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Regulatory and Legal Issues Respecting CBM Development in Alberta and British Columbia

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REGULATORY AND LEGAL ISSUES RESPECTING

CBM DEVELOPMENT IN ALBERTA AND BRITISH COLUMBIA

An Overview of Coalbed Methane (“CBM”) in Alberta and British Columbia

CBM, also known as natural gas in coal (“NGC”) or coalbed gas (“CBG”), is natural gas produced in the coal formation process, or coalification, and is stored on the internal surfaces of decomposing organic matter, such as plants and other vegetation, deposited in swamps and lakes, which is then over time transformed into coal.¹ Pressure develops, forcing this organic material further into the Earth while heat rises from below. This pressure produces methane gas, along with other gases, which are then adsorbed, (the process of accumulating to a solid), to the coal surfaces and trapped in coal seams.²

It is this adsorption characteristic that makes CBM unique from other natural gasses. Unlike conventional natural gas, which is merely stored in the open pore space of source rock, CBM is both produced and stored in the coal bed. Further, coal, due to its large surface area, is able to store considerably more gas than conventional source rock.³

The amount of CBM stored within the coal is affected by a number of factors. These include the composition, rank (reflecting the pressure under which it was formed) and quality of the coal, the

¹ E. Craig & M. Myers, “Ownership of Methane Gas in Coalbeds” (1978) 24 *Rocky Mtn. Mineral Law Institute* 767-68.

² “Coalbed Methane in Alberta” *Natural Gas in Coal Orientation* (September 2006), online: Alberta Energy <www.energy.gov.ab.ca>.

³ “Coalbed Methane” *EnerFAQs No. 10* (November 2006), online: Alberta Energy and Utilities Board <www.eub.gov.ab.ca> [*EnerFAQs*]; J. Buckingham & P. Steele, “Coalbed Methane: Conventional Rules for an Unconventional Resource?” (2004) 42 *Alta. L. Rev.* 1 at 9; M. Heath & Associates, “The Potential for Coalbed Methane (CBM) Development in Alberta” (September 2001) at 5 [*Heath*].

thickness of the coal seams, reservoir depth and permeability. Production of CBM is directly influenced by the presence of water in the coal formation and the area's hydrodynamics.⁴ Production is further affected by the relationship between these factors. For instance, coal with a higher rank is indicative of restrictive permeability.⁵

Although commercial production of CBM in Alberta was attempted as early as the 1970s, the first CBM pool was not defined by the Alberta Energy and Utilities Board ("EUB" or "the Board") until 1995 and commercial production of CBM did not occur until 2002.⁶

The EUB estimates established Alberta CBM reserves to be 24.7 billion cubic metres (.87 trillion cubic feet) as at the end of 2006 in areas where commercial production is occurring. Over 2400 CBM wells were connected in 2006, almost double the activity in 2004 and there are now over 10,000 CBM wells and well licenses and the annual production of CBM in 2006 was 1.2 billion cubic meters.⁷ The EUB projects that CBM production will increase nine-fold over the next 10 years and will account for 16 percent of all marketable produced gas in Alberta in 2015, a significant increase from the 2 percent it comprised in 2005.⁸

CBM is generally located within four geologic strata – the Ardley Coals of the Scollard Formation, the Coals of the Horseshoe Canyon Formation and Belly River Group, the Coals of

⁴ *Heath, ibid.*

⁵ "Coal Maturation and Coalbed Methane (CBM) Generation," online: Alberta Geological Survey <www.ags.gov.ab.ca>.

⁶ "ST98-2007: Alberta's Energy Reserves 2006 and Supply/Demand Outlook 2007-2016" (June 2007) online: Alberta Energy and Utilities Board <www.eub.gov.ab.ca> at 4-1 (ST98-2007).

⁷ *Ibid.* at 4-1 and 4-7; "ST98-2006: Alberta's Energy Reserves 2005 and Supply/Demand Outlook 2006-2015" (May 2006) online: Alberta Energy and Utilities Board: <www.eub.gov.ab.ca>, at 4-9; "ST41: 2006 Year in Review" (June 2007) online: Alberta Energy and Utilities Board:<www.eub.gov.ab.ca> at 45.

⁸ *Ibid.* ST98-2006 at 4-9.

the Mannville Group and the Kootenay Coals of the Mist Mountain Formation.⁹ These strata cover approximately half of the province, extending from just north of Grande Prairie, trending southeast to the Lloydminster area and running to the United States border.¹⁰

The Ardley Coals of the Scollard Formation, running from Southeast of Red Deer to Southeast of Grande Prairie, are the shallowest coals and often contain significant amounts of water. The Horseshoe Canyon/Belly River Coals, trending from the Southwest corner of the province and arcing past Edmonton, have received attention as not only the first coals to generate commercial production, but also as the preferred target. Generally, these coals contain low gas contents and low water volumes, which provide positive economics for developers.

The Mannville Coals cut a wide swath through Central Alberta, extending from Saskatchewan to the Rocky Mountains. These coals have not only high gas contents, but also high volumes of saline water, which demand extensive pumping, which raises water disposal issues for operators.

Lastly, the Kootenay Coals, present solely in the foothills of the Southwest corner of the province, have attracted little commercial attention due to tectonic disruption.¹¹

In British Columbia, the Ministry of Energy and Mines and Petroleum Resources (“MEMPR”) is responsible for development of the Province’s oil and gas resources and estimates B.C.’s CBM potential to be approximately 90 trillion cubic feet (“Tcf”).¹²

⁹ *Ibid.* at 4-6.

¹⁰ *Ibid.* at 4-8.

¹¹ *Ibid.* at 4-6; “Bulletin 2005-15” (June 23, 2005), online: Alberta Energy and Utilities Board <www.eub.gov.ab.ca>.

CBM can be found in various areas in British Columbia and development is being considered in the Peace Country in the Northeast and in the Elk Valley in the Southeast. Other areas with CBM potential include Vancouver Island, the South-Central Interior (Hat Creek, Merritt, Princeton), Northwest B.C. (Telkwa Iskut), and the Queen Charlotte Islands.¹³ As at March 15, 2007, the following is a current regional breakdown of the status of the 113 CBM wells in B.C. including CBM wells approved for drilling, in the process of being drilled and existing wells currently under approved tenure:

Northeast B.C. – 48 wells; Southeast B.C. 45 wells; Northwest B.C. – 18 wells; Vancouver Island – 1 well; Southern Interior (Princeton Area) – 1 well.¹⁴

Regulatory and Legal Issues Respecting

CBM Development in Alberta ¹⁵

1. Introduction

The past decade has seen CBM, once an uneconomic by-product of coal mining, emerge to become an economically viable resource whose impact on Alberta's resource development will be long lasting. This rapid ascendancy and the proliferation of CBM development has posed significant regulatory and legal challenges as regulators, the courts and the legislature attempt to keep pace with development. This portion of this paper will discuss how Alberta regulators are

¹² The Fograssy Report, citing Barry Ryan, "A Summary of Coalbed Methane Potential in British Columbia – 2003" at www.em.gov.B.C.ca/subwebs/oilandgas/resource/cbg/bg.htm; B.C. Government Statistical Report, Ministry of Energy and Mines, *Coalbed Gas Energy for Our Future*, at page 22.

¹³ Campbell, K. and Rutherford, S., *CBM: A B.C. Local Government Guide*, West Coast Environmental Law, May, 2006 at page 1.

¹⁴ Oil and Gas Commission staff, statistics current to March 15, 2007.

responding to these challenges and the way in which the courts may eventually apply existing Alberta law to CBM development issues.

1. Regulation of CBM in Alberta

a. EUB Informational Letter IL 91-11 (“IL-91-11”)

IL-91-11 was the first recognition of CBM in the Alberta regulatory context. It was issued on August 26, 1991 in an effort to acknowledge and clarify some of the uncertainty surrounding what was then a new resource and to outline some preliminary regulatory parameters until legislation, or fuller policy, was developed following testing of the resource.

IL-91-11 initially states that the then Energy Resources Conservation Board, now the EUB, and the Alberta Department of Energy (“Alberta Energy”) would examine and monitor CBM activity, prior to developing and implementing the appropriate regulatory scheme. IL-91-11 then sets out “Preliminary Regulatory Provisions” respecting: Crown leases, well licensing, surface leases, well spacing, drilling and completion, production, data reporting, experimental schemes, commercial development and Crown royalties. Of considerable import is that IL-91-11 states without equivocation that, “the ERCB and [Alberta] Energy consider coalbed methane to be a form of natural gas.” This is followed with an assertion that CBM development is subject to the same drilling, production and operational regulations that apply to conventional natural gas development.

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This statement was affirmed in a recent EUB publication *Across the Board*, the Board's monthly public newsletter, where the EUB stated:

CBM is natural gas contained in coal. It consists primarily of methane, the gas we use for home heating, gas-fired electrical generation, and industrial fuel. CBM is classified as sweet gas, as it contains no hydrogen sulphide (sour gas).

Because CBM is nothing more than natural gas contained in coal, it is subject to the same drilling, production, and operational requirements and regulations as other natural gas. The major difference between CBM and conventional gas development is that more wells are required to effectively recover gas from coal seams.¹⁶

The EUB has also affirmed this statement in its EnerFAQs public information series. A recent edition of EnerFAQs contains the following:

CBM is subject to the same EUB drilling, production, and operations rules and regulations as other natural gas. Alberta Energy also treats CBM as natural gas for royalty and tenure purposes.¹⁷

b. Directive 027: Shallow Fracturing Operations – Interim Controls, Restricted Operations, and Technical Review

After IL-91-11, it was not until 2006 that CBM-specific regulation, or regulation directed at shallow gas which would include CBM activity, was developed. The first regulation was *Directive 027*, which was issued to address increasing development of shallow gas reservoirs, being those less than 200 metres deep, utilizing high fracture volumes, pump rates and pressures, all common techniques in CBM extraction. *Directive 027* is aimed at ensuring that the fracturing of shallow gas reservoirs does not adversely impact potable groundwater reservoirs.

¹⁶ "Busting the myths behind CBM" *Across the Board* (March 2006), online: Alberta Energy and Utilities Board <www.eub.gov.ab.ca> at 1.

¹⁷ *EnerFAQs*, *supra* note 3.

Directive 027 requires licensees to demonstrate to the Board a full assessment of all potential impacts of the proposed fracturing program. The licensee must determine the “maximum of propagation expected for all fracture treatments;” provide an “identification and depth of offset oilfield and water wells within 200m” of the proposed fracturing operations; provide “verification of cement integrity” within 200m of the operation; and demonstrate landholder notification for water wells within 200m.

Licensees are further prohibited from conducting fracturing operations within 200m of water wells that have a depth within 25m of the proposed fracturing depth. Lastly, *Directive 027* mandates that all fracturing treatments “use only non-toxic fracture fluids above the base for groundwater protection;” “be designed so that no zone containing non-saline water is contaminated”; and “not reach any other wellbore, including both oilfield and water wells, at any point during fracturing.”

c. Bulletin 2006-15: Baseline Water Well Testing Requirement for Coalbed Methane Wells Completed Above the Base of Groundwater Protection

As a part of its “Water for Life Strategy,” Alberta Environment introduced the mandatory *Baseline Water-Well Testing for Coalbed Methane Operations*, effective May 1, 2006. In an effort to protect rural groundwater prior to any CBM well completion or re-completion above the base of groundwater protection, all CBM developers must offer to baseline testing to, landowners within a 600m radius. If the affected landowners accept the offer, baseline water well testing must be performed. If no water wells are located within the 600m radius, the developer must offer to provide testing on at least one well within an 800m radius. This standard

was developed in collaboration with the EUB and Bulletin 2006-015 reflects the incorporation of the standard into the EUB's compliance and enforcement regime.

d. Bulletin 2006-019: Applications Involving Objections Relating to the Legal Entitlement of Coalbed Methane

The Board issued this Bulletin on May 30, 2006, the effect of which was to suspend all well licenses and other applications involving questions respecting the legal entitlement to CBM. The Bulletin was issued as a result of Proceeding No. 1457147 (the "Split-title Proceeding"). The Split-title Proceeding was a challenge by coal owners, EnCana Corporation ("EnCana"), who owns a vast amount of coal rights as the successor to the Canadian Pacific Railway, and Carbon Development Partnership ("CDP"), the successor to coal rights granted to the Hudson's Bay Company, to a number of CBM well license applications brought by Lessees of natural gas rights on freehold, split-title lands.

