Comments [rv. 1] from S. D Hovorka, University of Texas at Austin, On Draft Accounting and Permanence Protocol for Carbon Capture and Geologic Sequestration under Low Carbon Full Standard.

Terminology on key topics is inconsistent: The 3-D volume which is to be certified as providing permanent storage should be named consistently. Is this the "storage complex"? Subdivisions less than this are confusing, for example "principle sequestration zone; "sequestration formation", "Sequestration zone" "formation", "injection" "reservoir formation". It may be useful to select one term for the permeable 3-D rock volume which will host most of the CO_2, to separate it from confining system or "dissipation" or other zones that may receive minor amount of CO_2. An "Area of Review" must be defined as an area, not a volume. It may be the surface footprint of the storage complex.

De minimus values should be set. Places this is a problem many places, for example p. 36 "any release of CO_2 outside the primary injection zone" falls in 24 hour reporting. This would seem to trigger a large number of reports for insignificant as well as uncertain events. Suggest only large releases are deserving of this 24 hour reporting requirement.

p.38. What is reasoning for specifying a minimum injection depth? In many cases (e.g. deep water table, underpressurized reservoir, or cold basin) the CO_2 will not be supercritical at this depth. Distant parts of the sequestration zone may be at shallow depths if the reservoir dips. Focus on quality of confinement will likely force sites to be deep, this prescriptive requirement is superfluous.

It might be important to ask for evidence that the storage complex is isolated from freshwater resources (that might be pumped, releasing CO_2)

p.39. "fissures" is not a widely accepted term for the deep subsurface. Better to specify "other high permeablity zones" which would capture any other transmissive features, e.g. breccia zones and fluid escape features.

p. 40 Regional hydrogeology would be better specified by asking for all available data. "groundwater flow direction, seepage velocity, and flow directions" are unlikely to be well known (see examples at http://www.beg.utexas.edu/gccc/CO2_data/Repetto_011.php and other formations)

p. 40 Should require information on if faults and fractures penetrate into the storage complex, even if they do not transect it. Should provide all data relevant to assessing the transmissivity of these features.

p. 42 This statement is not correct: "Faults and fractures that transect the confining layer (transmissive faults)." Many faults and fractures are non-transmissive. It is important to require a full assessment of potential for fault and fracture transmissivity, for example data on aperture, cements, fault gauge, local state of stress and full geometric description to support modeling of response to change of state of stress during injection.

p. 43. The "tabulation of readily available information on all saline and freshwater aquifers in the AOR" The language "readily available" and "must include" seem to be in conflict. Section 8 and 9 are not clearly distinct. It seems that 8 is a description of freshwater resources, which are protected under other rules.

P. 43. We do not recommend prescribing geochemical monitoring, because of relatively high cost and low areal coverage (Yang et al, 2015). If geochemical data are to be used for monitoring, it is important to specify dissolved gases must be assessed with control or correction for pressure and temperature effects. Free and dissolved gasses are the principal indicators of leakage and are difficult and expensive to sample properly. If geochemical species are to be used for monitoring, it is important that a site-specific procedure to separate leakage signal from background be developed. Other types of untargeted descriptive data give an appearance of completeness without adding value. Sampling saline formations is usually quite costly as well as difficult because changes in temperature and pressure will cause exsolution and precipitation, therefor if needed should be designed correctly.

Yang, C., Hovorka, S. D., Treviño, R. H., and Delgado-Alonso, J., 2015, Integrated framework for assessing impacts of CO2 leakage on groundwater quality and monitoring-network efficiency: case study at a CO2 enhanced oil recovery site: Environmental Science & Technology, v. 49, p. 8887-8898, http://doi.org/10.1021/acs.est.5b01574

p. 43. Recommend that any injection or production of fluids in or near the AOR be described and quantified. Production of any fluid creates some leakage risk (by accidental production) and the management strategy should be provided. Other injection (for disposal) should be considered in pressure and geomechanical response. Distant parameters such as production or recharge should be considered in boundary conditions.

