Water Law Review

Volume 10 | Issue 1 Article 6

9-1-2006

CBM Produced Water - The Emerging Canadian Regulatory Framework

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CBM PRODUCED WATER—THE EMERGING CANADIAN REGULATORY FRAMEWORK

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I. INTRODUCTION

Reports indicate that natural gas producers will drill at least 4200 coalbed methane ("CBM") wells in Alberta, Canada this year.[1] In light of the anticipated increase in commercial production from wet coals within ten years and the controversy surrounding the impact of CBM development on provincial water resources, this article reviews the current and emerging provincial regulatory framework that governs CBM

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[1] Kevin Lo & Steven I. Paget, *Coalbed Methane Activity Update*, THE NEGOTIATOR, May 2006, at 5, *available at* http://www.capl.ca/member/publications/negotiator/2006/may/2006_may.pdf; *see also generally* Laura Severs, *Unconventional Gas Plans Raising Fears*, BUS. EDGE, Mar. 16, 2006, *available at* http://www.businessedge.ca/printArticle.cfm/newsID/12126.cfm (noting that the number of CBM wells in Alberta currently exceeds 6000).

produced water and the associated environmental impacts.[2] This article analyzes the emerging provincial regulatory system in western Canada in the context of the CBM development experience in the western United States, American best management industry practices, and the Alberta Multi-Stakeholder Advisory Committee Recommendations released in May 2006.

CBM is natural gas that occurs in coal seams. Several western Canadian states have commercially produced CBM for two decades; however, Alberta is the only province with appreciable commercial production. Much of central and southern Alberta is underlayed by coals with the potential for CBM development.[3] Recently, EnCana Corporation budgeted $4.5 billion, and other companies anticipate spending a total of $9.1 billion, for CBM exploration and production in the next five years.[4] In 2004, western Canadian CBM production constituted only 0.5% of the total provincial marketable gas production; however, the Alberta Energy and Utilities Board ("EUB") predicts that by 2014, CBM production will constitute twelve percent of that total.[5] By the year 2025, it is anticipated that eighty percent of the new wells drilled in Alberta will target CBM, and the energy resource will account for fifty percent of the total marketable natural gas production.[6]

To date, most of Alberta's CBM production from "dry" coal, containing little or no water, comes from the Horseshoe Canyon and Belly River coal formations.[7] In 2005, commercial production was reported from wet coals in the Mannville Group.[8] Currently, limited data exists

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2. For a discussion of these impacts, *see generally* MARR GRIFFITHS AND CHRIS SEVERSON-BAKER, UNCONVENTIONAL GAS: THE ENVIRONMENTAL CHALLENGES OF COALBED METHANE DEVELOPMENT IN ALBERTA (2003), *available at* http://www.pembina.org/pdf/publications/CBM_Summary.pdf.

3. JEFFREY FIELL, OCTAGON, OPPORTUNITIES IN COALBED METHANE: ECONOMIC UPSIDE FOR INVESTORS 14-15 (2006), http://www.richardsoilandgas.com/industry_information/pdf/cbm_31012006.pdf (stating the Horseshoe Canyon formation is thought to contain 66 trillion cubic feet ("tcf") of CBM, the Scollard Formation 53 tcf, Belly River Group 66 tcf, and the Mannville Group 320 tcf potential resource-in place).

4. Paul Haavardsrud, *Another Giant in the Making: Coal Bed Methane Has Done in a Few Years What Took Decades for Oilsands Boosters: Attract the Big Money*, NAT'L POST (Can.), Apr. 3, 2006, at FP5.

5. ALTA. ENERGY & UTIL. BD., ST98-2005, ALBERTA'S RESERVES 2004 AND SUPPLY/DEMAND OUTLOOK 2005-2014, 4-9 (2005) [hereinafter ALTA. ENERGY & UTIL. BD., ST98-2005], *available at* http://www.eub.ca/docs/products/sts/st98-2005.pdf.

6. Severs, *supra* note 1.

7. ALTA. ENERGY & UTIL. BD., BULLETIN 2006-33, 2005 ALBERTA COALBED METHANE ACTIVITY SUMMARY AND WELL LOCATIONS 1 (2006), *available at* http://www.eub.ca/docs/documents/bulletins/Bulletin-2006-33.pdf (stating "[o]ver [ninety-five percent] of Alberta's CBM wells are completed" in these two regions).

8. Lynda Harrison, *Horseshoe Canyon Can Be Wet; Corbitt Could Be a Giant*, NICKLE'S DAILY OIL BULLITEN, Nov. 14, 2005; *See also* ALTA. ENERGY & UTIL. BD., ST98-2006, ALBERTA'S ENERGY RESERVES 2005 AND SUPPLY/DEMAND OUTLOOK 2006 – 2105, 4-6 (2006) [hereinafter ALTA. ENERGY & UTIL. BD., ST98-2006], *available at* http://www.eub.ca/docs/products/STs/ST98-2006.pdf.

on the volume of water that wet coals in western Canada may produce. Recent media reports in Alberta have focused on the environmental problems attributed to the surface discharge of produced water and the reported problems associated with CBM development in the western United States, and potential problems that may occur in western Canada due to methane migration from CBM wells into landowner water wells.[9] For several years, provincial regulators in Alberta and British Columbia monitored the CBM development experience in the western United States and the potential environmental and social impacts from development.

II. PRODUCED WATER IMPACTS IN THE WESTERN UNITED STATES

As CBM remains absorbed or attached to the coal due to overlying pressure from rock and/or water, the facilitation of methane production requires the reduction of the pressure in the coal seam. Removing the overlying water through a dewatering stage separates the CBM from the coal and allows pumping to the surface. Produced water refers to water pumped during this stage and subsequent production stages. Regulators in the United States have had more experience in managing large scale CBM development than in any other country.[10] CBM development in the western United States revealed that the quantity and quality of water produced from CBM wells will vary from basin to basin and at individual sites within each basin.[11] "Wet" coals, such as those found in the San Juan and Powder River sedimentary basins have produced significant volumes of fresh and saline water.[12] At some CBM well sites in Wyoming, the produced water is of drinking water quality, but at other sites the water is saline or contains natural salts and other elements that may prompt treatment prior to discharge.[13] Produced

9. *See* Hanneke Brooymans, *Taps of Fire Near Drill Site Spook Resident*, CALGARY HERALD, Dec. 13, 2005, at A3; Kelly Cryderman & Renata D'Aliesio, *Farmers, Landowners Voice Opposition to Coal Bed Methane: Info Sessions Tap Deep-Seated Suspicions*, CALGARY HERALD, June 19, 2006, at A6; Renata D'Aliesio, *U.S. Rancher Warns of Coal Bed Methane's Poison*, CALGARY HERALD, Mar. 10, 2006, at B3; Andrew Nikiforuk, *Coal Bed Worries Addressed Slowly*, CALGARY HERALD, Mar. 10, 2006, at A24; Severs, *supra* note 1; W. ORG. OF RES. COUNCILS, FACT SHEET: COALBED METHANE DEVELOPMENT: BOON OR BANE FOR RURAL RESIDENTS? (2003), http://www.worc.org/pdfs/cbm.pdf.

