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

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This article offers a review of significant regulatory and legislative developments in the petroleum industry. In addition to highlighting key decisions of the National Energy Board and the Alberta Energy and Utilities Board, the authors review several decisions pertaining to the energy sector that were made in other provincial jurisdictions. The article also summarizes important legislative changes from across the country and discusses the policy statements that have been made by key actors in the industry.

Cet article propose une revue des importants développements réglementaires et législatifs dans l'industrie pétrolière. En plus de souligner les décisions clés de l'Office national de l'énergie et du Alberta Energy and Utilities Board, les auteurs examinent plusieurs décisions relatives au secteur énergétique qui ont été prises dans d'autres juridictions provinciales. L'article résume aussi les importants changements législatifs au pays et examine les énoncés de politique faits par les acteurs clés de l'industrie.

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I. INTRODUCTION

This article involves a review of the recent significant regulatory and legislative developments relating to the petroleum industry. Part II of this article discusses regulatory developments. Focusing on the National Energy Board ("NEB") and the Energy and Utilities Board ("EUB") of Alberta, it also considers noteworthy events from other provinces in which the energy industry is active. Part III highlights legislative changes made over the last year by the federal government and by the western and maritime provinces.

The object of this review is to provide an aid to the continuing legal education of oil and gas lawyers. Various decisions and other developments are listed and discussed. The intention is not to be exhaustive, but rather to focus on significant events. Commentary that concentrates on ramifications for energy law practitioners is provided.[1]

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[1] The views expressed are solely those of the authors and do not represent the positions of any client of Stikeman Elliott.

II. REGULATORY DEVELOPMENTS

A. FEDERAL

Federal developments emanate primarily from NEB decisions, reports, and publicized policies. During the last twelve months the federal energy regulator has been active in the areas of pipeline jurisdiction, facilities, tolls, and the environment. It has also provided policy guidance to industry and has continued projects intended to increase regulatory efficiency (for example, electronic regulatory filing, and alternative dispute resolution).

1. NATIONAL ENERGY BOARD — DECISIONS

a. Pipeline Jurisdiction

Pipeline jurisdiction is a recurring issue for the NEB. In recent years it has been the subject of numerous regulatory[2] and judicial[3] decisions and the inspiration for analytical articles.[4] During the last twelve months the NEB has revisited the issue on at least four occasions, but clarity remains elusive.

The jurisdictional issue arises out of the provisions of ss. 91(29) and 92(10)(a) of the *Constitution Act, 1867*,[5] the combined effect of which is to grant exclusive jurisdiction over local (*intra*provincial) "works and undertakings" to the provinces, while *inter*provincial and international "works and undertakings" are, by exception, within federal jurisdiction.

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2 See *e.g.*, *Reasons for Decision In the Matter of an Application Under Section 49 and Subsection 59(3) of the National Energy Board Act of Cyanamid Canada Pipeline Inc.* (December 1986), No. GH-3-86 (NEB); *Reasons for Decision In the Matter of Westcoast Energy Inc. Application dated 6 October 1994, as amended, for the Fort St. John Expansion Project* (May 1995), No. GH-5-94 (NEB) [hereinafter *NEB Westcoast*]; *Reasons for Decision 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 (NEB) [hereinafter *Altamont*]; *Decision re WBI Canadian Pipeline, Ltd. Application Dated 9 October 1992 for an Order Pursuant to Section 58 of the National Energy Board Act in respect of the Construction and Operation of a Proposed Natural Gas Pipeline dated 25 February 1993* (NEB) [hereinafter *WBI Canadian*]; *Reasons for Decision In the Matter of TransGas Limited Application for Review re WBI Canadian Pipeline, Ltd.* (October 1993), No. GH-R-1-93, Review (NEB); *Decision In the Matter of Many Islands Pipe Lines (Canada) Limited Section 58 Application dated 22 August 1994 – Husky-Marwayne Pipeline* (2 November 1994); *Reasons for Decision In the Matter of Niagara Gas Transmission Limited* (September 1995) *Jurisdiction* (NEB).

3 See *e.g.*, *Westcoast Energy* v. *Canada (National Energy Board)*, [1998] 1 S.C.R. 322 [hereinafter *Westcoast*]; *Reference re National Energy Board Act* (1987), 48 D.L.R. (4th) 596 (F.C.A.) [hereinafter *Cyanamid*]; *Reference re Legislative Authority over Bypass Pipelines* (1988), 49 D.L.R. (4th) 566 (Ont. C.A.); *Consumers' Gas Co.* v. *National Energy Board* (1996), 195 N.R. 150 (F.C.A.) [hereinafter *Consumers' Gas*].

4 See *e.g.*, J.B. Ballem, "Pipelines and the Federal Transportation Power" (1991) 29 Alta. L. Rev. 617; S.A. Kennett, *Pipeline Jurisdiction in Canada: The Case of NOVA Gas Transmission Ltd.*, Canadian Institute of Resources Law, Occasional Paper #1 (Calgary: Canadian Institute of Resources Law, June 1996); R.J. Harrison, "The Interface Between Federal and Provincial Jurisdiction Over Pipelines: Recent Developments, Current Issues and a Suggested Mechanism for Reducing Turbulence in the Buffer Zone" (1997) 35 Alta. L. Rev. 389.

5 (U.K.), 30 & 31 Vict. c. 3.

In essence, a pipeline will be subject to federal jurisdiction if it *is itself* a federal "work or undertaking" or if it *is integral to* a federal "work or undertaking."[6] A federal "work or undertaking" is one that is *inter*provincial or international. It crosses a provincial or national boundary. A pipeline that is located entirely within a province is *intra*provincial and is *prima facie* within provincial jurisdiction. It will only become subject to federal regulation if it is determined to be *part of* or *integral to* a federal "work or undertaking."

The issue of regulatory jurisdiction has been litigated numerous times before regulators and courts. The current definitive authority is the 1998 decision of the Supreme Court of Canada in *Westcoast Energy* v. *Canada (National Energy Board)*[7] in which the majority of the judges held that the gathering and processing functions of Westcoast Energy are *part of* an interprovincial undertaking and properly subject to federal regulation.[8]

The majority in *Westcoast* stated that "functional integration and common management, control and direction" is the *primary factor* to be considered in determining jurisdiction.[9] There is, however, no single comprehensive test which will be useful in all cases.[10] Several factors are germane to the determination of whether the "work or undertaking" in question is *integral* to an existing federal "work or undertaking." One of these factors is functional and operational integration.[11] Other factors include physical connection, the

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6 The classic statement of this test is that of Dickson C.J.C. in *United Transportation Union et al.* v. *Central Western Railway Corporation*, [1990] 3 S.C.R. 1112 at 1124-25 [hereinafter *Central Western Railway*] where he stated:

> There are two ways in which Central Western may be found to fall within federal jurisdiction and thus be subject to the *Canada Labour Code*. First, it may be seen as an interprovincial railway and therefore come under s. 92(10)(a) of the *Constitution Act, 1867* as a federal work or undertaking. Second, if the appellant can be properly viewed as integral to an existing federal work or undertaking it would be subject to federal jurisdiction under s. 92(10)(a). For clarity, I should point out that these two approaches, though not unrelated, are distinct from one another. For the former, the emphasis must be on determining whether the railway is itself an interprovincial work or undertaking. Under the latter, however, jurisdiction is dependent upon a finding that regulation of the subject matter in question is integral to a core federal work or undertaking.

Cited with approval in *Westcoast*, *supra* note 3 at 357, 392.

7 *Westcoast*, *ibid.*

8 Note, however, that Beverley McLachlin, who was appointed Chief Justice of Canada early last year, dissented in *Westcoast*, taking the position that the majority judges misunderstood the *Central Western Railway* tests (*Westcoast*, *ibid.* at 392ff). In her view, the first *Central Western Railway* test is not whether the work or undertaking at issue is *part of* an existing federal work or undertaking. Rather, the first test is whether that work or undertaking is *itself* an interprovincial work or undertaking. An *inter*provincial pipeline, viewed by itself, is an interprovincial work. An *intra*provincial pipeline, viewed by itself, is not an interprovincial work because it does not extend beyond the province or connect the province with any others. In her view, an intraprovincial pipeline can only fall under federal jurisdiction under the second test of *Central Western Railway*, *i.e.*, by virtue of its relationship to an interprovincial work or undertaking. McLachlin J. (as she then was) stated that to inquire (as the majority judges did) whether a work or undertaking is "*part of*" an interprovincial work or undertaking or is "*integral to*" an interprovincial work or undertaking amounts to the same thing. In either case, the inquiry is whether the work or undertaking is part of an integrated scheme.

9 *Ibid.* at 368.

10 *Ibid.* at 361, 368.

11 See *Central Western Railway*, *supra* note 6; *Luscar Collieries, Ltd.* v. *McDonald and Others*, [1927] A.C. 925 (P.C.) [hereinafter *Luscar*]; *Cyanamid*, *supra* note 3.

purpose or object which is sought to be achieved by the undertaking, and ownership.[12] The adjudicator must be guided by the particular facts in each situation.[13]

(i) *The NEB Pipeline Jurisdiction Letter*

On September 17, 1999, the NEB issued a letter that sought to provide clarification of the circumstances under which upstream production facilities would come under its jurisdiction.[14] The letter, which was sent to pipeline companies subject to NEB jurisdiction, was precipitated by the decision of the Federal Court of Appeal ("FCA") in *Canadian Hunter Exploration* v. *Canada (National Energy Board)*[15] which held that certain upstream gas production facilities were not within federal jurisdiction even though they were connected to an interprovincial pipeline.

The NEB letter uses *Canadian Hunter* as justification for a policy pronouncement that mere connection between an interprovincial pipeline and upstream gathering and processing facilities will not, in the absence of other factors, serve to bring the upstream facilities within NEB jurisdiction. The statement goes on to say that upstream facilities will only come within NEB jurisdiction if those facilities are "integral" to the downstream interprovincial pipeline. It concludes that in cases where persons or companies are "contemplating the construction of facilities to gather, process, and transport *their own* gas, oil, or other commodities, across a provincial border," the jurisdiction of the NEB "typically will not extend upstream from the point of connection between the interprovincial pipeline and the upstream production facilities."[16]

This policy statement is a laudable attempt at clarification, which it has nonetheless been variously criticized for merely stating the obvious, for narrowness of scope, and for reliance on the highly questionable *Canadian Hunter* decision. The law was settled long ago that federal jurisdiction does not come with "mere connection" but requires that the facilities be "integral."[17] The NEB statement, therefore, adds nothing new or enlightening on that legal front. Further, the statement is limited by its own words to the very narrow situation where there are "upstream production facilities" and an "interprovincial pipeline" that are both owned and operated by the resource owner.

Lastly, reliance on the *Canadian Hunter* decision is tenuous at best given the lack of opposition to the appeal, the absence of factual findings by the NEB, and an apparent judicial misunderstanding of the application of the "secondary instance federal jurisdiction" test in *Consumers' Gas*.[18] Rothstein J.A. was very careful to point out that the lack of opposition to the appeal meant that the Court did not have the benefit of argument on the part of any person supporting the NEB decision that the downstream

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12 See *e.g.*, *Luscar*, *ibid.*; *Capital Cities Communications* v. *Canadian Radio-television Commission*, [1978] 2 S.C.R. 141; *Public Service Board* v. *Dionne*, [1978] 2 S.C.R. 191.

13 *Westcoast*, *supra* note 3 at 361.

14 *Letter To: Pipeline Companies Subject to the Jurisdiction of the National Energy Board Re: Upstream Jurisdictional Issues* (17 September 1999) (NEB).

15 (1999), 240 N.R. 186 [hereinafter *Canadian Hunter*].

16 *Supra* note 14 [emphasis added].

17 *Central Western Railway*, *supra* note 6 at 359.

18 *Supra* note 3.

pipeline should be under federal jurisdiction.[19] He also noted (twice) that the NEB made no factual findings, leaving the Court in the difficult position of having to infer from the record the degree of functional integration between the upstream facilities and the interprovincial pipeline.[20]

The question of whether the upstream facilities and the downstream pipelines were together a single federal undertaking[21] turned on distinguishing the *Westcoast* case.[22] The Court allowed the distinction without enthusiasm, stating: "In the absence of argument to the contrary, and without a factual determination on the point by the National Energy Board, we accept the appellant's and intervenors' argument that the circumstances here are different from those in *Westcoast*."[23]

On the question of whether the upstream production facilities were "integral" to the downstream federal pipeline,[24] the Court said that it was guided by the decision of the Federal Court of Appeal in the *Consumers' Gas* case, but it appeared to misconstrue that decision. Quoting Hugessen J.A. in *Consumers' Gas* for the proposition that "secondary instance federal jurisdiction" requires that more than only a minor part of the undertaking be interprovincial, Rothstein J.A. then held that the "primary undertaking" (production of natural gas by producers) was provincial, that the interprovincial pipeline was "clearly secondary," and that "where the undertaking is overwhelmingly provincial, portions of it do not become federal merely because they have some connection to a federal undertaking."[25] The *Consumers' Gas* reference to "cases of secondary instance federal jurisdiction," however, clearly refers to the second branch of the *Central Western Railway* test (*i.e.*, whether the local work or undertaking is *integral to* an existing interprovincial work or undertaking).[26] There was no suggestion in the case of classification of undertakings as "primary" or "secondary" or of any judicial distinction to be drawn between undertakings that may be so classified. *Canadian Hunter* is clearly a case of secondary instance federal jurisdiction, where the question is whether the undertaking that would otherwise be provincial (the production of natural gas) is integral to the federal undertaking (the interprovincial pipeline). In *Consumers' Gas*, the upstream facilities (the Ottawa East pipeline) were held not to be integrated with the downstream interprovincial pipeline (the Niagara Line) because the volume of gas provided to the Niagara Line represented only 13 percent of the total volume received at the Ottawa Gate Station. This is clearly a different circumstance than that in *Canadian Hunter*, where it seems (absent

19 *Canadian Hunter*, *supra* note 15 at 188.

20 *Ibid.* at 189.

21 The first branch of the *Central Western Railway* test.

22 In *NEB Westcoast*, *supra* note 2, the NEB held that the jurisdictional demarcation should be made between the gathering and processing facilities (provincial) and the transmission facilities (federal). This conclusion was overruled by the Federal Court of Appeal and the Supreme Court of Canada, the latter holding that the gathering and processing facilities were "part of" the interprovincial undertaking of Westcoast Energy. In *Canadian Hunter*, *supra* note 15, the Federal Court of Appeal held that the production and processing facilities were not part of the interprovincial pipeline.

23 *Canadian Hunter*, *ibid.* at 190.

24 The second branch of the *Central Western Railway* test.

25 *Consumers' Gas*, *supra* note 3 at 154.

26 See *e.g.*, McLachlin J. (as she then was) in *Westcoast*, *supra* note 3 at 393.

factual findings by the NEB) that all the gas produced by the upstream facilities moves to the interprovincial pipeline.

While questionable and narrow, the September 17, 1999, letter does appear to have expedited consideration of a least one NEB application — the *Pipestone* case.[27]

(ii) The Pipestone Case

The jurisdictional issue is often raised in applications for approval of so-called "sausage-link" or "bridge" pipelines which are short pieces of federal-jurisdiction pipe that cross provincial or national boundaries to link pipelines and which are not under federal jurisdiction. The myriad sausage-link pipelines in Canada existed quite happily under federal jurisdiction until 1992 when the NEB decided to review any new sausage-link applications in order to consider whether upstream or downstream facilities should come within federal jurisdiction. The first such case was *Altamont*,[28] which was followed by several others.[29] A 1999 instance involved an application by Pipestone Pipelines Ltd. ("Pipestone").

Pipestone used an agent to apply to the NEB pursuant to s. 58 of the *National Energy Board Act*[30] for approval to construct a 33-kilometre pipeline crossing the provincial border between Manitoba and Saskatchewan. The proposed pipeline would form part of a 75-plus-kilometre pipeline system originating at the Red Jacket Terminal near Moosomin, Saskatchewan and terminating at the Enbridge Pipelines (Virden) Inc. terminal near Virden, Manitoba. Pipestone withdrew its application upon receiving notice from the NEB that the pipeline system as a whole might form a single undertaking which would have required a comprehensive federal environmental assessment. It then proceeded to obtain provincial approvals for all but a 100-metre cross-border sausage link. After constructing the two provincial pipelines, Pipestone submitted a s. 58 application to the NEB for approval of the connecting sausage link.

The NEB responded by issuing a Notice of Constitutional Question regarding jurisdiction over the upstream and downstream facilities. Ultimately, the NEB concluded that the sausage-link pipeline, and each of the pipelines constructed pursuant to provincial authority, were all part of an interprovincial pipeline. Presumably relying on *Canadian Hunter* and its own September 17, 1999, letter, the NEB declined to include upstream production and gathering facilities with the result that the total length of the pipeline facilities became less than 75 kilometres and would therefore not trigger a comprehensive study under the *Canadian Environmental Assessment Act*.[31] It then decided that its mandate under the *CEAA* required it to conduct an environmental screening under s. 18

[27] *Reasons for Decision OHW-1-99: Pipestone Pipelines Ltd. Operation of Pipeline Facilities* (February 2000), OHW-1-99 (NEB) [hereinafter *Pipestone*].

[28] *Supra* note 2.

[29] *WBI Canadian*, *supra* note 2; *Decision re Remington Energy Ltd.* (11 March 1994) (NEB); *Canadian Hunter*, *supra* note 15.

[30] R.S.C. 1985, c. N-7 [hereinafter *NEB Act*].

[31] S.C. 1992, c. 37 [hereinafter *CEAA*]. See *Comprehensive Study List Regulations*, S.O.R./94-638, s. 14.

of that statute. The screening was restricted to the operation, decommissioning, and abandonment of the entire interprovincial pipeline. The NEB declined jurisdiction over issues arising from the *construction* of the pipelines on the basis that those pipelines had already been constructed pursuant to provincial regulatory authority.

The message from this case is an interesting one. Conventional wisdom holds that the requirements of provincial environmental statutes are less stringent and more easily understood than those of the *CEAA*, particularly in respect to pipeline construction. By going first to the provincial authorities for intraprovincial approvals, and only then to the NEB for approval of the sausage link, Pipestone avoided the application of the *CEAA* to the *construction* of all but 100 metres of its pipeline project. By effectively condoning this course of action, the NEB decision established a precedent that other interprovincial pipeline proponents could find irresistible.

(iii) The Shiha Case[32]

The NEB addressed jurisdictional issues respecting downstream facilities in an application by Shiha Energy Transmission Ltd. ("Shiha").[33] Shiha sought s. 58 approval for the Liard Pipeline Project, including wet gas flow lines, a central battery, and the 24-kilometre Shiha Pipeline which would transport raw natural gas from a facility near Fort Liard, Northwest Territories to a proposed gas plant located near Maxhamish Lake, British Columbia. By separate applications to regulatory authorities in British Columbia, two of the owners of Shiha[34] requested approval for downstream facilities — a pipeline from the proposed gas plant to an interconnection point on the Westcoast Energy Inc. pipeline system,[35] both points being located within British Columbia.

The NEB issued a Notice of Constitutional Question under the *Federal Court Act*[36] and held an oral hearing to deal with the preliminary question of whether the downstream facilities should properly be subject to federal jurisdiction. The Shiha position in support of provincial jurisdiction was unopposed, which left the NEB counsel to conduct cross-examination on the jurisdictional issue and meant that there was no argument supporting federal jurisdiction. In the result, the NEB determined that the downstream facilities did not form a single federal work or undertaking with the Liard Pipeline Project, nor were the downstream facilities integral to that project. Regrettably, the NEB decision does not assist in the resolution of the jurisdictional debate. The decision does not discuss the application of any of the various tests; it only states that "further and significant new evidence with respect to the proposed facilities related to the preliminary question has been presented to the Board," followed by the conclusion that the Board did not have

32 *Reasons for Decision Shiha Energy Transmission Ltd.* (January 2000), MH-4-99 (NEB).

33 Shiha is owned by Paramount Resources Ltd., Berkley Petroleum Corporation, and the Fort Liard Band.

34 Paramount Resources Ltd. and Berkley Petroleum Corporation.

35 Approval was received from the Province of British Columbia in December 1999.

36 R.S.C. 1985, c. F-7.

jurisdiction over the downstream facilities.[37] The regulator then proceeded to consider and approve the Shiha application for the Liard Pipeline Project.[38]

The *Shiha* case also involved an interpretation by the NEB of its jurisdiction for environmental screening pursuant to s. 18 of the *CEAA*. The NEB determined that the Shiha Pipeline, gathering facilities, and battery constituted a single project pursuant to s. 15(2) of the *CEAA* for the purposes of the environmental assessment. In conducting its environmental assessment, the NEB expanded the *CEAA* definitions of "environment" and "impact to the environment" to include the definitions found in the *Mackenzie Valley Resource Management Act*,[39] pursuant to which the NEB was a responsible authority in respect of the gathering facilities and battery.

(iv) The Government of the Northwest Territories Complaint about Jurisdiction over the NOVA Pipeline System[40]

NOVA Gas Transmission Ltd. ("NGTL") survived for another year under provincial jurisdiction. The issue of NGTL jurisdiction has been festering for many years. While articles have been written about the possible results of jurisdictional litigation,[41] no adjudication had been triggered until a combination of events culminated in the Government of the Northwest Territories ("GNWT") filing a complaint on May 7, 1999, that requested that the NGTL system in Alberta be declared a federal pipeline subject to the jurisdiction of the NEB.

The GNWT complaint was precipitated by a combination of increased exploration and development in the Northwest Territories and the merger of TransCanada PipeLines Limited ("TCPL") and NOVA Corporation. Seeking to facilitate the extension of the NGTL system into the NWT, the GNWT argued that the TCPL and NGTL pipeline systems were effectively part of a single interprovincial work and undertaking.

The NEB was not required to deal with the GNWT complaint or the jurisdiction over the NGTL system. An agreement was reached between the parties and the complaint was withdrawn.

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37 *Supra* note 32, transcript paragraphs 1216-20.

38 The NEB did not grant s. 58 approval to Shiha in respect of the gathering facilities or the battery as the NEB determined that the *Canada Oil and Gas Operations Act*, R.S.C. 1985, c. O-7 [hereinafter *COGOA*] applied to these facilities rather than the *NEB Act*. The *NEB Act* applied only in respect of the pipeline, the point of demarcation being the downstream side of the flow meter at the outlet of the central gas battery. Although the NEB administers COGOA as well as the *NEB Act*, Shiha was required to file an amended application with the NEB to include only the Shiha Pipeline. Shiha filed a separate application with the NEB under COGOA for the construction of the wellsite, flow lines, and battery. The NEB approved all facilities on January 28, 2000, including the Shiha application to construct the 24-kilometre natural gas Shiha Pipeline.

39 S.C. 1998, c. 25.

40 Complaint filed May 7, 1999, by the Government of the Northwest Territories requesting that the pipeline system in Alberta owned by TransCanada PipeLines and called the NOVA system under the jurisdiction of the Alberta Energy and Utilities Board be declared a federal pipeline subject to the jurisdiction of the NEB.

41 Ballem, *supra* note 4; Harrison, *supra* note 4.

b. Tolls

For several years, financial regulation by the NEB has been characterized by a policy of "letting markets work wherever possible." The regulator's philosophy is that competition can be far more effective than regulatory direction in promoting economic efficiency.[42] In 1994, the NEB published its *Guidelines for Negotiated Settlements of Traffic, Tolls and Tariffs*.[43] It has since approved every settlement that has been presented to it, apparently taking the position that compliance with the Guidelines, combined with absence of opposition, will result in just and reasonable tolls.

The infatuation with settlements now seems to be cooling. The 1995 TCPL incentive settlement[44] expired at the end of 1999, with no successor in sight. Enbridge Pipelines Inc. ("Enbridge") did not file its proposed 2000-2004 settlement until April 4, 2000, almost four months after the proposed effective date, and awaits a decision. The inability of parties to reach negotiated solutions required the NEB to hold an oral hearing on a request by TCPL for amendments to certain toll schedules.[45] The NEB also held the first toll hearing for the Maritimes & Northeast Pipeline.[46] Clearly, negotiations between major pipelines and their customers are increasingly difficult. Further, the NEB itself has expressed concern about the impact of negotiated settlements on its ability to discharge its regulatory mandate.[47] In the past year, the regulatory pendulum has started to swing away from the "settle everything" approach and back toward the use of adjudication for dispute resolution.

