The Characterization of Mechanical Integrity for Cased Boreholes Entering Solution Caverns

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ABSTRACT

The U.S. Environmental Protection Agency's (EPA) Safe Drinking Water Act (Public Law 93-523) contains an Underground Injection Control (UIC) program covering systems used for injection of hazardous materials down cased borehole penetrating usable water aquifers. The sodium chloride brine-producing industry and the underground storage industry are subject to these regulations. UIC regulations contain a requirement that the "mechanical integrity" of the underground injection system be proven prior to issuance of a use permit, and periodically thereafter. This could lead to controversy between the regulator and industry because the conditions that must prevail for "mechanical integrity" to be attained are not specified in most UIC regulations.

The objective of this paper is to establish a reference framework (with respect to concepts, design criteria, test acceptance criteria, etc.) within which the regulatory agency(ies) and industry can agree that "mechanical integrity" is inherent in an underground injection system design, is proven to exist by a given test result and will continue to exist, provided appropriate operational procedures are used and retesting is performed as prescribed in the UIC regulation.

The Author's comments are based on some thirty years experience in the underground storage field, a long-term interchange of ideas with other such specialists, and participation in various industry association committees whose function was to develop an industry consensus on matters relating to the underground storage field.

INTRODUCTION

The Environmental Protection Agency's (EPA) Safe Water Drinking Act contains an Underground Injection Control (UIC) program covering wells used for the injection of fluids down cased boreholes penetrating aquifers containing a usable source of drinking water (USDW). The Act requires that such wells be proven to have "mechanical integrity" but neither specifies parameters which constitute it nor the type or adequacy of proof required to demonstrate that it exists.

The Act appears to have originally been oriented toward injection wells disposing of hazardous wastes into "non-usable" water aquifers which are "open formations" and then was expanded to cover all injection wells. This extension then encompassed brine producing wells that obviously are extracting salt from a "closed formation." The Act does not make a distinction between the two and thus contains some very confusing wording. Texas UIC Rules and Regulations acknowledges this difference and eliminates certain requirements for "closed formation" systems such as monitoring wells (shallow and deep), investigation of other wells within a prescribed area, inerting and packing off an annulus, etc. This is an eminently sound approach to resolution of one dilemma which fully satisfies the practical aspects of the Act and eliminates the need to carry out certain practices and procedures that are not only costly but completely irrelevant to the issue.

States may establish "Primacy" under the Act, provided they promulgate and enforce rules and regulations no less stringent than those in the Act. Various states have taken Primacy under the Act; however, most of their regulations invariably paraphrase the Act's wording with respect to proving the mechanical integrity of injection wells. Because the intent of all such regulations is obviously the prevention of contamintion of USDW aquifers, state agencies invariably place the burden of proof on the owner (permitee, operator, ect.) that contamination will not occur from new wells and has not occurred from existing wells.

The state also takes the position that the responsible party(ies) must and will take all those precautions in the design, construction, operation and testing of injection wells necessary to protect themselves from the consequences of contamination. The mere fact that a state has issued a permit is not *prima facie* evidence that the state considers the permitted facility to be safe and secure for an indefinite period. There will always be agency inspections, public pressure group impacts, news media coverage of accidents in similar installations, etc. that will require continuous diligence on the part of the operator of the facility.

The state maintains control of its UIC program by the approval/rejection of construction and operating permits, of testing criteria and procedure (for proving mechanical integrity) and of plugging and abandonment practices.

With specific reference to proving the mechanical integrity of a brine producing well, most states require testing criteria and procedures be approved by them, that they be notified sufficiently in advance of the test date so their observers can be present, and that results of the test be reported in sufficient detail to substantiate its legitimacy.

Because there is a lack of distinction between "open" and "closed" formation injection systems, the thurst of most states' UIC regulations is toward proving the mechanical integrity of the final casing string and its cementation. It is certainly advisable to have, as a matter or record, some proof of the mechanical integrity of the solution cavern in the event of future controversy and for assurance of operational integrity of the salt body.

The mechanical integrity of the final cemented casing string and its cementation should be proven during the drilling of a well by hydrostatic pressure test. The cement between the casing and the borehole form a "seal" to prevent any fluid migrating upward through that area. These tests demonstrate the security of the casing/cementation system at that particular time. A cement bond log (CBL) is often run after the well has been drilled to total depth to provide a baseline record for future review of the security of cementation.

The problem most generally faced by brine well operators is to prove the mechanical integrity of the casing and its cementation after several years of solution mining. The principal areas of concern are 1) the final cemented casing string where its exterior is exposed to conditions that might cause corrosion penetration of the steel, and 2) the loss of cementation seal area due to less than saturated brine contacting the salt at (or above) the casing seat.

Brine wells which have two strings of casing set into the salt and have had the protective blanket maintained well below the casing seat are much less liable to loss of mechanical integrity then those having only one casing set into the salt.

