KANSAS GEOLOGICAL SURVEY

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April 19, 1997

Mr. Michael H. Cochran, Chief
Environmental Geology
Industrial Programs Section
Bureau of Water
Department of Health and Environment
Forbes Field, Bldg. 283
Topeka, KS 66620-0001

Dear Mr. Cochran:

I have reviewed the documentation concerning the request by Western Resources, Inc. to increase the maximum storage pressure in their underground salt storage cavities in the Yaggy Field, west of Hutchinson, KS, to a pressure gradient of 0.88 psi/ft of depth. The original Core Laboratories study contained a clerical error that resulted in incorrect fracture pressure gradient values. An amended table is attached. The attached text discusses both the data provided, interpretation of that data, and some aspects of rock mechanics of salt that are pertinent to the issues involved. This text also addresses the question you posed in your letter of January 22, 1997. I sincerely hope that this review is helpful. If you have any further questions please don't hesitate to contact me.

Sincerely,

Alan P. Byrnes

Alan P. Byrnes
Research Geologist-Petrophysicist

cc: Lee C. Gerhard
Tim Carr

Executive Summary

Western Resources, Inc. has requested an increase in the storage pressure in their Yaggy field salt cavern from the present value of 0.75 psi/ft to 0.88 psi/ft. In support of this request they submitted rock mechanical study performed by Core Laboratories, Inc. which is reviewed in this document. The study, as submitted, contained a clerical error that resulted in the miscalculation of the fracture and closure pressures and gradients. An amended table is attached that was provided by Core Labs when the error was brought to their attention. The amended elastic model-fracture pressure gradient (FPG) and closure pressure gradient (CPG) average 1.29±0.42 and 0.88±0.16 psi/ft (error bars are for 2 standard deviations) respectively. These values for the FPG and CPG were determined using the Kirsch equation which is an elastic model. This model is not completely correct for salt because *in situ* stress within salt is generally accepted to be hydrostatic. However, interpretation of the rock mechanics data within an elastic model framework provides conservative (i.e. minimum) FPG and CPG values. Based on these values, the probability of inducing fracturing in a reservoir at a fluid pressure gradient of 0.88 psi/ft is approximately 1.7 in 100. Using a static rather than elastic model the FPG and CPG values average approximately 2.0±0.42 and 1.0±0.16 psi/ft respectively. Using these static values, the probability of inducing fracturing is less than approximately 1 in 250,000. Laboratory studies indicate that the true mechanical response would lie between the static and elastic model values. These predictions assume that far-field stresses apply near the cavity wall. Modeling stress distribution around cavities indicates that fracture pressure is also a function of the rate of fluid pressure increase and the creep rate of the salt (Wallner, 1988). For slow pressure build-up rates, such as modeled in a sealed cavern, models indicate that pressures greater than lithostatic can be contained within the cavern without causing fracturing. However, at shallow depths and low creep rates fracturing can be induced at very low pressure change rates.

The study submitted provides information about fracture potential within the salt and shale but does not address the question of fracture reopening along horizontal salt/shale partings or fractures. Because it is probable that these partings exhibit a CPG near lithostatic pressure (1.0 psi/ft), which is greater than the elastic CPG value, the elastic CPG still represents a more conservative value. The laboratory data and the model employed address some of the questions concerning the predicted response of the cavern to pressure change but are not comprehensive because of uncertainty in local stratigraphy, *in situ* stress field, cavern geometry, mechanical behavior at lithofacies boundaries, and imprecision in the constitutive model applied. These questions can be addressed by a pressure test of the cavern. While it may be undesirable to fracture test the cavern, the rock mechanical data indicate it should be safe to pressure test the cavern to a pressure gradient of 0.97 psi/ft without inducing fracturing. Such a test could be halted during testing if incipient fracturing were evident. Pressure-temperature-volume data from such a test would provide evidence for the response of the cavern, would presumably confirm that fracturing was not induced, and at a test pressure gradient of 0.97 psi/ft would provide a safety coefficient of 1.1 over a pressure gradient of 0.88 psi/ft. This coefficient is similar to gas storage programs in Germany and is greater than many salt mine pillar design programs. Such a combination of rock mechanical and field pressure testing data has been used in other states to obtain regulatory certification for the safe use of pressure gradients above CPG values for subsurface disposal of liquid wastes.