(i) NEB Financial Regulatory Audits

The regulatory concern about the negotiated settlement process is expressed in a letter to pipeline companies dated February 23, 1999.[48] In this letter the NEB stated that "since the introduction of incentive settlements, the Board has concerns about whether it is maintaining an in-depth knowledge of the operations of pipeline companies sufficient to

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42 K.W. Vollman, "National Energy Board Business Plans and Priorities: 2000-2003" (Joint Conference of the Interstate Natural Gas Association of America and the Canadian Energy Pipeline Association, Calgary, Alberta, 19 April 2000), online: <www.neb.gc.ca/pubs/kwvppsp.pdf>.

43 23 August 1994 [hereinafter "Guidelines"]. The history of the NEB effort to encourage negotiated rather than adjudicated solutions to tolling issues was described in some depth by former NEB chairman Roland Priddle in his presentation to the 1998 Canadian Petroleum Law Foundation Jasper Research Seminar, "Reflections on National Energy Board Regulation 1959-98: From Persuasion to Prescription and on to Partnership" (1999) 37 Alta. L. Rev. 524 at 545ff.

44 Incentive Cost Recovery and Revenue Sharing Settlement reached by parties with respect to the components of TransCanada's Revenue Requirement, (except for those cost of capital related matters determined in RH-2-94), effective for the years 1996-1999.

45 See *Reasons for Decision In the Matter of TransCanada PipeLines Limited Interruptible Transportation and Short Term Firm Transportation Tariff Amendments* (April 2000), RH-1-99 (NEB) [hereinafter RH-1-99].

46 *Maritimes & Northeast Pipeline Management Limited Application for Final Tolls* (1 December 1999), RH-1-2000 (NEB) [hereinafter M&NP].

47 See discussion of *Letter To: Pipeline Companies Under the Board's Jurisdiction Re: Financial Regulatory Audit Policy* (23 February 1999) (N.E.B.) in section II.A.1.b(i), below.

48 This letter is discussed in M. Smith, *et al.*, "Recent Legislative and Regulatory Developments of Interest to Oil and Gas Lawyers" (2000) 38 Alta. L. Rev. 170. It is included here in the context of the current status of the NEB settlement process.

ensure that it is able to meet its responsibilities under the *National Energy Board Act*." It then proceeded to expand the focus of its pipeline Financial Regulatory Audit Policy beyond ensuring compliance with the *Oil/Gas Pipeline Uniform Accounting Regulations*.[49]

To this point, settlements proffered by the pipelines to the regulator for approval had been approved virtually as a matter of course. The February 23, 1999, audit letter represented the first time that the NEB showed any discomfort with the negotiated settlement "let the market work" method of regulation. The regulator is pursuing its audit function more strenuously. Thus settlement approvals may become less routine.

On March 23, 2000, the NEB issued its Final Audit Report to Enbridge. The audit was conducted under the February 23, 1999, audit policy. The issue of solicitor-client privilege was raised in the context of access to the minutes of directors' meetings. Enbridge declined to produce the documents on the basis of solicitor-client privilege, while the NEB took the position that its audit policy established that produced documents remained confidential. Faced with Enbridge's continued refusal to provide full access to the original minutes and supporting information, the NEB stated that the Enbridge claim of solicitor-client privilege was not a sufficient basis to preclude such access and that limited waiver of privilege for the purpose of complying with the audit would not constitute a complete waiver of privilege by Enbridge, but that it had decided it would not pursue further access.

Enbridge also declined to provide to the NEB audited financial statements for Enbridge Pipelines Inc. (as opposed to the consolidated Energy Transportation operations of Enbridge Inc.), even though they were filed with Revenue Canada and the Ontario Securities Commission. The NEB required that such financial statements be filed.

Finally, the NEB directed that a more concerted effort be made by Enbridge to measure the success of its negotiated incentive settlement in order to allow NEB staff to determine with more confidence during an audit that the process is working, thereby reducing the need for third-party intervention. Enbridge agreed to report on the performance measures outlined in its renegotiated incentive tolling agreement. The attitude of the NEB in the Enbridge audit, however, is perhaps a harbinger for the future.

(ii) RH-1-99: TransCanada PipeLines Interruptible Transportation Tariff Amendments[50]

In October 1999 TCPL applied to the NEB pursuant to Part IV of the *NEB Act* for approval of amendments to the methodology it uses to price and allocate Interruptible Transportation ("IT") and Short Term Firm Transportation ("STFT") services. Essentially, TCPL sought limited pricing discretion which it thought necessary to allow it to compete with other pipelines.

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49 S.O.R./83-190.

50 *Supra* note 45.

After refusing TCPL's request for interim relief, the NEB acceded to customer demands for a public hearing. Hearing Order RH-1-99 was issued on November 18, 1999 (noteworthy in that it was the first and only rate hearing order issued by the NEB in the 1999 calendar year) and a public hearing was held in January/February 2000.

TCPL suggested that the change in methodology was required because of current market conditions, including increased pipeline capacity[51] that gives shippers new alternatives and an incentive to decline to renew their firm transportation contracts with TCPL. It was feared that shippers continuing to use the TCPL system would "migrate" from firm service to interruptible service which was available at a lower price with virtually equal reliability. TCPL requested that the NEB allow it to continue allocating available capacity through a bidding process, but suggested that it should be able to establish a minimum bid price within a specified range prior to the bidding process in response to changing market conditions.

The TCPL proposal faced virtually unanimous opposition from its customers. Intervenors argued that "migration" had not been proven, that pricing discretion was not consistent with the extensive "market power" of TCPL, and that the bid floor should remain at the level of incremental variable costs required to move interruptible volumes. Several intervenors, including all three eastern local distribution companies ("LDCs") and the Canadian Association of Petroleum Producers ("CAPP"), defaulted to an alternative proposal to set the IT bid floor price at 80 percent of the applicable 100 percent load factor Firm Transportation ("FT") toll.

In its decision, issued in April 2000, the NEB denied the TCPL proposal for pricing discretion.[52] The NEB rejected TCPL's pricing discretion, noting a lack of objective criteria for the exercise of such discretion and the lack of accountability for errors in judgment. The NEB also considered that it would be inappropriate and unnecessary for the pricing discretion to apply across the whole TCPL system. The regulator found that the bidding mechanism for IT and STFT services was appropriate,[53] but held that the floor level for IT bids should increase to the 80 percent of FT level. The floor price for STFT would remain at 100 percent of the FT toll.

The NEB rejected all the TCPL arguments. In particular, the regulator expressed the view that the current excess capacity situation on the TCPL system would be "relatively short term" and that further decontracting by firm shippers would not create a serious long-term problem of underutilization. The NEB panel found that present and future migration was not supported by the evidence, suggesting that past decontracting was explainable by factors other than the excess capacity on the TCPL system. The NEB also rejected the TCPL argument that the true cost of providing short-term services is the fully

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51 In 1998 the Northern Border Pipeline Company increased its capacity and the Alliance Pipeline Ltd. ("Alliance") and Vector Pipeline Limited Partnership ("Vector") pipelines were under construction. The Alliance and Vector pipelines are expected to be in service by the fall of 2000.

52 *Supra* note 45.

53 The NEB specifically endorsed bidding as a fair and efficient way of allocating capacity for short-term services. Bids at or near the floor price in periods of excess capacity are consistent with competitive market conditions.

allocated cost equivalent to the 100 percent load factor FT toll. Rather, the NEB endorsed the continued use of a reasonable approximation of incremental variable cost for setting the IT floor price. This conclusion was necessary in order to support the ultimate decision to accept the intervenor proposal to set the floor price at 80 percent of the FT toll.[54]

The NEB also expressed concern with TCPL's market power and "dominant position" in western Canada, which the NEB believed would continue even following competition by companies such as Vector. The regulator specifically noted that TCPL was unable to establish that it "would not be in a position to potentially abuse its market power."[55]

Given how the evidence unfolded during the RH-1-99 hearing, the "no discretion/80 percent FT" decision was not a surprise. What was surprising was the attitude exhibited by the NEB in its written Reasons for Decision. First, it essentially stated that it would not entertain pipeline pricing discretion in the absence of "a comprehensive review of TransCanada's services and pricing methodology."[56] Second, it concluded that "absent an overall rate design review, the incremental variable cost continues to be the appropriate cost-based approach of setting the floor price for IT service on the TransCanada system."[57] Finally, and contrary to a specific previous decision, it took the position that any party offering "alternative proposals and new approaches" should adduce evidence and not advance such "substantive positions" by argument alone.[58] These comments do not appear to be intended to encourage settlements, to promote efficiency, and to allow the

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54 The NEB accepted the LDCs' secondary proposal for the floor price to be set at 80 percent of the FT toll. The primary proposal of the LDCs was to vary the floor price on a monthly basis.

55 RH-1-99, *supra* note 45.

56 *Ibid.* at 18.

57 *Ibid.* at 24.

58 *Ibid.* at 28. This position was taken by the NEB panel in accepting an argument made by the LDCs, who were the last of the intervenors to argue, and without the benefit of any reply by the intervenors whose conduct was impugned. Those intervenors. Renaissance Energy Ltd. and a group of three independent power producers, based their arguments on facts placed on the record through cross-examination, a course of conduct that had been specifically endorsed in an earlier NEB decision:

> Board Ruling — Subject-Matter of Final Argument
>
> THE CHAIRMAN: On Mr. Yates' request, the Board has the following ruling:
>
> Notwithstanding whether an intervenor chooses to adduce evidence or not, and notwithstanding whether an intervenor chooses to take a position on a certain issue in any evidence that he does adduce, that intervenor is not precluded from taking a position in argument on any issue that has been raised in the hearing.
>
> Naturally, such position must be supported by the record.
>
> The underpinnings of a party's position may have been developed through the presentation of direct evidence or through cross-examination.
>
> The only effect of an intervenor not stating his position through evidence prior to final argument is that he does not have his own evidence to support the positions he might take in argument.

National Energy Board In the Matter of the Application Under Part IV of the National Energy Board Act (Toll Application) of Trans Quebec & Maritimes Pipeline Inc. (3 March 1983), RH-4-82 (NEB) Transcript page 5035, per R.F. Brooks, Presiding Member, J.R. Hardie, and J.L. Trudel.

The issue was revisited in the RH-1-2000 hearing in June/July 2000, when Maritimes & Northeast Pipeline cited the RH-1-99 practice direction as a "procedural safeguard" which it had a "legitimate expectation" would be applied in that proceeding. The RH-4-82 Decision was argued to the contrary, and the NEB panel reserved its decision.

market to work. Rather, they encourage regulatory adjudication after longer hearings involving more evidence and witnesses.

(iii) RH-1-2000: Maritimes & Northeast Pipeline Tolls[59]

By application dated February 28, 2000, Maritimes & Northeast Pipeline Management Ltd., on behalf of Maritimes & Northeast Pipeline Limited Partnership ("M&NP"), applied to the NEB pursuant to s. 19(2) of the *NEB Act* for approval of final tolls for the transportation of natural gas for the period December 1, 1999, to September 30, 2000. The oral public hearing was held in Halifax, Nova Scotia in June/July 2000, with the expectation of a fall decision.

Previously, on October 14, 1999, the NEB approved an M&NP application for interim tolls effective November 1, 1999. Cost estimates and assumptions used in setting the interim tolls were subject to review in the RH-1-2000 proceeding, but the NEB declined to revisit issues, including rate of return, which were decided in the initial facilities case held pursuant to NEB Hearing Order GH-6-96.

(iv) Enbridge Line 9 Reversal — Tolls and Priority Access[60]

In 1999 Enbridge sought and obtained NEB approval for tolls to be charged on its Line 9, operating in reversed (east to west) mode to ship offshore crude petroleum between Montreal, Quebec and Sarnia, Ontario.

Enbridge had earlier sought and obtained approval from the NEB to reverse Line 9 and to use a specific negotiated toll methodology for reversal service.[61] In that decision, however, the NEB had declined to accept the Enbridge proposal that shippers that had provided the financial support for the reversal project ("FSA Shippers")[62] be granted priority access to 100 percent of the Line 9 capacity.[63] The NEB required that 20 percent of Line 9 capacity be kept available for nominations on a monthly basis.

In its tolls application, Enbridge proposed lower tolls for FSA Shippers than for non-FSA shippers in recognition of the unique circumstances of Line 9, and specifically of the substantially different circumstances of the shippers that provided financial commitments for the project and shippers that did not.[64] There was NEB precedent for granting

59 M&NP, *supra* note 46.

60 *Decision Re Application for Approval of Tariffs Governing the Transportation of Offshore Crude Petroleum* (2 November 1999) (NEB).

61 *Reasons for Decision Interprovincial Pipe Line Inc.*, Facilities and Toll Methodology (December 1997), OH-2-97 (NEB).

62 The "FSA Shippers" are a group of four owner/operators of Ontario refineries (Imperial Oil, Petro-Canada, Shell Canada Limited, and NOVA Chemicals (Canada) Ltd.) each of which signed the Facilities Support Agreement by which they provided certain commitments of financial support to the reversal project.

63 OH-2-97, *supra* note 61 at 49-54.

64 The toll difference was 25.4 cents per cubic metre (4 cents per barrel) for transportation from Montreal to Sarnia.

priority access to shippers that provided financial support for a pipeline, but not for a priority toll.

Section 67 of the *NEB Act* precludes a pipeline from making "any unjust discrimination in tolls, service or facilities." Section 62 requires that tolls be not only just and reasonable, but also charged at the same rate to all persons "under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route." Section 63 permits the NEB to determine, as a question of fact, whether or not traffic is or has been carried under substantially similar circumstances and conditions. Enbridge took the position that the differential tolls do not constitute discrimination, let alone unjust discrimination. It argued that the circumstances and conditions of FSA Shippers are not substantially similar to the circumstances and conditions of non-FSA shippers, with the result that differential tolls are just, reasonable, and non-discriminatory.

Specifically, Enbridge argued that the financial commitments of the FSA Shippers are not only the *raison d'être* of the reversal project, but they are also real costs for which compensation is warranted. Priority access to 80 percent of the capacity is insufficient compensation for shippers that have guaranteed the recovery by the pipeline of 100 percent of the project costs. A toll that is equal for FSA Shippers and non-FSA shippers would give the non-FSA shippers a competitive advantage over FSA Shippers. Given the financial commitments made by the FSA Shippers, an equal toll would effectively be a lower toll for the non-FSA shippers.The Enbridge application was unopposed. The NEB approved it, but appeared to do so with some reluctance. Noting that no party had raised any concerns about the proposed treatment of non-FSA shippers, or the amount of the proposed toll differential, the Board stated that it was "satisfied that there is no need to address these matters at this time."[65]

The decision shows that the NEB will still accept negotiated solutions that are unopposed, even where the result is to step onto previously untrodden regulatory ground, but it left open the possbility of reconsideration on a later complaint.

(v) Pipeline Return on Equity — 9.90 Percent for Year 2000[66]

In the Multi-Pipeline Cost of Capital decision in 1995,[67] the NEB fixed the equity components of the capital structures of Group 1 pipelines[68] and decreed that the rate of

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65 NEB Letter (2 November 1999) Re: Enbridge Pipelines Inc. (Enbridge) — Application for Approval of Tariffs Governing the Transportation of Offshore Crude Petroleum.

66 NEB letter, dated 2 December 1999 setting the rate of return on common equity for Group 1 pipelines at 9.90 percent for 2000.

67 *Reasons for Decision TransCanada PipeLines Limited, Westcoast Energy Inc., Foothills Pipe Lines Ltd., Alberta Natural Gas Company Ltd, Trans Québec & Maritimes Pipeline Inc., Interprovincial Pipe Line Inc., Trans Mountain Pipe Line Company Ltd., Trans-Northern Pipeline Inc.* Cost of Capital (March 1995), RH-2-94 (NEB).

68 The NEB view of Group 1 and Group 2 pipelines was discussed in *Reasons for Decision Alliance Pipeline Ltd. on behalf of the Alliance Pipeline Limited Partnership*, Facilities and Tolls & Tariffs (November 1998), GH-3-97 (NEB) at 84.

For administrative purposes, and in accordance with its *Memorandum of Guidance on the Regulation of Group 2 Companies* ('Memorandum of Guidance'), most recently issued on 6 return on that equity would be determined in accordance with a formula that relies on the equity risk premium method and keys off long-term Government of Canada bonds. The first return on equity was 12.25 percent for 1995.[69] With a general trending downward of interest rates, the Return on Equity ("ROE") reached 9.58 percent for 1999[70] before coming back up somewhat to 9.90 percent for 2000.

The import of the NEB ruling for 2000 lies in a comparison to Decision U99099 of the Alberta Energy and Utilities Board, issued in November 1999. In a comprehensive consideration of cost of capital of Alberta electric utilities, the EUB held that the ROE should be 9.25 percent in 2000,[71] some 65 basis points lower than that of the NEB.

The level of ROE at both the NEB and EUB is fomenting unrest among the pipelines, which look south of the border to see much higher returns in the United States. Pressure is mounting for one or more of the pipelines to go back to the federal regulator to seek an increase in allowed cost of capital. The pendulum swings back toward adjudication.

c. Facilities

(i) Maritimes & Northeast Pipeline — Satisfaction of Condition 22

Condition 22 of Certificate of Public Convenience and Necessity ("CPCN") GC-95, issued to M&NP for its mainline, required the company to "submit to the Board a written protocol or agreement spelling out Proponent-Aboriginal roles and responsibilities for cooperation in studies and monitoring." The NEB later concluded, apparently on the basis of information that was provided by M&NP to the regulator but not to other interested parties, that M&NP had satisfied Condition 22. The Union of Nova Scotia Indians applied to the Federal Court of Appeal for judicial review.[72]

On review, the Court remitted the matter to the NEB for a redetermination as to whether M&NP had satisfied Condition 22. The NEB established two written proceedings, one to establish a procedure to implement the directions of the Federal Court of Appeal and a second to consider the effect of the Court's decision on the start-up and operation

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December 1995, the Board categorizes the pipelines that it regulates as Group 1 or Group 2. The larger pipelines, which typically have many shippers and require ongoing financial regulatory monitoring, are designated Group 1. Group 2 pipelines are regulated on a complaint basis and are generally subject to a lower level of regulatory monitoring....

Although the Memorandum of Guidance does not identify specific criteria for determining Group 1 or Group 2 status, certain factors have been found relevant when making this determination. These include: (i) the size of the facilities, (ii) whether the pipeline transports commodities for third parties, and (iii) whether the pipeline is regulated under traditional cost-of-service methodology.

69 RH-2-94, *supra* note 67 at 6.

70 NEB letter, dated 24 November 1998, re: Rate of Return on Common Equity ("ROE") for Group 1 Pipelines for 1999.

71 *1999/2000 Electric Tariff Applications, ATCO Electric Ltd., EPCOR Generation Inc., EPCOR Transmission Inc., TransAlta Utilities Corporation* (25 November 1999), U99099 (EUB) at 328.

72 *Union of Nova Scotia Indians* v. *Maritimes and Northeast Pipeline Management Ltd.* (1999), 249 N.R. 76.

of the mainline, pending satisfaction of Condition 22.[73] On December 17, 1999, the NEB determined that M&NP had *partially satisfied* Condition 22 by entering into protocols or agreements with the Union of New Brunswick Indians, the Assembly of Nova Scotia Mi'kmaq Chiefs, the Union of Nova Scotia Indians and the Confederacy of Mainland Mi'kmaq. By letter dated December 21, 1999, the NEB advised M&NP that it considered Condition 22 to be satisfied in full, through M&NP's development of a *protocol* with the Native Council of Nova Scotia (NCNS) through meetings and discussions. In so holding, the NEB referenced the definition of *agreement* provided in the Federal Court of Appeal judgment, being a mutually agreeable set of terms between parties. Although the NEB agreed that terms of a protocol were not necessarily agreed to, a protocol was "expected to be derived from discussions and consultations." The NEB determined that although the document prepared was not executed by M&NP and NCNS, it contained the characteristics of a protocol. It confirmed its decision that Condition 22 had been satisfied in full and accordingly issued two final leave to open orders to M&NP.

(ii) GH-2-99: Maritimes & Northeast Pipeline — Halifax Lateral[74]

M&NP applied pursuant to s. 52 of the *NEB Act* for approval to construct and operate an approximately 121-kilometre natural gas lateral pipeline from the M&NP mainline to Dartmouth, Nova Scotia. It also applied pursuant to Part IV of the same statute for an order pursuant to the M&NP Lateral Policy confirming that no customer contribution-in-aid of construction was required and that the full cost of service for the Halifax Lateral be included in the calculation of the M&NP tolls. In a decision issued in October 1999 the NEB approved the M&NP applications, but not without attendant difficulty.

The M&NP project has struggled with aboriginal issues, and the Halifax Lateral is no exception. One such issue arose during the environmental assessment process. The NEB started by delegating the preparation of the Comprehensive Study Report ("CSR") to M&NP pursuant to s. 17 of the *CEAA*. The *CEAA* requires that the environmental assessment include consideration of the environmental effects of the proposal on aboriginal persons' current use of lands and resources for traditional purposes. Some nine months later (March 1999), the NEB, on behalf of itself and the Department of Fisheries and Oceans Canada ("DFO"), the other responsible authority for the project under the *CEAA*, forwarded the CSR to the Minister of the Environment and to the Canadian Environmental Assessment Agency ("Agency").

The Agency's public comment process concluded in April 1999, almost concurrently with the filing by M&NP of a Traditional Ecological Knowledge Study ("TEK Study") which had not been included in the CSR prepared by M&NP, and which the pipeline said was intended to complete its assessment of the potential effects of the Halifax Lateral on the current aboriginal use of the land. Deciding that there were inconsistencies between

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[73] In November 1999, pending a determination regarding the satisfaction of Condition 22, the NEB issued a restricted authorization permitting M&NP to operate the Mainline. Pursuant to ss. 47 and 19 of the *NEB Act*, the NEB issued interim temporary leave to open which would expire on January 20, 2000, renewable upon application to the NEB.

[74] *Reasons for Decision Maritimes & Northeast Pipeline Management Ltd.* (October 1999), GH-2-99 (NEB) (Halifax Lateral Facilities Application dated 5 June 1998, as amended).

the TEK Study and the CSR, the NEB revoked its delegation of the CSR to M&NP and decided to complete the CSR following the NEB hearing process. Ultimately, the NEB and the DFO concluded that the Halifax Lateral was not likely to cause significant adverse environmental effects provided that the mitigative measures and undertakings committed to by M&NP were implemented. The Minister of the Environment reached the same conclusion after a public comment process was conducted by the Agency, and referred the Halifax Lateral back to the NEB and the DFO for action under s. 37(1) of the *CEAA*. The NEB then approved the project under s. 52 of the *NEB Act*.

Aboriginal issues were also raised in the context of the public consultation issue at the GH-2-99 hearing. Condition 22 of CPCN GC-95, by which the M&NP mainline was approved, required M&NP to submit to the NEB a written protocol or agreement setting out "Proponent-Aboriginal roles and responsibilities for cooperation in studies and monitoring." Satisfaction of Condition 22 was a major issue for the mainline. In the GH-2-99 proceeding, at issue was whether the mainline protocol should be applied to the Halifax Lateral. Ultimately, the NEB decided that it was not willing to impose on M&NP the condition that an agreement be reached with the Assembly of Nova Scotia Mi'kmaq Chiefs, but, absent agreement, it would require M&NP to submit a Halifax Lateral protocol to the NEB for approval prior to the commencement of construction.

