" and provides for the proportionment of royalty liability.

(ix) *Reactivated Well Incentive Amendment Regulation*[162]

This regulation changes the applicable date for scheme boundaries for which the Minister has made a deduction or royalty reduction under the *Petroleum Royalty Regulation*[163] from November 1, 1991 to the later of November 1, 1991 or the date the approval was issued by the ERCB.

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156 Alta. Reg. 353/93 (filed 16 December 1993).
157 Alta. Reg. 96/91.
158 *Supra* note 151.
159 *Supra* note 148.
160 Alta. Reg. 354/93 (filed 16 December 1993).
161 Alta. Reg. 355/93 (filed 16 December 1993).
162 Alta. Reg. 357/93 (filed 16 December 1993).
163 *Supra* note 151.

c. Regulations Made Pursuant to the *Oil and Gas Conservation Act.*[164]

(i) *Oil and Gas Conservation Amendment Regulation*[165]

This regulation establishes log requirements for licensees before and after completion, abandonment or suspension of drilling operations at a well. These log requirements may be waived by the ERCB where special circumstances warrant.

(ii) *Oil and Gas Conservation Amendment Regulation*[166]

This regulation adds a new ss. (1.1) to s. 17.010 which requires an applicant for a license who has not previously held a license issued under this regulation to pay $10,000 in addition to the fee set out in ss. (1).

(iii) *Oil and Gas Conservation Amendment Regulation*[167]

This regulation amends Regulation 151/71 by clarifying several terms including basic well rate, common ownership, complaint level, control well, maximum rate limitation, minimum level, penalty factor and reference rate. Amendments to Part 5 — Blocks, Projects and Holdings, entitle the ERCB to establish blocks in oil pools and outlines the criteria which shall be contained in the application. The Proration, Distribution and Allowables section has been changed.

A new equation is designated for the maximum daily volume of production (Qmax) and there is a substituted Schedule 6 for calculating the Gas-Oil Ratio (GOR) penalty factor formula.

d. Regulations Enacted Pursuant to Various Provincial Acts.

(i) *Natural Gas Marketing Act*[168]
Natural Gas Marketing Amendment Regulation[169]

This amendment makes several additions to the Interpretation and Application provision of the *Natural Gas Marketing Regulation,*[170] including a "buy-sell arrangement", "end user", "field location" and "gas transmission pipeline". The regulation also imposes revised reporting requirements on the party removing gas from Alberta, whether a producer, distributor or buyer.

164 R.S.A. 1980, c. O-5.
165 Alta. Reg. 186/93 (filed 12 July 1993).
166 Alta. Reg. 225/93 (filed 30 August 1993).
167 Alta. Reg. 226/93 (filed 30 August 1993).
168 S.A. 1986, c. N-2.8.
169 Alta. Reg. 358/93 (filed 16 December 1993).
170 Alta. Reg. 358/86.

(ii) *Freehold Mineral Rights Tax Act*[171]
Freehold Mineral Rights Tax Amendment Regulation[172]

This amendment clarifies the meaning of "gas well condensate" and "well event".

(iii) *Fuel Tax Act*[173]
Fuel Tax Amendment Regulation[174]

This regulation amends *The Fuel Tax Regulation*[175] by restricting farm fuel distribution allowance to fuel delivered to a consumer between and including November 14, 1991 and August 20, 1993. The regulation also adds a new ss. 9(4) which designates distribution allowance for fuel delivered after August 20, 1993 at $0.02/litre for gasoline and aviation fuel and $0.08/litre for diesel fuel and heating oil. Additionally, this regulation repeals ss. 17(1) and (2) which entitle an agent-dealer to a commission and to deduct the commission for selling fuel oil or marked fuel.

(iv) *Electric Power and Pipeline Assessment Act*[176]
Pipeline Assessment Standards Amendment Regulation[177]

This regulation updates the previous regulation with minor technical changes (*i.e.* substitution of *City of Edmonton Fair Actual Value Regulation*[178] for *Edmonton Fair Actual Value Indexing Regulation*[179]).

(v) *Forests Act*,[180] *Mines and Minerals Act*,[181] *Public Highways Development Act*[182] and the *Public Lands Act*[183]
Exploration Amendment Regulation[184]

This regulation makes technical clarifying amendments and expires on October 1, 1998.

171 R.S.A. 1980, c. F-19, S.A. 1983, c. F-19.1, s. 28 (effective 14 May 1984).
172 Alta. Reg. 346/93 (filed 16 December 1993).
173 S.A. 1987, c. F-22.5.
174 Alta. Reg. 269/93 (filed 13 October 1993).
175 Alta. Reg. 388/87.
176 R.S.A. 1980, c. E-5.
177 Alta. Reg. 177/93 (filed 6 July 1993).
178 Alta. Reg. 387/92.
179 Alta. Reg. 392/86.
180 R.S.A. 1980, c. F-16.
181 *Supra* note 145.
182 R.S.A. 1980, c. P-28.
183 R.S.A. 1980, c. P-30.
184 Alta. Reg. 300/93 (filed 27 October 1993).

3. Evolving Matters

a. *Oil and Gas Conservation Amendment Act, 1994*[185]

Substantial changes to the *Oil and Gas Conservation Act*[186] have been proposed and are discussed below.

In addition to a number of definitive changes, Part 5 of the *Act* is to be amended to expand the ERCB's regulatory powers to allow it to make regulations:

(1) requiring licensees and other holders of other approvals to furnish deposits to guarantee the proper suspension or abandonment of wells;

(2) respecting the drilling, completion, repair, suspension, abandonment and abandonment costs of wells;

(3) respecting the approval, location, equipping, operation and abandonment of facilities to handle oil field waste; and

(4) prescribing qualifications of licensees.

With respect to well licences, the following changes have been proposed:

(1) *License to Drill*

- Section 11 is to be expanded to allow drilling, production or injecting operations by those "acting under instructions of the licensee" as well by the licensee.

- A non-licensed person with the direction or consent of the ERCB may undertake operations to suspend or abandon a well.

- Only a licensee or a person acting under the direction of the ERCB may undertake operations on an abandoned well without a license. A person acting under the instructions of a licensee may no longer do so.

(2) *Transfer of License*

- The requirement for ERCB approval for a licensee transfer is specifically stated to include the right to consent subject to conditions, restrictions and stipulations, or to refuse to consent.

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185 Bill 5, 2d Sess., 23d Leg., Alberta, 1994 (3rd reading 2 May 1994).

186 *Supra* note 164.

- The ERCB will have a general power to direct that the license be transferred. The power is no longer restricted to a case where the licensee is a corporation that has been dissolved.

- A transfer of a license will have no effect until consented to or directed by the ERCB.

(3) *Cancellation/Suspension of License*

- The ERCB will be given the express power to shut in a well for contravention of the *Act*, regulations or an ERCB order.

(4) *Abandonment of Wells*

- Sections 20.1 to 20.4 have been added to deal with abandonment of wells and the payment of the costs of abandonment by licensees or working interest participants ("WIP").

- Sections 20.1 to 20.4 deal with who shall pay, failure to pay and enforcement of payment. Specifically, s. 20.4 deems a person a WIP even if it divests of its interests if (1) the transaction occurred after the well ceased producing in paying quantities and (2) there is no successor or the successor WIP fails to pay its proportionate share of the abandonment costs.

Part 7 — Production and Conservation Projects — will be amended by adding paragraph 26(g) requiring ERCB approval for a scheme for the storage, treatment, processing or disposal of oil field waste.

Subsections 53(1) and (2) of Part 11 — Administration fees — are to be repealed and replaced with sections stating that if an operator, who is responsible for the administration fee, is not the operator of a well or oil sands project or has left Alberta, become bankrupt or insolvent or refuses to pay, then liability falls on the person who was the licensee or holder of approval under the *Oil Sands Conservation Act*,[187] on the prescribed date.

Subsection 53(2) empowers the ERCB to shut down wells or oil sands projects for non-payment and no longer requires reasonable notice first.

An abandonment fund is established to be funded by well licensees through the payment of prescribed levies on wells. The ERCB may shut down a licensee's wells for non-payment of levies and penalties.

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[187] S.A. 1983, c. O-5.5.

Section 80, which deals with unit operating expenses, is amended to become subject to ss. 20.3(3), which requires a WIP to pay a penalty if it fails to pay its share of well abandonment costs.

Section 83 is amended to require ERCB approval for the appointment of an agent by the licensee and for consent for a change or discharge of an agent with respect to registers, records and reports. In addition, if a licensee fails to comply with a duty or responsibility, the agent is responsible for compliance.

More generally, a new s. 92.1 provides for a person to enter on land to carry out an abandonment order and directs that compensation be made to the landowner or occupant for certain expenses and damages arising directly from the entry.

A new s. 93.1 grants a first and prior lien to the ERCB for costs of abandonment on a defaulting WIP's interest in an abandoned well and any other wells, lands and equipment, petroleum substances and production facilities. On receipt of a lien notice, a payor, defined as the purchaser of any gas, oil or hydrocarbon or any operator or any other person who holds or receives money on behalf of a person liable for costs of abandonment as a result of a sale of that person's share, must forward such money to the ERCB for payment of costs of abandonment.

Subsection 97(1) is to be expanded to make it an offence to cause "any person" (formerly "any licensee") to contravene or default under the *Act*.

b. *Mines and Minerals Amendment Act, 1994*[188]

This *Act* will allow agreements for storage of substances in subsurface reservoirs. It deals with ownership and disposition of underground storage rights. Storage rights in land are held by the owner of petroleum and gas rights. The *Act* defines fluid mineral substances and sets the parameters for their storage. Several detailed changes are made in the administration of royalty collection, the updating of payment rules and the repeal of redundant provisions. The bill would become effective on assent with the exception of s. 10, which requires proclamation.

c. *NOVA Corporation of Alberta Act Repeal Act*[189]

This *Act* will result in the repeal of *The NOVA Corporation of Alberta Act*[190] and bring the regulation of NOVA under the *Gas Utilities Act*.[191] Rates will continue to be rescheduled by the Public Utilities Board ("PUB") (until such time as that Board is merged with the ERCB) and conditions of service will be regulated by the ERCB. The amended *Gas Utilities Act* will apply to certain aspects of NOVA's corporate existence

188 Bill 6, 2d Sess., 23d Leg., Alberta, 1994 (3rd reading 2 May 1994).
189 Bill 29, 2d Sess., 23d Leg., Alberta, 1994 (1st reading 2 May 1994).
190 R.S.A. 1980, c. N-12.
191 R.S.A. 1980, c. G-4.

and NOVA will be prohibited from extra provincial operations except to the extent allowed by regulation.

d. *Alberta Energy and Utilities Board Act*[192]

This *Act* will effectively unite the PUB and the ERCB into one tribunal, named the Alberta Energy and Utilities Board ("AEUB"). The AEUB will consist of all of the current members of the ERCB and PUB and will have the jurisdiction and powers in respect of all matters that have been dealt with by the ERCB or the PUB. Provisions relating to AEUB administration, rules of practice and appeals are substantially the same as those relating to the PUB and ERCB. Of special note is the express jurisdiction of the AEUB over existing and proposed provincial pipelines.

4. Directives, Information Letters and Guides

a. ERCB Interim Directives

(i) Drilling Waste Management[193]

This directive, which was implemented June 1, 1993, provides guidelines for the management of drilling waste to ensure that the environmentally acceptable disposal of drilling waste. The directive addresses sampling, analysis, and disposal requirements for drilling waste which were developed in consultation with the Drilling Waste Review Committee. The goal is to achieve proper waste management and disposal methods which will allow drilling operations to take place with minimum impact on the land.

b. ERCB Informational Letters

(i) Drilling Waste Management Hydrocarbon/Salt Disposal Plan Content and Database[194]

This informational letter details the required contents of a drilling waste disposal plan in accordance with ID 93-1 and Guide G-50,[195] which require that a waste disposal plan be submitted with the well licence application when hydrocarbon or salt-based mud systems will be used during drilling or otherwise produced during the drilling operation. This informational letter also provides the form which will be used to collect information on all sump disposal operations. A satisfactory disposal plan and analytical form will be required for a reclamation certificate.

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192 Bill 15, 2d Sess., 23d Leg. Alberta, 1994 (3rd reading 18 May 1994).

193 (1 March 1993), No. ID 93-1 [hereinafter ID 93-1].

194 (1 June 1993), No. IL 93-6.

195 Drilling Waste Management (March 1993).

(ii) Orphan Well Fund — 1993 Orphan Well Levy[196]

The 1993 orphan well levy will be $60 per inactive well with assessment through the ERCB administrative levy system as a separate invoice on a licensee's inactive wells. Inactive wells include those that have had no production in the 1992 calendar year, but do not include abandoned wells, observation wells, domestic wells and test wells.

(iii) Upstream Petroleum Waste Management Steering Committee Report to the ERCB on Recommended Oilfield Waste Management Requirements[197]

The ERCB assumed jurisdiction for upstream oilfield waste on September 1, 1993. A steering committee was established to prepare the "Recommended Oilfield Waste Management Requirements" report for the ERCB to implement upon assuming jurisdiction. A draft report was submitted to the ERCB on August 24, 1993. The requirements reflect a compilation of existing regulations for waste management. After the ERCB reviews the report, it will go through a public/industry review before being finalized.

(iv) Oil and Gas Developments Eastern Slopes (Southern Portion)[198]

This informational letter confirms to all oil and gas operators the requirements for development along the southern portions of Alberta's eastern slopes. A program of public consultation, project pre-planning, environmental assessment and coordination of corporate activities must be complied with by any company intending to develop a project in this region to ensure that, should developments proceed in the eastern slopes, they will occur in a manner which best meets the interests of all Albertans.

