August 3, 2012

Quest. The Energy Resources Conservation Board approves the first commercial scale carbon capture and storage project in Alberta

By Nigel Bankes

Decision commented on:

Shell Canada Limited, Application for the Quest Carbon Capture and Storage Project, Radway Field, July 10, 2012, 2012 AERCB 008

In a long-awaited decision issued on July 10, 2012, Alberta's Energy Resources Conservation Board (ERCB or Board) approved Shell Canada Limited's application for a commercial scale CCS project (the Quest Project). The project is associated with the long standing Athabasca Oil Sands Project (AOSP) and the Scotford Upgrader where new facilities are designed to capture up to 1.2 megatonnes of CO_2 per year for ongoing injection. The cumulative stored volume is expected to be greater than 27 Mt of CO_2 over the expected 25 year life of the Scotford Upgrader. The approval is subject to some 23 conditions and, as contemplated by the scheme approval provision of section 39(2) of the *Oil and Gas Conservation Act*, RSA 2000, c O- 6 (*OGCA*), the project will only be finally approved by the ERCB following review by the Minister of the Environment who may impose additional conditions on the scheme approval.

The application to the ERCB was actually a composite application since Shell had three applications before the Board. Shell's application and supporting documents are available here (hereafter Application). One was an application under the *Pipeline Act*, RSA 2000, c P-15 for approval of an 80km pipeline to transport CO_2 from the capture facility at the upgrader to the injection site. A second application was an application under section 39(1)(b) and (d) of the *OGCA* for a scheme approval for the disposal of CO_2 into the Basal Cambrian Sand (BCS). Associated with this was an application to convert Shell's existing test (injection) well (the 8-19 well) into a Class III injection well. The application was prepared in accordance with Unit 4.2 of *Directive 065*: *Resources Applications for Oil and Gas Reservoirs* (*Directive 065*) (available here). This is the Unit that deals with Acid Gas Disposal schemes. The Board considers CCS injection projects to be a form of AGD project (see my *Mutatis Mutandis* blog here). The Board describes the application (at para 5) as an application for an approval "to dispose of CO_2 within a sequestration area of interest (AOI), located in central Alberta northeast of the City of Edmonton" and covering an area of nearly 40 townships. Although this part of the current application covered only one well, Shell anticipates that it might need to drill as many as seven additional injection wells into the BCS.

Finally, Shell applied under section 13 of the *Oil Sands Conservation Act*, RSA 2000, c O-7 to amend its existing approval for the Scotford Upgrader to allow for the construction and operation of the capture facilities

A hearing was triggered pursuant to the Board's rules because of unresolved objections from five parties (landowners) who had standing to object. No public interest group used the opportunity so created to mount an intervention (recall that in Alberta a public interest organization never has standing on its own to trigger a hearing, but can only piggy back at the Board's discretion on a hearing triggered by a landowner; see the blogs on this issue by my colleagues Fluker (see here and here) and Vlavianos (see here). Neither did the Wildrose Party, notwithstanding its continuing opposition to CCS or more especially public funding for CCS projects: see here. Perhaps the Alberta ENGO most likely to intervene was the Pembina Institute. Shell retained the consulting arm of the Pembina Institute (at para 369) (i.e. Pembina Corporate Consulting) to evaluate Shell's public consultation and communication program. This was not an effort to muzzle the advocacy arm of the Pembina Institute. Shell made it perfectly clear to Pembina that Pembina was free to take any position it liked in relation to Shell's activities (pers. comm., Shell Canada).

In the end, only three of the five parties who maintained objections participated in the hearing. One objection related to pipeline routing, a second related to the proposed injection well (800m from the owner's property) and concerns about water wells, and a third expressed more general concerns as to the effect of the project on land values for those located within the Area of Interest (AOI) of the project.

The Board identified the following list of issues with respect to the applications (at 4):

- the corporate structure of the applicant and other legal issues;
- the need for the project;
- amendment to the Scotford Upgrader;
- pipeline transmission of CO_2 to the injection sites;
- sequestration of CO_2 —containment in the subsurface;
- public safety and emergency response;
- environment and socio-economics;
- monitoring, measurement, and verification;
- public consultation, communications, and access to information;
- the public interest; and
- ongoing approval processes.