10. *See, e.g.*, MONT. DEP'T OF NATURAL RES. & CONSERVATION, RECORD OF DECISION: STATEWIDE COAL BED METHANE EXPLORATION AND DEVELOPMENT (2003), *available at* http://www.bogc.dnrc.state.mt.us/PDF/finalrod.pdf (approval of the 2003 environmental impact statement for CBM drilling and exploration throughout the entire State of Montana).

11. GARY BRYNER, UNIV. OF COLO. SCHOOL OF LAW, NATURAL RES. LAW CTR., COALBED METHANE DEVELOPMENT IN THE INTERMOUNTAIN WEST: PRIMER 9 (2002), *available at* http://www.colorado.edu/law/centers/nrlc/publications/CBM_Primer.pdf.

12. *Id.* at 13.

13. *Id.* at 16.

water may contain drill bit cuttings, lubricants, oil, and diesel fuel that, if improperly managed, can pollute surrounding creeks and rivers when discharged on to the surrounding landscape. In addition to the impacts from the discharge of produced water, methane migration[14] and the impact of CBM production on aquifers raise other important questions.[15] In light of the American experience, the emerging provincial regulatory regimes need to address these issues.

III. PRODUCED WATER MANAGEMENT OPTIONS

As the natural chemical content of produced water can be different in each well, the potential environmental impacts can vary at each site.[16] A regulatory framework that provides for mitigating environmental impacts from development must account for individual site characteristics. Pumping water from CBM wells to facilitate methane production has also raised questions about the impact of groundwater removal on aquifers and the potential depletion of sources of potable water for future domestic consumption and use.[17] In regard to CBM production from "wet" coals, the expense of water management and disposal is a significant factor in the economic viability of CBM projects.[18] Management of produced water disposal occurs through surface discharge, subsurface injection, or beneficial use of the water.[19] The type of water disposal approved by state regulators requires analysis of the water to determine the chemical content.[20]

If the produced water contains minerals, the water may require treatment before disposal. Regulators in Wyoming and Montana adopted different standards to evaluate the mineral content and quality of the water.[21] Surface discharge of produced water releases the

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14. VITO NUCCIO, U.S. GEOLOGICAL SURVEY, COAL-BED METHANE: POTENTIAL AND CONCERNS (2000), *available at* http://pubs.usgs.gov/fs/fs123-00/fs123-00.pdf (explaining methane migration as the process under which methane can move from a CBM well into the soil or water wells).

15. BRYNER, *supra* note 11, at 13-14.

16. *Id.* at 14 (listing some elements affecting water quality, such as sodium, calcium, magnesium, sulfate, and chlorine).

17. *Id.* at 16.

18. W. THOMAS GOEROLD, REVISED POWDER RIVER BASIN COALBED METHANE FINANCIAL MODEL (2002), *avialable at* http://www.lookoutmtn.com/Documents/NRLC_Revised_PRB_CBM_financial_model.pdf.

19. *Id.* at 14.

20. *Id.* at 25-26. The United States Environmental Protection Agency ("EPA") relies on the Clean Water and the Safe Drinking Water Acts to monitor the quality of water. If the water is determined to be saline, depending upon the mineral content of the produced water (total dissolved solids), some state regulators will require treatment of the water before surface discharge. At some sites the mineral content of the water will preclude treatment and subsurface injection will be required.

21. *Id.* at 25. Wyoming regulators apply narrative standards to evaluate water quality; however, in Montana numeric standards are used.

water along the land surface into creeks or rivers; or, if the produced water is saline, into structures such as tailing ponds or excavated pits for treatment. A United States Department of Energy report stated that allowing the water to flow along the ground surface into creeks and rivers is the "lowest cost option and results in the largest estimates of economically recoverable gas."[22] Regulators in Alberta and British Columbia are aware of the concerns of some landowners and environmental groups in the western United States about the environmental impacts arising from the surface discharge of water such as increased erosion, commingling of water of different qualities, and the destruction of wildlife habitats and ecosystems.[23] In 2004, the Governor of Montana objected to CBM development in southeastern British Columbia near Fernie, due to concerns about the downstream impact of produced water on the Flathead River that flows into the state.[24] Regulations in several states restrict or prohibit the surface discharge of saline water.[25]

Due to the regulatory requirements or, in some cases, the significant expense of storing and treating saline produced water before surface discharge,[26] the second method of water disposal frequently employed is subsurface injection. Injecting the produced water into subsurface disposal wells, insulated from groundwater, prevents the contamination of potential sources of drinking water.[27] A third water management method employed in the western United States is the beneficial use of produced water, such as diverting the water into storage for watering livestock or irrigation.[28]

IV. THE WESTERN GOVERNOR'S ASSOCIATION BEST MANAGEMENT PRACTICES

In response to lawsuits and controversies arising from CBM development in the western states, the governors of Wyoming, Montana,

22. Press Release, U.S. Dep't of Energy, Nat'l Energy Tech. Lab., DOE Study Raises Estimates of Coalbed Methane Potential in Powder River Basin (Dec. 16, 2002), http://www.netl.doe.gov/publications/press/2002/tl_cbm_powderriver.html.

23. Andrew Nikiforuk, *Coalbed Worries Addressed Slowly*, CALGARY HERALD, March 10, 2006, at A24; *see also* B.C. MINISTRY OF ENERGY & MINES, COALBED GAS: ENERGY FOR OUR FUTURE 18 (2006), *available at* http://www.em.gov.bc.ca/dl/Coalbedgas/CoalbedGas_Doc_web.pdf [hereinafter B.C. MINISTRY OF ENERGY & MINES, ENERGY FOR OUR FUTURE].

24. Scott Simpson, *Gas Drilling Plan Sparks Fight: Cross-Border Dispute Erupts Over Montana's Objections to a B.C. Bid for Coalbed Methane Development*, VANCOUNVER SUN, July 24, 2004, at G1; Andrew Nikiforuk, *BC's CBM Battle: The Montana Challenge*, LAND ADVOCATE, Sept. 2004, at 5, *available at* http://www.landadvocate.org/issues/Land_Advocate_Sept_04.pdf.