The protective blanket material is noncorrosive and is the only fluid in contact with the interior of the final cemented casing string. The possibility of corrosion penetration from the interior to the exterior of the final cemented casing string is minimal, and cement sheaths are normally not expected to deteriorate with time; however, it is considered good practice to verify the condition of both after 10 to 12 years of service life.

Either interior or exterior deterioration of the steel in the final cemented casing string can be detected by a Corrosion Analysis-Tubular (CAT) wireline log, and the condition of the cementation can be assessed by the Cement Bond Log (CBL). It is necessary that the protective blanket, tubing and protective liner be removed to run these logs, which may present some problem in scheduling on producing wells.

The cap rock, which sits on top of a salt dome, commonly contains a zone in which loss of circulation occurs (LCZ). This zone will not support a columm of fluid back to ground level. It is seldom possible to plug it off so cement can be circulated to the surface around the first salt casing. From the mid-1960s onward, it has been considered good practice, when it is encountered, to set one casing string into the salt and cement it back to the LCZ. The salt borehole is then extended some distance below this string, and the "final" casing string is set and cemented back to the surface.

Prior to the mid-1960s, most brine wells on salt domes were completed with only one casing string set into the salt. If no LCZ existed, a normal cement job was usually possible. If an LCZ was encountered and could not be plugged after a reasonable expenditure of time and money, the "final" casing string was simply cemented back to the LCZ.

The casing program in the latter instance provides a barrier of two thicknesses of steel and one of cement between the interior of the final cemented casing string and the usable aquifer, while the former (two strings into the salt) has three thicknesses of steel and two of cement across the same area.

The water in the LCZ is invariably corrosive and if in contact with the exterior of a casing string will eventually cause corrosion penetration of the pipe (typically within 25 to 30 years). When two casing strings are set into the salt, corrosion penetration of the first has no effect on the second (or final cemented casing string) because of the intervening cement sheath. When only one string is set in the salt, penetration might result in a release of protective pad material into the LCZ zone. If this zone has a direct vertical connection to the usable water aquifer the pad material could conceivably migrate upward because of its specific gravity; however, such connections are rare when salt tops are below 500 feet.

The mechanical integrity of the final cemented casing string and its cementation might be proved by demonstrating that the protective blanket/brine interface remains at a constant elevation below the casing seat. Since there are variations between individual interface logging tools and in different wireline truck odometers, a variance of ±2 to 3 feet between subsequent interface surveys must be considered.

The protective pad/brine interface can shift upward because of long-term solution mining effects slightly increasing the borehole cross section at the interface. Additional protective blanket is usually injected to offset this. If either of these situations existed, comparison of a subsequent interface to a current one would not be valid. It would be necessary to log the current interface, wait a minimum of 24 hours, and then run the log a second time. If there were no detectable shift between the two interfaces, it could be assumed that no protecive pad material had escaped through either the casing or casing seat, and mechanical integrity is proven. If operating conditions (i.e., the wellhead pressure of the blanket) are not identical when the two logs are run, a correction must be made to account for the expansion/compression of the blanket material. Making this correction is relatively difficult since the total volume of blanket and the volume of cavern (or borehole) in the interval where interface surveys are taken must be known.

Interface surveys should be run at periodic intervals as a precautionary measure to verify that the protective blanket elevation conforms with the solution mining plan and proof "for the record" that the final cemented casing and its cementation are secure.

When cement was circulated to the surface on the final cemented casing string, and there is an appropriate balance between the cement volume used and the space it was to have occupied, the cementation can be assumed to be competent. A Cement Bond Log should be run for the record and for baseline information against future logs. The CBL tool must be carefully centralized, have an appropriate intensity signal emmission and pickup for the I.D. of pipe being logged, and have a good sensitivity recording of the signal at the surface. There have been significant improvements in CBL logging equipment and techniques in the last 5 years.

When new casing is used for the final (salt) string, brine operators seldom run Corrosion Analysis (CAT) logs at the time pipe is set and cemented. As previously discussed, it would be highly unlikely that there would be corrosion penetration of this string either from the exterior or interior. It is good practice, however, to have a baseline log run (after 10+ years) on the final casing string in a well whose service life is contemplated to exceed 25 to 30 years.

SYSTEM CHARACTERISTICS

Wells used for underground storage are Class II wells, and those used for brine production are Class III. There would obviously be some difference in the design features between these two classes of wells with respect to wellhead pressure ratings, casing seat depths, allowable maximum operating levels and stringency of testing criterion.

Irrespective of the above, those elements of the well system which are directly involved in providing the means of constraint characterized as "mechanical integrity," in terms of preventing movement of contaminants into the usable source of drinking water, are the water protection casing string set and cemented exclusively for that purpose and the casing required to serve other functions. The latter casing is the first and second (final cemented casing) salt strings. The fact that these casings provide additional barriers between protective pads (or stored product) and the USDW aquifer is, to a large extent, ignored.