The NEB was required to consider the design of the Halifax Lateral, specifically its capacity. It accepted the size proposed by M&NP, taking the opportunity to state its views that precedent agreements and firm service agreements are the best evidence that a proposed facility will be used, and that the design of the pipeline should also include the capacity required to serve the new prospective market. These views are in accordance with the NEB's "general principles with respect to pipeline design," which require that design capacity include reasonably anticipated market growth.[75] The NEB applied its economic feasibility test by determining that the facilities were likely to be used at a reasonable level over their economic life, and that demand charges were likely to be paid.[76]

In the GH-6-96 proceedings related to the M&NP mainline, the NEB approved a postage stamp toll with a roll-in of costs. In the case of facilities to be added to an existing pipeline, the NEB will not allow roll-in of additional costs unless it is established that the new facilities would provide benefits to the existing system and its shippers. In the absence of such benefits, it is possible that the new facilities would be tolled on a stand-alone basis. The M&NP Lateral Policy resulted from the realization that a strict application of the NEB policy could inhibit the development of the market in the Maritimes in this greenfield situation. The Lateral Policy is designed to protect the interests of shippers by setting a test toll against which the economics of projects can be measured, while at the same time allowing the pipeline to give recognition to the existence of uncontracted markets. The NEB hoped that a postage stamp toll and the Lateral Policy would strike an appropriate balance of factors that would lead to future development of Maritime markets.[77]

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75 *Ibid.* at 10.
76 *Ibid.* at 6.
77 *Ibid.* at 26.

The Lateral Policy provides that M&NP will construct facilities to deliver gas, without requiring a contribution-in-aid of construction from the new customers, provided that the contracted demand generates sufficient revenue in each year of its operation to recover the cost of service associated with the facilities. If the test is failed, the amount of the customer contribution is calculated as the net present value of the revenue shortfall over the period of the contract. In the Halifax Lateral case, the NEB could only decide that no contribution was required by applying the Lateral Policy test over a period of 25 years, even though the relevant contracts were for only a ten-year term. Given that M&NP decided to waive the requirement of a customer contribution and to rely instead on the uncontracted market potential, the NEB required M&NP to absorb any shortfall that may occur in the 25-year period.[78]

On December 9, 1999, the NEB issued CPCN GC-101 to M&NP for the construction and operation of the lateral, at which time the NEB also approved the general route of the lateral. M&NP then applied for approval of the proposed detailed route. Following receipt of a single written statement of opposition, the NEB decided to hold a public hearing respecting the detailed route of the lateral,[79] but subsequent withdrawal of the objection caused the hearing to be cancelled.

(iii) GH-4-99 Maritimes & Northeast Pipeline — Saint John Lateral[80]

In November 1999, the NEB approved the M&NP application for a CPCN for the construction and operation of a natural gas lateral pipeline from the M&NP mainline in New Brunswick to the City of Saint John, together with related toll and tariff matters. In December, CPCN GC-102 was issued.

The Saint John Lateral proceeding involved similar issues to the Halifax Lateral, but involved less controversy. The environmental assessment was dealt with by delegation of the CSR to M&NP, leading ultimately to a finding by the Minister of the Environment that the project was not likely to cause significant adverse environmental effects. The economic feasibility test was applied and met, subject to a condition requiring M&NP to file assurances that the customers had executed project-specific gas supply agreements to underpin the volumes contained in firm service transportation agreements. The Lateral Policy test was met, and therefore, the full cost of service of the lateral would be included in the tolls without a contribution-in-aid of construction.

M&NP later applied for approval of the detailed route. Following the receipt of two written statements of opposition, the NEB set the detailed route for public hearing[81] to determine the best possible route of the pipeline and the methods and timing of its construction.

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78 *Ibid.* at 28.

79 *Maritimes & Northeast Pipeline Management Ltd. (M&NP) — Halifax Lateral — Detailed Route Hearing*, MH-1-2000 (NEB).

80 *Reasons for Decision Maritimes & Northeast Pipeline Management Ltd. Saint John Lateral Facilities, Application dated 5 June 1998 as amended* (November 1999), GH-4-99 (NEB).

81 *Maritimes & Northeast Pipeline Management Ltd. (M&NP) — Saint John Lateral — Detailed Route Hearing*, MH-2-2000 (NEB).

(iv) Maritimes & Northeast Pipeline — Leave to Open Point Tupper Lateral

Subsection 47(2) of the *NEB Act* requires that the NEB satisfy itself that a pipeline can be safely opened for transmission before it grants leave to open. An application by M&NP for leave to open the Point Tupper Lateral was rejected by the NEB on the basis that M&NP had not established that the lateral could be safely opened for the transmission of gas. After considering the hydrostatic tests and the Technical Report - Point Tupper Lateral Pipeline Integrity Engineering Assessment dated December 1999,[82] concerns were raised respecting the integrity and safety of the lateral.

In particular, the NEB was concerned with the finding that failed parts of the line pipe contained defects exceeding the limits allowed by CSA Standard Z245.1-95 and the finding that further sections of the pipe probably contained defects. The Technical Report identified longitudinal seam weld imperfections, some of which were considered "significant." The findings raised "considerable uncertainty" for the NEB respecting the overall integrity and safety of the lateral. The regulator rejected the conclusion of the *Fitness-for-Purpose Study of the Sable Offshore Energy Project, Natural Gas and Natural Gas Liquids Eight Inch Pipelines*[83] that the pipeline was fit for its intended purposes.

After considering the evidence, the NEB concluded that the lateral did not provide the level of integrity and safety that the NEB required for newly constructed pipelines. It also noted that the natural gas liquids pipeline was in close proximity to another natural gas pipeline which was constructed using the same pipe, thereby increasing the overall risk for both pipelines. The NEB made suggestions to M&NP to implement measures such as conducting pipeline digs, examining and repairing, conducting internal line inspections, and repairs or replacements of sections of the pipeline, but was not prepared to grant leave to open until the integrity issues were resolved.

(v) Detailed Route Hearings

The NEB held several hearings over the past year with respect to the detailed routing of pipelines, particularly that of the Alliance Pipeline which had received a certificate of public convenience and necessity from the NEB in December 1998[84] after a 77-day public hearing and a comprehensive study on potential environmental effects. The NEB also approved the general route of the pipeline at that time. Alliance subsequently applied for approval of the detailed route, and hearings were held by the NEB[85] in response to route objections that were filed by landowners.

Section 36 of the *NEB Act* limits issues for the detailed route hearings to (i) the best possible detailed route of the pipeline and (ii) the most appropriate methods and timing

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82 The NEB does note that the hydrostatic tests complied with the manual approved by the NEB.

83 The Welding Institute, TWI Report 12507/2/99 Rev. 1, "Fitness-for-purpose study of sable offshore energy project, natural gas and natural gas liquids 8" (December 1999).

84 The Alliance Pipeline is a high-pressure natural gas system from northeastern British Columbia and northwestern Alberta across Saskatchewan to the midwest U.S.

85 Pursuant to hearing orders MH-1-99 (Saskatchewan and Eastern & Central Alberta) and MH-2-99 (Northwestern Alberta and Northeastern British Columbia).

of constructing the pipeline. Issues considered at the certificate hearing, such as general route or need for the pipeline, are not revisited, and compensation for land use is outside the scope of the proceedings.

The Alliance detailed route hearings involved consideration of objections that raised issues including safety, anticipated future irrigation projects, potential development, noise, drainage, the number of already existing pipelines, disturbances to wood ravines and farming practices, restrictions on land use, and the effect on land values. In most cases, the NEB determined that the route proposed by Alliance was the best possible route and that the pipeline company had committed to the most appropriate methods and timing of construction.[86]

A review of the various decisions suggests that there are no particular tests that are applied by the NEB in determining the best route. Rather, various factors are considered, with the weight to be given to any particular factor being a matter to be decided by the NEB in the reasonable exercise of its discretion, in the circumstances of each case.[87]

On environmental and land use matters, the issue is whether there are "significant" environmental differences between the proposed route and alternative routes[88] and whether the pipeline company has committed to the most appropriate methods and timing of construction (which may include consideration of depth of cover, slope instability, *etc.*). Factors that were considered include: differences in length of pipeline (slight differences are not determinative); consideration given to avoidance of wetlands;[89] drainage; potential for soil erosion; present and future agricultural production; slope stability; minimization of overall disturbance; whether the proposed route deviates from existing linear disturbances for reasonable environmental reasons; the amount of necessary clearing; minimization of length and area of land which would be disturbed by construction and operation; mitigation plans by the company and whether such plans addressed concerns of the landowner;[90] and sensitivity of breeding sites for species and whether there is evidence of a confirmed nesting of a significant species.[91]

The NEB ruled that it may consider the cumulative effect of several pipelines: "[W]hile the disruption to the farming operation from individual construction and maintenance

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86 See *e.g.*, *Decision on Route Objection by Bryan Ellingson* (heard by the Board on 2 June 1999 in Grande Prairie, Alberta), MH-2-99 (NEB) [hereinafter MH-2-99 Ellingson]; *Decision on Route Objection by Dale & Gwen Smith* (heard by the Board on 31 May 1999 in Edmonton, Alberta), MH-2-99 (NEB) [hereinafter MH-2-99 Smiths].

87 See *e.g.*, *Decisions on Route Objections by Don & Linda Liland, Franklin & Joan Moller, Brian & Teresa Fast, and Peter & Levke Eggers* (heard by the Board on 1 & 2 June 1999 in Grande Prairie, Alberta), MH-2-99 (NEB) [hereinafter MH-2-99 Liland] at 5.

88 *Decision on Route Objection by Ms. Margaret Cook* (heard by the Board on 29 & 30 April 1999 in Edmonton, Alberta), MH-1-99 (NEB). The decision of the Board in respect of the objection by Ms. Katharine Murphy O'Flynn considers "residual environmental effects" after mitigation. See, *infra* note 89.

89 *Decision on Route Objection by Ms. Katharine Murphy O'Flynn* (heard by the Board on 15 April 1999 in Regina, Saskatchewan), MH-1-99 (NEB).

90 MH-2-99 Smiths, *supra* note 86.

91 *Decision on Route Objection by Alex and Mary Banga* (heard by the Board on 13 April 1999 in Regina, Saskatchewan), MH-1-99 (NEB) [hereinafter MH-1-99 Banga].

activities may be short term and mitigable, the cumulative disruption of six and now seven pipelines is greater than the sum of the disruption from the individual activities and represents a special situation."[92]

On engineering and safety matters, since details of design, safety, and constructability are generally addressed at the certificate hearing stage, the NEB limited its concerns to *site-specific issues* regarding design, safety, and constructability (*i.e.*, the regulator may consider whether the nature of the terrain would affect constructability). An illustrative issue was whether the proximity of the proposed route to existing residences or future building sites presented a safety concern.

Incremental cost to the company is a valid routing concern that must be weighed along with all other factors.[93]

Evidence regarding whether routing conflicts with present or future land use may be a factor. Issues also include avoidance of residences[94] and whether construction will affect the future development or efficiency of projects, such as drainage projects.[95]

Issues were raised with respect to the siting of facilities such as compressor stations.[96] The NEB concluded that compressor stations and other surface facilities were included in the definition of "pipeline" in the *NEB Act* and that the siting of a compressor station could be considered as part of the detailed route hearing.

d. Gas Export

(i) GH-1-99: Imperial Oil Resources Limited and Boston Gas Company — Export Licence for Sable Gas[97]

In 1999 exports of natural gas from Canada increased to 3.33 trillion cubic feet, a new record high.[98] The year 1999 also saw the NEB issue the first licence to export gas produced from the Sable Offshore Energy Project ("SOEP") to be transported in the Maritimes & Northeast Pipeline.

Imperial Oil Resources Limited ("IORL"), a SOEP producer, and Boston Gas Company ("BGC"), an LDC customer, submitted a joint application pursuant to s. 117 of the *NEB Act* and the *National Energy Board Act Part VI (Oil and Gas) Regulations*[99] for the

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92 *Decision on Route Objection by John and Linda Irving* (heard by the Board on 14 April 1999 in Regina, Saskatchewan), MH-1-99 (NEB).

93 MH-2-99 Liland, *supra* note 87.

94 MH-2-99 Ellingson, *supra* note 86.

95 MH-1-99 Banga, *supra* note 91.

96 *Decision on Route Objection by Mr. Paul Vincent Dyke* (heard by the Board on 12 April 1999 in Regina, Saskatchewan), MH-1-99 (NEB).

97 *Reasons for Decision Imperial Oil Resources Limited and Boston Gas Company*, Gas Export (June 1999), GH-1-99 (NEB) [hereinafter GH-1-99].

98 *Oilweek: Canada's Oil and Gas Authority*, Volume 51, No. 16, citing U.S Department of Energy import data.

99 SOR/96-244 [hereinafter *Part VI Regulations*].

export licence. The NEB decided to hold an oral hearing in which the major issues were whether the NEB Market-Based Procedure ("MBP") should apply to Sable gas, and if it did, whether the joint applicants had complied with it.

Since 1987 the NEB has been relying on the MBP to discharge the statutory requirement[100] that gas to be exported must be surplus to reasonably foreseeable Canadian requirements. The information requirements of the MBP are set forth in the *Part VI Regulations*. The MBP, which is applied through public hearings and ongoing monitoring, seeks to allow market forces to operate while permitting the regulator to intervene in cases of market failure. The public hearing aspect has three components — the Complaints Procedure, the Export Impact Assessment ("EIA"), and the Public Interest Determination — which must be addressed before a licence will be issued. Ongoing monitoring is conducted by the regulator to determine if markets are functioning normally.

In summary, the NEB determines that gas to be exported is surplus to Canadian needs if:

1) there are no complaints registered under the Complaints Procedure;

2) the EIA indicates that Canadians will have no difficulty in meeting their energy requirements at fair market prices;

3) there are no other major public interest concerns; and

4) ongoing monitoring suggests that markets are functioning normally and identifies no other issues relating to the evolution of supply or demand that cast doubt on the future ability of Canadians to meet their energy requirements.[101]

In this case there were no complaints. There were, however, issues with respect to the EIA. IORL and BGC did not undertake a project-specific or Sable-specific EIA, choosing instead to follow the established practice of adopting the EIA contained in the NEB Technical Report entitled *Canadian Energy Supply and Demand 1993-2010*.[102] In response to a directive in the NEB hearing order that applicants relying on the NEB EIA should be prepared to speak to it as part of their evidence, the joint applicants adduced expert evidence that the proposed export was not likely to cause Canadians difficulty in meeting their energy requirements at fair market prices.

The Public Interest Determination involves consideration by the regulator of various other relevant matters, such as whether the gas is under contract, the nature of the supply and sales arrangements, evidence that the export volumes will be taken, availability of pipeline space, upstream and downstream transportation arrangements, and environmental issues.

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100 *NEB Act*, *supra* note 30, s. 118.

101 GH-1-99, *supra* note 97 at 4.

102 December 1994.

IORL and BGC provided details of the gas export sale (including the pricing formula), the market, and the transportation arrangements. With respect to supply the joint applicants relied on the findings of the Joint Public Review Panel,[103] the NEB,[104] the Commissioner of the Canada-Nova Scotia Offshore Petroleum Board ("CNSOPB"),[105] and the CNSOPB itself,[106] all arising out of the original facilities application by M&NP. IORL/BGC also relied on the Joint Review Panel Report with respect to the assessment of the potential environmental effects of the facilities necessary to produce the gas and transport it to the border.

The only opposition to the export licence application was voiced by the Province of New Brunswick, which argued that the application should be denied or delayed on the basis that (a) there was insufficient Sable gas to serve the needs of Maritime Canada and (b) Maritime Canadian customers had not been given an opportunity to contract for the gas. New Brunswick took the position that the MBP, which had been developed in the context of gas from the Western Canada Sedimentary Basin ("WCSB"), should not be applied to Sable gas because of the lack of a properly functioning market.

The NEB approved the application and, with the approval of the Governor in Council, issued Export Licence GL-294. In the process of reaching its decision, the regulator took the view that the MBP is an appropriate procedure for assessing the merits of the application to export natural gas from the SOEP.[107] It also accepted reliance on the 1994 NEB Technical Report to conclude that Canadians would not likely experience difficulty in meeting their energy requirements at fair market prices, thereby satisfying the EIA component. The NEB also accepted the supply evidence of IORL/BGC and rejected the New Brunswick position on supply which had been advanced only through cross-examination and argument, without the filing of any written evidence or presentation of witnesses.

The NEB also concluded that no further environmental assessment was required. It went on to reject the New Brunswick argument that the Sable Island market is isolated from the North American gas market. Noting that SOEP was developed in the context of a North American gas market to satisfy domestic demand as well as the export market, the NEB refused to delay its decision and agreed with the joint applicants that all parties could at any time negotiate arrangements to buy gas. If necessary, buyers have the opportunity to complain about applications for licences to export natural gas. The NEB concluded that the proposed export was consistent with the Joint Review Panel Decision and reflective of normal commercial activities in the North American natural gas market.

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103 Canadian Environmental Assessment Agency, Nova Scotia Department of Environment, and National Energy Board, *The Joint Public Review Panel Report — Sable Gas Projects* (October 1997).

104 *Reasons for Decision, Sable Offshore Energy Project and Maritimes & Northeast Pipeline Project*, Facilities (December 1997), GH-6-96 (NEB).

105 *Report of the Commissioner on the Sable Offshore Energy Project* (19 October 1997).

106 Canada-Nova Scotia Offshore Petroleum Board, *Sable Offshore Energy Project — Development Plan Decision Report* (December 1997).

107 GH-1-99, *supra* note 97 at 12.

The IORL/BGC application has been the only application for an export *licence* in respect to Sable gas. It was driven by the requirement that BGC obtain a long-term licence to satisfy the Massachusetts regulator. All other exporters are sending gas out of the country under the authority of export *orders*, which do not require compliance with the MBP.

The essence of the NEB decision was the continued application of the MBP and an acceptance that the market should govern the export of natural gas. If the market becomes such that Maritime Canadians do in fact have difficulty accessing Sable gas, it is likely that the NEB will see an application to have the MBP apply to export orders or be changed entirely.

Unless local regulators, project lenders, acceptable corporate risk profile, or other reasons require a long-term *licence*, an exporter can use s. 15 of the *Part VI Regulations* to obtain an *order* to export an unlimited amount of gas for a period not exceeding two years.[108] The orders are issued as a matter of course by the NEB on 48 hours' notice. One of the advantages of utilizing an export order, as compared to an export licence, is that the MBP, which applies to licences but not to orders, requires disclosure of the price at which the sale of gas is made. The *National Energy Board Export and Import Reporting Regulations*[109] require holders of export orders (and licences) to report volumes and prices. However, the prices are only published in a subsequent month by the NEB on an aggregate basis, by export point, meaning that it is difficult if not impossible for competitors to determine the exact price at which the gas was sold.

In the hearing related to an application by Enco Gas Ltd. to export gas from British Columbia,[110] the NEB required export applicants to develop their own Export Impact Assessments. It appears, therefore, that the IORL/BGC application is the last for which the regulator was prepared to accept reliance on its own 1994 Export Impact Assessment.

e. Pipeline Access

(i) The Fletcher Challenge Case for Directed Pipeline Access[111]

Fletcher applied for an order under s. 71 of the *NEB Act* directing access to a gas pipeline owned by Renaissance. The NEB rejected the application on the basis that it was not in the public interest, but required Renaissance to prepare a tariff to provide the terms and conditions for the allocation of excess capacity and non-discriminatory expansion policy.

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108 Section 15 also permits the export by order of not more than 30,000 cubic metres per day of gas for a period of two to twenty years.

109 S.O.R./95-563.

110 *Hearing Order* (20 August 1999), GHW-3-99 (NEB).

111 *Application by Fletcher Challenge Energy Canada Inc. ("Fletcher") Pursuant to Subsection 71(2) of the NEB Act for Access to a Renaissance Energy Ltd. ("Renaissance") Gas Pipeline* (22 December 1999) (NEB).

The case is useful because s. 71 applications are rare and written guidance from the NEB even more so. In this case Renaissance had constructed and was operating a Group 2 pipeline as a contract carrier with all the available capacity being used by Renaissance. Fletcher volumes could only be accommodated on the pipeline by either expansion or allocation of existing capacity. The question for the NEB was to determine whether it would be in the public interest to allow Fletcher access to the pipeline.

In a letter decision the NEB confirmed its recognition of gas pipelines as contract carriers, while oil pipelines are common carriers. It went on to state, however, that under either characterization it may, as required by the public interest, impose conditions on the traffic, tolls, or tariffs which alter or modify the traditional role of such pipelines. Group 2 gas pipelines may be required to establish an open access tariff to allow all parties to have an equal opportunity to access the pipeline on similar contractual terms if it has been shown to be in the public interest to do so.

For two reasons, the NEB declined to order expansion of the Renaissance pipeline under s. 71(3). First, the record was not clear as to what expansion facilities would be required. Second, extra-jurisdictional downstream facilities might, unless expanded, be impediments to the utilization of any expansion of the Renaissance pipeline.

The regulator also declined to use s. 71(2) to order allocation of existing pipeline capacity, which would in effect be a directed decontracting of Renaissance volumes from its NEB-approved pipeline. Upstream production entitlements were not clear on the evidence, and in any event were within provincial jurisdiction and governed by Saskatchewan legislation.

Ultimately, the NEB was not persuaded by the evidence that granting the Fletcher application would be in the public interest. It did, however, leave the door open for further applications.

2. NATIONAL ENERGY BOARD — OTHER DEVELOPMENTS

a. Speeches by Kenneth W. Vollman, Chairman

Speeches by NEB members provide useful insight into the policies of the federal regulator. Kenneth W. Vollman, the Chairman of the National Energy Board, utilized this method of communication in two recent presentations to energy conferences.

The first presentation was given on April 19, 2000, to a joint conference of the Canadian Energy Pipeline Association and the Interstate Natural Gas Association of America.[112] In his speech entitled "National Energy Board Business Plans and Priorities: 2000-2003" Mr. Vollman discussed various aspects of the NEB business plan which could have broad-ranging impact on the sector. The first goal of the business plan is to move toward goal-oriented regulation, which is intended to enable the pipeline industry to

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112 K.W. Vollman, Chairman, National Energy Board, "Address" (Joint Conference of the Interstate Natural Gas Association of America and the Canadian Energy Pipeline Association, Calgary, Alberta, 19 April 2000).

rationally address risks in order that NEB-regulated facilities are not only safe but are also perceived as safe. The *Onshore Pipeline Regulations, 1999*[113] are the first set of goal-oriented regulations. Others, which are at various stages of development, will expand the regulatory style to other areas of NEB responsibilities. The NEB is also using companion Guidance Notes that provide assistance to interested parties in complying with the requirements of the regulations. Guidance Notes for the *Onshore Pipeline Regulations, 1999* were developed cooperatively with the regulated companies to promote shared responsibilities for safety and the protection of the environment.

Another goal of the NEB business plan is to ensure that Canadians derive the benefits of economic efficiency. The regulator continues to follow a policy of "letting markets work wherever possible," and takes the view that competition in gas and oil transmission could be far more effective than regulatory direction in promoting economic efficiency. The NEB encourages negotiated solutions during what it sees to be a transition from a heavily regulated transportation sector to an anticipated world of workable competition. While expecting that considerable flexibility in toll methodologies and regulatory processes will be required, Mr. Vollman suggested three principles for the transition market:

1. Incumbent pipelines should respond in a competitive fashion, using their assets in creative ways to maximize value to their shippers and to themselves.

2. Parties should recognize that investments made by incumbent pipelines were made in heavily regulated markets.

3. Incumbent pipelines often retain considerable market power and are not operating in fully competitive markets.

With respect to regulatory process, Mr. Vollman again cited flexibility and the often-used metaphor of "two doors into the NEB — one being public hearings and the other being 'negotiated settlements.'" He also offered to examine other approaches, such as facilitation, mediation, or workshops to determine suitability for economic decision-making.

Mr. Vollman also indicated that the NEB has a role to play in the provision of information that will further promote efficient market solutions. It seeks to ensure that the regulatory framework allows market participants to manage their business risk, and as part of that initiative it will undertake energy market assessment studies. It will also monitor, analyze, and report on key market and regulatory developments on an ongoing basis.[114]

The second presentation, entitled "The Regulator's Role — Promoting the Public Interest," was given to the World Forum on Energy Regulation in Montreal on May 24, 2000.[115] It is enlightening for at least two reasons. First, it provides a regulator's view

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113 SOR/99-294.

114 *Supra* note 112 at 10-11.

115 K. Vollman, Chairman, National Energy Board, "The Regulator's Role — Promoting the Public Interest" (World Forum on Energy Regulation, Montreal, 24 May 2000).

of the definition of "public interest." Second, it signals that the regulator is prepared to use the full "tool kit" to facilitate dispute resolution.