Bulletin 2006-019 effectively imposed a moratorium on the processing of CBM applications on split-title lands where CBM ownership is at issue, pending the Board's determination of the Split-title Proceeding. That determination was made March 28, 2007 at which time the moratorium was lifted. The Split-title Proceeding is discussed in greater detail below.

e. The Position of Alberta Energy

Alberta Energy has not established, nor communicated, an explicit policy respecting CBM development, other than to adhere to the position that CBM is natural gas¹⁸ and all policies,

¹⁸ Alberta Energy refers to CBM in all communications as Natural Gas in Coal (NGC).

regulations and legislation respecting natural gas development implicitly include and apply to CBM.

Alberta Energy maintains a position consistent with that of the EUB. The policy statement set out in IL 91-11 was legislated and enshrined in the *Mines and Minerals Act*, R.S.A. 2000, c. M-17, the governing statute respecting all mines and minerals and related natural resources belonging to the Crown, in 2003. This was done by the enactment of a new section, section 67, of the *Mines and Minerals Act*.

Section 67 (1) of the *Mines and Minerals Act* provides that a coal lease does not grant the right to any natural gas, including CBM:

67 (1) A coal lease grants the right to the coal that is the property of the Crown in the location in accordance with the terms and conditions of the lease but, subject to subsection (2), does not grant any rights to any natural gas, including coalbed methane.

Section 67 (1) is qualified by section 67 (2), which enables Alberta Energy to authorize a coal lessee to recover CBM. This provision reads as follows:

67 (2) The Minister, on the recommendation of the Alberta Energy and Utilities Board that it is necessary to do so for safety or conservation reasons, may authorize the lessee of a coal lease to recover natural gas, including coalbed methane, contained in a coal seam in the location of the coal lease.

Despite the relative lack of CBM-specific legislation and policy guidance to date, Alberta Energy has been proactive in attempting to identify and address CBM-specific issues. In November 2003, Alberta Energy initiated a multi-phase review of CBM with the express purpose of assessing the current regulatory scheme to determine how and where improvements can be made. Alberta Energy formed the Multi-Stakeholder Advisory Committee (“MAC”) to spearhead this review. MAC was charged with the “ultimate objective” of ensuring that “the economic benefits

of CBM/NGC development are balanced with the protection of land, air and water resources and the public.”¹⁹

MAC was comprised of a broad cross section of organizations representing the many stakeholders affected by CBM development. It included representatives from the oil and gas and coal industries, the agriculture sector and members of the environmental community, government and regulating bodies.²⁰ A consultation process and review was initiated that included public information sessions and research as to how CBM issues are handled in other jurisdictions. MAC released its Preliminary Findings in July, 2005²¹ and its Final Report in January, 2006.

In its Final Report, MAC made 44 recommendations. These recommendations were grouped under the following categories:

Water – identifying a need for improved scientific information and the protection of aquifers and water supplies;

Surface/Air – recommending regulatory review by the primary regulatory bodies, being the EUB, Alberta Environment and Sustainable Resource Development, to identify methods of land management to address cumulative impacts and environmental protection;

¹⁹ “Coalbed Methane/Natural Gas in Coal Final Report” *The CBM/NGC Multi-Stakeholder Advisory Committee* (January, 2006), online: Alberta Energy <www.energy.gov.ab.ca> at 3.

²⁰ *Ibid.* at 61.

²¹ “Coalbed Methane/Natural Gas in Coal Preliminary Findings” *The CBM/NGC Multi-Stakeholder Advisory Committee* (July, 2005), online: Alberta Energy <www.energy.gov.ab.ca>.

Royalties – recommending a royalty reduction and tax reductions for five years to encourage development of saline CBM wells in the Mannville formation in order to acquire information and data and the consideration of using fiscal tools to encourage the use of saline water for enhanced oil recovery and other uses (recommendations in this category were reached on a non-consensus basis);

Tenure – noting that the Alberta Government should increase awareness of the risks associated with split-title development, create a dispute resolution process to facilitate resolution of split-title ownership issues, review the criteria for the acquisition of shallow natural gas rights in situations of non-productivity and allow an additional one-year continuation to enable operators to submit evidence of work conducted during initial lease continuation period to hold Crown natural gas rights;

Broad-Based CBM/NGC Issues – encouraging project-based planning and disclosure, regulatory review respecting public consultation and notification, enhanced coordination among regulating bodies, increased opportunities for public dialogue and information sharing, the implementation of annual reviews and the implementation of a monitoring plan to assess the progress of the MAC recommendations.

Lastly, the MAC made recommendations respecting CBM best practices, encouraging industry and government to work towards developing and implementing a best practices regime for CBM operations. A few non-CBM-specific recommendations were also made dealing with noise, EUB hearings, sales results, land agents, wildlife and caveats.²²

²²*Supra* note 19 at 12.

In September, 2006, another stakeholder group, albeit on with identical membership as MAC, called the MAC II was formed in response to the recommendation that annual reviews to address the progress of MAC recommendation implementation be performed for three years following the Final Report.²³

As at March 31, 2007 implementation had commenced or been completed with respect to 36 of MAC's 44 recommendations.²⁴ Of significance, is the progress towards implementation of the B water-related recommendations and the adoption of the Canadian Association of Petroleum Producers' Best Practices Manual for CBM.²⁵

2. EUB Proceedings

- a. EUB Decision 2006-102: EnCana Corporation: Applications for Licenses for 15 Wells, a Pipeline, and a Compressor Addition: Wimborne and Twining Fields, October 31, 2006 (the "Torrington Decision" or "Torrington")

The Torrington Decision resulted from the first major public EUB hearing regarding CBM operations. Significant concerns were advanced by intervener landowners (the "Intervenors") who objected to the subject well license applications. The objections primarily concerned water quality and noise levels from an existing compressor station that EnCana was proposing to expand by adding a second compressor unit.

Of primary concern for the Intervenors was maintaining the integrity of aquifers and most significantly, the protection of their water supply. The Intervenors specifically requested that

²³ "Progress Update: Coalbed Methane Multi-Stakeholder Advisory Committee (MAC) Recommendations" MAC II (June, 2007), online Alberta Energy <www.energy.gov.ab.ca> at 3.

²⁴ *Ibid.*

surface casing be set to the base of the Paskapoo formation, the formation where most water wells in the area are completed, to ensure aquifer protection. This would have meant surface casing to varying depths of approximately 90 to 190 metres, whereas EnCana was proposing surface casing to depths varying from approximately 89 to 160 metres. As an alternative position, the Interveners urged the EUB to reject EnCana's applications to reduce the depth of surface casing.

The Board rejected both of these positions. It found that the requirements of its *Directives 008, 009 and 056*²⁶ provided adequate fresh water protection and that the proposed production from the Horseshoe Canyon would not adversely affect the overlying aquifers.²⁷

Another issue for the Interveners was EnCana's proposed fracturing process. The Interveners argued that fracturing at such shallow depths could adversely impact local groundwater reservoirs. The evidence led by the Interveners included three examples from the area where it was suspected that fracturing had affected water wells or springs. The Interveners sought a direction from the Board that EnCana be required to perform an assessment of all potential fracturing impacts, as is contemplated under *Directive 027*.²⁸

²⁵ "Best Management Practices: Natural Gas in Coal (NGC)/Coalbed Methane (CBM)," Canadian Association of Petroleum Producers (January, 2006), online: Canadian Association of Petroleum Producers <www.capp.ca>.

²⁶ "Surface Casing Depth Minimum Requirements" *Directive 008* (October 1997), online: Alberta Energy and Utilities Board <www.eub.gov.ab.ca>; "Casing Cementing Minimum Requirements" *Directive 009* (July 1990), online: Alberta Energy and Utilities Board <www.eub.gov.ab.ca>; "Energy Development Applications and Schedules" *Directive 056* (September 12, 2005), online: Alberta Energy and Utilities Board <www.eub.gov.ab.ca>.

²⁷ "EnCana Corporation: Applications for Licenses for 15 Wells, a Pipeline, and a Compressor Addition: Wimborne and Twining Fields" Decision 2006-102 (October 31, 2006), online: Alberta Energy and Utilities Board <www.eub.gov.ab.ca>.

²⁸ *Ibid.* at 13-14.

In response, the Board found that the proposed fracturing process posed no material risk to the area and did not trigger the requirements of *Directive 027* as the fracturing was planned to be below 200m.

An additional concern for the Interveners was EnCana's proposal to use untreated dugout water in drilling the surface holes. EnCana presented evidence that the use of untreated surface water would not harm aquifers and that the use of treated water would have little value as the water would come into contact with bacteria in the wellbore. The Interveners' expert concurred with EnCana in his evidence that bacteria found in surface water could not survive in an underground environment, but supported the Interveners' request that EnCana treat the water. The Board did not grant the Interveners' request.

In the result, the Board granted approvals for EnCana to drill 15 CBM wells, construct 46 lengths of pipeline, and upgrade a pipeline compressor on certain conditions that included the following:

- a. that EnCana submit fracturing operations data, with respect to the shallowest fracturing operations, to the Board and the Interveners within five days of the operations;
- b. that EnCana install a groundwater quality monitoring well in aquifers deeper than are currently used to determine what impact nitrogen fracturing operations may have on deep aquifers; and
- c. that EnCana demonstrate that night-time noise levels fall within certain specifications.²⁹

²⁹*Ibid.* at 25.

The panel also recommended that the EUB undertake the coordination of a third-party report, specifically written for a public audience, to address the issue of groundwater and water wells and CBM development using surface water for drilling operations.³⁰ This recommendation was prompted by the Board's concern that there is a widespread belief among members of the public in Alberta that CBM operations adversely impact potable groundwater, even though the technical and scientific evidence does not support this belief.

- b. Decision 2007-024: Bearspaw Petroleum Ltd., Devon Canada Corporation, and Fairborne Energy Ltd. – Part 2 of Proceeding No. 1457147 – Review of Certain Well Licenses and Compulsory Pooling and Special Well Spacing (Holding Orders in the Clive, Ewing Lake, Stettler, and Wimborne Fields. (the “Split Title Proceeding”)

As discussed above, the issue of disputed ownership of CBM in freehold, split-title situations (between the coal owners and the natural gas lessors) was recently considered by the Board in the Split-title Proceeding. A major public hearing involving 13 parties occurred over 11 days in October, 2006 with written closing submissions and arguments concluding in February, 2007. Succinctly, at issue was the legal entitlement to CBM produced from freehold split-title lands where coal is owned by one party and the natural gas rights are owned by another and commonly leased to a CBM developer.

The Split-title Proceeding arose from various approvals (28 in total), granted by the EUB to natural gas rights holders, Bearspaw Petroleum Ltd., Devon Canada Corporation and Fairborne

³⁰ *Ibid.* at 6.

Energy Ltd. (collectively, the “Applicants”) for well licenses, compulsory pooling orders and special spacing orders for the development of CBM (the “Approvals”).

Presumably based on an adherence to IL 91-11, and consistent with Alberta Energy’s position that CBM is natural gas contained in coal, the EUB approved the subject applications in the first instance. In order to grant the Approvals, the Board had to be satisfied that each of the Applicants were entitled to “the right to produce” the CBM, pursuant to s. 16 (1) of the *Oil and Gas Conservation Act*, R.S.A. 2000, c. O-6. Section 16 (1) reads as follows:

16(1) No person shall apply for or hold a licence for a well

(a) for the recovery of oil, gas or crude bitumen, or

(b) for any other authorized purpose

unless that person is a working interest participant and is entitled to the right to produce the oil, gas or crude bitumen from the well or to the right to drill or operate the well for the other authorized purpose, as the case may be.