25. U.S. GEOLOGICAL SURVEY, WATER PRODUCED WITH COAL-BED METHANE 2 (2000), *available at* http://pubs.usgs.gov/fs/fs-0156-00/fs-0156-00.pdf.

26. *Id.*

27. *Id.*

28. *Id.*

Colorado, New Mexico, and Utah, sponsored an initiative to encourage the development of best management practices ("BMPs") in the CBM industry.[29] After extensive consultation amongst stakeholders including landowners, environmental groups, industry, and government,[30] the project culminated with the identification of BMPs in April 2004.[31] The western United States definition of a BMP is a "proven way of conducting CBM operations, which eliminates or minimizes adverse impacts from CBM development to public health and the environment, landowners, and natural resources; enhances the value of natural and landowner resources; and reduces conflict."[32] BMPs are voluntary industry practices endorsed by the Western Governors that do not replace the regulatory requirements.[33] The Canadian Association of Petroleum Producers ("CAPP") recently published a set of best management practices for the emerging Canadian CBM industry.[34]

American BMPs relevant to produced water focus on water management planning, protecting water quality, and the beneficial use of produced water. Members of the Coal Bed Methane Advisory Committee for the Western Governors' Association included regulators from the United States Environmental Protection Agency, the Bureau of Land Management, United States Department of Agriculture, the United States Forest Service, individual states, oil companies, environmental groups, and other stakeholders.[35] Three BMPs focus on water management planning. The first provides for the preparation of a water management plan by the CBM developer.[36] As part of the plan, developers should "consult with surface owner(s) (as well as affected water-users) early in the planning process and throughout the development of [the plan]."[37] The second water management planning BMP prompts developers to consider the following twelve factors in evaluating CBM produced water management options:

- Landowner preference and concerns

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29. W. GOVERNORS' ASS'N, COAL BED METHANE BEST MANAGEMENT PRACTICES: A HANDBOOK 2 (2006), *available at* http://www.westgov.org/wga/initiatives/coalbed/CoalBedMethane.pdf, [hereinafter BEST MANAGEMENT PRACTICES HANDBOOK].

30. *See id.* at 24-25.

31. W. GOVERNORS' ASS'N, POLICY RESOLUTION 05-24, COAL BED METHANE DEVELOPMENT 1 (June 2005), *available at* http://www.westgov.org/wga/policy/05/CBM.pdf.

32. BEST MANAGEMENT PRACTICES HANDBOOK, *supra* note 29, at 4.

33. *Id.* at 3.

34. *See* CAN. ASS'N OF PETROLEUM PRODUCERS, BEST MANAGEMENT PRACTICES: NATURAL GAS IN COAL (NGC)/COALBED METHANE (CBM) (2006), *available at* http://www.capp.ca/raw.asp?x=1&dt=NTV&dn=103407.

35. BEST MANAGEMENT PRACTICES HANDBOOK, *supra* note 29, at 24-25.

36. *Id.* at 7.

37. *Id.*

- Quantity and quality of water to be discharged
- Quality of the receiving water standards
- Environmental/ecological impacts from surface discharge
- Downstream concerns
- Economic feasibility/cost effectiveness
- Beneficial use possibilities
- Proximity to streams/ponds/reservoirs/wetlands/lakes
- Proximity to clinker/scoria and gravel deposits
- Proximity to springs
- Long-term impacts to the environment
- Protection of groundwater[38]

The third BMP provides that a CBM developer will "ensure that the capacity of the receiving aquifer is adequate to handle the anticipated volume of water to be injected" if the developer chooses to inject produced water for disposal.[39]

The western United States adopted the following four BMPs to protect and maintain the quality of water resources: (1) "establish a baseline for ground- and surface-water quality in the area where development will occur..."; (2) "provide assistance to landowners who want monitoring data, either by providing the data, or directing them to the appropriate source, such as a regulatory agency..."; (3) "understand the hydrology of the basin to determine a sufficient distance for well placement to avoid contamination of water wells and methane seepage..."; and (4) "[d]iscontinue the use of diesel fuel in hydraulic fracturing fluids injected directly into formations that contain underground sources of drinking water."[40]

A review of the current regulatory framework in Alberta and British Columbia indicates that western Canada adopted all of the above BMPs, which are voluntary practices in the western United States, as regulatory requirements. For example, Alberta prohibits the injection

38. *Id.* at 8.
39. *Id.* at 9.
40. *Id.* at 10.

of diesel fuel into formations that contain drinking water under the Environmental Protection and Enhancement Act.[41]

Alberta's regulatory framework has not addressed the beneficial use of produced water on a comprehensive basis. The United States' BMP provides that "[w]hen the landowner is interested in possibly using CBM produced water, [the developer should] provide information about options for beneficial-use and about potential problems and liability."[42] One potential problem observed in semi-arid areas of the western United States, arises from creating dependency on a new source of water. After farmers and ranchers have become reliant on produced water, at the end of the productive life of the well and the availability of produced water, they can no longer sustain their operations.

To date the only governments in Canada to consider CBM development in some detail are the governments of Alberta, British Columbia, and Nova Scotia. The next section reviews the existing provincial regulatory frameworks to evaluate the extent to which they incorporate the BMPs that the western United States has already established.

V. REGULATION OF PRODUCED WATER IN ALBERTA

Before developing their respective regulatory frameworks, the Alberta and British Columbia governments sent delegations to the western United States to investigate reported problems attributed to CBM development. Provincial regulators met with their American counterparts to discuss these problems. The Alberta Government considers CBM to be another form of natural gas and has modified legislation and regulations developed for conventional natural gas wells to regulate CBM operations. Informational Letter 91-11 indicates all statutes and regulations that apply to conventional natural gas wells will also apply to CBM wells.[43] The EUB and the Department of Alberta Environmental Protection ("Alberta Environment") are the two main agencies that regulate water produced from CBM wells. The EUB, as the main regulator of energy projects, relies on the Oil & Gas Conservation Act,[44] and Energy Resources Conservation Act,[45] to monitor oil and gas well drilling. Pursuant to the Environmental Protection and Enhancement Act ("EPEA")[46] and the Water Act ("WA"),[47] the mandate of

41. Environmental Protection and Enhancement Act, R.S.A., ch. E-12, § 148(a) (2000).

42. BEST MANAGEMENT PRACTICES HANDBOOK, *supra* note 29, at 9.

43. ALTA. ENERGY & UTIL BD., INFORMATIONAL LETTER IL 91-11, COALBED METHANE REGULATION 1 (1991), *available at* http://www.eub.ca/docs/ils/ils/pdf/il91-11.pdf.