Mr. Vollman states, there is no precise definition of "public interest," and it is "a shifting mix of economic, environmental and social interests that changes as society's values and preferences change over time." Asserting that it is clear that the public interest embodies the concept of "the greatest good for the greatest number," Mr. Vollman says that the regulator must estimate the overall good a project may create against its potential negative aspects, balance its various impacts, and make a decision. Two trends — reliance on the marketplace and protection of the environment — have created a world in which business makes investment decisions and governments set conditions under which investments can proceed. In Mr. Vollman's view, these are exactly the proper roles for the private and public sectors.

The regulatory "tool kit" includes arbitration (oral and written public hearings), mediation (formal or informal hearings), suasion (workshops, speeches, publications), "showing the way" (white papers, rulemakings), and publication of information to improve the workings of the markets. An acknowledgement that a regulatory proceeding may be the preferred route, when necessary, suggests an enhanced appreciation that adjudication can be an effective recourse.

b. Electronic Regulatory Filing

Electronic regulatory filing ("ERF") is intended to move the NEB away from a paper-based regulatory process to an electronic system for the creation, exchange, use, and re-use of regulatory information. It is an effort to streamline the regulatory process, to improve levels of service and communication, to reduce the cost of regulation, to optimize business practices, and to assist participants regardless of their proximity to the Calgary office of the NEB.[116]

In alignment with the NEB Strategic Plan,[117] ERF is intended to increase public participation, to improve access to the NEB's information holdings, and to reduce the cost of participating in the regulatory process. For the purpose of seeking industry input, the ERF External Committee has been established, and is comprised of NEB and Ontario Energy Board representatives, and representatives from regulated oil, gas, and electricity components.

In 1999 the NEB conducted its first two pilot projects for ERF, applying the new filing requirements in respect of the M&NP tariff filing and the TCPL quarterly surveillance report filing. To fully implement ERF, the NEB is also proposing changes to the regulations under the *NEB Act* and changes to the *Canada Oil and Gas Operations Act*. Changes will also be made to the *National Energy Board Rules of Practice and*

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116 See Electronic Regulatory Filing Project (15 January 1999).

117 NEB Strategic Plan 2000-2003 (28 February 2000). The NEB Strategic Plan is focused on meeting the needs of the public to be involved with NEB issues and addressing issues regarding safety, protection of the environment, and economic efficiency.

Procedure, 1995[118] to permit participants to file documentation through electronic means.

On March 27, 2000, the NEB sponsored a workshop in Calgary to discuss ERF with lawyers practising before the regulator. Various comments were received and discussed, with an emphasis on how notification and service requirements could be met electronically. The present expectation is that ERF will be implemented in the first quarter of 2001. A prototype is, however, already available on the NEB website, which provides access to transcripts dating back to 1991 and decisions dating back to 1985.[119]

c. Alternative Dispute Resolution Pilot Project

In December 1999 the NEB announced that it would be implementing a pilot project for the use of alternative dispute resolution ("ADR") in detailed route proceedings conducted under ss. 34 and 35 of the *NEB Act*. After a pipeline company has received a CPCN, it must serve notice on the owners of all lands it wishes to acquire who may then object and seek a public hearing. The objective of the pilot project is to utilize mediation to resolve disputes between pipeline companies and landowners or other parties early in the process, before a hearing is required.

Essentially, the mediation is to apply to disputes regarding detailed routes of approved pipelines or methods and timing of construction. The parties are generally limited to the pipeline company and the landowner. The mediator will be NEB staff, trained in mediation. There will be voluntary recourse to a hearing.

The Department of Justice provided funding to establish the ADR pilot project that will be utilized in the detailed route hearings relating to the Saint John and Halifax laterals of the Maritimes & Northeast Pipeline. The hope is that mediation will reduce the significant costs of detailed route hearings (many of which are settled on the "courthouse steps") that are caused by the statutory requirement that the hearing be held "within the area in which the lands to which the [owner's statement of objection] relates."[120] This means that, in the pilot project examples, costs would be incurred to send three NEB members, one NEB lawyer, and three or four board staff from Calgary to the vicinity of the landowners' property in New Brunswick or Nova Scotia. The pipeline company would also have to send its staff and lawyers. There would also be costs of hearing rooms and transcripts, all of which might be avoided through mediation.

It is expected that the pilot project will be evaluated once the Halifax and Saint John lateral detailed route hearings are concluded.

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118 SOR/95-208.

119 Online: National Energy Board <www.neb.gc.ca>.

120 *NEB Act*, *supra* note 30, s. 35.

d. Energy Supply and Demand

(i) National Energy Board Report on Canadian Energy Supply and Demand to 2025[121]

This report provides a summary of the long-term energy outlook for Canada. It differs from previous supply and demand reports issued by the NEB because it does not contain an Export Impact Assessment, although the information contained in the report could be used to prepare assessments. Following a general review of the end-use energy demand, which the NEB expects to increase (although at a slower pace than the growth of Gross Domestic Product) the regulator reviews end-use energy demand for various sectors of the economy, including residential, commercial, industrial, road transportation, other transportation, and non-energy use of hydrocarbons. It also provides detailed data for secondary energy demand by the various regions in Canada. The NEB predicts that the production of primary energy for the years 1997-2025 will be lower than the average annual production growth of 4.5 percent in the 1990s. It expects lower demand growth with respect to domestic primary energy demand for the years 1997-2025 than for the period 1990-1997, which experienced an approximately 2.2 percent growth per year. Oil and coal continue to dominate energy imports, while natural gas and NGL imports were (and are predicted to remain) negligible.

(ii) National Energy Board Report on Short-Term Natural Gas Deliverability from the Western Canada Sedimentary Basin 1998-2001[122]

This report provides a summary of, and examines the factors affecting, short-term gas supply in the Western Canada Sedimentary Basin ("WCSB"). Although natural gas prices have been low in Canadian markets due to limitations on the capacity to remove natural gas from the WCSB to markets,[123] recent developments are predicted to alleviate the constrained pipeline capacity and to assist gas producers in meeting the demands. The NEB predicts that expansions on the TCPL and Foothills Pipe Lines Ltd. systems, together with new pipelines such as Alliance and Vector, will increase take-away capacity. However, the NEB does note that current drilling rates in the WCSB must be increased in order to meet future demand and to fully utilize pipeline capacity.[124]

121 *Canadian Energy Supply and Demand to 2025* (Calgary: National Energy Board, 1999).

122 *Short Term Natural Gas Deliverability from the Western Canada Sedimentary Basin 1998-2001: An Energy Market Assessment* (Calgary: National Energy Board, 1999).

123 *Ibid.* at 12. Approximately 20 percent of natural gas production from WCSB is consumed in the WCSB. Eighty percent is transported by pipeline to eastern Canadian and U.S. markets.

124 *Ibid.* at 21. The NEB notes that there are over 7,000 wells in Alberta and 380 in B.C. not yet producing. It is expected that production from existing wells will face a decline rate of approximately 19 percent per year.

B. PROVINCIAL

1. ALBERTA ENERGY AND UTILITIES BOARD — DECISIONS

a. Tolls

(i) *NOVA Gas Transmission Ltd. 1999 Products and Pricing*[125]

On February 4, 2000, the Alberta Energy and Utilities Board ("EUB") issued its decision in an application by Nova Gas Transmission Ltd. ("NGTL") for approval of new service offerings and related rates, tolls, and charges.

The NGTL application sought approval of a fundamental change from the postage stamp rate design which had been in place since 1980. Under the postage stamp rate design, all customers transporting natural gas to Alberta border delivery points pay the same rate regardless of the distance travelled within Alberta. Since 1989, the postage stamp rate for intra-Alberta deliveries was one-half of the postage stamp rate applicable for natural gas leaving the province. NGTL considered this rate design to properly reflect the fact that the average distance of haul for natural gas destined for intra-Alberta markets was approximately one-half the distance of that of natural gas destined for markets outside of the province.

Deregulation, increased competition, and bypass possibilities brought pressure to change the postage stamp methodology. Resolution was sought through negotiations that ultimately led to a Memorandum of Understanding ("MOU") being signed between NGTL and CAPP on March 16, 1999. The NGTL application reflected the MOU and sought approval of a new rate design, called Receipt Point Specific Rates, that reflected the costs associated with distance and pipeline diameter. Receipt and delivery contracts would remain separate such that market transparency and liquidity as currently afforded through the NOVA Inventory Transfer would be preserved. The method of determining intra-Alberta and extra-Alberta delivery charges would remain unchanged. Term-differentiated tolls would be introduced, together with a new pricing structure with floors and ceilings that would be phased in over four years.

Intervenor positions varied widely. Export customers, CAPP, and individual producers recommended approval of the NGTL proposal, though some did so with conditions. The Industrial Gas Consumers Association of Alberta ("IGCAA") expressed conditional support, subject to a local delivery service at a dramatically reduced toll,[126] and a different allocation of costs between intra-Alberta and extra-Alberta services. ATCO Gas proposed a six-zone toll structure.

After an extensive hearing the EUB approved the NGTL application with certain conditions. The regulator concluded that the objective of postage stamp rates had been accomplished. The postage stamp toll design had been effective in enhancing the

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125 (4 February 2000), D-2000-6 (EUB) [hereinafter Decision 2000-6].

126 Namely, 6¢/Mcf versus the postage stamp rate of 13.5¢/Mcf.

development of natural gas reserves through the significant expansion of the NGTL system over the past twenty years, but changing market conditions and increased competition in natural gas transportation required a new approach. The EUB concluded that Receipt Point Specific Rates best meet accepted ratemaking principles and are in the public interest. It entirely rejected the IGCAA and ATCO Gas proposals. The EUB directed NGTL to maintain the current cost allocation between intra-Alberta and extra-Alberta services, approved in principle the concept of term differentiated rates, changed the intra-Alberta service to firm from interruptible, accepted in principle the proposed revenue collar, and directed prompt implementation.[127]

One of the interesting aspects of the decision was that it represented a flexing of regulatory muscle. The EUB was not prepared to accept the application as a package, as requested by NGTL and CAPP, but rather examined and decided upon its individual elements. The regulator also concluded that there was no industry-wide consensus, only a bilateral agreement (the MOU) between NGTL and CAPP. It went on to deny various aspects of the application, including a proposal for new services, a proposal for 24-months' renewal incentive notice, and a proposed administrative fee. The message from the EUB was that negotiation is not enough. The regulator still must discharge its mandate to determine that the tolls resulting from the negotiation are just and reasonable. The EUB stated that it is obliged pursuant to its enabling legislation to independently assess, consider and determine whether a proposed rate design meets the public interest test of just and reasonable rates.[128]

The EUB also expressed its belief that regulated utilities have the responsibility and obligation to conduct a consultation process with their stakeholders that affords all constituents a reasonable opportunity to advance their positions and concerns.[129]

A group of intervenors — calling themselves Alberta Consumers — waited almost three months to make an application for review and variance of Decision 2000-6.[130] The application sought a direction from the EUB for NGTL to prepare and file, no later than May 1, 2001, a fully-allocated cost of service study. While the application was unclear, the Alberta Consumers seemed to be seeking assurance that future NGTL rates would be capable of being assessed relative to cost of service. In a decision dated July 13, 2000, the EUB dismissed the review application, stating that it is clear that Decision 2000-6 does not waive any future obligation of NGTL to prepare a fully-allocated cost of service study in support of future rates or rate design proposals.[131]

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[127] The first day of the month occurring eight weeks following issuance of the decision.

[128] *Supra* note 125 at 19.

[129] *Ibid.* at 15.

[130] The Alberta Consumers group was composed of the Industrial Gas Consumers Association of Alberta, The City of Calgary, Gas Alberta Inc. and University of Alberta. The application was filed on May 1, 2000.

[131] Letter, *Re: Decision 2000-6 Review and Variance Application by Alberta Consumers* (13 July 2000) (EUB).

(ii) *Canadian Western Natural Gas Company Ltd. Tolls Decision*[132]

In November 1997, Canadian Western Natural Gas Company Limited ("CWNG") was advised that the EUB would be examining its rates for 1997 and 1998. Following failed negotiations between CWNG and interested parties, CWNG filed Phase I of its 1998 General Rate Application ("GRA") forecasting that current rates would generate revenues in excess of its 1998 revenue requirement. The EUB directed CWNG to make one-time refunds to customers for the 1997 and 1998 interim rate adjustments and having regard to the time period and the size of the refund, it awarded interest on the 1997 and 1998 refund.[133]

The regulator also reviewed the 1997 return on common equity and capital structure for CWNG, including the method used for determining and composing the return and structure. Rather than conducting a detailed review, however, the EUB limited its review to circumstances in which it appeared that there was an error in or a change to the calculation or application of previously approved methods or a change in circumstance.[134]

The EUB did not adopt any new principles with respect to the determination of rate base, but followed its past practice of applying the risk premium methodology to determine that a fair rate of return on common equity would be 10.5 percent for 1997 with a common equity component of 37 percent. For 1998, the regulator approved a 9.375 percent fair rate of return on common equity with a common equity component of 32-37 percent.

To determine rate base, however, the EUB did undertake a detailed review of the CWNG expenditures and provided guidance on two issues. First, it applied the general principle that a company such as CWNG cannot include in rate base any costs related to non-utility activity.[135] Second, it addressed the issue of appropriate affiliate relationships noting that "these issues are of more general concern today than ever before."[136] The EUB took this opportunity to provide explicit guidelines which would be applicable to all affiliate transactions. Where affiliate relationships exist, the company must establish that

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132 *Canadian Western Natural Gas Company Limited 1997 Return on Common Equity and Capital Structure, and 1998 General Rate Application* (2 March 2000), D-2000-9 (EUB) [hereinafter Decision 2000-9].

133 Informational Letter 2000-1: *General Policy for Payment of Interest* (16 February 2000).

134 Applying this test to the various items, the EUB concluded that it would review for 1997 the income tax over provisions, rate base – necessary working capital, and rate base versus capitalization. The EUB considered that the following items would not be considered within the scope of review: the use of deferred taxes with respect to certain items, storage revenue, transportation revenue, rent expense, and severance costs.

135 Although the EUB found that the Cochrane office was required, an amount included in the rate base by CWNG was not prudent and included space dedicated to a non-utility activity. The EUB therefore directed CWNG to calculate a prudent capital cost and to readjust its rate base and depreciation.

136 Decision 2000-9, *supra* note 132 at 153. The restructuring of the gas industry has created an increased concern for relationships between regulated and non-regulated portions of a particular business.

the function that is being served is best provided from a source outside of the utility,[137] and that the services between the regulated and non-regulated entity are being provided at fair market value.[138] Services should be obtained through a fair bid or tendering process,[139] and contractual arrangements should be executed with the same or more detail than contracts between a regulated affiliate and third parties.

At several points during the proceeding, the EUB faced issues of confidentiality arising from information that had been disclosed during negotiations and which parties were attempting to submit as evidence at the hearing. The EUB Negotiated Settlement Guidelines address confidentiality both during and after settlement negotiations. In particular, s. 6 of these Guidelines provide that the EUB "will not admit any submissions, positions, evidence, or information so identified [as confidential] in any Board proceeding without the consent of the affected parties." Negotiating positions are to be treated as confidential. Although the EUB suggests that actual information and forecasts would generally be admissible at a hearing, they will not be admissible where they are clearly marked as confidential and identified in either the confidentiality agreement or the minutes of a settlement meeting. The regulator urged parties to contemplate the confidentiality of documents during settlement negotiations.

b. Facilities — Oil Sands

(i) The Corridor Pipeline — Crude Oil and Diluent Pipelines from Fort McMurray Oil Sands to Sherwood Park[140]

Significant development of Alberta oil sands continues. In early 1999 the EUB held hearings and approved two elements of the Shell Canada Limited Muskeg River Mine Project — a mine and extraction plant on Lease 13 near Fort McMurray (the "Mine") and an upgrader at Scotford in Strathcona County (the "Upgrader").[141] In September it approved the connecting pipeline to be constructed by Corridor Pipeline Limited ("Corridor"). In each case, the EUB stated that adequate oil sands resources are available and that the project contributes to the orderly development and efficient use of Alberta energy resources.

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137 Appropriate evidence must be provided to establish that the costs for services are not discriminatory to either the utility or its customers.

138 Where no fair market value is available in the marketplace, the services or property must be transferred at the cost-based price for the service or property.

139 In the absence of a fair bidding process, if services have not been obtained at the least cost, the EUB may disallow all or a portion of the costs for that service.

140 Applications No. 1029060 and 1033210, *Corridor Pipeline Limited Application to Construct and Operate Crude Oil and Hydrocarbon Diluent Pipelines and Associated Facilities from Muskeg River Mine Plant to Sherwood Park* (28 September 1999), D-99-23 (EUB) [hereinafter *Corridor*].

141 Application No. 970588, *Shell Canada Limited Application to Construct and Operate an Oil Sands Mine in the Fort McMurray Area* (12 February 1999), D-99-2 (EUB); Applications No. 980137 and 980337, *Shell Canada Limited Application to Construct and Operate an Oil Sands Bitumen Upgrader in the Fort Saskatchewan Area; Shell Canada Products Limited Application to Amend Refinery Approval in the Fort Saskatchewan Area* (6 April 1999), D-99-8 (EUB). The decisions in respect of the Upgrader and the Mine were included in the 1999 review of regulatory decisions, *supra* note 48.

Corridor applied for approval pursuant to Part IV of the *Pipeline Act*[142] to construct and operate four pipelines. One twin pipeline would transport diluted bitumen 450 kilometres from the Mine to the Upgrader and diluent from the Upgrader to the Mine (the "Mainline"). The other twin pipeline would transport synthetic crude oil 43 kilometres from the Upgrader to existing facilities of Enbridge and Trans Mountain Pipe Line Company Ltd. and supplementary feedstock from those facilities to the Upgrader (the "Delivery Lines").

Routing issues were the main focus of the Corridor hearing. Corridor chose the route in an effort to minimize environmental impacts and impacts on landowners and to utilize, where possible, the Alberta Oil Sands Multiple Utilities Corridor ("AOSMUC"). Nonetheless, objections were raised by landowners and by Mobil Oil Canada Properties ("Mobil"), a resource rights holder. Landowners were opposed to the routing because of future development issues, right-of-way widths and concerns about reclamation. The Mobil objection was based on its ability to recover bitumen from its Lease 37.

The EUB was satisfied with the general route selection and expressed its belief that the impacts could be mitigated and that the project is in the public interest. Nevertheless, its approval of the Corridor application was made subject to two conditions relating to routing. With respect to the Delivery Lines, the regulator requested that Corridor conduct additional public consultation regarding reduction of its right-of-way width. On the Mainline, the EUB required further consultation with Mobil with respect to routing.

The EUB expressed concerns about the adequacy of the Corridor consultation program. This concern with consultation is increasingly common in EUB decisions — for example, it can also be seen in the NGTL Products and Pricing decision[143] and various decisions relating to sour gas facilities.[144] A further example is an application brought by RioAlto Exploration Ltd. where the EUB expressed its concerns with the public consultation program and denied the application.[145] RioAlto failed to establish a clear method of obtaining local input, was not sufficiently thorough in its consultation efforts and ought to have established better communication with area residents. Consultation is a two-way street and the EUB requires that the public actively participate in the process.[146] Corridor was directed to conduct additional public consultation with all affected landowners along the Delivery Lines regarding the reduction of their rights-of-way. The regulator specifically stipulated that Corridor must satisfy it (1) that landowners had been consulted in an effective manner and (2) that the Delivery Lines right-of-way had been reduced to the least extent possible without compromising public safety.[147]

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142 R.S.A. 1980, c. P-8.

143 See discussion in section II.B.1.a(i), above.

144 See discussion in section II.B.1(c), below.

145 *Rio Alto Exploration Ltd. Application to Modify A Sweet Gas Processing Facility McLeod Field* (23 April 1999), D-99-9 (EUB). The EUB also found that the applicant had not adequately demonstrated that the proposed expansion of the McLeod Field sweet gas processing facility was in the public interest.

146 *Fletcher Challenge Energy Canada Inc. Application for an Approval to Construct A Sweet Multiwell Battery Leduc Area* (18 August 1999), D-99-19 (EUB).

147 *Corridor, supra* note 140 at 6-7.

The EUB paid particular attention to Informational Letter ("IL") 80-11: Joint Use of Right-of-Way, an issue which was raised by some landowner intervenors. IL80-11 requires pipeline applicants to evaluate the availability of shared rights-of-way as an alternative to the creation of entirely new ones. While not requiring Corridor to share the existing right-of-way, the regulator did require Corridor to reduce the right-of-way in several places.

At the north end of the Mainline, Corridor proposed a route that would generally follow the AOSMUC, with one exception being in the area of the Mobil oil sands lease. AOSMUC was endorsed in 1986 by the Alberta Government to identify preferred routing for future pipelines east of the Athabasca River in the forest green zone. The deviation in the vicinity of the Mobil lease was proposed to allow for a single crossing of the Steepbank River at what was perceived to be a favourable location.

Even though Corridor had received support for its proposal from all pertinent provincial and local government agencies with jurisdiction, the EUB directed consultation with Mobil to re-examine routing alternatives in the vicinity of Lease 37. The EUB expressed its concern that future *in-situ* bitumen production facilities on the Mobil lease may be negatively impacted by transmission pipelines.

It is important to note that the EUB gave credibility to the Mobil position even though Mobil adduced no evidence of its own and limited its participation in the hearing to cross-examination and argument. The importance lies in the focus of the regulator on oil sands development, a theme that is also evident in the *Gulf Surmont* decision.[148]

In the Corridor case cross-examination of the Corridor witnesses by Mobil counsel provided evidence that Mobil had not yet decided to proceed with development of its bitumen reserves, that it would have some flexibility in locating its wells and other facilities relative to the Corridor right-of-way, that there are uncertainties regarding the effects of pipeline operations upon *in-situ* recovery, and that the reserves were located more than 150 feet beneath the pipeline.[149] Argument included discussion of s. 34 of the *Pipeline Act* which empowers the EUB to direct a pipeline licensee to alter or relocate any part of the pipeline and to assign relocation costs. This statutory provision allows Mobil or any other operator sufficient future recourse to the EUB to address pipeline relocation should the need arise.[150] Notwithstanding all this, the EUB sent Corridor back to renegotiating with Mobil.

Another routing issue related to the utility corridors near Edmonton. In this case the EUB expressed its agreement in principle with the use of utility corridors to facilitate the orderly development of pipelines. As it had in previous decisions, the regulator placed the onus on applicants and municipal and regional authorities to assess industrial land use within the corridors. The EUB urged applicants, wherever possible, to utilize existing linear disturbances for their developments.[151]

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148 *Infra* note 168.
149 See transcripts of *Corridor*, *supra* note 140 at 50, 55-58, 76, 85-92.
150 *Ibid.* at 11.
151 *Ibid.* at 10.

c. Facilities — Sour Gas

An increasing number of applications for sour gas[152] facilities, and increasing concern for the safe operation of such facilities, has prompted the EUB to commence a public review of the regulatory requirements and safety measures used by the EUB.[153] The review was announced by the EUB in January 2000, expressing the need for such a review to ensure that sour gas resources are being developed responsibly and in the public interest.

The EUB has recently considered several applications requesting approval for sour gas facilities in Alberta, including the following applications:

1) Stampede Oil Inc. sour gas well at Turner Valley Field;[154]

2) Northrock Resources Ltd. sour natural gas processing facility in the Pembina Field north of Drayton Valley, a related pipeline, and sour gas well batteries;[155]

3) Pinon Oil and Gas Ltd. sour gas facilities east and southeast of Calgary;[156]

4) Crestar Energy Inc. sour gas batteries and pipelines at Vulcan Field;[157]

5) Startech Energy Inc. non-critical level 1 sour gas well at Turner Valley Field;[158] and

6) Mobil Oil Canada Ltd. application for a well licence to drill a critical sour gas well at Crossfield Field.[159]

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152 Sour gas is a natural gas containing hydrogen sulphide (H_2S) which itself is a toxic gas.

153 Operation of sour gas facilities also requires approval from Alberta Environment. In September 1999 Alberta Environment revised its *Environmental Protection and Enhancement Act Approvals and Registrations Procedure Regulation Applications for Sour Gas Processing Plants and Heavy Oil Processing Plants – a Guide to Content.*

154 Application 1031511, *Stampede Oils Inc. Application for a Well Licence Turner Valley Field* (14 December 1999), D-99-30 (EUB).