EnCana and Luscar Ltd. (now CDP) each hold coal rights on the lands which are the subject of the 28 different Approvals. EnCana and CDP sought a review of the Approvals on the basis of their objection that the Applicants were not entitled to the right to produce CBM under s.16 of the *Oil and Gas Conservation Act* because EnCana and CDP owned the CBM contained in the coal. The Board granted their request, determining that both were affected parties with respect to the issuance of the Approvals.³¹

In recognition of the fact that CBM ownership on split-title lands was an issue facing many mineral rights holders and affected parties, the Board invited and received submissions from a number of interested third parties, primarily CBM producers, but also royalty owners with royalties pertaining to the lands subject to the Approvals and the Freehold Petroleum and Natural

³¹ Alberta Energy and Utilities Board, Decision, Phase 1 Proceeding, March 9, 2006.

Gas Owners Association (“FHOA”), a non-profit group representing freehold land owners.³² The Board decided that the two royalty owners, Canpar Holdings Ltd. and Computershare Trust Company of Canada would be granted Intervener status.³³

Applying the criteria for participation at an EUB public hearing set out in the *Energy Resources Conservation Act*, R.S.A. 2000, c. E-10 and the Alberta Court of Appeal’s decision in *Dene Tha’ First Nation v. Alberta (Energy and Utilities Board)*,³⁴ the Board granted “Interested Third Party” status to four CBM producers (ARC Resources Ltd, Centrica Canada Limited, ConocoPhillips Canada Resources Corp., Quicksilver Resources Canada Inc.) and FHOA. This enabled these parties to present evidence, conduct cross-examinations and submit arguments.

The public hearing commenced on October 16, 2006. Over the course of two weeks, the Board heard policy, scientific and legal evidence respecting the ownership of and entitlement to CBM from virtually all parties. Further evidence was submitted as to the jurisdiction of the Board to determine the legal issue of the entitlement to produce CBM.

The legal arguments presented at the Split-title Proceeding, either in support of the proposition that CBM ownership resides with the coal owner or conversely, that it resides with the natural gas owner, had never before been heard and determined in Canada. While Canadian courts have

³² “Notice of Hearing: Part 2 of Proceeding No. 1457147” (June 23, 2006), online: Alberta Energy and Utilities Board <www.eub.gov.ab.ca>.

³³ Letter from Alberta Energy and Utilities Board to Registered Parties and Interested Third Parties (July 19, 2006) re: Proceeding No. 1457147, Coalbed Methane (CBM) Review Hearing. An additional gas producer, Apache Canada Ltd., was granted intervener status by the Board on August 23, 2006 by virtue of it holding mineral rights and being a lessor with respect of one of the subject properties.

³⁴ (2005) 45 Alta. L.R. (4th) 213, 2005 AB.C.A 68.

considered the issue of entitlement to competing resources³⁵ and US state and federal courts have considered the CBM issue,³⁶ no Canadian court has had the opportunity to consider ownership of CBM in the split-title context. This places considerable import on those arguments advanced at the Split-title Proceeding, as they will be similar to those advanced in litigation on the same issue.

The starting point of the gas producers' legal argument was *Borys*.³⁷ This is without question the seminal decision in Canadian oil and gas jurisprudence. In *Borys*, the subject land was originally acquired by the Plaintiff landowner through a Canadian Pacific Railway ("CPR") grant that reserved to the CPR "coal, petroleum and valuable stone," a situation similar to the vast majority of split-title lands. At issue were the rights with respect to petroleum, free gas and solution gas. The Privy Council, in agreement with the Appellate Division of the Supreme Court of Alberta, first found that petroleum and free gas, despite the similarities between the two, were separate and distinct substances.³⁸ It was then decided that free gas, existing in a gaseous state in the initial reservoir conditions (*in situ*) was not caught by a reservation of petroleum.³⁹

The Privy Council was then faced with a determination as to whether solution gas, or gas existing in a liquid state *in situ*, was included in the reservation. The Court's analysis was

³⁵ For example, oil vs. "gas cap" gas or bitumen vs. "gas cap" gas as has been considered in the following: *Borys v. Canadian Pacific Railway*, 7 W.W.R. (N.S.) 546, [1953] 2 D.L.R. 65 (P.C.) [*Borys*]; *Anderson v. Amoco Oil and Gas*, [2004] 3 S.C.R. 3, 2004 SCC 49 [*Anderson*]; *Alberta Energy Co. v. Goodwell Petroleum Corp.*, 339 A.R. 201, 2003 AB.C.A. 277 [*Goodwell*].

³⁶ See for instance, *United States Steel Corp. v. Hoge*, 503 Pa. 140, 468 A.2d (Pa. 1983); *Carbon County v. Union Reserve Coal Co. Inc.* 898 P.2d 680 (Mont. 1995); *Continental Resources of Illinois Inc. v. Illinois Methane LLC*, 364 Ill. App. 3d 691, 847 N.E. 2d. 897 (Ill. 2006) [*Continental Resources*]; *Newman v. RAG Wyoming Land Co.*, 2002 WY 132; 53 P.3d 540 (Wyo. 2002); and *Amoco Proc. Co. v. Southern Ute Tribe*, 526 U.S. 865; 119 S. Ct. 1719 (U.S.S.C. 1998) [*Southern Ute*].

³⁷ *Supra* note 35.

³⁸ *Borys*, *supra* note 35 at para. 4 (QL).

predicated on a consideration of the “vernacular” meaning of the reservation at the time of the grant.⁴⁰ The Court agreed with the lower courts and held that at the time of the grant, 1906, the vernacular understanding of the reservation was that petroleum included solution gas.⁴¹ Also of significance is that in preferring the vernacular test, the Privy Council explicitly rejected the scientific evidence that was advanced; evidence that was current at the time of its presentation.⁴²

Borys has been subsequently applied in two important cases *Anderson*⁴³ and *Goodwell*⁴⁴. In *Anderson*, the Supreme Court of Canada applied *Borys* in the context of an ownership dispute involving evolved gas on split-title lands. Evolved gas is solution gas that emerges or evolves from liquid hydrocarbons due to an increase in reservoir pressure. The Court relied on the principle enunciated by the Privy Council in *Borys* that the *in situ* conditions of the substance governs the relative ownership as between the parties to the original grant, transfer, reservation or contract and that the time for interpreting the meaning of substances, chiefly petroleum, is at the time the document in question was executed.⁴⁵ The Court also agreed with the lower court in *Borys*, upheld by the Privy Council, that changes in the state or phase of the substance do not affect the ownership of the substance.⁴⁶ The subject substance in *Anderson*, evolved gas, because it existed in a liquid state *in situ*, was found to belong to the petroleum owner.⁴⁷

³⁹ *Ibid.*

⁴⁰ *Ibid.*

⁴¹ *Ibid.* at 6.

⁴² *Ibid.* at 5.

⁴³ *Supra* note 35.

⁴⁴ *Ibid.*

⁴⁵ *Anderson*, *supra* note 35 at para. 34 (QL).

⁴⁶ *Ibid.* at para. 29 (QL).

⁴⁷ *Ibid.* at para. 19 (QL).

At issue in *Goodwell* was the ownership of natural gas overlying bitumen deposits on Crown split-title lands where natural gas was leased separately from bitumen, as is the statutory scheme set out in the *Mines and Minerals Act*. The gas producer, Goodwell, applied to the EUB for an order to shut-in concurrent bitumen production being obtained by Alberta Energy Co. (“AEC”). Goodwell’s shut-in application was made on the basis that in producing the bitumen AEC was also producing large quantities of overlying natural gas which was separately leased by Goodwell. In other words, Goodwell claimed that AEC was producing Goodwell’s gas. AEC argued that production of the overlying natural gas was necessarily incidental to production of its bitumen. The EUB agreed with Goodwell and ordered AEC to shut in its bitumen wells pending negotiation between AEC and Goodwell of a commercial arrangement for the production by AEC of Goodwell’s gas. AEC appealed the shut in order to the Alberta Court of Appeal.

The Court overturned the EUB’s decision. It held that gas cap pressure was critical to the recovery of bitumen and therefore bitumen owners had the right to produce gas cap gas along with bitumen.⁴⁸ The Court further considered the language of the original granting instrument and determined that in the case of a natural gas lease, the lessee had only the right to recover initial gas cap gas.⁴⁹ Moreover, the natural gas lessee’s right to gas is subject to the known and inevitable consequence of bitumen recovery, the production of gas cap gas.⁵⁰ The Court further expressly followed *Borys* and found that the EUB had erred by ignoring *Borys*.

⁴⁸ *Goodwell*, *supra* note 35 at para. 43 (QL).

⁴⁹ *Ibid.* at para. 78 (QL).

⁵⁰ *Ibid.*

In addition to this key Canadian jurisprudence, the gas producers relied heavily on *Southern Ute*,⁵¹ a decision of the United States Supreme Court, which is clearly the most persuasive and relevant US authority on this subject. *Southern Ute* is not only a relatively recent decision of the United States' highest court, but also employs a *Borys*-type approach to interpreting a land conveyance that was contemporaneous with those land grants and reservations that are at issue in the Split-title Proceeding.

Southern Ute arose as a result of a United States Government decision to restore title to coal to the Southern Ute Indian tribe on lands in Colorado. The Government had issued land patents to settlers, pursuant to legislation of 1909 and 1910, that conveyed the land and everything below it, except coal, which was reserved to the United States. These patented lands included reservation lands previously ceded by the Southern Ute tribe to the United States. Beginning in the 1980s, CBM production occurred on the lands pursuant to natural gas leases granted by successors in interest to the settlers. The Southern Ute tribe sued, claiming that by virtue of its ownership of the coal rights in the land, it also owned the CBM. The tribe therefore claimed that the royalties paid to the natural gas lessors in fact belonged to them. The Court was faced with the issue of whether the reservation of coal in the original patents included a reservation of CBM.

Like the Privy Council in *Borys*, the Court considered scientific evidence as to the nature of CBM, but preferred instead to utilize an interpretation of the vernacular meaning of the coal reservation at the time of the original grant. In finding that the initial reservation did not include

⁵¹ *Supra* note 36.

CBM, the Court relied on the common meaning of coal at that time, which was a “solid rock substance”⁵² distinct from any gas that may escape from it.

In the Split-title Proceeding, the coal owners, EnCana and CDP, relied on legal authority in support of the proposition that CBM ownerships lie with the coal owner. In particular, the coal owners relied on *Little v. Western Transfer & Storage Co. and Edmonton Collieries Ltd.*⁵³ This decision of the Alberta Supreme Court, Appellate Division, is one of the few Canadian cases that supports the coal owners’ position. The Court in *Little* was asked to interpret the scope of a coal grant by the landowner, Little, to Western Transfer, a coal company. More specifically, at issue was whether the rights granted included the right to remove coal mined on adjoining lands, through a process known as “outstroke.”

Following its interpretation of the grant and a consideration of the commercial relationship between the parties, the Court held that the right to use the space occupied by the coal carries with it an entitlement to all substance contained within that space, regardless of whether these substances were included in the original grant. The coal owners relied on *Little* to support the notion that ownership of coal strata includes the CBM located within that strata, a determination that can be made without consideration of the granting language.

Notably, EnCana also relied on the recent Illinois state court decision of *Continental Resources*.⁵⁴ Here, Continental Resources claimed that it had the right to explore for, drill and produce CBM underlying certain lands. These lands were the subject of a number of oil and gas

⁵² *Ibid.* at para. 7 (QL).

⁵³ [1922] 3 W.W.R. 356, 69 D.L.R. 364, (Alta. S.C. A.D.).

⁵⁴ *Supra* note 36.

leases to which Continental Resources was the lessee. These leases granted Continental Resources the right to produce oil, gas, liquid hydrocarbons and their constituent products.⁵⁵ However, at the time the litigation was initiated the coal owner, Illinois Methane, was producing CBM from the lands.