Discussion

Western Resources, Inc. has requested an increase in the storage pressure in their Yaggy field salt cavern, Hutchinson Fm., from the present value of 0.75 psi/ft to 0.88 psi/ft. In support of this request they submitted rock mechanical study performed by Core Laboratories, Inc. which is reviewed in this document. This review analyzes the submitted study to address the following questions:

(1) Were the test procedures and calculations correct for determining fracture pressure gradient?
(2) Is the interpretation of the rock mechanical study correct?
(3) Do the study results support the conclusion that it is safe to increase the storage pressure to a gradient of 0.88 psi/ft?
(4) What other tests or data could help determine the safe maximum operating pressure in Hutchinson salt caverns?

Because of the complexity of salt mechanics, any simple answers to the above questions are inappropriate without also providing some discussion of the conditions under which the answers are provided. Brief answers are provided below followed by some supporting background discussion on salt mechanics.

Question 1: The tests and calculations performed were both correct and incorrect (no ambiguity intended). The tests were appropriate and used standard experimental methodologies for rock mechanical testing of elastic rocks like sandstones, shales, and limestones. As such, they were completely correct for the caprock shale samples. However they were not necessarily correct for the salt samples. Salt is a viscoelastic-viscoplastic material with negligible porosity. For this type of material it is generally assumed that the *in situ* stress is approximately isotropic or hydrostatic ($\sigma z=\sigma x=\sigma y$) because long term ductile deformation or flow re-equilibrates initial stresses induced by overburden loading, boreholes, or mines. In the absence of strong tectonic stresses, the presence of a hydrostatic stress field has been observed and reported for salt beds in both the U.S. (at the Waste Isolation Pilot Plant near Carlsbad, NM; Wawersik and Stone, 1989; and Paradox Basin, UT; Nelson and Kocherhans, 1981) and Europe (at Bernburg gas storage field; Menzel and Schreiner {Institute of Safety in Mines, Leipzig}, 1983). Given that elastic moduli do not necessarily represent the long term behavior of salt, the use of dynamic elastic moduli, like Poisson's Ratio, are not always appropriate for calculation of *in situ* stress conditions which are better calculated using static test results. Use of dynamic moduli have further effects on experimental procedures and results including:

<u>Confining Stress</u> - The use of dynamic Poisson's Ratio values to determine the net effective stress to be used for core plug confining pressures results in calculated confining pressures that are <u>too low</u>. *In situ* hydrostatic stress would have required higher confining pressures for the test

samples (~500 psi confining pressure to simulate the top of the cavern) than those employed (240 psi net effective stress) and would have resulted in higher fracture pressure gradients than those reported.

Fracture Pressure Gradient - The calculation of the fracture pressure gradient in the study used the classic Kirsch solution for elastic media:

$$P_{frac} = 3\sigma_{hmin} - \sigma_{Hmax} - \alpha P_{pore} + \sigma_T \quad (1)$$

$$P_{frac} = 2[\mu/(1-\mu)][P_{overburden} - \alpha P_{pore}] + \alpha P_{pore} + \sigma_T \quad (2)$$

where σ_{hmin} = minimum horizontal stress, σ_{Hmax} = maximum horizontal stress, α=Biot constant, $P_{overburden}$ = overburden pressure (~1 psi/ft of depth), P_{pore} = pore pressure, σ_T=tensile strength, and μ=Poisson's Ratio. Use of the dynamic Poisson's Ratio in this solution assumed that salt behaves elastically and that therefore the minimum horizontal stress can be obtained using the expression $[(\mu/(1-\mu)][P_{overburden}-\alpha P_{pore}]$. This relation does not correctly express the long term stress in salt which flows to develop hydrostatic stress. Static Poisson's Ratio values are closer to 0.5 and Biot's constant values are approximately zero (because of the low porosity in salt) resulting in a $\sigma_{hmin} \approx \sigma_{Hmax} \approx P_{overburden}$. Using dynamic values, calculated fracture pressures and fracture pressure gradients as shown in the original and amended study table are low.

A clerical error in the Fracture Pressure Summary Table of the original Core Laboratories report also resulted in low fracture and closure pressure and fracture pressure gradient (FPG) and closure pressure gradient (CPG) values. The calculated fracture and closure pressures erroneously used a net overburden pressure (column 1) rather than a total overburden pressure (column 3 * 1 psi/ft) resulting in incorrect and low fracture and closure pressures and gradients. An amended table, supplied by Core Laboratories after bringing the error to their attention, is attached. FPGs, calculated using the correct overburden pressure, average 1.29±0.42 psi/ft (error bars are for 2 standard deviations). This dynamic value represents a low estimate of the FPG. Use of a static values, $\sigma_{Hmax}=\sigma_{hmin}=P_{overburden}$ and α=zero, in equation 1 above indicates that the FPG should theoretically be approximately 2.0 psi/ft.