(v) Injection and Disposal Wells — Well Classification, Completion, Logging and Testing Requirements[199]

This letter supersedes IL 84-12[200] and introduces ERCB Guide G-51[201] which clarifies completion, logging, testing, monitoring and application requirements for injection and disposal wells. The guide specifies procedures and practices designed to protect the subsurface environment, including useable groundwaters and hydrocarbon-bearing zones, from the potential impacts of casing failure and zonal communication. In addition, a system of classification of injection and disposal wells has been developed which is consistent with that used by the United States Environmental

196 (30 June 1993), No. IL 93-7.

197 (2 September 1993), No. IL 93-8.

198 (13 December 1993), No. IL 93-9.

199 (16 March 1994), No. IL 94-2.

200 Surface Casing and Logging Requirements; New Disposal and Injection Wells (23 November 1984).

201 Injection and Disposal Wells, Well Classification, Completion, Logging and Testing Requirements (March 1994).

Protection Agency. Operators of approved injection and disposal wells will be notified of their classification within three months.

(vi) Oil and Gas Industry Notification Requirements[202]

This informational letter presents the agreement between Alberta Environmental Protection ("AEP") and the ERCB with respect to the policies, procedures and roles of each organization regarding emergency response, investigations and inspections, and enforcement in the oil and gas sector. The agreement was developed to ensure consistent notification and reporting requirements and to provide a "one-window" notification and reporting procedure for industry. Highlights of the agreement are included in the informational letter. This agreement complements other existing agreements, including AEP/ERCB Information Letter IL OG 72-20,[203] which outlines the two organizations' environmental management and pollution control responsibilities in the gas processing sector.

c. ERCB General Bulletins

(i) Criteria for Disposal of Oily Waste[204]

The requirements of General Bulletin GB 92-10,[205] which detailed new criteria for sampling, analysis and disposal of oily wastes, remain in effect for the 1993 road application season. Research into the new criteria and the subsequent anticipated changes to the characterization requirements for oily wastes was yet to be completed.

(ii) Administrative Procedures for Environmental Impact Assessments on Energy Projects[206]

Pursuant to *AEPEA*,[207] environmental screening of many energy projects will be required and an increased number of projects will be subject to an EIA. To facilitate meeting these requirements, the ERCB and AEP have developed administrative procedures for EIAs which define the roles of both organizations.

(iii) List of ERCB Approved Oilfield Waste Management Facilities[208]

This bulletin provides operators with a current list of ERCB approved oilfield waste management facilities which can receive upstream oilfield waste. Generators that are found sending their material to an unapproved facility, or to an approved facility that

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202 (7 April 1994), No. IL 94-5.

203 Environmental Management and Pollution Control, Gas Processing Operations (20 December 1972).

204 (15 April 1993), No. GB 93-7.

205 Criteria for Disposal of Oily Waste to Roads (12 June 1992).

206 (13 December 1993), No. GB 93-14.

207 *Supra* note 122.

208 (9 December 1993), No. GB 93-15.

is not authorized to accept their specific waste, will be required to retrieve their waste plus any other material contaminated by their waste. The application requirements for an oilfield waste management facility are outlined in IL 93-8[209] which introduced the draft "Recommended Oilfield Waste Management Requirements" document.

(iv) Trucking of Sour Fluids and Control of Odorous Emissions[210]

The problem of nuisance odours resulting from trucking sour fluids has been addressed in the "Alberta Recommended Practices (ARPs) for Well Testing and Fluid Handling, ARP 4.4", included in this general bulletin. This bulletin confirms that the practices recommended by the ARP are to be utilized where trucking of sour fluids are, or could become, a concern. The responsibility for implementation of the recommended practices remains with the operating company, which will be required to take remedial action should public complaints arise.

(v) Alberta Environmental Protection Guides

In February and March 1994, Alberta Environmental Protection, Environmental Regulatory Services released "Guide for Oil Production Sites" and "Guide for Pipelines", pursuant to the *AEPEA* and regulations. The "Guide for Oil Production Sites" is intended to assist proponents and operators of oil production sites in understanding the regulatory requirements under the *AEPEA* and regulations. This guide sets out the conservation and reclamation approval and environmental protection guidelines and discusses issues surrounding reclamation certification.

The "Guide for Pipelines" is also intended to assist parties in understanding the conservation and reclamation approval process, and the requirements of the environmental protection guidelines and reclamation certification.

C. BRITISH COLUMBIA LEGISLATION

1. Statutes

a. *Environment, Land and Parks Statute Amendment Act*[211]

This *Act* amends the *Land Act*.[212] The amendment establishes the Crown Land Registry to record all land administered by the Crown and the acquisition and disposition of these lands. This amendment also clarifies that a grant of Crown land may be made to government-related bodies as well as to Crown corporations, and that the grant may be limited for a specific public purpose. Subsection 49(1) is amended by

209 Upstream Petroleum Waste Management Steering Committee Report to the ERCB on Recommended Oilfield Waste Management Requirements (2 September 1993).

210 (9 December 1993), No. GB 94-01.

211 S.B.C. 1993, c. 13 (assented to 18 June 1993).

212 R.S.B.C. 1979, c. 214.

allowing the minister to amend or replace a Crown grant if it contains an error or is no longer required for the purpose for which it was issued.

The *Waste Management Act*[213] is also amended. Section 3.2 is repealed and substituted with provisions which clarify that the regulation of special waste is in accordance with the regulations, rather than in accordance with permits, approvals or waste management plans. Sections were added to the *Waste Management Act*, allowing a manager under the *Act* to issue to a person, other than a municipality, a pollution prevention order where an activity or operation is being performed by that person in a manner that may cause pollution. New sections also empower the minister to exercise the powers of a manager under ss. 22.2(2) of the *Waste Management Act* in respect of an activity or operation performed by a municipality that may cause pollution. In addition, this *Act* allows a municipality to administer the regulations governing tanks used to store petroleum products and other substances, and protects a municipality from any liability arising out of that administration.

b. *Waste Management Amendment Act*[214]

This *Act* amends the *Waste Management Act*. Besides definitional changes, the *Act* also repeals and replaces Part 3.1 of the *Act* to provide a comprehensive process for managing contaminated sites. The amended *Act* requires certain persons to provide disclosures, known as "site profiles", to specified government or municipal officials. Regional waste managers are entitled to order site investigations, and the results of these site profiles and site investigations are to be kept at a site registry. Division 3 of Part 3.1 of the *Act* sets out the liability of certain persons for the remediation of a contaminated site. Persons who may be liable include the current owner or operator of the site, a previous owner or operator of the site and any person who produced, handled, treated, disposed of or transported the contaminating material. In addition, current or previous owners or operators of sites from which the contaminating substance migrated may also be liable for remediation. Excluded from such liability is a person who became a responsible person only because of an act of God and who exercised due diligence with respect to the substance that caused the site to become contaminated. The person responsible for remediation is jointly, severally and retroactively liable for any reasonable costs incurred by a government to remediate the contaminated site. Further, managers under the *Act* are empowered to order the remediation of a contaminated site.

c. *Energy, Mines and Petroleum Resources Statutes Amendment Act*[215]

This *Act* makes a number of changes to various energy-related *Acts*. For example, the definition of "energy device" in the *Energy Efficiency Act*[216] is expanded to include both energy-using devices and devices that control or affect the consumption

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213 S.B.C. 1982, c. 41.
214 S.B.C. 1993, c. 25 (assented to 18 June 1993).
215 S.B.C. 1993, c. 12 (assented to 18 June 1993).
216 S.B.C. 1990, c. 40.

of energy (such as windows and shower heads). Subsection 6(1) is also amended to allow the Lieutenant Governor in Council to prescribe as energy devices products that use energy, or that control or affect the consumption of energy; and it empowers the Lieutenant Governor in Council to make regulations requiring manufacturers to report information in respect of the energy consumption or efficiency of energy devices sold in British Columbia.

The *Petroleum and Natural Gas Act*[217] is amended by repealing definitions that are no longer required or that will now be made by regulations. Section 33.1 is amended to allow the Commissioner to designate an employee of the ministry to act on behalf of the commissioner for the purposes of ss. 33.1(1) and (2) of the *Petroleum and Natural Gas Act*. Sections 36 and 37 are amended to allow for the charging of application fees for an approval to undertake geophysical exploration, and to reduce to one block the basic area for which a permit is issued at a location. Subsection 74(1) is amended to allow the description of a location by regulation instead of in a schedule to the *Petroleum and Natural Gas Act*. Subsection 80(1) is amended to remove an existing waiver of penalty payments for the continuation of a lease beyond ten years where a well has been drilled in the location of the lease during the continuation period. The ninety day time limit for production of petroleum or natural gas from some tenures is removed in s. 127 and s. 132 is repealed and substituted with provisions which allow the Commissioner to designate an employee of the Ministry to act on behalf of the Commissioner for the purposes of s. 132 of the *Petroleum and Natural Gas Act*. Subsection 141(2) is amended to empower the Lieutenant Governor in Council to make regulations to define terms and expressions, to prescribe the area of a location, and to suspend certain obligations under the *Petroleum and Natural Gas Act* where study areas are established in which petroleum and natural gas exploration or development is not permitted.

The *Utilities Commission Act*[218] is amended by repealing ss. 133(2) which is the provision preventing the B.C. Utilities Commission from paying the costs of participants in proceedings before the commission and from ordering that costs of a participant be paid by another participant. A new section is enacted that allows the commission to order participants in proceedings before the commission to pay costs of other participants and gives the commission the discretion to pay participant costs itself. Participant costs paid by the commission must not exceed prescribed limits.

The *Geothermal Resources Act*[219] is amended with minor changes consequential to the repeal of definitions under s. 1 of the *Petroleum and Natural Gas Act*. Under s. 1, the definitions of "block" and "unit" are amended.

Section 7 of the *Geothermal Resources Act* and s. 10 to 23 of the *Petroleum and Natural Gas Act* were proclaimed in force on October 1, 1993. Sections 4 to 6 of the

[217] R.S.B.C. 1979, c. 323.
[218] S.B.C. 1980, c. 60.
[219] S.B.C. 1982, c. 14.

Energy Efficiency Act were proclaimed in force on December 2, 1993. Section 24 of the *Utilities Commission Act* was proclaimed in force July 23, 1993.

d. *Corporation Capital Tax Amendment Act*[220]

The relevant amendments to the *Corporation Capital Tax Act*[221] include extending exploration cost deductions to exploration for petroleum or natural gas, clarifying that deductions for exploration costs are available only if those costs have not been deducted under s. 14 for the taxation year in question, and permitting deductions for a corporation's proportionate share of specified partnership or joint venture amounts.

e. *Cabinet Appeals Abolition Act*[222]

This *Act* eliminates rights of appeal that had been in place with respect to certain ministerial decisions made pursuant to the following Acts: *Mineral Land Tax Act*,[223] *Mineral Tenure Act*,[224] *Natural Gas Price Act*,[225] and *Petroleum and Natural Gas Act*. Decisions of the responsible minister will continue to be subject to review under the *Judicial Review Procedure Act*.[226]

2. Regulations

a. *Energy Council Act*[227]
B.C. Energy Council Levy for the 1993/94 Fiscal Year Regulation[228]

A definition of energy is given in this regulation and provisions are made for each public utility to pay the Minister of Finance and Corporate Relations a levy in an amount equal, for the 1992 calendar year, to the public utility's energy expressed in gigajoules multiplied by $0.00132 per gigajoule. If the levy is less than $100, then the public utility need not pay the levy. The levy is payable in two instalments, and the council is authorized to collect a levy on behalf of the government and deposit it into the consolidated revenue fund to the credit of the Minister of Finance and Corporate Relations.

220 S.B.C. 1993, c. 10 (assented to 18 June 1993).
221 R.S.B.C. 1979, c. 69.
222 S.B.C. 1993, c. 38 (assented to 29 July 1993).
223 R.S.B.C. 1979, c. 260.
224 S.B.C. 1988, c. 5.
225 S.B.C. 1985, c 53.
226 R.S.B.C. 1979, c. 209.
227 S.B.C. 1992, c. 5.
228 B.C. Reg. 422/93 (deposited 17 December 1993).

b. *Energy Efficiency Act*[229]
Energy Efficiency Standards Regulation[230]

The old *Energy Efficiency Standards Regulation*[231] is repealed and this regulation substituted. Schedule 1 sets out products which are to be known as "energy devices". The schedule also sets out the standards to be adopted and prescribed for the energy devices as well as the commencement date for each product. In addition, this regulation sets out the persons and organizations designated to test and verify the energy devices. It establishes the labelling to be used and the placement of labels. However, it should be noted that there is an exemption to this regulation. The *Act* and the regulations do not apply to a person who manufactures in B.C. an energy device or anything that incorporates into it an energy device if that energy device or thing is manufactured for export from B.C.

c. *Mineral Land Tax Act*[232]
Regulation[233] Amending *Mineral Land Tax Adjustment Regulation*[234]

This regulation repeals various regulations relating to production revenue and mineral land tax assessment. It also amends the *Mineral Land Tax Adjustment Regulation* by repealing s. 4, which deals with a person objecting to being assessed as an owner of the mineral land, or to the amount of the assessment made against the mineral land or to the amount of mineral land tax payable by such person under the *Act*. Definitional provisions of the *Surrender of Interest in Mineral Land Regulations*[235] are also amended.

d. *Motor Fuel Tax Act*[236]
Regulation[237] Amending *Motor Fuel Tax Regulation*[238]

This repeals the definition of "authorized person" under s. 1. Further phrases and wording are amended dealing with "dye" and "leaded gasoline". A section was added to deal with suspensions and cancellations under the *Act*.

