OGS ASSOCIATES

CONCERNS INVOLVING
PARADOX VALLEY DEEP
DISPOSAL WELL PROJECT

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SUMMARY/CONCLUSIONS

The firm of O'Brien-Goins-Simpson & Assoc. (OGS) was hired to review current specifications and geological information concerning the "Deep Well Drilling, Completion, and Testing, Paradox Valley Unit, Colorado River Basin Salinity Control Project, Colorado." We were asked to comment on adequacy of these specifications and determine best bidding procedure to get the well drilled, completed and tested.

On June 15, 1983 W.C. Goins (Senior V.P.-OGS) and Larry H. Flak (Associate-OGS) met with 17 individuals with the Bureau of Reclamation in Salt Lake City. At this meeting our comments were given concerning the Deep Well Project. We directed our discussion to the following areas:

1) Salt Collapse
2) Brine Handling
3) Fracturing
4) Seismic Events
5) Faults
6) Specifications
7) Location
8) Testing/Completion

The following are the major recommendations presented at the June 15, 1983 meeting that are based on our knowledge of deep well drilling, completion and testing.

1) Hire an experienced drilling engineering consulting firm to prepare a detailed "Well Plan", outline bid areas, prepare bid specifications, review submitted bids and supervise the implementation of the "Well Plan".

2) A location should be selected where salt will not be encountered deeper than 11,000'.

3) Determine if the target reservoir at this location has sufficient area extent to meet long term injection requirements.

4) Design the disposal system to inject at fracture pressure. This will remove the need for filters.

5) Ideally, procede with temporarily abandonment after determining reservoir fracture pressure, permeability and fluid chemistry. Design and order the injection tubing and surface facilities based on this data.

Disposal of Paradox Valley Brine thru an injection well is viable with good engineering design, review and implementation. This project should not be taken lightly. OGS represents over 150 years of oilfield experience distributed between 8 individuals. To our knowledge no injection well has ever been designed to inject nearly saturated brine below deep salt at high rates with minimum system maintainance and long well life.

A great deal of technology was presented at that meeting. This information is detailed in the following report.

SALT COLLAPSE

Casing failures opposite salt formations are common in many fields throughout the world. Failures have occurred opposite salt as shallow as 5000'. [1] These failures occur because salt plastically flows into the wellbore driven by weight of overburden on the salt. The overburden gradient in Western Colorado is approximately 1 psi/ft. At 10,000', casing in a salt section must be designed to withstand collapse pressures of 10,000 psi. (1 psi/ft X 10,000'). The design assumes that the salt is uniformly loading the casing concentrically. We try to accomplish this with a cement sheath between salt and casing, but achieving a completely cemented annulus can be very difficult.[2] Most casing strings fail opposite salt sections because of a poorly cemented annulus. The most severe salt loading situation is point loading. When cement placement results in only a partial sheath around casing, salt moves into the uncemented portion of the annulus and loads only a small portion of the casing. [2] With all the forces concentrated on a small area of the casing, the pipe fails. Even completely cemented pipe can fail due to point loading. Salt has been known to move in a non-uniform manner. If the movement of salt occurs preferentially in one direction then non-uniform loading occurs. A completely cemented annulus may not be enough to resist directional salt movement. Directional salt movement results in another form of point loading. The results of point loading are devastating. In fact, no currently manufactured casing string is strong enough to resist point loading in its purest form. The final type of casing failure is one of salt movement induced bending moments. Salt is often interbedded with limestones and dolomites. Hole diameter is enlarged in the salt sections and near gauge in limestones. As salt moves into the wellbore after pipe is set, the salt tends to bend pipe around limestone ledge. This can lead to restrictions in the pipe, weakened pipe and ultimately failure.

Faced with these salt movement problems there are some procedures that must be followed to avoid casing failure.

1. Drill a gauge hole thru salt. Avoid hole washout to assist in proper cementation.

2. Design the casing string with 1.0 psi/ft. collapse design and high tensile efficiency.

3. Cement annulus between pipe and salt with salt saturated cements. Design cement placement techniques to maximize annular cement fillup.

4. To overcome risk of casing failure due to point loading or cementing problems run a scab liner cemented within the primary casing string to get double casing string protection opposite salt sections.

Using 8-1/2" internal drift diameter casing as the primary casing string, the deepest that salt could be drilled and completed thru with good well life would be approximately 11,000' without use of very exotic pipe. Example: (9-7/8" 62.8 ppf S-105 BTC, Collapse = 11010 psi, Burst = 10520 psi, Joint Strength = 1,437,000 lbs).

