5TH WELLBORE INTEGRITY WORKSHOP

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INTERNATIONAL ENERGY AGENCY

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ACKNOWLEDGEMENTS AND CITATIONS

The IEA Greenhouse Gas R&D Programme supports and operates a number of international research networks. This report presents the results of a workshop held by one of these international research networks. The report was prepared by the IEA Greenhouse Gas R&D Programme as a record of the events of that workshop.

The fifth international research network on Wellbore Integrity was organised by IEA Greenhouse Gas R&D Programme in co-operation with T. L. Watson & Associates and Alberta Research Council. The organisers acknowledge the financial support provided by T. L. Watson & Associates, Alberta Research Council, Cemblend Systems Inc. Doull Site Assessments Ltd., Spectra Energy, Oxand, Schlumberger, and RPS Energy for this meeting and the hospitality provided by the hosts Delta Calgary South Hotel, Calgary, Canada.

A steering committee has been formed to guide the direction of this network. The steering committee members for this network are:

Bill Carey, LANL (Chairman)
Walter Crow, BP
Toby Aiken, IEA Greenhouse Gas R&D Programme
Idar Akervoll, SINTEF
Mike Celia, Princeton University
Rick Chalaturnyk, University of Alberta
Stefan Bachu, Energy Resources Conservation Board
Theresa Watson, T. L. Watson & Associates
Neil Wildgust, IEA Greenhouse Gas R&D Programme

The report should be cited in literature as follows:

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Summary Report of 5th Wellbore Integrity Network Meeting

Date: 13 – 14 May 2009
Delta Calgary South Hotel,
Calgary, Alberta, Canada.

Organised by IEA GHG, T. L. Watson & Associates and Alberta Research Council.

With the sponsorship of:
T. L. Watson & Associates, Alberta Research Council, Cemblend Systems Inc. Doull Site Assessments Ltd., Spectra Energy, Oxand, Schlumberger, and RPS Energy.

FIFTH WORKSHOP OF THE INTERNATIONAL RESEARCH NETWORK ON WELLBORE INTEGRITY

Executive Summary

The IEA GHG Wellbore Integrity Network has been running for 5 years now, and the meeting in 2009 was held in Calgary, Canada. The attendance for the meeting covered the usual mix of industry, academia, research and regulators, but there was a noted increase in attendance from industrial companies. This was demonstrative of the local area that the meeting was held in, with a large number of oil companies working in the surrounding province.

This increased industry representation moved the discussion sessions to areas previously not addressed, or only addressed in brief outline, and this is indicative of the progress of the meeting and its continued worth. A possibility for the future of the network will be an alteration in its role, from pure research into wellbore integrity, materials and abandonment procedures, to one of education of industrial operators, and the broaching of the gap between experience gained from the oil and gas industry, and the needs and demands of regulations relating to CO_2 Capture and Storage (CCS) operations.

The format of the meeting allowed for short 20 minute presentations, with allocated time for questions, and also for prolonged discussion sessions where ideas and experiences were discussed at a greater level of detail. These discussion sessions are the primary focus of this report, and the presentations are available on the network webpage for reference. The meeting also encompassed thoughts for the future direction of the network, and the final session split the delegates into 3 breakout groups to discuss possible content for a status report to be issued by the network.

Presentations covered 4 areas; risk and regulatory environment, field studies, remediation and leakage, and modelling of wellbore processes. The facilitated discussions followed each session, and generated insightful debate amongst participants.

Again, the level of involvement that continues in these meetings demonstrates the continued relevance of wellbore integrity as a topic for investigation, and the gradual transit between research biased to industry experience is an important step in moving from research to demonstration.

Contents

Session 1: Introduction

1.1 Welcome and Introduction, Toby Aiken, IEA GHG.

The workshop was introduced by Toby Aiken, and as the delegates included many newly represented countries and individuals, the introduction commenced with a brief explanation and history of the network.

This meeting will look to the future, addressing the questions of what should be set as the objectives for the next few years, and how the network should be developed. A brief safety announcement was covered by Theresa Watson, and an additional introduction was given by Bill Carey in his role as Network Chair.

Bill reiterated the focus on the future, and urged delegates to think about the future during the course of the presentations and discussions to follow. Looking at the big picture, we need to determine how researchers focussed on wellbore integrity can make quantitative, confident predictions on how wells will perform in the long term in the presence of CO_2, and how can the Wellbore Network contribute to this process. These meetings are attended by delegates from all over world, with top researchers; how do we make a difference? We have the people, the knowledge and understanding necessary, so we need to work out how to turn this capacity into an effective contribution.

Session 2: Risk & Regulatory Environment for Wellbore Integrity, Chair: Walter Crow

2.1 Well Blowout Rates and Consequences in California Oil & Gas District 4 from 1991 to 2005. Preston Jordan, LBNL

This presentation addressed frequency of well blowouts, which in this context are seen as any uncontrolled or unplanned leakage event. Consequences of blowouts relate to the level of leak and the time passed before detection; a quick detection will result in lower consequences. A limitation of the data set is that events with comparatively low leakage rate are often taken care of in the field, and therefore they are not necessarily reported.

Recent newspaper reports included details of a fairly major blowout that wasn't reported by the regulatory agency. This is seen as another illustration that the more consequential the blowout, the more likely to be included in released figures. Graphical analysis shows a definite trend in blowout occurrence and frequency decreasing from 1991 to 2005, while over the same time period oil production doesn't show the same reduction. This suggests that improvements in engineering solutions or management practices over the corresponding time period have improved.

Data can be represented in terms of blowout frequency per operation[1], blowout rates according to well usage basis[2], on a fluid basis - i.e. how many blowouts per given volume of fluid injected.

Follow-on work is planned on the same methodology and analysis in Texas, where blowout patterns are much more erratic and less well understood.

Question:	Is there any noted correlation between blowout occurrences and well abandonment methods?
Answer:	No correlation was noted, but timescale analysis noted a pattern in failures occurring predominantly on either first stress event (first injection), and at the end of life. This wasn't analysed on a well-by-well basis, so no categorical conclusion can be made here.
Comment:	A comment was made that deeper drilling practices in Texas could be of relevance and lead to more peaks in blowout rates.
Comment:	Many sub-surface blowouts can lead to surface blowouts following migration along the fracture line instigated by the initial sub-surface blowout.
Question:	The rates suggest blowout occurrences are approximately 1 in 100,000 wells, per year; to qualify this, how many total abandoned wells are in the district?
Answer:	Not totally sure, but certainly 10's of thousands. The manner of reporting occurrences statistically means that the relevance of total number of wells is limited.
Comment:	A comment was made on the definition of "blowout" to include any uncontrolled release. This could include any process ranging from what in other contexts are called Sustained Casing Pressure (SCP) to major industrial accidents.

2.2 CO_2 Storage – Managing the Risks of Wellbore Leakage over Long Timescales, Olivier Poupard, Oxand

The context of this talk was aimed at how to demonstrate integrity and long term confinement to authorities in order to facilitate permitting of storage operations. Operators will need to be able to illustrate the extent of knowledge of wellbore leakage causes and processes, as well as an understanding of mitigation needs to address leaks.

The Oxand P&R™ approach is a risk based approach covering probabilities and likelihood of events according to many different factors. It provides a global overview of the risk associated with specific sub-systems of the wellbore (casing, shoe, external annulus), while defining acceptance levels facilitating determination of project feasibility.

Effectively Oxand's approach gives a one-stop option for risk assessment with specific focus on wellbore integrity. The system includes modelling of flow in a wellbore system, and case studies

[1] A potential limitation here is that no distinction is made between short and long term operations, casting the benefit of this statistic into doubt.
[2] From this it is possible to determine the relative importance and impact of usage to blowout rates.

shows the application of the approach to an abandoned well, and incorporates cement quality through wellbores as a factor for the probability of leakage.

Question: Does the simulation take into account interface pressures, and does it look at release to the atmosphere in relation to US EPA concerns over gas return to atmosphere?

Answer: Pressure conditions are taken into account, and the ‘maximum limit’ conditions are used for the modelling process.

Question: The presentation slides indicated complex reactions in the model, but the model only used a 2-phase flow approach. What was the level of complexity used in the modelling?

Answer: The project researchers developed a system which considers 2-phase flow, and also models the corrosion processes present at the different elements. The corrosion modelling is based on simplified models, which are derived from more detailed models which can provide information on the macroscopic kinetics derived from pH, pressure and temperature conditions.

2.3 Qualitative and Semi-Qualitative Risk Assessment Methods to Evaluate Potential CO_2 Leakage Pathways through Wells, Claudia Vivalda, Schlumberger

This presentation from Schlumberger looked at the limitations that can be encountered in the early stages of the project life-cycle; data is often not present, time to perform a risk assessment is often lacking as well; however despite these potential barriers, the order of magnitude of the results is often sufficiently indicative to provide an assessment.

The methodology described in the presentation uses experts’ judgements to assess the quality of the wells sealing capacity, and the potential for CO_2 leakage, together with an analysis of the impact on specified targets, i.e. geosphere, atmosphere and other areas.

In the process for defining methods to determine and identify leakage pathways, experts are used to identify potential pathways, including looking at how pathways occur and can be formed. The second method involved the experts filling in a risk register, looking at specific hazardous events at specific elements of the wellbore system. A risk register classifies whether an element or fault can or can’t be part of a leakage pathway, and this in turn identifies leakage pathways that are likely to have an impact on the storage integrity.

Question: Were the consequence tables established before the assessment, or with input from the expert panel?

Answer: The tables were set up before, so a potential issue or limitation of the assessment could be that the outcome is predetermined by rankings, levels and probabilities. The tables can ‘precondition’ experts to think along given routes.

Question: In relation to the term ‘severity’, severity relates to impact on a given consequence category. Did the study only look at health, safety and environmental impacts or also on technical performance issues as well? Also, if the expert judgement is relied upon too heavily, there could be difficulties in convincing the general public of the validity of the judgements based on relatively few experts.

Answer: All impacts are considered, not just health, safety and environmental. Although there could be issues with public perception, assessments are currently being completed to gain a technical understanding; this is the 1st step, and other steps will follow for public perception.

Question: Would this analysis be completed on every well in a project?

Answer: No, an assessment would be made based on well categories, and some common sense must be applied to the well groupings.

2.4 Regulatory Practices in Alberta, Tristan Goodman, ERCB (Energy Resources Conservation Board)

Next came a high-level presentation describing how Alberta regulates oil and gas operations including acid gas disposal. The role of the ERCB is to determine what operators can and can't do within the Alberta province. This involves gathering information from many sources before making decisions. The ERCB is neither pro- nor anti- development as resource conservation focuses on not wasting resources. This can be explained by utilising alternative energy supplies or uses for wastes such as reducing the amount of gas flared from oil production facilities by using the separated gas for other purposes.

ERCB is looking at transport and storage aspects of the CCS chain, but also incorporates EOR activities. ERCB currently regulates CCS (defined as permanent disposal of CO_2) under the existing acid gas regulations. The regulations currently focus on depleted oil and gas fields, with some smaller focus on aquifers, but with the overall aim to contain CO_2 in the subsurface.

Question: Will regulations be prescriptive?

Answer: Good question, they are currently at least semi-prescriptive, and working with operators, and although the ERCB would like the regulations to be fully prescriptive, that would involve a lot of work to develop from the current position.

Question: The government have suggested that the state will *never* take liability, with the view that if the risk is as small as stated, then the operator can retain the liability.

Answer: This is a good point; the regulator wouldn't make the decision on whether the Government of Alberta would accept liability. The process in place would be to ensure that the public purse doesn't get hit with huge liability costs. There are currently set ups that can help with this, such as the orphan well fund.

Question: The presentation indicated 12 permanent disposal wells: what differentiates this?

Answer: This should be clarified as internal data; it is not going to be used elsewhere. It is an internal marker, and refers to acid gas wells with high CO_2 content.

Question: Does the current regulation consider wells above a proposed or active storage formation?

Answer: Yes, the questions still outstanding are based around how far above, and a research team is currently working on this on a case by case basis. When more information is held on file following operational applications, then specific numbers may be drawn into regulations.

2.5 Well Abandonment Practices Study, Tjirk Benedictus, TNO, & Neil Wildgust, IEA GHG

Tjirk was unable to attend the network meeting, and Neil gave the presentation in his place. It reported the work of a recently completed IEA GHG-funded study on well abandonment techniques and practices, and the regulations that influence them around the world.

Comments were made regarding the wording of some of the comments in the report; the report suggests that recompletion of abandoned wells is unfeasible, and many participants contradicted this. In Canada and the USA, if the wells are on land and of known location, then recompletion is quite a common practice. In the USA, some examples exist of recompletions having been successfully performed on wells up to 70 or 80 years old. The comment would be more accurate by stating that in some circumstances, recompletion can be uneconomic. This suggests that if the situation and economic factors change, a recompletion could become economically feasible.

The survey that was distributed by TNO was not well returned, and suggestions were made that the questions could be reformulated and the questionnaire redistributed in order to obtain more responses, making the data gathered more valuable and defendable. To achieve this, the questions should be more closely focussed.

Concerns were also raised over the suggestion of venting as a method to mitigate leakage. This should be clarified further to stipulate that this would be a safety measure rather than a viable mitigation option. Also, pressure reduction should be emphasised as a preliminary measure before resorting to venting.

It was also commented that in some countries, well abandonments are classed as temporary, and some of these still have wellheads in place. Remediation of these wells could therefore be a much cheaper and simpler option than drilling new wells.

2.6 Facilitated Discussion, Session 2

Shell's decision not to proceed with storage in the De Lier field in the Netherlands (cited in Tjirk Benedictus' TNO presentation) is an example of the abandonment of a storage site due in part to difficulty in quantifying risks of wellbore leakage. The abandoned wells in question were cased and cemented over the proposed storage interval but lacked a cement plug protecting against flow through the internal annulus. The likelihood of wellbore leakage may be quite low, but uncertainty about the long-term behaviour of the wells led to rejection of the site. Shell abandoned plans for CO_2 storage at this site because of uncertainty and high cost of fixing the wells. This is an example of what we don't want to happen.

The problem was not with the wells or the abandonment methods used as such, rather that the wells were plugged and abandoned with the wellheads capped at a depth of 3 metres below the surface, in a location subsequently subjected to construction, and many wells are now under the foundations of residential and industrial properties. It is therefore not possible to re-enter and recomplete these wells without relocating the properties and buildings, and it is this aspect that is considered uneconomical. Another aspect of the excessive costs involved, was that the proposed storage layer was above the plugging levels of existing wells. Subsequently all plugs would have needed re-assessing and relocating to the desired depth.

Comments have been made about the risk assessment process looking at the worst case scenario, but the usage of 'worst case' in this instance is wrong. The worst case scenario would be a slow, undetectable leak to groundwater leading to mobilisation of heavy metals into underground sources of drinking water (USDW). If blowouts occur, they are readily detected and can be fixed, so in many ways, they are not 'worst case' scenarios.

A question was fielded at this point regarding the workshop held by IEA GHG and BGS in September 2008, and it was clarified that this workshop focussed on impacts to ecosystems, rather than impacts on water resources.

Discussion next moved to address what processes are being followed to verify models. It's easy to state that with the correctly identified procedures being followed everything will be fine, but we need to be able to verify this. Theresa Watson described a predictive tool that TL Watson have developed, that identifies wells that could be susceptible to leakage, and during the summer of 2009 there will be a project investigating the wells identified as high risk by this tool, and ongoing field work will monitor the wells for gas movement.

Alternatives to predictive tools are experimental methods whereby models are used to predict well performance, and then stress tests are undertaken to verify these predictions. This is a severe method of verification and is unlikely to be widely used due to the extreme nature of the tests, and the associated risks involved.

Models currently exist without verification, so the logical next steps are to put in place monitoring strategies to verify the in-situ behaviour. Costs can be avoided by reducing the monitoring / verification process to 1 well per field, but this wouldn't give a large amount of data. A possible solution would be random sampling in order to provide larger, more representative data sets. Other suggestions include re-entry of old wells and installing monitors, perhaps with the aim of forcing a leak to prove monitoring and verification, although this is another extreme measure.

Another issue to be addressed if we are looking to prove storage over long periods of time is the ability to have faith in the deployed monitoring equipment to last for the duration needed. If tools suffer break down or malfunctions after 5 years, then the verification process will be severely hindered, with costly redeployment involving increased risk. There is a need to develop credible monitoring system to verify models, and system behaviour needs to be determined over phases, including operation and closure. This will allow benchmarking against verified models. The overall performance of the storage system needs to be determined as the physics and geomechanics are understood, so combining these aspects into a 'whole-system' analytical tool would be a beneficial activity.

Another issue for future consideration is that of the potential for monitoring equipment installation to put the well at a higher risk than before installation. Monitor installation can cause cement integrity issues, and this challenge must be overcome. One potential way to get around this would be further development of enhanced surface monitoring methods. Alternatively, the cause of failure could be due to installation practices, and maybe improved installation methods could remedy this.

It was discussed that of the large repository of information available, expert analysis provides a non-destructive perspective, and we are not using all of the expertise available at this time. We have knowledge and data of failed wells, and generally these are mitigated or repaired. Perhaps tests should be undertaken to determine the cause of the failure, and this information can then be used as a learning tool. The initial data from failed wells can then be provided as input criteria for the models as a verification process; will the models predict the failure that were known to occur?

At this point, it was highlighted that conclusions should not be drawn from small samples, and as much data as possible should be combined to generate most accurate results as possible. Taking a step back and looking at the high level numbers, it is known that in Alberta there are between 10,000 and 20,000 known well leaks out of more than 350,000 wells. If it can be demonstrated that this can be detected, this number could be used as the basis to perform a risk analysis. However, some of the presentations given this morning describe well leakage rates of 1 in 100,000. This figure is several orders of magnitude different from the Alberta figures, which could suggest there are more failures in fields that haven't been detected. Qualification of definitions is necessary in order to determine what classifies as a leakage, and this would then need to be used uniformly in order to allow data comparison and compilation across reporting regions.

Session 3: Field Studies of Wellbore Integrity, Chair: Stefan Bachu

3.1 SACROC: a Natural CO_2 Sequestration Analogue in Wellbore Cement Integrity Assessment, Barbara Kutchko, NETL

This presentation described the use of the SACROC site as an analogue for CO_2 storage, while at the same time trying to broach the gap between field and lab work that has been undertaken around the world. It was explained that lab experiments were aimed at simulating the injection of CO_2, and monitoring the alteration that occurs.

The conclusions went some way to explaining the differences noted between laboratory and field samples, highlighting the complexities involved with the history of the field samples general trends, which could in turn be used to predict how cement will react in different circumstances. Experimental results were presented that replicated two distinct types of cement-CO_2 reactions: distinct reaction fronts with formation of barriers to further carbonation as observed at SACROC, and uniform and relatively rapid penetration of CO_2 at a CO_2 Capture Project field site in a natural CO_2 gas field. The agreement between laboratory and field results provides increased confidence that we can understand and quantify the impacts of CO_2 on wellbore materials. The presentation concluded with preliminary experimental results on the combined impacts of H_2S and CO_2 on cement integrity.

Question: Has any work focussed on the impact of injected steam on wellbore steel?
Answer: Not yet, but hopefully future research will address this.
Question: What is the source of iron in the experiments?
Answer: It seems to be derived from cement, but as yet this is unconfirmed.
Question: The presentation reported data on hardness; were any other aspects addressed such as permeability?
Answer: No, the carbonation zones were too small so no measurements were taken.
Comment: Regarding the presence of H_2S; some areas have H_2S dissolved in the existing brine, and some experiments show that this will dissolve into the CO_2, so the result will be acid gas, even if not originally intended.

3.2 CO_2 Capture Project Results from Buracica, Brazil, Walter Crow, BP

This presentation included some preliminary observations from a well integrity survey in an EOR field in Brazil. Immiscible injection began in 1991 at a relatively low rate over a series of 7 injector wells. A line of water injectors were also used to prevent gas breakthrough. The overall aim was to look at the results of 12 years of CO_2 exposure on the well materials.

The experiments and presentation placed a heavy emphasis on the interfaces as it is felt that they present potential migration pathways in all of the samples that were taken. Samples show very limited cement alteration or interaction with CO_2; however the duration and quantity of CO_2 injection was limited. This was despite the fact that the cement-caprock annulus contained abundant filter cake. The steel present in the wellbores was also found to be in good condition, showing little corrosion.

Question: Were you surprised by the differences between the bond log and the filtercake recovered?

Answer: The objective was to obtain data sets, so the variances were not as relevant, although this will possibly form the basis of future work. This could be an opportunity to test other tools in similar situations.

3.3 Salt Creek EOR Experience, Ken Hendricks, Anadarko

The Salt Creek project is an EOR operation that will eventually store 40Mt of CO_2 over the project lifetime, anticipated to be 30-40 years. The operation as a whole has 4000 wells, 70% of which were drilled prior to 1930. Due to this age range, the materials used throughout the wellbores are varied, and many could pose problems to the operation. The wells illustrate a variety of plugging methods, including telephone poles in some early wells which proved to be highly inefficient.

The presentation gave a good description of the challenges that can be encountered when dealing with older wells, many of which have no cement whatsoever. As a comparison to the report from TNO, regarding re-plugging feasibility, of the 1200 wells worked over at this site, 600 were re-plugged, so re-plugging is feasible in this situation.

Question: Are you allowed to inject without packers?

Answer: Yes, but this has only been permitted recently.

Question: Regarding the wells drilled pre-1930, what percentage is expected to leak?

Answer: A high pressure water flood has been in use since the 1960's, and the majority of problems occurred from wells that weren't already identified, so on this basis it is difficult to suggest a percentage.

Question: How much H_2S was found?

Answer: Very low quantities.

Question: What is the cost differential between conventional and fibreglass completions? There is approximately a 25-30% cost saving.

Question: What is the expected end of field life and does everything need plugging and proving before handing ownership to the federal authority?

Answer: The field life is approximately 30-50 years, and the second answer is that it's in the interest of the operators to perform remedial work, and although no issues are expected, they will do what is necessary.

3.4 Results of Wellbore Integrity Survey at Weyburn Canada, Rick Chalaturnyk, University of Alberta

This presentation gave a good overview of a large amount of data that has been obtained on wellbore properties at the Weyburn site, and described data mining operations that could be used to investigate correlations between wellbore properties and performance. The dataset that has been created can be queried in various ways and permutations, giving a very valuable tool for risk assessment and statistic generation.

Question: How will you handle uncertainties in the database?
Answer: Any uncertainties will be highlighted in the database, but they will be dealt with by the use of models.
Comment: It was not realised by all delegates how much information was available from historic well files. The information came from 4 sources of files, but there are likely to be errors in the original forms, so it is possible that the quality control could be an issue. It was also pointed out that while data entry error is possible, any entries that are incorrect by an order of magnitude are not possible as the database has inbuilt controls to prevents such input.
Question: Is the ultimate goal to enter data on all 3700 wells?
Answer: The database will only take that which is available digitally; so although it is anticipated that the database will hold more than the initial 80 wells, it will not hold data on all 3700.

3.5 Measuring and Understanding CO_2 Leaks in Injection Wells: Experience from MOVECBM, Matteo Loizzo, Schlumberger

ECBM is not a topic usually covered in the wellbore integrity network meetings, so Matteo gave a brief description of the processes involved, and described the experience gained through the MOVECBM project. The presentation included some simple definitions and explanations, for example that a micro-annulus would be smaller than a human hair, and full of fluid or gas.

The presentation went on to explain the modelling that was undertaken for the project, and concluded that various pieces of evidence suggested that CO_2 flow through the cemented annulus was present in one of the wells, and that wireline technologies available now are able to understand, predict, monitor and control CO_2 flow through an micro-annulus.

Question: In the wet CO_2 environment in the micro-annulus, do you see evidence of casing corrosion?
Answer: Corrosion logs were taken, and no corrosion was identified.
Question: The conditions look suitable for hydrogen entry into the steel, is there any evidence of this?
Answer: The pH doesn't drop below 5 until carbonation occurs, so this was not registered.
Question: Regarding the hydro-fracture procedure, was this performed down the casing or the tubing?
Answer: It was performed down the tubing, which avoided exacerbating the situation, however the pressure wouldn't have been great enough to exacerbate problems anyway.

3.6 Effective Zonal Isolation for CO_2 Sequestration, Ron Sweatman, Halliburton

Ron Sweatman described the main concerns that Zonal Isolation attempts to overcome, including the dissolution of cements damaging the annulus seal, leaks through damaged annuli, USDW contamination, detrimental impacts on flora and fauna at the surface and unabated greenhouse gas emissions.

No questions followed Ron's presentation.

3.7 Facilitated Discussion, Session 3

Discussion commenced with the question of: Can the CCS community afford to perform the research and data mining for all the potential CCS fields? It would be extremely expensive, and there would be questions regarding the quality of the data when it is known that some data isn't reported or recorded. In reality, it probably wouldn't be possible as the cost would be prohibitive. A more realistic approach would be to learn from that which has been done and extrapolate to other fields.

Next, the discussion moved to the definition of a well failure; it is frequently discussed, but conflicting figures reported suggest that maybe there isn't one strict definition being used across all research activities The differences shown in figures reported relate to variations in the definitions; the 1 in 100,000 reported in the morning session was related to abandoned wells only, and the sustained casing pressure (SCP) reported in the Gulf of Mexico is not always resulting from injected gasses, so can't be used for a direct comparison. There are acid gas operations where a hole will be drilled to release gas from depths of 20 metres, and under some classifications this qualifies as a leak, but there are some who think that this should not be recorded as such. Presentations and discussions continually talk about leakage rates, but without a clear definition of a leak. Additional clarification is needed regarding data from the Gulf of Mexico where SCP in the annulus is reported as up to 60%, but these wells can have 5 annuli so it is unclear which one has the leak, if it's the internal annulus then it's likely to be a tubing issue.

It was suggested that if the maximum flow is 800 tonnes per year (as per the ECBM example) does this represent a significant flow? This would depend greatly on the individual situation, method and other factors. Impacts of permeability and pressure are difficult to define as the link is not direct, but they do have related effects. Generalised 'acceptable limits' may have to be expressed as ratios to injected gas volumes. The question of leakage is important, and these workshops seem to continue to meet, discuss issues, and not generate definite results. It is understood that regulators will not accept leakage, so it is necessary for operators and researchers to generate the answers. Session 6 will look at generating a synthesis report on the current state of knowledge on wellbore integrity issues, and this could be encompassed into such a report.

At this stage, delegates representing industrial operators expressed the opinion that many delegates seem concerned about predicting leaks, even when there isn't a recorded history of leaking wells. Industry operators have always focussed on building wells that don't leak, and then fixing them if they do. It is widely accepted that industrial practices can do this, so why is there so much focus on predictive modelling?

This was countered by the fact that public opinion of CCS operations is focussed on leakage, so it is the responsibility of researchers to demonstrate the ability to predict, prevent, and mitigate leaks. As industry can do this, it appears that the difference is due to the materials involved. Carbonic acid is reactive with cements, but moist CO_2 isn't. This is the key difference. The impact of pressure increases exerted on depleted fields is also important, and if we look to over-pressurise reservoirs, then we need to allow for the fact that these are situations that haven't happened before. It is accepted that at initial reservoir pressure, there won't be issues, but as soon as operators want to exceed reservoir pressures, as will be the case of deep saline aquifers, they will be in new territory, and the situation may have potential problems.

Participants accept that one of the key aspects of wellbore integrity is that we have the technology and capability to fix leakage when they occurs; but we are looking to be proactive rather than reactive, and we also need to transcend the scientific knowledge to public acceptance, and this is the bottom line.

If we want to inject into a reservoir with 10,000 wells, we need to make the assessment to go in and deal with the wells that need addressing. Why do we model? If a problem occurs in 100 years, do we fix it or live with the situation? Modelling comes in here, and we need to try and work out what the future will look like and fix it now (proactive), rather than when it happens (reactive). If we build good wellbores, with a long life, then we shouldn't have problems. History shows us that we can deal with these issues, and we can design future wells to avoid such issues, but abandoned wells are widely recognised as the key problem. We need to prove to the regulators that storage will be safe and secure, and modelling can demonstrate our understanding of this. Scale is also an issue that requires addressing; all the active EOR operations take CO_2 from the equivalent of 9 power plants, and CCS will be required to deal with a much greater volume, in total there are thousands of power plants, so we need to upscale massively.

The discussion then moved on to the topic of micro-annuli, and whether there is a concern that the micro-annulus leaks discussed in CCS may occur in EOR operations as well, as it appear that regulators have not taken steps to address this in EOR. The volumes involved in EOR are negligible, so operators kill the well, fix it and go back to business as usual. In Alberta, the situation is different in so much as there are small methane leaks that are relevant; if a well leaks at the rate of 1 bubble in a minute, then it must be remediated before it is abandoned.

Most leaks have been recorded as less than a litre a day, so if this is what is being laid down by regulators for methane emissions, what will they demand for CCS? The angst is caused by the lack of motivation for fixing wells when the field is depleted and storing CO_2, there won't be anyone to go back and remediate it as there will be no profit based motivation to fix it. Regulations could form the motivation, if the regulations require remedial responsibility, and this would replace the financial motive. If a company is paid to store as much as possible, as quick as possible, and is not paid to monitor and detect leaks, it will undermine the operation.

Another question that was opened for debate and discussion was whether a well that performs adequately today will be a problem in the future. If an operation includes a well that isn't leaking, can operators be confident that these wells will continue to perform to the same standard; the level of confidence in this must be demonstrable.

Determining leakage rate is similar to an economic evaluation as it determines the cost of remediation for a project. Not convincing regulators will equate to no permits for CCS being granted, so research must address the ‘missing links’ to allow demonstrative predictability. This generates a question for the Monitoring Network; in the USA a Mechanical Integrity Test MIT is required before injection, so operators are unlikely to approach regulators and suggest more stringent testing. In order to get a permit, operators need to be able to confidently predict where the CO_2 will be retained. As soon as it leaves this area, it can still be classed as ‘stored’, but it is outside of the expected location, and this could be classified as a leak. Further complications occur when considering the potential for the CO_2 to be where it was expected, but the initial brine being displaced.

Pressure effects of injection into reservoirs must be determined, as the importance of this could be high. In oil and gas reservoirs, operations are unlikely to exceed the initial reservoir pressure by significant levels, but operations injecting into aquifers will exceed the initial pressure conditions by design as there is no initial production phase before the injection phase.

Finally, the discussion moved to the economic impacts of leakage. A DOE study suggested that 0.01% of leakage on a global scale would make the entire CCS option unviable as a greenhouse gas mitigation option. This seems unrealistic as it is not realistic to assume operations will continue to lose that amount on a yearly basis, negating the validity of the scenario.

In the underground gas storage industry, operators are required to make a full assessment twice a year. This assessment must check all reservoir conditions. Changes in pressures can reflect leakage, so accurate monitoring of reservoir pressures will show leaks if they occur.

There is a need to be able to address brine displacement. If brine migrates from the initial storage area, interacts with a poorly abandoned well in an adjacent formation, migrates along this well and then interacts with USDW this would be a problem not involving CO_2, but due to CO_2 injection. Operators need to be able to predict the occurrence of this, and prepare against it.

The US EPA area of review states a 10 yearly review with the need to remediate any leakage within 30 days of detecting it. However, operators must first remediate everything within the area of influence. If models show migration outside of the 1st area of review, then operators will probably have to review more frequently. If anomalies are detected outside of the area, then the area must be extended, and all additional wells within the new area must be remediated.

Session 4: Wellbore Remediation, Leakage and Alternative Practices, Chair: Theresa Watson & Mike Celia

4.1 CO_2 Injection Well Conversion and Repair, Mark Woitt, RPS Energy

This presentation described new well conversion approaches to creating CO_2 injection wells by enhancing wellbore integrity. Cements are not included in this as they have been covered in previous presentations, and discussion sessions and are implicitly understood. The design or set-up of the conversion process can play a major role in maintaining wellbore integrity, and the same criteria can be used for repair as and when risk assessments deem it necessary. Cements ability to resist CO_2 attack is secondary to the ability to obtain a good initial bond with the casing; if annuli exist then leakage pathways exist for migration and prolonged cement attack.

Question: Looking at the 78 Alberta wells, and the statistical difference in the converted wells to those built for purpose; if the best practice on conversion is so good, why is there a noticeable difference in performance in built for purpose wells?

Answer: Money – conversions are not the best practice.

Question: Do these conversions work best vertically or horizontally?

Answer: Better performance in achieved in vertical wells, but depending on the severity of the dog-leg, it may not be possible to rotate cement injection apparatus in the horizontal section. Experience suggests that the horizontal cementing section is not as crucial to the wellbore integrity.

4.2 Use of Alternative Cement Formulations in the Oilfield, Don Getzlaf, Cemblend

The presentation described a brief history of cement variations used in order to discover the formulation with the highest resistance that can be used in wellbores, without entailing excessive costs. The origin of the work is based on early development of phosphate-based cements by Argonne National Laboratory, in their work on storage of nuclear waste.

Some cement experiments used 2 parts oil to 1 part cement and the resultant cement does set, and this has been used to experiment further with the disposal of drilling fluids, which is an issue, so creating the cement with the drilling fluids can kill two birds with one stone. The bond testing of these cements gave good results, with 3-5 times better bonding than with ordinary Portland cement blends.

Question: What is the price difference?

Answer: The remedial market is more expensive, but in the primary market, they are very competitive.

Question: Is the mixing process similar to conventional Portland cements?

Answer: Slight differences, but reusable materials mean that batch mixing up front is a good idea, and can have knock on benefits.

Question: What is the viscosity like?

Answer: It starts thick, thins through pumping, but then thickens up again if it is kept moving. There seems to be a large interest from industrial practitioners as something they would be interested in utilising.

Question: Are there any comments on the acoustic properties for bonds?

Answer: An ultrasonic cement analyser is usually used, but this doesn't work in this situation as there is no Portland present. The water ratio is sometimes down around 25% so it should provide very good bond logs, however these haven't been completed yet.

4.3 Micro-seismic Studies Revealing Leakage Pathways, Marco Bohnhoff, Stanford University

This presentation reported on the detection of CO_2 leakage along a wellbore using remote seismic methods. The techniques used demonstrate that both P and S waves have shown very good performance in locating and identifying leakage pathways. The results have been repeated for the purposes of verification.

Question: Can the data be used to estimate flow rate?

Answer: At this stage, this has not been considered. This cannot currently be done, but possibly will be investigated in the future.

Question: Cause and effect correlation related to leaks from EOR formations suggest that shutting the injection wells shouldn't have the immediate effect shown. Is there any other explanation?

Answer: The signal is instant, so there is a fair certainty that it is not the injected CO_2. The pressure signal generated through injection allows upwards migration of previously injected CO_2, so when injection was shut off, this pressure wave vanishes resulting in the immediate detection of seismic changes.

Comment: Having worked with the same company, 18 months ago a well was drilled on fracture patterns, and seismic data interpreted 1 year before showed enhanced porosity along similar lines as is shown here. Also there was no evidence of CO_2 in well array so how can this be classed a leak? The tool is not used for determining leakage, rather for identifying the flow pattern. Millions of wells are in existence, and this could lead to the production of a regulation that would seriously hinder operations. Caution is advised before this conclusion is openly put forward.

4.4 Long Term Sealing of GHG Sequestration Wells, Homer Spencer, Seal Well Inc.

This presentation, titled 'A Convenient Truth' describes a new methodology for sealing wells for long periods of time using an alloy material.

Field tests have been carried out on fusible alloys injected into wells in order to seal against certain types of leaks. The alloy is a Bismuth / tin alloy. There are 4 materials in nature which expand when transforming from a liquid to a solid state and Bismuth is one of these materials. This property means that when a solid mass is lowered into a well and heated to 137^oC, the material becomes liquid and infiltrates all perforations before returning to solid state and increasing in volume to completely seal the well.

The durability is also very good, with negligible corrosion even in solutions with a pH of 3 suggesting that this alloy will resist corrosion for upwards of 10,000 years. The seal achieved against clean steel is in fact up to 5 times stronger than seals generated with Portland based cements, and it can also be squeezed to the extent where it can be forced into permeable formations to perfect a seal.

Question: What is the associated cost of this outfit compared to conventional methodologies?

Answer: It is similar in costs to the sealing of existing wells, other than the milling of the casing. Less than $10,000 per well could be a guide figure without the milling.

Question: The plug has good seal, but when the alloy expands adjacent to the rock face, does it crack the rock face, therefore creating a pathway up the interface?

Answer: No, this has not been detected, but further experiments would be wise. It's not expected due to the nature of the reactions.

4.5 Experimental Assessment of Brine and / or CO_2 Leakage through Well Cements at Reservoir Conditions, Brant Bennion, Hycal

Core-flood experiments were presented on CO_2 and brine flow through synthetic wellbore systems with manufactured micro-annuli and cracks. The experimental conditions used for the described process were among the worse conditions likely to be encountered in order to give results as realistic as possible. Many experiments are performing in 'best case scenario' conditions, but this is not necessarily realistic.

Question: Have you compared or calculated the flow in micro-annulus?

Answer: The flow calculations were based on classic Darcy flow, assuming that the cross sectional area was used in the equation. Just using the micro-annulus area itself gives a different range of much higher values.

Question: What pressure was the pH measured at?

Answer: 20 MPa at normal conditions.

Question: What was the confining pressure?

Answer: The internal pressure was 14 MPa, with 24 MPa external pressure to ensure there was no slipping

Question: Did you look at the chances of annular cracks from temperature variations?

Answer: Not in these experiments, all conditions were isothermal, but in the field, this would be an issue. The idea was to take out external factors in order to get a good picture.

Question: Did you see any indications of opening / closing of cracks?

Answer: No, experiments ran for short time periods, so these weren't identified. This may be looked at in future if funding is available.

4.6 Impact of CO_2 on Class G Cement, Static and Dynamic Long Term Tests, Francois Rodot, Total

The aim of this experiment was to make sure it was understood whether old and new wells encounter problems or not, as this will be necessary for commercial CCS operations. CO_2 was never detected outside of the plug, so the plugging was deemed to have been effective.

Question: How much uncertainty was there in the mechanical statements, as it was odd not to see deformations due to stresses?

Answer: There was deformation, but the results presented here are limited and brief.

Question: Mechanical properties are shown as averaged, but any changes would be extremely local, so average values may not show them. It is therefore possible that these figures should be viewed as un-reliable.

Answer: It wasn't understood at the time, exactly what was occurring. With small perturbations of the cement, it is logical that it may be overlooked, and some results did not show variations with other injected species.

Question: Many experiments have covered this, and there seems to be interesting aspects in the results showing the carbonation apparently stopping after a week. What is the mechanism for the blocking of carbonation? How can this be explained against other experiments showing different results?

Answer: Very acidic conditions can give rise to different results, but using pure CO_2, you see what happened here. This was done at a specific pressure and temperature, so it is possible that this could account for the variations from other results

Question: Was the CO_2 refreshed and how much volume of sample was used to each volume of water?

Answer: The CO_2 was changed every time a sample was taken.

4.7 Facilitated Discussion, Session 4

The discussion commenced with the session chairs expressing the opinion that it was a good sign that there was an increased focus on remediation techniques, and it is also good to see potential solutions being presented on restoring caprock functionality. A query was directed to the representatives from RPS Energy regarding the solutions presented for situations with no annular integrity; was it purely a conceptual idea or has it been applied in the field? RPS Energy representative confirmed that is was not purely a conceptual idea, but one that has been applied in the field at numerous applications. There are no specific CO_2-EOR applications that they are aware of, but the solutions have been used for zonal isolation for other instances. It has been in deployed in EOR applications, but not CO_2-EOR.

Another question was directed to the Hycal representative, asking whether any corrosion was seen with the calcium chloride mentioned in the presentation. It was confirmed that there was some evidence of corrosion on the injection face of the bar, but once the samples were sectioned, no specific evidence of corrosion in the annulus was present. It was a de-oxygenated system which also tends to minimise the corrosion. Other experiments have taken place which specifically looked at the extent of corrosion.

A challenging question addressed to those who specialise in micro-seismic technologies regarding the overall hydraulics of the system was proposed: why do you get such a rapid response in terms of pressure propagation? No answers were forthcoming on this, but it is possible that no feasible answer can be determined. A related question was asked regarding the origin of the signal being detected, there is a suggestion that something is happening along the wellbore. Was the communication completed within the EOR layers of the formation, and is it possible that the signal noise detected originated from the phase transition of the CO_2? Responses suggested that it was unlikely that a gradual change in density of the CO_2 phase could produce such an acoustic signal, and regarding the hydraulic communications, unfortunately constraints regarding proprietary data limit the detail that can be given at this stage, but it can be stated that the monitoring wells saw no CO_2 despite perforations. It is possible that the perforations were not at the CO_2 level, so discussions and investigations are ongoing.

Discussion remained on this subject with questions about the source of the signal. The experimental procedure did not consider this, but post experiment analysis suggested a shear slip event (induced seismicity), isotropic processes, or a single force source. The data exclude the first 2 options, indicating the single force source as the likely option. The exact manner in which this occurs has not been determined, but further experiments are being planned. It is possible that it is the same process as that which occurs below volcanoes, but this can't be checked. The increase in volume triggers an increase in the fluid filling the crack, and such signals have been modelled by certain groups, where synthetic seismograms are relatively similar to those obtained from the field.

Models were used to simulate the effects of cessation of injection on the propagation of pressure, and some results show it can be quick within a few metres of the wellbore, whereas at a distance of 100 metres, it may take several days for the pressure to drop. At still larger radii, pressure can continue to rise before a drop is seen as the fluid continues to move after injection ceases.

The discussion then moved to the subject of initial reservoir pressures, prior to hydrocarbon extraction. In Santa Barbara, California, historical data show that natural seeps are extensive. There are suggestions of further off-coast drilling to extract these remaining reserves to avoid them being released as they now are. From this, we can determine that reduced reservoir pressures have still not prevented seeps, so re-injecting into these reservoirs could make issues associated with wellbore integrity a moot point. Also, remediation of wellbores that are found to leak is much easier that remediating natural occurrences.

Information presented on new or novel materials are promising, and it appear that that some of the new materials could work very well if operators can get them into the wells. If these new materials and remediation strategies are as effective as they suggest, the need for this network could be greatly reduced, however this is unlikely as new technologies generally take much longer to prove themselves.

Questions still exist over the durability of these options. The short term assessment appears to demonstrate effective plugging, but in a storage scenario we need to be sure of effective plugging over geological time periods. Can we extrapolate from 4 years of results to centuries of adequate performance or are more extensive tests required? How can claims of 10,000 years of storage security be substantiated? These questions are difficult to answer, and it is likely that more research is needed in order to substantiate such claims. Issues associated with pure corrosion can be measured and validated by corrosion testing with the correct instrumentation and these extrapolations can be accepted as realistic due to the environment in which the testing occurs. In pure mechanical terms, the Bismuth plugs have advantages over conventional plugs, even in areas subject to tectonic movements, as it is not brittle, so it is less liable to stresses than cement plugging materials.

There are materials in nature that have existed for 10,000 years, and could therefore be looked on as analogous. The inverse of this argument is that although apparently 'perfect' plugs and seals may exist, other reports of equal technical standing show Portland based cements as performing equally well, providing installation is carried out in accordance with best practice.

Discussions also brought up the view that going and fixing leaks when they occur is not a problem. But greater understanding of why some systems leak more than others requires further research. With a better understanding, operators can design better systems, and this will in turn reduce the number of leaks, thereby arriving at an acceptable system for operators, regulators and the public alike.

So what is the best way to improve understanding?

- Laboratory experiments,
- Models, and
- Observations.

Of the first two options we have a reasonable knowledge of already, but observations are distinctly lacking. There are some, but not enough. With more observations, it could be determined whether abandonment failings are more common than cement failings. This is probably not the case, but without more extensive observation data, this cannot be determined.

Despite having numerous remediation methodologies, which can be used at various stages of the project life, and having numerous techniques for abandonment, there is still the possible for corrosion of the casing material, which would subsequently jeopardise the abandonment technique used inside the well. Research and development is needed to work on best practices for the whole system, where we don't rely on casing or some other metal component to be there in the long term.

At this point, it was suggested that in general, the application of plugs is not great. Plugging at the level of the caprock leaves up to 100's of metres of open casing. A preferable practice would be to cement all the way to the surface, but this is not economically feasible. It is recognised as effective, but at the same time, too expensive. A balance between the two extremes is probably necessary, whereby cementing is continued further than the caprock, in order to avoid the possibility of CO_2 migrating in stages, through overlying strata and wells, so a balance of costs versus safety must be determined.

Another related issue is the verification of plugs placed in the past. The challenge is to identify very slow rates of leakage and the placement of plugs could help to identify the conditions below the plug, and then operators could work out how to identify slow leaks at this instance. Detection of slow leaks is a challenge, but will likely prove to be very important; when a well is re-entered, that is when data should be collected. If a plug has been leaking when it is drilled through, measurements will give a good idea of conditions, and maybe even the origin of the leak. These types of measurements could be used to create a data set to determine how long it takes to leak through different types of plug.

Session 5: Modelling of Wellbore Processes, Chair: Neil Wildgust

5.1 Simulating Leakage through Well Cement: Coupled Reactive Flow in a Micro-annulus, Bruno Huet, Schlumberger

This was an in-depth presentation regarding the experimental set up of leakage simulations through a micro-annulus. The model involved incorporated aspects such as cement reactivity, fluid flow and chemical reactions in the micro-annulus and also mechanics of the wellbore system. Several scenarios were used, addressing cement exposed to wet CO_2 or brine in a 1D radial symmetry (demonstrating the validity of carbonation model), CO_2 flow within the micro-annulus and the flow of supersaturated brine within the micro-annulus.

Question: If the micro-annulus is opening due to elasticity, what is the initial stress state? Is the initial state zero so nothing needs to be overcome?

Answer: Correct, the model takes into account the initial stress state in the reservoir. For the different scenarios presented there is no initial stress.

Question: What is the material in the micro-annulus prior to the flow?

Answer: The timescales involved in the micro-annulus opening are short, so the fluid quickly enters as it causes the micro-annulus formation. This is a mechanism of hydraulic fracturing.

Question: There is a benefit in being able to predict the flow; could you optimise the well design with this information?

Answer: The input parameters could be adjusted to do just that, and this is why the model was developed.

Question: What value is given for bond strength?

Answer: The experiment assumes that the casing / cement interface it initially de-bonded, so you are pressurising an interface with no bond. The effective bond strength is therefore zero.

5.2 Modelling of Wellbore Cement Alteration as a Consequence of CO_2 Injection in Exploited Gas Reservoirs, Claudio Geloni, Saipem

This presentation described modelling specific to wellbore cement alteration in gas reservoirs. This is the second more method-specific talk, with a description of wellbore integrity in ECBM in session 3.

Session 6: Quo Vadis: Future Direction of the Network, Chair: Bill Carey

The aim of this session was to ensure that the network is still relevant, and is contributing to the problems that need to be addressed in the CCS arena. The group is important, and with a 5 year history, the steering committee feels that the time could be ripe for the formulation of a status report on wellbore integrity. The report would likely be a large, combined effort, with a synthesis paper submitted to the IJGGC.

A thorough review of the work, achievements and knowledge gaps will make sure the network covers topics that are relevant, and keeps the network vital. We understand much more about wellbore integrity issues now, but coupled with that is a new group of areas that are 'known unknowns', i.e. things we don't know, but that we are aware that we don't know – there are identified knowledge gaps and we need to work towards broaching these gaps.

There has been a shift away from numerical modelling, and towards modelling of specific actions and elements within wellbores and far-field wellbore environments. Monitoring is an area where we could look to increase our content, and this runs nicely with the increased focus this year on remediation measures and practices.

The participants then split into 3 groups to discuss:

- What should the report try to accomplish?
- Develop an outline of the main elements of the report,
- Identify key themes or issues to address,

The breakout group notes can be found in Appendix 3, but key points and summaries of the discussions are as follows.

- Corrosion engineers are most worried about CO_2 interactions with wellbore materials,
- Interactions of CO_2 with old cement will always be a problem if the cement was not designed with CCS in mind.
- The interaction with the steel is less likely to cause issues.
- Queries over the description and definitions of blow-outs – it would be best not to link the term blow-outs with drilling as they occur more frequently in interventions.
- Although outside of the scope of this network, more work and research is needed on blow-outs.
- More clarification needed in defining wells for CCS and other purpose wells.

The report should attempt to provide information to all parties, ensuring that all parties from field operators, laboratory researchers, regulators and public bodies are fully aware of the extent of knowledge and confidence that can be felt in assessments of wellbore integrity. An integral part of this education would the a series of definitions; the presentations given during this workshop showed various definitions of well failures, blow-outs and leakage for example, and use of the wrong definition in the wrong circumstance could cause significant problems for regulation and operation of sites.

Once the report has compiled a unified research position, regulatory input will be required, and the information that can be provided from industry, research and academia should be an important part of this. Although we hold workshops addressing issues, and identifying knowledge gaps, the obverse to this is that there is a great deal that is known and understood.

Clarification must be made that new wells that are drilled for purpose are much less likely to cause problems, and although the old wells could cause problems, there are many remediation measures available and experience gained from the oil and gas industry to mitigate any issues as and when they occur.

In conclusion, after the group notes were compiled, the following topics were highlighted for headings in the report:

- Definitions. This should include definitions of leaks, the types of wells likely to be encountered, and the different scales applicable to the area of influence.
- Abilities. This should demonstrate the extensive monitoring toolbox available, the ability to remediate and mitigate if problems arise, and that the industry has the ability to conduct operations now.
- Approaches. Different approaches have been developed depending on what type of target reservoir is being considered, and the differences between reservoirs is understood.
- Knowledge. Advances in knowledge and results gathered has lead to a good understanding of the processes involved, and the extent of the impacts and effects of CO_2 injection. The historical database inherited from the oil and gas industry is a valuable tool, and many reservoirs have been well characterised already

Session 7: Summary, Discussion and Close, Chair: Neil Wildgust

In his capacity as network chair, Bill Carey closed the meeting, briefly explaining the benefits of gaining new insights and perspectives from new participants. The different views expressed are necessary in order to have the ability to address the concerns of all parties. We are starting to see collaboration of results from field and laboratory work (specifically the work presented by Barbara Kutchko) which has always been an issue in previous years, so it is clear that progress is being made, and the formation of a synthesis report will further cement this progress. New topics have been covered, looking at remediation, complex modelling and novel detection methods using micro-seismic methods, as well as novel approaches to abandonment and plugging procedures.

The level of interest in the meeting suggests that it is not the right time to bring the network to a close, and indeed it may be that a change of direction or scope is more relevant, but this is a topic that will be debated outside of the meeting, possibly as a result of the proposed synthesis report.

Appendix 1: Meeting Agenda

Day 1 - 13th May	
Session 1 – Introduction	
08.30 to 08.50	Welcome/ Orientation/ Context
Session 2. Risk and Regulatory Environment for Wellbore Integrity	
08.50 to 09.15	Well Blowout Rates and Consequences in California Oil and Gas District 4 from 1991 to 2005: Preston Jordan; Lawrence Berkeley National Lab
09.15 to 09.40	CO_2 Storage--Managing the Risks of Wellbore Leakage over Long Timescales: Olivier Poupard; Oxand
09.40 to 10.05	Qualitative and Semi-quanlitative Risk Assessment Methods to Evaluate Potential CO_2 Leakage Pathways Through Wells: Claudia Vivalda, Schlumberger
10.05 to 10.20 Break	
10.20 to 10.45	Regulatory Practices in Alberta: Tristan Goodman; ECRB
10.45 to 11.20	Well Abandonment Practices Study: Tjirk Benedictus; TNO
11.20 to 12.15	**Facilitated Discussion**
12.15 to 13.30 Lunch	
Session 3. Field Studies of Wellbore Integrity	
13.40 to 14.05	SACROC a Natural CO_2 Sequestration Analogue in Wellbore Cement Integrity Assessment: Barbara Kutchko; NETL
14.05 to 14.30	CO_2 Capture Project Results from Buracica, Brazil: Walter Crow; BP
14.30 to 14.55	Salt Creek EOR Experience: Ken Hendricks; Anadarko
14.55 to 15.20 Break	
15.20 to 15.45	Results of Well Bore Integrity Survey at Weyburn, Canada: Rick Chalaturnyk; U. of Alberta
15.45 to 16.10	Measuring and Understanding CO_2 leaks in Injection Wells: Experience from MovECBM: Matteo Loizzo; Schlumberger
16.10 to 16.35	Effective Zonal Islolation for CO_2 Sequestration: Ron Sweatman, Haliburton
16.35 to 17.30	**Facilitated Discussion**
18.00 to 19.00	**Poster Session**
Close Day 1 19.00 to 21.00 Dinner sponsored by Schlumberger	

Day 2 - 14th May	
Session 4: Wellbore Remediation, Leakage and Alternative Practices	
08.30 to 08.55	CO_2 Injection Well Conversion and Repair: Mark Woitt; RPS Energy
08.55 to 09.20	Use of Alternative Cement Formulations in the Oilfield: Don Getzlaf; Cemblend
09.20 to 09.45	Microseismic Studies Revealing Lleakage Pathways: Marco Bohnhoff; Stanford University
09.45 to 10.10	Long Term Sealing of GHG Sequestration Wells: Homer Spencer; Seal Well Inc.
10.10 to 10.35 Break	
10.35 to 11.00	Experimental Assessment of Brine and/or CO_2 Leakage through Well Cements at Reservoir Conditions: Brant Bennion; Hycal
11.00 to 11.25	Impact of CO_2 on Class G Cement, Static and Dynamic Long Term Tests: Francois Rodot and André Garnier, Total
11.25 to 12.15	**Facilitated Discussion**
12.15 to 13.30 Lunch	
Session 5: Modelling of Well Bore Processes	
13.30 to 13.55	Simulating Leakage through Well Cement: Coupled Reactive Flow in a Micro-annulus: Bruno Huet, Schlumberger
13.55 to 14.20	Modelling of Well Bore Cement Alteration as a Consequence of CO_2 Iinjection in Exploited Gas Reservoirs: Claudio Geloni, Saipem
Session 6: Quo Vadis: Future Direction of the Well Bore Integrity Network	
14.20 to 14.40	Status Report Issued by the Well Bore Integrity Network: Elements and Outline
14.40 to 15.40	**Breakout Groups for Report**
15.50 to 16.00 Break	
16.00 to 16.30	Reports from Breakout Groups
16.30 to 17.30	**Open Discussion on Ideas for Future of the Network**
Session 7: Summary, Discussion and Close	
17.30 to 17.45	**Meeting Organisers**
Close Day 2	

Appendix 2: Delegates List

Toby Aiken, IEA GHG
Onajomo Akemu Schlumberger Carbon Services
John Arbeau, Weatherford Canada
Stefan Bachu, Alberta Research Council
Barbara Kutchko, US DOE - NETL
Tjirk Benedictus, TNO | Geo-energy
Glen Benge, ExxonMobil
Brant Bennion, Hycal Energy Research Labs
Marco Bohnhoff, Stanford University
Axel-Pierre Bois, CurisTec
David J. Brewster, ConocoPhillips
Lorraine Brown, Poyry Energy (Calgary)
Jesse Bruni, T.L. Watson & Associates
Lyle Burke, RPS Energy Canada
Bill Carey, Los Alamos National Lab
Michael Celia, Princeton University
Rick Chalaturnyk, University of Alberta
Simon Contraires, Schlumberger Carbon Services
Walter Crow, BP Alternative Energy
Jean Desroches, Schlumberger
Kerry Doull, Doull Site Assessments Ltd.
Andrew Duguid, Schlumberger Carbon Services
Robert Eden, Rawwater Engineering Company Ltd
John Faltinson, Alberta Research Council
Grant Ferguson, Baker Hughes
Roelien Fisher Shell Int. Exploration and Production
Emmanuel Giry, Oxand Canada Inc.
Claudio Geloni, Saipem SpA
Don Getzlaf, Cemblend Systems
Tristan Goodman, Alberta ERCB
Jonathan Koplos, The Cadmus Group, Inc.
Thomas La Rovere, Seal Well Inc.
Robert Lavoie, University of Calgary
Thomas Le Guenan, BRGM
Brice Lecampion, Schlumberger Carbon Services
Eric Lecollier, IFP
Matteo Loizzo, Schlumberger Carbon Services
Richard Luhning, Enbridge Inc
Andrew McGoey-Smith, Golder Associates Ltd
Patrick McLellan, Weatherford Adv. Geotechnology
Michael de Vos, Dutch State Supervision of Mines

Robert Mitchell, Schlumberger Carbon Services
Francisco Moreno, Alberta Geological Survey
Alexander Nagelhout, IF-WEP
Doug Nimchuk, Apache Canada Ltd
Olivier Poupard, OXAND SA
Michael Parker, ExxonMobil Production Company
Lutz Peters, RWE Dea AG
Scott Rennie, ConocoPhillips
Bill Reynen, Geological Survey of Canada (Calgary)
Richard Rhudy, EPRI
Francois Rodot, Total E&P
Andreas Ruch, Halliburton
Ryan Doull, Doull Site Assessments Ltd.
George Scherer, Princeton University
Ole Kristian Sollie, DNV
Tom Spenceley, Corr Science Inc.
Homer Spencer, Seal Well Inc.
Marty Stromquist, Cemblend Systems Inc.
Ronald Sweatman, Halliburton
Andrew Graham, EnCana Oil and Gas Partnership
Kristine Haug, Alberta Geological Survey
Kevin Heal, Golder Associates
Ken Hendricks, Anadarko
Mark Hobbs, Apache Canada Ltd
Dave Johnson, Cemblend Systems Inc
Jos Jonkers, Weatherford Canada
Preston Jordan, LBNL
Miss Khalfallah, Schlumberger
Trach Tran-Viet, LBEG State Authority for Mining Energy and Geology
Robert Trautz, EPRI
Roy Van der Sluis, Baker Hughes
Claudia Vivalda, Schlumberger
Murray Wallin, Apache Canada Ltd.
Theresa Watson, T.L. Watson & Associates Inc.
Klaus Udo Weyer, WDA Consultants Inc
Neil Wildgust, IEA GHG
Mark Woitt, RPS Energy
Min Zhang, Alberta Research Council

Appendix 3: Breakout Group Notes

Breakout Group 1

- What should the report try to accomplish?
- Attempt to educate:

  All categories need educating to some degree – regulators, field, lab need to know what each is doing. Need to get all research sides together before going to educate regulators. Need to overcome different approaches, and unify views of operators and service providers in field work area.
- Need to make benefits clear to all parties
- Create definitions:

  What is a leak?

  What is best practice?
- What should the report try to accomplish?
- Obtain policy direction from regulators, - classify leaks,
- Demonstrate that we have knowledge, and we also have known unknowns – we know what we need to work on and learn.
- Illustrate different issues to overcome with new wells and existing wells,
- Specific Task 1: develop an outline main elements of the report,
- Define what qualifies as a leak?
- Define well types:
  - Existing wells,
  - New wells, CCS compliant,
  - New wells, non-compliant due to location, lithography etc.
- Define area's of influence, scales and regulations encompassing area's of influence,
  - Quantity of CO_2 storage necessary means that all wells may be inside area of influence of a storage operation,
- Monitoring
  - Separate approaches for different target formations – oil, gas, aquifers,
- Specific Task 2: identify key themes or issues to address
  - What should report communicate? i.e. What are the resolved issues?
  - Level of understanding, both known's and unknown's
  - Cement degradation is not likely to be an issue in abandoned wells,
  - Wells can be built to resist most corrosion, as long as conditions are stipulated in advance,
  - We have the ability to gather baseline conditions,
  - What are the unresolved issues?
  - Impact of CO_2 plume encountering H_2S zone, and impact of lowering of pH on well materials of existing wells,
  - Future proofing of new wells, defining the area of influence to determine which wells need future proofing,
  - Inability to obtain data on gas leaks from operators – proprietary information,
  - We know we can fix leaks, but why do they occur?
  - Need more monitoring tools and abilities,
  - Better communication between interested parties,

- Quantification of leakage, small leaks need active effort to find them,
- What can we measure – leads to what can't we measure,
- Need methods to validate models,

Breakout Group 2

What should the report accomplish?

- Useful to have a 'state of the art' review of what's out there and what's being done
- Should be generalised
- Clarify the 'question' – FOCUS on old wells
- What constitutes leakage? Movement outside the container
- Technically focussed
- Provide information for technical, non-technical and outreach

Main Messages

- Three classes of wells – pre-existing, new and injection wells
- Distinction between artificial and natural systems – pathways of concern
- Initial condition of wells is critical, characterisation key
- Early concerns that CO_2 would degrade all borehole materials has been dispelled
- We have technologies that can remediate leaky wells i.e. Stop the leak
- We have technology to ensure secure abandonment of wells to hold CO_2
- Leakage remediation of wells may be dictated by economic and regulatory issues
- We have technology for assessing leakage in existing wells (non-abandoned)

Unresolved issues?

- Better methods for assessing condition of pre-existing wells
- Better record keeping
- Statistical analyses of well condition and performance
- Effects of impurities in CO_2 stream on wellbore materials and integrity
- Expanded studies on flaw evolution and small scale leakage pathways
- Need more samples off wellbore materials that have been exposed to CO_2 – vital for calibration of models
- Compare and contrast statistical studies

Breakout Group 3

What should the report try to accomplish?

- Potential audiences
  - Power industry
  - Oil and gas industry
  - Greenhouse Gas
  - Public
- Two target groups
  - Greenhouse gas: Int. J. of Greenhouse Gas Control
  - Oil and Gas: SPE journal
- Results can also be disseminated to industry association meetings
  - International Regulators Forum

What should the report communicate?

- We have a research strategy that will get us to an ability to assess risk
- A review of the character and relevance of historical database

This has to be combined with performance assessment modeling to address what is different about CO_2 storage (volume, pressure)

- Communicate improvement in processes
- Emphasize the difference between "no leakage" and wellbore integrity
- The industry has the ability to conduct operations now
- Figure showing frequency of leak as function of size of leak
- Ability to detect and mitigate leakage
  Managing blow-outs and small leakage
  Detection => monitoring
- Current knowledge of material durability
- Analogy of "blow-outs" has limitations as we aren't drilling into an unforeseen high-pressure and due to gradual increase pressure
- Define the boundaries of the system (not capture, transport, etc.)
- Failures do not imply significant environmental or health and safety problems
- Unknowns: Long-term degradation or sealing of defects
  Does risk increase with time?
- Unknowns: Detection limits of leakage
- Unknowns: Lost, abandoned wells
- What do we recommend for evaluation of "old", abandoned well with limited records?
- Missing: Validation of models
- Unknowns: Leak rates of various classes of wells
- Unknowns: Frequencies of leak rates
- Not just a list of monitoring technologies but annotated as to limits and applications
- API is engaged in a parallel task—relationship to present efforts
- Are we going to recommend abandonment practices (e.g., length of plug)
- Biggest risk: low top of cement

Wellbore Integrity Network, 2009

- Network History:
  - 1st Meeting: Houston, USA, 2005
  - 2nd Meeting: Princeton, NJ, USA, 2006
  - 3rd Meeting: LANL, Santa Fe, NM, USA 2007
  - 4th Meeting: Schlumberger, Paris, France, 2008
  - 5th Meeting: ARC and TL Watson & Associates, Calgary, Canada, 2009.
- Next Meeting
  - ????????
  - Any offers?

Wellbore Integrity Network, 2009

- Network Aims:
  - Determine impacts of CO_2 interactions with wellbore materials,
  - Bring together experts to discuss results and data,
  - Determine current level of understanding of CO_2 / wellbore reactions,
  - Collect and assess field and lab experiences,
  - Provide recommendations for field monitoring and evaluation methods,
  - Evaluate remediation measures for wellbores,
  - Provide platform for researchers to discuss findings.

Wellbore Integrity Network, 2009

- Joint Network Meeting:
  - Held in New York, June 2008,
  - Brought 3 existing storage networks together,
  - Assessed cross-overs / gaps in topics,
  - Develop integrated plan for cooperation,
  - Provide feedback to each network from others,
  - Any questions for RA or Monitoring Networks,

Wellbore Integrity Network, 2009

- 2009 so far:
  - Held first Modelling workshop, as discussed at JNM,
  - Agreed establishment of Modelling network, commencing Feb 2010,
  - Risk Assessment meeting held in Australia, April 2009,
  - Monitoring to be held in June in Japan.

Well Blowouts Rates and Consequences in California Oil and Gas District 4 from 1991 to 2005

Preston Jordan

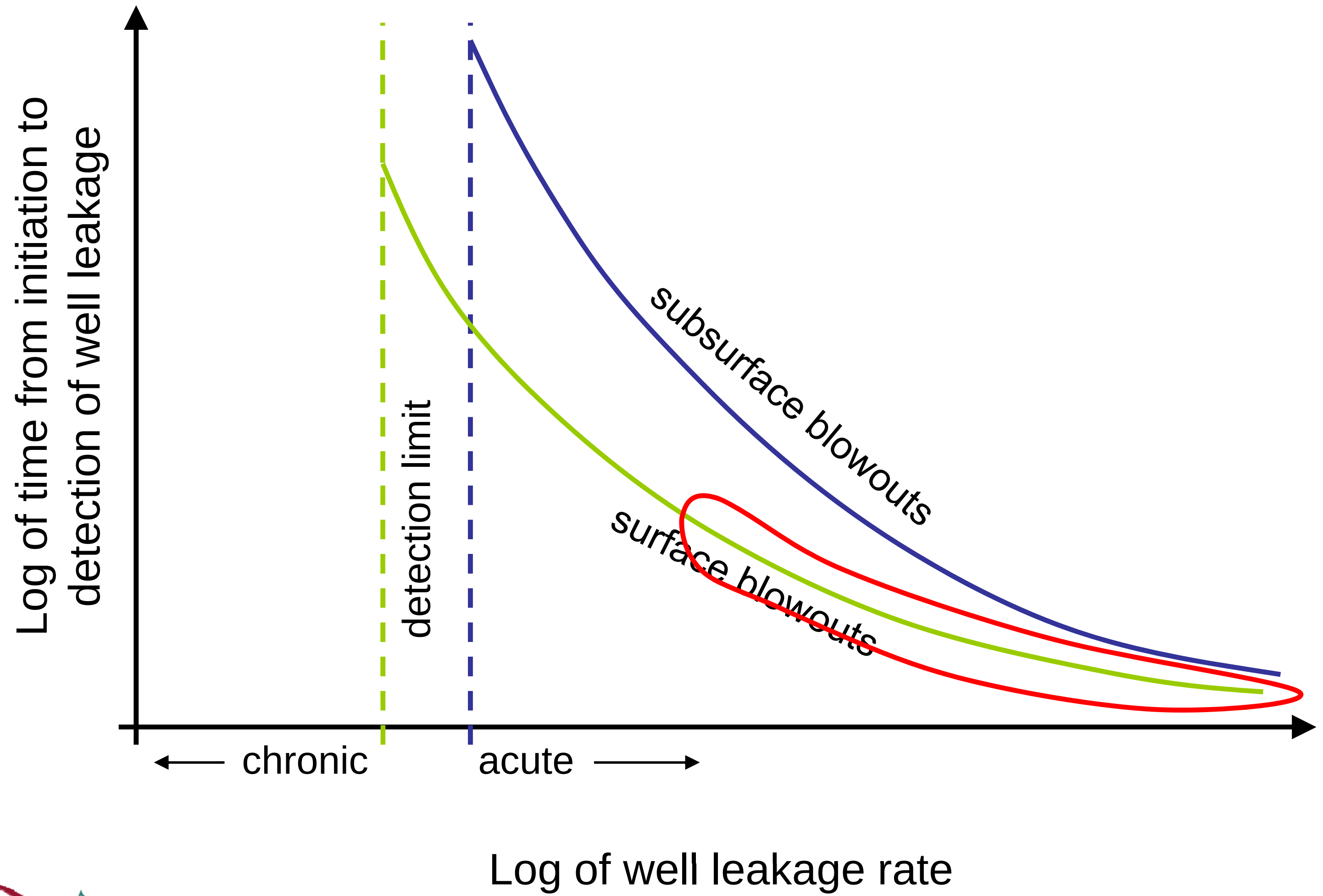
Earth Sciences Division

Lawrence Berkeley National Laboratory

(with acknowledgment to my co-investigator,
Sally Benson of Stanford University)

BERKELEY LAB

Surface Versus Subsurface Blowouts



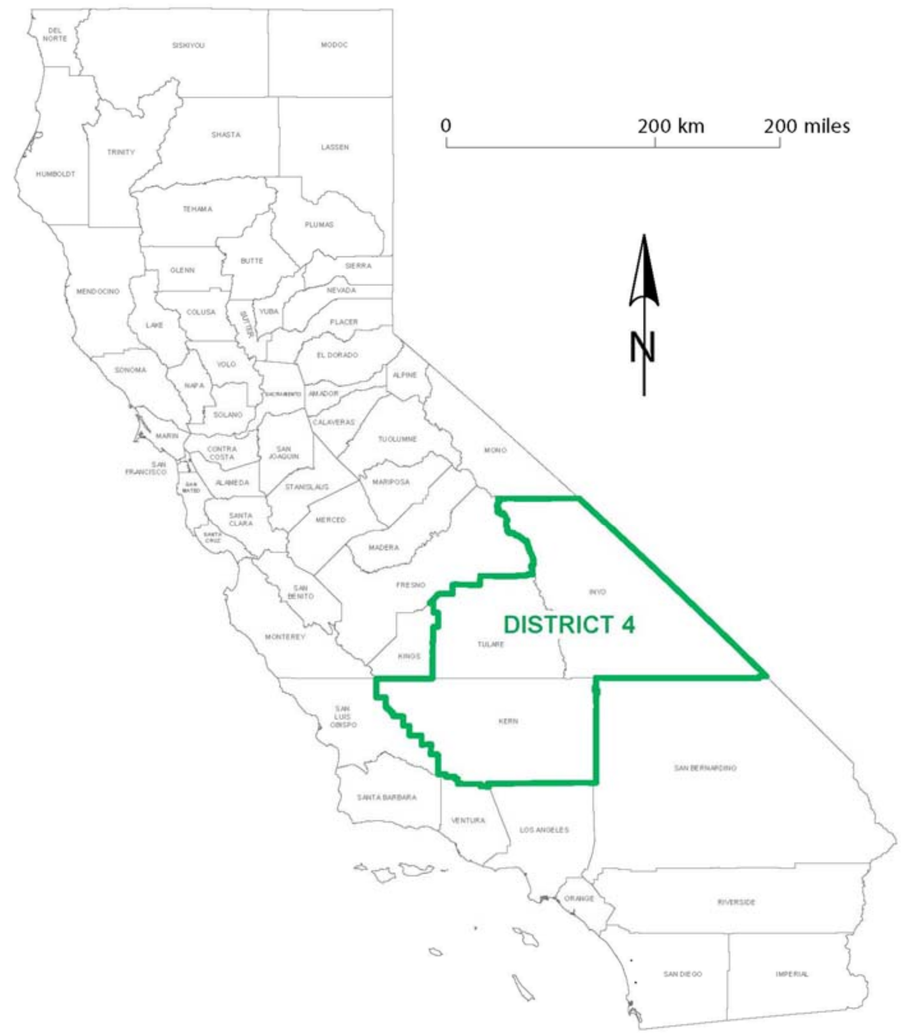
Chronic Versus Acute Well Leakage

Chronic ≈ Annular Flow?

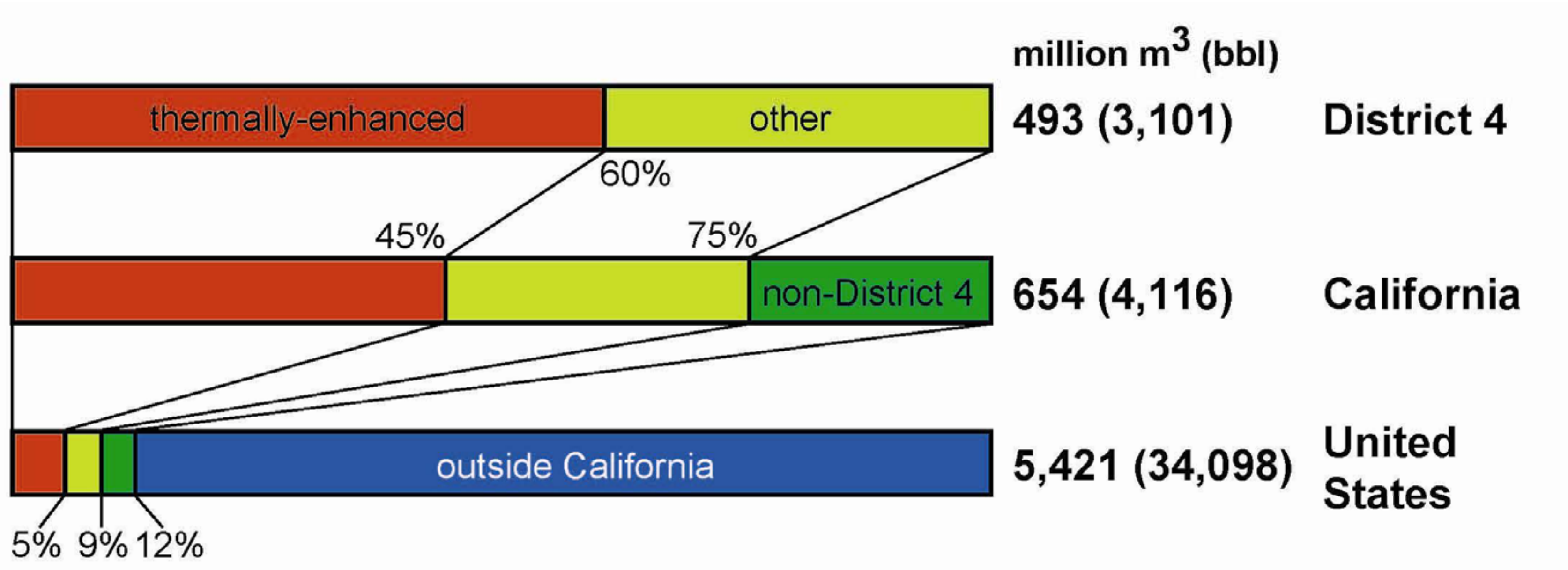
Versus

Acute ≈ Casing Flow?

California Oil and Gas District 4

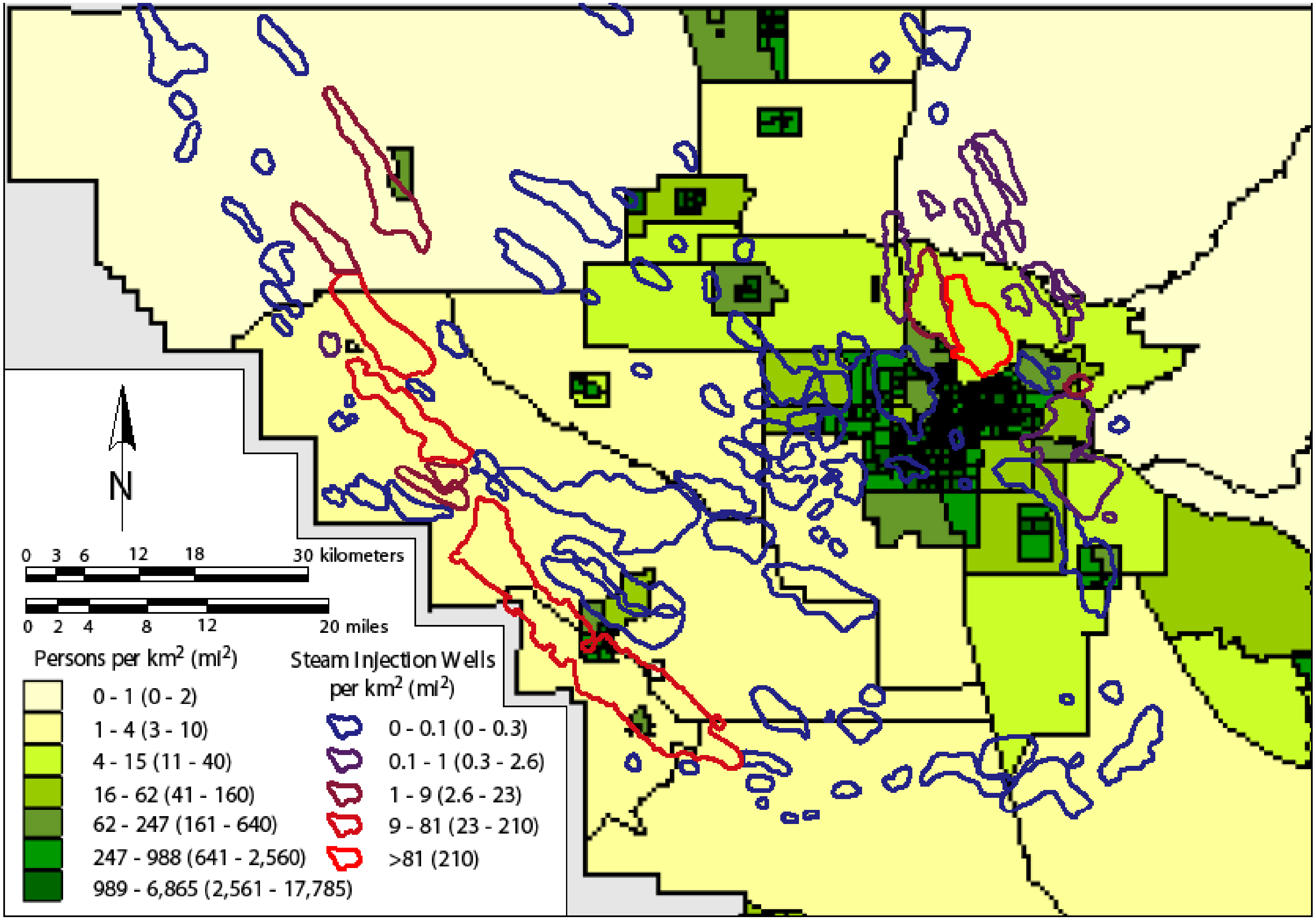


Thermally-Enhanced Production In District 4



5% of U.S. oil production is associated with the annual injection of 3.5 billion m^3 of steam (well head conditions) in CA D4 from 1991 to 2005. This volume is equivalent to 2.5 billion metric tons of CO_2 at 700 kg/m^3.

District 4 Oil Fields and Population Density



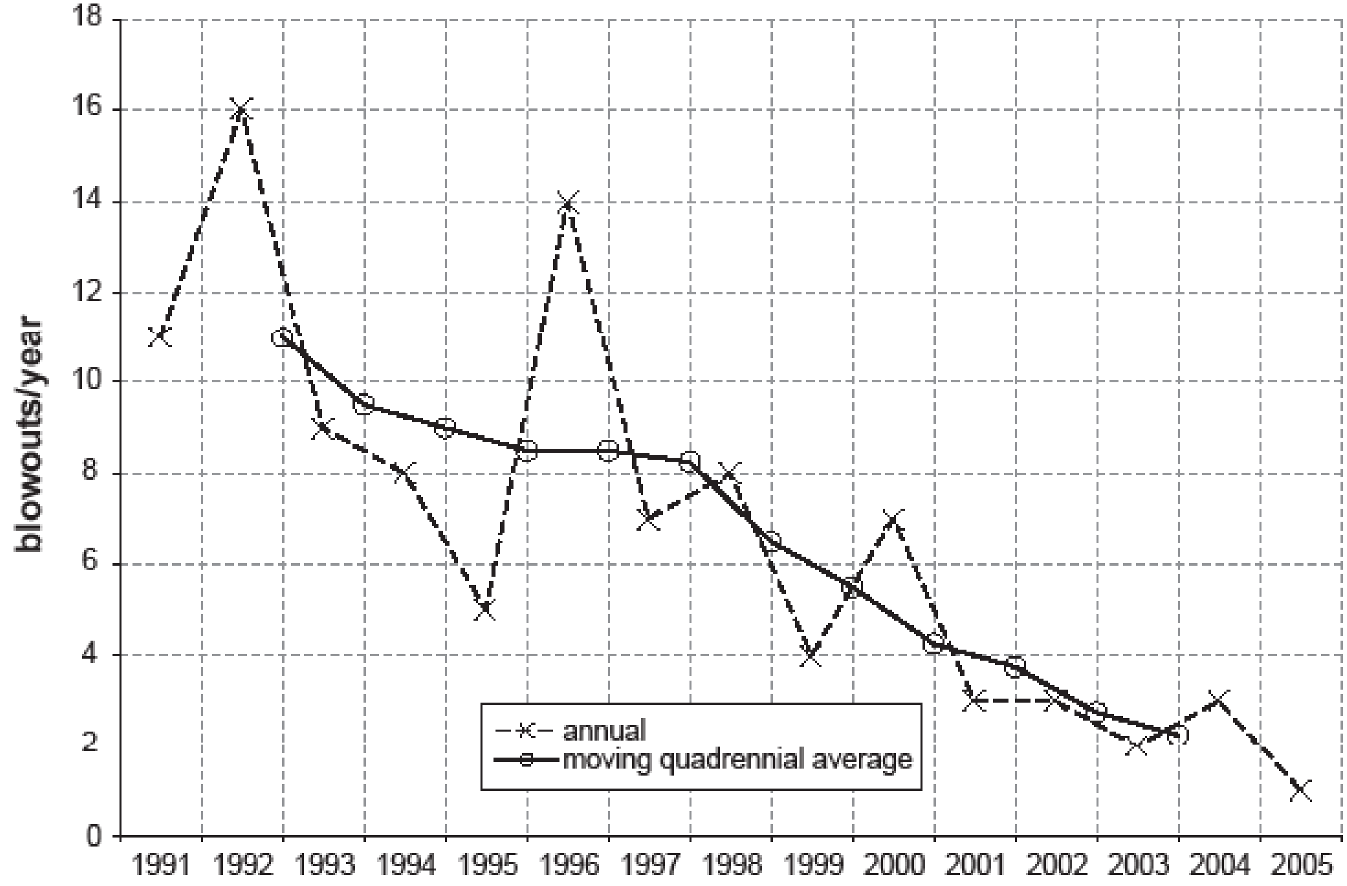
Steam Versus CO_2

	Steam (injection wells)	Steam (shut-in/abandoned wells)	CO_2
Injection depth	Shallower	Shallower	Deeper
Injection pressure	Lower	Lower	Higher
Buoyancy	Greater	Greater	Less
Expansivity	Greater	Greater	Less
Δ to standard conditions	Quenches	Quenches	Vaporizes
Thermomechanical stress	More	More	Less
Corrosivity	More (compared to dry CO_2)	Less (compared to dry CO_2)	Varies based on wet or dry

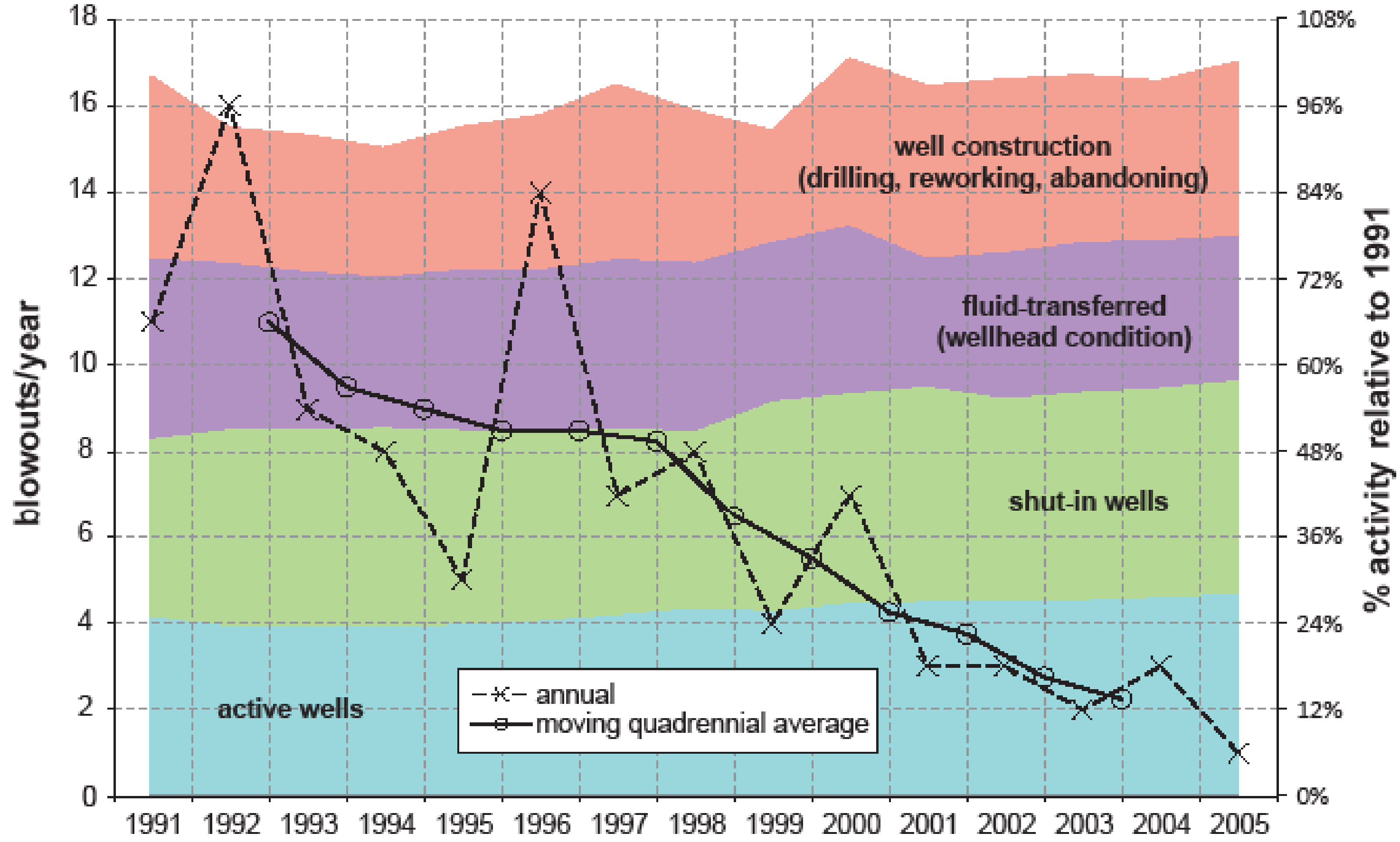
Data Sources

	Blowouts	Unique blowouts	Duplicated blowouts
DOGGR paper records	66	4	62
DOGGR database	65	9	56
DOGGR annual reports	68	18	50
Bakersfield Californian	7	1	6
Total	102	32	70

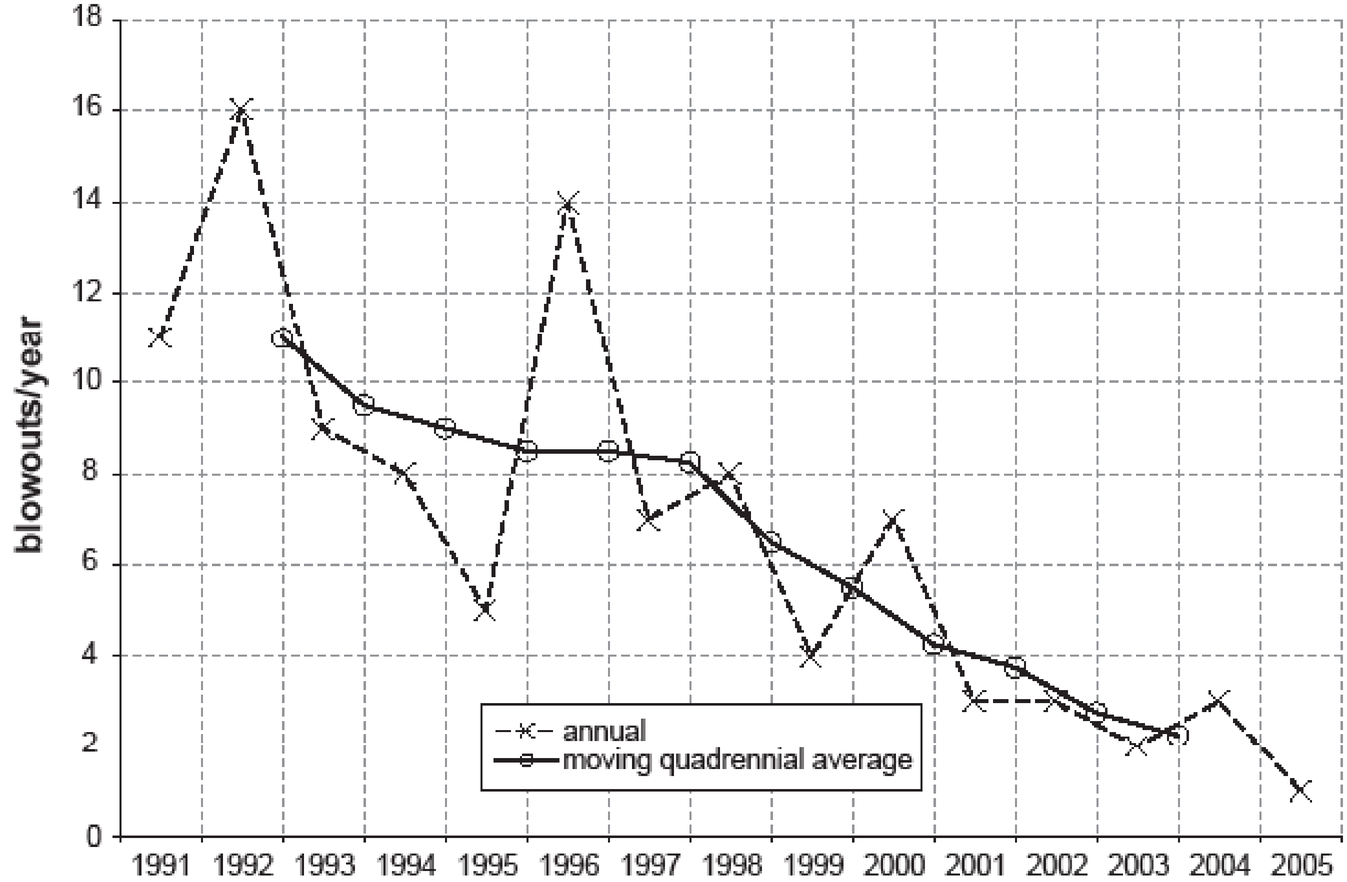
1991-2005 Blowout Trend in CA D4



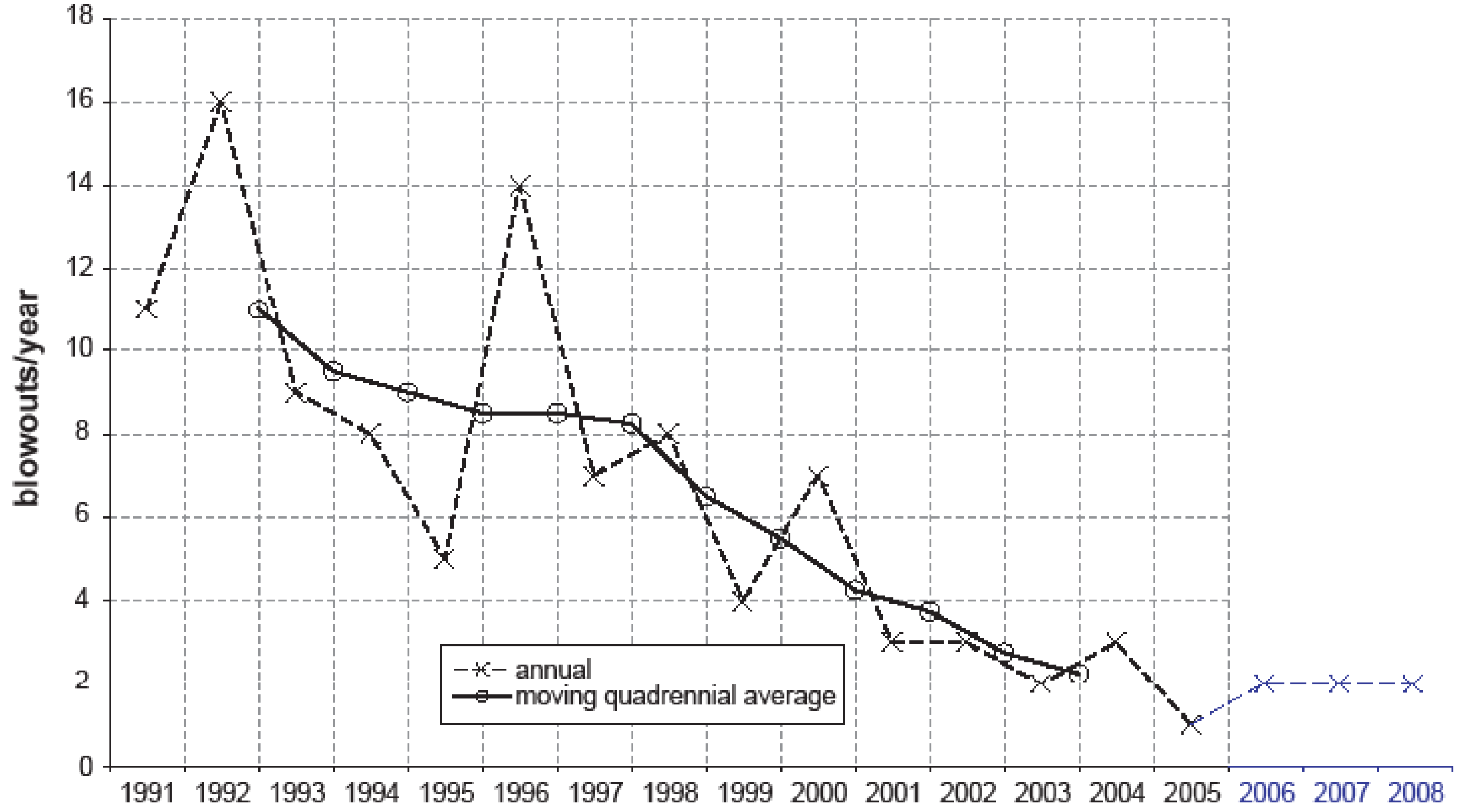
1991-2005 Blowout Trend in CA D4



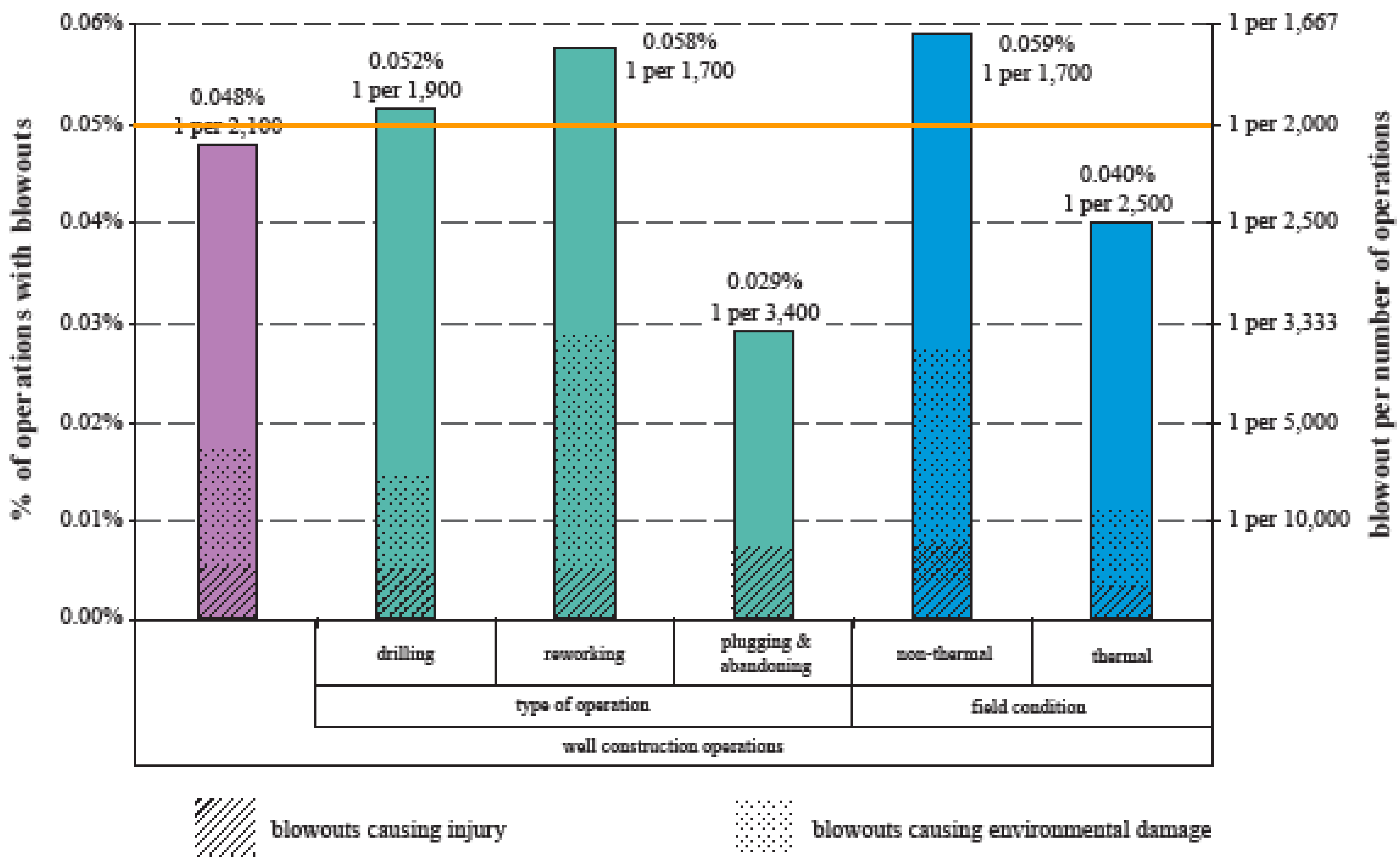
1991-2005 Blowout Trend in CA D4



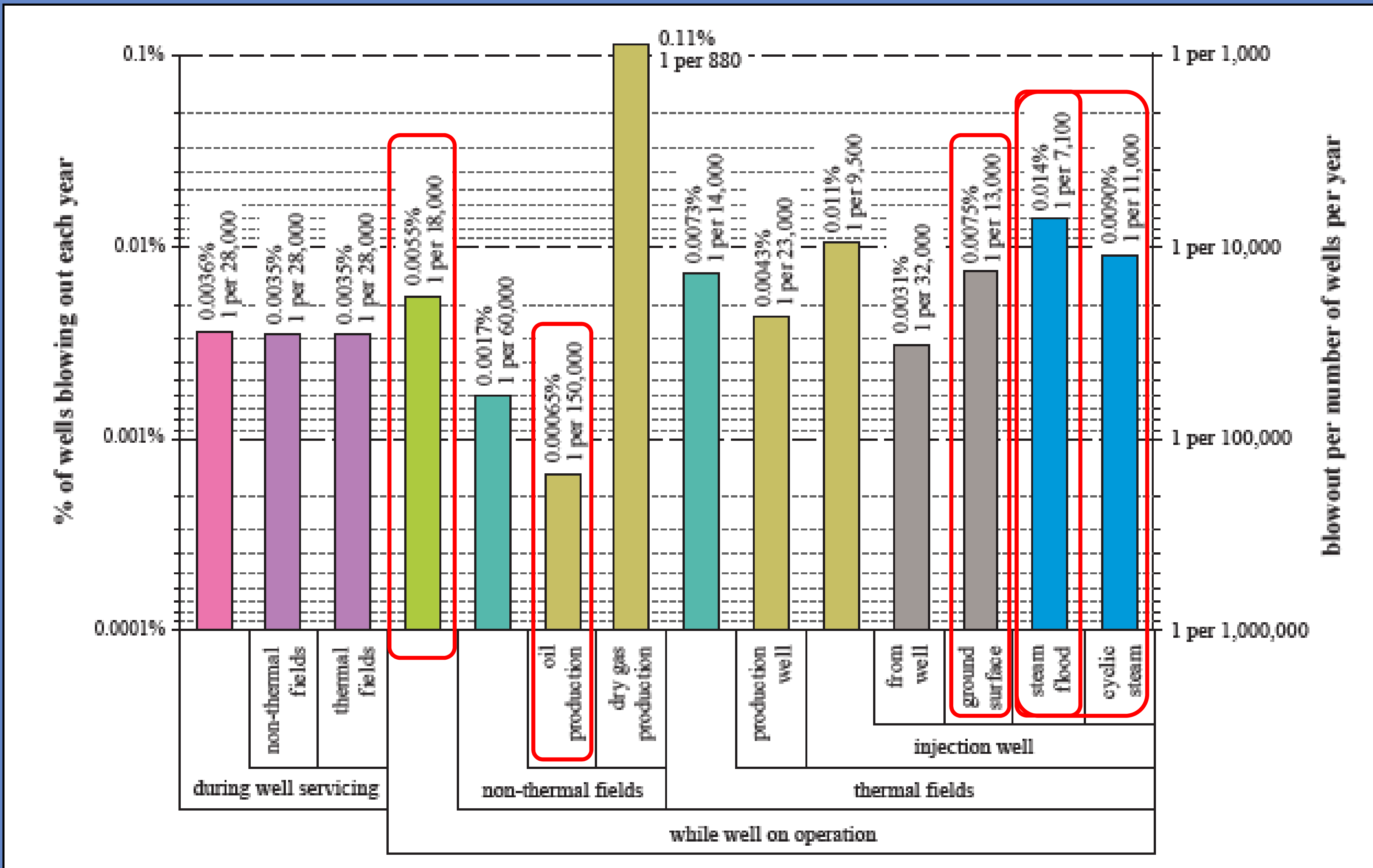
1991-2008 Blowout Trend in CA D4



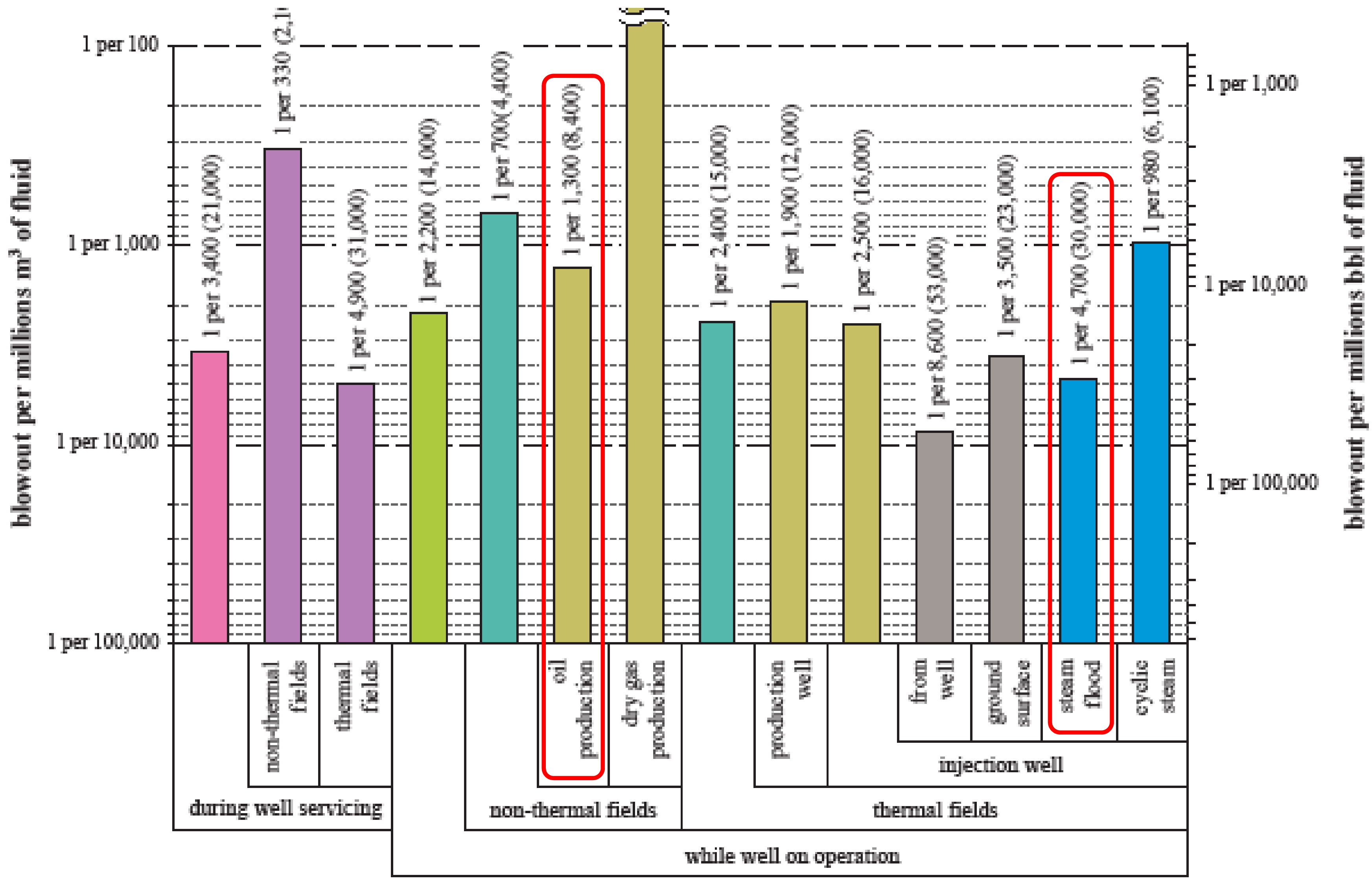
Well Construction Blowout Risk



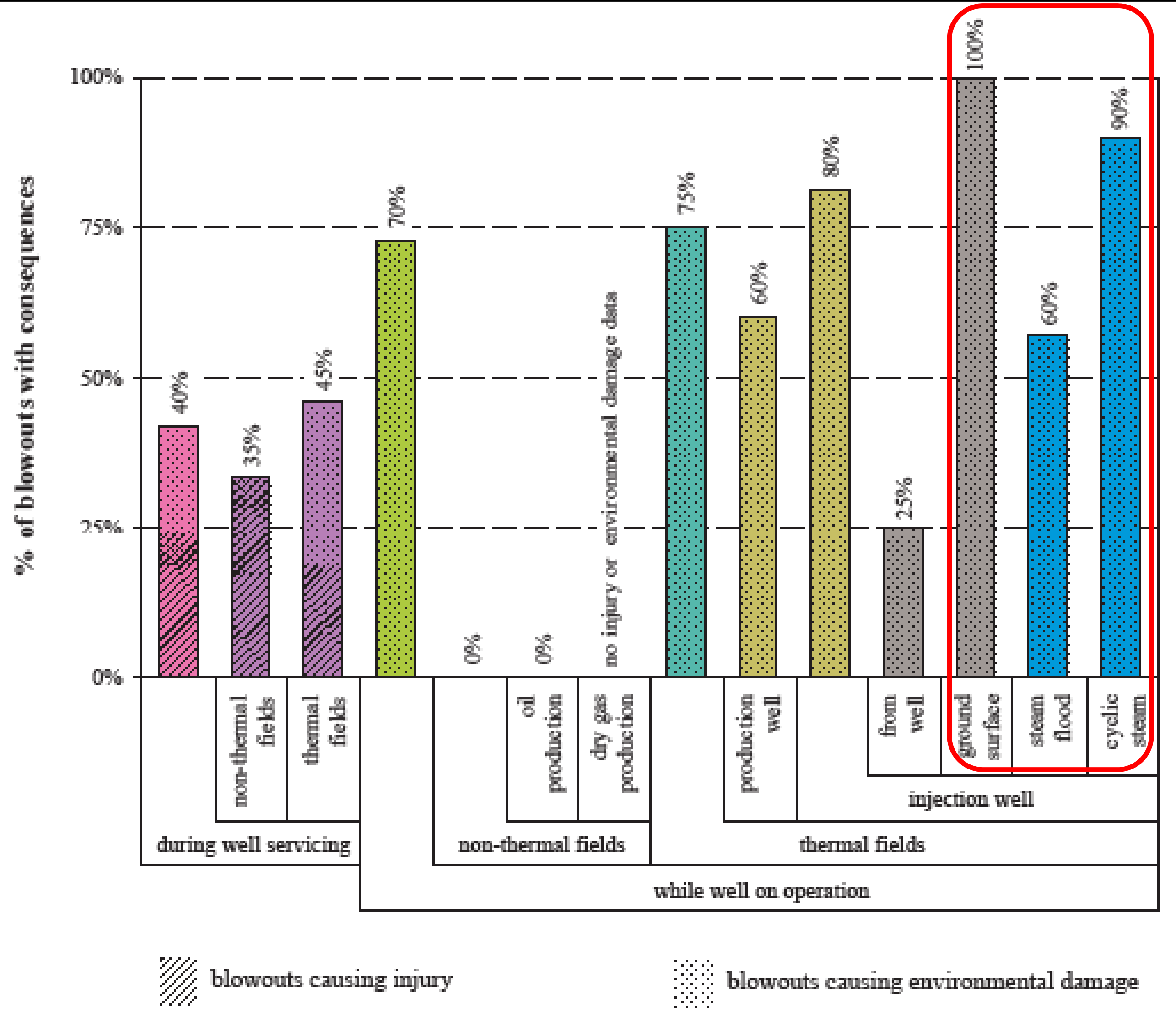
Operating Well Blowout Rate – Well Basis



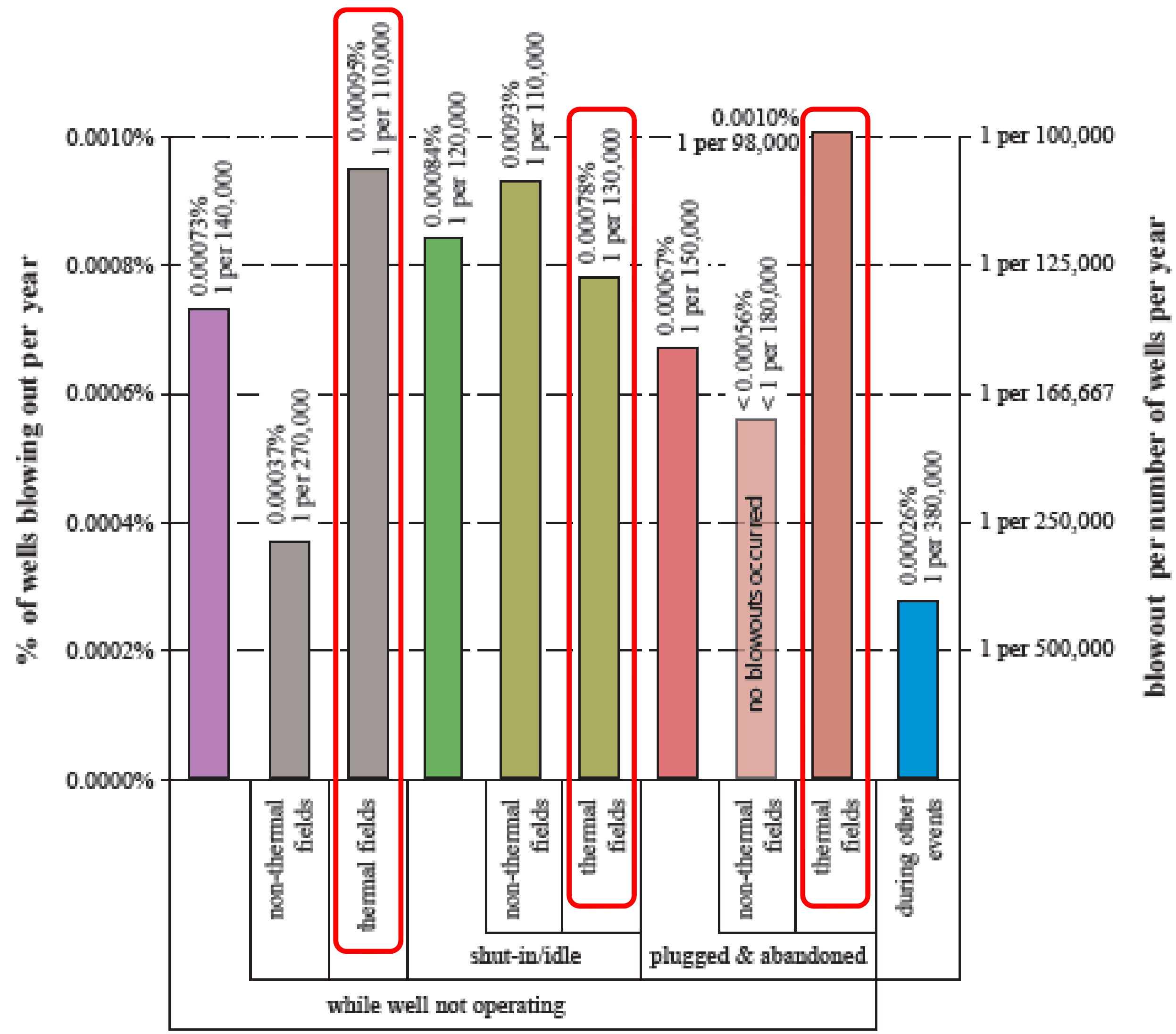
Operating Well Blowout Rate – Fluid Basis



Operating Well Blowout Consequences



Blowouts From Closed Wells



1991-2005 Thermal Blowout Risk in CA D4

Blowout during/from	Probability	Basis	Consequences					
			% impacting public	% causing worker injury	% impacting environment	Duration		
						Min.	Median	Max.
Well construction/ abandonment in thermal fields	**1 in 2,000**	**operations**	none	10% (foot burn)	20% (< 10 ha impacted)	~~20 minutes~~	~~6 hours~~	~~43 hours~~
Steam injection wells during operation	**1 in 5,000**	**wells per year**	none	none	80% (primarily earth displacement - 1/3 to 300 m^3)	~~<5 minutes~~	~~2 hours~~	~~5 days~~
Steam flood injection wells during operation	**1 in 5,000**	**million m^3 fluid**	none	none	see above			
Shut-in/idle and plugged & abandoned wells	**1 in 100,000**	**wells per year**	none	none	35% (displacement of 900 m^3 of earth)	~~20 minutes~~	~~3 hours~~	~~5 hours~~

Likely due in large part to low population density around thermal fields. Thermal producer blowout caused school evacuation and highway closure. Also, steam-driven earth displacement did effect private property.

GCS blowouts almost certainly much longer given current techniques due to larger volumes and non-quenchable phase

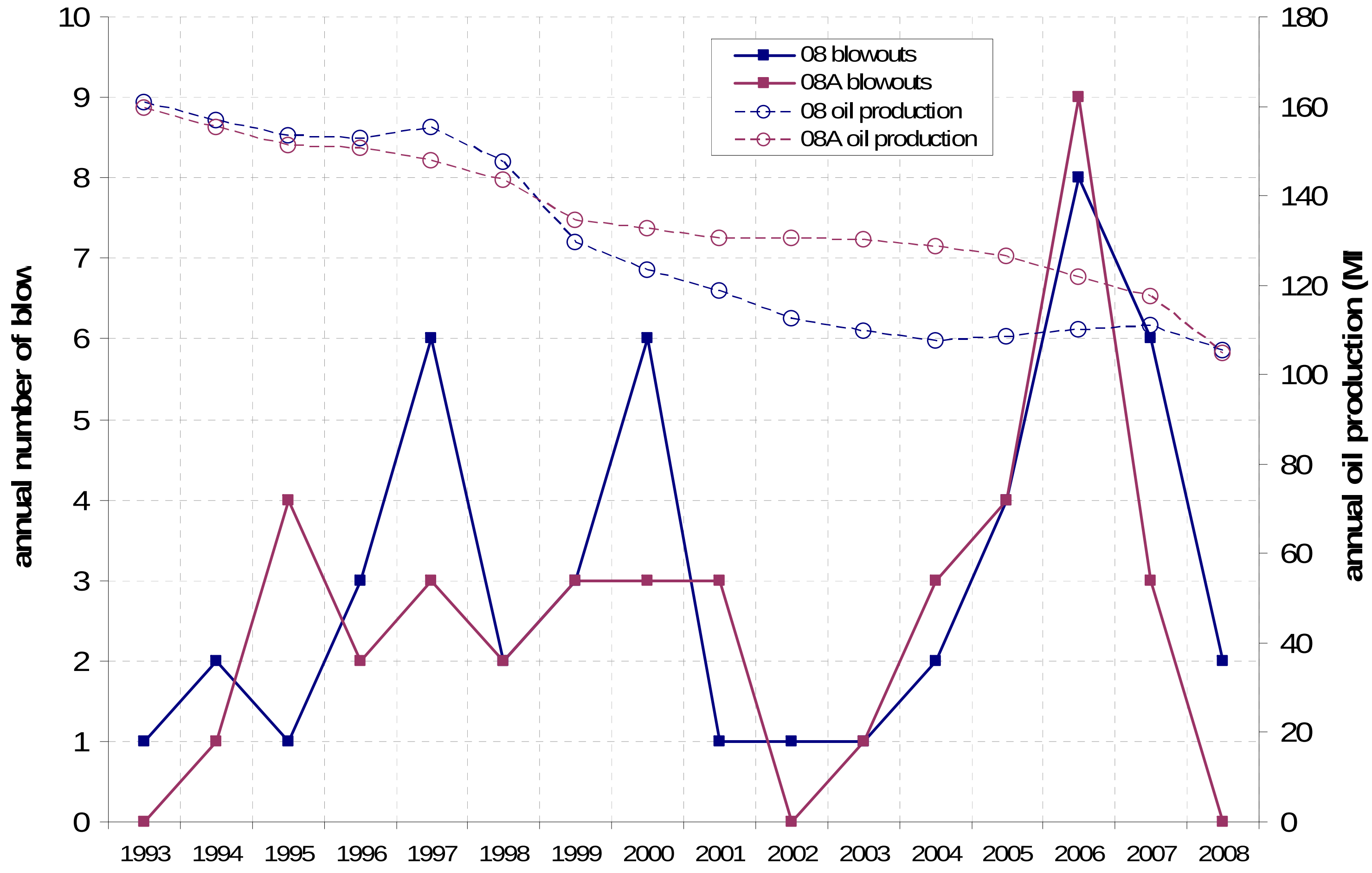
GCS Blowout Implications

- Comparison of all CA D4 blowout rates for wells in operation suggests injection pressure is a more important determinant of blowout rates than fluid type. If so, GCS field blowout rates will be somewhat higher than thermal EOR field blowout rates.
- There were no impacts to the public and only minimal worker injuries, but there is an element of happenstance for the former.
- Most injection and abandoned well blowouts displaced earth, some to such an extent that geotechnical engineering was required to restore the land surface. This consequence will likely be larger in CO_2 blowouts owing to the properties of CO_2 relative to steam, which will increase both blowout energy and duration.