Generally speaking, the term "proving the mechanical integrity" of the system is considered by state agencies to relate solely to the integrity of the final casing string and its cementation. Any fluid escaping the confines of this segment of the system is considered to move directly into the aquifer containing the USDW. Because the only material in contact with the inner face of the final cemented string and its casing seat is the protective pad (or stored product), the presumption is that this material moves directly into the USDW. It is also inferred that any quantity escaping the confines of the final cemented casing will contaminate the USDW to an unacceptable degree regardless of how small that quantity might be.

Neither of the above assumptions are valid, and recognition of this would contribute greatly toward a more rational approach to setting out those parameters which, when met or proven, would validate the fact that mechanical integrity exists in any class of well.

Presuming a given series of tests indicated that fluid was escaping from the casing seat of the final cemented casing string. It must pass through or bypass the cement sheath of the latter casing and, with two salt strings, thence either through the cement surrounding the first salt string or through the cement filled annulus between the first and second salt strings. Since the primary purpose of the first salt string is to isolate the second from corrosive water in a LCZ, the former fluid movement would cause pad material to move into LCZ waters, which are not usable for drinking water. In the latter instance, if pad material were considered to migrate through the cement filled annulus, it would eventually appear in the sealed area between the two at the surface. In neither case could pad material reach the USDW. It would be extremely unsual if the LCZ waters were connected hydraulically with the USDW and, therefore, it would act as an "intercept" area. Any pad material that might enter the annulus area between the two salt strings would still be isolated from the USDW aquifer by two thicknesses of steel and one of cement. (In the event there were no LCZ, both the first and second salt string should have had cement circulated to the surface, and there would then be an additional cement barrier.) One of the basic requirements of pad material is that it be non-corrosive so that its effect on the inner face of the first salt string would be neutral.

Assuming the worst possible set of circumstances—that a major LCZ had prevented cement being circulated to the surface behind the first salt string (the annular space between the elevation of the LCZ and the surface would still be partially filled with original drilling fluids or LCZ waters to within 100 to 150 feet below ground level; the remaining distance would be filled with air), there was a corrosive penetration of the first string at the LCZ, and that the cement sheath and steel of the second string were also penetrated there—the pad material would escape vertically upward. It would first fill the air space, and the sealed area between the water string and the first salt string would "pressure up." It could escape into the LCZ only when it had built up sufficient pressure to displace fluid originally in the annulus downward until the entire annular space was filled with pad material.

It should be understood that although the sequence and nature of the events described above apply to either a brine producing well or a product storage well, the rate at which the process would take place and the capability to detect a failure is quite different in the latter. The volume of pad material in a brine well is very small compared with the volume in a storage well.

The loss of pad material is readily apparent in a brine producing well because it is standard operating procedure to check the pressure on this annulus every tour.

The equivalent pressure indicating point on a storage well would seldom be steady for any appreciable time because of in/out movements and momentum effects in the system.

The volume represented by the compressibility of the product stored could be several orders of magnitude greater than in a brine well. Significant product losses could, therefore, take place before a pressure drop would become evident.

There is no more rigid and inflexible rule in the brine producing operating procedure than that of keeping the protective pad elevation in the well below the casing seat of the final cemented casing string. The most common method of brine production is via reverse circulation where freshwater is the outer-most fluid next to the protective pad. Even with brine as the fluid next to the pad (normal circulation), all the previously described barriers are between it and the USDW aquifer.

In any brine producing well, where a protective pad is used, the first material to escape would be the pad. Loss of pad pressure triggers a shutdown, either automatically or manually, on a brine producing well. Although the primary purpose of the pad is to provide a barrier to prevent contact of less than saturated brine with the salt surrounding the final casing seat, the same effect is utilized in controlled solution mining to restrict the area from which salt is extracted by maintaining an appropiate pad elevation. In either case, the pad pressure at the final casing seat is always greater than the brine head at that point. It should be obvious then, because of the position of the pad and its relatively higher pressure, that pad material would be the first to move through any hypothetical escape route, and assuming such a movement did occur, it would be readily detectable by surface pressure indications.

Although the points made in previous discussions are considered to be irrefutable, there will be those inevitable "what if" comments and claims made that the USDW aquifer is going to be totally and irreversibly contaminated by materials escaping from a brine producing well. The most prevalent belief appears to be that brine will escape and make drinking water "salty." There undoubtedly have been instances where shallow brine disposal wells in "open" formations have caused contamination of the USDW; however, it is completely illogical to compare such a system with a brine well producing salt from a "closed" formation, constructed and operated as herein discussed. A breach of system integrity is readily detectable, and all efforts are directed toward producing the maximum tonnage of salt from a very expensive borehole without loss of energy expended.