Although static values would indicate FPG≈2.0 psi/ft, it must be noted that the fracture mechanics of salt have been shown to not conform to the Kirsch equation at high confining stress (Doe and Boyce, 1989). *In situ* breakdown tests (discussed below) indicate that breakdown pressures are similar to or slightly greater than the dynamically calculated values. Salt fracture mechanics are also dependent on rates of pressure change (Wallner, 1989). In summary, FPG values for salt would be expected to lie within the range of 1.29±0.42 to 2.0 psi/ft.

Closure Pressure Gradient - Many of the considerations concerning fracture pressure in salt also apply to closure pressure. Closure pressure can be simply described by equation 1 but without the tensile strength term since the fracture is already initiated. As such, if the true in situ stress is hydrostatic then the closure pressure is approximately equal to the overburden stress and is not calculated using the Poisson's ratio.

Threshold Pressure - The threshold pressure test followed a standard experimental procedure. However, the interpretation of a 25 psi threshold pressure for the shale caprock sample seems inappropriate. The data indicate that flow existed from the first recorded pressure at 10 psi and that this pressure (or some lower pressure) would be the appropriate threshold pressure to report. The measurement of a liquid permeability of 0.0008 md and a threshold pressure value of less than several hundred psi is indicative of a fracture that would be unlikely to exist in the subsurface or would be unlikely to extend through the entire caprock section. Typical threshold pressures for shales are in the hundreds to thousands of psi. As such, this sample is likely not to be representative of the caprock shale and in short, was unsuitable as a representative test sample for the caprock unless one is interested in the flow properties of fractures in this strata.

Question 2: The use of only a mean or average value would not be considered appropriate by many for use as an FPG value in a formation. FPG is a function, amongst other variables, of the mechanical properties of the salt which obviously exhibit a range in values. The samples analyzed are assumed to be randomly selected and representative of the formation of interest. As such, the distribution of FPG values observed in the laboratory samples is considered to represent that in nature for the size of the sample population tested. As with any normally distributed population, only 50% of the samples exhibit FPG values greater than the mean (FPG=1.29 psi/ft), 84.1% of the samples exhibit values greater than 1 standard deviation (s.d.) below the mean (FPG=1.08psi/ft), and 97.7% greater than 2 s.d. below the mean (FPG = 0.87psi/ft). In brief, the FPG of a formation should not be expressed as a single value but as a distribution. It is important to note that these values for FPG are based on the dynamic elastic moduli, including the dynamically measured Poisson's Ratio. These may not correctly represent *in situ* stress conditions and would therefore be too low. Static values would indicate that the *in situ* FPG should lie within the range of 1.29-2.0 psi/ft and that the CPG should lie within the range 0.88-1.0 psi/ft.

Question 3: The rock mechanics data provide a basis for developing a numerical model of the mechanical response of the salt cavern to a change in the internal fluid pressure. Confidence that an increase in fluid pressure will not result in fracturing is completely dependent on our confidence in the data and in the model in which it applied. Irrespective of the mechanical or numerical model in which the data are used, the rock mechanical data confirm that the Yaggy field rocks behave similarly to salts and shales in other parts of the world and can be expected to not exhibit properties that would result in anomalously low failure pressure. This affirmation is necessary for application of any geomechanical modelling. As presented in the request, the data were interpreted within the context of an elastic fracture mechanical model (Kirsch equation) that is only partially applicable to the true stress conditions and mechanical response the might be anticipated to exist. The elastic model may be considered the most conservative since it predicts fracturing at lower pressures than a static model. As such it is worthwhile to examine the prediction of mechanical properties within this framework first.

The study provided data for eight salt samples shown in the attached amended table. The data indicate a mean dynamic FPG of 1.29±0.42 psi/ft. The minimum fracture pressure gradient (FPG) cannot be less than the closure pressure gradient (CPG) because a fracture would simply close at pressures below the CPG. The mean dynamic CPG, based on using the dynamic Poisson's Ratio values, is 0.88±0.16 psi/ft (2 s.d.). These statistics for the fracture and closure pressure gradients are based on the limited sample population size of 8 samples. Increasing the number of samples would both decrease the standard deviation and increase the confidence with which the mean or the second standard deviation below the mean is known. However, while this might be useful, it is unlikely that additional data would change the mean or deviation by more than 5 to 10%. Such a change is unlikely to affect interpretation of the data since greater uncertainties exist in using the data within an elastic model and with questions that lie outside the laboratory data and their application.

