CO2 Injection Well Design in the Geothermal Industry

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ABSTRACT

The geothermal industry is keen to reduce the climate impact for all their operations. Capturing associated CO2 and reinjecting it returns the naturally occurring geothermal CO2 back underground to where it came from.

Globally, CO2 re-injection is still in its infancy. In all of Australia, there is only one CO2 injection project currently in operation and globally there are still many valuable lessons being learned.

Many aspects of drilling CO2 injection wells are similar to drilling a conventional geothermal well though there are significant differences between them. This paper shall discuss key differentiators between conventional well design techniques and CO2 injection wells. Areas addressed include:

- Regulations
- Geological Characterization
- Metallurgy
- Cementing
- Load cases
- Well integrity
- Monitoring and Verification
- Risk Assessment
- Contingency planning including well control
- Design process
- Legacy wells and abandonment of existing wells

There are two options available for CO2 injection: re-using existing wells with remediation, workover, or recompletion activities, or drilling new wells dedicated to CO2 injection. Each option has its own advantages and disadvantages, but the main goal is always to ensure that the wellbore and reservoir can securely hold the CO2 for an extended period without any leaks into sensitive zones, such as to an aquifer or the atmosphere.

To choose the most suitable well design, it is important to have a thorough understanding of the pressure and temperature profile throughout the lifecycle of the well. These parameters will behave differently compared to a geothermal well. Analysis is necessary to accurately assess and mitigate any risks associated with the well.

To ensure the effectiveness of the CO2 injection well, a monitoring and verification plan may be necessary to ensure the containment of CO2 and to identify any potential anomalies. Monitoring may include pressure, temperature, logging of tubing integrity, and even conducting seismic surveys.

1. INTRODUCTION

In geothermal systems the presence of CO2 is a natural occurrence, influenced by reactions between the geothermal fluid and the reservoir rocks. In the subsurface formation, CO2 is dissolved in the reservoir fluids and when the fluids flow to surface, it undergoes boiling, causing the CO2 to be released during the generation of power. In the past, it has been widespread practice for geothermal power stations to vent this CO2 gas into the atmosphere. However, the geothermal industry has now begun investigating alternatives to reintroduce and store the CO2 underground.

CO2 injection wells serve as conduits for the efficient injection of CO2 into subsurface formations. This process can play a significant role in mitigating greenhouse gas emissions and helping to combat climate change. Designing an effective and reliable CO2 injection well involves many considerations, such as geology, fluid dynamics, corrosion, and integrity assurance. There are two methods of injecting CO2, one is to dissolve the CO2 in the geothermal reinjection water and the other is injecting pure CO2 with both having advantages and disadvantages.

This paper aims to provide a summary of the key aspects involved in the design of pure CO2 injection wells, including regulations, wellbore construction, well integrity, and well control. By understanding the complexities of CO2 well design, stakeholders involved in CCS projects can ensure the successful implementation of this vital technology. The lessons learned from pure CO2 injection are also frequently applicable to CO2 reinjection wells utilizing dissolved CO2.

2. REGULATIONS (CCS IN NEW ZEALAND)

In New Zealand, there is currently no comprehensive legislative framework specifically addressing carbon capture and storage (CCS). The existing legal framework is incomplete and lacks clarity with regards to the various stages of CCS, including capture, transportation, and storage. CCS is not covered under the Crown Mineral Act 1991.

The Resource Management Act (RMA) is the New Zealand law that seems most applicable to CCS. The RMA is a comprehensive environmental code that covers the environmental impacts of all activities and requires individuals to avoid, remedy, or mitigate any adverse effects on the environment caused by their actions. Carbon dioxide is likely to be considered a contaminant under the Act, which means that it imposes specific limitations on the release of carbon dioxide into the environment. In the event of any leaks from the storage reservoir, the owner of the CCS project could be held responsible for discharging a contaminant into the environment.

On a broader perspective, there are in general two types of regulatory regimes used globally which are:

Prescriptive Regulations: In the older regime, regulations are process-oriented, where the burden is on the regulator to explicitly describe the requirements. This approach is preferred in more "litigious" regimes such as the USA. However, these regulations can be inflexible and may fail to prevent incidents.

Safety Case Regimes: In the newer regimes such as New Zealand, regulations are outcome-oriented and were developed in the late 1980's. In this approach, the burden is on the Operator to convince the regulator that their proposed design, process, method, etc., is safe to operate. These regulations can be more comprehensive than prescriptive regulations and cover areas such as personnel training and procedures. They are also more flexible and require Operators to have experience in implementing safety measures.