The "way out," "what if" situation thus envolves into the potential escape of the pad material into a usable drinking water supply aquifer. Several factors should be evident. The volume of blanket material that could escape is small, the motive force available to make it escape decreases as the pad elevation moves upward toward the hypothetical escape point, and no more will escape once the level reaches that point. The multiple steel and cement barriers between the pad and the USDW rules out its escape laterally into the USDW. These barriers are reduced, down to the end of the first salt string only by the absence of the water protection string and its cement sheath, and at this point the barrier to lateral movement becomes one thickness of steel and one of cement. Since the pad material is non-corrosive, penetration from the inside of the casing to the outside is illogical. Presuming a loss of circulation zone (LCZ) did exist, penetration of the steel of the first salt string, which theoretically would be exposed to corrosive fluids, would be isolated from the pad by the cement sheath and steel of the second salt string. It is completely illogical to presume that whatever situation existed to cause penetration of the former would, in due course of time, result in penetration of the latter.

Because there is no mechanism present to cause exterior penetration of the second salt string, the only remaining route the pad material might follow is one *outside all the casings vertically through the cement, the cement/steel or cement/salt contact areas.* Previous discussions have covered the situation where migration was assumed to take place through the cement sheath of the second salt string and the interior (annular) portions of the system that are enclosed by steel.

Any knowledgeable person would readily concede such events are illogical, in view of the fact that cemented areas have previously been proven secure and with the small magnitude of motive force available to drive the pad through those areas of the second and first salt strings, through the LCZ (which normally is a low pressure area), and thence through the cement sheath of water protection string below the base of USDW aquifer.

The next "what if" gambit is questioning the potential consequence of pad material moving into the LCZ. As previously mentioned, LCZ waters are not usable. The LCZ, in its natural state (i.e., when not being used for high-volume rate brine disposal), is a low pressure strata which is in communication with down sloping saline aquifers on the skirts of the salt plug (dome). These saline aquifers are usually separated from the USDW aquifer by an impervious shale barrier; even if this were not the case and they were hydraulically connected, a termendous volume of fluid, incompetent rock or sand must be negotiated by the pad material before it can even get near the base of the USDW aquifer. When the magnitude of the volume pad material in a brine producing well is viewed in context with the volume of the geological masses it must traverse without wetting, entrapment, or otherwise being diminished in volume, the question of potential contamination becomes academic.

The above discussions are generally relevant to underground storage systems in domal salt; however, if the LCZ were subjected to high pressure, due to extremely high brine disposal rates, combined with occasional major volume product discharge due to storage well overfill (i.e., stored product flows up to the brine return string and is combined with other brine flows in a closed disposal system), the situation could be radically different.

The possibility of brine or protective pad material escaping through the salt mass itself and thence upward through the numerous strata between the top (or sides) of the salt mass and into the usable drinking water supply have not been discussed. There is no question but that salt itself has essentially zero porosity and permeability. The inclusions in the salt mass are invariably widely disseminated, either due to the nature of the inclusion of the manner in which the plastic salt mass moved from its original deep subsurface horizontal position to its present vertical position. In view of the fact that there has been no reported incident of products escaping through the salt mass after more than 30 years experience involving literally billions of barrels of processed fluids speaks for itself.

The main thrust of the previous discussions has been toward placing operating and monitoring features of a brine producing well in juxtaposition with failures within systems, which many consider will eventually occur, regardless of how illogical or farfetched the cause of failure is imagined to be. Assuming a failure did occur, the common perception of large quantities of contaminants being released directly into the usable drinking water supply simply has no validity based on logic and fact.

The objective of these discussions has been to demonstrate that not only have such potential failure modes been considered and design protection built into the system to prevent them, but even assuming all did fail, the magnitude of the forces within the system are insufficient to drive fluids from it and through the numerous geological or mechanical barriers that must be penetrated before the USDW is breached.

Because the protective pad is the only "foreign" material (the other being freshwater and brine) in the system, the nearesst one to the USDW and the most likely to "escape" a pad material which would not contaminate the USDW could be used.

COMPONENTS OF THE UNDERGROUND STORAGE SYSTEM

Several of the underground storage system components have been mentioned in the previous discussion and, although some repetition is involved, it would seem worthwhile to itemize all of them, state their function, the manner by which their soundness has previously been established, and set out those elements directly involved in final containment. When the latter have been proven secure, the machanical integrity of the system as a whole can be considered proven.

The wellhead is the uppermost pressure containment element of the system and must resist all pressures exerted on it by the pad material (or stored product), the freshwater for solution mining and the brine returns. It is designed and manufactured to rigid, universally accepted American Petroleum Institute (API) standards with respect to composition of materials, pressure and temperature ratings, flange ratings, machining tolerances, etc. It is tested in the shop and can be field tested. Its lowermost section (the Bradenhead) is generally mounted on the next to last cemented casing string. All the valves, flanges and fittings attached to it are also manufactured to either API or American National Standards Institute (ANSI) specifications and selected for the appropriate pressure and service.

The cased borehole involves several components. All the casings and cement are manufactured to API standards.