The Board decision covers close to sixty pages of text with additional figures and appendices. I will focus in this post on the following issues which are either central to the "project" of CCS (e.g. subsurface containment) or seem to be of particular legal interest: (1) who is the applicant, (2) the right to inject, (3) the concept of an area of interest, (4) proof of containment, (5) the protection of hydrocarbon production and storage interests, (6) the protection of potable groundwater, (7) the treatment of legacy wells, (8) Monitoring, Measurement and Verification (MMV), (9) the use of third party assessments, and (10), what the Board does not discuss.

1. Who is the applicant and who will hold the licences and approvals?

The Scotford Upgrader provides upgrading services to the Athabasca Oil Sands Project (AOSP). AOSP is a joint venture of Shell Canada Energy, Chevron Canada Limited and Marathon Oil Canada Limited. The applications in this case were all made by Shell Canada Limited and the sequestration leases are all held by Shell Canada Limited. The evidence further showed that the parties planned that actual operations would be carried out by Shell Canada Energy which is described in the decision (in a passage attributed to an intervenor) as wholly owned by Royal Dutch Shell.

In the end, the Board expressed itself to be satisfied with the proposed arrangements but the Board's reasoning on the point is laconic and repeatedly conflates partnership and joint venture. The Board concludes (at para 45):

> … the Board finds that Shell Canada Limited is eligible, and the appropriate person, to apply to the Board for the subject applications. The Board also finds it acceptable that Shell Canada Energy plans to be the operator of the project while Shell Canada Limited is named as licensee.

In the end it perhaps makes little difference in this particular case which member of the Shell corporate family holds the approvals. Shell in all its manifestations can be expected to stand behind the venture across all the links in the CCS chain. But that will not always be the case with other applicants for approval of CCS projects and the point might have been examined more rigorously. For example, we know that AOSP itself is a joint venture but is the proposed pipeline and the proposed injection facilities also a joint venture? I suspect so, but the Board might reasonably have examined the proposed arrangements to identify who might be the working interest participants in the various licences and approvals. This may be important in terms of liability (see *OGCA*, definitions and sections 29 – 31). The identity of the lessee (of the carbon sequestration leases) is also of some interest given the terms of the ultimate transfer of liability to the Crown pursuant to the *Mines and Minerals Act*, (*MMA*) (RSA 2000, c M-17 as amended by SA 2010, c 14). As noted in a previous post (see here) the indemnity arrangements under the *MMA* are with the holder of the agreement under the *MMA* (i.e. the lessee of the sequestration lease) which, in this case, is held 100% (at least in law if not in equity) by Shell Canada Limited.

2. The right to inject

Shell acquired the right to inject CO_2 within the area of interest from the Crown in right of Alberta under the terms of the *MMA* and the regulations (for comments see here, and here) and six carbon sequestration leases covering the entire area of the "area of interest" (AOI). The sequestration leases cover a little less than forty townships due north of the Scotford refinery, north of the community of Bruderheim but including the communities of Redwater, Thorchild, Waskatenau. There are six leases rather than one simply because section 12(1) of the regulations provides that "The area of the location of a carbon sequestration lease must not exceed 73 728 hectares." The leases are all in the same form and grant Shell the right [*not* as the Board suggests at para. 177 the *exclusive* right] to "drill wells, conduct evaluations and testing and inject capture carbon dioxide in to the deep subsurface reservoirs within the Location" for a 15 year term renewable in accordance with the *MMA* and regulations. The "Location" is described in the Appendix as the "pore space below the top of the Elk Point Group" in the interval between 783 and 1370 metres below the surface. The proposed injection wells are all within the central part of the lease block.