P. 43 Recommend that any gas accumulation (even if not economic) in the AOR be described. Gas can have a negative impact on feasibility of seismic tools and other chemical and physical tools, which should be managed.

p. 44 (or elsewhere). A requirement for temperature vs depth and a hydrostatic pressure profile seems to be missing. These are useful elements in risk assessment, monitoring, and monitoring design.

p. 44 (e) (4) Subpart B and C seem to be misplaced – these are post- casing installation activities.

45 well logging. If seismic is to be used, sonic logging should be added to the suite of logs collected prior to casing. Sonic logs are valuable for interpretation of seismic data.

P. 46. Downhole conditions listed in (g) cannot be collected before well completion because the well should be filled with drilling mud until casing is completed. Downhole parameters to be collected should be specified with care based on performance-based metrics, and should also be specified for quality. For example, if formation fluid sampling is required, fluids introduced during well drilling and completion will contaminate samples and invalidate them. Purging the well by pumping until parameters stabilize would have to be required. Note that the fluid composition will be damaged also by injectivity testing. As discussed above, PVT sampling of deep basin brine to get intact and undamaged chemistry is expensive and should be based on a need. A performance-based requirement might be phrased as “data on downhole conditions needed to support monitoring and modeling design must be collected.” You could require operator to justify the sufficiency of the data collected, and that the method by which it was collected and analyzed it suitable for the purposes to which it is applied. Temperature and pressure is usually perturbed by drilling, therefore they can best be collected after well completion during logging.

P. 50 section 2.4.1,

Adding chemical properties to the model adds a high level on difficulty and computational cost. Chemical modeling is usually done separately from physical modeling, because of the number of variables involved. Because of this, most commercial CO_2 models include minimum chemistry. Chemistry is not usually critical path for accounting and permanence. Language is already present in closure section to require the operator to assess CO_2-fluid-rock interactions and determine their impact on accounting and permanence, if small they could be ignored in the AOR determination etc.

The definition of pressure front in the definitions leads to a very large area of review. Some small pressure increase will occur even very far from the CO_2 plume, this change from the current equilibrium will cause fluid to migrate out of any sequestration zone, even very far away from injection, if there was a permeable pathway. This brine migration is why pressure in the injection zone will return to hydrostatic over relatively short times. Note that migration of brine out of the sequestration zone is not an accounting or permanence problem, it is actually a necessary process because it allows capacity for CO_2 to be created. A more workable risk–based method for requiring wells to be qualified as isolating prior to injection is needed. Definition of a storage complex larger than the sequestration zone would help. Changing the threshold at which pressure increase is defined as relevant to performance or risk basis important, for example CARB could define pressure that lift fluids into fresh water, or to the surface. A related issue relevant to much of the US, likely including California, is artesian aquifers, in which natural pressure gradients exist that can lift fluids out of the zone. These are self-testing, if fluid migration prior to project start is minimal, it is likely that confining systems do not have permeable pathways, and storage should be favored. A practical approach could be to require the operator to assess the pressure changes over time in the region near the site and assess the extent to which elevated risk results, and require risk management.

It is important to qualify what is meant by “plume movement ceases” and “pressure differentials”. Stabilization is asymptotic, most of the stabilization occurs in a few years, but slight adjustments will continue to occur for 1000’s of years as shown in this figure.