In a practical sense, within the context of an elastic model, the FPG and CPG values and their distribution can be viewed several ways. Based on the data, an elastic model would predict that, if the storage pressure were allowed to be increased to a value equivalent to a pressure gradient of 0.88 psi/ft, then it could be estimated (at the 95% confidence interval) that 1.7 out of 100 reservoirs would experience fracturing (given the standard deviation provided by the 8 samples). Alternatively, in a given reservoir, it can be estimated that 1.7 feet out of 100 feet of a formation face would be fractured. Probabilities are not 2.3 out of 100 (i.e. 100%-97.7%) because in 50% of these fractured reservoirs or rocks the fracture would not propagate since the CPG is ~0.88 psi/ft. Whether in the 1.7% of cases the initiated fractures would result in fracture propagation or whether the fractures would be halted at some rock fabric boundary cannot be definitively answered with the present data.

A static model predicts a very different response probability. Using a static FPG value of 2.0 psi/ft, and assuming the same second standard deviation as the elastic values, ±0.42 psi/ft, and further assuming a static CPG equal to lithostatic pressure (1.0 psi/ft), and the same second standard deviation as the elastic values, ±0.16 psi/ft, it could be anticipated that at a pressure gradient of 0.88 psi/ft, fracturing would be initiated in less than 1 reservoir in 250,000 or in less than 0.001 vertical ft of a 100 ft salt cavern face.

The above analysis of mechanical data from representative samples would indicate that the probability of initiating fracturing in the salt cavern ranges from small to negligible depending on the mechanical model adopted. These models are, however, simple and do not account for uncertainties in knowing the true *in situ* stress field, stratigraphy, geologic heterogeneities, mechanical properties at facies boundaries, and cavern geometry. Comparison with field-measured breakdown or fracture pressure gradients in other salt beds and storage fields is informative and provides a basis for assessing the reliability of "scaling" laboratory-based conclusions to the field scale. Breakdown or fracture pressure gradient tests for five different salt beds within the Paradox Basin, UT ranged from 1.14 to 1.43 psi/ft, averaging 1.30 psi/ft (Nelson and Kocherhans, 1981). Tests of breakdown pressures within the Bernburg-Gröna Mine, GDR averaged 1.18 psi/ft (Menzel and Schreiner, 1989) and within the Palo Duro sub-basin in the

Texas Panhandle breakdown pressure gradients of 1.36 and 1.56 psi/ft were observed in two salt beds of the San Andres Fm. (Bush and Barton, 1989). All these tests were conducted at depths ranging from 1,650 to 4,900 ft. At these depths the deviation from the Kirsch equation is significant and the observation of breakdown pressures significantly below a theoretical value of ~2.0 psi/ft is anticipated by the results of Doe and Boyce (1989). Tests by Haimson et al (1989) in Carwynnen Quarry at depth of 432 ft and 2,000 ft both exhibited breakdown pressures of approximately 2,300 psi or fracture pressure gradients of 5.3 and 1.15 psi/ft respectively. Correcting for the deviation from the Kirsch equation with increasing depth, all these field-based values are consistent with observed field fracture pressure gradients that are within the range between dynamic and static values. They are also consistent with values near 1.5 psi/ft observed at shalower depths in Kansas (Cochran, 1997).

Menzel and Schreiner (1983) report that the Institute of Safety in Mines, Leipzig GDR uses a safety coefficient of 1.1 between the minimum principal stress and the maximum permissible pressure for gas storage in Permian age salt beds in Germany. This value was obtained from analysis of the results of fracture tests over several years. In their area, the maximum operating pressure gradient is, not coincidentally, 0.88 psi/ft (since the minimum principal stress is near the hydrostatic value of 1.0 psi/ft). Thoms and Gehle (1983) report that, in general, maximum operating pressure used by Gaz de France is approximately 0.77 psi/ft at the casing shoe. It should be noted that the Bernburg field in the GDR prior to 1983 (publication date for study) was routinely operated at a pressure equivalent to a gradient of 0.70 psi/ft. Similar operating pressure gradients near 0.70 psi/ft are used at Tersanne and Etrez Gas Storage Projects in France (Boucly, 1981). Reasons for the difference between operating and maximum permissible pressure are not given nor do published articles provide the cavern geometry details necessary for understanding the stresses associated with these storage facilities.