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229 *Supra* note 216.
230 B.C. Reg. 389/93 (deposited 1 December 1993).
231 B.C. Reg. 72/91.
232 *Supra* note 223.
233 B.C. Reg. 47/94 (deposited 11 February 1994).
234 B.C. Reg. 825/74.
235 B.C. Reg. 826/74.
236 S.B.C. 1985, c. 76.
237 B.C. Reg. 78/94 (deposited 18 March 1994).
238 B.C. Reg. 414/85.

e. *Natural Gas Price Act*[239]
Regulation[240] Amending *Natural Gas Price Act Regulation No. 2*[241]

The definition of "administration expenses" in s. 10 is amended and the formula contained in ss. 11(1) is changed.

f. *Petroleum and Natural Gas Act*[242]

(i) *Regulation*[243] Repealing *Oil and Condensate Price Reporting Regulation*[244]

This regulation repeals the *Oil and Condensate Price Reporting Regulation.*

(ii) *Regulation*[245] Amending *Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation*[246]

This regulation orders that the definition of "producer cost of service allowance" in s. 1 be amended to include processing natural gas for use as fuel.

(iii) *Regulation*[247] Amending *Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation*[248]

In addition to certain definitional changes, s. 5 is amended such that the royalty or tax exempt period approved under ss. 5(2), Item 1 is subject to a maximum exempt production.

(iv) *Regulation*[249] Amending *Petroleum and Natural Gas Drilling Licence Regulations.*[250]

Section 2 is amended by replacing ss. (4), (7) and (8) with provisions which allow the minister, on receipt of an application, to choose either to accept the application subject to the changes the minister directs be made, or to refuse the application. A drilling license must be issued to a person whose tender is accepted by the minister. The maximum number of units, quarter sections in the Peace River block, or units and quarter sections in the Peace River block combined must not exceed 144 in an application under this section. Under s. 3, new subsections are added dealing with the

239 *Supra* note 225.
240 B.C. Reg. 104/93 (deposited 30 March 1993).
241 B.C. Reg. 241/90.
242 *Supra* note 217.
243 B.C. Reg. 255/93 (deposited 23 July 1993).
244 B.C. Reg. 227/85.
245 B.C. Reg. 256/93 (deposited 23 July 1993).
246 B.C. Reg. 495/92.
247 B.C. Reg. 357/93 (deposited 29 October 1993).
248 *Supra* note 246.
249 B.C. Reg. 55/94 (deposited 25 February 1994).
250 B.C. Reg. 10/82.

extension of the expiry date of a drilling license to the date upon which the drilling of a well within the area covered by the drilling license is completed. Section 4 is amended by repealing ss. (2) and (3) and substituting new provisions dealing with when a licensee may terminate and how far a lease may extend when issued on the basis of an earning well.

A new section is added with the heading "Grouping of Drilling Licenses". This new s. 4.1 states that the commissioner must, on the written application of a licensee, approve the grouping of two drilling licenses as one drilling license if a licensee has drilled an earning well that is a gas well or a petroleum well within the area covered by one of the drilling licenses to be grouped, the commissioner receives the application before the earliest expiry date of the drilling licenses being grouped, and the distance between the location of the drilling licenses being grouped does not exceed four kilometres. Drilling licenses grouped under this section must be treated as one drilling license for the purposes of a lease application under s. 4. This section does not apply to an application to group a drilling license that has previously been grouped.

(v) *Petroleum and Natural Gas Grid Regulations*[251]

This petroleum and natural gas grid is to be used to determine the location in British Columbia of petroleum and natural gas tenures under the *Act*, geothermal resource tenures under the *Geothermal Resources Act*[252] and coal tenures under the *Coal Act*.[253] The petroleum and natural gas grid is defined by a set of universal transverse mercator map projection coordinates for the northeast corner of each unit, all as described in Schedule 3 of the regulation. The petroleum and natural gas grid unit coordinates are based on the North American Datum of 1983 ("NAD 83"), a system of latitudes and longitudes defined by the positions of provincial geodetic control monuments based on the international geocentric ellipsoid of revolution reference system titled "Geodetic Reference System 1980". Using these coordinates does not affect existing rights and recognizes the historical petroleum and natural gas grid using the North American Datum of 1927 system of latitudes and longitudes. A unit is an area defined by the coordinates given in Schedule 3. A block consists of 100 units. A group consists of twelve blocks identified by the letters "A" through "L". The coordinates of the Peace River block are established in Schedule 1. The petroleum and natural gas grid is issued and maintained by the Surveyor General Branch, Ministry of Environment, Land and Parks, and is available for inspection at the Surveyor General Branch.

251 B.C. Reg. 321/93 (deposited 22 September 1993).

252 *Supra* note 219.

253 R.S.B.C. 1979, c. 51.

g. *Pipeline Act*[254]
Regulation[255] Amending *Pipeline Regulations*[256]

Section 7 is repealed and substituted with new provisions dealing with the requirement for leave of the minister before a pipeline is opened for transportation of oil or gas. Section 22 is repealed and substituted with detailed provisions dealing with inspection of certain facilities.

h. *Waste Management Act*[257]
Regulation[258] Amending *Spill Reporting Regulations*[259]

The schedule was amended to deal with flammable gases other than natural gas and with certain pipeline breaks.

i. *Wildlife Act*[260]
Motor Vehicle Prohibition (Temporary) Regulation[261]

The roads set out in the schedules are designated as having restricted access for the purposes of wildlife management; however, the regulation does not apply to a person who uses or operates a motor vehicle for commercial purposes, industrial purposes or governmental purposes directly related to the development or operation of oil and gas tenures authorized by the province.

3. Evolving Matters

a. *Environmental Assessment Act*[262]

This *Act* is intended to establish an open, accountable, integrated and mutually administered process for the assessment of the environmental, economic, social, cultural and heritage effects of reviewable projects. The "reviewable projects" that will be subject to this assessment process are to be defined by regulations developed through a process of consultations with interested persons.

Under this *Act*, the proponent of a reviewable project must obtain a "project approval certificate" before constructing, operating, modifying, dismantling or abandoning the project. A proponent who receives such a certificate must carry out the project in accordance with the certificate.

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254 R.S.B.C. 1979, c. 328.
255 B.C. Reg. 173/93 (deposited May 26, 1993).
256 B.C. Reg. 451/59.
257 *Supra* note 213.
258 B.C. Reg. 166/93.
259 B.C. Reg. 263/90.
260 S.B.C. 1982, c. 57.
261 B.C. Reg. 59/94 (deposited 1 March 1994).
262 Bill 29, 3d Sess., 35th Parl., British Columbia, 1994.

This *Act* provides for participation in the assessment of reviewable projects by the public, project proponents, First Nations, municipal and regional districts, the provincial government and its agencies, the Government of Canada and its agencies and British Columbia's neighbouring jurisdictions.

Major development proposals in British Columbia are currently assessed by three separate processes. For mines, assessment is carried out under the *Mine Development Assessment Act*[263] which is being repealed by this *Act*. In the case of energy projects, assessment is carried out under part 2 of the *Utilities Commission Act*,[264] which is being consequentially amended by this *Act*. Other major industrial projects are assessed through the process generally known as the "Major Project Review Process". This Bill will amalgamate the existing processes into a single, comprehensive process.

b. *British Columbia Environmental Protection Act*[265]

The most recent draft of the *BCEPA* has been released to the public for discussion and input. Numerous revisions are expected prior to the proposed *Act* being introduced to the legislature.

D. SASKATCHEWAN LEGISLATION

1. Statutes

a. *The Corporation Capital Tax Amendment Act*[266]

The Corporation Capital Tax Act[267] is amended by adding an additional tax to be paid by a resource corporation with respect to each of its fiscal years. The tax is equal to the positive difference between a specified percentum of the resource corporation's value of resource sales in the fiscal years, 1988-1992 (2 percent), 1993 (3 percent), 1994 (3.6 percent), and the tax payable by the resource corporation.

b. *The Crown Minerals Act*[268]

The definition and application sections are amended to clarify the definition of "Indian Band", to entitle the Crown to transfer the administration and control of Crown mineral lands to Indian bands, and to enter into agreements with Indian bands with respect to these transfers.

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263 S.B.C. 1990, c. 55.
264 *Supra* note 218.
265 Draft (10 February 1994) [hereinafter *BCEPA*].
266 S.S. 1993, c. 24.
267 S.S. 1979-80, c. C-38.1.
268 S.S. 1984-85-86, c. C-50.2.

c. *The Freehold Oil and Gas Production Tax Amendment Act*[269]

This *Act* amends the *Freehold Oil and Gas Production Tax Act*[270] by imposing a tax on all freehold oil and freehold gas produced in Saskatchewan. The amendment also provides the minister with certain audit and inspection rights.

A new section (26.1) is added which entitles a taxpayer to appeal to the Board of Revenue Commissioners in respect of any act or thing done by the minister with respect to the assessment, calculation and payment of tax by a taxpayer. The regulations provision is amended such that regulations may be made respecting the calculation and payment of taxes on freehold oil and gas produced in Saskatchewan.

d. *The Mineral Taxation Repeal Act*[271]

This *Act* repeals *The Mineral Taxation Act.*[272]

e. *The Fuel Tax Amendment Act, 1994*[273]

This *Act* adds a new regulation making authority and a new section regarding interjurisdictional fuel tax programs and agreements. This latter provision entitles a minister to participate in arrangements or programs respecting the interjurisdictional administration and enforcement of the tax or similar taxes imposed by other jurisdictions inside or outside Canada, and to enter into agreements with the governments of those other jurisdictions for the purpose of more equitably applying and collecting the tax and similar taxes imposed by those other jurisdictions or of avoiding the duplicate application of the tax and similar taxes.

f. *Gas Inspection Act*[274]

This *Act* pertains to the inspection of gas installations and gas equipment.

g. *The Natural Resources Act*[275]

This *Act* relates to the acquisition, promotion, development, maintenance and management of the parks and natural resources of Saskatchewan, including the fish, wildlife, forests, resource lands and provincial forest lands, ecological reserves, and other lands.

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269 S.S. 1993, c. 25.
270 S.S. 1982-83, c. F-22.1.
271 S.S. 1993, c. 10 (proclaimed 4 May 1993).
272 R.S.S. 1978, c. M-17.
273 Bill 14, 4th Sess., 22d Leg., Saskatchewan, 1994 (assented to 28 March 1994).
274 S.S. 1993, c. G-3.2 (proclaimed 21 May 1993).
275 S.S. 1993, c. N-3.1 (proclaimed 21 July 1993).

h. *The NewGrade Energy Inc. Protection Act*[276]

This *Act* provides for settlement of disputes and the protection of NewGrade Energy Inc.'s ("NewGrade") financial liability. Financial liability is protected by requiring the Consumers' Cooperative Refineries Limited ("CCRL") and the Government of Saskatchewan to make equal cash payments to NewGrade whenever the minister considers that NewGrade has experienced or may experience a cash flow deficiency that may adversely affect its financial liability. The *Act* prescribes the amount, timing and manner of, and the terms and conditions governing, the payments made, including directing whether the cash payments are to be made by way of shareholder loans or by share purchases or otherwise. Directives are issued respecting the manner in which NewGrade shall use cash payments made to it. The *Act* also provides for remedies should CCRL fail to make a payment as noted above.

i. *The Oil and Gas Conservation Amendment Act*[277]

This *Act* amends the *Oil and Gas Conservation Act*[278] by providing for the winding-up of the Oil and Gas Revolving Fund. All assets and liabilities of the revolving fund are to be transferred at their book value to the consolidated fund as of April 1, 1993. The revolving fund ceases to exist after March 31, 1993. A transitional and annual report, and a financial statement showing the business of the revolving fund, must be submitted to the Minister of Energy and Mines for the fiscal year ending March 31, 1993.

j. *The Ozone-Depleting Substances Control Act*[279]

This *Act* repeals the *Ozone-Depleting Substances Control Act*[280] and provides for the prohibition of manufacturing, offering for sale, selling, packaging, and use of certain ozone-depleting substances (chlorofluorocarbons and halons). Provisions respecting the collection, recycling and disposal of ozone-depleting substances, prohibitions on the repair of certain equipment and provisions respecting regulations are included in this amendment. The *Act* provides for a fine of not more than $1,000,000, imprisonment of not more than three years or both for contravention of the *Act* or the regulations.

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276 S.S. 1993, c. N-4.02 (assented to 22 July 1993).

277 S.S. 1993, c. 35.

278 R.S.S. 1978, c. O-2.

279 S.S. 1993, c. O-8.1.

280 S.S. 1990-91, c. O-8.

k. *The Saskatchewan Natural Resources Transfer Agreement (Treaty Land Entitlement)*[281]

This *Act* amends *The Crown Minerals Act*[282] by entitling the Minister, on behalf of the Government of Saskatchewan, to enter into agreements with the Government of Canada or Indian bands or both with respect to the transfer of the administration and control of Crown minerals and Crown mineral lands.

l. *The SaskEnergy Amendment Act*[283]

This *Act* amends the "in lieu of taxes" provision of the *SaskEnergy Act*[284] by allowing the corporation to add to the monthly account of every customer, or of customers of a subsidiary in an urban municipality, an amount calculated in accordance with the regulations, and to pay the amounts collected to the urban municipality as a further payment in lieu of taxes. The liability provisions of the *Act* are amended such that no action or proceeding may lie against the corporation, its subsidiaries or any of their officers, directors, employees or agents for any injury, loss or damage to any person or property arising out of, or directly or indirectly resulting from the failure to supply, distribute or transport gas due to any cause, except failure by the corporation.