For CO2 injection, Operators in New Zealand and Australia tend to follow the Safety Case route which shows one has the ability and means to control major incident hazards.

Industry organizations such as ISO, OEUK and the United States Environmental Protection Agency (EPA) have all developed standards and guidelines though the USA EPA's document is the most prescriptive from a wells perspective and is the document which most Operators use as a reference.

The reason US EPA guidelines being preferred is that it is well-established, well-developed, and highly comprehensive when compared to other available documents. The US EPA guidelines, developed in the early 2010s, primarily focus on CCS Service for "Class VI Wells and are an extension of previous regulations for Class I, II, III, IV, and V Wells. One of the main goals of these regulations is to ensure the protection of underground sources of drinking water. These regulations are frequently used as a model for the development of similar regulations globally. In New Zealand we have observed Operators performing gap analysis of their well designs against the US EPA guidelines and justifying their decisions accordingly.

The reason the focus on international regulations / guidelines is that in addition to the environmental considerations of CCS there are also financial drivers at play. If an Operator is participating in the Emissions Trading Scheme the Regulator will want to ensure the CO2 being injected back into the ground is not going to escape. A number of Regulators therefore want proof of this and one way of being able to demonstrate this is by adhering to international CCS regulations.

Requirements	Evidence
Preventing Fluid Movement Outside of Injection Zone	Demonstrating Mechanical Integrity
Designing Class VI Wells for Logging and Workovers	Design Considerations Continuous Monitoring of the Annulus Deviation Checks Calliper Logs
Well Plan and Design Information	Project Plans
Designing Class VI Wells for Down-hole Stresses	Types of Stresses Corrosion Considerations Stress and Compatibility Information
Cementing the Casing	Different Stage Options for Cementing Cementing Information Requirements Cement Compatibility Cement Bond and Variable Density Logs
Selecting the Tubing and Packer	Elastomers Compatibility
Selecting Surface and Down- Hole Shut-Off Devices	Surface Safety Systems Down-Hole Devices
Conversion of wells (existing wells)	Material Strength Material Compatibility Well Design Mechanical Integrity
Operating Requirements	Injection Pressure Requirements Monitoring of the Annular Space Maintaining Mechanical Integrity

Table 1: High Level Construction Requirements for Class VI Injection Wells Operations

3. REUSING WELLS

Existing wells may potentially be re-used for injecting CO2 though there are challenges that will need to be examined. Advantages of using existing wells include known subsurface parameters, operational well data, knowledge of field dynamics and availability of existing usable infrastructure where applicable.

There are also several methods available to prepare existing wells for re-use, including:

- Utilizing the well as is without making any modifications.
- Conducting a workover on the well by making modifications.
- Creating a side-track by branching off a portion of the well.
- Deepening the wellbore to reach a deeper target.
- Milling or perforating the well to access a shallower target.
- Partially plugging specific sections of the well.
- Re-entering a previously abandoned well.

As a first step a comprehensive well screening and risk assessment must be performed to support the decision-making for well re-use. Areas that need to be examined include:

- Well history
- Mechanical integrity
- Well load cases (including thermal loads)
- Well barrier placement/status,
- Out of zone injection risk
- Cement compatibility and integrity
- Cement evaluation logs
- Annular integrity
- Well maintenance / monitoring
- Metallurgy (designed for corrosive CO2 exposure)
- X-mas tree bodies and valves
- Surface location / site
- Safety
- Dual containment (what happens if primary barrier fails)
- Bottom-hole location for CO2 injection (is it optimal)
- Remedial intervention may be necessary to install tubing and completion equipment.
- CO2 storage wells have different risk profiles when compared to other types of wells and as the CO2 plume moves subsurface it may come into contact with existing wells and even abandoned wells which needs to be considered.

Geothermal reservoirs may not be confined in that that they may have water recharge from the top or sides or the reservoirs may not have a cap rock or if a cap rock is present, it may be fractured. For long term storage of pure CO2 some geothermal reservoirs may not be suitable but that is not to say shallower formations are not suitable. The screening exercise needs to examine the full stratigraphic column, identify all potential traps and leak paths.