44. Oil and Gas Conservation Act, R.S.A., ch. O-6, §§ 1-110 (2000).

45. Energy Resources Conservation Act, R.S.A., ch. E-10 (2000).

46. Environmental Protection and Enhancement Act, R.S.A., ch. E-12 (2000).

47. Water Act, R.S.A., ch. W-3 (2000).

Alberta Environment is "to ensure the water resources of [Alberta] and the environment are sustained for current and future generations."[48] Individual CBM wells may require authorizations from the EUB and Alberta Environment.[49] Ownership of all water lies with the Crown in Alberta,[50] requiring licenses to use, dispose, and divert all water in the province.[51] If there is the potential for a CBM well to produce non-saline water, the WA requires a license.[52] Alberta Environment focuses on the regulation of produced non-saline water. Saline water contains more then 4000 milligrams per litre of total dissolved solids (mg/L TDS).[53] In light of its experience in regulating saline water from conventional wells, the EUB has the primary responsibility to regulate subsurface injection of saline water.[54]

VI. NON-SALINE WATER

Alberta Environment, through the WA and EPEA, regulates the production, diversion, and disposal of non-saline surface and groundwater.[55] CBM developers must follow the application procedures specified in Alberta Environment's Guidelines for Groundwater Diversion for Coalbed Methane/Natural Gas in Coal Development, adopted in 2004.[56] The WA broadly defines diversion of water to include "the impoundment, storage, consumption, taking or removal of water for any purpose...and...any other thing defined as a diversion in the regulations...."[57] To obtain approval for a proposed activity, an applicant must provide evidence to substantiate that the diversion will not damage a source aquifer or other aquifers, and will not have an immediate or long-term impact on nearby water supplies.[58] CBM developers must apply for a permit if they anticipate encountering non-saline water in a proposed well.[59] The developer must complete and submit a preliminary groundwater assessment ("PGA") to Alberta Environment.[60] The purpose of the PGA is to collect local baseline data and identify issues

48. ALTA. ENV'T, GUIDELINES FOR GROUNDWATER DIVERSION FOR COALBED METHANE/NATURAL GAS IN COAL DEVELOPMENT 1 (2004), *available at* http://www3.gov.ab.ca/env/water/Legislation/Guidelines/groundwaterdiversionguidelines-methgasnatgasincoal.pdf [hereinafter ALTA ENV'T, GUIDELINES FOR GROUNDWATER DIVERSION].

49. *Id.* at 2.

50. Water Act, R.S.A., ch. W-3, § 3(2).

51. *See id.* §§ 1(1)(b), 36(2).

52. ALTA ENV'T, GUIDELINES FOR GROUNDWATER DIVERSION, *supra* note 48, at 2.

53. *Id.*

54. *Id.*

55. *Id.* at 1-3.

56. *Id.* at 1.

57. Water Act, R.S.A., ch. W-3, § 1(1)(m) (2000).

58. ALTA ENV'T, GUIDELINES FOR GROUNDWATER DIVERSION, *supra* note 48, at 2.

59. *Id.*

60. *Id.*

of interest to regulators and the public.[61] As of May 1, 2006, the EUB requires all CBM developers to offer to conduct baseline well testing before issuing a new well license application to drill or re-complete CBM wells above the base for groundwater protection.[62] The design of the new well testing program establishes a water quality determination and baseline before drilling proceeds. CBM developers encourage landowners to agree to test their wells; if the landowner agrees to baseline testing, CBM developers test all active water wells within a minimum 600 meter radius of the proposed drilling or re-completion site.[63] If there are no wells within 600 meters, the developer must offer to provide testing for at least one well up to 800 meters away.[64] The developer collects baseline information on the well water production capability and water quality, including bacteria, and the presence or absence of gas, including methane.[65] CBM developers must pay for the well water testing and provide the landowner and Alberta Environment with the results.[66] Mandatory testing of water wells before CBM drilling proceeds is consistent with the "Water For Life" strategy adopted by Alberta Environment; increased baseline data will improve regulator knowledge of provincial water resources and should assist in protecting the quality of water wells.[67] The developer files the sample results with Alberta Environment as part of the new water well testing information database.[68] Alberta Environment will use the database to evaluate the baseline testing initiative after six months and again after twelve months.[69] The results of the baseline testing should provide information to assist Alberta Environment with investigations when there are complaints about water contamination from CBM exploration or production activities.[70]

Developers collect baseline data to help identify any groundwater changes that may occur from CBM development over time. The PGA must contain extensive technical data, including the proposed loca-

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61. *Id.* at 5.

62. ALTA. ENERGY & UTIL. BD., DIRECTIVE 035, BASELINE WATER WELL TESTING REQUIREMENT FOR COALBED METHANE WELLS COMPLETED ABOVE THE BASE OF GROUNDWATER PROTECTION 1-3 (2006), *available at* http://www.eub.ca/docs/documents/directives/directive035.pdf.

63. *Id.* at 1.

64. *Id.*

65. WATER FOR LIFE, ALTA. ENV'T, BASELINE WATER WELL TESTING STANDARD 3, *available at* http://www.waterforlife.gov.ab.ca/coal/docs/baseline_factsheet.pdf [hereinafter WATER FOR LIFE, BASELINE WATER WELL TESTING STANDARD].

66. *Id.*

67. WATER FOR LIFE, ALTA. ENV'T, GROUNDWATER PROTECTION AND COALBED METHANE DEVELOPMENT 5, *available at* http://www.waterforlife.gov.ab.ca/coal/docs/display_handout.pdf [hereinafter WATER FOR LIFE, GROUNDWATER PROTECTION].

68. WATER FOR LIFE, BASELINE WATER WELL TESTING STANDARD, *supra* note 65, at 4.

69. *Id* at 2.

