ABSTRACT
Geofirma was contracted to prepare engineering and modelling studies assessing the feasibility of increasing the maximum storage pressure in several underground natural gas storage reservoirs. This required an assessment of the potential for pressure and gas propagation in the caprock, and the geomechanical response to pressure change in the storage reservoir. To solve this problem in an efficient manner, TOUGH2 and FLAC3D models were combined in series. Two-phase flow models were developed in TOUGH2 and calibrated with data collected on-site. The mechanical response of the caprock to delta pressuring was modelled using FLAC3D, allowing assessment of the induced stresses in formations surrounding the reservoirs. Here we focus on two sites: In the first, field data was obtained from a deep borehole above the gas reservoir, which provided indirect observations of the geomechanical response of the caprock to pressure changes in the reservoir. In the second, open boreholes intersecting two thin caprock units immediately above the reservoir allowed gas flow to a shallower unit, significantly impacting the modelled fracture gradient.

INTRODUCTION
Imposed changes in pore pressure may have a considerable impact on effective and total stress in a host rock, with important implications in many subsurface engineering applications. Rutqvist and Tsang (2003) suggested that TOUGH2 could be combined with FLAC3D, leveraging the strengths of each code; simulating two-phase flow in TOUGH2, while mechanical processes are handled by FLAC3D. They showed one possible application, coupling these models to simulate CO₂ sequestration. Walsh et al. (2015) combined these codes in a different way to characterize damage development and flow in a tunnel excavation damaged zone. Depending on the problem, there are many different ways to combine these models. Here we present a straightforward application where TOUGH2 and FLAC3D were combined in series to solve problems in underground natural gas storage in depleted natural gas reservoirs.

Gas Storage in Pinnacle Reefs
Underground natural gas storage is common, representing a long-established, safe technique. The issues in this industry are analogous to those encountered in CO₂ sequestration, and in radioactive waste isolation where anaerobic degradation of organic material and ferrous metals may produce sufficient gas to pressurize a waste repository (Geofirma and Quintessa, 2011). Gas storage systems provide an opportunity to verify and refine modelling tools to assess gas flow and rock mechanical response in deep underground systems.

In Canada, most jurisdictions apply the most recent version of CSA Z341 to regulate the technical aspects of natural gas storage (CSA, 2014). This standard allows delta pressuring, or pressurization of the storage pool beyond the gas pressure that existed when the pool was initially discovered. The maximum delta pressuring must remain at or below 80% of the fracture gradient, defined as “the pressure gradient that, when applied to subsurface formations, causes the formations to fracture physically.” Put another way, this condition requires that gas pressure be less than or equal to 80% of the minimum principal stress. To meet this standard, the operator must estimate how changes in the pressure of stored gas and movement of gas...
drive changes in total and effective mechanical stress in the caprock above the storage pool.

In our work, we have modeled a large number of gas storage pools. Here we highlight modelling results and field measurements from two pools, which exemplify the geomechanical response to pool pressurization operations and movement of gas in the subsurface. Both gas storage pools are in Silurian age pinnacle reefs in close proximity to one another, and both have been safely operated as storage pools for decades. The ground surface elevation is 200 mASL (metres above sea level), and the minimum depth of both pools is roughly 500 m. The caprock overlying the reef consists of relatively thin anhydrite and shale units, overlain by a somewhat more permeable carbonate unit, a thin anhydrite, and an extensive and thick salt unit.

In both cases, the historical data set includes local data on key properties (permeability and porosity) of the reservoir and cap material, additional property data (retention curves, mechanical properties) from surrounding reefs, and micro-fracture test results at two nearby pinnacle reefs. Modelling was primarily two-dimensional, based on geological cross sections through the buried pinnacle reefs. For one of the pools a three-dimensional model was developed to verify the accuracy of the 2D model.

**MODELLING PLAN**

Two models were used to understand the hydromechanical behavior of each storage pool: a TOUGH2 model and a FLAC3D model. The TOUGH2 model was used to test and develop a two-phase flow model of the system, generating pore pressures for input into the FLAC3D model. The FLAC3D model was used to assess the impact of the changing pore pressure field on the distribution of stress in and above the storage pool. The FLAC3D model used the same grid and property distribution as the TOUGH2 model to facilitate interpolation of scalar values from one grid to the other.

The sequence of events for modelling the geomechanical consequences of pool pressurization were as follows:

1. Horizontal and vertical stresses were initialized using the lithostatic pressure curve and estimated stress boundary conditions. Initial pore pressures were set to hydrostatic in most of the model domain, and to discovery pressure in the reservoir.

2. As the initial stress distribution was only approximately correct, the FLAC3D model was stepped forward until it reached a stable equilibrium, representing the initial stress state more accurately given the variation in lithology across the cross-section.