155 Applications No. 1039083, 1040394, 1040831, and 1039502, *Northrock Resources Ltd. Application to Construct and Operate a Sour Gas Processing Facility, Associated Pipelines, Wellsite Facilities, and an Acid Gas Disposal Scheme Pembina Field* (23 December 1999), D-99-31 (EUB).

156 Applications No. 1034767 and 1034762, *Dynègy Canada Inc. Application for Pipeline Licence Amendments Okotoks Field; Pinon Oil and Gas Ltd. Application for a Sour Gas Compressor Station and Pipeline Licence Crossfield Field* (31 March 2000), D-2000-20 (EUB) [hereinafter *Dynegy*].

157 Applications No. 1033453 and 1037084, *Crestar Energy Inc. Applications to Construct and Operate Sour Gas Batteries and Pipelines Vulcan Field* (2 June 1999), D-99-13 (EUB) [hereinafter *Crestar*].

158 Application 1027549, *Startech Energy Inc. Application to Drill a Noncritical Level-1 Sour Gas Well Turner Valley Field* (25 October 1999), D-99-26 (EUB) [hereinafter *Startech*].

159 Application 1037560, *Mobil Oil Canada, Ltd., and Mobil Resources Ltd. Application for a Well Licence to Drill a Critical Sour Gas Well LSD 4-36-27-28 W4 Crossfield Field* (17 December 1999), D-99-28 (EUB) [hereinafter *Mobil*].

Although the EUB determined that there was a need for each of the facilities, each decision expresses dissatisfaction with the public consultation process conducted by each of the applicants.

The most scathing disapproval was expressed by the EUB in respect of the Stampede Oil application where the EUB actually denied the application for a well licence. The EUB determined that the public consultation conducted by Stampede was "seriously inadequate" and that the company had a "lack of appreciation" for emergency response planning. Stampede had to address substantive issues related to emergency response planning before its facility could be approved. Of interest in this decision is the expressed intention of the EUB to revise its application requirements to require applicants to file detailed plans at the *application stage*.

Although the EUB did not deny the other applications on the basis of inadequate public consultation, the EUB did take the opportunity to remind applicants of the need to conduct meaningful and ongoing public consultation with both individuals and industry, regarding proposed projects and emergency response plans ("ERPs").[160] In Northrock, for instance, although the EUB recognized that an ERP is not required at the application stage,[161] it urged applicants to take a proactive approach to emergency planning in order to address public concerns.[162] As well, although the EUB notes that Northrock met the requirements for public consultation as set out in Guide 56 by undertaking a thorough public notification process, it indicated that Northrock ought to have established regular communications with affected individuals and ought to have notified all adjacent landowners about well tests or any other similar activities earlier on in the process. The EUB did require that Northrock establish regular and ongoing communications with landowners to deal with operations throughout the life of the facilities.

Similar comments were expressed by the regulator in an application brought by Dynegy Canada Inc. and Pinon Oil and Gas Ltd.[163] It is arguable that the regulator here expanded the requirements for consultation beyond the limits of Guide 56. With respect to the Pinon application, the EUB commented that Pinon *could have* held a broader public meeting and open houses to discuss its proposal, and it required Pinon to make efforts to "improve its communication with all affected parties."[164] In so doing, the EUB suggested that Pinon establish avenues of communication and provide a company contact designated to address attendant concerns and issues. Although the parameters set out in Guide 56 may no longer be the norm for consultation activities, the EUB has clearly expressed its intention that consultation efforts must communicate *as fully as possible* with

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160 Guide 56 sets out the EUB's expectations for notification and consultation with the public regarding facilities.

161 In *Ranger Petroleum Corporation Application for a Well Licence Sturgeon Lake Area* (5 July 1999), D-99-18 (EUB) the EUB deferred its decision on a well licence application until an approved ERP was in place.

162 The EUB expects completed ERPs to be submitted for EUB review and approval well in advance of and at least thirty days prior to the commissioning of facilities.

163 *Dynegy*, *supra* note 156.

164 *Ibid.* at 47. Although Pinon did discuss issues including ERPs in general with the public, the EUB held that such discussions were not sufficiently detailed.

residents even in respect of future development.[165] The exchange of information must establish a trust between industry and the public[166] and must provide sufficient information to allow the public to participate meaningfully in the decision-making process by being able to voice concerns and have their concerns addressed, and if possible, resolved.

Through the Stampede decision, the EUB has demonstrated that it is prepared to deny applications where public consultation efforts are insufficient. Companies planning to construct sour gas facilities should review these decisions in detail in order to ensure that their public consultation efforts are adequate and that the level of information being provided to the public is appropriate.[167]

With respect to industry consultation, the EUB has indicated its expectation that sour gas processing project proponents undertake a reasonable and well documented evaluation of the long-term facility needs of an area in establishing its design capacities.

d. Conservation and Correlative Rights

The EUB is frequently called upon to determine correlative rights. Noteworthy in the past year were two decisions in which the regulator concluded that wells should be shut-in because production of *associated gas* presented a significant risk to future bitumen recovery. Another notable decision dealt with the competing interests of gas producers.

(i) The Gulf Surmont Case[168] *and the Goodwell Case*[169]

Gulf Canada Resources Limited applied to shut in associated gas production from 183 wells located on and around its Surmont oil sands leases. The basis for the request was that pressure depletion of the gas pools in association with the oil sands zones would adversely affect the recovery of bitumen by the steam assisted gravity drainage ("SAGD") process to the extent that bitumen may not be recoverable.

Following an extensive hearing the EUB agreed and ordered the shut-in of 146 wells, concluding that associated gas production that occurs before a SAGD process *may* have a negative impact on bitumen recovery. Following a consideration of the benefits and risks of continued gas production in the circumstances, the EUB concluded that it would not

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165 *Crestar*, *supra* note 157.

166 *Startech*, *supra* note 158.

167 In Mobil, *supra* note 159, the EUB took the opportunity to provide a list of information that should be provided, at a minimum, to all residents and landowners as part of the information package respecting any critical sour well, including H_2S concentrations and release rates, a description of the equipment to be installed, type of flaring as well as noise sources. Although Mobil failed to provide residents with the appropriate information, the EUB did not find that failure sufficient reason to deny the application.

168 *Gulf Canada Resources Limited Request for the Shut-In of Associated Gas Surmont Area* (30 March 2000), D-2000-22 (EUB) [hereinafter *Gulf Surmont*].

169 *Goodwell Petroleum Corporation Ltd. Request to Shut-in Bitumen Wells Wabiskaw - McMurray Oil Sands Deposit Athabasca Area – Brintnell Sector* (15 February 2000), D-2000-21 (EUB) [hereinafter *Goodwell*].

be in the public interest to permit gas production that *may* jeopardize the bitumen recovery.

Although the EUB found that gas produced from twenty-two other wells was not associated with bitumen on the Gulf leases, it stated its intention to conduct a review of the production from those wells to determine whether they were in fact associated with underlying bitumen.

A similar request was made by Goodwell Petroleum Corporation Ltd. ("Goodwell"). Goodwell requested that the EUB shut-in sixteen horizontal wells owned by AEC West on the basis that the wells were producing original gas-cap to which AEC did not have rights to produce, and that this was affecting bitumen recovery. Following an extensive review of technical information regarding gas production, bitumen, and solution gas production, the EUB determined that four of the sixteen wells were producing original gas-cap which was in contravention of the well licence issued to AEC and which could impact future bitumen recovery.

The EUB noted that there are a wide range of producing situations arising from bitumen producing wells and indicated its support for a review of the regulatory and documentary requirements for operating practices that may affect bitumen recovery.The decisions are extremely technical, discussing the evidence in detail and providing some guidance respecting the information and evidence that will be required by persons requesting the shut-in of wells. Of particular note, however, is the fact that the regulator was required to determine that it had jurisdiction to order the shut-in of wells.

The EUB began with a discussion of its enabling legislation. In *Goodwell* it cited s. 2(c) of the *Energy Resources Conservation Act*,[170] ss. 3(a) and (b) of the *Oil Sands Conservation Act*,[171] and ss. 4(a) and (c) of the *Oil and Gas Conservation Act*.[172] In *Gulf Surmont* the EUB relied in addition on s. 2(e) of the *ERCA*, but did not specifically rely on s. 4(a) of the *OGCA*. It concluded that its power for conservation and the orderly and efficient development of energy resources is both general and specific.[173] In *Gulf Surmont* the regulator cited s. 5 of the *OSCA* and s. 86 of the *OGCA* as giving it the exclusive jurisdiction to examine, inquire, hear, and determine questions arising under the *OSCA* and the *OGCA*.

The EUB then inquired into the substantive provisions of the legislation that provide the authority to shut in wells. The *Goodwell* decision relied solely on the *OSCA* as authority to shut in wells, citing s. 13(2), paragraph 21(1)(u), and ss. 9 and 20. Section 13(2) empowers the EUB to suspend licences where the "licensee was not entitled ... to produce the oil, gas or crude bitumen at the time the license was granted." Where

170 R.S.A. 1980, c. E-11 [hereinafter *ERCA*].

171 S.A. 1983, c. O-5.5 [hereinafter *OSCA*].

172 R.S.A. 1980, c. O-5 [hereinafter *OGCA*].

173 In *Gulf Surmont*, *supra* note 168, the EUB cites the enabling legislation as support for its jurisdiction to "hear" the issues raised. In *Goodwell*, *supra* note 169, the wording of its decision at 6 seems to rely on the enabling legislation as support for its position that it has the jurisdiction to order the shut in of wells.

operations of bitumen wells are not in accordance with an approval, the EUB has the authority to shut in the well pursuant to ss. 9 and 20 of the *OSCA*.

In *Gulf Surmont* the EUB relied on ss. 42 and 21 of the *ERCA* as its authority to order the shut-in of the wells, interpreting the power in s. 42 to "review, rescind, change, alter or vary an order or direction ... or may rehear an application" as authority to review the well licences on the basis that new information has come to the Board, being the SAGD technology. The regulator was not clear whether it in fact relied on s. 42 for its authority to order the shut-in, as it stated that s. 42 "gives the Board the requisite authority to *at least hear* the application, and maybe ultimately to rescind, change, alter or vary the well licences."[174] Regardless of the authority granted by s. 42, the EUB found the requisite authority to shut in wells in s. 21 of the *ERCA* if it "determines that such an order is necessary to effect the purposes of the ERCA."[175]

The Surmont producers applied for leave to appeal the jurisdictional determination, a process that has been placed in abeyance pending determination by the EUB of compensation for the shut-in.

(ii) The Northstar Rateable Take Case[176]

Drainage is a recurring issue for the EUB. In a recent case, brought pursuant to s. 23 of the *OGCA*,[177] Northstar Energy Corporation ("Northstar") requested an order distributing gas produced from certain wells in the Darwin Bluesky A Pool on the basis that the Northstar gas reserves were unfairly being drained by ongoing production from wells of Baytex Energy Ltd. ("Baytex"). Section 23 of the *OGCA* empowers the EUB to restrict the amount of gas or gas and oil that may be produced during a defined period from a pool in Alberta. The EUB can either limit or distribute the total amount of gas that may be produced from the pool in an equitable manner to ensure that a well owner has the opportunity to receive its share of the gas in the pool.

Although the Northstar wells were producing by the time the dispute reached the hearing stage, Northstar maintained its application for relief in respect to drainage that occurred *prior to* the Northstar wells being placed on production. However, the EUB concluded that s. 23 did not allow it to award relief for *past drainage*. Rather, s. 23 was *prospective* and applied where drainage was likely to occur in the absence of an order of the EUB. Therefore, the regulator was not prepared to reallocate production retroactively in cases where potential for drainage had been eliminated. Although the EUB did note that common purchaser, common carrier, and common processor orders do have an element of retroactivity under the statute, Northstar had withdrawn its application for common carrier and common processor orders.

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174 *Gulf Surmont*, *ibid.* at 4.

175 The EUB was unable to answer that question with the benefit of hearing evidence and submissions.

176 Application No. 1027106, *Northstar Energy Corporation Rateable Take Darwin Bluesky A Pool* (27 May 1999), D-99-12 (EUB).

177 Northstar also applied for common carrier and common processor declarations pursuant to ss. 37 and 42 of the *OGCA* but withdrew those applications.

2. ALBERTA ENERGY AND UTILITIES BOARD — OTHER DEVELOPMENTS

The EUB has implemented significant changes to its structure, reporting requirements, and industry compliance in an attempt to streamline its operations and the regulatory process for stakeholders and applicants.

a. Reorganization of the EUB

The EUB is being reorganized to enhance its strategic objectives, to establish accountabilities, and to require communications with stakeholders. The EUB will consist of nine branches including law, applications, and corporate enforcement and surveillance, each with specified roles and responsibilities.[178]

One significant initiative is the "90 day rule," by which the regulator commits to have a decision issued within 90 days from the close of a hearing. In 2000 the commitment is "90 in 90," meaning that the EUB will issue 90 percent of its decisions within the 90-day limitation. The 2001 goal is "95 in 90," and 2002 will be "100 in 90."

b. Revision of the Rules of Practice

On April 27, 2000, the EUB issued General Bulletin GB-2000-10,[179] which sought stakeholder consultation on a revision of the Rules of Practice for energy and utilities proceedings. The stated aim of the revision is to replace the rules of the two predecessor boards[180] with a single comprehensive, contemporary set of rules that ensure "the most fair, expeditious and efficient determination of proceedings" before the EUB.

Draft rules were disseminated, as well as a list of questions for discussion. Comments are due June 1, 2000.

c. Changing Reporting Requirements

The EUB has adopted numerous new and revised reporting requirements for industry. By Informational Letter IL 99-3[181] and Informational Letter 2000-02,[182] the EUB adopted guidelines to formalize the reporting and filing requirements of all regulated natural gas utilities, except NGTL. This requires gas utilities to file financial and other operating information including surveillance reports and, where rates have been established by a negotiated settlement, a forecast rate of return on equity, a benchmark rate of return on equity, and details of incentive clauses, if any. The ILs recognize the need for formalized and standardized reporting requirements, with balanced analysis, and recognize the special character of filings where rates have been negotiated.

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178 "EUB Organizational Restructuring" (30 June 1999), GB 99-13 (EUB).

179 "Stakeholder Consultation on Draft EUB Rules of Practice for Energy and Utilities Proceedings" (27 April 2000), GB 2000-10 (EUB).

180 The ERCB and the PUB.

181 "Guidelines for Reporting Requirements by Natural Gas Utilities."

182 "Updated Guidelines for Reporting Requirements by Natural Gas Utilities" (17 March 2000), IL 2000-2 (EUB).

Informational Letter IL 99-07[183] made significant changes to the EUB Data Quality Management Program which was implemented by the EUB to improve accuracy and timelines of production reporting on the S-1 Monthly Production Statement and the S-2 Monthly Disposition Statement, as well as to reduce error rates. The EUB has implemented a "grace period" applicable to most changeable errors to allow for corrections before the EUB imposes a non-compliance fee, as long as the corrections are made prior to the EUB month-end cut-off date. If the overall industry performance falls below the "industry benchmark," the EUB will revert back to the automatic invoking of changeable errors.

The EUB has also placed greater responsibility on the oil and gas industry for reporting and eliminating surface casing vent flow/gas migration problems. Interim Directive ID 993[184] requires industry to prevent SCVF/GM problems by addressing the issue at the initial planning of a well drilling program and by focusing on certain cementing operations, including casing centralization and hole conditioning.

By General Bulletin GB 99-08[185] the EUB has re-engineered the S-4 form to improve the efficiency and accuracy of its Well Records Data Gathering Project to replace the former S-4: Notice of Commencement or Suspension of Production or Injection at a Well. The specific change is that written status descriptions are no longer required.

d. Enforcement Process

Informational Letter IL 99-04[186] establishes guidelines for EUB enforcement when dealing with regulatory non-compliance by allowing the EUB to take what it considers to be a firm, fair and consistent approach to regulatory non-compliance. The purpose of this IL is to implement *escalating enforcement* consequences for companies failing to meet EUB requirements or direction. In accordance with the guidelines, enforcement measures are escalated where a company fails to comply with regulations or other EUB requirements or requests. The Informational Letter is intended to be consistent with the EUB commitment to reduce unnecessary requirements, and to actively enforce those requirements considered necessary.

IL 99-04 introduces two enforcement ladders consisting of three categories for initial non-compliance items: minor, major, and serious. The first is a generic enforcement ladder applying in all situations where there is no specific ladder in place and providing the foundation to develop specific EUB enforcement ladders. The second is a field surveillance enforcement ladder focusing on field inspections of upstream oil and gas

183 "Revisions to the EUB's S-1/S-2 Production Reporting Non-Compliance Program." (Superseded by "Update to Guide 7: Production Accounting Handbook" (10 May 2001), IL 2001-6 (EUB)).

184 "Surface Casing Vent Flow/Gas Migration (SCVF/GM) Testing and Repair Requirements" (16 February 1999).

185 "New S-4 Form - Change of Well Status" (26 April 1999).

186 "EUB Enforcement Process, Generic Enforcement Ladder, and Field Surveillance Enforcement Ladder." See also "EUB Enforcement Process-Clarification" (24 February 2000), IL 99-4 (IL 99-4 Clarification of IL 99-04).

operations, effective as of August 1, 1999.[187] Guide 64 is the Facility Inspection Manual which identifies the results of compliance and non-compliance. If the non-compliance is deemed "major" and the non-compliance escalates to a level three or level four, its impact will be province-wide for the company involved, rather than facility-specific.

e. Appropriate Dispute Resolution

On February 2, 2000, the EUB issued General Bulletin GB 2000-4 entitled "Stakeholder Consultation on Dispute Resolution Initiative" to establish a consultation process inviting people to provide feedback on the use of an expanded dispute resolution process that could be applied to the upstream petroleum industry. A public consultation document was issued as the starting point for review and development.

The EUB does have some flexibility, notwithstanding its statutory constraints, to use alternative dispute mechanisms. The most "effective process appears to have been one in which early dispute resolution mechanisms are used where necessary (*e.g.*, EUB staff facilitation and third-party mediation), supplemented with an efficient hearing process."[188] There is, however, no legislative ability to require parties to enter into a mediation process.

Essentially, the EUB is seeking to develop processes to improve facilitation and introduce dispute resolution into the application process. The goal is to improve the overall satisfaction with the process by adding the option of utilizing dispute resolution techniques. The term "appropriate dispute resolution" was chosen over the more common "alternative dispute resolution" ("ADR") in order to reflect the wide number of options available within the EUB initiative, including mediation, and to reinforce the important facilitation role of the EUB staff in dispute resolution.

A consultant's report[189] on the comments received with respect to the initiative was commissioned, accepted and strongly endorsed by the EUB. A key recommendation in the report is the convening of a preliminary meeting, organized and run by a neutral third party and funded by the energy applicant, so that the parties in dispute can discuss the options available to them, including such issues as procedures, confidentiality, enforcement, and funding. Other recommendations include interest-based facilitation training to be provided to EUB staff, establishment of a roster of third-party ADR experts, development and implementation of a communication plan to explain the EUB role and the ADR framework which is intended to result in enhanced efficiencies, better use of time and other resources, and improved landowner-industry relations. The program is scheduled to be in place and active by the fall of 2000.[190]

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187 By General Bulletin GB 2000-09, the EUB advised industry of a new "Guide 64: Facility Inspection Manual," replacing "Guide 45: Battery Inspection Manual," and replacing "Guide 54: Gas Inspection Manual" and assisting the EUB to achieve consistent inspection requirements in Alberta.

188 "Stakeholder Consultation on Dispute Resolution Initiative" (2 February 2000), GB 2000-4 at 5, s. 3.1.

189 Canadian Dispute Resolution Corporation — The ADR Team, *Report for implementation of an Appropriate Dispute Resolution System for Alberta's Upstream Petroleum Applications* (May 2000).

190 "EUB Announces Successful Stakeholder Consultation on Appropriate Dispute Resolution (ADR) Initiative" (20 June 2000).

The EUB has been facilitating dispute resolution for many years. The vast majority of the thousands of facility applications (wells, pipelines, batteries, and gas plants) received each year are processed in an expeditious manner by the Board. In 1999 there were only 35 hearings out of some 20,000 applications. In 1999 the EUB successfully facilitated 40 cases.[191] However, a reason for the current EUB initiative is the fact that, notwithstanding the small number of hearings and the facilitations that have occurred, disputes between residents and petroleum companies appear to be increasing in number and intensity in recent years.

The EUB sees dispute resolution as an extension of its expectations for public consultation that began in the mid-1980s. EUB Guide 56, "Energy Development Application Guide and Schedules," first issued in 1996,[192] establishes parameters for public consultation before applications can even be filed.

f. Noise Control Directive

In order to keep sound levels to acceptable minimums in the face of continued widespread growth of energy operations throughout the province, in November 1999, the EUB introduced a Noise Control Directive[193] to impose proper sound control features into facility design. The directive applies to all facilities under EUB jurisdiction or where the EUB has issued a permit to operate. Facilities approved prior to April 1988 are to be dealt with on a case-by-case basis, while all new facilities must be designed to meet the directive. While the directive does not apply to construction activity, all activities must be conducted with some consideration for the directive and noise created. In conjunction with the Interim Directive, Guide 38: Noise Control Directive Use Guide has been revised.

g. Effect of Oil and Gas Development on Production from Oil Sands Areas

Debate has arisen in several applications before the EUB with respect to the effect that oil and gas activities may have on production from oil sands areas. In an effort to resolve these issues, Alberta Environment issued Information Bulletin 99-3[194] seeking comments from stakeholders on oil sands issues, including the use of a "gas to oil ratio" ("GOR") to determine whether "solution gas"[195] obtained from Alberta's oil sands would be disposed pursuant to a lease of natural gas rights or oil sands rights. The ambiguity arises, in part, from the definitions of "oil sands" and "natural gas" in the *Mines and Minerals*

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191 *Across the Board* (February 2000) (EUB) at 2.

192 Alberta Energy and Utilities Board, Guide 56, "Energy Development Application Guide and Schedules," October 1997 Edition.

193 "Noise Control Directive" (November 1999), ID 99-08.

194 "Solution Gas in Oil Sands Area" (2 June 1999) Information Bulletin 99-3 (AENV). In March 2000, Alberta Environment released a Conservation and Reclamation Information Letter respecting Guidelines for Wetland Establishment on Reclaimed Oil Sands Leases, providing guidelines to industry for the development of wetlands on reclaimed lands in oil sands regions.

195 "Solution Gas" is dissolved gas in crude oil or crude bitumen under initial reservoir conditions, including dissolved gas that evolves as a result of pressure changes, temperature changes, and from human disturbance. See *Oil Sands Conservation Regulation* 76/88, s.1(2)(z.1), as amended.

Act (Alberta),[196] which does not indicate whether "solution gas" should be granted under oil sands leases or petroleum and natural gas leases. On December 14, 1999, the EUB released Informational Letter 99-38 confirming that it would not, having regard to the difficulty of calculation and fairness of calculation, be using GOR to determine entitlements to solution gas. However, effective January 1, 2000, new P&NG agreements respecting oil sands areas would contain a specific exclusion of "solution gas."[197]

h. Policy for Awarding Interest

In Informational Letter IL 2000-1 the EUB advises stakeholders and regulated utility companies that it is in the process of establishing a policy for awarding interest in certain situations that involve utility companies subject to EUB jurisdiction. The General Policy for Payment of Interest allows for the EUB to award interest on, for example, adjustment of utility company rates, tolls or charges, and other costs or charges that are administered within the jurisdiction of the EUB. The regulator recognizes that the policy must be flexible and fair and must provide a reasonable degree of certainty regarding when and how interest will be awarded. IL 2000-1 sets out six guidelines that will apply to all utilities:

1. An adjustment from interim to final approved rates will normally be excluded from the awarding of interest since the interim rate is designed to reduce significant amounts that would otherwise be outstanding. (Interest will only apply to situations such as where the adjustment resulted from significant errors or excesses on the part of the utility concerned, or from circumstances that could not otherwise be contemplated when the rate(s) in question were set.)

2. The regulatory lag before implementation of the rate adjustment will have to exceed a period of twelve months. (Short-term situations will normally not involve amounts of material consequence.)