As noted above, the Board is in error in stating that the leases afford Shell the exclusive rights to store in the zone of influence (and as a matter and unlike a true lease of law a *profit* – and presumably its counterpart the right to dispose – does not afford an exclusive right unless so expressed). Perhaps as a matter of practice, nothing much turns on this although interesting questions might arise were the Crown to grant an overlapping lease to another party or were the

Crown to grant a lease on an adjacent block from which the pressure front extended on to the Shell lands. Shell itself certainly framed its application in "exclusive" terms. Thus section 2.2 of its Directive 65 application notes that "Shell has requested the exclusive right to drill through and store CO_2" but the Board itself cannot grant Shell any exclusive rights; that privilege lies with the Crown, not the Board.

Shell's concerns as to the nature of its rights are also evident in the following extract in which it describes the importance of determining the geographical coverage of the Area of Interest (and hence as noted above and as we shall see in the next section, the lease area)

> There must be sufficient injectivity and capacity to meet the Project objectives, assuming one or more potential CCS schemes in the BCS storage complex. Competing CCS projects have the potential to affect one another, in terms of injectivity, monitoring and liability, through overlapping areas of elevated pressure. Overlapping pressure fronts may result in each offsetting project reaching the ERCB imposed limit for bottomhole pressure … prematurely. This would result in additional wells being required to redistribute pressure, or in the scheme being closed prematurely. (Application s.2.2.2)

3. The concept of an area of interest (AOI)

Shell and the Board repeatedly use the term Area of Interest (AOI) and the cognate term zone of interest (ZOI) which is a subset of the AOI comprising, within the AOI, the overall storage complex including the various seals and baffles above the target storage formation. The ZOI is defined in Figure 2 of the Board's decision and it corresponds with the description of the "Location" within Shell's Sequestration leases (at para 117). Examples of the use of the terms AOI and ZOI in the decision are legion: see, for example, paras 22 & 23, describing where the interveners were located; paras 112 – 119 describing the geographic extent of the pore space leases; and paras 120 - 141 dealing with such matters as the location of legacy wells, oil and gas potential etc, and the geological characterization of the storage complex.

Thus it is clear that both terms are of central importance to the application and its assessment. Yet the terms are not legal terms of art and they are not used in any of the relevant legislation or the key Board Directives. The term "area of interest" is used once in Directive 65 (at s.3.2.7) but only in the context of commingling applications; and the term "area of influence" is used in s.4.1.4 in relation to Class 1 disposal wells (oilfield or industrial waste fluids.. The notice requirement for acid gas injection (sections 4.1.3 & 4.2.2) covers the area within a 1.6 km radius of the proposed injection wells. In fact (Application at section 9.3), Shell elected to extend its notification procedures to include:

1. Unit operators, Approval Holders of Schemes, Well Licensees, Mineral Lessees, Mineral Lessors with rights that lie within both the BCS Storage Complex and the modeled maximum extent of the CO_2 plume; and,
2. Unit Operators with existing penetrations within both the BCS Storage Complex and the Project Area of Interest.

Shell's application provides a good and useful discussion of the methodology and technical reasoning associated with determining the scale and configuration of the AOI but the Board's decision does not discuss that reasoning at all. Shell's reasoning turns largely on an assessment of the pressure front associated with the injection wells and the need (as the quotation in the last section "the right to inject" suggests), to protect the project from adjacent competing projects. The evidence here suggested that the CO_2 plume would vary between 440 – 2860m with a pressure front of between 4 and 30 km (at paras 167 and 171).

In any event, and for the purposes of future applications, the Board might usefully clarify, perhaps in an amendment to Directive 65, what it means by the terms AOI and ZOI and how they are to be determined for the purposes of a CCS project application. The point is important since, as noted above, the term evidently controls the geographical scale of such things as, lease configuration, the provision of notice, identification of legacy wells, geological characterization etc., and the scale (as one might expect) is much larger than that provided for cognate operations such as acid gas disposal projects.