Typically, existing geothermal wells lend themselves readily for CO2 injection and have inherent advantages in that they are typically large bore and casing strings are cemented back to surface. The large bore (often 7" slotted liner with 9.5/8" casing back to surface") is of critical importance as this provides the Operator with options of running corrosion resistant tubing. Most geothermal CO2 injection wells require injection rates of 10-30 MMSCF/D which means that 2.7/8" to 4.1/2" tubing may be sufficient.

The decision to reuse an existing well is not a cost alone decision but one based on all the items above.

4. WELL RISK

Well integrity risk assessment and management are crucial for ensuring the long-term integrity and safe operation of the well. In the context of wells, risk pertains to the potential negative outcomes that can occur if there is a failure in maintaining the integrity of the well, resulting in unintended migration of CO2 outside the designated containment area.

The risks associated with CO2 injection wells vary depending on several factors but generally include:

- Corrosion
- Seal failures such as tubing and casing thread, packer seal failure, Xmas tree valves etc
- Caprock's sealing effectiveness.
- Cementing
- Casing / tubing loads
- Nearby abandoned or operational wells.

The assessment of these risks must consider both the likelihood of such an incident happening and the corresponding costs or consequences.

The ramifications of a breach in a well can include hazards to staff / public safety, health, the environment (including ecosystems) and financial.

To evaluate the risks associated with CO2 projects, a range of specialized tools and methods have been created. These tools include extensive databases that compile relevant factors, events, and processes for identifying and analyzing risks specific to each well. Moreover, qualitative and quantitative tools have been developed to assess the likelihood and potential outcomes of various scenarios linked CO2 leak paths associated with wells situated in CCS reservoirs/developments. The recommendation is to not reinvent the wheel as there are good proven and industry accepted tools available.

Automated software-based quantitative risk assessment tools are available in the public domain, namely NRAP-open-IAM, developed in the US, and REX-CO2, developed in the EU. These tools can evaluate the likelihood of undesired release of CO2 and analyze the performance of individual system components and include tools for assessing / detecting well and seal leakage, evaluating groundwater effects, and studying induced seismic activity for example.

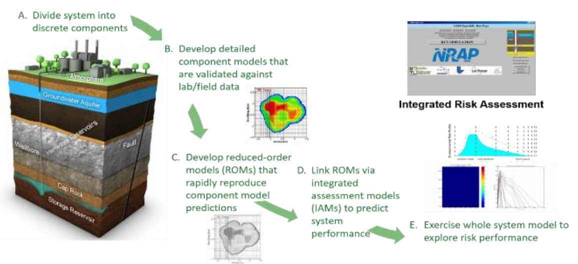

Figure 1: NRAP-Open-IAM QRA process overview. Courtesy of NRAP

5. WELL DESIGN PLANNING

The tools and knowledge base for drilling CO2 injection wells is well understood and the drilling of such wells is similar to that of drilling a conventional geothermal well though there are differences which include material selection, cementing, integrity management, monitoring and equipment such as blowout preventers

The well design process for a CO2 injection well typically involves a formal process such as below to achieve the required consistency, cost effectiveness and safe conduct of drilling activities.

The objective of the planning process is to ensure that:

- Well planning is performed with due regard to relevant legislation.
- Wells are planned and designed in accordance with company standards.
- Well Planning is conducted in a consistent and timely manner.
- The relevant departments are involved in the decision making process.
- The necessary approvals are obtained, both internally and externally.
- Sufficient resources are in place and allocated to the project.

Throughout the entire process, it is crucial to involve multidisciplinary teams including geologists, engineers, and environmental scientists to ensure a safe and effective CO2 injection well design. Regular communication and collaboration with regulatory authorities and stakeholders are also important to address any concerns and ensure compliance.

The main differences in the design process include:

- Joule-Thomson cooling effects (large temperature changes)
- Gas to liquid phase changes
- Metallurgy
- Cementing
- Integrity concerns – well and subsurface
- Elastomers – explosive decompression
- Corrosion
- Monitoring and verification
- Risk assessments tend to be significantly more comprehensive
- Casing design modelling is more complicated with more additional cases

Due to the uniqueness of CO2 wells a longer planning time frame than is normal is recommended. Lead times for CO2 resistant materials can also be considerable, the duration to discuss designs with Regulators should not be underestimated and for most Operators there is a learning curve in the design process. A dedicated CO2 injection well often requires significantly more subsurface definition in the front-end planning as more certainty is required to ensure that the reservoir is able to contain CO2.

6. PHASE BEHAVIOUR

Carbon dioxide (CO2) phase behavior can vary depending on the temperature and pressure conditions it is subjected to.