The Appellate Court of Illinois considered decisions from other US states dealing with CBM ownership and stated that while the approaches utilized by other state courts were helpful, they were not founded in Illinois law. Further, the Court held that it was necessary to consider the characteristics of CBM and the methods and rights engaged in its extraction and production generally.⁵⁶

The Court then considered the coalification process by which organic material is transformed into coal and the historical perception of CBM as a dangerous waste product.⁵⁷ The Court also noted that the theory of oil and gas ownership employed in Illinois is based on the rule of capture and because CBM is similar to and migrates in the same fashion as conventional natural gas, there is no reason that the rule of capture would not apply to CBM.⁵⁸ Lastly, the Court considered the specific wording of the leases in question, which granted the right to drill through coal. Ultimately, the Court found that under the rule of capture, CBM cannot be owned until it is reduced to possession.⁵⁹ Accordingly, CBM ownership was retained with the coal owner who in this case was also the CBM producer.

⁵⁵ *Continental Resources*, *supra* note 36 at para. 2 (QL).

⁵⁶ *Ibid.* at para. 3 (QL).

⁵⁷ *Ibid.*

⁵⁸ *Ibid.*

⁵⁹ *Ibid.*

Although the intent of this paper is not to address the science of CBM in an in-depth fashion, as can be seen from the application of the legal tests relied on by both sides in the Split-title Proceeding, science is a crucial component to the debate and accordingly demands some consideration. Both sides presented considerable scientific evidence in support of their respective positions.

As described above, CBM is natural gas contained in coal, stored primarily through adsorption to the coal, as opposed to conventional natural gas, which is stored in open pore space. The storage of CBM can give rise to a claim of ownership by the coal owners on the basis that because CBM is adsorbed to the coal it is a “constituent” of coal. The argument is that CBM is not a separate substance (natural gas) that is simply stored in coal, but rather that due to the way that CBM interacts with other coal constituents, is a part of the coal itself.

By contrast, the natural gas producers argued that CBM and coal are distinct, both at initial reservoir conditions and upon production; that coal is nothing more than a container for the CBM and that the fact that CBM is stored by means of adsorption does not mean that CBM is a constituent of coal.

As noted above, the Board released its findings in the Split-title Proceeding, Decision 2007-024, on March 28, 2007. The Board confirmed that the subject well licenses and orders were properly issued. Further, Bulletin 2006-019 was set aside,⁶⁰ lifting the moratorium on CBM split-title applications.

⁶⁰ By way of the immediate issuance of Bulletin 2007-07, the EUB rescinded the directions set out in Bulletin 2006-019.

The Board found in clear favour of the natural gas producers and associated parties. On all points, the entitlement to produce CBM by the natural gas Lessees was confirmed. Although recognizing the limitations of its finding (i.e. that the EUB cannot make a final or conclusive determination of ownership as this power rests solely with the courts), the Board concluded that as the Applicants had demonstrated entitlement to produce CBM, per s.16 of the *Oil and Gas Conservation Act*, it would grant the requested licenses and orders.

Key to the Board's finding was the conclusion, based on the technical evidence before it, that "CBM is not an intrinsic component of coal ... CBM is a form of gas stored in and produced from coal that is gaseous and distinct in *in situ* conditions."⁶¹ Further, this is considered by the Board to be consistent with the statutory definition of gas, as set out in the *Oil and Gas Conservation Act*.⁶² The Board also dispensed with the argument advanced by EnCana and CDP that it did not have jurisdiction to decide entitlement concluding that a determination of entitlement to produce under the *Oil and Gas Conservation Act* was wholly within the ambit of its jurisdiction.

The most significant portion of Decision 2007-024, of course, is the EUB's consideration of the entitlement arguments by the parties, which the Board found entailed an analysis of "regulatory entitlement" as well as legal theories of entitlement and ownership.⁶³

⁶¹ "Bears paw Petroleum Ltd., Devon Canada Corporation, and Fairborne Energy Ltd.: Part 2 of Proceeding No. 1457147 – Review of Certain Well Licenses and Compulsory Pooling and Special Well Spacing (Holding) Orders in the Clive, Ewing Lake, Stettler and Wimborne Fields," Decision 2007-024 (March 28, 2007), online: Alberta Energy and Utilities Board <www.eub.gov.ab.ca> at 8.

⁶² Section 1 (1) of the *Oil and Gas Conservation Act* defines: "gas" means raw gas or marketable gas or any constituent of raw gas, condensate, crude bitumen or crude oil that is recovered in processing and that is gaseous at the conditions under which its volume is measured or estimated.

⁶³ *Supra* note 61 at 22.

In finding in favour of the arguments advanced by the natural gas producers, the Board relied on the two premises established at the outset of its decision, that CBM is “gas” as that term is defined in the *Oil and Gas Conservation Act* and that this is consistent with its own internal understanding as set out in IL 91-11. The Board’s view is that these determinations are sufficient to establish regulatory entitlement, meaning that all an applicant need do is submit to the Board a valid and subsisting natural gas lease. This constitutes *prima facie* proof of entitlement to the right to produce. Significantly, the Board observes that while its analysis could have ended there with the establishment of regulatory entitlement, it carries on to provide⁶⁴ its assessment of the legal arguments. At the outset, the Board notes that the ultimate authority in determining ownership or entitlement rests with the courts, however, it relies on the Court in *Goodwell*, stating that “in order to make a legal determination of the right to extract resources, the Board must examine the relevant leases, energy statutes, and applicable case law.”⁶⁵ The applicable case law is covered by the Board’s statements that the “proper principles to apply in considering entitlement or ownership are set out in the *Borys*, *Anderson*, and *Goodwell* cases.”⁶⁶

The Board noted its preference for the “Borys interpretative approach”⁶⁷ and accordingly relied on *Southern Ute* and dictionary definitions of coal at different historical periods that were submitted as evidence by natural gas producers. It found that “the vernacular meaning of coal has remained consistent throughout the last century and into the current time period.”⁶⁸ Further, *Borys*, and its application in *Anderson*, together with *Southern Ute*, provided the rationale for

⁶⁴ *Ibid.* at 25.

⁶⁵ *Ibid.* at 27.

⁶⁶ *Ibid.*

⁶⁷ *Ibid.* at 31.

⁶⁸ *Ibid.* at 32.

distinguishing *Continental Resources*. The Board also dispensed with *Little* considering that case to be “primarily concerned with the right of outstroke and not with competing claims of ownership to other minerals contained in the same interval.”⁶⁹

The Board concluded its findings with a review of the specific instruments in question and determined that on all counts the Applicants had demonstrated the *prima facie* entitlement necessary for approval and dispensation of the objections of EnCana and CDP.

On April 26, 2007, both EnCana and CDP filed Notices of Motion in the Alberta Court of Appeal seeking leave to appeal Decision 2007-024.⁷⁰ The grounds for these applications include:

- (a) that the Board found that it had jurisdiction, and then exceeded same, to decide entitlement to produce CBM in the face of a *bona fide* ownership dispute;
- (b) that the Board misconstrued the law on a number of counts such as failing to find that a reservation of coal precludes a natural gas lessee from entitlement to produce CBM; failing to apply the proper legal test to determine ownership, especially in light of competing claims; and determining entitlement to CBM despite extant litigation in the Court of Queen’s Bench;
- (c) that the Board took into account irrelevant evidence and failed to take into account relevant evidence;

⁶⁹ *Ibid.*

⁷⁰ *EnCana Corporation v. Alberta Energy and Utilities Board*, April 26, 2007, Calgary 0701-0111 AC (C.A.); *Carbon Development Partnership v. Alberta Energy and Utilities Board*, April 26, 2007, Calgary 0701-0110 AC (C.A.).

(d) that the Board improperly applied and ignored pertinent sections of the *Oil and Gas Conservation Act*;

(e) that the Board breached its duty to act in accordance with the principles of natural justice and fairness in not providing adequate notice of its intention, and what would be required by EnCana, to decide the ownership issue; and

(f) that the Board defeated EnCana's legitimate expectation that the Board would follow its usual practice and not determine contractual matters.⁷¹

The leave applications have not been heard, at the time of the preparation of this paper, however, it is anticipated that should leave be granted, the Court of Appeal will hear the respective appeals in a timely manner.

3. CBM Litigation

As mentioned above, the ultimate resolution of the split-title issue can only be decided by the courts. Throughout the Split-title Proceeding, it was clear that the scope of the Board's inquiry exceeded the typical facility or license review request. All parties submitted sophisticated legal arguments and evidence to buttress the scientific evidence and the Board provided a comprehensive and reasoned decision. It is likely, however, and certainly acknowledged by the Board,⁷² that through either appeal or by virtue of the litigation that has been recently initiated, the CBM ownership issue will be decided by the courts.

⁷¹ *Ibid.*

⁷² *Ibid.* at 33.

At present, there have been ten claims initiated in the Alberta Court of Queen's Bench respecting the legal ownership of CBM.⁷³ All ten actions have been commenced by EnCana, in its capacity as the coal owner in freehold split-title scenarios, against natural gas Lessees who have commenced CBM production. Of these suits, nine are active and the first, commenced in July, 2005, has not proceeded,⁷⁴ however the nine remaining actions, commenced in October, November, December, 2006 and January, 2007, remain active.⁷⁵

All the claims are virtually identical. EnCana asserts its status as the coal owner, alleges that the defendant gas producer has perforated the coals and has commenced production without colour of right. EnCana alleges trespass, conversion and unjust enrichment resulting from same. The relief sought is a declaration that the gas producer is in trespass and has converted the CBM and an accounting of the proceeds of production.

Currently, these actions are in the earliest of procedural stages and it remains to be seen how this litigation will unfold. It is likely that should they remain on course for a judicial determination, we will see application of most of the legal submissions heard during the Split-title Proceeding and hopefully a conclusive and final determination of the ownership issue.

⁷³ The writers are aware of ten as of the time this paper was initially prepared.

⁷⁴ See *EnCana Corporation v. Trafina Energy Ltd.*, July 15, 2005, Calgary 0501-10483 (Q.B.).

⁷⁵ See *EnCana Corporation v. Devon Canada Corporation*, October 25, 2006, Calgary 0601-12266 (Q.B.); *EnCana Corporation v. Devon Canada Corporation*, October 25, 2006, Calgary 0601-12267 (Q.B.); and *EnCana Corporation v. Devon Canada Corporation*, December 19, 2006, Calgary 0601-14382 (Q.B.); *EnCana Corporation v. Quicksilver Resources Canada Inc.*, November 3, 2006, Calgary 0601-12671 (Q.B.); *EnCana Corporation v. Enerplus Resources Corporation*, November 7, 2006, Calgary 0601-12767 (Q.B.); *EnCana Corporation v. Enerplus Resources Corporation*, November 7, 2006, Calgary 0601-12781 (Q.B.); *EnCana Corporation v. Enerplus Resources Corporation*, November 7, 2006, Calgary 0601-12782 (Q.B.); *EnCana Corporation v. ARC Resources Ltd.*, January 10, 2007, Calgary 0601-12766 (Q.B.); *EnCana Corporation v. Excite Energy Corp. and Canadian Natural Resources Limited*, November 7, Calgary 0601-12765 (Q.B.).

4. Conclusion

The future of CBM development in Alberta is clear in some regards – it will occur, increase and become a significant economic factor. The ease of this, however, depends on the ability of regulators, chiefly the EUB, government and the courts to effectively resolve the disputes that currently exist and that will no doubt arise in the coming years.

The groundwork for managing CBM development has been laid. The Multi-Stakeholders Advisory (MAC) process provided a thorough consultation process that facilitated a comprehensive review of a multitude of CBM-related issues. The EUB has been active in developing and implementing policy and regulation and has demonstrated a willingness to encourage and stimulate CBM exploration.

However, as the level of CBM development increases, concrete action needs to occur. The MAC recommendations need to be implemented, especially those aimed at encouraging coordinated efforts between and among regulators such as Alberta Environment and Sustainable Resource Development. The EUB needs to balance public concerns about water safety and well proliferation with the need for development of the CBM resource. Alberta Energy needs to become visible as well. The absence of Alberta Energy at the Split-title Proceedings was telling, particularly in the face of compelling submissions by the Freehold Petroleum and Natural Gas Owners Association (FHOA).