Investigation of CO_2 Plume Behavior for a Large-Scale Pilot Test of Geologic Carbon 61

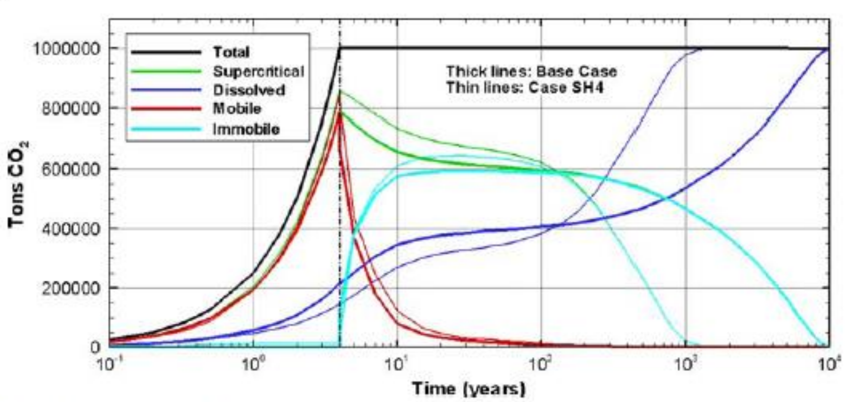

Fig. 10 Time evolution of the CO_2 mass distribution for the entire model for the base-case (thick lines) and sensitivity-study case SH4, which models the Vedder Formation as a homogeneous, isotropic sand (thin lines)

(Model of stabilization Doughty el al, 2010).

Qualification might be "plume on a trend toward a stable configuration". Because CO_2 is buoyant, if it is in a structural trap, it will always be capable of migrating vertically. Pressure equilibration is asymptotic also.

p.51 (B)(C) Expecting a model to input all the variables listed and has probably never been accomplished before in one model, and would be difficult and expensive to develop especially if it needs to be repeated and have new data added. The model should not attempt to include everything.

The accounting protocol needs to determine what model outputs are needed (evolution of the plume and pressure in 2.4.2 (7)) and require that a list of inputs "be considered". The modeling team can conduct sensitivity analysis and provided justification for the simplifications that they select, which should be specific to the site.

This section could be cleaned up by comparison to several storage models in the existing permits and the literature for example Class VI permit at ADM or FutureGen.

Approaches developed by NRAP (https://www.netl.doe.gov/research/coal/crosscutting/nrap-home) which provides model modules that can be used as needed, rather than one super-complicated model that does everything, are a best practice.

Most available geocellular models in use for storage problems are isothermal, they do not deal with heat flow.

Groundwater flow pattern would be a model output, not an input. Matching pressure response is used for calibration. Adding "chemistry" into this discussion greatly increases the level of difficulty, for no clear value.

A multi-layer model with a dissipation interval and second confining layer is very expensive in run time (we have one, it runs on supercomputer). Geomechanical and leakage models for shallower zones are best run as separate models (NRAP approach), based on an output from the injection zone.

Missing from this description is a best practice of sensitivity analysis. It is normal to qualify a model by assessing the implications of uncertainties in input data to the model predictions. For example, the hysteretic curves (relative permeability) usually require extrapolation to model scale. It is reasonable to do some model runs and determine how much impact this upscaling has on AOR and plume migration at the end of injection. The uncertainties that have significant impact on permanence should then be the targets of monitoring.

p. 54. (5) and (6). This output file definition is unclear. Models have many parameters in each cell at each time step and very large number of cells. Is CARB asking for all the data for all the time-steps dumped? Not clear how this can be done or what the agency would do with dump.

p. 56. The risk statement here is much less stringent than other occurrences, and specifies corrective action only on wells that serve as a conduit such at that CO_2 is likely to reach the atmosphere. This disregards the major leakage cases known from past injections -- wells that leak out of the injection zone and into a shallower zone. The shallower zone then accumulates fluids and leaks to the surface via different shallower wells that were not prepared for CO_2. This failure mechanism occurred at least one of Denbury's CO_2 EOR fields. All wells that might allow leakage out of the storage complex should be remediated.

Figure 5, p. 57. The work flow does not seem to assess consistently assess all the well problems. Uncased wells, like dry holes, should be evaluated for risk. Not enough cement emplaced during well construction leading to possible open the rock – casing annulus. Some wells may not be reenterable, an option to conduct surveillance to determine if they are/are not transmissive should be allowed.

p. 59, section 2.4.3.1. The statement "to the extent known" is very important, as all this information is rarely available.