70. WATER FOR LIFE, GROUNDWATER PROTECTION, *supra* note 67, at 5.

tions of "test holes, test wells and exploratory wells, any surface water bodies, drainage courses, roads and infrastructure...[and] results of [] field-verified survey[s] of water wells, springs, and dugouts...."[71] The report must identify potential users and receptors of produced water, as well as identify and record the concerns of well or property owners about the proposed CBM project.[72] As part of the PGA, the developer must prepare a technical report that covers all aspects of the water diversion/disposal program and how it will affect the environment and stakeholders.[73] The report must include: a description of the geologic and hydro-geological conditions in the project area verified by a field survey; a description of the drilling program, including test hole and observation well locations, and drilling methods; aquifer parameters; water sample test results; gas sample test results; selected aquifer water quality sample results; an operational water management plan; consideration of cumulative impacts; a description of the water monitoring program; and a mitigation program to address environmental impacts.[74]

VII. PUBLIC NOTIFICATION

Once a developer submits an application to Alberta Environment, the CBM operator must notify the public about the project concerning the proposed diversion or disposal of produced water, which provides the public with some awareness of the proposed diversion/disposal program and the opportunity to raise concerns or submit questions.[75] If the public expresses any concerns or questions, the CBM operator is required to respond in writing to those parties directly affected by the proposed diversion/disposal program, and must file copies of all correspondence between the affected parties.[76]

If Alberta Environment approves an application, the CBM operator begins the de-watering phase for the project. The CBM operator must divert or dispose of all produced water in a manner approved by Alberta Environment—which usually grants authorization with conditions including requirements for monitoring production volumes, performing on-going water quality analyses, and monitoring water levels over time.[77] Alberta Environment may also require the operator to drill dedicated observation wells into the targeted coal zone to monitor the effects of groundwater production.[78] Thus, flexibility in the require-

71. ALTA ENV'T, GUIDELINES FOR GROUNDWATER DIVERSION, *supra* note 48, at 5.
72. *Id.* at 6.
73. *See id.* at 2.
74. *Id.* at 5-9.
75. *Id* at 3.
76. *Id.*
77. *Id.* at 3, 8.
78. *Id.* at 3.

ments for CBM development exists within the regulatory framework through exemptions from certain requirements.

VIII. SURFACE DISCHARGE

The CBM operator must apply to the EUB and Alberta Environment for permission to dispose of non-saline water onto the ground surface or into a suitable shallow subsurface aquifer.[79] Historically, Alberta does not allow the disposal of produced water above the base of groundwater protection ("BGWP") or on the surface.[80] However, if the information collected and presented to the EUB and Alberta Environment from the PGA indicates no damage to the environment or subsurface aquifers, the EUB and Alberta Environment may consider these disposal methods.[81] Currently, there are no guidelines for the approval of surface or shallow aquifer disposal—the EUB and Alberta Environment consider these disposal methods on a case-by-case basis.[82]

Saline water diversion[83] technically falls under the WA[84] but is exempt from Alberta Environment jurisdiction under the Water (Ministerial) Regulation,[85] because the EUB has the responsibility to regulate saline water.[86] In respect to co-mingling groundwater of different salinities, the EUB applies standards developed by Alberta Environment, and CBM operators must follow EUB requirements. The EUB requires developers return all saline water to the zone of origin if below the BGWP, or if not below the BGWP, to a zone deeper than the BGWP.[87]

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79. *Id.*

80. *See* Letter from Mary Griffiths, Senior Policy Analyst, Pembina Inst., to Commingling Review Res. Application Group, Alta. Energy & Util. Bd. 2 (June 12, 2006), *available at* http://www.pembina.org/pdf/publications/commingling_pembina_response.pdf (noting that "regulators in both the EUB and Alberta Environment must make every effort to ensure that...commingling [of poor quality saline and high quality non-saline water in the BGWP] is not allowed....").

81. ALTA ENV'T, GUIDELINES FOR GROUNDWATER DIVERSION, *supra* note 48, at 3.

82. ALTA. ENV'T, SURFACE WATER QUALITY GUIDELINES FOR USE IN ALBERTA 2 (1999), *available at* http://environment.gov.ab.ca/info/library/5713.pdf.

83. Water (Ministerial) Regulation, C.R.A. 205/98, § 1(1)(z) (defining saline groundwater as that water having "total dissolved solids [TDS] exceeding 4000 milligrams per lit[er] [mg/L]").

84. Water Act, R.S.A., ch. W-3, § 1(1)(m)(ii) (2000) (noting that diversion of water includes "any other thing defined as a diversion in the regulations for the purposes of this Act").

85. Water (Ministerial) Regulation, C.R.A. 205/98, sched. 3(1)(e).

86. Oil and Gas Conservation Act, R.S.A., ch. O-6, § 37(b) (2000).

87. ALTA. ENERGY & UTIL. BD., NATURAL GAS IN COAL 11-12, *available at* http://www.energy.gov.ab.ca/docs/naturalgas/pdfs/cbm/GAM_AppB3_Backgrounder.pdf Developers must follow EUB Directives 051 and 065 for deep well injection of saline water. *See* ALTA. ENERGY & UTIL. BD., DIRECTIVE 065, RESOURCES APPLICATIONS FOR CONVENTIONAL OIL AND GAS RESERVOIRS (2006), *available at* http://www.eub.ca/docs/documents/directives/directive065.pdf; ALTA. ENERGY & UTIL. BD., DIRECTIVE 051, INJECTION AND DISPOSAL WELLS: WELL CLASSIFICATIONS -COMPLETION, LOGGING, AND

Finally, the CBM operator must track, monitor, and report information on the disposal of produced water to the EUB.[88]

This review of the regulatory framework indicates that Alberta incorporated the United States BMPs for water management planning and water quality into its regime as regulatory requirements. The CBM developer must prepare a water management plan and Alberta Environment and EUB consider the twelve factors outlined in the United States BMPs before approving the drilling. With respect to BMPs providing for baseline data, Alberta regulations strongly encourage well testing before drilling approval. The Alberta regime incorporates BMPs designed to protect and maintain water quality by requiring monitoring CBM development impacts on water resources. The Alberta regime prompts developers to understand basin hydrology before authorities will approve CBM projects. To address the United States BMP aimed at discontinuing the use of diesel fuel in fracturing fluids, the EPEA prohibits the injection of deleterious substances such as diesel fuel into the environment. With respect to subsurface injection of produced water, the provincial regulatory approval framework requires an understanding of aquifer capacity.[89] Provincial regulators must consult with landowners, surface occupants, and other stakeholders concerning proposed projects prior to CBM project approval.

IX. REGULATION OF PRODUCED WATER IN BRITISH COLUMBIA

British Columbia has not seen significant commercial CBM production yet; however, wet coal zones contain CBM reserves.[90] CBM test wells drilled to date indicate that produced water may be non-saline or saline, but limited data exists as most of the wet coal projects are experimental.[91] As in Alberta, multiple regulatory bodies regulate produced water. The British Columbia Oil and Gas Commission

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TESTING REQUIREMENTS (1994), *available at* http://www.eub.ca/docs/documents/directives/directive051.pdf.

88. ALTA ENV'T, GUIDELINES FOR GROUNDWATER DIVERSION, *supra* note 48, at 8. For outlines of regulatory monitoring requirements, see Oil and Gas Conservation Regulations, C.R.A. 151/71, § 12.010; ALTA. ENERGY & UTIL. BD., DIRECTIVE 059, WELL DRILLING AND COMPLETION DATA FILING REQUIREMENTS (2004), *available at* http://www.eub.ca/docs/documents/directives/Directive059.pdf; ALTA. ENERGY & UTIL. BD., DIRECTIVE 007, PRODUCTION ACCOUNTING HANDBOOK (2001), *available* at http://www.eub.ca/docs/documents/directives/directive007.pdf.