These submissions provided a clear indication as to the position of FHOA, one that has become more pronounced since Decision 2007-024 was released. FHOA has been clear that the best way

to avoid costly and lengthy litigation is for the Alberta government to legislate split-title ownership as has occurred in British Columbia.⁷⁶ FHOA further asserts that this legislation needs to be in place soon. As FHOA spokesperson, David Spiers states, “the problem I see is if it proceeds ... the issue could be five or 10 years in being decided by the courts ... during that period, we will have lost the majority of our coalbed methane through drainage.”⁷⁷ In response, Alberta Energy has stated that “the provincial government has no plans to change the legislation on freehold rights as they differ from title to title.”⁷⁸

This is in contrast to the situation in British Columbia, where the provincial government was motivated to provide as much certainty as it could. Of course, it can be argued that there are far fewer freehold split-title lands in British Columbia than in Alberta and accordingly there are far fewer freehold rights owners and the scale of development is much smaller. This, however, does not necessarily demand less involvement, if anything it may require more, or at the very least, a presence.

While we have the persuasive, but not binding, Decision 2007-024, in the absence of any activity by Alberta Energy, the courts will still likely be brought into the fray, given the pending leave to appeal applications and the Court of Queen’s Bench litigation. It is presumed that this will eventually provide the final answer to the CBM ownership issue, one that will enable the certainty that both industry and the public require.

⁷⁶ S. Polczer “Energy board rules coal, gas separate rights” *Calgary Herald*, (29 March 2007) C4.

⁷⁷ D. O’Meara “Entitlement scrap over coalbed methane gaining force in Alberta’s oil patch” *Canadian Press* (29 March 2007) (QL).

⁷⁸ *Ibid.*

COALBED METHANE IN BRITISH COLUMBIA

THE NEIGHOURING JURISDICTION

INTRODUCTION⁷⁹

This portion of the paper discusses the current legislative regime in British Columbia, including applicable Codes and Guidelines and the role of various governmental agencies and highlights the legal, regulatory and environmental issues relating to CBM development. The focus will be on what B.C.'s regulatory regime means for oil and gas companies operating in B.C. and outline key issues and current trends relating to First Nations, surface rights, produced water disposal management and environmental issues.

Overview

The Provincial Government is supportive of CBM development in B.C. Current legislation in B.C. brings together a number of different agencies collectively regulating CBM activities. These agencies include the Ministry of Water, Land and Air Protection, the Ministry of Sustainable Resource Development, the Ministry of Energy, Mines and Petroleum Resources ("MEMPR"), and the Oil and Gas Commission (the "OGC").

The OGC was created under the *Oil and Gas Commission Act*⁸⁰ and is tasked with regulating all provincial oil and gas activities including exploration and development, production, processing and storage of the Province's resources. The Act mandates the OGC to regulate the oil and gas

⁷⁹ MILLER THOMSON LLP, Barristers & Solicitors, Patent & Trade Mark Agents, Phone: 604.687-2242, Fax: 604.643.1200, Website: www.millerthomson.com, Robson Court, 1000-840 Howe Street, Vancouver, B.C., Canada V6Z 2M1, c.bois@millerthomson.com; shansen@millerthomson.com

⁸⁰ *Oil and Gas Commission Act*, S.B.C. 1998 c. 39.

industry to ensure sound development of B.C.'s oil and gas resources. Accordingly, the OGC is responsible for developing processes to accept and review industry applications related to oil and gas activities and/or pipeline activities (falling within Provincial jurisdiction). To approve such applications, the OGC must ensure that the application is in the public interest having regard to environmental, economic and social effects of the activities.

The Crown owns most of the petroleum and natural gas rights. The *Coalbed Gas Act*⁸¹ (the "CGA") was enacted in 2003 and provides that CBM is owned by the party who holds the natural gas rights. Accordingly, unlike the situation in Alberta, there is no issue respecting ownership of the resource because the legislation decides the issue, applies retroactively, and prohibits litigation against the legislature for any rights that may be lost as a result of the Act coming into force.

Large parts of B.C. are subject to aboriginal rights and title claims and several First Nations have voiced strong opposition to CBM development in their traditional territories. Until these First Nations' claims are resolved and thereafter, First Nations will undoubtedly play a big role in the process leading up to CBM development and production. To date, B.C. has negotiated Memoranda of Understanding with various Treaty 8 First Nations in accordance with its Consultation Operating Guidelines⁸² for First Nations consultation. Much work has yet to be done and includes resolution of such issues as:

⁸¹ *Coalbed Gas Act*, S.B.C., 2003, c. 18.

⁸² Publications and Documents, Memoranda of Understanding for the Doig River, Fort Nelson, Halfway River, Prophet, Saulteau, West Moberly, and the Dene Tha' First Nations, McLeod Lake Indian Band and the Blueberry River First Nations, at www.ogc.gov.ba.ca/pubdoc.asp.

- a. the role First Nations will play in the development of the resource;
- b. existing regulations, environmental safeguards; and
- c. economic opportunity for First Nations are generally the subject of negotiation between the Province and First Nations. Industry proponents can expect to become involved in consultation sessions and commercial negotiations with the affected First Nation to conclude benefits agreements and other terms and conditions in order to secure the necessary surface and subsurface rights of entry and access to the area to be explored and drilled.

Referencing CBM exploration and development, Nickle's Daily Oil Bulletin describes the situation in B.C. succinctly as follows in an article entitled, "*Oilpatch Cautious But Hopeful About B.C. Coalbed Methane*":

B.C.'s CBM is much more technologically challenging because it's distributed in a much different fashion. In Alberta, one type of coal - in the Horseshoe Canyon formation - is available in one large regional play on accessible terrain. Alberta CBM plays have access to an established oil and gas infrastructure and surface landowners are more knowledgeable of the industry.

In B.C., by contrast, the coal is in mountainous areas and is localized in areas like Merritt, Princeton, Hat Creek and Vancouver Island. There's little oil and gas development outside of northeastern B.C., and surface landowners are inexperienced in petroleum development.⁸³

CBM development will continue to be slowed by this learning curve. All parties, including landowners, First Nations, government and industry must work towards creating a regime for responsible and environmentally safe CBM development and production and certainty of the costs associated with such development and production.

⁸³ Stewart, M., "*Oilpatch Cautious But Hopeful About B.C. Coalbed Methane*", Nickel's Daily Oil Bulletin, April 19, 2005.

Legislative Regime

In B.C., CBM development is primarily governed by the OGC through a three-phase approval process established in accordance with the *Petroleum and Natural Gas Act*⁸⁴ (the “PNG Act”), together with the CGA,⁸⁵ and the *Code of Practice for the Discharge of Produced Water from Coalbed Gas Operations* (the “Code”)⁸⁶ promulgated under the *Environmental Management Act* (the “EMA”).⁸⁷ The OGC created *Guidelines for Coalbed Methane Projects in British Columbia* released October 21, 2002 (the “Guidelines”). The Guidelines refer to CBM and Coalbed Gas (“CBG”) interchangeably and categorize the progress of CBM projects into the following plans:

- CBG Evaluation Plan: This plan permits a proponent to apply to drill for the purposes of testing a small number of wells to collect data and determine feasibility for gas recovery and dewatering requirements and water quality. Under this stage, a proponent can collect samples of the produce water.
- CBG Feasibility Plan: This plan permits a proponent to apply to develop and operate a limited number of wells (in the range of 20-40) in order to determine whether the recovery of the CBM is commercially viable.
- CBG Production Plan: This plan permits a proponent to apply to undertake full scale commercial CBM recovery and operations at the location.⁸⁸

As highlighted in the flow chart below, each of the foregoing plans has its own approval process.

From a practical perspective, issues relating to produced water and its disposal will need to be

⁸⁴ *Petroleum and Natural Gas Act*, R.S.B.C., 1996, c. 361.

⁸⁵ *Supra*, at footnote 81.

⁸⁶ *Code of Practice for the Discharge of Produced Water from Coalbed Gas Operations*, B.C. Reg. 156/2005 M74/2005 effective July 1, 2005.

⁸⁷ *Environmental Management Act*, S.B.C., 2003, c. 53.

addressed in the feasibility planning stage. Pursuant to section 100 of the PNG Act,⁸⁹ a proponent must submit a plan to the OGC for its approval that details how the proponent intends to deal with produced water. A scheme for any of the following activities must not proceed unless the OGC approves the scheme on terms the OGC may decide relating to:

- (a) the development or production of petroleum or natural gas, or both, from a field or pool or portion of a field or pool;
- (b) the experimental application of oil field technology as defined by regulation;
- (c) the processing, storage or disposal of natural gas; and
- (d) the gathering, storage and disposal of water produced from a field or pool.⁹⁰

In February 2007, the B.C. Government produced its new Energy Plan.⁹¹ That Plan mandates that produced water from CBM development is to be disposed of by water injection as a first priority to other disposal methods outlined in the Code. While the policies in the Energy Plan have yet to be translated into regulations or codes of practice, it is reasonable to assume that the OGC will not approve water disposal plans that run contrary to those stated in the Energy Plan. The OGC is also responsible for approving of well spacing, guided by the PNG Act, and authorizing flaring and wildlife protection. Again, the recently released new Energy Plan could adversely impact CBM production as it mandates significant reduction of flaring in oil and gas operations. The Energy Plan is discussed in greater detail below.

⁸⁸ *Guidelines for CBM Projects in British Columbia* released October 21, 2002, online at www.ogc.gov.B.C.ca/situpdates.asp?update=173; doc # OGC 04-27.

⁸⁹ *Supra*, at footnote 84, s. 100.

⁹⁰ *Ibid*, at s. 100.

⁹¹ The B.C. Energy Plan: A Vision for Clean Energy Leadership, located online at www.B.C.energyplan.gov.B.C.ca, issued on or about February 2007.

Critics of CBM development have expressed concern in whether the Code has the same effect as regulations promulgated under the EMA and specifically, whether the enforcement and other penalty provisions in the EMA will apply in respect of a violation of the Code. As the Code has yet to be judicially considered, this issue has not been answered. The key arguments raised in the debate are discussed below in the review of key provisions of the Code.

In B.C., surface rights are also governed by the PNG Act. The PNG Act also governs all aspects of exploration, development and production, providing for the entry, occupation or use of publicly held land for the purposes of exploration and development of CBM.⁹² The chart entitled, "Oil and Gas Commission Regulatory Process for Coalbed Methane Projects", reproduced below is taken from the *Guidelines for Coalbed Methane Projects in British Columbia*⁹³ and provides a good summary of the procedures required.

The *Pipeline Act*⁹⁴ also administered by the OGC, sets out the legislative regime for the safety and integrity of pipelines and transmission facilities as well as the design, construction, operation and maintenance of gas gathering systems, pipelines and compressor stations. Other Acts that speak to CBM development include the *Forest Act*, the *Heritage Conservation Act*, the *Forest Practices Code of British Columbia Act* and the *Water Act*.

⁹² Ministry of Energy, Mines and Petroleum Resources, *Coalbed Gas Energy for Our Future*, at page 14.