3. The adjustment will have a threshold. For general utility rates, the minimum amount of the forecast aggregate change in revenue shall ordinarily be the greater of $1,000,000 or 3 percent of the revenue from the rate(s) being revised. (For the purposes of administration by the utility, the interest payment will not involve amounts that will be immaterial to either the utility or to its customers. The threshold may need to be tailored where unusual circumstances or conditions preclude its use or where acceptable procedures already exist, for example, in respect of the reconciliation of a deferred gas account.)

4. Interest will be calculated from the date on which the rate adjustment becomes effective. (Either the utility or the customers, as the case may be, will be compensated for the time value of money over the period to which the adjustment applies.)

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196 R.S.A. 1980, c. M-15, s. 1.

197 Changes to legislation and regulations will be made to reflect this policy decision.

5. Interest will be calculated using a rate equal to the Bank of Canada's Bank Rate plus 1½ percent, subject to any previously approved EUB procedure for awarding interest, for example, in the deferred gas account reconciliation procedures.

6 In circumstances where this Policy applies, the EUB shall give prior approval of an estimate of the rate of interest and the aggregate amount of the interest payment.[198]

i. Flaring Requirements

EUB Guide 60: Upstream Petroleum Industry Flaring Requirements was issued in July 1999 and implemented on January 1, 2000.[199] The new flaring requirements, which apply to all flaring in the province, are intended to result in significant flaring reductions. The reduction schedule for solution gas flare requires a 25 percent reduction from 1996 baseline solution gas flare volumes by the end of 2001. The Guide also includes flare performance requirements to improve combustion efficiency and to assist industry in meeting Alberta Ambient Air Quality Guidelines. It sets out compliance deadlines for flare performance and evaluation. Along with the new flaring requirements, industry will also be subject to new public consultation and notification requirements. These require that operators notify landowners or occupants living within 500 metres of each existing flare with respect to the outcome of flare evaluations and intentions for the future operation of the flare. A conflict resolution process is also included in order to address flaring concerns. General Bulletin GB 99-23[200] clarifies certain aspects of the Guide in response to stakeholder questions. As well, General Bulletin GB 2000-07[201] addresses "Industry Performance Reporting" on the solution gas flaring reduction process.

j. Review of Sulphur Recovery Guidelines

During the spring of 1999, by General Bulletin 99-10, the EUB advised industry that a review of the Alberta Sulphur Recovery Guidelines would be undertaken. The EUB, together with Alberta Environment ("AENV"), conducted a review of certain portions of its Sulphur Recovery Guidelines described in Informational Letter IL 88-13 (the "Sulphur Recovery Review Process").[202] The purpose was to update EUB policy and ensure that the guidelines regarding sulphur recovery requirements for grandfathered sour gas plants, the application of sulphur recovery guidelines to other facilities, and small gas plant proliferation guidelines were still appropriate. In 1988 when requirements for sulphur recovery at sour gas plants were revised, the new Sulphur Recovery Guidelines were not applicable to *existing* sour gas plants, as the environmental benefits did not outweigh the

198 "General Policy for Payment of Interest" (16 February 2000), IL 2000-1 (EUB).

199 "Updates and Clarifications" to Guide 60 answers stakeholder questions and provides updates and interpretations of the Guide 60 requirements.

200 "Guide 60 Upstream Petroleum Industry Flaring Requirements: Update and Clarification Document and Guide Update Process" (20 December 1999).

201 "Guide 60 Upstream Petroleum Flaring Requirements — Industry Performance Reporting" (8 March 2000).

202 "Sulphur Recovery Guidelines for Sour Gas Plants in Alberta" (15 August 1998).

costs. As well, the 1988 guidelines do not apply to non-sour gas facilities such as refineries and heavy oil upgraders.

The Sulphur Recovery Review Process is intended to address the issues of sulphur recovery guidelines for grandfathered sour gas plants, the application of the guidelines to non-sour gas facilities, and the small gas plant proliferation guidelines. Approximately thirty sulphur recovery plants remain grandfathered and approximately thirty smaller plants hold approvals to flare gas in amounts which are not in compliance with the current guidelines. With increasing sour gas activity, a review of the guidelines was thought timely. The EUB and AENV conducted stakeholder consultations through the preparation of a discussion paper posted to the EUB website on September 28, 1999, upon which public comment was received. A multi-stakeholder Advisory Group also submitted a report on April 12, 2000, providing its views and comments on the guideline review.[203] The Advisory Group recommended that all sour gas plants be "degrandfathered" and that the guidelines should apply to heavy oil upgraders, oil refineries, and other industrial facilities, as well as to other upstream petroleum facilities including oil and gas batteries and compressor stations. Although the committee did not recommend additional regulations for proliferation of gas plants, it suggested that current regulations must be followed and enforced more diligently in accordance with the EUB's enforcement ladder. In Decision 99-29[204] the EUB demonstrated a willingness to require companies to upgrade facilities to meet sulphur recovery and inlet rates. In that decision, the EUB required Canadian 88 to upgrade its Olds Garrington sour gas processing plant to meet sulphur recovery efficiency requirements for existing plants undergoing significant expansion or extension of anticipated plant life span.

k. Costs

In October 1999 the EUB issued General Bulletin GB 99-18 advising that it was initiating a review of its procedures for awarding costs in energy and utility proceedings and hearings.[205] The costs procedure review will examine numerous issues associated with the awarding of costs to local intervenors and costs awarded to parties who participate in utility applications and hearings. The issues to be addressed include the definition of "local intervenor," the level of awards to individual organizers of local resident groups, interest on cost awards, restrictions on cost recovery, responsibility for costs, and in respect of utility proceedings, the quantum, timeliness, advance funding, and costs related to negotiated settlement processes. In conjunction with General Bulletin 99-18, discussion papers were prepared and distributed for comment.

Regulatory tribunals have no inherent jurisdiction to award costs, and may only do so with specific statutory authorization. The EUB was formed in 1995 from the merger of the ERCB and the PUB, which had dramatically different cost powers from each other.

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203 See EUB News Release "EUB Encourages Stakeholder Consultation on Grandfathered Gas Plants — Announces Membership of Sulphur Recovery Review Advisory Group" (25 November 1999).

204 Application 990177 "Canadian 88 Energy Corp. Application to Amend the Approval for a Sour Gas Processing/Sulphur Recovery Facility Carrington Field" (21 June 1999), D-99-29 (EUB).

205 "Stakeholder Consultation Discussion Papers for the Review of Costs Procedures for Energy and Utility Proceedings" (12 October 1999).

EUB jurisdiction to award costs in facilities cases arises from s. 31 of the *ERCA*[206] and the *Local Intervenors' Costs Regulation*.[207] The EUB may only make an award of costs to "local intervenors"[208] who establish a proprietary or other recognized legal interest in lands that may be directly and adversely affected by a decision of the regulator. With respect to energy applications, the EUB is proposing to expand the definition of "local intervenor" to include environmental groups, non-government organizations, and other individuals and associations with respect to energy developments of lands where no "local intervenor" would have the requisite legal rights to own or occupy in accordance with the definition of local intervenor in the *ERCA*.[209]

The EUB is also considering whether to provide for cost awards to persons who found, organize, and coordinate a particular group intervention where a significant level of commitment has been displayed and in order to cover costs incurred to prepare for pre-hearing negotiations.[210] The past practice has been to approve an honorarium for an organizer, which often does not reflect the actual amount of time and effort put into an intervention by that person. Interest on costs awards is being contemplated to address delays in the payment of awards.

Section 60 of the *Public Utilities Board Act*[211] empowers the PUB (to which the EUB has succeeded) to award costs in utility proceedings. Advance funding can also be provided. Because utility hearing costs are included in the revenue requirement of utilities, the EUB "considers it has a mandate to ensure that hearing costs do not become excessive." It has invited suggestions from interested parties for measures that may be implemented to ensure that cost awards are fair and reasonable and for procedures that could be used for awarding costs where parties proceed through the negotiated settlement process.

A meeting was held in late May to receive final comments prior to the EUB issuing its directions.

I. Responding to Public Concerns

In November of 1999 the EUB issued Guide 62: Responding to Public Concerns about Oil and Gas in Alberta, to improve public awareness to promote the resolution of issues between landowners and the petroleum industry. In addition to the traditional means of

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206 *Supra* note 170.

207 Alta. Reg. 517/82. Section 31 of the *ERCA* (*ibid.*) states that the regulator may make an award of costs to a local intervenor.

208 "Local intervenor" is defined in s. 31 of the *ERCA* as a person who is an owner as defined in the *Land Titles Act* of, or a person who is in actual occupation of or who is entitled to occupy, land that is or may be directly and adversely affected by a decision of the board, or a group or association of such persons, but does not generally include a person or group or association of persons whose business includes the trading in or transportation or recovery of any energy resource.

209 The expanded definition would be limited to situations where a resource project is being undertaken on land where there is unlikely to be anyone who meets the test of a local intervenor.

210 Such costs would include costs to obtain counsel or experts in order to valuably participate in the negotiation process.

211 R.S.A. 1980, c. P-37.

dispute resolution such as contact between companies and landowners and reporting concerns to the field centre, the EUB indicates its increased involvement by making staff available to facilitate early discussions between landowners and companies in order to identify and promote the resolution of conflicts. The regulator also indicates that it is looking at other dispute resolution tools such as company sponsored consultation or negotiation and third-party mediation.

3. ALBERTA SURFACE RIGHTS BOARD

a. *Enbridge Pipelines (Athabasca) Inc.*

In April 1999 the Surface Rights Board ("SRB") rendered a precedent-setting decision, granting for the first time an application for an access road to a pipeline. Enbridge Pipelines (Athabasca) Inc. applied to the SRB for a right-of-entry order for an access road to a valve site. Having regard to the scope of its jurisdiction under the *Surface Rights Act*,[212] the SRB has historically rejected such applications. Subsection 12(3) of the *SRA* sets out the SRB's jurisdiction to make an order for right-of-entry. Paragraph 12(1)(c) states that "no operator has a right of entry in respect of the surface of any land ... for or incidental to the construction, operation or removal of a pipeline" until the operator has obtained consent from the landowner or obtained an order of the SRB. Although s. 12(3) of the *SRA* empowers the SRB to make an order granting right-of-entry in respect of the *surface of land*, it has never been interpreted as broad enough to empower the SRB to make a right-of-entry order in respect of a pipeline.

However, in Decision No. 99-0109 respecting the Enbridge application,[213] the SRB granted to Enbridge a right-of-entry order permitting the establishment of an access road connecting the Husky Oil Operations Ltd. access road to Enbridge's pipeline right-of-way. The SRB accepted the Enbridge argument that the *SRA* should be read in a broad and liberal way to fulfil the intent of the legislation, thereby permitting the SRB to exercise its jurisdiction in a way that enabled it to balance the interests of landowners and energy companies in a sound, fair and reasonable manner. In determining that it did have the jurisdiction to grant access to a pipeline right-of-way, the SRB cited the argument made during the hearing that paragraph 12(1)(c) "brings the land under the purview of the Act" and that the SRB has the jurisdiction to grant a right-of-entry even though pipelines are not specifically mentioned in s. 12(3) of the *Act*.

b. *Renaissance Energy Ltd.*

In June 1999 and October 1999 the SRB considered two separate applications, each brought by Renaissance Energy Ltd. in its capacity as an operator, requesting orders for *reductions* in the rate of compensation payable in respect of four surface leases on the

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212 R.S.A. 1983, c. S-27.1 [hereinafter *SRA*].

213 *Enbridge Pipelines (Athabasca)* v. *Her Majesty the Queen in Right of Alberta* (7 October 1999), 99/0109 (SRB).

basis that the sites had been abandoned.[214] The SRB noted the novelty of such applications as it is usually the lessor applying to the SRB for an *increase* in compensation.

Nothing in the *SRA* prevents a company such as Renaissance in its capacity as an operator from making applications to reduce annual compensation. However, in considering whether a reduction in compensation is warranted, paragraphs 25(1)(c) and 25(1)(d) of the *SRA* must be considered. These subsections provide that the SRB, in determining compensation, may consider loss of use, adverse effect, nuisance, inconvenience, and noise arising from the area granted to the operator and the operations conducted on that area.[215]

Following a consideration of the facts in the Walker decision, the SRB in the Williams decision set out the following four factors as representing *some of the factors* that would be required to support an application for a reduction in compensation, pursuant to either a surface lease or a right-of-entry order: (1) evidence that all equipment and workings have been removed, (2) the state of reclamation, (3) evidence that the operator had given up all rights to enter the land except for reclamation purposes, and (4) productivity on the reclaimed site. With respect to the surface lease with Walker, the SRB found that title to the lands would not be cleared until the Reclamation Certificate issued and that debris remained on the lands. However, the SRB also found that Walker had use of the land. Therefore, the SRB concluded that a significant (almost 50 percent) reduction in compensation was justified. With respect to one of the three surface leases respecting Williams, although growth deficiencies were still prevalent and the operator continued to have full control of the site, the SRB reduced annual compensation on the basis that the adverse effect had been reduced. With respect to the other two sites, the SRB did not order a reduction in compensation as each site continued to show major deficiencies. A gas leak was present on one site and one site remained fenced precluding the lessor's use of a storage area.

c. *Poco Petroleums Ltd.*

In a decision dated May 8, 2000,[216] the SRB clearly stated its views on the issue of whether compensation for a pipeline right-of-way could be granted as a yearly rental or as a single payment. Poco Petroleums Ltd. ("Poco") obtained a right-of-entry order from the SRB, which held that the effect of the grant of right-of-entry was to superimpose a second user right, which is an exclusive and dominant right for the term of the order, on the landowner's existing right. The exercise of the right by Poco resulted in disturbance to the vested interest of the landowner which would attract the award of compensation.

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214 *Renaissance Energy Ltd. and Walker* (15 June 1999), 99/0074 (S.R.B.) in respect of a single surface lease; *Renaissance Energy Ltd. and Williams* (4 October 1999), 99/013 (S.R.B.) in respect of three surface leases.

215 The SRB notes that reductions in compensation awards should not discourage mitigation or encourage operators to be dilatory in obtaining a reclamation certificate for the land.

216 *Poco Petroleums Ltd. and Daniel Stephenson, June Elizabeth Stephenson, and Lindale Rural Electrification Association Limited* (8 May 2000), 2000/0068 (S.R.B.).

The SRB held that the rights granted by the order are virtually granted in perpetuity, and that they traditionally can only be acquired by up-front payment of value, or by a long-term lease subject to periodic contract payments to maintain that right of occupancy. It further held that a long-term lease is not compatible with a statutory grant of a right to occupy and use the property of another person. Having particular regard to the indefinite term of the right-of-entry order, the SRB found that the disturbance and damage to the surface rights of the landowner resulting from the right-of-entry equates to the full value of the land, and that proper and just compensation to the landowner is the per-acre value to the owner of that land. It held, further, that the request for annual rental to offset land devaluation "is not an area of compensation covered under the present Surface Rights Act in regards to pipelines. The only area that the Board can award annual rental on pipelines is where there is a continuing loss of use and/or adverse effect to the farming operation."[217]

4. Alberta Environmental Appeal Board

a. *Sovereign Castings Ltd.* v. *Manager of Enforcement and Monitoring, Environmental Service, Bow Region, Alberta Environment*[218]

In the case of *Sovereign Castings*, the Director imposed an administrative penalty for violations of performance required, environmental limits and for failure to report the violations. Although on appeal the administrative penalty was reduced, the Alberta Environmental Appeal Board ("AEAB") rejected the argument of Sovereign Castings Ltd. ("Sovereign") that it had a "legitimate expectation to receive AEP notification about proposed penalties in a ... timely manner."[219] The appellant argued that, as a purchaser of certain property, it had "legitimate expectations" that the Director would inform it in a timely manner of any proposed penalties so that it could make a proper financial arrangement with the vendor of certain property. Citing a Supreme Court of Canada case,[220] the AEAB was of the view that the "legitimate expectations" doctrine was limited to procedural claims involving an expectation of an opportunity to make representations to a government decision-maker before the decision is made and did not apply to instances where an appellant argues that the Director should have kept it better apprised of the potential for penalties. The AEAB commented that even if the legitimate expectations doctrine was relevant in the circumstances, Sovereign had not satisfied its burden of proving that it had a legitimate expectation of a right to notice regarding potential penalties or of the precise penalty amount.

217 *Ibid.*

218 (18 October 1999), Appeal No. 99-130 (AEAB) [hereinafter *Sovereign Castings*].

219 *Ibid.*, para. 17.

220 *Old St. Boniface Residents Association* v. *Winnipeg (City)*, [1990] 3 S.C.R. 1170.

b. *Dzurny* v. *Director, Northeast Boreal Region, Alberta Environment re: Dow Chemical Canada Inc.*[221]

In *Dzurny* the AEAB dismissed an appeal pursuant to subparagraph 87(5)(b)(i) of the *Environmental Protection and Enhancement Act*,[222] holding that the appellant had the opportunity to participate in a hearing held by the EUB and that the EUB had "adequately dealt with" all of the issues raised in the appeals to the AEAB.[223]

c. *Whitefish Lake First Nation* v. *Director, Northwest Boreal Region, Alberta Environment re: Tri Link Resources Ltd.*[224]

The Whitefish First Nation appealed an amendment to an approval which allowed Tri Link to add additional "booster compression" to its sour gas "Seal Gas Processing Facility" and to increase the emissions. The First Nation argued that the director had a duty to consult with the First Nation before deciding to issue the amended approval given the "potential" effects and impairment of aboriginal rights arising from the seal plant.[225]

Dismissing the appeal, the AEAB cited the *EPEA*, its enabling statute, and in particular ss. 83-85 and 91-92. The broadest grounds of appeal that the AEAB can consider are those that relate to the public interest, the environmental objectives of the *EPEA*, *and* those that the director considered or should have considered in making a decision. Although the AEAB has the implicit jurisdiction to narrow the scope of appeal grounds, it cannot broaden those grounds. Although the First Nation's claim appeared to be grounded in environmental concerns directly related to the environmental public interest objectives of the *EPEA*, the AEAB found that the director had no duty and no authority to determine whether the First Nation legal claims were valid. It was therefore also inappropriate for the AEAB to decide the validity of the First Nation's claim. The validity of those rights were not therefore "properly before" the AEAB.

5. BRITISH COLUMBIA

a. British Columbia Oil and Gas Commission[226]

In 1998 the British Columbia government passed the *Oil and Gas Commission Act*[227] providing for the establishment of the Oil and Gas Commission (the "Commission") which is assigned responsibility for administering various sections of existing legislation pertaining to oil and gas activity. The Commission is both an independent corporation and

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221 (24 November 1999), Appeal No. 99-137 (AEAB) [hereinafter *Dzurny*].

222 R.S.A. 1992, c. E-13.3 [hereinafter *EPEA*].

223 *Ibid.* Subparagraph 87(5)(b)(i) requires that the AEAB determine whether an appellant "received notice of," "participated in" or "had the opportunity to participate in" a review of a project conducted by the EUB and, if so, whether the EUB review "adequately dealt with" the issues raised in the appeal to the AEAB.

224 (19 November 1999), Appeal No. 99-009 (AEAB).

225 The First Nation based its appeal on a claim that areas around the Seal Plant were "traditional territories" pursuant to which it claimed to have "treaty, constitutional, and aboriginal rights."

226 See online: the British Columbia Oil and Gas Commission <http://www.ogc.gov.bc.ca.>.

227 S.B.C. 1998, c. 39 [hereinafter *OGCA*].

an agent of the Crown,[228] operating as a government corporation funded entirely by fees and charges levied on the oil and gas industry.

The Commission was created to provide a "single window" for the management and regulation of upstream oil and gas activity in British Columbia, to provide an efficient, integrated approach to the management and regulation of the oil and gas industry in order to meet economic, environmental, and social objectives, and to cut red tape for industry. The establishment of the Commission is a key component of a plan developed by industry and government to increase investment and to create jobs in British Columbia.

The statutory purposes of the Commission, found in s. 3 of the OGCA, are (i) to regulate the oil and gas activities of pipelines in British Columbia, (ii) to provide for effective and efficient processes for the review of applications related to oil and gas activities of pipelines, (iii) to ensure that applications that are approved are in the public interest having regard to environmental, economic, and social effects, (iv) to encourage the participation of First Nations and aboriginal peoples in processes affecting them, (v) to participate in planning processes, and (vi) to undertake programs of education and communication in order to advance safe and efficient practices and the other purposes of the Commission.

Curiously, the *OGCA* does not provide any procedural provisions and, in particular, does not provide for a hearing process. However, s. 8 requires that the Commission encourage "consensual alternative dispute resolution" ("CADR") to resolve disputes relating to the Commission's discretion, functions, and duties under the *OGCA* and other legislation. CADR, which is limited to facilitation, can be triggered by the Commission at any stage of the application and approvals process, or at the request of an interested party. Under s. 8, the Commission may authorize one or more persons to facilitate settlement. The Commission itself may, but is not required to, participate in the dispute resolution process. If the parties are unable to settle, the Commission may ask the person or persons who were authorized by the Commission to facilitate the settlement to make recommendations to it; these recommendations must be considered by the Commission before the it renders a decision.

Examples of disputes that could be referred to CADR include conflicts with First Nations, correlative rights issues, concurrent seismic applications covering overlapping areas, complaints from environmental organizations, and issues with guides/outfitters. CADR will not address disputes with commission staff prior to approval, compensation issues with private landowners, or cost of service matters. The triggering of CADR on a specific issue need not delay the review process for the entire application. Although the Commission is developing a comprehensive policy on CADR process and timelines, it has not yet been completed.

A special "reconsideration process" involving the alternative dispute resolution procedures is established under s. 9 of the *OGCA*. Once a decision is rendered by the Commission, an interested person may apply and the advisory committee may request that

[228] *Ibid.*, s. 2.

the Commission authorize one or more persons to conduct CADR. It would appear that the Commission must ultimately determine whether its initial decision must be reviewed. Following the dispute resolution process, the Commission must reconsider its decision and must take into account any recommendations made by the person or persons authorized by the Commission to facilitate the settlement. Following the CADR, the Commission must reconsider its original decision.

The CADR efforts of the B.C. legislators remain untested to date, but a proceeding is underway. In a decision dated August 27, 1999, the Commission granted a licence to Canadian Hunter Exploration Ltd. to develop and operate an underground natural gas storage facility in northeast British Columbia. The decision was made over the objections of two parties, one of which, Unocal Canada Ltd., asked the Commission to authorize CADR. The Commission ignored that request, and is now the subject of two requests to the advisory committee[229] for review of the decision on grounds of breach of natural justice, error of law, and inconsistency with the public interest. Failure to act by the advisory committee has resulted in an application for judicial review of the Commission decision. In the absence of a settlement, the Supreme Court of British Columbia may provide some guidance.

In an unrelated matter, the OGC issued Interim Guideline OGC 00-01, entitled *Natural Gas Flaring During Well Testing* effective February 2000, which sets out the pre-application, application, approval, and post-approval processes relating to flaring of natural gas during well-testing operations. Flaring during drilling operations is addressed through a separate well-drilling regulatory process.

Also in February 2000 the OGC released a stakeholders' consultation document called *Compliance and Enforcement Regulatory Delivery—A Discussion Paper for Stakeholders Consultation*. This document is intended to initiate discussion between the OGC and stakeholders to examine and ensure compliance with and enforcement of the *Petroleum and Natural Gas Act*[230] and the *Drilling and Production Regulations*,[231] to discuss the long-term direction of regulatory enforcement, and to communicate with the stakeholders respecting methods for enhancing the OGC compliance and enforcement programs, including higher levels of industry accountability and escalating fines for repeat non-compliance.

6. SASKATCHEWAN

a. The Interim Rate Review Panel

In November 1999 the Saskatchewan Government responded to political pressure and appointed a ministerial advisory committee known as the Saskatchewan Interim Rate Review Panel ("IRRP"). The purpose of the IRRP is to conduct independent reviews of Crown corporation monopoly rate change requests pending the implementation of legislation to establish a permanent rate review mechanism.

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229 One by Unocal Canada Limited and the other by CanWest Gas Supply Inc.
230 R.S.B.C. 1996, c. 361.
231 B.C. Reg. 362/98.