89. ALTA ENV'T, GUIDELINES FOR GROUNDWATER DIVERSION, *supra* note 48, at 3.

90. ALTA. ENERGY & UTIL. BD., ST98-2006, *supra* note 8, at 4-2. TDS concentrations in this zone are approximately 40,000 mg/L. COALBED METHANE/NATURAL GAS IN COAL WATER WORKING GROUP, ALTA. ENV'T, FINAL REPORT TO MULTI-STAKEHOLDER ADVISORY COMMITTEE 7 (2005), *available at* http://www.energy.gov.ab.ca/docs/natralgas/pdfs/cbm/PF-WaterPaper.pdf.

91. Karen Campbell, Editorial, *Coming to Your Backyard: Coalbed Methane*, W. COAST ENVTL. LAW, Nov. 1, 2004, at 3, *available at* http://www.wcel.org/4976/30/30-02.pdf.

("BCOGC') is the main regulator for CBM operations, with functions analogous to the EUB. The Ministry of Water, Land and Air Protection, like Alberta Environment, administers permits for water production under the Environmental Management Act ("EMA").[92] While the regulatory authorities are similar, the British Columbia government, unlike the Alberta government, created legislation and a Code of Practice specific to CBM. In British Columbia, the Ministry of Environment ("ME") and the BCOGC regulate the disposal of produced water. The ME oversees the application of the EMA as it is the provincial agency responsible for environmental protection.[93] The BCOGC regulates the drilling of oil, gas, and CBM wells.[94] Although the ME and OGC both regulate produced water, the BCOGC is the main regulator, administering the application review and approval process.[95] The BCOGC employs a three-phase approach for CBM development, including evaluation, feasibility, and production. Each phase requires an application to the BCOGC outlining the plans for each phase with the following purposes:

> (1) Evaluation Phase – determine the technical feasibility of a proposed CBM project through test drilling and the collection of produced water;
>
> (2) Feasibility Phase – ascertain the commercial viability of a project through the operation of twenty to forty wells; and
>
> (3) Production Phase – establish a full-scale commercial recovery of CBM reserves.[96]

British Columbia created a Code of Practice for the Discharge of Produced Water from Coalbed Gas Operations ("COP")[97] that came into effect on July 1, 2005.[98] The legislature designed the COP to ensure that when CBM drilling produces water, the drilling companies protect the surrounding environment including surface and ground-

92. Environmental Management Act, C.S.B.C., ch. 53, § 14(1) (2006).
93. *Id.* § 5.
94. Oil and Gas Commission Act, C.S.B.C., ch. 39, § 3 (2006).
95. *Id.* § 3(b).
96. Information Letter, B.C. Oil & Gas Comm'n, OGC 04-27, Coalbed Gas Development Stages (Oct. 7, 2004), *available at* http://www.ogc.gov.bc.ca/documents/informationletters/OGC%2004-27%20CBG%20Development%20Stages.pdf.
97. *See* Code of Practice for the Discharge of Produced Water from Coalbed Gas Operations, C.R.B.C. 156/2005 (2006) [hereinafter Code of Practice].
98. B.C. Ministry of Energy, Mines & Petroleum Res., Questions and Answers: Coalbed Gas 7, http://www.em.gov.bc.ca/subwebs/coalbedgas/FAQs/CBG-FAQs.pdf (last visited Nov. 20, 2006) [hereinafter B.C. Ministry of Energy, Questions and Answers].

water from contamination.[99] During the dewatering phase, companies must determine both the water quality and quantity prior to commercial production, because these factors weigh heavily in the determination of how to appropriately dispose of or use the produced water.[100] If a company proposes to discharge produced water, it must complete baseline monitoring similar to the PGA required by Alberta Environment.[101] British Columbia restricts surface discharge under the COP to perennial streams, seasonal streams, or the ground by percolation.[102] The COP contemplates several disposal options, including beneficial use of produced water.[103] Even though re-injecting water into the formation from which it originated is the most commonly used method, other alternatives, such as surface discharge, treating the water to meet the standards set by the Ministry of Water, Land and Air Protection and then disposing of it, and beneficial use of non-saline water for irrigation, habitat, livestock, or recreation purposes are possible.[104]

The first step in the application process requires a preliminary water analysis test and the development of a receiving environment baseline monitoring program, designed and conducted by a qualified and licensed professional.[105] Results of the preliminary water analysis test must satisfy the numerical standards set out in the COP, for the following parameters: total dissolved solids ("TDS"); total suspended solids ("TSS"); dissolved chloride; temperature; dissolved oxygen; boron content (seasonal only), toxicity to fish; and toxicity to invertebrates.[106] The standards vary depending on whether the discharge is into a perennial or seasonal stream. With respect to surface discharge, the COP requires use of a ground disposal facility, the total dissolved solids in the produced water be less than or equal to two times the underlying ground water values, and the total suspended solids be less than or equal to twenty-five milligrams per liter.[107]

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99. *Id.* (noting that, "[i]f the water quality and the receiving environment are suitable, the [COP]...allows for discharge to surface streams or to the ground via infiltration"). The COP defines produced water as:

> water extracted from a coal seam or a formation contiguous to a coal seam that (a) originates 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...

Code of Practice, C.R.B.C. 156/2005, § 1(1).

100. *Id.* § 11.

101. *Compare id., with supra* text accompanying notes 60-70.

102. Code of Practice, C.R.B.C. 156/2005, § 2.

103. *Id.* § 3(1).

104. *See* B.C. MINISTRY OF ENERGY & MINES, ENERGY FOR OUR FUTURE, *supra* note 23, at 6.

105. Code of Practice, C.R.B.C., 156/2005, § 11.

106. *Id.* scheds. 1-2.

107. *Id.* § 6.