BRINE HANDLING

The Paradox Valley Brine has a very poor quality of injection. With proper tubular and surface piping material selection and chemical treatment, this brine can be made into an acceptable injection fluid. The small (100 ppm) sulfide concentration in the brine may be sufficient enough to cause sulfide stress cracking problems. This should be investigated. The nearly saturated brine could lead to corrosion stress cracking failures in stressed, brine wet steel. The prefered steel for use in downhole tubulars will be Cr-Mo type (4130) alloys with good toughness and low hardness. Due to the nature of this brine, corrosion could be a problem without chemical inhibition or use of stainless materials.

Stainless materials are available that are completely resistant to corrosion and should be used in the injection string. The major difficulty in material selection is caused by the very high salinity of the brine. Many of the stainless steel materials resist corrosion because of a durable oxide on the steel's surface. This oxide can be eroded away by the high salinity brine and this exposes a surface that will corrode very fast as there is no oxygen in the system to reestablish the oxide.

The brine must be kept nearly oxygen free to prevent corrosion of carbon steels and some types of stainless steels. The produced brine must be maintained at pressures in excess of atmospheric pressure to prevent air entrapment from the producing wellhead to the injection wellhead. Chemical oxygen scavenging (sodium sulfite type or ammonium bisulfate type) may be necessary if the dissolved oxygen content of the brine is in excess of .05 ppm where it is in contact with carbon steel. Amine - type film forming corrosion inhibitor injection may be required if carbon steel is used in the tubing string or if surface piping needs additional protection.

The major forseen injection problem will be scale deposition. There will be scale deposition problems in surface piping systems and in downhole tubulars without chemical scale inhibition. Scale formation in water injection systems contributes to formation plugging, flow restriction, equipment corrosion, and the survival of corrosive bacteria under the deposits. The main deposits will be calcium sulfate and calcium carbonate scales. Scaling tendency should be controlled by application of suitable scale inhibitor (ex., phosphate ester) that will act on the scale crystals while they are still microscopic and thereby prevent further growth. Iron sulfide can be a problem if anaerobic sulfate-reducing bacteria (SRB) are present in the produced brine. Microbiological iron sulfide scale could be a problem if SRBs are present. SBR control will require continous chlorination with use of a hypochlorite generator and batch treatments of biocide chemicals (aldehyde and/or amine types) on probably a monthly schedule. Internal plastic coating of the injection well tubing should be investigated. Internal coating will not prevent corrosion, but helps to prevent scale deposition due to its "slickness".

We have indicated the possible scale problem areas. The Bureau of Reclamation will need to fully study this problem and get exact treatment recommendations.

Compatability checks should be made between Paradox Valley brine and insitu formation brine of the injection reservoir. The formation of insitu precipitates may be a major injection problem.

FRACTURING

A common mistake made by designers of disposal wells is the assumption that formation permeability will accept the disposal fluid more or less indefinitely without fracturing as long as the injection fluid is filtered to the point that total suspended solids content is very low. Eventually surface pressures must be increased to the point of fracturing if a sufficient injection rate is to be maintained.

The basic problem with designing to pump at low pressures without fracturing is that formation permeability is too easily plugged. If not by suspended solids carried thru the filters, plugging can occur by calcium carbonate, calcium sulfate, iron oxide, or iron sulfide scale products and by chemical precipitates formed from the interaction of injected brine with reservoir fluids.

The formation receiving the injected brine is a very effective filter. As in surface system, if the designer wants to filter at high rates with minimum pressure drops, he increases the size of the filter. We accomplish this downhole by establishing a fracture. If we assume that 200' vertical feet of permeability is exposed in a 8½" diameter hole, the flow area works out as 445 sq.ft. If a fracture is established extending 200' out from this wellbore the flow area is increased over 125,664 sq.ft. or 2.9 acres! This fracture does not intially extend 200' but increases in length as the fracture face is plugged and the injection pressure increases to maintain the required injection rate. The 2.9 acres calculation only exhibits the tremendous increase in flow area when fracturing occurs. The injection system must be designed to pump at the required rate at fracture extension pressures if long term injection is required.

No surface filtration will be needed due to the tremendous increase in flow area when fracturing occurs and because of the naturally low total suspended solids content of the Paradox Valley Brine. This will decrease surface facility cost and greatly reduce maintenance problems. Filter systems generally require more maintenance that other surface equipment. The Bureau of Reclamation would also be saved the trouble of disposing of filter media solid waste.