The comparatively high FPG values observed for both the salt and shale caprock would indicate that fracturing within either of these lithologies is not the probable source for containment failure. Within the Hutchinson salt a weak point in salt deposits is likely to be in the horizontal salt/shale layer interfaces where existing fractures require only a pressure approximately equal the overburden pressure to reopen salt/shale horizontal fractures since there is no tensile strength in existing fractures. This pressure would still be approximately equivalent to a lithostatic gradient of 1.0 psi/ft and operation at pressures equivalent to 0.88 psi/ft would represent a 1.1 safety coefficient, similar to that used in the GDR.

Question 4: Additional core analysis data from the same core are unlikely to provide significantly greater confidence in prediction of possible fracturing except to the degree to which they might decrease the standard deviation of FPG and CPG values. These data do not address the question of possible fracturing reopening along salt/shale partings or of existing fractures. These questions are best addressed at the field scale.

It is not uncommon to perform small-scale hydraulic fracture tests to evaluate the breakdown pressure of a storage cavern. While such testing is clearly definitive for the pressurization rate used, it is also clear that this method relies on the cavern "healing" itself after the test and is similar to burst pressure testing for pressure vessels. While definitively answering questions about fracturing, this method can be considered to potentially compromise the cavern seal. As a practical solution, pressure testing below the cavern breakdown pressures may provide acceptable confirmation of safe limits for operating pressures. Both elastic and static FPG data and field studies indicate that neither fracturing nor fracture reopening should occur at pressures equivalent to a gradient of 0.97 psi/ft. If a pressure test were performed, using a pressure rate increase similar to the maximum to be employed during operation, to a pressure equivalent to 0.97 psi/ft, this would test the cavern without subjecting it to actual fracturing. Such a pressure would also provide a safety margin of 1.1 over an operating pressure of 0.88 psi/ft. Pressure-time curves, similar to small-scale fracture tests should provide clear indication if fracturing were initiated (figure 1). If, during the test, a pressure response similar to that exhibited during fracturing (P=Pc) or fracture reopening (P=Pb) were observed, the pressure would be immediately decreased and an appropriate operating pressure decided upon based on the observed pressure and the desired safety margin. Immediate pressure decrease if fracturing is observed should preclude loss of containment. Pressure-volume-temperature data collected during this test could also establish, within approximately 1%, the size of the storage cavern, which would be useful for convergence evaluation. If the response were characteristic of the anticipated PVT response of filling a sealed vessel then all parties could have confidence that the cavern was intact. Such testing has been employed to evaluate and receive regulatory approval for safe injection pressures above the CPG for subsurface disposal of liquid wastes (Abou-Sayed and Thompson, 1994)

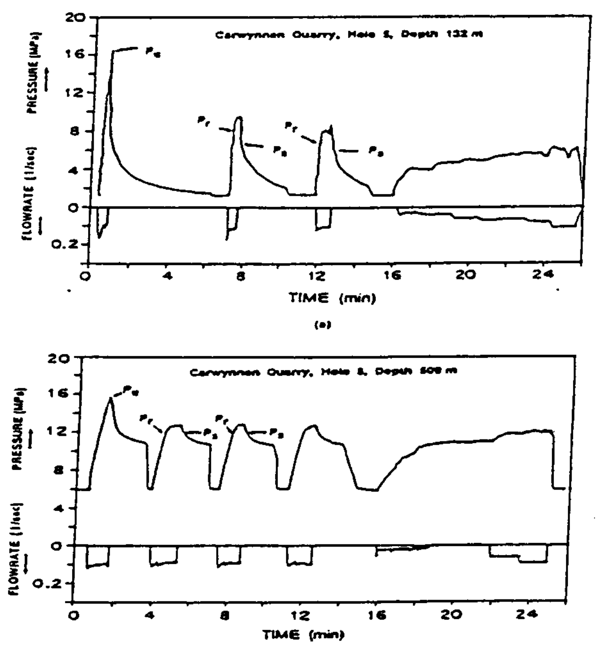

Fig. 1. Typical pressure–time record during a hydrofracturing test in Borehole 5 (a) and Borehole 8 (b). General locations of breakdown (P_c), fracture reopening (P_r) and shut-in (P_s) pressures are indicated.