The developer must conduct a baseline environmental monitoring program at least once a year before the initial discharge.[108] If the discharge is into a stream, the program must include a survey of the current water quality, the aquatic biota and riparian vegetation community, and the current flow of the stream.[109] If the discharge is into the ground, the program must include a survey of the current quality of the groundwater.[110] A company proposing surface discharge under the COP must register and provide well information pursuant to section 4 of the Waste Discharge Regulation ("WDR") for exemption from the WDR.[111] After completing the application for surface discharge to the BCOGC and satisfing the COP, applicants must also submit information to the BCOGC for either a permit for discharge or approval without the need for a permit under the EMA.[112] Section 100 of the Petroleum and Natural Gas Act ("PNGA") may require additional approval, including approval to proceed with a scheme to gather, store, and dispose of produced water.[113] Additionally the BCOGC requires approval under section 94 of the Drilling and Production Regulation ("DPR") if the company does not re-inject the produced water into a subsurface disposal well.[114] An applicant need not submit multiple separate applications, but rather submit a single application satisfying all the regulatory requirements to the OGC. Applicants for surface disposal authorization should also be aware of the BCOGC requirements with respect to public consultation outlined in the Guideline for Approval to Dispose of Produced Water ("GADPW").[115]

The COP addresses other issues, such as: the location of points of discharge relative to sensitive-stream habitat features; erosion effects; distance from existing drinking water and irrigation withdrawal points; the required flow rate of the streams; the maximum amount of produced water that may discharged from a well (1850 cubic meters per day ("m^3/day")); and discharge proximity to drinking or irrigation water sources.[116] The COP outlines monitoring, record-keeping, and reporting of water discharge requirements the applicant must complete on an ongoing basis.[117] These include the development of programs to measure the quantity of water flow on a weekly basis and the development of ongoing environmental monitoring and assessment reports for

108. *Id.* § 11(2)(a).
109. *Id.* § 11(2)(a)(i).
110. *Id.* § 11(2)(a)(ii).
111. Waste Discharge Regulation, C.R.B.C., 320/2004, § 4 (2006).
112. Environmental Management Act, C.S.B.C., ch. 53, § 15 (2006).
113. Petroleum and Natural Gas Act, C.S.B.C., ch. 361, § 100 (2006).
114. Drilling and Production Regulation, C.R.B.C., 362/98, § 94 (2006.).
115. B.C. Oil & Gas Comm'n, Guideline for Approval to Dispose of Produced Water, http://www.ogc.gov.bc.ca/arb/arb_print.asp?aoid=49 (last visited Nov. 28, 2006).
116. Code of Practice, C.R.B.C., 156/2005, §§ 4-5, 8, 13 (2006.).
117. *Id.* § 10.

each year of discharge.[118] Approved applicants must retain monitoring and assessment data gathered for periods ranging from a minimum of five years to the entire life of the project.[119]

CBM developers should be aware that a CBM project in British Columbia might fall under the authority of the Environmental Assessment Act, either because of the length of time and rate at which the project produces water from the ground, or because of significant pipeline construction.[120] In both scenarios the Ministry of Environment could classify the CBM project as reviewable, thus requiring the company to obtain an environmental assessment certificate before proceeding with the development.[121]

There are similar provisions in Alberta. Like conventional wells, small projects involving multiple CBM wells do not require a comprehensive and costly environmental assessment ("EA") under Alberta's EPEA. Conversely, under the EPEA, an EA may be required for larger scale projects if the CBM development is of sufficient magnitude, or the Minister of Environment believes one is warranted.[122]

Pursuant to the EMA, the British Columbia government may grant exemptions from specific COP requirements.[123] Additionally, the EMA allows the government to grant variance orders for specific relief from permits or restrictions on a temporary basis.[124] When the quality or volume of produced water does not satisfy the COP standards, companies must apply for approval to inject water into subsurface formations.[125] The applicant must identify the targeted formation and structure in the injection program to prevent any release of produced water into the environment.[126] The GADPW developed by the BCOGC specifies the type of information required for an application for subsurface disposal.[127]

British Columbia legislation, guidelines, and the COP incorporate the American BMPs. CBM developers in British Columbia must evaluate how to manage produced water by considering factors such as the anticipated water quality and quantity, the cost of water treatment, the

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118. *Id.* § 12.
119. *Id.* § 14(1).
120. Environmental Assessment Act, C.S.B.C., ch. 43, § 5 (2002).
121. *Id.* § 6.
122. Environmental Protection and Enhancement Act, R.S.A., ch. E-12, § 44 (2000).
123. Environmental Management Act, C.S.B.C., ch. 53, § 138(2)(s) (2006).
124. *Id.* § 9(1)(b).
125. B.C. OIL & GAS COMM'N, GUIDELINES FOR COALBED METHANE PROJECTS IN BRITISH COLUMBIA 13 (2002), *available at* http://www.ogc.gov.bc.ca/documents/guidelines/Coalbed%20Methane%20Guidelines.pdf.
126. The regulatory authority for subsurface injection rests with the BCOGC under section 100 of the Petroleum and Natural Gas Act and section 94 of the Drilling and Production Regulation. *See* Petroleum and Natural Gas Act, S.B.C., ch. 361, § 100 (2006); Drilling and Production Regulation, C.R.B.C., 362/98, § 94 (2003).
127. B.C. Oil & Gas Comm'n, *supra* note 115.

landscape of the receiving environment, the potential for beneficial uses such as irrigation, and existing infrastructure. In addition, the regulatory framework in British Columbia more thoroughly addresses the issue of beneficial use of produced water than does the Alberta framework. The legislature intended the COP to be a work in progress and changes are contemplated. The COP 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 the COP 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 ("MAC") included in its recommendations, released in January 2006, that the Alberta Government adopt a "decision tree approach" and a "code"[128] to improve the coordination of the regulatory approval process.

X. CONCLUSION AND RECOMMENDATIONS

As the CBM industry is in its infancy in both Alberta and British Columbia, and each geological environment has unique characteristics, there is considerable uncertainty about the environmental impacts from CBM development on provincial water resources. The fact that the existing Alberta and British Columbia regulatory schemes incorporate American best management practices is encouraging and suggests the provincial governments have created frameworks to address some of the problems reported in the western United States. However, in light of the importance of sustaining provincial water resources for future generations, the current framework can improve by addressing the following unresolved water management issues:

1. The baseline data on provincial groundwater resources is currently inadequate;

2. It is unclear what the CBM development impacts will be on provincial aquifers, and what the scientifically-based volume of produced water should be from a single CBM well or multiple wells in a specific area;

3. It is unclear what the level of drawdown should be from aquifers;

4. Standard procedures and reporting requirements for sampling, analysis, and monitoring of produced water and water wells potentially affected by CBM development have not been incorporated into the regulatory framework;

128. CBM/NGC MULTI-STAKEHOLDER ADVISORY COMM., COALBED METHANE/NATURAL GAS IN COAL: FINAL REPORT 5, 7 (2006), *available at* http://www.energy.gov.ab.ca/docs/naturalgas/pdfs/cbm/THE_FINAL_REPORT.pdf.