2. Regulations

a. *The Petroleum and Natural Gas Amendment Regulations, 1993*[285]
The Petroleum and Natural Gas Amendment Regulations, 1993 (No. 2)[286]

As a result of a significant policy change implemented by the Minister of Energy and Mines, the *Petroleum and Natural Gas Regulations*,[287] was amended. Effective January 1, 1994, new royalty initiatives include the introduction of a new "third tier" Crown royalty tax structure applicable to oil production from new, vertically drilled oil wells and to incremental production from new or expanded water flood projects. The royalty is price sensitive and applies differently to heavy and non-heavy oil. The third tier structure does not apply to horizontal wells.

The previously existing "royalty/tax holiday" incentive for vertically drilled oil wells was replaced by volume based "royalty/tax reduction" incentives. Changes were also made to horizontal drilling incentives and oil well reactivation programs. Qualifying exploratory natural gas wells are also entitled to certain royalty incentives.

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281 S.S. 1993, c. S-31.1.
282 S.S. 1984-85-86, c. C-50.2.
283 S.S. 1993, c. 38.
284 S.S. 1992, c. S-35.1.
285 S.R. 83/93 (filed 7 October 1993).
286 S.R. 110/93 (filed 22 December 1993).
287 S.R. 8/69.

b. *The Freehold Oil and Gas Production Tax Amendment Regulations*[288]

This regulation, made pursuant to the *Freehold Oil and Gas Production Tax Act*,[289] amends the *Freehold Oil and Gas Production Tax Regulations*[290] by providing new definitions and formulae necessary for royalty calculation.

A new section is added to allow the minister to estimate and to set prices for certain elements of royalty calculation. The calculation of tax date is amended from January 1, 1991 to November 1, 1993, and a new well tax rate is substituted.

c. *The Gas Inspection Regulations*[291]

These regulations, promulgated pursuant to *The Gas Inspection Act*,[292] regulate the certification and approval of gas equipment, and the standards for installations and obtaining of permits.

d. *The Hazardous Substances and Waste Dangerous Goods Amendment Regulations*[293]

This amendment regulates the operation of underground petroleum product storage tanks owned by farmers for their personal use and the operation of underground storage tanks used for hazardous substances. Exempted from the application of this regulation are pipelines, pipeline storage facilities and storage facilities regulated under the *Oil and Gas Conservation Act*.[294]

e. *The Mineral Disposition Amendment Regulations*[295]

This regulation, made pursuant to *The Crown Minerals Act*,[296] amends *The Mineral Disposition Regulations, 1986*,[297] by specifying which expenditures are included and which are excluded in the calculation of administrative and corporate expenditures.

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288 S.R. 84/93 (filed 7 October 1993).

289 *Supra* note 270.

290 S.R. 11/83.

291 R.R.S.C. G-3.2 Reg. 1, Sask. Gaz. 1994.II.146.

292 S.S. 1993, c. G-3.2.

293 S.R. 28/94 (filed 29 March 1994).

294 *Supra* note 278.

295 S.R. 99/93 (filed 17 November 1993).

296 *Supra* note 282.

297 S.R. 30/86.

f. *The Mineral Vesting Regulations, 1994*[298]

This regulation, made pursuant to *The Crown Minerals Act*,[299] vests certain mines and minerals in Camco Oil & Gas Limited.

g. *The Ozone-depleting Substances Control Regulations*[300]

This regulation, made pursuant to the *Ozone-depleting Substances Control Act*,[301] lists a number of prescribed ozone-depleting substances and makes regulations regarding their release, recovery and recycling.

II. REGULATORY DEVELOPMENTS

A. FEDERAL

1. National Energy Board

a. Decisions

(i) TransGas Limited Application for Review of Decision re: WBI Canadian Pipeline, Ltd.[302]

TransGas Limited ("TransGas") applied for a review and variance of the February 1993 NEB decision dismissing WBI Canadian Pipeline's ("WBI Canadian") application to construct an international gas transmission pipeline from North Portal, Saskatchewan to the United States border. In that decision, the NEB found the primary purpose of both the Steelman/North Portal Extension, proposed to be constructed by TransGas, and the WBI Canadian line was to deliver gas produced in Canada to the United States. Even though ownership of the two lines was separate, it was apparent that the lines were intended to be constructed and operated as one system. The NEB determined that the WBI Canadian line and the Steelman/North Portal Extension together constituted a federal work or undertaking properly within federal jurisdiction under the *Constitution Act, 1867*, and thereby within NEB regulation.

In its "Reasons for Decision" dated October 1993, the NEB denied TransGas' application for review on the basis of an error of law or jurisdiction. However, the NEB recognized the two separate, distinct and independent components of the overall project (*i.e.* the TransGas lateral and the WBI Canadian line) and agreed with WBI Canadian's position that since its line fell clearly within NEB jurisdiction and since all of the

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298 R.R.S. c. C-50.2 Reg 6, Sask. Gaz. 1994.II.133.

299 *Supra* note 281.

300 R.S.S. c. O-81, Reg. 1, Sask. Gaz. 1993.II (filed 20 July 1993).

301 S.S. 1993, c. O-8.1.

302 *In the Matter of TransGas Limited Application dated 23 April 1993 for a review and variance of a decision of the Board dated 25 February 1993 dismissing an application dated 9 October 1992 by WBI Canadian Pipeline Ltd.* (October 1993), No. GH-R-1-93.

requirements for approval had been met, the NEB could approve this pipeline. The NEB confirmed its earlier decision that once the new TransGas lateral was connected to the WBI Canadian line, it formed part of a federal work or undertaking subject to regulation by the NEB. Therefore, TransGas must obtain the appropriate authorizations under the *National Energy Board Act*[303] to construct, own and operate the extension. A work falls within federal jurisdiction if it is integral to a federal work or undertaking. Despite three important considerations — firstly, that mere physical connection does not trigger federal jurisdiction; secondly, that there was no corporate relationship between TransGas and WBI Canadian; and, thirdly, that the TransGas line is wholly within Saskatchewan — the NEB characterized the pipeline as an inter-provincial work or undertaking. Two of the six NEB members issued dissenting opinions, disagreeing with the decision of the majority concerning the NEB's jurisdiction over the Steelman/North Portal Extension.

Subsequent to the NEB's denial of TransGas' application, a commercial solution was negotiated which has allowed this project to proceed. From a practical standpoint, this decision (as well as the prior Altamont decision[304]) raises concerns over the economic implications for current and future inter-provincial or international undertakings. These transactions were originally intended to take advantage of the fact that both TransGas and NOVA Corporation of Alberta ("NOVA") operate their systems on a "rolled in, postage stamp" transportation rate basis. Consequently, construction costs of the respective laterals would have been rolled in to the overall rate base of these pipeline companies, and users of the laterals would simply pay the normal system-wide postage stamp rate for transportation on the lateral. The resultant reduced financial impact increases the economic attractiveness of the project from a shipper's point of view. If the laterals in question are forced to operate on a "stand-alone" tolling basis, they become much more expensive and may not be economical. One option utilized in the past to avoid such adverse economic consequences has been to have the upstream pipeline contract the entire capacity of the downstream facilities and roll these transportation costs into its overall revenue requirement in order to preserve the underlying economic justification for the project while at the same time satisfying the NEB's jurisdictional requirements.

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303 R.S.C. 1985, c. N-7.

304 *In the Matter of Altamont Gas Transmission Canada Limited Application dated 26 July 1991 for Gas Transmission Pipeline Facilities Preliminary Question of Jurisdiction* (February 1993), No. GHW-1-92.

(ii) Six Applications for Natural Gas Export Licenses[305]

In "Reasons for Decision" dated June 1993, the NEB considered a number of gas export license applications. The Speak-Up for Wildlife Foundation intervened in these proceedings and submitted that since the export applications would draw gas from a vast area of southern Alberta and northeastern British Columbia, a wide range of environmental concerns arose and must be taken into account. Citing paragraph 92(a) of the *Constitution Act, 1867*, which confers exclusive jurisdiction upon the provinces to legislate in relation to non-renewable resource exploration and development, the NEB decided that as a federal regulatory body it lacked jurisdiction to consider the environmental effects of the proposed exports on areas of natural gas development and production. Therefore, the NEB did not take these submissions into account in arriving at its final decisions.

The NEB considered applications from five companies for licenses to export natural gas. The NEB reduced Unigas Corporation's applied-for term volume by one-sixth, due to concerns over its ability to satisfy projected productive capacity shortfalls in the latter stages of the applied-for term. Otherwise, the export licenses were granted as requested.

(iii) CanWest Gas Supply Inc. and ProGas Limited Applications for Natural Gas Export Licenses[306]

In "Reasons for Decision" dated July 1993, CanWest Gas Supply Inc. ("CanWest") and ProGas Limited ("ProGas") applied for licenses to export natural gas, and ProGas further applied to amend an existing license. The NEB issued licenses to CanWest and ProGas, and amended the existing ProGas license by reducing the currently authorized volumes, as requested. ProGas applied for a 5 percent annual tolerance in order to obtain more flexibility and to possibly sell additional volumes during periods of tight supply; however, the NEB authorized only the traditional 2 percent annual tolerance approved for most export applicants. Tolerances are not intended to be used to sell additional volumes of gas. Rather, the daily and annual operating tolerances included in export licenses are intended to provide flexibility due to operational and measurement discrepancies.

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305 *In the Matter of Canadian Hydrocarbons Marketing Inc.; CanWest Gas Supply Inc; Enron Gas Marketing, Inc.; New York State Electric & Gas Corporation; Unigas Corporation Applications Pursuant to Part VI of the National Energy Board Act for Licences to Export Natural Gas* (June 1993), No. GH-7-92.

306 *In the Matter of CanWest Gas Supply Inc. Application Pursuant to Part VI of the National Energy Board Act for a Licence to Export Natural Gas; Pro Gas Limited Application Pursuant to Section 21 and Part VI of the National Energy Board Act to Amend a Licence to Export Natural Gas and for a Licence to Export Natural Gas* (July 1993), No. GH-3-93.

(iv) TransCanada PipeLines Limited Facilities Application[307]

In "Reasons for Decision" dated September 1993, the NEB approved TransCanada PipeLines Limited's ("TCPL") application to expand its natural gas pipeline system in western and central Canada during 1994 and 1995. The proposed facilities sought by TCPL included 164.4 kilometres of new pipeline loop across the system, 129 megawatts of compression equipment, two after-coolers, one meter station and compression-related items, including aero assemblies and standby plants —at an estimated capital cost of $397.3 million. The NEB, in approving TCPL's application, was satisfied that the applied-for facilities were required by the present and future public convenience and necessity. The NEB acknowledged the economic feasibility of the proposed expansion, emphasizing the likelihood of the facilities being used at a reasonable level over their economic life and, further, finding that demand charges would likely be paid. TCPL's expansion will enable the provision of new long-haul firm service for both existing domestic service and two new export services. Further, the proposed expansion will afford new short-haul firm service for export customers. The NEB attached conditions to the certificate mandating that only those facilities needed to meet aggregate firm service requirements should be built and that construction must occur in an acceptable technical and environmental manner. The NEB required TCPL to demonstrate, prior to the release of facilities for construction, that the proposed design was still the optimal design, given developments that may have taken place since the approval of the facilities. The environmental screening conducted by the NEB in compliance with the Environmental Assessment and Review Process Guidelines Order ("EARP Guidelines Order")[308] indicated no significant or unmitigable environmental effects.

The NEB, in accepting the sufficiency of the overall gas supply capability, expressed significant reservations with respect to the ability of the gas supply capability model prepared by Sproule and Associates to accurately assess the capability of the western Canada sedimentary basin to respond to an imposed level of gas demand, noting that Sproule's supply estimates were consistently higher than the NEB's supply estimates. The NEB accepted TCPL's projections for natural gas consumption in eastern Canada and the United States northeast and midwest markets as sufficient to support the facility's construction. The NEB reviewed both the reserves and productive capacity and was satisfied with the supply arrangements outlined for both domestic and export shippers. The certificate was issued conditional on TCPL providing assessments (prepared in consultation with shippers) on the impacts of the New York State Public Service Commission's examination of the curtailment provisions in power purchase agreements between state utilities and various cogeneration developers, as well as, Federal Energy Regulatory Commission Order 636,[309] requiring the restructuring of the U.S. interstate pipeline industry. Order 636 is the final step in moving the U.S.

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[307] *In the Matter of TransCanada PipeLines Limited Application dated 18 December 1992, as amended 26 March and 28 May 1993 for 1994 and 1995 Facilities* (September 1993), No. GH-2-93.

[308] SOR/84-467.

[309] 59 F.E.R.C. (1992), para. 61,030.

interstate pipeline industry from being highly regulated to being more market-oriented, characterized by non-discriminatory open-access transportation.

Environmental and directly related social effects were considered concurrently under two separate processes: (1) a project review pursuant to the NEB's mandate under Part III of the *Act*; and (2) an environmental screening of the application pursuant to the EARP Guidelines Order.

While satisfied with the environmental information provided by TCPL, the NEB required that TCPL submit the results of plant and wildlife surveys to the NEB for its review at least ten days prior to the commencement of construction. Additionally, the NEB conditioned the certificate so as to ensure adherence to those environmental protection measures and undertakings, and to ensure that unresolved issues are addressed prior to construction.