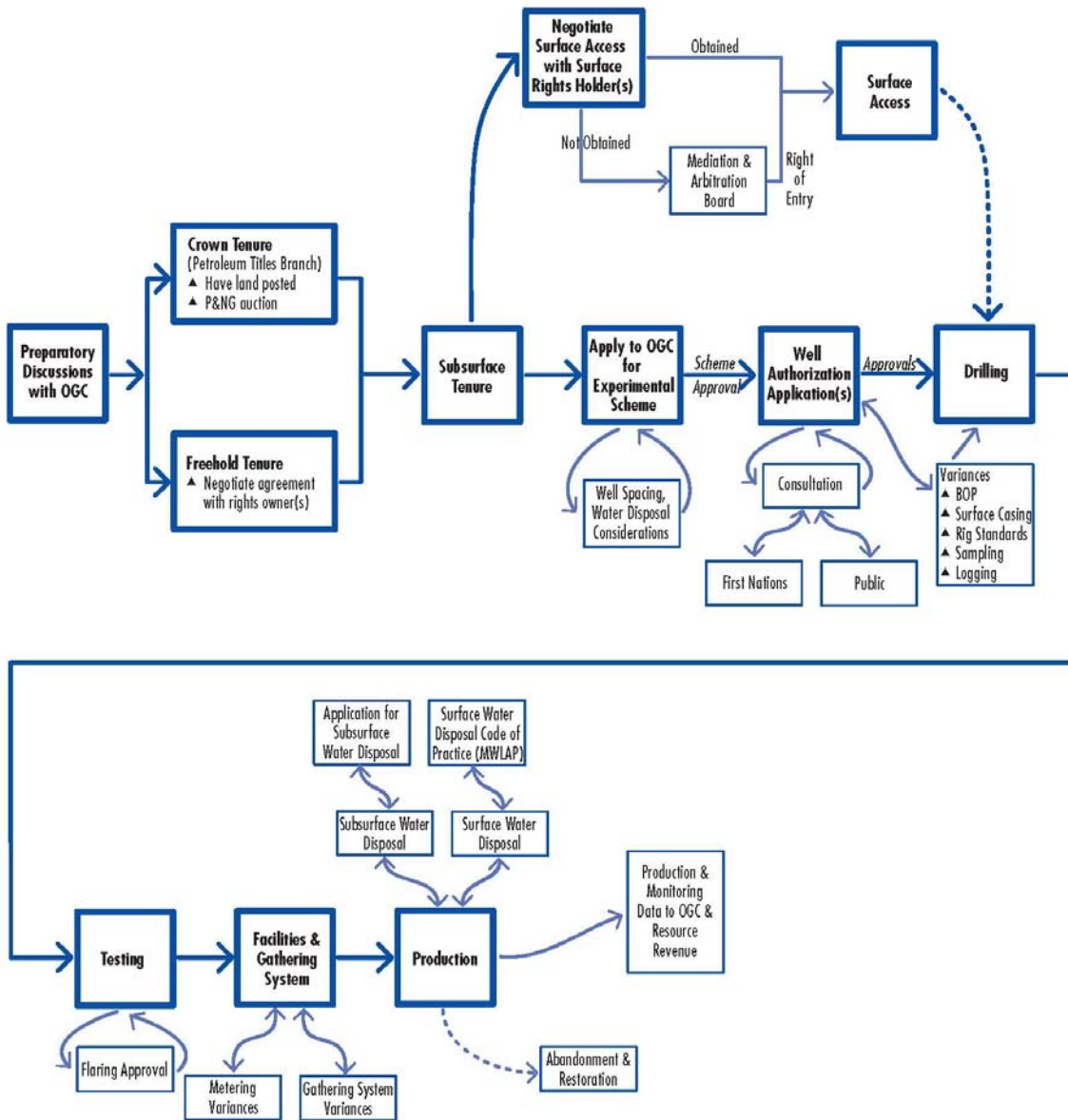
⁹³ *Supra*, at footnote 88, page 25.

⁹⁴ *Pipeline Act*, R.S.B.C., 1996, c. 367

Also, the federal *Canadian Environmental Assessment Act*⁹⁵ may be triggered in some circumstances, such as when resources are located on federal lands (including First Nations lands), or when federal agency approvals may be required. Further, section 35 of the federal *Fisheries Act* designed to prevent “harmful alteration, disruption and destruction” (“HADD”) of fish and fish habitat may be applicable to CBM development in certain circumstances. Notably, Bill C-45, a Bill to amend the federal *Fisheries Act*, was recently introduced by Parliament and represents a significant change to existing legislation.

⁹⁵ *Canadian Environmental Assessment Act*, S.C. 1992, c. 37

Oil and Gas Commission Regulatory Process for Coalbed Methane Projects



CBM projects are also subject to the B.C. *Environmental Assessment Act*⁹⁶ (“EAA”) if CBM is extracted at the rate of 75 litres per second or more,⁹⁷ or because of significant pipeline construction. Pursuant to section 8 of EAA and associated regulations, groundwater extraction required for CBM production may be considered a “reviewable project” subject to an existing certificate for the project or a determination by the Executive Director that such a certificate is not required for the project. Depending on whether the project is considered a new facility or a modification to an existing facility and considering the design of the facility itself, CBM production involving groundwater extraction characterized as a water management project, may be subject to the *Reviewable Project Regulations*.⁹⁸

Finally, pursuant to the *Local Government Act*⁹⁹ and *Vancouver Charter*,¹⁰⁰ municipalities have certain powers of strategic planning for growth and development, zoning powers to regulate use and density, and powers to pass bylaws related to environment, disturbances and economic development. However:

The zoning power is limited in relation to CBM development. “Land” in the Community Charter and Local Government Act is defined as excluding mines or minerals, and recently the term “minerals” has been defined to specifically include CBM.¹⁰¹

And further:

⁹⁶ *Environmental Assessment Act*, S.B.C. 2002, c. 43, ss. 5, 6 & 8.

⁹⁷ Levson, V., et al., “*Understanding the Business of Coalbed Methane: Managing CBM Water in B.C.: New Approach for Industry*”, presented Tuesday, February 25th, The Metropolitan Centre, Calgary, AB, at page 5; *Environmental Assessment Act*, S.B.C. 2002, c. 43, ss. 3 and 8.

⁹⁸ *Reviewable Project Regulations*, B.C. Reg 370/2002, ss. 3 and Part 5.

⁹⁹ *Local Government Act*, R.S.B.C. 1996, c. 323.

¹⁰⁰ *Vancouver Charter*, S.B.C. 1953, c. 55.

¹⁰¹ Campbell, K. and Rutherford, S., “*CBM: A B.C. Local Government Guide*”, West Coast Environmental Law, May, 2006, at page 12.

In 2004, the Union of B.C. Municipalities passed a resolution calling upon the provincial government to consult directly with local governments regarding the Ministry of Energy and Mines' Oil and Gas Regulatory Improvement Initiative..."¹⁰²

Accordingly, some groups take the position that while recognizing that local governments cannot prohibit CBM development, local governments may be able to "regulate associated land uses as well as other important issues such as set backs, density of structures, location of structures, and landscaping"¹⁰³ in particular:

Courts have upheld zoning bylaws that stopped a mine from storing and processing minerals,¹⁰⁴ and gravel pit operators from crushing gravel,¹⁰⁵ or from mixing gravel to produce ready mix.¹⁰⁶ They have even held that processing which was essential to the economic viability of a mine could be prohibited.¹⁰⁷

It remains to be seen how local governments in B.C. will respond to proposals for CBM development and production.

The CGA

The CGA establishes separate tenure rights for CBM and expressly provides that natural gas must be considered to be and to have always been a "mineral"¹⁰⁸ and that coalbed gas is a "natural gas".¹⁰⁹ Section 4 states that:

¹⁰² *Ibid*, at page 12.

¹⁰³ *Ibid*, at page 12.

¹⁰⁴ *Ibid*, at page 12 citing *Squamish (District) v. Great Pacific Pumice Inc.* (2003), 38 M.P.L.R. (3d) 163, 229 D.L.R. (4th) 93, (B.C.C.A).

¹⁰⁵ *Ibid*, at page 12 citing *Maple Ridge (District) v. Thornhill Aggregates Ltd.* (1993), 14 M.P.L.R. (2d) 288 (B.C.S.C).

¹⁰⁶ *Ibid*, at page 12 citing *Pitt River Quarries Ltd. v. Dewdney-Alouette (Regional District)* (1995), 27 M.P.L.R. (2d) 257 (B.C.S.C).

¹⁰⁷ *Ibid*, at page 12 citing *Cowichan Valley (Regional District) v. Norton*, (July 14, 2005) Victoria Registry: Docket 05/3148 (B.C.S.C).

¹⁰⁸ *Supra*, at footnote 81, s. 2.

¹⁰⁹ *Ibid*, at s. 3.

Natural gas tenure includes coalbed gas

4(1) A natural gas tenure, whether made before or after the coming into force of this Act, includes any coalbed gas rights.

(2) A coal tenure, whether made before or after the coming into force of this Act, does not include any coalbed gas rights.

In an effort to address split title claims and ongoing court actions, Section 6 of the CGA expressly eliminates any rights of action against the government, the natural gas rights holder, or the coal rights holder for claims. Section 6 provides that:

No compensation or right of action

6(1) A person has no right of action and must not commence or maintain proceedings, as a result of the enactment of this Act or the exercise by the minister of powers referred to in section 5 or 7,

(a) to claim damages or compensation of any kind from the government, or

(b) to obtain a declaration that damages or compensation are payable by the government.

(2) For all purposes, including for the purposes of the Expropriation Act, no expropriation or injurious affection occurs as a result of the enactment of this Act or the exercise by the minister of powers referred to in section 5 or 7.

(3) The natural gas owner or a person who has acquired coalbed gas rights from the natural gas owner has no right of action and must not commence or maintain proceedings against the government, the surface owner or the coal owner for damages or compensation because of extraction, production or removal of coalbed gas if that extraction, production or removal occurred before the coming into force of this Act.

Before passing the CGA, the B.C. government conducted several rounds of discussion with industry participants to obtain comments on the CGA. The CGA came into force on April 10, 2003, and to date, it has not been judicially considered. The B.C. government also negotiated agreements with various parties affected by the retroactive application of the CGA, namely the owners of major blocks of coal lands on Vancouver Island and in the Kootenay region,

specifically for Crown petroleum and natural gas rights within specific coal formations. While the terms of those agreements appear not to be publicly available, the MEMPR website indicates that the agreements allow the Crown to acquire petroleum and natural gas tenures in the form of drilling licenses for a five-year period and that the Crown must exercise the option on at least twenty percent of the lands each year.¹¹⁰

Split Title

MEMPR has issued Information Letters setting up a process for disputes between coal and petroleum and natural gas rights existing separately within a single parcel of land. A description of the process for resolving conflicts is provided in the *Titles-05-02 – Managing Co-existing Coal and Petroleum and Natural Gas Rights* (Replacing E92-11) Information Letter issued by the MEMPR.¹¹¹ The Information Letter outlines MEMPR's policy for reducing conflicts and managing development where co-existing coal and petroleum and natural gas rights occur and appears to apply to CBM development as well. In brief, the policy states that:

If the coal and P&NG rights holders cannot reach agreement on compatible work programs, a three member panel from MEMPR and the OGC will examine the issues and facts associated with the development of the resources and recommend a resolution to the appropriate decision maker. The panel may recommend that the decision maker approve, approve with conditions, or not approve the application.¹¹²

¹¹⁰ *Titles-04-06 Issuance of Crown Petroleum and Natural Gas Rights on Vancouver Island and the Kootenay's to the Holders of Freehold Coal Agreements with the Province* dated July 4, 2004 online at www.em.gov.B.C.ca – Info Letter/Titles.

¹¹¹ *Titles-05-02 – Managing Co-existing Coal and Petroleum and Natural Gas Rights* (Replacing E92-11) Information Letter issued by the MEMPR on or about April 2005 online at www.em.gov.B.C.ca – Info Letter/Titles.

¹¹² *Ibid*, at page 3.

When dealing with such disputes, MEMPR and the OGC will consider facts such as financial feasibility, cost/benefit of each resource activity, social and environmental impacts, resource recovery potential, resource compatibility and the respective projected project commencement and completion dates of each activity. The Director of OGC's Project Assessment Branch is empowered to make the decision for an oil and gas activity, and the MEMPR's Chief Inspector of Mines is empowered to make the decision for a coal activity. It is possible that the Directors may require indemnity agreements as a condition to the activity approved.¹¹³ While the policy does not provide for a right of appeal, any decision rendered is arguably subject to a judicial review.

Surface Rights

Surface rights are governed by the PNG Act including all aspects of exploration, development and production, providing for the entry, occupation or use of publicly held land for the purposes of exploration and development of CBM. In order to exercise subsurface rights to develop a CBM well, a surface lease must be negotiated with existing land owners, which in B.C. generally means the Crown. The CBM developer would also be wise to negotiate with First Nations. In addition, modern day treaties or land claim agreements, include provision for consultation and accommodation. Accordingly, the situation is markedly different from other jurisdictions, including Alberta, because for the most part in B.C., industry must consult with and negotiate directly with First Nations affected by CBM development.

¹¹³ *Ibid*, at page 4.

