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Regulatory and Legal Review

WABAMUN AREA CO₂ SEQUESTRATION PROJECT (WASP)

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INTRODUCTION

The WASP project aims to examine the feasibility of storing 20 Mt-CO₂/year for 50 years within 30 km of Wabamun, Alberta. Several of the science studies for this project identify issues that are relevant to a legal analysis of the project. Perhaps the most important in this context is the contribution of Ghaderi and Leonenko (2009). That paper highlights the geographical scale of the project (the saturation plume and the pressure plume) but also discusses the implications of injecting carbon dioxide (CO₂) into brines that are potentially saturated with hydrogen sulphide (H₂S), with the degree of saturation is as yet unknown. The first is important in terms of identifying the property rights and consents that a project operator might require; the second is significant in terms of the level of regulatory scrutiny (from the Energy Resources Conservation Board [ERCB]) and public concern that a carbon capture and storage (CCS) project of this nature will likely generate.

Ghaderi and Leonenko (2009) examine the number of wells that might be required to achieve the target volume and also estimate the size of the saturation and pressure plumes following injection over a period of fifty years, taking account of modelled reservoir properties, and without exceeding fracture pressure. The results of their work include the following:

- The rate at which CO₂ can be injected without exceeding fracture pressure is a more significant limitation on reaching the project goal of 20 Mt-CO₂/year than is the available pore space.
- Using single vertical injector wells with an injection rate of 1Mt/year, the saturation plume for each well will have a diameter of about 4.6 km with a pressure plume of about 65 km.
- In order to reach the target volume (1 Gt over 50 years) the authors suggest that the project would require 25 vertical wells, 8 km apart.
- Additional wells do not provide much additional injectivity after the first 15–20 wells.
- By the 50th year individual pressure plumes (as opposed to the saturation plume) will tend to merge creating a large scale pressure disturbance (hundred kms).
- Drilling horizontal wells may increase injectivity by up to 50%.

Goodarzi and Settari (2009) address the question of injectivity. They suggest that injection in the Nisku zone at or below fracture pressure is not likely to cause any significant surface heave and is not likely to have any environmental impact associated with surface deformations (at 21). They estimate that, with an injection rate of 20 Mt-CO₂/year for fifty years, vertical displacement at the surface should be approximately 2 mm (at 6). They further note that injection above the fracture pressure will have the potential to increase the well injectivity, but also the possibility of fracturing the caprock. Thermal effects of cold CO₂ injection will reduce the fracture pressure and enhance vertical fracture propagation through caprock. In light of this, and consistent with the idea of using a pilot project to enhance our understanding of CCS, the authors suggest (at 22) using variable injection rates, including injection at a higher rate than fracture pressure in order to initiate the fracture, and then use micro-seismic to measure the extent of the fracture.

This brief review deals with some of the property and regulatory issues that a CCS project in the Nisku would need to resolve. It concludes with a short discussion of crediting issues in the context of Alberta's *Climate Change and Emissions Management Act* and the regulations. The paper does not deal with liability issues.

1. THE PROPERTY ISSUES

The focus area includes large areas of private surface lands but also significant areas of private mineral titles. Private mineral titles are not evenly distributed though the study area. None of the townships have more than 50% private mineral lands. In five of the nine townships there are private mineral titles to between 16 and 18 of the 36 sections in the township (R2, T49 and T47; R3, T48 and T49; and R1, T48). The townships with the least amount of private mineral title are R3, T46 in the south east of the study area (only 2 sections) and R2 T48 (1.5 sections). There are no Indian reserve lands within the focus area although there are some Indian reserve lands (surface and mineral estate) to the south east of the study area. Based on mapping of October 7, 2008 there are significant areas of open Crown land available throughout the study area except in R3 T48 (in the northwest of the study area) where only 7.5 sections (out of 36) are open.

We do not have additional data on the breakdown of the private mineral titles. However, it is reasonable to assume that in any one section where there are private lands that the mineral title will be broken into several tracts (i.e., there will not be a single title for the entire section but multiple tracts with different acreages), and that in some cases there will be split estates as to the minerals (with one party holding, say, natural gas rights, and another party holding, say, petroleum and coal rights). In some cases these private lands may be under petroleum and natural gas leases.

There is considerable uncertainty in Canadian law as to the ownership of aquifer pore space for the purposes of disposal. There are two main possibilities. One possibility is that pore space ownership follows surface ownership. The other possibility is that pore space ownership follows ownership of the mineral title. It is also possible that ownership of the aquifer (or more specifically the water in the aquifer) may be significant given the initial importance of solubility trapping. In Alberta, formation water is owned by the Crown (*Water Act*).