The term AOI also bears some superficial resemblance to the term Area of Review used by the US EPA for its Class VI wells under the EPA's UIC program although EPA's definition of that term is, given the origins of its program, very closely tied to the protection of USDWs (underground sources of drinking water). Thus, the Class VI Regulations (available here) define the AoR as "The region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and displaced fluids, and is based on available site characterization, monitoring, and operational data …." A Canadian definition would not be so USDW-centric and might refer instead to the area affected by the pressure front and the area within which the applicant needs protection from potentially competing offsetting projects (important for the lease application) and the area for which the applicant must be able to present evidence of assured containment (important for the regulatory application).

4. Proof of containment

Perhaps the most important issue that a CCS proponent must address is the overall issue of proof of geological containment of the injected substances. In this case there was considerable evidence that the BCS storage complex would provide appropriate containment. The base of the storage formation is sealed by the Precambrian granite basement (at para 136) while the seals above included shales (between 90m and 22m in thickness), salt formations between 35m and 85m in thickness and an evaporite formation. The water chemistry of these shallower formations indicated that they were isolated as did evidence of pressure differences in relation to other formations. Additionally, Shell noted that a number of porous zones would act as baffles (i.e. they would restrict any vertical fluid flow since they would allow CO_2 to migrate into these zones). There was no evidence of faulting (at para 196) while there was evidence that the area has been one of relative tectonic stability over a long period of geologic time. This BCS is clearly a very favorable geological storage site.

5. The protection of hydrocarbon production and storage interests

Under section 39(1.1) of the *OGCA* (added by SA 2010, c14), the Board may not approve a CCS scheme unless the proponent "satisfies the Board that the injection of the captured carbon dioxide will not interfere with (a) the recovery or conservation of oil or gas, or (b) an existing use of the underground formation for the storage of oil or gas." The evidence showed that there was no organic material below the base of the BCS and therefore no source rock; while the BCS itself (at para 130) "exhibits no structural or stratigraphic closure as a trapping mechanism for oil or gas, and for that reason was not suitable for natural gas storage either, even though the BCS storage complex has excellent sealing capacity." Furthermore, the nearest producing hydrocarbon formation lies more than 1,000 metres above the BCS and 10 km from the storage wells. This allowed the Board to conclude (at para 180) (and notwithstanding the fact that there were existing Crown leases granting rights down to the basement as well as non-Crown oil and gas rights) that there was little prospect that anybody would apply to drill an oil or gas well into the formations in the "Location" (at para 180 and see also at paras 187 – 188). Furthermore, the evidence suggested that, on a prospective basis, the Crown would not lease oil and gas rights within the zone of interest (at para 180).

All of this allowed the Board to conclude (at paras 187 – 188) that Shell had satisfied the statutory test – although the Board does state a few paragraphs later (at para 195), "that producing fields might see a slight increase in salinity or acidity of produced fluids, but finds that their lateral and vertical distances from the injection area—the nearest field is 1000 m vertically and 10 km laterally from the injection area—render this outcome unlikely." Implicitly, the Board must be concluding that this risk is not inconsistent with the non-interference test prescribed by the statute.

6. Protection of potable groundwater

While the *OGCA* requires that the applicant establish that its proposed operation will cause no harm (or more precisely "will not interfere with") to oil and gas interests there is no similar requirement in relation to potable groundwater. I have commented on this curious statutory preference for resource interests and values over environmental values in previous posts. That said, the ERCB is clearly of the view that it has the responsibility to ensure that CCS operations will not affect potable groundwater. In this case the target formation is highly saline (311,000 milligrams/litre TDS). The Board addressed concerns as to the potential for groundwater contamination at several points in its decision emphasising, *inter alia*, the completion requirements for injection wells, the fact that there would be three layers of casing cemented to surface (at para 198), and the importance of the proposed MMV program (combined with development of baseline data including well testing within a 3.2 km radius of any injection well (at 356 - 360.)) See further discussion of the MMV program below [8].