The first segment of the system is the conductor pipe, which is generally driven into place and functions to hold back surface soils and as a drilling "nipple" while the borehole for the water protection string is being drilled. It serves no further purpose.

The next segment is the water protection casing, which is set some 100 feet below the bottom of the USDW aquifer and is cemented back to the surface. This casing is often set on top of the cap rock of a domal salt plug and then is termed the "cap string" and its cement sheath is the first protective string for the USDW. The pipe is hydrostatically tested before drilling out the cement. If the casing seat (i.e., cement sheath) is not hydrostatically tested, a cement bond log is run to verify the adequacy of its cementation.

The next casing is set through the cap rock and 100 to 200 feet inside the domal salt body. If no LCZ has been encountered, it is cemented back to the surface. If an LCZ is encountered and cannot be sealed off, the casing can only be cemented back to the LCZ. In the former case, a secondary barrier consisting of a cement sheath and a thickness of steel is placed between the interior of the borehole system and the USDW. In the latter case, the barrier is one thickness of steel. This casing is often called the first salt string. The cement sheath between the end of this casing and the lower end (casing seat) of the water protection string or the LCZ acts as a seal to prevent fluid migration upward around the outside of the casing. The pipe is tested before drilling out the cement plug, and the cementation is tested via hydrostatic pressure or checked by a cement bond log. The drilling fluid, of course, is salt saturated to prevent enlargement of the borehole from the top of the salt downward.

The final cemented casing string (second salt string) is often set 500 feet or more below the top of the salt and cemented back to ground level. Because this is the most crucial string in the casing system, it is often hydrostatically tested on the surface racks and connections (collar and pins) are externally tested as the pipe is being run inside the first salt string and the new borehole. The entire casing string has an internal hydrostatic test applied to it.

There are two fields of thought on timing the running of this string. One group feels it best to drill the entire borehole in the salt to total depth, set a bridge plug just below the proposed casing seat , then run the pipe and cement it back to ground level. After the bridge plug has been drilled out of the casing, cementation and borehole are hydrostatically tested as a unit. The second group prefers to drill the borehole to casing seat depth, run pipe and cement it back to the surface, hydrostatically test the pipe before drilling out the cement plug, then drill out the plug, make 20 to 30 feet of new borehole, and then test the cementation. Either proceedure is acceptable.

The choice of casing seat depth of the final cemented casing string is set by the intended use of the well (i.e., the operating pressure that will be exerted at this point when the well is being subjected to the most extreme allowable operating pressure conditions).

Because the difference in density between the brine returning to the surface and the protective pad material, and the vertical length of the latter, creates the major system pressure at both the wellhead and the seat of the final cemented casing string, the maximum allowable operating pressure of a series of wells designed for different purposes can vary widely. By the same token, the depth of the casing seat sets the magnitude of the counteracting force exerted by the weight of the overburden above that point.

In other words, a brine producing well having a total depth of 4,500 feet and a diesel oil protective pad length of 2,500 feet could have a much lesser casing seat depth than a completely filled ethylene storage well of the same depth.

Obviously, there are other effects, such as the friction pressure drop of the brine returning through the 4,500 foot length of tubing (or possibly a lesser annulus length), and the back pressure exerted on the wellhead brine outlet, etc., coupled with the above, which in the final analysis, determines where the casing seat must be set.

In addition to the actual design features and proposed operating mode, other factors can influence the choice of the casing seat depth. These factors are influenced to a great extent by the requirements of the state regulatory agencies as well as the owners design and operating philosophy.

For instance: If the state required the final cemented casing string be set a minimum of X feet below the top of the salt, and the criterion for proving its mechanical integrity is deemed accomplished if the casing and its cementation will hold an applied pressure equal to the maximum allowable operating pressure plus $Y\%$ (i.e., a Safety Factor of $1 + Y$), a new element is introduced. Once the casing seat depth that satisfies the state requirements is determined, then the total depth of the borehole can be established. In determining the casing seat depth, the following must be considered: depth to the top of the salt; length of "to gauge" borehole between the casing seat and the final roof elevation to assure that only saturated brine can contact the casing/cement/salt; the maximum tonnage of salt to be extracted through the one borehole; and the maximum solution cavern diameter required by the well distribution pattern and the "sand trap" dimensions.

The solution mining plan "sets"the depth at which protective pad must be maintained, sometimes the type of pad material to be used, and the sequence of normal and reverse circulation steps. It is possible that the casing seat depth may be changed when these, and possibly certain other decisions are made.

STATE REGULATIONS VS. OWNER REQUIREMENTS

The situation now envolves into one of reconciling those parameters that the reviewing officer in the state agency deems appropriate and necessary for a brine producing well (or a product storage well, disposal well, etc.) under a given set of circumstances with those the owner knows to be sufficient based on many years of industry experience. The owner must design the system to produce brine at the rate and quantity, in a cost effective manner that allows for delivery of the brine at a competitive price. The owner cannot afford loss of permits or production time by engaging in a running controversy with state regulatory agencies. By the same token, a prudent owner conducts operations in a way that protects his own property from damage and protects the rights of adjacent landowners and other affected individuals, thus avoiding activities that could lead to time-consuming and expensive lawsuits that would affect profits.