P 61, (3) (1). This activity would not be "recalibration", but a prior step to modify the model input parameters. It is important then to re-do calibration against the historic data, including the recent observations of plume size. It would be wise to ask for a description of the changes made in the model and justification.

P. 62, 2.4.4.1 triggers for AOR reevaluation prior to next scheduled re-evaluation (1) through (7) are not correctly targeted. The effort to set triggering thresholds is commendable, however the trigger should be developed as part of the plan based on site-specific risks. CARB should require project operators develop and quantify triggers* that would require AOR reevaluation. Some observations that would indicate that something is wrong with the model that risks permanence would be:

A) Observed migration of the plume in any direction that is faster* than predicted.

B) Thickness of CO_2 plume much* thinner than modeled. This might indicate the "dreaded pancaking" where not all zones are accepting CO_2, and the area of the CO_2 plume in the energized zones would grow much faster than modeled. Plume thickness could either be observed in an injection well or through other monitoring.

C) A trend* in pressure increase at the injection well(s) or other monitoring point that deviates systematically from the predicted trend. An unexplained lower pressure in the injection zone is a possible leakage indicator. Operator should consider if the anomalous pressure response has a near-well (skin) origin, which is not important, or if it is an indication of unexplained reservoir response (possibly important). Deviation should be defined based on risk evaluation.

D) CO_2 leakage charging a zone above the storage complex

Other things listed are not reasons for AOR reevaluation are: temperature changes, pressure leakage above confining zone, if mitigated. MIT or well failure should not require AOR review nor should natural earthquakes.

p. 63, section 2.5.

The stated purpose of the surface and near-surface activities are to "monitor... leakage that may endanger public health and the environment" is inconsistent with the goals of an accounting and permanence protocol". CO_2 is a relatively benign substance and risk and environmental impacts from any site are likely to be small locally and in terms of global impact (e.g. Roberts et al, 2011). If endangerment is the monitoring target, HS&E approaches such as identifying receptors, for example occupied closed structures or lake ecosystems would be most protective (e.g. Loscheller et al, 2017). To be effective, HS&E concerns should be clearly separated from accounting needs so that monitoring resources can be focused properly.

Most of the near –surface techniques developed for CCS applications have been developed either for leakage detection or to attempt leakage qualification for accounting. Leakage detection applications for all near-surface applications have been consistently been challenged by 1) high CO_2 emissions from respiration in biologically active zones, 2) high daily, seasonal, lateral, and complex variability in CO_2 biologic productivity, 3) complex flow paths that cause leakage to come to surface far from the leakage point from depth (at a spring discharge point for example), and 4) complex systems that mix and dilute, take-up for Krebs cycle etc., dissolve, sorb, and react-out CO_2. These process mean that CO_2 emitted generally does not travel at high concentrations far from the emission sources. Because of low viscosity, CO_2 gas vents typically form small (m^2) areas. Combining small emission points with attenuation away from the vent mean that they are difficult to detect; even with a dense grid it is difficult to certify no leakage. Further, expected climate change and possible land use changes are likely to cause systematic shifts over time, "baseline" should therefore be used with extreme care. Erroneous reliance on baseline has caused stoppage of the Japanese injection at Tomakomai when no leakage actually occurred.

If an anomaly is observed, near surface monitoring can be quite effective in attributing the source of the gas or dissolved phases to the injected CO_2 or other causes, this can be a contribution to a GS project.

We suggest that the surface and near-surface section be revised substantively to 1) define clearly CARB's goals, preferably with probabilistic measures of success, 2) require that a plan be developed to meet these goals without prescribing the plan.