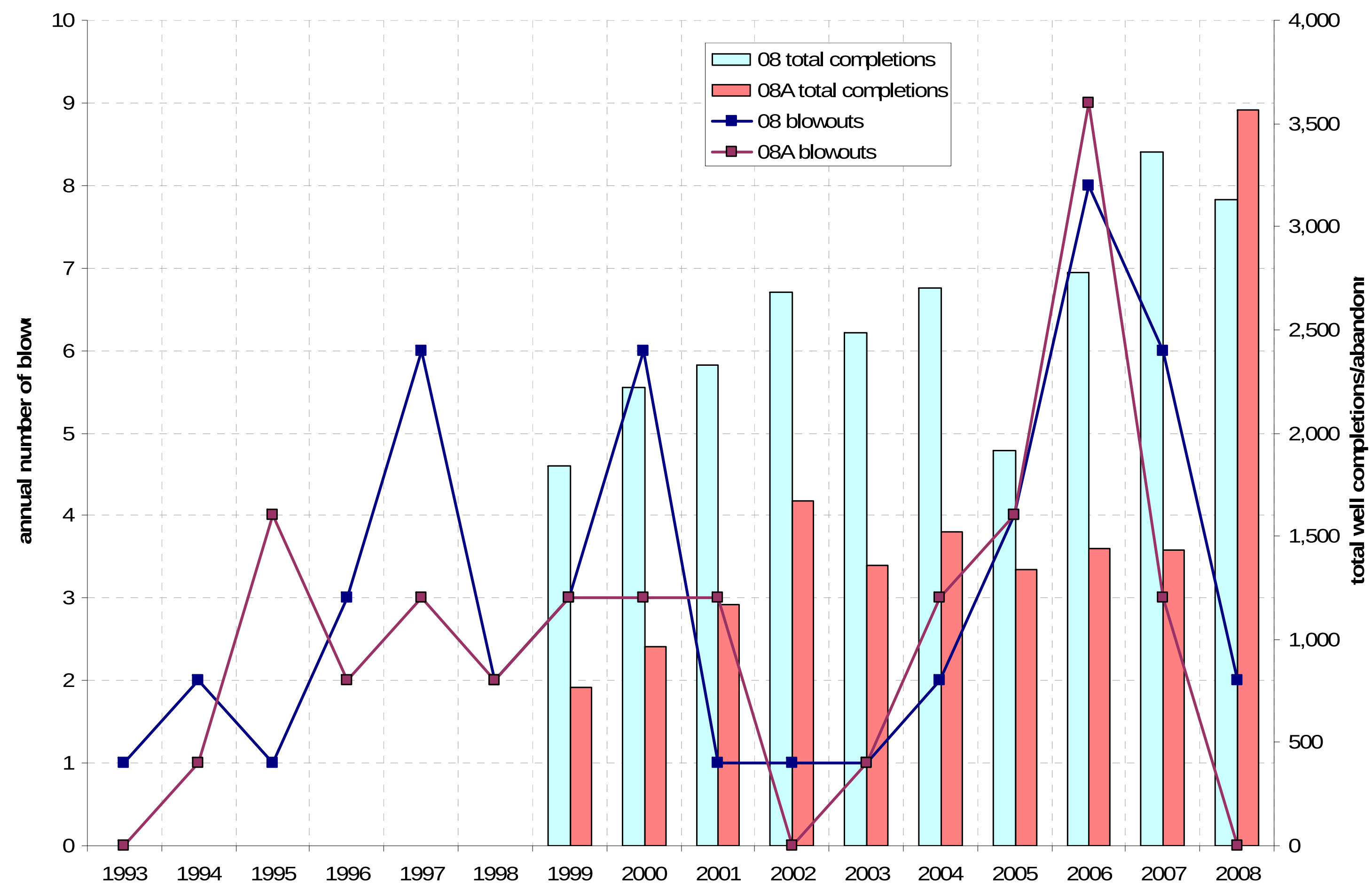
Blowout Risk Analysis Next Step - Texas

- Data from Railroad Commission of Texas similarly to data from CA DOGGR.
- Texas Oil and Gas Division Districts 08 and 08A have at total of approximately 10,000 CO_2 injection wells for EOR.
- Districts 08 and 08A also have a total of approximately 50,000 water injection wells and 2,000 hydrogen sulfide injection wells, allowing in district comparison of blowout risks associated with different fluid types.
- District 08 and 08A produce more than half of Texas' oil but have less than a quarter of the blowouts, indicating the blowout rates in the rest of Texas are more than three times as great.

Texas Districts 08/08A Oil Production And Blowouts



Texas Districts 08/08A Oil Production And Blowouts



Acknowledgments

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Optimizing Infrastructure Solutions

CO_2 Storage - Managing the Risks of Wellbore Leakage over Long Timescales

<u>O. Poupard*</u>, E. Giry**

*Oxand SA, **Oxand Canada Inc.

IEAGHG Wellbore Integrity, Calgary, May 13-14, 2009

In partnership with Schlumberger

AGENDA

1. Context and objectives
2. P&R™ approach
3. A 2-flow coupled model
4. Simulations – case study
5. Conclusion - A tool as Decision Making Support

1. Context – well integrity, a key challenge

Is CO2 likely to leak through wells?

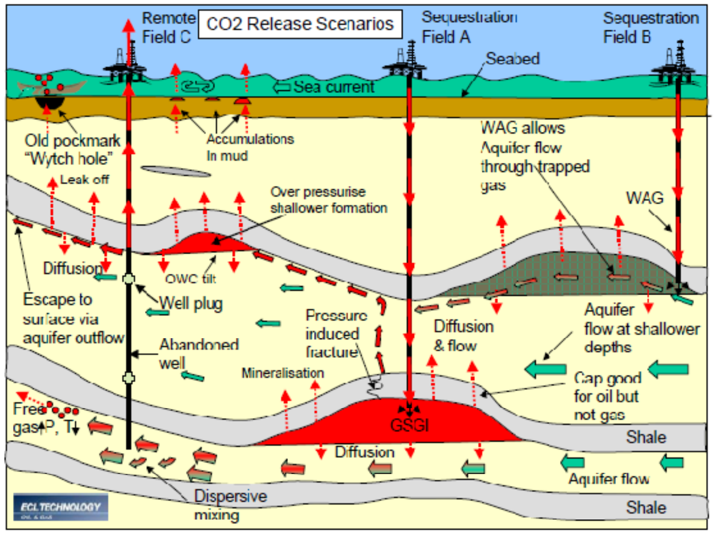
How? What pathways?

How much?

When? During injection? In 100 years? 1000 years?

What is an acceptable level of leakage ?

What should be done to mitigate critical risks on the long term?



NGCAS Project :Wikramaratna & Lawrence, ECL. Dec-2003

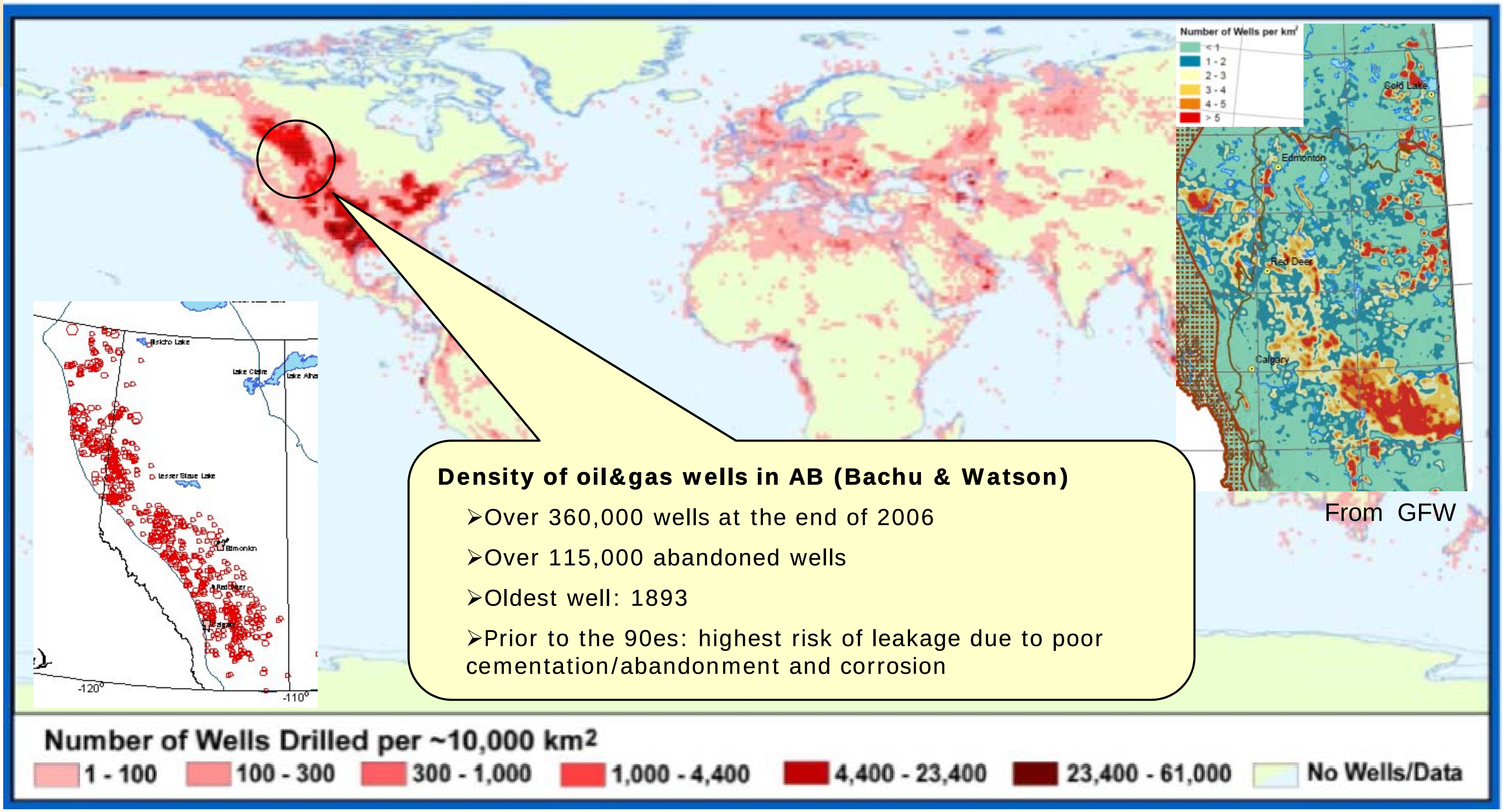
Focus on wellbore integrity

- Poor quality or aging of existing wells (injection, monitoring)
- Surrounding abandoned wells

How am I going to demonstrate CO2 long term confinement to authorities?

Xand Risk Management Solutions

1. Context – wells density in North America

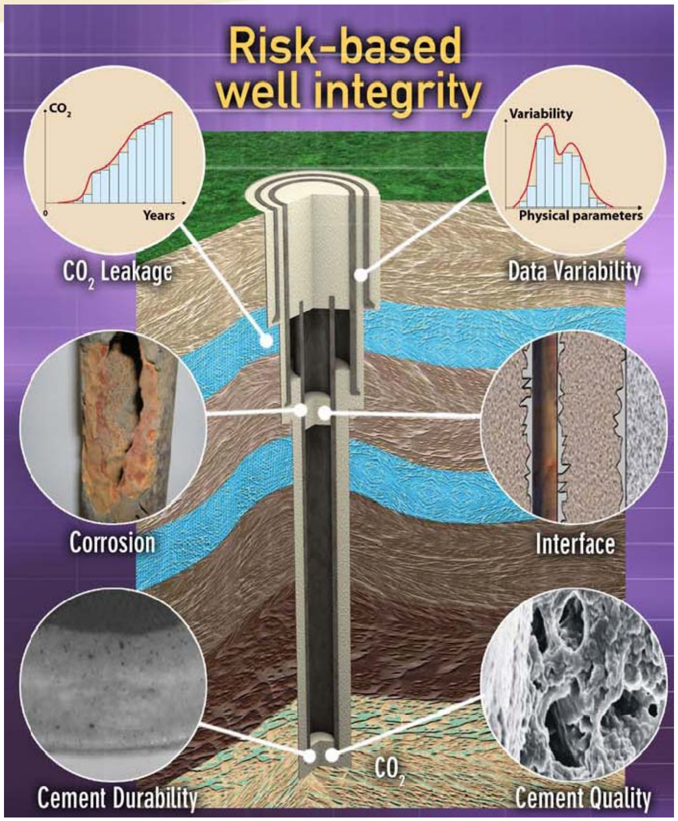


Sources: IPCC Special report 2005, ERCB, AGS, GFW

1. Objectives

- **Estimate the possible CO2 leakage through the wells, thanks to advanced flow well simulations**
- **Create a project-specific scale of severity levels associated with CO2 leakage, through involvement of stakeholders**
  - health & safety, technology, financial, public acceptance, environmental, image …
- **Combine probability of occurrence & severity levels to assess risks and deliver an overall risk profile of the well relative to CO2 leakage**
- **Recommend action plans to address critical risks, and lay the foundations of a tailored MVA protocol from WI issue**

2. P&R™ approach



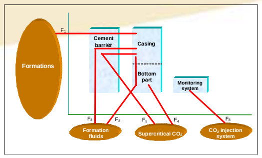
A risk-based approach

- A well-structured and objective process
- Functional analysis
- Scenarios identification & quantification
- Risk mapping
- Acceptance level

Quantitative CO_2 flow model along the wellbore

- Systemic approach
- Well, flow and ageing models
- Uncertainties
- Prognosis
  - ➢ Leakage rates towards sensitive zones
  - ➢ No predefined migration pathways along wellbore

2. A multi-well quantitative process



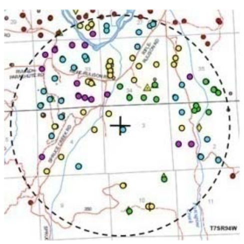
Well data screening

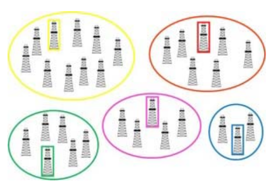
Well families identification

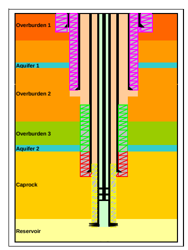
Representative wells construction

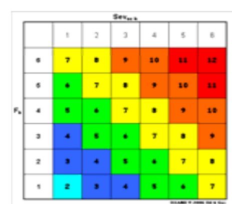
Quantitative P&R on representative wells

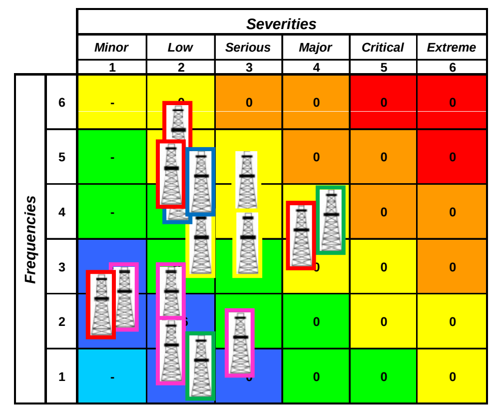
Extrapolation & Recommendations Mitigation options for CO2 field



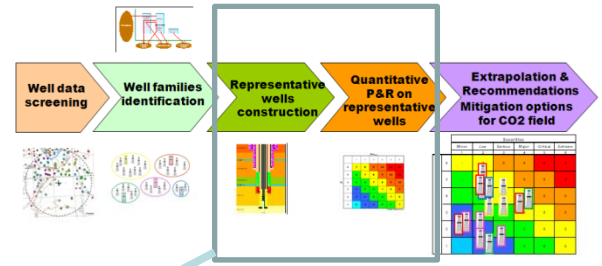






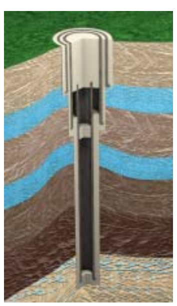


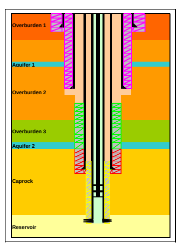
2. A quantitative approach for specific well

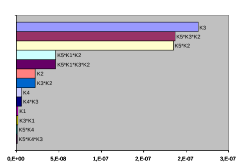


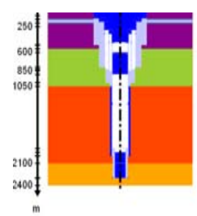
Severity levels	Stakes	Safety/ Health	Environment
	1: Minor		
	2: Low		
	3: Serious		
	4: Major		
	5: Critical		
	6: Extreme		

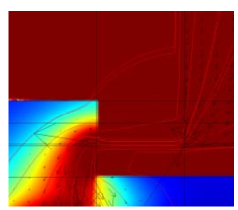
Well data Collection & Interpretation → System analysis & scenarios construction → CO_2 flow model and simulations → Risk assessment → Recommendations Mitigation options

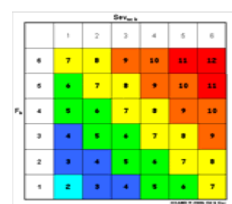








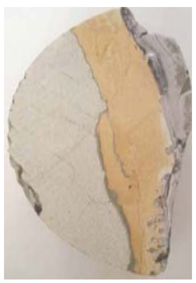




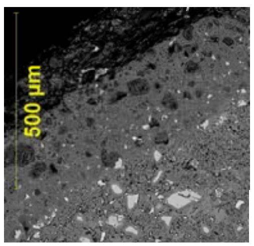
1. Characterization/ Inspection
2. Design recommendations
3. Operational recommendations
4. Monitoring recommendations

3. A 2-flow coupled model

Cement degradation



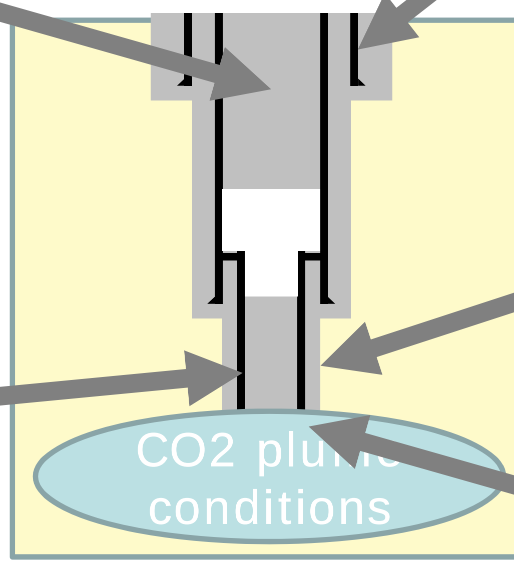
Leaching / Carbonation



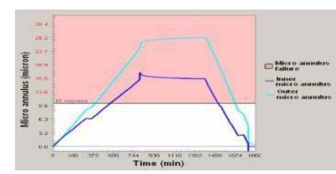
pH, P, T

Corrosion

Chlorides / pH
P, T / CO_2



Thermo-mechanical effect



CemSTRESS[TM] (Schlumberger)

Fluid flow model

3D
2-phase flow (gas, liquid)

Dry out

A 2-phase flow model

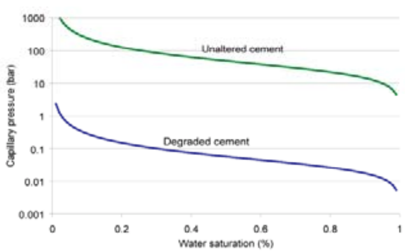
- *2D axisymetric well representation*
- *2 phases flow – darcy law*
- *Relative permeabilities: Van Genuchten and Mualem's model*

$$q_{nw} = -\frac{kk_{rnw}}{\mu_{nw}}\left[\overrightarrow{\mathrm{grad}}(p_{nw}) + \rho_{nw} g \vec{k}\right]$$

$$\begin{cases} k_{r,nw}(\Theta) = \sqrt{1-\Theta}\cdot\left(1-\Theta^{1/M}\right)^{2M} \\ k_{r,w}(\Theta) = \sqrt{\Theta}\cdot\left(1-\left[1-\Theta^{1/M}\right]^{M}\right)^{2} \end{cases}$$

$$\left(1+\left(\frac{p_c}{p_{ec}}\right)^{N}\right)^{M} = \frac{1}{\Theta}$$

$$\Theta = \frac{S_w - S_{rw}}{1-S_{rw}}$$



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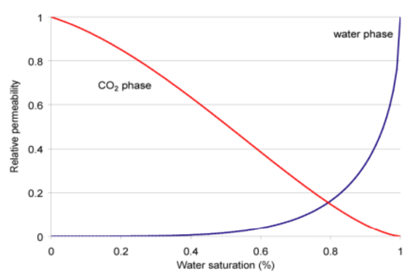
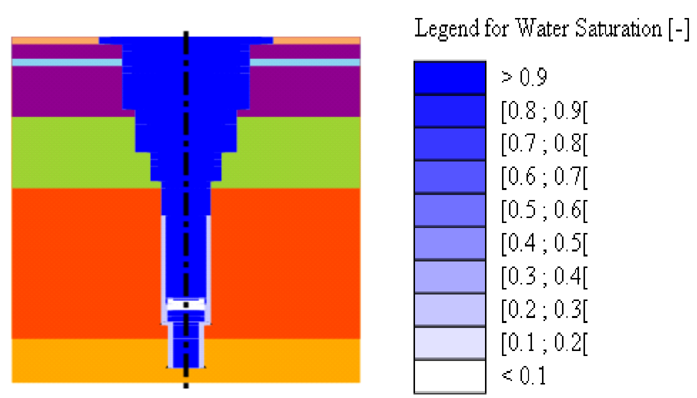
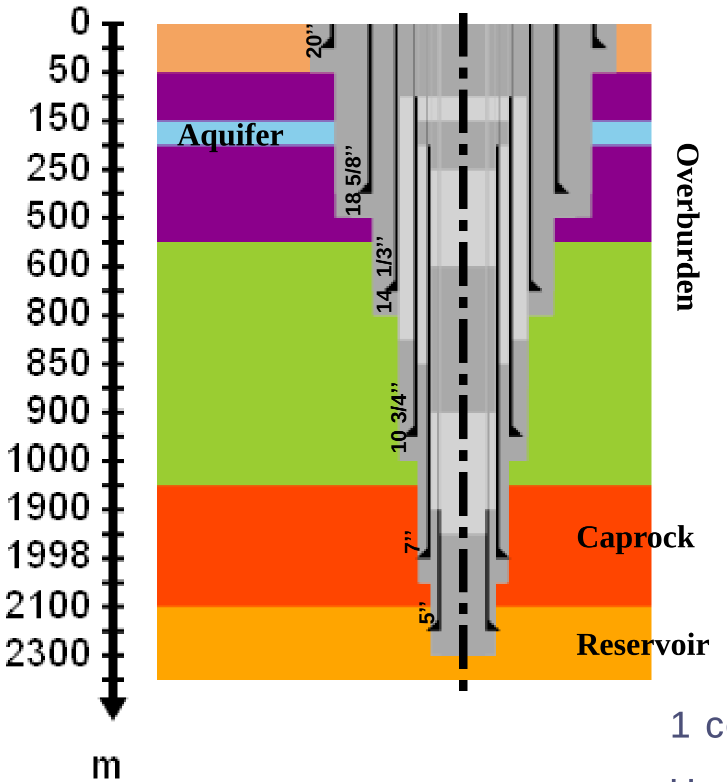




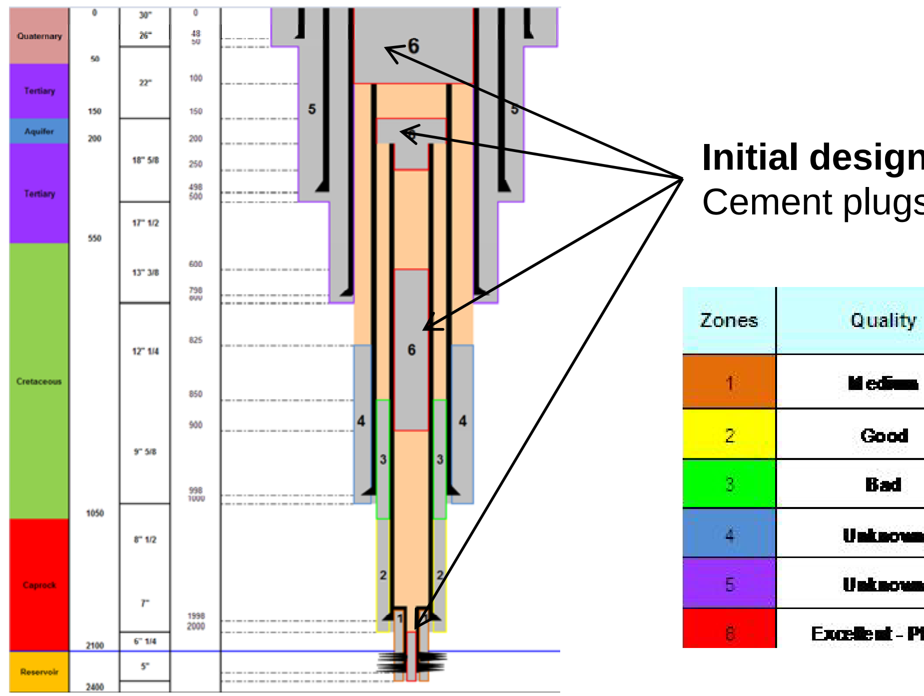
At a time t

4. Simulations – case study for abandoned well (synthetic)

Static and dynamic model



Well integrity data interpretation



Zones	Quality
1	Medium
2	Good
3	Bad
4	Unknown
5	Unknown
6	Excellent - Plugs

Initial and limit conditions

1 connected aquifer (freshwater)

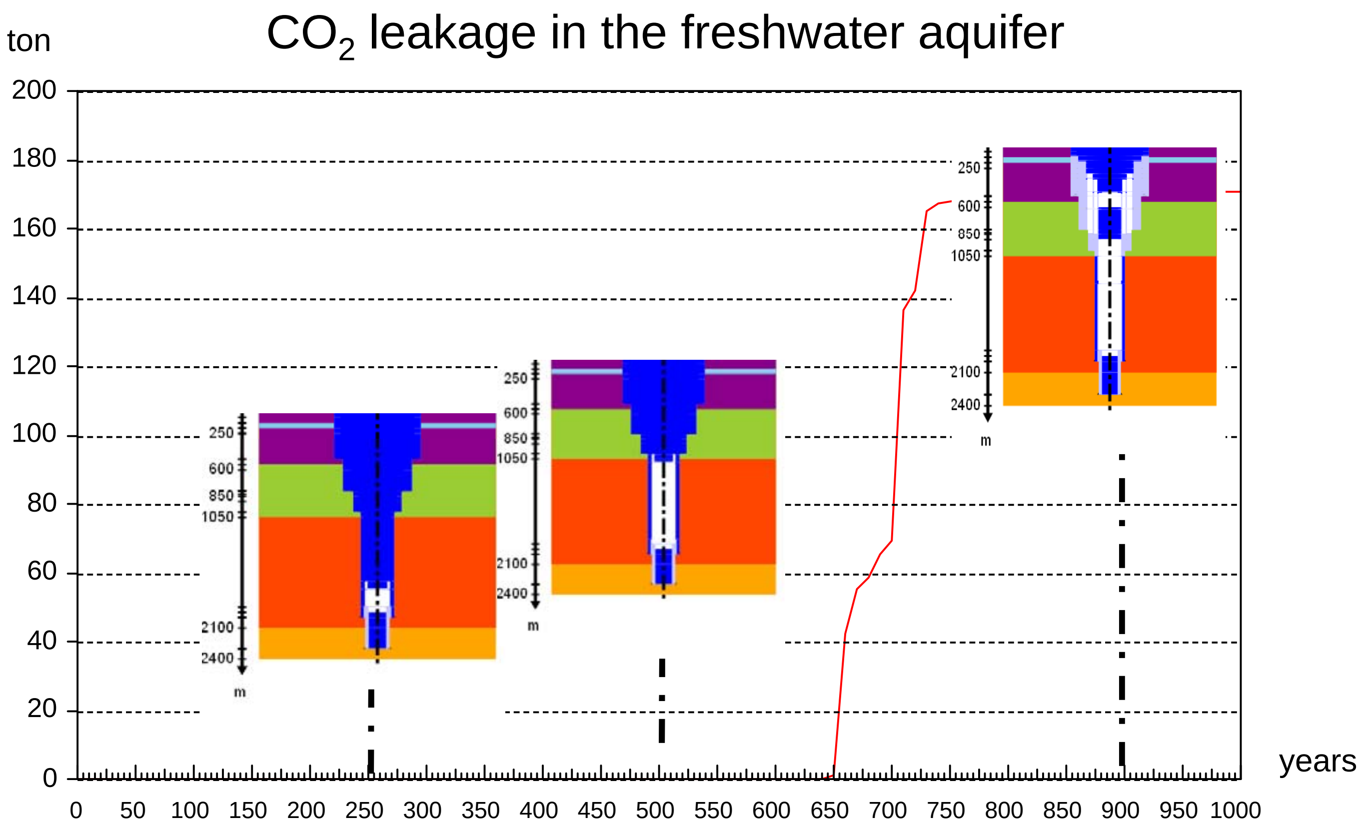
Hydrostatic pressure along the wellbore

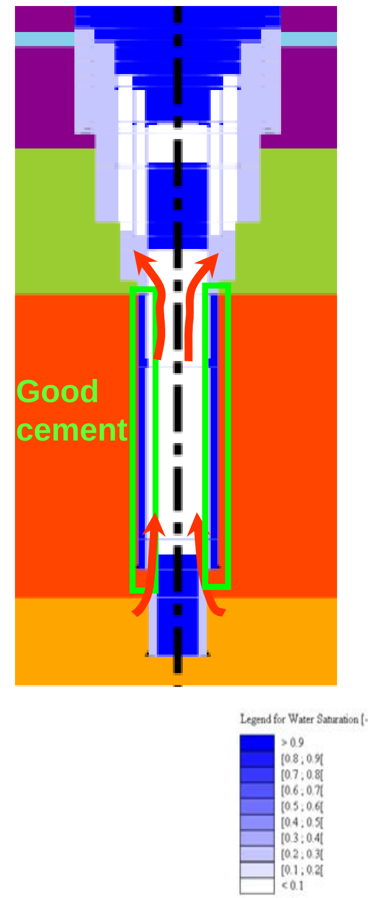
Top reservoir CO2 pressure in contact to the well: 400 bar (cste over time period, conservative)

xand Risk Management Solutions

4. Simulations – CO2 flow results

- **Simulation results (an example for a 1st scenario)**



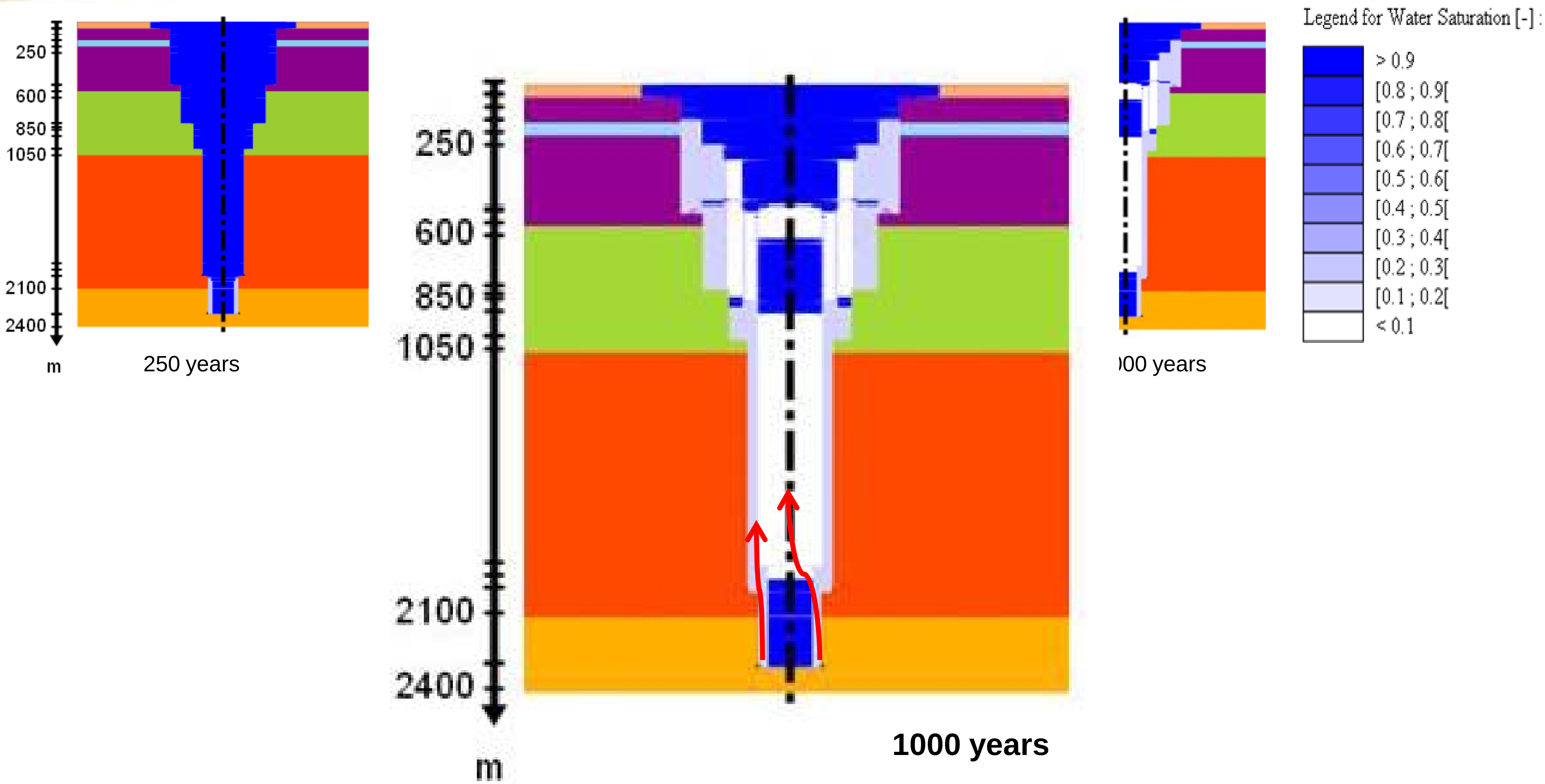


Even though there is good quality cementation in 7'', CO2 flows up.

The CO2 migration paths are not predefined!

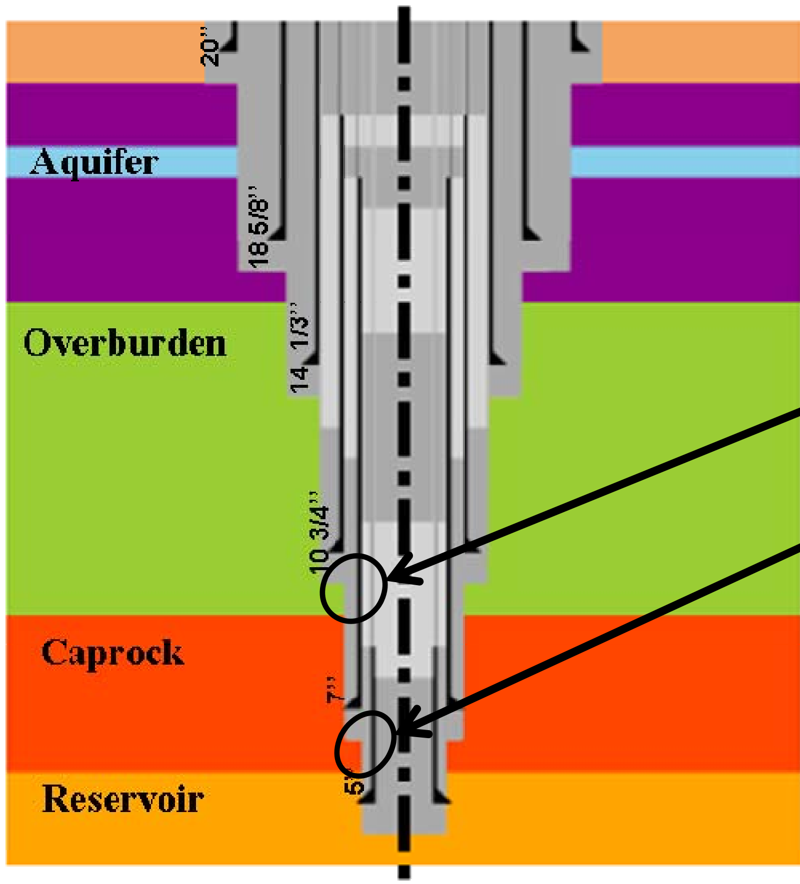
4. Simulations – CO2 flow results

- **Simulation results (an example for a 2nd scenario)**



4. Simulations – risk mapping

Risk mapping at 1000 years



Frequencies \ Severities	1	2	3	4	5	6
6	0	0	0	0	0	0
5	0	0	0	0	0	0
4	64	0	0	8	22	50
3	368	16	48	127	104	489
2	0	0	0	0	0	0
1	0	0	0	0	0	0

Risk sources:

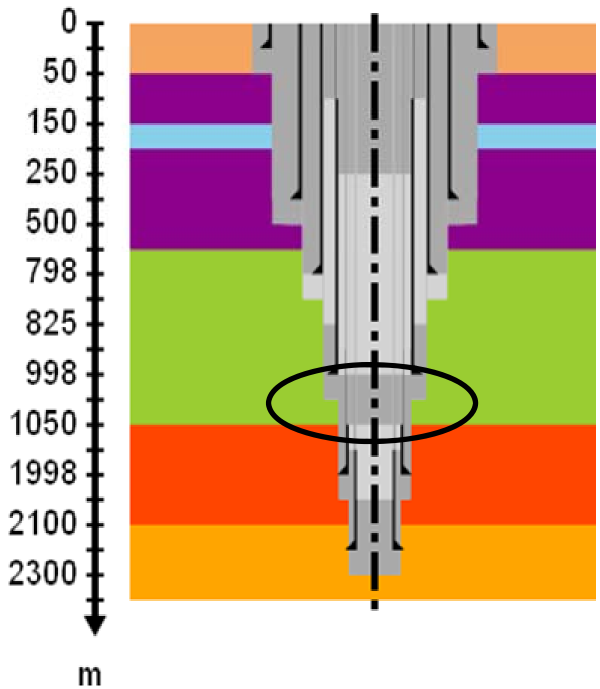
- quality cementation of 5” annulus
- corrosion process above the caprock due to presence saline formation within overburden (aggressive formation fluids)

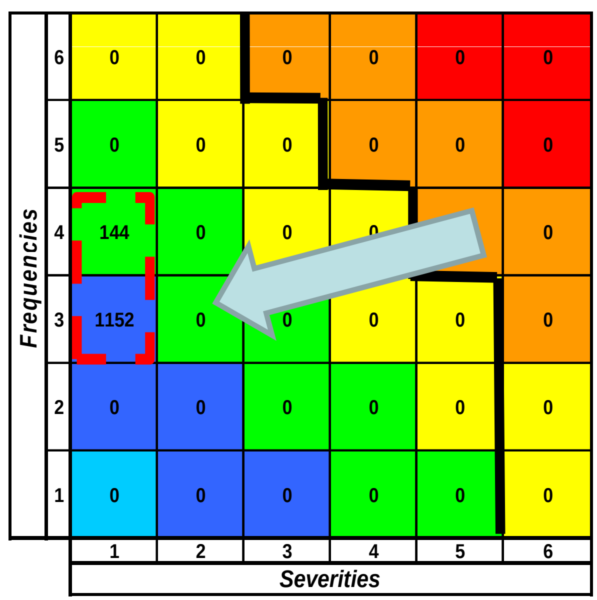
4. Simulations – recommendations & update

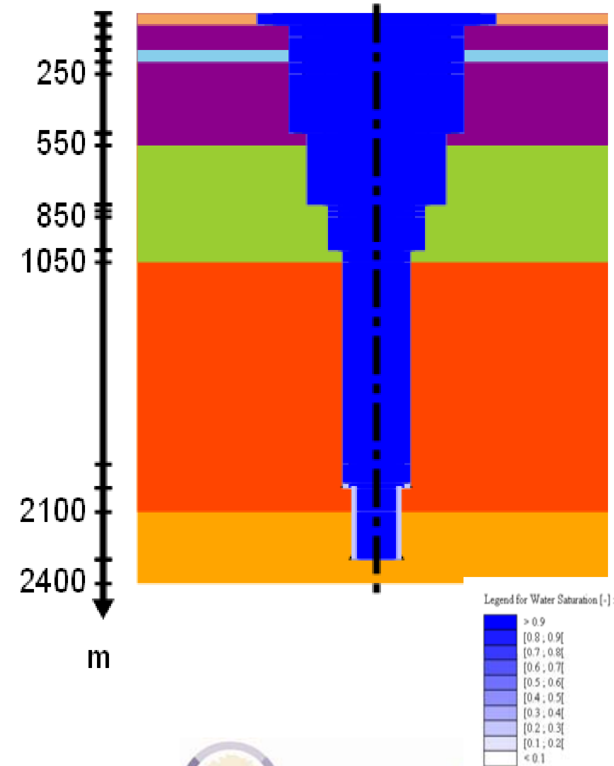
a possible new abandonment design :

- Mill the 7'' casing
- Put a cement plug in front of geological formation layer

Well integrity QRA update







Oxand Risk Management Solutions

5- Conclusion - A tool as Decision Making Support

- **A structure and objective process**
  - A well model, update
- **A predictive CO_2 flow model along the wellbore**
  - Leakage rates towards freshwater aquifer
  - No predefined migration pathways
- **A global rating of the risks related to well integrity in CO_2 storage (vs. CO_2 migration)**
- **A powerful support to the decision-making process**
  - Quantitative and objective elements to support to all major decisions: site selection, well selection, go/no, mitigation and monitoring strategy, design strategy, MMA procedure

Thank you

Qualitative and semi-quantitative risk assessment methods to evaluate potential CO_2 leakage pathways through wells

Claudia Vivalda - Schlumberger

Outline

- Context
- Qualitative and Semi-quantitative Risk Assessment Methods
  - Methodological Approach
  - Implementing Procedure
- Discussion

Context

- During initial stages of project life-cycle, i.e. screening, preliminary characterization:
  - **data** are often **scarce**;
  - **time** to make **assessment** is **limited**;
  - "**order of magnitude**" of the results is often sufficient.
- **Qualitative and semi-quantitative methods** can be used for **preliminary assessment of wells integrity**

Well Integrity Qualitative and Semi-quantitative Risk Assessment Methodological Approach

Objective: *use of experts' judgment to assess the quality of the wells sealing capacity and the potential for CO_2 leakage with impact on specified targets, e.g. geo-sphere, atmosphere, other resources, …*

STEPS

1. *Site Description*
2. *Wells Description*
3. *Wells characteristics classification*
4. *Leakage pathways identification*
5. *Leakage pathways scoring*
6. *Experts judgment*
7. *Results summary*

Well Integrity Qualitative and Semi-quantitative Risk Assessment Steps description

1. *Site description*
   - **Site description including initial hypotheses for the study.** Usually carried out during characterization phases assuming the site be operated according to pre-designed conditions
2. *Wells description*
   - **General information on the well** and its **history** including degradation effects due to aggressive formations
   - **Wells grouping** in families (optional)
   - **Static model** including a breakdown in zones according to geology, completion components, and a first evaluation of cement quality
3. *Well characteristics classification (optional)*
   - **Experts** initially asked to **evaluate the quality of zonal isolation** for each zone, on a well by well basis. Note: 3 to 5 levels to be used: (very poor), poor, medium, high, (very high quality).
   - **Output** of this step - qualitative: an “indexed” description of the integrity of the seal individually given by each expert per each well or well families

STEPS

1. Site Description

2. Wells Description

3. Wells characteristics classification

4. Leakage pathways identification

5. Leakage pathways scoring

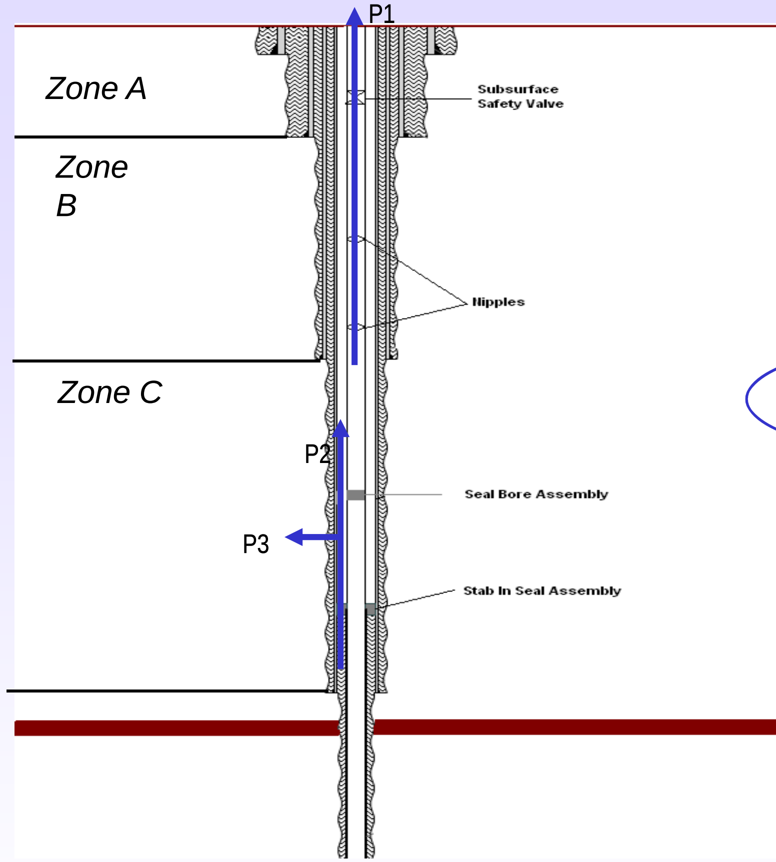
6. Experts judgment aggregation

7. Results summary

Well Integrity Qualitative and Semi-quantitative Risk Assessment Steps description

4. *Leakage pathways identification – METHOD 1*

- Experts asked to identify the potential leakage pathways with respect to a type of impact, for example geo-sphere, atmosphere, …
- Leakage paths built by combining predefined degraded features (failure modes) in each well sub-zone



P1: Direct path to surface
P2: Secondary leak path via inner cementation
P3: degradation of casing

STEPS

1. *Site Description*
2. *Wells Description*
3. *Wells characteristics classification*
4. *Leakage pathways identification*
5. *Leakage pathways scoring*
6. *Experts judgment aggregation*
7. *Results summary*

Well Integrity Qualitative and Semi-quantitative Risk Assessment Steps description

4. *Leakage pathways identification – METHOD 2*

- Experts asked to fill in a risk register where hazardous events pertaining to a specific well zone (degraded features) are recorded, …
- Leakage paths built by selectin / combining hazardous events according to the following:
  - Single events: hazardous events that singly are at the origin of a potential CO_2 leakage from the storage to the targets. Each of them represents a potential leakage path.
  - Combined events: hazardous events with the potential to evolve into a leakage path if combined with other events.

STEPS

1. Site Description

2. Wells Description

3. Wells characteristics classification

4. Leakage pathways identification

5. Leakage pathways scoring

6. Experts judgment aggregation

7. Results summary

Nb	Hazard Title	Hazard description	Causes	Consequences		Likelihood	Severity		Barriers	Control measures
				Local	Site level		Local	Site Level		
28	Sealing failure elem. 3	Increase cement permeability	P and T cycle	Potential for CO2 leakage	None		C2			
33	Sealing failure of tubing	Flow path between tubing and annulus above parker	Corrosion - erosion	Potential for CO2 leakage	CO2 leakage to atmosphere		C3			

Severity (Local)	Containment	
Minor	C1	No potential for hazardous event escalation. Hazardous event cannot contribute to a leakage path.
Medium	C2	Potential for hazardous event escalation if combined with other events. Hazardous event can evolve into a leakage path if combined with other events.
High	C3	Potential for single hazardous event escalation. Hazardous event corresponds to a leakage path.

Well Integrity Qualitative and Semi-quantitative Risk Assessment Steps description

5. *Leakage pathways scoring*

- **The credible leakage pathways scored.** They are representative of the well leakage risks.
- Scoring made with respect to the **likelihood** of occurrence of the leakage pathway and the **severity** of the consequences.
- **Likelihood** classed in **categories**. Two possibility:
  - Method 1: assessment of the **likelihood of the leakage pathway**
  - Method 2: assessment of the **likelihood of the hazardous events composing the leakage pathway** and mathematical calculation of the overall likelihood

- **Severity** classed in categories per **type of impact.**
- **Risk matrices** used to **record the scored pathways** of all the wells with respect to a type of impact. The matrix is used to **screen the wells** from the most critical (high L and S) to the less.

Likelihood	Qualitative definition	Quantitative definition (statement)	Quantitative definition (probability)
Improbable (1)	Highly improbable it occurs	... probably not at all; never.	<0.01%
Unlikely (2)	Unlikely it occurs but not impossible	... fewer than 1 time among the 1000 similar wells.	0.01% to 0.1%
Possible (3)	Light possibility it occurs	... Between 1 to 10 times among the 1000 similar wells.	0,1 to 1%
Likely (4)	Not negligible possibility it occurs	... Between 10 to 100 times among the 1000 similar wells.	1 to 10%
Probable (5)	The event can occur	... in most or nearly all cases.	10 to 100%

Severity	CO2 Leakage
Light (1)	No detectable CO2 leakage. No abnormal modification of composition of underground water or vegetation.
Serious (2)	CO2 Leakage detectable at measurable levels with specific techniques (ppms). Light evidence (e.g. light modification of composition of underground water or vegetation).
Major (3)	CO2 Leakage detectable in monitored points. Clear evidence but without consequences (e.g. modification of composition of underground water or vegetation around the leakage area).
Catastrophic (4)	Substantial CO2 Leakage. Require immediate action but controllable (e.g. the area have to be evacuated. CO2 injection should stop).
Multi-Catastrophic (5)	Massive CO2 Leakage. Uncontrollable.

S \ L	I (1)	U (2)	P (3)	L (4)	Pr(5)
L (1)					
S (2)					
M (3)					
C (4)					
MC (5)					

STEPS

1. *Site Description*
2. *Wells Description*
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7. *Results summary*

Well Integrity Qualitative and Semi-quantitative Risk Assessment Steps description

6. *Experts' judgment aggregation*

- **Statistical methods used to aggregate the individual expert judgments** concerning each specific well (integrity zones and L and P of pathways).
- In case of **large dispersion of judgments** with respect to one or more wells, **discussion during a group meeting** to solve conflicts and reach a consented estimation. In the case of no consensus, reasons recorded and actions taken.

Steps implemented for the integration of the experts review:

1. **Well by well (or family)**, go through the pathways description given by each expert, **group the equivalent pathways** recording the expert name, and compile a final list of all the credible pathways
2. **Well by well (or family)**, and **pathway by pathway**, **statistically aggregation of L and S estimations**. For the aggregation, fitting of the individual scoring related to L and S on a distribution and calculation of the mean and the confidence interval.
3. **Well by well (or family)**, pathway by pathway, **mapping of the pathway** position **on the risk matrix** by using L and S mean values and their confidence intervals.

STEPS

1. Site Description

2. Wells Description

3. Wells characteristics classification

4. Leakage pathways identification

5. Leakage pathways scoring

6. Experts judgment aggregation

7. Results summary

Well Integrity Qualitative and Semi-quantitative Risk Assessment Steps description

7. *Results summary*
   - Use of **one criticality matrix** per type of **impact**
   - **Record leakage pathways** per well (family) on the criticality matrix
   - **Initial well ranking** based on the number of pathways in the most critical areas of the matrix
   - Rationale and discussion

S \ L	I (1)	U (2)	P (3)	L (4)	Pr(5)
L (1)					
S (2)		P3	P2		
M (3)					
C (4)				P1	
MC (5)					

STEPS

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Well Integrity Qualitative and Semi-quantitative Risk Assessment
Expert panel sessions

- **6 to 8 experts** selected for the assessment with expertise on well design, construction, operation, cement and cementing, completion, CCS, geosciences.
- Example. Three experts' sessions run.

  Session 1 - Get together. Experts are gathered for 1 day meeting to:

  - Be briefed about the site and the wells characteristics
  - Be introduced to the methodological approach for qualitative assessment
  - Make a 'simulation" exercise in class to train on the process and clarify misunderstanding

  Session 2 – Individual

  - At "home" experts assess the wells and compile the results according to a predefined format.

  Session 3 – Second get together

  - The final results of the assessment presented. Potential high dispersions among the judgments on specific wells discussed with the experts, conflicts possibly solved and consensus on a final estimation. Possible non-consensuses recorded and identification of a few actions to deal with concerned wells.

Structure for Expert Elicitation

Project Phases

- **Site screening**
  Pre-characterization
  - **Limited Information Available**
    - **Experts: collate information;**
      Estimate key parameters & their uncertainty
      - **Perform preliminary risk analysis**
        - **Elicit experts for likelihood & severity**
          Individual interview
          - Average judgments
            Separate non-consensus
            - Decide for further characterization
        - or
        - **Elicit experts for likelihood & severity**
          Get together
          - Organize 1 (max 2) sessions
            - Average judgments
              Separate non-consensus
              - Decide for further characterization
  - or
  - **Large Information Available**
    - CONTINUE …

Project phases

- Site selection
- Site screening
- Characterization
- Design
- Injection
- Long term storage/surveillance

What for …

- Preliminary assess the quality of the **sealing potential of existing wells**
- **Compare** perceived **integrity** of set of **wells**
- Determine the **need** for **further characterization** (e.g. additional measurements, sampling, lab tests, etc.)
- Determine **mitigating measures** and their **implementation plan**
- Etc.

Likelihood, Severity & Criticality Matrix

Likelihood	Qualitative definition	Quantitative definition (statement)	Quantitative definition (probability)
Improbable (1)	Highly improbable it occurs	... probably not at all; never.	<0.01%
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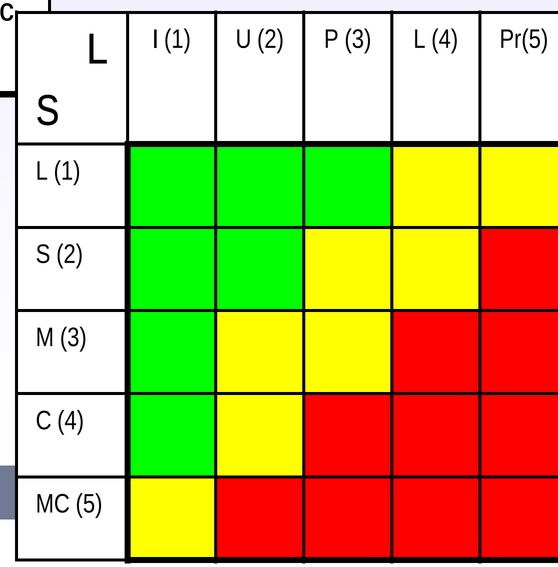


The ERCB's Involvement and Approach to Carbon Capture and Storage

Tristan Goodman, Ph.D.

Advisor to the Chairman

May 13, 2009

ERCB Energy Resources Conservation Board

Presentation Overview

1. The term “Carbon Capture and Storage” (CCS) and the ERCB
2. Current ERCB CCS Approach
3. Work with Government of Alberta
4. CCS Development Council
5. Alberta Economic Development Authority
6. ERCB CO2 Sequestration Initiative
7. Recommended Next Steps

ERCB Energy Resources Conservation Board

The Energy Resources Conservation Board

- An independent provincial agency of the Alberta government
- Primary regulator for the upstream oil and gas business in Alberta
- Adjudication, regulation and information collection/dissemination
- Alberta Geological Survey
- Decisions are in the public interest based on prevention of resource waste, public safety and the natural environment
- around 1,000 staff – about 500 are technical

ERCB Energy Resources Conservation Board

ERCB and CCS

- **CCS is the GOA accepted description of:**
  1. Enhanced oil recovery using CO_2 (EOR),
  2. Storage of CO_2,
  3. Permanent disposal of CO_2 (i.e. sequestration).
- **ERCB has regulations for EOR, storage and permanent disposal**
- **ERCB currently regulates CO_2 disposal under its acid gas regulations**
- **ERCB has 20+ years of experience with CO_2 injection in Alberta on a small scale**

ERCB Regulatory Focus to Date

- In Alberta focus has been on "depleted" oil and gas reservoirs and saline aquifers at depths of 1500 to 3000 meters.
- Containment of the CO2 in the subsurface once injected, has been the focus of regulations to date.
- Research and regulatory development has shifted from examination of reservoir to wellbores.
- Also greater focus on emerging surface infrastructure.

ERCB Energy Resources Conservation Board

CO2 Injection Scheme

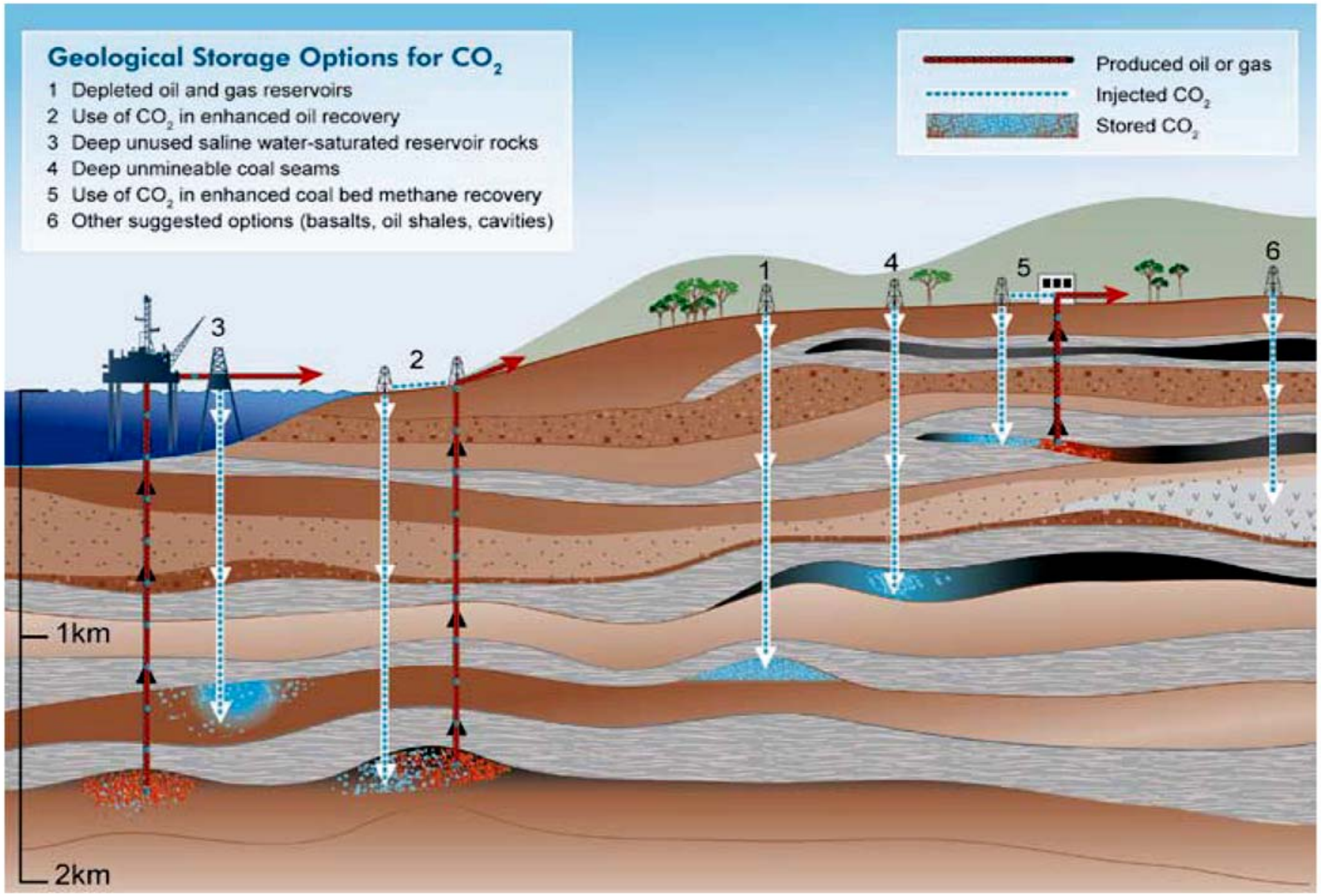
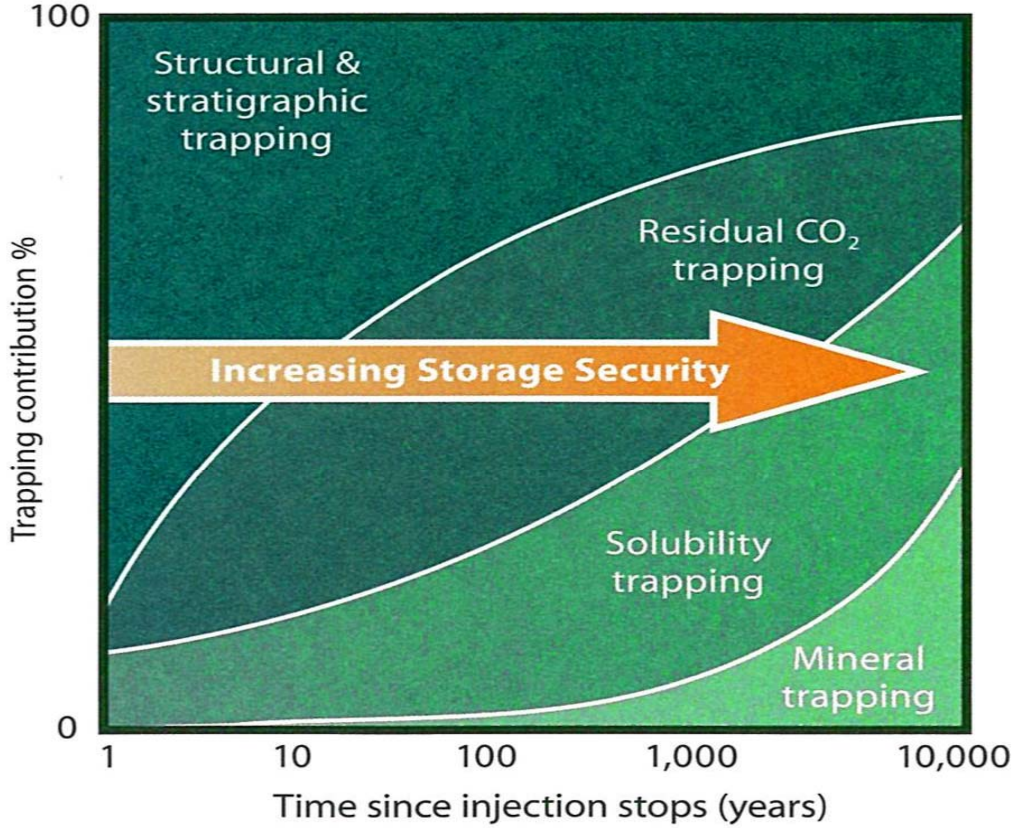


Figure 5.3 Options for storing CO_2 in deep underground geological formations (after Cook, 1999).

Timeline Diagram for CO2 Reaction in Subsurface



Source: Golder and Associates, 2007

ERCB Energy Resources Conservation Board

Current Approved Projects

- **11 approved EOR projects using CO_2**
- **Main industry operators are:**
  - **Penn West (Joffre field/Viking pool)**
  - **Glencoe Resources (Chigwell field/Viking pool)**
- **High recovery factors when CO_2 used in EOR**
- **49 acid gas wells in the province**
  - **12 can be considered CO_2 permanent disposal (i.e. sequestration)**

ERCB Energy Resources Conservation Board

Alberta’s Capacity

- Estimated EOR capacity available in Alberta to store 20 to 35 Mega tons per year of CO_2
  - Produce 2 to 3 billion barrels of incremental oil
- Estimated sequestration capacity is not yet determined but ball parks by experts is estimated to be at 3 Giga tons of total capacity (Basal Cambrian is main focus).
- GOA has committed to 139 mega tons using CCS technology by 2050 (likely to change in the future).

Coordinated Approach with other Government bodies to Manage CCS

1. **Other government agencies are involved in application, operational and closure stage of CCS projects.**
2. **ERCB staff have met with other government staff to discuss technical issues around a comprehensive framework (Energy, Environment, SRD, etc) and a coordinated approach.**

Carbon Capture and Development Council

- Council has develop Alberta's plan to move ahead with CCS in Alberta - Chaired by Jim Carter
- 3 sub groups (technical, legal/policy, economic)
- Interim-report was released in October, final report shortly
- ERCB committed to providing a sequential overview of the application process for a CCS application.
- Public concern around safety determined to be significant issue in the future.

ERCB CO2 Sequestration Initiative

- **Two Phases**
  - **Phase One = conducts high level analysis on existing regulatory framework to determine:**
    - Gaps in existing regulations
    - ERCB jurisdiction and areas that are not clear
    - Areas where regulatory enhancements may be required
    - Sequentially document the ERCB application process for a CO_2 sequestration applicant
  - **Phase Two = Manage gaps, conduct additional analysis if required and implement regulatory enhancements**

ERCB Energy Resources Conservation Board

CO_2 Sequestration ERCB Life Cycle

Capture of Co2

- This involves the source of CO_2 (not in ERCB Jurisdiction

Pipelines

- Rail and truck are also transport methods but are not regulated by the ERCB

Injection

- Involves well construction and completion

Sequestration (Disposal)

- This deals with the reservoir and containment

Post-operational and Closure Monitoring

- Deals with long-term financial liability, any potential remediation and what type of monitoring at post closure is needed.

Phase One Conclusions

1. ERCB has processes in place to disposition applications for CO2 sequestration
2. Continue to treat CO2 under acid gas regulations
3. Maintain ERCB existing application process of specific regulatory requirements and scheme specific approvals.
4. Subsurface monitoring is important and should continue in future approvals.
5. Future approvals require detailed assessment of existing producing, suspended or abandoned wellbores in the area of influence to the injector.
6. Continue to work with GOA to provide advice on areas that could impact the ERCB's regulatory framework.

Five Areas for Possible Regulatory Enhancements

1. Injection wellbore construction practices
2. Well abandonment requirements
3. Public notification requirements for CO2 sequestration schemes
4. Regulations that ensure integrity of all wells in the area of influence
5. Regulatory requirements for converting existing wells to CO2 injectors

Recommended Phase II Work

1. Examine ERCB jurisdiction on CO_2 sources
2. Ensure consideration of CO_2 in re-writes of Directives
3. Examine reservoir characteristics and performance criteria for CO_2 schemes (pressure, injection rate, etc.)
4. Review existing acid gas disposal approval conditions
5. Determine type and degree of operational monitoring for large scale projects
6. Continue work with GOA on jurisdiction and coordinated approach
7. Determine approach for injection volume tracking
8. Pipeline release considerations
9. Continued work on wellbore research

ERCB Energy Resources Conservation Board

Key ERCB Contacts:

Dr. Kevin Parks – Alberta Geological Survey, Provincial Geologist

Dr. Tristan Goodman, Advisor to the Chairman

Mr. Herb Longworth, Senior Technical Advisor

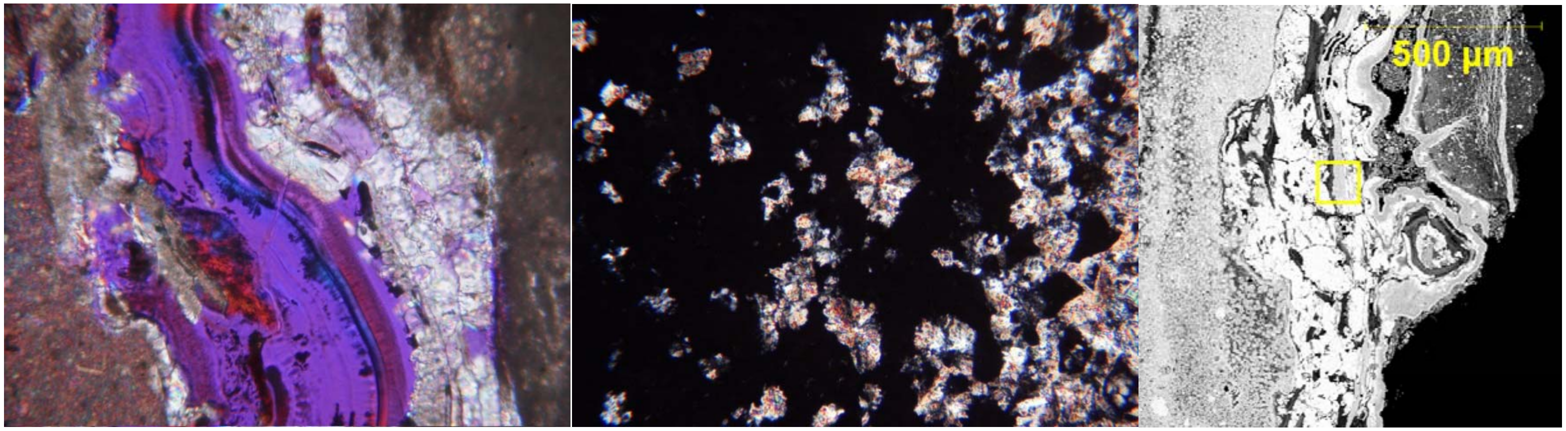
Well Abandonment Practices

IEA GHG Wellbore Integrity Network Meeting
Calgary, May 13, 2009

TNO | Knowledge for business

Tjirk Benedictus

NATIONAL ENERGY TECHNOLOGY LABORATORY



Natural CO_2 Sequestration Analogs in Wellbore Cement Integrity Assessment

National Energy Technology Laboratory: Barbara Kutchko, Brian Strazisar, Nicolas Huerta, George Guthrie

Los Alamos National Laboratory: Bill Carey

RJ Lee Group Inc.: Neils Thaulow

WBI Seminar May, 2009

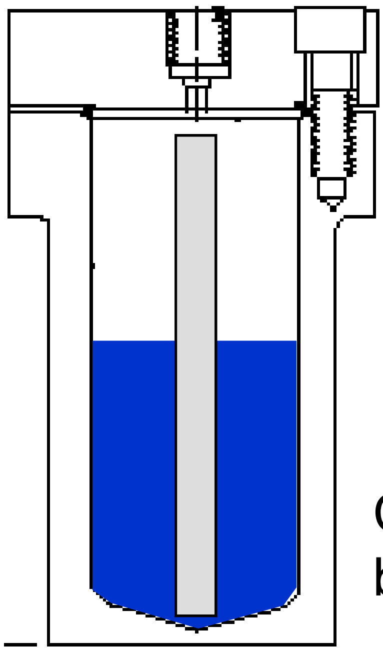
Wellbore Integrity and CO_2 Storage

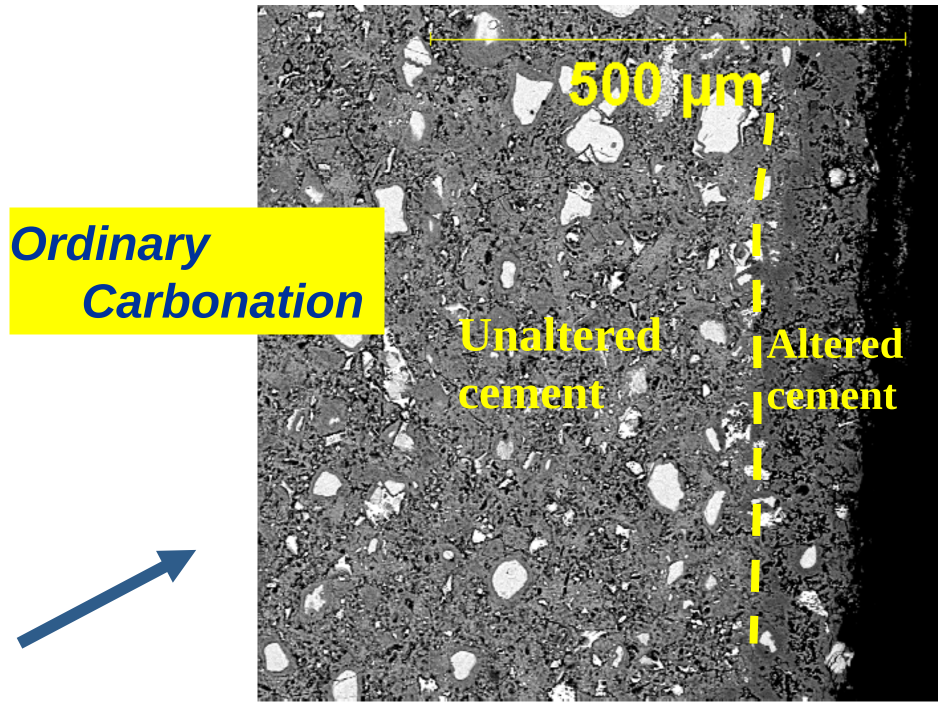
- **In the field, cement microstructure and permeability can be affected by a variety of processes:**
  - Cement Type
  - Cure Conditions
  - Additives
  - CO_2 Properties
    - CO_2-saturated brine
    - Supercritical CO_2
  - Brine Composition
  - Formation Rock Type
- **Can we understand what happens in the field by simulating various conditions in the lab?**
- **How does CO_2 affect chemical/physical properties of cement over time?**
  - Narrow uncertainties with series of experiments

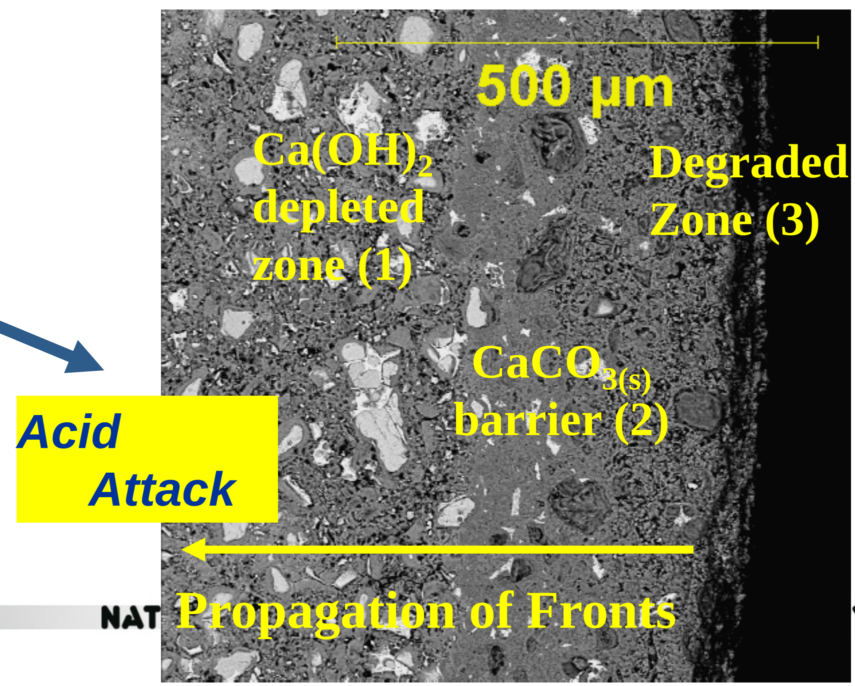
Lab Experiments

Simulate injected CO_2

- Hydrodynamic trapping
- Solubility trapping







Kutchko et al., ES&T 2007, 2008

CO_2-Saturated Brine Exposure

Proposed Alteration Mechanism

1. **Dissolution of $Ca(OH)_{2(s)}$ (zone 1) and precipitation of $CaCO_{3(s)}$ (zone 2)**

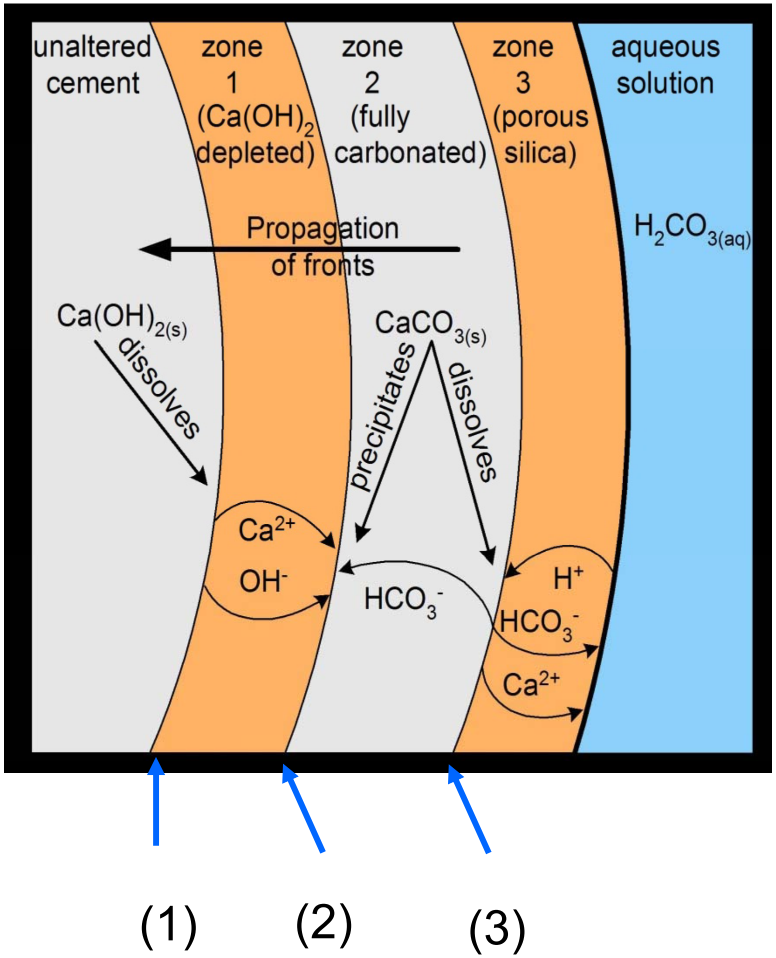
(1) $Ca(OH)_{2(s)} \rightarrow Ca^{2+}_{(aq)} + 2OH^-_{(aq)}$

(2) $Ca^{2+}_{(aq)} + HCO_3^-{}_{(aq)} + OH^-_{(aq)} \rightarrow CaCO_{3(s)} + H_2O$

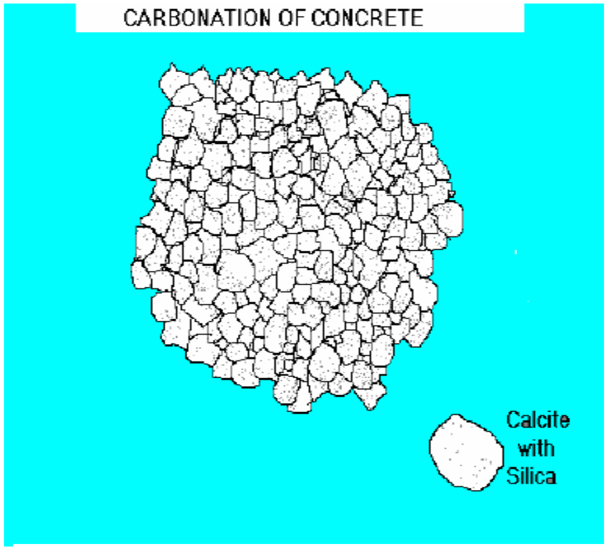
2. **Dissolution of $CaCO_{3(s)}$ and leaching of Calcium ions from the cement matrix (zone 3)**

(3) $H^+_{(aq)} + CaCO_{3(s)} \rightarrow Ca^{2+}_{(aq)} + HCO_3^-{}_{(aq)}$

(4) C-S-H(s) $\rightarrow Ca^{2+}_{(aq)} + OH^-_{(aq)}$ + am-$SiO_{2(s)}$



Kutchko et al., ES&T 2007, 2008



The Good: Ordinary Carbonation

CC is ppt from a supersaturated solution – good binder

Crystals nucleate and grow rapidly

How fast the ppt is compared with migration of species

diffusion < precipitation

low porosity, high strength

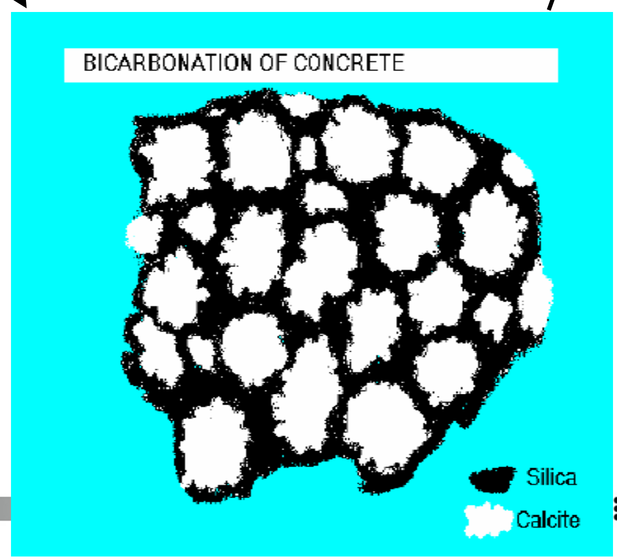
The Bad: Popcorn Carbonation

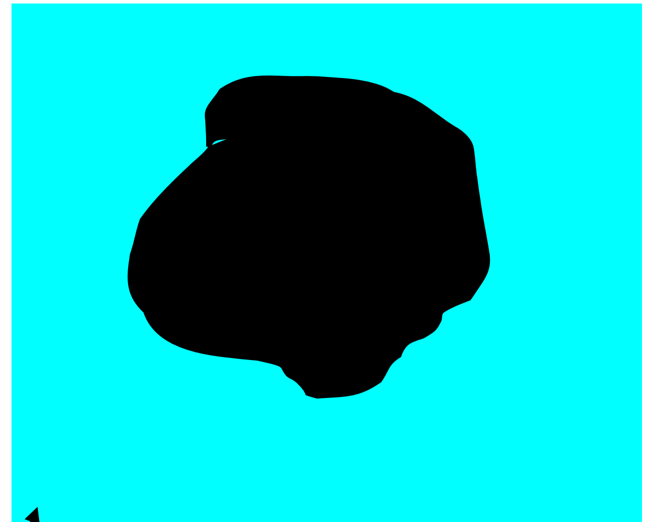
Determined by the balance between available CH and concentration of CO_2 in system

CC is ppt from a low supersaturated solution

Less nucleation sites = larger crystals

diffusion > precipitation





The Ugly: Amorphous Silica Gel/ Acid Attack

End state: furthest extent of reaction

(Carbonate is not sufficient to buffer cement)

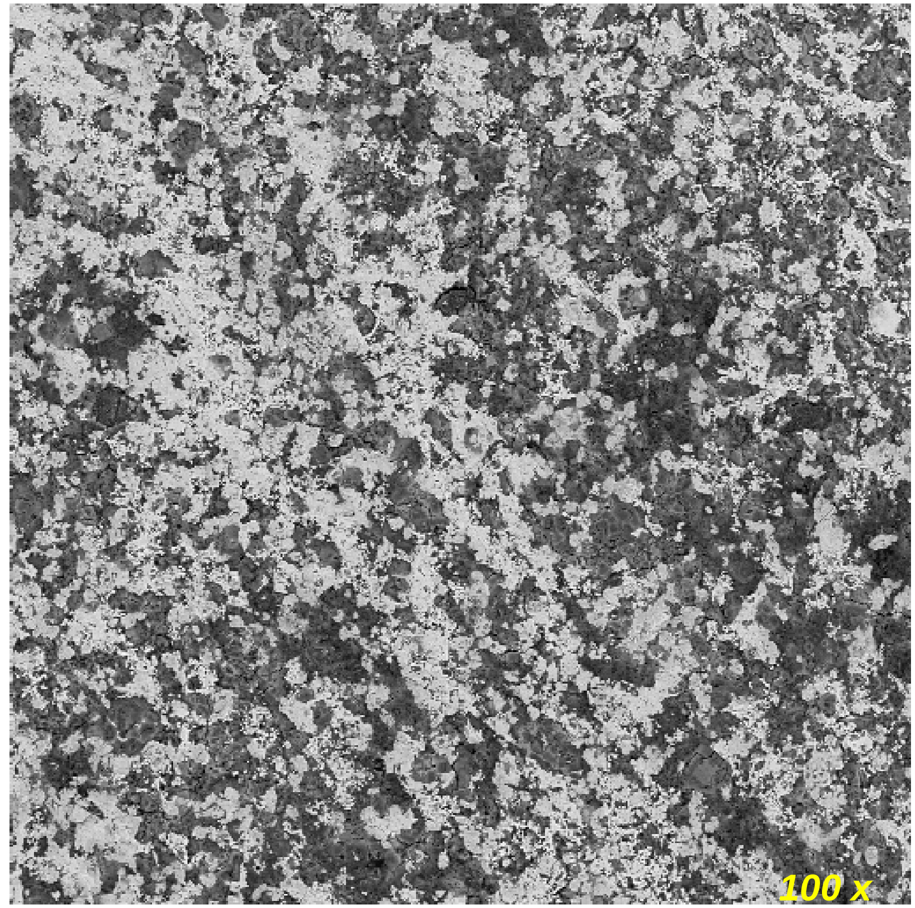
high porosity, low strength

Thaulow et al., 2001

Popcorn Carbonation

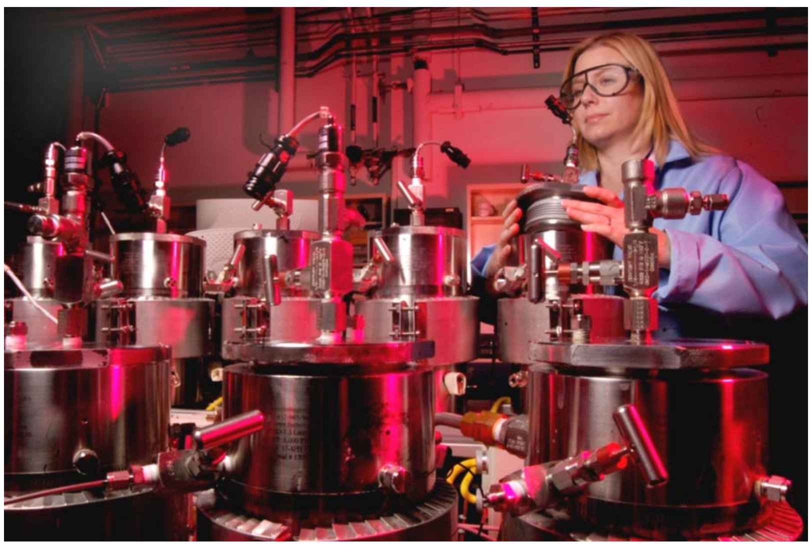
"Popcorn" crystals of calcium carbonate in isotropic matrix of silica gel

- Act as sand grains rather than binding agent.
- New binding agent is now the decalcified silica gel
- *Resulting microstructure is different than ordinary carbonation and acid attack*



Thaulow et al., 2001

How have laboratory experiments provided insight to alterations observed in the field? Comparison of Field and Laboratory Samples



SACROC Case: Neat Portland cement

SACROC Field Sample

Cement Properties:

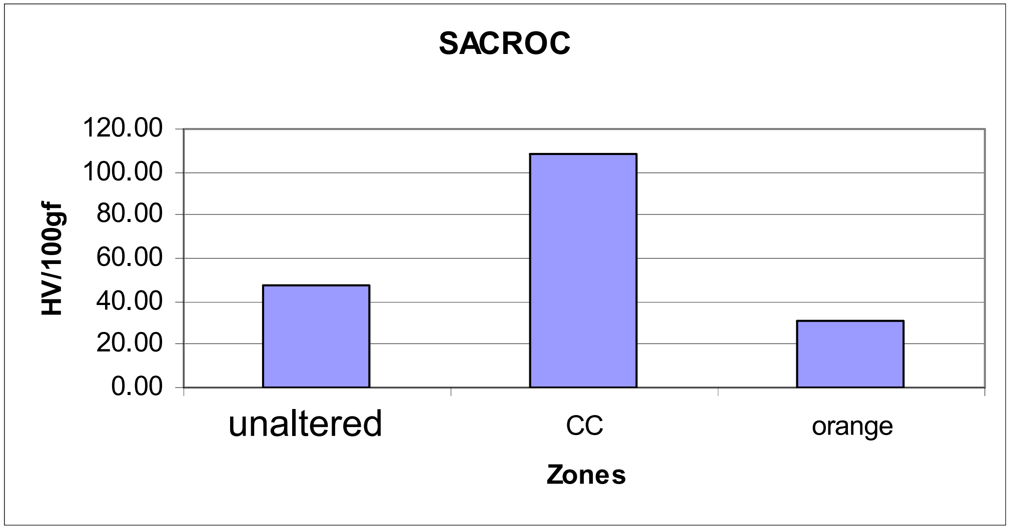
- **Neat Portland cement**
  - Density ≈ 15.5 lb/gal
- **Reservoir T = 54ºC & p = 18 MPa**
- **Exposed to CO_2 at 54ºC & 18 MPa *after 25 years in place***
  - Extensive hydration
- **Exposed to CO_2 (-brine) (EOR) for 30 yrs**
- **Water/cement ratio ??**
- **Brine composition ?? (>1% NaCl)**
- **Alteration depth ranged from 2 – 10 mm**

NETL Lab Samples

Cement Properties:

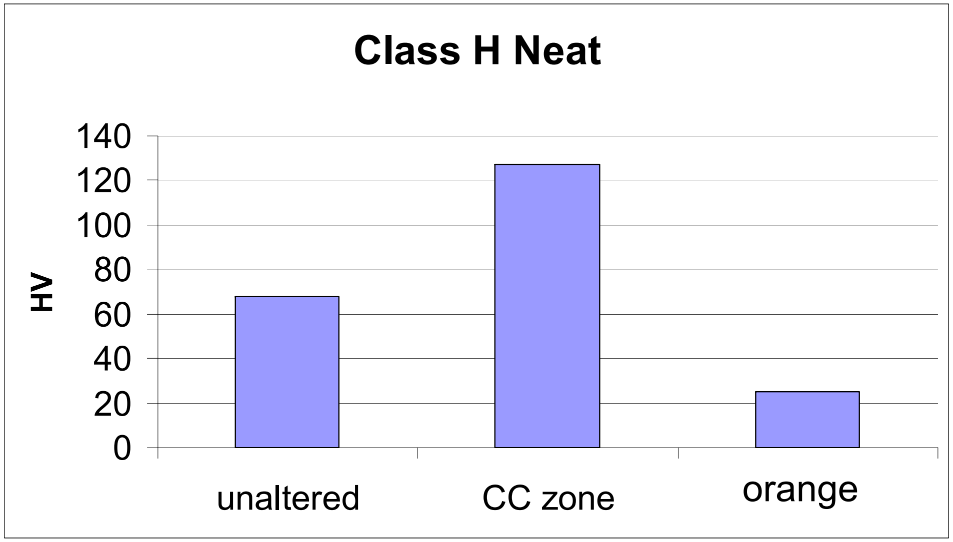
- **Class H neat Portland cement**
  - Density ≈ 16.5 lb/gal
- **Cured at T = 50ºC & p =15 MPa**
- **Exposed to CO_2 at 50ºC & 15 MPa *after 28 days***
- **Exposed to CO_2 (-brine) for 1 year**
- **Water/cement ratio = 38%**
- **Brine composition = 1% NaCl**
  - CO_2 more soluble
- **Alteration depth averaged 1.00 ± 0.07 mm for 30 year extrapolation**

Carey et al., IJGGC 2007; Kutchko et al., ES&T 2008

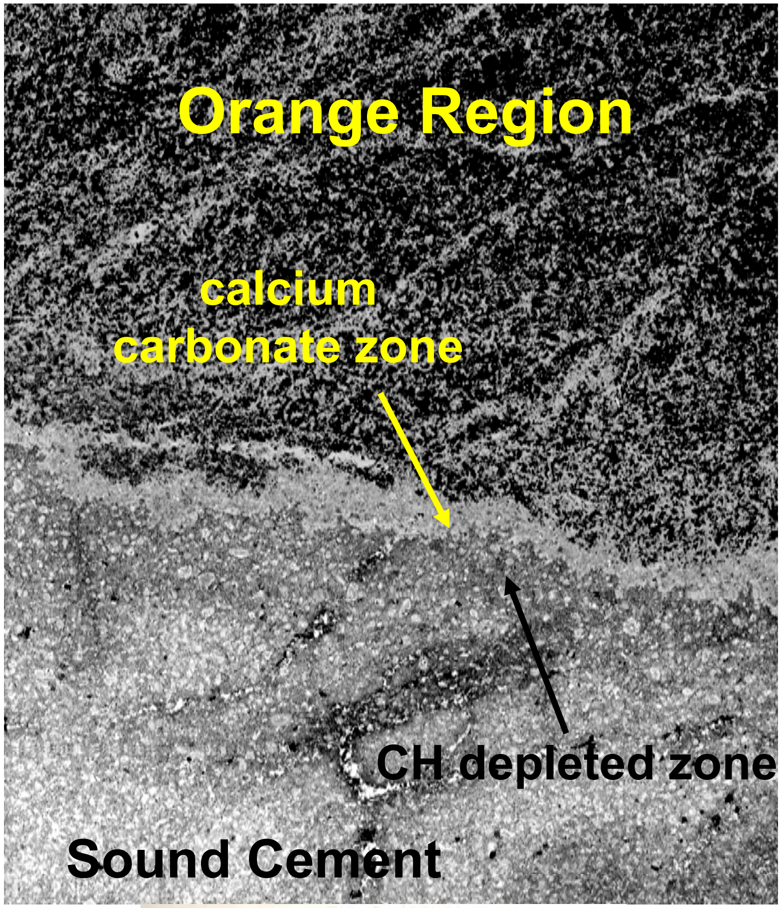


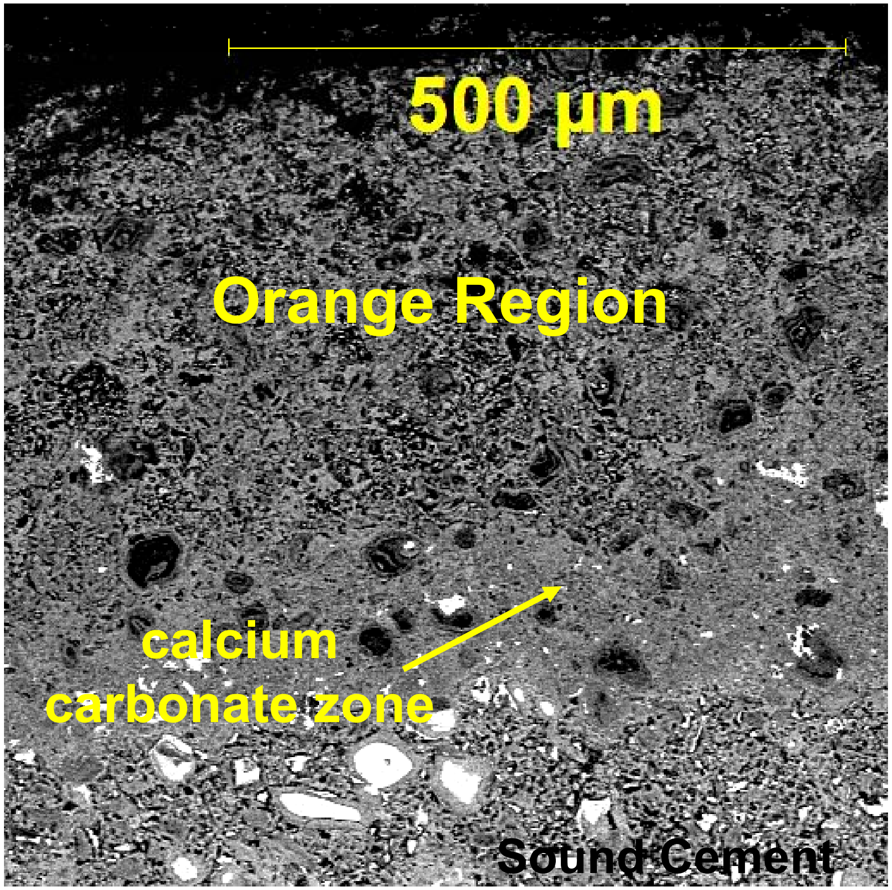
SACROC compared to NETL CO_2-saturated brine lab samples:

- **similar mechanical properties**



Similar Carbonation patterns





LANL SACROC field sample

NETL laboratory sample

Discussion

SACROC Field Sample

Driven by the interaction of CO_2-bearing brines

Alteration induced by carbonation followed by dissolution and precipitation of CC

-altered from C-S-H and CH

-result: *popcorn carbonation*

-indicates higher pH of reaction environment in cement matrix

-CC popcorns will dissolve if CO_2 concentration is high enough to further decrease the pH *(i.e. acid attack)*

CC zone is carbonation front

-acts as a possible diffusion barrier

-migrates through cement followed by dissolution/ precipitation which leads to popcorn carbonation formation

NETL Lab Sample

Driven by the interaction of CO_2-bearing brines

Alteration induced by carbonation followed by dissolution (and leaching) of CC

-altered from C-S-H and CH

-result: *amorphous silica gel*

-indicates lower pH of reaction environment in cement matrix

-aka *acid attack:* end state and furthest extent of reaction

CC zone is carbonation front

-acts as a possible diffusion barrier

-migrates through cement followed by dissolution of CC due to low pH of CO_2-bearing brines

Carey et al. (2007); Kutchko et al. 2008

$SCCO_2$ Alteration of Cements with Pozzolan

CCP Field Sample

Cement Properties:

- **Portland based 50:50**
- **Estimated original reservoir T = 57.7 ºC & p = 10.2 MPa (1480 psi)**
- **Exposed to 96% CO_2 for 30 yrs**
  - Natural CO_2 producer
- **Alteration depth varied along depth of well**

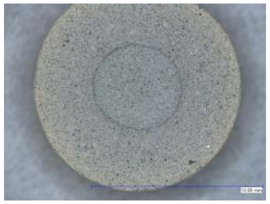
  - indicated alteration by CO_2 migration along cement-formation interface
- **Permeability: increased from ~1 μD to ~ 30 μD**

NETL Lab Samples

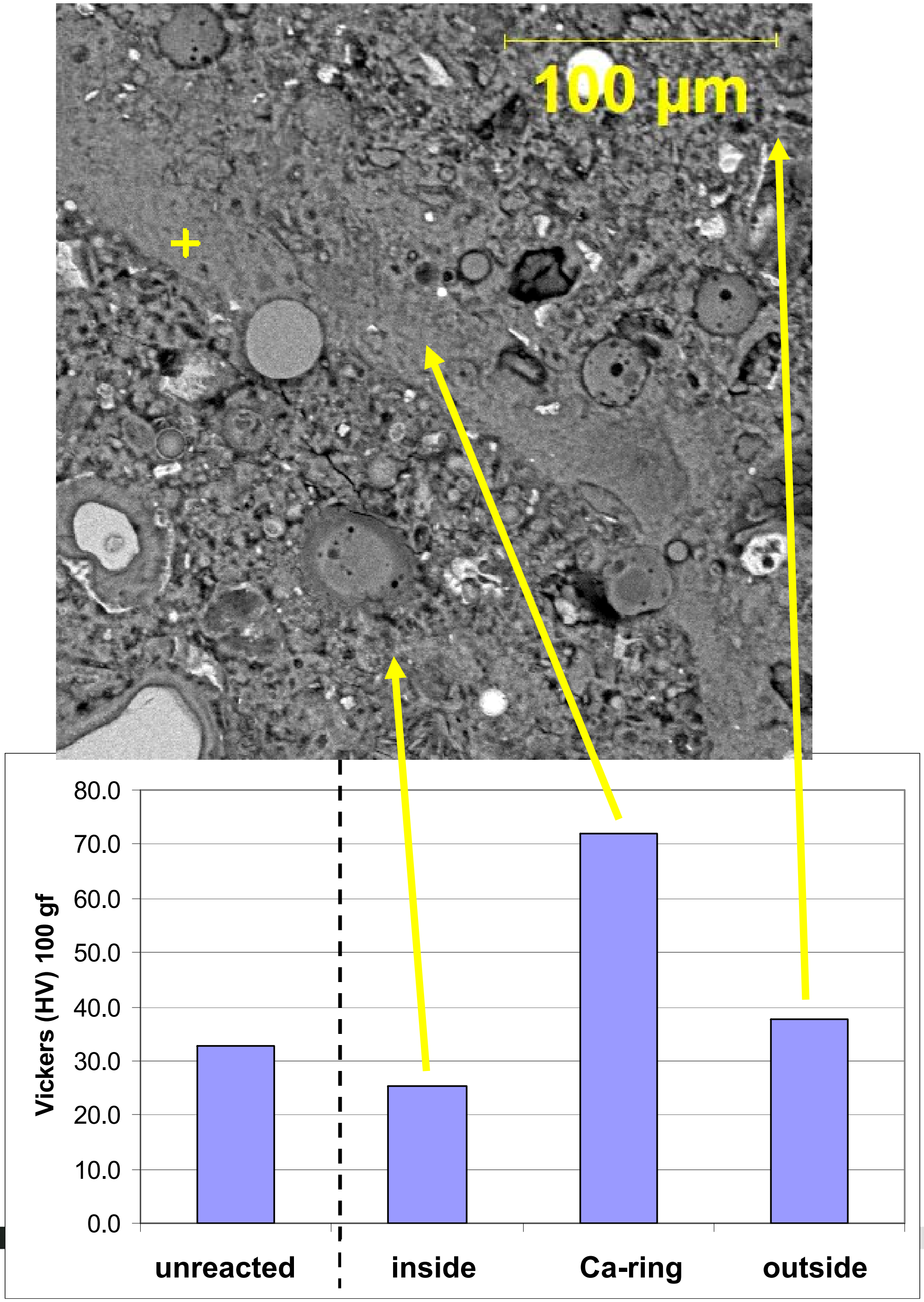
Cement Properties:

- **Class H 35:65 and 65:35**
- **Cured at T = 50ºC & p =15 MPa (2200 psi)**
- **Exposed to CO_2 at 50ºC & 15 MPa *after 28 days***
- **Alteration depth extrapolated to 170 - 180 mm for 30 year**

  - ordinary carbonation observed
- **Permeability: increased from ~1 μD to ~21μD (*65:35)***



Crow et al., CCS 2008; Kutchko et al., ES&T 2009



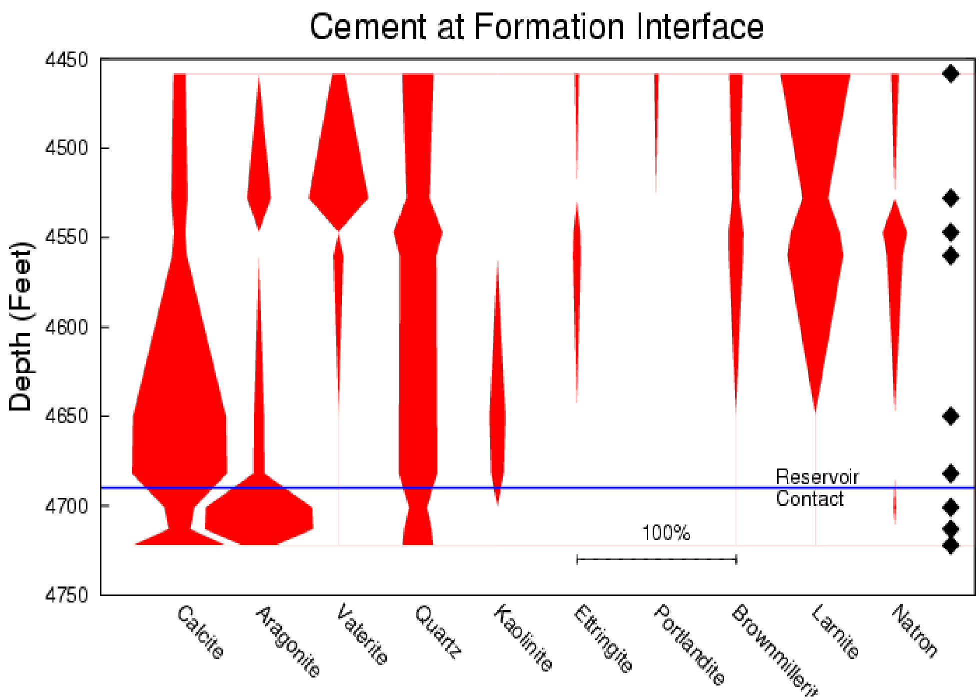
NETL Lab Samples:

- **Thin CC ring**
- **Inside the ring**
  - AFt (ettringite)
    - $[Ca_3Al(OH)_6 \cdot 12H_2O]_2 \cdot (SO_4)_3 \cdot 2H_2O$
  - Chloride
  - Unhydrated Cement grains
- **Outside the ring**
  - No AFt or Chloride
  - Calcium depleted cement grains
  - ***Fully Carbonated***

CCP Samples:

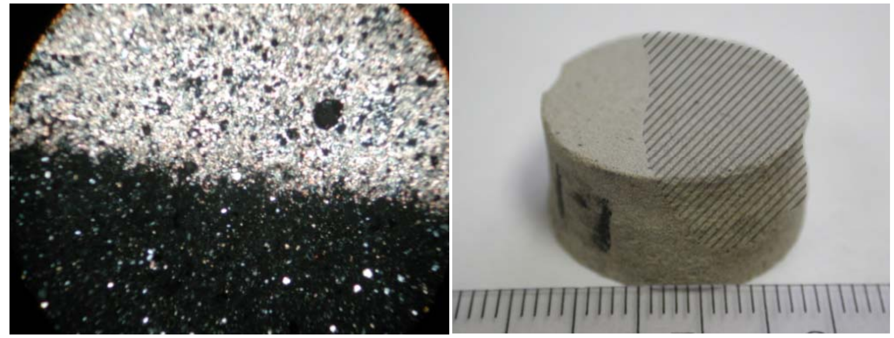
- Relatively uniform carbonation
- No CC rings observed
- Carbonate observed inside and outside reaction fronts

CCP Samples:

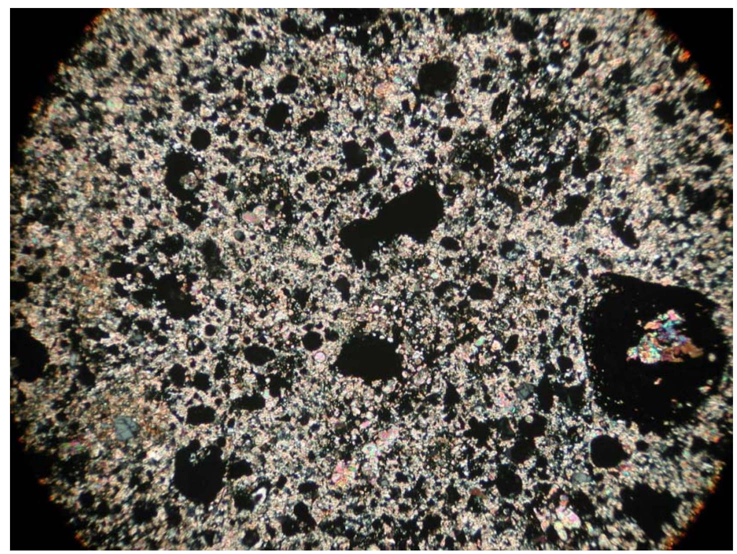


Summary “Pagoda” diagram showing mineral abundances in the cement at the cement-formation interface as a function of depth. The width of the column reflects mineral abundance. Actual sample locations are indicated at right-hand side.

Crow et al., CCS 2008



CCP Samples: PLM and optical images showing a region of carbonation: penetration depth varied depending on sample location (depth) in well



CCP Sample: PLM image showing a carbonated region of the cement

Summary of Field and Lab Observations

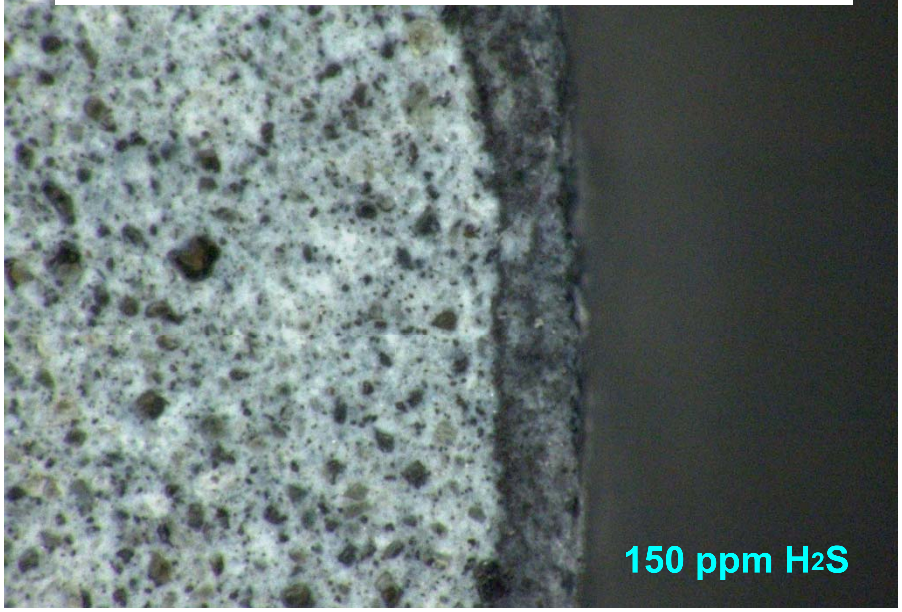
- **Neat Portland cement forms distinct orange zone—calcium carbonate fronts**
- **Pozzolan-bearing cement carbonates more uniformly**
- **Laboratory studies consistent with field in showing that rate of CO_2 penetration in pozzolan-cements is faster than neat cements**
- **In field and laboratory, there is little evidence for mass wasting or loss during carbonation**
- **Carbonation results in increased porosity and permeability but cement still acts as hydrologic barrier**

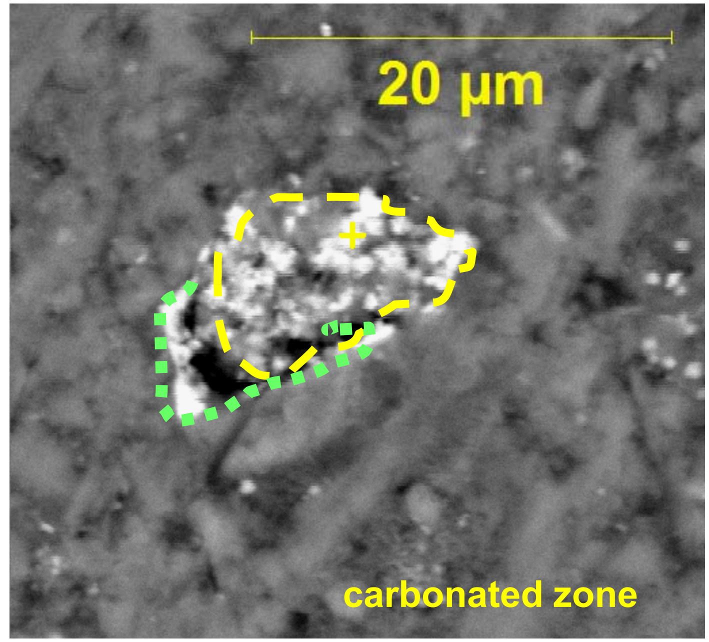
New Experiments at NETL: Can laboratory experiments be used to understand (predict) how cement will respond under other field conditions?

H_2S-CO_2 Cement Exposure Experiments – Preliminary Results

Performed in collaboration with Energy & Environmental Research Center (*EERC*) with Steven Hawthorne and David Miller

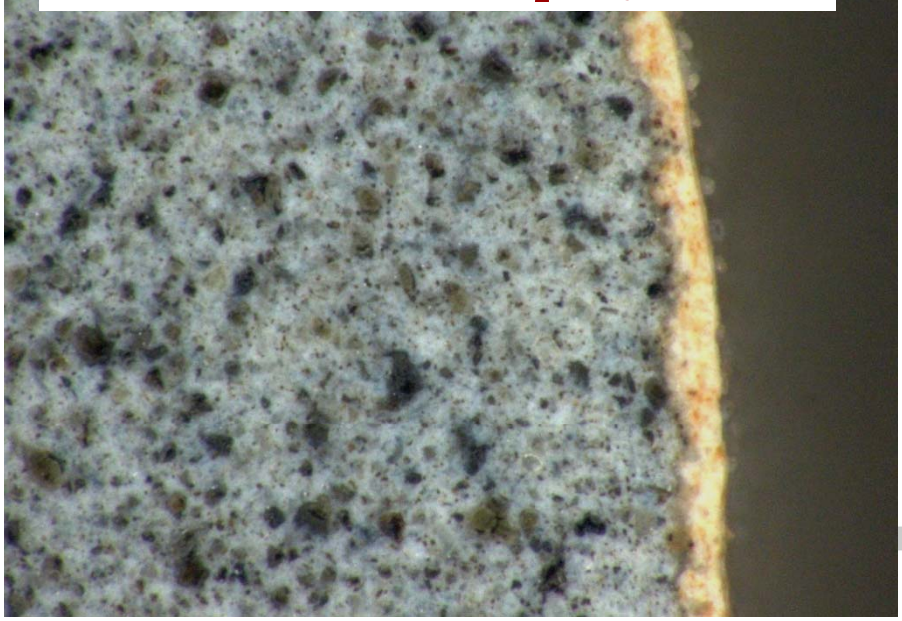
Exposed to H_2S-CO_2

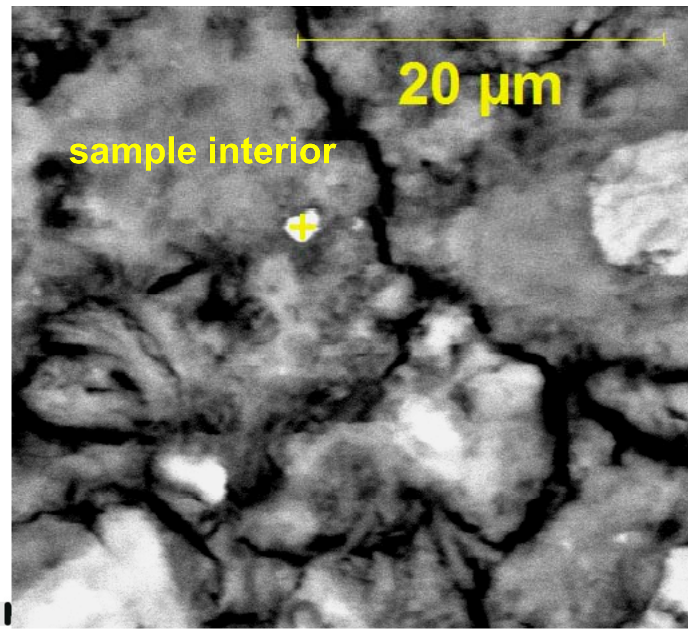




Exposed to H_2S-CO_2

Exposed to CO_2 only





Exposed to H_2S-CO_2

General Conclusions

- **Field samples vs. laboratory samples**
    - Field samples are very complex with complex histories
    - Lab experiments can't match the complexity but can be used to understand general trends
    - Use lab experiments to understand (predict) how cement will respond under different various field conditions

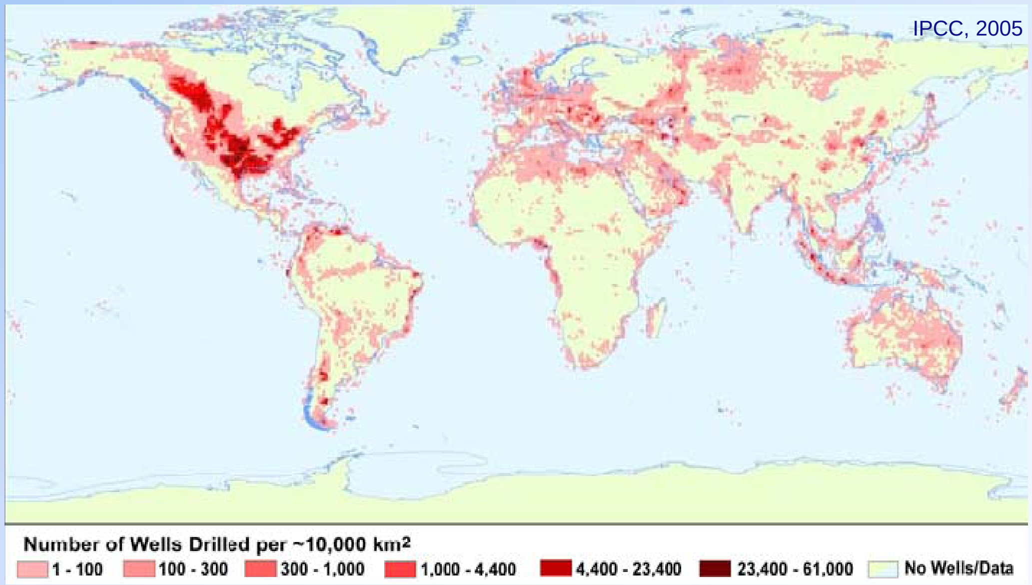
  – **Leakage due *entirely* to chemical degradation of cement will not be a significant concern.**
    - Chemical reaction alone is not going to cause leakage
    - Reaction with cement is diffusion limited and slowed by the precipitation of carbonates

  – **Field Samples indicate that degradation mainly occurs along *existing* or *induced* pathways.**

- **Current and Future Work:**
  – Will pathways be sealed or enhanced by CO_2 exposure?
  – What effect does brine composition have?
  – Effect of H_2S-CO_2(-Brine) on well cement?
    - Simulate acid gas injection

Introduction

- In 2008 TNO was contracted by IEA GHG to conduct a review study into well abandonment practices based on available literature
- Results are to be published as IEA GHG report
- Draft results presented here: any feedback is appreciated!