A second ministerial order established terms of reference for the IRRP to consider a rate change review for SaskEnergy Inc. ("SaskEnergy"), which is the Crown corporation that controls natural gas transmission and delivery in the province. The IRRP was instructed to provide an opinion of the fairness and reasonableness of a rate change proposed by SaskEnergy and, in doing so, to consider the interests of the customer, of the Crown corporation, and of the public. It was directed to consider various factors including anticipated cost of gas, gas supply contracts, payments for transportation of gas, and natural gas commodity market conditions. It was instructed to "consider ... as given" the current operating rate structure, the approved cost of capital, the existing service level, and the allocation of rates between services and customer classes.

The IRRP conducts its reviews through meetings which do not have an evidentiary process or cross-examination. It does not make decisions, but rather recommendations to Cabinet. In the case of SaskEnergy, the IRRP accepted virtually all of the application and recommended that the corporation be permitted to recover its costs of gas for the year 2000.

Options for a permanent rate review mechanism are still being developed, but legislation is not expected to be implemented until the fall.

b. Canada-Saskatchewan Agreement on Environmental Assessment Cooperation

On November 30, 1999, the federal Minister of the Environment and the Saskatchewan Minister of the Environment and Resource Management signed the Canada-Saskatchewan Agreement on Environmental Assessment Cooperation marking the implementation of the first bilateral agreement on environmental assessment between Canada and Saskatchewan. The agreement provides for a single joint assessment that meets the requirements of both the federal and provincial jurisdictions for projects that require both a federal and a provincial environmental assessment. Where a project requires an environmental assessment by each government, the project will now undergo an assessment administered cooperatively by both governments.[232] However, the agreement does not delegate authority from either Canada or Saskatchewan to the other and each level of government will retain responsibility to make decisions regarding the projects that are within its own legislative jurisdiction. Saskatchewan joins Alberta and British Columbia in the ranks of interjurisdictional cooperative environmental assessment.

c. Liability for Contaminated Sites

In December 1999 Saskatchewan Environment and Resource Management ("SERM") published a brochure clarifying its policy regarding contaminated sites.[233] The SERM policy approach to contaminated sites is based on the "polluter pay" principle. Liability follows the act of contamination, which is consistent with the *Environmental Management*

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232 The Agreement will not apply where Aboriginal Governments have an established process for assessment.

233 *A Muncipal Guide to Saskatchewan Environment and Resource Management's Strategic Approach*, online: Saskatchewan Environment and Resource Management <http:/www.serm.gov.sk.ca/environment/protection/liability/faq/php> (last modified: 13 March 2001).

and Protection Act[234] definition of "responsible parties." On this basis, SERM confirms that the intent of the legislation is not to impose liability on persons who have not caused or contributed to contamination, such as innocent owners of land who have acquired the land through inheritance or purchase.

7. NOVA SCOTIA

a. Award of the Franchise for Distribution of Natural Gas in Nova Scotia

On November 16, 1999, the Nova Scotia Utility and Review Board ("UARB") issued its recommendation pursuant to s. 8 of the *Gas Distribution Act*[235] that Sempra Atlantic Gas Incorporated ("Sempra") be granted a full regulation class franchise for the distribution of natural gas in the Province of Nova Scotia.[236]

The purposes of the *Gas Distribution Act* are to encourage the development of natural gas distribution in the Province of Nova Scotia and to maximize the benefits from the distribution of natural gas in Nova Scotia. Section 8 of the *Act* requires that the UARB consider several factors before granting a franchise: supply, markets, economic feasibility, experience of the applicant, the plans of the applicant to provide gas distribution services, rate design proposal, socio-economic impacts and benefits, the applicant's financial capability, and whether the grant of a franchise will impede competition. The franchise grants the exclusive right to construct and operate a gas delivery system within the geographical area over which the franchise extends.[237]

The decision of the UARB reviews in detail the applications filed by Sempra and by its competitor, Maritimes NRG. In choosing to recommend Sempra, the UARB focused on six factors, all of which relate to the expeditious development of natural gas distribution facilities in Nova Scotia and maximizing the benefits from doing so.[238]

In particular, the Sempra proposal was preferred because of commitments to build a distribution system for at least four years, and to build a system that would meet or exceed provincial access targets within seven years across eighteen counties. Sempra also committed to financing construction from corporate resources or borrowing, and assumed all risk of construction and operation.[239] Guaranteeing that the price of natural gas to customers would be at least five percent less than the price of fuel oil, which exposed customers to less risk, Sempra also met the statutory financial requirements. By a press

234 S.S. 1983-84, c. E-10.2.

235 S.N.S. 1997, c. 4. Although amendments were proposed to the *Act* by Bill 39, 1st Sess., 57th Gen. Ass. N.S., 47 Eliz II, 1998 and received first reading on October 22, 1998, those proposed amendments are not in force.

236 "In the Matter of the Gas Distribution Act and In the Matter of Franchise Applications for the Distribution of Natural Gas in the Province of Nova Scotia" (16 November 1999) (UARB).

237 See *supra* note 235, s. 13.

238 Government of Nova Scotia Policy Statement, "Policy Statement of Maximizing Benefits from Natural Gas Delivery" (3 November 1998).

239 The proposal put forward by Maritimes NRG was based on the condition that it be permitted to recover all accumulated losses from future rate payers to ensure that it received a cumulative 11 percent return on equity.

release dated November 16, 1999, the Government of Nova Scotia expressed its intentions to review the UARB decision to ensure that Sempra can provide a viable, affordable and safe alternative for customers in Nova Scotia.

The UARB also had the opportunity to consider applications requesting a grant of a franchise to municipalities or cooperatives. The UARB noted that the requirements that must be met by future applicants are the same as the requirements that must be met by parties applying for a full regulation class franchise. Following a rejection of all four applications by the municipalities and cooperatives,[240] the UARB set out general guiding principles for franchise applications. First, the applicant must establish financial capability, the ability to bear risks associated with inaccurate forecasts without reliance on government assistance or subsidies,[241] and that it has the necessary experience and ability to meet provincial operating requirements. Second, the UARB noted the importance of rates and the importance of avoiding the risks that can result where a franchise is granted to a municipality or cooperative with the potential result that customers wait longer for service and, when service is finally available, pay higher costs for the gas.

8. NEW BRUNSWICK

a. Award of the Franchise for Distribution of Natural Gas in New Brunswick

In September 1999 Enbridge Gas New Brunswick Inc. ("Gas NB"), a subsidiary of Enbridge Consumers Energy Inc., was selected as the New Brunswick natural gas distributor.

The distribution of natural gas in New Brunswick will be regulated by the 1999 *Gas Distribution Act*.[242] The *NBGDA* is much more extensive and detailed than its counterpart in Nova Scotia. In particular, the New Brunswick statute addresses not only gas distribution rights and obligations arising from the grant of a franchise, but also establishes that a gas distribution system owned or operated by a gas distributor is deemed to be a public utility and that the gas distributor is deemed to be a common carrier of gas.[243] The grant of the franchise under the New Brunswick legislation does not entitle the franchise holder to build the gas distribution system.[244] The franchise holder must

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240 The UARB rejected four applications for franchises from the Town of Berwick, Central Annapolis Valley Natural Gas Cooperative, the Town of Annapolis Royal, and Antigonish Community Gas Cooperative Limited on various grounds including insufficient analysis and study, cursory examinations of market demand, the failure to examine ability to compete with existing energy sources, and inadequate filings and financial capabilities. The UARB did express a willingness to consider a subsequent application from the Town of Annapolis Royal if no satisfactory service arrangement could be made with Sempra. The UARB notes in its denial of the Central Annapolis application that the area was included in the Sempra build-out and that Sempra would construct the necessary facilities quicker with lower cost natural gas.

241 The UARB stated that it would not be in the public interest to award a franchise to any applicant if it appears that subsidies may be required for construction of the system, especially if there is an available alternative.

242 S.N.B. 1999, c. G-2.11 [hereinafter *NBGDA*].

243 *Ibid.*, s. 14.

244 Compare s. 13 of the Nova Scotia legislation, *supra* note 235, where the grant of a franchise grants the holder the right to construct and operate a gas delivery system.

still obtain a permit before commencing construction.[245] Section 27 of the *NBGDA* requires that leave of the regulator be obtained before any amalgamation or purchase/sale of shares where the acquisition of shares will result in the acquiring company holding 20 percent of the outstanding shares of the gas distributor. The *NBGDA* also provides for gas storage prohibiting any person from injecting gas for storage into an underground storage facility unless an underground storage lease is issued.

In July 1998 the Government of New Brunswick issued an Expression of Interest and Consultation Document requesting parties interested in obtaining the gas distribution franchise to file a statement of interest. A Request for Proposals ("RFP") was then issued requiring that parties interested in obtaining the franchise demonstrate their ability to build and operate a gas distribution system, the areas proposed to be served, the services expected to be provided, the proposed pricing and rate policies, and their methods and costs of service. The selection of Gas NB as the provincial distributor was the unanimous choice of a selection committee following the RFP process. In the future, applications for natural gas franchises will be made to the Board of Commissioners of Public Utilities.

III. LEGISLATIVE DEVELOPMENTS

A. FEDERAL

1. *NATIONAL ENERGY BOARD ACT*[246]

a. *Onshore Pipeline Regulations*

Effective August 1, 1999, the *Onshore Pipeline Regulations*[247] were replaced by the *Onshore Pipeline Regulations, 1999*,[248] providing revised requirements for onshore pipelines which are designed, constructed, operated, or abandoned after August 1, 1999.[249] The *OPR 1999* support a goal-oriented approach to the regulation of onshore pipelines, requiring that companies develop detailed designs, risk assessments, and specifications that will meet the design, construction, operation, and abandonment safety and integrity requirements of the *OPR 1999*.[250] The Guidance Notes issued by the NEB provide guidance to industry for complying with the new regulatory requirements under the *OPR 1999*.

The *OPR 1999* emphasize monitoring and maintenance activities and the actual development of designs, assessments, and specifications to ensure the safety and integrity of pipelines. Companies will nonetheless be required to submit documents for NEB approval where there are no applicable standards found in the *OPR 1999*.[251] In addition,

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245 Part 2 of the *NBGDA* regulates the application for permits, acquisition of land for purposes of constructing the pipeline and reporting requirements where a break occurs in a pipeline.

246 *NEB Act*, *supra* note 30.

247 S.O.R./89-303.

248 S.O.R./99-294 [hereinafter *OPR 1999*].

249 *Ibid.*, ss. 2-3. The *OPR 1999* adopt the *NEB Act* definition of "pipeline."

250 See Vollman, *supra* note 112 at 5ff.

251 *OPR 1999*, *supra* note 248, s. 8.

the NEB retains discretion to require that a company submit such documents where a company makes an application under Part III (for the construction and operation of a pipeline) or Part V[252] of the *NEB Act*. Companies may also be required to submit such documents where the NEB receives information that the design, construction, operation, or abandonment of a pipeline, or any part thereof, may be a hazard to persons or a detriment to the environment.[253]

The NEB has expressed its intention to ensure that companies comply with the *OPR 1999* by undertaking detailed audits of company specifications, records and procedures, assessing skill levels of personnel and staff, and performing inspections of pipeline facilities.[254] The NEB believes that the amendments will promote industry responsibility, provide flexibility, and reduce the regulatory burden without compromising safety or environmental concerns.

b. *Part VI (Oil and Gas) Regulations*

The *National Energy Board Act Part VI (Oil and Gas) Regulations*[255] were amended to make them consistent with a 1997 NEB licensing procedure which bases the licensing for long-term exportations of crude oil on "Fair Market Access." The *Regulations Amending the National Energy Board Act Part VI (Oil and Gas) Regulations*[256] also now detail the information that an applicant wishing to export oil from Canada must furnish to the NEB on an application for a licence for the export of "light crude oil" or "heavy crude oil." Applications must include the applied-for terms of the licence, information regarding the applicant's oil market, proposed environmental and social effects of the export, details of environmental reviews, and descriptions of how the applicant has informed others of the availability of supply and the option of purchasing light crude oil for use in Canada.[257]

c. *Processing Plant Regulations*

In the past the NEB has used the *Onshore Pipeline Regulations* to regulate processing plants that are owned and operated by federally regulated transmission companies and whose function is integral to transportation.[258] Pursuant to s. 48(2) of the *NEB Act*, the NEB has developed draft *Processing Plant Regulations* ("*PPR*") to comprehensively regulate and ensure the safety and integrity of the design, construction, operation and

[252] Part V of the *NEB Act* regulates powers of pipeline companies, including the power to sell or purchase a pipeline.

[253] *OPR 1999*, *supra* note 248, s. 7.

[254] See Preamble to the Guidance Notes for the Onshore Pipeline Regulations, 1999. The Guidance Notes were issued by the NEB as a guide to assist industry in understanding and complying with the new requirements.

[255] S.O.R./96-244.

[256] S.O.R./99-443.

[257] See s. 25.1 of the *Regulations* as amended. Section 2 of the *Part VI Regulations* defines "light crude oil" to include a substance with a density less than or equal to 875.7 kg/m^3 and which is an oil, a blend of oils other than refined petroleum products, or a blend of oils other than refined petroleum products with refined petroleum products.

[258] See the discussion in Part II.A.1.a, above, respecting NEB — Pipeline Jurisdiction section.

abandonment of hydrocarbon processing plants designed, constructed, operated, or abandoned after the *PPR* come into force.[259]

The *PPR* establish requirements for engineering, reporting, record keeping, and safety of hydrocarbon processing plants, and address environmental issues and requirements regarding the design, construction, operation, and abandonment of such plants. Similar to the *OPR 1999*, the *PPR* adopt a goal-oriented approach to regulation. All companies must develop detailed designs for the processing plants and must develop and implement procedures and programs respecting safety and integrity, including a safety program and an environmental protection program. Companies need not submit the details of safety or integrity programs to the NEB for approval, except as required by the NEB. In December 1999 the NEB posted for comment Draft Guidance Notes for the *Processing Plant Regulations* and expressed its intention to monitor compliance with the *PPR* through audits and inspections of designs, procedures, records, and facilities during construction, operation and abandonment.[260]

d. *Pipeline Crossing Regulations*

In January 2000 the NEB announced its intention to enact the *Damage Prevention Regulations* to replace the existing *Pipeline Crossing Regulations, Part II.*[261] The existing regulations establish the responsibility of a company with respect to informing third parties about the existence of its pipelines, including the establishment of an ongoing public awareness program. It also establishes the responsibilities of a company granting permission to other companies to excavate near its pipelines, including an obligation to maintain records of all construction and installation of facilities and to respond within three business days to any request from a facility owner or excavator to locate its pipes.[262] The new regulations would seek to achieve the same goals by regulating activities on or adjacent to pipeline rights-of-way, promoting safety, and preventing damage to property and the environment.

e. Section 104 Right-of-Entry Orders

In October 1999 the NEB provided clarification to industry with respect to the filing of right-of-entry applications pursuant to s. 104 of the *NEB Act*. This clarification was prompted by existing inconsistencies between s. 104(2) of the *NEB Act* (which provides that an owner of lands must be served with a right-of-entry application not less than 30 days and not more than 60 days before the date that the right-of-entry application is to be made) and s. 55 of the NEB *Rules of Practice and Procedure, 1995*[263] which require that an application for a right-of-entry order be filed "forthwith" after service of the notice

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259 The *PPR* will not apply to well site facilities, field facilities or pipelines which are subject to the *OPR 1999*. See s. 3 of the *PPR*.

260 NEB letter To: All Companies Under the National Energy Board's Jurisdiction and Other Interested Parties re: Draft Guidance Notes for the Proposed *Processing Plant Regulations* Under the *National Energy Board Act* — Request for Submission (16 December 1999).

261 S.O.R./88-529.

262 *Regulations Amending the National Energy Board Pipeline Crossing Regulations, Part II (Miscellaneous Program)*, S.O.R./2000-58.

263 S.O.R./95-208 [hereinafter *Rules*].

on a landowner. The NEB has directed that s. 55 of the *Rules* will be "read down" to avoid the "forthwith" filing requirement. Therefore, all right-of-entry applications filed on or after November 1, 1999, are to be dated and filed no less than thirty days and no more than sixty days after service of notice of the right-of-entry application on a landowner.[264]

2. *CANADIAN ENVIRONMENTAL ASSESSMENT ACT*[265]

Under the *CEAA* federal authorities, as defined in s. 2, are required to conduct environmental assessments on certain projects before funding or issuing regulatory approvals. The *Inclusion List Regulations*,[266] the *Exclusion List Regulations*,[267] the *Law List Regulations*,[268] and the *Comprehensive Study List Regulations*[269] together determine which projects will be subject to an environmental assessment.

a. Regulations Amending the *Inclusion List Regulations*[270]

The *Inclusion List Regulations* identify activities that are subject to an environmental assessment under the *CEAA*. Several activities were added to these regulations this past year, thereby requiring that the additional activities undergo an environmental assessment. Harmful alteration, disruption, or destruction of fish habitat that is caused by physical activities that will alter more than 500 metres of continuous natural shoreline and that require approval from the Minister of Fisheries and Oceans pursuant to s. 35(2) of the *Fisheries Act*[271] will be subject to an environmental assessment under the *CEAA*.[272] Environmental assessments will also now be required for the exploitation of oil and gas on Indian lands that requires a surface lease, right-of-way, or right-of-entry pursuant to the *Indian Oil and Gas Regulations, 1995*.[273] Environmental assessments must also be conducted for long-based seismic surveying if more than 50 kilograms of chemical explosives would be detonated in one blast, and for marine or freshwater seismic surveys where air pressure is greater than 275.79 kilopascals measured at one metre from the source.[274]

264 *Letter to: Pipeline Companies Under the Jurisdiction of the National Energy Board (NEB or the Board) and NEB Practitioners* (27 October 1999) (NEB).

265 *CEAA*, *supra* note 31.

266 S.O.R./94-637.

267 S.O.R./94-639.

268 S.O.R./94-636.

269 S.O.R./94-638.

270 S.O.R./99-436.

271 R.S.C. 1985, c. F-14.

272 Schedule to the *Inclusion List Regulations*, *supra* note 266, s. 46.1.

273 *Ibid.*, ss. 65 and 66.

274 *Ibid.*, s. 79.

b. Regulations Amending the *Exclusion List Regulations*[275]

Projects which involve physical works that have insignificant environmental effects are identified in the *Exclusion List Regulations* and are exempt from environmental assessments under the *CEAA*. The relocation of a section of an oil and gas pipeline and the addition or installation of certain components[276] to an existing onshore oil and gas pipeline will not be subject to an environmental assessment under the *CEAA* *unless* the relocation, addition, or installation will result in the extension of a pipeline beyond the existing limits of the right-of-way or of other property on which the pipeline is located, the installation will be undertaken within thirty metres of a body of water, or the installation is likely to involve the release of a polluting substance into a body of water or result in an increase in airborne emissions or noise during the operation of the facility.[277] The portion of an oil and gas pipeline, a pipeline used for the transmission of any other flammable or highly volatile liquid or a water pipe that will cross under a railway or a road will be exempt from the environmental assessment requirement. This exemption extends to the portion of the pipeline or pipe that crosses under the railway or road and that is located within the railway or road right-of-way.

c. Regulations Amending the *Law List Regulations*[278]

The statutory and regulatory approvals that will trigger an environmental assessment are provided for in the *Law List Regulations*. An environmental assessment will now be triggered by the sale, lease or disposal of territorial land under s. 8 of the *Territorial Lands Act*,[279] an application for a right-of-way, surface lease or exploratory licence or the production of crude bitumen under ss. 6(4), 27(4), 32(1), 39(1), or 39(3) of the *Indian Oil and Gas Regulations, 1995*,[280] and the issue of permits for the cutting of timber on territorial lands pursuant to ss. 4(1) or 7(1) of the *Yukon Timber Regulations*.[281] Amendments are now being proposed to the *Law List Regulations* and *Inclusion List Regulations* to ensure that the Department of Indian Affairs and Northern Development would have the jurisdiction to approve mining projects in the Yukon, thereby triggering the application of *CEAA*.

d. Regulations Amending the *Comprehensive Study List Regulations*[282]

Projects that are automatically subject to an extensive environmental assessment are provided for in the *Comprehensive Study List Regulations*. Pursuant to the amendments made in 1999, an oil sands mine with a bitumen production capacity of more than 10,000 cubic metres per day and an industrial facility for the commercial production of non-

275 S.O.R./99-437.

276 The components include new connections, pipings. cathodic protection systems, valves, compressor and pump station components, storage tank components, metering and regulating facilities, quality measurement systems, and mechanical and electrical systems of a facility building.

277 *Exclusion List Regulations*, *supra* note 267, ss. 30.1 and 30.2.

278 S.O.R./99-438.

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

280 S.O.R./94-753.

281 S.O.R./87-191.

282 S.O.R./99-439.

ferrous metals or light metals by pyrometallurgy or high-temperature electrometallurgy will automatically be subject to an environmental assessment.

3. *MACKENZIE VALLEY RESOURCE MANAGEMENT ACT*[283]

The full title of this *Act* is *An act to provide for an integrated system of land and water management in the Mackenzie Valley, to establish certain boards for that purpose and to make consequential amendments to other Acts.* Although most of the provisions of the *Act* came into force in December 1998 establishing the Gwich'in Land Use Planning Board, the Sahtu Land Use Planning Board, and each of the Gwich'in and Sahtu Land and Water Boards,[284] Part 4 and ss. 160(2), 165(2), and 167(2) came into force March 31, 2000.[285]

Part 4 of the *Act* establishes the Mackenzie Valley Land and Water Board, which regulates all uses of land and waters or deposits of waste for which a permit or licence is required, including the use of land for the exercise of subsurface rights.[286] The Land and Water Board has the power to suspend licences or to issue, amend, renew, or cancel licences and permits and approve assignments of licences and permits.[287] Sections 160(2), 165(2), and 167(2) make consequential amendments to the *Access to Information Act*,[288] the *Northwest Territories Act*,[289] and the *Privacy Act*,[290] respectively.

B. PROVINCIAL

1. ALBERTA

a. *Environmental Protection and Enhancement Act*[291]

(i) *Environmental Appeal Board, Amendment Regulation*

The *Environmental Appeal Board Regulations*,[292] setting out the practice and procedure of the Environmental Appeal Board ("AEAB"), have been amended effective May 3, 1999, by the *Environmental Appeal Board Amendment Regulation*.[293] Pursuant to the amended Regulations, persons who disagree with a decision made by the director are required to file "appeals" or "notices of appeal" rather than objections. Amendments are also made to notices which the AEAB must give in respect of a hearing, requiring that the AEAB give seven or twenty-one days' notice, depending on the nature of the appeal, rather than forty-five days' notice of the hearing. No specific notice period is provided

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283 S.C. 1998, c. 25.
284 SI/99-1.
285 SI/2000-17.
286 *Supra* note 283, s. 102.
287 *Ibid.*, ss. 59, 60, 102.
288 R.S.C. 1985, c. A-1.
289 R.S.C. 1985, c. W-27.
290 R.S.C. 1985, c. P-21.
291 S.A. 1992, c. E-13.3 [hereinafter *EPEA*].
292 Alta. Reg. 114/93.
293 Alta. Reg. 106/99.

for hearings that will be conducted on the basis of written submissions. Provision is also made for the AEAB to allow parties to direct written questions to other parties where hearings are conducted on the basis of written submissions.

b. *Surface Rights Act*[294]

Effective September 1, 1999, the *Surface Rights Amendment Act*[295] came into force, thereby amending ss. 39 and 44 of the *SRA*. Section 39 of the *SRA* deals with compensation payable by an operator and in particular, the ability of the Surface Rights Board to enforce payment of the compensation. "Operator" for purposes of s. 39 will include successors, assignees, and agents of persons who were liable to make compensation as holders of a surface lease, a right-of-entry order, an approval, registration, licence, or permit, as a working-interest participant in an energy development, or as a person carrying on an activity as defined in the *EPEA*.