(v) Foothills Pipelines Ltd. Application Respecting Tolls and Tariffs[310]

In "Reasons for Decision" dated November 1993, the NEB approved a rate of return on common equity of 11.5 percent for Foothills Pipelines Ltd. ("Foothills"). Foothills had initially applied for a 13 percent return, but subsequently reduced its request to its previously approved rate of 12.5 percent. The NEB also approved a common equity ratio for Foothills of 28 percent. Foothills had applied for 35 percent, despite it having operated since 1981 with an approved common equity component of 25 percent, plus or minus 5 percent. Foothills justified the requested increase on the basis of changes in its business risk over this period.

Of primary interest in this decision is the dissenting opinion of Board Member Andrew, who differed with the majority's finding with respect to the capital structure and the rate of return on common equity. The NEB has traditionally avoided directly comparing toll applicants with the currently approved parameters for other pipelines, in order to avoid unwarranted increases premised solely upon such a circular comparison which in turn could unduly influence subsequent applications. In this case, the two main interveners submitted that an assessment of Foothills' business risks requires two comparisons: (1) a comparison of the current business risk of the pipeline to its risks at the time of its last toll proceeding; and (2) a comparison of Foothills' risks relative to other Canadian gas pipelines. The majority opinion relies on the historical comparison and places little weight on the inter-pipeline comparative analysis. Mr. Andrew was of the view that a common equity ratio of 28 percent may be insufficient to ensure Foothills the required flexibility to manage its debt. He stated that in his view Foothills' business risks are not significantly different from those of TCPL, Alberta Natural Gas Company or NOVA (all of which have a common equity ratio of 30 percent), and that evidence had been led at the hearing to the effect that all gas pipelines have about the same minimal risk. In his view the majority did not effectively

[310] *In the Matter of Foothills Pipelines Ltd. Application dated 28 May 1993 for Certain Orders Respecting the Tolls and Tariffs of Foothills Pipelines Ltd.* (November 1993), No. RH-1-93.

balance the interests of both the tollpayers and the pipeline companies. The consequences of the majority decision *vis à vis* the dissenting position was a loss of several million dollars in returns for Foothills. In Board Member Andrew's opinion this amounted to an unjustifiable imposition by the NEB on the business affairs of Foothills.

Foothills filed an "Application for Review" with the NEB, seeking a reversal of the NEB's aforementioned decision as it related to the appropriate deemed common equity ratio for the company. Foothills concurrently filed an "Application for Leave to Appeal" with the Federal Court of Appeal in order to preserve its rights to pursue this route should it be necessary. By its "Reasons for Decision" dated April 22, 1994, the NEB denied Foothills' review application and found that it had not presented sufficient evidence to warrant a review.

(vi) Interprovincial Pipeline Inc. Application for Expansion Facilities and Toll Methodology[311]

In its "Reasons for Decision" dated December 1993, the NEB accepted Interprovincial Pipeline's ("IPL") position with respect to available supply, market demand, reasonable use and significant need, as well as the location, safety and environmental soundness relating to the construction and operation of the facilities. This proceeding was initially established as a competitive proceeding between the IPL application and an alternative project by Express Pipelines Ltd. ("Express"). However, on the eve of the public hearing Express withdrew its proposed pipeline application, primarily due to numerous large producers coming out in support of IPL's application.

(vii) Brooklyn Navy Yard Cogeneration Partners *et al.* Export License Application[312]

In "Reasons for Decision" dated February 1994, the NEB approved export license applications by Brooklyn Navy Yard Cogeneration Partners, L.P. ("Navy Yard Partners"), Husky Oil Operations Ltd. ("Husky"), ProGas, Western Gas Marketing Limited ("Western Gas") and Shell Canada Limited ("Shell"). The NEB curtailed the term-volume associated with the Shell license due to concerns over the gas reserves and deliverability put forth in support of the application.

The most significant aspect of this case involved the NEB's findings regarding the potential environmental effects associated with granting the subject export licenses. The NEB found that the ProGas, Shell and Western Gas applications did not require the

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[311] *In the Matter of Interprovincial Pipeline Inc. Application for Expansion Facilities and Toll Methodology dated 24 June 1993, as amended 17 September and 11 November 1993* (December 1993), No. OH-1-93.

[312] *In the Matter of Brooklyn Navy Yard Cogeneration Partners, L.P.; Husky Oil Operators Ltd; ProGas Limited; Shell Canada Limited; Western Gas Marketing Limited Applications Pursuant to Part VI of the National Energy Board Act for Licences to Export Natural Gas and, ProGas Limited Applications Pursuant to Section 21 and Part VI of the National Energy Board Act to Amend Two Licences to Export Natural Gas* (February 1994), No. GH-5-93.

development of new gas transmission facilities and, as such, fell within the ambit of note 3 of the NEB's list of Automatic Exclusions pursuant to the EARP Guidelines Order.

The export proposals by Navy Yard Partners and Husky required new facilities on existing TCPL and Westcoast Energy Inc. ("Westcoast") pipeline systems, respectively. However, the NEB determined, pursuant to *Quebec Attorney General* v. *Canada (National Energy Board)*[313] ("Hydro Quebec Decision"), that its jurisdiction in the environmental screening of gas exports was limited to the actual export and did not extend to upstream environmental matters. Although the Hydro Quebec Decision dealt with the export of electricity, the NEB considered its jurisdiction to authorize gas exports to be equivalent to the jurisdiction to authorize electricity exports.

Despite argument by the Rocky Mountain Ecosystem Coalition ("RMEC"), the NEB refused to consider evidence relating to the causal relationship between the subject exports and upstream environmental effects. The NEB found that such upstream environmental matters are properly dealt with in other forums and that the RMEC's concerns did not represent the level of public concern necessary to refer the export applications to the Minister of the Environment.

Subsequent to the hearing, the Supreme Court of Canada in *The Grand Council of the Crees (Quebec)* v. *Canada (Attorney General)*[314] reversed the Hydro Quebec Decision and determined that the NEB's jurisdiction over exports can extend to the facilities used for the production of the goods for export. The Supreme Court of Canada held that the Court of Appeal erred in limiting the scope of the NEB's environmental inquiry. If new facilities are required, the environmental effects of construction are related to the export and the NEB appropriately ought to consider the environmental effects of the source of the export product. No specific constitutional question with respect to subparagraph 92(a)(i) of the *Constitution Act, 1867* was put before the Court; however, the distribution of powers between provincial and federal governments was discussed generally. The Court held that the NEB may consider the environmental effects within a province which are relevant to its decision under the federal jurisdiction to grant an export license.

The NEB, based on a review application by the RMEC that the Supreme Court decision constitutes a change in circumstances, has decided to conduct a review of its decisions regarding these exports, as it relates to the upstream environmental effects associated with the applied-for natural gas export applications. The review proceeding is ongoing at this time and it is clear that this case will establish the environmental criteria to be applied by the NEB in this, and future, export license cases.

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313 [1991] 3 F.C. 443 (C.A.).

314 [1994] 1 S.C.K. 159.

(viii) Westcoast Energy Inc. Application for New Tolls[315]

In its "Reasons for Decision" dated March 1994, the NEB considered Westcoast's toll application. The NEB approved uniform final tolls throughout 1994 and directed Westcoast to refund or recover toll variations from those approved on an interim basis by Order TGI-5-93.[316] The NEB directed Westcoast to remove from its applied-for Gas Plant In Service the forecast amount for projects which were either denied or not yet approved. The NEB accepted Westcoast's 1994 forecast inventory level for inclusion in the rate base, and reduced Westcoast's cash working capital allowance by approximately $5.5 million, while allowing a cash working capital allowance of $1 million to cover GST. In determining the appropriate capital structure, the NEB was guided by the business risks posed by the company's utility operations, the maintenance of an appropriate balance between the debt and equity elements of the deemed capital structure, and the determination that sufficient actual equity is left to non-utility activities, having regard to the equity financing attributed to the utility through the deeming process. The NEB approved a deemed common equity ratio of 35 percent for the 1994 test year; however, Board Member Illing stated that the analysis of changes to Westcoast's risks over a longer time horizon was inadequately examined and should be more vigorously pursued in future proceedings. He found insufficient evidence to support a conclusion concerning differences and risks between Westcoast and TCPL. In approving operating and maintenance expenses in the amount of $126 million, the NEB noted that "when inefficiencies affect Westcoast's costs of operating the utility, then it becomes the business of the National Energy Board and its shippers."[317] The NEB, however, found no evidence to suggest that Westcoast had engaged in discriminatory hiring and, further, no evidence that hiring practices had an adverse impact upon Westcoast's costs.

(ix) InterCoastal Pipeline Inc. and Interprovincial Pipeline Inc.[318]

By application dated June 29, 1993 (as amended October 29, 1993) InterCoastal Pipeline Inc. ("ICP") applied to the NEB for an order approving the purchase of crude oil pipeline facilities from IPL and an order allowing it to convert those facilities from crude oil to natural gas service. In addition, ICP applied for a Certificate of Public Convenience and Necessity and a related order in respect of new facilities that would have to be constructed. The cost of the project was estimated to be $46.6 million. The natural gas pipeline, to be located in southern Ontario, would be capable of transporting up to 175 MMcf/d from the ANR Pipeline Company facilities at the international border near Sarnia to an interconnection with Consumers' Gas Company ("Consumers'"). The project was intended to provide an alternative means of delivering

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315 *In the Matter of Westcoast Energy Inc. Application dated 14 July 1993, as amended, for New Tolls effective 1 January 1994* (March 1994), No. RH-2-93.

316 *Ibid.* at 53.

317 *Ibid.* at 37.

318 *In the Matter of InterCoastal Pipeline Inc. and Interprovincial Pipeline Inc. Applications dated 29 June 1993, as amended 29 October 1993, for New and Converted Facilities in Southwestern Ontario* (April 1994), No. GH-4-93.

Canadian and US-sourced natural gas to markets in eastern Canada and the northeast United States. Consumers' had contracted for substantially all of ICP's capacity through to the year 2009, subject to renewal and ICP's right to partially reduce Consumers' capacity after year two. Consumers' intended to use the transportation capacity to access alternate supply sources to serve its existing and projected market requirements.

While the NEB was satisfied with the proposed route of the line, the insignificance of environmental and socio-economic impacts, the adequacy of gas supply, markets and transportation arrangements, and the appropriateness of tolls and tariffs, it had serious concerns about certain technical matters and the related public safety. On the basis of these latter concerns the NEB denied ICP's application.

During the hearing, the NEB focused on a number of technical aspects of the project. It noted that the safety standards set for natural gas pipelines (the CAN/CSA Z184-M92 Gas Pipeline Systems Code — "CSA Z184") did not specifically address conversions of a crude oil pipeline to a natural gas pipeline. However, the NEB concluded that these standards could be used as a guide in determining the suitability and safety of the proposed pipeline conversion. As ICP had to make a number of judgments and engineering assessments based on its interpretation of the intent of the CSA Z184 code, the NEB conducted a thorough review of the technical aspects of ICP's proposed conversion. It was noted that this was the first federally regulated line to be converted from oil to high pressure natural gas service. The NEB accepted ICP's approach to use the CSA Z184 code as a guide, and where explicit requirements did not exist or could not practically be applied, to conduct engineering assessments to ensure a level of safety at least equivalent to that contemplated by the code. In that regard, ICP supported its case with expert evidence about the code, the properties and integrity of the steel pipe in natural gas service, anticipated soil and pipe temperatures and the integrity of the line under the proposed operating conditions. On several key issues, the NEB was not persuaded by ICP's evidence that the public safety, having regard to the available technology, could be adequately protected.

Specifically, ICP was unable to persuade the NEB that its 0° celsius design temperature was sufficient. Canadian pipelines typically use -5° celsius as a minimum design temperature and even this minimum was considered by the NEB to be conservative. Further, the NEB had reservations about certain data presented by ICP which allegedly supported the use of the 0° celsius temperature. Even with a 0° celsius design temperature, two loops of pipe did not have sufficient toughness to arrest a fracture. Although ICP's proposal to use crack arrestors to address this problem was viewed as a novel approach, the NEB was prepared to consider such a method. However, ICP had not provided an expert on hazard assessment and the NEB could not be satisfied that the use of crack arrestors provided adequate protection.

In addition, ICP encountered some difficulty with respect to the construction of new facilities. After conducting the early public notification process (which requires a proponent to advise affected local residents of a proposed project), ICP changed its plans with respect to the routing of the new facility. The new route would have implications for people who were not involved in the earlier public process. The NEB also had concerns about the unusually large number of incidents of errors and misunderstandings between land owners and ICP. For these reasons, the NEB suggested that there was considerable scope for improvement in ICP's routing and land acquisition practices. With respect to one segment of the facilities proposed to be constructed, the NEB found that the evidence filed by ICP was not adequate to support a finding that the route should be considered as the preferred route.

The appropriateness of many aspects of ICP's proposed toll design methodology and tariff were questioned during these proceedings. It appeared that the proposals, while quite unique, were designed to make the project attractive to Consumers'. Otherwise the project would not be marketable. Despite the concerns expressed by a number of parties, the NEB approved ICP's proposed tariff and toll methodology. The NEB emphasized that Consumers' was ICP's only customer and was well able to protect its own interests. On that basis, the NEB also agreed that ICP would be regulated on a complaints basis. More specifically, the NEB approved of a number of unique tolling practices that had been agreed to by Consumers' and ICP. For example, the capital structure and rate of return had been agreed to for the life of the project. In addition, the NEB approved a Reverse Sum of the Years Digits ("RSYD") depreciation methodology. This RSYD methodology resulted in a gradual increase in depreciation charges throughout the term of the project and shifted greater costs to future users. However, it did result in minimal initial toll impacts and provided a greater degree of toll stability. As it did throughout its consideration of tolling issues, the NEB deferred to the agreement of the pipeline and its only customer, allowing each party to bear its own risks.