When CO_2 is subjected to higher temperatures and increased pressure, it transitions from a gas to a liquid state. When the temperature and pressure of CO_2 exceeds its critical point, it enters a supercritical state and exhibits properties which have a viscosity comparable to that of gas and a liquid-like density.

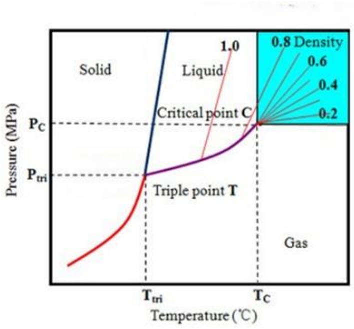

Figure 2: Phase Diagram for CO2

Overall, the various states of CO_2 (solid, liquid, gaseous, and supercritical) are determined by the temperature and pressure conditions it experiences as it is pumped down the well. The stability of CO_2 flow is greater when it is in a liquid-like state above the critical pressure and this is often the preferred phase as it occupies less volume, has less friction losses and therefore allows for the use of smaller pipe diameters. However, the pressure required for stability is often determined by the reservoir pressure when injecting CO_2 into a wellbore.

It is critical that a thorough understanding of phase behavior during the life of the well is understood as CO_2 changes from liquid to gaseous phases can cause large temperature and pressure fluctuations which can result in operational issues. It is necessary to perform a range of possible injectivity scenarios. Composition of the CO_2 stream (contaminants) will also affect the phase behavior.

With the high expansion as CO_2 liquid enters a depleted reservoir a Joule-Thomson cooling effect can be caused resulting in a large temperature drop. This temperature drop can result in thermal fraccing, casing/tubing failures or hydrates formation if there is water present in the reservoir. If reusing existing geothermal wells, this Joule-Thomson effect can be significant as the existing wells would not have been originally designed for this potential temperature range and could suffer catastrophic failure.

When injecting liquid CO_2, the hydrostatic pressure alone can cause a high pressure (overbalance) and thus increase the Joule-Thompson effect. A solution is the use of smaller tubing diameters as it will result in increased frictional pressure losses and pressure drops. Additionally, smaller pipe diameters result in lower capital costs as smaller pipes are less expensive to manufacture, especially if using corrosion resistant materials. A downhole choke can also be used to increase the backpressure in the wellbore.

Injecting CO_2 in the gaseous phase is generally less efficient as a larger volume is required for the same mass. Injecting CO_2 in the gaseous phase often only lasts for a brief time as when the reservoir reaches ca 1,100 psi it is no longer possible to pump CO_2 in a gaseous phase and it must be in either liquid or supercritical phase. This change to liquid phase leads to a higher hydrostatic head in the tubing, resulting in increased hydrostatic pressure and injection pressure downhole. Another point to add is that as the gaseous phase approaches the phase boundary and becomes a liquid it can cause an unstable phase behavior to occur. The well design should ideally be capable of accommodating both gas and liquid phase injection and be able to handle the transition from one phase to another throughout the lifespan of the well.

To accommodate the injection of both gaseous and liquid phases, different well design options need to be considered. CO_2 gas phase injection requires low pressures and minimal tubing friction pressure loss to maintain the gas phase, which necessitates larger tubing sizes. As formation pressure increases downhole and the injection phase changes to liquid/dense, it may be necessary to introduce additional resistance, such as friction, to create backpressure and offset a portion of the hydrostatic head.

If the phase change occurs at surface such as across a choke it can create serious complications in terms of well design and operability as the temperature may be below the lower threshold limit of some well equipment. For example, the lower temperature limit of a Xmas tree block may be -20 deg C and the actual temperature may be -25 deg C.

It is important to select materials that can maintain the required specifications under both normal and abnormal flow conditions. Low temperatures can also lead to the freezing of annulus fluids if present and significant contraction of the tubing/casing. The temperature range to be modelled in a well is greater than what is typically experienced in a geothermal well, potentially leading to significant growth/contraction and additional loads on the well. For example, loss of containment temperature load case is important to consider as it progresses down the phase diagram as resulting temperatures may be as low as -40degree C. This could result in severe casing yield occurring.

7. METALLURGY / MATERIAL SELECTION

One of the first deliverables in any CO_2 injection well design is to perform a metallurgy study.

Corrosion of steel products in wellheads, casing, and completion strings is a common occurrence in CO_2 plus water environments and can cause casing failure and the creation of leakage pathways.