The criterion by which a brine producing well can be proven to have mechanical integrity to the satisfaction of the controlling agency of the state is extremely important where several owners are conducting operations on the same dome that conceivably could damage the USDW aquifer.

The real difficulty arises because neither the Environmental Protection Agency's Safe Drinking Water Act nor most states' underground injection control rules and regulations specify what, in their view, constitutes mechanical integrity in a borehole penetrating the USDW aquifer.

The dilemma the state agencies face is the popular misconception that any borehole penetrating a usable supply of drinking water, regardless of how well it is designed and constructed and the care taken in operation, will inevitably fail and, thus, release contaminants into the aquifer. They further postulate that any subsurface release of a potential contaminant, regardless of how small the volume or location of the point of release, will immediately be transported into a USDW aquifer. The major portion of this paper has been directed toward presenting a logical and rational analysis of what actually happens in a brine producing well so that such misconceptions and vague fears will be laid to rest.

Assuming this discussion has alleviated unfounded fears and eliminated the premise(s) *of irrational concepts*, certain very real problems exist.The main one is that a change in volume (either an increase or decrease) cannot be determined with absolute precision because of the tremendous volume of the cavern from which salt is being solution mined or within which products are to be stored. Another is the physical characteristics of the surrounding salt body. It is extremely difficult to devise a test that will give an unequivocable result. Hydrostatic tests of open-ended cased boreholes and solution caverns have been universally used for many years, and material balances in brine wells (product loss experience in storage caverns) has demonstrated that if there is as little as +10 psig change in the applied brine test pressure during a continuous 24-hour period, no loss of material will occur from the system. Unfortunately, this test is an empirical one.

It is also usually not possible to hydrostatically test the wellhead, wellhead seals and upper areas of the final cemented casing string art, or in excess of, their normal operating pressures without risk of overpressuring the casing seat of that string.

There have been recent and rather dramatic advances in the "state of the art" of testing cased boreholes and their cementation with nitrogen, such as the NITRAC method. This method is based on a capability to measure the volume of nitrogen injected with a high degree of accuracy so that the space it occupies can be determined. The method can be used to prove the mechanical integrity of the wellhead, wellhead seals and the final cemented casing string and its cementation to a level greater than the maximum allowable operating pressure. This can be done without pulling the protective liner and tubing or removing the protective pad material or (stored product).

Because the objective of the test is to be prove a "leak" does not exist in the system, further refinement must be incorporated in the nitrogen test procedure. The sensitivity, or "minimum leak detection" capability of the equipment, meaning no "detectable leak" in terms of a pad loss volume using "state of the art" methods such as NITRAC, must be established in terms of the test parameters they are measuring. For instance, the interface detection logging system is making a measurement in feet, and the accuracy with which an interface can be located at its true position must be defined. By the same token, the degree of accuracy must be established for making calculations used for determining the volume of the interval traversed by the interface(s) or making adjustments for changes in system conditions

The nitrogen test has an ultrasensitive detection capability because gaseous phase nitrogen, at test pressures, would escape in far greater quantities from the system than would pad material or stored product. The magnitude of that ratio is unknown at this time but will vary with test pressure and from one pad material to another. In the absence of any criterion, it would seem very conservative to set the ratio at 30 volumes of nitrogen to 1 of diesel fuel oil and vary the ratio for other products proportionally to their relative viscosities.

The "minimum detectable" nitrogen volume change is a function not only of the sensitivity of the test equipment and mathematical concepts but also of the volume of the borehole annular interval across which interfaces are to be measured. Because this volume will undoubtedly vary from one well to another, setting an "allowable variance volume" of nitrogen too low will prevent (because of time constraints) testing some wells by the NITRAC method and force a return to much less accurate tests.

If the "minimum detectable" nitrogen volume change is translated into terms of "maximum allowable" pad (or stored product) loss, then the basis is set for a truly meaningful test criterion. Such a criterion should satisfy even the most demanding of public pressure groups, and if they insist that all losses go directly into an underground drinking water source they could compute the ppm (weight) that might enter the aquifer.

Assuming the "allowable variance volume" of nitrogen (at bottom hole conditions) was set at 2,000 bbl/yr, and the nitrogen-diesel oil pad ratio was 30:1, the volume of pad material "escaping" would be only 66.7 bbl/yr. When this is viewed in the context of the billions of barrels of water in an underground drinking water source, it would have a completely insignificant impact on the water quality.