Scope of the study

- Previously abandoned deep oil and gas wells
- Well abandonment techniques
- High order evaluation of abandonment practices, through:
  - Expert opinions (questionnaire)
  - Governing regulatory frameworks
- Suitability for CO_2 storage
  - Overview of state of knowledge on well material degradation
- Risk assessment
- Recommended best practice

Types of wells

- Regarding CO_2 storage, different types of wells need to be distinguished (after Watson & Bachu, 2007):
  - Future wells
    - Wells directly related to the storage operations (i.e. CO_2 injection or monitoring wells)
    - Wells penetrating or transecting CO_2 storage reservoirs aiming at reservoirs at deeper levels

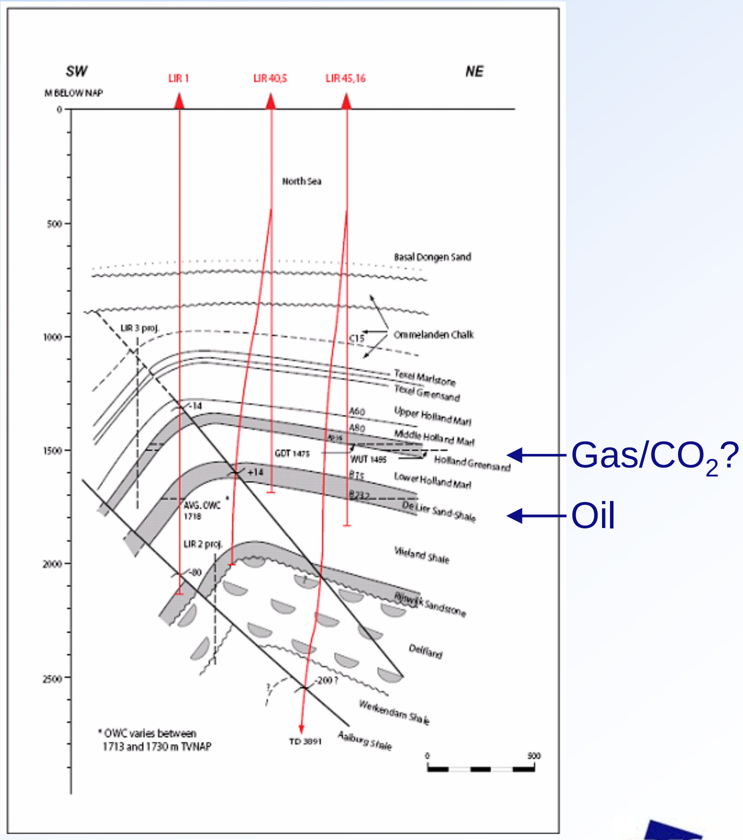
    To be designed and abandoned taking into account CO_2 storage
  - Existing wells **To be abandoned taking into account CO_2 storage**
    - Accessible wells (e.g. operating, shut-in)
    - Previously abandoned wells

    Main risk for well integrity (leakage)

Case study: De Lier (the Netherlands)

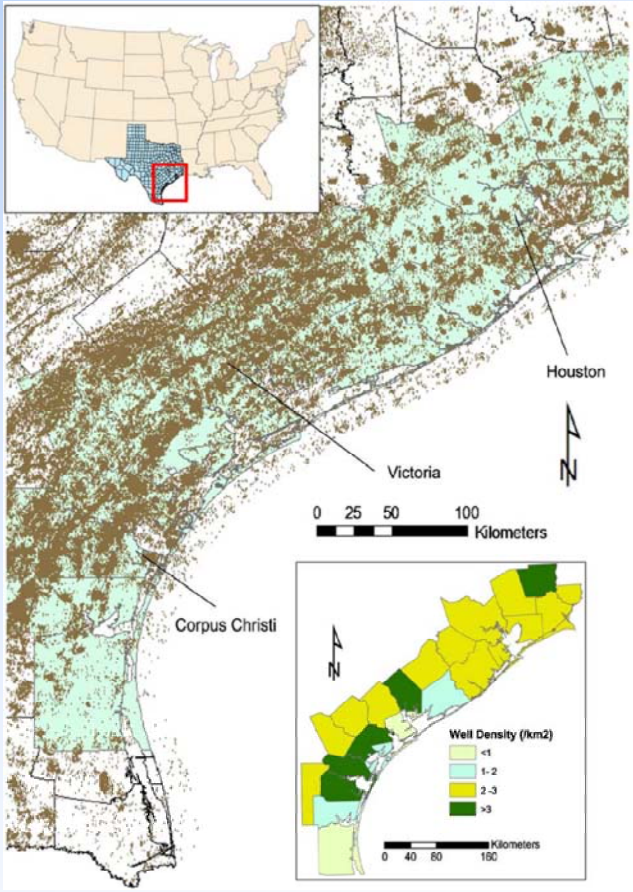
previously presented at the 3rd Wellbore Integrity Network meeting

- Feasibility study to store CO_2 in the depleted gas reservoir of the onshore, stacked De Lier field
- Penetrated by 51 abandoned wells
- Wells are abandoned according to regulations; abandonment did NOT take into account CO_2 storage
- Some wells would need reabandonment
- Consequently, the proposed storage project was discontinued



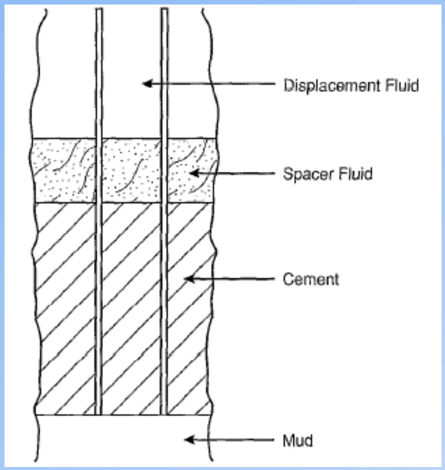
Case study: Gulf Coast, Texas (USA)

- Suitable geology for CO_2 storage, but…
- Extremely high well density (although decreasing with depth): high probability of encountering (abandoned) wells
- No comprehensive database on oil and gas wells ever drilled (especially older wells, i.e. pre-1930s, are lacking): high uncertainty regarding abandoned wells (e.g. location, abandonment status)

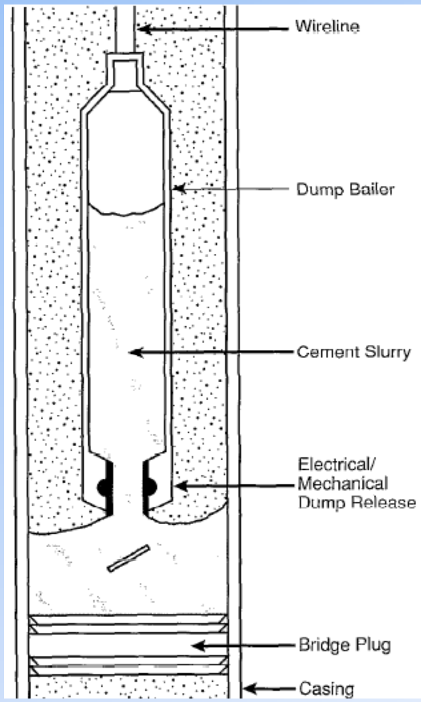


- After: Nicot et al., 2006; Nicot, 2008

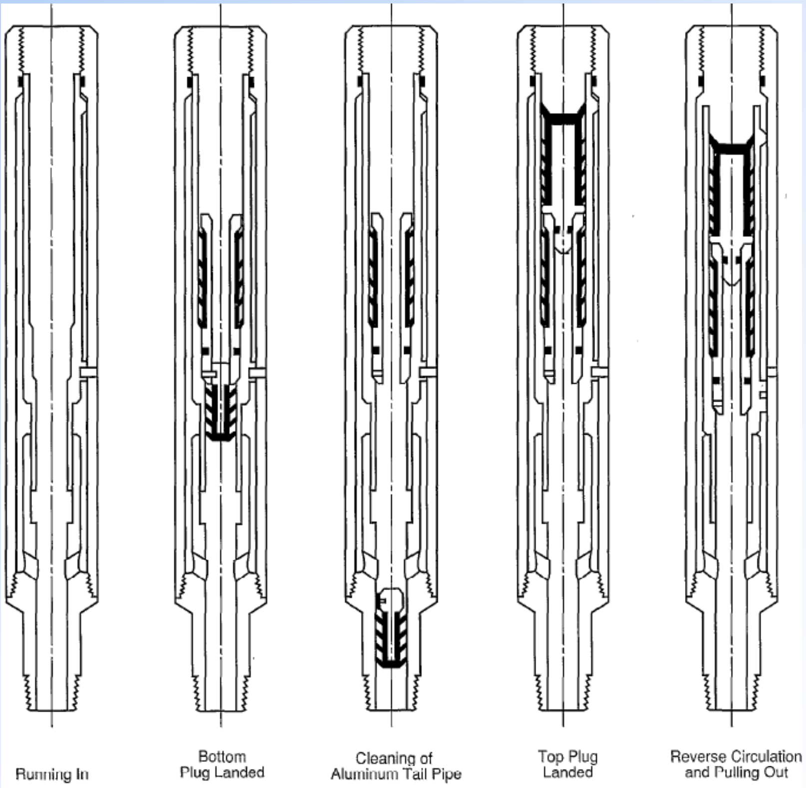
Plugging techniques



Balanced plug method



Dump Bailer method

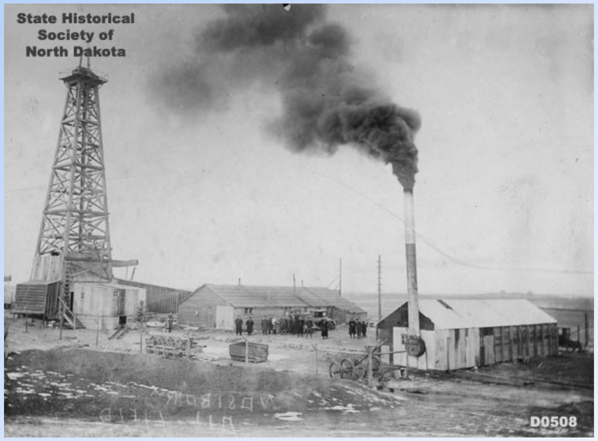


Two-plug method

Cement squeeze method

After: Nelson and Guillot, 2006

Historical developments in plugging



- 1922: Patent on Two-plug method by Halliburton, limiting potential mud contamination
- 1928: Multiple cement types became available for plugging
- ~1930: Introduction of centralizers, enabling more uniform cement distribution in wells
- 1940: Introduction of two types of Portland cement and three types of additives
- 1940s: Invention and widespread use of caliper, enabling calculation of the exact quantity of cement
- 1953: Publication of API standards on well cements

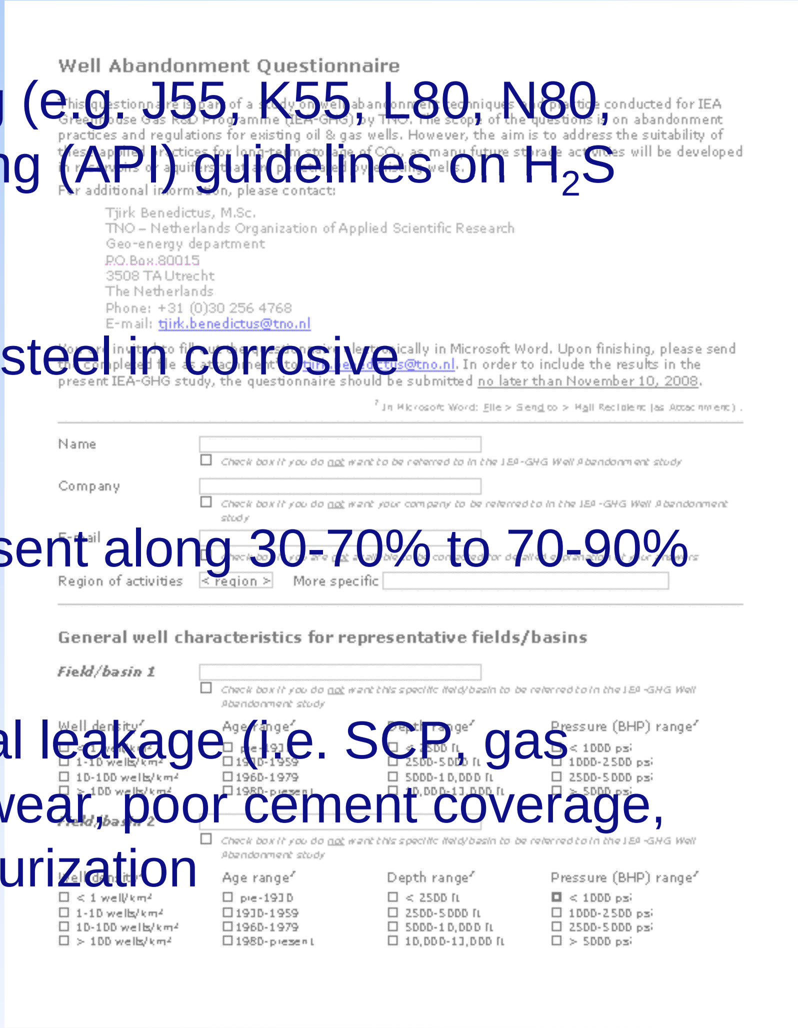
- Wells that were abandoned prior to 1953 are often not considered to have effective cement plugs

Abandonment practices

- Results based on a survey/questionnaire presented to approximately 200 experts (at operators, service companies, research institutes, regulatory bodies).
- Only 9 responses from different regions (North America, Europe, Australia)
- Questionnaire subjects comprise:
  - Drilling & completion operations
  - Abandonment regulations
  - Abandonment practices
  - Data availability

Questionnaire: Drilling and completion

- Various steel grades used for casing (e.g. J55, K55, L80, N80, C95, P110, Q125), generally following (API) guidelines on H_2S content, temperature and pressure.
- Common practice to use Cr-13 type steel in corrosive environments
- Primary cement sheath typically present along 30-70% to 70-90% of the wellbore
- 0-10% to 10-30% of wells show initial leakage (i.e. SCP, gas migration), due to casing corrosion/wear, poor cement coverage, improper slurry design, or overpressurization


Well Abandonment Questionnaire

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The Netherlands
Phone: +31 (0)30 256 4768
E-mail: tjirk.benedictus@tno.nl

Name
Company
Region of activities < region > More specific

General well characteristics for representative fields/basins

Field/basin 1

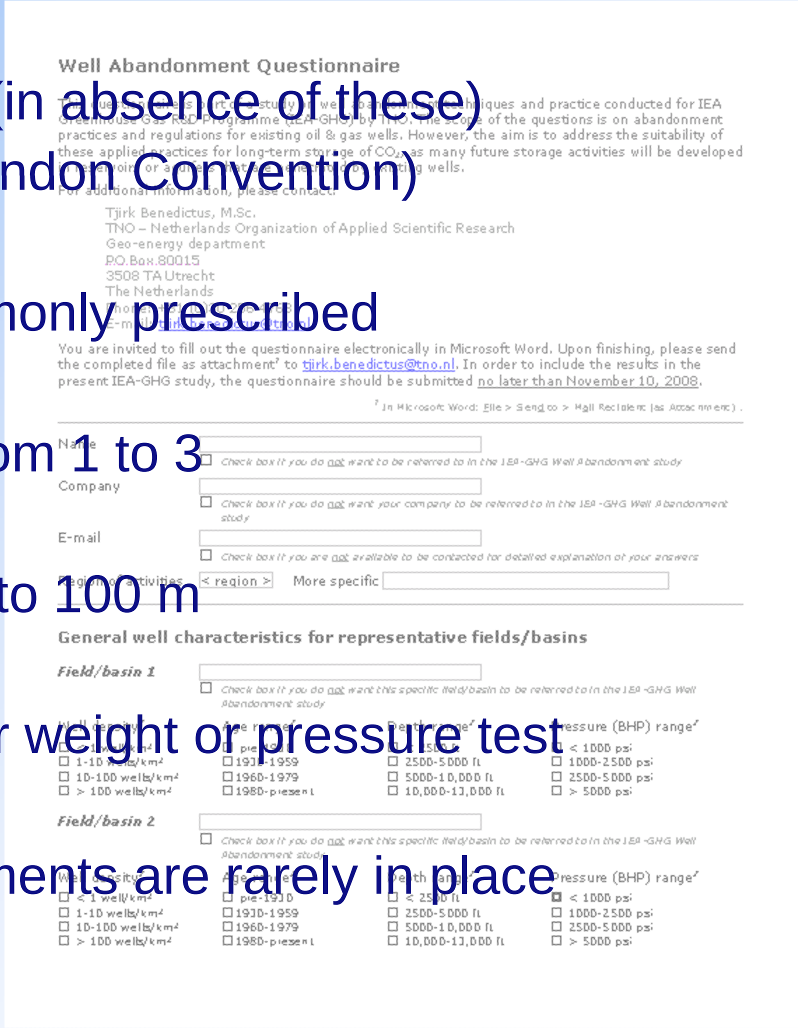
Well density | Age range | Depth range | Pressure (BHP) range

Field/basin 2

Well density | Age range | Depth range | Pressure (BHP) range
< 1 well/km² | pre-1930 | < 2500 ft | < 1000 psi
1-10 wells/km² | 1930-1959 | 2500-5000 ft | 1000-2500 psi
10-100 wells/km² | 1960-1979 | 5000-10,000 ft | 2500-5000 psi
> 100 wells/km² | 1980-present | 10,000-13,000 ft | > 5000 psi

Questionnaire: Abandonment regulations

- Regional or national regulations, or (in absence of these) international guidelines (OSPAR, London Convention)
- Balanced plug method is most commonly prescribed
- Minimum number of plugs ranges from 1 to 3
- Minimum plug length ranges from 8 to 100 m
- Plug testing generally involves either weight or pressure test
- Requirements for corrosive environments are rarely in place


Well Abandonment Questionnaire

practices and regulations for existing oil & gas wells. However, the aim is to address the suitability of

Tjirk Benedictus, M.Sc.
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The Netherlands

You are invited to fill out the questionnaire electronically in Microsoft Word. Upon finishing, please send the completed file as attachment[1] to tjirk.benedictus@tno.nl. In order to include the results in the present IEA-GHG study, the questionnaire should be submitted no later than November 10, 2008.

Company

☐ Check box if you do not want your company to be referred to in the IEA-GHG Well Abandonment study

E-mail

☐ Check box if you are not available to be contacted for detailed explanation of your answers

< region > More specific

General well characteristics for representative fields/basins

Field/basin 1

☐ Check box if you do not want this specific field/basin to be referred to in the IEA-GHG Well Abandonment study

Pressure (BHP) range

Field/basin 2

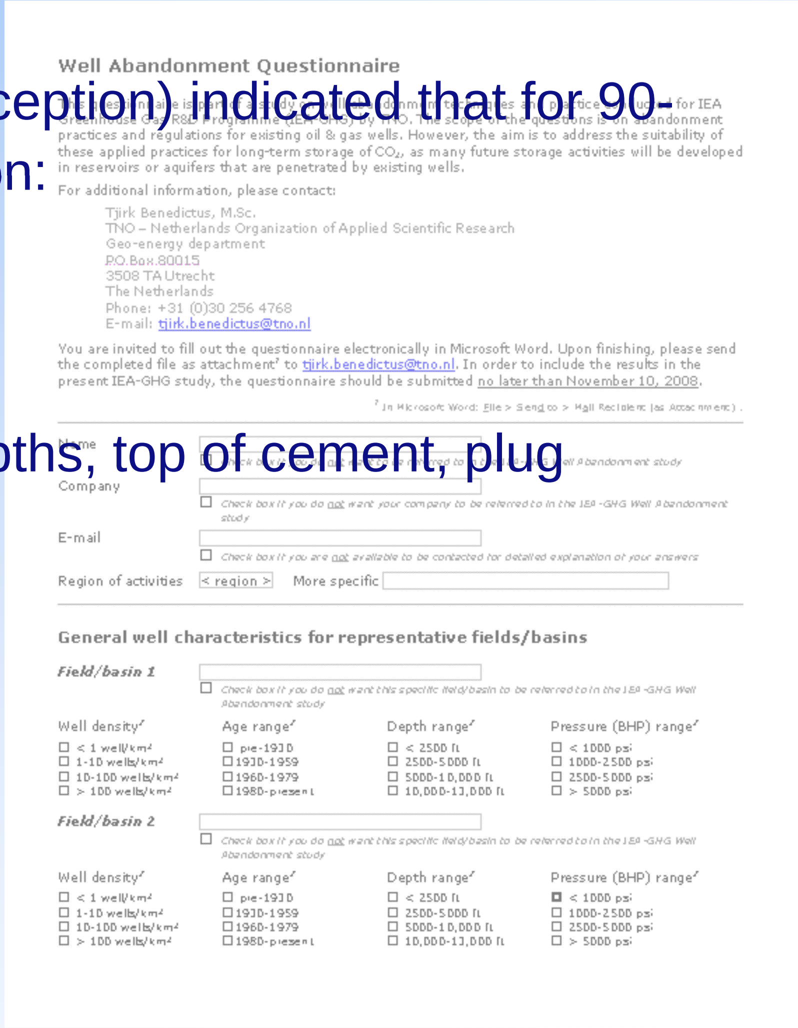
Pressure (BHP) range

Questionnaire: Abandonment practice

- Majority of operators has not been taking into account potential second life applications when abandoning
- However, some operators recently started to evaluate field's value for future purposes prior to abandonment
- Company practices closely reflect governing regulations; more stringent measures (e.g. longer plug lengths, advanced materials) may be applied, especially in corrosive environments

Questionnaire: Data availability

- Majority of respondents (a single exception) indicated that for 90-100% of the wells data is available on:
  - Well location (coordinates)
  - Present well status
  - Well configuration (i.e. cased depths, top of cement, plug lengths, materials applied)


Well Abandonment Questionnaire

practices and regulations for existing oil & gas wells. However, the aim is to address the suitability of these applied practices for long-term storage of CO_2, as many future storage activities will be developed in reservoirs or aquifers that are penetrated by existing wells.

For additional information, please contact:

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General well characteristics for representative fields/basins

Field/basin 1
☐ Check box if you do not want this specific field/basin to be referred to in the IEA-GHG Well Abandonment study

Well density	Age range	Depth range	Pressure (BHP) range
☐ < 1 well/km²	☐ pre-1930	☐ < 2500 ft	☐ < 1000 psi
☐ 1-10 wells/km²	☐ 1930-1959	☐ 2500-5000 ft	☐ 1000-2500 psi
☐ 10-100 wells/km²	☐ 1960-1979	☐ 5000-10,000 ft	☐ 2500-5000 psi
☐ > 100 wells/km²	☐ 1980-present	☐ 10,000-13,000 ft	☐ > 5000 psi

Field/basin 2
☐ Check box if you do not want this specific field/basin to be referred to in the IEA-GHG Well Abandonment study

Well density	Age range	Depth range	Pressure (BHP) range
☐ < 1 well/km²	☐ pre-1930	☐ < 2500 ft	☒ < 1000 psi
☐ 1-10 wells/km²	☐ 1930-1959	☐ 2500-5000 ft	☐ 1000-2500 psi
☐ 10-100 wells/km²	☐ 1960-1979	☐ 5000-10,000 ft	☐ 2500-5000 psi
☐ > 100 wells/km²	☐ 1980-present	☐ 10,000-13,000 ft	☐ > 5000 psi

Well Abandonment Regulations

- Literature research of well abandonment requirements in international regulations and a selected number of countries/states with petroleum history, including;
  - Australia
  - Canada
  - China
  - Europe (e.g. Denmark, Netherlands, Norway, UK)
  - Japan
  - USA (Alaska, California, Texas)

- Data obtained of plug lengths and position requirements used in;
  - the transition zone from uncased to cased sections
  - reservoir (uncased) section
  - perforated cased sections

Selection of minimum plug requirements

- Transition zone from uncased to cased sections;
  - Europe; 50-100 m, except UK; 30 m
  - International; 30-60 m, except Canada; 15 m depending on formation

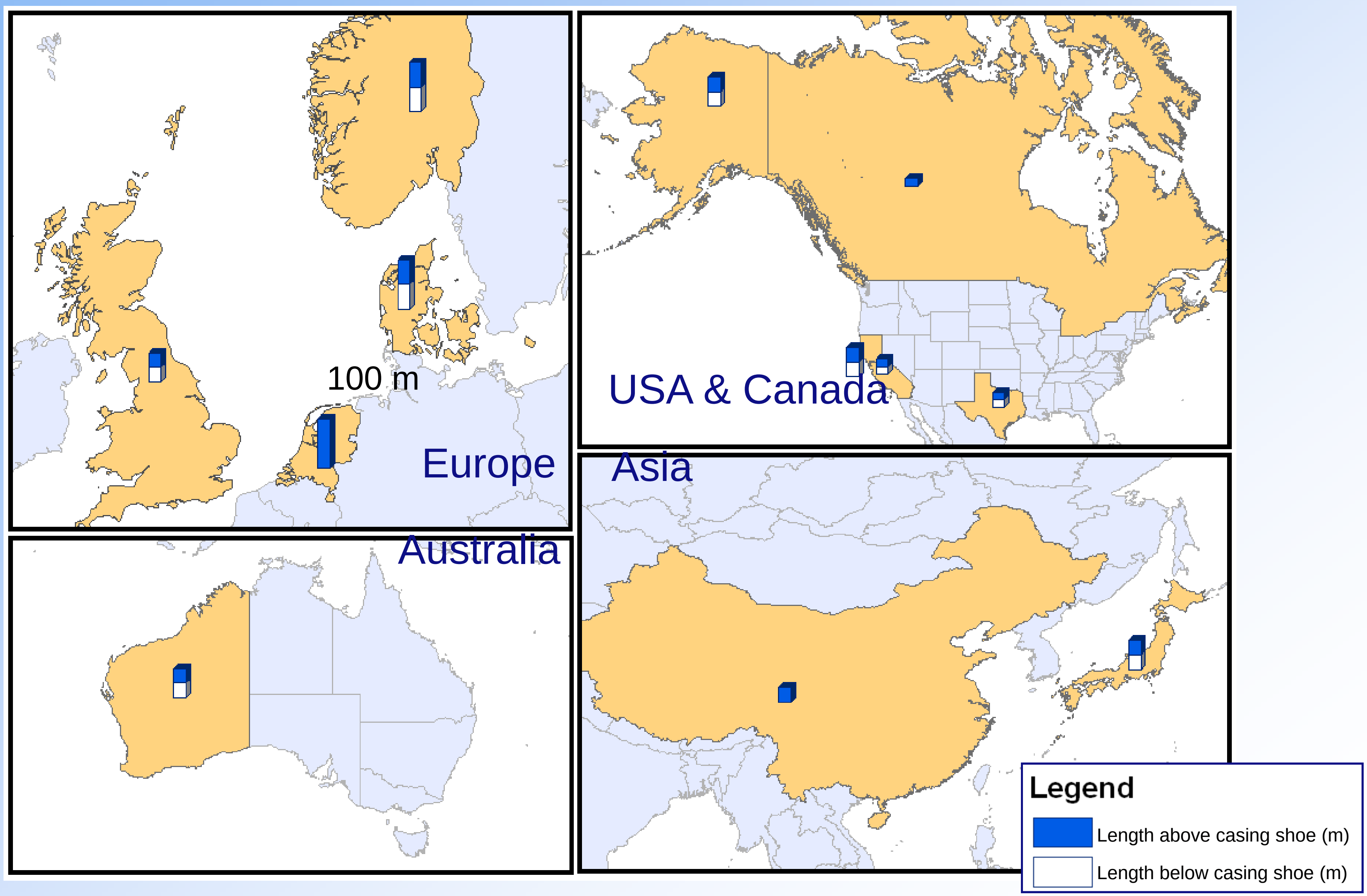
- Reservoir (uncased) section
  - Europe and International; 50-100 m, except UK and Canada; 30 m

- Perforated cased sections
  - Europe; 50-100 m, except UK; 30 m
  - International; 30-60 m, except Canada; 80 m

Note: plug lengths in feet have been converted into meters and rounded off

Minimum plug lengths per country/state

Transition zone from uncased to cased sections



Remarks on review of abandonment regulations

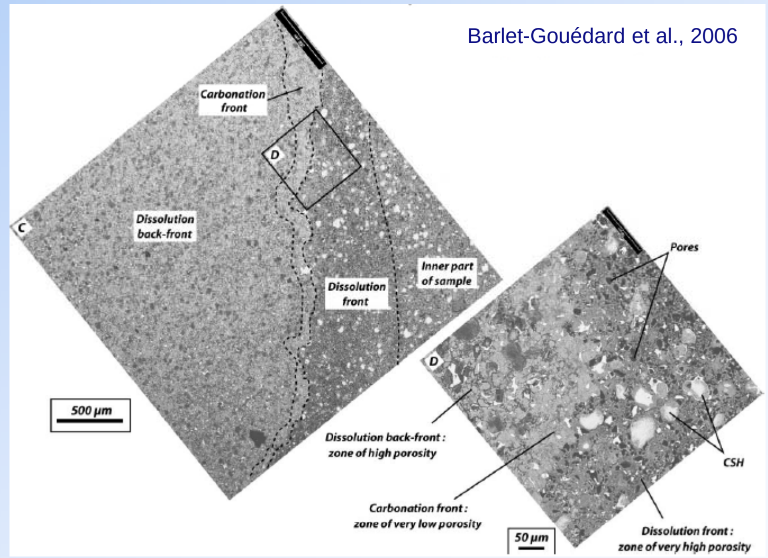
- Assessment of the regulatory framework provides a first order proxy for initial identification of abandonment practices only
- Cement plug is compulsory in all evaluated regulatory documents
- Main differences involve plug requirements (lengths) at the level of the deepest casing shoe
- The application of mechanical plugs often require additional cementing (exact requirements differ significantly among regulations)

Note that reviewed documents often involve unofficial translations of the original documents from the native languages to English

Impact of CO_2 on wellbore integrity: an overview

- Cement degradation is considered to be diffusion-controlled

- Function of e.g. pH, T, P and salinity, but also on curing conditions, experimental setup (static vs. flowing, supercritical vs. dissolved CO_2)

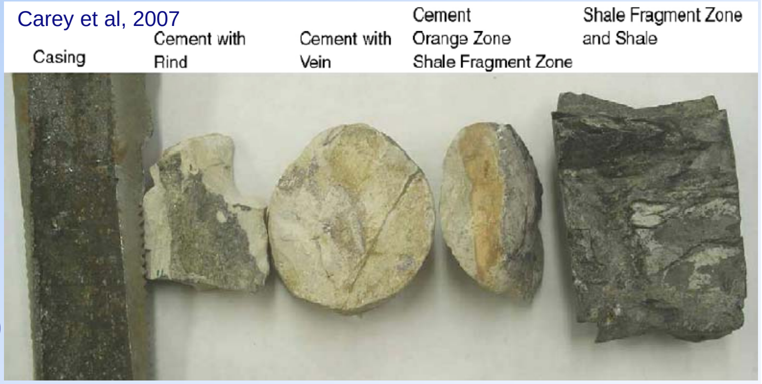


Barlet-Gouédard et al., 2006

- Extrapolating published experimental data according to Fick's Law of diffusion ($d = C \cdot t^{½}$), shows divergent results: Time (t) required to degrade d = 25 mm of cement, ranges from 15 days to over 724,000 year (under different conditions)

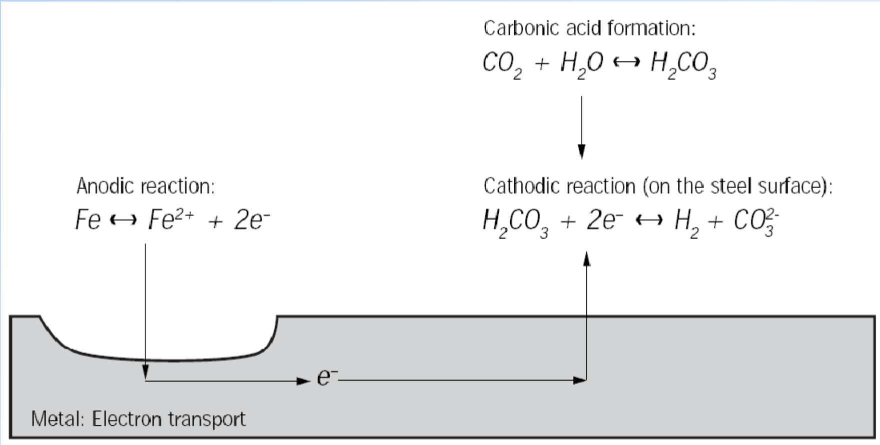
Impact of CO_2 on wellbore integrity: an overview

- Limiting factors apply translating experimental results to field cases, e.g.:
  - Limited reaction surface in the field (taken into account by some authors)
  - Limited availability of free water (especially for some depleted gas fields)
  - High salinity (especially abundance of Ca^{2+}) may reduce degradation or even lead to self-healing through calcite precipitation



Impact of CO_2 on wellbore integrity: an overview

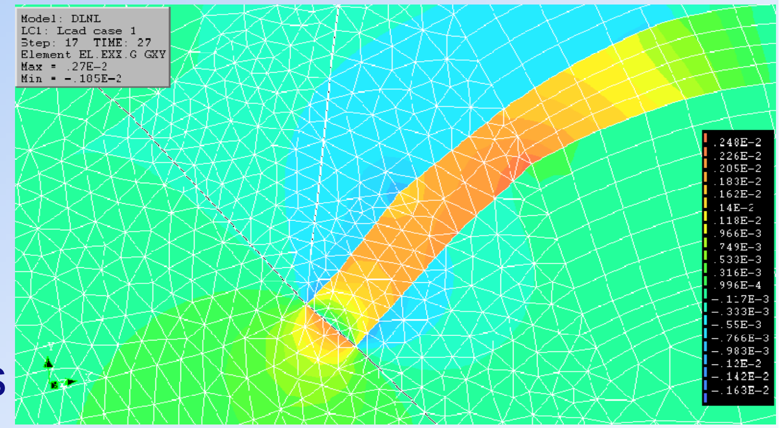
- Steel corrosion is a linear process
- Function of pH, temperature, salinity and partial CO_2 pressure
- Published experimental results show corrosion rates in the order of mm's per year



- Under favorable conditions (T>60-100ºC; pH>5) siderite ($FeCO_3$) precipitation can retard corrosion, forming a (partially) protective layer
- In general, higher grade steel is more susceptible to corrosion

Impact of CO_2 on wellbore integrity: an overview

- Mechanical deformation



  - Reservoir decompaction due to CO_2 injection: strain incompatibility at cement-steel interface may cause debonding, and tensile cracks in the cement sheath

  - Shear deformation at the interface between reservoir and cap rock may damage the wellbore

  - Micro-fractures and micro-annuli may arise from:
    - Poor cement job (incl. cement shrinkage)
    - Temperature and/or pressure changes or cycles

Impact of CO_2 on wellbore integrity: an overview

- Interaction of casing corrosion and cement degradation along micro annuli

- Experimental work on a cement-steel sample in CO_2-brine (incl. Ca^{2+}) by Carey et al. (2008) shows:

  - No significant loss of mass of both steel and cement

  - Precipitation of siderite ($FeCO_3$) on the steel surface

  - Limited penetration of CO_2 in cement consistent with 1-D diffusion

Impact of CO_2 on wellbore integrity: an overview

- Interaction of chemical, mechanical and physical processes
  - Huerta et al. (2008) and Lécolier et al. (2008) report self-healing at cement-casing interface in lab experiments
  - At increasing confining stress, mechanical weakening results in rapid closure of fractures
  - Lécolier et al. (2008) report decreasing permeability and flow rates

Recommended best practice

- Future wells can be designed, drilled completed and abandoned taking into account any CO_2 storage reservoirs
- Suitability of existing wells for CO_2 storage needs to be evaluated
  - Accessible wells may require workover operations to be able to adequately isolate CO_2 storage reservoirs; techno-economical considerations determine the feasibility
  - Abandoned wells generally are not accessible. Especially older wells may pose threats to CO_2storage. Furthermore, timing and stringency of global abandonment regulations varies considerably

Managing previously abandoned wells

- Lab experiments show cement degradation rates extrapolating to a maximum of 12.4 m in 10,000 years under severe T conditions, i.e. 204ºC, 69 bar (in practice penetration is likely to be less)

- Prescribed cement plug lengths range from 15 to 100 m

- Quality and mechanical integrity of cement plug and sheath seems to be of more significance than chemical degradation:
  - Fractures or annular pathways in or along the cement will likely govern the permeability of the wellbore system

- Supported by investigations of downhole cement samples by Carey et al. (2007) and Crow et al. (2008):
  - Diffusion-based degradation of cement is limited
  - CO_2 migration was observed along cement-steel and cement-formation interfaces

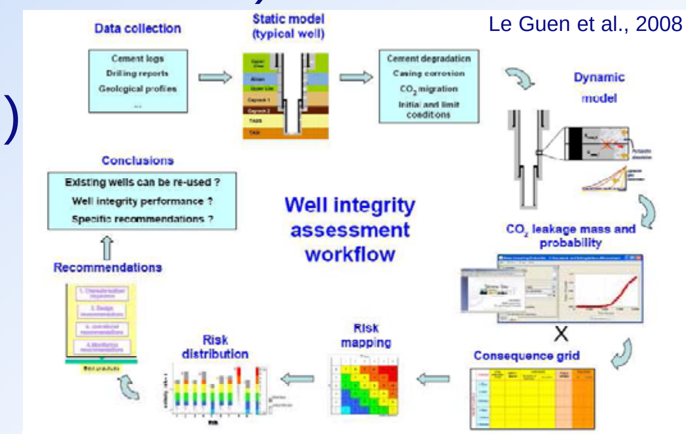
Risk Management: assessment

- When considering long-term CO_2 storage, the current state of wells involved needs to be confidently assessed, including previously abandoned wells
    - Evaluation of abandonment configuration with respect to second life application
    - Evaluation of current state of materials and placement, extrapolating from data gathered prior to abandonment

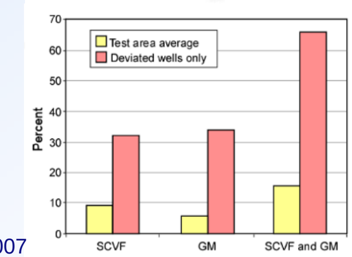
Risk assessment methodologies

- Qualitative RA → FEP (Feature, Event, Process) analysis to identify site-specific CO_2 storage related hazards (e.g. TNO CASSIF, Quintessa)
- Quantitative RA
  - Deterministic (applicable to small numbers of wells)
  - Probabilistic (applicable to large sets of wells; e.g. OXAND methodology →)

Le Guen et al., 2008



- Semi-quantitative: e.g. data mining



Watson and Bachu, 2007

Risk Management: monitoring

- Monitoring well integrity as part of the entire suite of monitoring techniques employed on a storage site
- Monitoring abandoned (inaccessible) wells will be limited
- Potential techniques involve:
  - (near-)surface measurements (soil gas/fluxes, groundwater chemistry)
  - remote sensing
  - geophysical methods (e.g. seismic)

- In order to enhance discrimination between natural and injected CO_2, tracers could be added to the injected CO_2

Risk Management: remediation

- Remediation of abandoned wells requires re-entering and re-abandonment and is extremely costly and generally unfeasible
- The ultimate measure to mitigate leaking storage reservoirs would be releasing pressure by venting CO_2 into the atmosphere

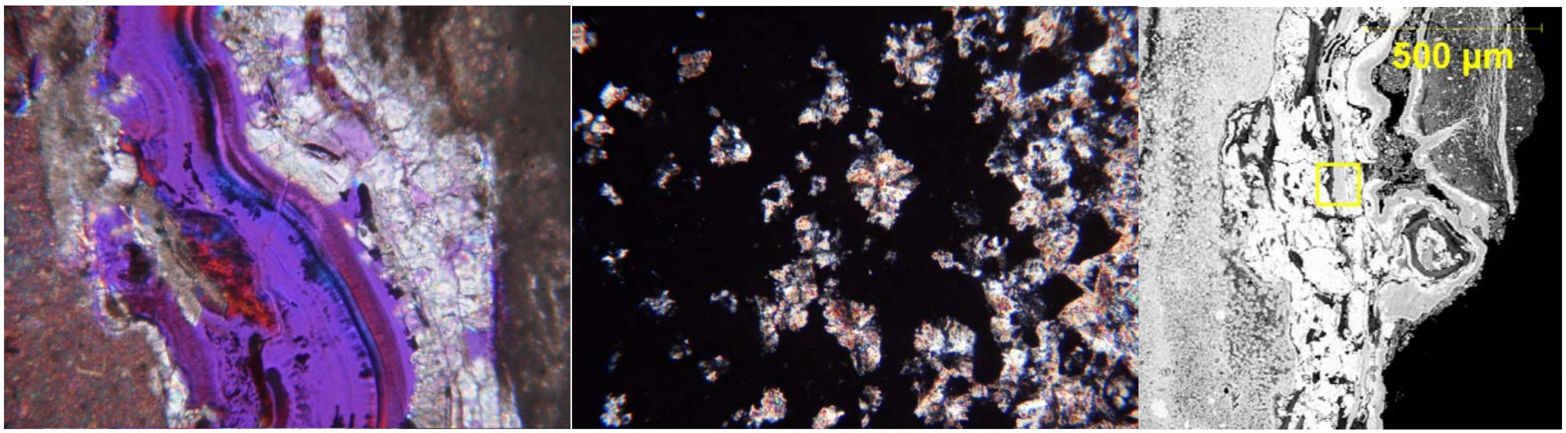
- Obviously costly remediation or venting CO_2 should be prevented, initially by performing a comprehensive assessment of the wells involved prior to CO_2 injection

Thank you!

Any suggestions, comments or input regarding the Well Abandonment report would be appreciated.

tjirk.benedictus@tno.nl

NATIONAL ENERGY TECHNOLOGY LABORATORY



Natural CO_2 Sequestration Analogs in Wellbore Cement Integrity Assessment

National Energy Technology Laboratory: Barbara Kutchko, Brian Strazisar, Nicolas Huerta, George Guthrie

Los Alamos National Laboratory: Bill Carey

RJ Lee Group Inc.: Neils Thaulow

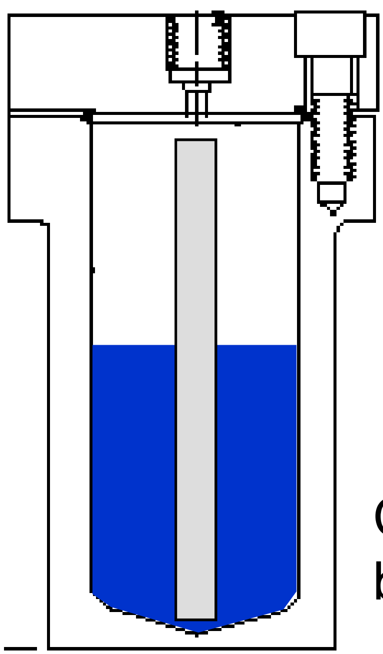
Wellbore Integrity and CO_2 Storage

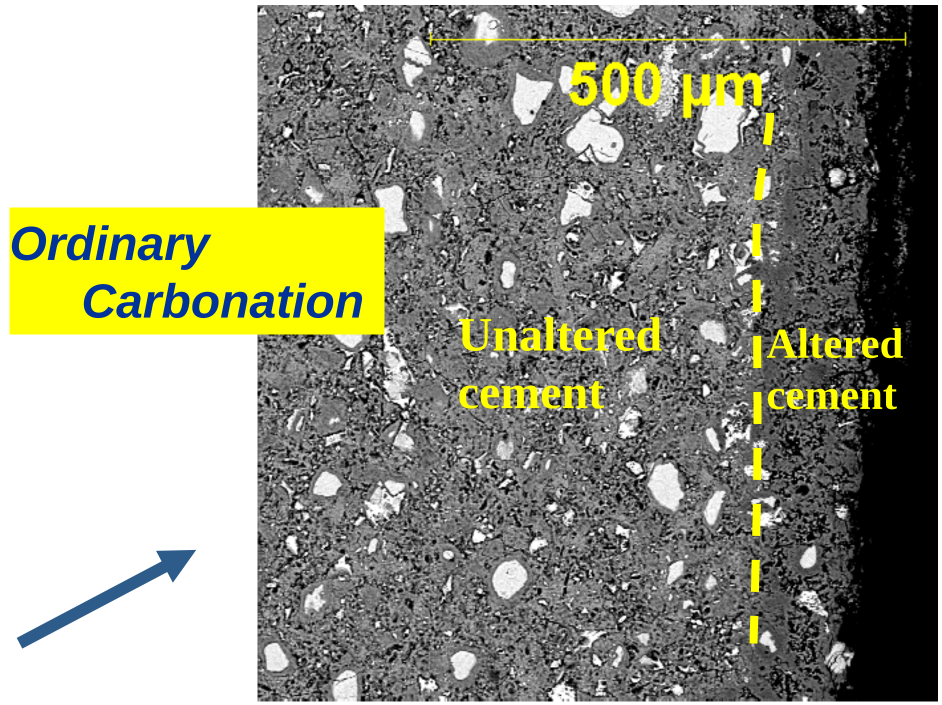
- **In the field, cement microstructure and permeability can be affected by a variety of processes:**
  - Cement Type
  - Cure Conditions
  - Additives
  - CO_2 Properties
    - CO_2-saturated brine
    - Supercritical CO_2
  - Brine Composition
  - Formation Rock Type
- **Can we understand what happens in the field by simulating various conditions in the lab?**
- **How does CO_2 affect chemical/physical properties of cement over time?**
  - Narrow uncertainties with series of experiments

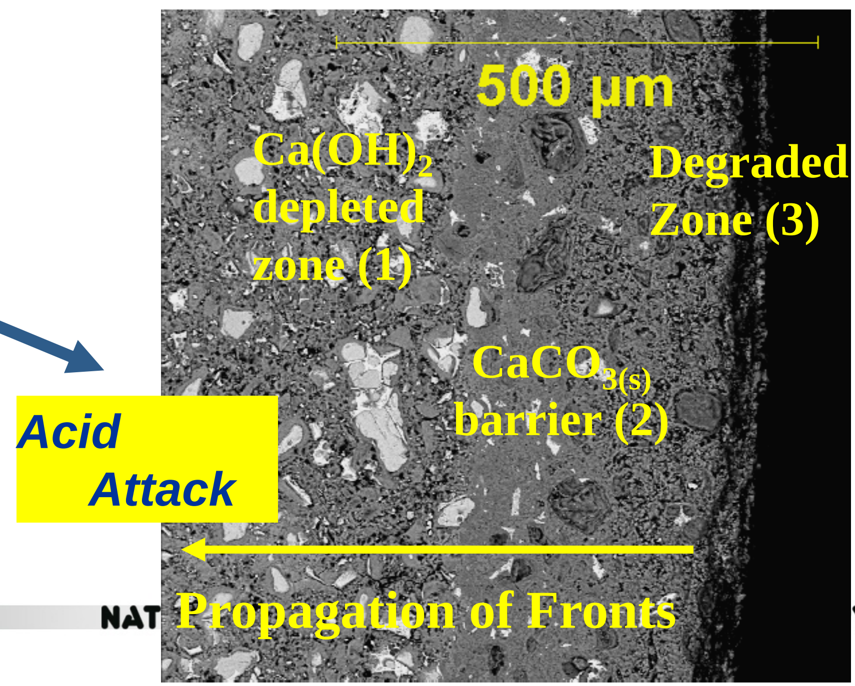
Lab Experiments

Simulate injected CO_2

- Hydrodynamic trapping
- Solubility trapping







Kutchko et al., ES&T 2007, 2008

CO_2-Saturated Brine Exposure

Proposed Alteration Mechanism

1. **Dissolution of $Ca(OH)_{2(s)}$ (zone 1) and precipitation of $CaCO_{3(s)}$ (zone 2)**

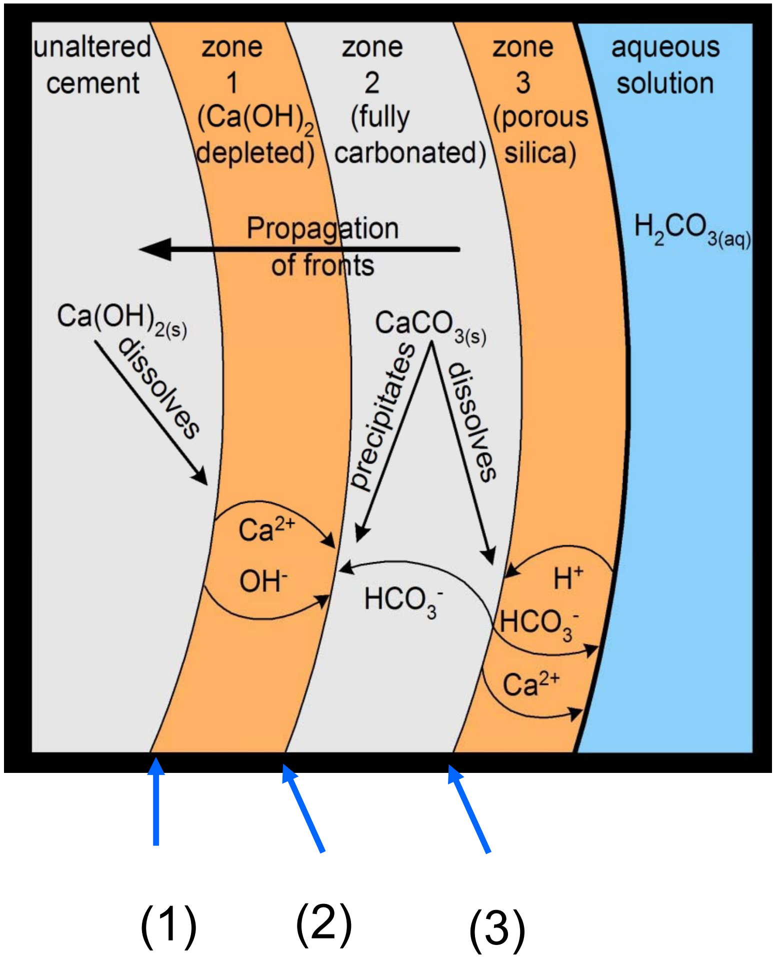
(1) $Ca(OH)_{2(s)} \rightarrow Ca^{2+}_{(aq)} + 2OH^-_{(aq)}$

(2) $Ca^{2+}_{(aq)} + HCO_3^-{}_{(aq)} + OH^-_{(aq)} \rightarrow CaCO_{3(s)} + H_2O$

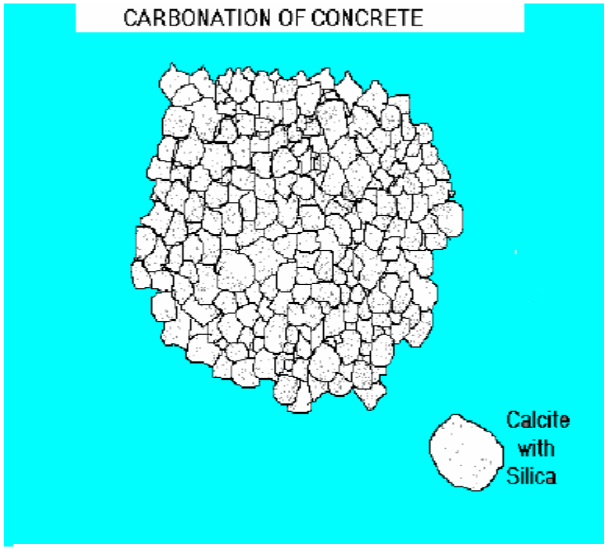
2. **Dissolution of $CaCO_{3(s)}$ and leaching of Calcium ions from the cement matrix (zone 3)**

(3) $H^+_{(aq)} + CaCO_{3(s)} \rightarrow Ca^{2+}_{(aq)} + HCO_3^-{}_{(aq)}$

(4) $C\text{-}S\text{-}H_{(s)} \rightarrow Ca^{2+}_{(aq)} + OH^-_{(aq)} + am\text{-}SiO_{2(s)}$



Kutchko et al., ES&T 2007, 2008



The Good: Ordinary Carbonation

CC is ppt from a supersaturated solution – good binder

Crystals nucleate and grow rapidly

How fast the ppt is compared with migration of species

diffusion < precipitation

low porosity, high strength

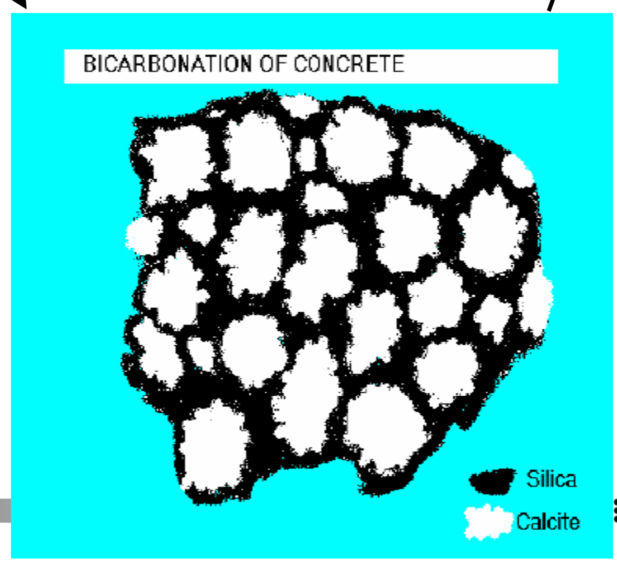
The Bad: Popcorn Carbonation

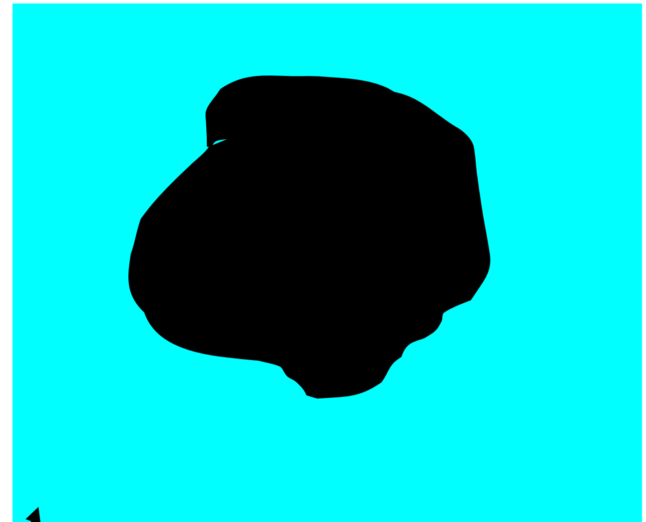
Determined by the balance between available CH and concentration of CO_2 in system

CC is ppt from a low supersaturated solution

Less nucleation sites = larger crystals

diffusion > precipitation





The Ugly: Amorphous Silica Gel/ Acid Attack

End state: furthest extent of reaction

(Carbonate is not sufficient to buffer cement)

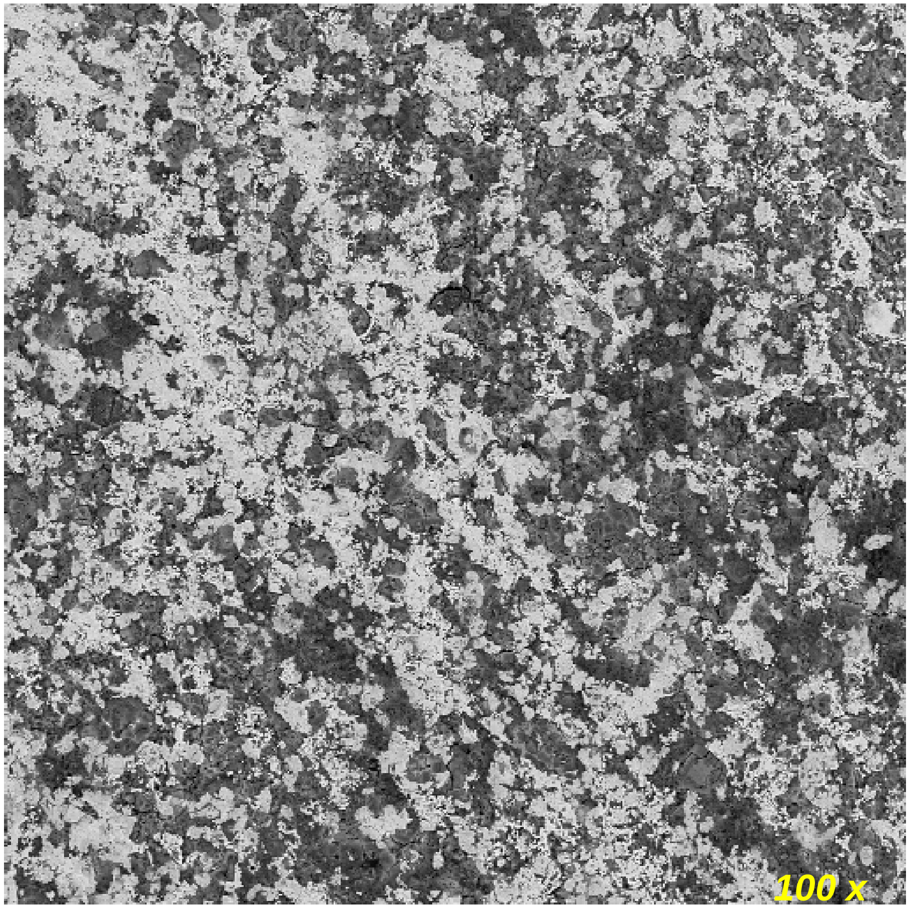
high porosity, low strength

Thaulow et al., 2001

Popcorn Carbonation

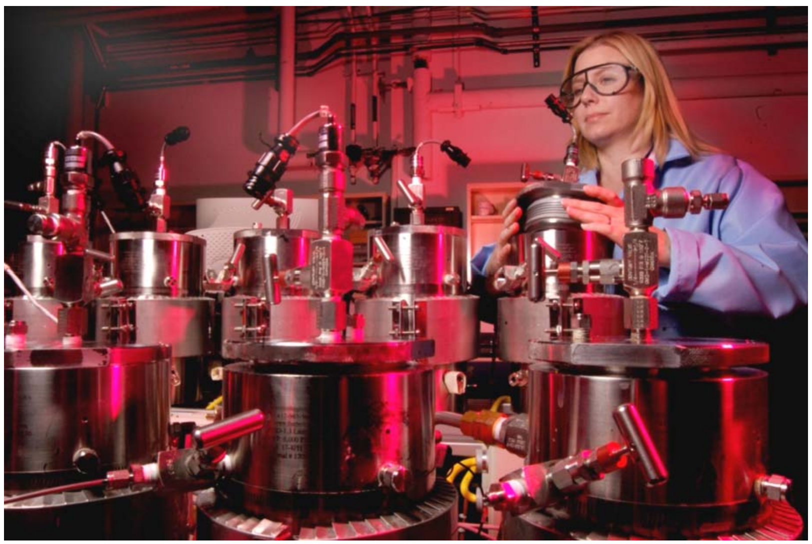
"Popcorn" crystals of calcium carbonate in isotropic matrix of silica gel

- Act as sand grains rather than binding agent.
- New binding agent is now the decalcified silica gel
- *Resulting microstructure is different than ordinary carbonation and acid attack*



Thaulow et al., 2001

How have laboratory experiments provided insight to alterations observed in the field? Comparison of Field and Laboratory Samples



SACROC Case: Neat Portland cement

SACROC Field Sample

Cement Properties:

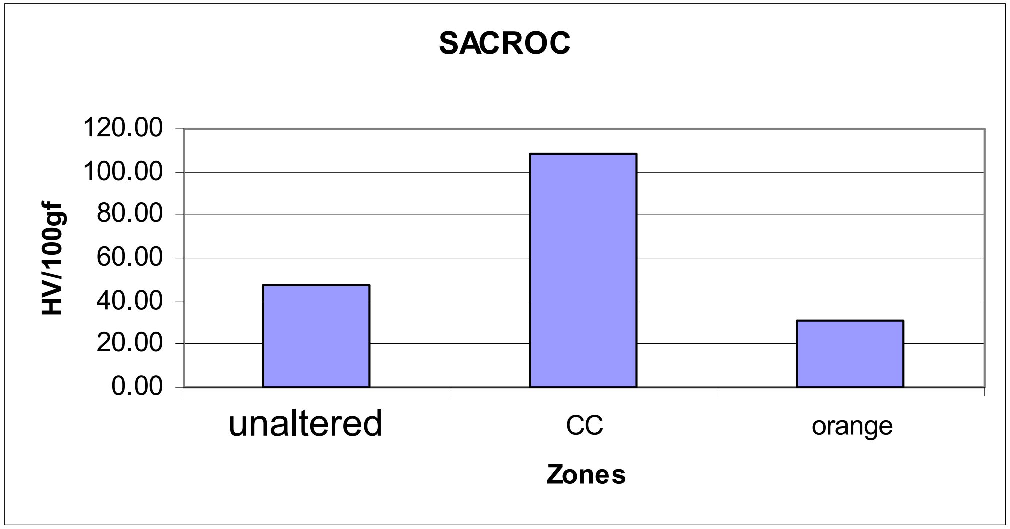
- **Neat Portland cement**
  - Density ≈ 15.5 lb/gal
- **Reservoir T = 54ºC & p = 18 MPa**
- **Exposed to CO_2 at 54ºC & 18 MPa *after 25 years in place***
  - Extensive hydration
- **Exposed to CO_2 (-brine) (EOR) for 30 yrs**
- **Water/cement ratio ??**
- **Brine composition ?? (>1% NaCl)**
- **Alteration depth ranged from 2 – 10 mm**

NETL Lab Samples

Cement Properties:

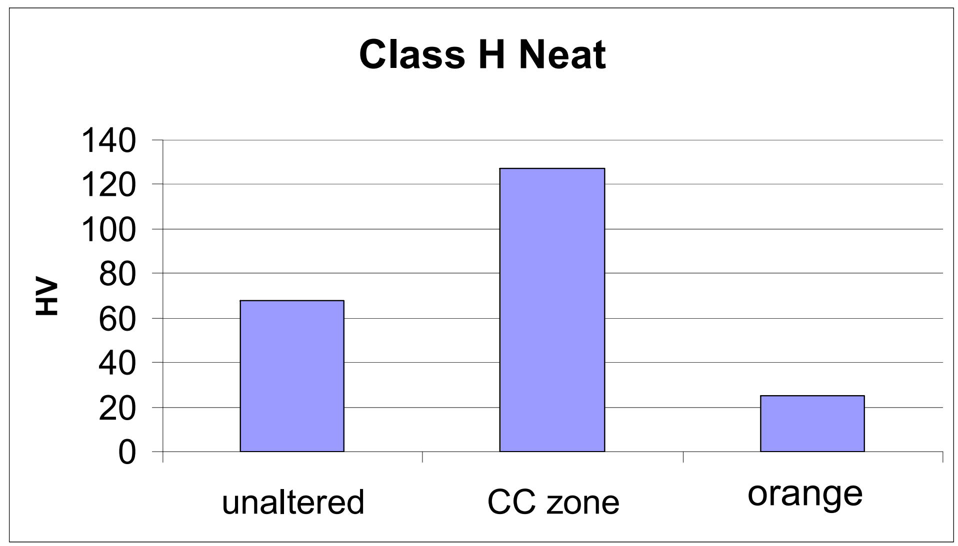
- **Class H neat Portland cement**
  - Density ≈ 16.5 lb/gal
- **Cured at T = 50ºC & p =15 MPa**
- **Exposed to CO_2 at 50ºC & 15 MPa *after 28 days***
- **Exposed to CO_2 (-brine) for 1 year**
- **Water/cement ratio = 38%**
- **Brine composition = 1% NaCl**
  - CO_2 more soluble
- **Alteration depth averaged 1.00 ± 0.07 mm for 30 year extrapolation**

Carey et al., IJGGC 2007; Kutchko et al., ES&T 2008

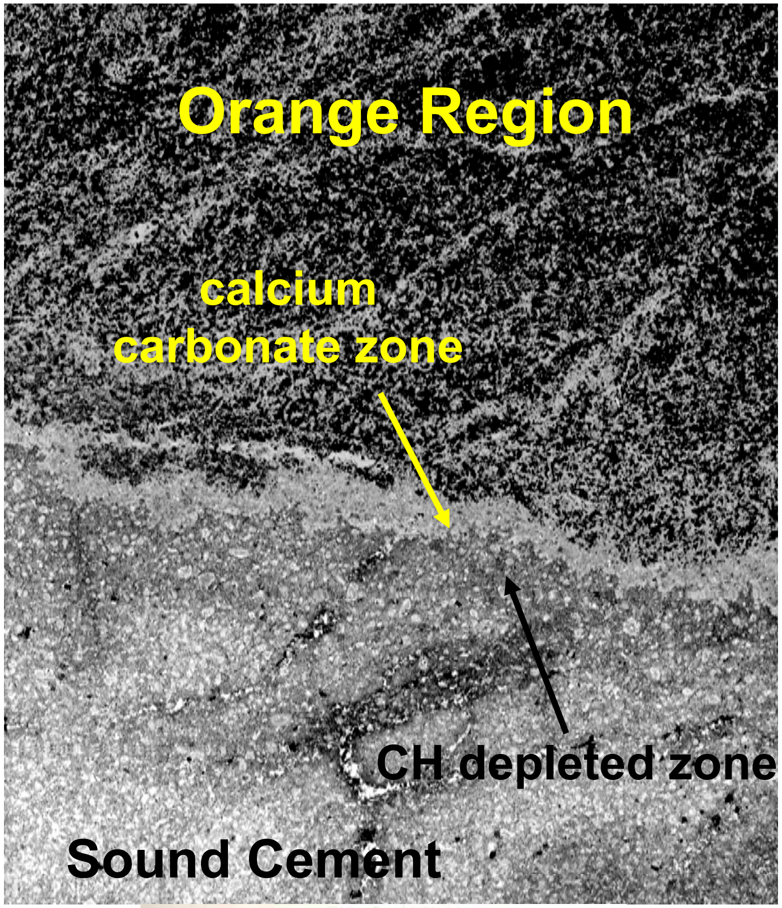


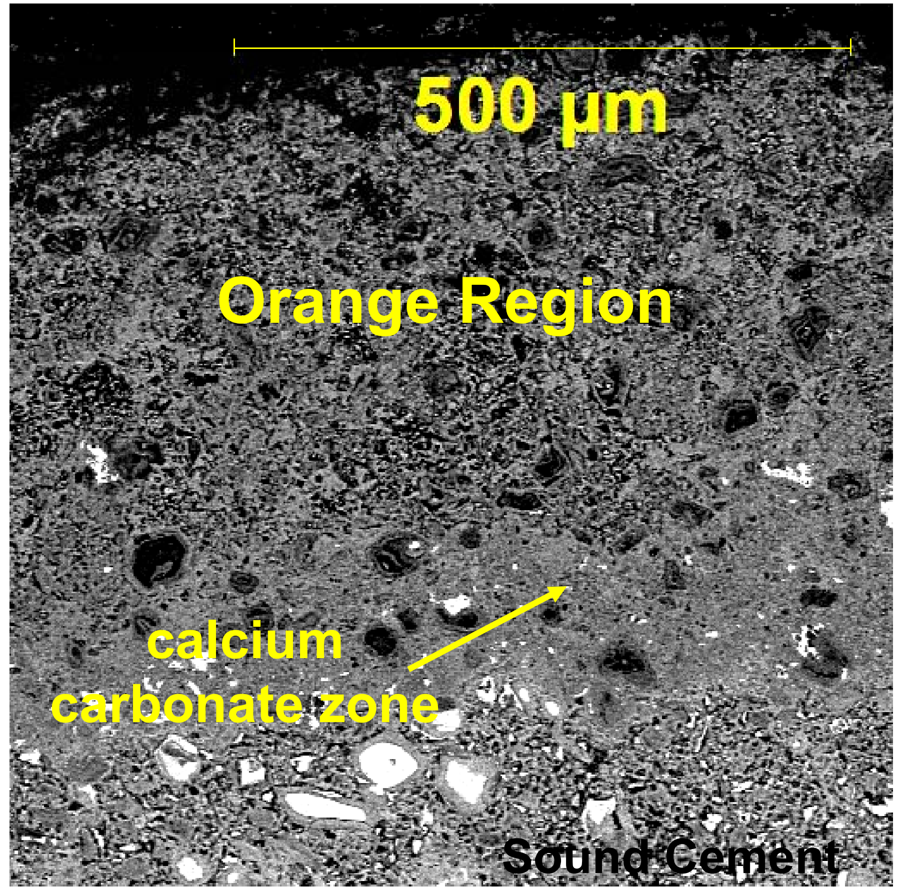
SACROC compared to NETL CO_2-saturated brine lab samples:

- **similar mechanical properties**



Similar Carbonation patterns





LANL SACROC field sample

NETL laboratory sample

Discussion

SACROC Field Sample

Driven by the interaction of CO_2-bearing brines

Alteration induced by carbonation followed by dissolution and precipitation of CC

-altered from C-S-H and CH

-result: *popcorn carbonation*

-indicates higher pH of reaction environment in cement matrix

-CC popcorns will dissolve if CO_2 concentration is high enough to further decrease the pH *(i.e. acid attack)*

CC zone is carbonation front

-acts as a possible diffusion barrier

-migrates through cement followed by dissolution/ precipitation which leads to popcorn carbonation formation

NETL Lab Sample

Driven by the interaction of CO_2-bearing brines

Alteration induced by carbonation followed by dissolution (and leaching) of CC

-altered from C-S-H and CH

-result: *amorphous silica gel*

-indicates lower pH of reaction environment in cement matrix

-aka *acid attack:* end state and furthest extent of reaction

CC zone is carbonation front

-acts as a possible diffusion barrier

-migrates through cement followed by dissolution of CC due to low pH of CO_2-bearing brines

Carey et al. (2007); Kutchko et al. 2008

$SCCO_2$ Alteration of Cements with Pozzolan

CCP Field Sample

Cement Properties:

- **Portland based 50:50**
- **Estimated original reservoir T = 57.7 ºC & p = 10.2 MPa (1480 psi)**
- **Exposed to 96% CO_2 for 30 yrs**
  - Natural CO_2 producer
- **Alteration depth varied along depth of well**

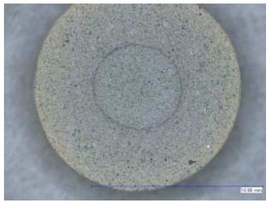
  - indicated alteration by CO_2 migration along cement-formation interface
- **Permeability: increased from ~1 μD to ~ 30 μD**

NETL Lab Samples

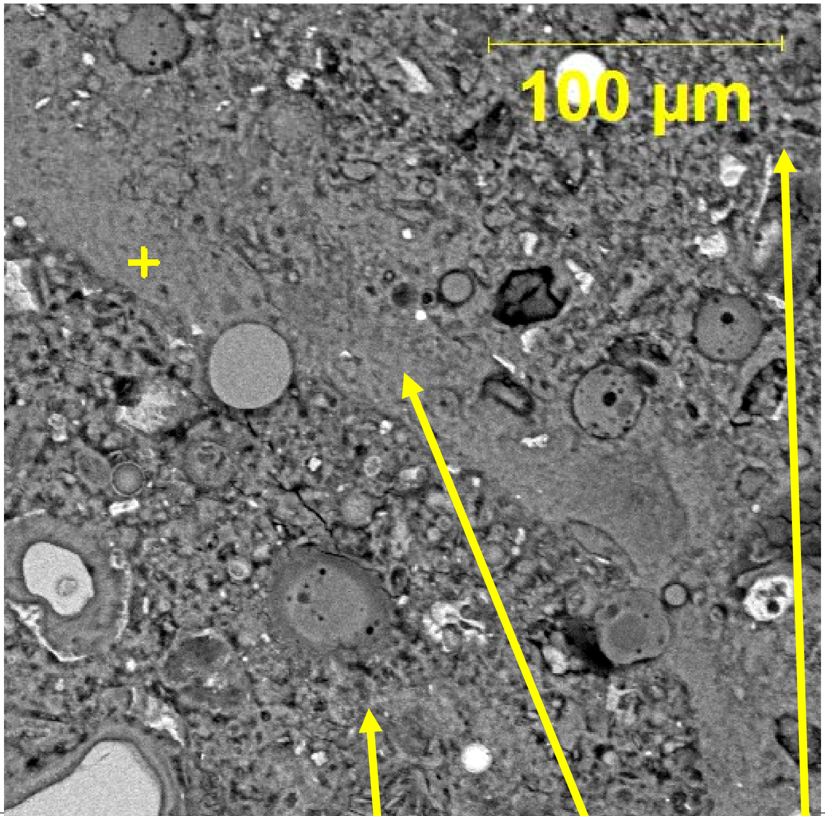
Cement Properties:

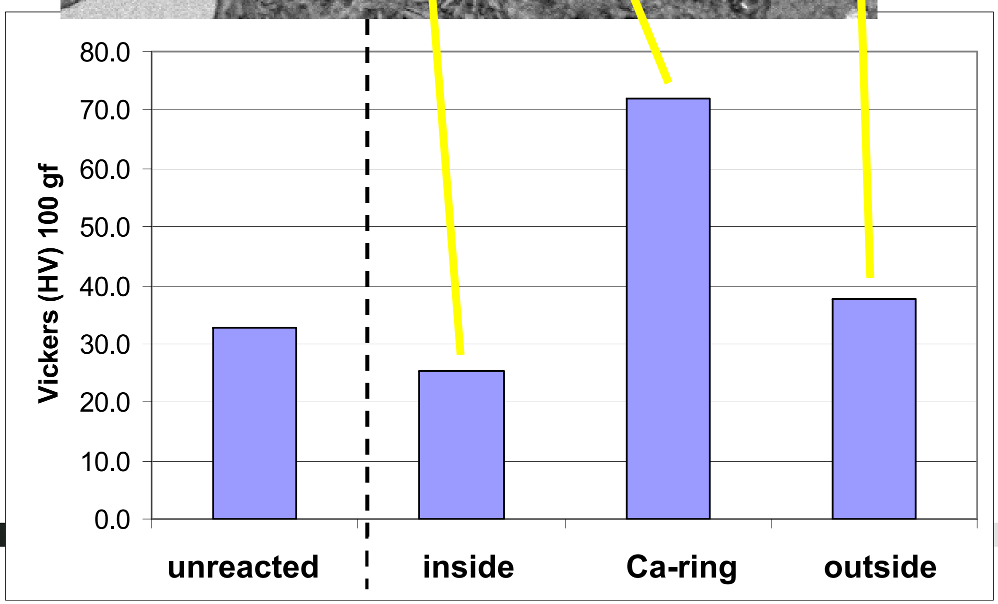
- **Class H 35:65 and 65:35**
- **Cured at T = 50ºC & p =15 MPa (2200 psi)**
- **Exposed to CO_2 at 50ºC & 15 MPa *after 28 days***
- **Alteration depth extrapolated to 170 - 180 mm for 30 year**

  - ordinary carbonation observed
- **Permeability: increased from ~1 μD to ~21μD (*65:35)***



Crow et al., CCS 2008; Kutchko et al., ES&T 2009





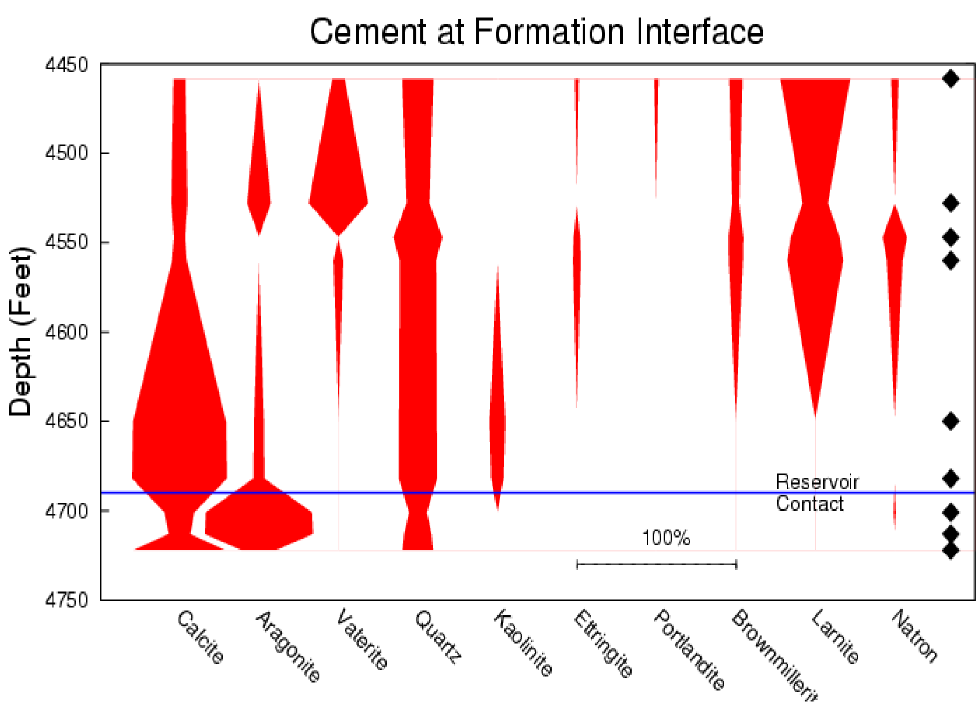
NETL Lab Samples:

- **Thin CC ring**
- **Inside the ring**
  - AFt (ettringite)
    - $[Ca_3Al(OH)_6 \cdot 12H_2O]_2 \cdot (SO_4)_3 \cdot 2H_2O$
  - Chloride
  - Unhydrated Cement grains
- **Outside the ring**
  - No AFt or Chloride
  - Calcium depleted cement grains
  - ***Fully Carbonated***

CCP Samples:

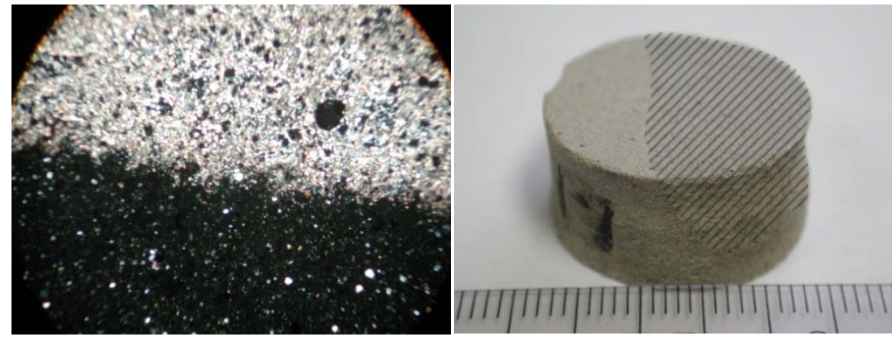
- Relatively uniform carbonation
- No CC rings observed
- Carbonate observed inside and outside reaction fronts

CCP Samples:

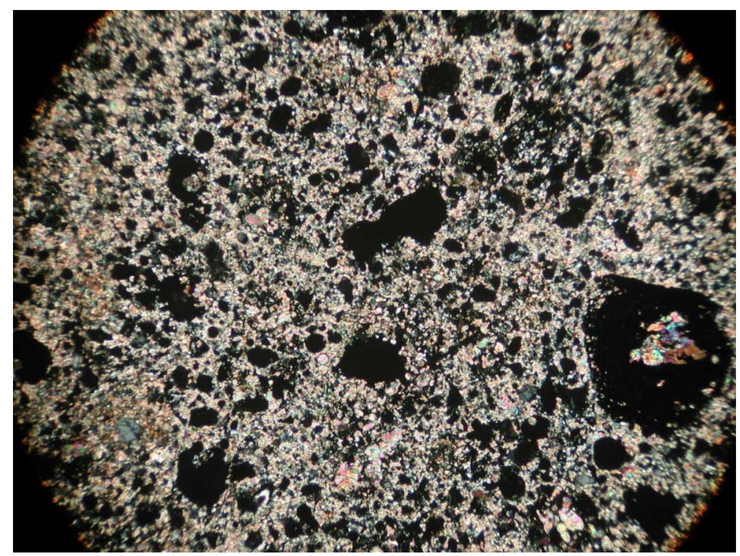


Summary “Pagoda” diagram showing mineral abundances in the cement at the cement-formation interface as a function of depth. The width of the column reflects mineral abundance. Actual sample locations are indicated at right-hand side.

Crow et al., CCS 2008



CCP Samples: PLM and optical images showing a region of carbonation: penetration depth varied depending on sample location (depth) in well



CCP Sample: PLM image showing a carbonated region of the cement

Summary of Field and Lab Observations

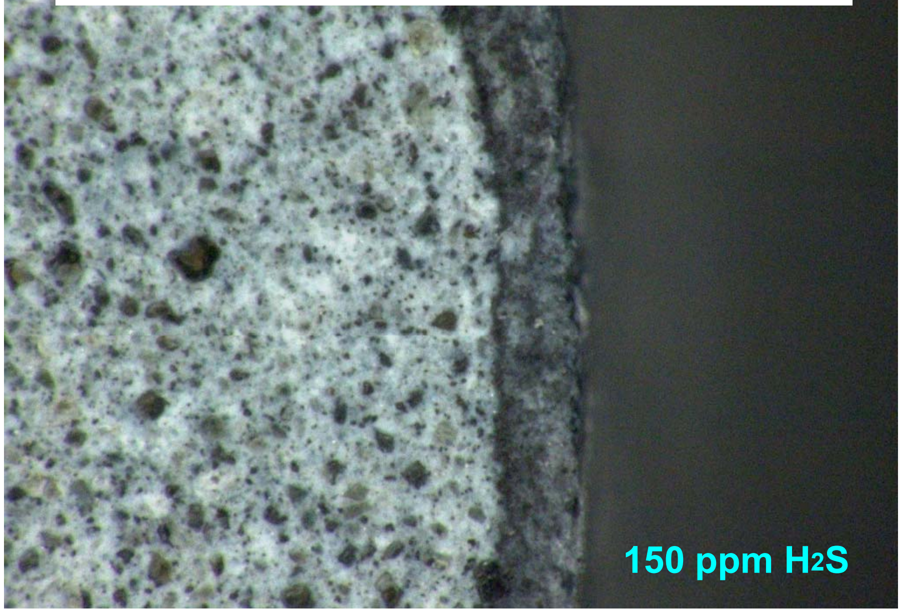
- Neat Portland cement forms distinct orange zone—calcium carbonate fronts
- Pozzolan-bearing cement carbonates more uniformly
- Laboratory studies consistent with field in showing that rate of CO_2 penetration in pozzolan-cements is faster than neat cements
- In field and laboratory, there is little evidence for mass wasting or loss during carbonation
- Carbonation results in increased porosity and permeability but cement still acts as hydrologic barrier

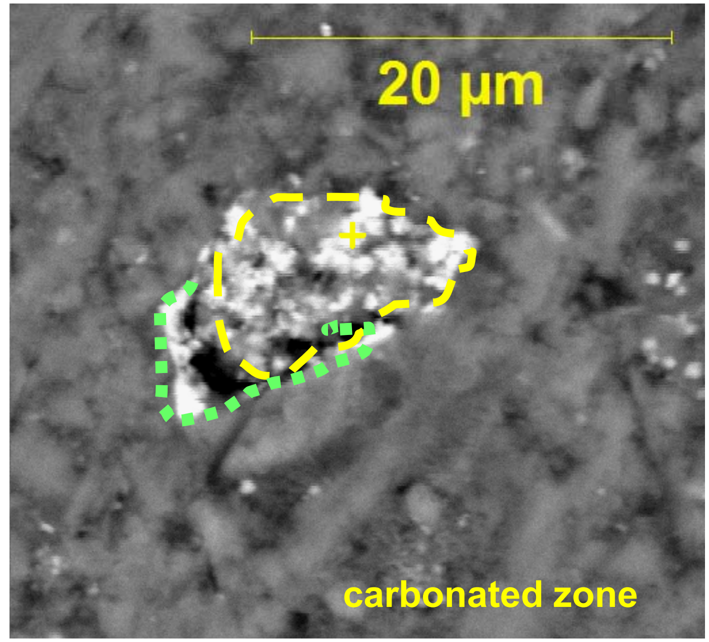
New Experiments at NETL: Can laboratory experiments be used to understand (predict) how cement will respond under other field conditions?

H_2S-CO_2 Cement Exposure Experiments – Preliminary Results

Performed in collaboration with Energy & Environmental Research Center (*EERC*) with Steven Hawthorne and David Miller

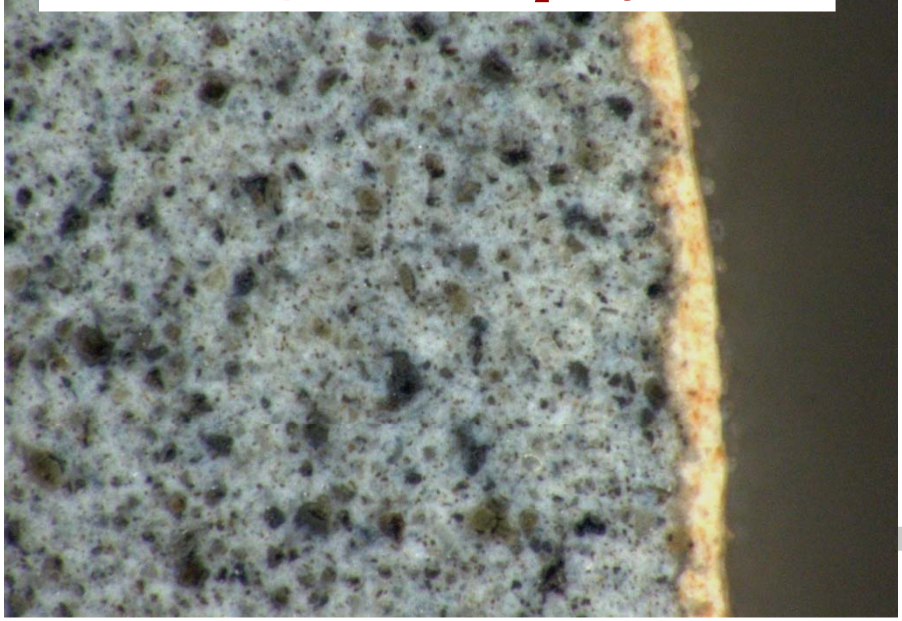
Exposed to H_2S-CO_2

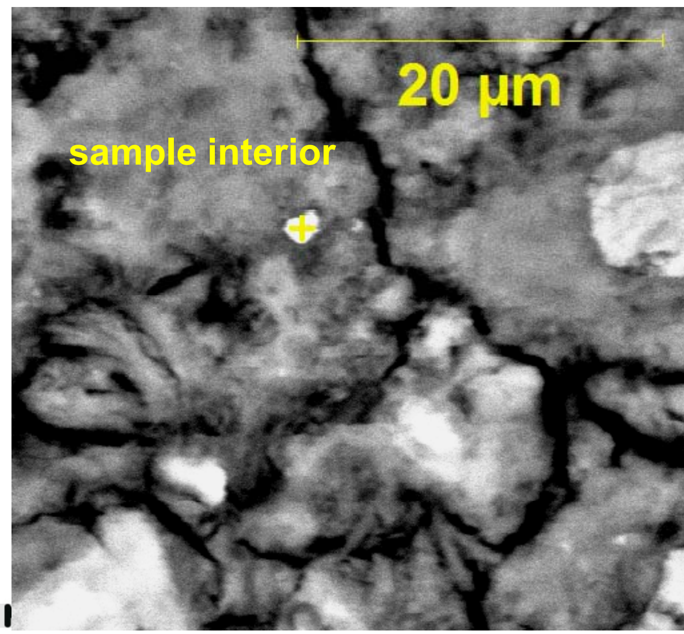




Exposed to H_2S-CO_2

Exposed to CO_2 only





Exposed to H_2S-CO_2

General Conclusions

- **Field samples vs. laboratory samples**
    - Field samples are very complex with complex histories
    - Lab experiments can't match the complexity but can be used to understand general trends
    - Use lab experiments to understand (predict) how cement will respond under different various field conditions

  – **Leakage due *entirely* to chemical degradation of cement will not be a significant concern.**
    - Chemical reaction alone is not going to cause leakage
    - Reaction with cement is diffusion limited and slowed by the precipitation of carbonates

  – **Field Samples indicate that degradation mainly occurs along *existing* or *induced* pathways.**

- **Current and Future Work:**
  – Will pathways be sealed or enhanced by CO_2 exposure?
  – What effect does brine composition have?
  – Effect of H_2S-CO_2(-Brine) on well cement?
    - Simulate acid gas injection

Experiences in the Salt Creek Field CO2 Flood

Ken Hendricks
Anadarko Petroleum Corp.

5th Annual Wellbore Integrity Network

May 13-14, 2009

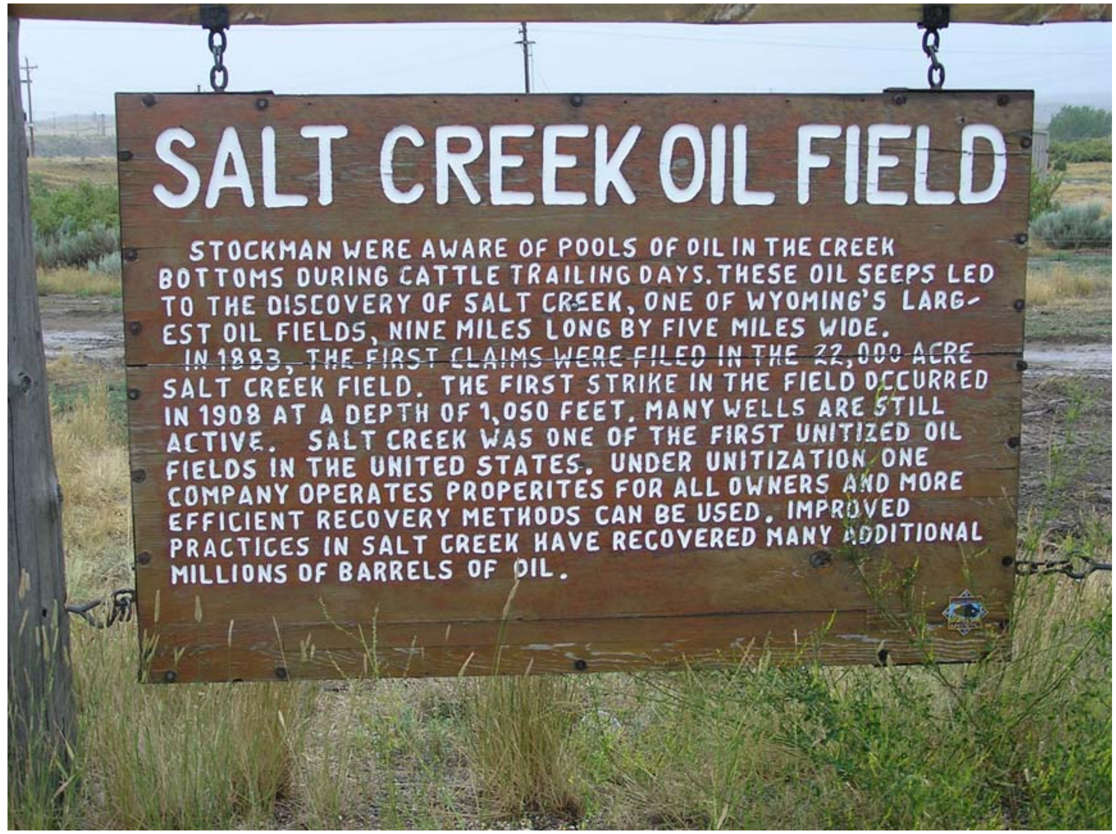
Calgary, Alberta

Thank you

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Anadarko believes that its expectations are based on reasonable assumptions. No assurance, however, can be given that such expectations will prove to have been correct. A number of factors could cause actual results to differ materially from the projections, anticipated results or other expectations expressed in this presentation. See “Risk Factors” in the company’s 2008 Annual Report on Form 10-K and other public filings and press releases. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements.

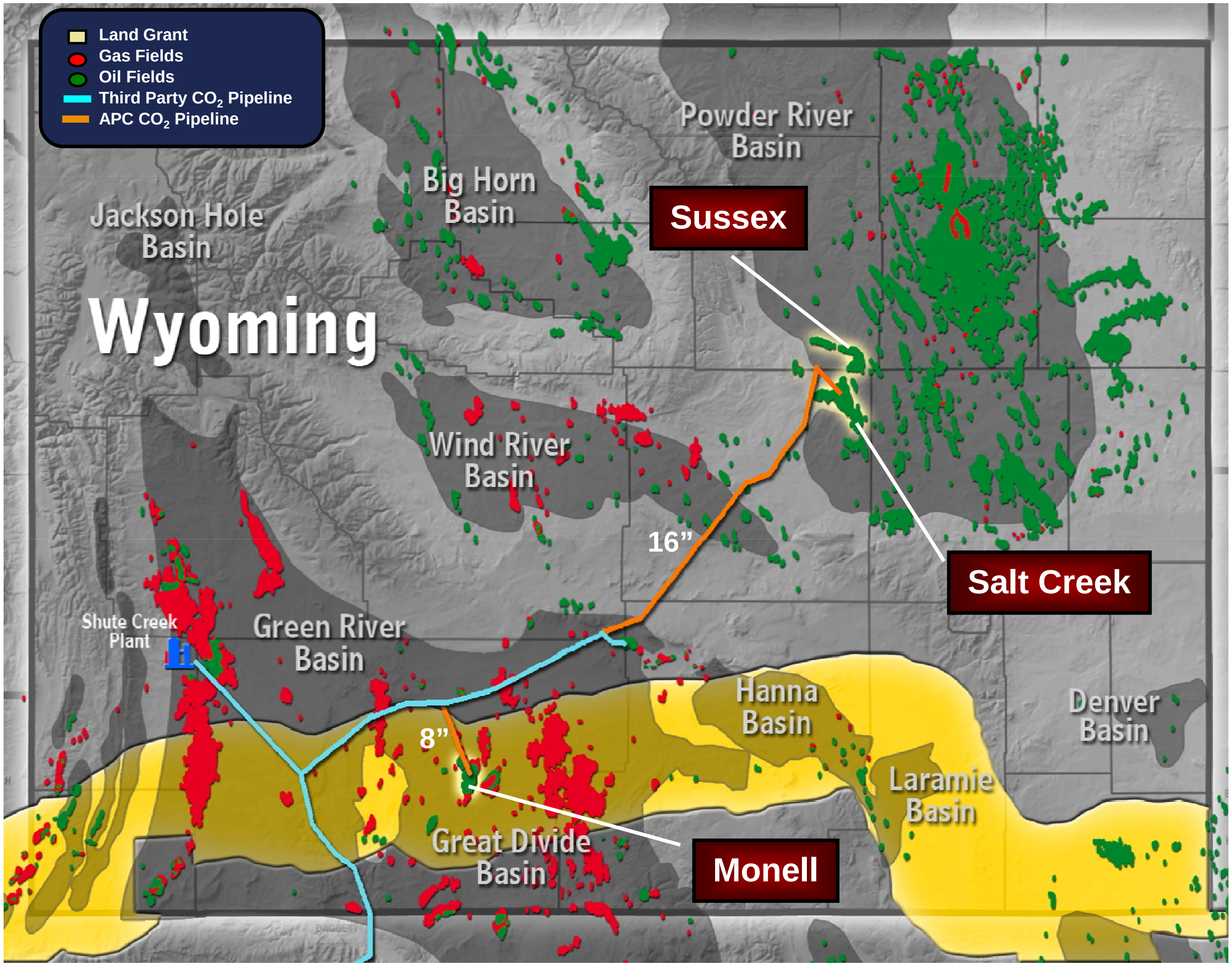
Outline

- Field/System Overview
- Challenges
    - Wells
    - Others
- Lessons Learned
- Benefits
- Questions



Anadarko's Wyoming EOR Assets

- Fields
  - Monell
  - Salt Creek
  - Sussex
- Pipelines
  - 33 mile, 8"
  - 125 mile, 16"
- CO_2 Supply
  - XOM Shute Creek



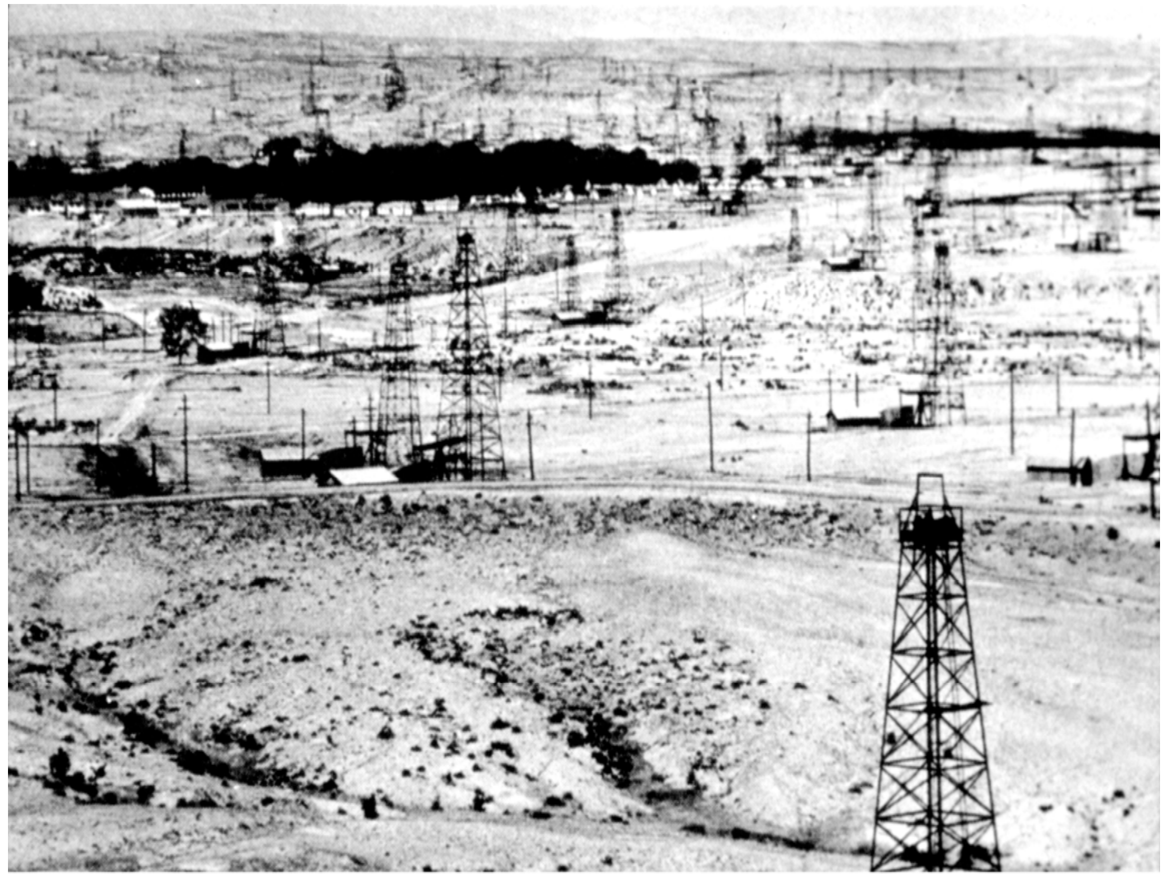
Salt Creek – Overview

History

- Discovered in 1908
- >4,000 wells drilled
- 1.7 Bbbl of OOIP
- 0.7 Bbbl cum. production
- 10 producing horizons
- Depths range from 22' to 4,500'
  - Second Wall Creek ~ 1,800'
- Waterflooding began mid-1960s
- CO_2 injection began Jan 2004
  - CO_2 production began May 2004
- >90% located on BLM acreage
- Planned Sequestration of ~40 million tons (700 BCF) of CO_2

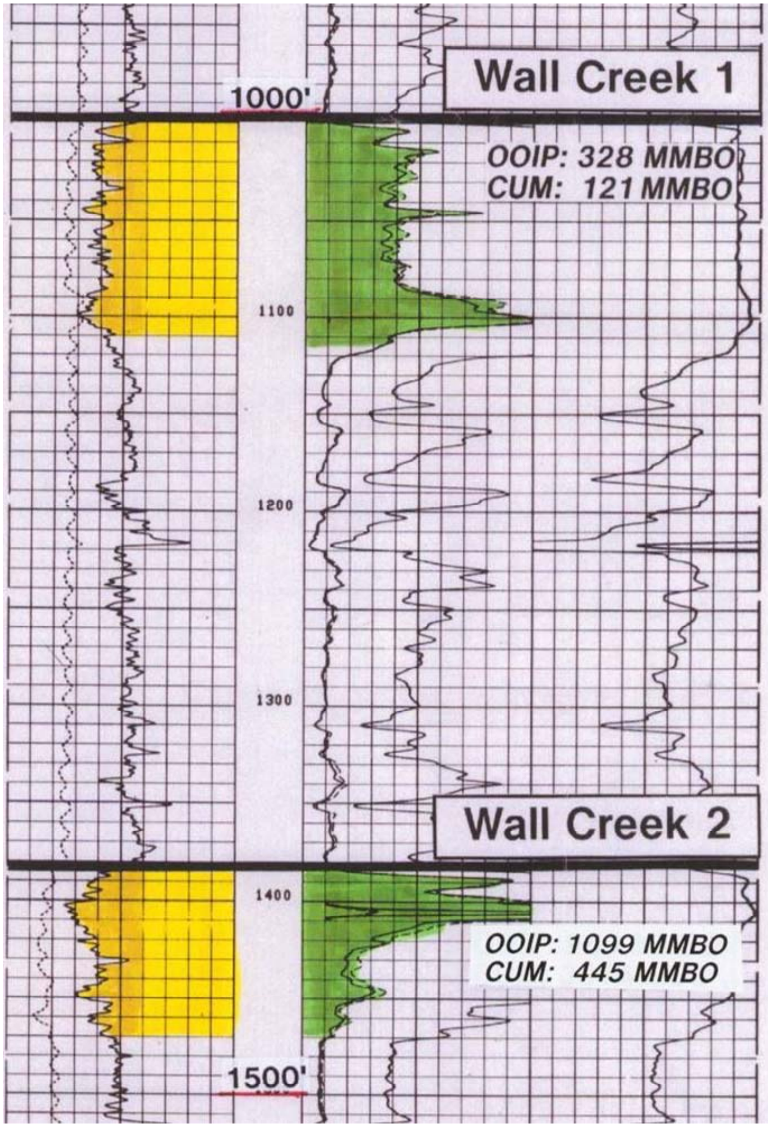
Current Rates

- 8,000 b/d from CO_2, (9,500 b/d total)
- 350 MMcf/d CO_2 injection
  - ~125 MMcf/d new CO_2
  - ~225 MMcf/d recycled CO_2
- CO_2-EOR Cumulative > 8 MMBO



Salt Creek Oil Field, early 1920s.
Required Credit: AMOCO Refining Co. Collection, Casper College Library.

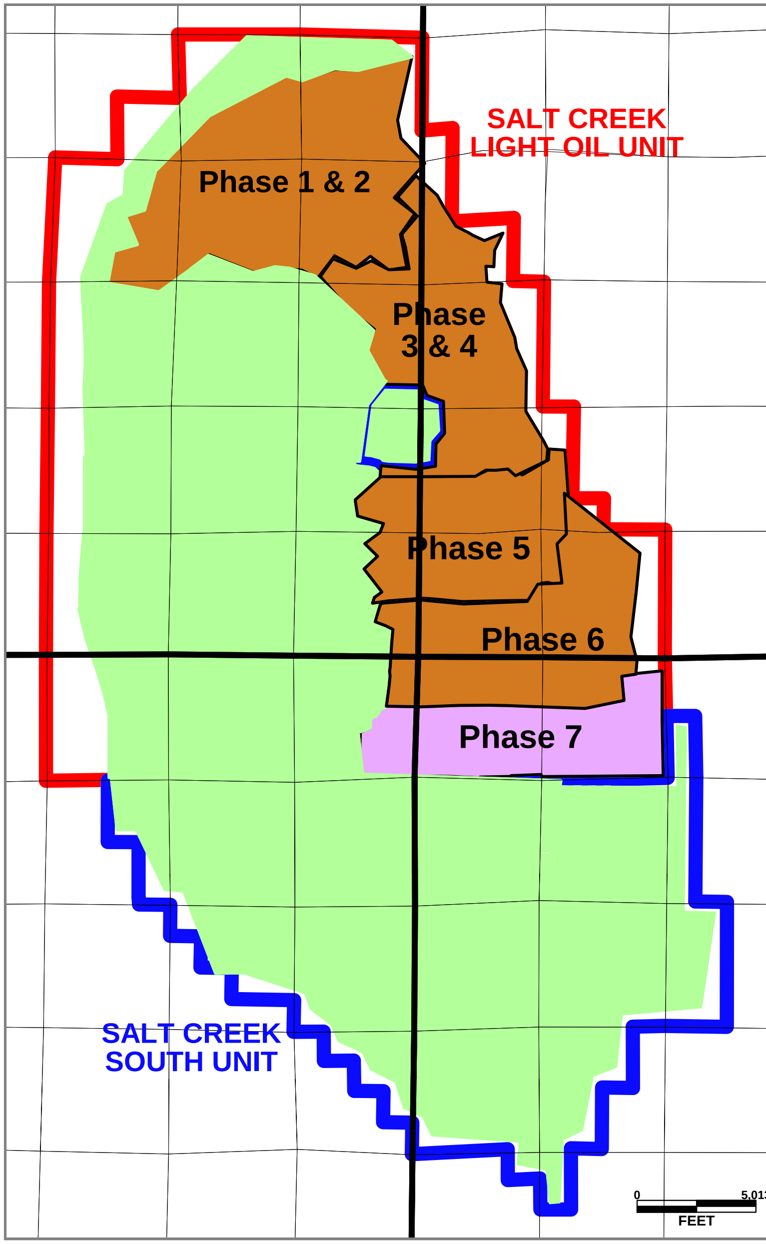
Salt Creek Type Log – Wall Creek 1 & 2



Wall Creek 2 (Primary Horizon)

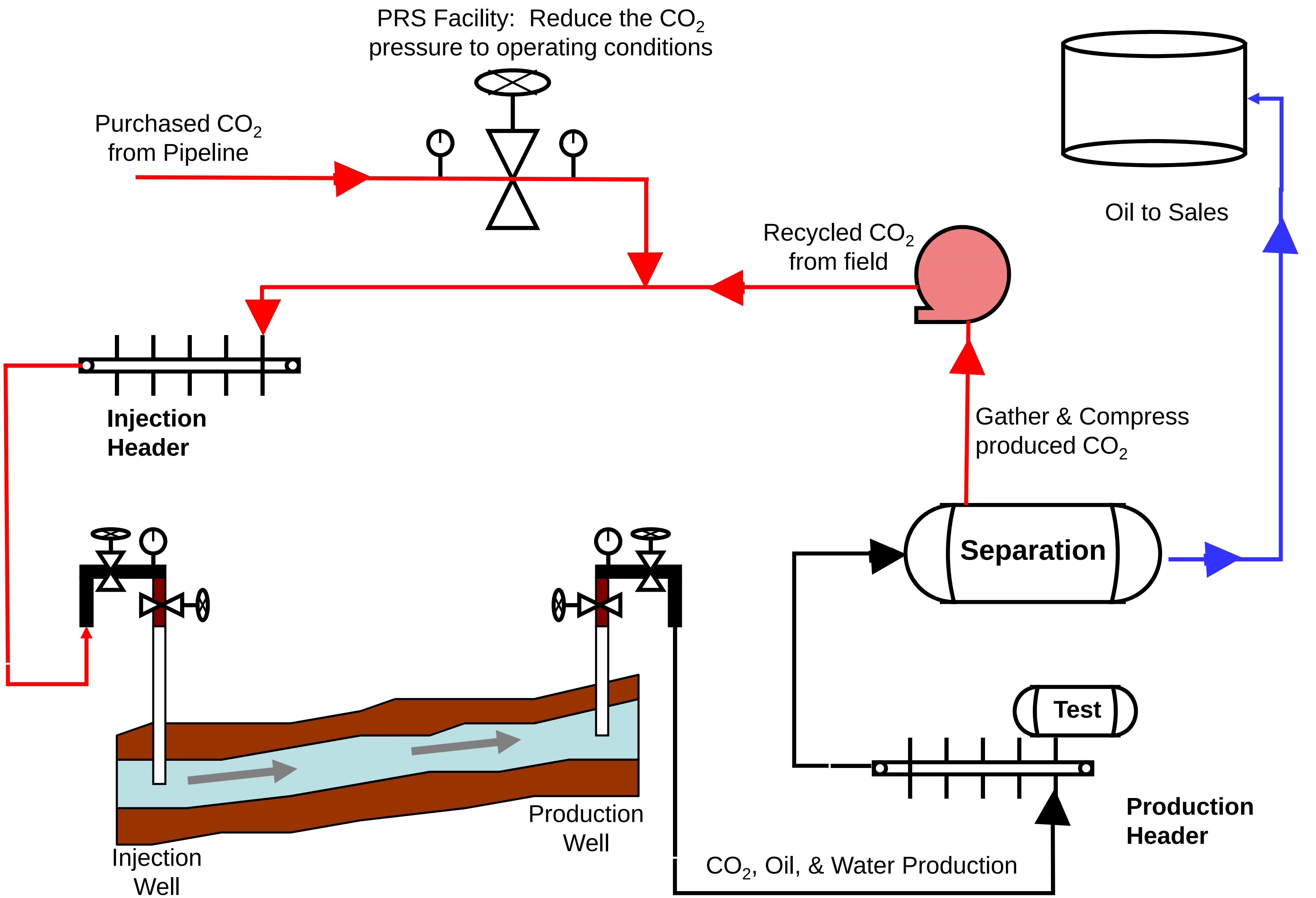
- Salt Creek structure is a large asymetrical anticline
- Area: 40 sq. miles
- Depth: 1,500 - 2,500’
- Thickness: 130’ grs / 70’ net
- Por / Perm: 19% por / 52 mD
- 39 API; MMP 1,250 psi
- Primary: 1917 – 67
- Waterflood: 1967 – present
- CO_2: 2004 – present

WC2 CO_2 Flood

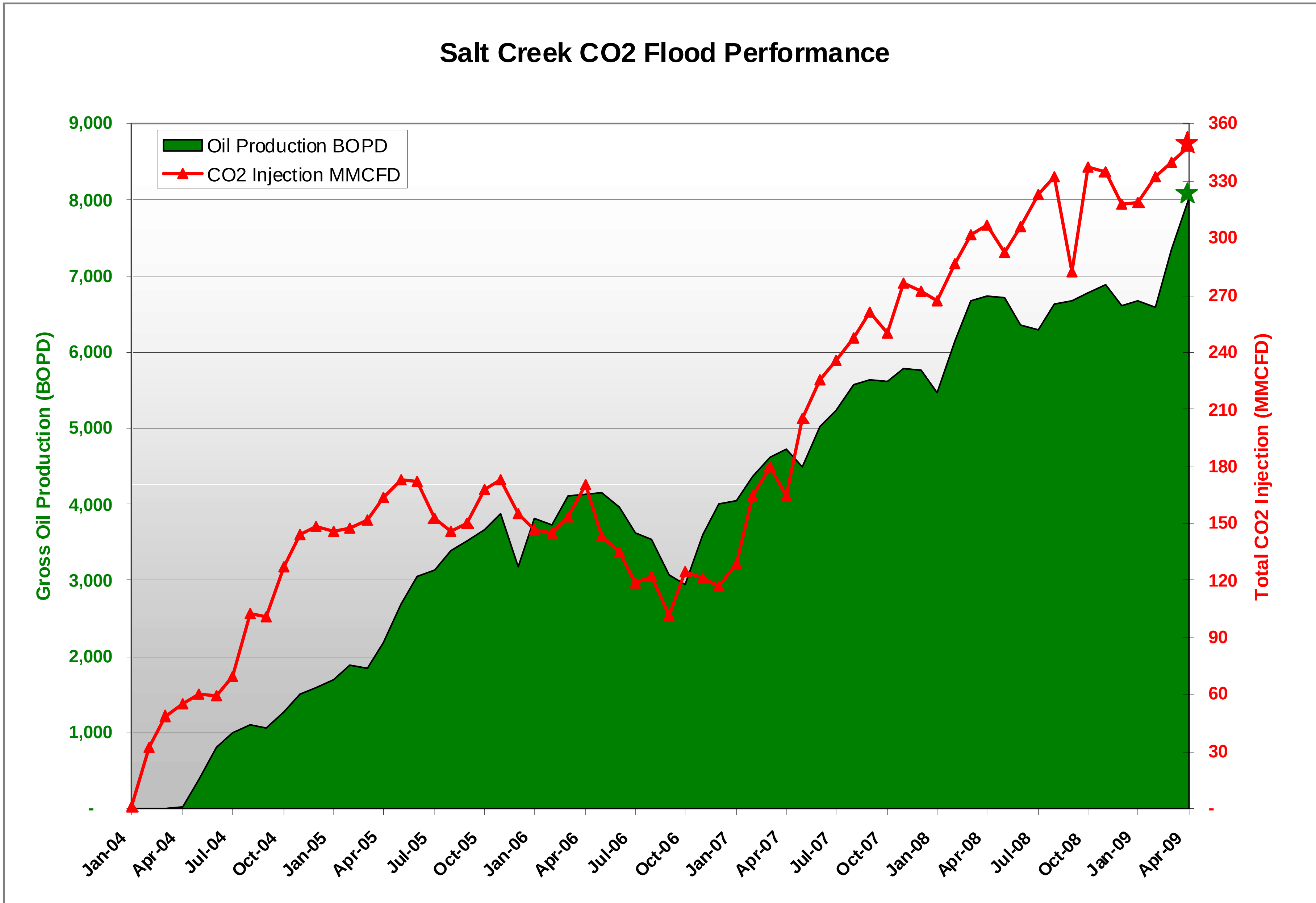


- **Oil: 39º API**
- **MMP: 1,275 psi @ 105º**
- **Miscible areas on flanks**
- **Flood Type: (WAG) Water Alternating Gas**
- **Producers: Flowing wells (against surface backpressure of 200 – 400 psi)**

CO_2 Flow Process at Salt Creek



~8 MMBOE from Salt Creek CO2 flood

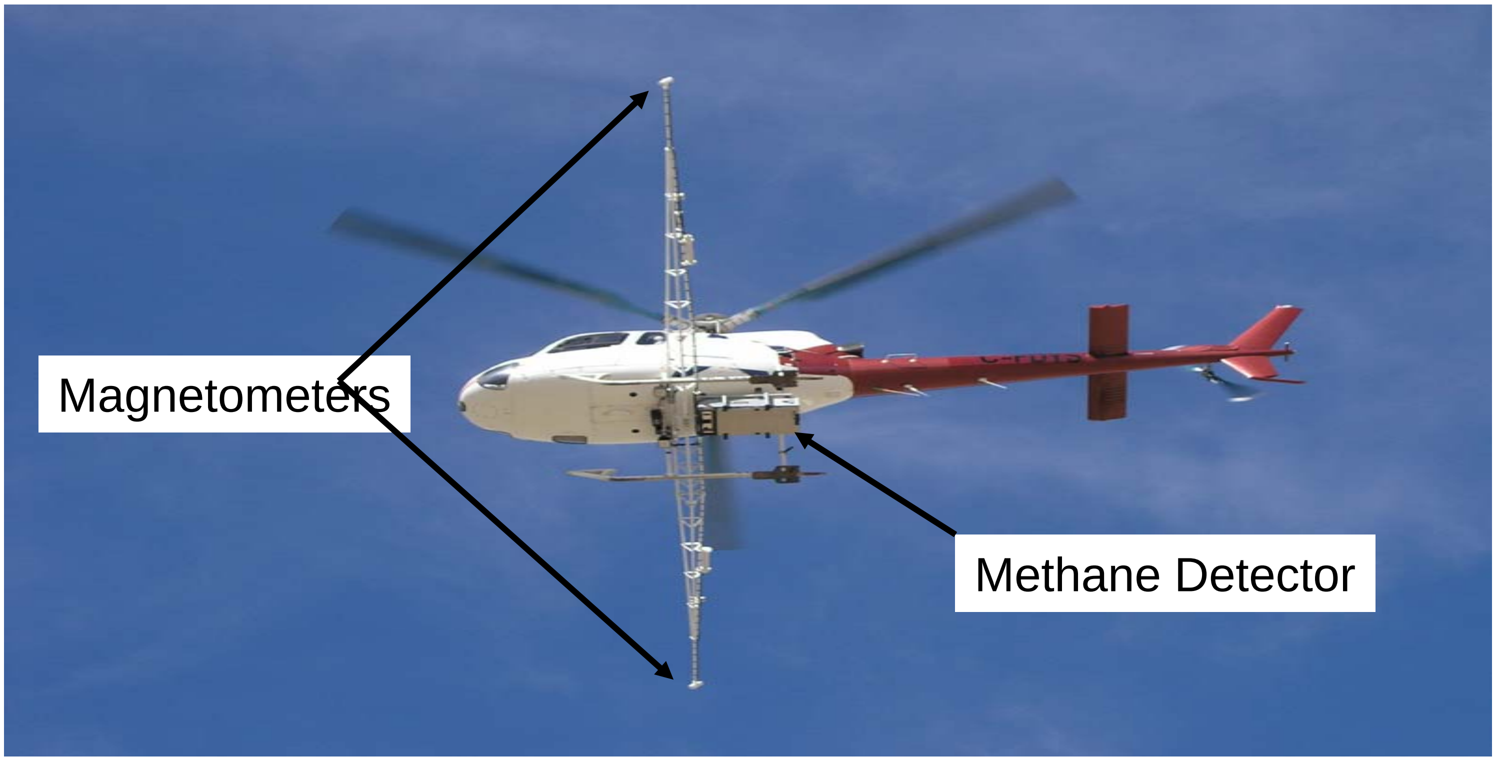


Pre-CO_2 Development – What did we have?

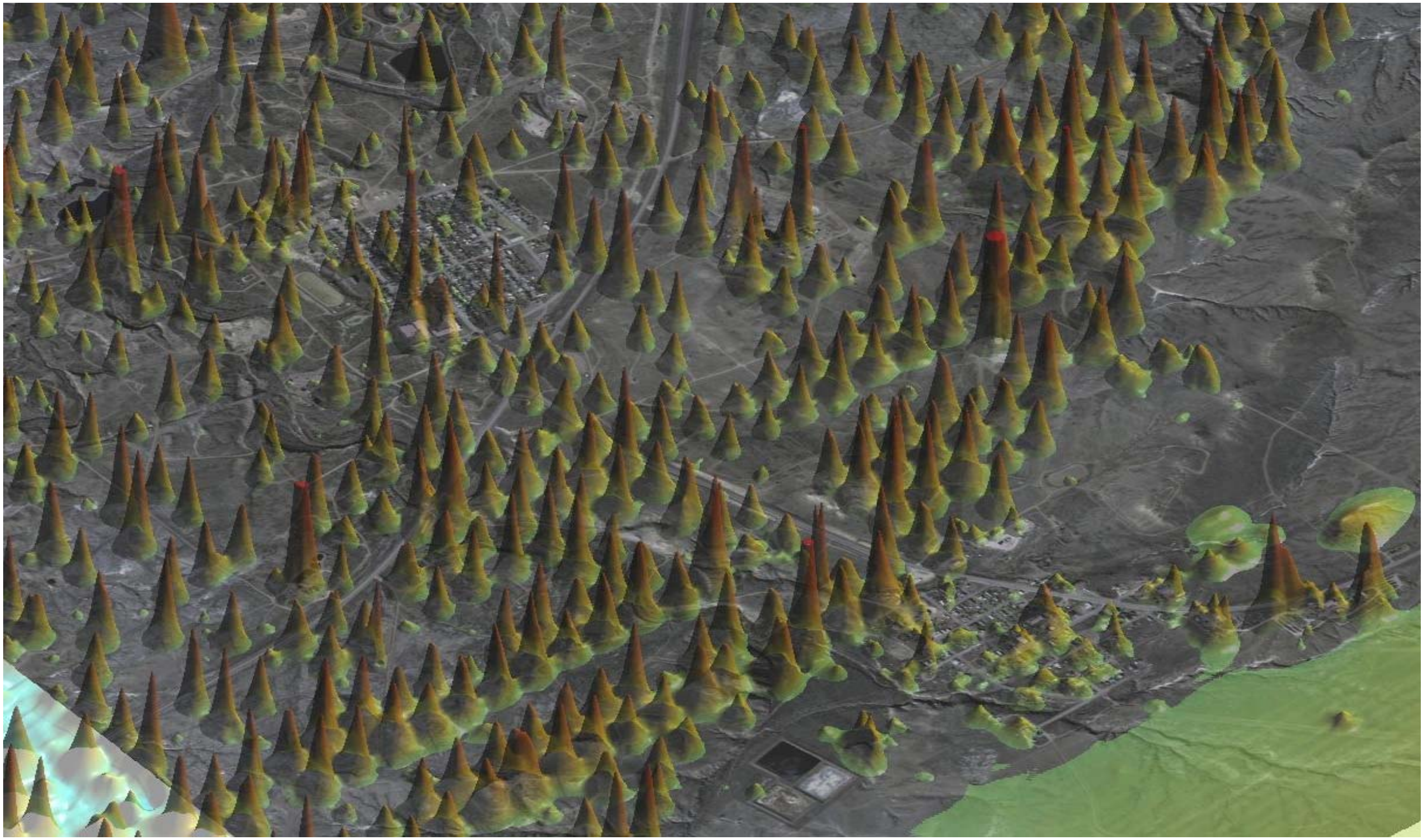
- More than 4,000 wells drilled; ~70% prior to 1930
  - ~1,000 well waterflood producing +/- 5,000 b/d; 99.4% water cut
  - High well density with the Second Wall Creek formation developed on ~ 4-acre spacing
  - Limited open-hole log data – Most wells drilled prior to this technology existing
  - Existing production/injection casing not designed for corrosive CO_2 service & of questionable integrity
  - Over 3,000 plugged and inactive wells with questionable cement isolation & questionable plugging quality
  - Incomplete well data & numerous unknown wellbores

Well Challenges

- Identification of all existing wellbores
  - Extensive record searches, conventional & unconventional. Difficult because of limited or nonexistent records for numerous wells
  - Magnetic surveys, both aerial and ground

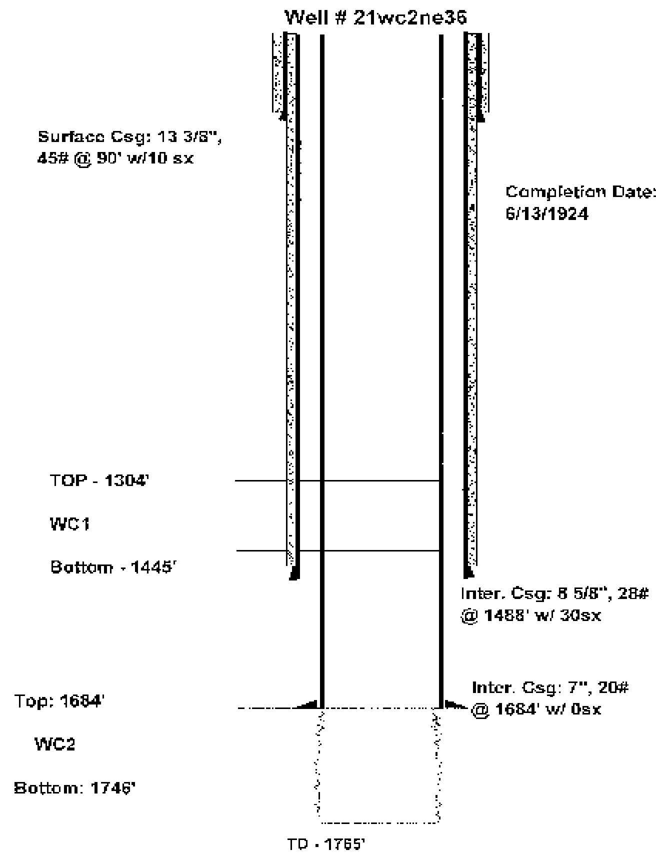


3D Perspective of Magnetic Survey



Well Challenges (cont.)