Brief Background Discussion of Salt Mechanics

The safe storage (sealed off from biosphere) of petroleum liquids in underground salt caverns requires a good seal between the wellbore and the cavern roof and an understanding of the rock mechanics of the cavern to avoid fracturing or collapse of the cavern. The history of the Yaggy field would indicate that the wellbore(s) presently have good seals and provide containment. This leaves only the question of whether an increase in storage pressure would result in fracturing of the cavern wall or roof. Rock mechanical data have been provided by Western Resources, Inc. to address this question. The purpose of this review is to examine whether the rock mechanical data provided can be interpreted to confirm that an increase in the pressure gradient to 0.88 psi/ft will not result in fracturing of the cavern and loss of fluid containment. The rock mechanics of salt caverns and the interpretation of rock mechanical data concerning these structures is a complex field and is still not completely resolved. Constitutive equations (equations describing the stress-strain behavior of salt and salt caverns) exist that allow reasonably accurate prediction of salt cavern performance under changing pressure and temperature conditions. However, because these equations are still being developed and refined, analysis and interpretation of the provided data requires some discussion of the assumptions and conditions used for the interpretation. Before addressing questions concerning the interpretation of the rock mechanical properties data and the possible effects resulting from an increase in storage pressure within a salt cavity, it is worthwhile to review some issues concerning the mechanical properties of salt and in situ stresses within salt deposits since these have a direct bearing on the interpretation. This is particularly important because conventional rock mechanics require significant modification when applied to salt (often referred to as "salt mechanics"). The following discussion reviews some important aspects of salt mechanics. Copies of several relevant publications are also attached. However, entire books have been devoted to understanding salt mechanics and clearly this discussion is directly primarily only at issues pertinent to gas storage.

Salt Mechanics

The response of salt to stress is a highly nonlinear function of stress (pressure) , time, temperature, and salt composition (including crystal structure and chemical composition). While most carbonates and sandstones exhibit elastic (deformation in response to stress is reversible) behavior at low stress levels and brittle (fracture or break) behavior at high stress levels, salt response is best described as viscoelastic-viscoplastic. Under rapid loading conditions or below the yield limit (stress at which flow begins) salt can exhibit pseudo-elastic behavior, deforming reversibly, or brittle behavior. However, above the yield limit or under shear stress exerted over longer time periods, salt flows or permanently deforms plastically. Numerous, mostly empirical, constitutive equations have been proposed in the last two decades to describe the strength and stress-strain (deformation) relations for salt. These equations quantitatively describe both elastic behavior including strength and elastic moduli and plastic behavior including primary creep (slowing of deformation rate due to strain-hardening after initial loading), secondary creep (constant deformation rate), and tertiary creep (increased deformation rate leading to creep fracture).

Determination of the stability and safe operating conditions for underground salt storage cavities is a function of numerous variables the most important of which are: (1) *in situ* stress field (vertical and horizontal, isotropic and anisotropic), (2) internal fluid pressure (minimum and maximum), (3) cavern geometry (shape and size), (4) internal pressure cycles (injection-withdrawal, pressure changes and rates of pressure change), (5) temperature (ambient and gas expansion/compression induced), (6) mechanical properties of the salt and adjacent rock strata (a function of composition and grain texture of the salt and adjacent rock), and (7) cavity proximity if more than one cavity is present. Wallner (1988) has briefly described the role of these variables in the constitutive equations that can be used to predict salt cavern behavior. In general, of greatest influence for issues concerning fracturing and containment are (1) the *in situ* stress field (a function of the lithostatic and native fluid pressures), (2) the induced fluid pressure and the rate of pressure change also related to the fracture or breakdown pressure) , (3) the salt mechanical properties, and (4) cavern geometry. These variables are discussed below.

In Situ Stress Field

The stability of a salt storage cavity and the potential for elevated internal pressures to result in hydraulic fracturing or loss of containment are both strongly influences by the *in situ* stress field. The *in situ* stress field is rarely known with certainty but rock mechanical properties and measurements provide information for predicting the stress field. The *in situ* stress field within a formation is a function of the lithostatic pressure exerted by the overburden (and sometimes by tectonic stresses), the distribution of lithostatic stress as a function of rock mechanics properties, and the pore fluid pressure. Because porosity in salt is so low and pore connectivity is also low the influence of pore pressure can often be ignored. The stress exerted by an overburden load is supported or decreased by pore fluids. The net effective vertical stress or pressure acting on the rock framework can be expressed:

$$P_{effective} = P_{lithostatic} - \alpha P_{fluid}$$

where P=pressure, α=Biot elastic constant (ranges from fractional porosity to 1.0).