American law generally awards ownership of pore space for natural gas storage purposes to the surface owner. Canadian jurisdictions have not followed this model and have preferred to recognize that pore space for storage purposes is owned by the mineral owner. Alberta amended the *Mines and Minerals Act* (1994) to clarify that natural gas storage rights are owned by the owners of the petroleum and natural gas rights (Acorn and Ekelund, 1995). However, this amendment did not deal explicitly with the use of pore space for disposal purposes of a substance that is not a by-product of hydrocarbon production (Banks et al, 2008).

In Canada, a few provinces have chosen (New Brunswick, Quebec and Nova Scotia) to vest gas storage rights in the Crown, while British Columbia has a mechanism for vesting storage rights in the Crown on a case-by-case basis. Some of the jurisdictions that recognize the possibility of private ownership of pore space for storage or disposal purposes have enacted schemes for dealing with holdout (or assembly) problems (i.e., to deal with private owners who refuse to contribute land to a storage scheme). Ontario and British Columbia offer different models for dealing with holdouts (Banks and Gaunce, in prep). Alberta has no legislation to deal with holdout problems in relation to storage projects (Acorn and Ekelund, 1995) and *a fortiori* to deal with CCS disposal projects.

Given uncertainties as to ownership of pore space for disposal purposes, and given the absence of legislation to deal with private holdout problems or any provincial legislation clarifying pore ownership rights in favour of the Crown, early CCS projects may wish to avoid private mineral lands if possible, both in terms of the spud and bottom hole location of the well, but also in terms of the projected extent of at least the saturation plume for the period of active injection. Early projects may also wish to avoid active Crown leases to avoid concerns that may be raised as to resource sterilization.

The right to dispose of a substance in Crown lands can be obtained by means of a letter of consent from the Department of Energy under the terms of s.56 of the *Mines and Minerals Act* (Bankes et al, 2008). An operator who requires greater certainty might seek to acquire a so-called Crown agreement under s.9 of that same Act (issued by the Minister with the approval of the Lieutenant Governor in Council (Storage Council Interim Report, 2008)) although arguably the section will need to be amended to cover injection for disposal purposes (Bankes, 2008: 16). In either case, the Crown can be expected to address resource sterilization issues (i.e., the potential for a CCS project or other disposal project to prejudice the recovery of other resources) as part of its decision to grant or withhold the requested consent letter or tenure.

2. REGULATORY ISSUES

Alberta does not yet have specific regulatory rules to deal with the review and approval of CCS projects. The Energy Resources Conservation Board takes the view that an application for a CCS project could be accommodated within the existing well licensing and scheme approval provisions of the *Oil and Gas Conservation Act* (OGCA) and the Board's various Directives. More specifically, the Board suggests that the rules pertaining to acid gas disposal projects are equally applicable to CCS projects. The relevant Directives include: Directive 8 on Surface Casing; Directive 20 on Abandonment; Directive 51 (on the classification of wells including disposal wells), Directive 56 on Energy Development Applications (including general consultation, well licences, and special conditions in relation to sour gas), Directive 65 on Resources Applications (including applications for "scheme approval for acid gas disposal projects) and Directive 71, Emergency Preparedness and Response Requirements for the Petroleum Industry. Most of these Directives are discussed in Zeidouni, Moore and Keith (2009) and in Bankes et al. (2008). The Board does not intend to issue a new Directive to govern CCS projects but may issue a Bulletin indicating how it intends to use existing Directives to review CCS projects (WASP meeting with ERCB, May 26, 2009). Zeidouni et al (2009) emphasize that one particular weakness of the current directives is they do not make provision for post-closure monitoring.

An applicant that proposes to drill a well to conduct tests in the Nisku to validate the hypotheses generated in this study will require a well licence (OGCA, s.11; Directive 56). An applicant that proposes to inject CO₂ or any other liquid or gas into an underground formation will require Board approval for that disposal scheme under s.39(1)(d) of the OGCA. I discuss each in turn and then add a note in relation to sour gas issues.