- Hyper-mature wellbores with minimal to no original cement and questionable wellbore integrity
  - Cement is critical to keep CO2 contained in target reservoir
  - Significant efforts to quantify cement quality, CBLs, temp logs, tracers, etc.
  - Squeeze cementing is very common
- Effective cement blends
  - Presently Type I/II cement is used.
  - Work in low temps < 105 F
  - Available & economic
  - Low permeability (finer grind)
  - Performs well in acid resistance testing and is rated as sulfate resistant

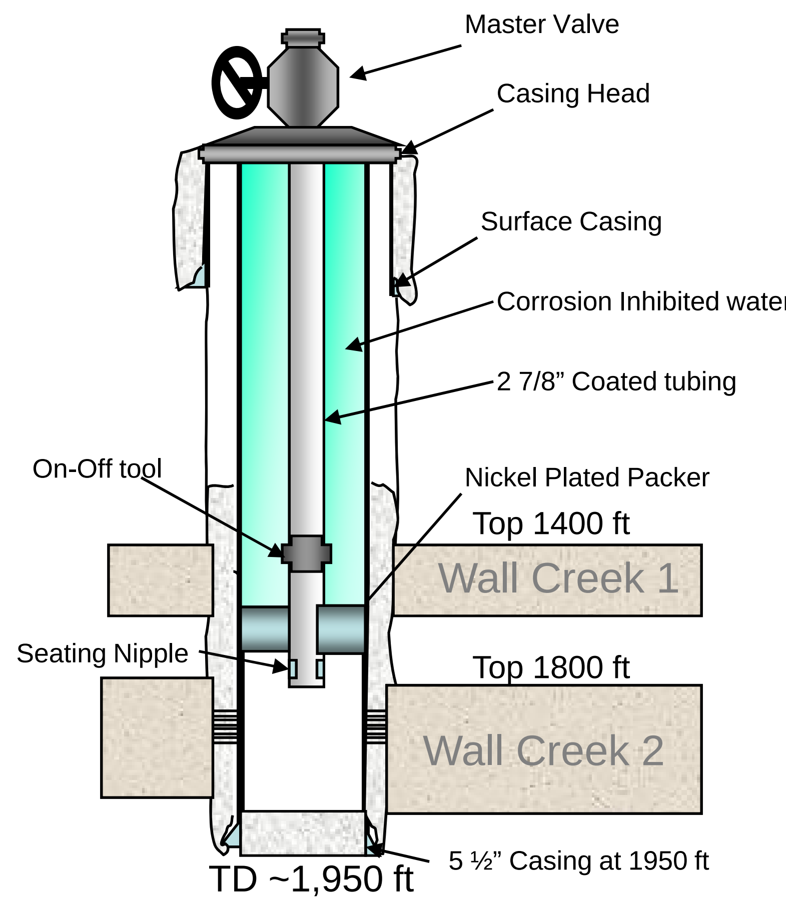


Well Challenges (cont.)

- Effective sealing with high durometer packing/sealing elements
  - High durometer elements unsuitable at Salt Creek, presently 60 - 80 durometer elements are used
- High volume of well work
  - >1200 wells worked over in Phases 1-6
  - 95+% success rate in reactivating plugged wells
- High pore pressure gradients – 14 to 18 ppg equivalent

Salt Creek Well Design / Requirements

- Every well is evaluated, make no assumptions of adequacy
- Existing wellbores used when possible – typically extensive work is required
- Zonal isolation required in all wells, including P&A wells
- Basic Well Requirements
    - Pressure integrity within the casing above perforated interval
    - 100' of behind-pipe cement above the WC2 & WC1
- All CO2/Water injected down tubing - internally lined, coated, or fiberglass
- Nickel plated packers used to mitigate potential corrosive effects, and to aid in isolation
- Injectors and producers are equipped identically



Lessons Learned

- Cement isolation above both the WC1 and WC2 is required to prevent behind pipe fluid movement
  - Properly designed common oilfield cements are effective in carbonic acid solutions
  - CBLs have proven to be effective for evaluation
- Perform well work in advance of CO2 development, all objectives are more attainable in a lower pressure environment
- All wells drill to the WC1 or deeper will be evaluated and worked on as necessary, this includes making sure that all inactive wells are plugged properly. If records are uncertain, rig up and confirm the status of the wellbore. This will mitigate potential wellbore integrity issues
- Casing will be pressure tested. Pressure requirements will vary as individual well reliability requirements increase. This will mitigate potential wellbore integrity issues
- All packers will utilize sealing elements rated no higher than 80 durometer to allow for a better packer seal within the wellbore
- Wellheads will utilize a tubing hanger equipped to handle a back pressure valve, and will be flange connected to the master valve. This expedites well control and improves safety
- Step-rate tests will be performed and are critical for optimizing injection rates and pressures
- Remedial cement work is the most effective way to correct most wellbore integrity problems
- Slimhole completions using fiberglass tubing/casing is a viable option on both existing older wells and newly drilled wells. Fiberglass pipe will be cemented to surface.

Lessons Learned (cont.)

- Well problems can occur. At the first indication of a problem be prepared to utilize one, or more, of the following diagnostic tools:
  - Injector / producer pattern reviews (High level check)
    - Reservoir pressure evaluation
    - Injection-Withdrawal ratios/Pattern balancing
  - Temperature logging (Joule-Thompson effect)
    - Common and useful in identifying both internal and external wellbore problems
    - Fiber Optic Cable can be run in some cases, allowing for fully distributed temperature logs
  - Radioactive tracer logging. Can be performed with both gas and liquid transported tracer material
    - Can also identify internal and external wellbore problems
    - Gas tracer material can be run with CO2
  - Other technologies
    - Noise logs
    - Seismic
    - Interwell Tracers

Other Challenges

- Continued Waterflood Operations concurrent with CO2 Development & Ops
- Significant project activity beyond Second Wall Creek Development
- Challenging Regulatory Environment
  - Environment Assessments
  - Wildlife Stipulations
  - Oversight by both State & Federal Agencies
  - Long permit lead times
  - Changing regulatory requirements

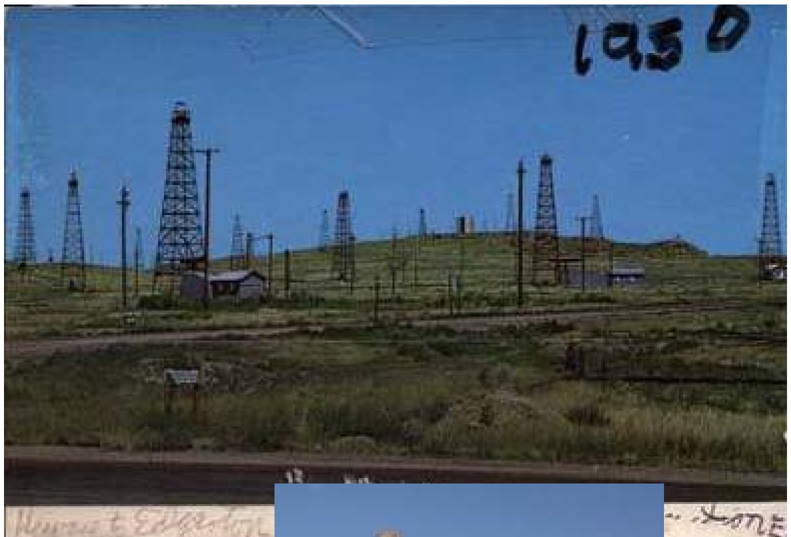
Non-Typical Benefits

- Salt Creek development viewed positively by State and Federal Agencies
  - Vintage plugged and abandoned wells are re-plugged to modern standards, reducing liability
  - Improving viewshed & more aggressive field reclamation
  - New flowlines reduce leak frequency, minimizing spills
  - CO2 sequestration

- Salt Creek's brownfield development assists the regulatory agencies in meeting their stated multiple use objective, while minimizing new disturbance

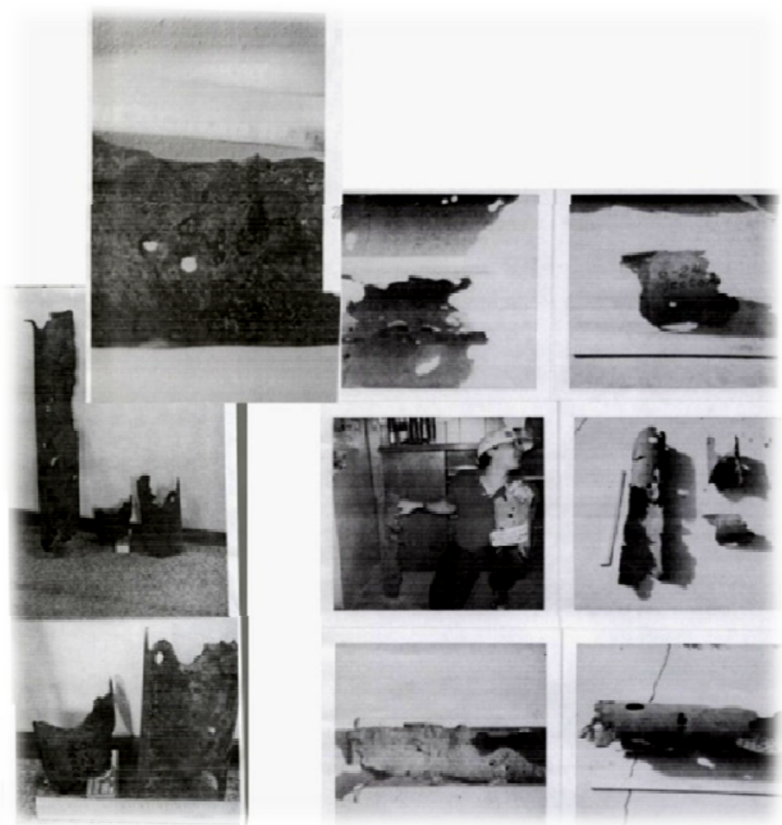
Questions ??

The past …



Today and beyond …

Weyburn Well Integrity Database



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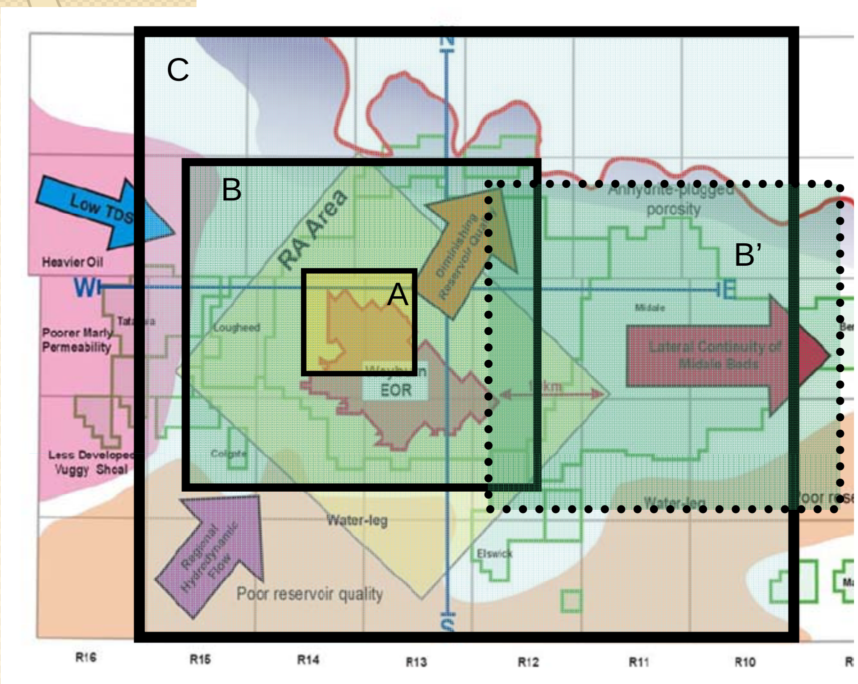
AND STORAGE PROJECT

Brandi Mitchell
Rick Chalaturnyk
Reservoir Geomechanics Research Group
Department of Civil and Environmental Engineering
University of Alberta

Scope of Database and Knowledge Synthesis Tasks



- Expand the wellbore database to cover ALL wells within the Phase 1A area and to extend this coverage to Region A
- New parameters will be added to the database, such as workover frequency and casing vent gas or sustained casing pressures.
- Effort will also be expended in making the database more user-friendly by implementing graphical user interfaces for well identification.

Data Mining

- Identify parameters that are most likely to affect long-term wellbore integrity.
- Produce a relative ranking between well construction methods/materials and wellbore integrity.
- Assessment of the mechanisms and magnitudes of leakage to be expected in wellbores with the construction methods and materials used in the Weyburn Field.
- Generate a family of statistics that will properly characterize the range of physical and behavioural conditions of the wellbores within Region A.
- By combining the well integrity assessment methodology developed in Phase I of the Project and the relationships established from the data mining task, an empirical long-term well integrity risk criteria will be developed for the range of well types found within Region A of the project area.

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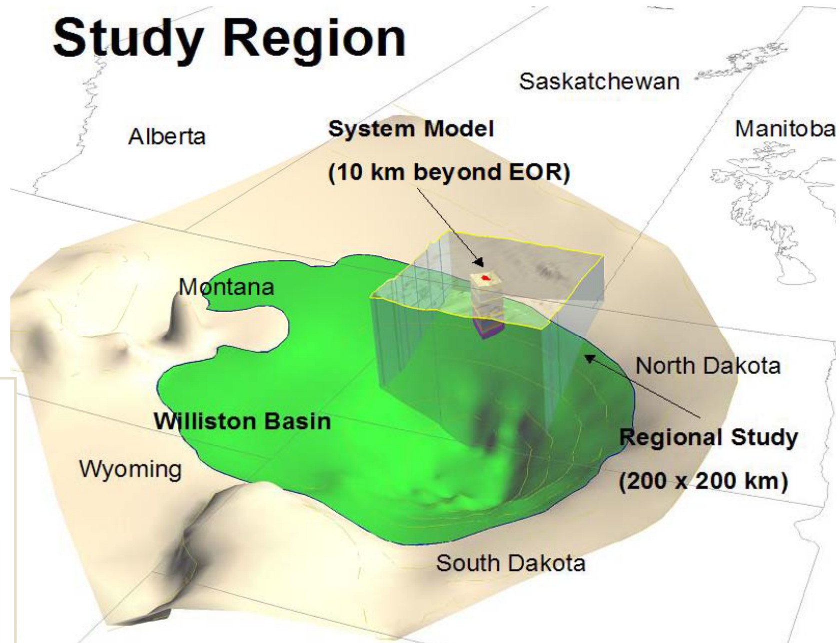
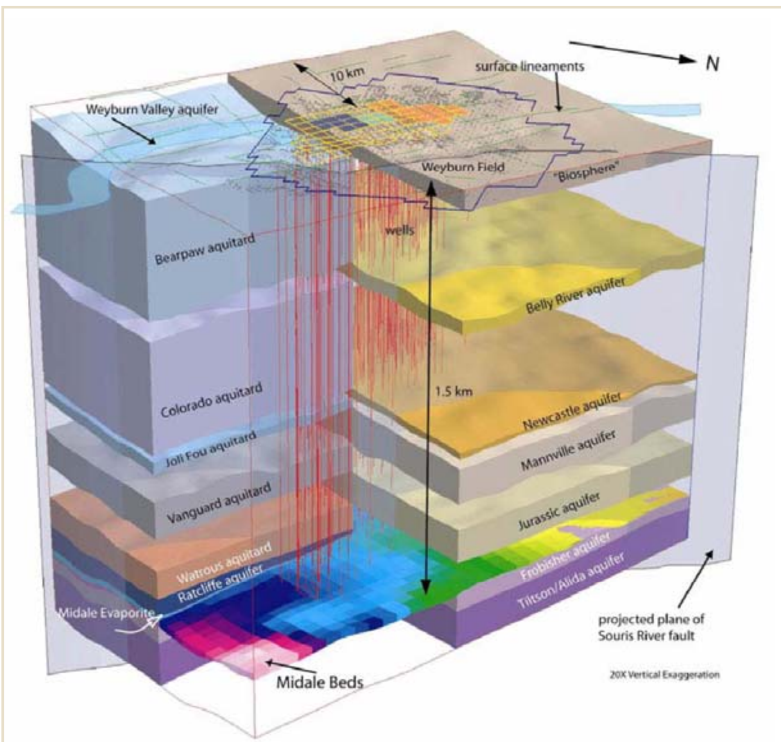
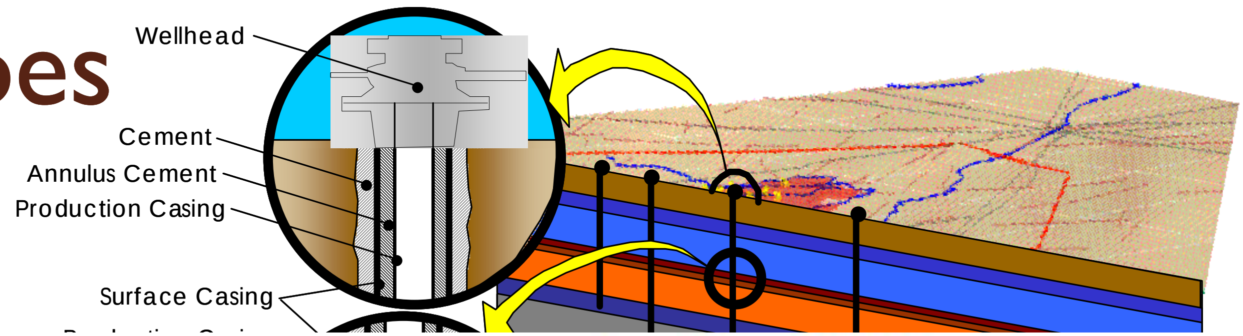
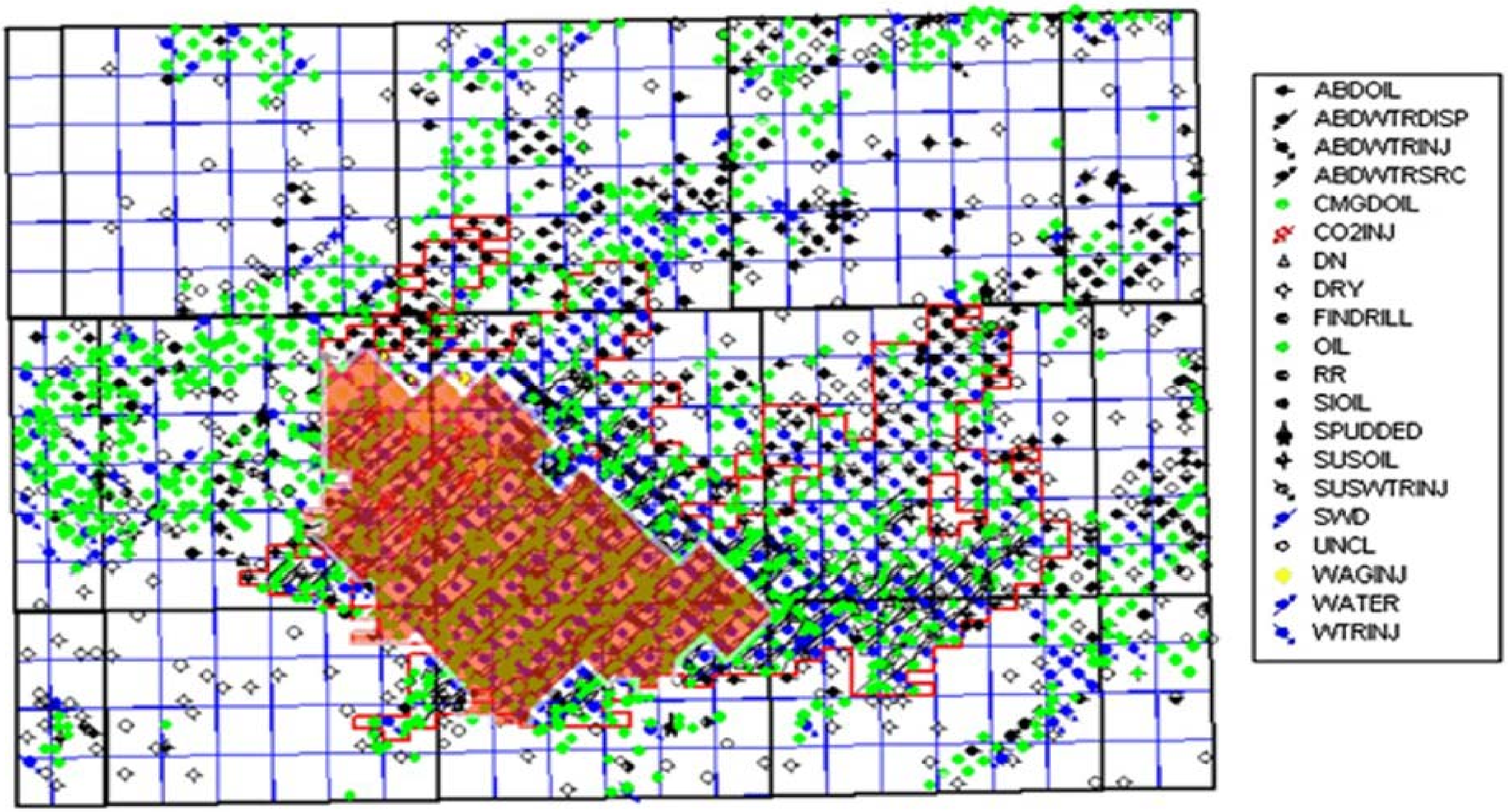
Weyburn Setting

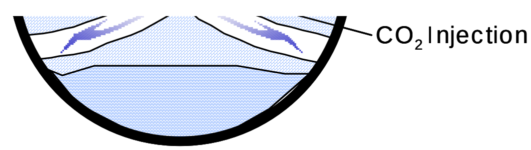




Well Types







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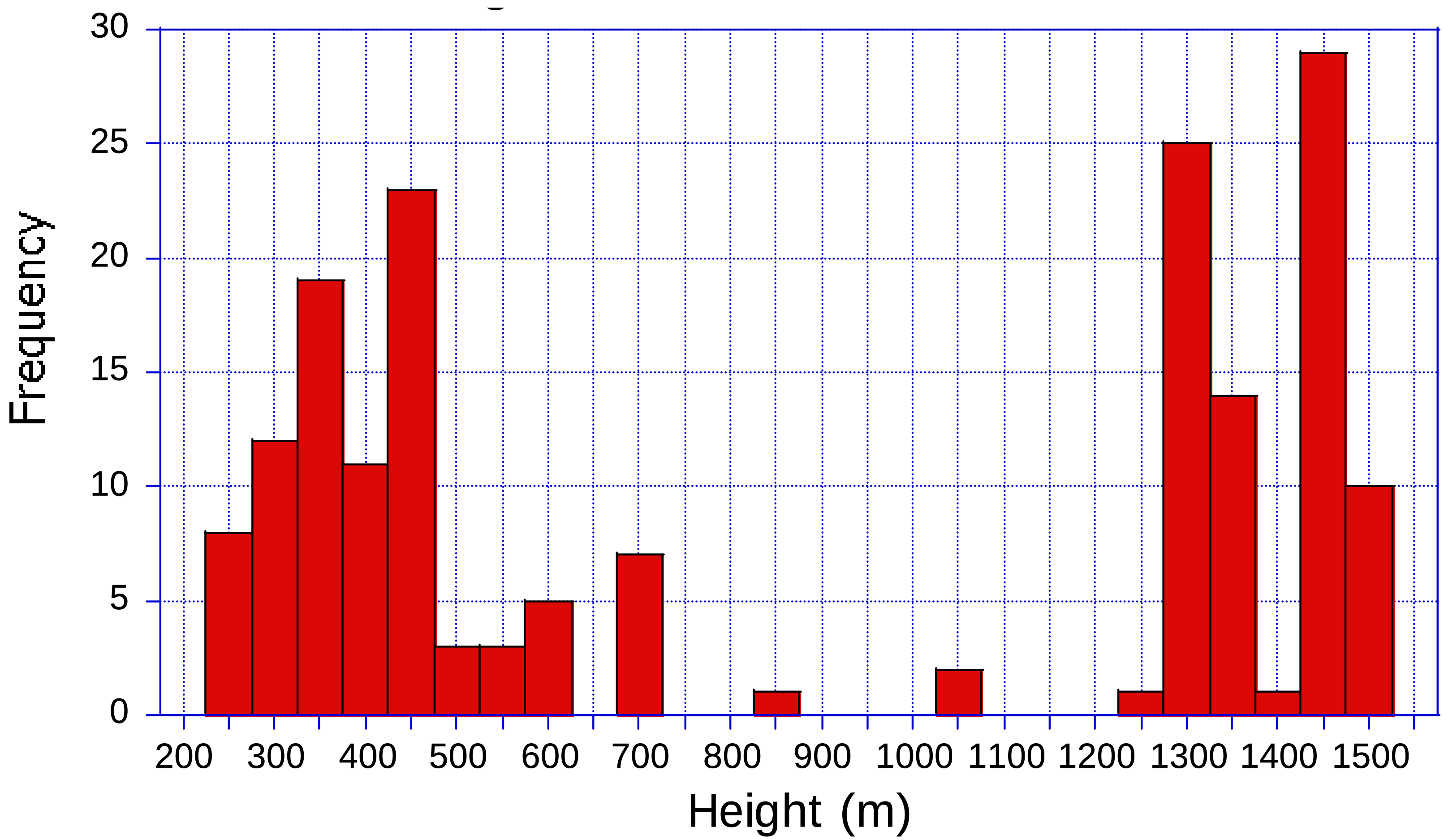
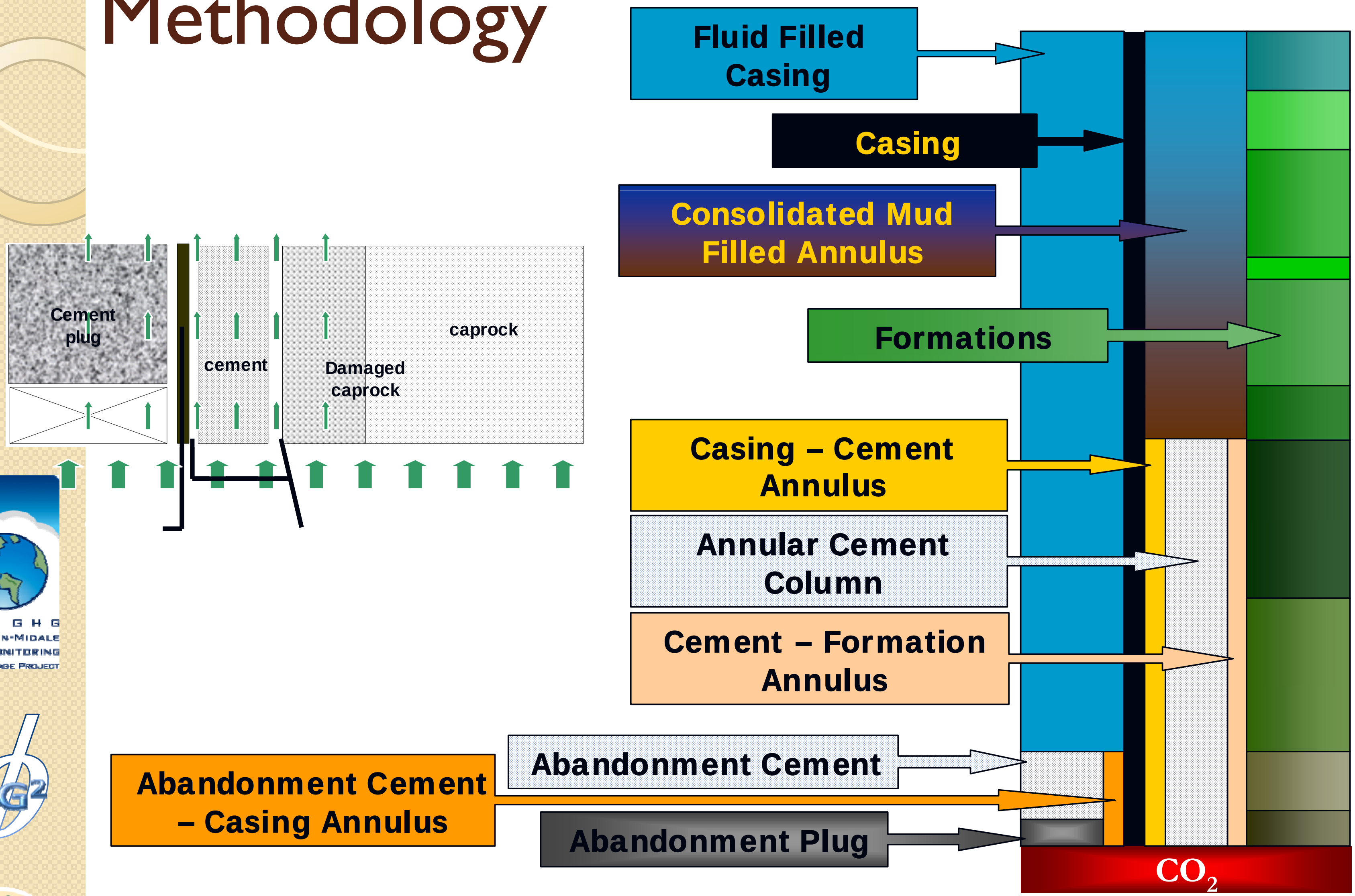
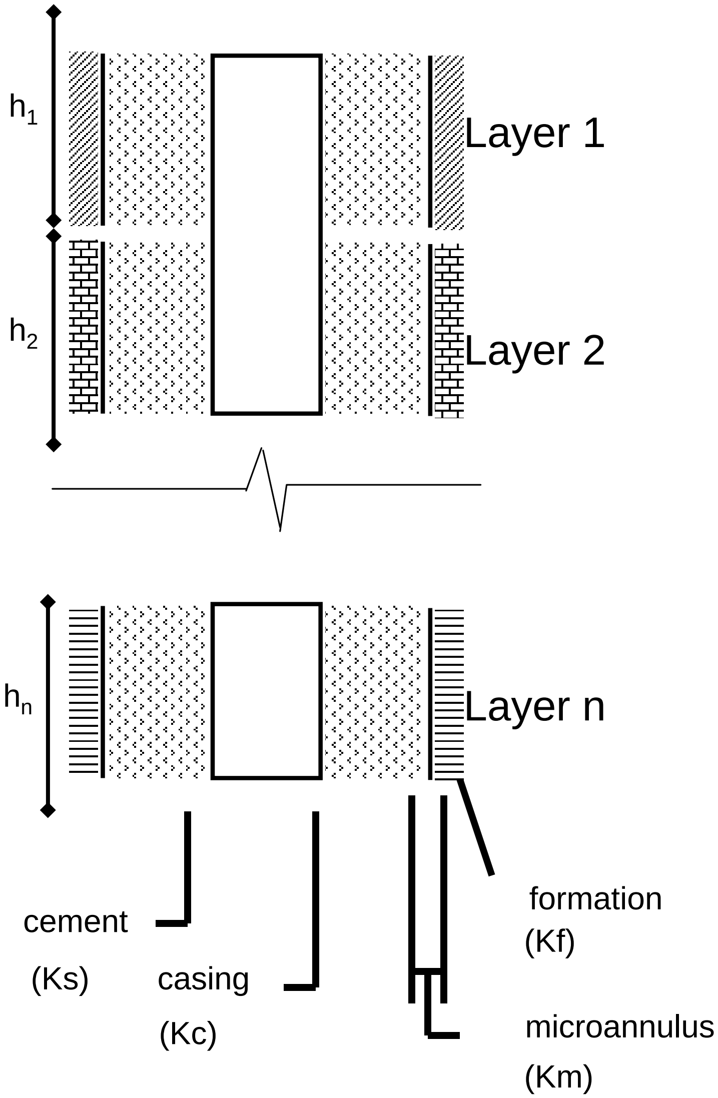
Phase I of Project
Ht of Annular Cement Column

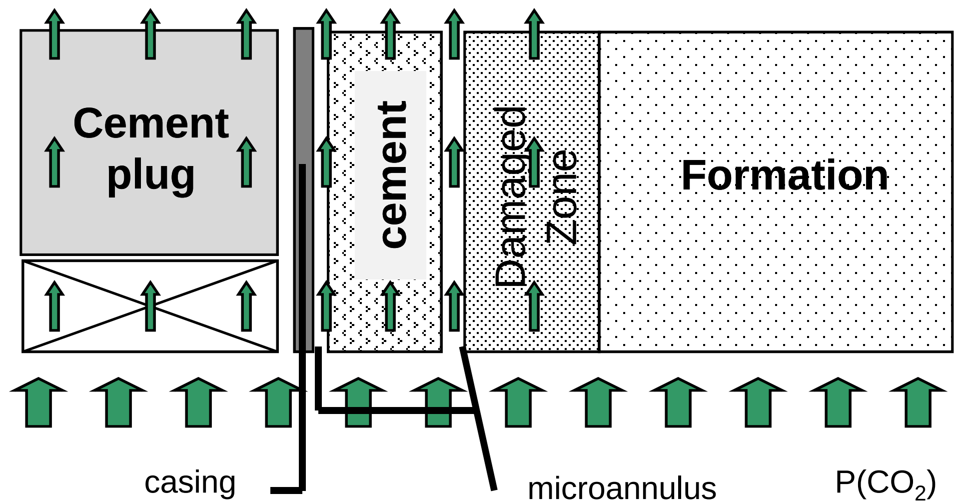


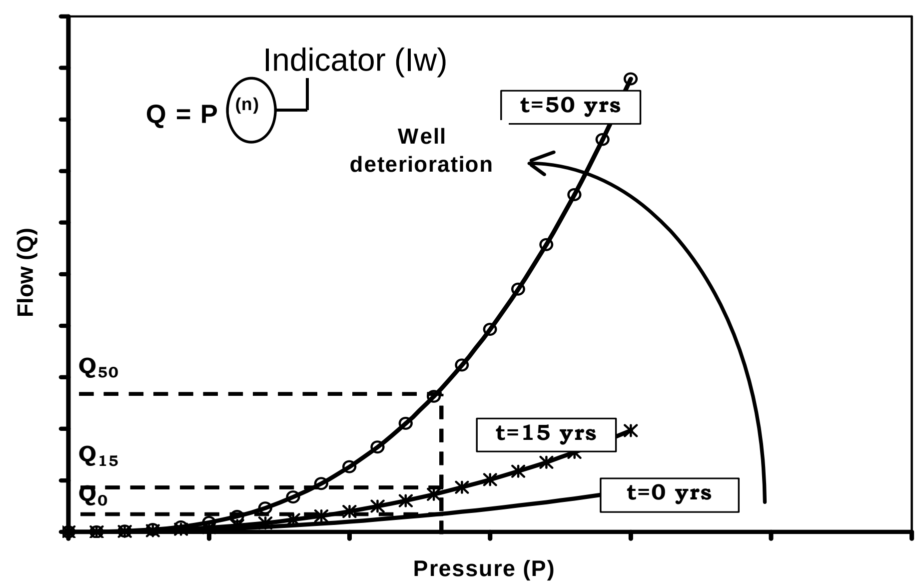
Well Integrity Assessment Methodology



Process Modeling of CO_2 Flow in Wells







Project Goal

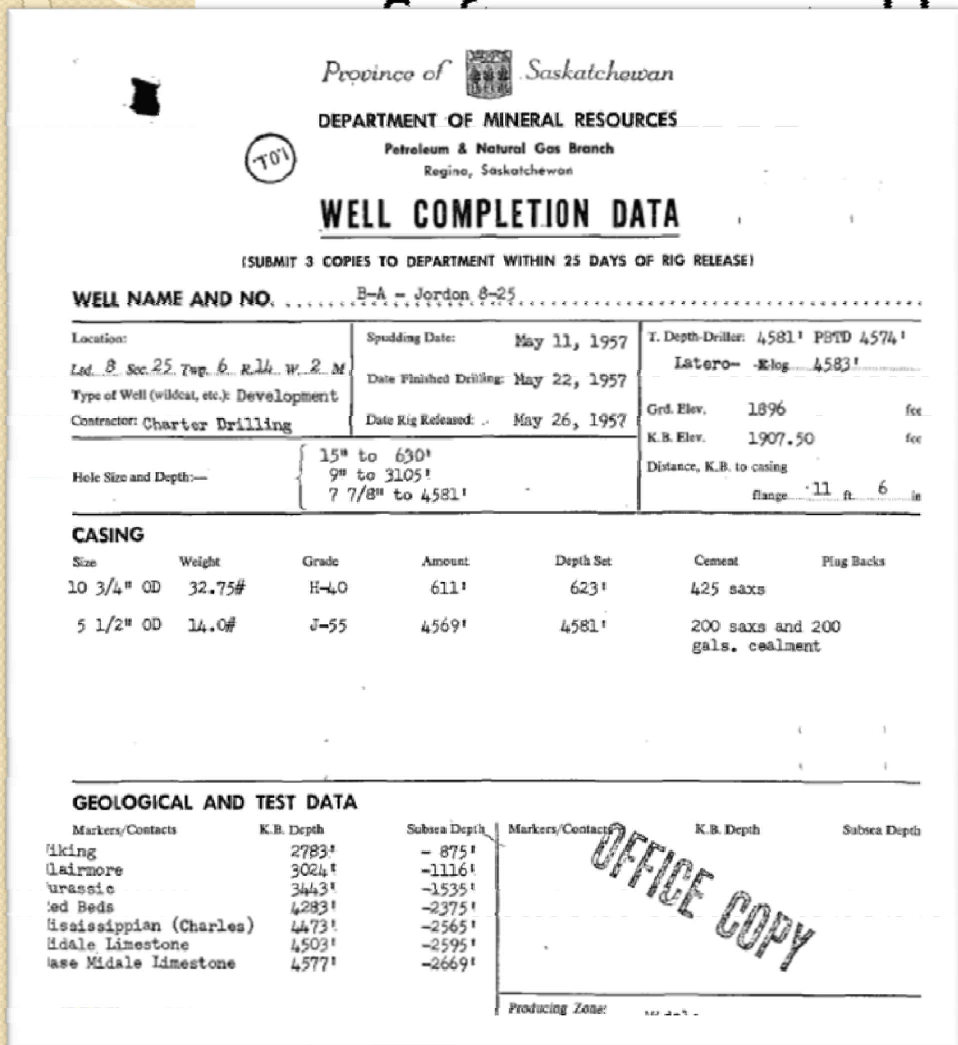
- Create a complete database of the Weyburn Unit wells
  - With enough wells to accurately represent the entire well population in the Weyburn Area
  - Where data can be easily mined
  - Maximizing the use of the original Phase 1A database to capitalize on previous work

Essential Resources

GeoScout by geoLogic

IHS Well Documents

- Database containing PDFs of original well



Province of Saskatchewan

DEPARTMENT OF MINERAL RESOURCES

Petroleum & Natural Gas Branch

Regina, Saskatchewan

T01

WELL COMPLETION DATA

(SUBMIT 3 COPIES TO DEPARTMENT WITHIN 25 DAYS OF RIG RELEASE)

WELL NAME AND NO. B-A – Jordon 8-25

Location: Lsd. 8 Sec. 25 Twp. 6 R. 14 W. 2 M

Type of Well (wildcat, etc.): Development

Contractor: Charter Drilling

Spudding Date: May 11, 1957

Date Finished Drilling: May 22, 1957

Date Rig Released: May 26, 1957

T. Depth-Driller: 4581' PBTD 4574'

Latero- Elog 4583'

Grd. Elev. 1896 feet

K.B. Elev. 1907.50 feet

Distance, K.B. to casing flange 11 ft. 6 in.

Hole Size and Depth:— 15" to 630'; 9" to 3105'; 7 7/8" to 4581'

CASING

Size	Weight	Grade	Amount	Depth Set	Cement	Plug Backs
10 3/4" OD	32.75#	H-40	611'	623'	425 saxs	
5 1/2" OD	14.0#	J-55	4569'	4581'	200 saxs and 200 gals. cealment	

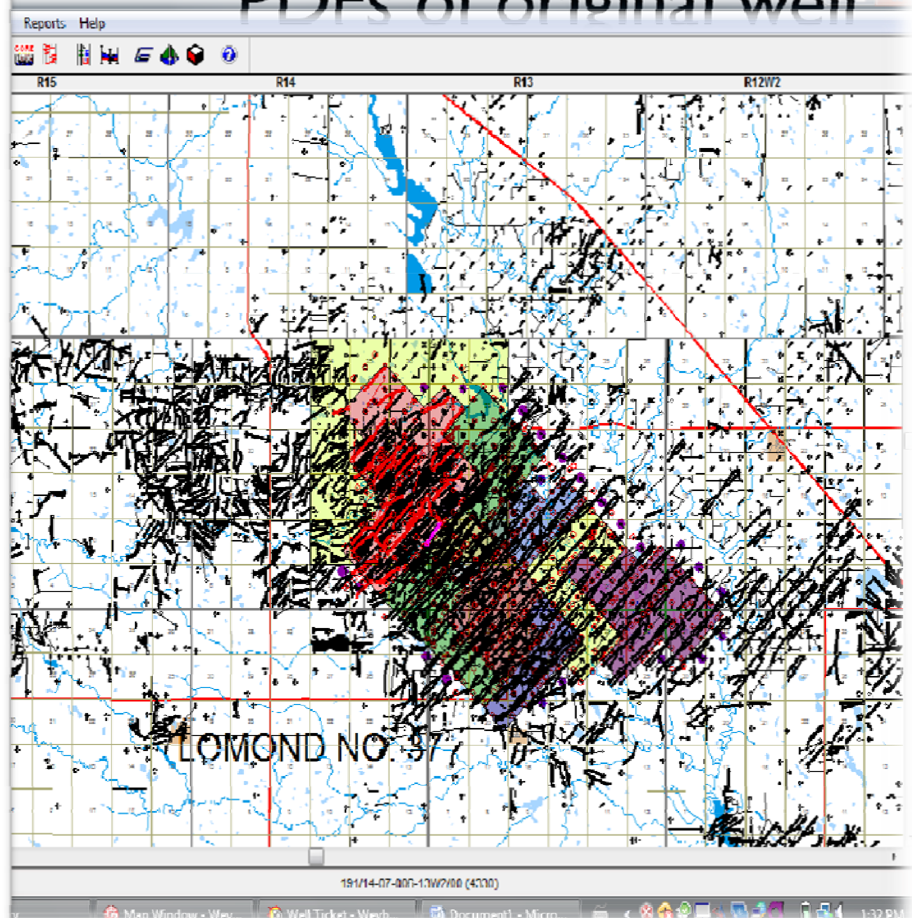
GEOLOGICAL AND TEST DATA

Markers/Contacts	K.B. Depth	Subsea Depth
Viking	2783'	– 875'
Blairmore	3024'	-1116'
Jurassic	3443'	-1535'
Red Beds	4283'	-2375'
Mississippian (Charles)	4473'	-2565'
Midale Limestone	4503'	-2595'
Base Midale Limestone	4577'	-2669'

Markers/Contacts | K.B. Depth | Subsea Depth

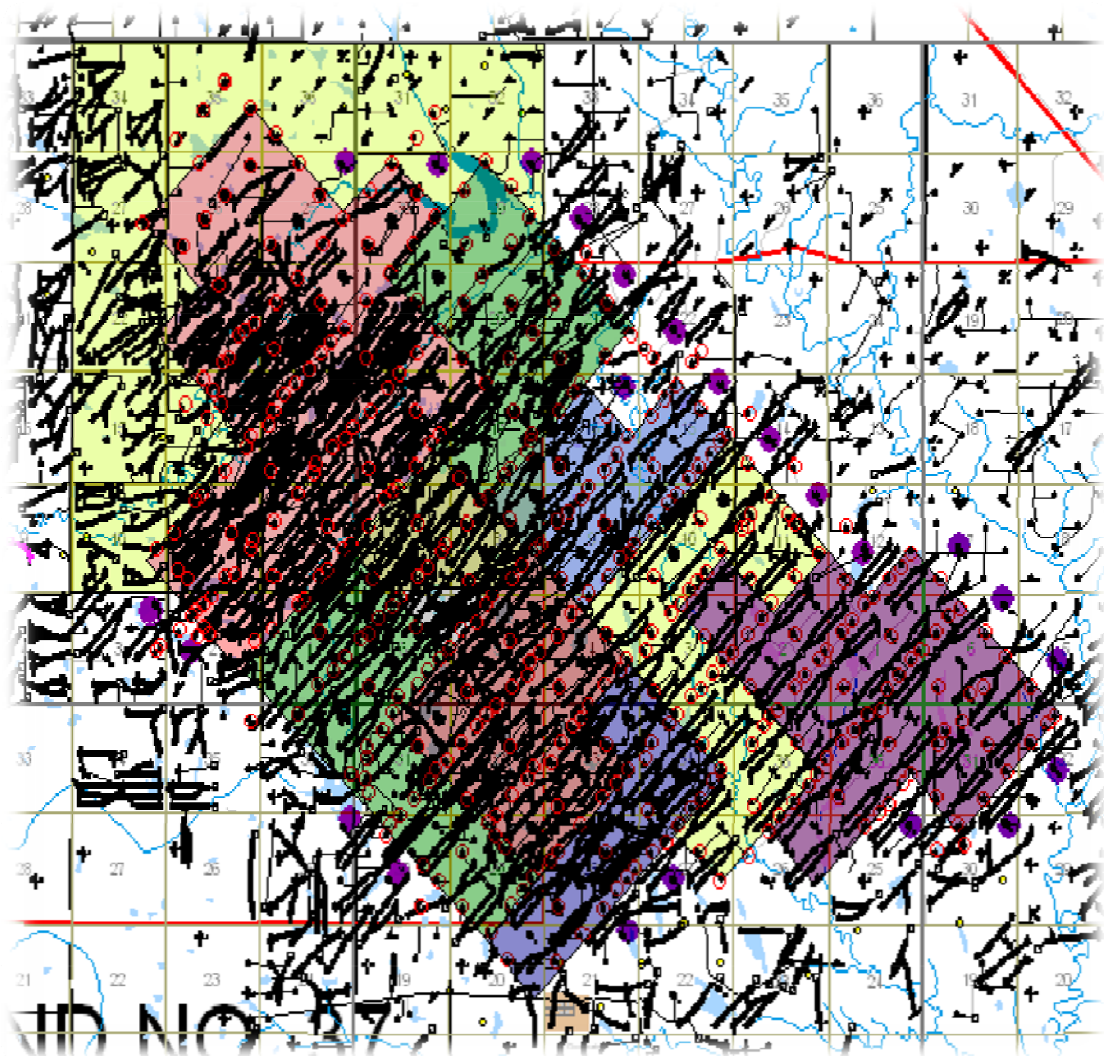
OFFICE COPY

Producing Zone:



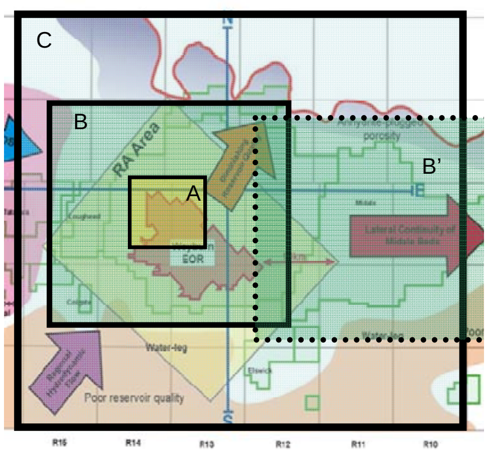
Weyburn Areas Investigated

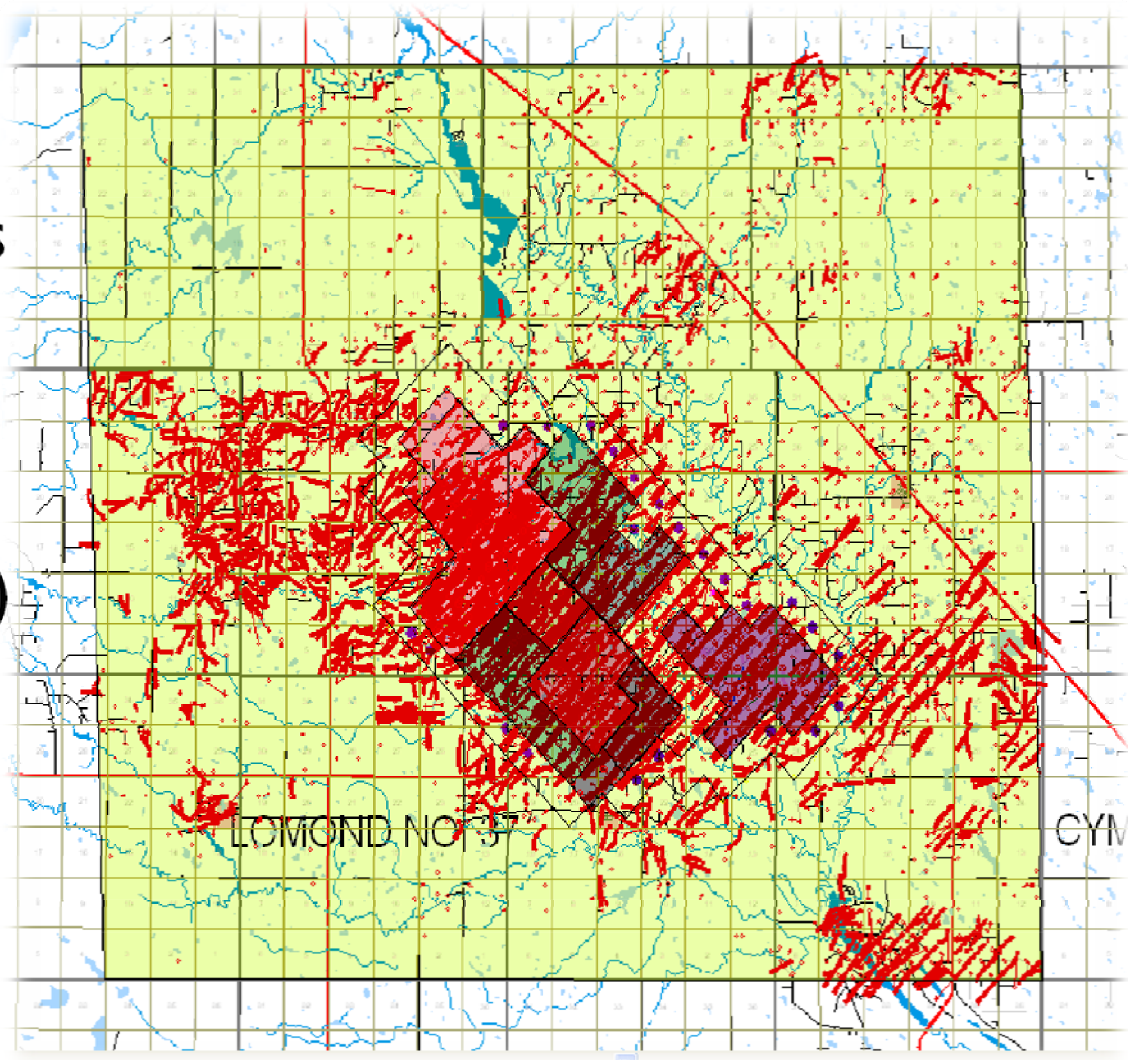
- Area A
  - Yellow Square Area (683 wells)
- Phase 1A
  - Pink Area (349 wells)
- EnCana Injection Fields
  - Represented in Colors (1175 wells)



Weyburn Areas Investigated Cont.

- Area B
  - Consists of multiple pools in areas surrounding the Weyburn Pool (3734 wells)





Database Sample Size

- Experimental Sampling and Analysis
  - Revealed a random sample of 80 Phase 1A wells experimentally represents the Area A and EnCana Injection Area wells
  - Results within acceptable (90-95%) experimental confidence and error (<6%)
  - ~36 out of 80 will need to be completely added to the already established database
  - How were these numbers determined?

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Choosing Database Sample Size

EnCana Injection Field
Area Average TVD
1521.09 mKB

5% TVD Error Interval
1445 to 1597.1 mKB

100 random Samples (n=70) from Phase 1A Database compared to Encana Field TVD							
Sample #	Mean	Sample #	Mean	Sample #	Mean	Sample #	Mean
1	1466.5	26	1506.3	51	1526.2	76	1543.3
2	1467.8	27	1507.5	52	1526.4	77	1543.4
3	1467.9	28	1508.7	53	1526.5	78	1544.2
4	1468.7	29	1509.8	54	1526.6	79	1544.6
5	1471.7	30	1510.1	55	1528.5	80	1545.7
6	1485.7	31	1510.7	56	1530.0	81	1550.4
7	1488.9	32	1512.5	57	1531.3	82	1552.2
8	1490.1	33	1513.3	58	1531.5	83	1553.7
9	1490.2	34	1514.1	59	1531.8	84	1553.9
10	1490.2	35	1515.1	60	1532.9	85	1554.8
11	1491.6	36	1516.5	61	1533.1	86	1556.1
12	1492.8	37	1517.3	62	1533.2	87	1557.5
13	1493.0	38	1518.3	63	1533.7	88	1560.3
14	1493.0	39	1519.2	64	1535.9	89	1561.1
15	1493.9	40	1519.2	65	1536.4	90	1561.8
16	1495.1	41	1519.8	66	1536.4	91	1563.9
17	1496.6	42	1520.1	67	1536.9	92	1567.4
18	1496.7	43	1520.8	68	1537.2	93	1567.4
19	1497.9	44	1522.5	69	1538.5	94	1568.6
20	1498.0	45	1523.1	70	1539.0	95	1572.4
21	1498.7	46	1523.9	71	1540.0	96	1578.0
22	1500.3	47	1524.6	72	1540.9	97	1584.7
23	1500.5	48	1525.1	73	1541.3	98	1585.1
24	1500.7	49	1525.6	74	1541.7	99	1595.4
25	1504.1	50	1526.0	75	1542.7	100	1608.3

99%
Experimental
Confidence at
5% Error

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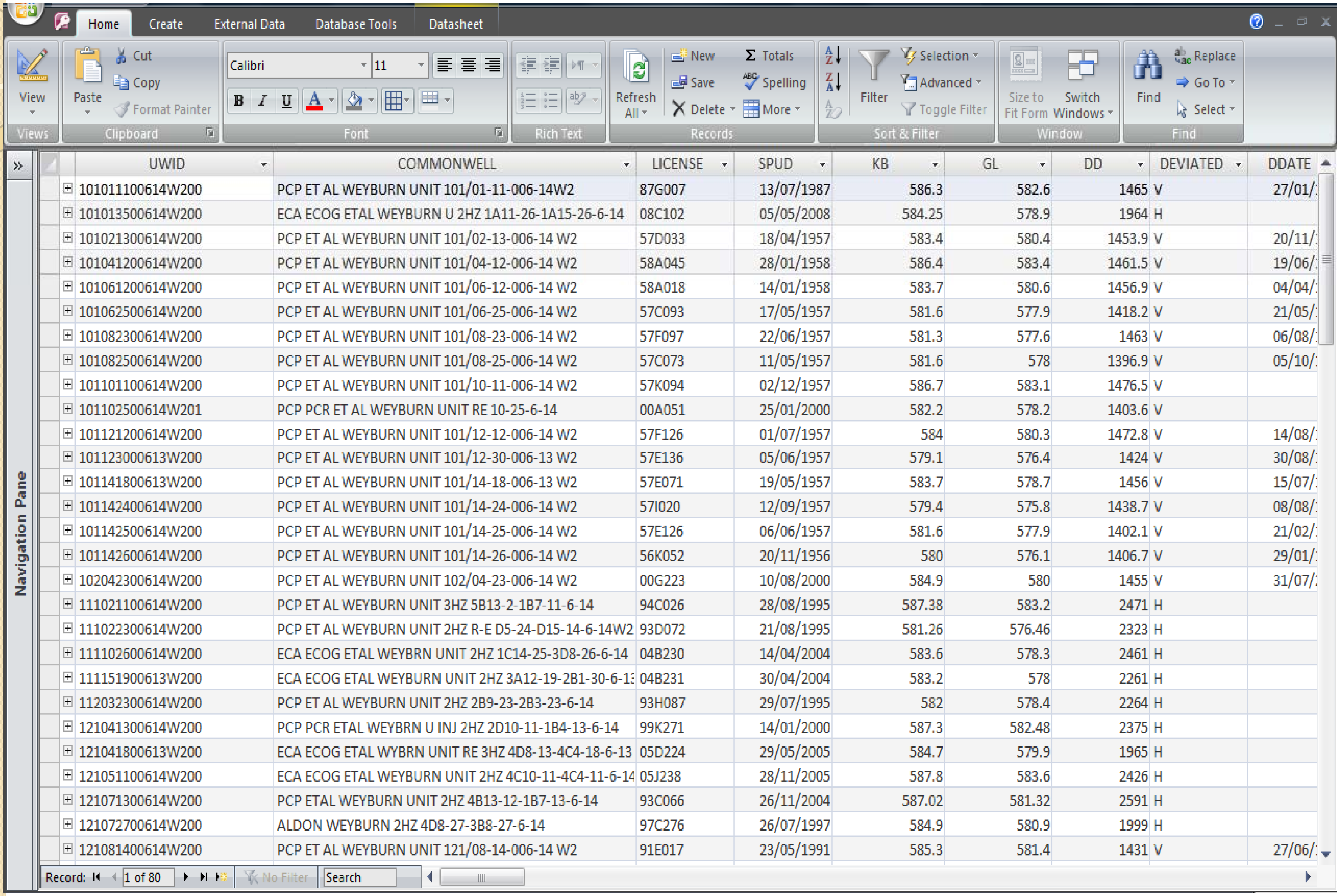
Original Microsoft Access Database



UWID	COMMONWELL	LICENSE	SPUD	KB	GL	DD	DEVIATED	DDATE
101011100614W200	PCP ET AL WEYBURN UNIT 101/01-11-006-14W2	87G007	13/07/1987	586.3	582.6	1465	V	27/01/
101013500614W200	ECA ECOG ETAL WEYBURN U 2HZ 1A11-26-1A15-26-6-14	08C102	05/05/2008	584.25	578.9	1964	H	
101021300614W200	PCP ET AL WEYBURN UNIT 101/02-13-006-14 W2	57D033	18/04/1957	583.4	580.4	1453.9	V	20/11/
101041200614W200	PCP ET AL WEYBURN UNIT 101/04-12-006-14 W2	58A045	28/01/1958	586.4	583.4	1461.5	V	19/06/
101061200614W200	PCP ET AL WEYBURN UNIT 101/06-12-006-14 W2	58A018	14/01/1958	583.7	580.6	1456.9	V	04/04/
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101082300614W200	PCP ET AL WEYBURN UNIT 101/08-23-006-14 W2	57F097	22/06/1957	581.3	577.6	1463	V	06/08/
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101101100614W200	PCP ET AL WEYBURN UNIT 101/10-11-006-14 W2	57K094	02/12/1957	586.7	583.1	1476.5	V	
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101123000613W200	PCP ET AL WEYBURN UNIT 101/12-30-006-13 W2	57E136	05/06/1957	579.1	576.4	1424	V	30/08/
101141800613W200	PCP ET AL WEYBURN UNIT 101/14-18-006-13 W2	57E071	19/05/1957	583.7	578.7	1456	V	15/07/
101142400614W200	PCP ET AL WEYBURN UNIT 101/14-24-006-14 W2	57I020	12/09/1957	579.4	575.8	1438.7	V	08/08/
101142500614W200	PCP ET AL WEYBURN UNIT 101/14-25-006-14 W2	57E126	06/06/1957	581.6	577.9	1402.1	V	21/02/
101142600614W200	PCP ET AL WEYBURN UNIT 101/14-26-006-14 W2	56K052	20/11/1956	580	576.1	1406.7	V	29/01/
102042300614W200	PCP ET AL WEYBURN UNIT 102/04-23-006-14 W2	00G223	10/08/2000	584.9	580	1455	V	31/07/
111021100614W200	PCP ET AL WEYBURN UNIT 3HZ 5B13-2-1B7-11-6-14	94C026	28/08/1995	587.38	583.2	2471	H	
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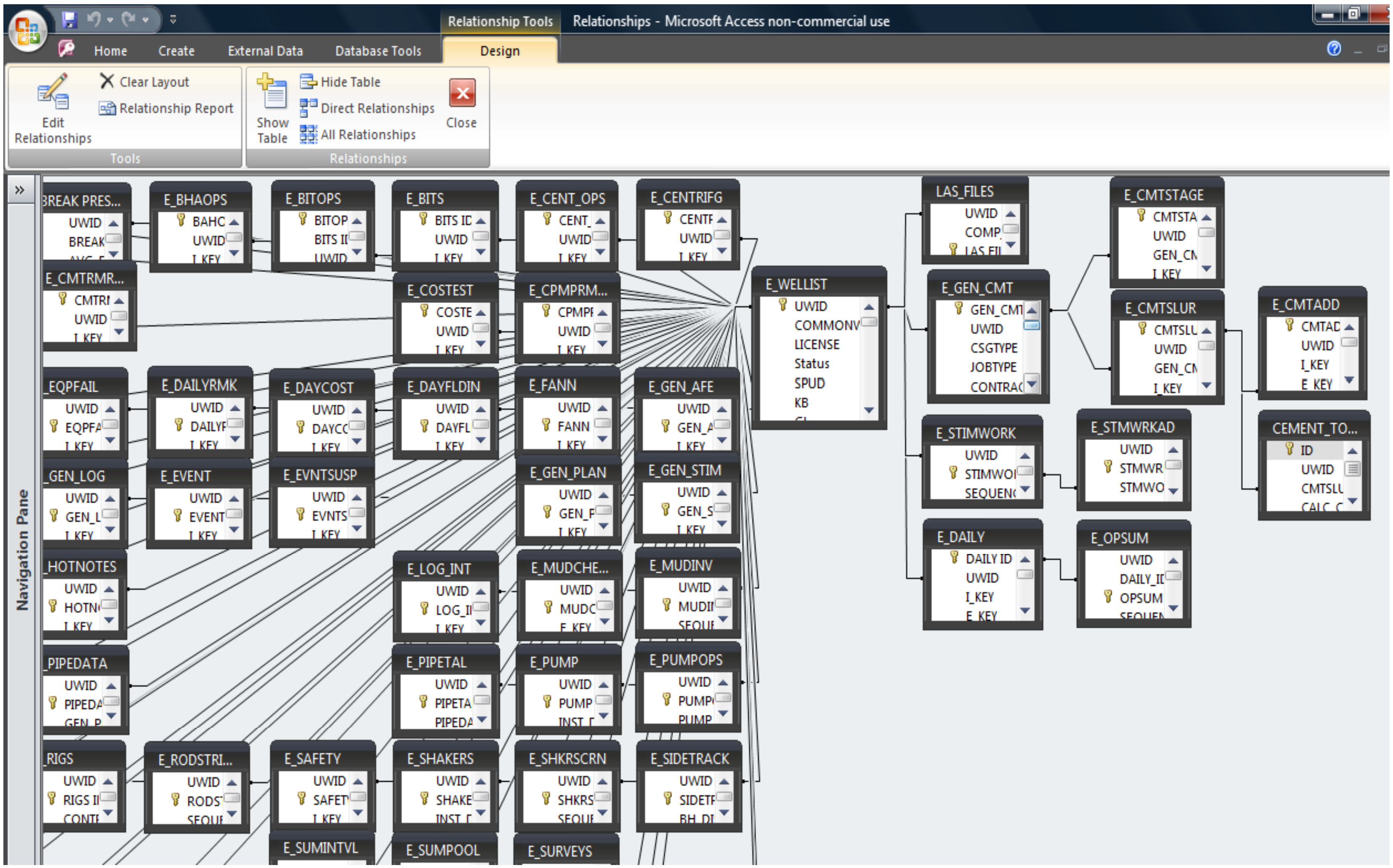
Record: 1 of 80

Current Weyburn Database Table Relationships

- Linked tables to general well list data page



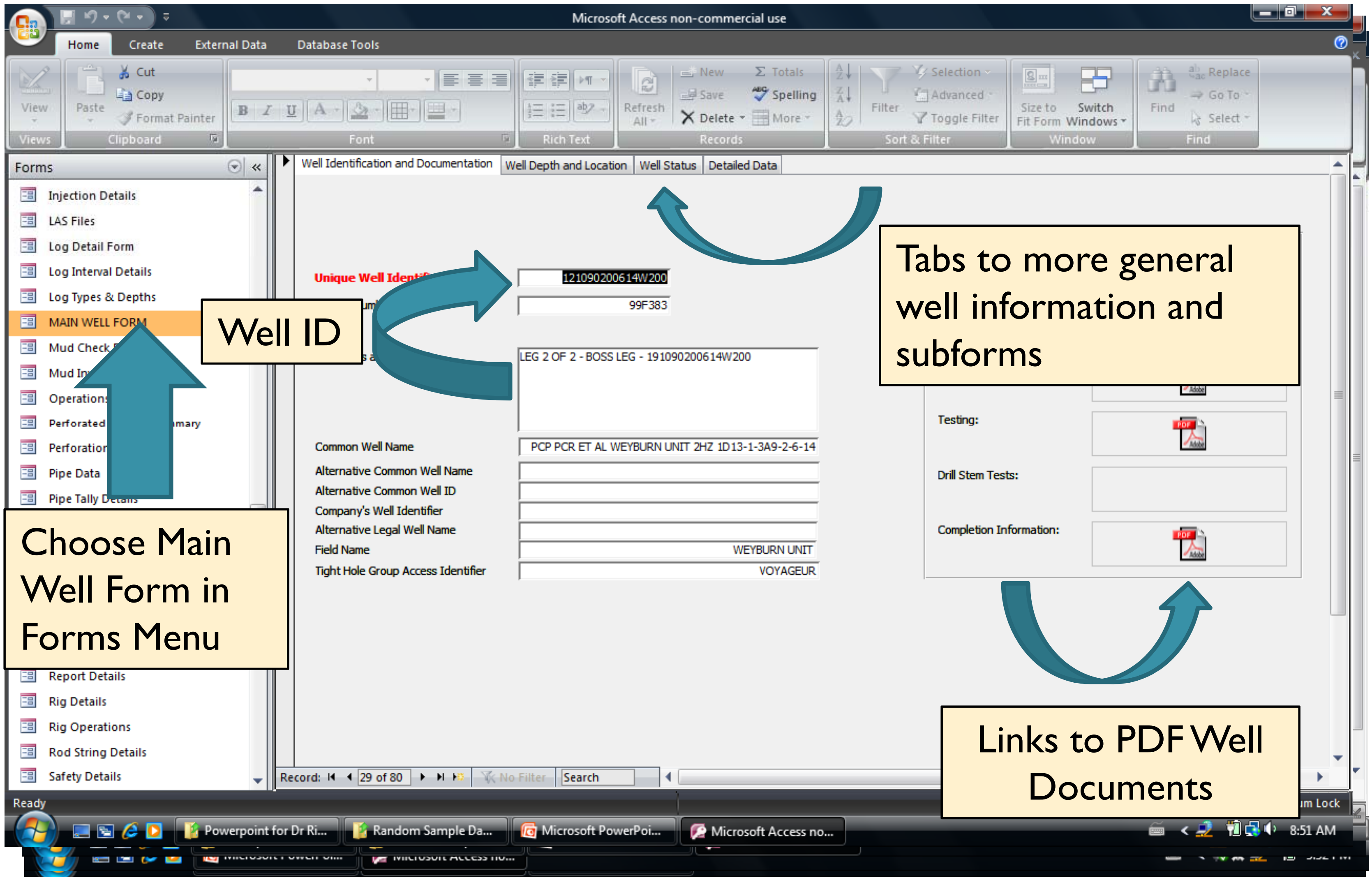
Current Weyburn Database

Forms

- Forms were created which allow user friendly data entry and interpretation
- Main Well Form contains general well data with all other forms linked to it via UWID
- Allows access to all information at the "push of a button"
- PDF well documents and .LAS files are linked to each well

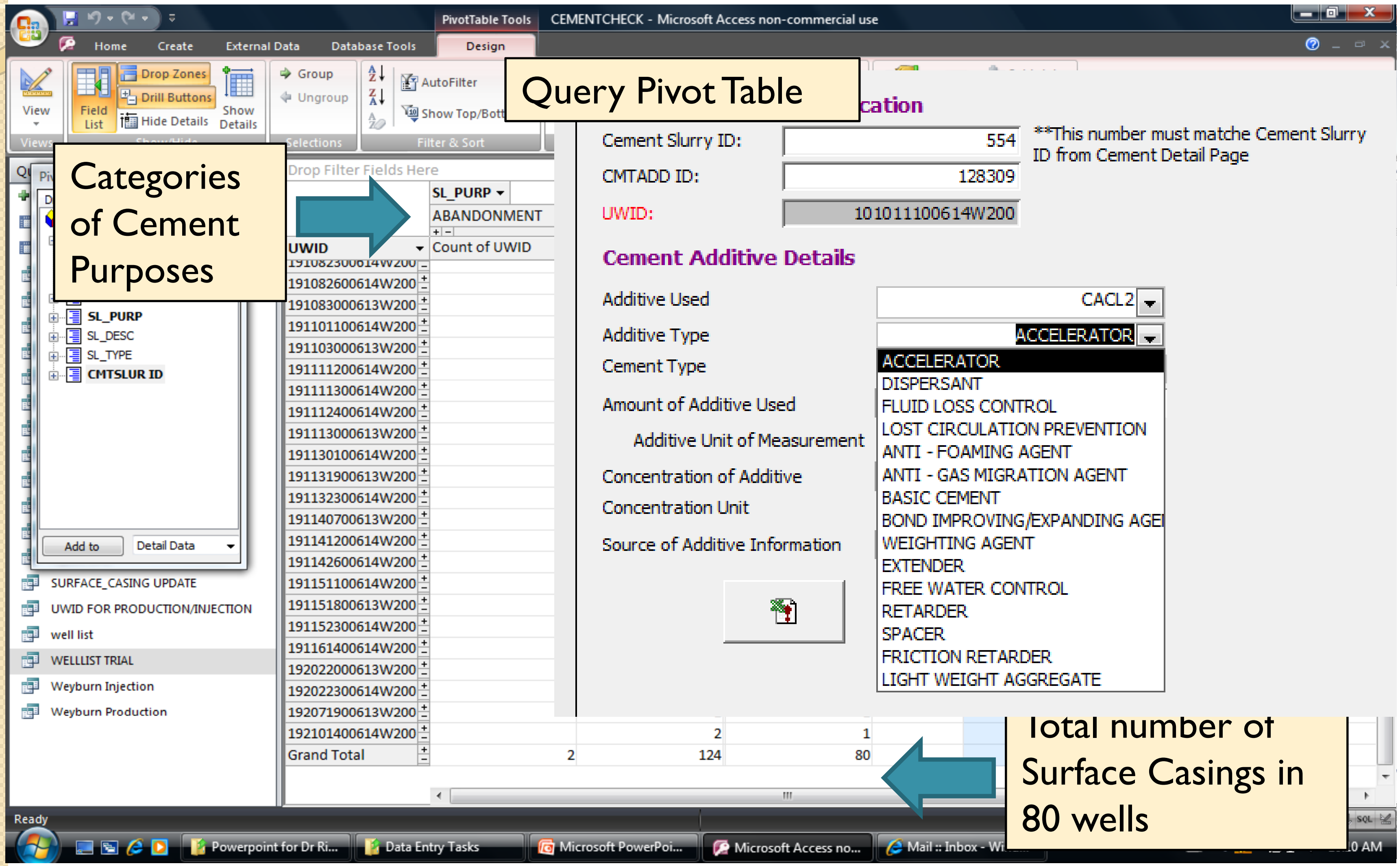
Current Weyburn Database

Forms Cont.



Current Weyburn Database

Data Mining with Queries

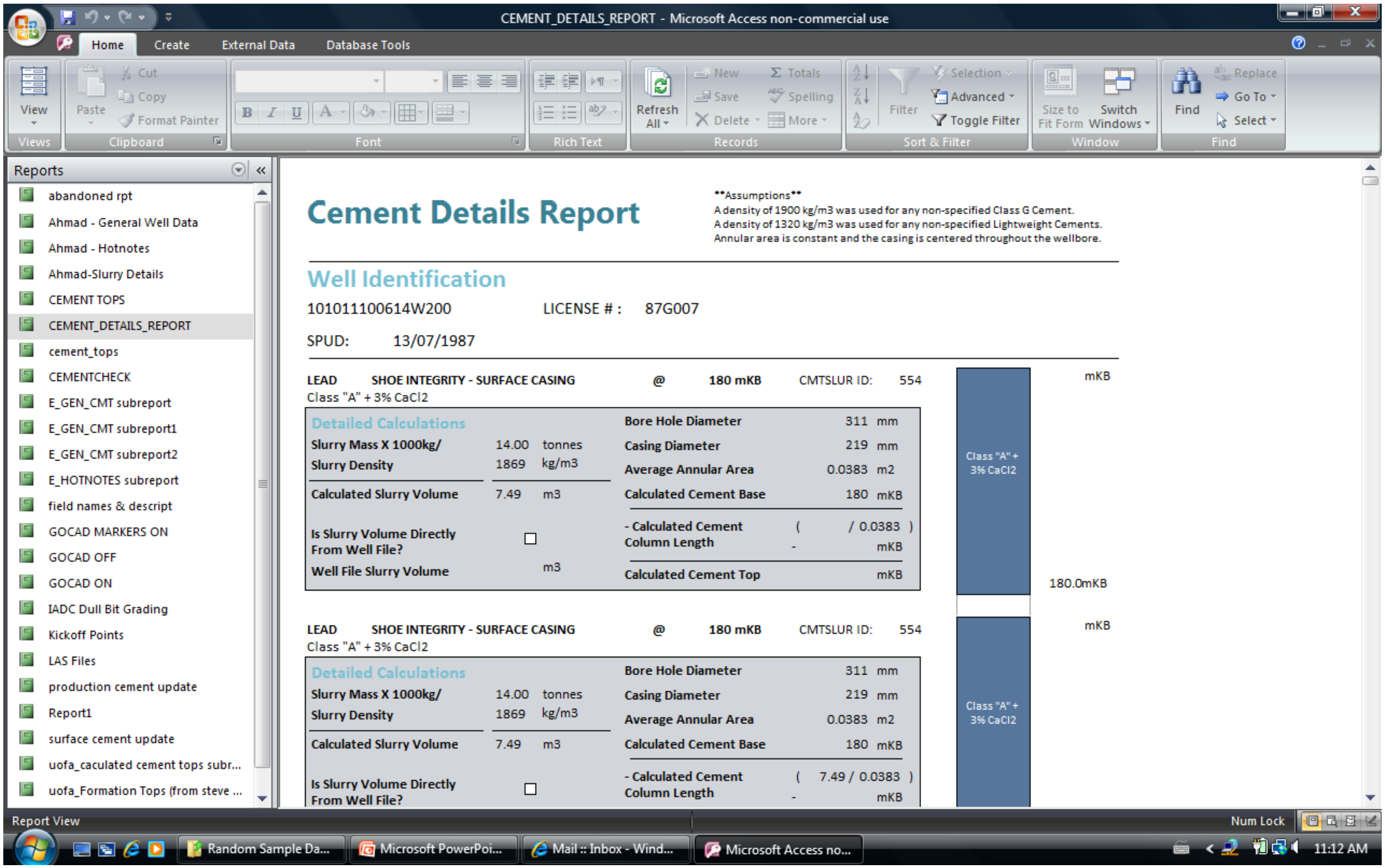


Current Weyburn Database - Reports

- Reports can be created
  - Directly from database
  - From specific queries
- Data in reports can not be used in other data programs such as Excel
- Reports allow easy visualization of clearly organized and presented data

Current Weyburn Database
History of Reports

- Original Database



Current Weyburn Database

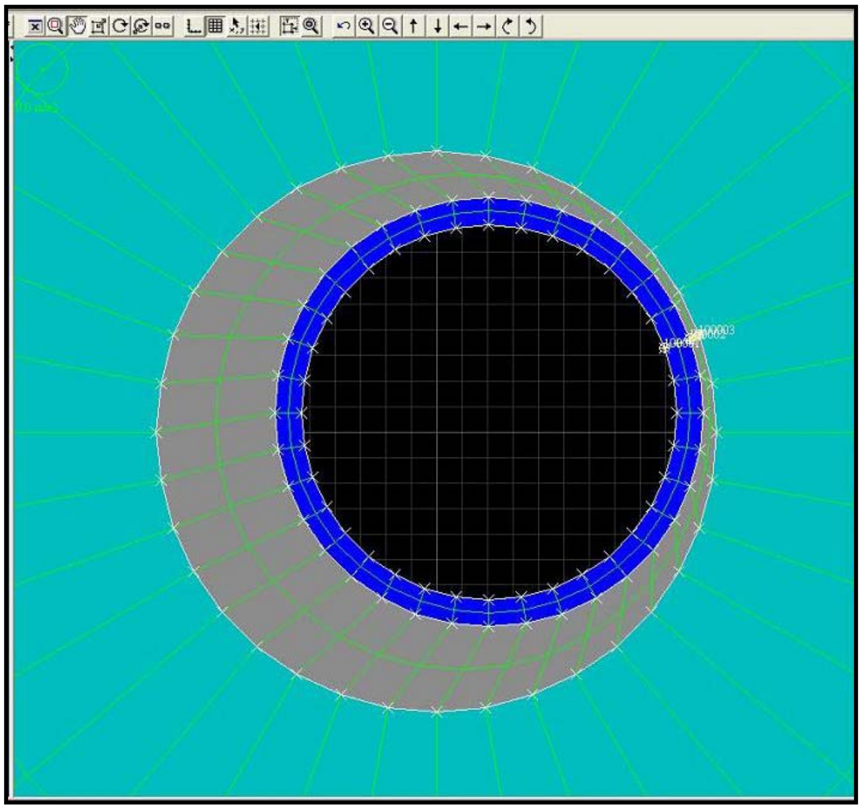
Future Work

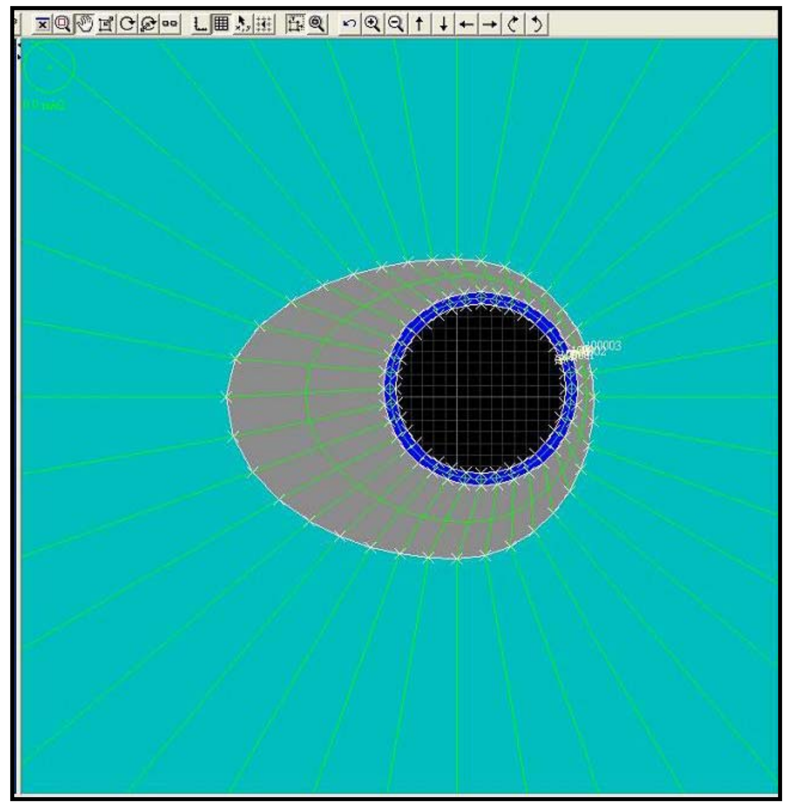
- Complete Entry of all 80 wells
  - Each well can take 40-80 hours depending on information in well file
  - Tasks are already created for data-entry in areas including:
    - Daily Operations
    - Perforations and Completion
    - Bits and Bottom hole data
    - Casing and Mud Checks
    - Formation and Production Data

Data Requirements for Numerical Model

- Theoretical Well Geometry
  - Depth
  - Bit Diameter
  - Casing Diameter and Grade
  - Eccentricity (Centralizer program, if available)
- Field Well Geometry
  - Directional Survey
- Materials
  - Formation
  - Drilling Mud
  - Casing
  - Cement
- In-Situ "Initial" Conditions
  - Mechanical
  - Hydraulic
  - Thermal

Geometry of Analysis "Slices"





Simulation Stages $\boldsymbol{0 \leq t \leq t_{target}}$

The simulation can be divided to the following main stages which are:

Initial stage, $t = 0$

Drilling stage, $0 < t \leq t_{\text{primary cementing}}$

Cementing stage, $t_{\text{primary cementing}} < t \leq t_{\text{100\% cement hydration}}$

Operation stage, $t_{\text{100\% cement hydration}} < t \leq t_{\text{Abandoned time}}$

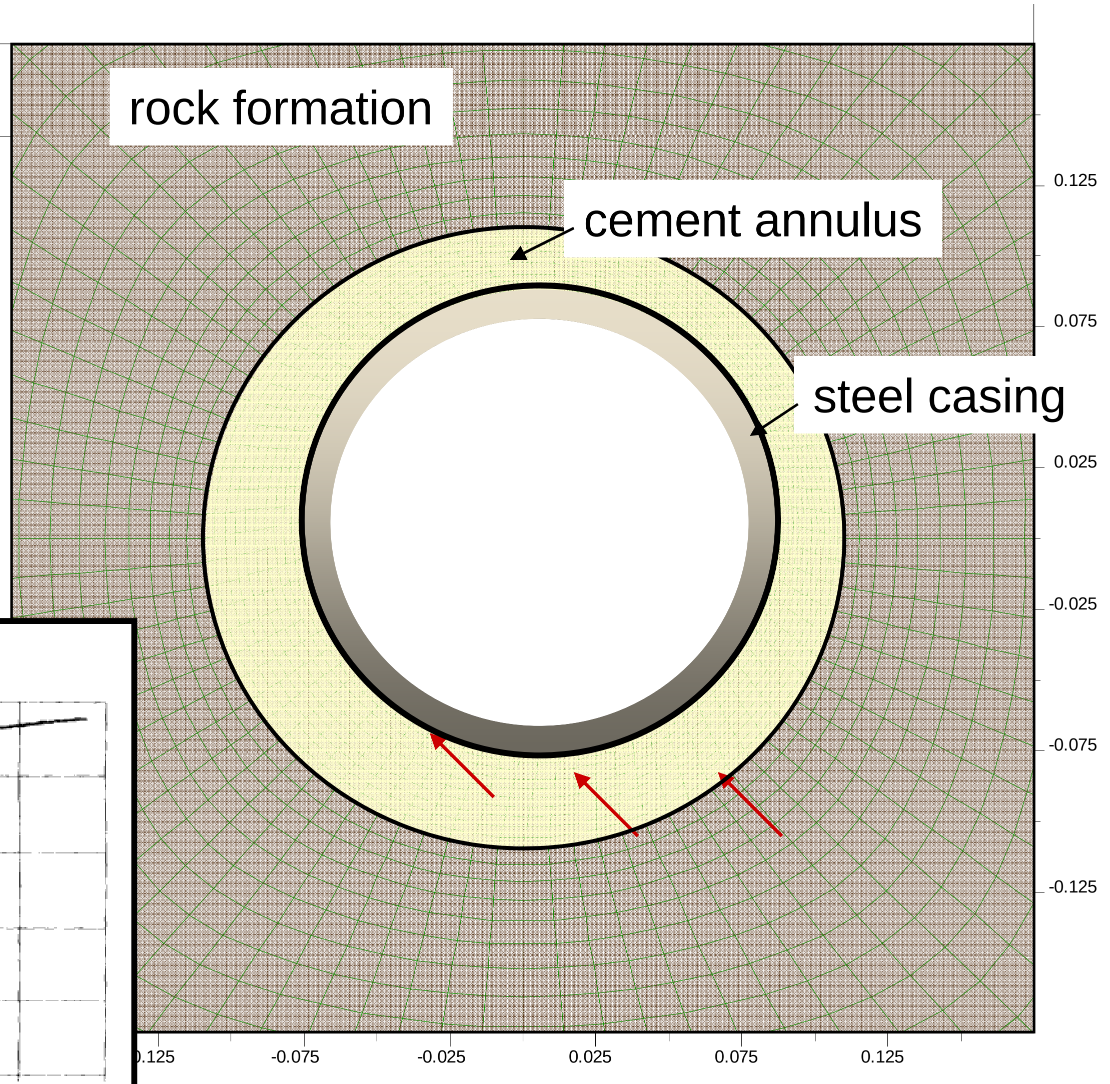
Abandonment stage, $t_{\text{abandoned}} < t \leq t_{\text{target}}$

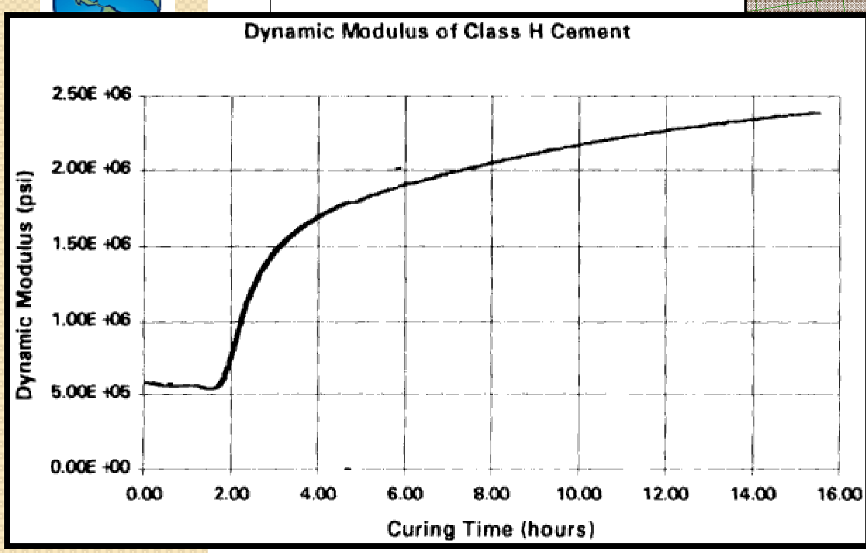
These stages may be subdivided to more stages.

Example of subdivision in Stages

Stage_000	Original state
Stage_001	Formation with drilling mud
Stage_002	Formation with casing and cementing
Stage_003	Casing and pre-wash circulations pressures
Stage_004	Cementing circulation pressures
Stage_005	Bumping the plug beginning of cement hydration
Stage_006	Removal of plug pressure at t = t?
Stage_007	Continued cemented hydration
Stage_008	Pressure increase due to casing bowl testing
Stage_009	Finish with setting up time for cement (hydrostatic pressure in casing)
Stage_010	Begin either production or Injection well history

Detailed Near-Well Modeling

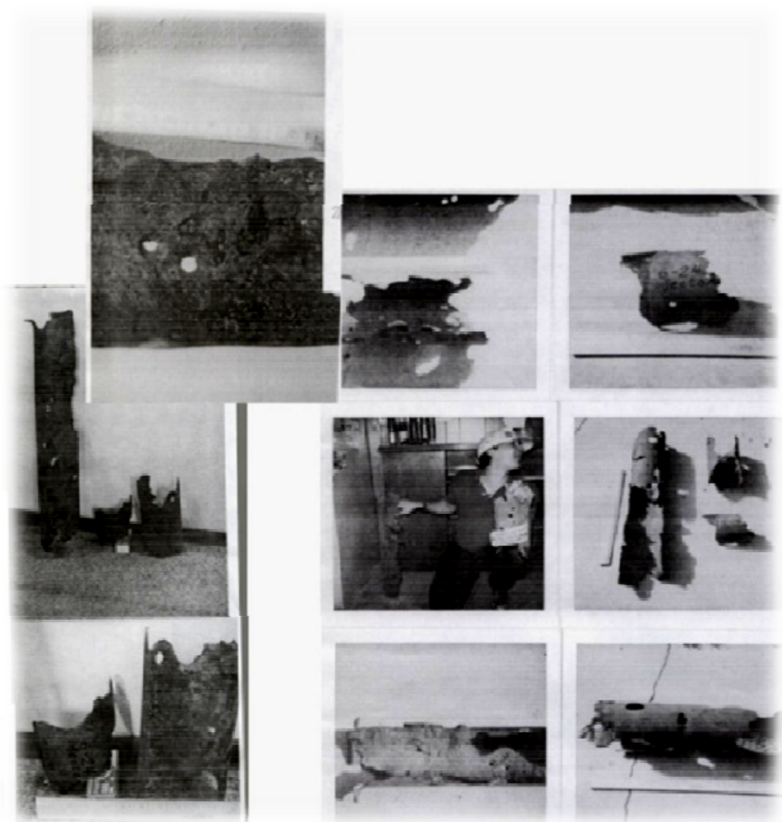




Current Weyburn Database Future Work Cont.

- Add Programming Features
  - Map displaying locations and links to all wells in database
  - Add .las reader file to visually interpret .las files
- Possible addition of more wells than original 80 chosen
- Continued improvements to form layouts and data fields to improve database usability

Weyburn Well Integrity Database



Brandi Mitchell

Rick Chalaturnyk

Reservoir Geomechanics Research Group

Department of Civil and Environmental Engineering

University of Alberta

Measuring and understanding CO_2 annular flows in injection wells: experience from MovECBM

IEA-GHG 5th Wellbore Integrity Network Meeting, Calgary, 2009 May 13

Matteo Loizzo, Laure Deremble, Bruno Huet, Brice Lecampion, Daniel Quesada, Ines Khalfallah – Schlumberger Carbon Services

Salvatore Lombardi, Aldo Annunziatellis – Universita di Roma "La Sapienza"

Frank van Bergen – TNO

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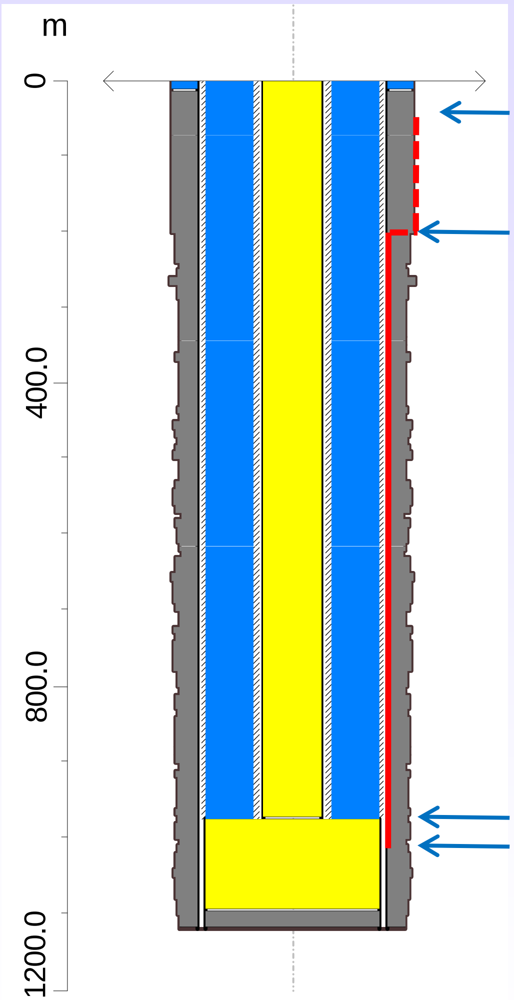
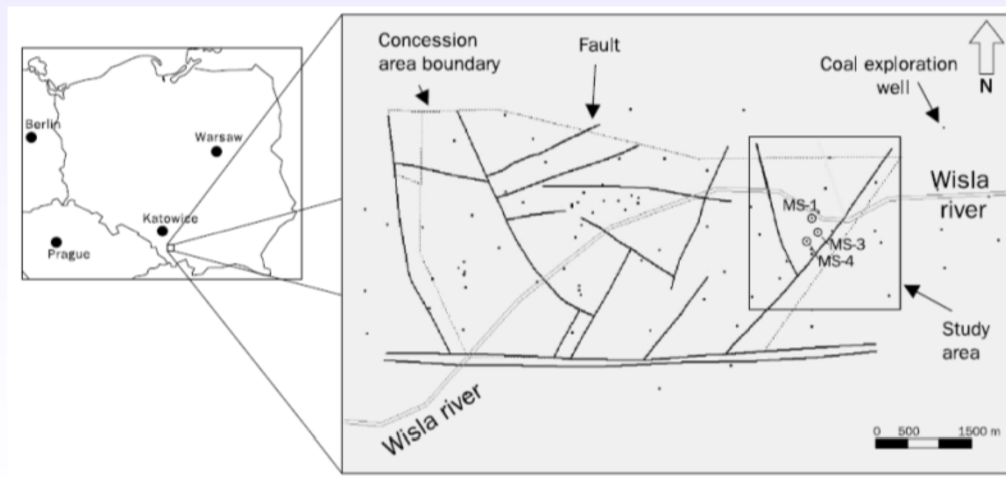
Contents and goals

- This presentation will discuss evidence that supports past flow of CO_2 through a pathway (casing-cement microannulus) in the cemented annulus of the Kaniow MS-3 well
- First line of evidence: cement evaluation logs identify a fluid-filled microannulus
  - Mechanical models show how injection pressure could have been its cause
- *Transport reaction models predict CO_2 flow to surface and carbonation of cement*
- Second line of evidence: soil gas surveys seem to indicate CO_2 flux at surface
- Third line of evidence: changes in ultrasonic cement response are consistent with the predicted pattern

Kaniow site – introduction



- Enhanced Coal Bed Methane project started in 2001
  - Kaniow site, upper Silesian basin, Poland
- Financed by European projects
  - RECOPOL and MovECBM
  - MovECBM finished in Dec 2008
- MS-3 injection well drilled in 2001



Source: Van Bergen et al., Env. Geosciences, 2006

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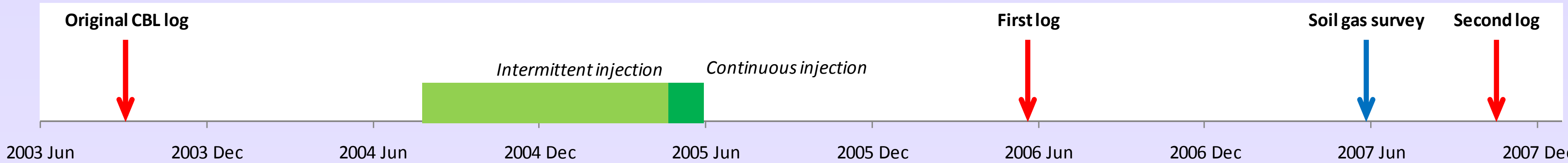
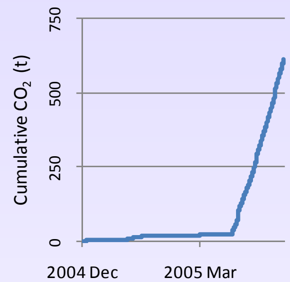
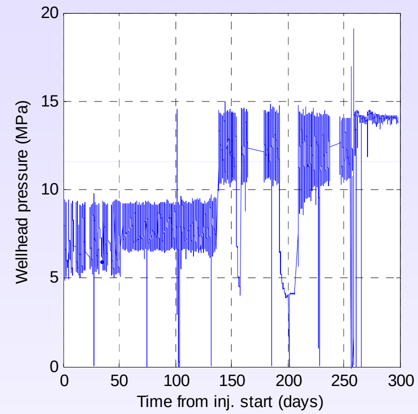
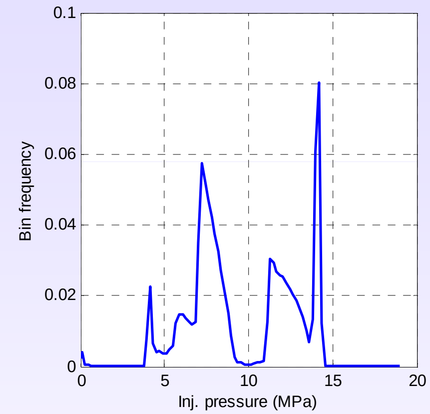
CO_2 injection history





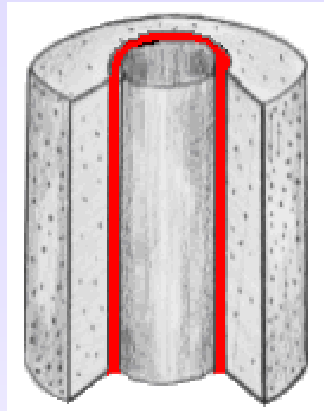


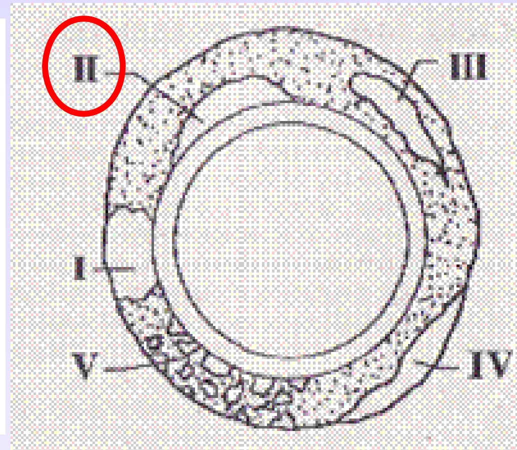


- ~760 t of CO_2 injected over 330 days
  - Initially intermittent injection
  - Wellhead pressure increased from 9 MPa to 14 MPa in Dec 2004
  - Hydraulic fracture job in Apr 2005 to establish continuous injection
    - ✓ Successful: ~80% of CO_2 injected after stimulation
- Soil gas survey in May 2007
- Wireline cement logs on 2006 May 26 and 2007 Oct 20 (512 days time-lapse)
  - Original CBL log on 2003 Sep 12

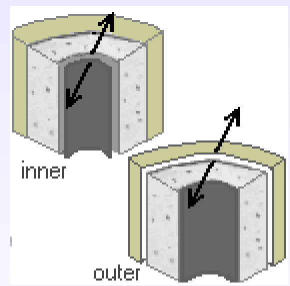
Microannulus – introduction

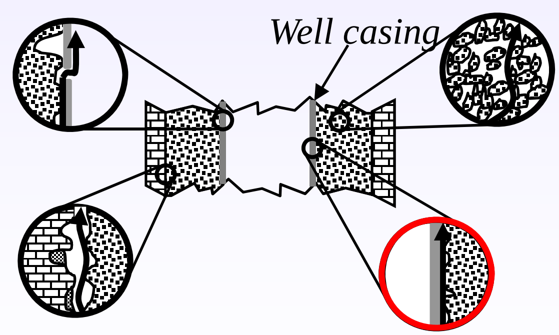
- <u>Micro</u>annulus → interfacial debonding between casing/cement or cement/formation
  - Can be 10's to 100's μm thick
  - Fluid- or gas-filled
    - ✓ Heritage of ultrasonic logs → "gas-filled" are opaque to ultrasounds due to the large acoustic impedance contrast
  - Cement/formation microannulus debated, currently no quantitative measure
- CBL very sensitive to debonding
  - Cement <u>Bond</u> Log → measures (only) bond
  - Quantitative evaluation of microannulus (and channels) requires joint runs with imaging tools





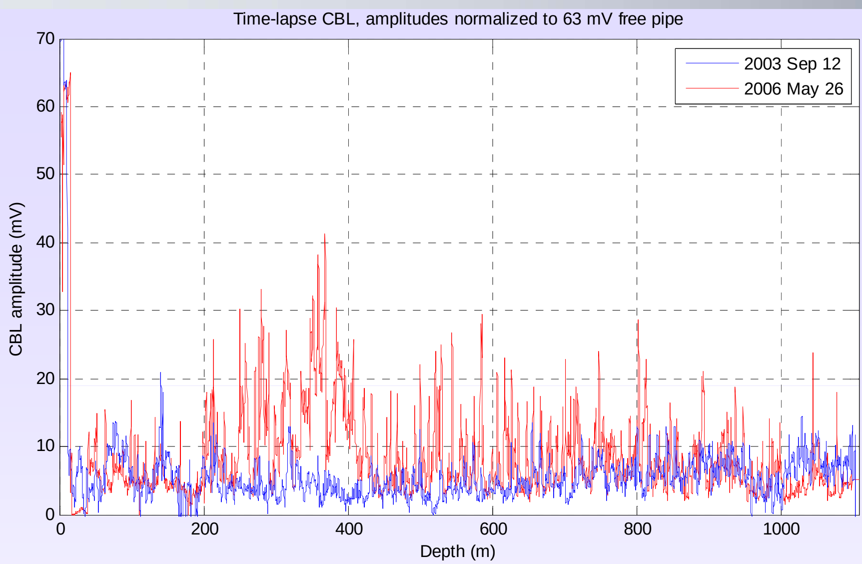
Source: J. Smolen, "Cased Hole and Production Log Evaluation", Penn Well 2004

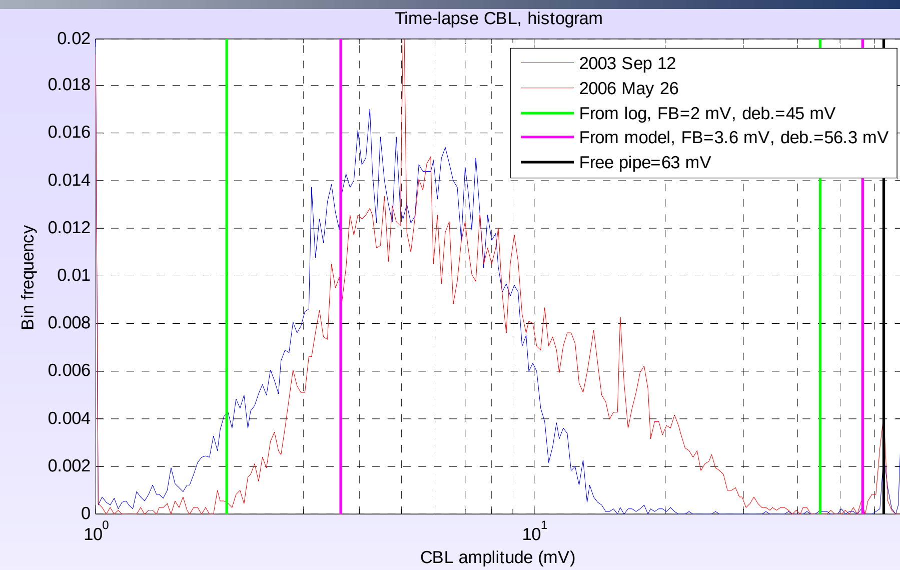




Adapted from A. Duguid et al., 2006

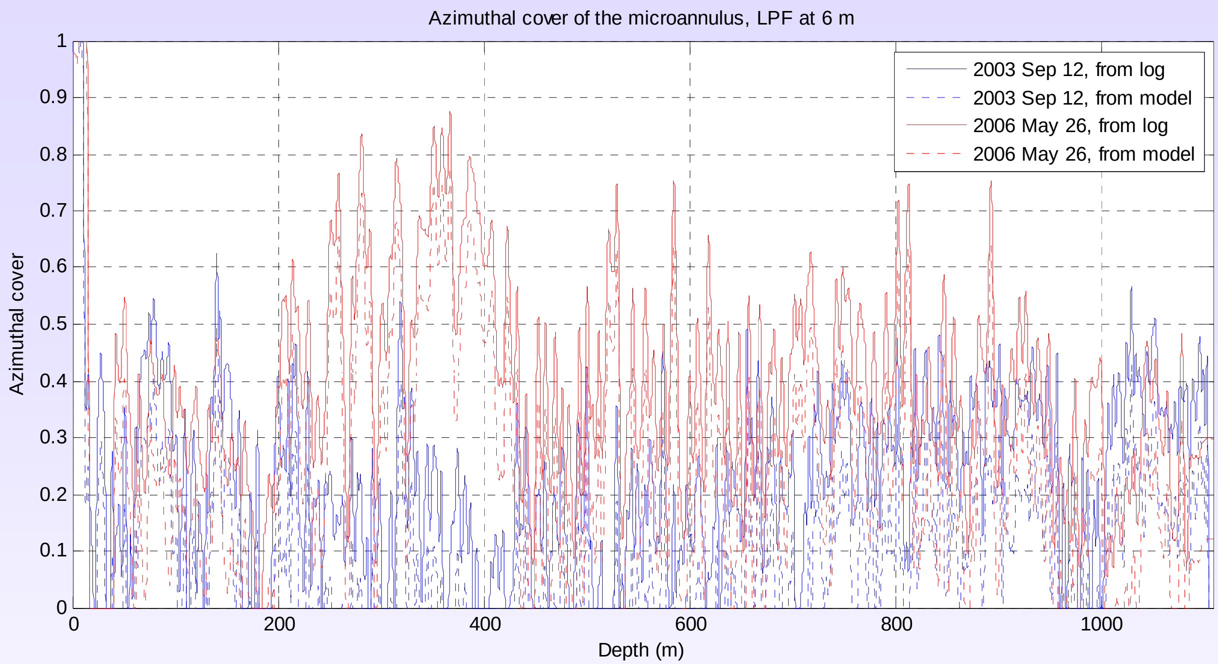
First line of evidence – liquid-filled microannulus





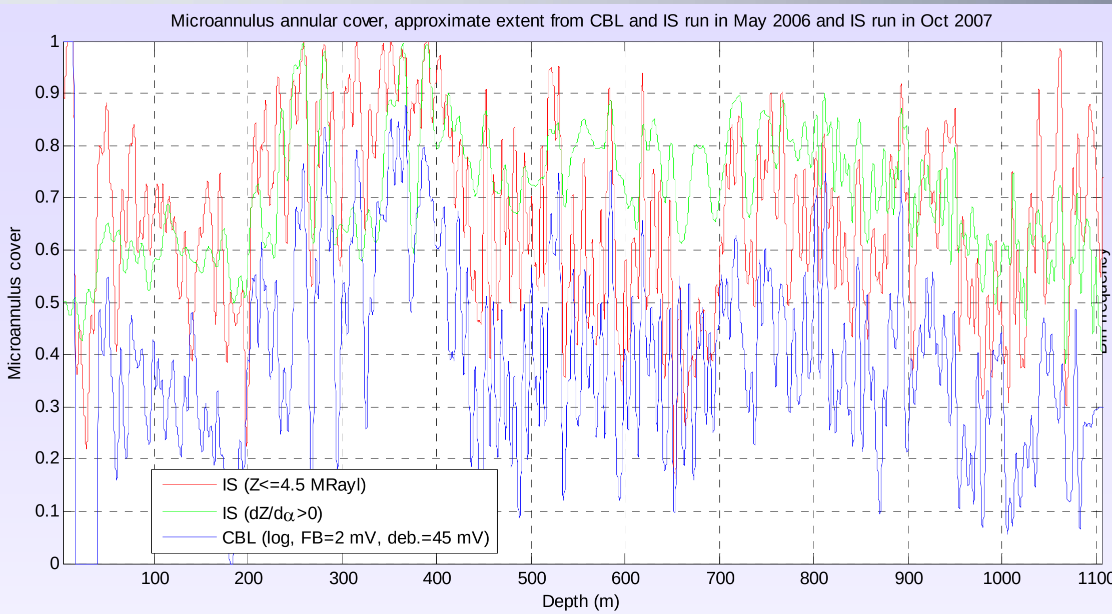
- CBL logs before and after injection show amplitude increase, mostly below 200 m
- Quantitative interpretation issues
  - First log calibration : 3 possible Free Pipe (FP) values above the Top of Cement
    - ✓ Lowest (more pessimistic) value seems most likely: better histogram match, even if amplitude decreases in 2006 below 1000 m
  - Some uncertainty on Fully Bonded (FB) and Fully Debonded (FD) values
    - ✓ Logs suggest lower values than model → log values preferred
    - ✓ Bond Index ~log(amplitude) → largest effect of uncertainties at low microannulus coverage

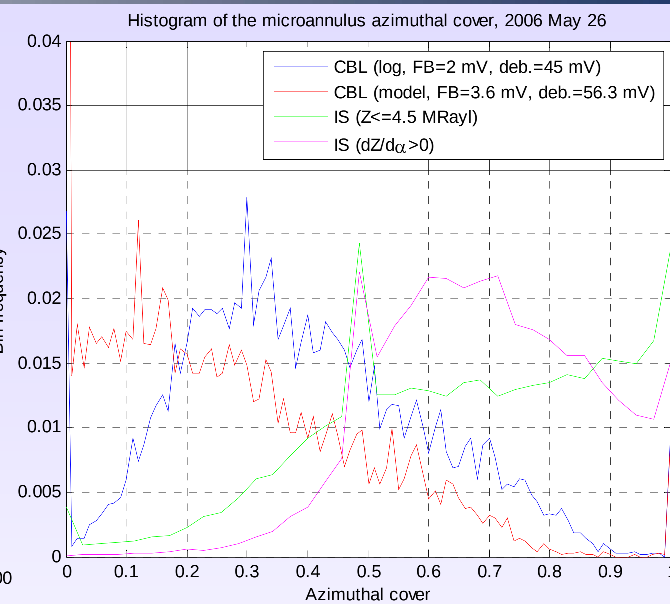
Microannulus from CBL – quantitative analysis



- FP, FD and FB amplitudes → (pseudo)attenuation can be computed, proportional to the microannulus azimuthal cover
  - Increase in microannulus cover, especially above 1000 m
  - Microannulus above 200 m roughly unchanged
- Attenuation-based tools require less guess-work

Microannulus from CBL – comparison with IS

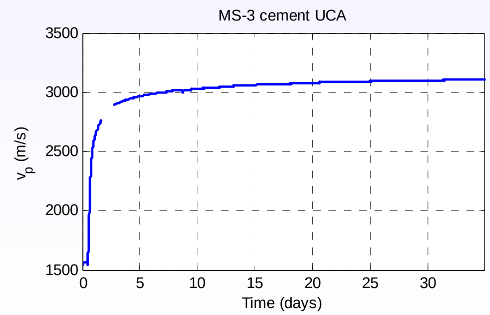


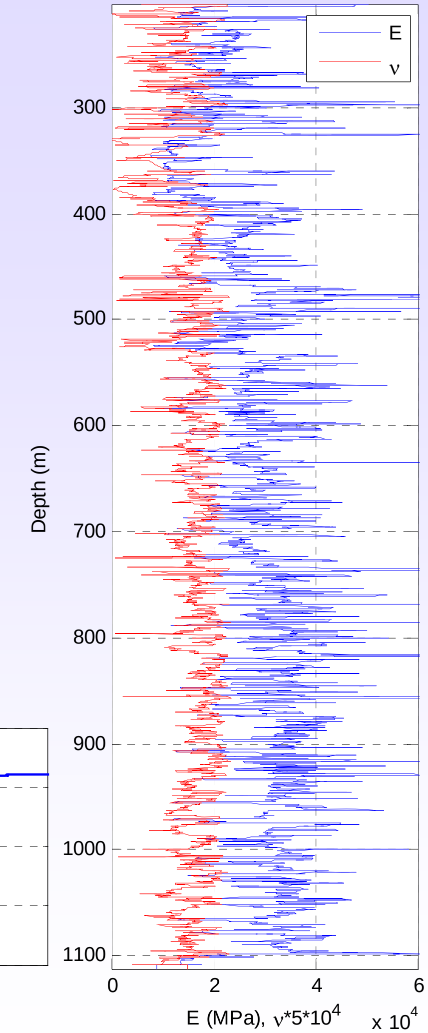


- Simplified processing can extract rough microannulus coverage from IS
  - Low acoustic impedance, on assumption of good uniform cement
  - Joint increase of Z and α between time-lapse logs, on assumption of full carbonation
- CBL more optimistic, but overall trend consistent (e.g. peak 250-450 m)
- Most microannulus cover between 20% and 50% of pipe (70º to 180º)

Modeling microannulus formation

- Need to build a model of the system casing-cement-formation
  - Open-hole logs → Mechanical Earth Model (MEM)
  - Estimate cement properties from UCA and composition
    - ✓ Cement evaluation logs may be affected by carbonation…
- Stressor: buoyancy-driven delamination of casing and cement
  - Caused by injection pressure
  - Radially symmetrical model
- It is likely that the microannulus switched to the outside of the 9 5/8" casing above the rat-hole (202 m)
  - Outer microannuli less stiff?
  - Above the 13 3/8" casing shoe (20 m) the CO_2 plume may have been dispersed in the vadose zone





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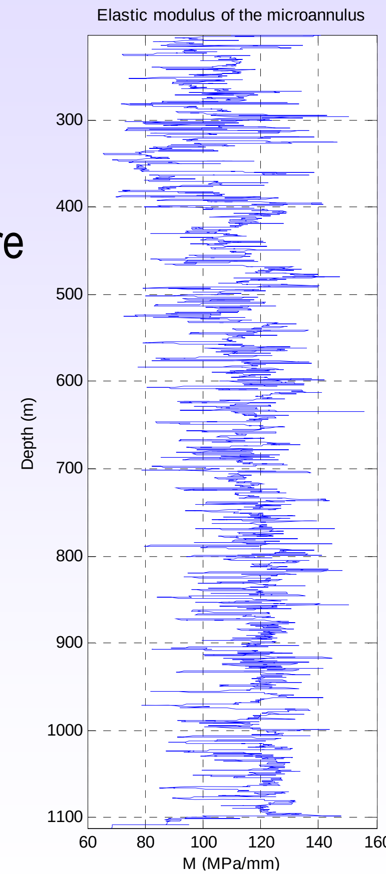
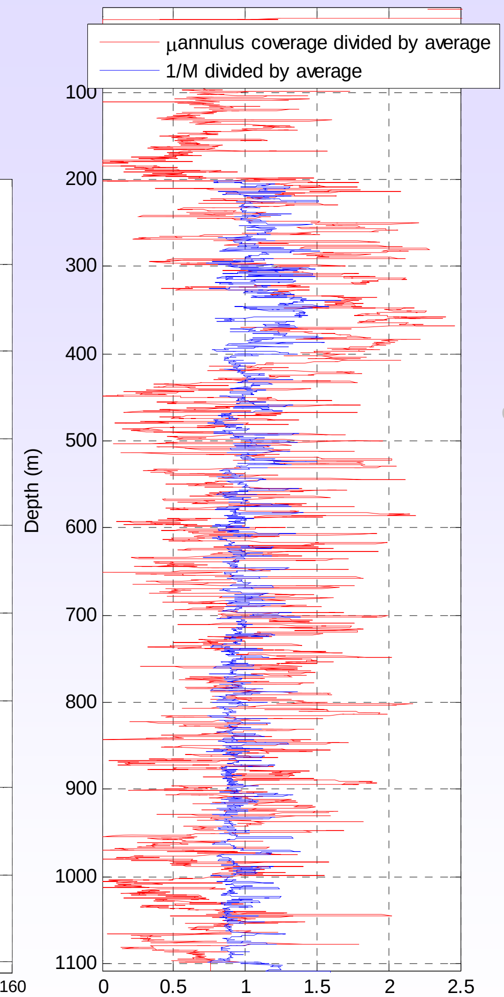
Modeling microannulus – comparing model with logs

- Mechanical models predict microannulus width (w) as a function of casing and microannulus pressures
  - $w=1/M*p_{ma} - H/M*p_c$
- CBL measures azimuthal coverage
  - Initial results suggest width and coverage are correlated
- 1/M (microannulus compliance) is reasonably well correlated to microannulus coverage
  - R=0.363
- Cement-casing delamination during CO_2 injection (*model*) could be the cause of the fluid-filled microannulus measured by the cement evaluation tools (*observation*)





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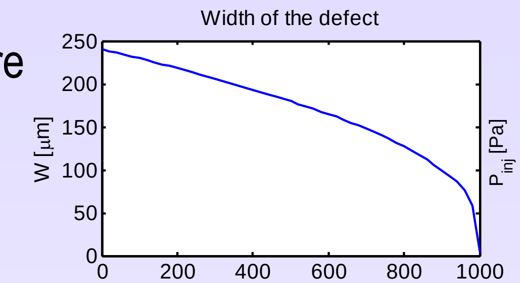
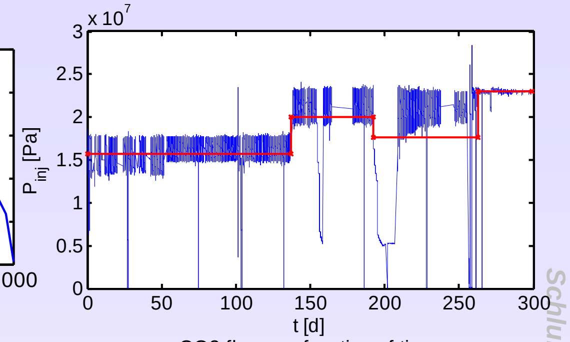
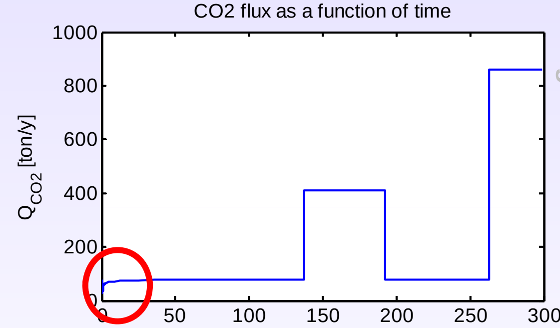
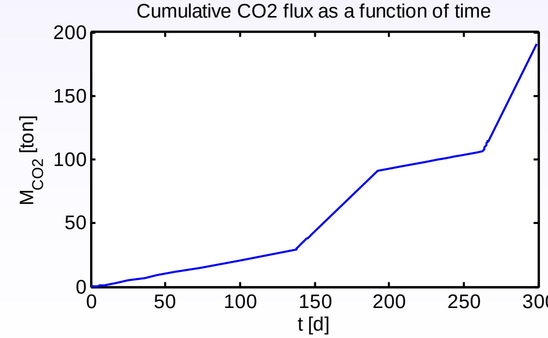
Modeling CO_2 flow in the microannulus

- Boundary Conditions
  - Piecewise-constant injection pressure
    - ✓ Computed from surface pressure
  - Isothermal @ geothermal gradient
  - Single μannulus
    - ✓ Similar behavior for the possible 9 5/8" μannulus
- Multiphase flow
  - CO_2 saturates with water almost immediately
- Coupling mechanics-flow
- Reaction model calibrated on lab tests
- Microannulus hydraulic resistance consistent with leak-off/injection behavior
  - 2005 Feb 2-7 (days 180-186), intermittent injection → Q_{in}=354 t/y, Q_{out}=410 t/y
  - *2005 Apr 29-May 29 (days 266-296), continuous injection → Q_{in}=5,452 t/y, Q_{out}=861 t/y (16%)*



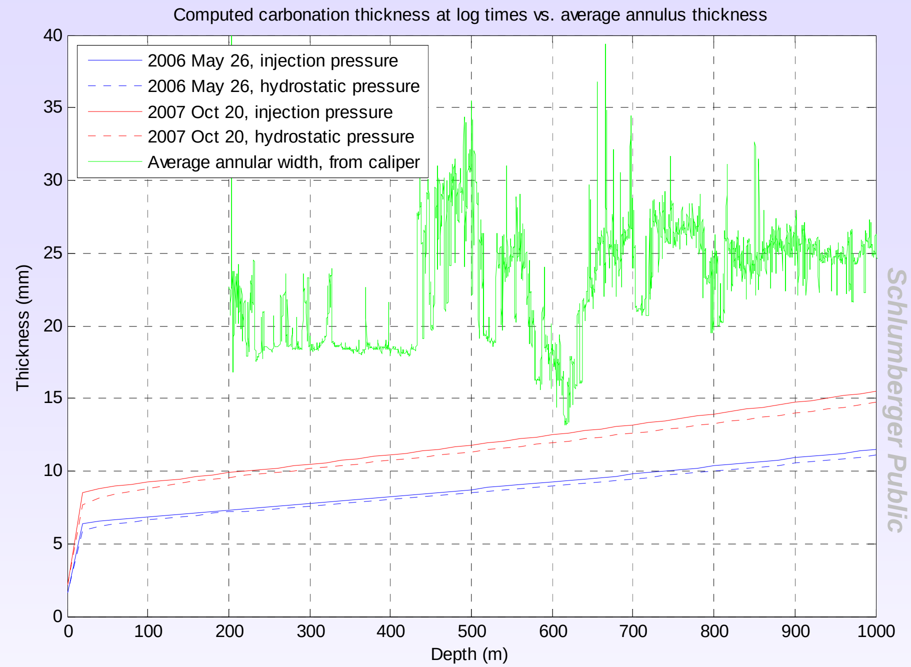


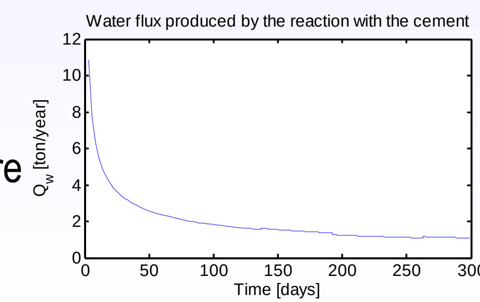


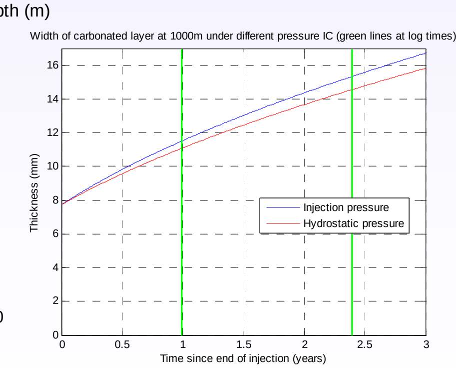


Modeling CO_2 flow – cement carbonation

- Exposure to (wet) CO_2 causes cement to carbonate
  - Portlandite $Ca(OH)_2 \rightarrow$ calcite $CaCO_3$ + water
  - Water production delays drying-out and introduces transients *(see next slide)*
    - ✓ Calcite precipitation in the µannulus neglected
- Carbonation layer progresses ~sqrt(t)
  - Unknown µannulus pressure after the end of injection (pressure dissipation)
    - ✓ Injection pressure (t_0) vs. hydrostatic (t_∞)
    - ✓ Evolution of carbonated layer almost independent from Initial Condition in pressure
    - ✓ More than half of the cement carbonated at the time of the second log