Water Disposal

The Code is the “nuts and bolts” of CBM development in B.C. and details quality and quantity criteria for disposing of produced water. The Code pulls together a myriad of other provincial legislation to address the discharge of produced water, including legislating applicable standards for produced water discharged to perennial, seasonal streams and groundwater, and monitoring, record-keeping and reporting. Various other guidelines and legislation in B.C. are referenced including:

- *British Columbia Approved Water Quality Guidelines (Criteria), 1998 Edition;*
- *British Columbia Laboratory Methods Manual: 2003;*
- *Waste Discharge Regulation, B.C. Reg. 320/2004; and*
- *A Compendium of Working Water Quality Guidelines for British Columbia, 1998 Edition.*

Two overriding issues are notable with respect to the Code. First and foremost, while it is entitled a *Code of Practice*, it is promulgated under the EMA as a regulation and thus has the force of a regulation. There may however be some uncertainty with respect to whether the penalty and enforcement provisions under the EMA apply to a violation of the Code. Secondly, the Code does not provide for a permit process and treats each CBM project generally, including the discharge of produced water from coalbed production, rather than on a case-by-case basis with reference to the particular stream or ecological area potentially affected.

With respect to the first issue, namely whether the penalty and enforcement provisions under the EMA apply to a violation of the Code, the following analysis is relevant to the discussion. The Code was created pursuant to section 22(1) of the EMA which states that, in addition to the regulation-making powers of the Lieutenant-Governor in Council:

The Minister may make regulations establishing codes of practice for industries, trades, businesses, activities or operations, or classes of industries, trades, businesses, activities or operations, for the purposes of section 138(2)(s).

Section 22 of the EMA goes on to list the types of regulations which the Minister can make. The Code was issued pursuant to subsections 22(2) (a),(g),(h) and (j), which state:

For the purposes of establishing codes of practice under subsection (1), the minister may make regulations as follows:

(a) prescribing the form and content of a notice;

(...)

(g) prescribing a substance as a waste and prescribing circumstances in which a substance is a waste;

(h) regulating and imposing requirements and restrictions respecting the use, supply, storage, transportation, handling, treatment or disposal of any substance specified in the regulations, whether natural or artificial and whether in solid, liquid or other form, if the minister considers it appropriate to do so for the purpose of preventing the substance from causing damage to persons, animals or plants or pollution of air, water or land;

(...)

(j) requiring the keeping of records and authorizing the inspection of records; ...

It has been suggested that because the Code is a code of practice, it does not have the force and effect of an ordinary regulation consistent with the Supreme Court of Canada's decision in *Via Rail v. Canadian Transportation Agency* ("Via Rail")¹¹⁶ wherein the Court stated that, "voluntary codes of practice cannot be elevated to the status of laws as if they were legally binding

¹¹⁶ *Via Rail v. Canadian Transportation Agency*, 2007 SCC 15.

regulations”. However, in this case, the Code was promulgated under the EMA as a regulation and thus it has the force of a regulation and cannot be described as “voluntary”.

There may however be some issue with respect to whether other sections of the EMA are still applicable in respect of a violation of the Code, namely the enforcement and penalty provisions of Part 10 of the EMA. The Code was promulgated under section 22 of the EMA pursuant to the Minister’s powers under subsection 138(2)(s) which states:

(E)xempting any operation, activity, industry, waste or works or any class of persons, operations, activities, industries, wastes or works from any or all of the provisions of this Act or the regulations in circumstances and on conditions that the Lieutenant Governor in Council prescribes.

By enacting the Code, the Minister exempted certain CBM activities from the provisions of the EMA, but arguably, did not provide a complete exemption in that only certain of the provisions of the EMA were exempted consistent with the authority in subsection 138(2)(s) to exempt “any or all of the provisions” of the EMA. Accordingly, compliance with the general provisions of the EMA is arguably still mandatory.

Secondly, the Code does not provide for a permit process, but treats each CBM project generally, including the discharge of produced water from coalbed production, rather than on a case-by-case basis with reference to the particular stream or ecological area potentially affected. Contrast the B.C. situation with Alberta where legislators have recognized that individual review is required in every circumstance. Critics point to the fact that in this way, the Code does not limit

the number of operations that could discharge into the same stream or into seasonal streams that discharge into the perennial stream with many dischargers.¹¹⁷

On the other side of debate, reviewers of the emerging regulatory framework in Canada state that in reference to the B.C. legislative regime:

The B.C.OP [referring to the Code] provides a well coordinated framework to protect water quality and address the potential impact of CBM development on aquifers. In light of the success of B.C.OP in providing a more streamlined approval process than currently exists in Alberta, it is interesting to note that the Alberta CBM/NGC Multi-Stakeholder Advisory Committee has included in the recommendations released last week that the Alberta Government adopt a “decision tree approach” and a “code” to improve the coordination of the regulatory approval process.¹¹⁸

The Energy Plan recently introduced by the B.C. government in February, 2007 mandates that the default process to deal with produced water must be subsurface injection. Subsurface injection is governed by the PNG Act and the *Drilling and Production Regulations* pronounced under that legislation. The Energy Plan expressly mandates that companies will not be permitted to surface discharge produced water. The Energy Plan therefore throws into question the issue of whether those provisions of the Code that addressed surface disposal water will still be operative. What happens in situations where subsurface injection cannot be achieved? Will the Code govern or will a proponent be denied approvals to proceed with the CBM development? The answers are unknown at this time. However, it may be useful to reference the Code provisions for dealing with surface disposal of produced water. The provisions of the Code relating to the

¹¹⁷ Myers, T., et al., , “*Technical Review: Code of Practice for the Discharge of Produced Water from Coalbed Gas Operations in British Columbia*”, Center for Science in Public Participation January 25, 2005, at page 6.

¹¹⁸ Ingelson, A. et al, *CBM Produced Water – The Emerging Canadian Regulatory Framework*, The Institute for Sustainable Energy, Environment and Economy, Calgary, Alberta: November 2006, at page 22.

surface discharge of produced water can be found in Section 2 of the Code. Pursuant to the definition of “produced water” found in Part 2 – Discharge of Produced Water:

“produced water” means water extracted from a coal seam or a formation contiguous to a coal seam that

- (a) originated from within the coal seam or contiguous formations,
- (b) is pumped out in advance of and in aid of the release of gas from the coal seam, and
- (c) is produced in the course of a coalbed gas exploration and production industry operation.

The definition of produced water establishes a three part test for water to be considered “produced water”. First, the water must originate from a coal seam; second, it must be water that is pumped out in advance of and aids the release of gas from the coal seam; and, third, the water must be produced in the course of coalbed gas exploration and production.

Section 2 provides that:

Where produced water may be discharged

2 Produced water may be discharged under this code only to

- (a) a perennial stream,
- (b) a seasonal stream, or
- (c) the ground by percolation through the ground.

There are similar sections for perennial and seasonal streams groundwater discharges. A “perennial stream” is defined to mean, “a watercourse that from a point directly upstream of a point at which produced water is discharged or proposed to be discharged has observable water flow at all times.” A “seasonal stream” is defined to mean “a watercourse that between a point at which produced water is discharged or proposed to be discharged and its confluence with a

perennial stream (a) has intermittent observable water flow each year, and (b) is associated with a water table.

The Code establishes guidelines regarding surface disposal of produced water by setting out discharge standards for the three types of surface disposal methods. Schedules 1 – 3 of the Code provide the legislated quality and quantity details of such discharges.

Section 4 of the Code provides that:

4 (1) Produced water may be discharged into a perennial stream only if

(a) the flow of the perennial stream directly upstream from the point of discharge is sufficient, at all times, to provide **a minimum of 10:1 dilution for the total produced water** discharged by the discharger into that perennial stream, and

(b) the requirements of this code and the standards specified in **Schedule 1** are met.

(2) Produced water may not be discharged into a perennial stream **in a manner or quantity that impairs the proper ecological function** of the perennial stream or otherwise **causes excessive erosion**.

(3) A discharger must ensure that a discharge of produced water into a perennial stream is treated, if necessary, to remove iron and manganese precipitates **so that discoloration in the perennial stream is minimized** (emphasis added).

What is meant by the phrases “in a manner or quantity that impairs the proper ecological function of the perennial stream or otherwise causes excessive erosion” or “so that discoloration in the perennial stream is minimized” has yet to be considered by any regulatory agency or court.

The Code also provides specific rules for points of discharge in proximity to existing drinking water and irrigation use and the maximum amount of produced water that may be discharged

from a well, namely 1850 m³ a day.¹¹⁹ An exemption from the *Waste Discharge Regulation* can be obtained.

The New B.C. Energy Plan

In February 2007, the government announced its new B.C. Energy Plan.¹²⁰ It is apparent that the government listened to some of the criticisms of the Code as the Energy Plan effectively changed the current regulatory regime for CBM. First, the Energy Plan mandates that produced water from CBM development be disposed of by water injection as a first priority to other disposal methods outlined in the Code. Secondly, in response to climate change issues and greenhouse gas emission reductions, the Energy Plan mandates that flaring from oil and gas producing wells will come to an end in 2016.

The relevant parts of the new B.C. Energy Plan as quoted in the Plan of Action - Oil and Gas section and applicable to CBM development are as follows.

Best coalbed gas practices in North America. Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer ...¹²¹

Specifically with reference to the “Best Coalbed Gas Practices in North America”, the B.C. Energy Plan says this:

Government will continue to encourage coalbed gas development with the intent of demonstrating that British Columbia is a leading socially and environmentally responsible coalbed gas

¹¹⁹ *Supra*, at footnote 86, sections 7 and 8.

¹²⁰ *Supra*, at footnote 91.

¹²¹ *Ibid*, at pages 3 and 29.

developing jurisdiction. Coalbed gas, also known as coalbed methane, is natural gas found in coal seams. It is one of the cleanest burning of all fossil fuels. Proponents wanting to develop coalbed gas must adopt the following best practices:

- Fully engage local communities and First Nations in all stages of development;
- Use the most advanced technology and practices that are commercially viable to minimize land and aesthetic disturbances;
- Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer (emphasis added);
- Meet any other conditions the Oil and Gas Commission may apply;
- Demonstrate the company's previous experience with coalbed gas development, and information must be made publicly available as to how the company plans to meet and be accountable for these best practices;¹²²
- Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011;¹²³
- Through the B.C. Energy Plan, government has committed to eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011. In addition, government will adopt policies to reduce natural gas flaring and venting at test sites and pipelines, and encourage compressor station efficiency to cut back emissions. Government will also explore opportunities and new technologies for safe, underground disposal of carbon dioxide or sequestration from oil and gas facilities. Sequestration is considered a cost effective mitigation strategy in reducing carbon dioxide emissions.¹²⁴
- Establish policies and measures to reduce air emissions in coordination with the Ministry of Environment; and
- Enhance the Oil and Gas Environmental Stewardship Program, ensuring sound environmental, land and resource management.

The Energy Plan has yet to be translated into a regulation or a code of practice so there is some uncertainty with respect to the discharge of produced water from CBM development in B.C.. However, it is reasonable to assume that the OGC and the relevant government ministries and agencies will no doubt be driven by the Energy Plan when considering CBM applications for

¹²² *Ibid*, at page 31

¹²³ *Ibid*, at page 31

¹²⁴ *Ibid*, at page 30

approval. It is equally reasonable to assume that the Code will eventually be amended to account for these changes in government policy.

Critique of the Code

Part 3 of the Code addresses discharge, monitoring, record-keeping and reporting requirements relating to CBM activities. This Part of the Code has also been highly criticized because the government has adopted a general, permissive process with no apparent consideration of case specific situations. Further, critics argue that the government has taken a “hands-off” approach with respect to who will monitor, keep records, and report on water quality relating to discharge. The responsibility for monitoring and reporting has been delegated to qualified professionals. Under the Code, a “qualified professional” is defined to mean:

"qualified professional", in relation to a duty or function under this code, means an individual who

(a) is registered in British Columbia with a professional organization, is acting under that organization's code of ethics, and is subject to disciplinary action by that organization, and

(b) through suitable education, experience, accreditation and knowledge, may reasonably be relied on to provide advice within his or her area of expertise, which area of expertise is applicable to the duty or function;

The definition is broad and mandates that a qualified professional need only be registered with a professional organization and have “suitable education, experience, accreditation, and knowledge” to provide advice on the issues in question. However, it is unclear whether the professional should be for example, a biologist or an environmental engineer. The effect is to leave it open to the proponent to decide what qualified professional they will rely upon.

