ABSTRACT

High acid gas content streams, consisting primarily of carbon dioxide, hydrogen sulphide or a combination of both are commonly generated as a by-product of the sweetening process used to bring many produced gases and solution gases to pipeline specifications for sales and transport. Typically, sour gas has been extracted from acid gases through the use of Claus or other types of elemental sulphur reduction processes, the sulphur sold or stockpiled, and the residual carbon dioxide vented to atmosphere. With depressed prices for the commercial sale of sulphur and environmental concerns with the emission of large volumes of greenhouse gases, considerable interest has been extant in the industry into the feasibility of the re-injection of acid gas from sweetening processes, either back into the original producing formation, or into selected disposal zones which may consist of aquifers or depleted previously produced oil or gas zones. A major concern with the re-injection process is the potential for formation damage and reduced injectivity in the vicinity of the acid gas injection/disposal wells, as well as reservoir screening criteria with respect to suitable gas containment concerning the subsequent migration of injected acid gases. This paper discusses screening criteria for reservoir selection for zones suitable for acid/sour gas re-injection or disposal, and highlights potential areas of concern for reduced injectivity. Such phenomena include acid gas induced formation dissolution, fines migration, precipitation and scale potential, oil or condensate banking and plugging, asphaltene and elemental sulphur deposition, hydrate plugging and multiphase flow phenomena associated with acid gas compression phenomena. Variations on acid gas injection schemes, such as concurrent contacting with produced water at elevated pressures and subsequent disposal of the sour water, will also be discussed and potential damage concerns highlighted. A variety of screening and laboratory tests and results will be presented which illustrate the various damage mechanisms outlined and provide a specific set of design criteria to evaluate the feasibility of an acid gas injection/disposal operation.
INTRODUCTION

Acid gases (gases which contain carbon dioxide (CO₂) and hydrogen sulphide (H₂S)) are produced from many formations as either free gas or liberated solution gas from sour oils. These gases must be "sweetened" to selectively remove the acid gas components before the gas can be transported and sold for commercial use. A variety of sweetening processes are used to remove acid gas components (amine extraction being the most common).

The sweetening process results in the production of acid gas-free "sales" gas, and a rich waste gas stream consisting of virtually pure CO₂ and H₂S (commonly referred to as concentrated acid gas). In the past, a variety of techniques have been used to handle acid gas streams, most of them primarily concerned with the reduction of the extremely toxic hydrogen sulphide to an inert/non-toxic reaction product. The most common technique is the Claus reaction process where the H₂S gas in the acid gas stream is catalytically converted to elemental sulphur. This process was an economic one in the past, particularly when sulphur prices were in excess of $150/tonne. Many operators deliberately attempted to exploit reservoirs containing high concentrations of H₂S with sulphur recovery, rather than the value of the sweet sales gas, being the primary motivating factor. However, with a significant reduction in world prices for sulphur in recent years, the commercial sale of sulphur has become less economic and the market volatile. Much of the sulphur produced in recent years has been stockpiled in large poured sulphur blocks. Considerable concern has also been created over the environmental impact of gas sweetening operations ranging from SO₂ and non-reduced H₂S gas emissions, greenhouse gas emissions, the impact of the sulphur dust generated from pouring/prilling operations and the impact of runoff from sulphur storage sites.

This has motivated a considerable degree of interest in alternate techniques to handle acid gas streams for disposal. One technique gaining in popularity involves the re-injection of the rich waste acid gas stream (or water which has been contacted with the acid gas and contains a high concentration of the acid gas in a dissolved state) directly back into the producing or a disposal formation. The subject of this paper concerns criteria which should be considered when selecting a reservoir candidate for acid gas disposal and provides a summary of selected techniques and data used to screen acid gas injection projects.

TYPICAL ACID GAS STREAMS

Table 1 provides a summary of basic properties of CO₂ and H₂S. Both gases have a diatomic structure and exhibit high natural solubility in both aqueous and hydrocarbon solutions, a fact which can be used to our advantage in some disposal operations, as will be discussed shortly. Composition of the injected rich acid gases can vary widely and is a direct function of the acid gas content of the oils/gases which are acting as the feedstocks for the sweetening process. In general, most acid gas blends contain at least 40% H₂S, and often the fraction of H₂S in the injection gas is considerably greater than this value. At the majority of downhole injection conditions, most acid gas stream blends are injected and would be typified as a supercritical fluid phase. Supercritical phases are considered to be either dense gases or light liquids, but result in considerable compression of the surface volume of the acid gas phase. This results in a considerable reduction in volume of the gas injected at the surface vs that injected downhole (much more so than would occur in a conventional lean gas injection operation). Figures 1-3 provide an illustrative data set on this phenomena showing the relative gas formation volume factor (unit volume of sour gas at downhole injection conditions vs the equivalent volume of the same amount of gas at surface conditions of 101 kPa and 15.5°C) for mixtures of 40, 60 and 80% H₂S (balance being CO₂, calculated via equation of state). This fact also has considerable impact in the eventuality of a blowout of a sour gas disposal well as a huge volume of potentially lethal gas can be contained in a relatively small reservoir radius as a compressed supercritical liquid phase.