While the NEB was satisfied with the economics of the project, finding that the need for the facilities was justified, that the costs were appropriate and that there was adequate gas supply to ensure the long-term utilization of the proposed facilities, the NEB rejected ICP's application stating as follows:

> In discharging its responsibilities under section 52 of the Act, the Board must consider all factors that to it appear relevant. Of the many considerations which must be weighed in determining the public interest, public safety, having regard to the available technology, is primary. InterCoastal has put forward its proposal in recognition of the primacy of public safety and in the belief that it achieved a design which is suitable and safe. InterCoastal's proposal raised complex and difficult issues. On many issues the Board has been persuaded by the evidence marshalled by InterCoastal. However, on several key issues the Board has not been persuaded by InterCoastal's evidence. The applications to convert the Existing Segment to natural gas service and to construct new facilities, which includes the segment [in which there were public notification problems], are therefore denied.[319]

As these applications were central to the project, the NEB did not deal with the associated applications relating to the transfer of the ownership of the crude oil pipeline. Further, because the applications were rejected, the NEB did not need to perform a screening under the EARP Guidelines Order. In some respects, it is

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319 *Ibid.* at 113.

surprising that the NEB chose to deal with the toll and tariff issues given its decision to deny the facilities.

In conclusion, the NEB stated as follows:

> The Board is cognizant of ICP's evidence suggesting that revisions to its design could jeopardize the economic viability of the project. The foregone benefits are not matters the Board has taken lightly in arriving at its decision. However, the Board has a responsibility which is primary, and that is to satisfy itself that the safety of the public is ensured.[320]

(x) Trans Mountain Pipeline Company Limited Application for 1993 and 1994 Tolls[321]

Following a complaint by the Canadian Association of Petroleum Producers ("CAPP") regarding certain aspects of Trans Mountain Pipeline Company Limited's ("Trans Mountain") proposed tolls for 1993 Trans Mountain filed an application for 1993 and 1994 tolls on September 30, 1993. This toll application was prepared under the assumption that certain expansion facilities for which approval would shortly be requested, would ultimately be approved by the NEB. On February 7, 1994 the NEB released its decision regarding Trans Mountain's application, with complete "Reasons for Decision" being issued in March 1994. In its decision the NEB directed Trans Mountain to remove from the applied-for plant-in-service forecast amounts for projects which had been denied or which had not been approved by the NEB at this time. While the NEB accepted Trans Mountain's depreciation rates for the 1993 and 1994 test years, it directed Trans Mountain to carry out a depreciation study and file it with the NEB by March 1, 1995. The NEB also approved the requested number of person years, the year over year salary increase and the amount of employee benefits for the 1993 and 1994 test years. While the NEB found that the existing methodology for allocating costs to non utility activities continued to be appropriate it did disallow 50 percent of the severance payments to the former Chief Executive Officer of Trans Mountain. The NEB directed Trans Mountain to convert the method under which it calculates its provision for income taxes from the normalized to flow through method. However, the NEB did not direct any drawdown of the accumulated deferred income tax balance at this time. The NEB approved a continuation of a deemed common equity ratio of 47.5 percent for the 1993 and 1994 test years. In its application Trans Mountain had requested a rate of return on common equity of 12.75 percent for 1993 and 12.5 percent for 1994. The NEB approved rates of return of 11.5 percent and 11.25 percent for 1993 and 1994, respectively.

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320 *Ibid.*

321 *In the Matter of Trans Mountain Pipeline Company Ltd. Application dated 30 September 1993 for New Tolls effective 1 January 1993 and 1 January 1994* (March 1994), No. RH-3-93.

(xi) Trans Mountain Pipeline Company Limited Facilities Application[322]

In its "Reasons for Decision" dated April, 1994 the NEB approved Trans Mountain's application to expand its oil pipeline facilities in western Canada. Trans Mountain's application included the reactivation of an eighty-one kilometre pipeline loop, the construction of a new pump station, modification to a number of existing pump stations and the installation of additional facilities at the company's Sumas tank farm. The expansion would permit Trans Mountain to ship an additional 6,000 cubic meters per day of product through its pipeline system. The estimated cost of the project was $27.5 million. The NEB found that adequate supply and market existed to justify approval of the project. In light of the minor amount of new facilities that would be required to accommodate this expansion, the NEB found that the environmental effects of the proposed facilities would be insignificant or mitigable with known technology. The NEB found that since the proposed expansion was designed to increase the transportation capacity of the existing mainline system the facilities should be tolled on a rolled-in basis.

(xii) TransCanada Pipelines Limited — 1994 Tolls[323]

By application dated July 8, 1993 TCPL applied to the NEB for approval of tolls effective January 1, 1994. The NEB conducted a public hearing into this application in February and March 1994. TCPL also put forth a controversial "renewals" tolling proposal. In brief, TCPL proposed a series of premiums and discounts to an established "base toll", depending upon the length of the Firm Transportation Service Agreement ("FS Contract") held by a particular shipper and the duration of the renewal notice (ranging from eighteen down to six months) provided to TCPL by shippers whose FS Contracts were expiring. These toll premiums and discounts would be paid by all shippers on the system.

Under TCPL's current tariff a shipper holding an FS Contract can, over time, allow the remaining term of that agreement to reduce to one year and, thereafter, retain its firm service entitlements on an evergreened year over year basis by providing TCPL with notice of its intention to renew not less than six months prior to the end of the contract.

Another significant issue which arose during the course of this debate was whether or not TCPL possessed a unilateral right to suspend the renewal rights of a firm service shipper, despite the objection of that shipper.

TCPL proposed to implement a queue entry fee, such that requests for service must be accompanied by a cash deposit in the amount of one times the daily demand charge for the service and volume requested, to a maximum of $10,000. If the applicant is

322 *In the Matter of Trans Mountain Pipeline Company Ltd. Application dated 29 October 1993 for Stage 2 Expansion Project* (April 1994), No. OHW-1-93.

323 *In the Matter of TransCanada Pipelines Limited Application dated 8 July 1993, as amended, for New Tolls effective 1 January 1994* (June 1994), No. RH-4-93.

accepted into the queue, this deposit would be credited against the first month's firm transportation service charges. If the application for entry into the queue is declined the deposit would be returned. In either case no interest would be payable on the amount provided to TCPL. The deposit would be forfeited if the service applicant is removed from the contract year queue if, for example, it is offered the service and declines to accept it.

TCPL also requested that the NEB approve a return on equity of 12.375 percent on a deemed capital structure including 30 percent common equity.

B. ALBERTA

1. Energy Resources Conservation Board

a. Decisions

(i) NOVA Corporation of Alberta Western Mainline Additions[324]

NOVA applied for the approval of various facilities for proposed mainline additions to its Western Mainline. In approving the application, the ERCB identified the following issues:

(1) the relationship of the current facility applications to other regulatory procedures;
(2) the need for the facilities;
(3) the possible adverse effects of the facilities; and
(4) the need for conditions relating to size and timing of the facilities.

While the ERCB agreed that those affected by the proposed facilities ought to have expressed their concerns at the earliest opportunity, it found that a delay in doing so should not deprive such parties of the opportunity to address outstanding issues, which remain unresolved throughout the complicated review and approval process. The ERCB also stated that it views applications for facilities as separate and distinct from applications to remove gas from the province. Therefore, applications to remove gas from the province are assessed on their own merits against the test of overall public interest and the ERCB will not give weight to arguments that removal permits are required because of previous facilities commitments.

With respect to the need for the facilities, the ERCB stated that private contractual arrangements between the parties are only one consideration, albeit a persuasive one, in relation to the need for the proposed facilities. Apart from contractual arrangements, the ERCB looks to gas supply and the ability of the market to absorb the gas in a reasonable time frame. The ERCB did not consider the reported delivery shortfalls

[324] *NOVA Corporation of Alberta Permits to Construct Additional Facilities on NOVA Western Mainline* (2 March 1993), No. D93-1.

experienced by NOVA as a reflection of inadequate provincial gas supply, noting it is unlikely that all volumes contracted to move in the new facilities would be delivered under long-term contracts. It was realistic to expect that the gas would be delivered under both long- and short-term contracts, including some volumes of spot gas.

With respect to possible adverse effects of the facilities, the ERCB was satisfied that Alberta gas would remain competitive in the California market, taking a neutral stance with respect to increasing competition in that market and reiterating its unwillingness to limit competition through regulatory action. The ERCB held that the proposed facilities are technically and environmentally satisfactory and declined to approve only a portion of the facilities, as significant incremental capacity could be added at little cost by approving the entire applied-for facilities.

(ii) Northwestern Utilities Limited Review Application[325]

Northwestern Utilities Limited ("NUL") applied for a review and variance of the ERCB's decision to approve applications by the Imperial Pipeline Company ("Imperial") and Esso Resources (1989) Limited to convert a portion of the Edmonton - Sundre Expansion Pipeline ("ESEP") from blended crude bitumen to natural gas service.[326]

In denying NUL's request, the ERCB considered: (1) whether the facilities to reconfigure the Imperial pipeline system were related to the ESEP conversion, and whether such facilities undermined the cost effectiveness of crude movements to Montana; and (2) the merits of the alternate service offered by NUL, to the extent that such service was varied from the original offer by NUL.

The ERCB was satisfied that additional costs were a business risk assumed by Imperial alone and would not be rolled into pipeline tariffs or absorbed by third-party producers. If ESEP were not converted to gas service, it could be available for other service and result in fewer facilities needed in the overall Imperial system reconfiguration. The ERCB was satisfied that the proposed facilities related to changes in light crude oil delivery requirements, and would not undermine the cost effectiveness of crude movements to Montana.

Further, with respect to NUL's submission that it could provide alternate service, the ERCB acknowledged that Imperial's reluctance to specify its long-term strategic business interests made it unlikely that a suitable alternative to the ESEP conversion

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325 *Proceeding Resulting from a Request by Northwestern Utilities Limited for the Board to Review Decision D91-6 Pursuant to Section 42 of the Energy Resources Conservation Act* (29 March 1993), No. D93-4.

326 *Applications by the Imperial Pipeline Company Limited/Esso Resources (1989) Limited to Change Substance in the Edmonton to Sundre Pipeline from Blended Bitumen to Natural Gas and for Associated Pipeline Facilities and Connections; Application by Northwestern Utilities Limited to Reconsider Approval of Federated Pipelines Limited Natural Gas Liquids Pipeline* (13 August 1991), No. D91-6.

would be negotiated. The ERCB's responsibilities justify overruling such disparate corporate preferences where it is clearly within the public interest. In this case, absent significant public interest aspects, such as harmful environmental impact or unnecessary public expenditures, the issue of suitable alternative service ought to be resolved between parties.

(iii) Amoco Canada Petroleum Company Ltd. *et al.* Facilities Application[327]

Amoco Canada Petroleum Company Ltd. ("Amoco"), Imperial and Koch Pipelines Ltd. ("Koch") sought approval to construct pipelines and related facilities to transport crude oils, condensate and blended bitumen between Sundre and Edmonton. The ERCB was satisfied that all technical, environmental and landowner concerns were sufficiently addressed by the applicants and that the only remaining relevant issue was the need for the pipelines. The conversion of Conoco's Billings Refinery from light to heavy crude, the shut-down of Turbo's Balzac Refinery, and the start-up of Shell's Caroline Gas Plant prompted significant alteration to crude movements from southern Alberta. In granting the applications, the ERCB was satisfied of the increased need to ship oil and condensate north to Edmonton and agreed that segregation of sweet and sour crude oil would benefit producers.

(iv) Chancellor Energy Resources Inc. Application for Sweet Gas Plant[328]

Chancellor Energy Resources Inc. ("Chancellor") received ERCB approval No. 7112 to construct and operate a sweet gas processing plant east of Olds. Amerada Hess Canada Ltd. ("Amerada") intervened to request a hearing. Amerada, as a sour gas plant owner in the area, submitted that it was an affected party and identified an alternative proposal for processing and delivering the gas to a sales pipeline.

The central issue identified by the ERCB was plant proliferation and whether the approval of the new plant would be in the public interest. Beside surplus processing capacity, the ERCB must have regard for:

(1) public concerns about the proposal;
(2) environmental impacts;
(3) economics of a new plant compared to using an existing plant; and
(4) overall public interest.

No public concerns were at issue and environmental concerns did not favour one proposal over the other. The economics of the two options were slightly in favour of Chancellor proceeding with its own plant, and it was not in the overall public interest

327 *Applications by Amoco Canada Petroleum Company Ltd., The Imperial Pipeline Company, Limited and Koch Pipelines Ltd. for Permits to Construct Crude Oil/Condensate/Blended Bitumen Pipelines and Related Facilities in Sundre/Edmonton Areas; Application by Northwestern Utilities Limited for a Review and Variance of Decision D91-6* (3 May 1993), No. D93-5.

328 *Chancellor Energy Resources Inc. Application to Construct and Operate a Sweet Gas Processing Plant in the Stewart Field* (19 May 1993), No. D93-6.

to deny the Chancellor application. The ERCB concluded that absent significant resource conservation, correlative rights, public interest or environmental concerns, involvement in the business decisions of oil and gas producers is unwarranted.

(v) Shell Canada Limited Application to Expand Shantz Storage[329]

Shell applied to expand its sulphur block storage area at the Shantz Sulphur Facility and to transport sulphur from other producing plants for storage at Shantz. In approving Shell's application the ERCB focussed on the following issues:

(1) need for additional sulphur storage;
(2) options to storing sulphur at Shantz;
(3) environmental impacts of storing sulphur at Shantz; and
(4) future storage needs and transfer of sulphur from other plants.