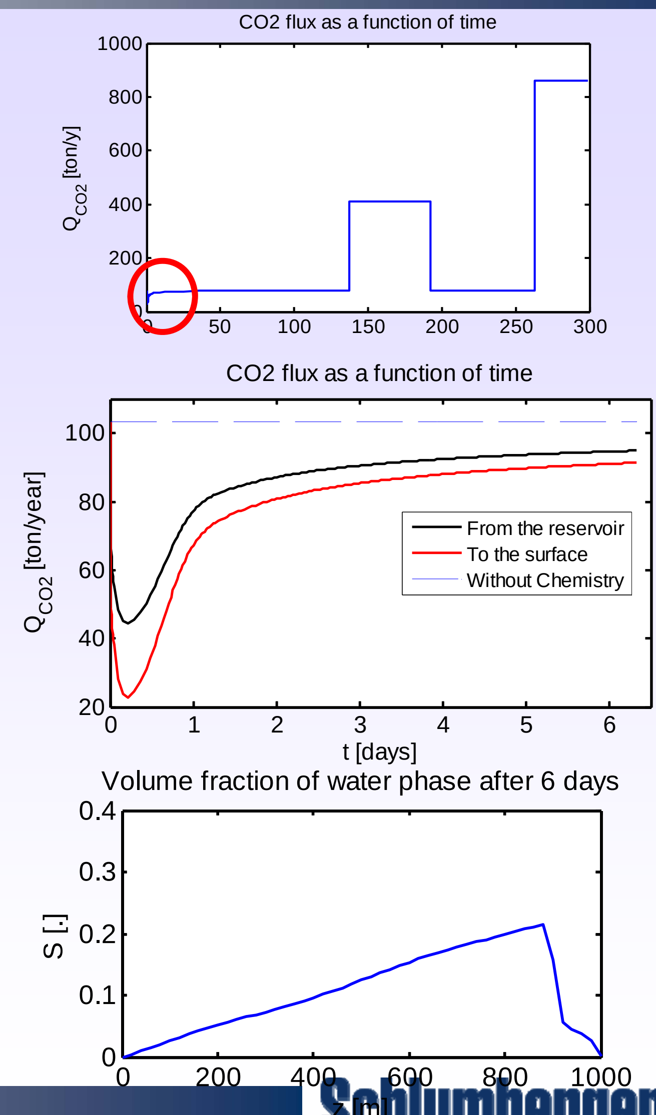






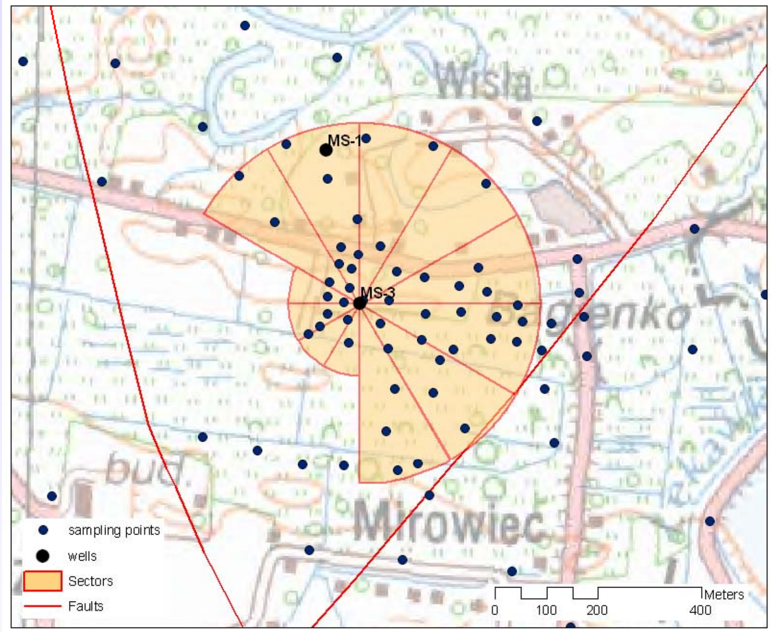
Modeling CO_2 flow – carbonation-related transient

- Cement "sweats" reaction water during carbonation
  - Part of the CO_2 is captured by the cement
- Water saturates the dry CO_2 flow, then condenses
  - Flow instabilities in the capillary μannulus suggest multiphase “droplet” flow
  - Water volume fraction drops near surface (z~1000 m) because of rapid expansion of CO_2
- Water initially reduces flowrate
  - Transient lasting ~1 week



Second line of evidence – soil gas survey

- 150 soil gas samples (CO_2, light HC, N_2,He, O_2) and the same number of CO_2 flow measurements were taken in the Kaniow area in May 2007
  - The majority of measure points was concentrated around the wells (MS-3 injection, MS-4 production)
- A subset of 47 sample points were selected within a radius of 350 m from the MS-3 well



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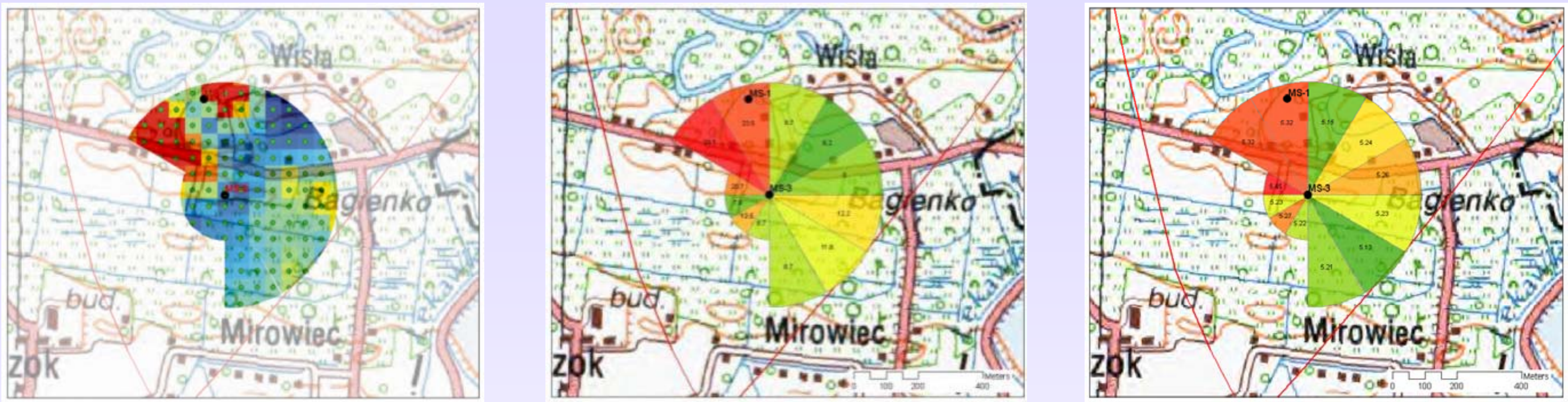
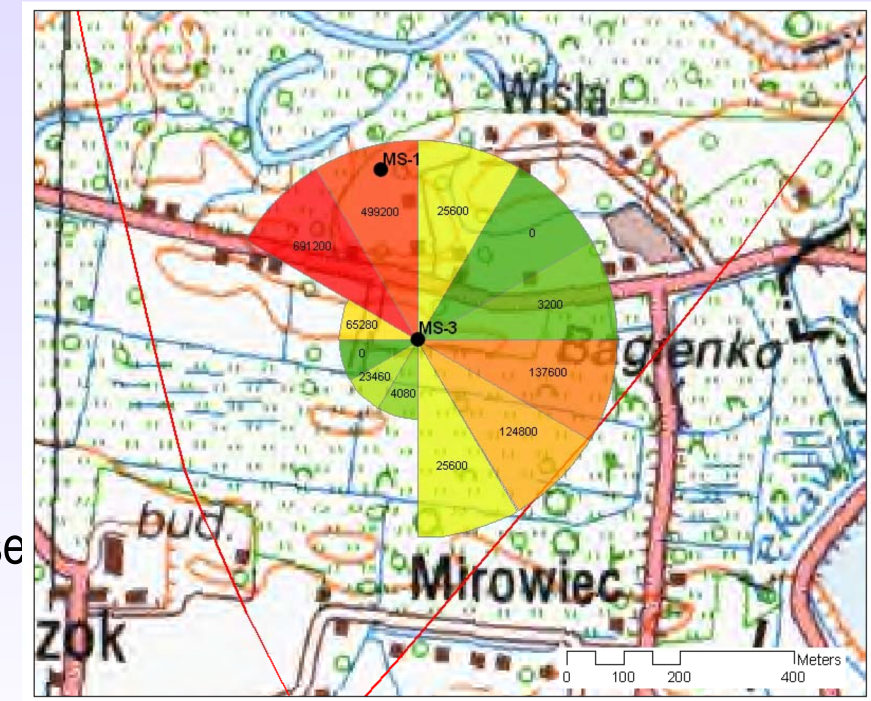
Soil gas survey – CO_2 concentration



- Concentration maps were sampled on 50 m-side cells
- For every 32,000 m^2 slice, the median value of its cells was chosen
- Anomalies in CO_2 concentrations (centre map) are aligned NNW, along the line connecting the two wells and the local fault direction
  - Anomalies in He concentration (right map) follow the same pattern and they cannot be attributed to a biological origin

Soil gas survey – CO_2 flux

- CO_2 flux mapped using the same method
  - Subtracting the median background value
- Total flux computed → 584 t/y
  - Very small amounts → <~20 g/m^2/d
  - Model predicts a peak flux out of the microannulus of 860 t/y
  - Global direction NW-SE, consistent with concentration anomalies
- The plume might have spread in the vadose zone (above 13 3/8" shoe) and might have been preferentially transported along NW/SE local faults



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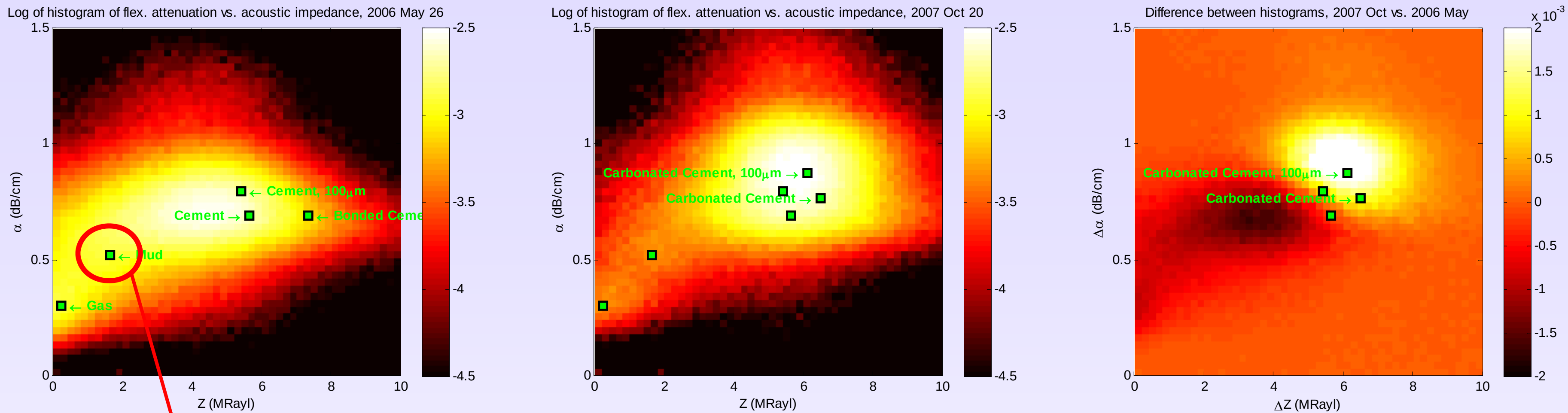
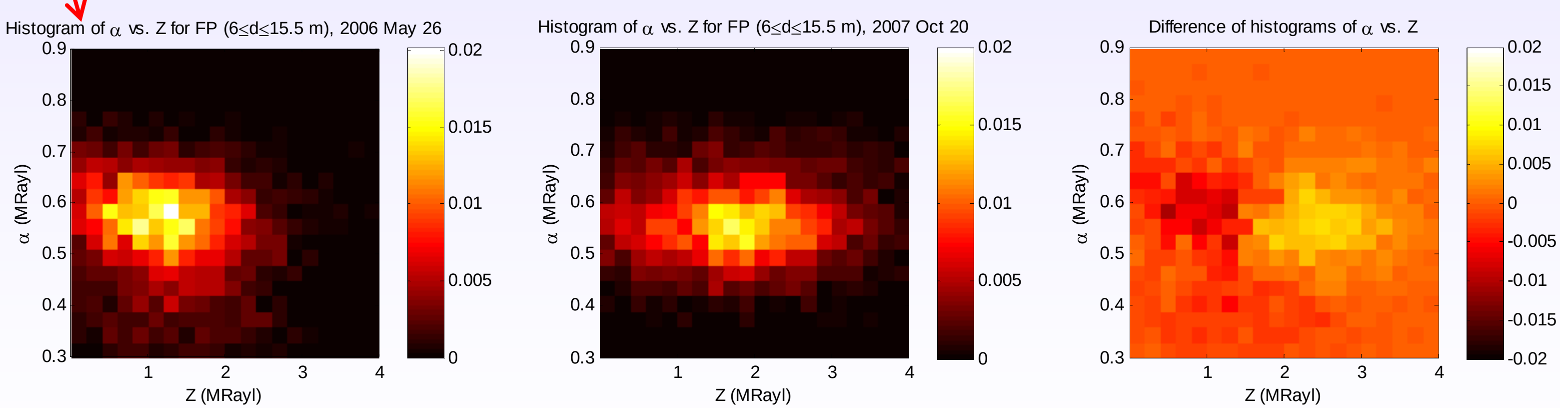
Third line of evidence – changing cement log response

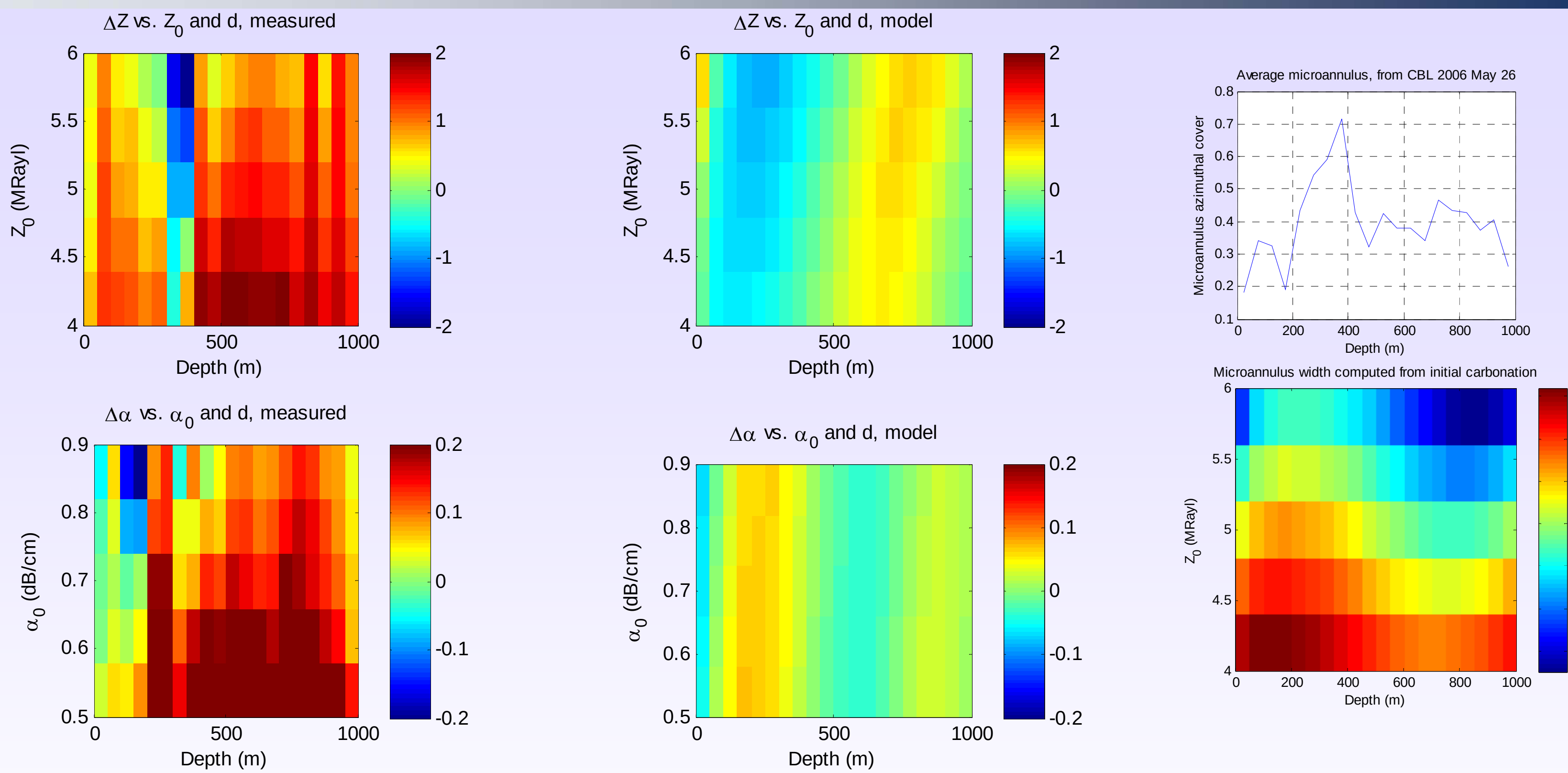


– Joint increase in Z and α in the cement pole for the whole-log histogram…



– …but little change in the 10 m of free pipe above the cement

Cement changes – Z and α vs. depth



- Histogram of variations of acoustic impedance and flexural attenuation vs. depth, observed (left) vs. model (right)
  - μannulus computed from Z_0 (supposing known cement), behavior consistent with CBL
  - Very large ΔZ and $\Delta \alpha$ at low values $\rightarrow$ contaminated cement + μannulus?

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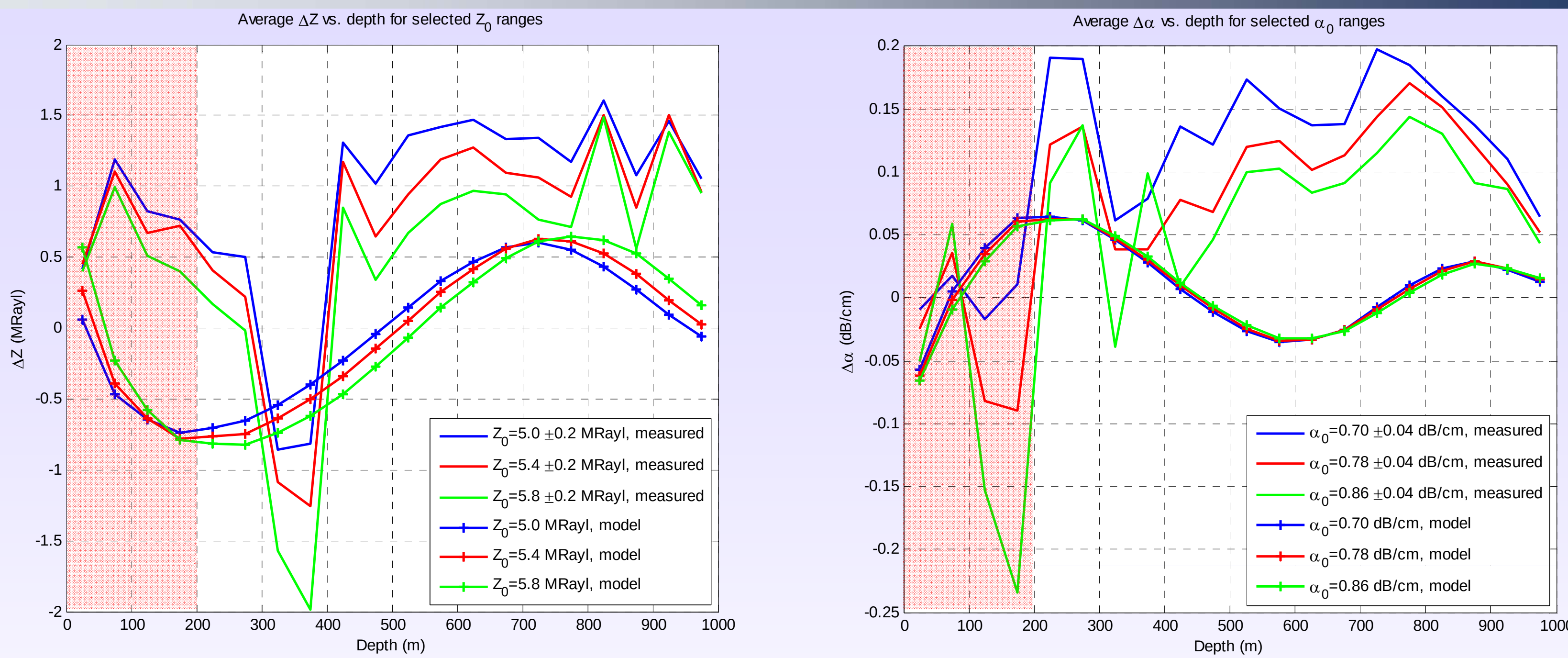
Cement changes – Z and α vs. depth, details



- Fairly good match at 5.8 MRayl and 0.86 dB/cm
  - Same variation, same period, similar phase
  - Possibly no pathway above 202 m (9 5/8" casing shoe)
- More complex behavior than the "simple" dZ/dα already identified
  - Overlapping effect of cement contamination and accelerated carbonation?

Open issues

- Microannulus
  - Is azimuthal coverage really proportional to opening?
  - Could the temperature drop during continuous injection have created the microannulus?
    - ✓ Later debonding would reduce the total CO_2 flow to ~90 t
- Soil gas
  - 1 year injection, then 2 years wait: how can the delay be properly explained?
- Changing cement log response
  - Is carbonation the only explanation for the ΔZ and $\Delta\alpha$ behavior?
    - ✓ As opposed to $\Delta Z/\Delta\alpha$

Conclusions

- Three separate lines of evidence seem to support that CO_2 flowed in the cemented annulus of the MS-3 well up to surface during injection
  - Flow happened through a casing-cement microannulus, likely created by the high injection pressure
  - About 190 t of CO_2 may have flown during the 330 days of injection
  - Flow stopped at the end of injection; coal creep/swelling and CO_2 sorption effectively sealed the well
- Technologies in the market or currently under development seem able to understand, predict, monitor and control CO_2 flow through a microannulus
  - In this case, transport/reaction models based on Navier-Stokes flow seem to be better suited than those based on Darcy flow to capture the chemo-mechanical coupling

- We wish to thank the European Commission for funding and support of the RECOPOL and MovECBM projects

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5th IEA Wellbore Integrity Network Meeting

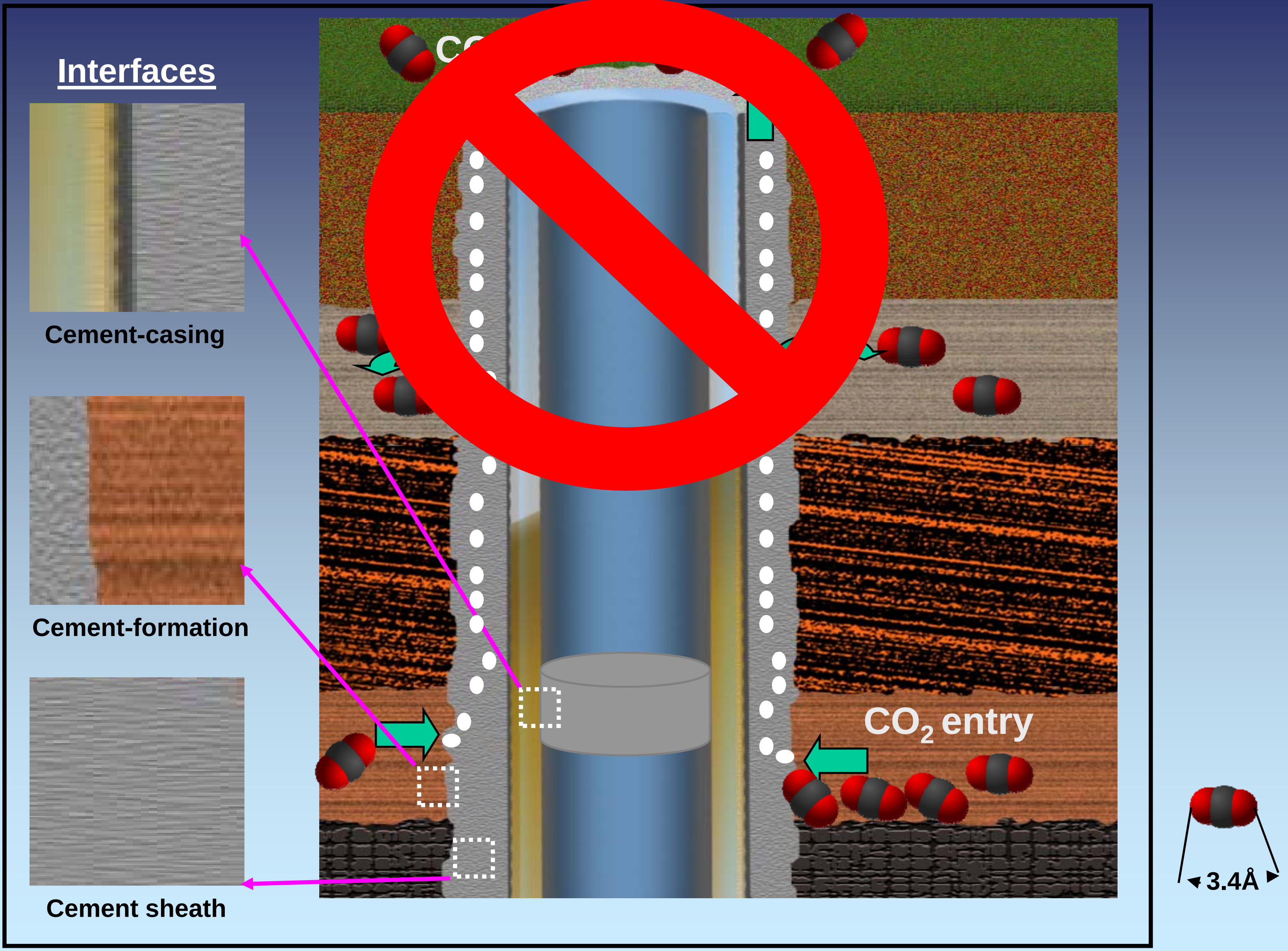
Session 3: Field Studies of Wellbore Integrity

Effective Zonal Isolation for CO_2 Sequestration Wells

Ashok Santra, Lewis Norman and Ron Sweatman
Halliburton

13 -14 May, 2009 • Delta Calgary South • Calgary, Alberta, Canada

What are CO_2 Zonal Isolation Concerns?



What are CO_2 Zonal Isolation Concerns?

- CO_2 dissolves Portland cement & unseals annulus!
- CO_2 leaks through unsealed annulus!
- USDW is contaminated by CO_2 and unusable!
- CO_2 escapes the well and kills all life in the area!
- GHG increases causing more climate change!
- Life on Earth is imperiled!!!

True or False?

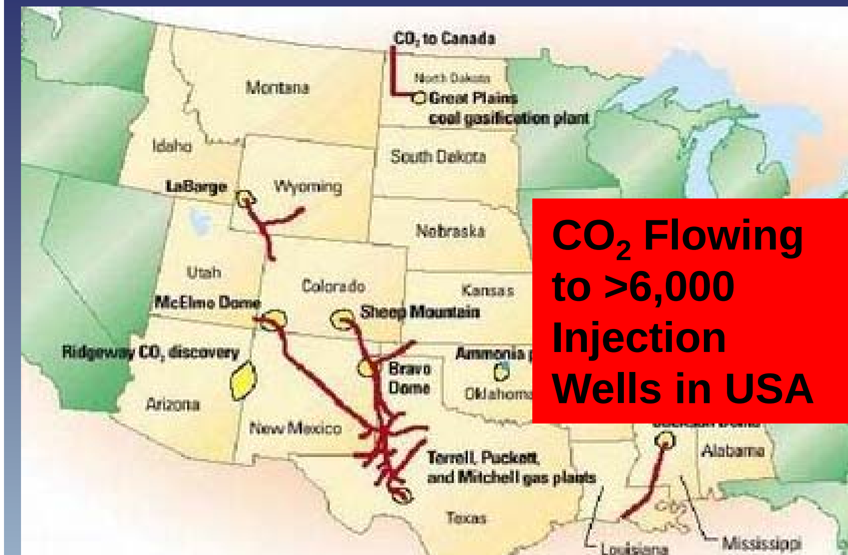
In USA CO_2 EOR Operations:

FALSE ➔ CO_2 Wells Leak & Endanger!
TRUE ➔ Infrequent, Small Internal Leaks are Contained & Don't Endanger!

Who Says So?

- Oil & Gas Industry MIT Records & Well Integrity Studies:
  - Sporadic, Minor Leaks Inside Wells are Contained, Detected and Mitigated
  - No Major External Leaks in +25 Years Since UIC Program Started
  - API "Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2EOR) Injection Well Technology"
- Regulators' Inspections, Reports, & CCS Rules:
  - "There have been no documented cases of leakage from these projects (CO_2EOR), nor has there been release and surface accumulation of CO_2 such that asphyxiation would have been possible." inserted from page 30 in EPA Proposed CCS Rules
- Consortiums' Old Well Samples Show CO_2 Contained in Annulus
- 3rd Party Measurements Don't Find CO_2 in USDW above CO_2 Zones
- Research Explains "WHY NO LEAKS"

CO_2 Pipelines and Flowlines for EOR



European Energy Forum

CO_2 Flowing to >6,000 Injection Wells in USA

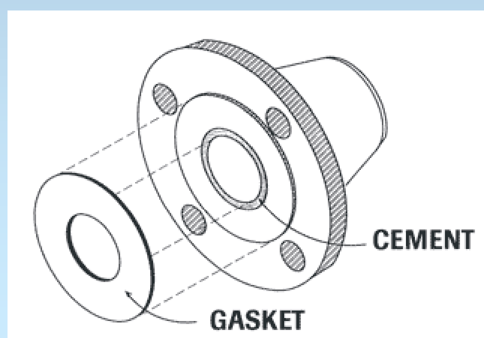
Carmito, Mexico

>9,000 producing wells flow out wet CO_2 with oil thru >80 million feet of cement-lined well tubing & flowlines

- **Cortez Pipelines (McElmo,etc), 504 miles, 1.3BCFD**
- **Sheep Mountain Pipeline, 408 miles, 480 MMCFD**
- **Bravo pipeline, 218 miles, 382 MMCFD**

CO_2 injected: 655 million tons in last 37 years (average 17.7 million tons/yr) equivalent to emissions from ~4 - 500 MW power plants/yr (average)

Data approved for release by Kinder Morgan 5-7-09

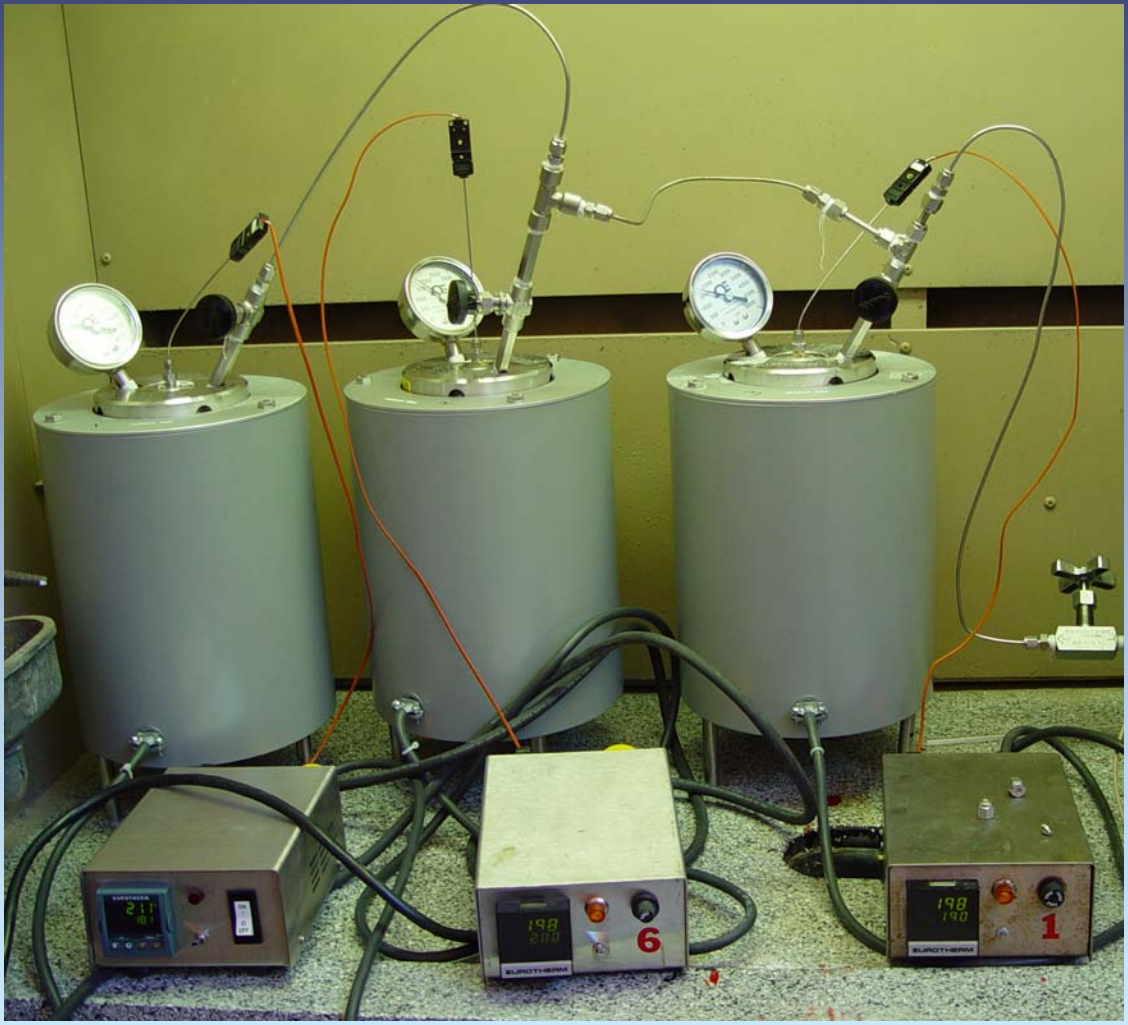


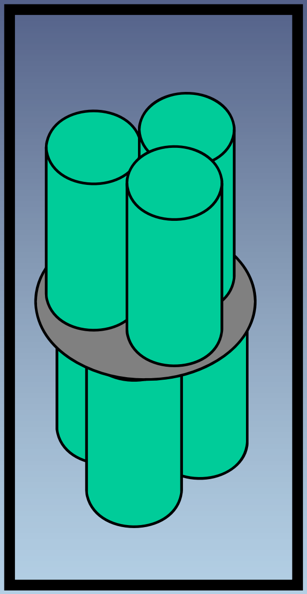
Research Explains Why No CO_2 Leaks!

- 1836 - French Academy of Science finds **cement seals CO_2 by thin carbonated layer**
- 1800's - Manufacturers say **cement has excellent anti-corrosive properties** for lining steel water lines
- 1964 - SPE 995, Runyan reports "**Cement-Lined tubing is impervious to any normal oilfield water, including very sour waters. Erosion due to high flow rates presents no problems**."
- 1970 - SPE 2478, Beach[et al], Gulf Oil, develops **cement/flyash/sand lining for steel pipe that is "uniform, strong and inert (to wet CO_2)"**
- 1973 - SPE 4667, Schremp[et al], Chevron, tests cement-lined pipe in WAG supercritical CO_2 flow and reports "**cement linings showed no evidence of deterioration or separation from the pipe wall. There also was no indication of stratification or spalling of the cement**."
- 1977 - SPE 6391, Newton[et al], Chevron SACROC's cement-lined pipe, "**Although the CO_2 content of the produced water has increased, no deterioration of the cement lining has been noted**."
- 1986 - GRC article, Milestone[et al], Brookhaven National Lab, says that **cement forms an "impermeable layer of $CaCO_3$......preventing further penetration of (wet CO_2)"**
- 2008 - GHGT-9 paper, Carey[et al], LANL+NMT+BP, test cement in CO_2-brine flow (41,000 pore-volumes), "The **Portland cement was carbonated to depths of 50-150 µm** by a diffusion-dominated process. **There was no evidence of mass loss or erosion of the Portland cement."**
- 2008 - GHGT-9 paper, Huerta[et al], UT+NETL, used Hassler cells with confining pressure to test acid flow (simulated CO_2-brine) thru stress cracks in cement cores, "**Cyclic loading of naturally fractured cement cores shows a decrease of aperture size with increased confining stress, hysteresis in loading / unloading cycle, and strain-hardening........Degradation of cement by CO_2-rich fluids coupled with decreasing reservoir fluid pressure could render leaky wellbores self sealing.**

Test Cell Setup

SPE 121103





1”-dia x 2” long

Test conditions used: 2000 psi and 200F

Samples After CO_2 Exposure up to 3 months



15 days

Conventional Portland

Portland-Fly Ash -reg

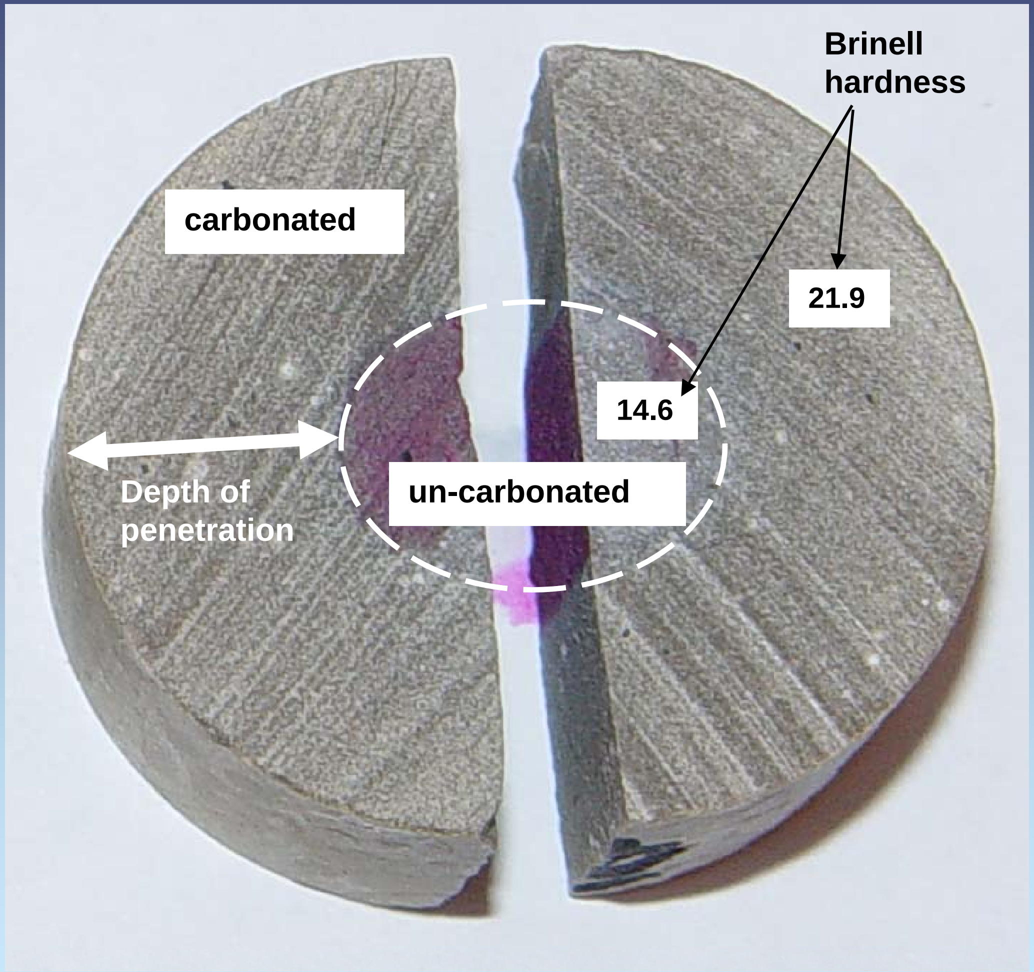
Portland-Fly Ash @low water/solid ratio



3 months

SPE 121103

Effects of Carbonation



SPE 121103

Ways to Reduce CO_2 Penetration Depth

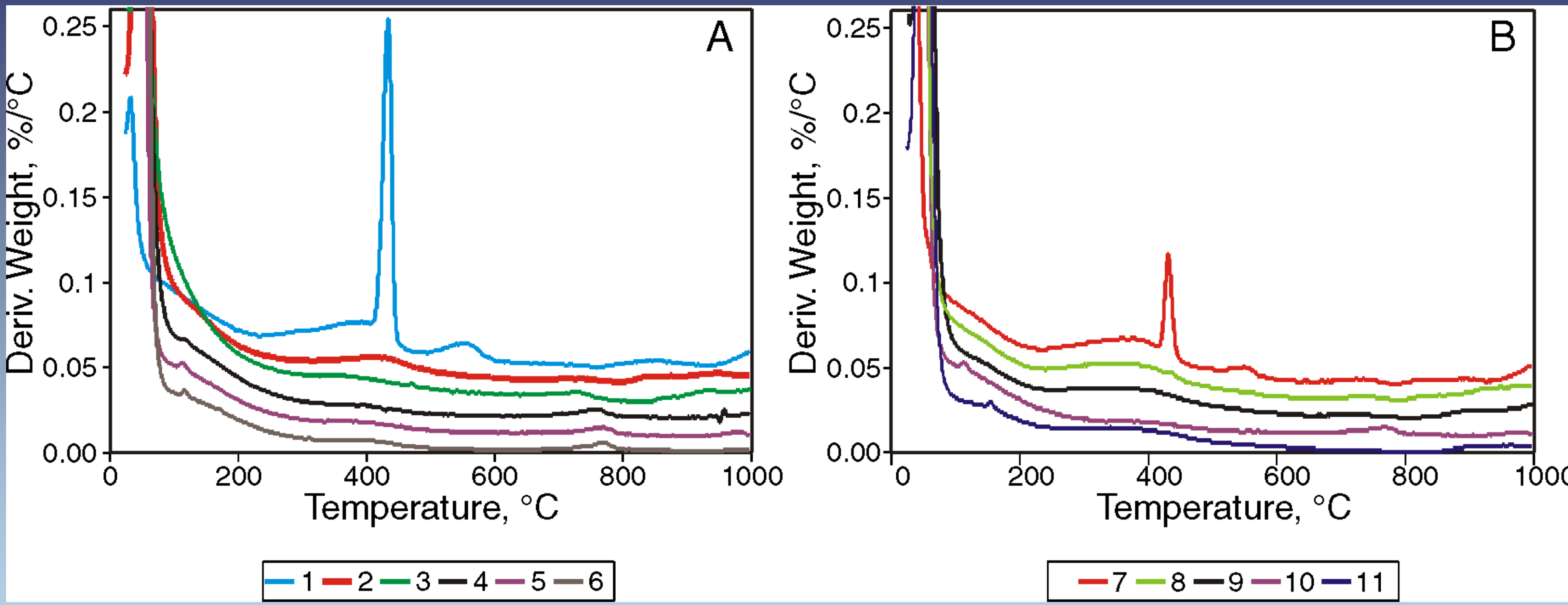
- Reduce Permeability
- Increase Lime (Portandite) content
  - May not be practical in every scenario

Ways to Reduce CO_2-induced Damage?

- Design cements with low % carbonation
- Seal 1-2" into borehole rock permeability

Thermo-Gravimetry and $Ca(OH)_2$ Content

SPE 121103



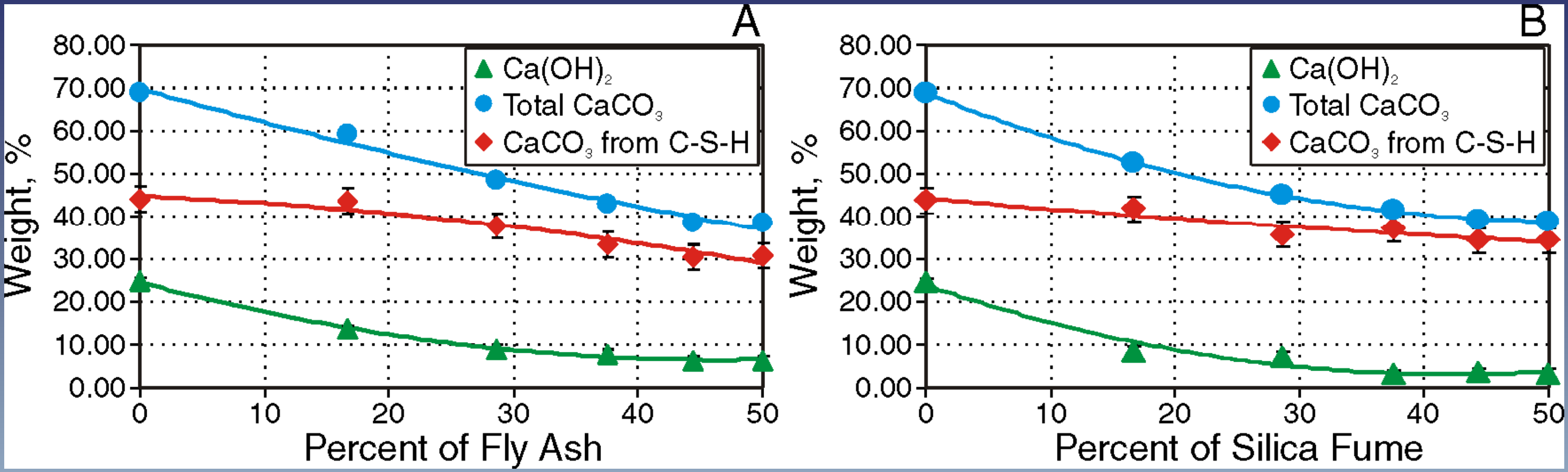
1- Neat Portland, 2- 16.7%, 3- 28.6%, 4- 37.5%, 5- 44.4% & 6- 50% Silica Fume

7- 16.7%, 8- 28.6%, 9- 37.5%, 10- 44.4% & 11- 50% Fly Ash

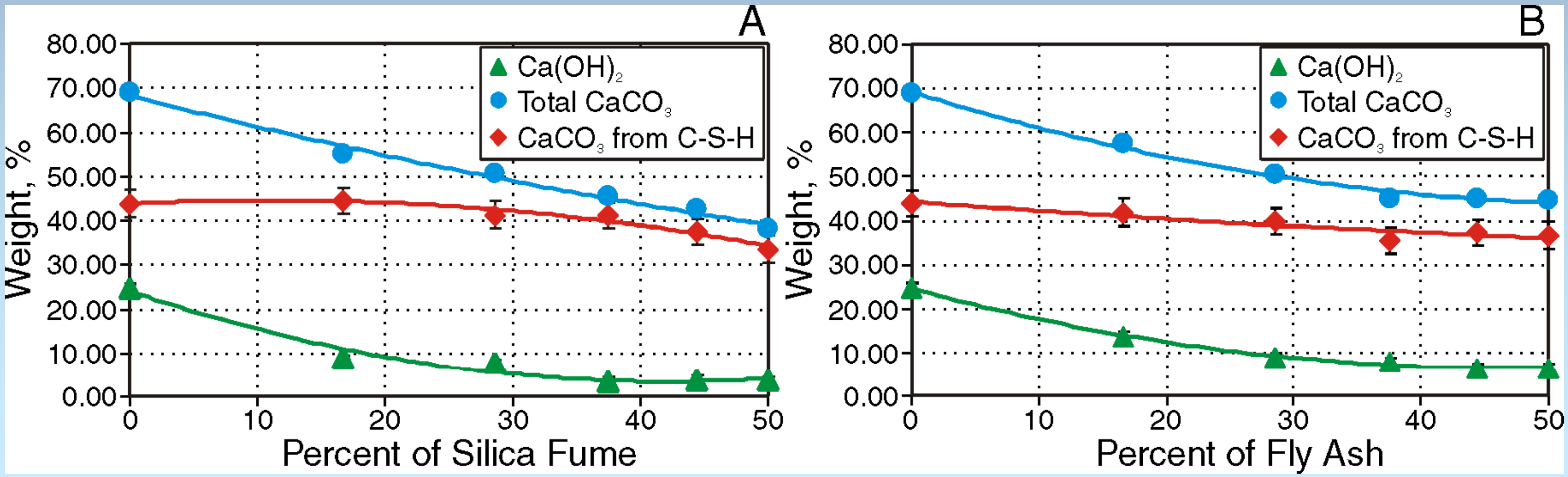
$Ca(OH)_2$ content decreases with increasing either Silica or Fly Ash:
- **Pozzolanic reaction**

Sample Halves after 15 days CO_2 treatment at 200F and 2000psi

Estimation of $CaCO_3$ content after 15 Days

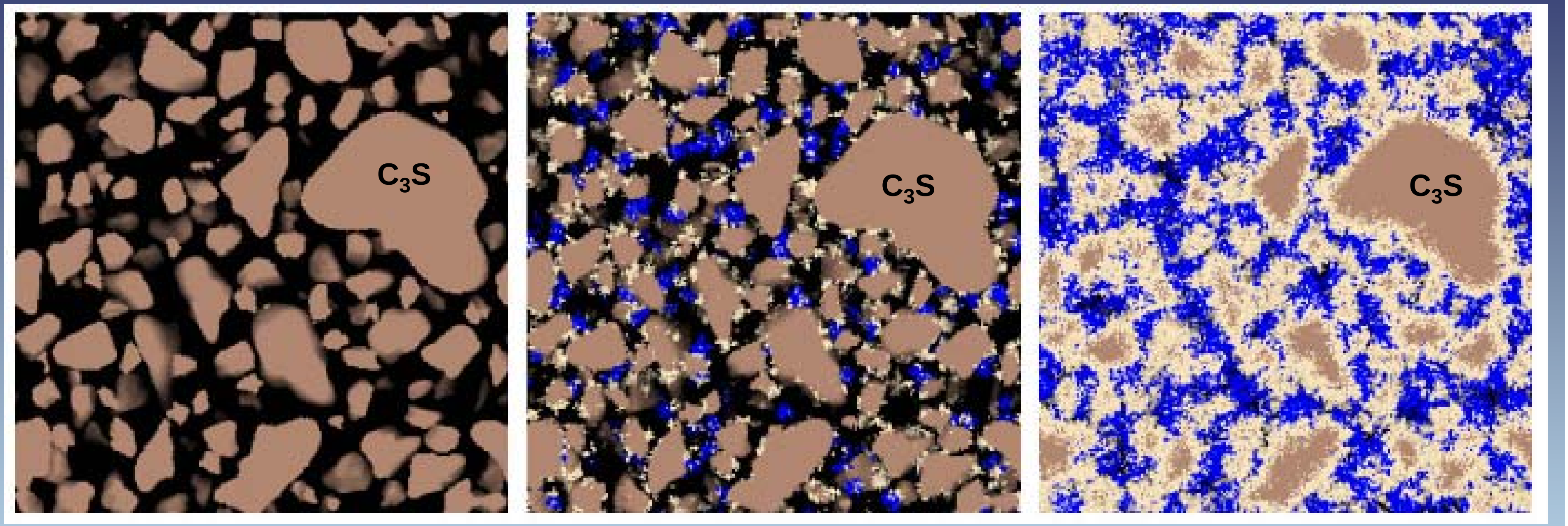


Estimation of $CaCO_3$ content after 90 Days



Hydration and $Ca(OH)_2$ Formation

Water/cement = 0.5

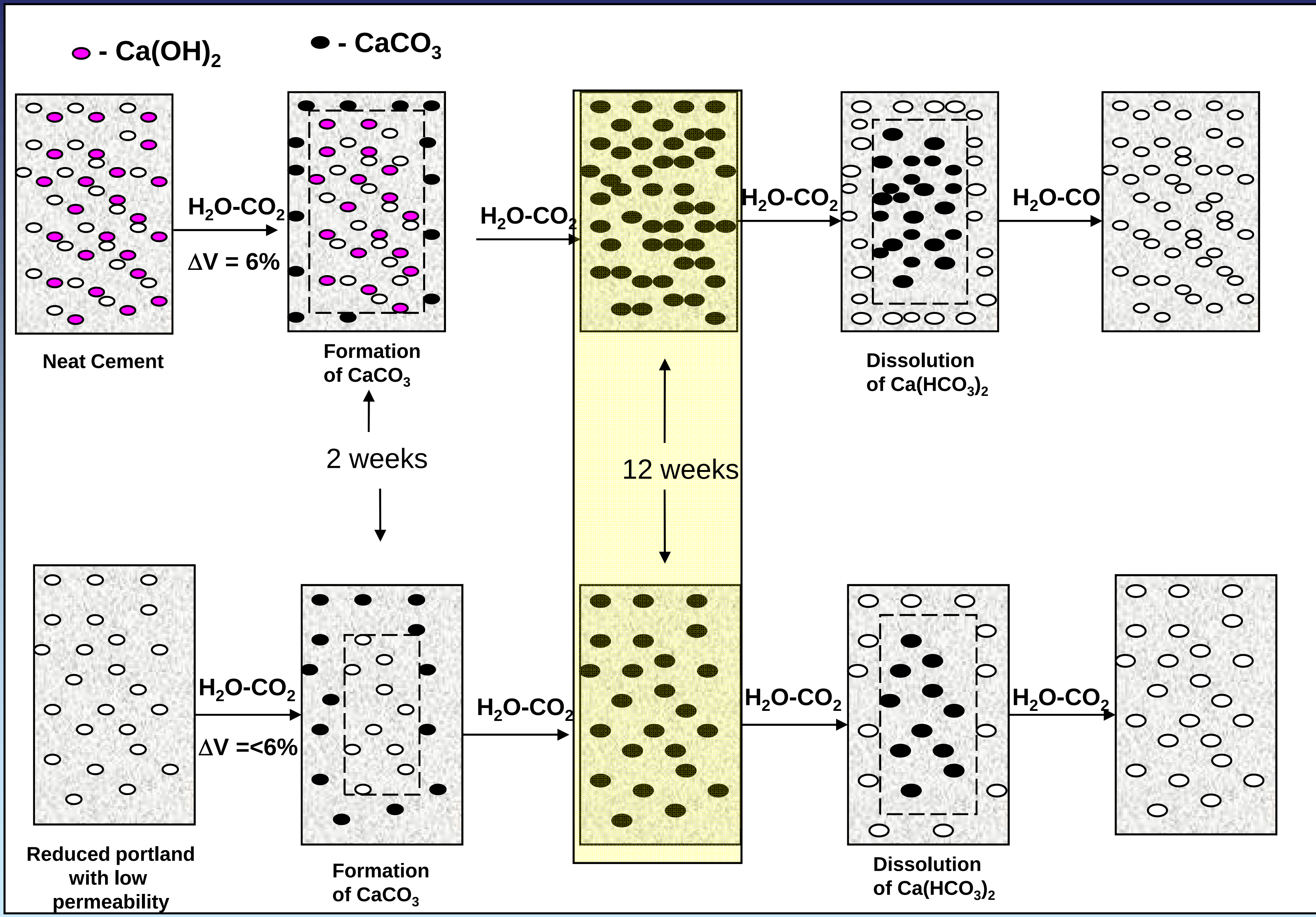


Hydration = 0% **10%** **60%**

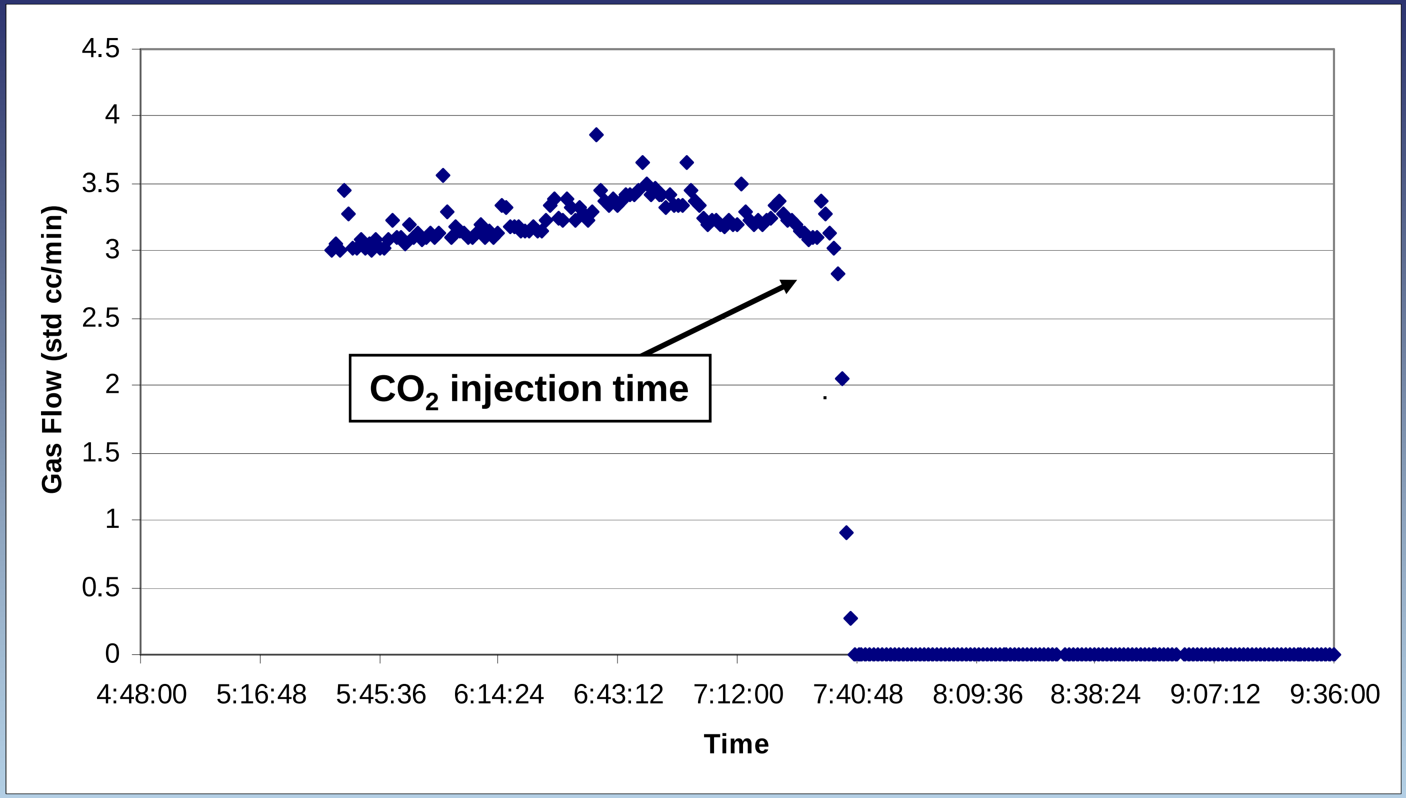
■ -Capillary pores; ■ – $Ca(OH)_2$; ■ – CSH;

Jennings et al. J. Adv. Conc. Tech. 6 (2008) 5-29

Reduce the Portland Content



CO_2 -Induced Self-Healing/Sealing



<u>Hassler Cell Core Test conditions:</u>

BHST: 220F

CO_2 pressure: 500 psi (water std@RT)

Confined press: 2000psi

Duration: 2 hours

Initial Flow: ~3.4 std cc/min

Final Flow: non-detectable

Time to STOP flow ~6min

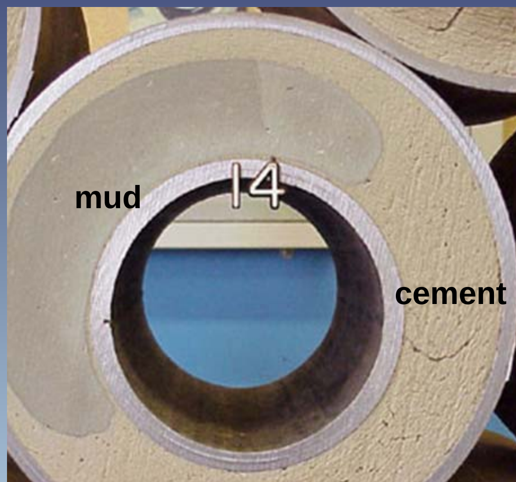
Cement Options to Resist Acidic Conditions

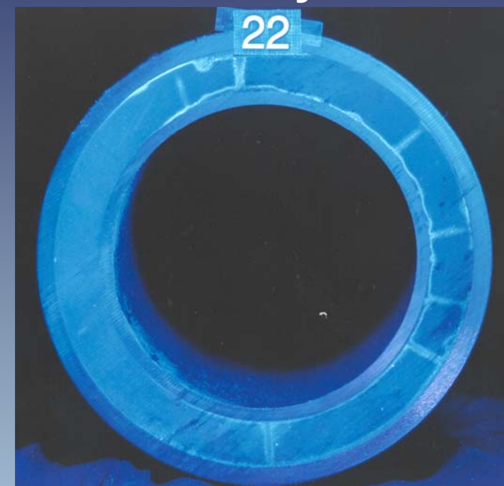
Calcium Aluminate Systems Resist Carbonic Acid Up to 600F at pH<3

- **Reduced Portland Cements: pH>4**
- **Calcium Aluminate/Phosphate: pH<4**
- **Epoxy-based Cements: pH<3**
  - **EPA Class I wells**
  - **Disposal of Strong Acids**
  - **EPA Accepts for 10,000 years**
- **Chemical Gels for Sealing Formations**
  - **Leak Remediation & Prevention**
  - **Impair Rock Permeability 100%**
  - **Block Fissures, Faults & Fractures**
  - **Field proven CO_2 resistant in EOR projects**

Follow Cementing Best Practices

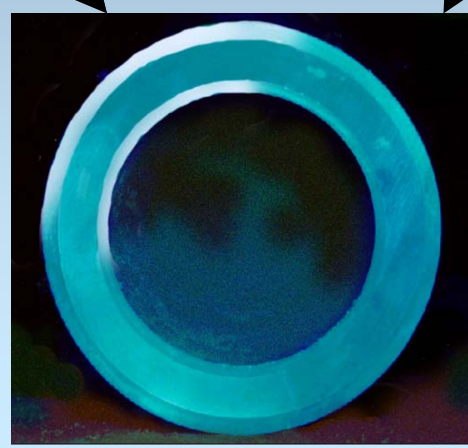
- Mud displacement, long term sheath integrity, etc
- Best practices reported in API RP 65-2 & others by API/ISO





100% mud displacement

Improve resiliency



Ready for Testing Protocol?

Thank You

Comments?

Questions?

$C0_2$ / Acid Gas Injection Well Conversion

Prepared for the 5Th Well Bore Integrity Network Meeting.

Calgary Alberta

May 14, 2009

Agenda

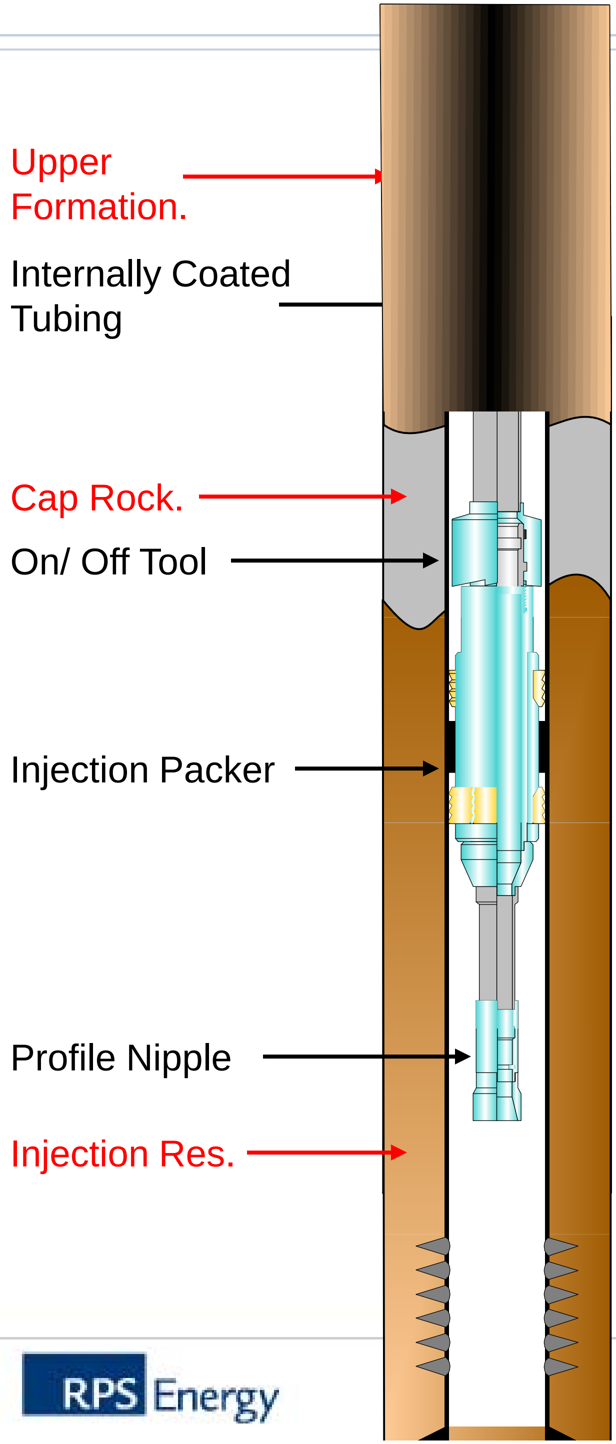
- Wellbore integrity
- Well design with annular integrity
- Well design without annular integrity
- Elastomers
- Coatings
- Threads
- Risk & Cost
- Best practices
- Conclusions

- The issue of cement integrity and bonding as well as cap rock competency/ integrity are outside the scope of this presentation and will therefore focus on the conversion and repair of wells for injection !

Well Bore Integrity

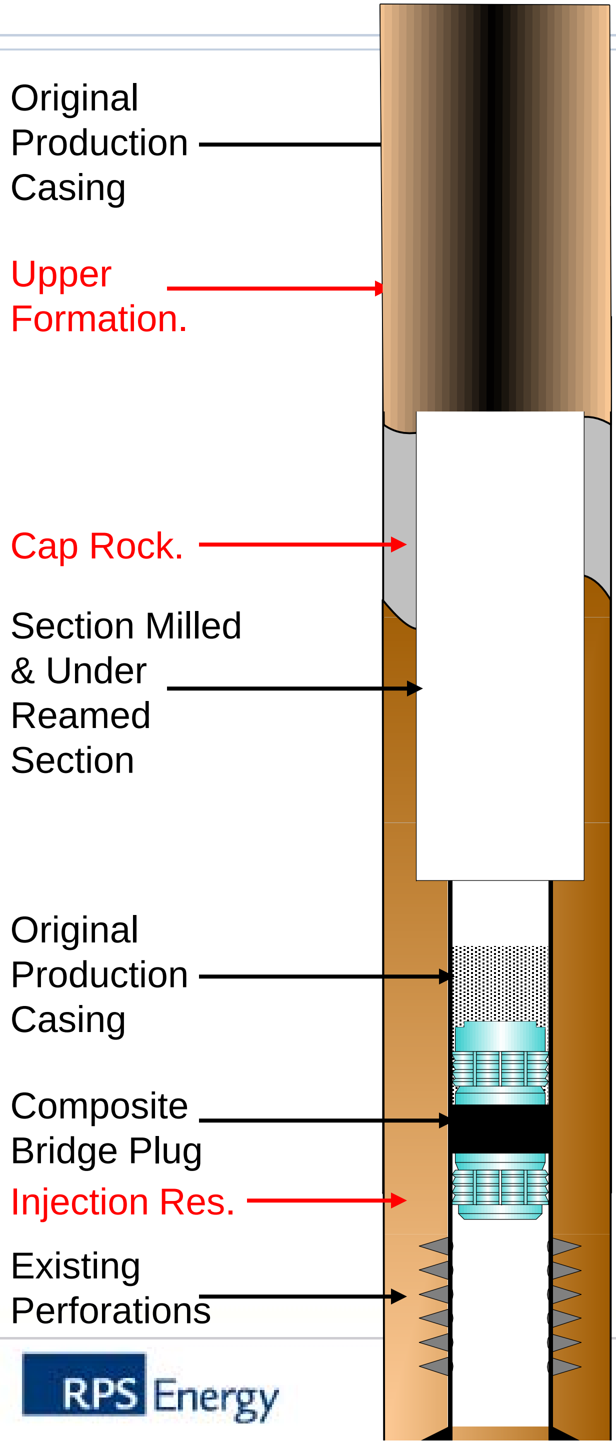
- Well bore failures are either external or internal.
  - External failure could occur as a result of;
    - Leakage via cement channeling/ deteriation (poor primary cement)
    - External casing corrosion (incorrect cement formulation)
    - Casing thread leaks (wet $C0_2$ in reservoir)
  - Internal failure
    - Packer leak
    - Tubing leak
    - Corrosion (wet $C0_2$ in flow stream and or reservoir)

Design With Annular Integrity



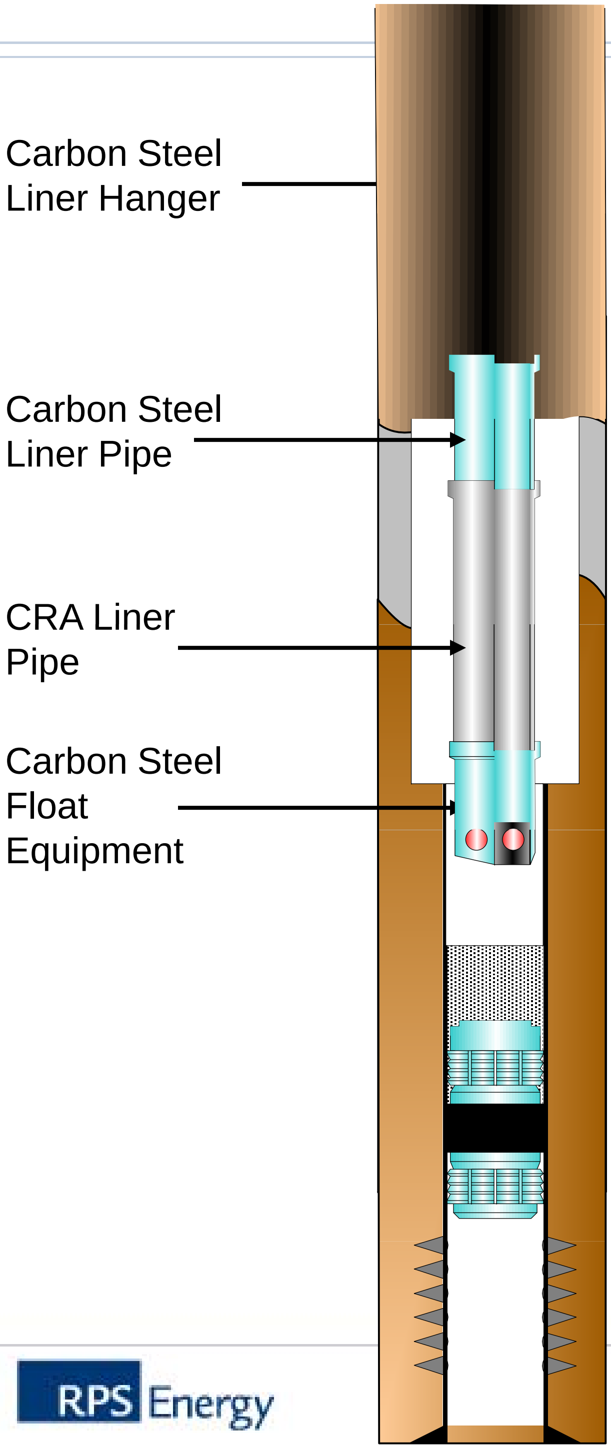
- This injection well example assumes that cement quality and bond were acceptable, external casing condition is good and is suitable for internal conversion
- The existing completion is pulled and the well is prepped for conversion to injection by cleaning and stimulating if necessary
- An injection packer is set high enough to facilitate monitoring logging but must be kept within the injection zone to provide annular pressure isolation to the top of that zone

Design Without Annular Integrity



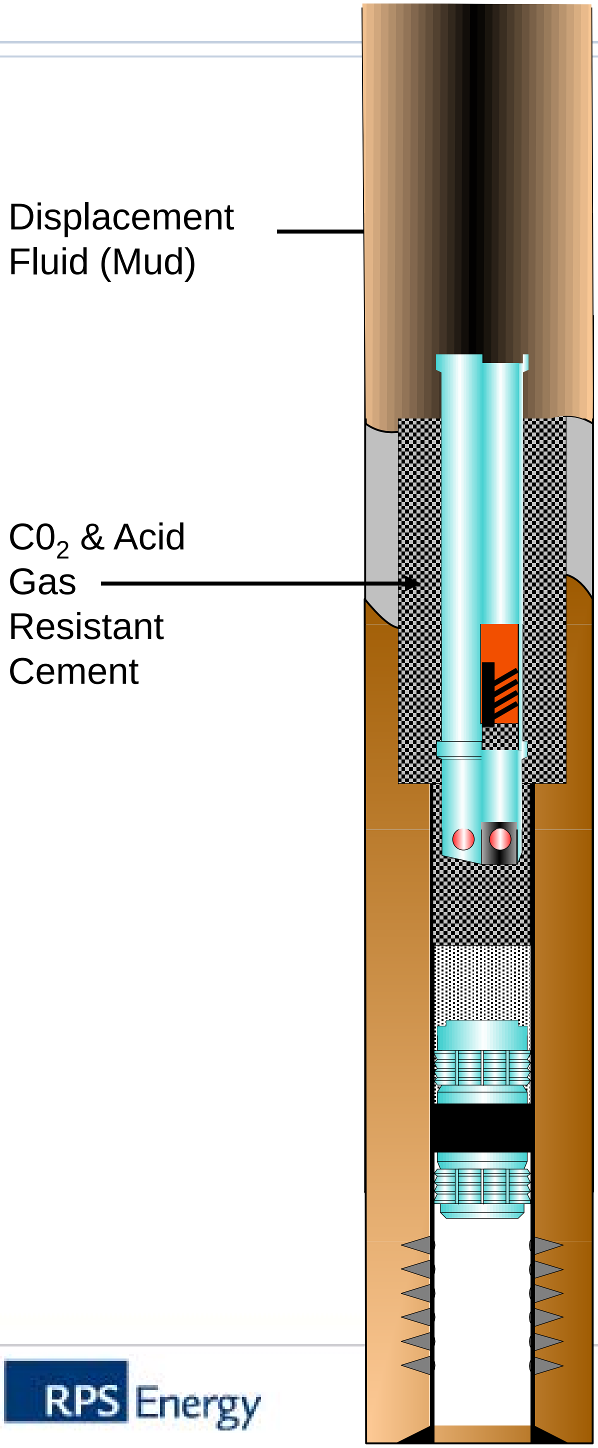
- This example assumes that near well bore annular communication/ channeling exists and must be repaired outside the well bore but within the bore hole
- Existing production casing must be of fair or better condition
- Previous failed completion to be removed and well prepped for workover
- Set composite material bridge plug above the perforations to isolate injection interval
- Section mill (remove) the production casing across the upper section of the injection zone and past the cap rock
- Under ream back to the original bore hole to expose uncontaminated rock

Design Without Annular Integrity



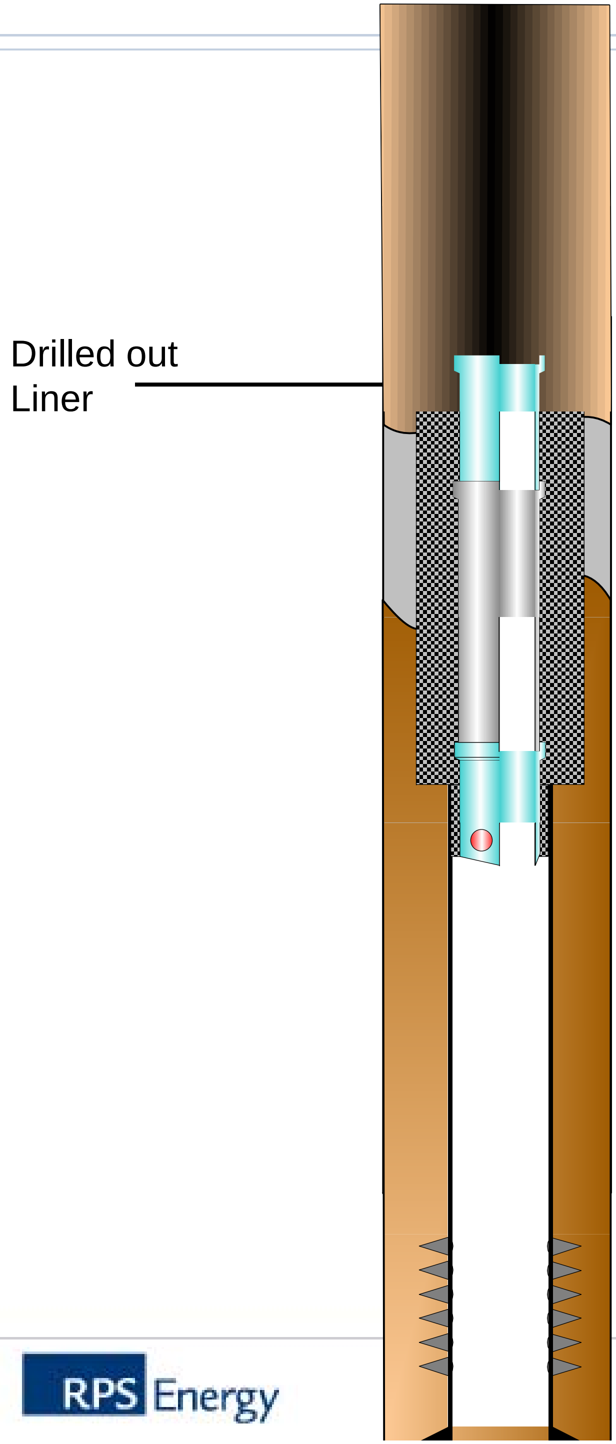
- Run a conventional rotating liner hanger with standard cementing float equipment
- Liner hanger and float equipment can be low alloy carbon steel
- The liner pipe across the injection zone and into the cap rock should be CRA (corrosion resistant alloy) to prevent internal/ external corrosion and facilitate setting of the injection packer thereby mitigating internal corrosion as well

Design Without Annular Integrity



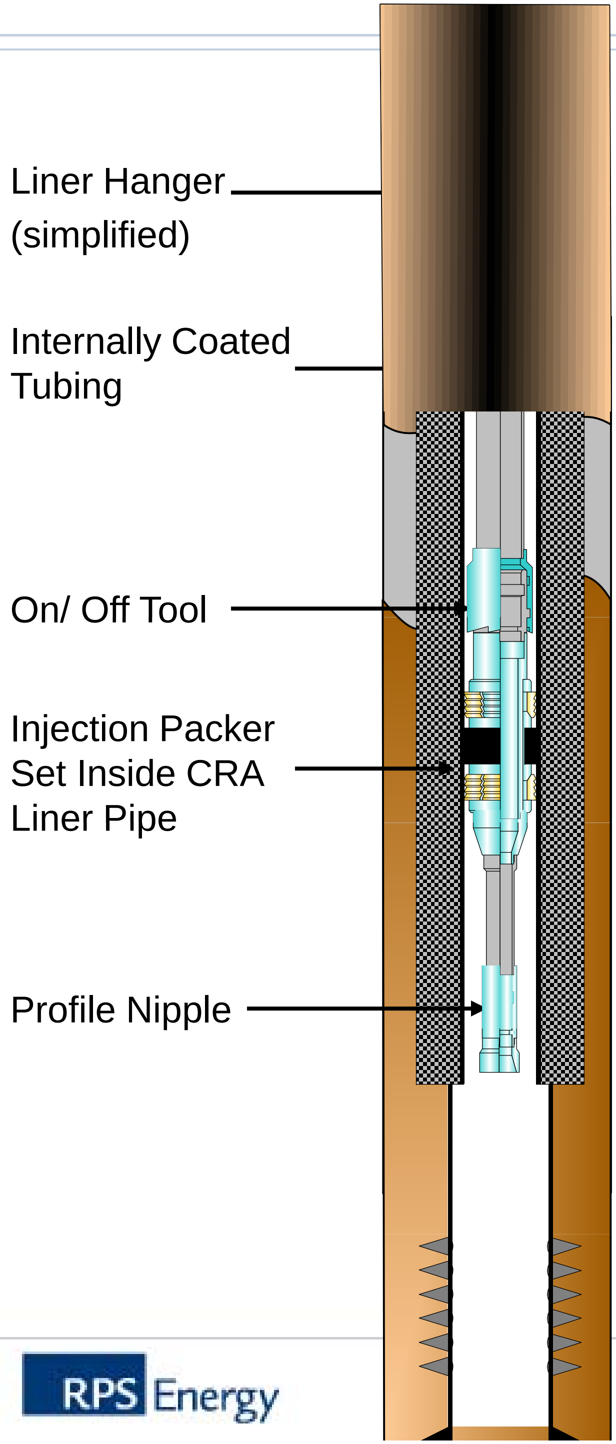
- Rotate the liner during cement displacement to improve the cement bond with the pipe and bore hole by reducing laminar flow
- Keep the liner well centralized to improve liner concentricity within bore hole
- Use CO_2 and acid gas resistant cement

Design Without Annular Integrity



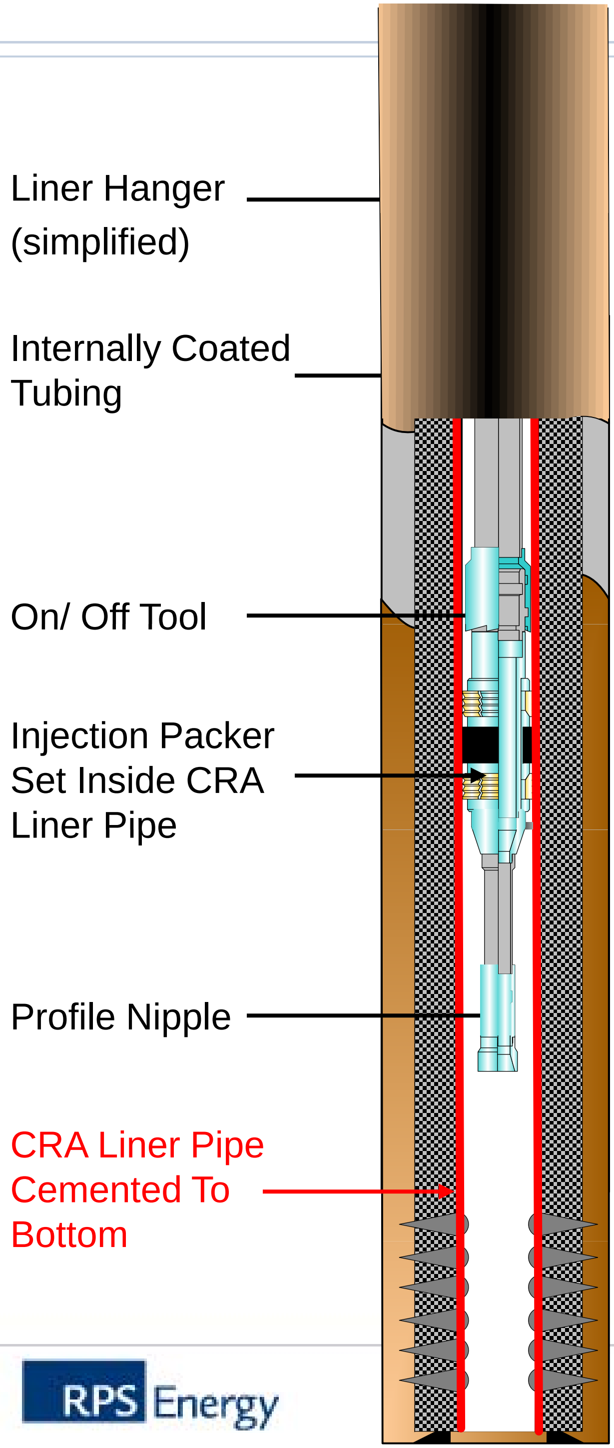
- Drill out excess cement from the production casing to top of liner
- Drill out cement inside the liner and float equipment
- Pressure test the liner and cement job to confirm integrity
- Drill to top of the composite bridge plug and circulate clean
- Run under reamer and drill out the composite bridge plug and clean to bottom.
- Stimulate the perforated interval if required
- Run cement integrity, tracer & temp logs to confirm annular integrity

Design Without Annular Integrity



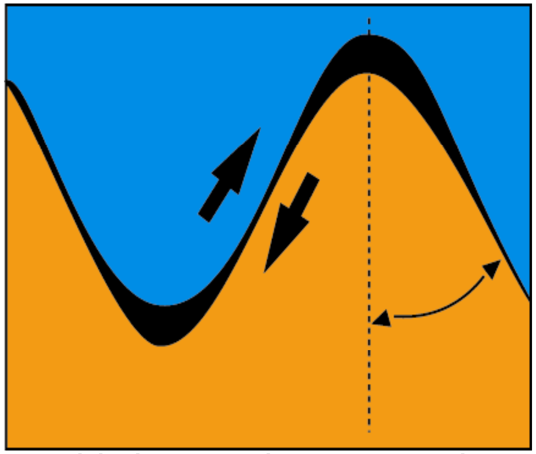
- •Run the injection packer on wireline or work string
- •Set the packer near the bottom of the CRA casing
- •Run the internally coated injection tubing and latch onto the packer
- •Pressure tested to confirm annular integrity and land in the optimum (modeled) condition to minimize or eliminate tubing cycling

Design Without Annular Integrity



- This example assumes the original production is poor to very poor condition and will not allow down hole tools to be set
- The well is under reamed across the perforated interval and the liner cemented accordingly
- Re-perforating and possible stimulation will be required
- Controlling fluid and cement losses will be difficult in depleted reservoirs and may require creative temporary plugging techniques to hold cement in place while setting
- Need to consider how those losses will affect the injectivity post workover

Threads

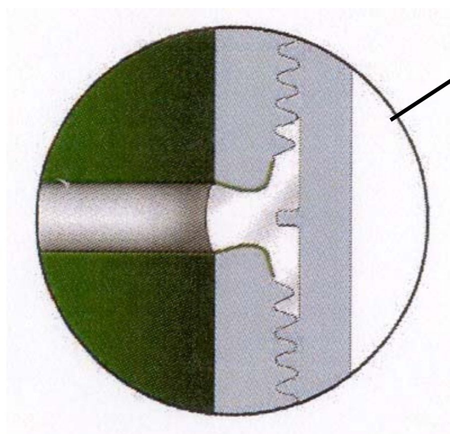


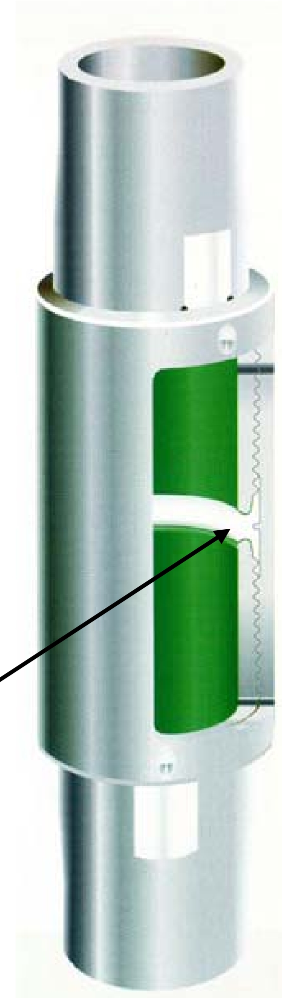
This image shows an 8rd thread and the Helix seal formed at the crest of the thread forming the dope seal.

- API Connections
  - Round thread type
  - Buttress thread type
  - Sealing relies on thread compound/dope
  - Examples; EUE, LTC, BTC
  - Should not be used without additional sealing aids for $C0_2$ & Acid Gas injection
  - **Should not be used for casing threads**

Eue Pin Thread

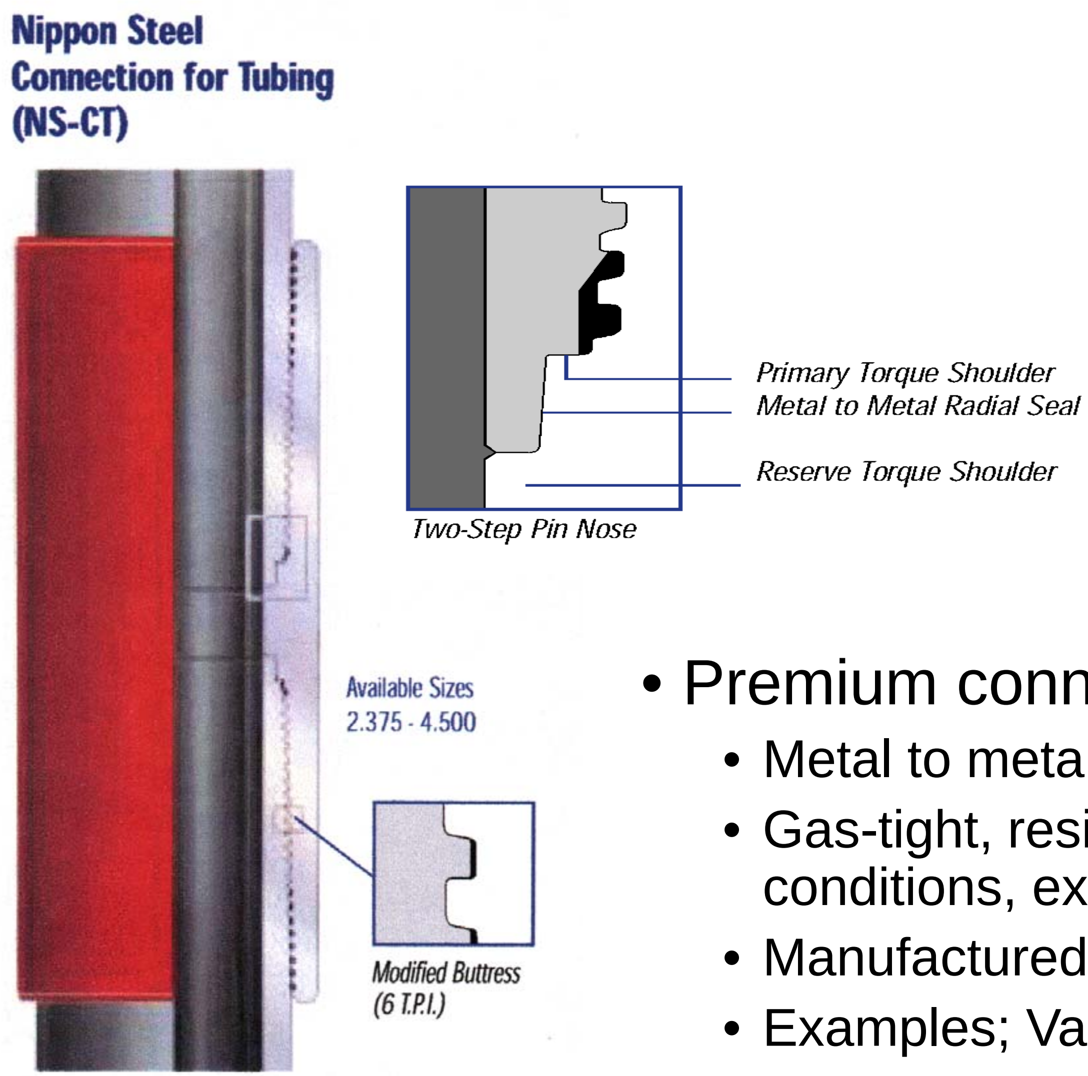
PTFE insert protects the bare threads from corrosion





MMS Coupling

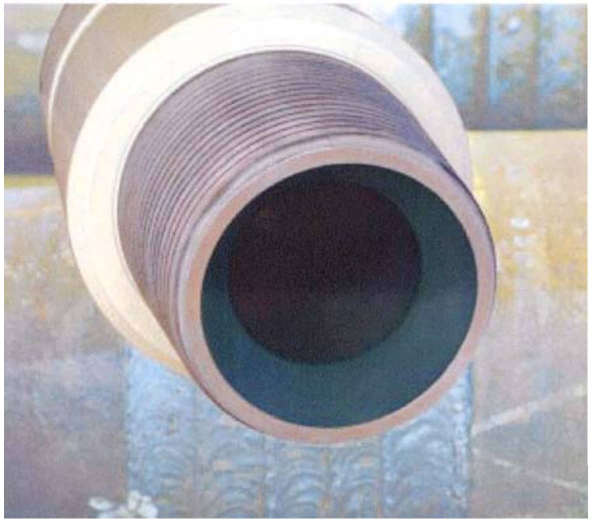
Threads



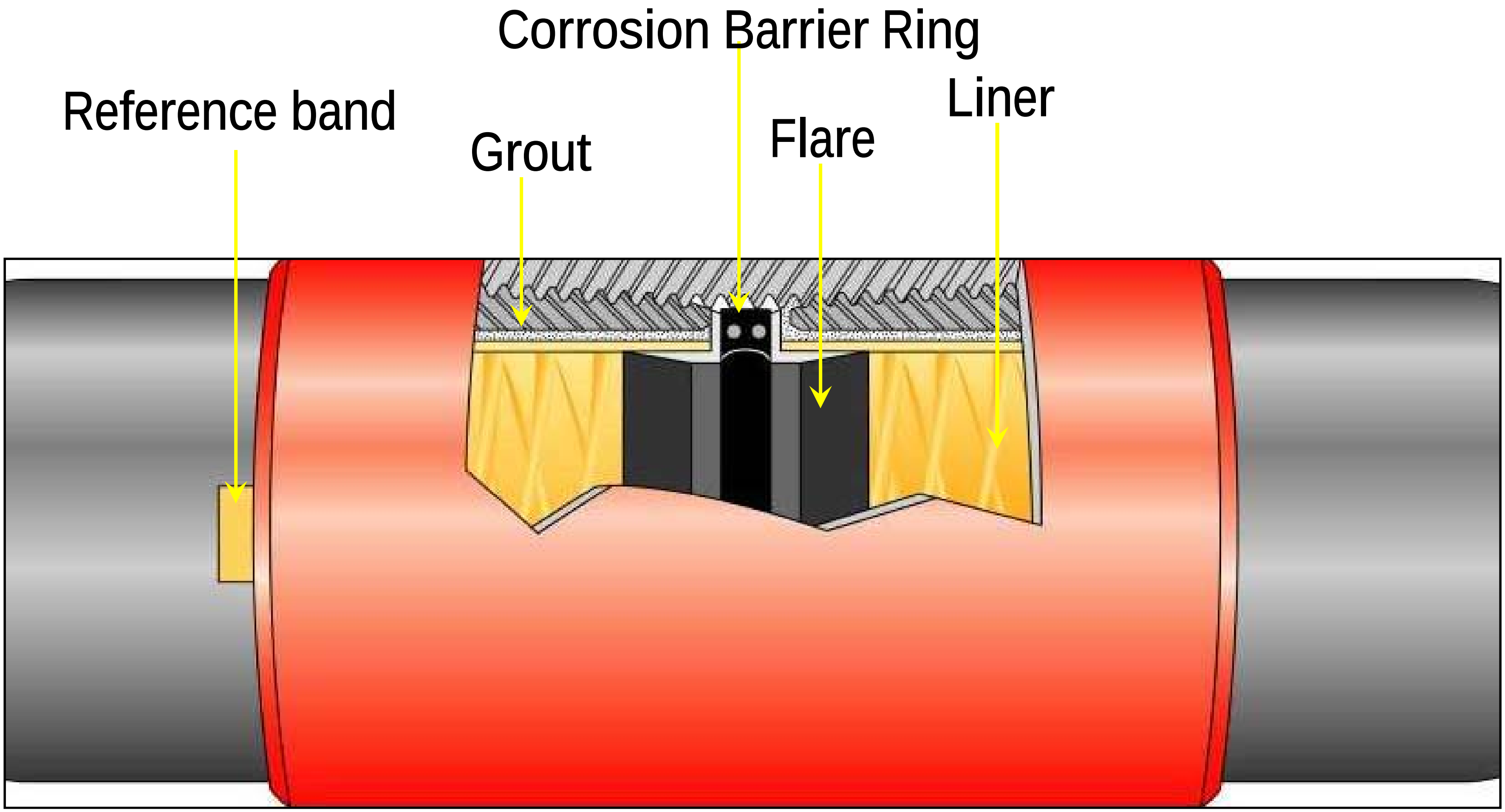
- Premium connections
  - Metal to metal seal
  - Gas-tight, resistance to severe well conditions, expensive
  - Manufactured outside API specification
  - Examples; Vam, Hydril, Teneris, Hunting

Commonly used anti corrosion coatings for tubing

- Coating types, phenolic, epoxy, urethane, nylon, fiberglass (GRE), HDPE & EXPE
- Thick film up to 25 – 30 mils
- Susceptible to damage from intervention
- Premium threads pose coating challenges
- Suppliers, Tuboscope, Bison, MasterKote & Rice Engineering



Tubing/ Coupling Protection



Rice Engineering “DUOLINE” EUE Connection With CB Ring

ENC Coatings

- Electroless nickel coating (ENC).
  - Has been used for coating downhole tools in CO_2 injection applications since the mid 1980’s in West Texas
  - Has excellent performance in CO_2 injection applications & is now being used in Acid Gas injection but too soon to determine long term performance
  - Resistant to $C0_2$ & moderate H_2S
  - Thickness ranges between .0001” and .003”
  - Surface hardness = 480 to 600 HV (resistant to erosion)
  - Cost is comparable to PFA & FEP coatings
  - An excellent alternative to CRA (corrosion resistant alloys) in many applications but not a replacement

Elastomers

- CO_2 has no chemical effect on elastomers but is easily compressed and can lead to explosive decompression damage in seals
- HNBR was in part developed to combat the effects of $C0_2$ exposure by offering better resistance to explosive decompression and to amine corrosion inhibitors
- Exposure to higher H_2S concentrations (>2%) tends to harden most elastomers such as NBR & HNBR therefore materials such as TFE/P (Aflas) are recommended for packer elements
- FFKM materials such as Kalrez and Chemraz are well suited for acid gas injection at all temperature ranges up to ~260^{o}C(500^{o}F)
- TFE/P (Aflas) is well suited for $C0_2$ but may be effected by the cool bottom hole temperatures on shallow and high rate injection wells
- Use the highest possible Shore A Durometer (hardness) elastomer as possible to minimize gas impregnation

Elastomers

•Both test samples were 90 durometer HNBR material but different blends from different vendors

•Autoclave Environment; 98% $C0_2$, 2% H_2S, 60K ppm Cl H20 for 40 hrs

Risk & Cost Matrix

CO_2/ Acid Gas Injection Well Risk & Cost Matrix	Injection Is Contained Within The Zone	Injection Out Of The Zone	Ability To Rotate During Cementing Ops.	Suitable For Use With Standard Injection Packer	Containment Confirmation with RA Tracer Log	Containment Confirmation with Temp Survey	Containment Confirmation Ultrasonic Cement Imaging	Time Expected	Cost Expected
Casing Size 177.8mm									
Liner cemented across the injection zone, cap rock and upper formation								**19 Days**	**$460K**
Liner cemented across the injection zone, cap rock and upper formation **with under reaming**								**23 Days**	**$660K**
Casing Size 139.7mm									
Liner cemented across the injection zone, cap rock and upper formation								**19 Days**	**$450K**
Liner cemented across the injection zone, cap rock and upper formation **with under reaming**								**23 Days**	**$670K**
Casing Size 114.3mm									
Liner cemented across the injection zone, cap rock and upper formation	Under Review	Under Review	Under Review	Under Review	Under Review	Under Review	Under Review	**Under Review**	**Under Review**
Liner cemented across the injection zone, cap rock and upper formation **with under reaming**			Under Review	Under Review				**Under Review**	**Under Review**

Probability Of Success Legend: Excellent | Good | Fair | Poor | N/A

Suitability Legend: Yes | No

Containment Confir. Legend: Yes | No

Best Practices

- Accurately determine the wellbore pressure/ temperature changes and model the optimum state to land the tubing in (tension where possible)
- Minimize (eliminate) the dynamic movement of down hole tool seals to improve performance and life expectancy of equipment
- Cement CRA casing joints across and well above the storage formation for setting of tools and external corrosion management
- Manage abrupt pressure changes to avoid explosive decompression of elastomers
- Properly selected permanent packer will perform better and out last retrievable packers and plugs

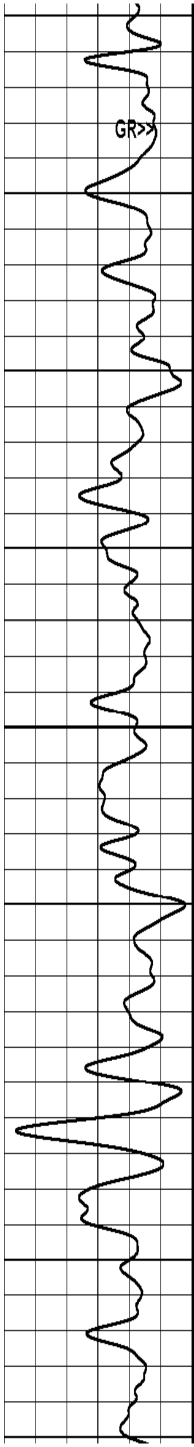
Conclusions

- A well bore of a minimum size and most any condition can be repaired and or converted for the purpose of $C0_2$ & acid gas injection
- Depleted reservoirs may be difficult to effectively cement (new or old wells)
- Better cement placement practices will yield better results regardless of cement type
- Proper material selection can balance costs with reliability & performance
- Risk and cost increase as casing size decreases

Thank you

Questions?

mwoitt@rpsgroup.com



Use of Alternative Cement Formulations

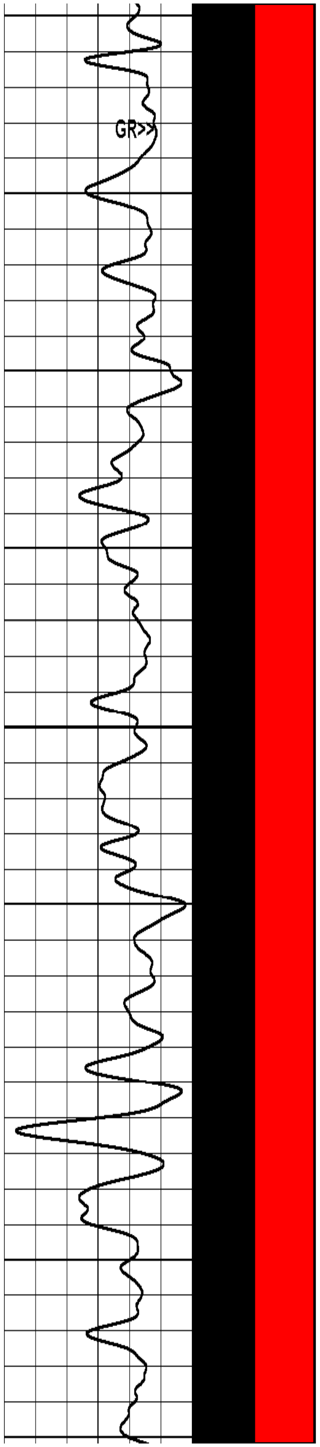
Don Getzlaf

Marty Stromquist

Cemblend Systems Inc.

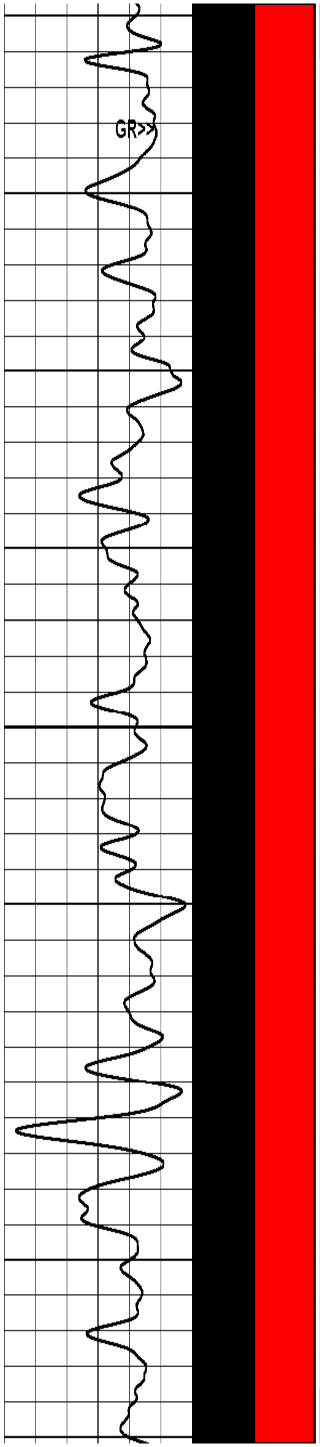
CEMBLEND SYSTEMS INC.