SEISMIC EVENTS

Hydraulic fracturing does not cause earthquakes. Changes in reservoir pressure and/or temperature due to fluid withdrawal or injection may have caused slight seismic events in some very limited cases. Nearly every oilfield in the world either produces water with the oil that must be reinjected for pressure maintainence, or disposed of in a seperate reservoir.Many oilfields require water injection from some extraneous water source for waterflood operations or pressure maintainence. Many of these oil reservoirs are traps caused by natural faulting. In California many hydrocarbon reservoirs are traps formed by faults that are known to be seismically active. Many of the "Overthrust" wells in the Rockies are drilled in the structures formed by near wellbore thrust faulting.

Studies[3] of the Rangely Field in Colorado have indicated a fairly high frequency of small earthquakes associated with a natural fault bisecting the oil field. The author of this paper attempted to relate daily field operations (production and injection) with earthquake frequency. It is troubling that no baseline of earthquake frequency was established prior to production operations at Rangely. Yet, the author of this paper attempts to equate production/ injection operations with highly variable earthquake activity (5-175 earthquakes/month). If earthquake frequency was inter-related with oilfield activites, then these series of slight movements may have been beneficial in reducing the chance of a major fault movement/earthquake.

It is recommended that a study by carried out to mitigate concern over the risk of earthquakes caused by injection. The study should consist of the following:

1. Place seismometers at the proposed Paradox Valley Brine disposal site to investigate present seismic activity and to establish an activity baseline.

2. Re-investigate the seismic history near or at Chevron's Rangley Field. The field has been produced for over 30 years. The last published analysis of seismic activity was in mid 1971. What has happened since that time? What has happened to the reservior pressure since that time? What are the magnitude of these seismic effects?

FAULTS

There is a misconception that natural faults could act as leak paths for injected fluids. Natural faults are normally sealed (non-permeable). This is particulary true for geologically old faults, as these faults are sealed by diagenic processes over time. If faults were not sealed, the oil industry would not find oil or gas trapped in structures formed by faulting where the fault is the impermeable boundry the contained the hydrocarbon within the structure. Hydrocarbons are less dense than formation brines and migrate up structure until trapped by a impermeable boundry. Many of these boundries are faults. Exploration methods for hydrocarbons tend to look for a fault that might form a trap and to place a well very near the fault to get in the best structural position within the possible reservoir. Natural micro fractures which improve permeability and increase reservoir size also occur near major natural faults. In many areas, the oil industry attempts to get close to the fault to maximize the chances of intercepting a naturally fractured reservoir.

SPECIFICATIONS

There are no common industry standards that detail sufficiently how one would drill a deep disposal well thru salt in the Paradox Valley to inject a nearly saturated brine. The worst possible mistake would be to let some low-bid contractor drill such a well on a loose specification where undetailed steps are left up to the contractor's whim. Far too many things will impact the utility of the well.

A major problem with setting up an elaborate specification to prevent this sort of situation is that many things can happen during the course of drilling, evaluation, completion, and testing such a well that would require a specification change or addition to handle. A list of the major specification topics will include the following:

1. Casing Point Selection
2. Casing Designs
3. Drilling Mud
4. Drilling Mechanics
5. Hydraulics
6. Cementing
7. Well Control
8. Formation Evaluation
9. Location Design
10. Logistics
11. Safety
12. Rig Selection
13. Completion
14. Testing
15. Surface Facilities

This elaborate specification is what the petroleum industry calls a "Well Plan". Following this "Well Plan", unless well conditions indicate that some changes are necessary, is something hammered into drilling personnel all throughout their careers.

Enforcement of the procedural guidelines established in the "Well Plan" should be left up to knowledgeable personnel in employ of the operator (i.e.: Bureau of Reclamation) who had association with the planning.

To reduce drilling costs and provide for competative bidding, certain common activities should be identified in the "Well Plan" and then bids let to perform that service. For example, each string of casing run must be cemented. There are companys that perform this service. Give them the part of the "Well Plan" that outlines cementing procedure, cement chemistry and volume to set up the bid spec. As volumes of cement that will be actually required are hard to estimate, ask for a unit cost bid. Set up a detailed specification for required type of drilling rig and ask for a straight "Daywork" bid. This is necessary if the Bureau of Reclamation wants to control operations, but competatively bid the work. Every activity can be detailed to the point that a bid specification can be issued and competative bids returned to the satification of both parties.