Dry CO_2 is fundamentally non-corrosive to carbon steels. Use of corrosion resistant alloys such as Duplex (25% Cr)is typically used for wet CO_2 situations. Impurities such as H_2S can also have significant consequences in terms of the corrosion of tubulars.

Even where dry CO_2 is injected there are scenarios where reservoir fluids can enter the wellbore between injection cycles or when the well is shut-in causing a corrosive environment.

The most common method of corrosion control involves selecting materials that can withstand the corrosive environment. In some cases, materials can be chosen that will last for the entire lifespan of the well. However, in other situations, less resistant and less expensive materials can be selected, where the materials will only last for a limited time before needing replacement. To use this method, it is crucial to fully understand the failure mechanism and the expected duration of service as well as implementing quality control measures of the injected CO_2. Regular inspections must be carried out to ensure replacement occurs before the downhole tubular loses its integrity (such as tubing or packer). With high chrome tubulars costing many multiples the cost of carbon steel there are occasions where regular workovers to replace carbon steel tubulars is more cost effective than purchasing high chrome tubulars.

It should be noted that when the chromium level in materials exceeds 17%, the tubulars have mixed yield strengths in different directions and must be accounted for in the design phase.

In addition to carbon steel and chrome tubulars, glass reinforced epoxy (GRE) tubulars may be considered. GRE can be utilized as an interior lining for corrosion protection though there are temperature limitations, and it can be influenced by factors such as pH and velocities. Also, if the lining of GRE is damaged during installation or at any point during the lifespan of a well such as when performing wireline, the steel tubular will be exposed to corrosive agents in the well injection stream.

Corrosion can also be reduced or managed by employing chemical inhibitors in either continuous or batch injection mode. For continuous inhibition, an injection port is installed in the tubing, allowing the inhibitor to be injected downhole. With the batch method, a quantity of inhibitor is pumped into the formation for a specific duration. The downside of the batch method is the necessity to temporarily shut down the well to perform the batch chemical injection, resulting in downtime for injection operations. Chemical inhibition requires a formation damage study to be performed to ensure there is no reaction which could cause plugging of the fractures.

7.1 Elastomers

While the use of elastomers in geothermal wells is not common, they may be required in CO2 injection wells if packers and PBR's are to be utilized.

CO2 presents unique additional challenges as the elastomer needs to resist rapid gas decompression and be qualified appropriately. Elastomers become more rigid at low temperatures and their sealing ability can thus fail. All elastomers need to be checked against the field specific CO2 specification and operating conditions.

BOP rams also include elastomers and have a maximum CO2 rating which needs to be considered for shutting in a well with CO2 at surface. Minimum temperature operating limits also need to be considered.

8. WELL INTEGRITY

CO2 injection wells must demonstrate their mechanical integrity before being used for injection. This proves that the well is structurally sound, with no leaks in the tubing, packer, or casing. It also ensures that any CO2 injected into the well is properly contained within the designated injection zone, preventing any upward migration or potential issues caused by inadequate cementing or poor well design.

When CO2 is injected, there is a risk that it may migrate upwards or sideways due to differing pressures and buoyancy. The main way for the CO2 to escape is through the wells, as they provide clear pathways out of the reservoir. These pathways can include leaks at various interfaces between dissimilar materials, such as the steel casing cement interface and the rock cement interface. Leakage can also occur through fractures in the cement or because of insufficient coverage of the well circumference (channeling). Corrosion of the casing may also contribute to casing failure and the creation of larger pathways for leakage.

Figure 3 below illustrates the potential routes through which CO2 injection wells may experience leakage.

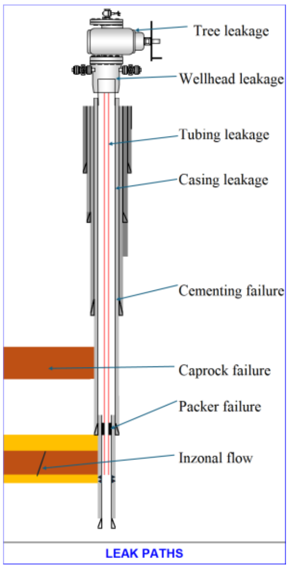

Figure 3: Potential Leak Paths

Integrity issues are identified as part of the risk assessment process described earlier and failure of the pressure envelope must be considered in the design phase of the well so that contingency plans can be put in place for say a tubing or casing integrity failure.