7. The treatment of legacy wells

The CCS literature confirms that one of the principal possible pathways for leakage is posed by the existence of legacy wells within the storage complex. A working definition of a legacy well (see para 181) is an old well (since abandoned) which penetrates the proposed storage complex (in this case the basal Cambrian sands). It is clear that Shell carefully selected its injection target with a view to minimizing the number of legacy wells it would need to deal with. In this case there are only four legacy wells within the AOI and the nearest was located more than 18km from any of the proposed injection wells. The wells in question were "*owned* and licensed to" (at para 125, emphasis supplied) Imperial, Mantol and Devon Canada. Recall that as per section 29 of the *OGCA* a licensee continues to be responsible for an abandoned well (see post, "A Century of Liability …" here) but *quaere* whether such licensees retain ownership of wells for which the relevant leases have expired? See section 32 *MMA* in relation to Crown leases.) Three of the wells were abandoned between 1949 and 1955 and the other in 1978. In one case the evidence was to the effect that the abandonment left about 900m of open hole below the first cement plug (at paras and 126 & 183). However, the Board was satisfied that there was little risk of the injected substances migrating and reaching the legacy wells and even it did there was little risk that the induced pressure increases at these locations would lift the brine to reach protected groundwater aquifers (at paras 181 – 186). The Board did however indicate (at para 340) that it would require Shell to address in its annual reporting the need for additional monitoring wells adjacent to the legacy wells if a risk emerged that the plume pressure might be sufficient to raise BCS brine to the base of groundwater protection (BGWP).

It seems safe to assume that the licensees of these legacy wells did not object to Shell's proposal. If they had objected that would likely have been noted in Board's decision at the outset where it lists the surface owners who had objections. We do not, however, know from the decision whether these licensees never objected from the outset, or whether Shell was able to satisfy any concerns that they might have had. Given that an operation to pressure up formations penetrated by a legacy well increases the risk for the licensee and working interest participants in that legacy well, one might have expected that a licensee of a well within the AOI that penetrates the BCS would seek to have Shell take an assignment of the licence or to have Shell provide an indemnity to cover any costs associated with possible future re-abandonment operations. But perhaps these licensees simply thought the risk of a problem was too small given the distance between the injector and legacy wells. The decision is silent on the point.

8. Monitoring, Measurement and Verification (MMV)

Shell submitted a comprehensive MMV program for the project emphasising, as did the Board, the importance of conducting appropriate baselines studies over the next two years before injection begins. The MMV measures include three (shallow) non-saline groundwater monitoring wells for each injection well, at least three deep injection wells in the Winnipegosis formation in the upper part of the storage complex, repeated 3-D seismic to monitor the plume, and the use of InSAR a radar based technology to measure any ground deformation (ground heave) associated with the injection activities. The Board also emphasised that the MMV program needed to be adaptive (at para 333) and, in recognizing that the proposed MMV program had yet to be finalized, took the opportunity to add a number of conditions to the scheme approval and also to warn Shell that additional requirements might be imposed as the project evolved, depending upon how the injection plume performed. Some of these requirements such as the possible need for additional evaluation wells could be quite onerous. Indeed of the 23 conditions included in the Board's decision, 21 relate to the MMV portion of the report. This should not, I think, be read to mean that the Board was dissatisfied with the quality of Shell's proposal but instead as the outcome of a dialogue between the proponent and the Board in which both parties seem to be using best efforts to design an MMV program that permitted both Shell and the Board (at para 273) "to verify that actual storage performance conforms to model-based forecasts, and to trigger additional control measures to prevent or correct any loss of containment before significant impacts occurred."

9. Third Party Assessments

Shell took the unusual step of having several aspects of its application materials vetted by external assessors and filing those assessments with the Board in support of its application. On the technical side, Shell retained Det Norsk Veritas (DNV) (at paras 143 and 278) to review Shell's proposed MMV program. DNV issued a "certificate of fit for purpose." Shell also retained Oxand (at para 148) to assess the long term (200 years) integrity of injection wells. And finally, Shell retained the Pembina Institute (at para 369), Alberta's highest profile ENGO, to evaluate and provide advice to it on its public consultation and communication program. These assessments (and Shell's responses to the assessments) were presented as part of the evidence supporting its application and in Shell's words, to encourage transparency in relation to the technical aspects of the proposal (at para 143).