It should be understood that the 2,000 bbl/yr nitrogen restriction in reality is intended only as a means of setting the maximum size of borehole interval (below the casing seat of the final cemented casing string) in which the NITRAC testing method may be used within a practical time interval (i.e., 5–7 days). In many brine wells the borehole interval is very small in volume, and the "minimum detectable" nitrogen would be much less—perhaps as low as 100 bbl/yr of nitrogen (3 bbl/yr of diesel oil pad). It should also be recognized that pad materials other than diesel fuel will have different nitrogen-pad ratios (i.e., propane may have only a 10:1 ratio).

The physical characteristics of the subsurface system can limit use of the nitrogen test. The limitation is imposed where the nitrogen pressure, in a static system, would exceed 0.9#/ft with pad interface at the casing seat. This can come about if any one or a combination of the following exist:

- Excessive depth of the casing seat
- Extremely low density pad material
- Excessively long vertical dimension of the solution cavern with the nitrogen/pad interface near the bottom.

A practical limitation may also be imposed if the volume of the space immediately below (i.e., 3 to 5 ft) the casing seat is so large that a potential shift of the nitrogen-pad interface (i.e., within the logging system limits of detection) would require an inordinately long test period.

The nitrogen test method can be used to prove the mechanical integrity of the final casing string and its cementation but not the cavern itself.

Because of the physical characteristics of the salt envelope, it is almost inconceivable that material could "leak" from it. The only materials below the pad elevation are partially or fully saturated brine. The proposition that such relatively heavy (i.e., 1.2 sp gr) materials could "escape" through the salt body, and from the point of escape migrate upward through the numerous existing geological barriers and intercept zones and then enter the underground drinking water sources, is contrary to all physical laws.

If the pad "leaked" its change in elevation could be detected by its reduced pressure reading at the wellhead and/or by interface survey. The same arguments as above apply; in addition, the steel and cement barriers stand between the pad and usable drinking water source.

Because it is impracticable to test the solution cavern with nitrogen the only practical method is the hydrostatic test. The arguments presented in the second paragraph above apply insofar as "escape" of brine into the drinking water supply is concerned.

CONCLUSIONS

The previous discussions have been directed toward dispelling misconceptions and unfounded fears which the public, in general, consider are involved in a brine producing system extracting salt via solution mining from a domal salt plug.

It has not been the intention to either question the need for UIC regulations or the content of those already promulgated.

The primary thrust of this paper has been toward establishing a reference framework within which both the governing state agency and owners or representatives of the brine producing industry can make sensible and logical decisions relating to the actual application of Underground Injection Control rules and regulations to specify wells.

In the final analysis, the parties responsible for writing and enforcing such regulations should have specific criteria to be met if a brine producing well is to be considered to have mechanical integrity. By applying those criteria to results obtained, as set out in the owners' or operators' test report on a well, they should be able to make a just decision. By the same token, if the owner or operator knows in advance the criteria by which the mechanical integrity of his well will be judged, he can devise methods and procedures which will give test data required by the state to make such a decision. If this result could be attained, reporting formats could be standardized and superfluous or inappropriate data taking eliminated.

This objective could be met if the criteria, hereinafter set out, were agreed to by the state and the owner or operator as representing proof that mechanical integrity exists; that test methods and time intervals to be used provide valid data having demonstratable accuracy of definition; or that, in lieu of formal testing, certain evidence could be presented which would establish the fact that mechanical integrity exists (such as protective pad pressure records, pad volume injected vs. pad volume recovered, pad volume injected vs. sequential interface logging records showing the brine pad interface has not shifted over a substantial period of time, etc.).

The following criteria could be used as a basis for establishing that mechanical integrity does exist in a given cased borehole and its cementation:

1. The wellhead and its associated seals and valves should be proven capable of restraining pressure equal to 1.2 times the maximum expected operating pressure in the protective pad annulus with no detectable leakage.
   a. If it is an API stamped wellhead, the designated working pressure rating may be considered as proof.
   b. If there is no leakage from a pressurized annulus into the next inner annulus, the seals may be considered secure.
   c. If the wellhead valves are manufactured to API or ANSI standards and have working pressure ratings equal to or greater than the applied test pressure, they may be considered satisfactory.
   d. If the weld between the casing head and the final cemented casing string (or the test port on the Bradenhead, if one is used) shows no evidence of leakage either visually, by sound or by soap bubble test, this area may be considered secure.
2. It should be proven that there is no detectable leakage in the final cemented casing string from its juncture with the wellhead to its casing seat, when a test pressure 1.2 times the maximum expected pad pressure is applied along its vertical length.
   a. Certain information would assist the State in making its finding in 2. above and should be included in the test report.
      (1) The O.D., weight and grade of the casing and the collar type
      (2) Evidence that the pin and body side of the collar connecting each joint was "made up" by controlled torque methods or was back welded with a full stringer head
      (3) Whether two strings were set into the salt and, if so, the distance of each casing seat below the top of the salt; if this is the only casing string set into salt, whether a loss of circulation zone was encountered and, if it was, whether it was sealed off or left open
      (4) The type and volume of cement used and, if cement returned to the surface, the approximate volume of such returns; if cement did not return to the surface, the level it did reach should be stated.
   b. It should be considered proof that no leakage exists in a final cemented casing string that has been in place 5 years or less, if it was hydrostatically tested after being run and there were no detectable leaks during a specified time interval (i.e., +2 hours)
   c. It should be considered proof that mechanical integrity exists in a final cemented casing string which has been in place more than 5 years, if
      (1) When the pad is retracted ±30 feet above the casing seat and subjected to the stated pressure test level for a 24-hour period, the pad/brine interface does not move upward across an annular interval which, when multiplied by 365, equals no more than 10 bbl/yr of pad loss, or
      (2) The same result may be attained by using nitrogen to push the brine/pad interface down, to the same point, and then tracking the nitrogen/pad interface for a period of time sufficient to prove the nitrogen movement represents no more than a 10 bbl/yr loss of pad material.
3. Mechanical integrity of the final casing string cementation, after the casing itself is proved to have mechanical integrity (as set out in 2.c. above), should be considered proven when the folowing conditions are present or met.