For the Yaggy field salt cavern the P_{eff} can be estimated to be approximately 1 psi/ft of depth*500 ft = 500 psi. Some details concerning determination of P_{lith} and P_{fluid} are presented below.

Lithostatic Stress

Lithostatic stress can be separated into the three principal stress components (σ_z, σ_x, σ_y). The vertical stress, σ_z, is directly a function of the weight of the overlying column of rock which is a function of the cumulative vertical bulk density:

$$\sigma_z = \int_0^Z \rho_b(z)\, g dz$$

where z = depth, ρ_b= bulk density (g/cc), and g = acceleration of gravity.

For most geologic settings, overburden bulk density is assumed to equal approximately 2.3 g/cc resulting in a vertical stress or overburden stress of approximately 1.0 psi/ft of depth. The top of the slat caverns at Yaggy field lie at an approximate depth of 500 ft below the surface. The top of the Permian Hutchinson Salt Member of the Wellington Fm. in the Yaggy field area occurs at a depth of 390 ft below surface. The Hutchinson Salt is overlain by Permian Ninnescah Shale, comprised of shale with thin beds of gypsum, anhydrite, dolomite, and siltstone, and a thin veneer (<70 ft) of Kiowa Fm. shale with thin beds of sandstone and Quaternary loess. Readily available density logs that are considered representative of the Ninnescah Shale (Nicklin #1, Eagle Exploration, Sec. 33, Twn. 22S, Rng. 8W) exhibit bulk densities that generally range from 2.35 to 2.45 g/cc with intermittent 10 to 40 ft thick beds exhibiting bulk densities as high as 2.55 g/cc. Bulk density within the salt section overlying the top of the cavern is approximately 2.17 g/cc. Based on these bulk density values, it is probable that the overburden stress on the top of the Yaggy salt cavity at is not less than 1.0 psi/ft and may range up to 1.04 psi/ft.

When tectonic stresses are small, which may be tentatively assumed for this area, horizontal stresses for rocks exhibiting elastic behavior (sandstones, shales, carbonates) can be described by the overburden stress and Poisson's ratio (ratio of change in horizontal deformation over change in vertical deformation). The principal horizontal stress,σ_H, can be described as

$$\sigma_H=(\mu/1-\mu)\sigma_v$$

where μ is the Poisson's Ratio and σ_v is the overburden stress. For typical values of $\mu = 0.33$ for shales, the principal horizontal stress $\sigma_H \approx (0.33/(1-0.33)\sigma_v \approx 0.5\sigma_v$.

In elastic, isotropic media, Poisson's Ratio can be calculated from acoustic velocities of the compressional (P) and shear (S) waves:

$$\mu = \frac{(Vp/Vs)^2-2}{2((Vp/Vs)^2-1)}$$

where Vp=P wave velocity, Vs=S wave velocity.

The data presented by Western Resources, Inc. used this calculation procedure to determine Poisson's Ratio. Using this method to determine Poisson's ratio resulted in an average Poisson's Ratio for the salt of 0.307 ± 0.09 (2 standard deviations). Using a Poisson's Ratio of 0.32, the net confining stress on the salt would be approximately 240 psi as used in the core testing.

The determination of the net stress using Poisson's Ratio for salt may underestimate the true net stress. The use of dynamic measurements to determine Poisson's Ratio assumes an elastic and isotropic media. Because salt is generally not elastic at subsurface stress conditions, elastic properties, including Young's Modulus and Poisson's Ratio, describe the mechanical properties of salt only for low stresses, brief time periods, and at low temperatures. As reported for the Yaggy salt samples, Poisson's Ratio for salts from other regions, determined from dynamic tests, range from 0.15 to 0.5 with a typical value of 0.35 (Hansen et al, 1981; Kelsall and Nelson, 1983). However, static values, which can be considered an "effective" Poisson's Ratio, have been reported to range from 0.45 to 0.49 (Chabannes et al, 1981). Because salt will flow given sufficient time, these static values are considered more representative of *in situ* values relative to long term response to stress. Using a Poisson's Ratio of approximately 0.5, the horizontal stress can be assumed to approximately equal the vertical stress resulting in near-hydrostatic stress conditions. The assumption that stress within salt is hydrostatic and that the three principal stress components are approximately equal in salt, is commonly adopted and has been measured *in situ* on bedded salts similar to the Hutchinson Salt by a limited number of *in situ* measurements in the Salado Fm, NM (Wawersik and Stone, 1989) and the San Andreas Fm, TX (Bush and Barton, 1989).