Loschetter, A., Lary De Latour, L, Grandia, F, et al, 2017, Assessment of CO_2 health risk in indoor air following a leakage from a geological storage: results from the first representative scale experiment, Energy Procedia 114 (2017) 4287 – 4302 doi: 10.1016/j.egypro.2017.03.1573

Roberts, Jennifer, Wood, Rachel, Haszeldine, R Stuart. (2011). Assessing the health risks of natural CO 2 seeps in Italy. Proceedings of the National Academy of Sciences of the United States of America. 108. 16545-8. 10.1073/pnas.1018590108.

p. 69 section 3.2 (b). Sampling deep wells has risk within it. Taking core can result in damage to the borehole and reduce the quality of cement, adding to risk. In a pioneer area, sometimes a pilot well is drilled to provide rock property data, and then the injection wells are then not cored, to maximize cement quality. In a well-known area, new core may not be needed.

p. 70 3.3 (c) "no injectate other than CO_2..." this statement would preclude using many substances used for monitoring, conformance control, optimization and repair for both saline and EOR conditions. Foam, water and chemicals to prevent salt-precipitation, mitigate near-well damage, tagged fluids to evaluate conformance. Suggest revise to say "Justify the use of any injectate other than CO_2."

p. 72, 4.1. The statement of purpose of testing and monitoring ´"to ensure that the GCS project is operated as certified and that the injected CO_2 is permanently sequestered" is a good performance based approach. Rather than then specifying what must be done zone-by-zone, a checklist of what would constitute certified, in terms of model match and leakage risk reduction to achieve the permanently sequestered goal would lead to better assurance. The burden of developing sufficiently robust site specific details should be a charge to the Operator. CARB could add requirement to provide the probability of attaining various confidence levels of permanence.

Section 4.1 (4) "periodic monitoring of groundwater quality and geochemistry above the confining layer". In this zone under static conditions, pressure monitoring has been shown in modeled and field conditions to be more sensitive to leakage than chemistry (Hovorka, et al, 2016). However, under other conditions, seismic, logging, or chemical methods may be favored. Suggest "Periodic monitoring of pressure and/or fluid composition above the confining layer. Rational for and leakage detection threshold of selected monitoring method should be shown".

> Hovorka, S. D., Bolhassani, B., Hossieni, S, Yang, C. Anderson, J. and Young, M, 2016, http://ieaghg.org/docs/General_Docs/2modmon_pres/4.1%20Sue%20Hovorka%20-%20Model-based%20costs%20for%20monitoring.pdf. Full details at https://repositories.lib.utexas.edu/bitstream/handle/2152/40309/BOLHASSANI-THESIS-2016.pdf?sequence=1

Section 4.1 (9)

Tracking the dissolved plume is very difficult. This to my knowledge has only been done successfully at one project, Nagaoka, under special conditions of low salinity and non-conductive research casings. This likely cannot be duplicated in other projects in more saline settings. Model assumptions likely overpredict the dissolved plume area and therefore are conservative, and should be sufficient to serve the purpose of this protocol.

"track" is a rather non-technical word choice. More technical language could assure better performance e.g. "collect quantitative data on CO_2 saturation distribution and pressure that will validate the correctness of the model predictions of pressure and CO_2 plume distribution". Could add accuracy and probability-specification requirements to this to make this more robust.

4.1 (10) "Surface air monitoring and soil gas monitoring to detect potential movement of CO_2 in the shallow subsurface or atmosphere". This part of the monitoring plan could be easily done, because ecosystem monitoring is a mature field, however it will provide biologic data and does not require the operator to accomplish the goal "to ensure that the GCS project is operated as certified and that the injected CO_2 is permanently sequestered". Site- and risk -specific suitability of these methods should be critically assessed though modeling based on site-appropriate parameters to determine if the techniques can be effective to meet the goal. CARB should incentivize selection of tools that can be shown to be effective.