The procedure for enforcing payment under the *SRA* has also been revised. In particular, the SRB is now required to send a written notice to an operator demanding full payment before directing the provincial treasurer to make the payment out of the General Revenue Fund. If an operator fails to comply, the SRB can suspend an operator's right-of-entry to the site and may terminate all of the operator's rights under a right-of-entry order. If the SRB terminates the operator's rights but full payment is outstanding, the SRB can direct that the provincial treasurer make the payment. In the case of a subsequent non-payment of compensation by the operator in relation to the same site where the provincial treasurer has made a payment out of the General Revenue Fund on a prior occasion, the SRB may direct the provincial treasurer to make further payments without any further application to the SRB by the person entitled to the compensation. Any amounts paid or expenses incurred in enforcing the payment of compensation becomes a debt due to the Crown and can be enforced as a judgment of the Court of Queen's Bench following the filing with the Court of a written certificate issued by the provincial treasurer. The minister's regulation-making power in s. 44 is accordingly amended to empower the minister to establish any "procedural provisions" for the purposes of s. 39.

c. *Mines and Minerals Act*[296]

(i) Natural Gas Royalty Regulation

On January 1, 2000, amendments to the *Natural Gas Royalty Regulation, 1994*[297] came into force.[298] The two significant amendments made to the regulations are, first, the addition of a new section which identifies the circumstances for being exempt from the royalty and, second, a provision regarding interest. On an application from the operator of a "crude oil battery" that is not a "qualifying battery," the minister may approve a "well event" from which gas is recovered. Gas that is recovered from an

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294 S.A. 1983, c. S-27.1 [hereinafter *SRA*].

295 S.A. 1999, c. 5.

296 *Supra* note 196.

297 Alta. Reg. 351/93.

298 Alta. Reg. 269/99.

"approved well event," delivered to a crude oil battery, and used or consumed is exempt from the payment of the royalty.[299] Gas that is recovered from a "qualifying well event" and delivered to a qualifying battery is exempt from the payment of royalties to the Crown, as long as that gas is recovered from the qualifying well event after December 31, 1998, and before January 1, 2009. The minister retains the discretion to terminate a royalty exemption if the average production of gas from the well event exceeds 15,000 cubic metres per day for each month during a period of three consecutive months, the regulator recommends that the exemption be terminated, and the minister is of the opinion that the exemption should no longer be in place.

The regulation provides the details of calculating interest in the event of an overpayment or underpayment of royalty. If the royalty is underpaid to a royalty client, interest is payable from the first day of the third month following the production month to which the royalty compensation is payable to the last day of the month in which the first royalty invoice is issued in which the underpayment first appears. Interest on an overpayment is payable from the first day of the third month following the end of the production month to the last day of the month in which the first royalty invoice is issued in which the overpayment and interest are credited.

Other amendments have deleted the requirement for "major purchasers" of propane, butanes, or pentanes plus to report costs attributable to the transportation of propane, butanes, and pentanes plus. A new schedule 7 is added respecting batteries which are excluded from the definition of "qualifying battery" pursuant to paragraph 12.1 (1)(d) of the Regulation. The amendments also revise the provisions regarding the CAP election. "CAP" is the corporate average price determined in accordance with s. 6 of schedule 1 to the Regulation. The "CAP election," in relation to a royalty client, is defined as the corporate average price for gas and ethane established for that royalty client for that year. With respect to the CAP election, where a royalty client submitted a CAP election during 1999 and the aggregate of the amounts paid during 1997 was not more than $225,001, the CAP election will be applicable to all production months in 1999 and succeeding years.

Further amendments were made to the *Natural Gas Royalty Regulation, 1994*, by the *Natural Gas Royalty Regulation, 1994 Amendment Regulation*.[300] The minister has an obligation to prescribe an amount per gigajoule as the Ethane Reference Price and as the Ethane Par Price for February 2000. The minister is also required to prescribe an amount per gigajoule as the new ethane select price and the old ethane select price. The amendments add a definition of "new ethane" to mean ethane obtained from new gas and a definition for "old ethane," which means ethane other than new ethane.

Under s. 8(3), a separate provision has been added respecting the calculation of royalties reserved to the Crown with respect to ethane. Those royalties are calculated in accordance with schedule 1.1. Schedule 1.1 also sets out the method for calculating royalties for low productivity wells and royalty compensation payable to the Crown.

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299 *Ibid.*, ss. 12.1(2), 12.1(4).
300 Alta. Reg. 51/2000.

(ii) Petroleum and Natural Gas Tenure Amendment Regulation[301]

The *Petroleum and Natural Gas Tenure Amendment Regulation*, effective January 26, 2000, requires that wells be drilled to a "minimum depth" of 150 metres, precludes multiple applications in respect of a single qualifying well, and permits applications for continuation.[302] The provision respecting qualification as a validating well for purposes of a licence was amended and new rules were added requiring that applications under part 1 or part 2 be authorized pursuant to the *Mines and Minerals Administration Regulation*.[303] Amendments were also made to continuation, offset requirements, offset notices, and the liability of a lessee to pay offset compensation. Amendments to the calculation and payment of offset compensation were also made.

(iii) Oil Sands Tenure Regulation[304]

Effective March 8, 2000, the *Oil Sands Tenure Regulation* empowers the minister to issue an Oil Sands Agreement ("OSA"), which is a permit or a lease, conveying the exclusive right to drill for, win, work, recover, and remove oil sands that are the property of the Crown. During the term of a permit and upon the submission of a technical report and data to the minister, the permittee may apply for a "primary lease of oil sands rights." The minister will determine whether to issue a primary lease on the basis of the extent and degree to which the permittee has attained the minimum level of evaluation of the oil sands in accordance with s. 3 of the Regulation. During the last year of the term of an oil sands lease or otherwise with the consent of the minister, a lessee can apply to the minister for a primary lease of oil sands rights. The minister has an obligation upon receiving the application to issue the primary lease.[305]

Within the last year of the term of a primary lease or otherwise with the consent of the minister, the lessee of a primary lease can apply to the minister for approval of the *continuation* of the lease. The minister will determine whether to continue the lease based on the extent to which the lessee has attained the minimum level of evaluation of the oil sands in accordance with s. 3 of the Regulation, and whether the lease is producing.

The lessee of a continued lease which is designated as non-producing is liable to pay to the Crown an escalating rental pursuant to s. 16 of the Regulation. The Cold Lake and Wabasca areas are established as areas that will be subject to escalating rents. The regulation expires on December 1, 2004.

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301 Alta. Reg. 11/2000.
302 See also, Alberta Environment Information Letter 2000-6 (23 February 2000).
303 Alta. Reg. 262/97.
304 Alta. Reg. 50/2000.
305 The term of the primary lease is fifteen years.

(iv) Oil Sands Royalty Regulation, 1997

The *Oil Sands Royalty Regulation, 1997 Amendment Regulation*[306] amends the *Oil Sands Royalty Regulation, 1997*[307] by adding new rules for calculating any cost that is calculated pursuant to the Regulation or pursuant to s. 125.1 of the *Mines and Minerals Act*. The new rules will apply where cost is determined in relation to a capital asset, good or service, other than an asset, good or service obtained from a person who is not affiliated with the owner or operator of the project or an affiliate thereof.

The cost of a good or service, other than a "basic service" is, where the minister is satisfied that a fair market value can be determined, the lesser of the amount charged to the project for the good or service and the fair market value of the good or service. Where the minister is satisfied that a fair market value cannot be reasonably determined, and that service is performed without utilizing a capital asset, the cost of the good or service is the lesser of the amount charged, the actual cost incurred by the project owner, operator, or affiliate and the actual cost incurred by the person from whom the good or service was obtained. The cost for "basic services"[308] or any other service for which the minister is satisfied that a fair market value cannot reasonably be determined and that is performed utilizing a capital asset, is the lesser of the amount charged to the project and the cost of service. New rules are also provided for determining the fair market value of a good or service and determining the cost of a capital asset.

(v) Public Lands Act[309] *in Relation to the Fees Regulation*

Various changes have been made to the *Fees Regulation*[310] respecting leases, easements, registration of assignments, and reinstatement of a disposition. Changes have also been made to fees under the *Special Areas Act*,[311] including fees for the issuance of leases, pipeline agreements, mineral surface leases, easements and permits, and licences of occupation.

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306 Alta. Reg. 52/2000.

307 Alta. Reg. 185/97.

308 A "basic service" is defined to mean a service that is performed in order for oilsands or oilsands products to be recovered or cleaned, crude bitumen to be obtained from oilsands products and utilizing a capital asset that is not part of the project.

309 R.S.A. 1980, c. P-30.

310 Alta. Reg. 78/88.

311 R.S.A. 1980, c. S-20.

d. *Pipeline Act*[312]

(i) Pipeline Regulation

The *Pipeline Regulation*[313] has been amended by the *Pipeline Amendment Regulation.*[314] The *Pipe Line Assessment Standards Regulations*[315] are repealed by the *Regulation Repeal Regulation.*[316]

The *Pipeline Amendment Regulation* makes CSA Z662 Oil and Gas Pipeline Systems the only minimum standard for the design, construction, operation, maintenance, and repair of pipelines unless the EUB[317] otherwise permits.[318] The restrictions on the use of threaded joints for the construction of buried steel or aluminium pipeline is repealed, as are the requirements for external protective coating and cathodic protection and the requirement for installation of an electrically conductive wire for locating buried non-metallic pipe during construction. Licensees are required to maintain internal and external corrosive testing and inspection results records for at least six years from the date that the record is made.[319]

Subject to the CSA standard, gas which contains hydrogen sulphide cannot be intentionally released unless consent of the ERCB is obtained or unless the gas is vented from the pipeline during a quarterly inspection.[320] A new Schedule 4 is added to the Regulation to provide excavation procedures for exposing pipelines that are more than 1.5 metres below the surface. The amendments prohibit the operation of vehicles or equipment across a pipeline at a point not within the travelled portion of a highway or public road unless approval is obtained from the permittee or licensee, or the vehicle or equipment is being used for agricultural purposes. The provisions respecting pressure testing have been simplified and the provisions for inspecting tie-in wells have been repealed.

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312 R.S.A. 1980, c. P-8.

313 Alta. Reg. 122/87.

314 Alta. Reg. 220/99.

315 Alta. Reg. 467/83.

316 Alta. Reg. 270/99.

317 In 1995 the Alberta Energy and Utilities Board was formed to deal with all legislative responsibilities of the Energy Resources Conservation Board and the Public Utilities Board; *Alberta Energy and Utilities Board Act*, S.A. 1994, c. A-19.5, s.8.

318 The CSA Z169 Aluminum Pipe and Pressure Piping Systems is no longer an acceptable standard.

319 *Supra* note 314, s. 53.

320 Prior to the amendments, only gas containing more than 0.16 moles of hydrogen sulphide gas per kilomole of natural gas was subject to the restriction regarding intentional release.

e. *Miscellaneous Statutes Amendment Act, 1999*

(i) *Public Utilities Board Act*[321] and the *Gas Utilities Act*[322]

Effective May 19, 1999, the *Public Utilities Board Act* has been amended with respect to "section 99 applications." Prior to the amendments, an owner of a public utility under the *PUB Act* or an owner of a gas utility under the *Gas Utilities Act* was required to obtain the approval of the EUB before "uniting" with a public or gas utility. Following the amendments, s. 99 applications will only be required where one or more of the "uniting" public utilities or gas utilities has been designated by regulation to be an owner of a public or gas utility to which s. 99 of the *PUB Act* applies.

f. *Energy Statutes Amendment Act, 2000*[323]

On March 6, 2000, the *Energy Statutes Amendment Act* was introduced in the Alberta Legislature, which, if passed, will make several changes to the OGCA and the *Pipeline Act*, imposing on industry more responsibility and liability for the clean-up of sites and more stringent surveillance and enforcement mechanisms.

The proposed amendments to the OGCA will make that legislation applicable to the construction, maintenance, repair, and suspension of any well or facility. In this respect, a broad definition of "facility" is provided to include any building, structure, installation, equipment, or appurtenance that is subject to the jurisdiction of the ERCB[324] and connected to or associated with the recovery, development, production, handling, processing, treatment, or disposal of hydrocarbon-based resources or any associated substances or waste. The definition of "facility" excludes wells, a pipeline as defined in the *Pipeline Act*, a mine site or processing plant as defined in the *Oil Sands Conservation Regulation*,[325] and a mine site or coal processing plant as defined in the *Coal Conservation Act*.[326]

Proposed amendments to the licensing requirements will permit only licence or approval holders to construct or operate facilities. Applicants for well licences or facilities licences must be working-interest participants[327] and must hold a subsisting identification code issued pursuant to the OGCA. Additionally, applicants for well licences must be entitled to produce, drill, or operate the well.

More responsibility will be placed on industry respecting escaped substances and the suspension and abandonment of wells and facilities. Licensees, approval holders, and

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

322 R.S.A. 1980, c. G-4.

323 Bill 13, *Energy Statutes Amendment Act*, 4th Sess., 24th Leg., Alberta, 2000. This Bill received First Reading on 6 March 2000, Second Reading on 20 April 2000, Third Reading on 16 May 2000, and was in force 30 June 2000.

324 See *supra* note 317.

325 Alta. Reg. 76/88.

326 R.S.A. 1980, c. C-14.

327 A working-interest partner will no longer be deemed to include a person who has actual control of a corporation.

working-interest partners will remain responsible for abandonment costs. Liability for escaped substances will be broadened to apply not only to oil, but also to crude bitumen, water, or any other substance which has escaped from a well, facility, or pipeline.

Proposed amendments to Part II.I of the OGCA will legislatively extend the Orphan Well Program[328] to include all upstream oil and gas facilities, including pipelines and gas plants. Although the Orphan Fund has in practice been available for the clean-up of liability associated with upstream facilities since 1996, no legislative amendment has been made to reflect this practice. Where a licensee, approval holder, or working-interest partner contravenes or fails to comply with an order of the ERCB or has an outstanding debt to the ERCB or in respect of the Orphan Well Program, proposed amendments to the Regulations will empower the ERCB to name as responsible parties one or more directors, officers, agents, or other persons who, in the ERCB's opinion, were directly or indirectly in control of a licensee, approval holder, or working-interest participant.

Similar amendments will be made by the *Energy Statutes Amendment Act* to the *Pipeline Act*, including amendments with respect to the discontinuation and abandonment of pipelines. With respect to pipeline licences, the ERCB will have the power to name as responsible parties one or more directors, officers, agents or other persons who in the ERCB's opinion are directly or indirectly in control of a licensee at the time of a contravention. There are also consequential amendments made in order to delete references to "permits" and replace those references with "licences."

2. BRITISH COLUMBIA

a. *Miscellaneous Statutes Amendment Act, 2000*[329]

On April 17, 2000, *Bill 8: Miscellaneous Statutes Amendment Act, 2000* received first reading in the Legislative Assembly of British Columbia. The *Act* proposes to amend the *Petroleum and Natural Gas Act*[330] by permitting the director to *continue* a lease if a geophysical survey of the drilling of a well is submitted to the commission and the director considers that the geophysical survey of the well will provide data relevant to the evaluation of the lease, and approval of the application is delayed for more than six months pending completion of environmental or other evaluations. Section 63.1 would empower the division head to *reinstate* a lease within one year after the date of expiry where the expiry is due to a lessee's failure (described in s. 63). The reinstatement, however, will be limited to circumstances where the division head is satisfied that the failure of the lessee was due to inadvertence or circumstances beyond the lessee's control, other than financial circumstances, that there has been no disposition pursuant to s. 71 of any of the petroleum or natural gas that was subject to the lease immediately before its expiry, the lessee pays the rental and does the work, and the lessee pays a fine of $500.

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328 The Orphan Program is funded by industry and administered by the EUB and is used to pay for the abandonment, decommissioning, and reclamation of orphan wells, upstream facilities and sites associated with the orphan wells or facilities where there is no existing or traceable owner to the well.

329 Bill 8, 4th Sess., 36 Parl., (3rd reading 9 May 2000).

330 *Supra* note 230.

3. SASKATCHEWAN

a. *The Pipelines Act, 1998*

Effective April 1, 2000, *The Pipelines Act, 1998*[331] repeals *The Pipe Lines Act*,[332] incorporating several changes to the regulation of pipelines in Saskatchewan. The *1998 Act* requires that persons intending to construct, alter, operate, abandon, or discontinue the operation of a pipeline obtain a *licence* rather than a permit. The definition of "flow line" is amended and is now defined as a pipeline connecting a wellhead with an oil battery facility, a fluid injection facility, or a gas compression or processing facility and any pipes used to transport fluids within such facilities. The *1998 Act* now includes a definition of "natural gas": it is any mixture composed primarily of hydrocarbons that exists as a gas at normal pipeline pressures and temperatures, whether or not it contains impurities. The *1998 Act* also takes away the ability of the minister to exempt from its operation pipelines which are less than 15 kilometres in length.

The new legislation also introduces the concept of "common carrier" that, pursuant to s. 19, is applicable to all pipelines except pipelines for the transportation of natural gas. Where a licence holder is declared to be a common carrier, that licence holder must provide transportation or delivery services, or storage used in the normal course of providing that transportation services on demand when capacity is available at rates comparable to the rates charged by the common carrier to other customers for similar services. The Saskatchewan government also appears to be taking a stronger stance against persons or companies that do not comply with the legislation. Under the repealed *Act*, persons who wilfully did damage to or obstructed the construction, completion, maintenance, or repair of any pipeline were guilty of an offence and liable for a fine of not less than $50 but not more than $500. Under the new *1998 Act*, a person who wilfully does any damage is liable to a fine not exceeding $5,000 but, in the case of a continuing offence, to a further fine not exceeding $5,000 for each day or part of a day during which the offence continues. As well, a contravention of the repealed *Act* or any Regulation subjected a person to a fine not exceeding $1,000. Under the *1998 Act*, a contravention of the *Act* or any Regulation or order made pursuant to it could subject a person to a fine not exceeding $50,000. In the case of a continuing offence, the person could be subject to a further fine not exceeding $50,000 for each day or part of a day during which the offence continues. Officers, directors, managers, or agents of the corporation who direct, authorize, or participate in the commission of certain offences will also be guilty of the offence and liable, whether or not the corporation is prosecuted.

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331 S.S. 1998, c. P-12.1 [hereinafter *1998 Act*]. The new legislation was discussed in the 1999 review, Smith *et al.*, *supra* note 48, but is included here due to the date it came into force and the new regulations.

332 R.S.S. 1978, c. P-12.

b. *The Pipelines Regulations, 2000*[333]

Effective April 1, 2000, *The Pipelines Regulations 2000*, enacted pursuant to *The Pipelines Act, 1998*, repeals *The Pipe Lines Regulations*.[334] The new Regulations set out the information requirements that must be satisfied when making an application for a pipeline licence. Applications for pipeline licences must include a copy of the pipeline plan, profile and cross-section of the pipeline including depth of burial, a road crossing and stream crossing profile, the commencement point and end point of the pipeline, a description of the substance to be transported, the length and size of pipe, protective coatings, flow rate, design pressure, and an application fee of $350. The applicant must also confirm that appropriate notifications have been provided to interested parties, including municipalities, the Department of Environment and Resource Management, and surface owners. The licence expires one year from the date of its issuance.[335] The Regulations also set out the requirements for applications to alter, discontinue, or abandon pipelines and require that all pipelines be constructed in accordance with the most recent version of CSA Standard Z662, *Oil and Gas Pipeline Systems*. Leave of the minister is required pursuant to s. 18 of the Regulations before an operator can commence operations.

4. NOVA SCOTIA

a. *Petroleum Resources Removal Permit Act*[336]

In June 1999 Royal Assent was granted to the *Petroleum Resources Removal Permit Act* of Nova Scotia. The essence of the legislation is that parties wishing to remove gas from the province are required to obtain provincial removal permits. The *PRRPA* purports to apply to all oil and gas produced in Nova Scotia including the offshore within the area known as the "Nova Scotia Lands" as defined in the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation (Nova Scotia) Act*.[337] The area includes Sable Island and the sub-marine areas offshore that are owned by the province or in respect of which the province has the right to exploit natural resources.

The *PRRPA* is of doubtful constitutional validity, although it is unlikely to be challenged. The law is clear that a province can only make laws in the province and provincial boundaries do not extend offshore. Two Supreme Court of Canada cases have held that the right to explore and exploit the Continental Shelf is the exclusive right of the federal government.[338] Consequently, a legal challenge would probably result in a finding that the Province of Nova Scotia does not extend to the Continental Shelf. Further, provincial laws regulating resources can only operate within the province. Section 92A of the *Constitution Act, 1867* allows provinces to make laws with respect to the export to other provinces of their natural resources, but does not allow provinces to enact

333 Chapter P-12.1 Reg. 1.

334 Sask. Reg. 612/68.

335 Licences can be extended for a six-month period at the discretion of the minister.

336 S.N.S 1999, c. 7 [hereinafter *PRRPA*].

337 S.C. 1988, c. 28.

338 *Reference Re: Seabed and Subsoil of the Continental Shelf Offshore Newfoundland*, [1984] 1 S.C.R. 86; *Reference Re: Ownership of Offshore Mineral Rights (British Columbia)*, [1967] S.C.R. 792.

interprovincial export restrictions concerning those natural resources. While it is difficult to imagine what party might launch a constitutional challenge, it is also unlikely that the Nova Scotia government will precipitate such a challenge by refusing an export permit.[339]

On November 19, 1999, the *PRRPA* was amended, first to give the Governor in Council authority to make regulations to exempt a person who has executed a "petrochemical supply" agreement with the province, and second to defer the effective date from November 1, 1999, to March 1, 2000.[340]

The *PRRPA* seeks to provide protection for a petrochemical business in Nova Scotia by prohibiting the removal from the province of certain petroleum substances, except pursuant to a permit issued by the minister responsible for the Petroleum Directorate. The legislation applies to gas including raw gas and "marketable" gas. Permits are not required to export coal gas, methane, oil, or condensates unless otherwise required by regulation. The M&NP gas stream, however, contains ethane in sufficient quantities to make the legislation applicable.

b. *Petroleum Resources Removal Permit Exemption Regulations*[341]

The amendments to the *PRRPA* allow regulations to be made to exempt exporters who have entered into so-called "petrochemical supply" agreements with the province. The *Petroleum Resources Removal Permit Exemption Regulations* exempt the SOEP producers since they have such agreements in place.

5. NEW BRUNSWICK

In March 1999 the New Brunswick *Gas Distribution Act, 1999* was passed and will regulate the distribution of natural gas in New Brunswick.[342] Pursuant to that *Act*, New Brunswick has passed four regulations to facilitate the construction of pipelines and facilities and the distribution of natural gas.

The *Gas Pipeline Regulation*[343] applies to high-pressure pipelines, distribution lines operating at a hoop stress less than or equal to 30 percent of the specified minimum yield strength, and polyethylene lines. The *Gas Pipeline Regulation* sets out construction, design, operating, and abandonment standards for pipelines, facilities, and compressor stations and identifies the obligations of a gas distributor to prepare detailed documents including designs, emergency procedure manuals, and construction safety manuals and the ability of the distributor to contract for the construction or maintenance of its line.

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339 The issue of constitutional validity of export restrictions was the subject of an earlier paper presented to the Canadian Petroleum Law Foundation Research Seminar, C.K. Yates & P.J. Keeley, "Alberta Gas in United States Markets: Canadian and American Perspectives on Competition, Constitutional and Contract Enforcement Issues" (1991) 30 Alta. L. Rev. 219.

340 *An Act to Amend Chapter 7 of the Acts of 1999, the Petroleum Resources Removal Permit Act*, S.N.S. 1999, c. 14.

341 O.I.C. 2000-88 (March 1, 2000); N.S. Reg. 28/2000.

342 *Supra* note 242.

343 N.B. Reg. 99-61.

The *Gas Distribution Rules of Procedure*[344] set out the rules and practices of the Board of Commissioners of Public Utilities including the power of that board to determine a point of law or jurisdiction or practice or procedure, to conduct and adjourn hearings, and to permit parties to file written evidence.

The *Gas Distribution and Marketers' Filing Regulation*[345] sets out the specific information that must be filed pursuant to s. 21(1) with respect to applications for pipelines and facilities, applications for licences and applications for rates and tariffs.

The *Gas Distribution Uniform Accounting Regulation*[346] identifies in significant detail the accounting information that gas distributors must maintain in accordance with generally accepted accounting principles.

[344] N.B. Reg. 99-59.
[345] N.B. Reg. 99-60.
[346] N.B. Reg. 99-62.