3. Pore pressures were reset using output from TOUGH2. The saturation averaged pressure was passed to FLAC3D.

4. The geomechanical model was run to reach a new equilibrium, representing the mechanical impact of the applied pore pressure.

For the subsequent calculation of the percent fracture gradient the maximum fluid pressure was used, rather than the saturation averaged pore pressure passed to FLAC3D in step 3.

The EOS3 equation of state module was used to simulate the transport gas. Modifications to EOS3 were performed to use alternative gases, specifically methane (CH4). The modifications entailed changes to Henry's law constants, molecular weights, and viscosity calculations. EOS3 was also modified to correct methane density as function of pressure under conditions where methane compressibility diverges from ideal gas behavior (such as high gas pressures in the storage pool). This correction uses the Peng-Robinson equation; further details on the Peng-Robinson cubic equation of state can be found in Reid et al. (1987). Finally, EOS3 was altered to model a higher density liquid component (i.e. brine). This was done to achieve realistic saturated formation pressures without inducing unrealistic vertical flow gradients.

**IN-SITU STRESS**

The in-situ stress is the primary factor determining the fracturing pressure and therefore the safe operating pressure of a gas storage reservoir. The best available synopsis of the regional stress regime is presented in Lam and Usher (2011). Based on their report, the value of the minimum horizontal principle stress ($\sigma_h$) in this region and at these depths is between 1 and 1.2 times the vertical stress ($\sigma_v$), while the maximum horizontal principle stress ($\sigma_h$) is
likely between 1.5 and 2.1 times higher than the minimum horizontal principle stress. The orientation of the maximum principle stress is approximately ENE. A series of micro-fracture tests at two nearby gas storage pools confirmed that the minimum principle stress in the area is likely vertical, as it was very close to lithostatic.

Information on the other principle stresses could not be gleaned from the test data. To manage this uncertainty, the horizontal principle stress was assumed to be equal to the lithostatic stress gradient. This is likely a conservative assumption with respect to the potential for tensile hydraulic fracturing, but produces low shear stress as the horizontal and vertical principle stresses are nearly equal throughout the model domain. To assess the development of shear stress and the potential for shear failure, cases in which the horizontal stress was set to 2.5 times the vertical stress were also run. Shear failure was found to be an unlikely failure mode, and these results are not discussed further here.

**STORAGE POOL A**

Pool A was discovered in December 1970 at a pressure of 5981 kPag, and produced until August 1972, when it was shut-in at a pressure of 764 kPag, having produced 152 Mm$^3$ (at 15°C, 1 atm). Use of the pool for gas storage began in 1975. Pool A is of interest due to the installation of a pore pressure monitoring system in the water saturated formations directly above the buried pinnacle reef. At the time this model was prepared, the pool operated at a delta pressure gradient of 0.73 psi/ft (16.5 kPa/m).

In 2013, site characterization work was completed by Geofirma. This work included drilling one borehole to approximately 490 m deep, providing further site/geological information by coring through the formations directly above the pool. Core was sampled and tested for geomechanical properties, retention properties, permeability, and geochemical analysis. Subsequent to coring, a field hydraulic testing program was undertaken, providing in-situ measurements of formation permeability for these very low permeability formations. Thereafter, a multi-level piezometer with 12 intervals was installed and used to measure the pressure profile after allowing three months for pressure stabilization. After that, datalogger pressure probes were installed in seven intervals, to record the evolution of pressure in the caprock above the reservoir during pressure cycling. This monitoring continues to the present, and this data has been used for model development and analysis.

**Model Setup**

The grid and property distribution in the cross-sectional model for Pool A are shown in Figure 1. The general structure of the reef and surrounding formations is evident. The overlying caprock formations are generally very tight, with permeabilities on the order of $10^{-20}$ m$^2$ or less. The carbonate formation directly above the reef is divided into an upper zone with a permeability of $1.4 \times 10^{-21}$ m$^2$, and a lower zone with permeability of $5.5 \times 10^{-18}$ m$^2$. The reef itself has an average permeability of $7.2 \times 10^{-15}$ m$^2$.

![Figure 1. Grid and properties, Pool A model.](image)

Stabilized inventories for Pool A between 1983 and 2013 were provided. These inventories were used to calculate average gas injection and withdrawal rates, which were applied as a methane source/sink term in the model. The methane injection/extraction rate is shown in the upper part of Figure 2. The source term was scaled for the smaller reef volume in the 2D model which had a nominal thickness of 1 m (as compared to the real 3D reef). Note that for the first 23 years the model used a simplified source term which allowed the model to run more quickly, matching maximum and minimum stabilized pressures and establishing a reasonable pressure history.

**Model Results**

Figure 2 also shows the comparison of measured and modelled storage pressures. In general, the
model does a good job of matching the actual pressure in the reef. While not a perfect fit, the match between modelled and measured pool pressures is good, particularly given that the model prediction is very sensitive to the production or injection rate of the source term.