Due to a world surplus of sulphur, Shell's only alternatives to storing additional sulphur at Shantz were to shut-down the Caroline Gas Plant or to find another site to store the sulphur. Construction of additional sulphur storage facilities at Shantz was necessary. Despite intervenors' concerns with respect to the reliability of world market forecasts and the effects of long-term sulphur storage, the ERCB allowed an increase in block storage of sulphur as well as the trucking of sulphur from other plants to Shantz. Shell reiterated its continued commitment to maintain environmental testing, safeguards and public awareness. The ERCB found that in the absence of a requirement by Alberta Environmental Protection in its "Clean Air and Water Licenses", a textile liner was not required for the subject facilities. The ERCB noted environmental protection measures at Shantz exceed normal standards for sulphur storage.

(vi) Ranchmen's Resources Ltd. *et al.* Facilities Application[330]

Ranchmen's Resources Ltd. ("Ranchmen's") sought approval to continue the operation of a capped gas well and to construct production facilities and pipelines from the surface location to existing pipelines. The ERCB considered the following issues:

(1) the need for the well, production facilities and pipelines;
(2) the testing of a second, potentially productive zone in the well;
(3) the impact of the well, production facilities and pipelines;
(4) the safe operation of the facilities; and
(5) communications among all parties.

The ERCB took interveners' concerns into account, but determined that the well could continue to operate and that the production facilities and related pipelines could

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329 *Shell Canada Limited Application to Expand Block Storage at Shantz Sulphur Facility SW 1/4-35-31-4 W5M* (5 January 1994), No. D93-7.

330 *Ranchmen's Resources Ltd. Reopening of Hearing of Application No. 901312 Applications for Approval to Construct and Operate Wellsite Facilities, Permits to Construct Pipelines; Knopcik Field* (24 November 1993), No. D93-8.

be operated safely with minimum impact. The holder of a mineral lease has the right to develop underlying reserves established in commercial quantities. All necessary consents and easements were obtained with respect to the production facilities and related pipelines and the need for the associated facilities was established. ERCB approval was subject to sufficient mitigation efforts and proper oilfield practices by Ranchmen's. Further testing operations were required, but did not represent a nuisance or hazard to the interveners. While the ERCB recognized that the interveners chose a lifestyle to insulate themselves from industrial intrusions, oil and gas operations and rural communities coexist throughout the province with minimal impact. The ERCB ordered Ranchmen's to conduct tests, to put in place procedures and equipment to prevent releases, and to develop an Emergency Response Plan ("ERP"), even though H_2S concentration was lower than Alberta Health's mandatory evacuation standard. Finally, while Ranchmen's initial communication attempts were inadequate, the interveners must share the responsibility for the failure to maintain communication as a result of their refusal to cooperate.

(vii) Home Oil Company Limited *et al.* Well Licences and Pipeline Permits[331]

Home Oil Company Limited ("Home"), Imperial Oil Resources Limited ("Imperial Oil") and Renaissance Energy Ltd. ("Renaissance") applied for well licenses and approval to construct pipelines in northeastern Alberta. Their applications were opposed by trappers holding permits in the area. In approving the applications the ERCB identified the following issues:

(1) the need for the wells and the pipelines;
(2) the impacts of the wells and pipelines; and
(3) other matters.

The ERCB concluded that there was a need for the wells and the pipelines and that they would not have significant environmental or trapping impacts. The proposed Imperial Oil well was required to further investigate brackish aquifer deliverability as an alternative water source for the Cold Lake project. The use of brackish water is environmentally preferable to the use of fresh water. The well would cause little surface disturbance and would require no additional pipeline right-of-way, resulting in no significant impact to the environment or trapping. Likewise, Home established a need for its wells and associated pipelines and noted that because a development infrastructure exists already, the additional facilities would cause no significant additional impact, especially as Home was required to comply with Alberta Environmental Protection conditions. With respect to other matters, the ERCB reiterated its policy not to entertain blanket objections but rather to deal with site specific applications only. The ERCB concluded that compensation was the major issue behind the trappers' objections and as such the proper forum for the objections was the Trappers' Compensation Board. Finally, Imperial Oil and Renaissance committed their

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331 *Home Oil Company Limited, Imperial Oil Resources Limited, Renaissance Energy Ltd. Applications for Well Licences and Pipeline Permits; Cold Lake, Leismer and Leming Fields* (22 December 1993), No. D93-9.

participation to the preparation of a study in the Cold Lake area of the cumulative impacts upon trapping resources.

(viii) Mobil Oil Canada, Ltd. Well Licence Application[332]

Mobil Oil Canada, Ltd. ("Mobil") applied for a well license to obtain sour gas production from the Leduc formation. The well would be a Level IV critical well with a reduced emergency planning zone of four kilometres. Interventions were received from land owners and concerned persons in the vicinity of the well in the Bearberry Valley northwest of Sundre. In approving the application, the ERCB considered the following:

(1) the need for the well;
(2) the location of the well and uniqueness of Bearberry Valley; and
(3) the impacts of the well.

Mobil established the proposed well as necessary to determine what, if any, future drilling activity could occur in relation to its mineral lease. The ERCB weighed the need for the well against surface impacts to ensure the proposal was in the public interest and would not affect neighbouring residents to a significant degree. Mobil had originally intended to drill a vertical well, but because of landowners' objections shifted the proposed surface location. Area residents suggested an alternative surface location outside the valley; however, Mobil asserted that directional drilling from a surface location outside the valley would push the limits of current drilling technology and increase geologic and safety risks.

Mobil did not submit any substantive data refuting the interveners' submission as to the climatic and environmental uniqueness of the Bearberry Valley. The ERCB recognized that many areas in Alberta exhibit unique climatic and environmental characteristics and accepted that the Bearberry Valley may be in such respects unique. Therefore, the ERCB had to determine whether potential adverse impacts could be mitigated or reduced to an acceptable level. The ERCB determined that, given Mobil's drilling plan and ERP, the well could proceed safely. Mobil committed to take additional measures respecting noise abatement and the protection of adjacent water sources. The ERCB accepted Mobil's ERP, although it emphasized that companies must recognize the need for good communication with residents at an early stage of development, and that better communication leading up to the development of the plan could have alleviated residents' concerns. The ERCB declined to defer its decision pending the issuance of an Alberta Cattle Commission study, as it was not known what information resulting from that study could impact the ERCB's decision.

[332] *Application for a Well Licence; Ricinus Field; Mobil Oil Canada Ltd.* (13 January 1994), No. D94-1.

(ix) Husky Oil Operations Ltd. Well Licence Applications[333]

Husky applied for well licenses for five wells proposed to be drilled from three surface locations in the Moose Mountain area in order to obtain production from the Turner Valley formation. One well, from each of the three pads Husky proposed to use, would be for the purpose of delineating and testing reservoir productivity, while additional wells would be used for a closed-system testing program in which produced fluids would be re-injected into the reservoir. Various interveners raised numerous concerns including over impacts on the environment, hunting and recreation, and public safety. A number of noteworthy preliminary matters were addressed. The Tsuu T'ina Nation requested an adjournment to allow Husky to study the impact of the applications on treaty and aboriginal rights. In the alternative, the Tsuu T'ina Nation requested an adjournment in order to prepare its own submissions. The ERCB agreed with Husky and Alberta Justice that the onus fell on the Tsuu T'ina Nation to present a *prima facie* case with regard to the rights it believed would be affected by the application.

The ERCB also upheld Alberta Justice's argument that where constitutional rights were not clearly established, it was inappropriate for an administrative tribunal to arbitrate on the nature of those rights. As the Tsuu T'ina Nation had reasonable opportunity to prepare its submissions and to participate in the hearing, the ERCB was not prepared to grant the requested adjournment. The RMEC requested that the ERCB compel the attendance of certain witnesses from Alberta Environmental Protection, in order that they might respond to questions as to why certain decisions were made regarding the location of access road, and the proposed pads, as well as to facilities construction techniques. The ERCB ruled that it will compel witness attendance only if convinced that the evidence to be adduced is critical to an understanding of the issues. It must further be established that there is no other reasonable way to obtain this evidence. The interveners failed to establish why the information would be critical to the ERCB's decision and why such evidence could not be brought forward in another fashion.

Questions were also raised throughout the hearing concerning the ERCB's procedure, as set out in its rule of practice, and the presentation of evidence. The ERCB is not bound by the rules of evidence and allows considerable latitude in the types and presentation of evidence before it. Concurrent with this flexibility is the duty of the ERCB to ensure a fair process to all parties. Oral presentation of complex technical issues without companion written submissions are undesirable but were allowed in the hearing as the applicant did not object. The ERCB was also concerned with the decision of certain interveners to file an intervention but not provide a witness to speak to their submissions and answer questions. The lack of an opportunity for cross-examination diminishes the weight of any evidence on which the ERCB may rely.

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333 *Applications for Well Licences; Moose Mountain Area; Husky Oil Operations Ltd.* (11 March 1994), No. D94-2.

The ERCB identified the following main issues:

(1) the need for the wells;
(2) the testing procedures for the wells;
(3) public consultation;
(4) environmental assessment;
(5) environmental impacts;
(6) traditional use of Moose Mountain;
(7) public safety;
(8) public access; and
(9) greenhouse gases.

Husky's right to recover the petroleum and natural gas resources was undisputed, as was the need to further delineate and test the reservoir. The matter in which the testing was to occur was contested; however, the ERCB held that the proposed drilling program was technically feasible and an acceptable approach. Husky's proposal to use a second well at each pad to re-inject fluids into the reservoir, although relatively untried, did have a significant potential to reduce environmental impacts.

Husky's public consultation process encompassed regulatory agencies, environmental and other special interest groups, local residents, and other area oil and gas operators. Generally, the ERCB accepted that Husky made genuine and appropriate efforts to consult with the public and to resolve the resulting issues. However, the ERCB criticized Husky for not being more pro-active in advising the Tsuu T'ina Nation regarding its application. The ERCB noted that Husky could have been more sensitive to the unique political structure of native groups, which can make public consultation tools such as mail-outs and newspaper articles less effective in their communities. It is not enough to assume, particularly with native groups, that a lack of response constitutes a lack of concern. The ERCB also criticized the Tsuu T'ina Nation for not being more pro-active in advising Husky of its concern, noting that an applicant can only address contentious issues with the public if it is aware of those issues. In approving the application, the ERCB required Husky to meet its undertaking to establish ongoing consultation with the Tsuu T'ina Nation.

With respect to the subject environmental assessment, Husky contended that although it could not estimate the possible extent of commercial development, which in turn reduced its ability to determine possible environmental impacts, its application for Moose Mountain still contained much more environmental data than had historically been required and, as such, was adequate for a project still in an early delineation stage. Interveners challenged the adequacy of Husky's environmental data, noting that while Husky conceded various environmental impacts, particulars with respect to the regional significance of those impacts were lacking. The ERCB agreed with both Husky and the interveners that the impact of development on local wildlife habitat and populations was as yet unknown. While the ERCB found Husky's submissions adequate for the purposes for the current limited proposal, should a permanent commercial development be desired, more extensive environmental assessment would be required.

With respect to environmental impacts, Husky argued that should the project prove commercial, the pads had been located so as to reduce the need for pipeline corridors, access roads and other surface disturbances. The RMEC and the Wildlife Foundation countered that the likely impact of the proposed pads and access roads on the ecological integrity of the area was unacceptable and that present recreational development had already reduced or degraded available habitat to the point where many species were now endangered. It was submitted that this application could eventually lead to the degradation of the entire ecosystem. The concept of multiple uses along the Eastern Slopes, including oil and gas development, was asserted as essentially incompatible with the maintenance of the abundance, diversity and distribution of fish and wildlife. The ERCB determined that until a reasonable estimate of the area's economic value is available, the interveners' broad assertion that the natural values of the Moose Mountain area far outweigh potential economic benefits of oil and gas development was premature. Similarly, with respect to the traditional use of Moose Mountain for hunting and spiritual purposes by native groups, the ERCB considered the concerns proposed to be unsubstantiated and therefore, refused to deny the Husky application.

With respect to public safety, Husky filed an ERP, despite the fact that its calculation of likely sour gas release rates indicated that such a plan would not normally be required under ERCB regulations. The risk posed to public safety by the Husky well was, in the ERCB's opinion, no greater than that posed by other provincial energy developments and, as such, no undue risk to public safety was established.

Ultimately the ERCB concluded the proposed wells were in the public interest, and that the methods of accessing, drilling and completing, planned to be utilized in testing the wells, would avoid unacceptable environmental and public impacts.

(x) Cardinal River Coals Ltd. Permit Extension[334]

Cardinal River Coals Ltd. ("CRC") applied for an expansion to its 50-A8 coal pit. The ERCB addressed the following relevant issues: (1) the need for the expansion; and (2) the impacts of the expansion on the area environment.

CRC, a reliable supplier of high quality coal, had obtained markets for medium volatile coal and development of the mine was essential to meet contractual obligations. Further, CRC intended to modify the mine plan in order to reduce the impact on the Hamlet of Cadomin by developing fewer pits, moving the mine back from the hamlet boundary and reducing the area to be disturbed. An Environmental Impact Assessment ("EIA") showed the potential for noise, dust and water impacts on the residents was small and within existing regulations. Reclamation would be completed within five years of the application.

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[334] *Cardinal River Coals Ltd. Permit Extension Application to Include 50-A8 Pit* (5 April 1994), No. D94-3.