The aim of a well integrity risk assessment is to assess not only the adequacy of the CO2 injection well but of all adjacent wells near the injection well in handling CO2. This evaluation encompasses both abandoned wells, operational wells as well as the CO2 injection wells.

There are numerous methods available to identify leak paths of injected CO2 such as RA tracers, temperature logs, cement bond logs, noise logs and ultrasonic leak detection tools. Regularly running of caliper and/or electromagnetic thickness surveys is recommended for monitoring the potential impacts of corrosion and erosion on casing and tubing.

9. CASING / TUBING DESIGN

Well casing undergoes various loads during distinct phases of the well operation and the casing, liner and completion-string need to be designed to withstand all planned and/or expected loads and stresses including those induced during potential well control situations.

The casing strings must be able to endure all tension, burst, and collapse forces that they could be exposed to during the life of the well. Casing design is based on a comparison of the casing's published API performance properties and the anticipated maximum load conditions. There is no standard methodology for the estimate of CO2 load cases and each company usually develops its own 'guidelines' as standards such as API and ISO are silent on this load case area and only address performance properties.

The critical components for CO_2 injection are the injection tubing and the production casing and liners if applicable. Casing design for geothermal load cases are well understood so the focus must be on load cases that are specific to CO_2 injection wells. Below are several load cases which must be considered:

Temperature: The potential for very low temperatures will be of particular concern due to contraction. This is especially important if a Polished Bore Receptacle (PBR) and/or production packer is utilized. Also, the lower temperature range which CO_2 injectors may be exposed to can result in far greater thermal loads/stresses on the casing strings.

Annulus Pressure: Most geothermal wells have casing strings cemented back to surface, and this is also preferred for CO_2 injection wells if possible.

Because of the cost of CRA materials it is not unusual to use a tubing string in a CO_2 injector well. These tubing strings are typically 2.7/8" – 4.1/2" OD depending on the required injectivity rate, CO_2 phase and injection pressures. If a tubing string is run and not cemented to surface an annulus between the tubing and inner casing string will be open and contain an annulus fluid. This fluid can expand/contract as operations dictate and the associated load cases must be modelled. Indeed, an N_2 filled annulus may be beneficial because of the temperatures encountered.

It is normal practice to perform an annulus pressure test to ensure integrity of the system and this pressure test needs to be modelled. The pressure for the test is determined based on a tubing leak scenario (injection pressure acting on a full fluid hydrostatic column in the annulus). Modelling should also include late life load case as casing parameters change through a well's lifespan due to corrosion or wear.

Cyclic Loading: Highest loads may be imposed by transient/upset conditions. Changes in the phase behavior from gas to liquid can cause large changes in wellbore pressures and temperatures. These changes may occur in a cyclical manner and their onset is difficult to model as is the well warm-back duration to the static geothermal temperature gradient in-between injection cycles. The operations team will attempt to change the injection parameters to minimize the severity of the cyclic loading but if the cyclic loading is not identified it could last for a long duration resulting in a worst-case casing/tubing/cement failure.

Shut-in Surface Pressure: A standard calculation for all geothermal wells but a little more complicated in CO_2 injection wells. Generally, one assumes the tubing is full of the injection fluid and reservoir pressure is used to calculate the maximum shut-in wellhead pressure. For CO_2 wells, it is not uncommon that CO_2 gas is initially injected into a reservoir and over time the reservoir pressure builds up as more CO_2 is injected. As the reservoir pressure increases CO_2 injection in the gas phase is no longer possible and the hydrostatic will change to liquid. Modelling is required to determine when maximum shut-in pressure occurs such as at the beginning of the well life or near the end of well life when the reservoir pressure is greater but then CO_2 injection is in liquid phase.

Tubing leak: Surface tubing leaks are important to model if using uncemented tubing as the tubing shut-in pressure could act upon the annulus hydrostatic column.

Well Kill: Bullhead kill is a typical load case considered as part of the casing design. In this case one examines the loads experienced if having to bullhead the tubing contents to the formation. Again, two phases should be modelled, and a convincing argument can be made for ensuring the production casing can also take these loads if the tubing were to fail.

CO_2 Injection (early and late stages): Load modelling is required for both gas and liquid phases. Early in the field life, the gas phase may be injected whilst later this may change to liquid phase. Corrosion modelling is required to estimate corrosion rate and wall reduction with time. Also, as reservoir pressures increase over time, key casing/tubing load cases will be encountered late in the well life.