2.1 Well Licences

A party seeking to drill a well for either exploration (testing, evaluation) or injection purposes (see OGCA definition of "well") will need a well licence from the ERCB. Prior to applying for a well licence, the applicant must engage in notification and consultation with the affected parties including surface owners and those owning offsetting acreage (Directive 65, at 17–18; Directive 56). The notification and consultation should be designed to provide appropriate information about the proposed project and, if possible, resolve all concerns of affected parties so that the application can be dealt with administratively (routine) and without the need for a Board hearing. If the concerns cannot be resolved even after invoking the Board's Appropriate Dispute Resolution Mechanisms (ERCB Information Letter, 2001) the matter may be referred for a public hearing as a result of which the Board will issue a reasoned decision granting or denying the application. While matters set down for public hearing are frequently settled where an applicant can satisfy the concerns of a party who may be directly and adversely affected by the application, it

would not be unreasonable to expect early applications for CCS projects to attract significant public attention and a public hearing on a licence application or scheme approval application.

In addition, an applicant for a well licence must also be able to demonstrate (*OGCA*, s16) that it has the right to drill the well for the specified purpose (i.e., for disposal purposes). In the case of an oil and gas exploration well, an applicant would be expected to hold a lease and have any necessary pooling agreements in place for the rights for the prescribed “spacing unit” for that type of well (oil or gas) and target formation. Well spacing varies for different pools and formations in the province, but the default spacing units for gas and oil wells are one section and one quarter section respectively (Oil and Gas Conservation Regulations, s. 4.020). Neither the *Act* nor the Regulations specify spacing for the purposes of an injection well.

In the absence of a concept such as spacing in relation to a disposal well it is unclear how broad (geographically) an area of “authorization” the Board will require. Will it be confined to the bottom whole location of the well? Or will the area currently prescribed for an AGD project provide the model (for an AGD project the relevant area is the disposal section plus adjoining offsetting sections up to a 1.6 km radius)? Or, will it extend to the projected saturation plume or even the area of pressure influence?

Directive 56, Energy Development Applications, currently provides (at s.7.10.11) that: “Water source and injection/disposal wells do not require the acquisition of a complete DSU. A letter authorizing the activity from the mineral rights lessee or, in the case of undisposed minerals, the Alberta Department of Energy, is sufficient to demonstrate the right to produce or operate the well.” The Directive does not indicate what authorization will suffice when there is a freehold mineral title (rather than active or undisposed of Crown lands); nor is it clear that the Board will take such an approach where the scale of the solution plume will be as large as projected by Ghaderi and Leonenko (2009).

2.2 Scheme Approval

As stated above, an applicant that wishes to go beyond testing and evaluating the target formations will also need the Board’s approval under s.39 of the *OGCA* for a disposal scheme. An applicant for a disposal scheme approval must comply with the requirements of Unit 4.2 of Directive 65, which requires the applicant to provide information in relation to: (1) containment “to determine that there will be containment of the disposal fluid within a defined area and geologic horizon to ensure that there is no migration to hydrocarbon-bearing zones or groundwaters”, (2) the reservoir —to ascertain “the impact of the disposal fluid on the reservoir rock matrix, native fluid” and “address phase behaviour, pressure, and migration issues”, (3) hydraulic isolation (cross-referencing Guide 51 on well classification) – to ensure “hydraulic isolation between the disposal fluid and any other wellbores drilled into or through the disposal zone”; and (4) equity and safety (including, in relation to equity, proof of the right to dispose of acid gas in the formation and in the case of an aquifer the “disposal section and the adjoining offset sections up to a 1.6 km radius ...”; and in relation to safety, the Board will require an emergency response plan if the injected fluid contains any H₂S.) The Board can also be expected to address potential resource sterilization issues as part of its determination of whether the project is in the public interest.

In the case of AGD projects the Board chooses to specify MMV requirements, injection rates, cementing and casing requirements, logging requirements, and operating parameters (including injection pressures) in the terms and conditions of scheme approvals rather than through general Directives or regulations. The Board will likely see this as a model to use in the context of CCS projects although it would be necessary to add to existing terms and conditions for scheme approval

to provide for both a closure plan and post closure monitoring. One advantage of this approach is that it allows the Board to tailor all of the above requirements to individual projects and that it permits experimentation and learning by doing. The downside of this approach is that in the early going it does not offer much certainty to applicants. In addition, scheme approvals may well be a good method of communicating with a proponent but they are a poor method of communicating with the public about the rules for CCS projects.