In approving the proposal, the ERCB acknowledged that the mine was necessary to meet contractual obligations but centred on what it considered to be the main issue of environmental and social impacts. The ERCB concluded that the EIA provided a reasonable description of potential environmental impacts but directed that CRC rigorously carry out and enforce the proposed mitigation measures and reclaim the land as rapidly as possible. The ERCB recognized the particular sensitivities of one of the intervening neighbors, who was asthmatic, and expected CRC to maintain an ongoing sensitivity to future dust problems.

b. Ongoing Matters

(i) Amoco Canada Petroleum Ltd. — Whaleback Well License Application[335]

Amoco has applied to the ERCB for a well license for a proposed surface location in the Whaleback Ridge area. Numerous individuals and interest groups had expressed concerns over drilling in the area and the ERCB convened a pre-hearing meeting to receive submissions respecting issues related to the location, timing and scope of the hearing as well as the issue of funding for local interveners. Amoco submitted that the hearing should focus on the effects of the proposed well only, while the interveners were unanimous in their position that the hearing should address the potential effects of the development of the entire gas play. It was submitted that, as the Whaleback Ridge area is environmentally sensitive and ecologically important both locally and provincially, the initial question to be addressed at the hearing ought to be whether any new development of the area should occur at all. If development is to occur, interveners agreed that the entire potential development must then be addressed rather than limiting the scope of the hearing to a consideration of the effects of a single well.

The ERCB referred to Information Letter ("IL") 93-9, which deals with potential drilling in the southern portion of the Eastern Slopes. The overall area was assessed by the provincial Integrated Resources Planning process, in which the public participated, as well as by an internal government process under the Crown Mineral Disposition Review Committee. These processes included environmental considerations and concluded that the area should not be precluded from potential oil and gas development, with site specific assessments being conducted by the ERCB.

The ERCB characterized its function as determining whether new drilling is in the public interest, through a comparison between the potential value to society of successful development with the potential costs to society imposed by that development. As the southern portion of the Eastern Slopes is viewed as an important ecosystem, the ERCB encourages companies to adopt a more coordinated approached to oil and gas development. IL 93-9 outlines ERCB expectations for area development proposals and is intended to allow sufficient flexibility to accommodate various settings in the area. The ERCB recognized the uncertainty in projecting full fuel development at the

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335 *Application for a Well Licence; Porcupine Hills — Whaleback Ridge Area; Amoco Canada Petroleum Company Ltd.* (31 December 1993), (Memorandum of Decision — Application No. 931598).

preliminary first well stage, emphasizing the need for a sequential approach to development planning. Due to the Whaleback's special sensitivity, the ERCB will require more information in this case than is usually provided in an application for a single well; however, any attempts to define future development and its environmental impacts would be speculative and inefficient, if not impossible. Therefore, the ERCB determined that its proposed hearing would focus largely on the applied-for well and its effects, although future development may give rise to future public proceedings at each stage of the process. Finally, the ERCB reiterated that it would not limit its scope only to the narrow issue of drilling the well but rather would address possible production options such as the well being produced on its own and the requirement of further production facilities.

Again, as with the Moose Mountain application, a request was made to require the attendance of representatives of Alberta Environmental Protection. Once again, without further clarification of the potential contribution of those representatives, the ERCB was unwilling to compel the attendance of such witnesses.

Further, with respect to the issue of intervener funding, a subsequent preliminary hearing was held on January 27, 1994.[336] Although the ERCB normally hears requests for advanced funding through written submission, an exception was made at the request of the applicant to expedite the process. The ERCB identified the following issues: (1) whether the Whaleback Coalition, the Hunter Creek Coalition, and the Peigan Nation were local interveners for the purposes of costs; and (2) if any or all of them qualify as local interveners, the amount of the advanced funds.

A claimant must meet the "local intervener" test and the ERCB must further be satisfied of the need for the advance, the reasonableness of the proposed budget and that the issues to be put forward are within the hearing scope. With respect to the Whaleback Coalition, only one member, Mr. Tweedie, would potentially qualify for consideration as a local intervener and even his residence was a considerable distance (eight kilometres) from the proposed well site. The ERCB refused to accept the mere fact that Mr. Tweedie's land is within the Emergency Plan Zone ("EPZ") as justification, in and of itself, for his designation as a local intervener. The ERCB stated it would consider Mr. Tweedie's status for cost purposes further in light of representations and evidence presented at the April hearing. The ERCB intimated further that should the Whaleback Coalition argue, and the ERCB accept, that Mr. Tweedie qualifies because of potential adverse effects related to a potential emergency, eligible costs would be those relating only to these potential effects. Because the ERCB was unable to designate the Whaleback Coalition as a local intervener, no advance of funds could be made available to it and broad or general issues argued by Mr. Tweedie (which do not address the potential impact of the well on Mr. Tweedie's land) are unlikely to be funded. Hunter Creek, as individual land holders in the vicinity of the well site and within the EPZ and as holders of Crown grazing leases near the proposed

[336] *Amoco Canada Petroleum Company Ltd.; Whaleback Ridge Area; Advance Local Intervener Funding* (3 March 1994), (Memorandum of Decision — Application No. 931598).

well site, qualified as a local intervener. As the Whaleback Coalition was not successful in obtaining advance funding, Hunter Creek stated its wish to provide evidence in the following areas:

(1) wildlife habitat areas;
(2) wildlife habitat and potential disruption of wildlife populations;
(3) loss of extensive ecological and recreation values; and
(4) protection of landscape values.

Further, in addition to those areas in which the Whaleback Coalition had unsuccessfully requested advance funding, Hunter Creek also requested funding for the following experts:

(1) an oil and gas consultant to provide advice and assistance with respect to the impact exploratory drilling may have on the area;
(2) an expert on environmental impact assessments to assess the adequacy of the information provided by the applicant;
(3) a land economist to address cost/benefit issues and to look at alternative uses for the area;
(4) an expert in the area of human and animal health related to H_2S and SO_2 exposure;
(5) a hydrologist to review the potential effect the well may have on the ground water regime;
(6) a dispersion meteorologist to advise on the impact of emissions; and
(7) a rancher-historian to gather evidence on the uniqueness of the area and the traditional ranching lifestyle.

The ERCB was prepared to advance some funds for the preparation of the Hunter Creek submission; however, it voiced caution with respect to the relevance of experts on the adequacy of the environmental impact assessment and on the uniqueness of the area with respect to the traditional ranching lifestyle. The relevance of all the experts engaged would be assessed on the basis of the evidence presented at the hearing. Advance funding was granted in the amount of $10,000.

The Peigan Nation submitted a written request, stating that it lacked independent sources of funding and thus required an advance. The Peigan Nation proposed to provide expert assistance in the following areas:

(1) an oil and gas expert to advise on the reasonably anticipated impacts to the environment;
(2) a Peigan ethnographer to identify spiritual and historic sites, to determine the historical and present uses of the area;
(3) an expert in Peigan history and archeological sites;
(4) biologists to determine the impact to both plants and animals that may affect the Peigan Nation in this area;
(5) legal representation; and

(6) a Peigan coordinator to relay instructions among the lawyer, the experts and the band members.

Amoco did not object to the granting of advance funds to the Peigan Nation, as it believed that the Treaty Seven rights conferred on the Peigan Nation may be sufficient to give it local intervener status. Further, Amoco agreed to fund the Peigan Nation directly with the request for advanced funds to be handled outside the ERCB local intervener's costs process.

2. Alberta Public Utilities Board

a. Decisions

(i) NOVA Corporation of Alberta — Complaint by Canadian Association of Petroleum Producers[337]

CAPP submitted a complaint to the PUB that the rates charged by NOVA effective January 1, 1993 were unjust and unreasonable. Included in its complaint was an application that the PUB establish interim rates effective until a final determination by the PUB. The PUB identified the following issues:

(1) the appropriate capital structure for NOVA, including the common equity ratio and an appropriate level for such ratio;
(2) the appropriate cost factor of each component of the capital structure, including the return on common equity;
(3) without restricting the generality of the foregoing, the effect of corporate diversification by NOVA outside the traditional utility area; and
(4) the appropriate method for recovery of costs of the elements of the capital structure inasmuch as such costs may vary from time to time or be affected by the corporate diversification of NOVA.

The *NOVA Corporation of Alberta Act*[338] is silent as to the factors to be considered by the PUB in assessing justness and reasonableness of rates in relation to the Alberta Gas Transmission Division ("AGTD"). The PUB has in the past determined that AGTD should be allowed to earn a fair return on its rate base on a stand alone basis. AGTD is a diversified operation and the cost factor for each of its component operations ought to be determined on a stand alone basis consistent with its business risk and its ability to attract capital on reasonable terms. The PUB will, however, inquire into non-utility operations to ensure that the financial integrity of NOVA is not being threatened in a way that will result in cessation of safety or service provided by AGTD and that AGTD customers are not subsidizing NOVA's non-AGTD operations. So long as AGTD remains consolidated with NOVA's other operations, the question of whether NOVA's

337 *In the Matter of a Complaint by the Canadian Association of Petroleum Producers that the rates, tolls or charges for customers of the Alberta Gas Transmission Division of NOVA Corporation of Alberta for the calendar year 1993 are not just and reasonable* (20 August 1993), No. E93060.

338 R.S.A. 1980, c. N-12.

corporate diversification has placed additional financing or other costs on AGTD's operations will have to be addressed.

With respect to business risk, CAPP submitted that the PUB should recognize that AGTD was the least risky of all pipelines, including TCPL. The PUB found that AGTD faces virtually no risk or regulatory lag with regard to recovery of its annual cost of service because the actual cost of service is recovered monthly through its cost of service tolls. AGTD differs from other utilities under PUB jurisdiction whose costs and revenues are subjected to forecasting risk. The PUB concluded that AGTD's business risk is very low — considerably lower than other utilities regulated by the PUB and marginally lower than TCPL.

With respect to capital structure, the PUB held that AGTD's common equity ratio should be lower than other large utilities with a higher business risk and slightly lower or approximately the same as the 30 percent common equity ratio of TCPL. The PUB reduced AGTD's common equity ratio from 32 percent to 30 percent. With respect to the relative costs of prefunded and unfunded debt, the PUB considered a 5 percent investment rate for prefunded debt to be reasonable, as was a 6.88 percent cost rate for unfunded debt. The cost of long-term debt was likewise addressed and the PUB was satisfied that non-utility operations would not result in a cessation of safety or service and further, that AGTD customers are not subsidizing NOVA's non-AGTD operations. The PUB directed NOVA to include the actual cost for 1993 preferred shares in its cost of service bills for AGTD and to include the actual cost of a $500 million standby facility in the operating and maintenance portion of the cost of service bills for AGTD in 1993. The PUB found it prudent for AGTD to incur the cost of the standby facility to ensure funds are available to AGTD should it be denied access to capital markets but the PUB found it unlikely that AGTD would be so denied for any period in excess of six months. CAPP had argued that a standby facility of $200 million to $300 million would be more than sufficient, while NOVA had submitted AGTD's requirement for a standby facility of $900 million.

Finally, with respect to AGTD's method of cost recovery, the PUB held that costs in accordance with the actual capital structure should be used in the monthly billing provided deviations from the capital structure are prudent. AGTD sought a review and variance of the PUB's decision with respect to its appropriate common equity ratio. A decision is pending on this application at this time.

(ii) Peace Pipeline Ltd. — Complaint by Canadian Hunter Exploration Ltd. *et al.*[339]

By application dated June 4, 1993, Canadian Hunter Exploration Ltd., Crestar Energy and PanCanadian Petroleum Limited filed an application with the PUB seeking:

(1) an order, pursuant to s. 101 of the *Public Utilities Board Act*,[340] fixing just and reasonable rates, tolls and charges for service on the Peace Pipeline Ltd. ("Peace") system; and

(2) an order, pursuant to ss. 52(2) of the *PUB Act*, establishing as interim the rates, tolls and charges for service provided on the Peace system.

This was the first application filed before the PUB seeking regulation of the rates of an intra-provincial oil pipeline system. On September 13, 1993, the PUB held a pre-hearing conference primarily to deal with certain jurisdictional issues raised by Peace regarding the ability of the PUB to deal with this application. The jurisdictional issue focuses on whether or not the powers granted the PUB by s. 101 of the *PUB Act* permitted it to set tolls for the Peace system based on the facts of this case. Peace argued that since s. 101 does not explicitly authorize an override of contracts, the PUB is not permitted to interfere with its existing contractual arrangements with the applicants. Peace maintained that if the PUB were to grant the requested orders, the PUB would be interfering with existing, legally binding long-term contracts. Peace argued that the structure of the *PUB Act* is such that the PUB cannot issue orders which would override contracts unless it has expressly been given this authority. As the explicit power to override contracts is contained in other parts of the governing legislation and has not been incorporated into that part of the legislation containing s. 101, the PUB has no power to grant the above-referenced applications.

The applicants rely on a plain reading of s. 101 and maintain that there is no constraint on the PUB's jurisdiction to set just and reasonable tolls. Additionally, a significant portion of the throughput on the Peace system is not transported under long-term contracts and, therefore, the restrictions forming the basis of the Peace argument would not apply to these volumes. A decision by the PUB on this preliminary issue of jurisdiction is still pending at this time.

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339 *In the Matter of an Application by Canadian Hunter Exploration Ltd., Crestar Energy, Pan Canadian Petroleum Limited and Rigel Oil & Gas Ltd. requesting: (1) An Order, pursuant to section 101 of the Public Utilities Board Act, to fix just and reasonable rate, tolls and charges for service provided on the Peace Pipeline Ltd., pipeline system; and (2) An Order, pursuant to Section 52(2) of the Public Utilities Board Act, establishing as interim the rates, tolls and charges for service provided on the Peace Pipeline, pipeline system* (3 August 1994), No E94047.

340 R.S.A. 1980, c. P-37 [hereinafter *PUB Act*].