Assuming that the true *in situ* net stress on the salt is approximately hydrostatic, the use of a net stress of 240 psi for the experiments would be too low and a more appropriate value would be 500 psi.

Internal Fluid Pressure

Generally pore pressures increase with depth as a direct function of the density of the overlying water column. For water salinities ranging from fresh water to NaCl-saturated brine the hydraulic gradient increases from 0.43 to 0.52 psi/ft with typical values being 0.45 psi/ft. Pores within shales, sandstones, and carbonates are generally well connected. Within these lithologies the pore fluid pressure gradient is approximately equal to 0.45 psi/ft of depth. Fluids trapped or enclosed by rock are subject to lithostatic stress and can reach pressures ranging from hydrostatic to near lithostatic (actual maximum pressure is the fracture pressure of the formation). Small pores within salts are generally enclosed and are subject to the same lithostatic load as the salt itself. Fluid filled pores within salt beds are sufficiently small, are enclosed, and porosity is so low that the net effective stress on the salt is approximately equal to the lithostatic stress. Because the porosity in salt beds is so small, internal fluid pressures are generally considered negligible.

Net Effective Stress

Since the net effective stress is the lithostatic stress minus the pore pressure stress, and since the pore pressure stress can be assumed to be negligible in salt beds, the net effective stress in salts and the minimum principal stress can be approximately assumed to equal the overburden stress which can be approximately calculated as 1 psi/ft*depth(ft). For the Yaggy field cavern this would be 500 psi.

Fracture Pressure

The classic hydraulic fracturing equation for elastic media is:

$$P_{frac} = 3\sigma_{hmin} - \sigma_{Hmax} - \alpha P_{pore} + \sigma_T \quad (1)$$

where P_{frac} = fracture or breakdown pressure, σ_{hmin} = minimum stress normal to the borehole axis, σ_{Hmax} = maximum stress normal to the borehole axis, α=Biot's constant, σ_T = tensile strength of the rock, and P_{pore} = fluid pore pressure.

While the above equation applies well to hydraulic fracturing applications in elastic media such as sandstones and carbonates, several studies have shown that the equation is not valid for inelastic media like salt (Fairhurst, 1967; Bush and Barton, 1988; Doe and Boyce, 1988; Waverik and Stone, 1989). Deviation from the elastic equation can result from non-linear deformation over time, which reduces tangential stress and decreases the breakdown pressure (Fairhurst, 1967; Bush and Barton, 1988), or from the presence of micro-cracks (Rummel, 1987; Doe and Broyce, 1988). Based on the above equation, under hydrostatic conditions ($\sigma_z = \sigma_{hmin} = \sigma_{Hmax}$) the breakdown pressure should increase in proportion to twice the confining pressure. Laboratory experimental work (Doe and Boyce, 1989) indicated that breakdown pressures in hydrostatically-confined Avery Island salt were approximately twice the hydrostatic pressure for pressures below about 750 psi but decrease progressively with increasing hydrostatic pressure, reaching values as low as 1.4 times the hydrostatic pressure at hydrostatic pressures near 4,000 psi. As noted, breakdown pressure gradient tests for five different salt beds within the Paradox Basin, UT ranged from 1.14 to 1.43 psi/ft, averaging 1.30 psi/ft (Nelson and Kocherhans, 1981). Tests of breakdown pressures within the Bernburg-Gröna Mine, GDR averaged 1.18 psi/ft (Menzel and Schreiner, 1989) and within the Palo Duro sub-basin in the Texas Panhandle breakdown pressure gradients of 1.36 and 1.56 psi/ft were observed in two salt beds of the San Andres Fm. (Bush and Barton, 1989). These tests were conducted at depths ranging from 1,650 to 4,900 ft. At these depth the deviation from the Kirsch equation is significant and the observation of breakdown pressures significantly below a theoretical value of ~2.0 psi/ft is anticipated by the results of Doe and Boyce (1989). Tests by Haimson et al (1989) in Carwynnen Quarry, Great Britain at depth of 432 ft and 2,000 ft both exhibited breakdown pressures of approximately 2,300 psi or fracture pressure gradients of 5.3 and 1.15 psi/ft respectively. The value of 5.3 psi/ft for the 432 ft depth test is the result of high tensile strength.

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