4.2 (c) The frequency of taking the well out of service or pulling packer and tubing for logging or MIT should be balanced against increased risk from the activities themselves. Entering wells can increase likelihood of loss of control or damage the well by creating even scratches that can focus corrosion and increase the chance of propagating microannulus, and possible damage to injectivity if fluids contact the sandface. If a corrosion management program with coupons shows low risk and the tubing-casing annulus is pressurized and monitored (as in 4.3.1.3 (d)) to determine that both casing and tubing are isolated and holding pressure, MIT and logging may add little value. CO_2 injection wells have shown few failures. Suggest that CARB focus effort on surveillance of other wells penetrating storage complex. Other wells, such as monitoring, production, TA, P&A, and wells completed in deep intervals will each present a different risk. Rather than specify a program for each well type, suggest that CARB require operator to provide a program and specify how it will reduce risk to desired thresholds.

p. 79 (b) (2) recommend against routine downhole shut-off valves, unless well location has a very high HS&E risk. Most loss-of-well-control incidents occur during well-entry operations, such equipment would not be helpful and might hinder recovery on control. This installation would not help abate risk from other wells that penetrate the injection zone. HS&E damage from blowouts have been modest. Preparation of a plan to reduced frequency and severity of blowouts would be more protective than excessive and duplicative equipment.

p. 80. In EOR, the injectate will combine newly supplied CO_2 and recycled CO_2. The composition of both should be provided to support correct accounting as well as modeling. Sampling immediately upstream of downstream of the flow meter is not clear, as there may be multiple meters at different locations. Better phrasing might be "justify that the samples are representative of the fluid streams and suitable for use in accounting and fluid-flow modeling."

4.3.2 (b) Statement of *no* emissions from sequestration zone is not attainable because 1) some emissions will occur, even as part of monitoring itself (for MIT or sampling), 2) measurement of zero is not attainable. This statement should be modified to "measurement of emissions from *sequestration zone* with an estimate of measurement accuracy and precision." Does CARB really want emissions to air? Or outside of storage complex?

4.3.2.1 See above "plume tracking" discussion. What is really needed is confirmation of model predictions of 100 year permanent storage. CO_2 saturation is a model-match parameter. The extent of the plume is usually weaker than a center-of-mass calculation. Performance-based requirement would be tied closely to a probabilistic model activity, and confirm that the observations support an acceptable match with the model, and that *plume and pressure responses leading to elevated leakage or other risk are probed by monitoring and confirmed to be not developing*.

The list of tools is very conservative and is already out of date, given breakthroughs in DAS, fixed sources and receivers etc. Is it possible to require evaluation of the current best available technologies? An estimate of the site-specific quality of detection should be required, otherwise CARB is likely to get reports of we saw nothing, so everything is great.

Should consider in tool selection how well out-of-storage-complex CO_2 migration will be detected. This is likely more important to achieving protocol goals than a beautiful history match.

4.3.2.1 (b) timing should not be related to baseline, this make no sense. Timing should be "as required to confirm that the observations support an acceptable match with the model, and to determine that plume and pressure responses leading to elevated leakage risk are probed by monitoring and confirmed to be not developing."

4.3.2.1 (c) (3) this is trying to say Electrical Resistance Tomography (ERT)? Might be misunderstood as resistivity logging, which is not ready for steel casings.

Wireline-based saturation logging should be considered a basic tool, it is the workhorse of model-matching. Must have sonic logs and VSP in combination with 3-D to back out saturation.

Gravity should maybe be considered a basic.

4.3.2.1 (d) An estimate of the site-specific quality of detection should be required for any of these pressure-plume detection methods. Very important to consider noise, e.g. impact of groundwater withdrawal/recharge on surface tilt.

4.3.2.2 Our work consistently shows that near –surface monitoring does not perform well in detecting leakage from depth. This is based on extensive work on natural releases, controlled releases, and field work on non-leaking sites, lab experiments, and models. Key issues:

> 1) even if a pathway is present from depth to the surface, migration time may take centuries to reach the surface. Leakage is greatly attenuated and retarded by geosystems.
>
> 2) Noise from CO_2 activities in ecosystem is high, complex and variable, both masking leakage signal and causing a large number of false positives

Best investment in monitoring leakage out of the sequestration zone or storage complex is at depth, where a) signal is high and fast and 2) noise is low.