2.3 Sour Gas Issue

A CCS project may give raise concerns in relation to sour gas in at least two ways. First, it is possible that the injection fluid might contain H₂S. Second, as Ghaderi and Leonenko (2009) point out, the result of introducing CO₂ into the Nisku formation (assuming the brine in the formation was saturated with H₂S or even saturated to some degree), is to sweep the H₂S to the edge of the plume and to increase the H₂S concentrations at the edge of the plume. Specifically, the authors suggest (at 25) that “simulation results indicated that injection of pure CO₂ into a saline aquifer that is initially saturated with H₂S causes the vaporization and release of dissolved H₂S into the expanding CO₂ plume. Moreover, the expanding CO₂ plume delivers all of the vaporized H₂S progressively towards the leading edge of the plume.” The authors further note that H₂S concentrations at the leading edge of the pool may reach “a significantly high concentration” which depends on the initial level of H₂S saturation.

The Board has rules to deal with sour gas wells and other facilities in several Directives including ERCB Directive 71, Emergency Preparedness and Response Requirements for the Petroleum Industry and Directive 56, Energy Development Applications. Directive 56 classifies wells for H₂S purposes on the basis of projected H₂S content, H₂S release rates and proximity to the public. The classification of the well triggers different (and progressively more stringent) consultation, notification and consultation requirements (Directive 56, s.7.4 and Table 1), special drilling requirements (*id.*, s.7.10) and may trigger the need for an emergency planning zone (EPZ) and the preparation of a site-specific emergency response plan (ERP) (*id.*, s.7.10.2). Directive 71 deals with calculating EPZs for H₂S and refers to is a software program (ERCBH2S) that calculates site-specific EPZs using thermodynamics, fluid mechanics, atmospheric dispersion, and toxicology modelling. Calculations for a well are based on absolute open flow rates. While this Directive does deal with injection wells it is possible that it may require some adaptation to be applied in the scenario contemplated. Directive 71 also creates an additional and broader area known as an Emergency Awareness Zone.¹

Board Directive 56 indicates that in preparing its well licence application “the applicant must base the category type on the maximum wellhead, cumulative drilling, producing, or completion H₂S release rate. *Applicants must review available production data and consider future production operations that may result in a reservoir originally not containing H₂S gas evolving to gas containing H₂S*” [emphasis supplied].

A project proponent will need to review carefully the implications of the work by Ghaderi and Leonenko (2009) in light of the Board’s requirements in preparing its application and in consulting with potentially affected owners and residents. There will likely be significant public concerns with respect to potential acid gas issues and applicant can expect the Board to carefully scrutinize any application in relation to this issue and to take a precautionary approach.

¹ The implications of Directive 71 for requiring the Board to give standing to request a hearing to parties residing in EPZs and PAZs was recently considered by the Court of Appeal in *Kelly v. Alberta (Energy Resources Conservation Board)* 2009 ABCA 349, October 28, 2009.

3. CREDITING ISSUES

A CCS project proponent will expect to receive credit for the volumes of CO₂ injected as part of a disposal project. In other words, the project proponent will expect the project to generate performance credits or offset credits within the meaning of the Specified Gas Emitters Regulations (SGERs). Allocation of the credit with the CCS chain as between the capture entity, the transportation entity and the storage entity will likely be a matter of commercial negotiation between the parties. While the SGERs provide the basic rules for determining who is a covered entity, the emission reduction obligations of the covered entity and the different ways in which a covered entity can meet its obligations, some parts of the scheme appear to be better developed than other parts. For example, there is a well developed procedure for developing and claiming offset credits (and protocols have been developed for enhanced oil recovery and acid gas injection projects but not for CCS projects) but the procedure for claiming performance credits is not as well developed nor transparent. In particular it is not clear how proponents should allocate responsibility for CO₂ emissions that occur between the boundary of a covered facility and injection and storage. These uncertainties need to be resolved both to afford guidance to project proponents but also to provide assurances to the public as to the environmental integrity of the emissions reduction program.

CONCLUSION

The literature (including government task force reports and the like) all suggest that it will be important for governments and regulators to establish a clear legal and regulatory framework in order to facilitate the adoption of commercial scale CCS projects. The government of Alberta (Department of Energy with respect to tenure rules and the clarification of ownership and holdout issues and the Department of the Environment with respect to crediting issues) and the ERCB (with respect to regulatory approval) have yet to establish a clear regulatory framework. This means that early project proponents will face considerable uncertainty.

Proponents may seek to manage the property uncertainties by trying to confine their projects to Crown lands. It will be more difficult for a proponent to manage the regulatory uncertainties. For the time being, proponents should follow the regulatory roadmap for AGD projects. Where the application raises issues that are not covered by the existing Directives proponents should draw these issues to the Board's attention since the failure to do so may result in delays in processing an application.

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