Figure 3 represents a single point in time. The orange line in Figure 2 shows the timeseries of average fluid pressure in the carbonate formation above the reef. The model predicts that over many years of operation pressures in the carbonate unit move toward equilibrium with the average storage pool pressure, tracking the average pressure during the preceding 4-5 years. This calibrated model allows small quantities of gas to seep into the lower part of the overlying carbonate during the decades-long operational period of the pool. The modelled overpressure in this formation does have implications for the effective stress and fracture gradient in this unit.

These pressures from TOUGH2 were interpolated onto a FLAC3D grid and imported into the previously initialized FLAC3D model. Figure 4 shows the model results, from both TOUGH2 and FLAC3D. The results are for a pool pressure maximum, under current operating conditions at the time the model was run. The first panel shows the gas saturation, the second shows the saturation averaged pore pressure which was exported to FLAC3D, the third shows the resultant total stress distribution (horizontal), and the final panel shows the calculated percent fracture gradient. The maximum percent fracture gradient was 65.4% at 0.73 psi/ft. Increasing the delta...
pressure gradient to 0.8 psi/ft, by increasing injection and extraction rates, raised the maximum fracture gradient to 71.4%. In both cases, this maximum occurred at the top of the reef, and not in the overlying carbonate. The fracture gradient was calculated using the maximum fluid phase pressure, not the average gas and water pressure.

In Figure 4, panel 3, the reduction in horizontal compressive stress directly above the storage pool is evident. A vertical profile showing model results at the midpoint of the reef is shown in Figure 5. The reduced compressive stress above the pool is apparent, as is the increased stress at minimum storage pressure (second panel). The stress change is reduced in the salt unit, as it is more elastically compliant.

A 3D model for this pool was also developed. It confirmed that the 2D model adequately captures the important mechanical processes, predicting a maximum fracture gradient of 65.5%, as compared to the value of 65.4% returned by the 2D model (see Figure 6).

**Indirect Measurement of Stress Change**

As mentioned earlier, datalogger probes were installed in seven intervals above the storage reservoir, to record the evolution of fluid pressure in the cap during reservoir pressure cycling. The instruments were intended primarily to measure the in-situ pore pressure, and provide an early warning should the increased storage pressure cause detrimental pressure changes in the cap. Pressures from six dataloggers are shown in Figure 7. Data from the seventh, installed at -160 m ASL, is difficult to interpret due to pronounced underpressure in the adjacent formation, which may be causing the packer to leak.

Figure 7 shows that, despite the variation in pool pressure between 3.5 and 8.2 MPa, the pore pressure measured in the caprock does not change significantly. The gradual pressure rise, especially apparent in ports 2, 3, and 4, is due to gradual equilibration between the initial water pressure in the isolated section of borehole, and the formation fluid pressure. Port 1, in the relatively permeable part of the overlying carbonate unit shows virtually no change during this time, as equilibration was more rapid.
Even at the scale of Figure 7, small perturbations are evident in some of the pressure timeseries. To highlight these perturbations, a cubic spline fitting the overall trend of the pressure recovery curve was subtracted from the data. The resulting timeseries highlights the small pressure fluctuations, as shown in Figure 8. Plotted in this way, there is clearly a relationship between pressure changes in the storage pool and small pressure fluctuations in the cap. It is equally clear that this is not caused by movement of fluid, but rather by hydromechanical coupling. The observed pressure response is virtually instantaneous, and the pressure perturbations are inversely proportional to the pool pressurization.

Given the very low permeability of the caprock units, established through hydraulic testing and also evident in the long equilibration times, the pore pressure response measured by these sensors is likely not due to a change in formation pressure, but rather to borehole deformation.

There are no similar small pressure fluctuations in Port 1, in the lower carbonate, closest to the storage reservoir. Pressure at this port is remarkably stable. The permeability of this unit is approximately three orders of magnitude higher than other units, which may allow any hydromechanically induced pressure fluctuations in the borehole to dissipate much more rapidly. Alternatively, even very low gas saturations in the borehole would reduce the hydromechanical pressure response (e.g. Walsh et al., 2012).

It might be possible to model the observed borehole hydromechanical response to stress changes, and thereby use pore pressure changes in the borehole as a proxy measurement for changes in rock stress; however, this was beyond the scope of this project. In order to develop such a model, it would be necessary to have a very good understanding of the in-situ stress field, compliance of the packer and casing system (Westbay MP55 in this case), and rock mechanical properties for the entire isolated interval. If all of these conditions were met, this analysis could still be confounded by very low saturations of gas in the test interval. Low gas saturations could explain the lack of pressure response in Port 1, and may also affect the observed pressure change in other ports, albeit to a lesser degree. On the other hand, the observed pressure fluctuations do provide a qualitative confirmation of the modeled stress changes.