5. It is unclear whether the current regulations governing drilling fluids, casing fracturing, and completion practices developed for the conventional gas industry are adequate to prevent groundwater contamination;

6. It is unclear whether the current practice of using untreated river water or dugout water in CBM drilling fluids negatively impacts aquifer water quality;

7. The current regulatory framework in Alberta does address the issue of beneficial use of non-saline produced water; and

8. There is uncertainty about the extent to which methane migration may be a potential problem in Alberta.[129]

Regarding the first issue, MAC recommended Alberta Environment "complete its inventory of groundwater in the province, beginning in areas that could experience intense CBM/NGC development", and the "EUB and Alberta Geological Survey [] should complete the Base of Groundwater Protection mapping project...."[130] To better protect aquifers and water supplies, MAC recommended Alberta Environment determine a "scientifically-based threshold volume for produced non-saline water below which a simplified approval under a Code of Practice for production or use of the water would apply"[131] The volume determination and adoption of a Code should increase the consistency in the standards Alberta applies and streamline the regulatory approval process. In respect to the third issue of aquifer drawdown, MAC recommended Alberta Environment clarify the existing rules concerning aquifer drawdown.[132] The fourth issue pertains to the lack of standard procedures for water sampling, testing, monitoring and reporting. MAC's recommendation to develop quality assurance and control measures should provide increased protection for provincial water resources.[133] In light of the fifth issue, MAC prudently recommended the EUB and Alberta Environment review existing regulations in the context of the emerging CBM industry to address the adequacy of regulations concerning drilling, fracturing, and completion practices designed for the conventional gas industry.[134] In respect to the sixth issue—aquifer contamination from bacteria in untreated river water or dugout water used in drilling fluids—MAC recommended EUB and

129. *See id.* at 7-10.
130. *Id.* at 7.
131. *Id.*
132. *See id.* at 8.
133. *See id.*
134. *See id.* at 9.

Alberta Environment research such environmental impact to provide increased protection for water resources.[135]

As commercial production from wet coals in Alberta has been minimal, the beneficial use of produced water is not an issue on which regulators have focused. Alberta has not defined an appropriate beneficial use of produced water; however, suggestions include irrigation, impoundments—for example, wildlife watering, recharge, or evaporation ponds—industrial use, or public and domestic use.[136] As ownership of water vests in the Crown under the WA, produced water arguably also belongs to the Crown. Wet coals have the potential to produce a significant volume of CBM; therefore, increased production from wet coals is probable. The Alberta government, in conjunction with the regulatory bodies responsible for oil and gas development, should provide CBM developers with guidance as to whether produced water can be used and, if so, under what conditions. With pending CBM projects in wet coals and the economic and environmental implications, the best policy and regulatory approach to the use of water is an important issue that Alberta must address.

Currently, the objectives listed in the WA suggest that, to give effect to the provisions within that Act, the Director must consider the water's useful purpose.[137] The Director must consider whether to grant or withhold a license for a particular water use, disposal, or diversion because of the intended use. This issue tends to arise in the context of when a company applies to divert non-saline water for an industrial purpose, as in the Capstone case.[138] Requests from CBM producers for licenses are distinguishable because those companies are applying to divert groundwater absorbed to coal that is usually saline. The Director may only need to balance the interests of multiple users in these types of diversions if dewatering a CBM formation is going to cause adverse changes to the quality or quantity of groundwater in the vicinity of the well. It would appear both the EUB and Alberta Environment are concerned about the mitigation of environmental impacts; therefore, if companies comply with the existing regulations, companies are open to propose any and all ideas with respect to how they will beneficially use produced water. This raises a number of questions.

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135. *See id.* at 27-28.

136. *See, e.g.*, H. William Hochheiser, Manager, Oil & Gas Envtl. Research Office of Fossil Energy, Presentation to U.S. – Russia Energy Working Group on U.S. Department of Energy Environmental Activities Related to Coal Bed Methane Produced Water (Apr. 8, 2003), http://www.pi.energy.gov/pdf/usrussaewg/hochheiser_cbm.pdf (last visited Nov. 28, 2006).

137. Water Act, R.S.A., ch. W-3, § 2 (2000).

138. Mountain View Reg'l Water Servs. Comm'n v. Dir., Cent. Region, Reg'l Servs., Alta. Env't *re* Capstone Energy, Nos. 03-116 & 03-118-121-R, slip op. at 1 (A.E.A.B. Apr. 26, 2004), *available at* http://www.eab.gov.ab.ca/dec/03-116_118-121-R.pdf.

One issue is whether the provincial government itself should have authority over dictating a possible hierarchy of water uses, or if this type of policy-making should be left to regulatory bodies such as the EUB, or even the Environmental Appeal Board. In Capstone, the Director balanced which license-holders should receive priority, necessitating a consideration of the intended use of the proposed diverted water.[139] Capstone's application to divert water from the Red Deer River for oilfield injection purposes were balanced against the interests of other license-holders, such as domestic or recreational uses.[140] The question remains whether the court should decide these issues on a case-by-case basis, or if the legislature should develop a more formal policy.

Another issue is whether the existing regime is sufficient to regulate companies that may eventually find ways to treat saline water economically. If the companies produce large quantities of treated water, then the Crown, as owner of all water in Alberta, is open to charge royalties for the use of the water if that company is able to sell this treated water to other users.

The Alberta government should carefully consider the MAC recommendation that Alberta Environment and the EUB develop criteria and guidelines. In light of the potential water scarcity in southern Alberta, provincial regulators should also reflect on the western United States experience in semi-arid areas.[141] This experience suggests that beneficial use of water for ranching and irrigation may not be appropriate in some cases due to the lack of a sustainable water supply.

Methane migration has created water and soil contamination problems in the western United States; therefore, as MAC recommended, Alberta Environment and the EUB should investigate this issue to understand the potential for future problems.

On May 11, 2006, the Alberta Government issued a press release in which it accepted the MAC recommendations on water, and indicated that the MAC Final Report provides a blueprint for responsible coalbed methane development.[142] Provincial government progress in the implementation of MAC's recommendations should provide a higher level of confidence amongst residents that the regulations will protect provincial water resources for future generations.

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139. *Id.* at 2.

140. *Id.* at 3-4.

141. BEST MANAGEMENT PRACTICES HANDBOOK, *supra* note 29, at 9-10 (stating "long-term reliance on produced water should not be encouraged").

142. News Release, Alta. Gov't, Report Provides Blueprint for Responsible Coalbed Methane Development (May 11, 2006), http://www.gov.ab.ca/acn/200605/1986224903061-BAA7-A9D2-840E8D7FBFCE213C.html (quoting the Alberta Environment Minister as stating "'[a] safe, secure drinking water supply is a priority for this government'").