LOCATION

Initial plans were to drill a 15500' disposal well at the brine well site. This is impractical due to problems completing thru deep salt, high fracturing pressures and excessive well cost. A new well location needs to evaluated with consideration to the following:

1. Minimize depth of salt.
2. Reservoir size.
3. Reservoir permeability.
4. Distance from brine field.

As previously discussed, salt collapse is a major well design consideration. The deepest salt can be completed thru with good well life is approximately 11,000'. Ideally, a location should be picked so that salt is no deeper than 9000' to further reduce the risk of salt collapse and well cost.

This location should be picked so that a large reservoir is encountered below salt. This reservoir should encompass several thousand acre/ft. so that brine injection will not quickly increase reservoir pore pressure to the point that wellhead injection pressures exceed economic design levels. Reservoir calculations can be made to better define the required reservoir size.

The reservoir should have a reasonable amount of permeability. The required amount of permeability is very hard to define. The required magnitude of permeability is reduced by designing to inject at fracturing pressures as previously discussed. Some amount of permeability is required so that brine can leak-off from the fracture into the reservoir. This magnitude will probably in the range of 1 - 10 md. Injection into non-permeable rock will induce two continuously lengthening vertical fractures orientated 180° apart, radiating from the wellbore. This fracture growth will continue until the rate of leak-off exceeds injection rate to the point that internal fracture pressure drops below fracture extension pressure. Picking a location near a large natural fault will tend to increase the chances of locating good reservoir permeability due to natural micro fractures.

The brine injection well needs to be reasonably close to the brine field. Pump horsepower is used in frictional pressure drop to the injection well. Construction costs and maintaince costs increase. As corrosion and scaling are a problem, longer pipelines will require greater chemical and maintenance expenditures.

With these parameters in mind, it is recommended that the Bureau of Reclamation investigate currently available seismic data to determine possible injection well sites. Use Continental's - #1 Scorup-Sumerville-Wilcox well as a lithology correlator as well as other offsets. Salt is a very good seismic reflector because of its low density (2.17) in respect to carbonates or shales (over 2.5). Once prospective areas are located further definition (if required) can be done with new seismic work.

TESTING/COMPLETION

After drilling to total depth, certain tests should be performed to better design the injection tubing and pumping plant.

Drillstem tests should be done to evaluate formation permeability and sample reservoir fluids. These fluid samples should be checked for compatability with the injection brine.

Hydraulic fracturing tests should be run to determine fracture breakdown and extension pressures. This critical information is needed to design injection tubing and pumping plant.

After performing these tests, a liner should be run thru the open hole to maintain hole integrity. At this point, the well should be temporarily abandoned.

Design and order tubing string and pumping plant based on obtained information. After receiving tubing, the well can be re-entered and completed.

Temporary abandonment could be avoided by overdesigning tubing to meet any expected fracture pressure. The expected fracture gradient should be between 0.65 - 1.0 psi/ft. Unless the rocks are tectonically stressed, the gradient should be approximately 0.65 psi/ft. Many areas in the Rockies are tectonically stressed and have higher corresponding fracture gradents. This variation is great enough to significantly effect injection system design. Overdesign to meet any condition would require designing for a 1.0 psi/ft gradient. This would greatly increase tubing, piping and pump plant costs.

Bibliography

1) Clegg, J.D.: "Casing Failure Study - Cedar Creek Anticline", Journal of Petroleum Technology (June,1971) 676-684.

2) Pattillo, P.D. and Rankin, T.E.: "How AMOCO Solved Casing Design Problems In The Gulf Of Suez", Petroleum Engineer. (Nov. 1981) 86-112.

3) Haimson, B.C.: "Earthquake Related Stresses At Rangely, Colorado", Rock Mechanics (1972) 689-707.

BACKGROUND

This project will be a two-step formally advertised procurement.

The Bureau intends to solicit bids from firms that will assume the management responsibilities for the deep well drilling, completion, and testing. The effort to be contracted is similar to the services that an oil company, or owner, would normally provide.

We would prefer to have one bid item, i.e., "Drilling, completion, and testing one deep well hole as detailed in the specifications."

For payment purposes in drilling the well, would a lump sum be the most cost effective or should we set the bid up to reflect either a price per day or price per footage payment for drilling plus the costs normally assumed by the owner?

Also, due to the risk involved in drilling through a salt dome to a depth of approximately 15,500 feet, review the design of the well for completion and operation, which of the above payment methods would a company be inclined to build in the most contingencies?

Provide your comments/recommendations relative to the adequacy of the specification to produce the successful completion of a deep well hole.

We are including information compiled on the geology aspects and request the geology section be returned with you analysis.

Your analysis is requested on or before June 15, 1983.

Our point of contact is Beverly Karinen at (801) 524-5541.