10. What the Board does not discuss

What is not in this decision? I will refer to two issues here: (1) the Board's discussion of liability and financial assurance, and (2) its limited discussion of the area of interest concept. I comment more briefly on a number of other matters.

The Board has very little to say about the related topics of liability and financial assurance. Indeed, the only discussion of these topics occurs at the beginning of the report at paras 33 – 40 (evidence) and paras 52 – 57 all under the heading of "Corporate Structure of the Applicant and Other Legal Issues." This discussion occurs in response to the concerns of one of the interveners who argued, *inter alia*, that the Board should defer consideration of the application until the Government of Alberta had put in place all the regulations and decisions required under the carbon sequestration amendments to the *MMA.*

The Board responded with the following assessment. First, it noted (at para 52) that Shell was responsible for the project during its operation and that as the licensee Shell "must have reasonable insurance … appropriate for the size of the company and the type of operation that the company carries out." The only evidence that the Board refers to on this point is the statement (at para 35) that the project will be self-insured by Shell. The Board provides no assessment of how this meets its own test.

Second, the Board went on to discuss its Licensee Liability Rating (LLR) Program and related Liability Management Rating (LMR) observing that Shell had an LMR ratio of over 10. But what is missing here is the Board's assessment of how the unique nature of CCS projects and the special liability rules provided for by the carbon sequestration amendments to the *MMA* (including the creation of a separate liability fund) fit within the Board's general programs like the LLR. The Board alludes to this at paragraph 56 where it discusses the transfer of liability when a closure certificate is issued but the Board might also have noted that the Fund provided for by the carbon sequestration amendments to the *MMA* can also be used to fund CCS orphan liabilities before closure.

As for the Board's discussion of the concept of Area of Interest (AOI), I have already noted above that the Board does not define this term or provide any guidance as to how the AOI was determined in this particular case. One gets the impression that the Board simply deferred to Shell's assessment of the AOI. Since, as I have noted, the determination of the appropriate AOI is crucial to much of what follows one might have expected the Board to provide a rigorous and transparent analysis of this point but one does not find it. One reason for this is perhaps the Board's conclusion (inferred on my part) that this issue had already been dealt with by the Government of Alberta (GoA) in issuing leases for the entire AOI\ZOI (see para 174). While the Board's deference to the GoA may be appropriate in certain parts of the Board's decision (e.g. its decision at para 49 to proceed notwithstanding gaps in the legislation; its discussion of the transfer of liability at para 56; its discussion of the need for the project at para 67; and its public interest assessment at paras 396 - 400) it seems less appropriate in relation to technical matters such as the assessment of the AOI. In my view (a point I have made in previous posts), the carbon sequestration amendments to the *MMA* have not helped matters here since they seem to have divided responsibility for technical assessments (especially in relation to closure) between the ERCB and the Department of Energy of the GoA.

A more technically oriented reviewer might well notice other omissions. For my part, I was surprised not to see any discussion of anticipated injectivity rates in relation to the target formation. I also expected to see some discussion of the proposed closure plan (beyond the discussion of the MMV issues) but the term "closure plan" gets only a single mention (at para 267, disclosing that Shell evidently filed a closure plan –in fact Shell included its Closure Plan as part of its updated Directive 65 application, available here). There are perhaps two reasons for this. First, responsibility for issuing a closure certificate rests (under the *MMA* and regulations) with the Minister (acknowledged by the Board at para 56), and second, Directive 65 does not currently required that a closure plan be filed as part of an AGD application.

11. A final note

In reading the decision one cannot help but be impressed with the thorough manner in which Shell seems to have prepared and presented this application and its evident concern to ensure that this project will offer a globally important demonstration of a large scale CCS project. But approval does not of course mean that the project will go ahead. Shell and its partners still have to make that business decision. Both the federal and provincial governments have committed funding to the Quest project.

Acknowledgement: Bankes' research on legal issues associated with carbon management is supported by a grant from Carbon Management Canada.