**STORAGE POOL B**

The pool was discovered in 1931 at a well head pressure of 6,029 kPaa. The pool has a depth to crest of 479.9 m, and this translates to a discovery gradient of 12.6 kPa/m (0.56 psi/ft). The pool was designated as a natural gas storage area in 1943 and currently operates between a cushion and maximum pressure of 3,447 kPaa and 7,320 kPaa (measured at well head).

In contrast to Pool A, the shale and anhydrite units separating the carbonate reef storage pool from the overlying carbonate formation are discontinuous. The casing of two production wells ends in the overlying carbonate, so the wells are open from the reef into the overlying carbonate. Three abandoned wells are also open to both the reef and the carbonate, with the seals...
ending partway through the overlying carbonate. During drilling, gas shows were recorded in the overlying carbonate in four wells. The cross connections between the overlying carbonate and the reef and the initial presence of gas in the overlying carbonate mean that this unit likely acts as a secondary gas storage zone.

**Model Setup**

The grid and property distribution in the cross-sectional model of Pool B are shown Figure 9. Geologically, Pool B is very similar to Pool A. The primary difference between the pools is due to the five open boreholes perforating the anhydrite and shale cap. As a consequence, the caprock for Pool B is effectively the thick salt unit (plus another thin anhydrite layer). This is a dense and low permeability unit with an average thickness of 33.4 m over the reef. There is evidence, in the form of gas pressure observations, that a debris bed on the flanks of the reef forms a secondary storage zone.

Stabilized inventories for Pool B between 1991 and 2015 were provided and used to calculate a methane source/sink term. A three month data gap exists starting in January 2003. The model commences after this gap.

**Model Results**

To assess suitability of the model, measured gas pressures in the storage pool, the flanking carbonate debris bed, and the overlying carbonate were compared to modelled pressures, as shown in Figure 10. The model does a good job matching the measured pool pressure, as well as those in the flanking debris bed and the overlying carbonate. The observation borehole in the overlying carbonate is above the reef flank (approximately Model X = 525 m). Modeled pressures directly above the pool are greater than the measured values above the flank.

To fit the overlying carbonate pressure, the model required a connection across the thin cap, as exists in five boreholes. This was approximated in the 2D model by a single line of nodes with high vertical permeability crossing the anhydrite and shale, and extending half-way into the carbonate. The observed pressure response in the overlying carbonate follows the pressure in the reef, with reduced amplitude and a time delay. Short duration pressure changes in the reef have minimal impact on pressures within the overlying carbonate. Permeability in the overlying carbonate unit was calibrated to fit the observed pressures. The calibrated permeability of $5 \times 10^{-16} \text{ m}^2$ is close to the measured horizontal permeability of $4 \times 10^{-16} \text{ m}^2$ for the same unit at an adjacent reef.

Figure 11 shows the model results, from both TOUGH2 and FLAC3D models. As in Figure 4, the results represent a pool pressure maximum. The panels show gas saturation, saturation averaged pore pressure, the total stress, and the calculated percent fracture gradient. The maximum percent fracture gradient was 70.4% at 0.70 psi/ft. Increasing the delta pressure gradient to 0.8 psi/ft, by increasing injection and extraction rates, raised the maximum fracture gradient to 80.4%. In both cases the maximum is located within the overlying carbonate unit. As in Pool A, the reduction in horizontal compressive stress directly above the storage pool is evident. When this is combined with the increased gas pressure in the same unit, the
increased maximum fracture gradient is the result. An adequate model of this system requires a model (or as in this case a series of models) which can represent the physics of gas flow processes affecting the pore pressure in the units above the storage pool, and the physics of stress redistribution above the pool resulting from expansion and contraction of the reef in response to pool pressure cycling. The use of TOUGH2 and FLAC3D in series allowed an efficient and defendable solution.

CONCLUSION

In this paper, we have briefly described two similar models developed to investigate gas flow and geomechanical processes in underground natural gas storage operations. This work provides an application example combining TOUGH2 and FLAC3D models to quantify the subsurface processes which occur when gas is injected into deep formations at pressures exceeding those that were naturally present. Uncertainty, which is present in all subsurface engineering, was managed through conservative, but plausible, assumptions, based on the available evidence. The use of all available field data to calibrate and confirm model predictions fostered confidence in the model. At Pool A, pore pressure measurements in a borehole above the pool provided qualitative confirmation of model predicted stress changes, and offered a potential method to estimate stress changes by the proxy measurements of pore pressure. The combined use of TOUGH2 and FLAC3D allowed us to establish the safety of proposed operating pressures for these pools, allowing the client to fully develop the value of their assets.

REFERENCES


Figure 11. Pool B model results. In panel three, tensile stress is positive.