"Providing Cementing Solutions"

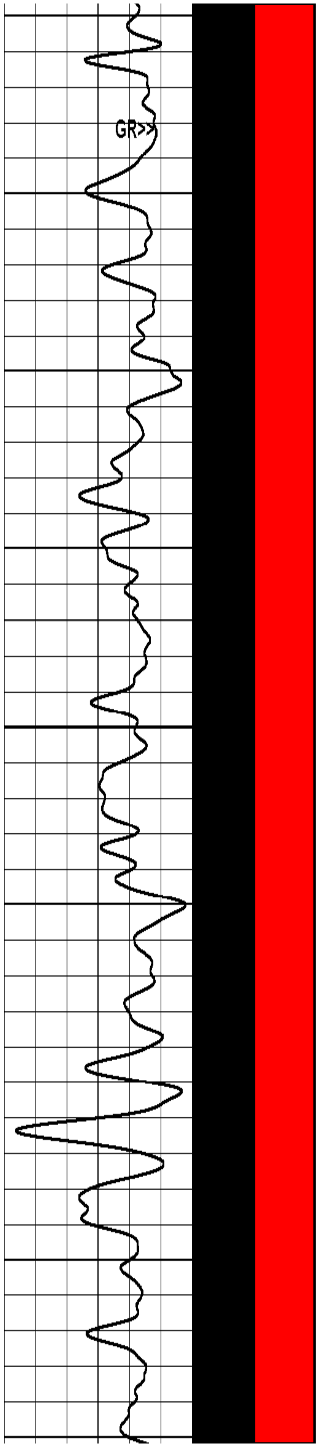


Wellbore

Removing formation
Removing drill fluids
Replacing with
Casing and Cementing



Portland



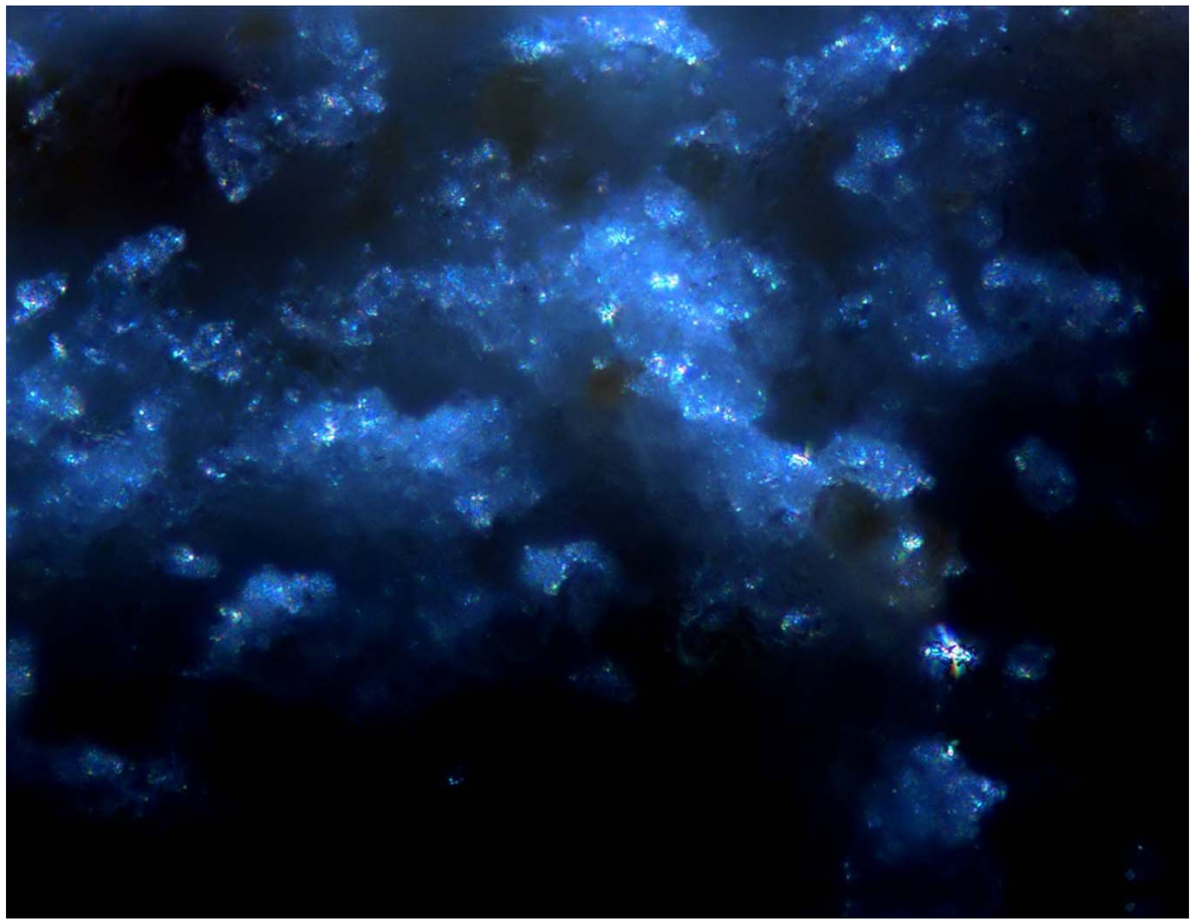
Cement History

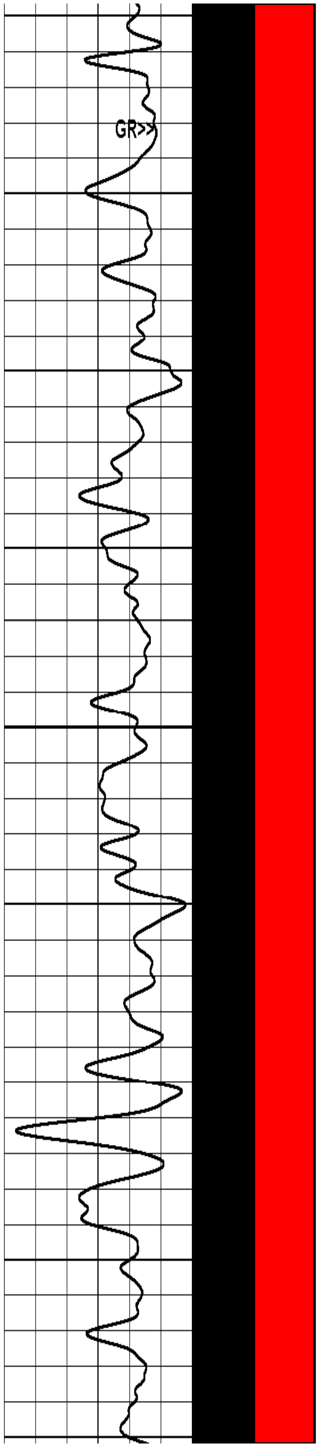
Bentonite
Silica
Foams
Latex

Flyash
Silicafume
Zeolites
Metakaolin
Beads

Fondu
Plaster

Chemically Bonded Phosphate Ceramics



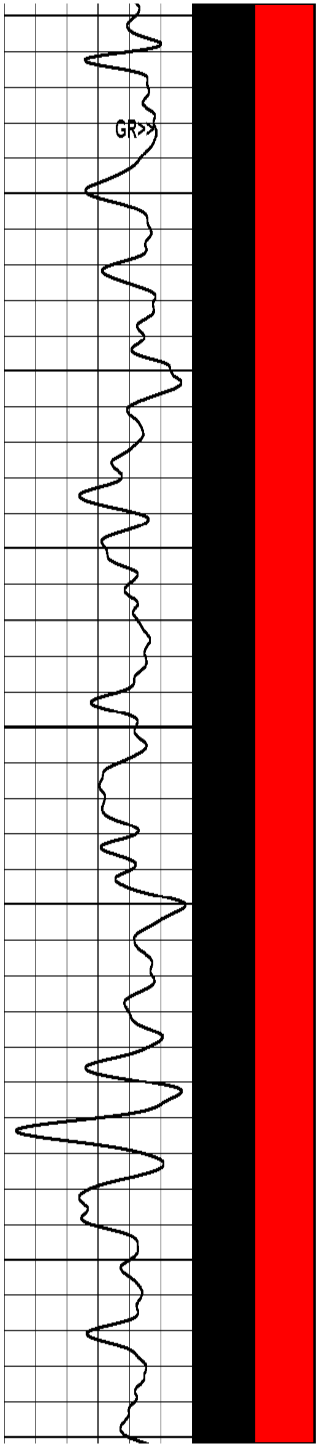


Development

ARGONNE NATIONAL LAB

Developed for

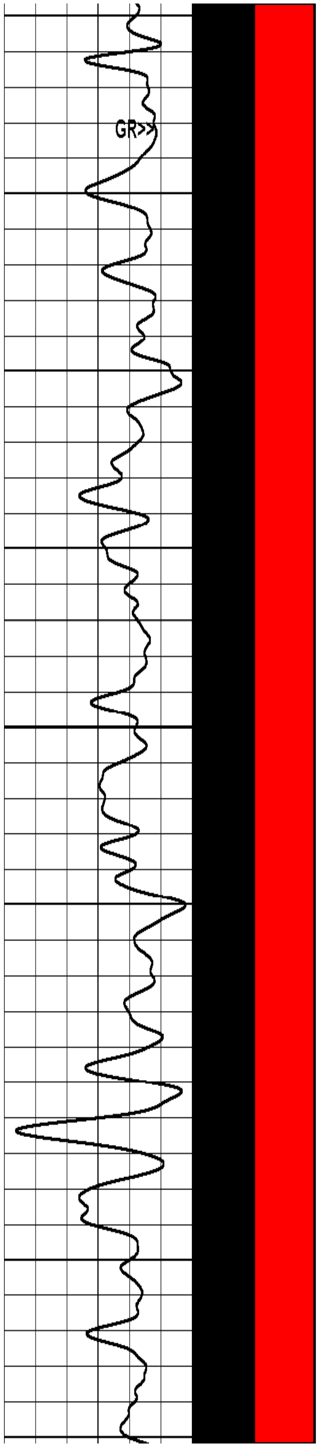
Nuclear waste containment



Development

Argonne saw benefits in:

- Good mechanical properties
- Unleachable
- Does not degrade over time
- Neutral PH
- Incorporate organics

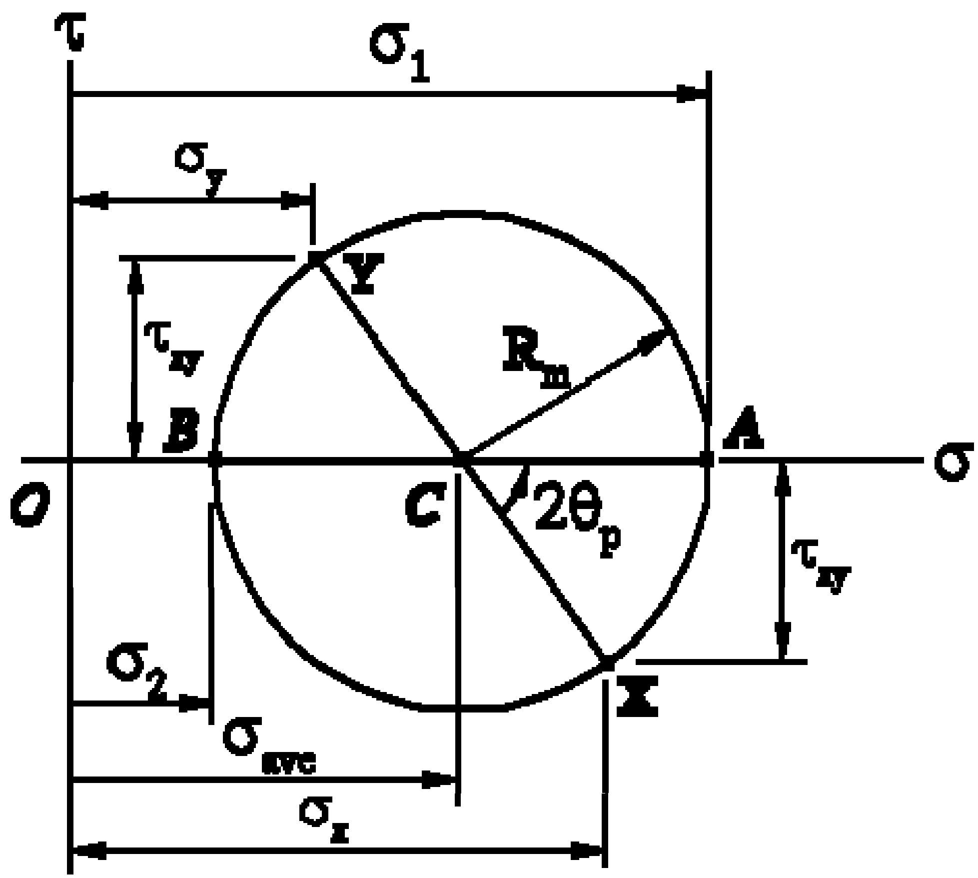


What we saw

Benefits in:

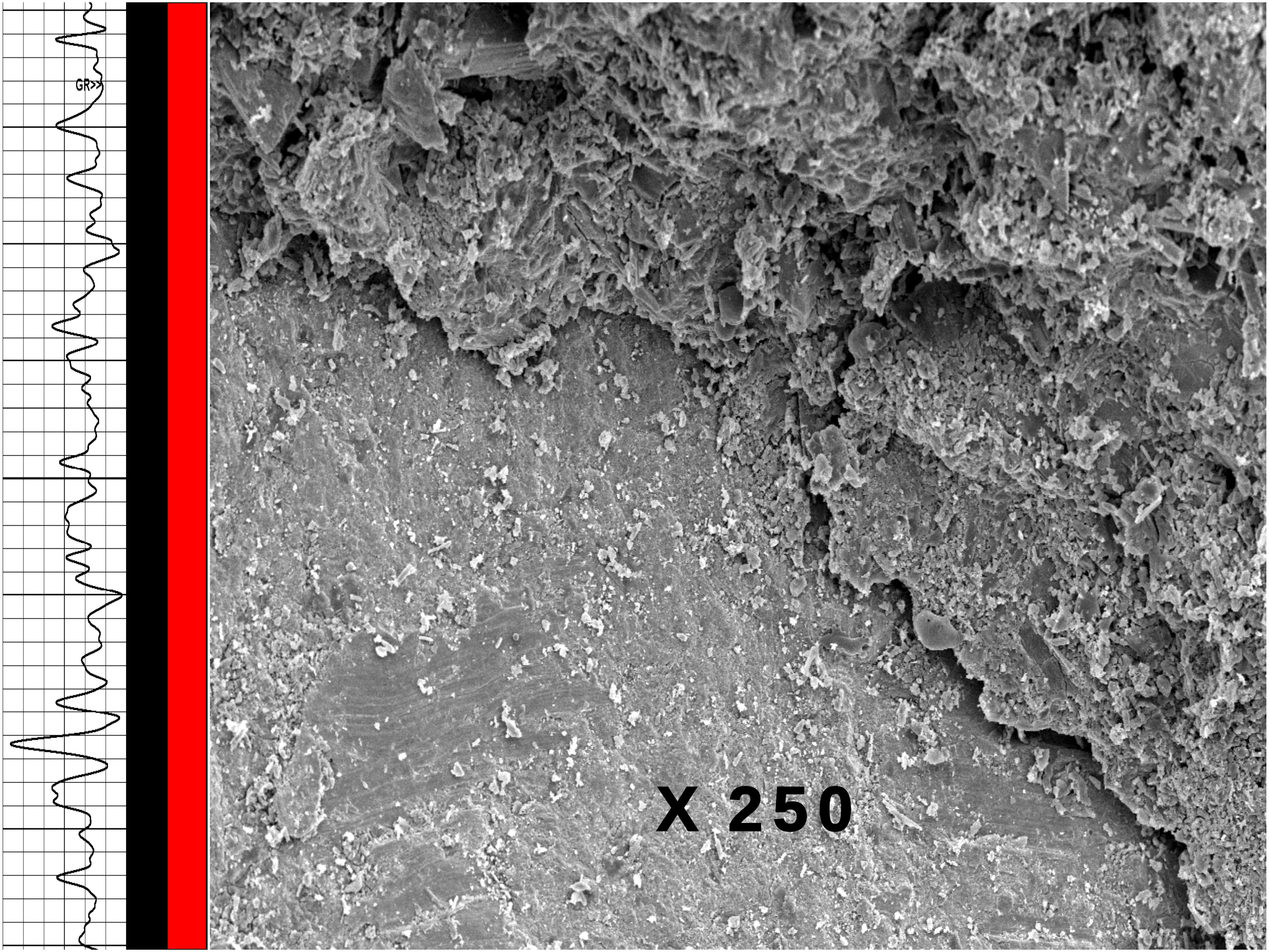
- Good mechanical properties
- Does not degrade over time
- Quick setting
- Incorporate organics (OBM)
- Covalent internal bond

Mechanic Properties



Bond Testing

Bond tests between 20^0 C and 315^0 C are Typically 3 – 5 times higher then Portland.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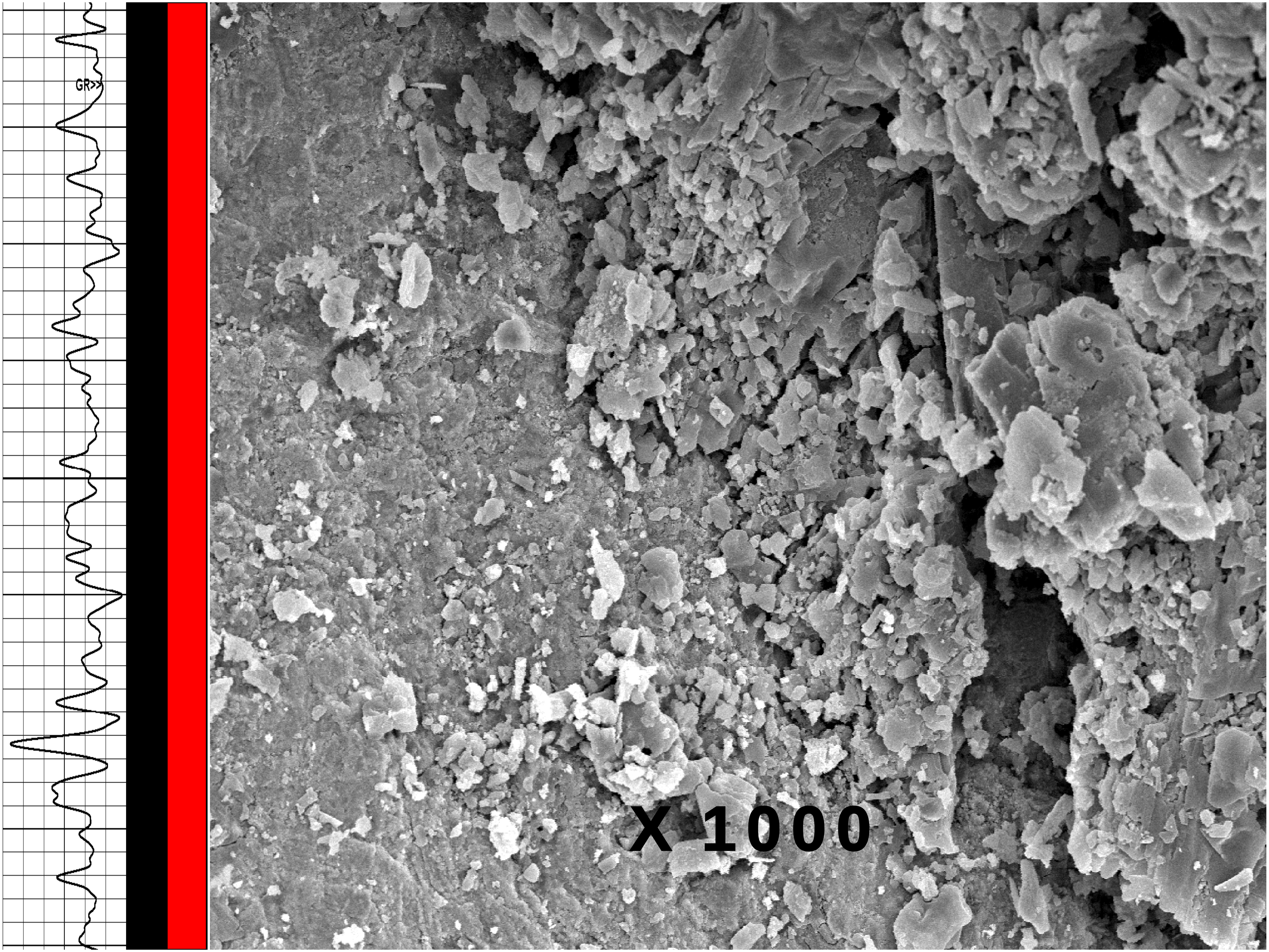
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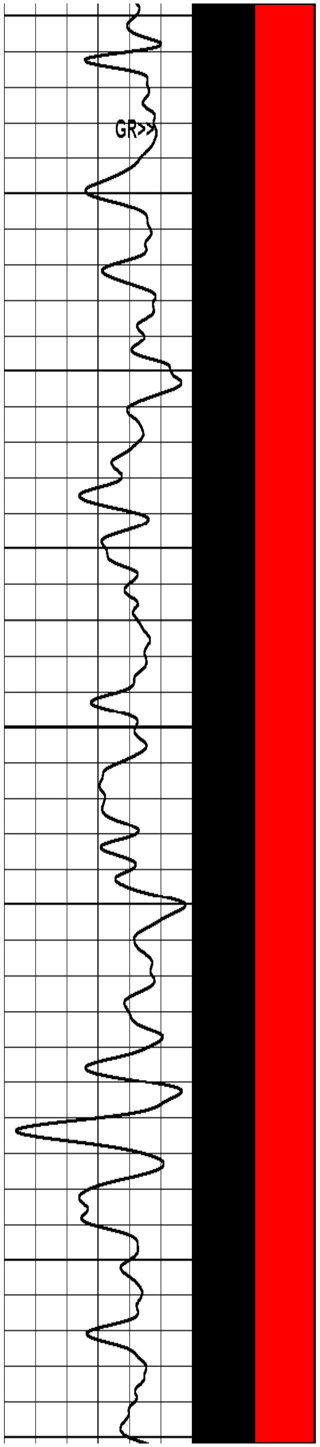
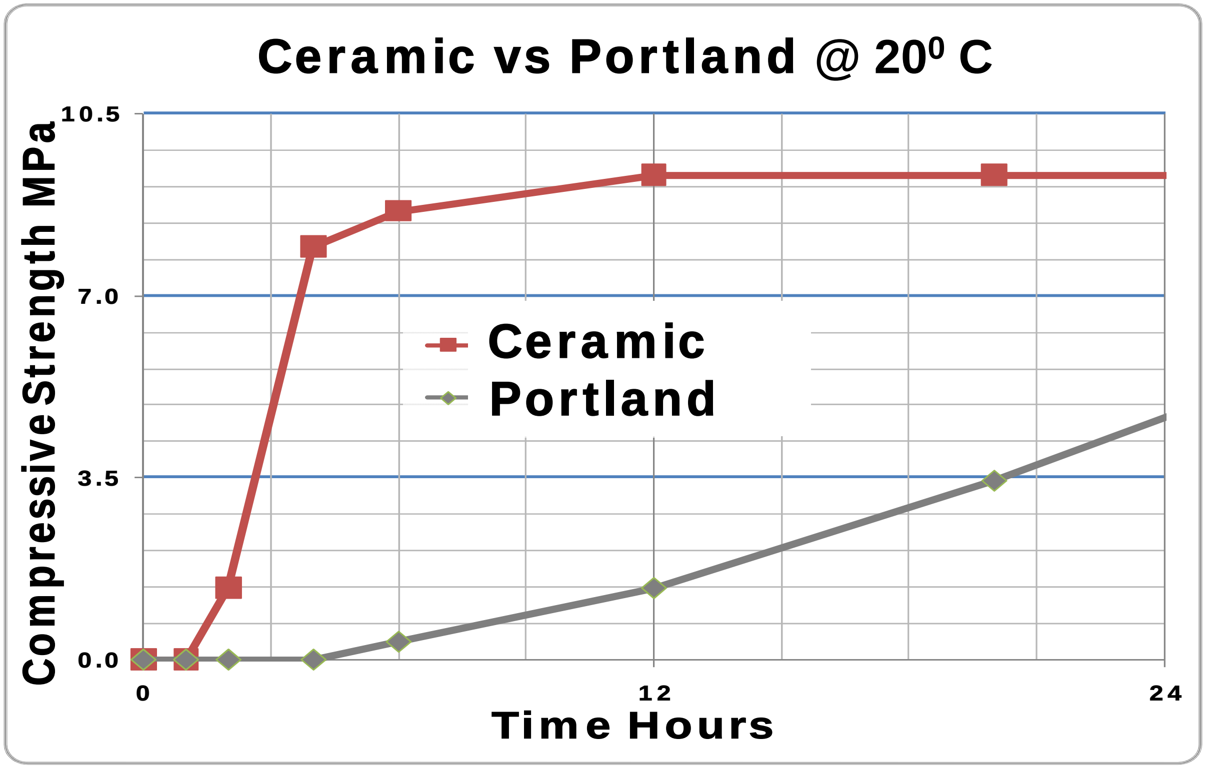
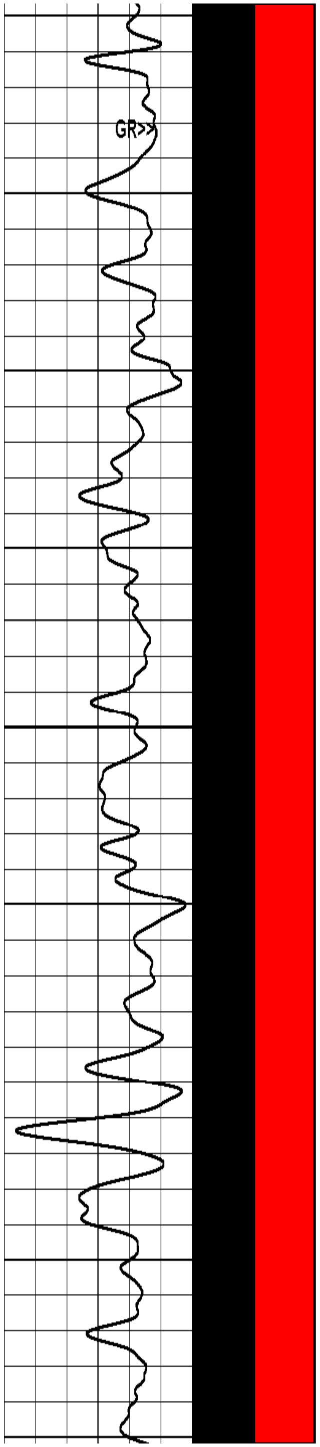


Strength

- Most of the strength is obtained in first few hours
- Slightly expanding





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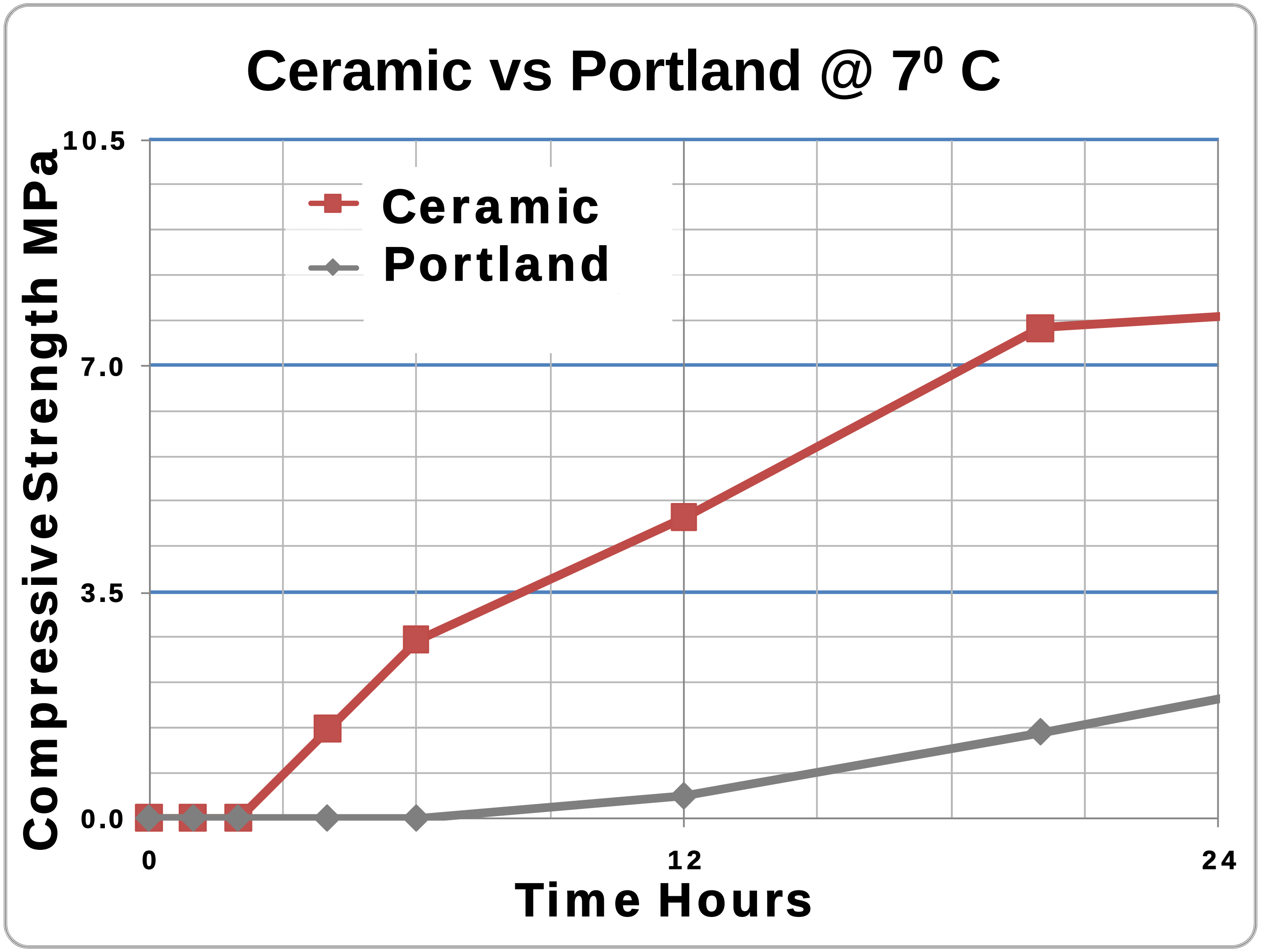
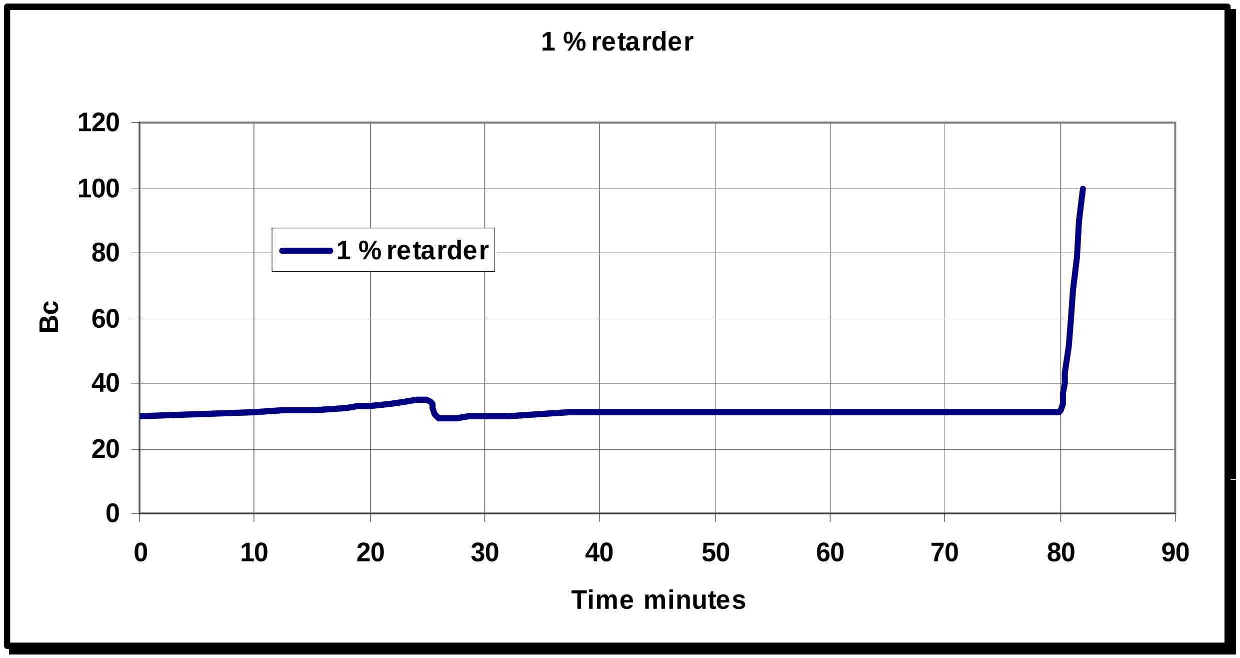
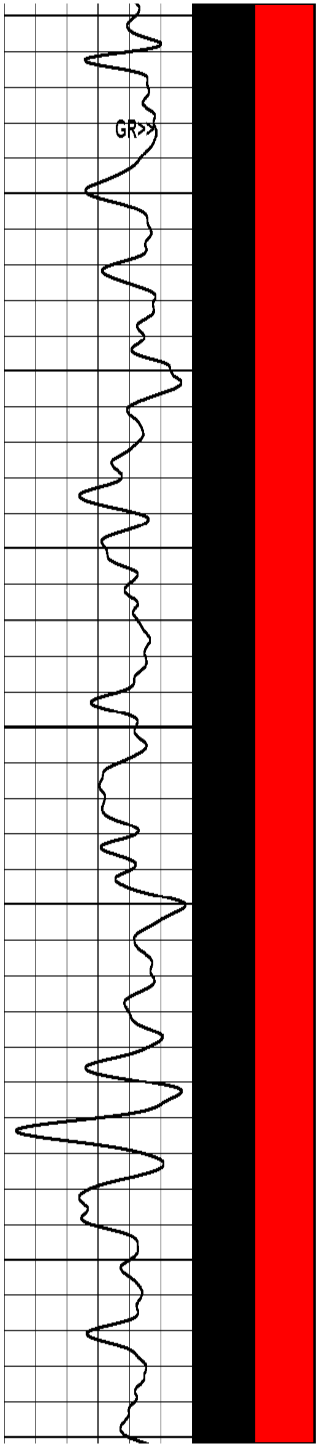


Ceramic vs Portland @ 7⁰ C
Compressive Strength MPa
10.5
7.0
3.5
0.0
0
12
24
Time Hours
Ceramic
Portland

Thickening time example

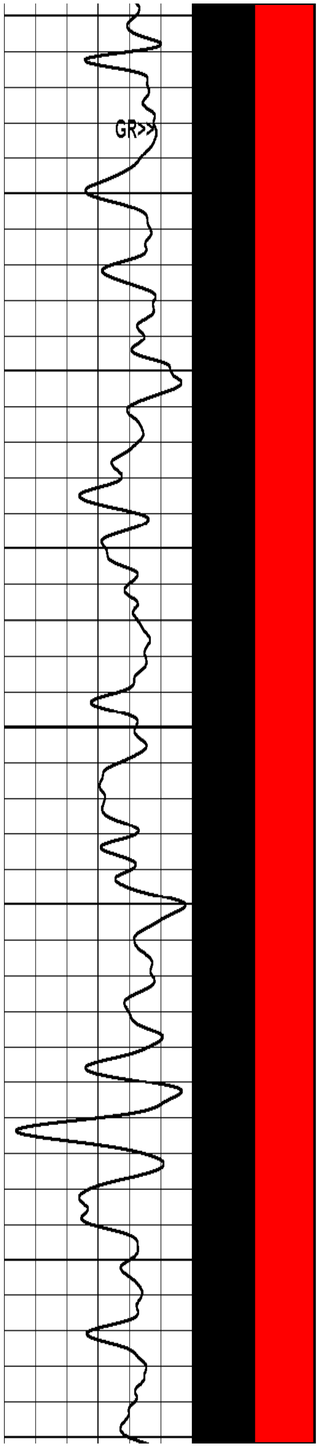


32 Bc to 100 Bc in 2 minutes
Bearden units of consistency



Other Properties

- Concentrated filter cake
- Compatible with most common drilling fluids and Portland cement
- Temperature independence
- Broad PH application



Latex Permeability

Flyash

Porosity Fondue Silica

Portland Tension

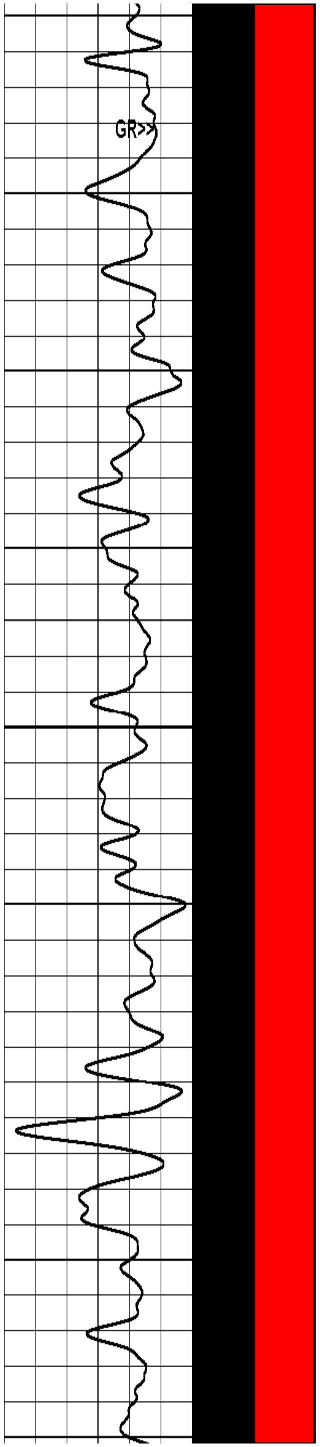
Silicafume Solubility

Metakaolin Ceramics

Beads Fibers

Bentonite Zeolite

IEA

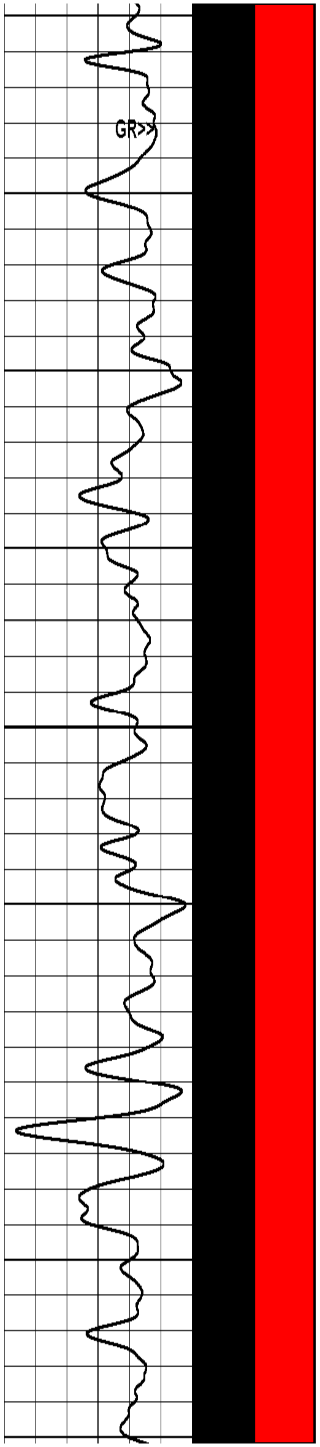


Where have we been

~100 remedial jobs completed

- Gas migration
- Casing repair
- Water conformance
- Vent repairs

Thickening time extended (6 hrs)



Where are ceramics going

Primary work

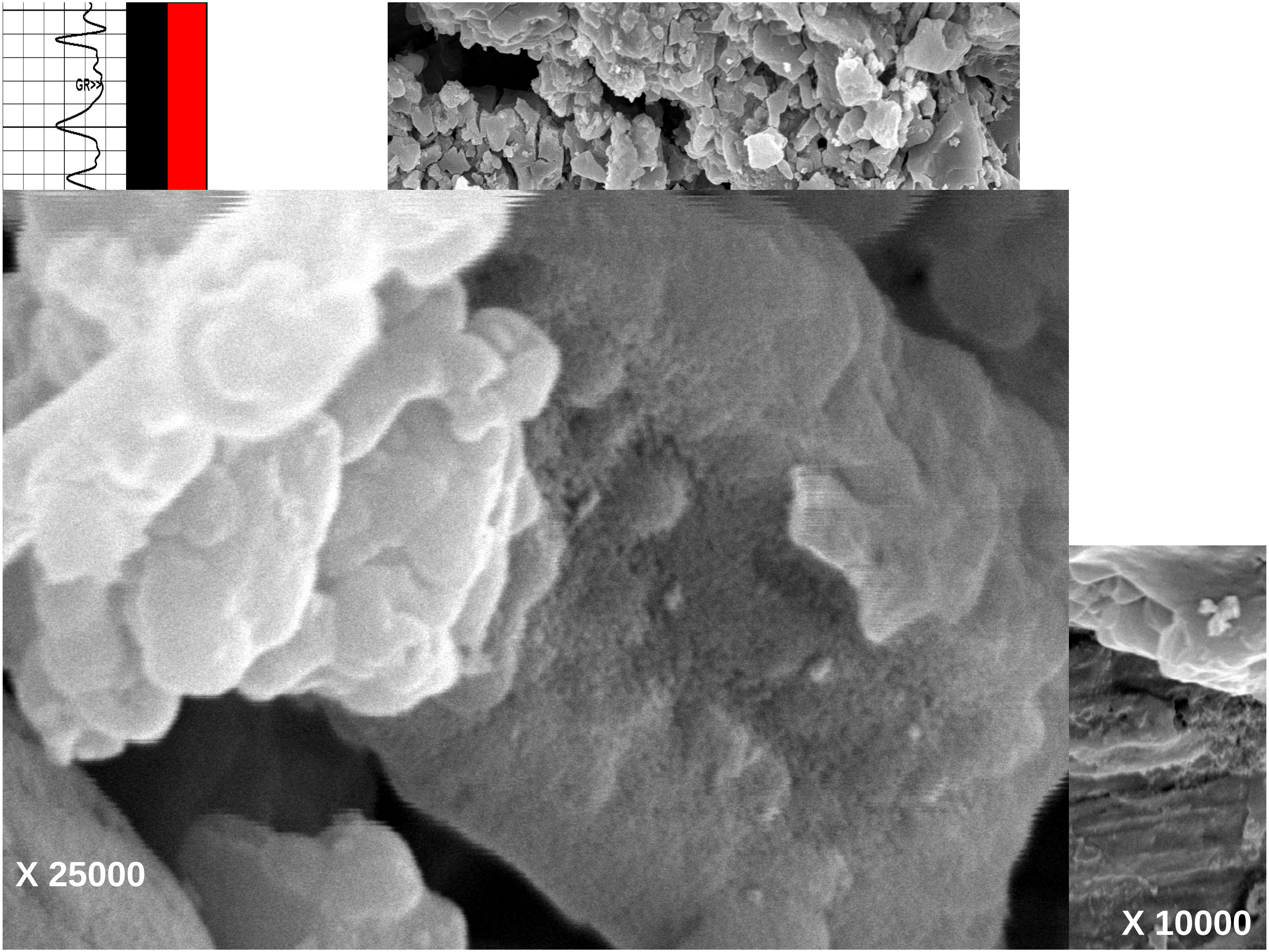
Thermal

Permafrost

Injection wells

Do “YOU” have a question?

CEMBLEND SYSTEMS INC.
"Providing Cementing Solutions"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X 25000
X 10000

Agenda

- Wellbore integrity
- Well design with annular integrity
- Well design without annular integrity
- Elastomers
- Coatings
- Threads
- Risk & Cost
- Best practices
- Conclusions

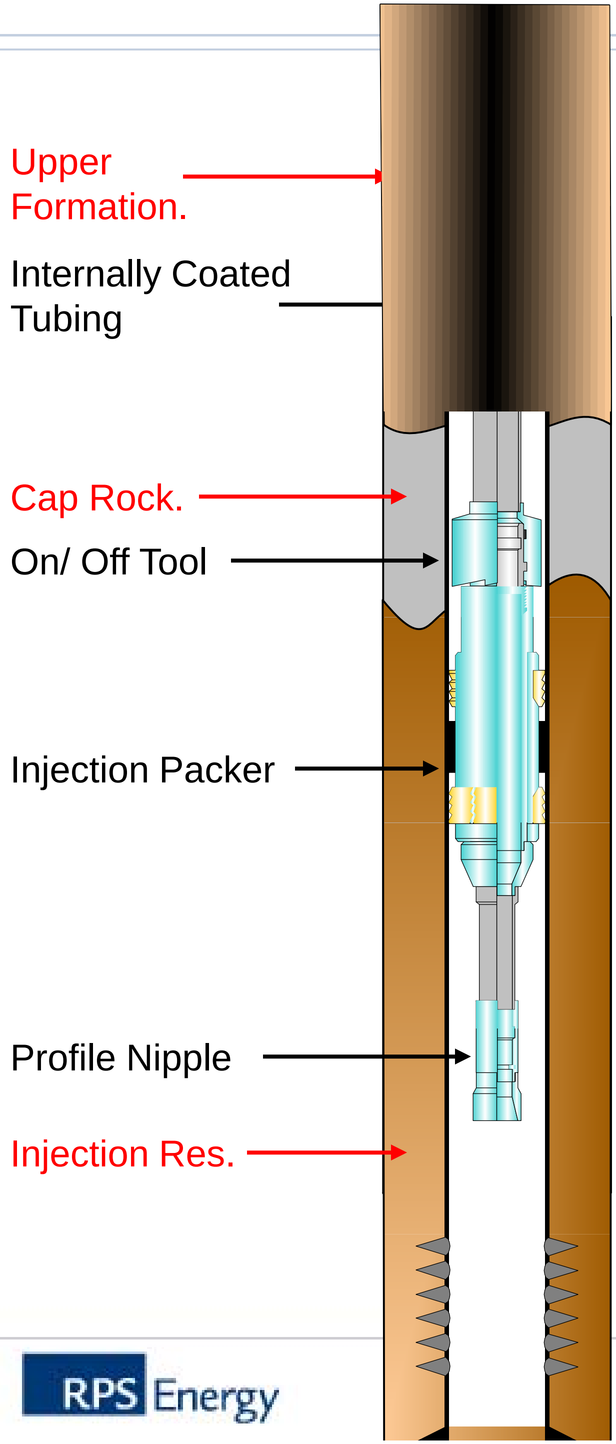
Well Bore Integrity

- The issue of cement integrity and bonding as well as cap rock competency/ integrity are outside the scope of this presentation and will therefore focus on the conversion and repair of wells for injection !

Well Bore Integrity

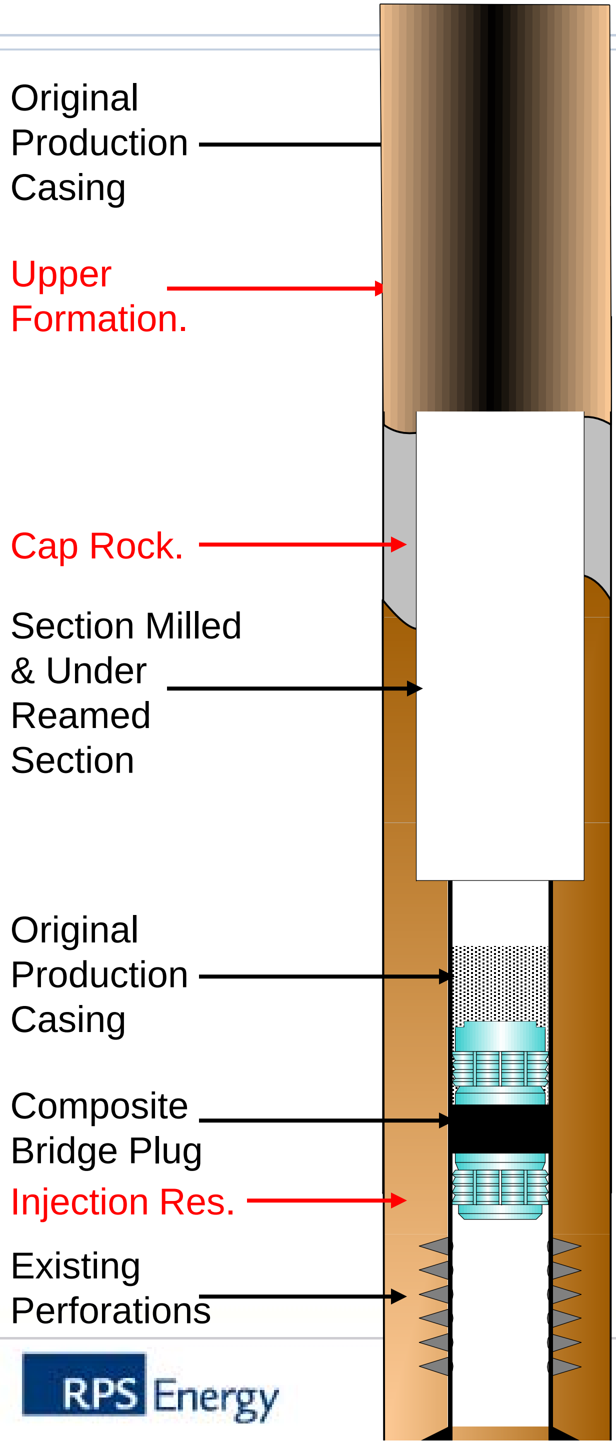
- Well bore failures are either external or internal.
  - External failure could occur as a result of;
    - Leakage via cement channeling/ deteriation (poor primary cement)
    - External casing corrosion (incorrect cement formulation)
    - Casing thread leaks (wet $C0_2$ in reservoir)
  - Internal failure
    - Packer leak
    - Tubing leak
    - Corrosion (wet $C0_2$ in flow stream and or reservoir)

Design With Annular Integrity



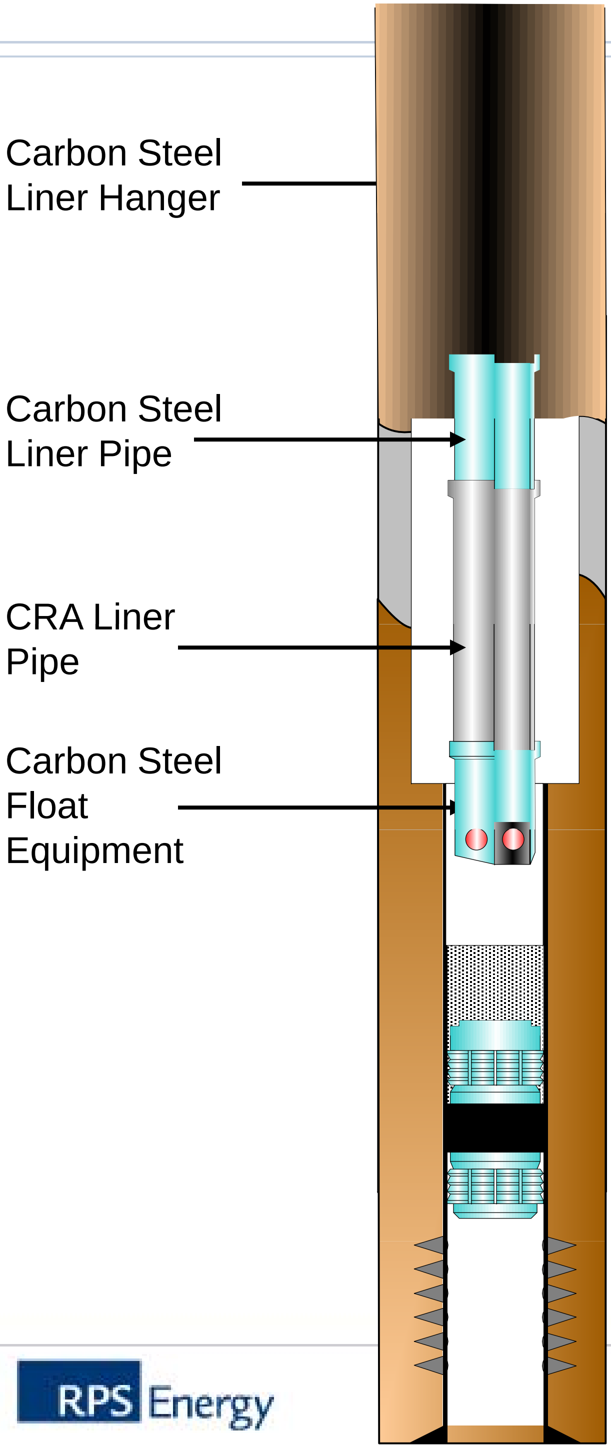
- This injection well example assumes that cement quality and bond were acceptable, external casing condition is good and is suitable for internal conversion
- The existing completion is pulled and the well is prepped for conversion to injection by cleaning and stimulating if necessary
- An injection packer is set high enough to facilitate monitoring logging but must be kept within the injection zone to provide annular pressure isolation to the top of that zone

Design Without Annular Integrity



- This example assumes that near well bore annular communication/ channeling exists and must be repaired outside the well bore but within the bore hole
- Existing production casing must be of fair or better condition
- Previous failed completion to be removed and well prepped for workover
- Set composite material bridge plug above the perforations to isolate injection interval
- Section mill (remove) the production casing across the upper section of the injection zone and past the cap rock
- Under ream back to the original bore hole to expose uncontaminated rock

Design Without Annular Integrity

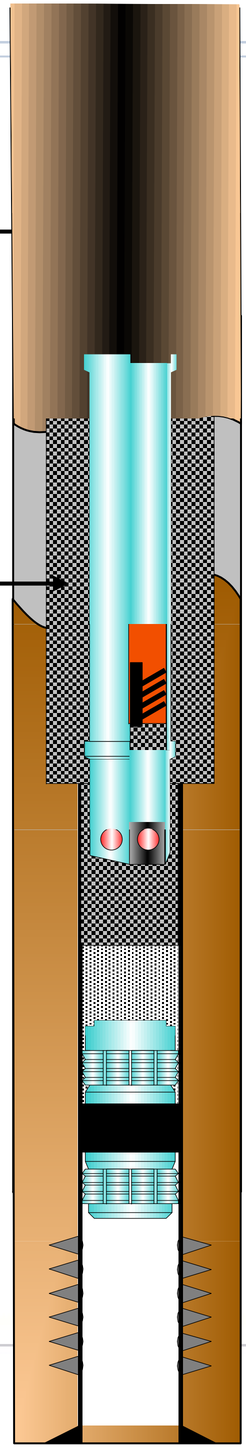


- Run a conventional rotating liner hanger with standard cementing float equipment
- Liner hanger and float equipment can be low alloy carbon steel
- The liner pipe across the injection zone and into the cap rock should be CRA (corrosion resistant alloy) to prevent internal/ external corrosion and facilitate setting of the injection packer thereby mitigating internal corrosion as well

Design Without Annular Integrity

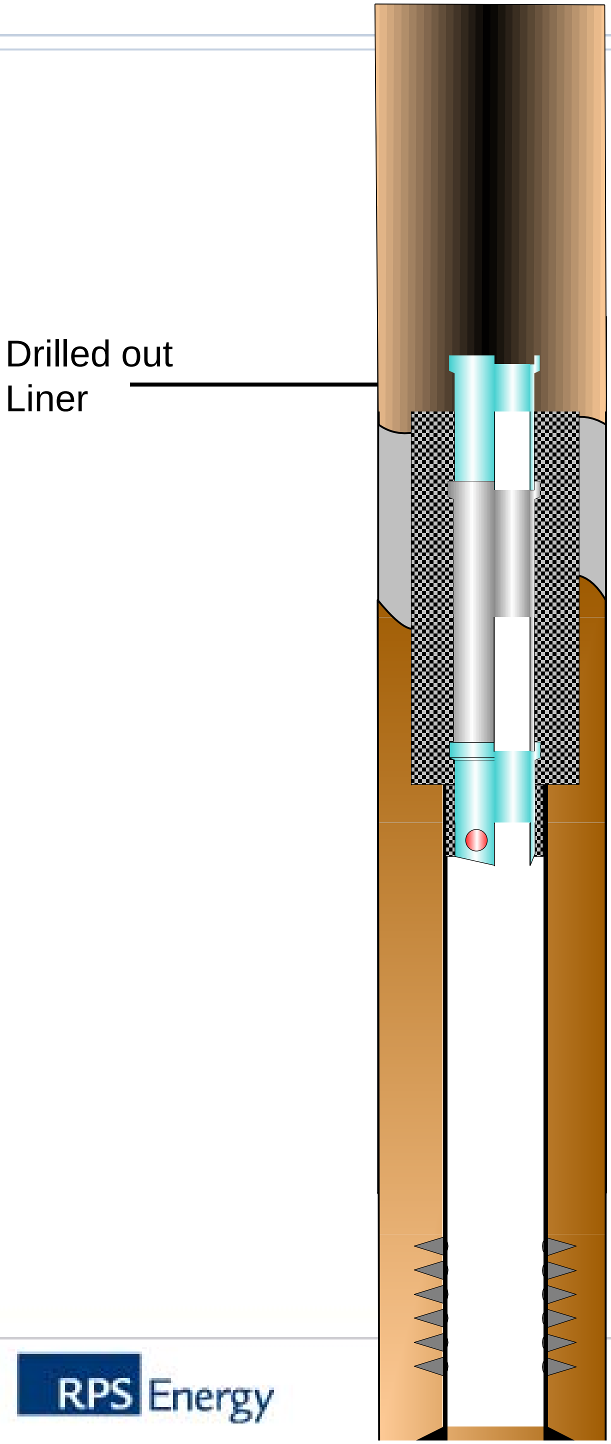
Displacement Fluid (Mud)

CO_2 & Acid Gas Resistant Cement



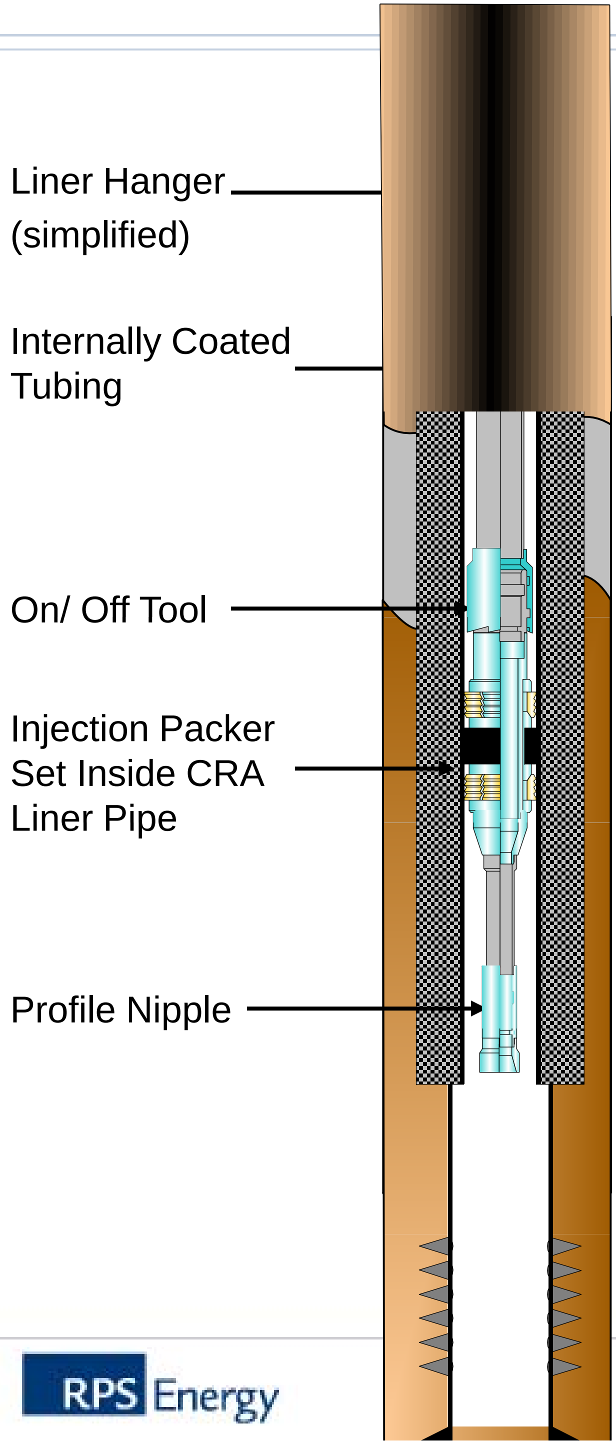
- Rotate the liner during cement displacement to improve the cement bond with the pipe and bore hole by reducing laminar flow
- Keep the liner well centralized to improve liner concentricity within bore hole
- Use CO_2 and acid gas resistant cement

Design Without Annular Integrity



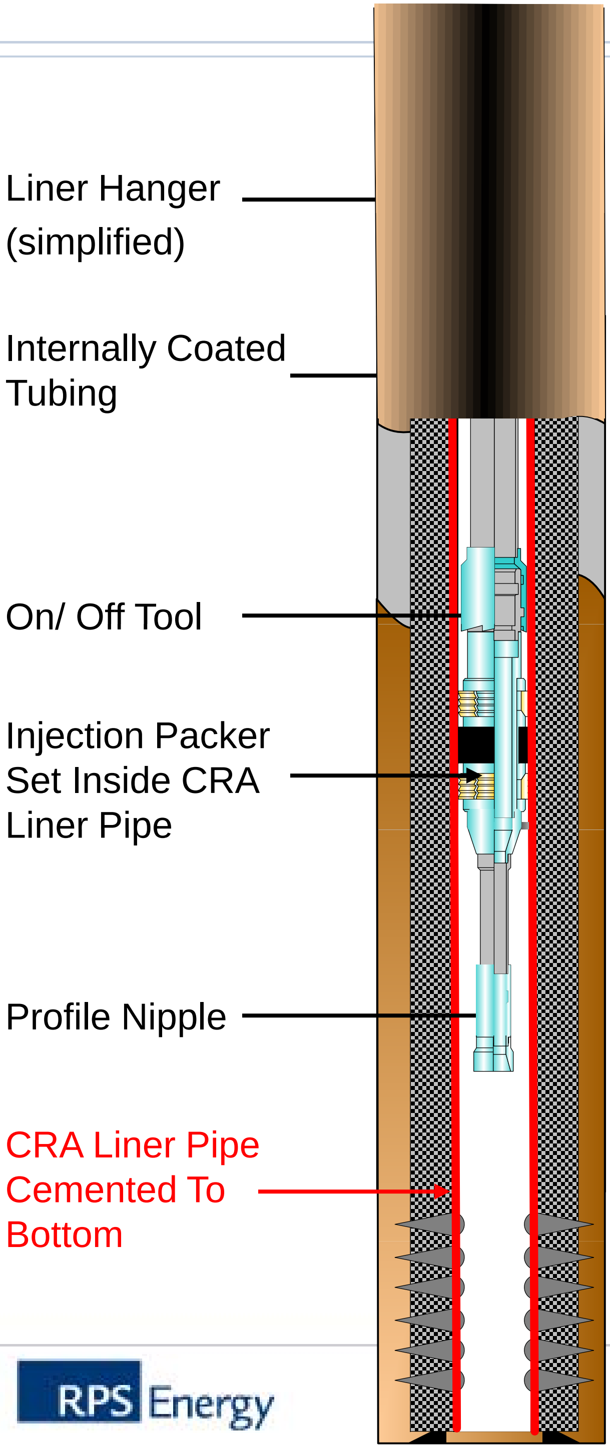
- Drill out excess cement from the production casing to top of liner
- Drill out cement inside the liner and float equipment
- Pressure test the liner and cement job to confirm integrity
- Drill to top of the composite bridge plug and circulate clean
- Run under reamer and drill out the composite bridge plug and clean to bottom.
- Stimulate the perforated interval if required
- Run cement integrity, tracer & temp logs to confirm annular integrity

Design Without Annular Integrity

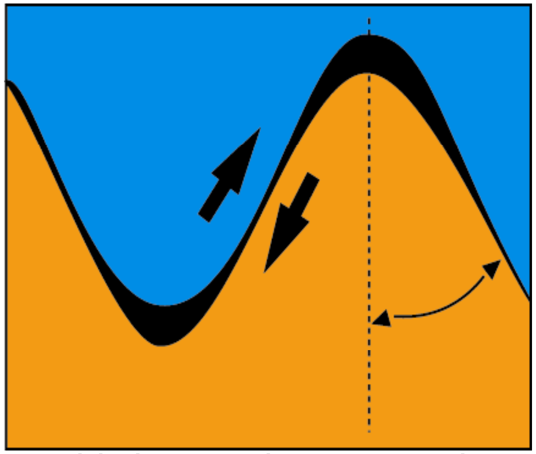


- Run the injection packer on wireline or work string
- Set the packer near the bottom of the CRA casing
- Run the internally coated injection tubing and latch onto the packer
- Pressure tested to confirm annular integrity and land in the optimum (modeled) condition to minimize or eliminate tubing cycling

Design Without Annular Integrity



- This example assumes the original production is poor to very poor condition and will not allow down hole tools to be set
- The well is under reamed across the perforated interval and the liner cemented accordingly
- Re-perforating and possible stimulation will be required
- Controlling fluid and cement losses will be difficult in depleted reservoirs and may require creative temporary plugging techniques to hold cement in place while setting
- Need to consider how those losses will affect the injectivity post workover



This image shows an 8rd thread and the Helix seal formed at the crest of the thread forming the dope seal.

Eue Pin Thread

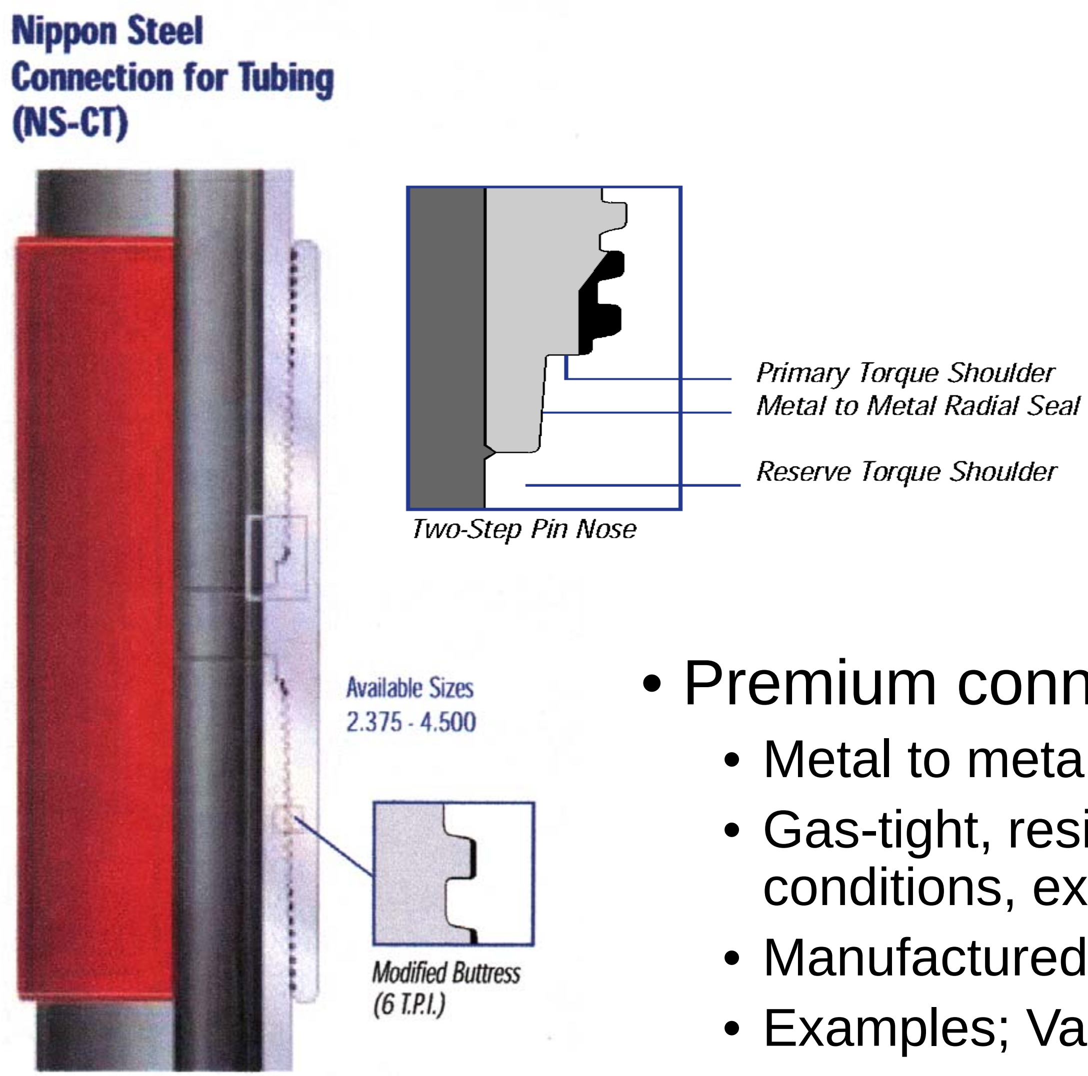
Threads

- API Connections
  - Round thread type
  - Buttress thread type
  - Sealing relies on thread compound/dope
  - Examples; EUE, LTC, BTC
  - Should not be used without additional sealing aids for $C0_2$ & Acid Gas injection
  - **Should not be used for casing threads**

PTFE insert protects the bare threads from corrosion

MMS Coupling

Threads

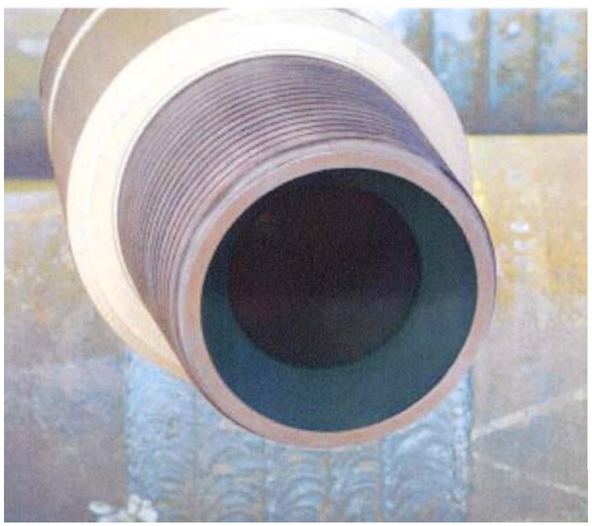


- Premium connections
  - Metal to metal seal
  - Gas-tight, resistance to severe well conditions, expensive
  - Manufactured outside API specification
  - Examples; Vam, Hydril, Teneris, Hunting

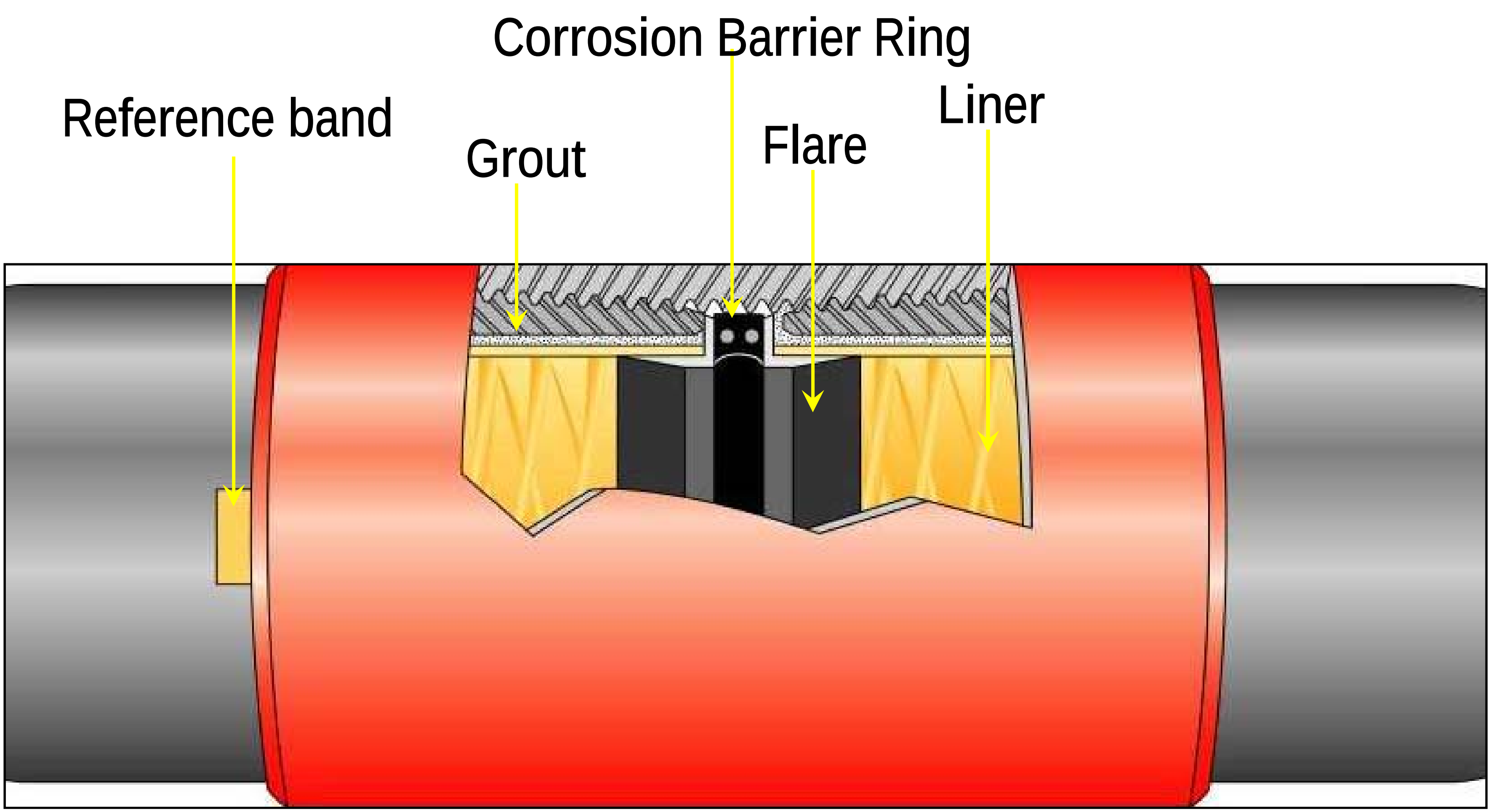
Tubing Coatings

Commonly used anti corrosion coatings for tubing

- Coating types, phenolic, epoxy, urethane, nylon, fiberglass (GRE), HDPE & EXPE
- Thick film up to 25 – 30 mils
- Susceptible to damage from intervention
- Premium threads pose coating challenges
- Suppliers, Tuboscope, Bison, MasterKote & Rice Engineering



Tubing/ Coupling Protection



Rice Engineering "DUOLINE" EUE Connection With CB Ring

ENC Coatings

- Electroless nickel coating (ENC).
  - Has been used for coating downhole tools in CO_2 injection applications since the mid 1980's in West Texas
  - Has excellent performance in CO_2 injection applications & is now being used in Acid Gas injection but too soon to determine long term performance
  - Resistant to $C0_2$ & moderate H_2S
  - Thickness ranges between .0001" and .003"
  - Surface hardness = 480 to 600 HV (resistant to erosion)
  - Cost is comparable to PFA & FEP coatings
  - An excellent alternative to CRA (corrosion resistant alloys) in many applications but not a replacement

Elastomers

•CO_2 has no chemical effect on elastomers but is easily compressed and can lead to explosive decompression damage in seals

•HNBR was in part developed to combat the effects of $C0_2$ exposure by offering better resistance to explosive decompression and to amine corrosion inhibitors

•Exposure to higher H_2S concentrations (>2%) tends to harden most elastomers such as NBR & HNBR therefore materials such as TFE/P (Aflas) are recommended for packer elements

•FFKM materials such as Kalrez and Chemraz are well suited for acid gas injection at all temperature ranges up to ~260^{o}C(500^{o}F)

•TFE/P (Aflas) is well suited for $C0_2$ but may be effected by the cool bottom hole temperatures on shallow and high rate injection wells

•Use the highest possible Shore A Durometer (hardness) elastomer as possible to minimize gas impregnation

Elastomers

- Both test samples were 90 durometer HNBR material but different blends from different vendors
- Autoclave Environment; 98% $C0_2$, 2% H_2S, 60K ppm Cl H20 for 40 hrs

Risk & Cost Matrix

CO_2/ Acid Gas Injection Well Risk & Cost Matrix

	Injection Is Contained Within The Zone	Injection Out Of The Zone	Ability To Rotate During Cementing Ops.	Suitable For Use With Standard Injection Packer	Containment Confirmation with RA Tracer Log	Containment Confirmation with Temp Survey	Containment Confirmation Ultrasonic Cement Imaging	Time Expected	Cost Expected
Casing Size 177.8mm									
Liner cemented across the injection zone, cap rock and upper formation								**19 Days**	**$460K**
Liner cemented across the injection zone, cap rock and upper formation **with under reaming**								**23 Days**	**$660K**
Casing Size 139.7mm									
Liner cemented across the injection zone, cap rock and upper formation								**19 Days**	**$450K**
Liner cemented across the injection zone, cap rock and upper formation **with under reaming**								**23 Days**	**$670K**
Casing Size 114.3mm									
Liner cemented across the injection zone, cap rock and upper formation	Under Review	Under Review	Under Review	Under Review	Under Review	Under Review	Under Review	**Under Review**	**Under Review**
Liner cemented across the injection zone, cap rock and upper formation **with under reaming**			Under Review	Under Review				**Under Review**	**Under Review**

Probability Of Success Legend: Excellent | Good | Fair | Poor | N/A

Suitability Legend: Yes | No

Containment Confir. Legend: Yes | No

RPS Energy

Simplified Version For Presentation Purposes

rpsgroup/canada

Best Practices

- Accurately determine the wellbore pressure/ temperature changes and model the optimum state to land the tubing in (tension where possible)
- Minimize (eliminate) the dynamic movement of down hole tool seals to improve performance and life expectancy of equipment
- Cement CRA casing joints across and well above the storage formation for setting of tools and external corrosion management
- Manage abrupt pressure changes to avoid explosive decompression of elastomers
- Properly selected permanent packer will perform better and out last retrievable packers and plugs

Conclusions

- A well bore of a minimum size and most any condition can be repaired and or converted for the purpose of $C0_2$ & acid gas injection
- Depleted reservoirs may be difficult to effectively cement (new or old wells)
- Better cement placement practices will yield better results regardless of cement type
- Proper material selection can balance costs with reliability & performance
- Risk and cost increase as casing size decreases

Thank you

Questions?

mwoitt@rpsgroup.com

Seal Well Inc.

A Convenient Truth

Creating Well Plugs to Contain CO_2 and Other Acid Gases

Homer L. Spencer, P.Eng.
Calgary, AB

Phone: (403) 616-5247
E-Mail: hlspencer@shaw.ca

- Alberta basin water slightly alkaline
- Stored CO_2 will drop the pH
- Injected CO_2 damages cement and steel

- Seal CO_2 storage wells with Bi:Sn
- Cast expanding alloy plugs in situ
- Seal resists >6000psig
- Alloy passivates
- Longevity in shut-in pH 3 brines >10,000 years

Bi:Sn alloy has the following remarkable combination of properties that makes it ideal for sealing wells against gas flow:

- **Expands 1.4% by volume**
- **Can be squeezed and absorbed into permeable rock**
- **Fills small fissures very efficiently**
- **Components are non-toxic and environmentally safe**
- **Does not cause galvanic corrosion in contact with steel.**

Creating a Plug to Seal Wells in CO_2 Storage Projects, 1/4

Seal Well Inc.

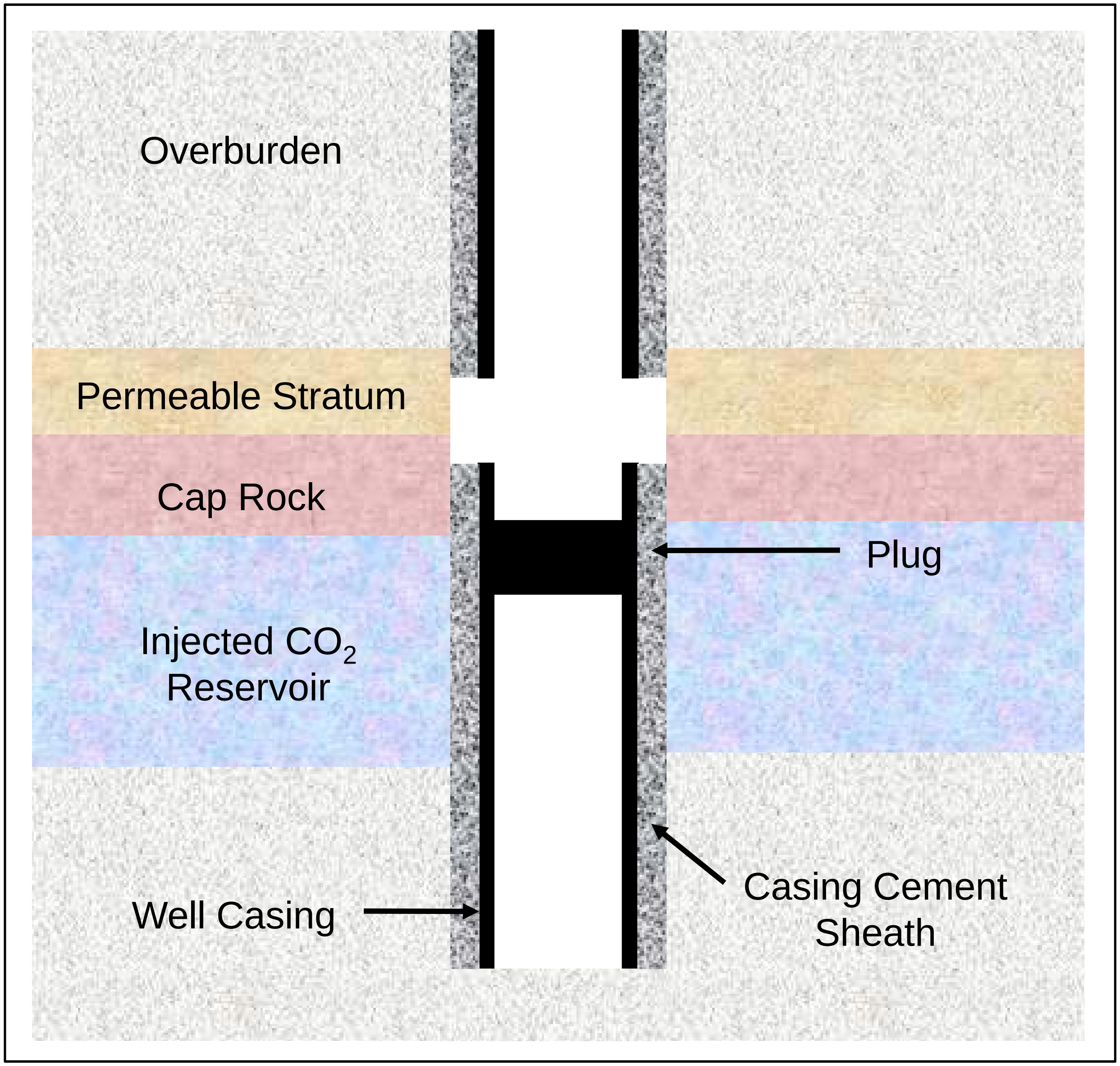


Figure 1:

Well with a window milled through the casing wall and cement sheath

Creating a Plug to Seal Wells in CO_2 StorageProjec ts, 2/4

Seal Well Inc.

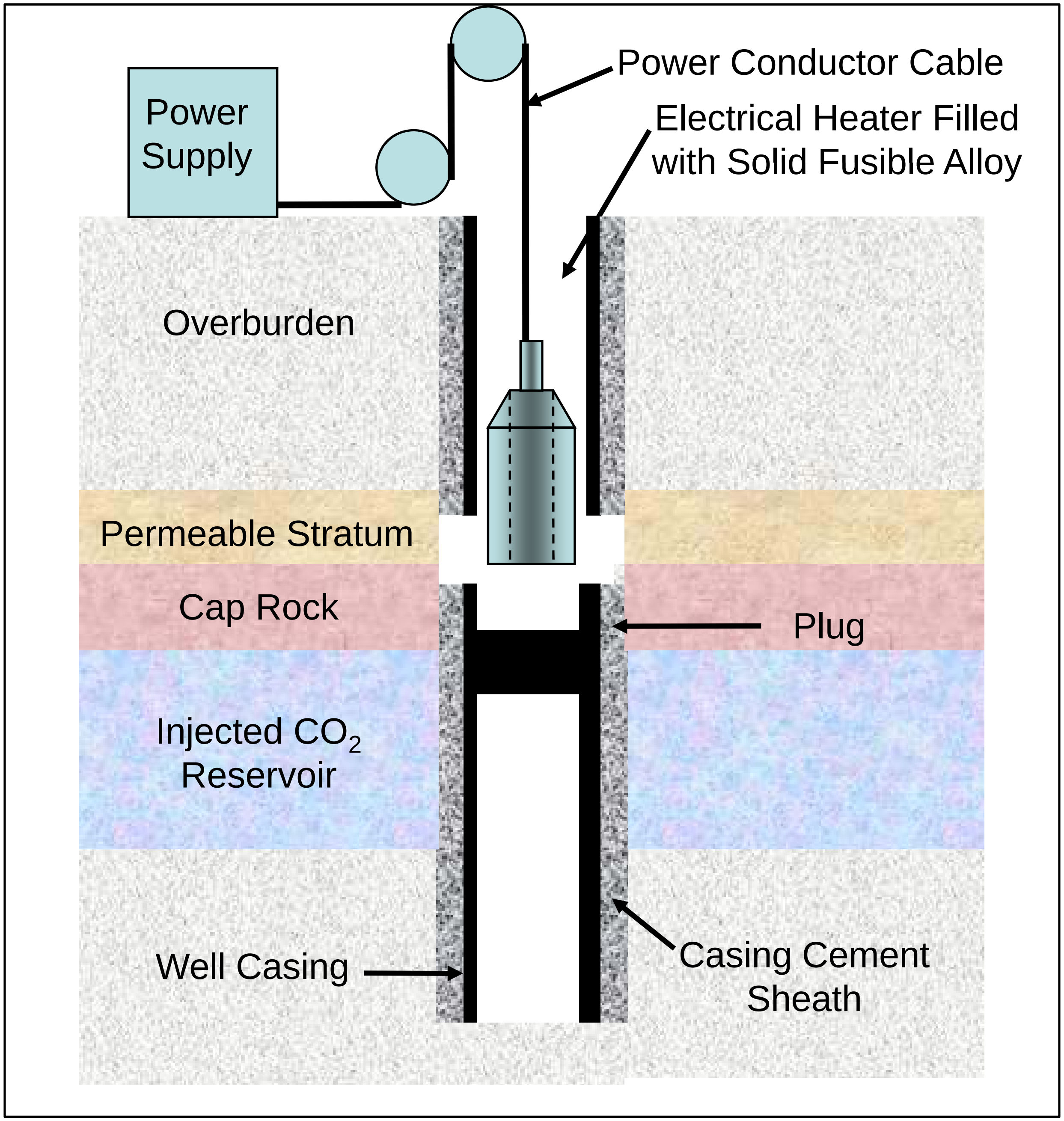


Figure 2:

Electrical heater and solid fusible alloy deployed into well

Creating a Plug to Seal Wells in CO_2 Storage Projects, 3/4

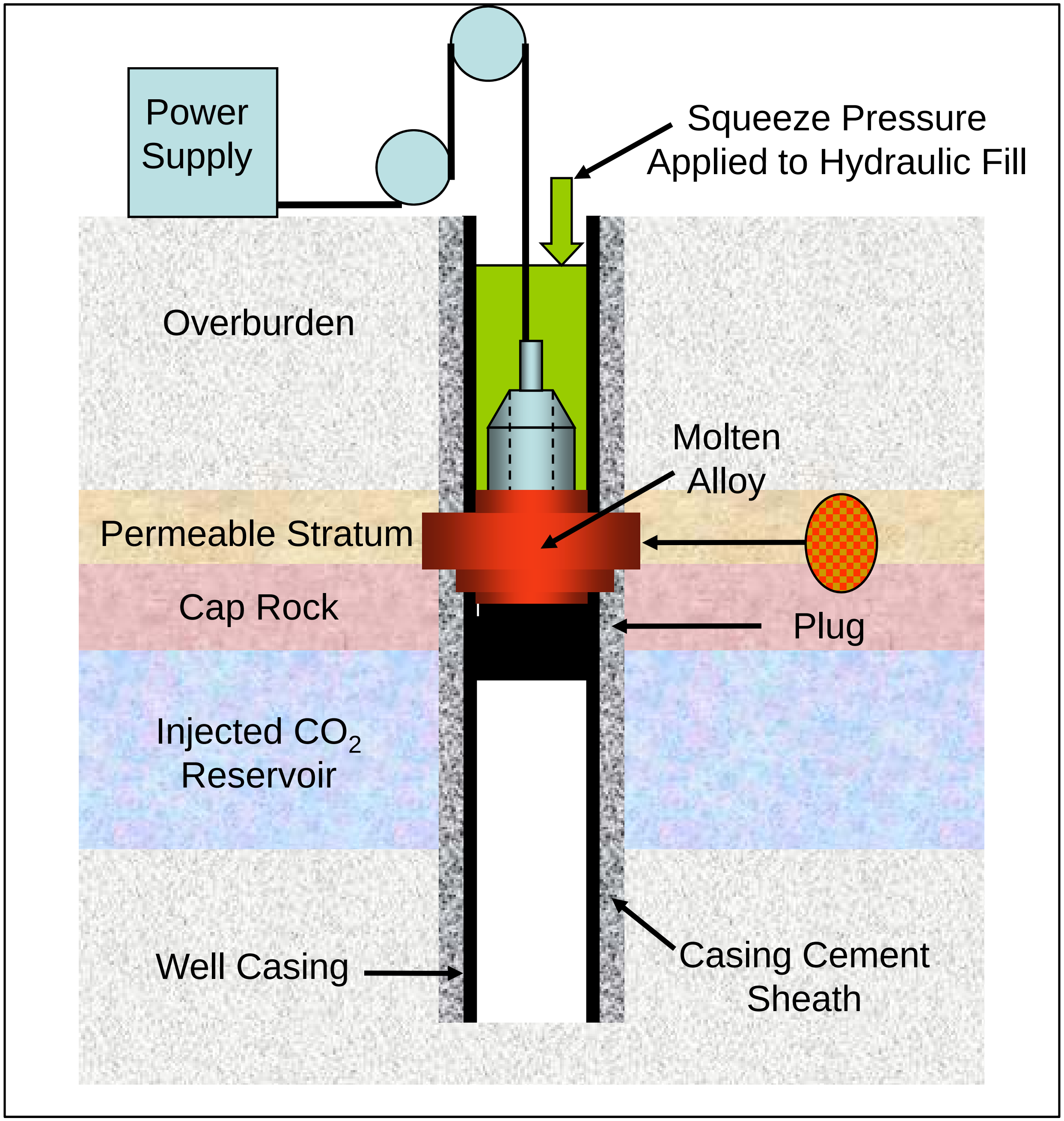


Figure 3:

Alloy melted by heater to form sealing plug. Penetrates permeable stratum

Creating a Plug to Seal Wells in CO_2 Storage Projects, 4/4

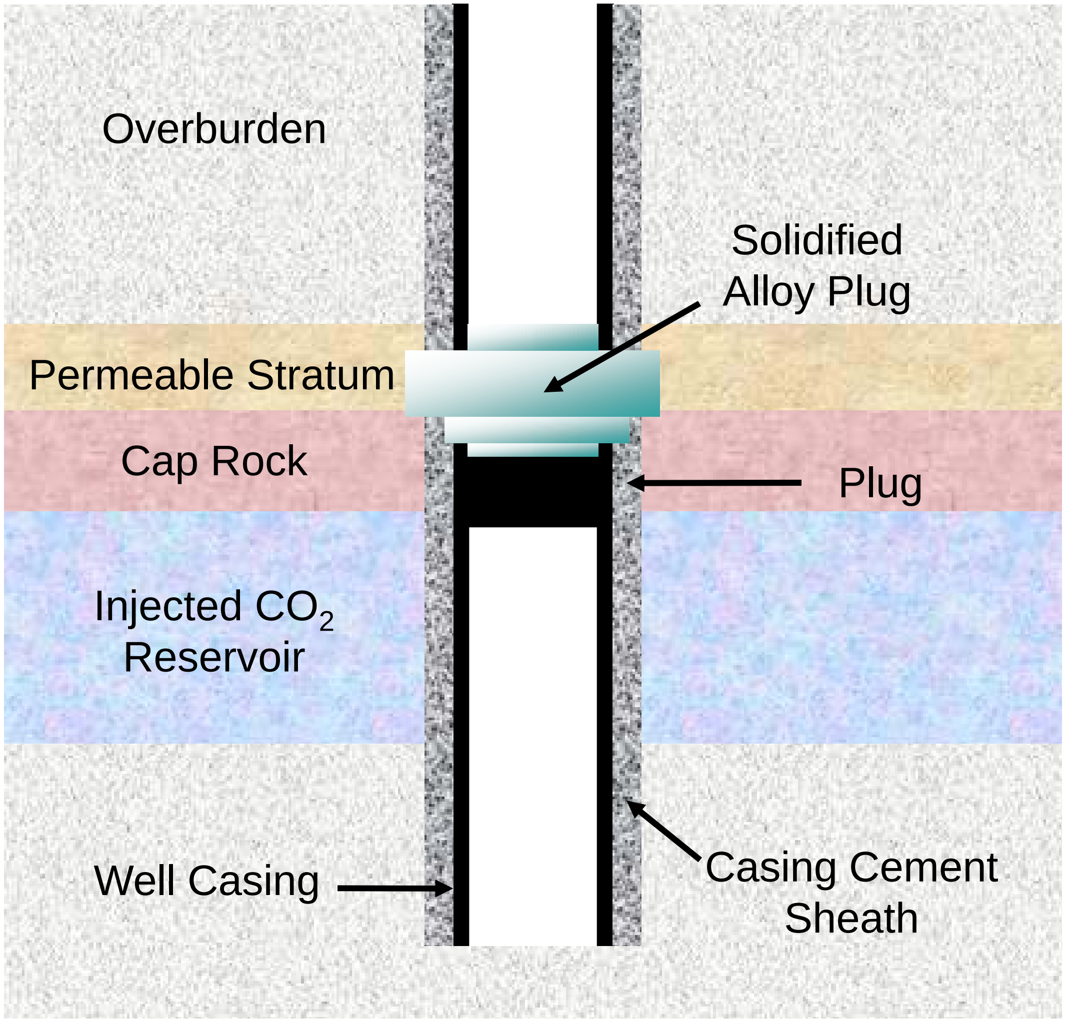
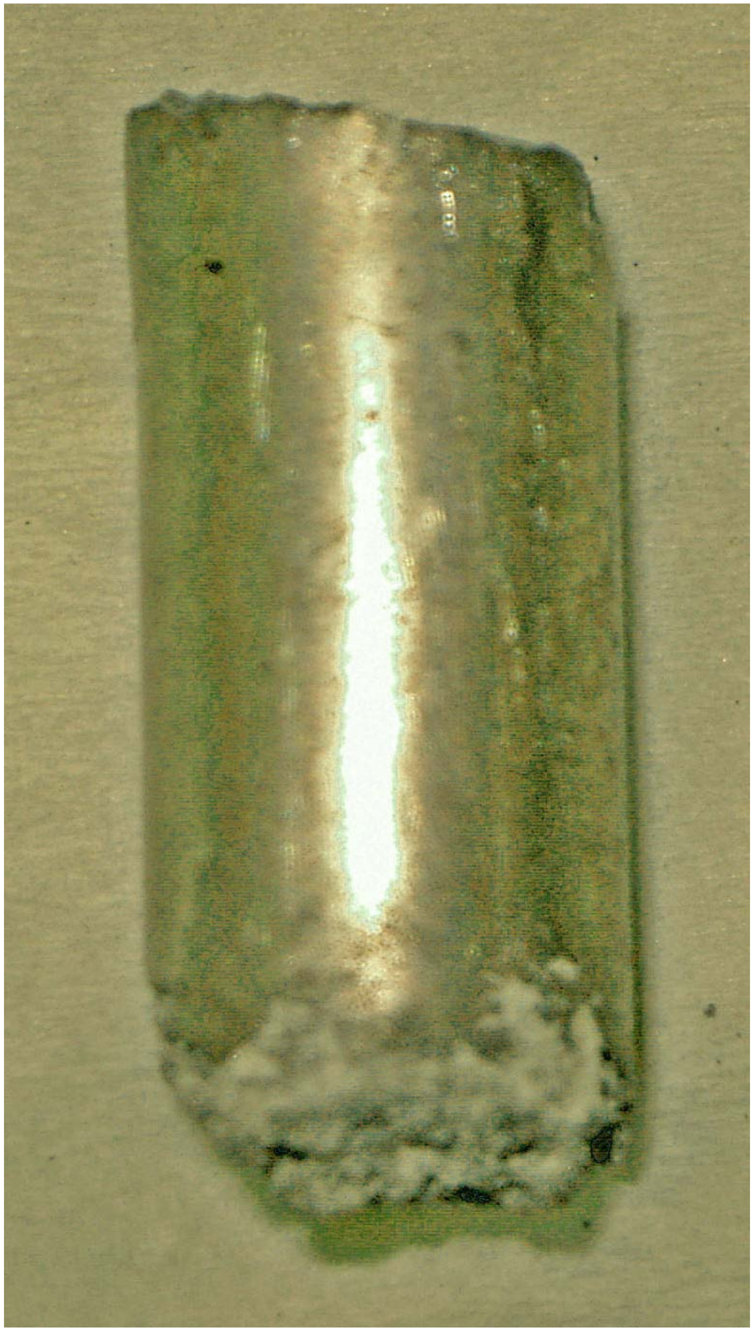


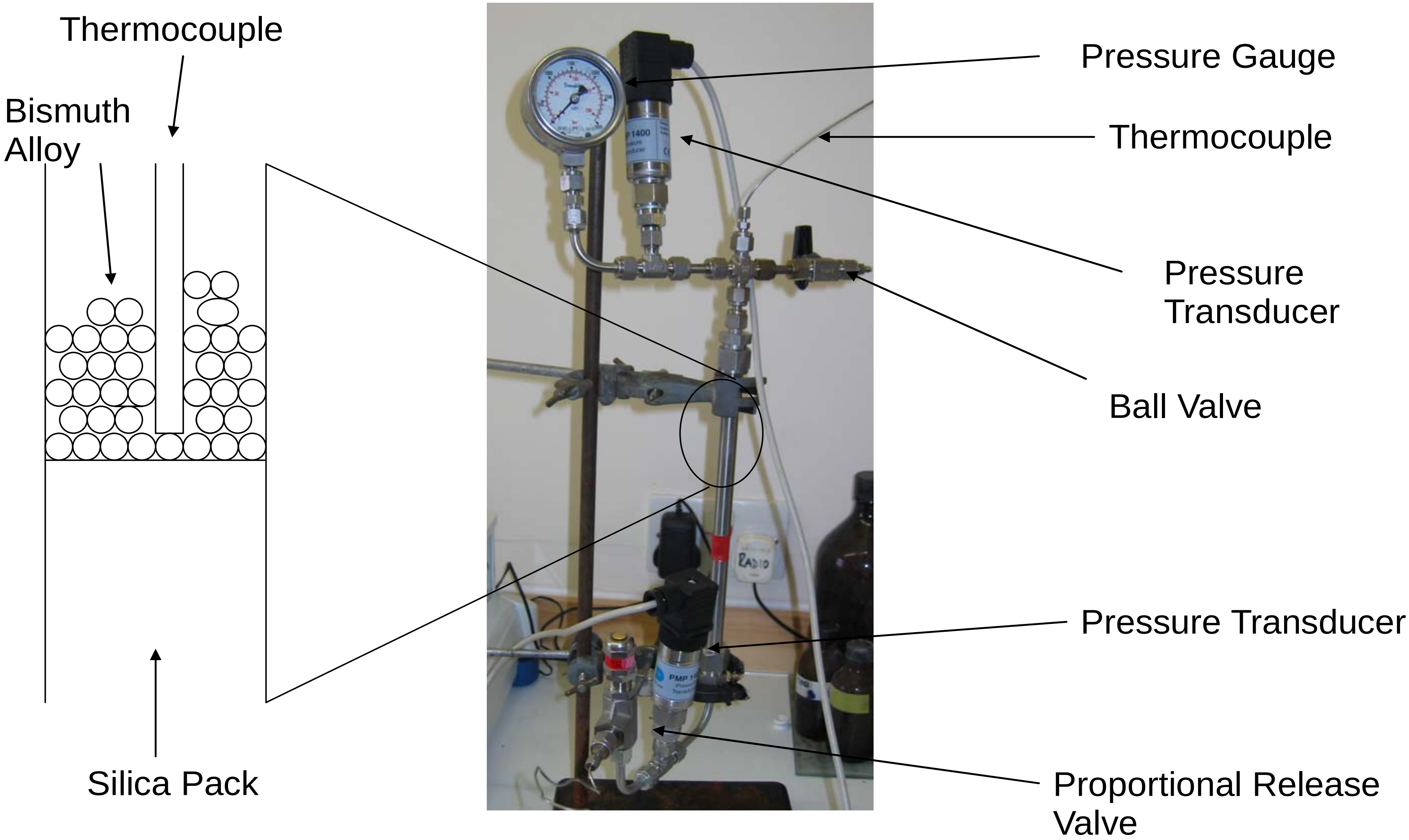
Figure 4: Solidified alloy formed as a sealing plug



An impermeable plug formed by squeezing alloy into water-saturated 20 mD silica flour.

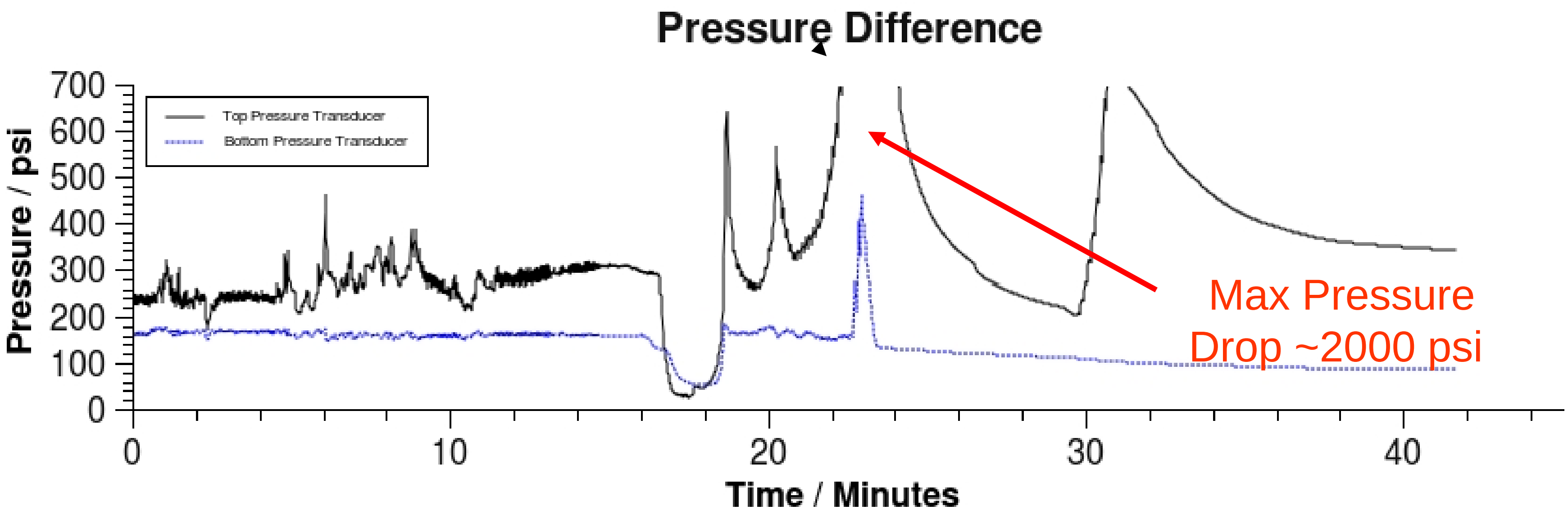
It withstood a pressure differential of 2000 psi.

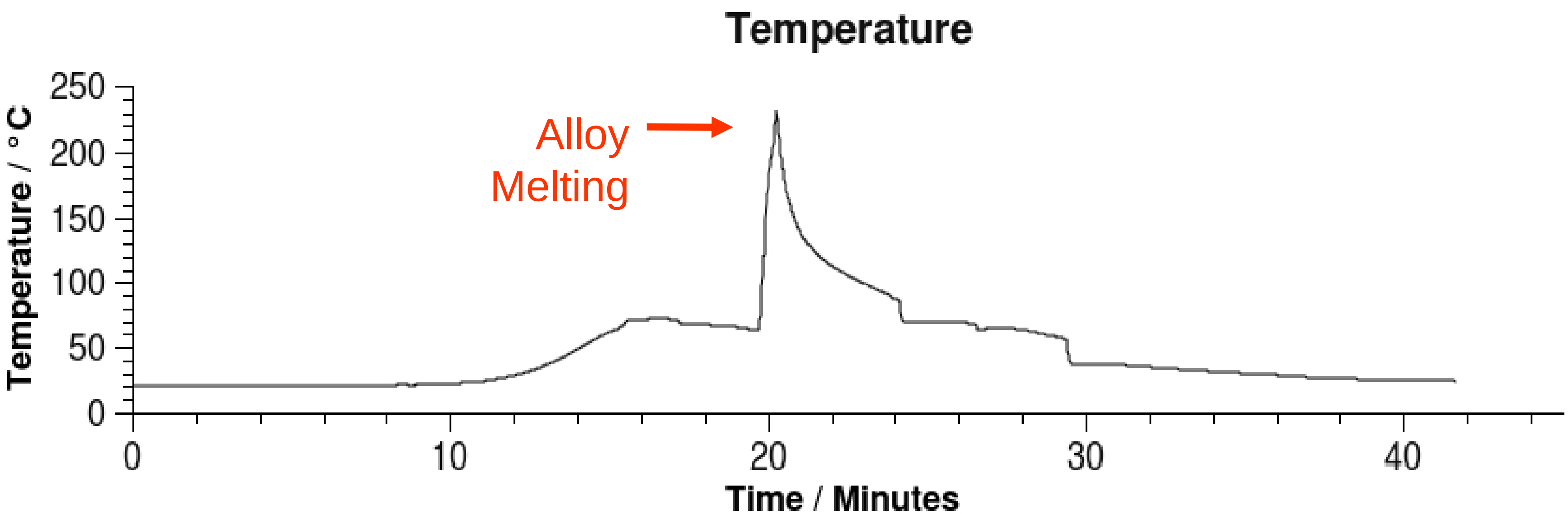
Alloy Squeezing Test Apparatus



Alloy Squeezing Test Data

Seal Well Inc.





Question:

Does the presence of bismuth/tin alloy in carbon steel well casing lead to troublesome galvanic corrosion?

Answer:

No, it does not.

Question:

Does bismuth/tin alloy corrode in contact with CO_2 and brine?

Answer:

No, it does not.

Bismuth:Tin Alloy Corrosion

- Bismuth:tin alloys are cathodic to carbon steel
- The bismuth:tin alloy cannot corrode galvanically
- Tin dissolves in acid solutions and passivates in alkali solutions
- Bismuth is immune to corrosion

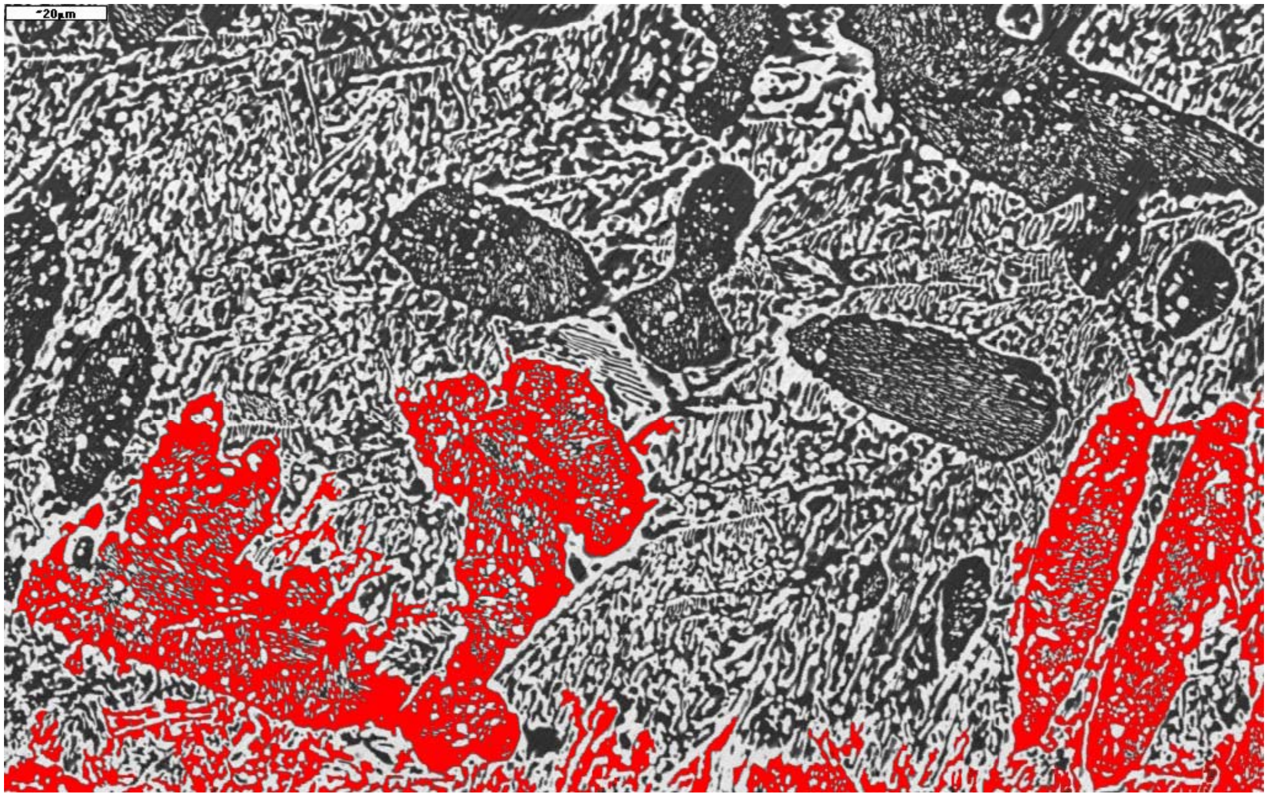
Figure 5:

Back-Scattered SEM Micrograph of Solid Bi:Sn Eutectic Alloy

Black = Tin

White = Bismuth

Marker bar = 20µm



↑↑↑↑ **Corrosion** ↑↑↑↑

Figure 6:

Tin percolation cluster

Tin oxidation can result in a corrosion-immune pure bismuth surface.

Test in 7" OD Casing

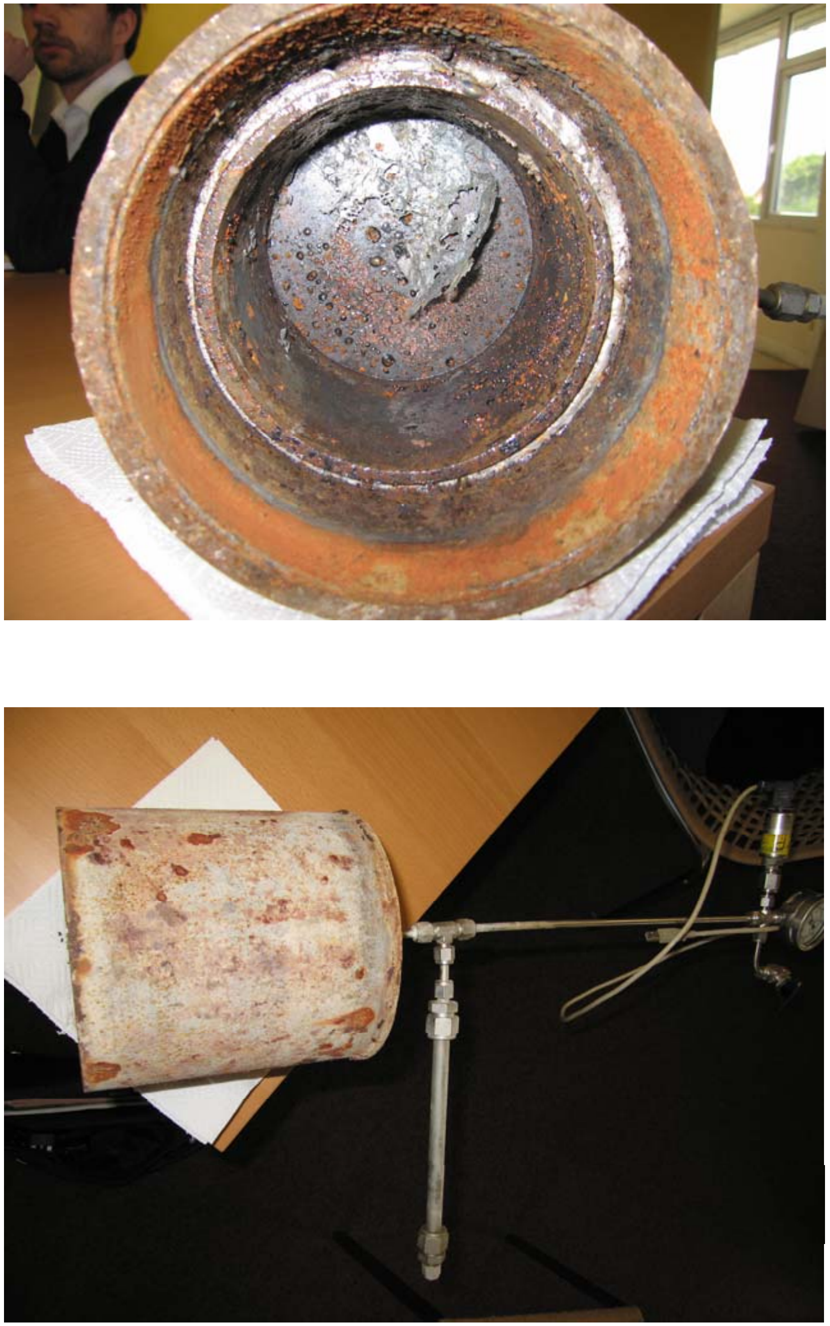


Figure 7:

This Bi:Sn alloy based plug with only 2" of alloy contact against the rusty casing wall withstood a pressure differential of 1500 psi.

Deployment Equipment at Site

Heating Tool

Loading Heating Tool with Alloy Billets

Monitoring Real Time Downhole Temperatures

Seal Well Inc.

Thank you for your attention!

For further information, please contact:

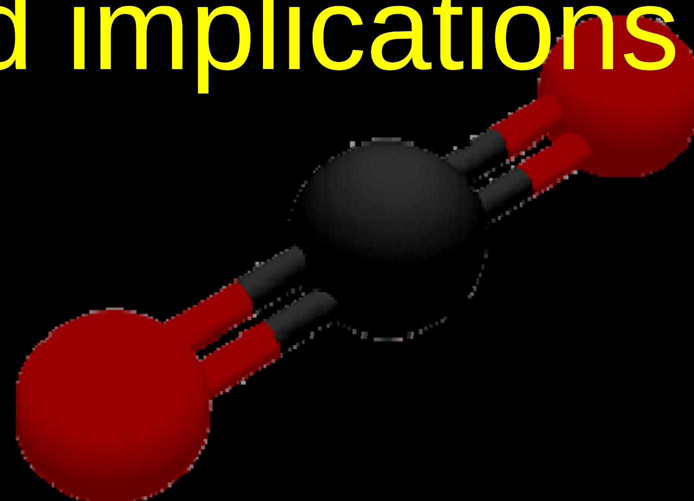
Homer Spencer
Seal Well Inc.
Phone: (403) 616-5247
E-Mail: hlspencer@shaw.ca

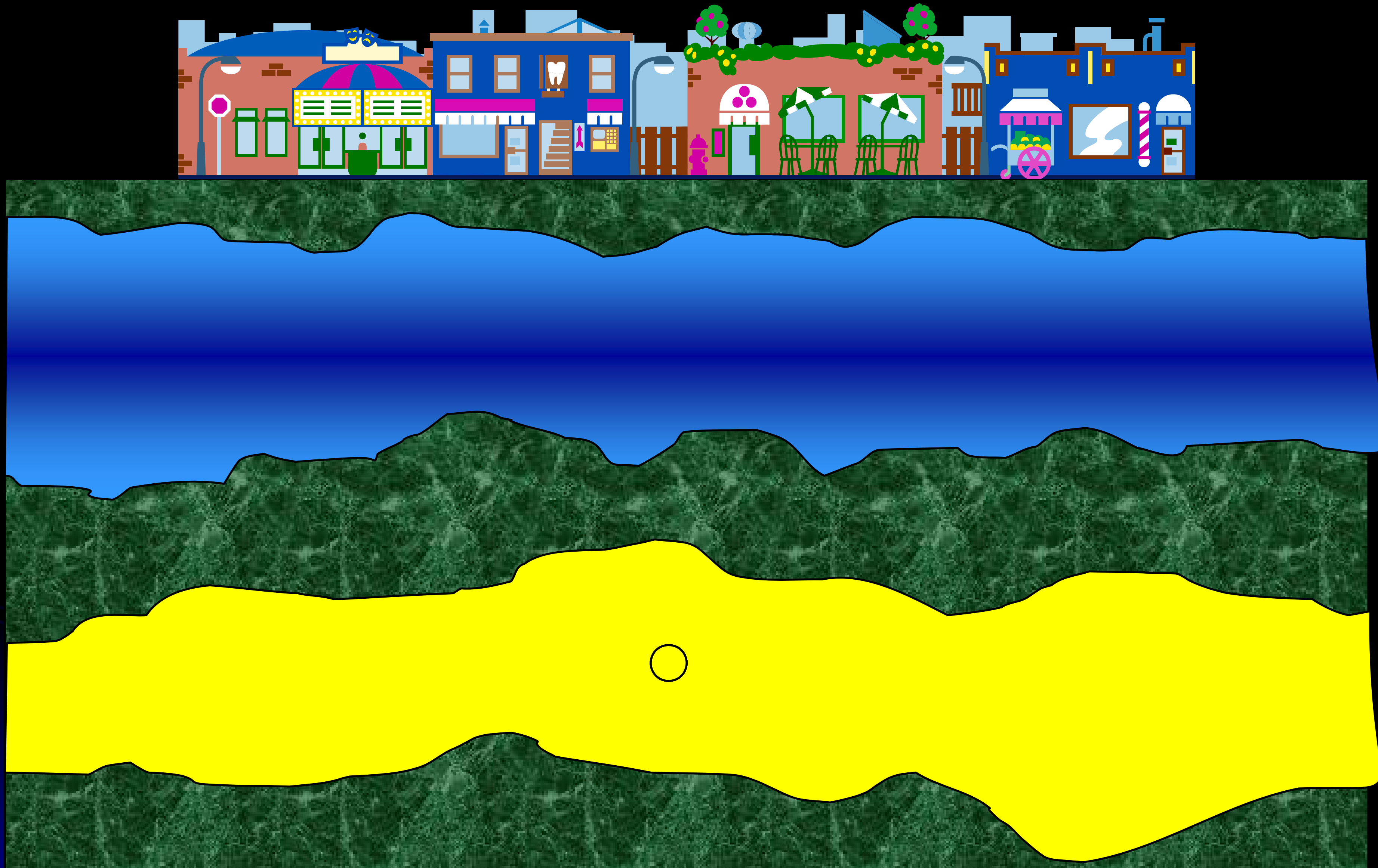
Experimental Assessment of Brine and/or CO2 Leakage Through Well Cements at Reservoir Conditions

Dr. Brant Bennion
Hycal Energy Research Labs/Weatherford Labs
Dr. Stefan Bachu
ERCB
(Now With Alberta Research Council)

Presentation Summary

- Context of the problem
- Experimental design
- Experimental Results
- Interpretation and implications
- Conclusions

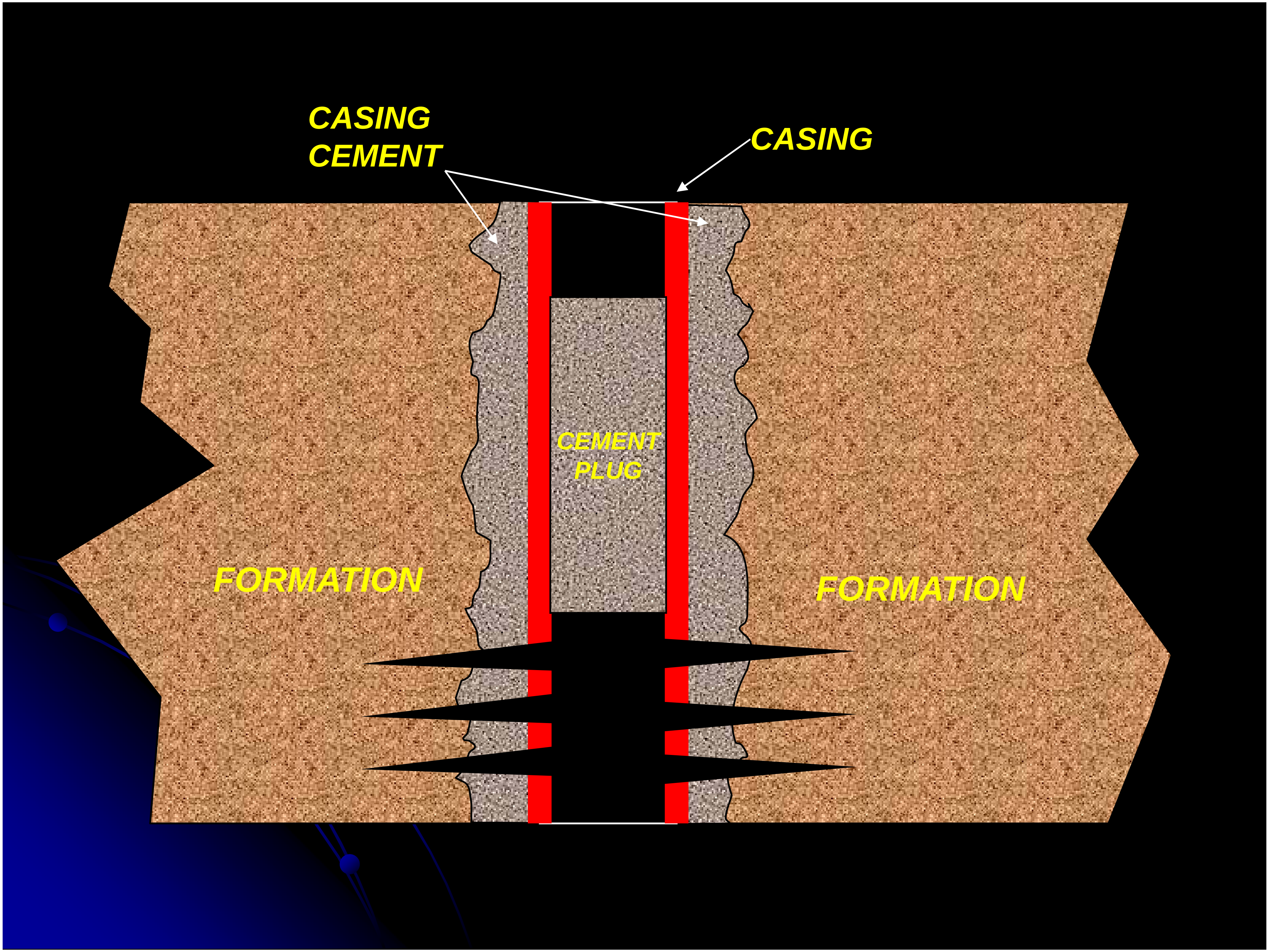




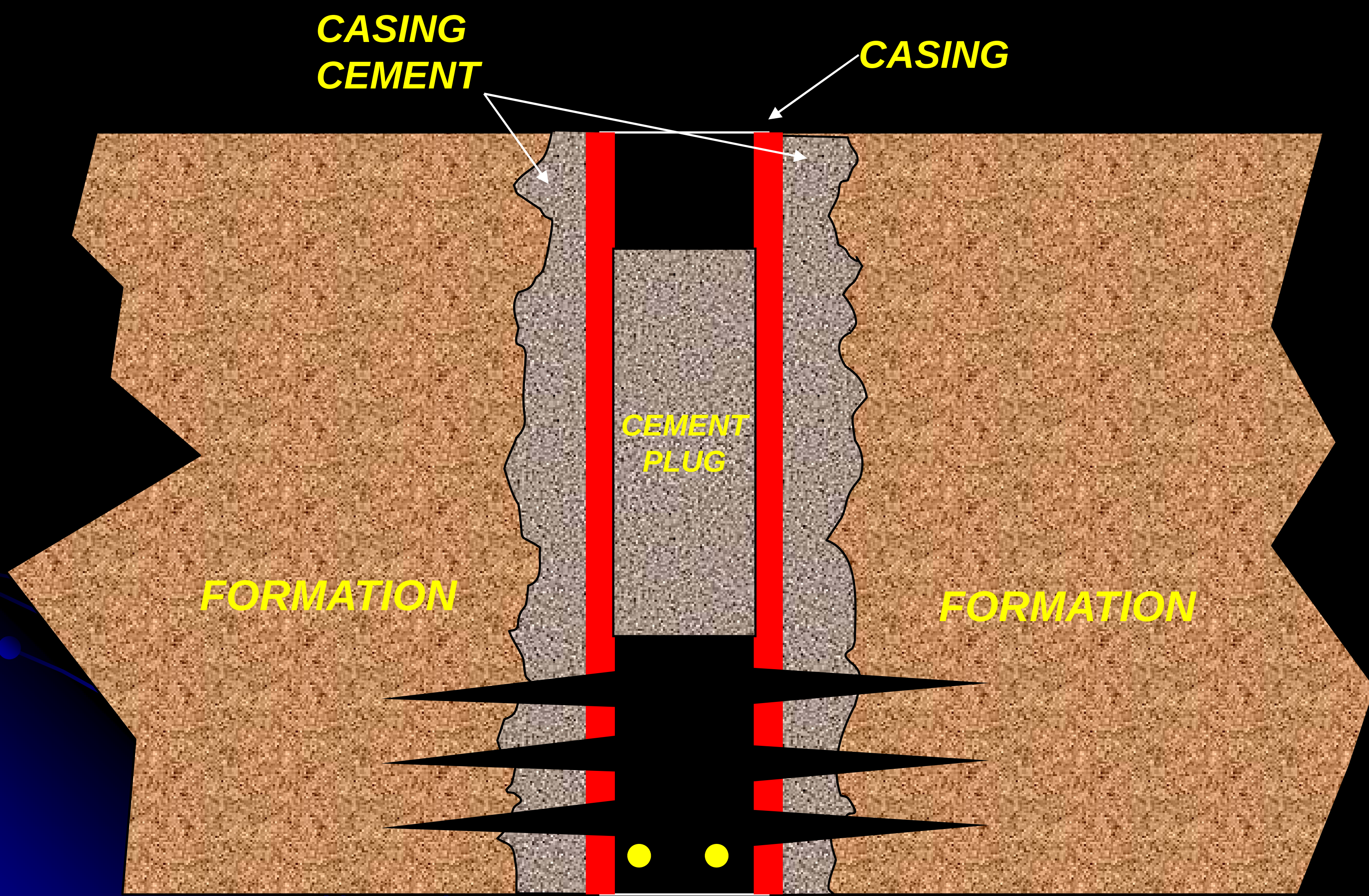

AZER.com

The Issue

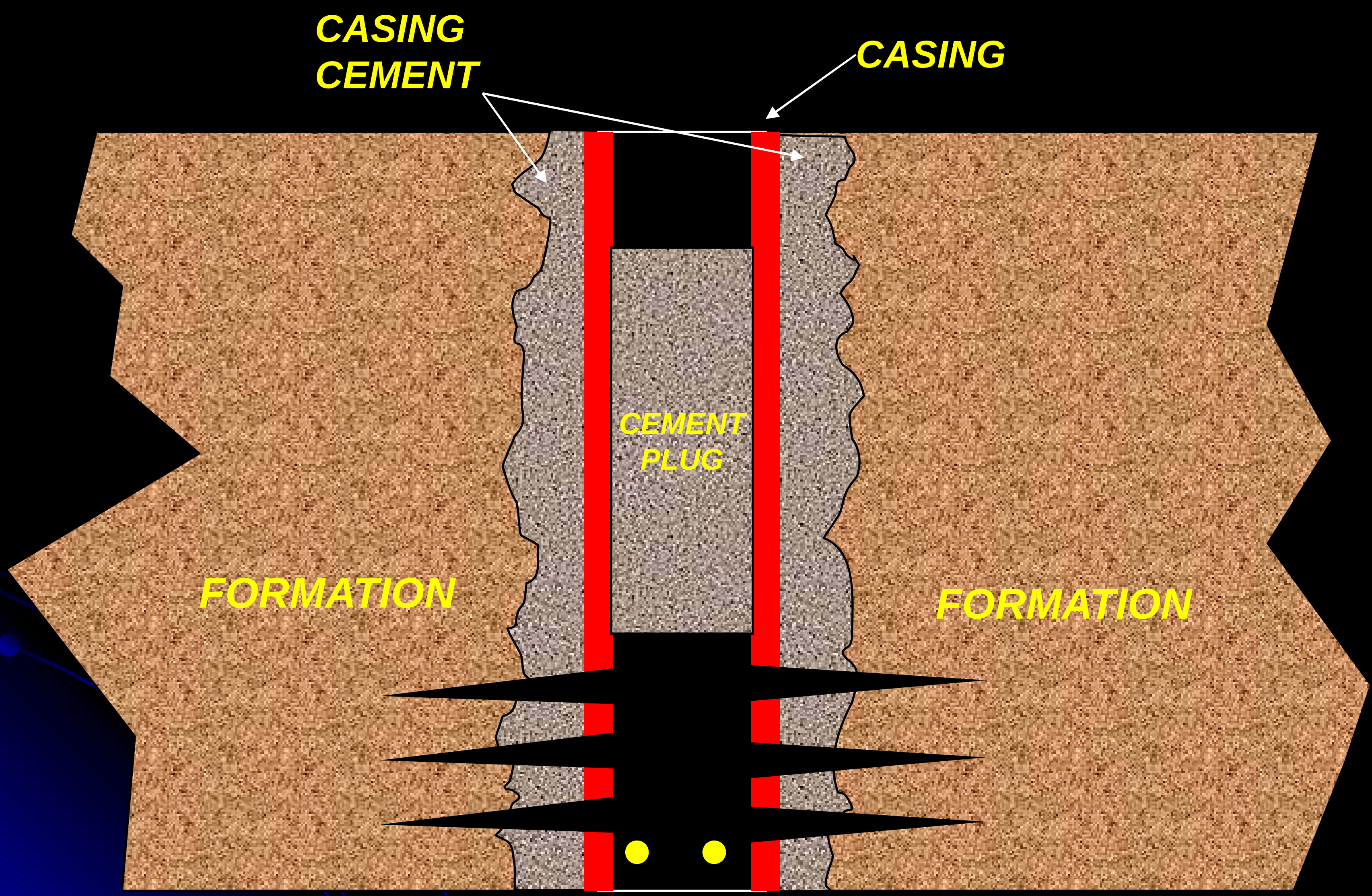
- Formations may have adequate sealing caprock
- The caprock may be broached in multiple (sometimes hundreds) of locations by wellbores of varying age and completion type
- Long term isolation of the formation due to leakage through these wellbores is a major concern