Loss of Surface Integrity: In the unlikely event of a surface failure at the wellhead/Tree there is the potential for the well to experience 'Absolute Openhole Flow' and this needs to be included in the casing thermal and stress analysis as the thermal contraction of the tubulars could be severe resulting in casing failure. Collapse loading of the tubing will also need to be modelled as the internal pressure will decrease significantly in this load case.

10. CEMENTING

For CO_2 injection wells, the CO_2 is frequently injected in a dry state and due to the absence of water there is no mechanism to create corrosive carbonic acid though interactions with downhole formation water can occur, which may cause the appearance of carbonic acid at the wellbore. Elevated temperatures as is observed in geothermal wells can speed up the degradation process and these considerations need to be considered during the planning phase.

There are also many potential routes for CO_2 migration through cement which can include the following:

- Microannulus between cement/casing.
- Via the pores in the cement, caused by deterioration.
- Traveling along fractures in the cement.
- Channelling
- Space between cement and the formation.

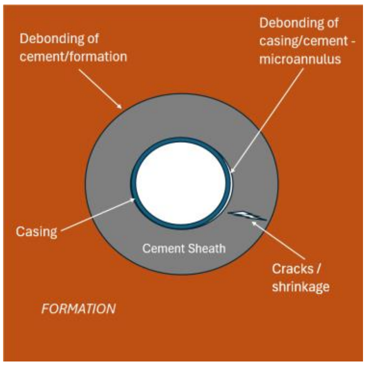

Figure 4: Cement Failures Routes

The proper selection of a wellbore cement is therefore crucial for maintaining the integrity of the wellbore. For many years, Portland cement has been successfully used in well cementing. However, Portland cements are often thought of as not suitable in CO_2 injection wells as the cement can degrade when exposed to CO_2 in combination with water and over time, the compressive strength can reduce resulting in a loss of integrity. Several more recent studies show that when

Portland cement reacts with carbonic acid, it can result in a layer of $CaCO_3$ on the surface of the cement. This layer acts to slow down or even halt the reaction process altogether. A cementing study for a CO_2 injection well is therefore critical to ensure cement integrity is maintained throughout the well life cycle.

Specialty CO_2-resistant cements are being used more frequently in CO_2 injection wells to ensure long-term well integrity. These cements have demonstrated good resistance to CO_2 attack during laboratory tests under downhole conditions. Furthermore, there is ongoing development of self-healing cement specifically designed for CO_2 service. These innovative cements incorporate an engineered particle size distribution (EPSD) material capable of swelling when exposed to CO_2. This swelling action helps seal micro-fissures, repairs the cement sheath, and restores integrity.

It should be noted that the well design should first determine if a CO_2 resistant cement is indeed required in the specific application. Out of zone injection involves the injected CO_2 breaching to formations other than the intended injection zone. In the figure below, if zonal isolation alone is considered the cement area exposed to the CO_2 plume is small and it has been estimated that 30m of vertical Portland cement could be impermeable for 10,000+ years if the cement sheaths/plugs have strong integrity and create a "dead end."

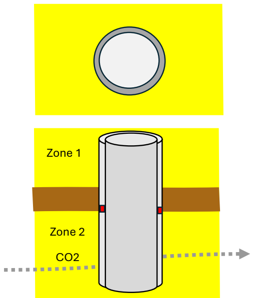

Figure 5: Cement Exposure Areas

To minimize the risk of cement failure, it is important to apply good cementing practices regardless of the cementing option used. Final cement quality should be determined by cement evaluation tools.

11. WELL CONTROL

The likelihood of a control incident is slim but nevertheless must be planned as part of the well planning process. Prior to any well being drilled, a well contingency plan should be prepared and should include well control procedures, responsibilities, relief well location, outline relief well design and equipment and rig availability. The main objective with the drilling of any well is always to prevent a well control incident. The well control contingency plan should be updated for CO_2 wells as the well control issues can be quite different.

In the rare occurrence of a CO_2 well control incident, the rapid expansion of CO_2 can result in rapid cooling. This cooling could be intense enough to cause solid dry ice particles to form in the jet stream and for hydrates to form. The primary concern with a CO_2 blowout lies in the extremely low temperatures resulting in brittle fracture of materials. Elastomers in BOP's can also fail under these circumstances. There are also safety aspects with cold burns and frostbite even with minor surface leaks.