From a practical perspective this approach may be reasonable, however, critics point to the fact that the Code does not require qualified professionals to be certified by the government. Critics also argue that these qualified professionals are not required to and may not operate at arms length from the company proposing the CBM project and, as a result, their discretion and opinions may be compromised. For example, Myles, T. at the Centre for Science Participation argues that:

The Province must recognize that there is potential for Qualified Professionals to be co-opted to a lesser or greater extent by the people they depend upon for their livelihood. In order to prevent this from happening and since a good portion of the regulatory authority normally invested in the government is being delegated to the Qualified Professionals, the Province should take care to define just who and what a Qualified Professional is, and to ensure that there is a mechanism to ensure accountability for this delegated authority.¹²⁵

Section 11 of the Code requires that a company planning to discharge produced water must first ensure that a “receiving environment baseline monitoring program is designed by, and conducted under the supervision of” (noticeably not *actually conducted or undertaken* by) a “qualified professional” for at least one year before discharging the produced water. This requirement means that the baseline study should be included in any applications to the OGC and effectively means that CBM development at the site will be delayed by at least this one year period.

Critics also argue that the lack of government oversight and monitoring could mean that the discharge of produced water could be allowed to carry on unchecked, perhaps indefinitely. For example, Sierra Legal Defence Fund in its critique of the Code states that:

B.C.’s new laws controlling polluted water produced by coalbed methane operations (Code of Practice for Discharge of Produced Water) merit particular mention. They put virtually all the decision-making authority in the hand of consultants paid by the companies, and permit the deposit of polluted water at levels fatal to fish right into a drinking or irrigation stream, as long as the consultant says it’s ok. The Code represents an extreme example of off-loading government

¹²⁵ *Supra*, at footnote 117, at page 8.

responsibilities to private companies with a vested interest in pumping the gas, leaving the environment and affected drinking water users at risk.¹²⁶

This concern emanates from the Code provisions that provide that the company must maintain appropriate records. However, only upon the request of the Director (appointed under the Code) or if a company exceeds allowable discharge quality criteria, must the company report to the Director and submit or post monitoring data. Environmentalists and opponents to CBM argue that the lack of positive government enforcement and oversight is bad news as it allows rogue operations to avoid the requirements of the Code until caught.

From an industry perspective, the lack of enforcement and oversight while beneficial in some ways may also prove to be a significant detriment for those in the industry that strictly adhere to the legislation of the day because of the risk that other companies who do not strictly adhere to the rules will further tarnish the view of the public with respect to CBM development. This will inevitably make it more difficult for other projects to get off the ground and may lead to more stringent regulations and enforcement.

Finally, the lack of involvement of the public is arguably another mistake on the part of the B.C. government. B.C. is home to a strong environmental movement and many opponents to CBM projects. Even industry has commented that for CBM development to succeed in B.C. public consultation is going to be integral to that process. CAPP's manager predicted that:

... CBM's success in B.C. will hinge on land-use issues, available technology and adequate public-consultation processes. Public consultation is a key component ... because the public helps to address specific issues. The industry would prefer that the government reach agreements with

¹²⁶ Sierra Legal Defence Fund, "*This Land is Their Land: Executive Summary and Audit of the Regulation of the Oil & Gas Industry in B.C.*", undated, online at www.sierralegal.org, at page 7

the stakeholders before activity begins in earnest. Producers can't invest until they are more certain of their costs¹²⁷

There are also numerous other groups outside of B.C. opposing CBM development in B.C. that refer to the controversial and negative early experiences of CBM production in the United States particularly with respect to produced water disposal issues. On April 7, 2005 for example, the Montana Legislature passed a resolution¹²⁸ respecting CBM development in the Flathead Valley of B.C., recognizing the importance of the transboundary region of the Flathead Lake and river drainage. That resolution urged the Governor of Montana to negotiate an operating agreement with the B.C. government and to request that the International Joint Commission conduct and complete an environmental assessment prior to a final decision on CBM development in the area.

Concerns have also been expressed by the Governor of Montana when B.C. held a land sale in Southeast B.C. Montana's Governor strongly opposed CBM recovery in the Flathead area arguing that the potential risk of adversely affecting transboundary rivers and watercourses was too high. Under the present provisions of the Code, unless there is a compliance issue that requires the attention of the Director and the Director requires reports to be produced and filed with the OGC or other governmental agency, it is doubtful that the public will have access to the requisite information to monitor CBM development in their area. The lack of access to such information will continue to create misunderstandings and increase the distrust between the public, industry, and various stakeholders.

¹²⁷ *Supra*, at footnote 83.

¹²⁸ Montana Legislature, Senate Joint Resolution No. 7, April 7, 2005

Finally, assuming that the Code provisions relating to disposal of produced water remain relevant and of use in light of the Energy Plan mandating subsurface injection of produced water, there are some that take the view that B.C.'s CBM legislation encroaches too much on federal jurisdiction because it allows for discharge of produced water into streams. Setting aside any jurisdictional issues, proponents must consider the federal regulatory regime when developing CBM in B.C. and that regime is changing. In December 13, 2006, the Federal Government tabled Bill C-45, an Act respecting the sustainable development of Canada's Sea Coast and Inland Fisheries (*Fisheries Act*, 2007). An in-depth discussion of such legislation is beyond the scope of this paper; however, the new *Fisheries Act* will need to be considered for any CBM project.

First Nations

Notwithstanding the B.C. government's promotion of CBM, there has been little interest expressed in exploring and producing CBM in B.C. In fact, no one attended at the government's last attempt to auction CBM lands. Unfortunately, there is a perception in the industry that it is impossible to do anything in B.C., let alone explore, develop and produce CBM given outstanding and unresolved First Nations claims. That is truly not the case. However, significant consultation and accommodation is required for a proposed CBM project and industry must be prepared to negotiate for benefits and accommodation in respect of any project.

Now is the time to seize the opportunity, both for industry and First Nations and work together towards the development of CBM. CBM development raises unique issues distinct from traditional oil and gas development. First Nations need the requisite expertise and technical

background on CBM and the industry needs to move away from an individualistic “can-do” attitude and move towards fostering a community of understanding with a view to sharing technologies and benefits.

The first step towards developing new relationships is to recognize, acknowledge, and give weight to the strong ties between First Nations and the land, recognizing the fact that the land provides a means of survival and not merely an asset for recreation or resource development, and that the land must be preserved so that fishing, hunting and other traditional uses of the land will remain intact. Accordingly, the cumulative impacts of CBM development must be addressed and dealt with by industry and First Nations working together.

It must also be recognized that because of historical uses of the land First Nations have inherent knowledge and values about the land including skills and expertise in relation to land management activities. First Nations people understand the cumulative effects of resource development and the connectivity of all things in ways that someone that does not live off the land may not fully appreciate. These concepts appear to have been recognized in the new B.C. Energy Plan as follows:

Government is working to ensure that oil and gas resource management includes First Nations’ interests, knowledge and values. Government has recently concluded consultation agreements for oil and gas resource development with First Nations in Northeast British Columbia. These agreements increase clarity in the process and will go a long way to enhancing our engagement with these First Nations.¹²⁹

The B.C. government developed its *Consultation Operating Guideline* in December 1, 2006 for consultation with First Nations on CBM projects. This Guideline includes pre-determined

criteria for CBM development such as Application Criteria, Notification Requirements, Extension Criteria, and Complex Consultation Zones, including methodology for documenting, and mapping.¹³⁰ Pursuant to the Guidelines, to date, the Ministry has negotiated Memoranda of Understanding with various Treaty 8 First Nations.

One such agreement was negotiated with the Doig River First Nation and describes the process for consultation between the Doig River First Nation and the Government of British Columbia with respect to Oil and Gas Activities, defined to include “oil and gas exploration development ... for which the approval of the OGC is required”, that have the “potential to adversely impact the exercise by the First Nation of rights recognized and affirmed by section 35(1) of the *Constitution Act*, 1982.”¹³¹ The Province has yet to negotiate a consultation agreement under these guidelines with a First Nation not party to a treaty.

Environmental Concerns

First Nations and other stakeholders must inform themselves about CBM development and recognize that exploration and production of CBM is distinct from conventional oil and gas exploration and production and development and thus must be treated in a distinct manner. In particular, the following characteristics are unique to CBM development and of interest to First Nations and stakeholders:

¹²⁹ *Supra*, at footnote 91, at page 29

¹³⁰ Consultation Operating Guidelines, dated December 1, 2006

¹³¹ Consultation Process Agreement dated on or about December 1, 2006 between Her Majesty the Queen in Right for the Province of British Columbia and the Doig River First Nation, at Article 2.1.

- In order to access the methane gas, coal seams need to be dewatered. While the quantities of produced water will vary from basin to basin, it is possible that large quantities of produced water could be released for which disposal will be an issue.
- ... To allow water or CBM to flow more easily, companies will usually inject a high-pressure compound of sand and chemicals into the well to fracture or “frac” the coal seam. Such fracturing compounds can contain toxic chemicals including diesel fuels and other hydrocarbons.¹³²

Moreover:

- Methane gas is often held in the coal by water pressure and this pressure must be decreased by “de-watering” or pumping out the groundwater. This “produced” water can vary in quality from being relatively pure to being highly polluting. It is often saline, and may contain heavy metals that can have long-term effects on aquatic ecosystems, depending on disposal practices. In the US, courts have determined the CBM produced water is a “pollutant” under the US Clean Water Act. . . .¹³³
- CBM wells generally require much denser spacing than conventional gas wells ... CBM wells have a longer lifespan and can be in operation for up to 40 years, whereas conventional wells tend to be exhausted after 25 years and CBM wells are likely to be flared for longer periods than conventional gas wells.¹³⁴

However, the recently announced Energy Plan which mandates that produced water must be disposed of by subsurface injection should go some way towards addressing First Nations and other stakeholder concerns relating to the impact of CBM on the water tables.

Again, the recently announced Energy Plan purports to eliminate gas flaring in 10 years in an attempt to address concerns with respect to flaring, including the impacts on climate change and greenhouse gas emissions.

¹³² *Supra*, at footnote 101, page 1-8.

¹³³ *Northern Plains Resources Council v. Fidelity Exploration and Development Company*, United States Court of Appeals for the 9th Circuit, No. 02-35836, D.C. No. CV-00-00105-SHE, April 10, 2003

Other factors to consider include:

- Setback requirements for infrastructure, post-construction operations measures for equipment, visual impacts of compressors, meter houses, pump jacks, tanks and water pits;¹³⁵
- Increased production life means that the length of the lease for production could be negotiated to bring certainty to land-use conflicts and to limit the long-term environmental impact of CBM;
- Water management planning, water quality issues and protection of wetland riparian rights issues; communication notice provisions for surface owners, dispute resolution planning, pipelines, power lines, habitat species production and public safety issues;¹³⁶
- Direct involvement with selecting “qualified professionals” under the Code to monitor and obtain baseline data including cumulative impact analysis for land-use planning, including zoning amendments, performance standards, use of development permits and land-use resource development agreements;
- Tax assessment mechanisms to address property values, disclosure of mineral ownership and land transfers, resources and means to maintain additional and existing road infrastructure, diversion of tax revenue, extra fees, bonding, road construction and use¹³⁷; and
- Noise abatement and aesthetic issues including the use of berms, compressors, location and size of flare stacks and air quality and emissions issues.

Conclusion

¹³⁴ *Supra*, at pages 1-8.

¹³⁵ *Supra*, at pages 10 - 11

¹³⁶ *Ibid*, at footnote 58, at pages 10 – 11.

¹³⁷ *Ibid*, at pages 10-11

To conclude, the current legislative regime, including Codes and Guidelines as modified by the new Energy Plan and the role of various governmental agencies represents a sophisticated approach to CBM development in B.C. that is not immune from criticism. There are several key issues and current trends including First Nations issues and surface rights, produced water disposal management and general environmental issues including flaring which continually need to be reassessed by oil and gas companies conducting, or intending to conduct, CBM operations in B.C.

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