CASING
CEMENT
CASING
CEMENT
PLUG
FORMATION
FORMATION

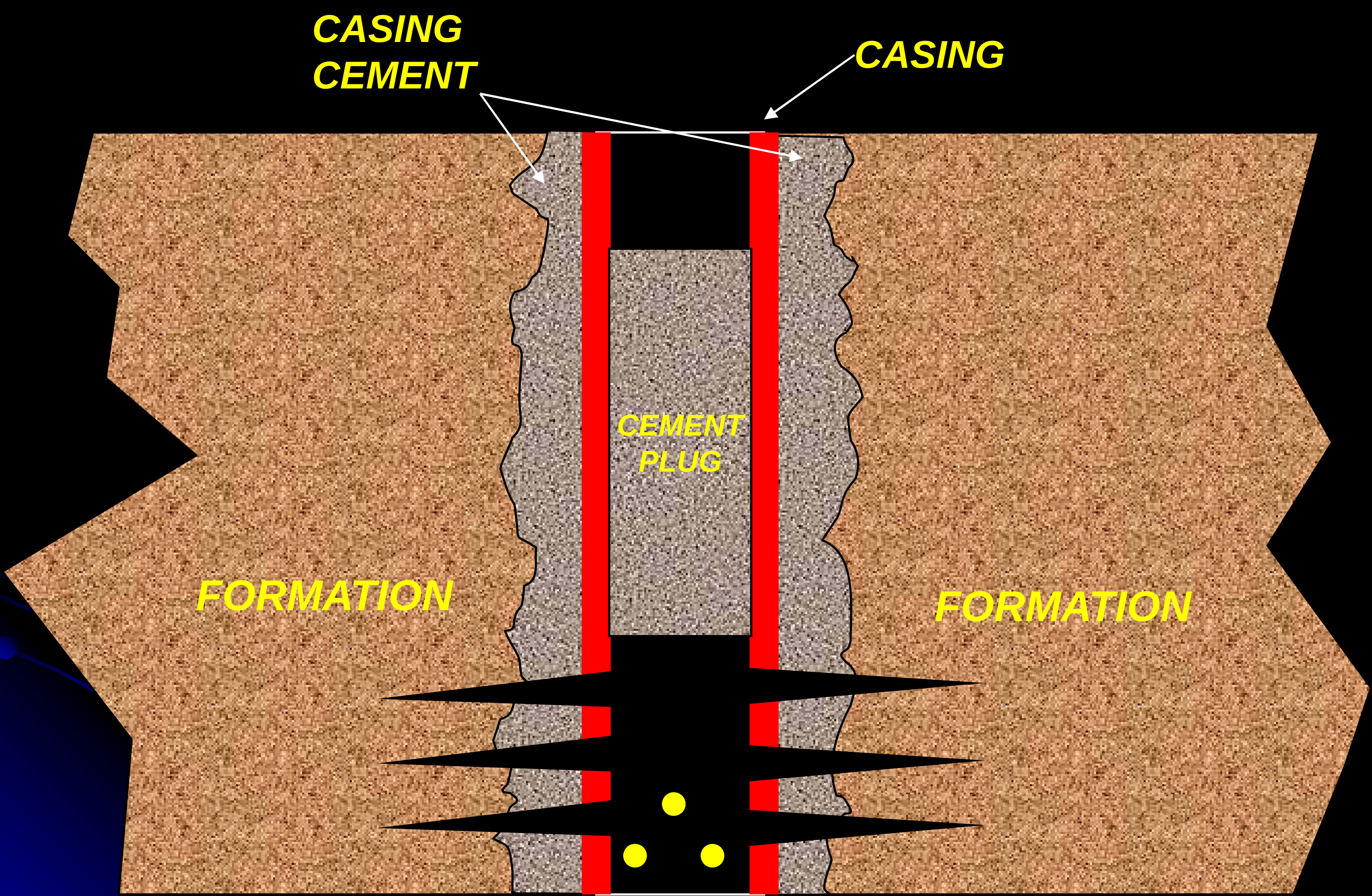
Poor Cement Bond



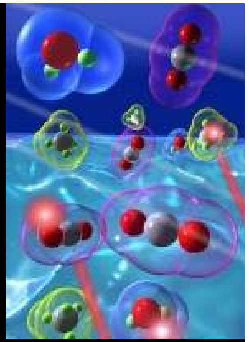
Casing Corrosion



Cement Degradation

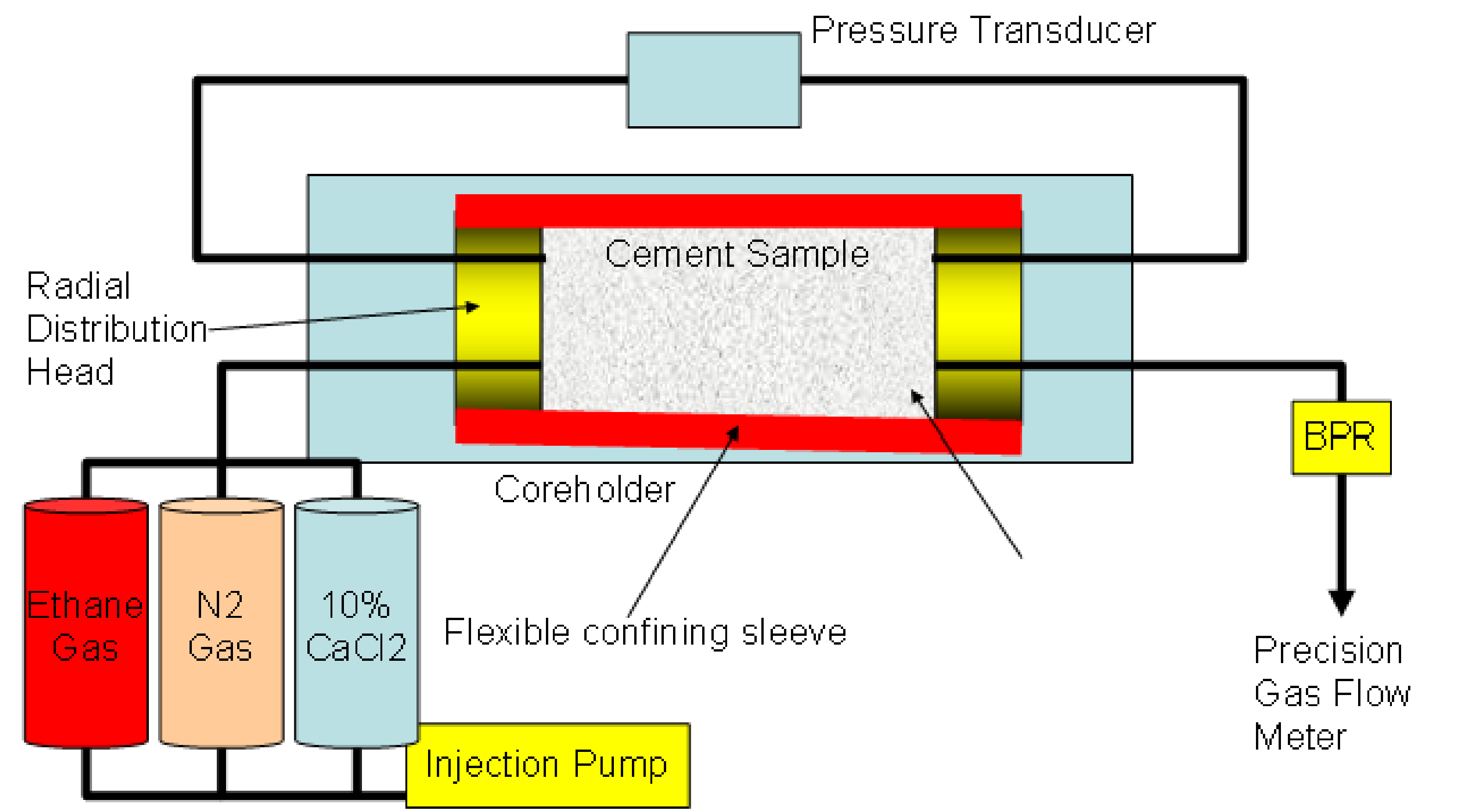


Program Objectives



- To quantify the in-situ permeability to CO_2 and CO_2 saturated brine at reservoir conditions for typical class G well cement
- To evaluate permeability between typical casing and class G cement with varying degrees of cement and cement bond integrity present at reservoir conditions

Class G Cement Permeability Measurements



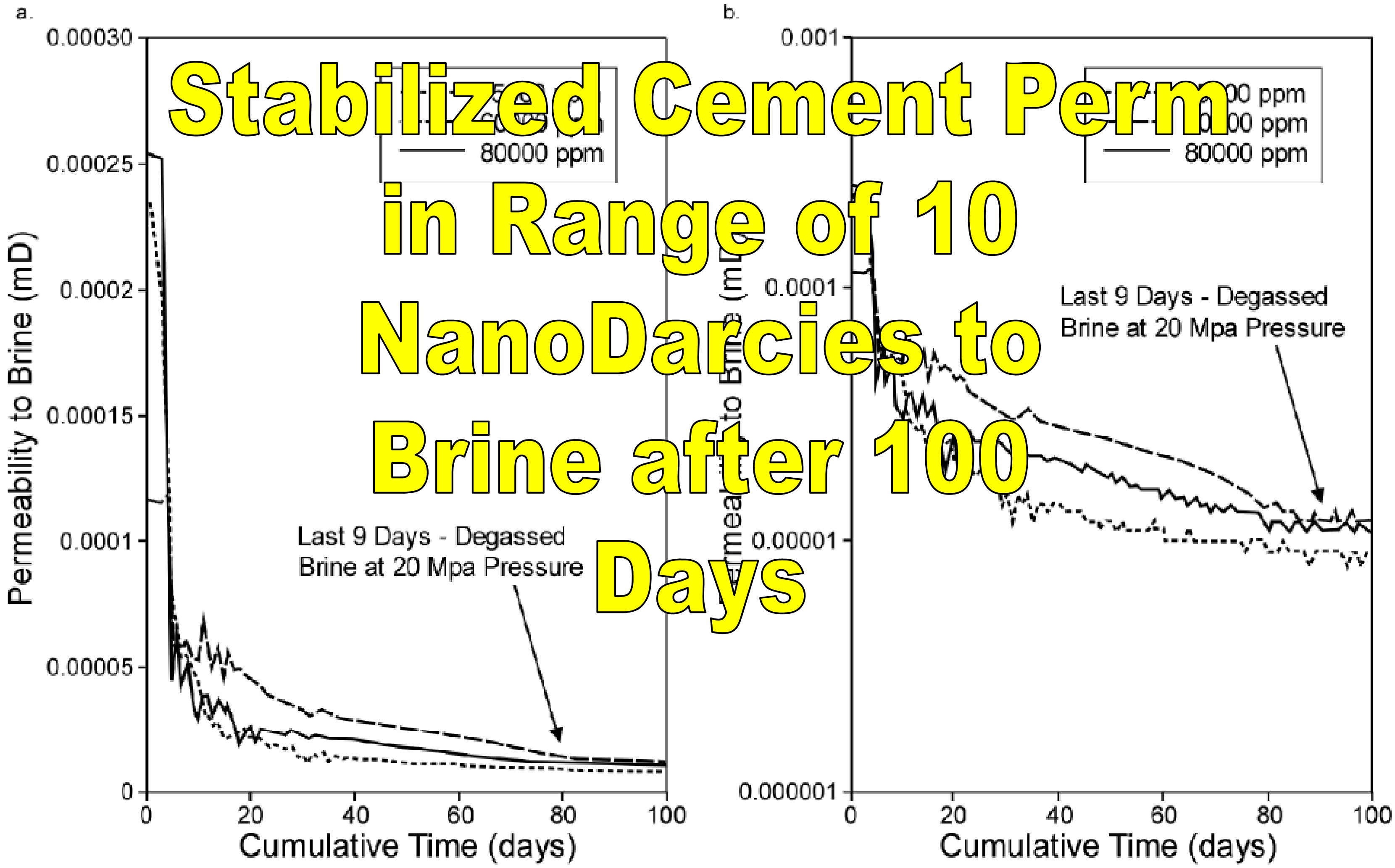
Test Conditions for Cement Permeability Measurements

- Temperature – 65 deg C
- Differential pressure across 5 cm cement sample – 15,150 kPa
- Backpressure – 5000 kPa
- Confining stress – 25,000 kPa
- Brine – 1.5, 6 and 8 % NaCl solution saturated with CO_2 gas at 65 deg C and 20,150 kPag pressure

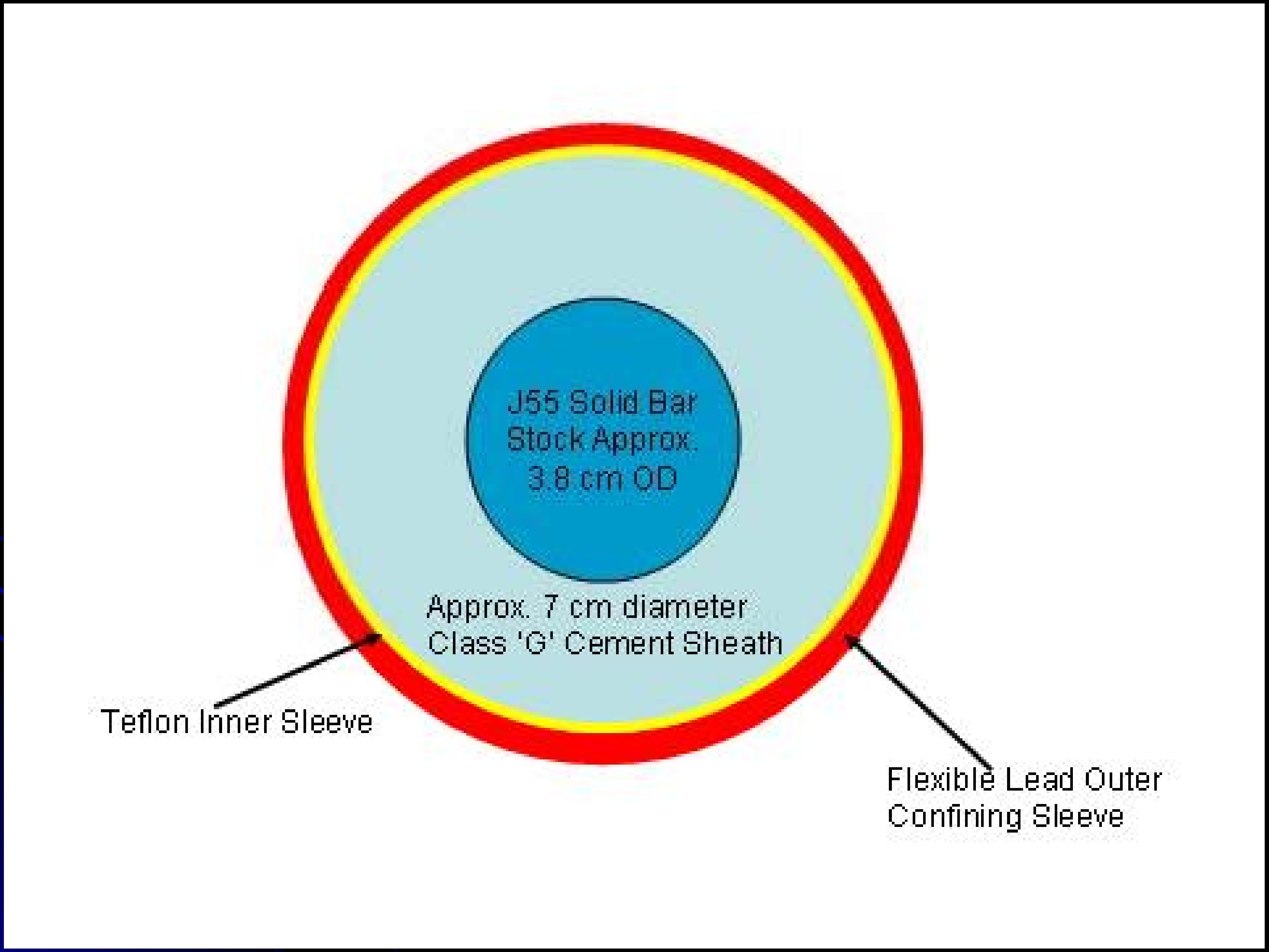
Lab Equipment

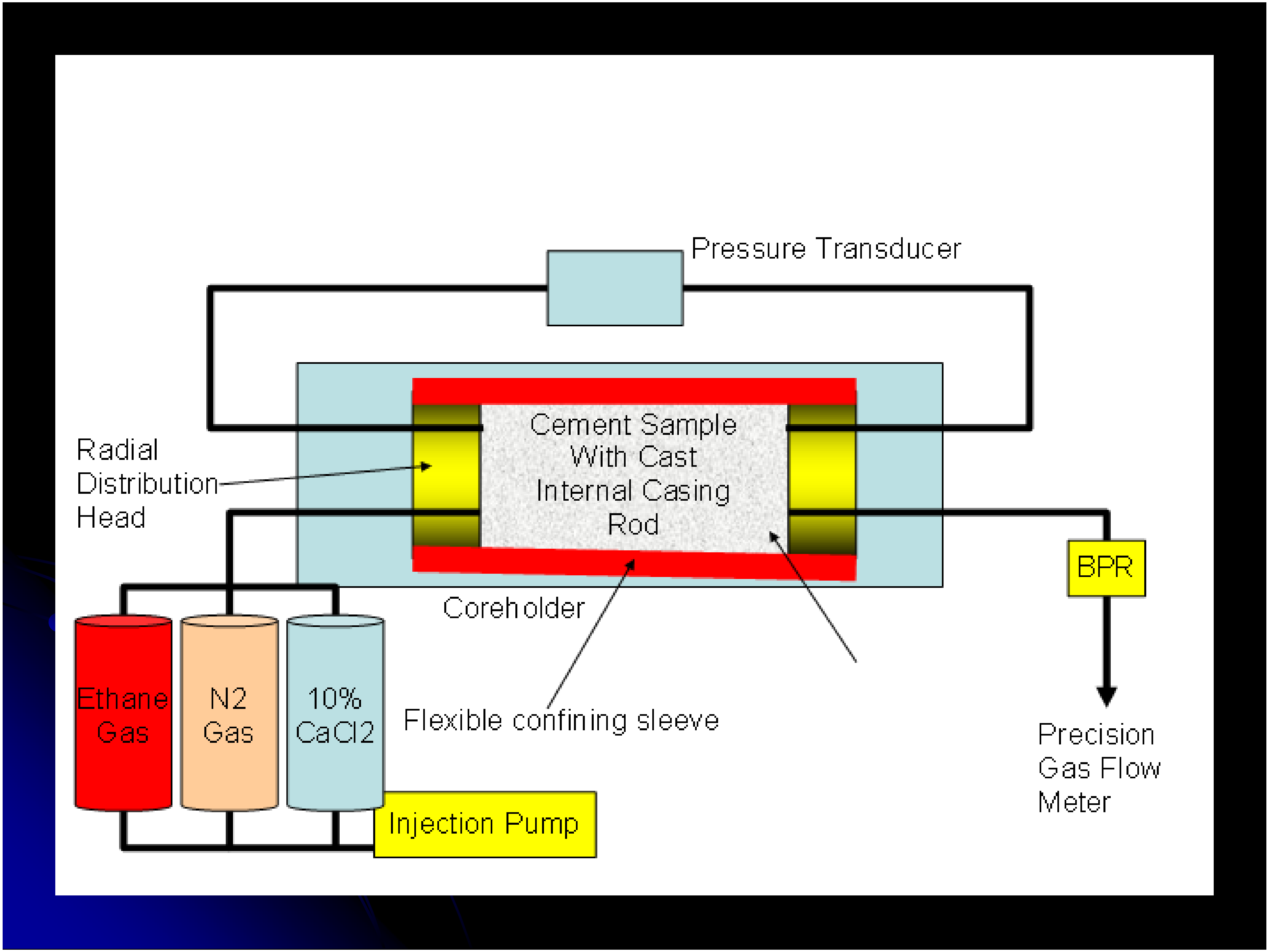
Test Results

Stabilized Cement Perm in Range of 10 NanoDarcies to Brine after 100 Days



Cement-Casing Bonding Tests

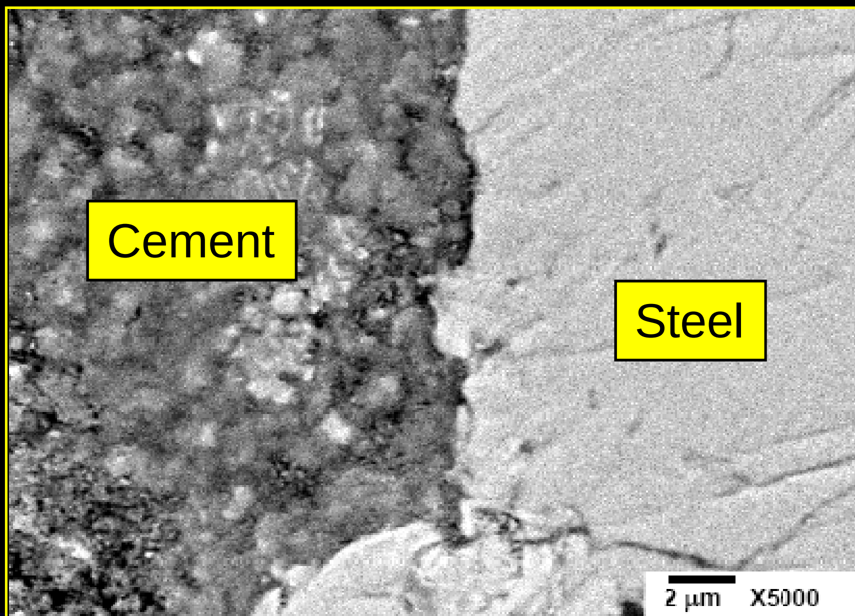


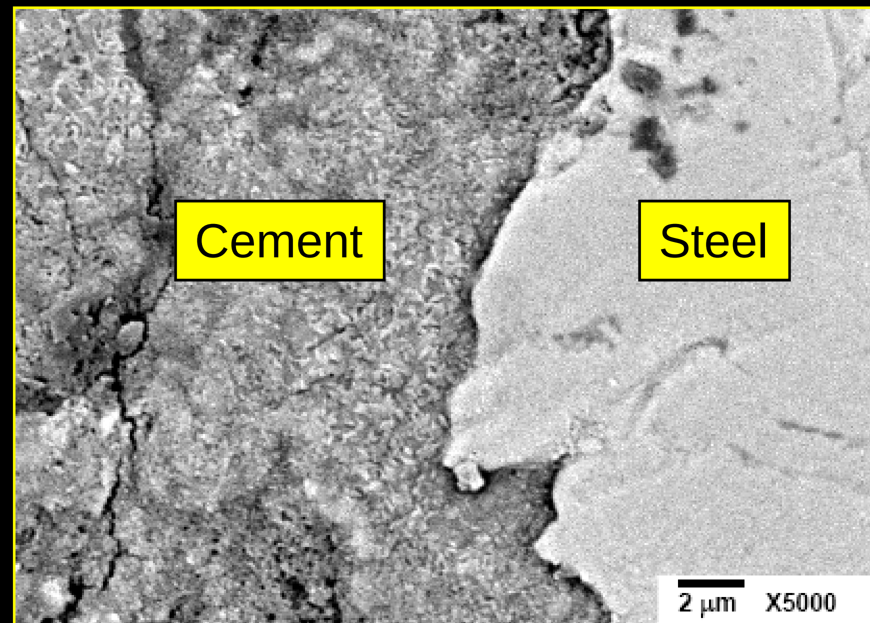

Pressure Transducer
Radial
Distribution
Head
Cement Sample
With Cast
Internal Casing
Rod
BPR
Coreholder
Ethane
Gas
N2
Gas
10%
CaCl2
Flexible confining sleeve
Precision
Gas Flow
Meter
Injection Pump

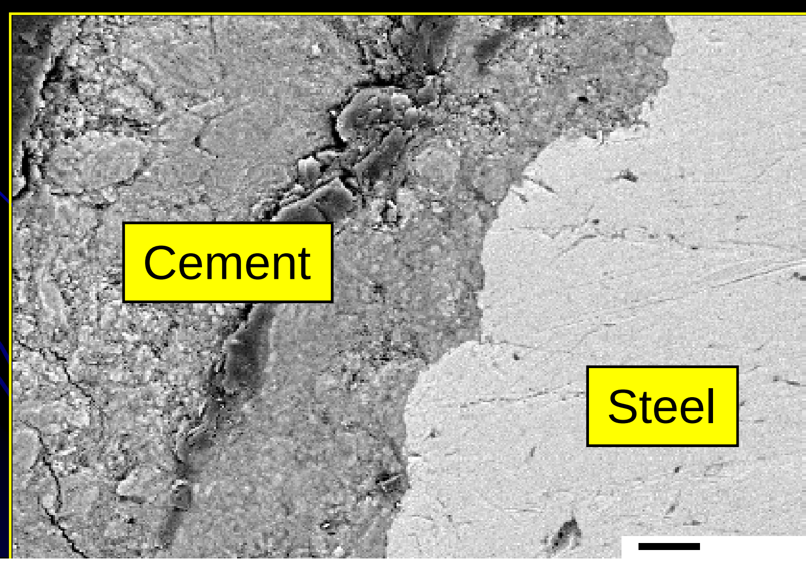
Test Conditions

- Diameter of composite – 7 cm
- Diameter cement sheath – approx 1.6 cm
- Length – approx. 10 cm
- Temperature – 60 deg C
- Pore pressure – 13780 kPag
- Confining pressure – 24100 kPag
- Fluid – supercritical ethane or $CaCl_2$ saturated brine

Test #1 – ‘Perfect Bond’



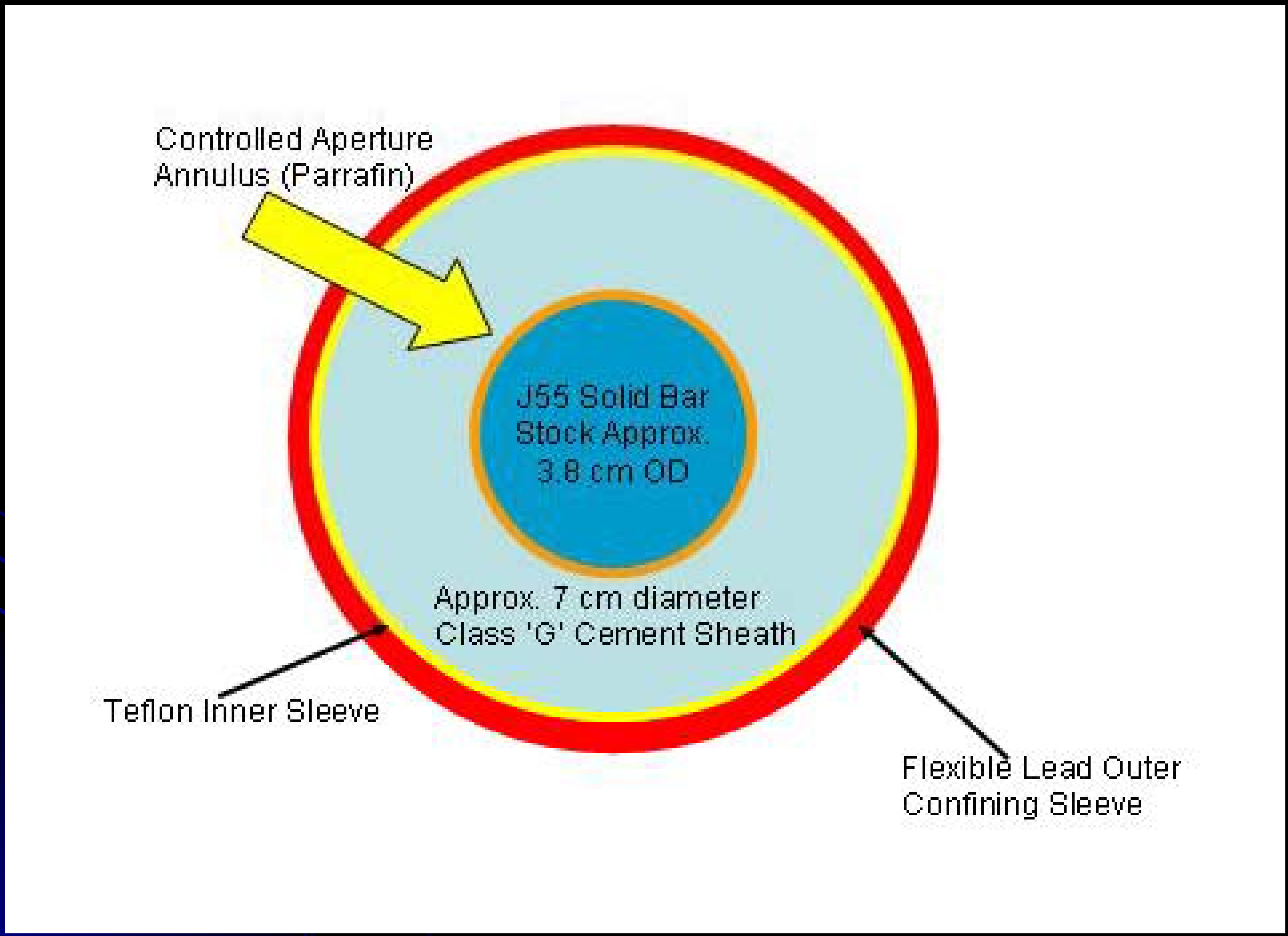




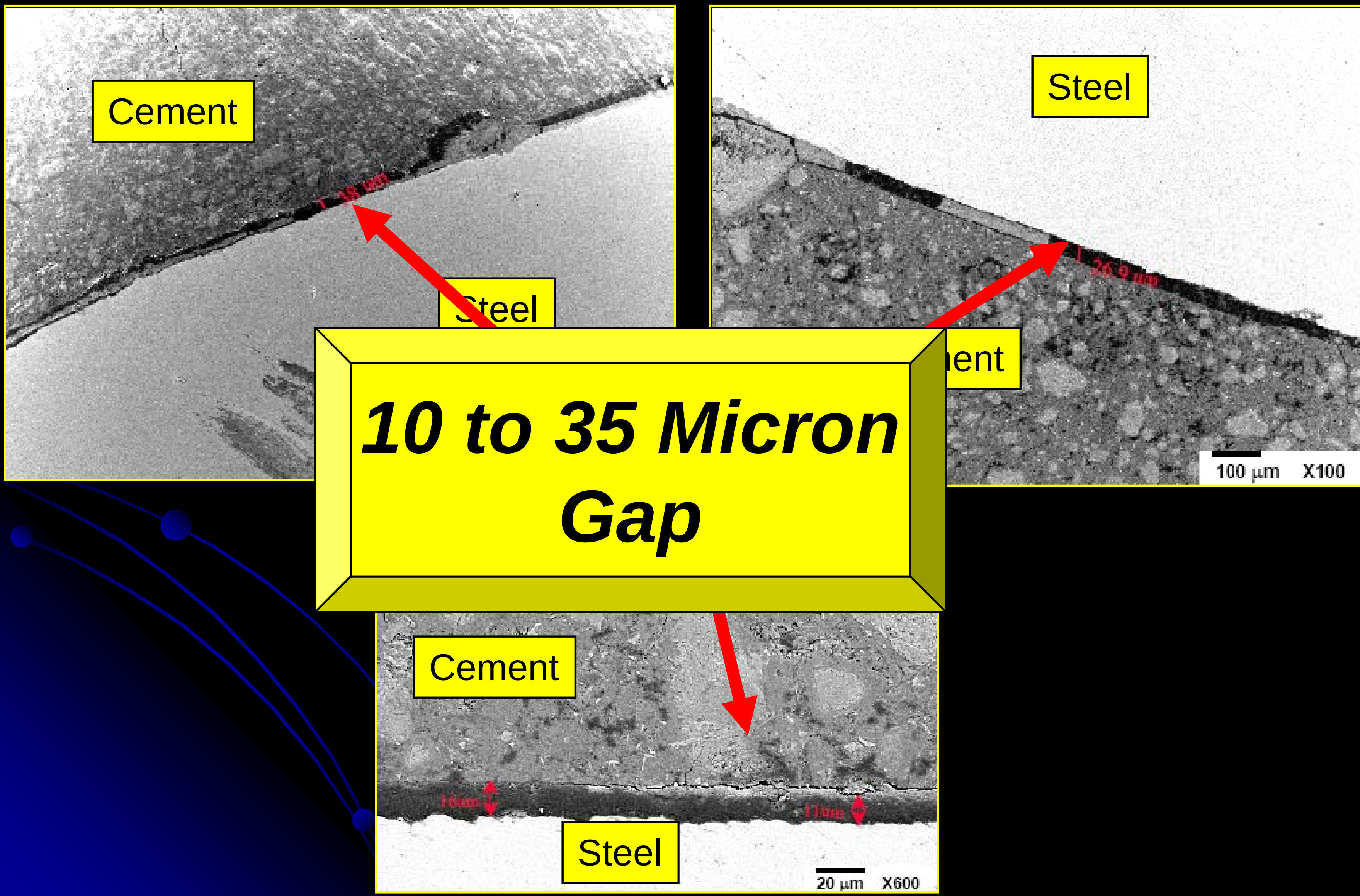
Perfect Bond Test Results

Test Phase	Displacing Fluid	Measured Permeability mD
Initial Nitrogen Displacement	Dry Nitrogen	0.005
10% CaCl2 Flood	10% CaCl2	<0.000001
Dense Phase Ethane	Supercritical Ethane	<0.000001
10% CaCl2 Flood	10% CaCl2	<0.000001

Poor Micro Annular Bond Test



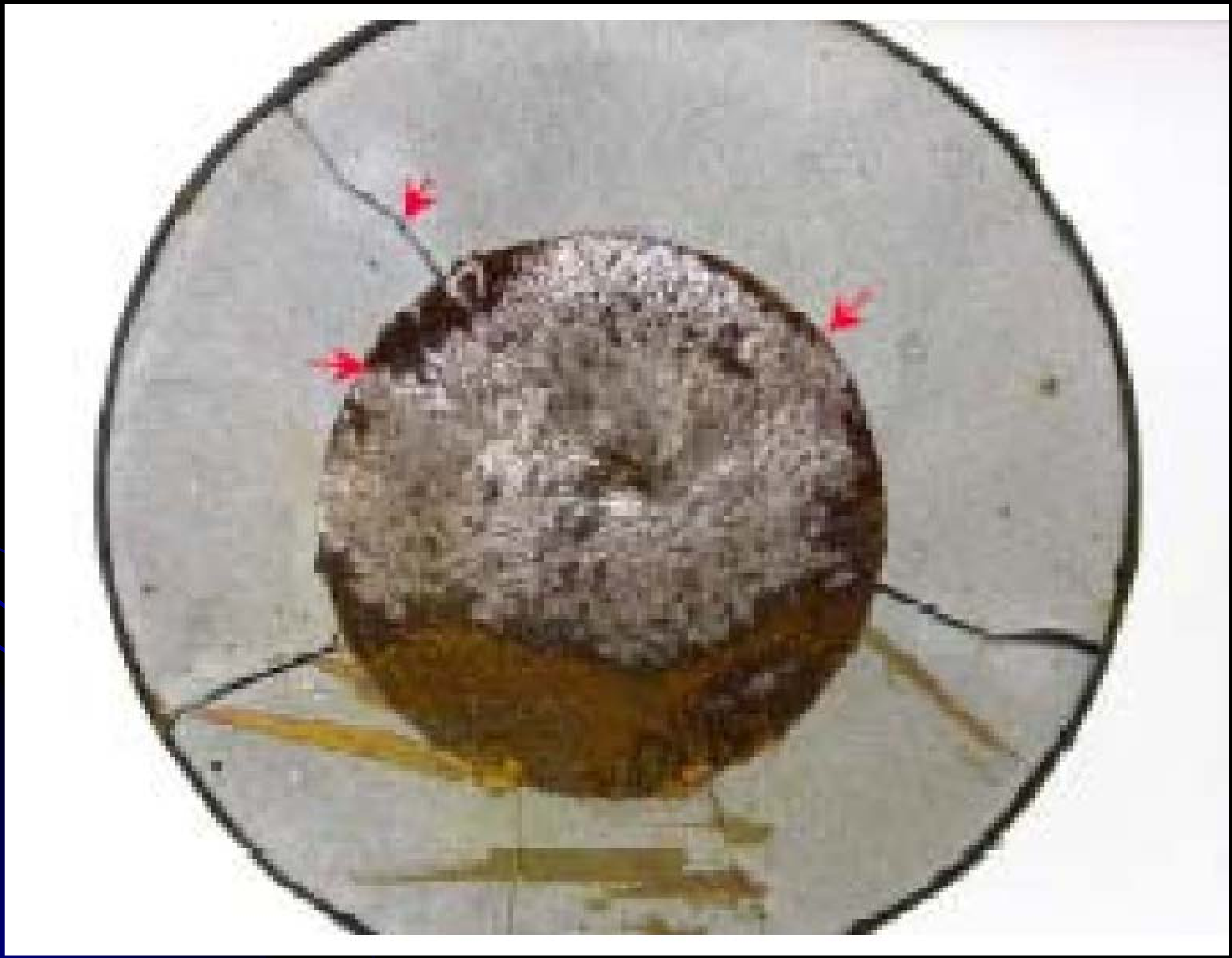
Poor Micro Annular Bond Test



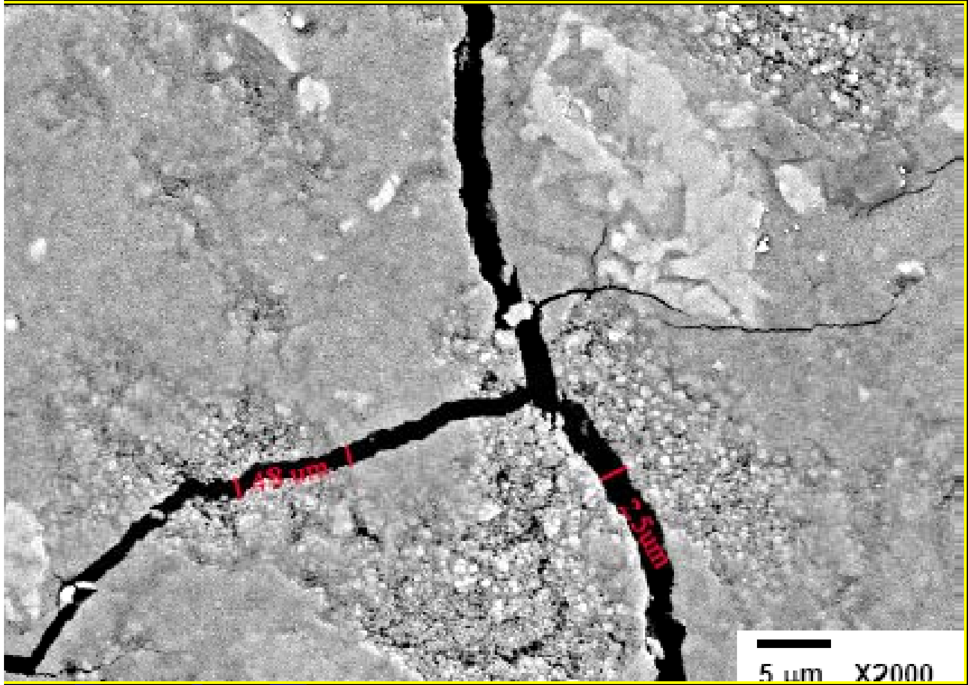
Poor Micro Annular Bond Test Results

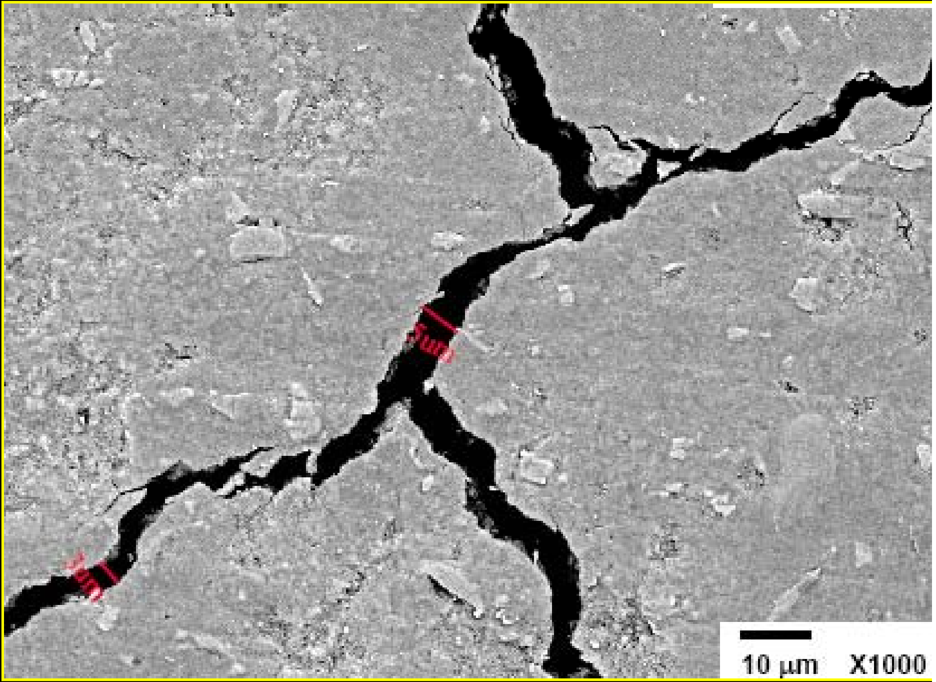
Test Phase	Displacing Fluid	Measured Permeability mD
Initial Nitrogen Displacement	Dry Nitrogen	120.43
10% CaCl2 Flood	10% CaCl2	0.241
Dense Phase Ethane	Supercritical Ethane	0.533
10% CaCl2 Flood	10% CaCl2	0.079

Cracked Cement Annulus



‘Small’ Cracks Test



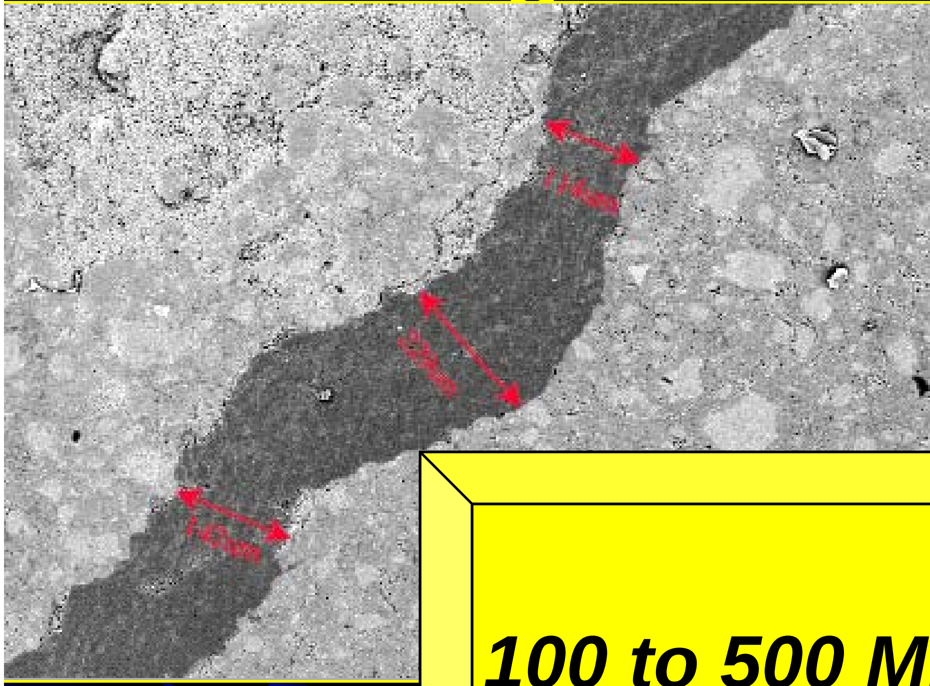


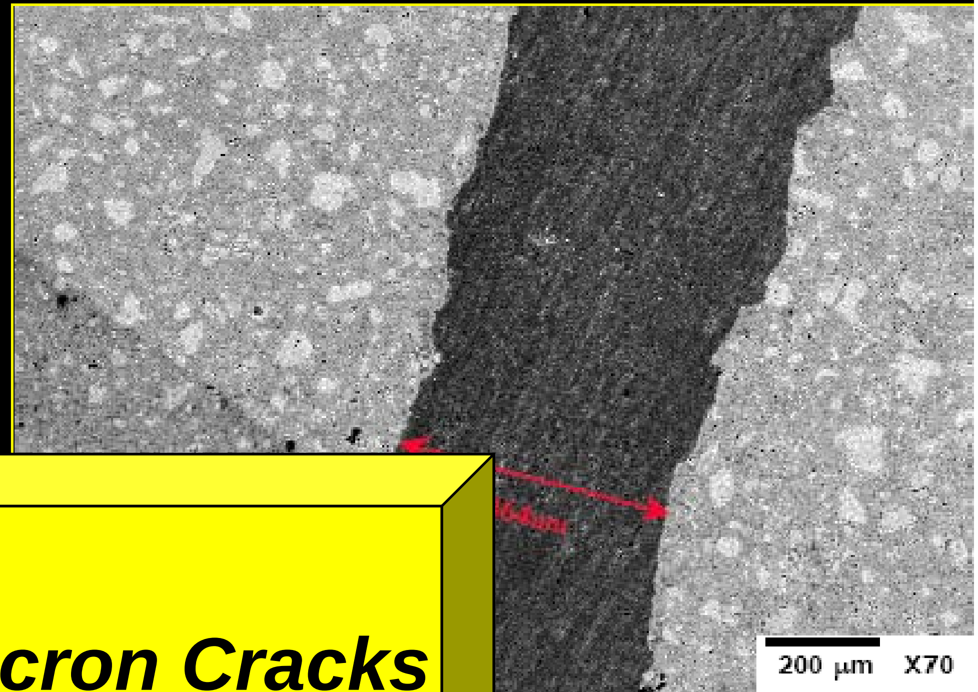
1 to 5 Micron Diameter Cracks

Small Cracks Results

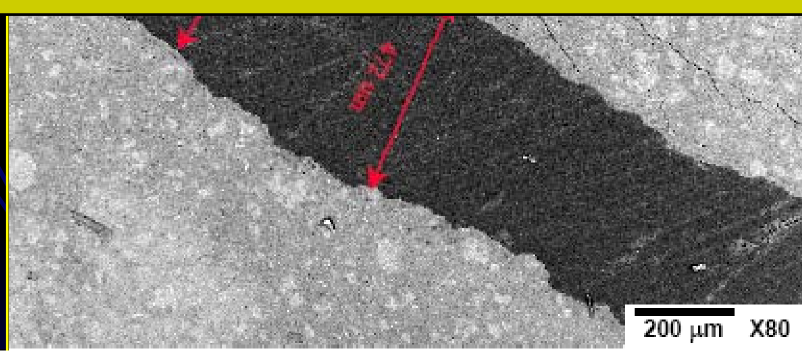
Test Phase	Displacing Fluid	Measured Permeability mD
Initial Nitrogen Displacement	Dry Nitrogen	236.6
10% CaCl2 Flood	10% CaCl2	0.402
Dense Phase Ethane	Supercritical Ethane	0.212
10% CaCl2 Flood	10% CaCl2	0.105

Large Cracks in Cement





100 to 500 Micron Cracks

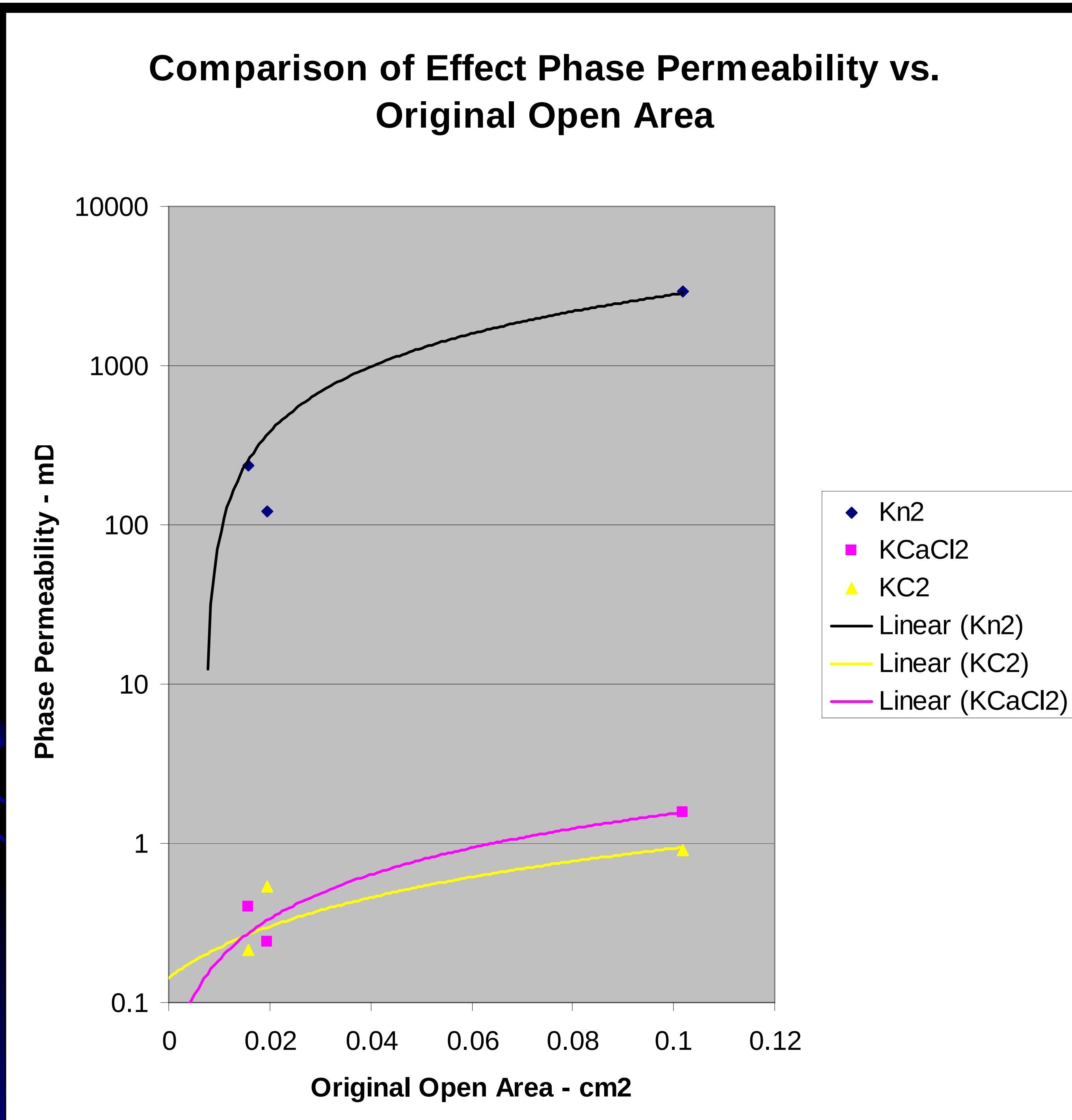


Large Cracks Test Results

Test Phase	Displacing Fluid	Measured Permeability mD
Initial Nitrogen Displacement	Dry Nitrogen	2897
10% CaCl2 Flood	10% CaCl2	1.56
Dense Phase Ethane	Supercritical Ethane	0.905
10% CaCl2 Flood	10% CaCl2	0.725

Test	Type	Average Aperture of Annular Gap* (cm)	Average Crack Aperture (cm)	Average Crack Length Across Sample (cm)	Average Flow Area (cm^2)
1	Perfect Bond	0	0	0	0
2	Small Annular Gap	0.0030	0	0	0.019685
3	Small Cracks and Annular Gap	0.0012	0.0004	4.2	0.015996
4	Large Cracks and Annular Gap	0.0018	0.0200	4.0	0.101474

* The circumference of the annular gap is 11.93 cm



Comparison of Effect Phase Permeability vs. Original Open Area
Phase Permeability - mD
10000
1000
100
10
1
0.1
0
0.02
0.04
0.06
0.08
0.1
0.12
Original Open Area - cm2
Kn2
KCaCl2
KC2
Linear (Kn2)
Linear (KC2)
Linear (KCaCl2)

More Details

- 'Experimental Assessment of Brine and/or CO_2 Leakage Through Well Cements at Reservoir Conditions', To be Published in The International Journal of Greenhouse Gas Control (In proof, available online at www.sciencedirect.com)

Conclusions

Conclusions

- Good quality class G cement without fractures appears to provide a good barrier to CO2 (in the shorter term periods evaluated in this work)
- Good bonding of typical J55 metal casing to class G cement was observed which appeared to have very low permeability
- The presence of micro cracks or a micro annulus severely degraded the ability of the cement/casing pair to restrict the motion of supercritical gas with several orders of magnitude increase in permeability observed

Conclusions

- Hydration of the cement during testing resulted in a non linear relationship between fracture size and effective permeability to liquids and supercritical gases after liquid flow
- The results suggest that mechanical issues associated with cement and casing integrity may represent the greatest challenge to CO_2 sequestration in wells containing existing wellbores, particularly multiple older existing wellbores

Thank You for Your Attention

Impact of CO_2 on neat class G cement

IEAGHG Wellbore Integrity Network, 13th-14th May 2009

François Rodot, André Garnier

May 2009

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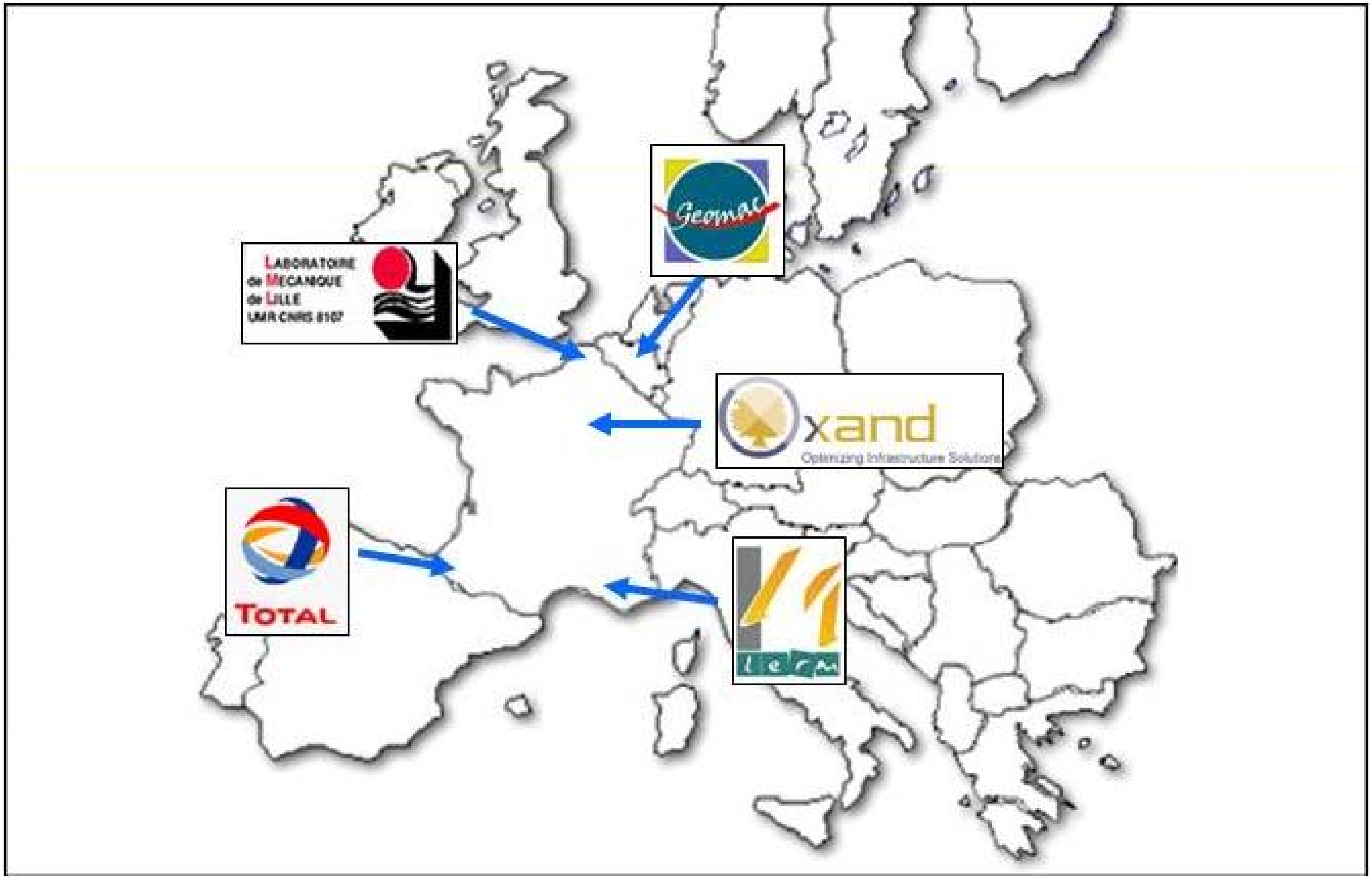
- **Introduction**
- **Objectives**
- **Static tests (degradation)**
  - CO_2-rich water (10 bar, 90°C)
  - Supercritical CO_2 (80 bar, 90°C)
- **Coupled tests : chemo-mechanical tests**
  - CO_2 saturated water (10-25 bar, 90°C)
  - Supercritical CO_2 (80-100 bar, 90°C)
- **Conclusions**

TOTAL

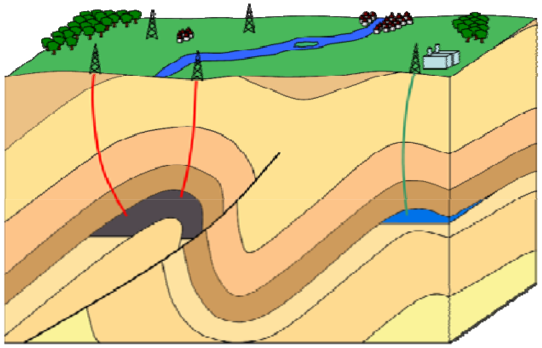
Project partners



TOTAL

Introduction

- **CO_2 storage and well integrity issues**



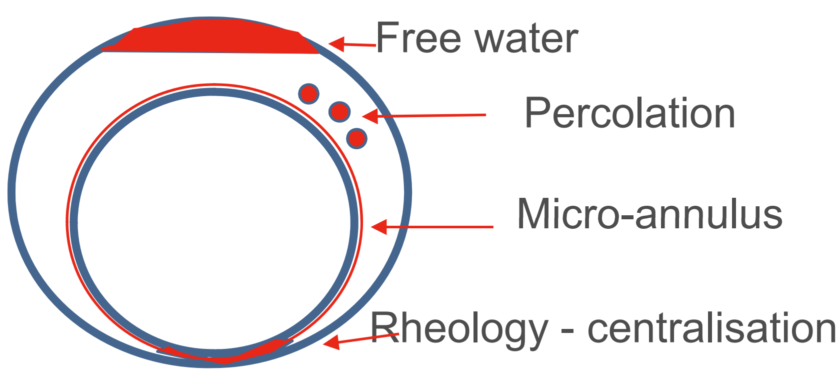
- **CO_2 experiments run in 2004 / 2005 after feasibility study with NH_4NO_3 (ammonium nitrate)**
  - To validate degradation procedures
  - To validate analysis setups

- **The objective was to degrade class G cement sample in the presence of CO_2**

TOTAL

Introduction: leak factors in a cement job

- **No cement (did not set). Can be caused by contamination by mud, or cement quality, or cross-flow while cementing**
- **Cement placement during primary cementing: mud displacement incomplete due to rheology, hole diameter (wash out), casing centralisation.**
- **Cement quality: free water in deviated wells, gas percolation while setting, mud contamination**
- **Microannulus (cement sheath mechanical problem)**
- **Chemical attacks classically only mitigated by the use of HSR cement (High Sulfate Resistant): IS THERE A PROBLEM WITH CO2??**



Objectives of this study

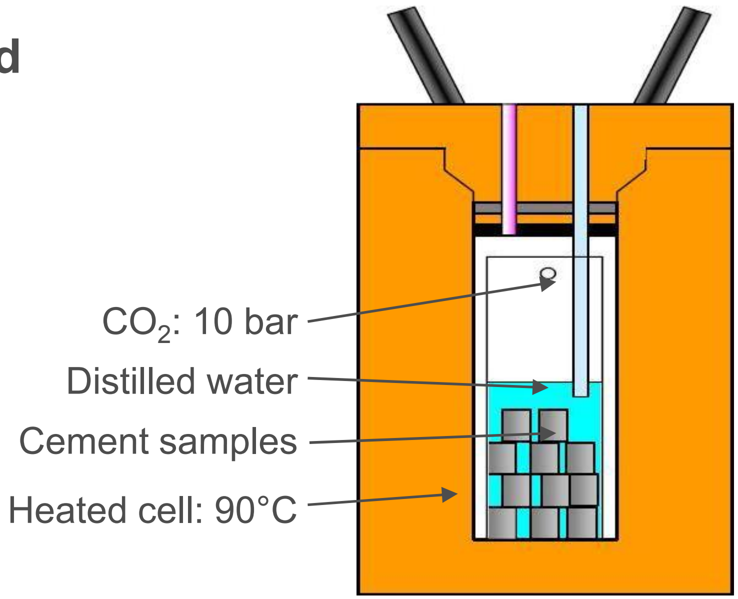
- **Assess the phenomenology of neat class G cement degradation in the presence of CO_2**
  - ➔ Static tests: pCO_2 = 10-80 bar, 90°C (194°F)

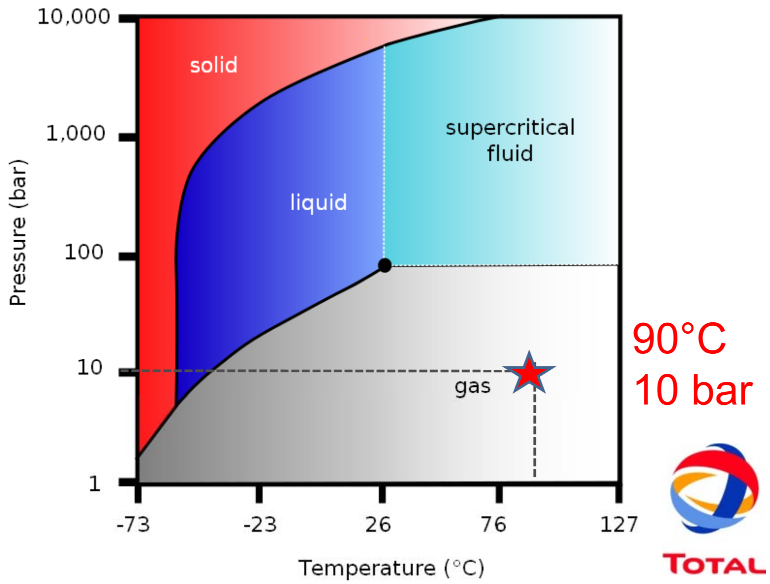
- **Assess kinetics of class G cement degradation in the presence of CO_2**
  - ➔ Static tests: pCO_2 = 10-80 bar, 90°C

- **Assess the impact of CO_2 on <u>transport</u> and <u>mechanical</u> properties of class G cement**
  - ➔ Static tests: pCO_2 = 10-80 bar, 90°C
  - ➔ Coupled tests: pCO_2 = 10-100 bar, 90°C, hydrostatic and deviatoric stress

Static tests – CO_2-rich water – The principles

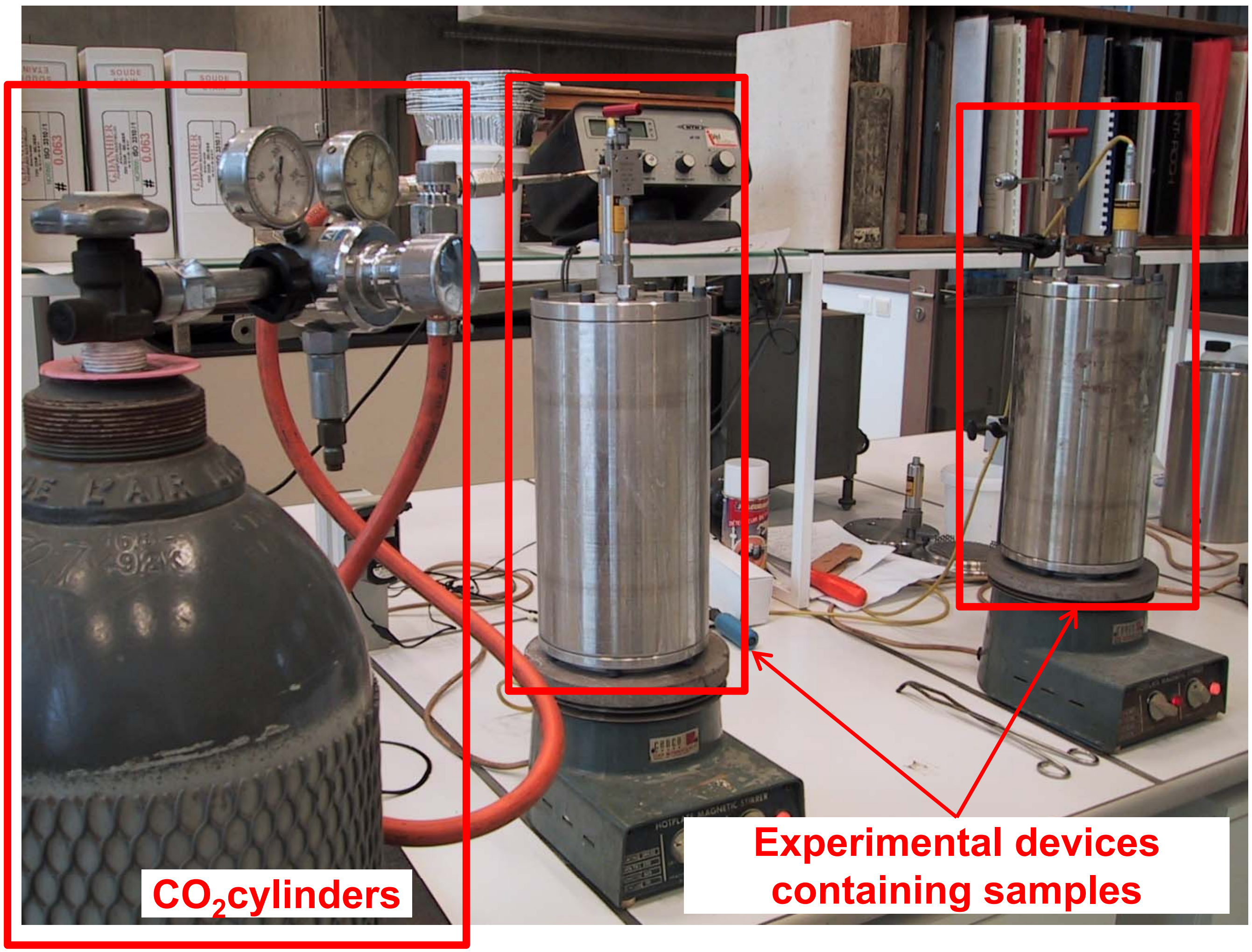
- **Class G Portland cement cylinders (cured during 5 weeks @ 90°C & atm pressure)**
  - Dimensions: 36 x 100 mm
- **Initial conditions**
  - Samples immerged in CO_2-rich water (water in contact with CO_2 gas)
  - 90°C
  - CO_2 gas pressure in the cell : 10 bar
- **Cement sampling**
  - 7 days (1 week)
  - 30 days (1 month)
  - 75 days (2.5 months)
  - 150 days (5 months)
- **Characterization**
  - Mechanics : Brazilian tensile test (Rt)
  - Chemistry





TOTAL

Static tests – CO_2-rich water – Picture of experimental devices



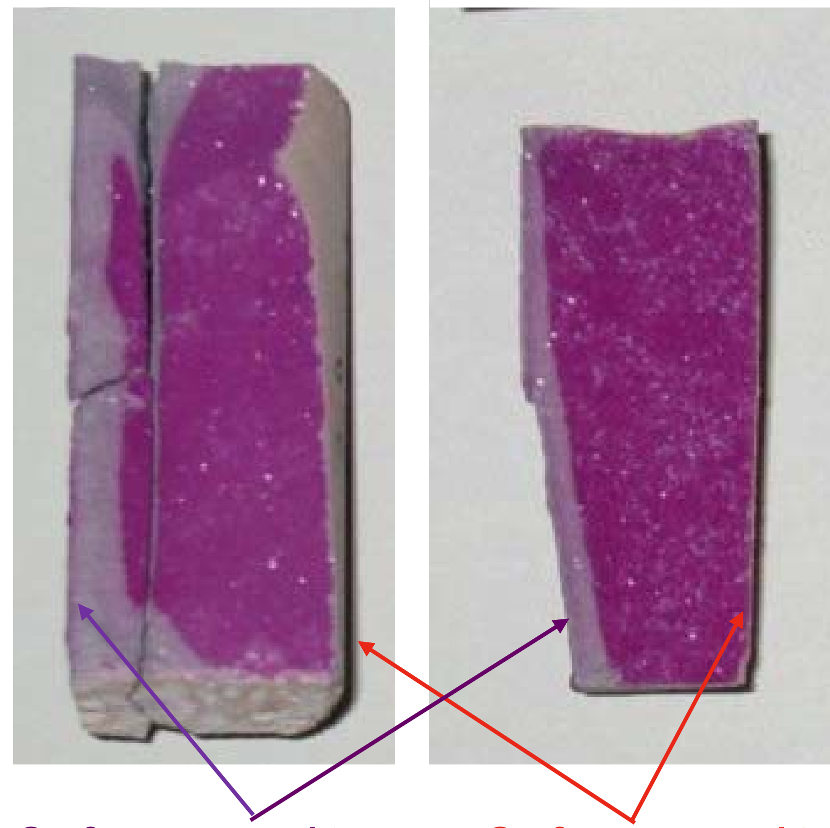
TOTAL

Static tests – CO_2-rich water – Phenolphthalein test (1)

- Very little carbonation due to CO_2-rich water: < 1 mm
- Faster carbonation when exposed to air after static test: up to 4 mm in 4 months

30 days in CO_2, then 4 months in air

75 days in CO_2, then 75 days in air



Surface exposed to air after Brazilian test

Surface exposed to CO_2 during static test

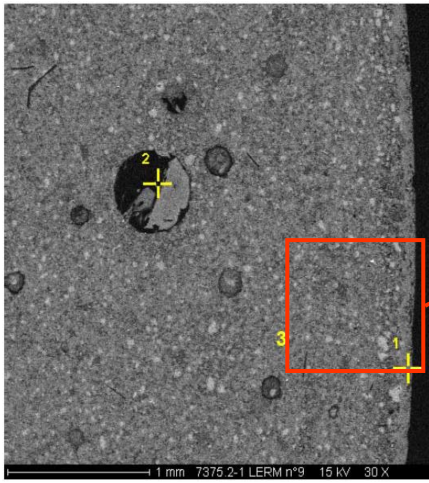
Static tests – CO_2-rich water – Phenolphthalein test (2)

Sample after 5 months of exposure to CO_2-rich water: no visible evidence of carbonation

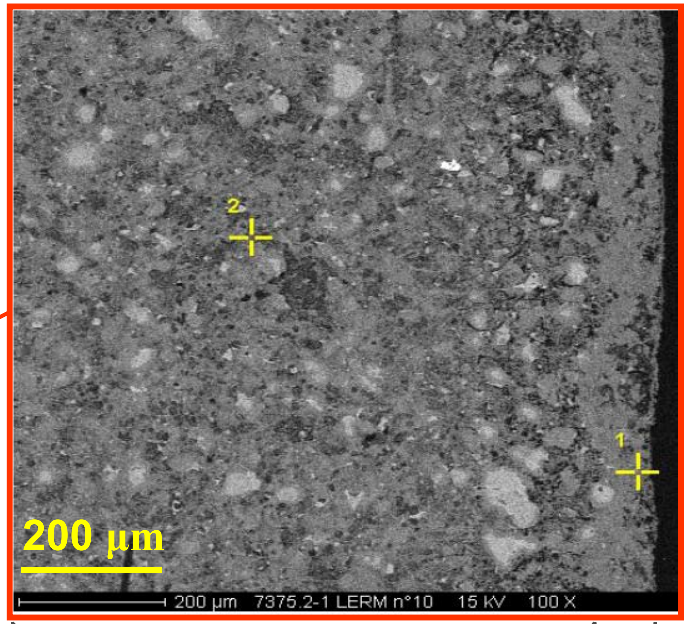
Phenolphthalein test on a fresh fracture after exposure to CO_2

TOTAL

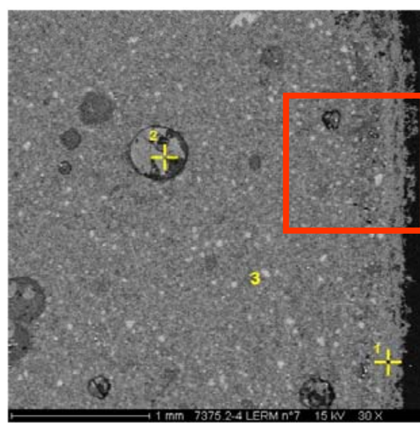
Static tests – CO_2-rich water – Thin carbonated zones

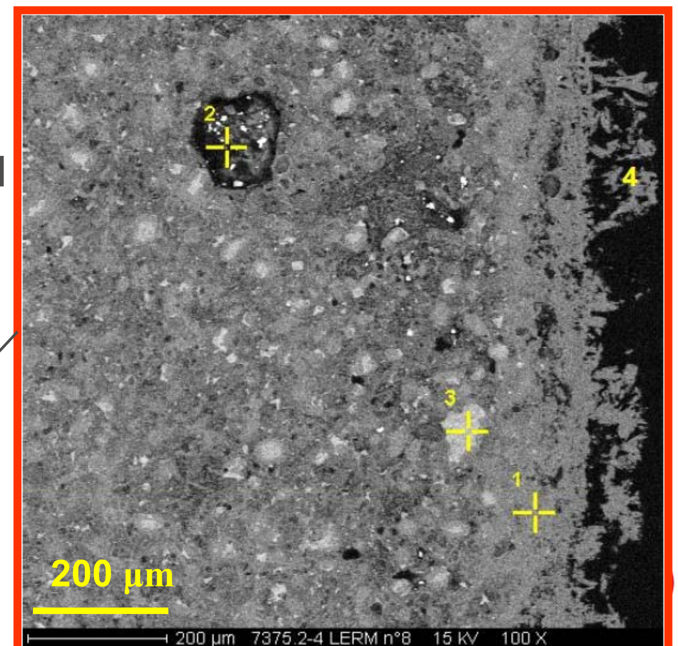


1 week exposure to CO_2



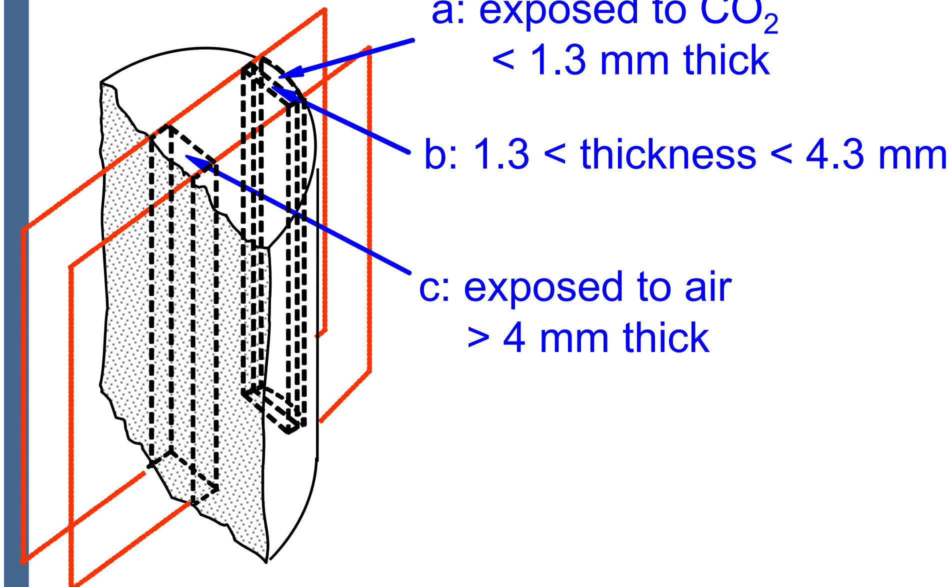
5 months exposure to CO_2





Static tests – CO_2-rich water – Chemical composition after 5 months

Sampling for chemical analysis



Evolution after CO_2 exposure – Qualitative comparison

Minerals	Relative intensity			
	a	b		c
Portlandite	**++**	**+++**	***Inside***	**+++**
Calcite	**++**	**t**	***of***	**+**
CO_2 content (associated to calcite)	**5.6 %**	**3.0 %**	***sample***	**3.3%**

+++ : high intensity; ++ : average intensity; + : low intensity
p : present; t : traces; - : not detected

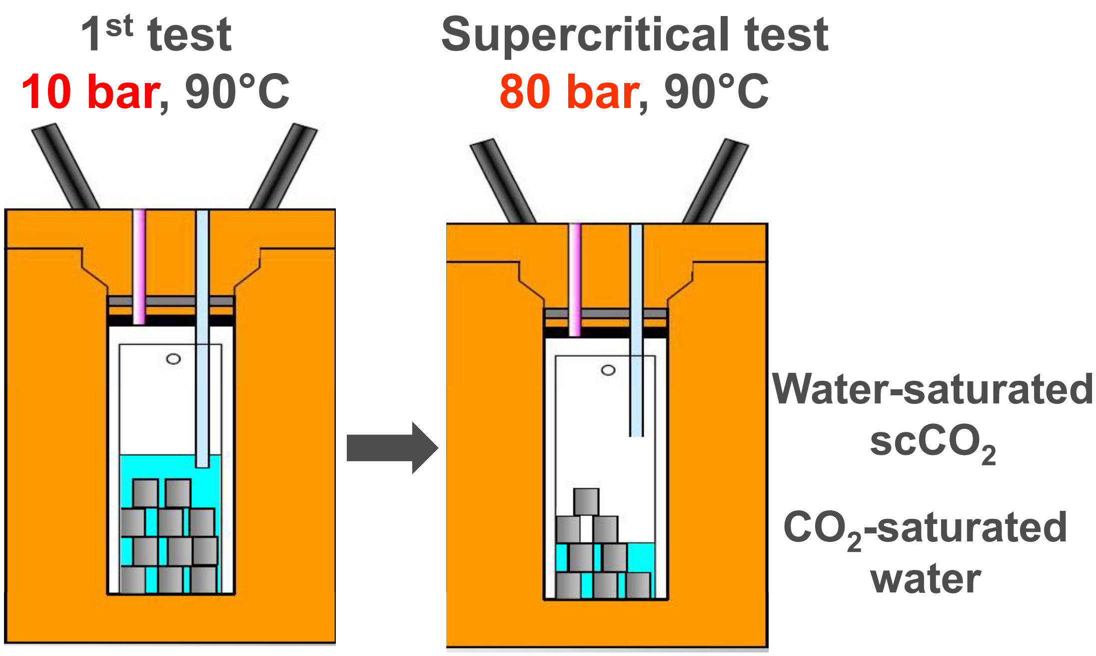
- **Formation of calcite at the expense of Portlandite during CO_2 exposure**

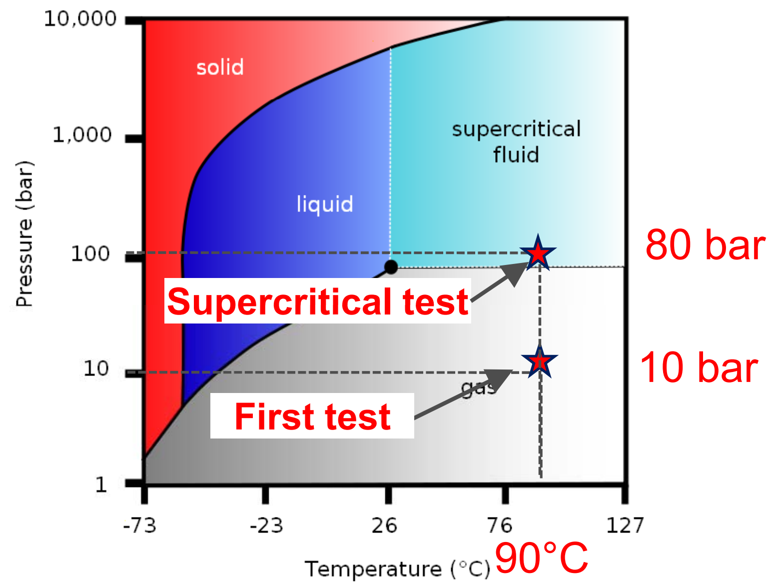
Static tests – CO_2-rich water – Brazilian tensile test after CO_2 exposure

- CO_2rich water : pCO_2 = 10 bar
- Temperature = 90°C
- Exposure : from 1 week to 5 months

- No significative change in strength (22-37 bar tensile strength)

Static tests – Supercritical CO_2 – The principles





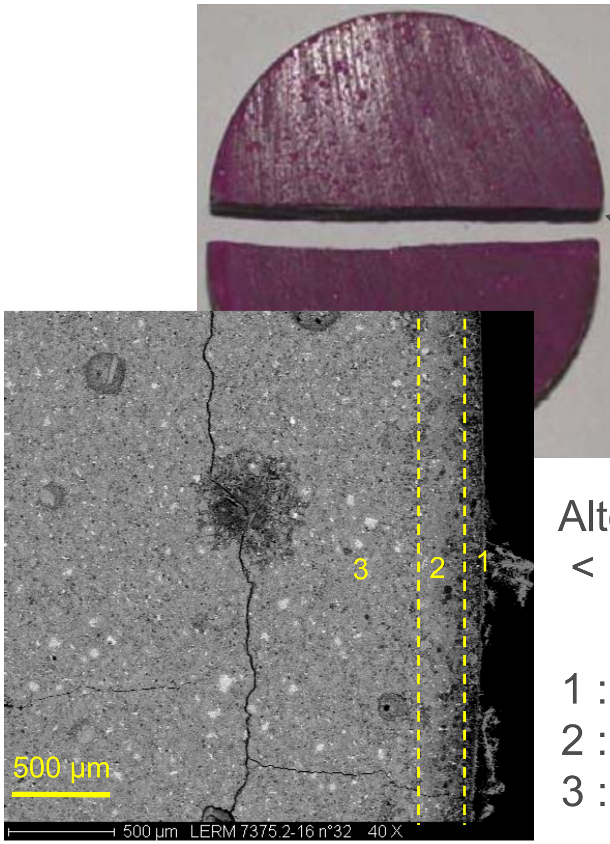
- **3 weeks exposure to:**
  - Wet supercritical CO_2 (top of cell)
  - CO_2-rich water (bottom of cell)
- **Similar procedure than previous tests, but greater CO_2 pressure → Supercritical CO_2**

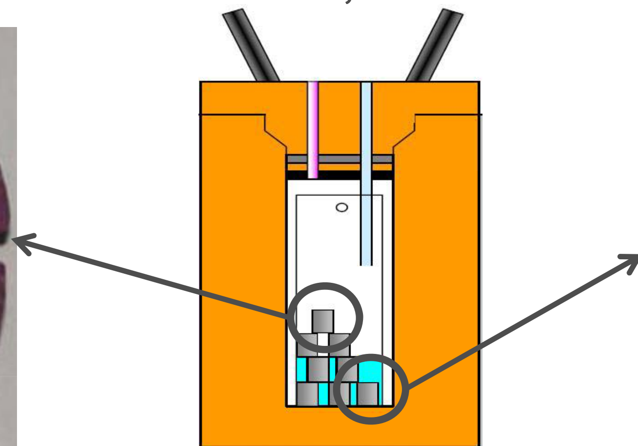
Static tests – Supercritical CO_2 – Carbonated zones

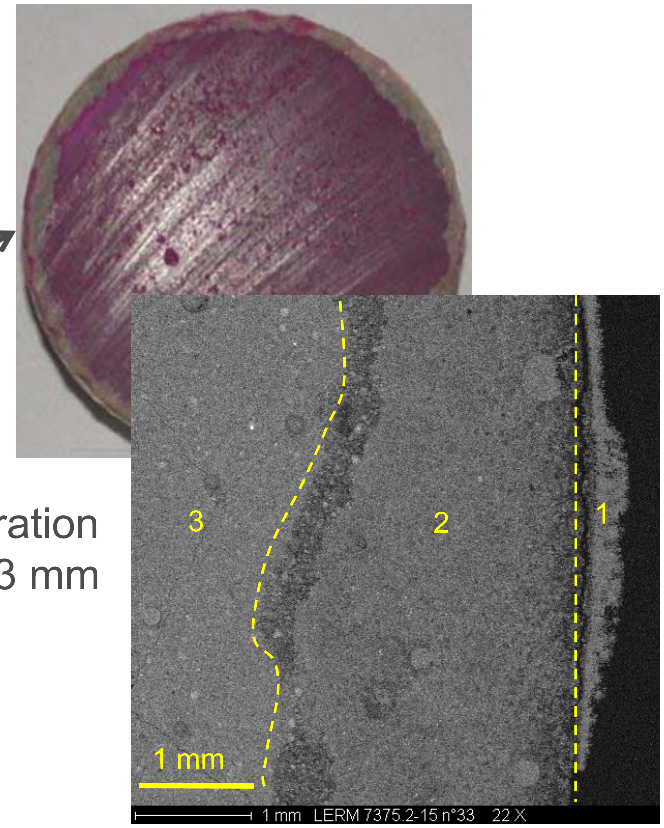
In $scCO_2$

80 bar, 90°C

In water







Alteration
< 1 mm

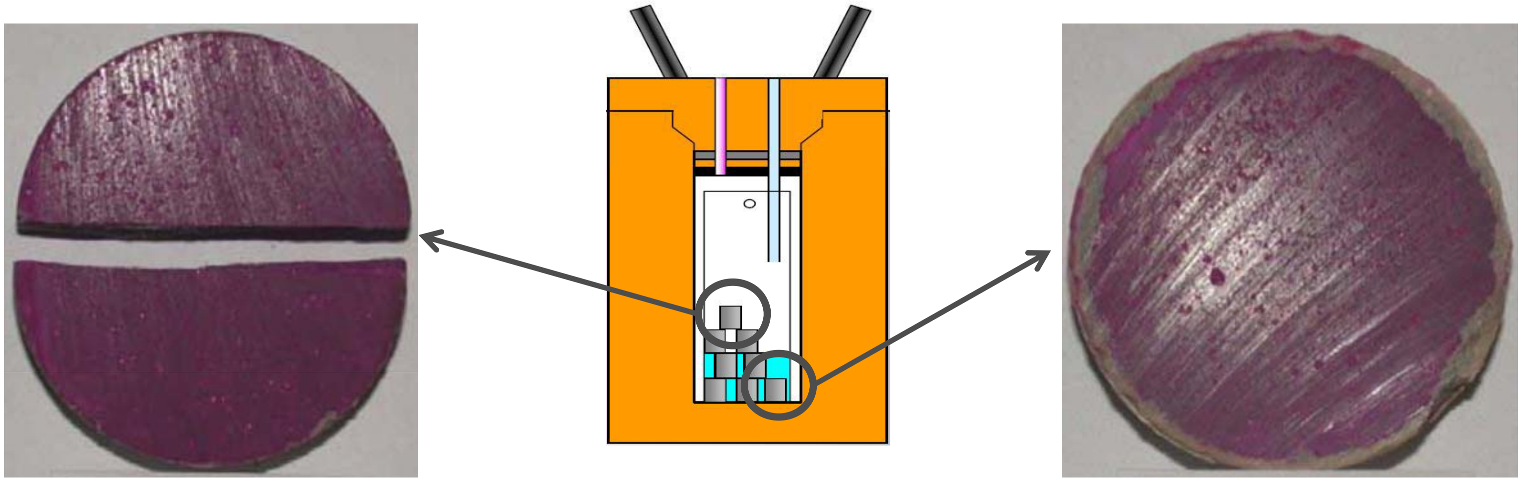
Alteration
= 2-3 mm

1 : high $CaCO_3$ content
2 : altered porous zone
3 : unaltered cement

- **Faster carbonation with supercritical CO_2 (higher gas pressure)**
- **Faster carbonation when exposed to CO_2-rich water (compared to $scCO_2$)**

Static tests – Supercritical CO_2 – Chemical composition

In $scCO_2$ — **80 bar, 90°C** — **In water**



	Minerals	Relative intensity a	b	c
	Thickness from surface [mm]	0 -1	1 - 2	2 - 3
Exposed to CO_2	Portlandite	++	+++	+++
	Calcite	++	-	-
	Aragonite	t	-	-

	Minerals	Relative intensity a	b	c
	Thickness from surface [mm]	0 -1	1 - 2	2 - 3
Exposed to water	Portlandite	++	+++	+++
	Calcite	++	t	-
	Aragonite	+	-	-

+++ : high intensity; ++ : average intensity; + : low intensity
p : present, t : traces, - : not detected,

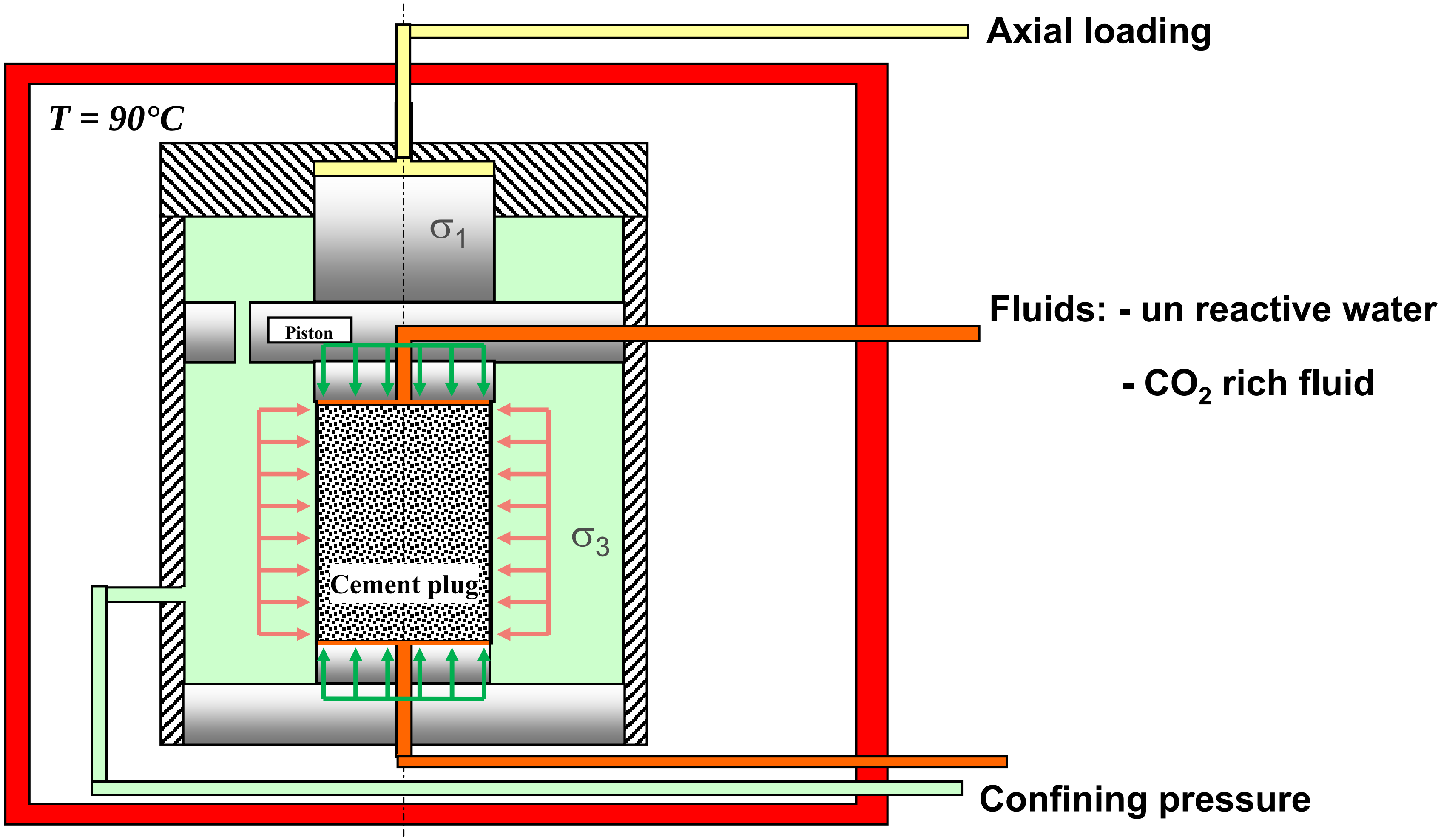
- **Deeper carbonation front when degraded in the presence of water**
  - Lower Portlandite content
  - Greater carbonate content

Coupled "chemo-mechanical" tests – The principles

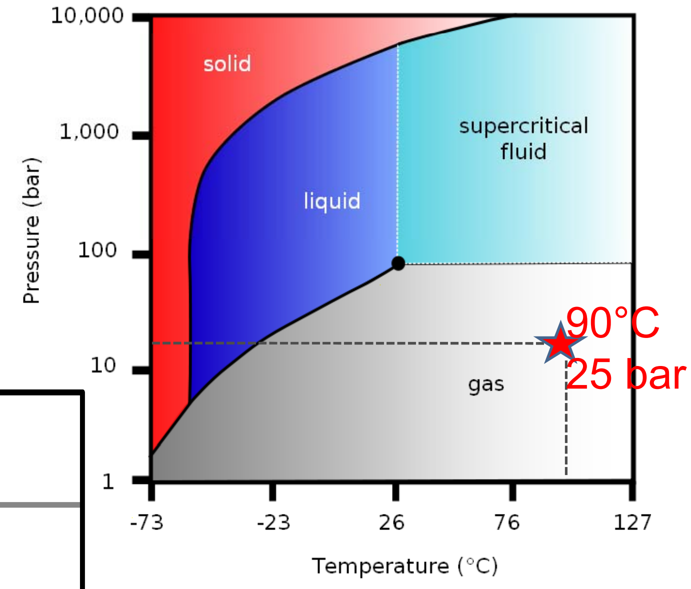
- **Objectives:**
  - Assess the impact of CO_2 degradation on the mechanical behavior of cement, and on the permeability values
- **Conditions for the 5 tests:**
  - Temperature : 90°C
  - Initially saturated samples (with unreactive aqueous fluid)
  - Samples under stress
- **Three tests with CO_2-rich water:**
  - PCO_2 = 10/25 bar
- **Two tests with SC CO_2, dry and wet**
  - PCO_2 = 85-110 bar

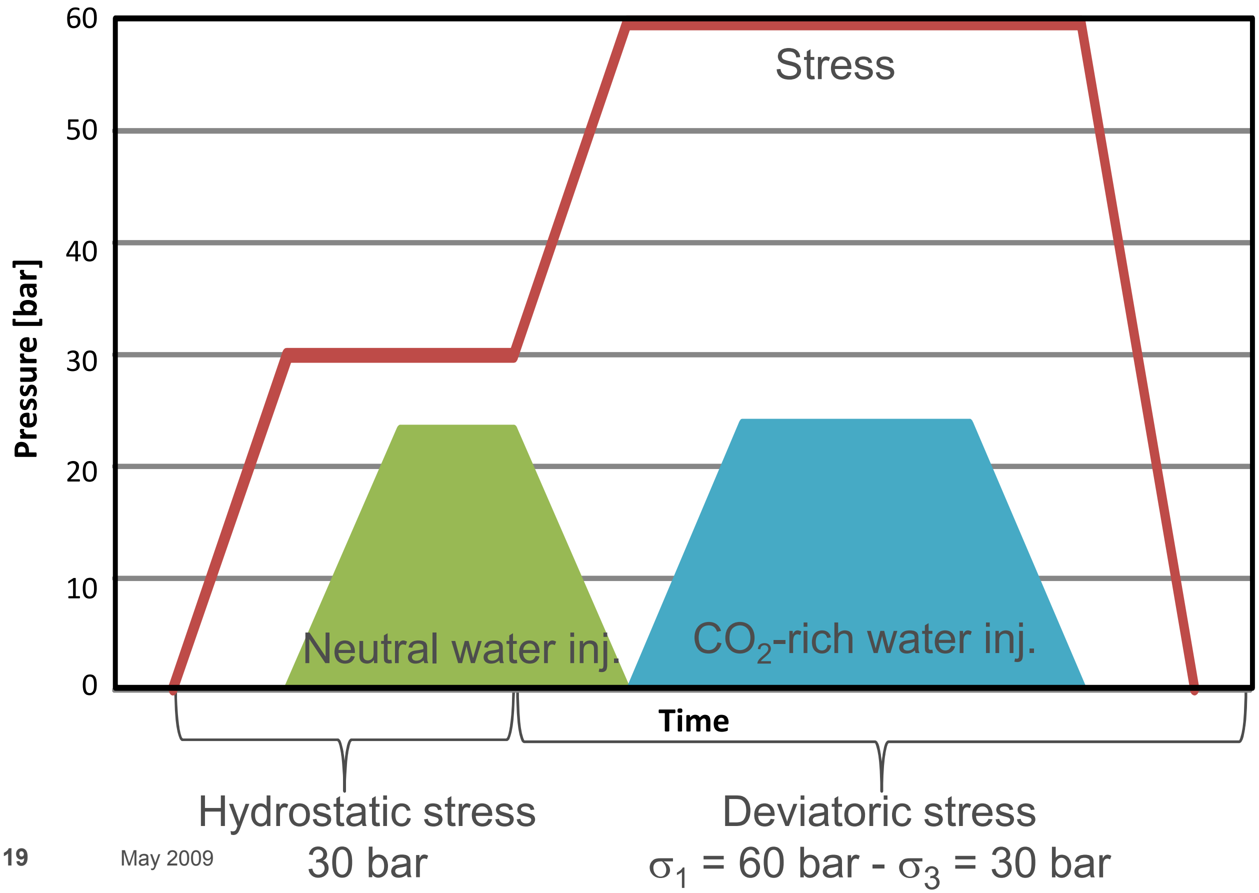
TOTAL

Coupled “chemo-mechanical” tests – The triaxial cell



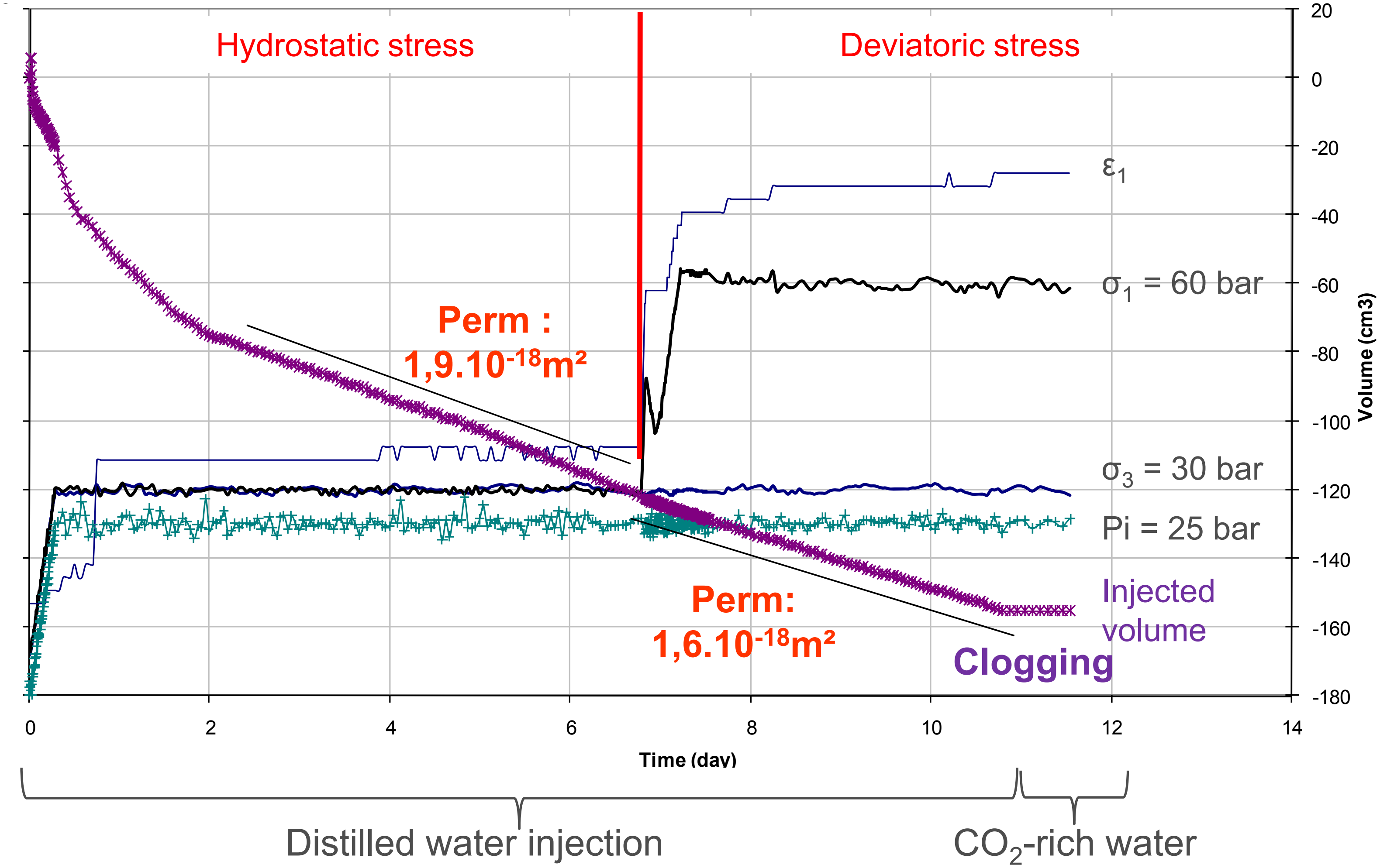
Coupled "chemo-mechanical" tests – CO_2-rich water – Loading path





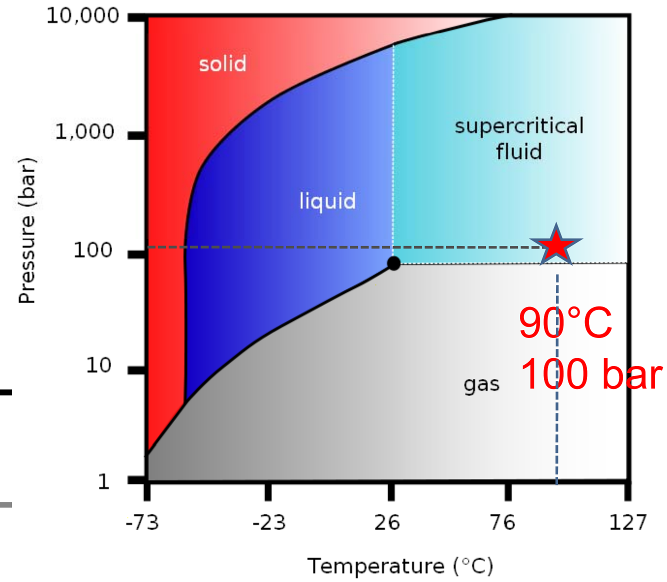
TOTAL

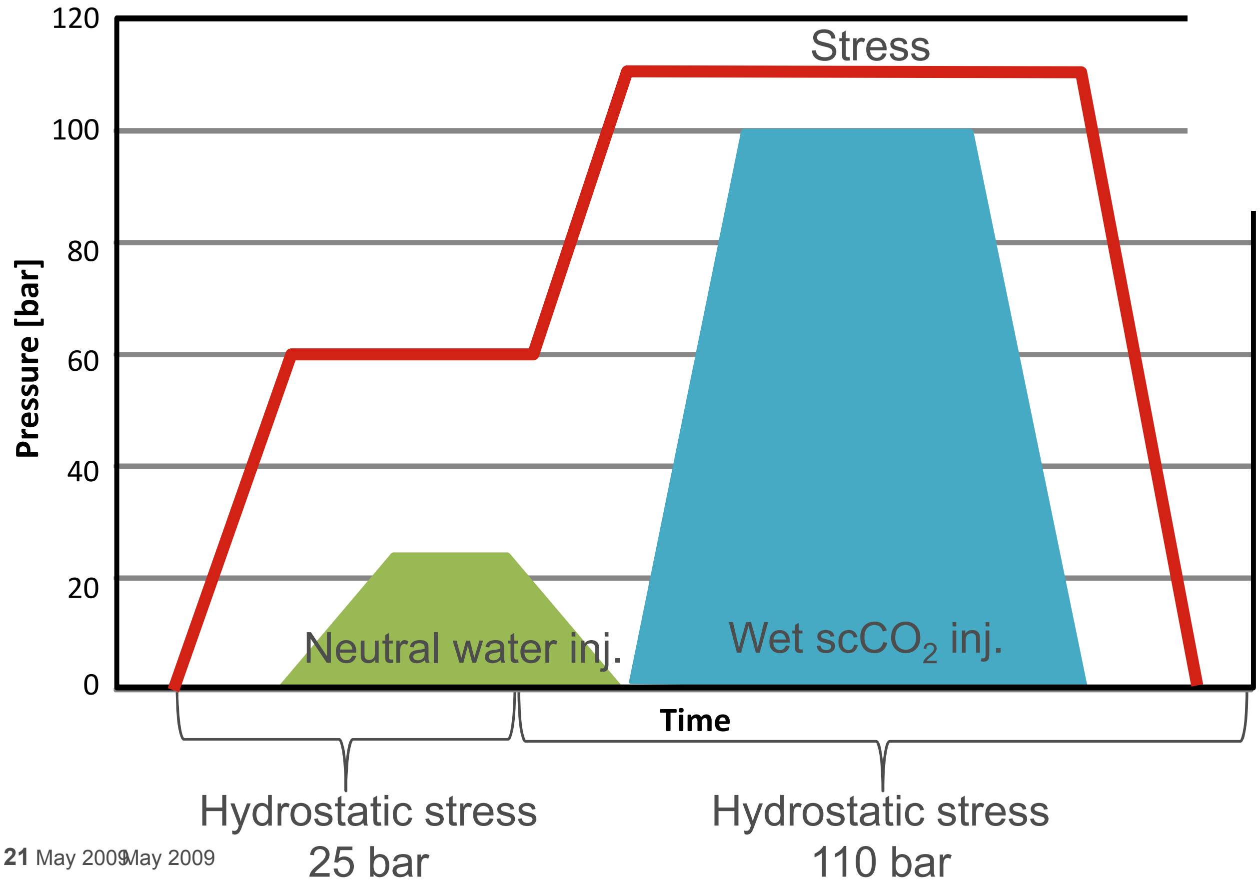
Coupled "chemo-mechanical" tests – CO_2-rich water



- **No evolution of strain with the injection of CO_2-rich water**
  - Evolution of strain because of stress change (increase of σ_1)
- **Clogging of cement during CO2-rich water injection**

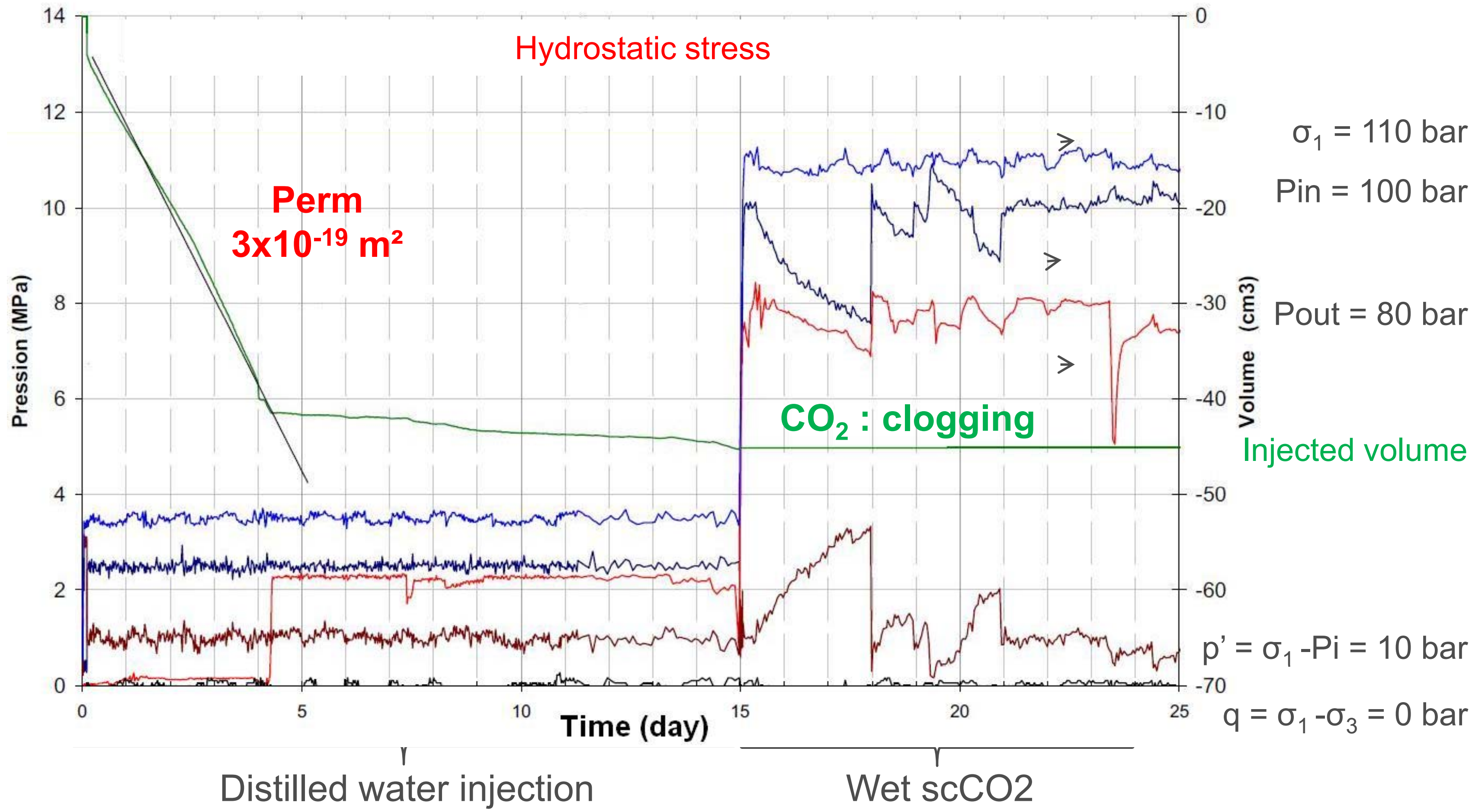
Coupled "chemo-mechanical" tests – Wet supercritical CO_2 – Loading path





TOTAL

Coupled "chemo-mechanical" tests – Wet supercritical CO_2



- **No evolution of strain with the injection of wet $scCO_2$**
- **Clogging of cement during wet $scCO_2$ injection**

Permeability values - Synthesis

Fluid	K w/water 10^{-18} m^2	K w/ CO2 10^{-18} m^2	Final w/ CO2	Stress
CO2 in water 1	1,6	Not measurable	Plugging	Deviatoric
CO2 in water 2	0,05	0,02	Plugging	Deviatoric
CO2 in water 3	1,95	0,28	Plugging	Isotropic
Dry SC CO2	1,14	Not measurable	Plugging	Deviatoric
Wet SC CO2	0,3	Not measurable	Plugging	Isotropic

- **Significant decrease of permeability values during CO_2 rich fluid injection**
  - ➔ Clogging of cement porosity → un measurable permeability values

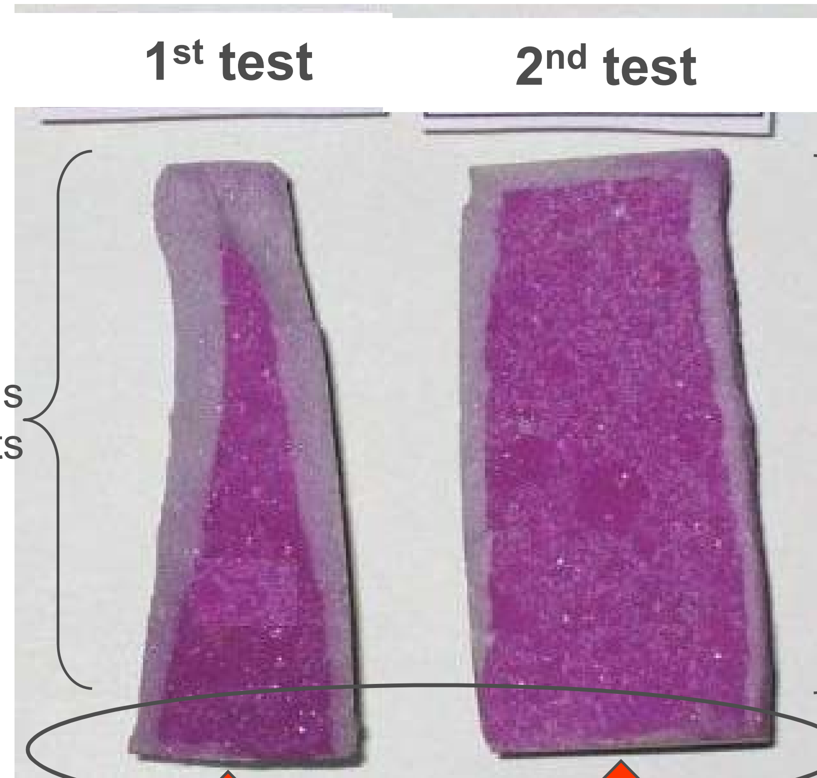
1mD = 10^{-15} m^2

TOTAL

Mechanical strength

- No additional deformation associated to CO_2 rich water injection during the experiment
- No evolution of cement mechanical properties

Chemical impact



Exposed 2.5 months to air after tests

Exposed to 1 week air after tests

Surface exposed to CO_2 during injection

CO_2-rich water injection

- **Low carbonation at injection surface**
  - Sample carbonation is due to air exposure after test

Conclusions

- **Improvements achieved in experimental procedures and samples characterization**
  - Development of detailed procedure and quality controls
- **Degradation in the presence of CO_2-saturated water leads to deepest carbonation ≈ 3 mm after 5 months**
  - Similar degradation after 1 week and 5 months
- **No mechanical properties degradation with injection of CO_2-rich fluids**
- **Plugging of cement samples with CO_2-rich fluid injection**

Questions?