   NOTE: It is extremely difficult to prove via fluid pressure measurements that the cementation (i.e., casing seat) is not (or is) leaking because of possible pressure fluctuations in the cavern itself due to lack of saturation and temperature equilibrium, salt rebound (still in progress) resulting from applied test pressure, salt creep taking place after rebound effects cease, or combined effects of salt rebound and salt creep which could be taking place simultaneously, etc.

   It should also be noted, when nitrogen is used as the testing medium in the final cemented casing string, testing of cementation is simply a continuation of the process by addition of more nitrogen.

   The protective pad material can either be removed or displaced below the casing seat when nitrogen is used.

   Certain volumetric adjustments must be made of the nitrogen if changes in the system pressure or temperature occur during the test time period.

   a. When the precise (±5%) volume of the borehole annular space between the outermost hanging string and the salt face is known in 1-foot increments to a point approximently 5 feet below the casing seat, that interval can be filled with nitrogen and the nitrogen/brine or nitrogen/pad interface tracked for a specific period of time to prove no detectable leak exists. This time period is "set" by the theoretical "maximum allowable loss" the state will permit, in terms of barrels/year of pad material. (In the previous discussion, this was considered to be 66.7 bbl/yr.) The volume of annular interval across which movement of the interface must take place, in terms of the limits of repeatability of the interface measurement system, and the nitrogen/pad material "escapability" ratio (herein assumed to be 30:1 diesel oil) must be specified.

In most cases, the above discussed annular volume will be of a magnitude which will allow definition of a detectable* leak considerably less than the 66.7 bbl/yr diesel pad equivalent.

b. If the volume of the annular space(s), discussed in 3.a. above, is not known, the NITRAC method can be used to establish it to within ±5% accuracy.

c. In certian circumstances, the state should be willing to accept sequential interface measurements of the protective pad, which demonstrates that the pad elevation has not changed between dates interfaces were taken. Records indicating the volume(s) of pad injected and the date(s) it was done are important if this procedure is to be properly supported. Time intervals between interface surveys should be at least 30 days.

d. It is also possible that the state would accept a total withdrawal of the pad material and a comparison between the volume recovered and the cumulative volume injected. Accurate pad material volume injection records are essential in this procedure as is the measurement of the volume recovered.

This test should satisfy the state that neither the final casing string nor its cementation is leaking.

4. If the state required proving the mechanical integrity of the cavern itself, the only method presently known is the hydrostatic test. The time needed to obtain meaningful data from thes type of test could be as much as 60 to 90 days, depending on the rate at which brine was being produced and the volume of the solution cavern itself. Experience indicates that if pressure change is no more than +10 psig during a 24-hour time interval, the cavern is not leaking. It is quite possible that a cavern would not leak even if the pressure change was greater than −10 psig; however, in terms of the present state of the art in hydrostatic pressure testing of large solution caverns, it would be extermely diffecult to prove this.

If the pressure increased (above +10 psig), no means exists to prove the pressure increase does not "mask" a small magnitude leak.

It should be clearly understood that neither the Solution Mining Research Institute nor members of the sodium chloride brine producing industry have concurred, nor might necessarily be expected to concur, with every item on the foregoing list. The legitimacy of these criteria is based solely on the opinion of the author and do not necessarily represent that of Texas Brine Corporation. In any event, the criteria should serve as a basis for development of a dialogue between the state and owners or operators having installations in domal salt formations.

A major portion of this paper has been directed toward a dissertation on the physical characteristics of the salt body, the natural force (gravity) governing movement of heavier fluids through lighter ones, the nature of geological formations on top of and surrounding the salt plug, the mechanical barriers preventing fluid movements from the cased bore, and the relative position (and monitoring procedures) of protective pads vs. brine in the near gauge and cased borehole system. All have the end purpose of demonstrating how illogical it is to presume that saturated brine could enter the underground drinking water supply aquifer from a brine producing well.