We suggest that site-specific near-surface monitoring tools should be designed and a plan for deployment prepared in case of loss incident or allegation that fluids have leaked. The plan should be based on baseline characterization and it should be able to quickly identify leaked fluids and separate them from ambient non-leaked CO_2. Tools should be ready to map and quantify any losses and provide input to the remediation plan.

One of the much-desired uses of near-surface monitoring is being ready to quantify any observed loses from earth systems to atmosphere. Readiness to conduct such an assessment should be considered.

Suggest overall, the protocol should require that contributions that can be made to storage permanence from near surface monitoring should be evaluated, and most effective applications for site-specific conditions be deployed.

The tools listed do not include current best practices, such as CO_2 to fixed-gas ratios, stable and radioactive isotopes, better sensitivity because of trace gas signal, and remote unmanned deployments.

Experience suggests that periodic re-evaluation of the monitoring tools should be done at as least as high a frequency as AOR reevaluation. CARB should require that recent improvements in technology be evaluated.

4.3.2.3. Seismic monitoring has key components missing. For example, the design of the array should consider the seismic risk. Location of small events can be helpful in risk reduction, but sufficient planning is needed to collected data. The array should be calibrated with check-shots, preferably at depth.

p. 95, Section 5.2 (b) (2) The 100 year duration of storage is assured by a robust calibrated model, based on long time scales typical of geologic processes. It is not conjectural.

The CCS technical community has not considered tools that could be used over 100 years post closure. It is not clear how 100 years of monitoring data can be used to further improve a robust model, or be effective in detecting previously unimagined failure.

p. 95, Section 5.2 (b) (C) leaving idle wells open for 15 years is a serious risk in itself because of unmanaged geomechanical and geochemical disequilibrium. Idle wells must therefore be subject to various serious MIT and corrosion inhibition programs. A risk/benefit assessment should be done at high frequency. Consideration of using injection wells as monitoring points should be allowed.

p. 95, Section 5.2 (b) (D) Groundwater sampling is not the tool wanted here. Expensive, error prone, and environmentally damaging because of the need to purge and dispose of brine. If the point is to wait for CO_2 breakthrough, the most sensitive tool is wellhead tubing pressure rate-of-change. When CO_2 displaces water in the tubing, the change in density of the fluids will provide a sharp change in slope at the wellhead pressure gage. Wireline saturation logging could be effective, as it could be done within the CO_2 plume. This type approach will be needed to observe stabilization in trap. A definition of stabilization in risk context is needed, as some readjustments are sharp in early time and then continue over centuries at a slow rate. Note that pressure equilibration depends on boundary conditions, an all-way closed volume may show excellent "stabilization" by remaining high pressure, whereas an open aquifer with decrease pressure sharply at first and then slowly over decades.

p. 95, Section 5.2 (b) (E) the suitability of geophysical methods to documenting stabilization should be critically assessed in terms of assisting model match. Note that the thin edges of plumes are likely poorly detectable, other or advanced approaches should be required, via a sensitivity analysis under site-specific conditions. Model match, not direct observation, should form the basis for assessment of stabilization.

p. 95, Section 5.2 (b) H) We do not recommend soil gas on well pads. If leakage occurs, flow may be retarded by the compacted surface, and therefore occur at the pad margin. The well head should be cut off at P&A, so no surface air monitoring should be called for. If there is remaining concern about a P&A or open well, operators sometimes build a closed –top box over it, and sample to see if subsurface fluids build up in the box. This is cheap, durable and sensitive. Focus should not be on injection wells, but on any poorly–known historic wells for which fluid column pressure might the change the leakage risk profile.