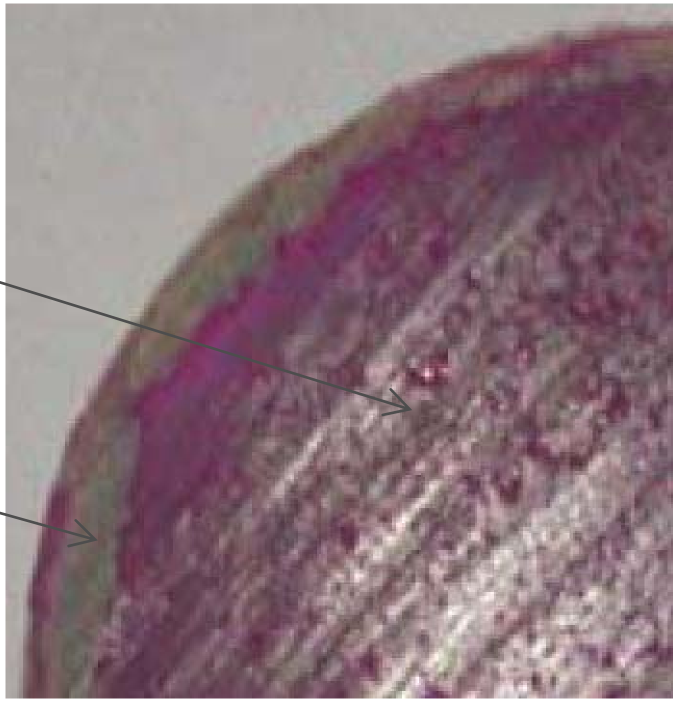
SPARES

Phenolphthalein test

- **Phenolphthalein is a colour indicator**
  - Color evolves with pH
    - Greater that 10 : pink colour due to Ca OH (OH-) = Portlandite = cement not carbonated
    - Lower than 8.2 : no colour = no Ca OH

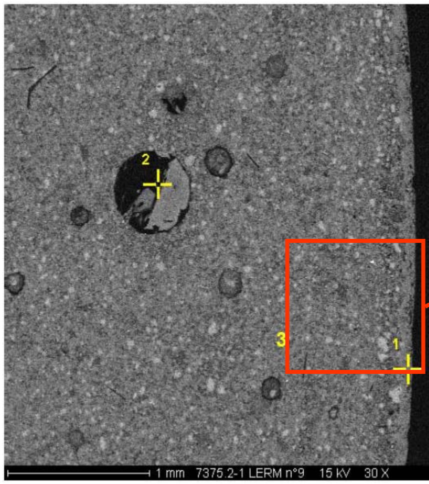
High pH value :
no degradation

Low pH value :
possibly associated
to carbonation



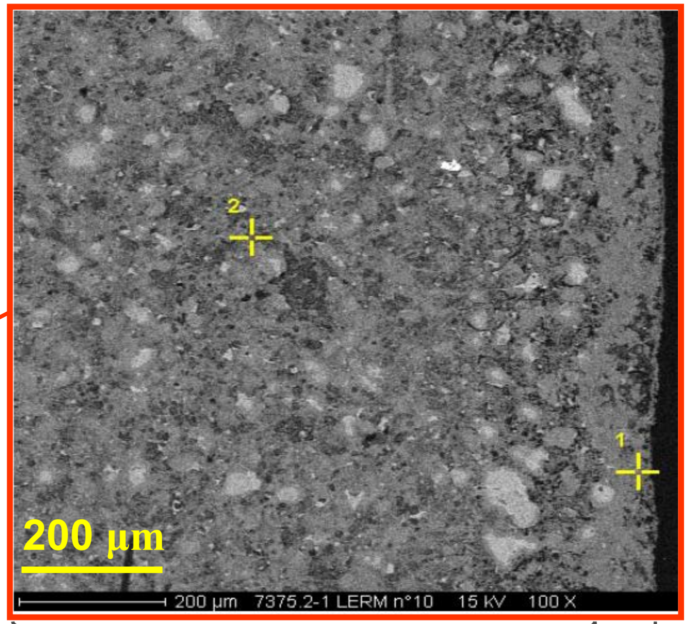
Static tests – CO_2-rich water – Thin carbonated zones

1 compact surface
2 Portlandite in air bubble
3 matrix



1 week exposure to CO_2

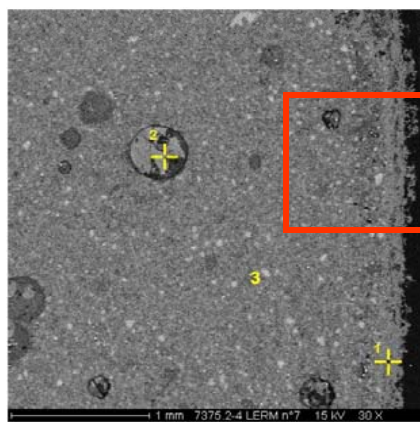
2 matrix



Unaltered cement Carbonated

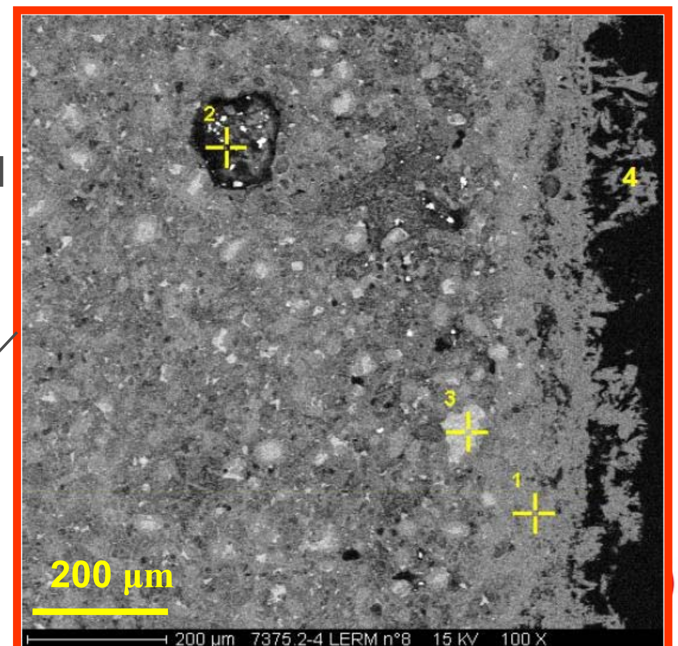
1 compact surface
2 Portlandite in air bubble
3 matrix

5 months exposure to CO_2

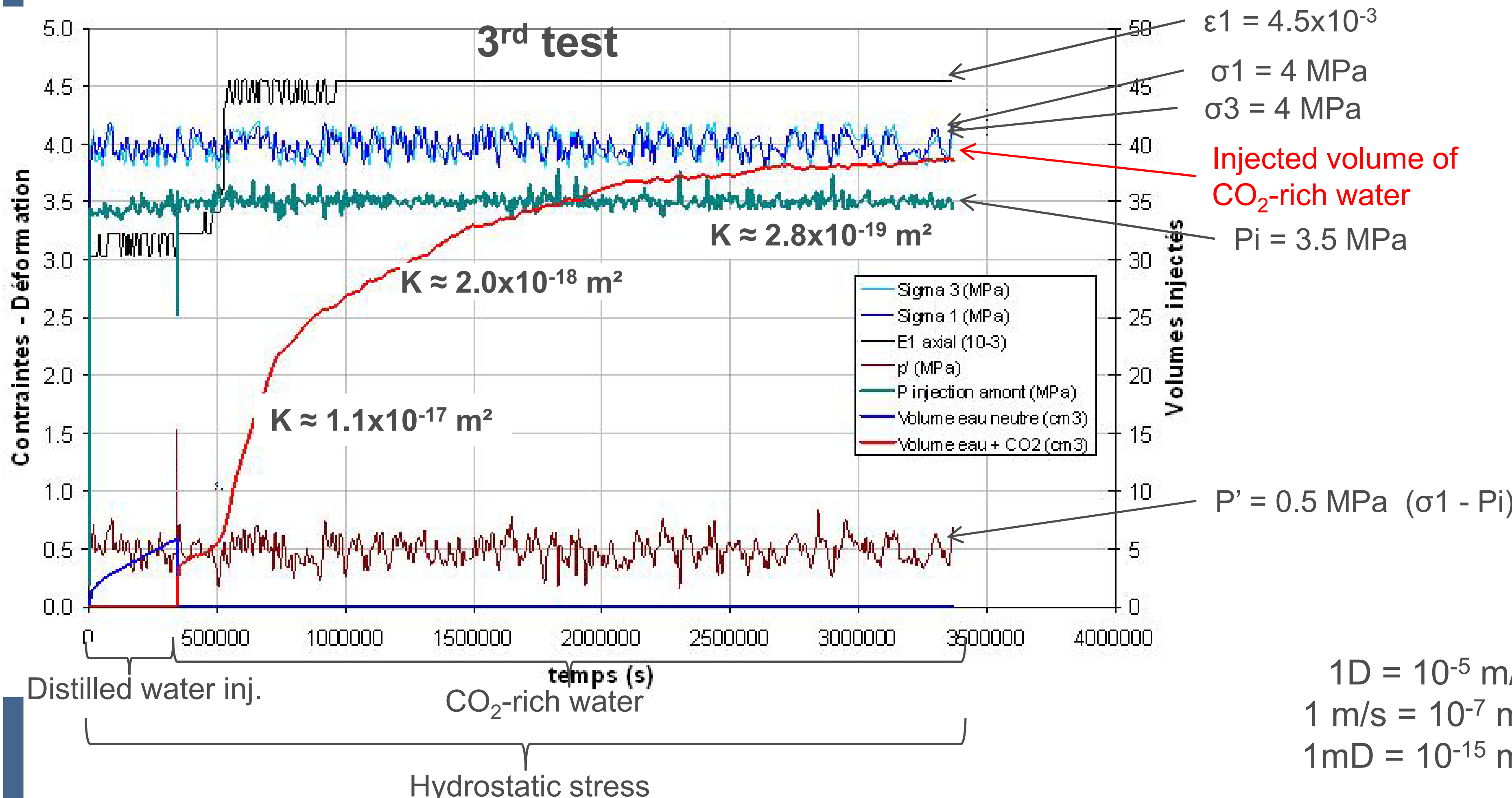


1compact surface
2matrix porosity
3 clinker grain
4$CaCO_3$ deposits

Unaltered cement Carbonated



Test 3



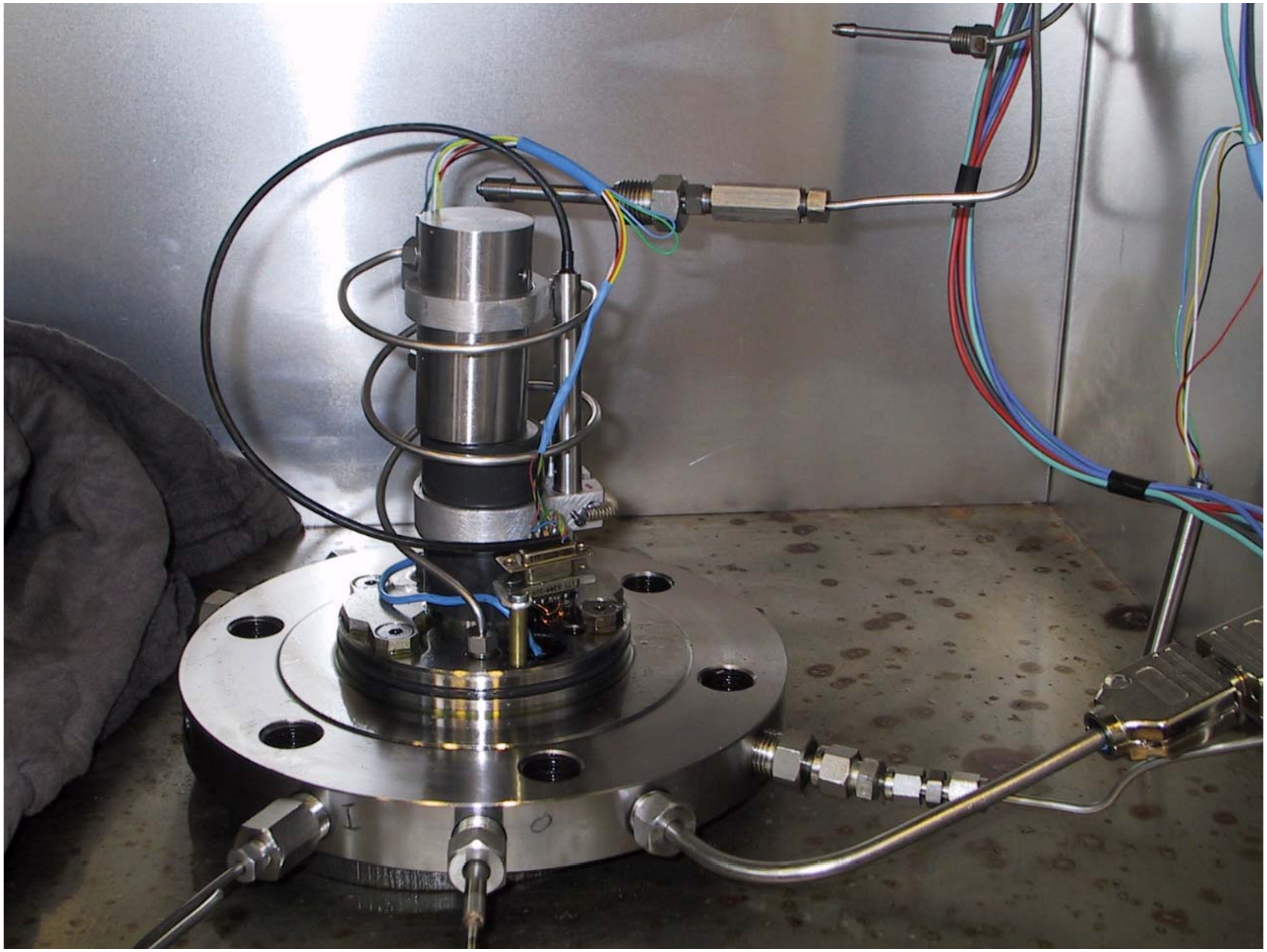
$1D = 10^{-5}$ m/s
1 m/s = 10^{-7} m²
1mD = 10^{-15} m²

- → Strain with injection of CO_2-rich water : $\Delta\varepsilon 1 \approx 1.5 \times 10^{-3}$
- → Clogging of cement during CO_2-rich water injection

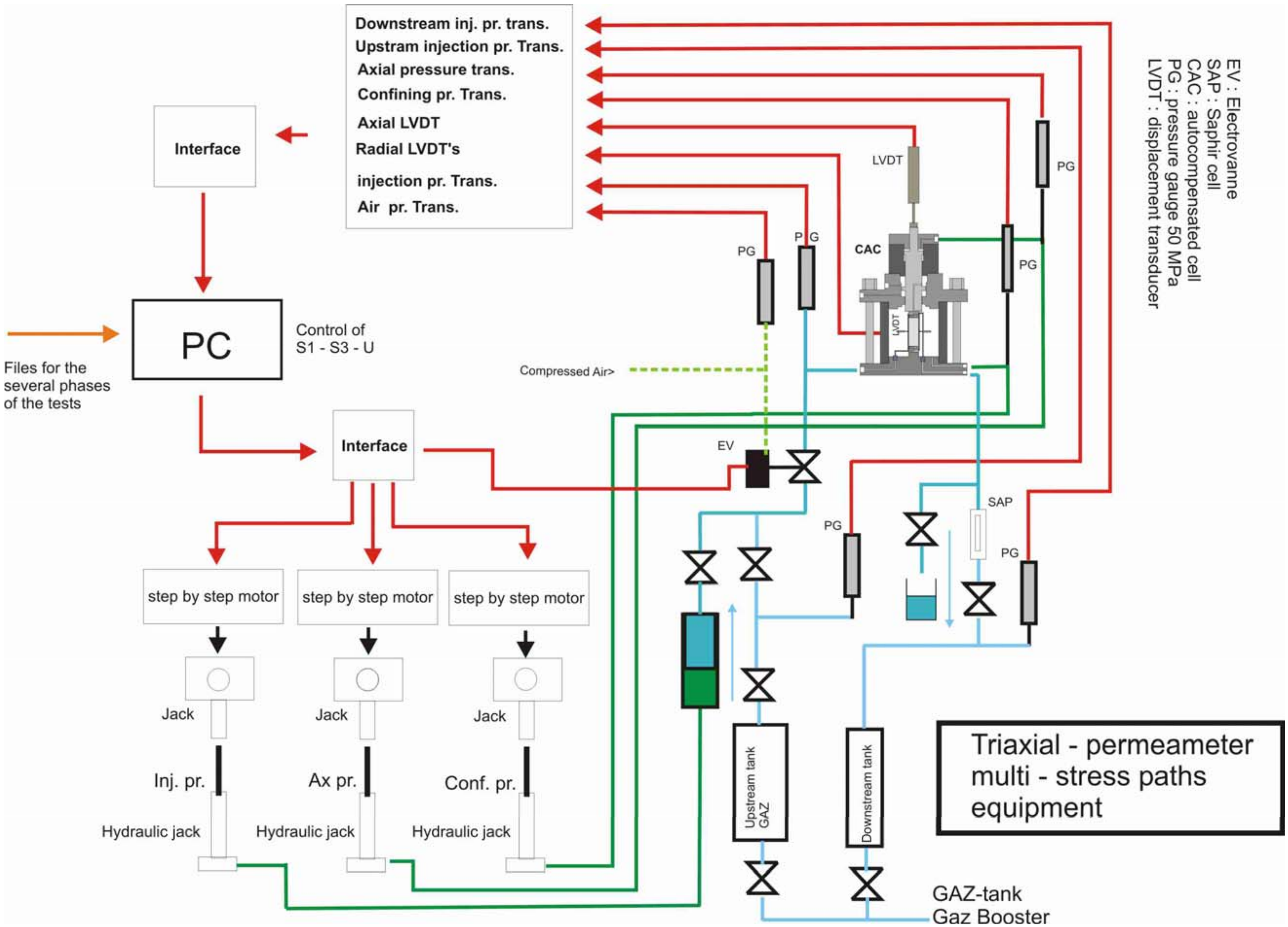
Picture of the cell for static test with 80 bar of CO_2 pressure

TOTAL

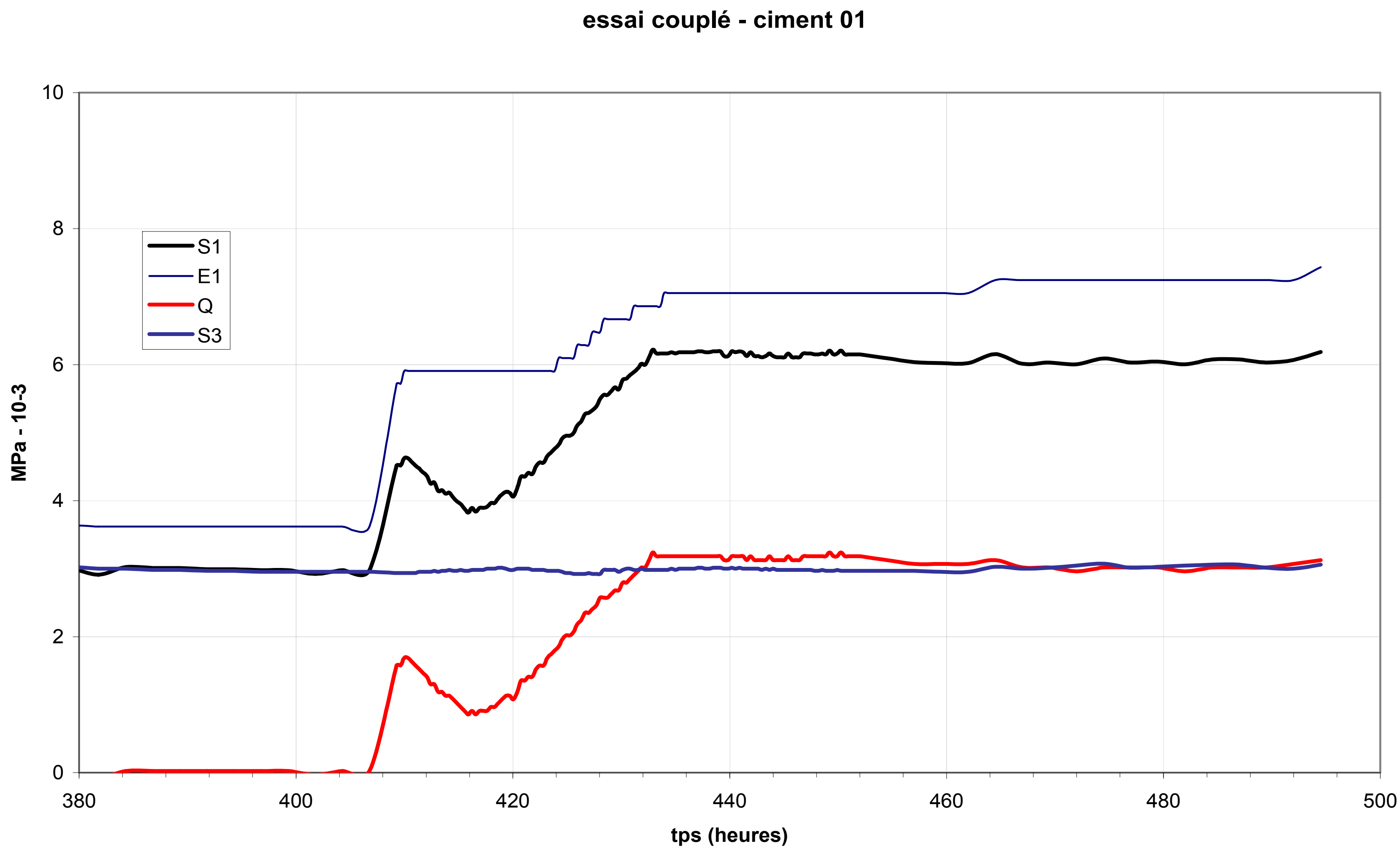
Picture of the cell for coupled tests



Schematic of coupled test setup



Test 1: strain during increase of deviatoric stress



Young modulus during deviatoric phase : E = 1.1 GPa

TOTAL

Coupled "chemo-mechanical" tests

- **Conditions :**
  - Temperature : 90°C
  - Initially saturated samples (with un-reactive aqueous fluid)

- **Procedure**
  - Hydrostatic stress :
    - Preliminary test : S1 = S3 = 20 MPa
    - Test 1 : S1 = S3 = 3 MPa
    - Test 2 : S1 = S3 = 3 MPa
  - Injection of non reactive aqueous fluid
    - Preliminary test : Pf = 10 MPa
    - Test 1 & 2 Pi = 2.5 MPa
  - Deviatoric stress:
    - Preliminary test : S1 = 35 MPa, S3 = 20 MPa
    - Test 1 : Dev = 3 MPa
    - Test 2 : Dev = 9 MPa
    - Test 3 : n/a
  - Injection of non reactive fluid
  - injection of CO_2-rich fluid
    - Test 1 & 2 Pi = 2.5 MPa (PCO2 = 1 MPa)
    - Test 3 : Pi = 3.5 MPa , Ps = 1 Mpa (ΔP = 2.5 MPa)
  - Stress decrease

Simulating leakage through well cement: coupled reactive flow in a micro-annulus

Laure Deremble, Bruno Huet, Brice Lecampion, Matteo Loizzo

Schlumberger Carbon Services

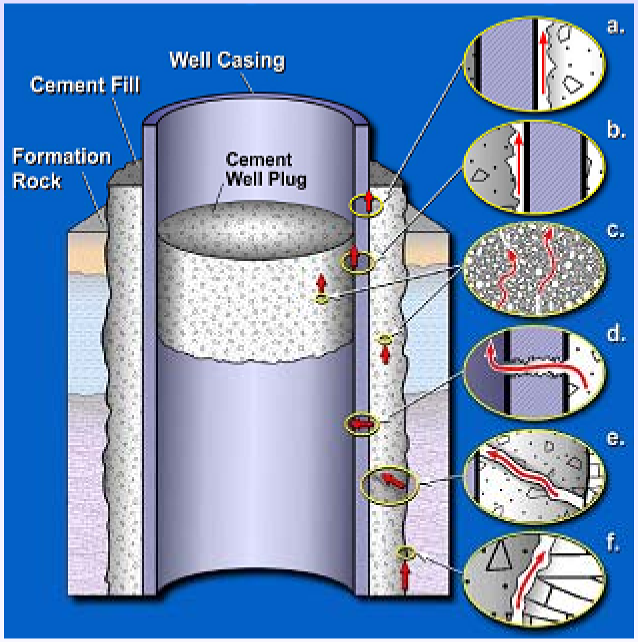
Schlumberger

Context of Gas leaks:

- Field evidence…
  - Surface Casing Vent Flow (SCVF)
  - Gas migration (GM)
- ….Explained by gas flow through defects
  - Microannulus (inner, outer)
  - Mud channels
  - Cracks (?)

- Existing models of gas leaks based on ….
  - Equivalent permeability (i.e. upscaled properties and no defect)
    - ✓ Stochastic model (LANL, PU)
    - ✓ Full reactive transport model (TOUGHREACT , FLOTRAN, HYTEC)

- …do not address the actual physics of leak dynamic:
  - 10^2 m high defect vs 10^{-2} m thick cement sheath
  - Nature of **defects**: micro-annulus, channels
  - **No local equilibrium** between annular fluid and cement sheath
  - **Opening/closing of defects**

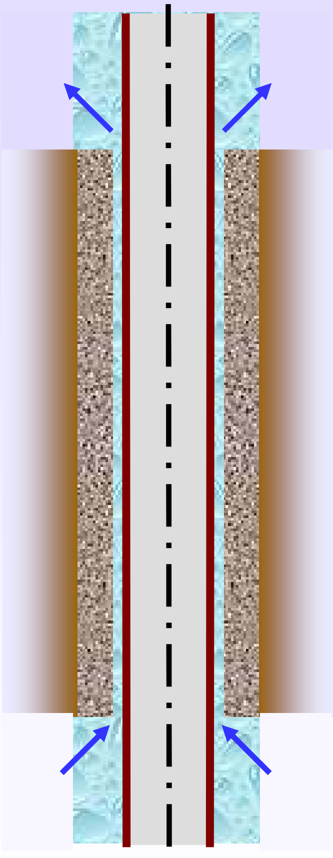


From Celia *et al.* (2004)

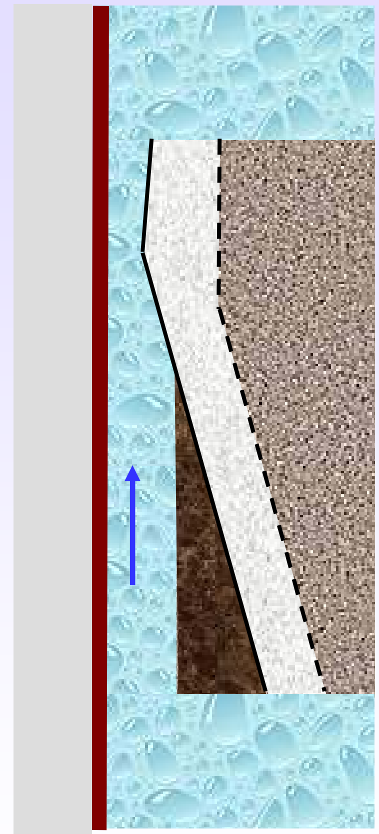
Integration: mechanics, flow, chemistry

- Mechanisms considered for opening (☹) or closing (☺) of µannulus:

Cement
Calcite
Silica Gel



- Mechanics:
  - ✓ Fracturing / debonding of defects ☹
  - ✓ Pressurization of defect ☹
- Cement:
  - ✓ Cement hydrates carbonation ☺
  - ✓ Calcium leaching ☹
  - ✓ Gel erosion and deposition ☹ ☺
  - ✓ Drying shrinkage ☹
  - ✓ Crystallization pressure of calcite ☺
- µannulus reactive flow:
  - ✓ Water condensation ☺
  - ✓ CO_2 bubbling ☹
  - ✓ Calcite precipitation and deposition ☺
  - ✓ Phase change / heat effects ☹ ☺



Building a fast wellbore leakage model

- Modeling strategy:
  - Simplified model for each of relevant mechanism $\Rightarrow$ Modules
  - Smart integration of **modules** (based on dimensional analysis) $\Rightarrow$ Decoupling
  - Explicit identification of the pathways
  - Module validation against experiments

- Governing equations
  - Mechanics:
    - ✓ Annulus width (w): $w = \frac{1}{M}\left(p_{ma} - H\, p_c\right)$
  - Annular chemistry:
    - ✓ Mass balance: $Z^k = \sum_{\beta} \nu_{kj}\, f_\beta X_\beta^j$
    - ✓ Chemical equilibrium constraint: $\mu_j = \sum_c \nu_{jk}\, \mu_k$
  - Cement:
    - ✓ Front tracking: $\frac{dL_j}{dt} = f(L_j, D_j, c_{ij}^{aq}, c_{ij}^{sol}) \quad and \quad Q_i = g(L_0, D_0, c_{i0}^{aq})$
  - Annular flow (isothermal, T=f(z)=cst)
    - ✓ Pressure: $\frac{\partial \rho}{\partial t} = -\nabla(\rho V) \quad and \quad V = \frac{w^2}{\mu}\nabla p$
    - ✓ Composition: $\frac{\partial \rho Z_i}{\partial t} = -\nabla(\rho X_i V - \rho De \nabla X_i) + Q_i$

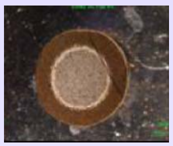
Scenarios

- Case 1: Cement reactivity in CO_2 rich environment
  - CO_2 saturated brine and open system
  - CO_2 liquid phase and closed system
- Case 2: CO_2 rich phase annular flow
  - Flow + mechanics
  - Flow + mechanics + cement reactivity
- Case 3: CO_2 saturated brine annular flow
  - Flow + mechanics
  - Flow + mechanics + cement reactivity

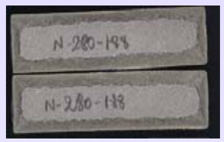
Case 1 - Rapid Cement Degradation Model = RCDM

- RCDM = Simplified model for Portland cement / CO_2 interactions

Reactor experiments

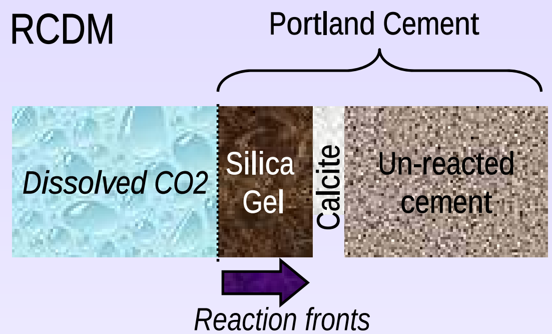


Open system + CO_2 saturated brine (Duguid et al.)

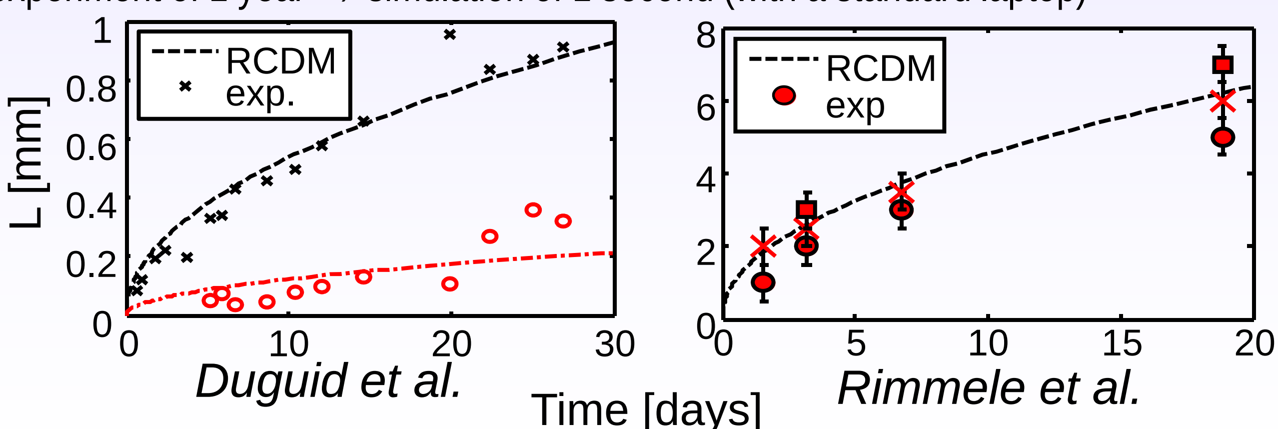


Closed system + CO_2 rich phase (Rimmele et al.)

RCDM

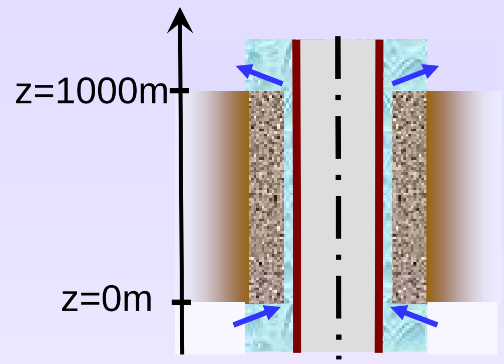


- Comparison with experiments
  - ✓ experiment of 1 year ⇒ simulation of 1 second (with a standard laptop)

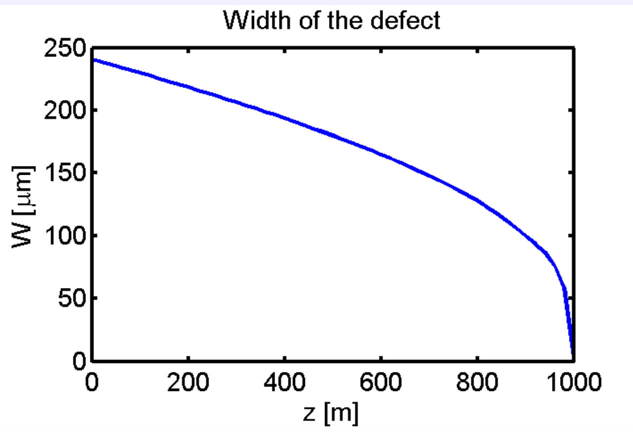


Case 2 – CO_2 rich phase annular flow

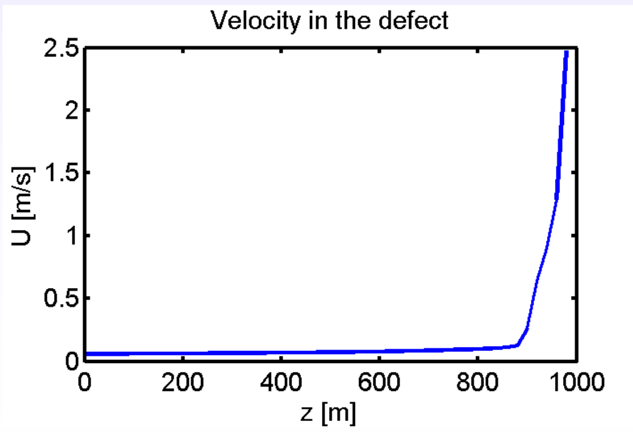
- Annular flow and mechanics:
  - Initial / boundary conditions:
    - ✓ Top of defect:
      - z=1000m, Pt=1bar, T=10°C
    - ✓ In defect:
      - geothermal gradient, $w_0 = 0\ \mu m$
    - ✓ Bottom of defect:
      - z=0m, Pt=150bar, T=42°C, dry liquid CO_2



- Results:
  - Opening of annulus

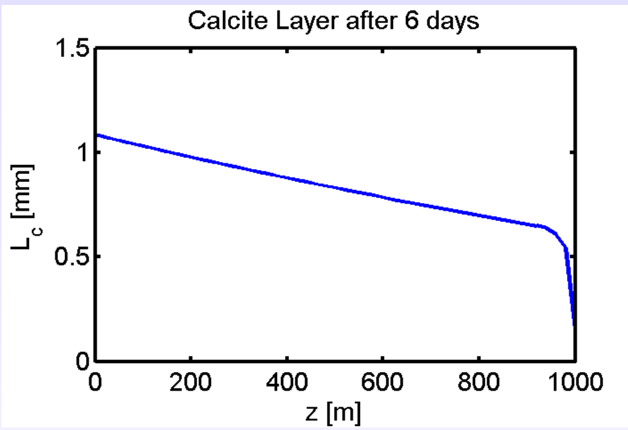


  - Velocity increase at the top

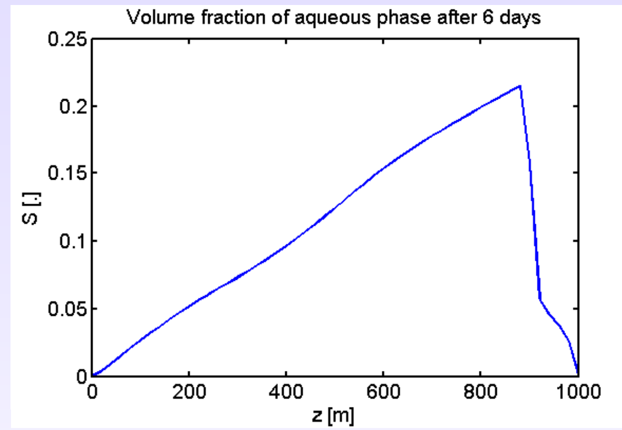


Case 2 – CO_2 rich phase annular flow

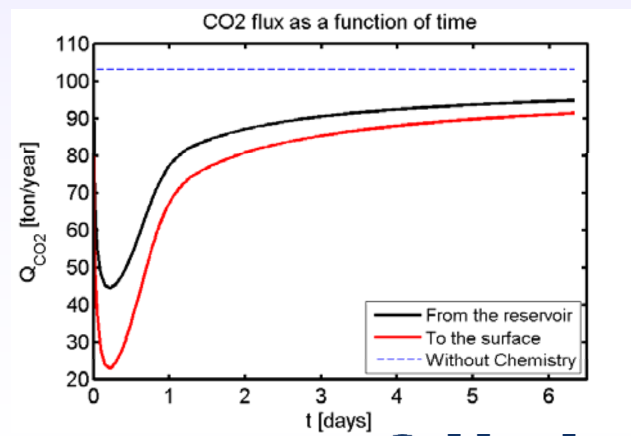
- Annular flow + mechanics + cement reactivity:
  - Carbonation of cement sheath



  - Water condensation in μannulus



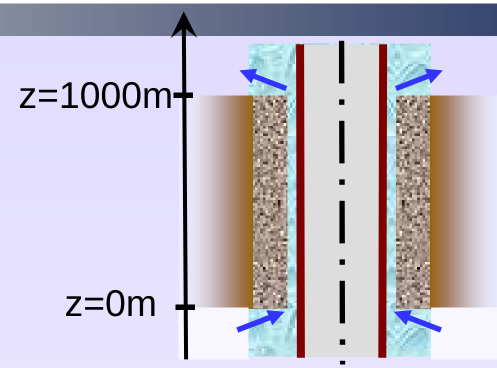
  - Leak rates:
    - ✓ Cement reactivity =
      - High at early stages ⇒ CO_2 sink
      - Low at later stages ⇒ limited by diffusion

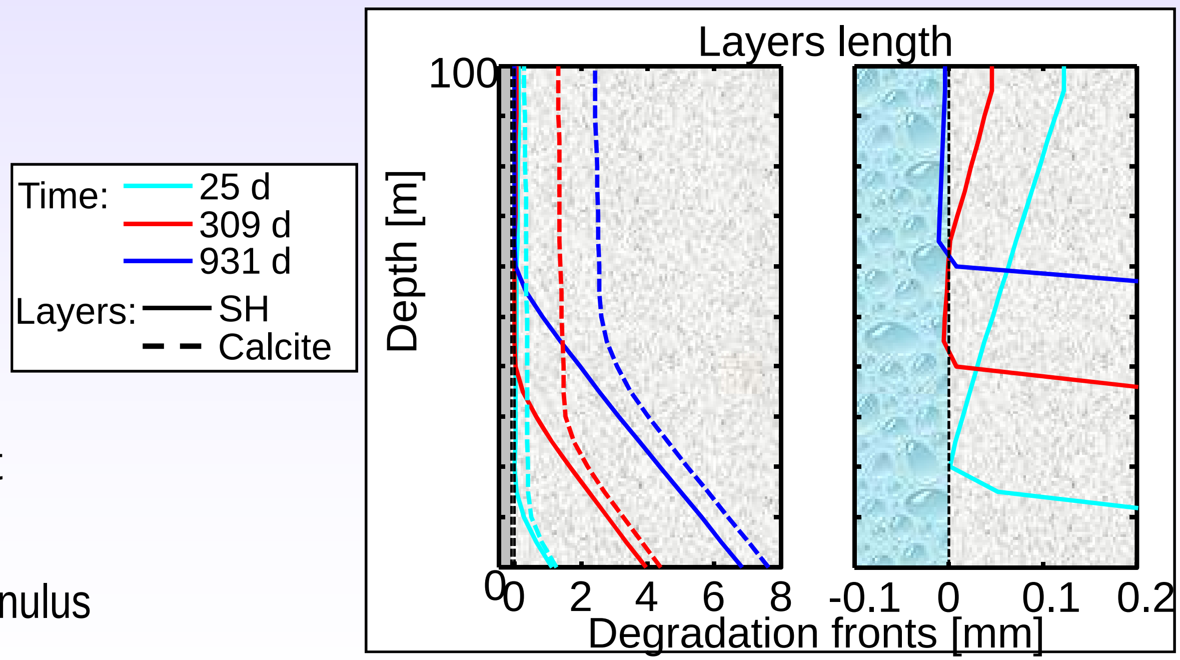


Schlumberger

Case 3 – Brine Annular Flow

- Initial / boundary conditions:
  - Top of defect:
    - ✓ z=1000m, Pt=1bar,
  - In defect:
    - ✓ geothermal gradient, w_0 = 0 μm
  - Bottom of defect:
    - ✓ z=0m, Pt=150bar,
    - ✓ Brine with CO_2

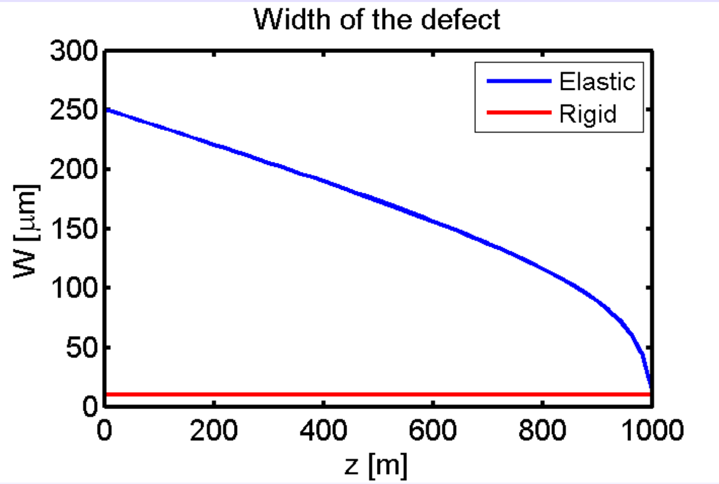


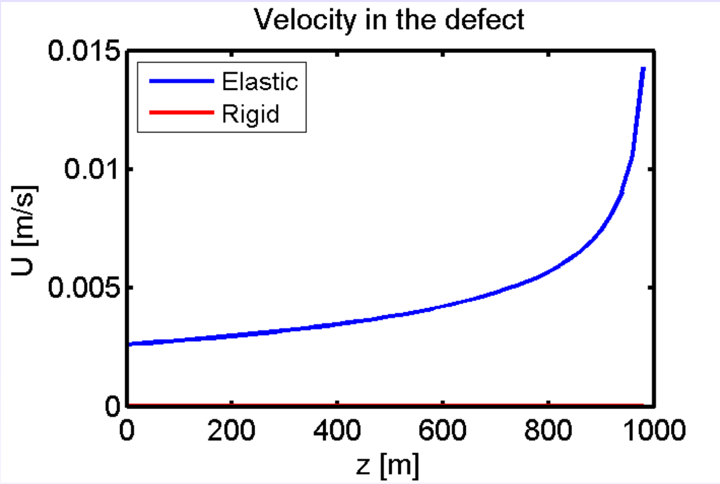


- Results
  - Ca leakage from cement
  - CO_2 ingress into cement
  - $CaCO_3$ formation in μannulus

Case 3 – Brine Annular Flow

- Flow and mechanics:
  - Opening of annulus (bottom)
  - Velocity increase (top)

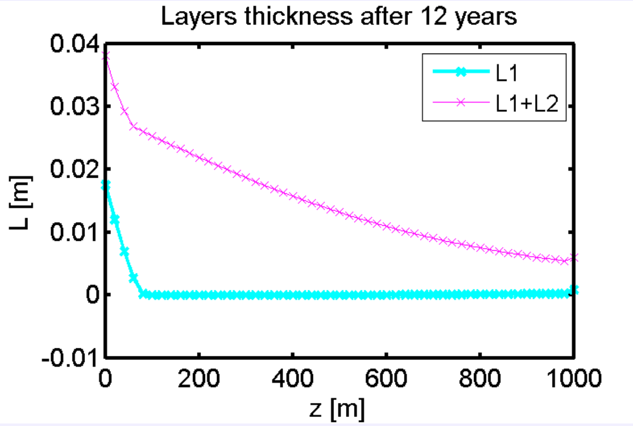


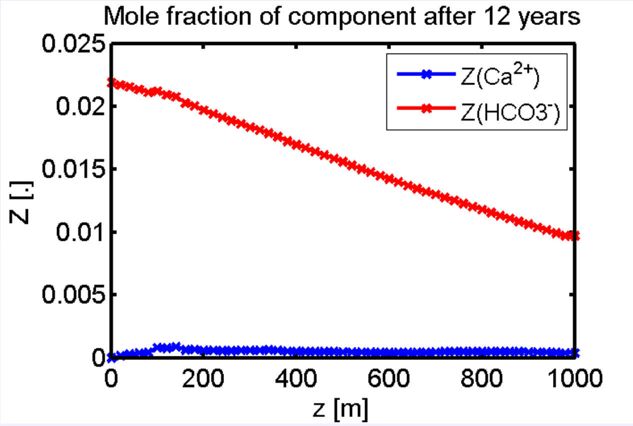


- **opening** of μannulus related to defect **elasticity**
  - 1st order mechanism

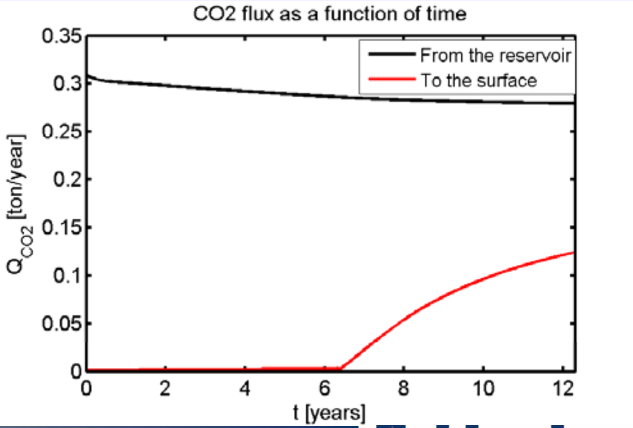
Case 3 – Brine Annular Flow

- Flow + mechanics + cement reactivity:
  - Layer thicknesses
  - Concentration profile





  - Leak rates:
    - ✓ Initial inhibition due to cement reactivity



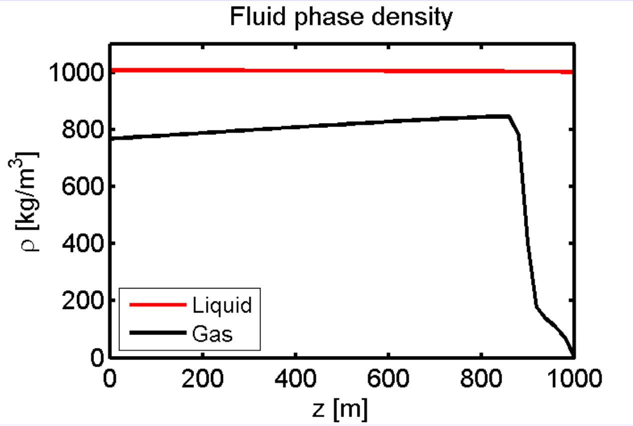
Conclusion

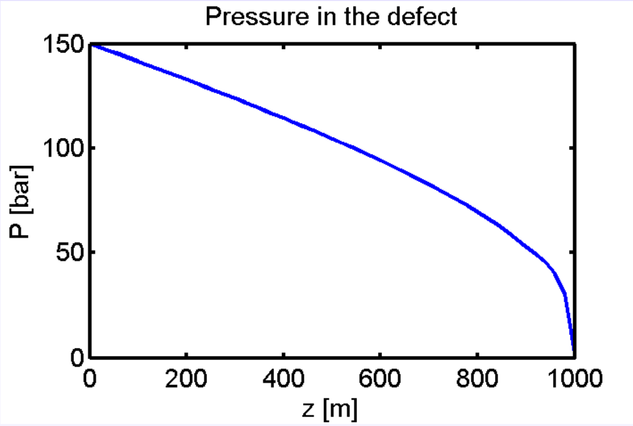
- Modular simulator based on the integration of 1) cement chemistry, 2) annular 1D reactive flow, 3) defect elasticity.
- At early time (small time scale):
  - Cement / CO_2 fluids interactions control leak rate.
- At longer time:
  - Cement buffering capacity limited by diffusion
  - Defect elasticity is a 1st order parameter for CO_2 leak rate evaluation.
- Identification of specific mechanisms:
  - micro-annulus **opening**: wellbore elasticity
  - micro-annulus **closing**: calcite precipitation

- Consistency with field results (Loizzo's talk)
- Study of different leak scenarios and risk analysis now available with this simulation tool

Additional figures

- CO_2 rich phase annular flow
  - Fluids density
  - Pressure





5th MEETING of the WELLBORE INTEGRITY NETWORK
Calgary, 13th - 14th May 2009

Modelling of Well Bore Cement Alteration as a Consequence of CO_2 Injection in an Exploited Gas Reservoir

Geloni C.[1], Giorgis T.[1], Biagi S.[2], Previde Massara E.[3] and Battistelli A.[1]

[1] Saipem S.p.A.– Environmental Engineering Unit
[2] National Research Council of Italy – Institute of Geosciences and Earth Resources
[3] Eni S.p.A. – R&M Division

Introduction

Within the studies performed to evaluate the feasibility of CO_2 geologic sequestration in an exploited natural gas reservoir, a reactive transport numerical model was developed to evaluate the sealing efficiency of the geological structure intended for the disposal and well cement completions.

The focus of the modelling study is on the physico-chemical and mineralogical transformations that could occur in proximity to a former gas production well under high-P_{CO2}, low-pH brine conditions arising from the displacement of natural gas as a result of CO_2 injection.

Object

Estimation of cement alterations, in terms of mineralogical reactivity, due to the interactions with reservoir and caprock fluids in the medium period by means of numerical simulations.

Numerical Code: TOUGHREACT-TMGAS

The non isothermal multi phase reactive flow **TOUGHREACT** simulator was coupled to **TMGAS** EoS module with the technical support of Lawrence Berkeley National Laboratory (LBNL) in the framework of the **TOUGH2 V.2** reservoir simulator (Pruess et al., 1999), within Eni R&D projects sponsored and coordinated by Eni E&P Division.

- *Discretization in space of continuum equations using the Integral Finite Difference approach (IFD; Edwards, 1972)*
- ***TMGAS** provides an accurate description of the two-phase thermodynamic equilibrium of mixtures of organic and inorganic gases with NaCl dominated brines*

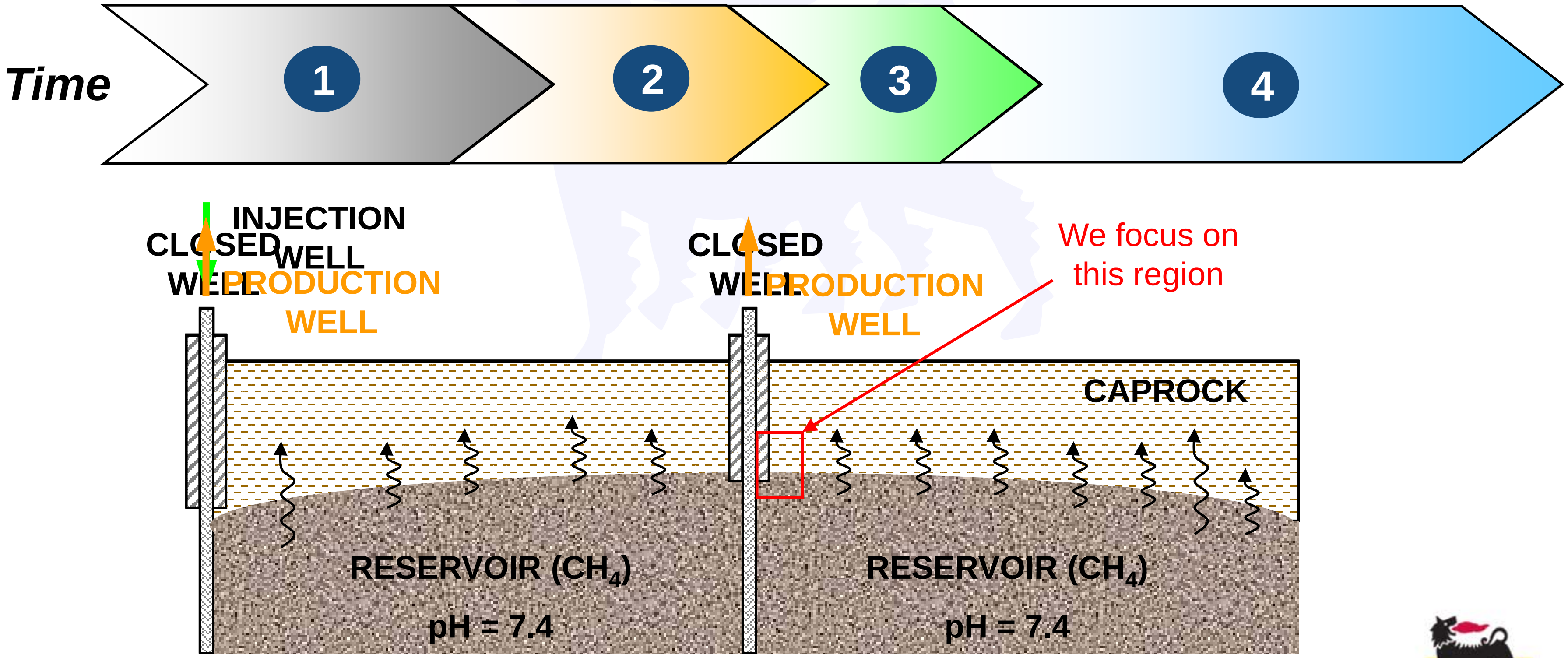
  *Range of applicability → Pressure up to **1000 bar** / Temperature up to **200°C***
- *Reactive transport is solved with the **S**equential **N**on-**I**terative **A**pproach (SNIA):*

  Mass transport equations and chemical reaction equations are considered as two relative independent subsystems
- ***precipitation/dissolution reactions** → thermodynamic or **kinetic approach***

Conceptual model at reservoir scale

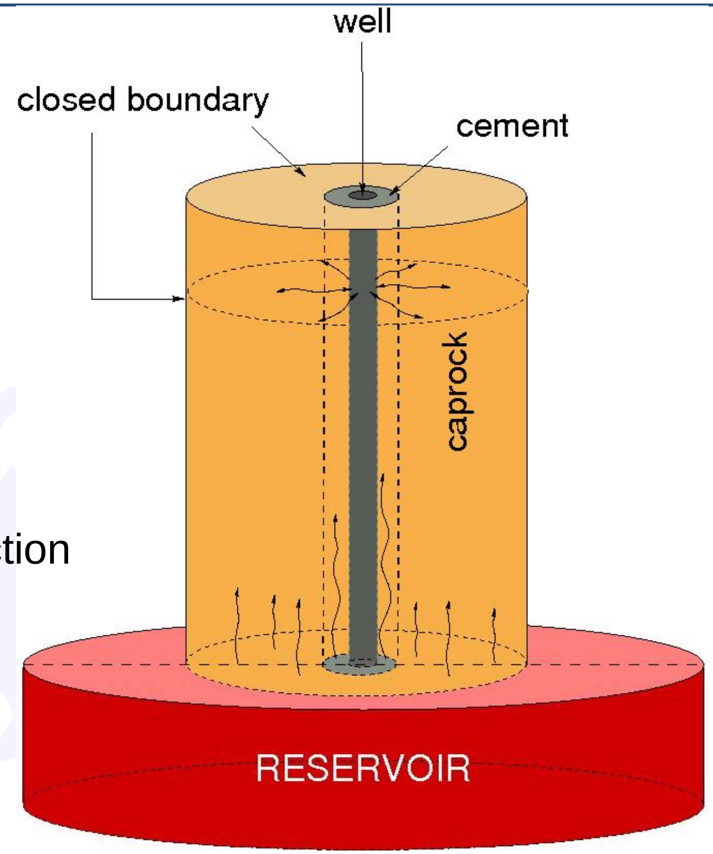
The conceptual evolution of the simulated model can be schematically summarized as:

1) reservoir and caprock evolution/interaction for long times (1,000-10,000 yr)
2) 40 years ageing of the cement sheath with the caprock and reservoir alkaline fluids
3) 20 years of CO_2 injection into the reservoir→ CH_4 displacement
4) 500 years Reservoir-Cement-Caprock interaction



Conceptual model at well scale

The domains have their symmetry axis centered on the vertical axis of an hypotetical well.



Main working hypotesis:

- Isothermal conditions
- No pressure gradients are considered → no advection
- Chemicals can **diffuse** across 3 interfaces:
    1. reservoir – cement
    2. caprock – cement
    3. reservoir – caprock (not discussed here)
- Reservoir is an **evolving boundary** for the overlying domains (cement and caprock)
- Fluid interactions with **casing** are neglected

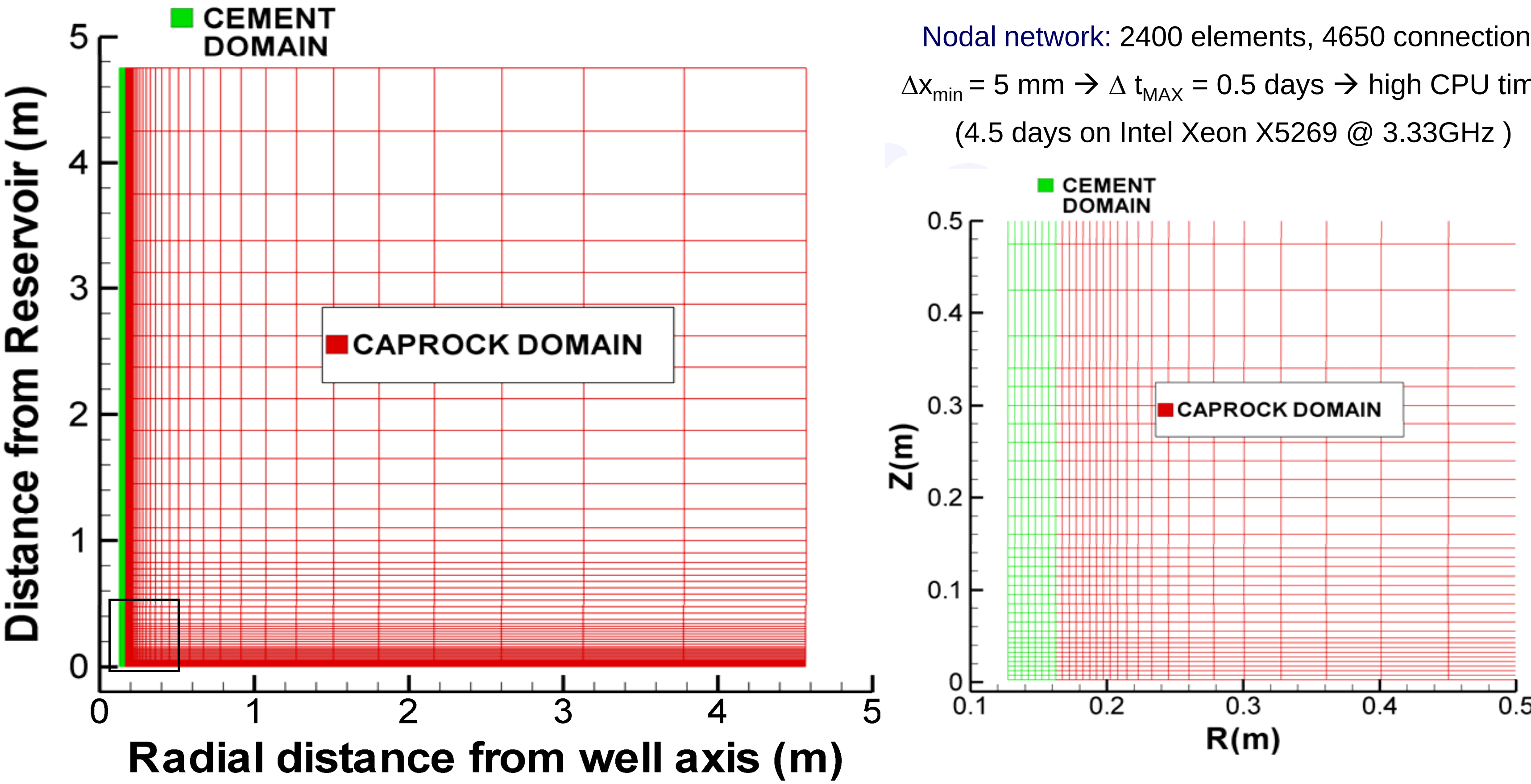
Geometrical details

- 2D radial grid with external radius = 5 m and height = 5 m
- radial logarithmic progression after the first 16 nodes with constant element width of 0.005 m
- cement sheath thickness of 0.04 m
- reservoir is represented by a 35 m thick single layer radially discretized

Nodal network: 2400 elements, 4650 connections

Δx_{min} = 5 mm → Δt_{MAX} = 0.5 days → high CPU times

(4.5 days on Intel Xeon X5269 @ 3.33GHz)



Sensitivity runs on kinetics and thermodynamics data were preliminarily performed by means of simplified 1D cartesian (vertical) and radial (horizontal) grids

Definition of the system conditions

Thermodynamic conditions and petrophysical parameters

P	T	Porosity (ϕ, volume fraction)			Liquid Saturation (S_L)			Tortuosity (τ)		
(bar)	(°C)	**res**	**cem**	**cap**	**res**	**cem**	**cap**	**res**	**cem**	**cap**
128	50	0.18	0.10	0.05	0.25	1.00	1.00	0.10	0.05	0.05

Field data ***Estimated from literature***

The formal treatment of diffusion implemented in the code stems from Fick's law. The dependence of the diffusive flux on porosity (f), tortuosity (t) and liquid saturation (SL) is expressed through an effective diffusion coefficient (EDC)

$$D^{eff} = D^{bulk} \cdot f(\phi, S_L, \tau)$$

- D^{eff} → EDC in porous medium
- D^{bulk} → Diffusion coefficient in bulk water (the same for all species)
- $f(\phi, S_L, \tau)$ → The functional form depends on the way diffusion is calculated at the interface between two interacting nodes

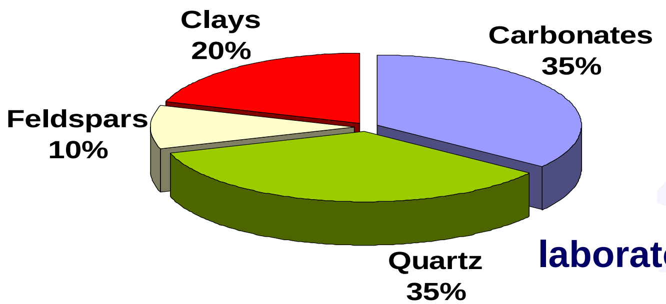
D^{bulk} = 8.0E-10 m^2/s D^{eff} = [1.0E-12 – 1.0E-11] m^2/s

Mineralogical composition (%vol)

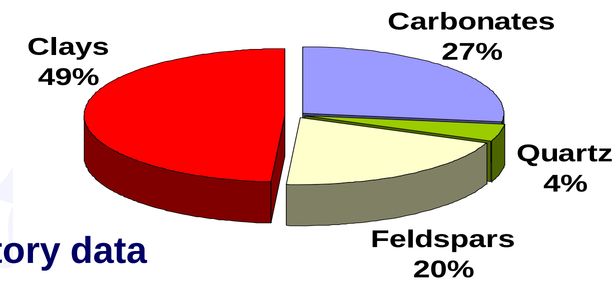
The mineralogical composition of the **reservoir** rock is an average taken from laboratory analyses

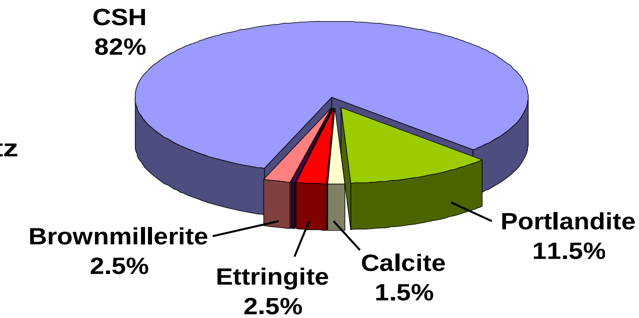
The **caprock** is a carbonate-rich shale with high contents of silicate-clay minerals

The **cement** is a hydrated GeocemTM, an API Class G High Sulphate Resistant grade commercial oilwell cement



laboratory data

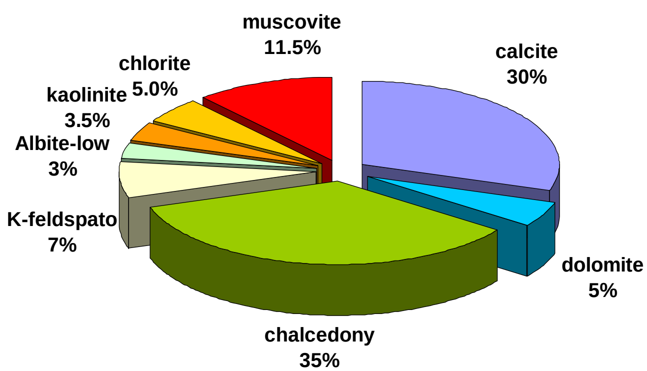


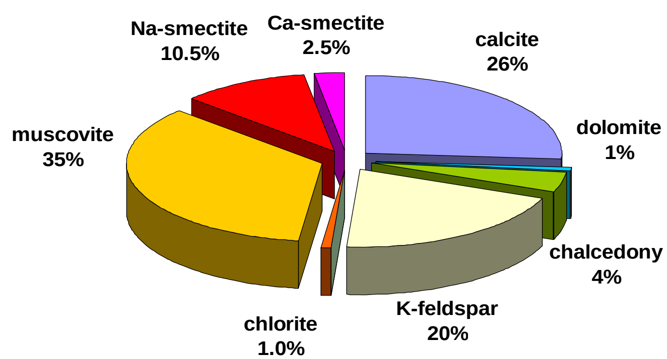


We made the assumption that all amorphous materials are represented by the calcium silicate hydrate (CSH):

- is the principal product of the hydration of cements
- may occur in semi-crystalline or crystalline state only at elevated temperatures and after prolonged hydration and curing times

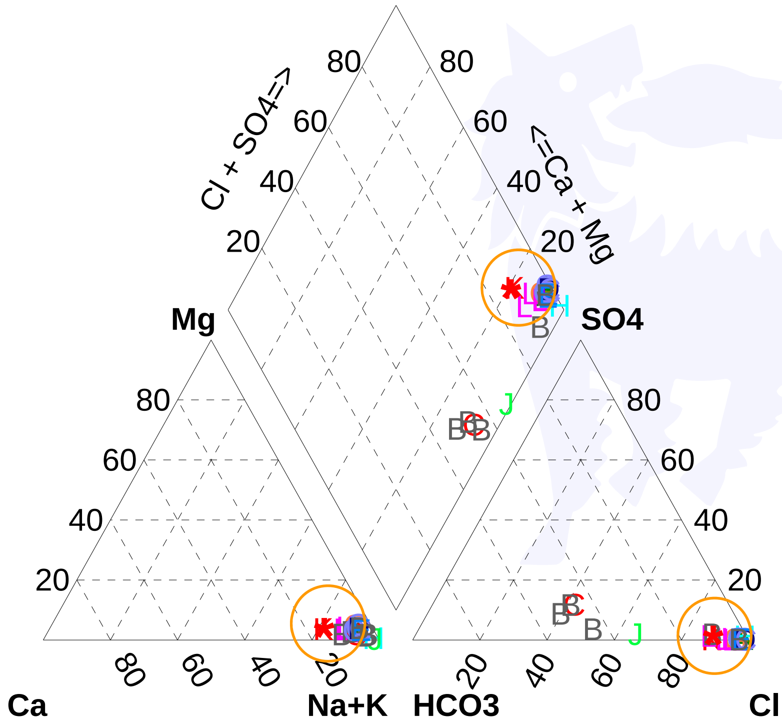
Mineral phases used in the model





Aqueous phase composition

Several chemical analysis available for the pore water → * is used to constrain the total concentration of the aqueous species to obtain a **synthetic** water equilibrated with respect to the local primary mineralogy of **reservoir** and **caprock** (batch models).



Piper diagram of chemical analysis made available by Eni Div. E&P for the characterization of the aqueous phase for reservoir and caprock

A **sythetic** nearly-equilibrated **cement** pore water has been computed by allowing a low salinity solution to react with the primary mineralogy of the cement, accordind to the following criteria:

- pH=12.5 @ 25°C (controlled by portlandite. Glasser, 1997)
- OH/Cl ratio of about 5 (Page et al., 1986)
- Na and K contents have been set to 1E-2 mol/kgw (Hong and Glasser,1999,2002, Brouwers and van Eijk, 2003)

Thermodynamic and kinetic data

Thermodynamic data mainly derives from TOUGHREACT database *(thermXu4.dat)*.

For the mineral phases of the concrete a sensititvity on thermodynamic data was previously performed, selcting data from:

- *data0.ymp2.R2.dat* (EQ3/6)
- *thermo.com.v8.r6+.dat* (The Geochemist's Workbench)
- *thermoddem.dat* (Blanc et al., 2007)

Due to the internal structure of the simulator, only discrete composition for the amorphous phases are considered in the data bank; i.e.: CSH → Ca/Si=1.7, 1.1, 0.8

1) CSH:1.7, CSH:1.1, CSH:0.8 *(data0.ymp2.R2.dat)* vs. CSH:1.6, CSH:1.2, CSH:0.8 *(thermoddem.dat)* → no significant differences → CSH's from *data0.ymp2.R2.dat*

2) Brownmillerite ($Ca_4Al_2Fe_2O_{10}$, from *data0.ymp2.R2.dat)* vs. Fe-ettringite ($Ca_6Fe_2(SO_4)_3(OH)_{12}$:$26H_2O$, from *thermoddem.dat)* → no significant differences → CSH's from *data0.ymp2.R2.dat*

3) Friedel's salt is taken from *thermoddem.dat* database

Kinetic parameters

quartz, amorphous silica, hematite, magnetite, brucite, gibbsite, calcite, gypsum, anhydrite, pyrite (Palandri and Kharaka, 2004)

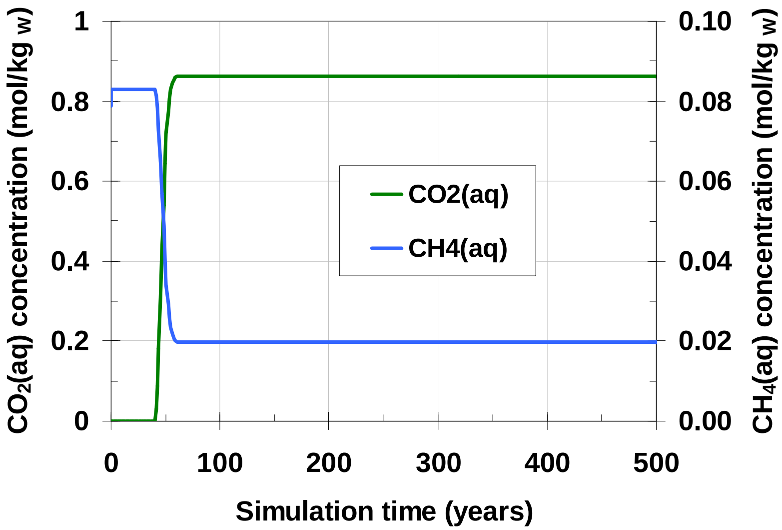
Kinetic constants assigned to the cement phases make the reaction rate decrease as follows:

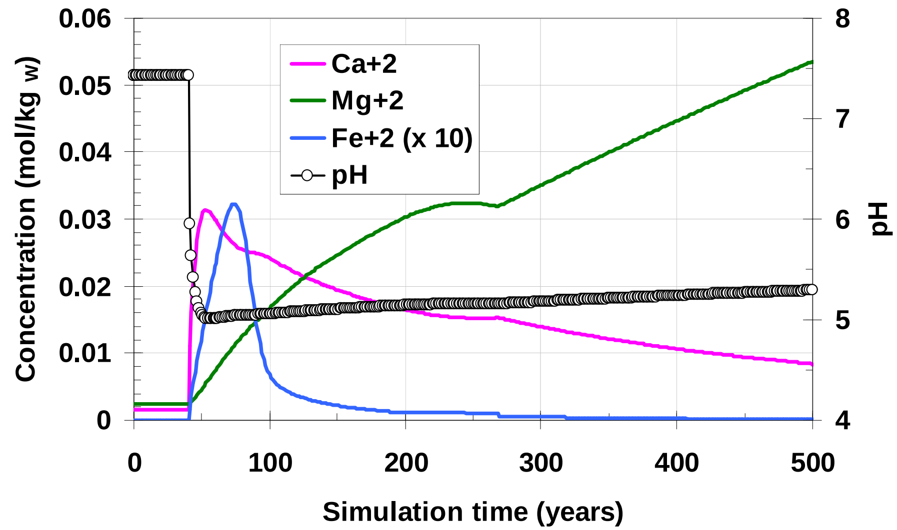
Porlandite (Halim et al. 2005) > gypsum,calcite > CSH,monosulfate,ettringite,brownmillerite (Baur et al.2004)

zeolites → Murphy (2000) but a sensitivity on scholecite kinetics parameters was performed

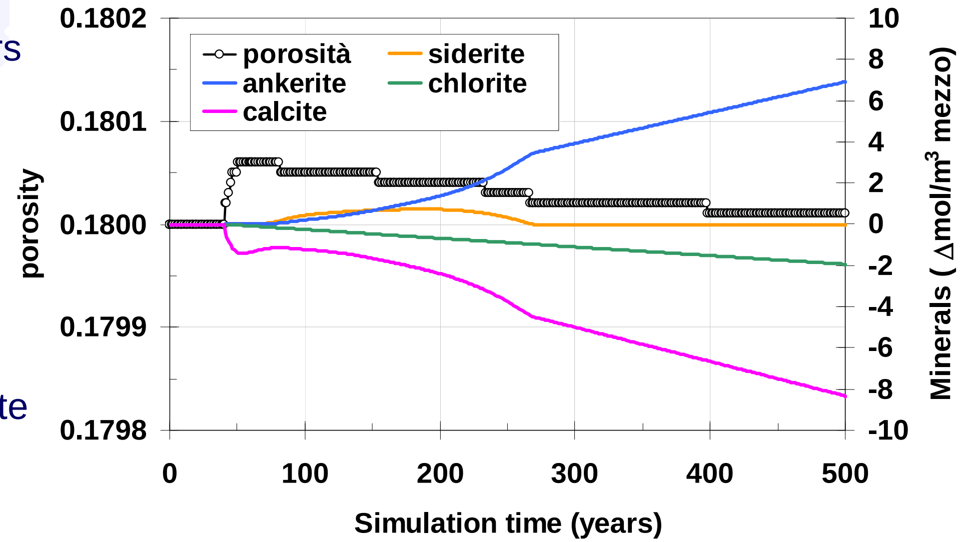
Results(1): reservoir evolution

CO_2 injection begins after 40 years of simulation





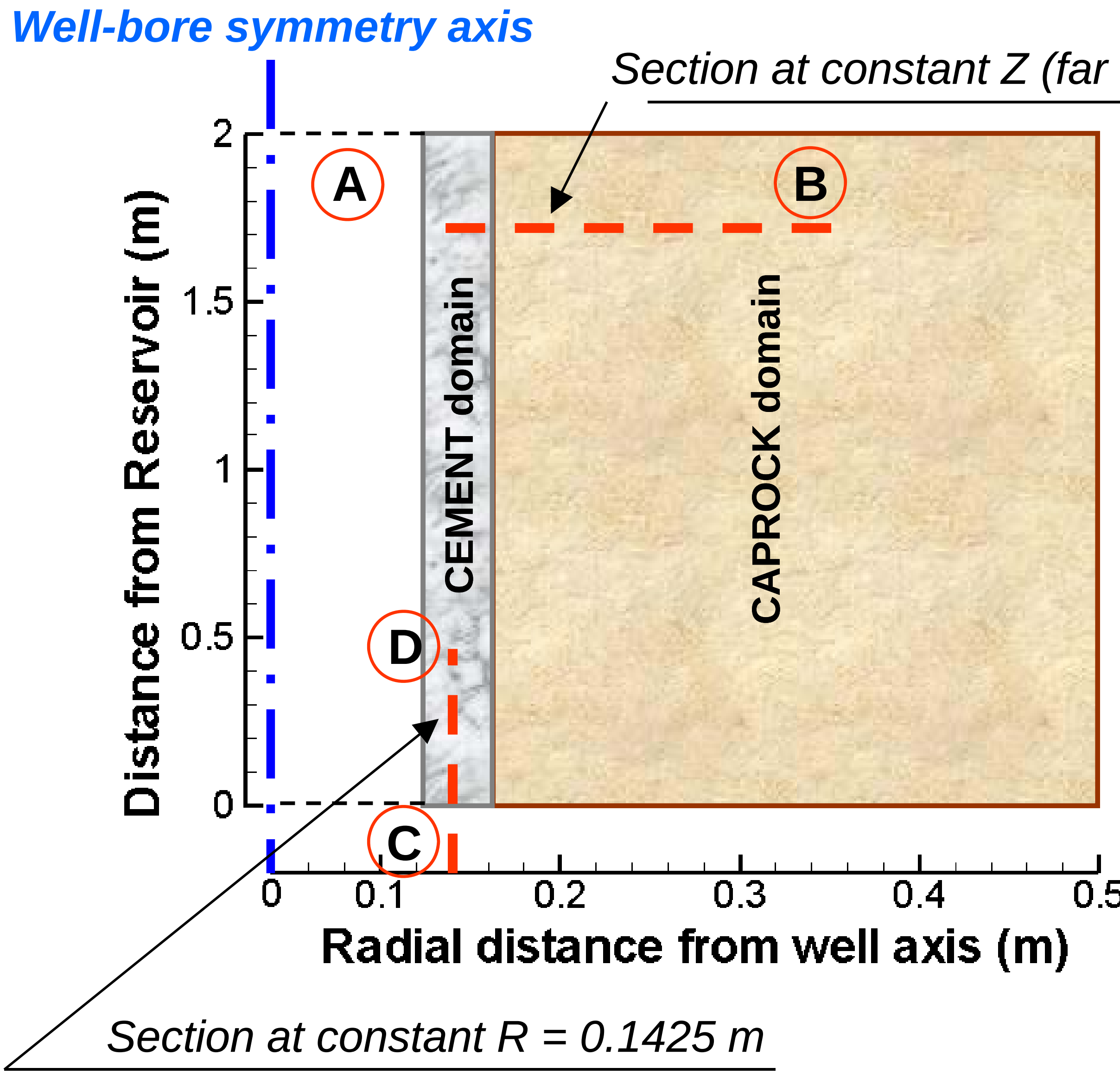
- Displacement of CH_4 by CO_2 is completed within 20 yrs
- pH is lowered from the initial values of about 7.4 (CH_4 dominate conditions) to about 5.0 (CO_2 dominate)
- Porosity does not undergo significant changes
- The Fe profile results from the competition of chlorite dissolution and ankerite/siderite precipitation
- Calcium is mainly constrained by the reactivity of calcite and ankerite



saipem

eni

Results (2): representation of the results

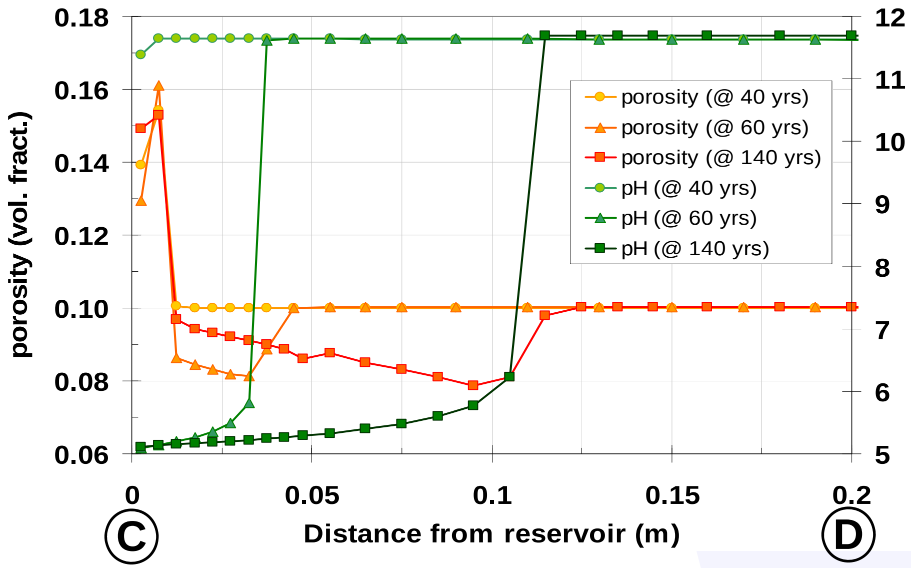


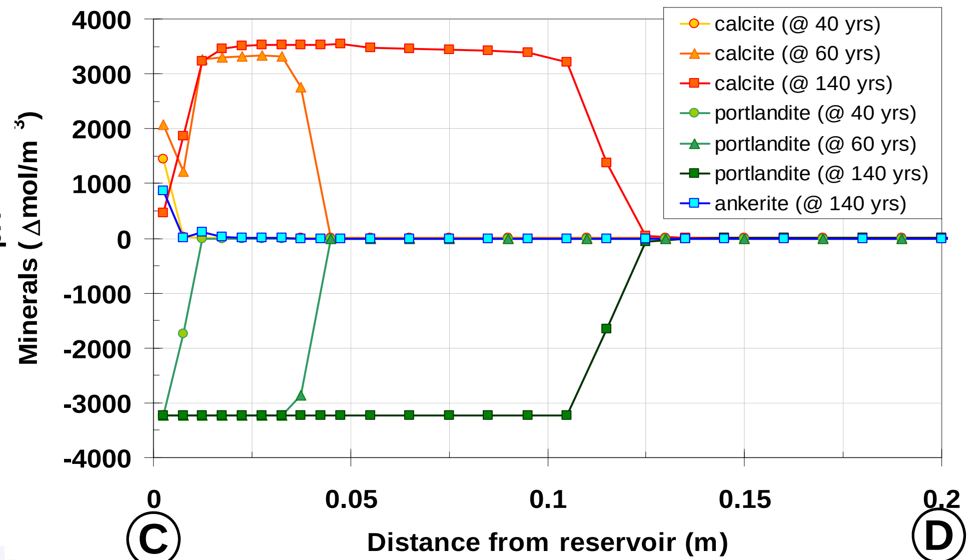
Data plotting

1. Contour patterns in the XZ cartesian space (*obtained by sectioning the 2D radial domain with a vertical plane along the simmetry axis of the well*)
2. Concentration profiles along linear sections (**A-B**, **C-D** segments) in the XZ plane

Results(3): reservoir-cement interaction

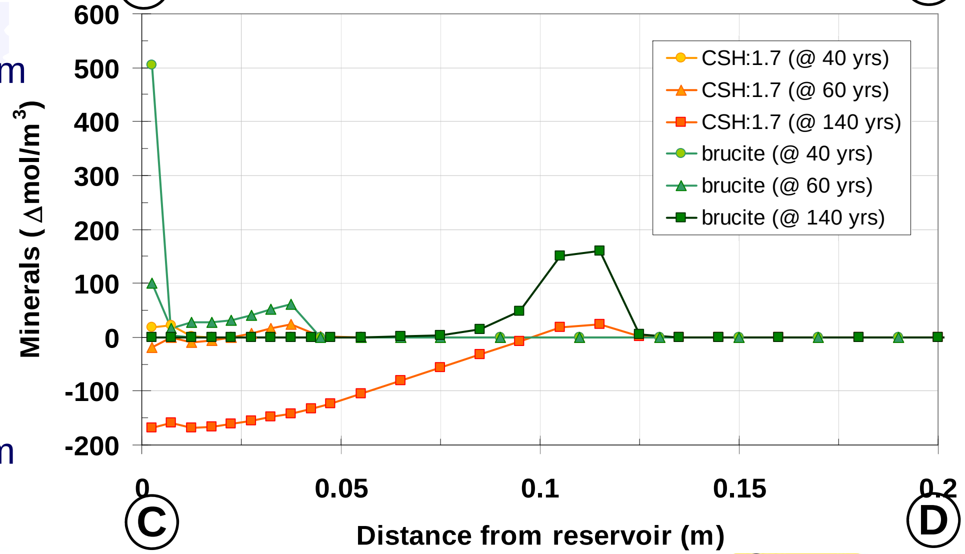
T_{sim} = 40yr → beginning of CO_2 inj. / T_{sim}=60 yr → end of CO_2 inj



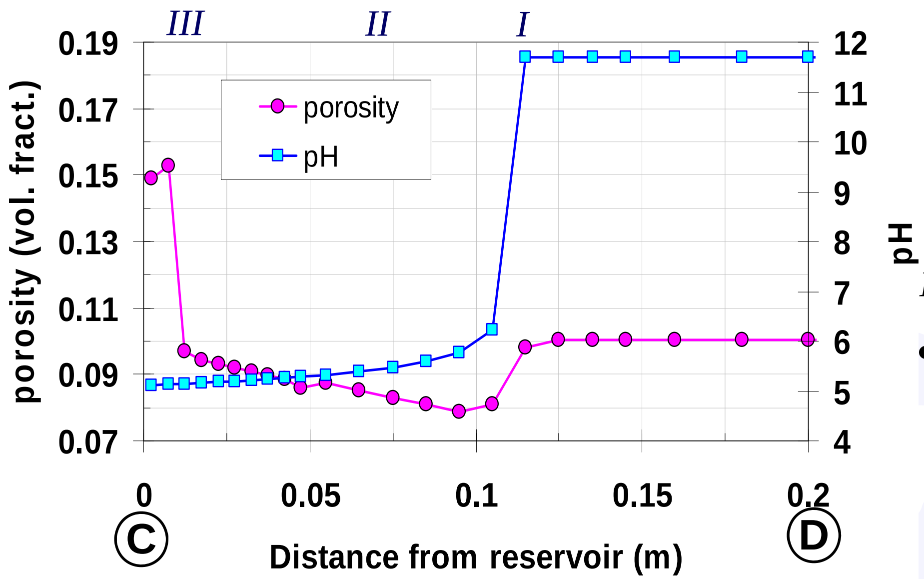


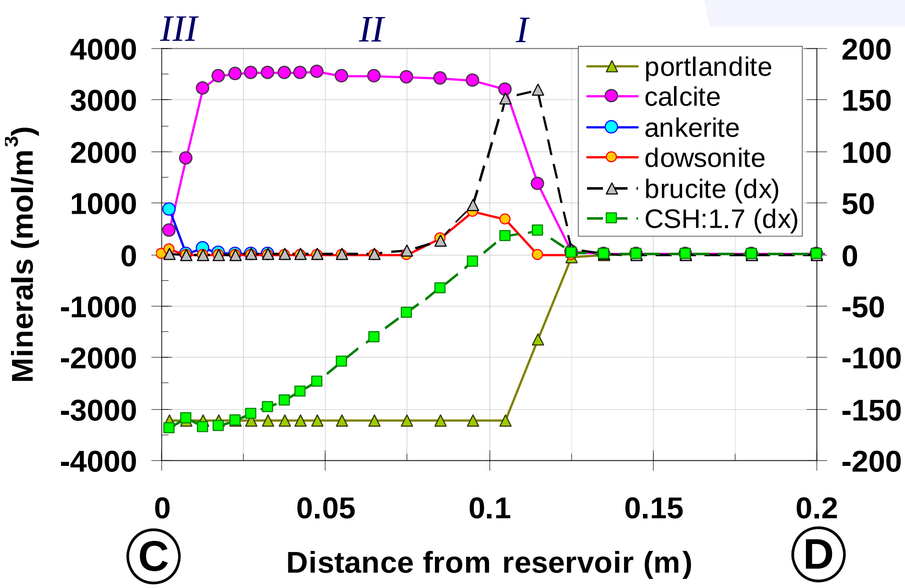
The diffusion of mild acidic carbon rich fluids coming from the reservoir promotes:

- the dissolution of portlandite and CSH:1.7 (H^+)
- formation of calcite (HCO_3^-)
- precipitation of brucite in the high pH region (Mg^{+2})
- formation of ankerite (Fe^{+2})
- after 100 yr the reactive advancing front reaches 10 cm



Results(4): reservoir-cement interaction (T_{sim} = 140 yr)





"Macro reactivity": 3 zones can be identified according to the different reactivity

I

- portlandite $\xrightarrow{\{H^+,HCO_3^-,Mg^{+2}\}_{RES}\ [high\ pH]}$ calcite + CSH:1.7 + brucite

II

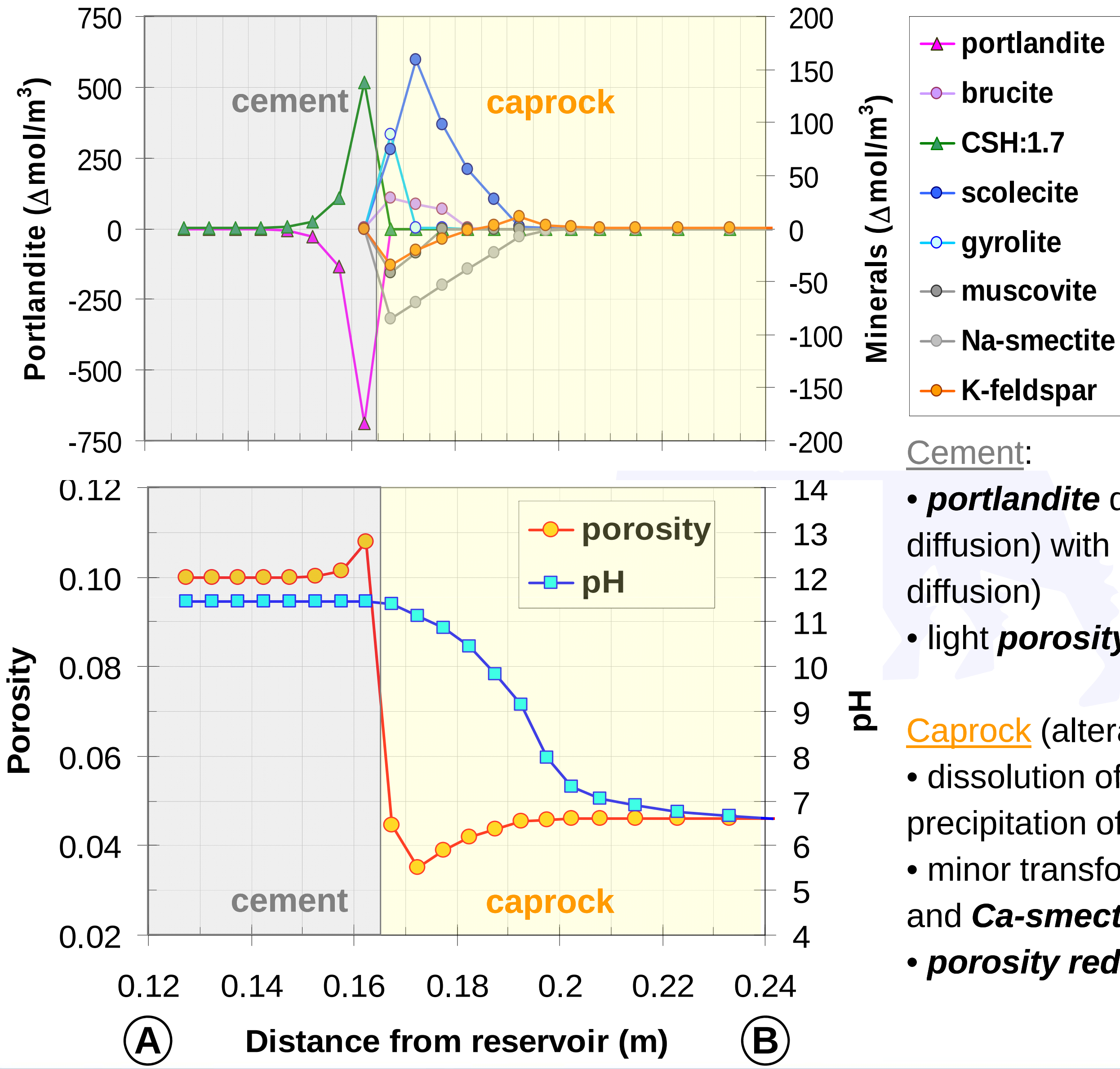
- CSH:1.7 $\xrightarrow{\{H^+,HCO_3^-\}_{RES}}$ calcite + $SiO_{2(aq)}$ + H_2O
- $\xrightarrow{\{H^+\}_{RES}}$ brucite dissolution

III

- calcite $\begin{cases} \xrightarrow{\text{dissolution}} \text{porosity increase} \\ \xrightarrow[\{Fe^{+2},Mg^{+2},HCO_3^-\}_{RES}]{} \text{ankerite} \end{cases}$

Dawsonite precipitation is driven by the migration of HCO_3^- from the reservoir, Na^+ from both reservoir and caprock aqueous phase, while the needed Al is mainly provided by the reactivity of alluminosilicate occurring at the caprock-cement interface (see 2D model results).

Results(5): caprock-cement interaction (T_{sim} = 140 yr)



Cement:

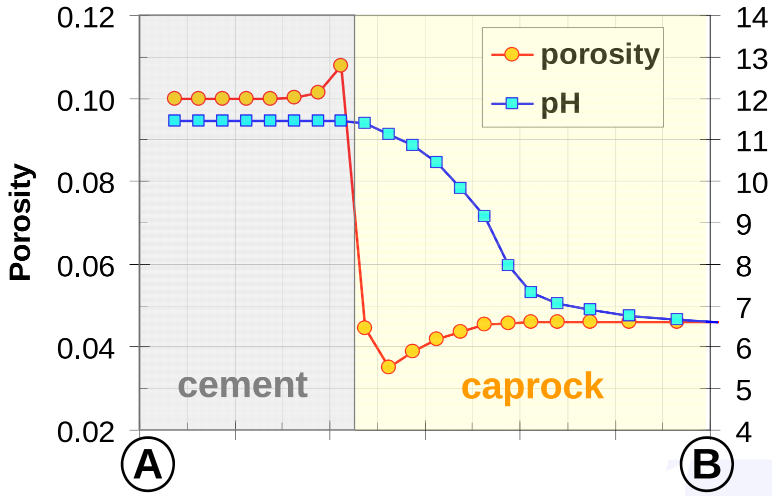
- ***portlandite*** destabilization (cem → cap OH^- diffusion) with **CSH** precipitation (cap → cem Al,Si diffusion)
- light ***porosity increase*** in a 2 cm thick region

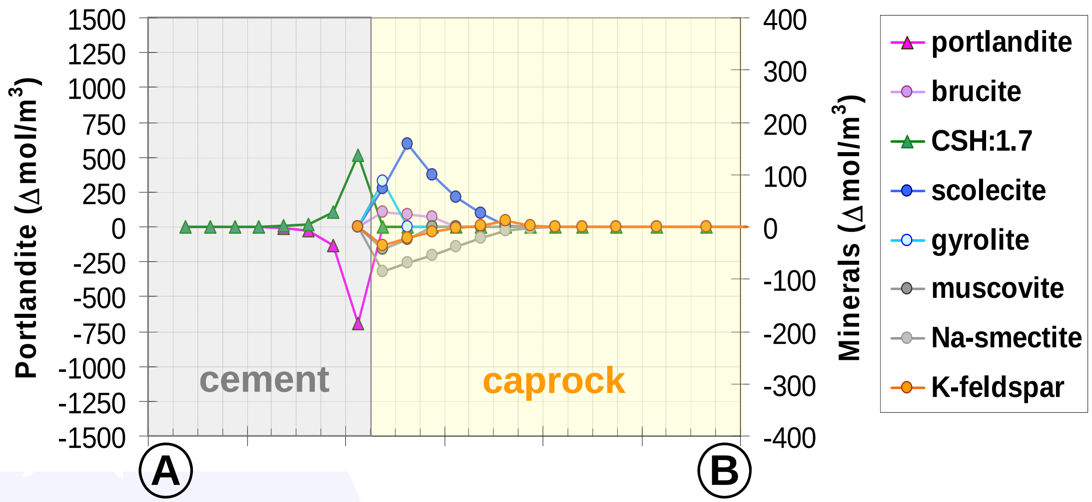
Caprock (alteration of about 5 cm)

- dissolution of ***muscovite*** and ***Na-smectite***, and precipitation of ***zeolites (scolecite)***
- minor transformations → conversion of **K-feldspar** and ***Ca-smectite*** into ***brucite*** and ***gyrolite***
- ***porosity reduction*** at the contact with the cement

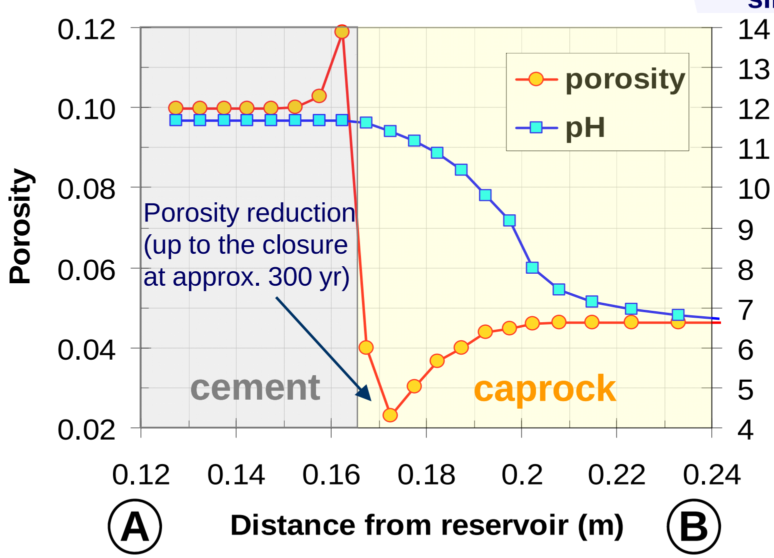
Results(6): caprock-cement interaction (time evolution)

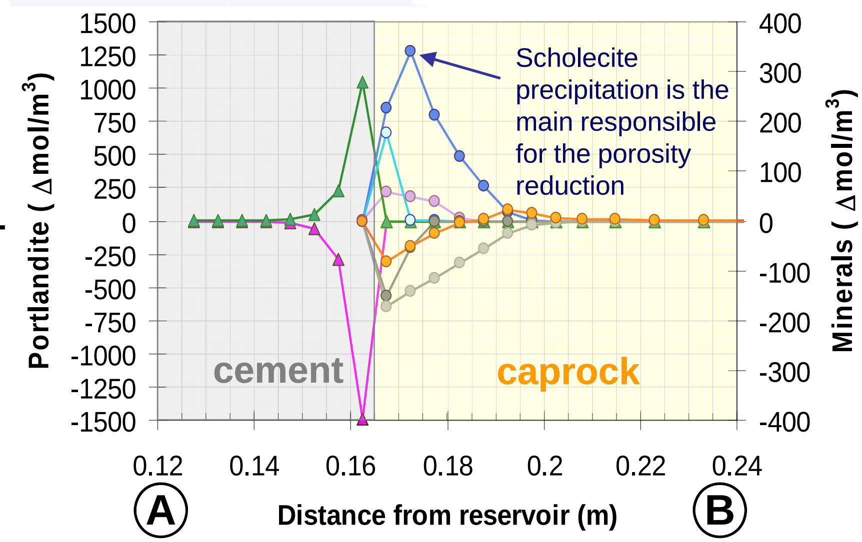
T_{sim} = 140 yr





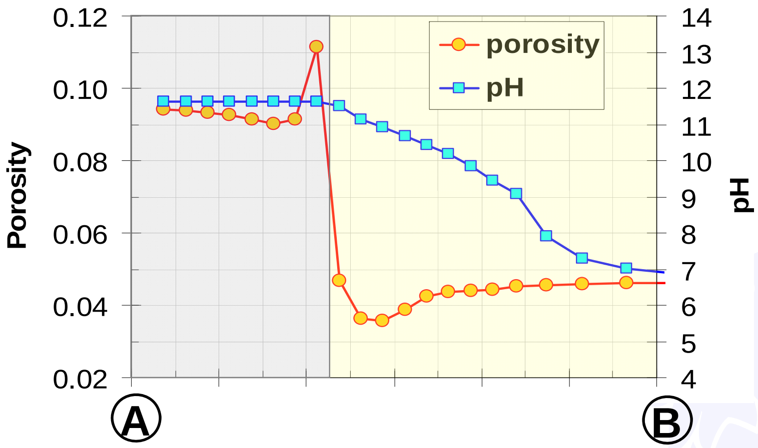
T_{sim} = 240 yr

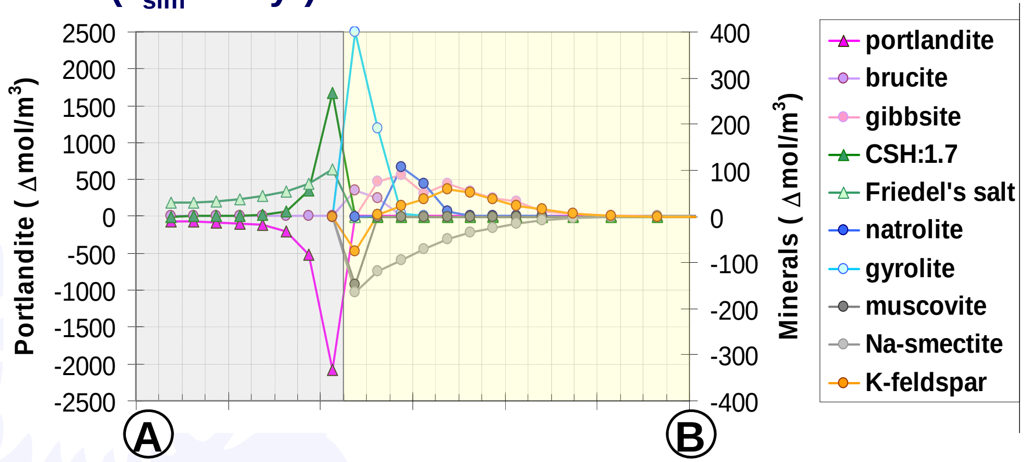




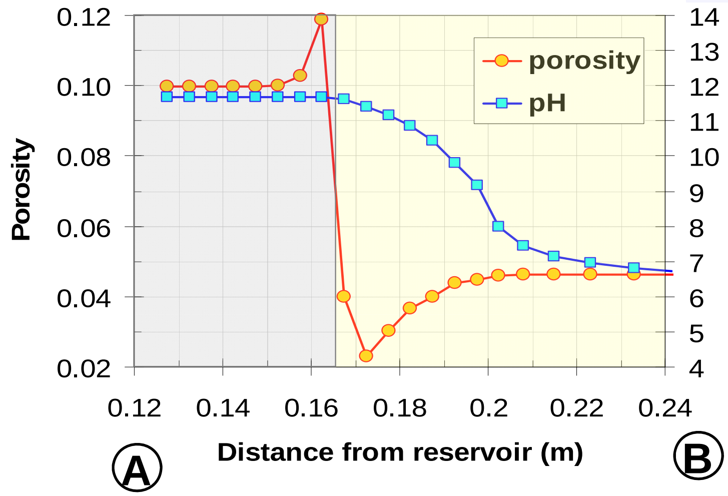
Results(7): caprock-cement interaction (scholecite kinetics)

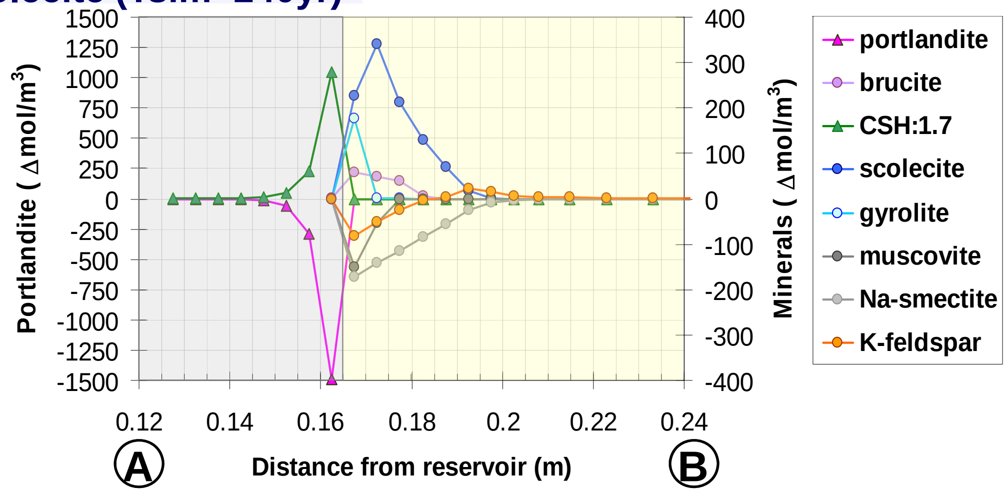
"slow" scolecite (T_{sim}=240yr)





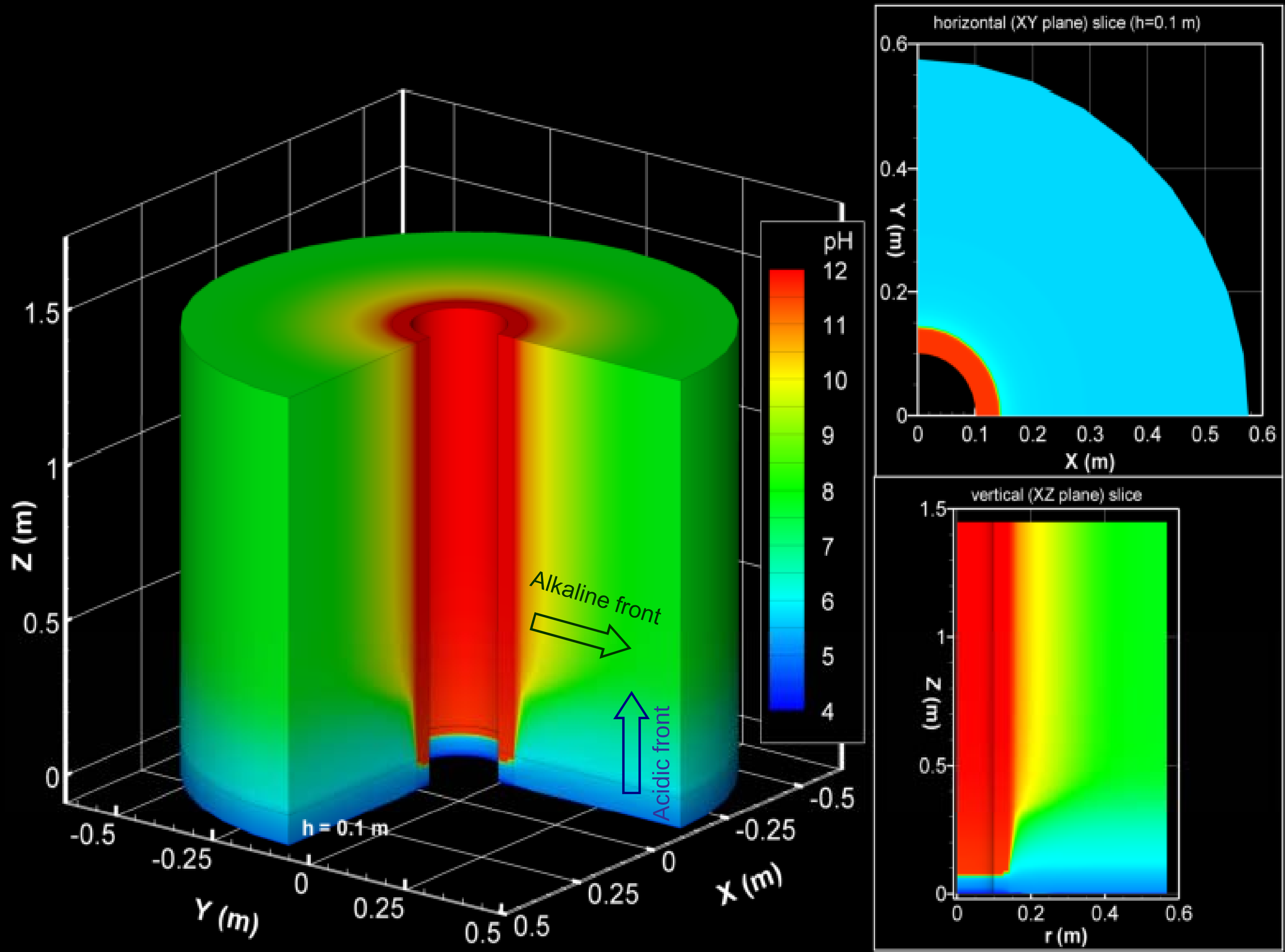
"Fast" scolecite (Tsim=240yr)





The slowing down of scholecite reaction rate shifts the weigth of zeolites reactivity towards **natrolite** and **gyrolite** precipitation (minor porosity reduction). This process likely promotes **Friedel's salt** precipitation inside the cement.

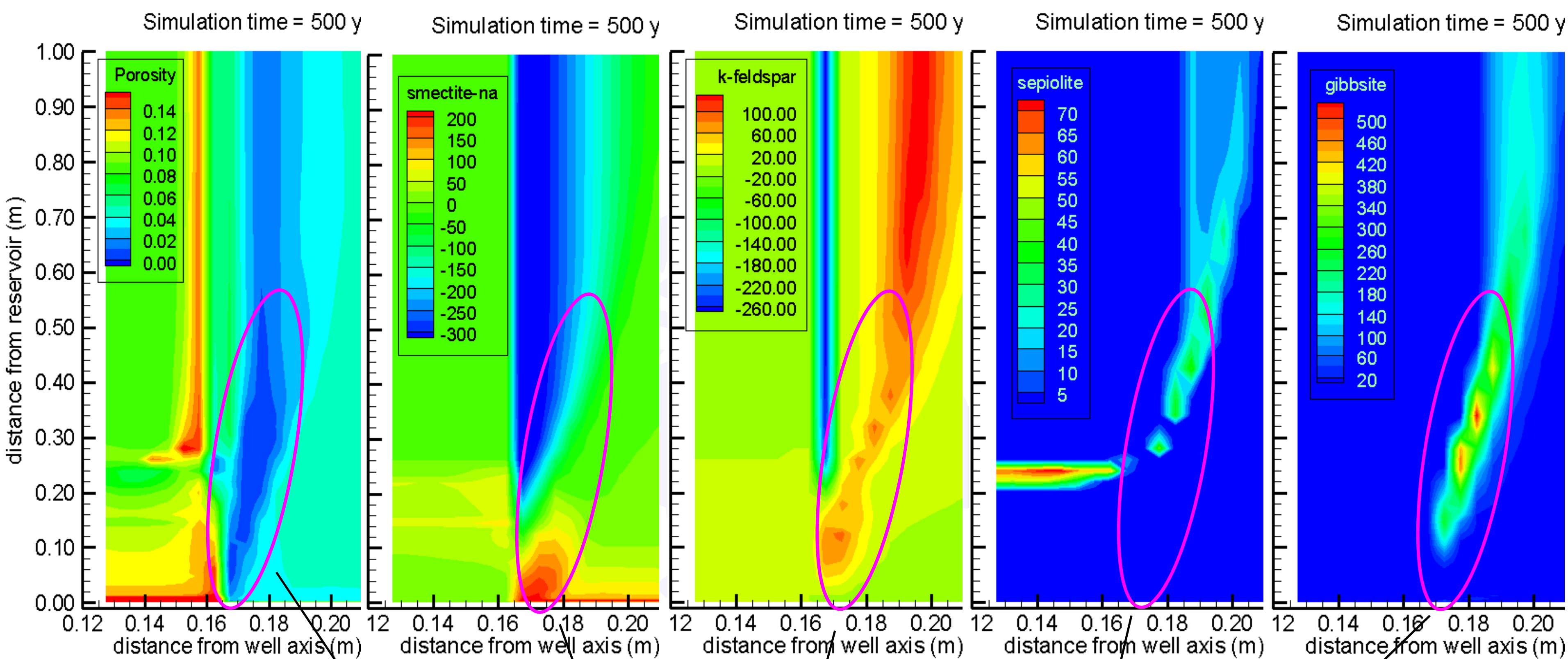
Results(8): 2D system evolution @ 140 yr



Two different fronts of pH are predicted by the model:

- advancing front of an acidic plume (low pH, high carbon) from reservoir
- migration front of OH^- from alkaline fluids of unaltered cemen

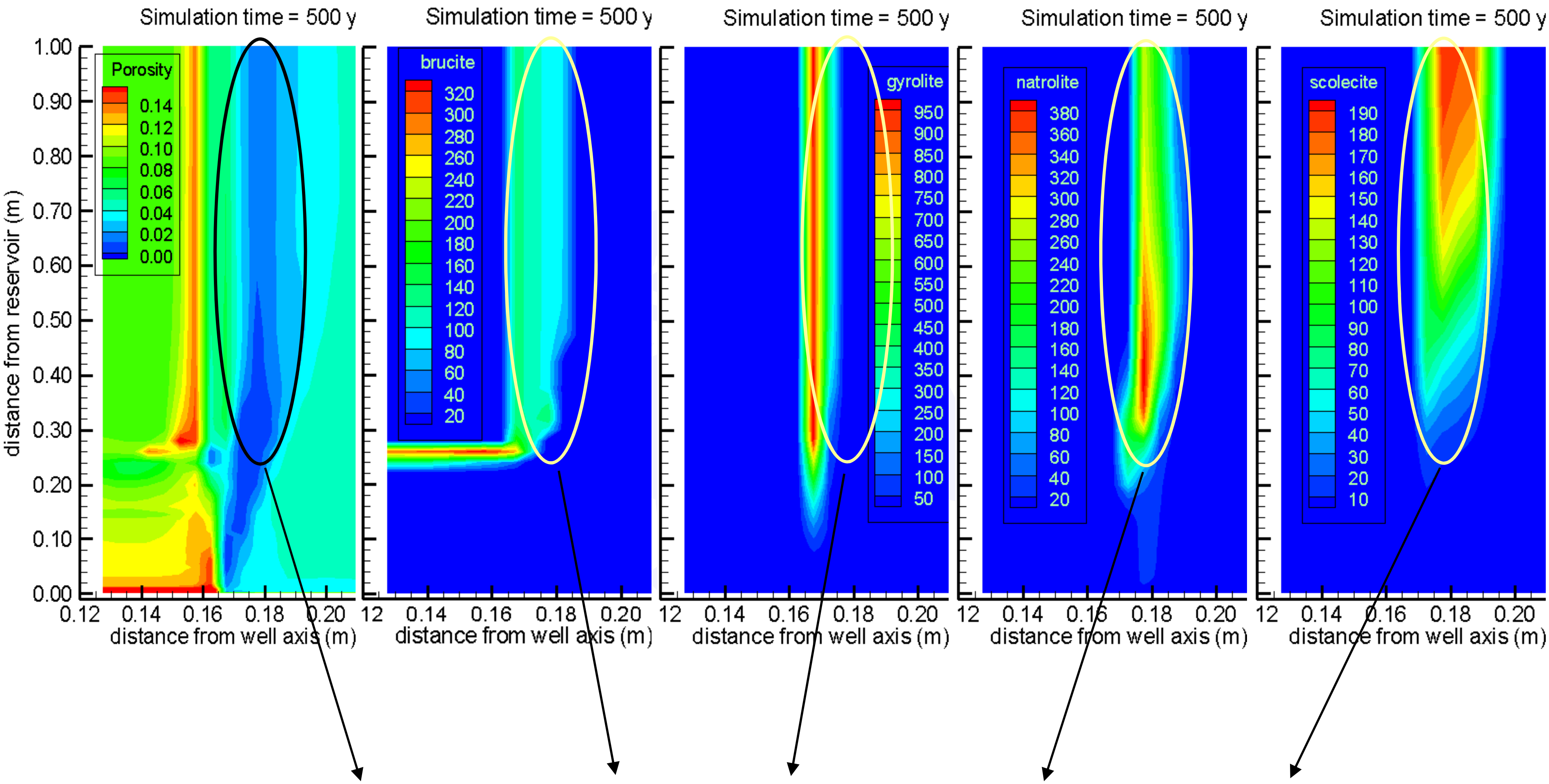
Results(11): Radial 2D



Caprock porosity at the res-cem-cap interface is mainly controlled by the precipitation of gibbsite, K-feldspar and sepiolite

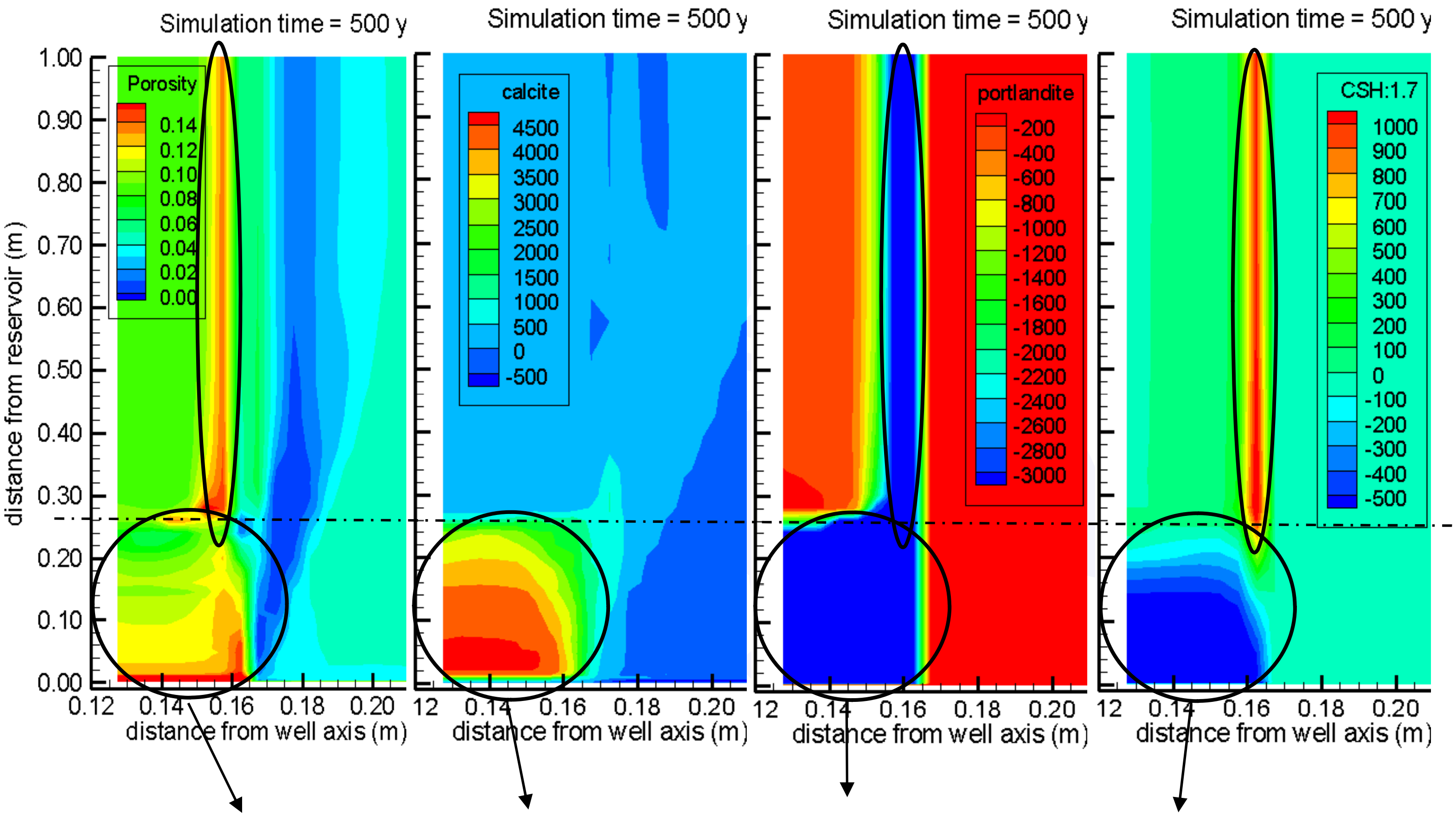
Caprock porosity at the cem-cap interface is controlled by the dissolution of smectites and…

Results(10): Radial 2D



precipitation of zeolites, brucite

Results(9): Radial 2D



Cement porosity at reservoir interface is controlled by the cement carbonation process + ankerite prec.

Cement porosity at caprock interface is a result of portlandite dissolution and CSH precipitation

Concluding remarks:

Simulation results indicate that:

1_a) The initial sealing effect due to calcite deposition occurring in the cement carbonation front can be followed by a dissolution stage (increase in porosity) due to the calcium carbonates instability in mild acidic environments

1_b) The diffusive migration of chemicals from the underlying mild acidic reservoir fluids induce alterations only in the first few centimetres of the wellbore cement and caprock (10 cm at 100 years, 30 cm after 500 years)

→ in these conditions cement sheath and cap-rock alteration due to the reservoir interactions does not seem to rise any concern about their containment capacity over time

2) The diffusion of hydroxyl ions from the cement into the caprock increases the pH in the portion of the caprock at the contact with the cement far from the reservoir interface promoting:

i) a destabilization of portlandite which converts into CSH inside the concrete → slight increase in porosity

i) zeolites precipitaion in the caprock → sealing of the caprock at about 300 yr.

Aknowledgments

The study was performed within the R&D program “GHG - GreenHouse Gases” financed by Eni SpA.

Thanks are due to the GHG project management for the permission to publish the results of this study, to Eni E&P and R&M Divisions for making available the reservoir and laboratory data.

THANK YOU FOR YOUR ATTENTION

Mineralogical and water phase chemical composition

The mineralogical composition of the **reservoir** rock is an average taken from laboratory analyses. It mainly consits on: carbonates, quartz and clays

The **caprock** is a carbonate-rich shale with high contents of silicate-clay minerals

The **cement** is a hydrated GeocemTM, an API Class G High Sulphate Resistant grade commercial oilwell cement. We made the assumption that all amorphous materials are represented by the calcium silicate hydrate (CSH): is the principal product of the hydration of cements may occur in semi-crystalline or crystalline state only at elevated temperatures and after prolonged hydration and curing times

Several chemical analysis were available for the pore water, an average is used to constrain the total concentration of the aqueous species to obtain the "analogous" **synthetic** water equilibrated with respect to the local primary mineralogy of **reservoir** and **caprock** (batch models).

A **sythetic** nearly-equilibrated **cement** pore water has been computed by allowing a low salinity solution to react with the primary mineralogy of the cement, accordind to the following criteria:

- pH=12.5 @ 25°C (controlled by portlandite. Glasser, 1997)
- OH/Cl ratio of about 5 (Page et al., 1986)
- Na and K contents have been set to 1E-2 mol/kgw (Hong and Glasser,1999,2002, Brouwers and van Eijk, 2003)

Breakout Group 1

- What should the report try to accomplish?
- Attempt to educate:

  All categories need educating to some degree – regulators, field, lab need to know what each is doing. Need to get all research sides together before going to educate regulators. Need to overcome different approaches, and unify views of operators and service providers in field work area.
- Need to make benefits clear to all parties
- Create definitions:

  What is a leak?

  What is best practice?
- What should the report try to accomplish?
- Obtain policy direction from regulators, - classify leaks,
- Demonstrate that we have knowledge, and we also have known unknowns – we know what we need to work on and learn.
- Illustrate different issues to overcome with new wells and existing wells,

Breakout Group 1

- Specific Task 1: develop an outline main elements of the report,
  - Define what qualifies as a leak?
  - Define well types:
    - Existing wells,
    - New wells, CCS compliant,
    - New wells, non-compliant due to location, lithography etc.
  - Define area's of influence, scales and regulations encompassing area's of influence,
    - Quantity of CO_2 storage necessary means that all wells may be inside area of influence of a storage operation,
  - Monitoring
  - Separate approaches for different target formations – oil, gas, aquifers,

Breakout Group 1

- Specific Task 2: identify key themes or issues to address
  - What should report communicate? i.e. What are the resolved issues?
    - Level of understanding, both known's and unknown's
    - Cement degradation is not likely to be an issue in abandoned wells,
    - Wells can be built to resist most corrosion, as long as conditions are stipulated in advance,
    - We have the ability to gather baseline conditions,

Breakout Group 1

- Specific Task 2: identify key themes or issues to address
  - What are the unresolved issues?
    - Impact of CO_2 plume encountering H_2S zone, and impact of lowering of pH on well materials of existing wells,
    - Future proofing of new wells, defining the area of influence to determine which wells need future proofing,
    - Inability to obtain data on gas leaks from operators – proprietary information,
    - We know we can fix leaks, but why do they occur?
    - Need more monitoring tools and abilities,
    - Better communication between interested parties,
  - Quantification of leakage, small leaks need active effort to find them,
  - What can we measure – leads to what can't we measure,
  - Need methods to validate models,

Breakout Group 2

5th IEA GHG Wellbore Network

What should the report accomplish?

- Useful to have a ‘state of the art’ review of what’s out there and what’s being done
- Should be generalised
- Clarify the ‘question’ – FOCUS on old wells
- What constitutes leakage? Movement outside the container
- Technically focussed

- Provide information for technical, non-technical and outreach

Main Messages

- Three classes of wells – pre-existing, new and injection wells
- Distinction between artificial and natural systems – pathways of concern
- Initial condition of wells is critical, characterisation key

- Early concerns that CO2 would degrade all borehole materials has been dispelled
- We have technologies that can remediate leaky wells i.e. Stop the leak
- We have technology to ensure secure abandonment of wells to hold CO2
- Leakage remediation of wells may be dictated by economic and regulatory issues

- We have technology for assessing leakage in existing wells (non-abandoned)

Unresolved issues?

- Better methods for assessing condition of pre-existing wells
- Better record keeping
- Statistical analyses of well condition and performance
- Effects of impurities in CO2 stream on wellbore materials and integrity
- Expanded studies on flaw evolution and small scale leakage pathways

- Need more samples off wellbore materials that have been exposed to CO2 – vital for calibration of models
- Compare and contrast statistical studies

What should the report try to accomplish?

- Potential audiences
  - Power industry
  - Oil and gas industry
  - Greenhouse Gas
  - Public
- Two target groups
  - Greenhouse gas: Int. J. of Greenhouse Gas Control
  - Oil and Gas: SPE journal
- Results can also be disseminated to industry association meetings
  - International Regulators Forum

What should the report communicate?

- We have a research strategy that will get us to an ability to assess risk
- A review of the character and relevance of historical database
  - This has to be combined with performance assessment modeling to address what is different about CO_2 sequestration (volume, pressure)
- Communicate improvement in processes
- Emphasize the difference between “no leakage” and wellbore integrity
- The industry has the ability to conduct operations now

What should the report communicate?

- Figure showing frequency of leak as function of size of leak
- Ability to detect and mitigate leakage
  - Managing blow-outs and small leakage
  - Detection => monitoring
- Current knowledge of material durability
- Analogy of “blow-outs” has limitations as we aren’t drilling into an unforeseen high-pressure and due to gradual increase pressure
- Define the boundaries of the system (not capture, transport, etc.)
- Failures do not imply significant environmental or health and safety problems

What should the report communicate?

- Unknowns: Long-term degradation or sealing of defects
  - Does risk increase with time?
- Unknowns: Detection limits of leakage
- Unknowns: Lost, abandoned wells
- What do we recommend for evaluation of "old", abandoned well with limited records?
- Missing: Validation of models
- Unknowns: Leak rates of various classes of wells
- Unknowns: Frequencies of leak rates

What should the report communicate?

- Not just a list of monitoring technologies but annotated as to limits and applications
- API is engaged in a parallel task—relationship to present efforts
- Are we going to recommend abandonment practices (e.g., length of plug)
- Biggest risk: low top of cement