CO_2 influxes act differently to that of gas or water. If the CO_2 influx is in a supercritical phase, then detecting it can be more challenging due to the smaller volumes. As the influx moves up the well it expands and moves up the well quickly potentially forming hydrates and blocking off circulation. Multiphase kick simulators should be run to show how CO_2 interacts with drilling muds, calculation of minimum allowable kick volumes, reaction times and optimal kill methods.

Geothermal wells do not utilize downhole safety valves in their well designs, but they are typically used in gas wells. It is necessary to evaluate the regulatory requirement, practicality and suitability of this equipment. There are not many downhole safety valves available which are suitable for CO_2 use.

12. MONITORING

Monitoring is standard practice in geothermal wells where pressure, temperature and flow are monitored as standard. In addition, regular caliper runs are frequently run to confirm casing integrity as is the use of corrosion coupons so often there is not much change required from an existing monitoring programme to that for a CO_2 injection well.

Monitoring of CO_2 wells can be split into three categories:

1. Plume monitoring - confirming the behaviour of CO_2 in the reservoir.
2. Containment monitoring – confirming the injected CO_2 stays within the formation
3. Contingency monitoring: evaluating well integrity solutions in the case of a leak/failure

Well integrity monitoring is often a regulatory requirement, and Operators may need to demonstrate that the long-term safety and integrity of the CO_2 injection wells is maintained not just during operations but also post abandonment. There are also safety and environmental reasons for performing regular monitoring. There is no one size that fits all monitoring solutions and the Operator does have a degree of freedom in designing their monitoring programme so that it is well/field/area specific. Monitoring is generally risk based so that the greatest risk items receive the greatest monitoring.

In geothermal wells, the high temperatures can restrict the type of monitoring/diagnostics tools being used but with CO_2 injection wells the temperatures are generally significantly lower so there is a greater range of tools available. Monitoring tools may include the following:

- Temperature – leaks and optimising injection parameters
- Pressure – leaks, optimising injection parameters, ensuring injection pressure is below frac pressure.
- Callipers – corrosion, pitting, well integrity
- Seismic profiling – tracking of plume in the formation
- Water sampling – CO_2 leak into shallow aquifers
- Well logs – identifying CO_2 above injection zones

For CO_2 injection wells, it is not uncommon for fibre optic cable to be run for distributed temperature sensing due to its reliability and performance. From an integrity perspective fibre optic is invaluable as it can immediately provide the depth of a leak.

One of the main differences in monitoring programs between a standard geothermal well and a CO2 injection well is monitoring of the CO2 plume, and this can be challenging (and expensive). Often time-lapse seismic data is used to track the development and movement of the plume. CO2 in the reservoir (supercritical) gives a strong sonic velocity contrast when compared to the initially water filled reservoir and therefore provides positive settings for seismic monitoring.

Periodic monitoring of the ground water quality may also be required as well as air and soil gas monitoring.

Monitoring requirements need to be determined up-front as they may affect the well design. Real time sensors such as fibre optic will require careful engineering and wellhead modifications (ports). Downhole gauges may require nipples and tubing ID's may restrict the use of certain logging tools.

13. CONCLUSION

Geothermal and CO2 injection wells have many shared features, and the design process is broadly the same with similar casing, sizes, equipment and drilling rigs being used.

The main differences between CO2 injection wells and geothermal wells are as follows:

- Load cases – temperature and pressure, cyclic loading
- Corrosive environment – material selection
- Cementing
- Monitoring
- Joule-Thomson effect resulting in significant temperature drops which could lead to material failures
- Well control
- Technical risk
- Safety

It is important to understand local regulations and understand their impact on the well design requirements.

It is recommended that up-front studies into metallurgy, cementing, monitoring requirements and phase behavior are performed. These studies will result in considerable savings during the well life cycle as there may not be a requirement for specialty materials or cements.

It may be possible to use standard equipment during most planned operating conditions though it is important to ensure it can withstand transient / cyclic conditions.

Ensure a full well integrity risk analysis, metallurgy review and load analysis are performed if considering the use of existing wells. Retrofitting existing wells can quickly escalate and purpose-built new wells may be more cost effective and safer in the long term.

Ensure there is no risk to adjacent wells even if these wells are abandoned. Perform a risk assessment of all wells where the CO2 plume may be encountered.

Inter-company standards and manuals/guidelines will need to be updated for CO2 wells.

Allow for a longer planning cycle if this is the first CO2 injection well. There is a learning curve, and it takes time to adopt new processes and practices.

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