Because of their supercritical nature, sour gas streams can also exhibit relatively high densities and apparent viscosity in comparison to conventional hydrocarbon gases, rendering them more difficult to inject than conventional lean gas. Conventional cubic equations of state can result in some errors with respect to the correct prediction of the properties of sour gas mixtures. Mohsen-Nia et al and Gu et al provide details on modified simple and complex equation of state techniques to accurately predict the volumetric properties of acid gas systems.
RESERVOIR SELECTION CRITERION

One of the major concerns with respect to acid gas disposal zone selection is the ability of the formation to isolate the injected gas and prevent it from migrating into other producing zones or into groundwater sources where significant contamination could be an issue.

Containment issues generally fall into two categories, these being: competent caprock above and, in some cases, below the injection zone, and areal containment. Many of the criteria for investigating containment for acid gas injection zones are similar to the analogous design of gas storage reservoirs. Sealing caprock above the injection zone should have a threshold entry pressure for gas of a minimum of 7000 kPa (this is the pressure when gas can first start to infinitesimally invade the caprock matrix when it is fully saturated with water), and an absolute liquid permeability of less than 10^-6 mD (1 nanoDarcy). Obviously, injection pressures nearing or exceeding the fracture pressure of the formation/caprock are unacceptable as this may result in a loss of containment of the sealing reservoir cap. In general, bottomhole injection pressures are constrained at a maximum value of 80% of the most conservative fracture gradient estimates, but this value may vary (often towards lower pressures in the interests of safety) in many situations as required by legislation as defined by local regulatory agencies. Caprocks which are tectonically stressed may exhibit suitable low permeability matrix properties, but naturally existing vertical fractures through the caprock may render it non-viable as a sealing barrier to injected gases. The presence of natural fractures or high permeability streaks within the formation may improve injectivity, particularly in low permeability formations, but may create problems with rapid areal spread of the injected acid gas. Compositional numerical simulation studies, coupled with an accurate geological model of the injection zone, can be a useful tool in predicting the speed and extent of acid gas spread in an injection operation.

Typically, reservoirs selected for injection fall into the following categories:

Re-injection into the producing interval. This provides the advantage of a limited degree of pressure support (not usually significant due to the high formation volume factor associated with the supercritical injection state of the injected rich acid gas). The rich nature of the injected gas can also act as a low IFT/miscible/near miscible displacement solvent in some cases if temperature, pressure and oil gravity conditions permit (a fact discussed in greater detail later in the paper). Breakthrough of a high H2S concentration gas at a producing well is a potential concern in this scenario, in addition to some of the other previously mentioned issues.

2. Re-injection into a depleted gas leg. This likely provides the maximum injectivity (due to the high pre-existing gas saturation) and minimum compatibility issues. High potential mobility of the injected gas may also be a concern in this case.

3. Re-injection into an oil leg, depleted oil-bearing strata or a depleted sub-dewpoint rich gas reservoir which contains a trapped liquid hydrocarbon saturation. All of these injection scenarios, in addition to the potential adverse relative permeability effects which may be associated with the presence of the trapped immiscible liquid hydrocarbon saturation, may also encounter potential difficulties due to swelling, mobilization of or de-asphalting of the trapped hydrocarbon phase by acid gas contact.

4. Re-injection into a wet aquifer zone. This technique involves potential adverse relative permeability effects and requires detailed knowledge of the solubility of the injected gas in the contacted water and potential dissolution/precipitation issues associated with the creation of carbonic/sulphuric acid.

RESERVOIR LITHOLOGY CONCERNS

Generally, disposal formations will consist of quartzose sands, limestone or dolomite or a mixture of one or more of these types of facies. Injection of acid gas contacted water, or subsequent contact of the injected acid gas with connate water results in disassociation of the gas into the aqueous phase and the creation of weak carbonic or sulphuric acid and a significant reduction in pH. Reduction of pH may result in short/long-term dissolution of soluble limestone/dolomite matrix and cements and compatibility/precipitation issues with in-situ connate
waters. The partial dissolution of matrix/cementing constituents in the near injection well region may also release insoluble encapsulated fines which could migrate. Dissolution may, in some cases, cause increases in permeability which may enhance injectivity. Figure 4 provides an illustration of these phenomena. The combination of H₂S and water can also raise concerns over significant corrosion of downhole injection equipment with respect to sulphide stress cracking and conventional weight loss corrosion. Other authors have also discussed required casing and tubing design considerations for sour and acid gas injection conditions.

In clastic formations, pH induced dissolution is less problematic, although many clastic formations may contain potentially soluble carbonate-based cements which may be eroded by acid gas contact.

RESERVOIR PHASE BEHAVIOUR CONCERNS

Phase behaviour concerns with sour gas injection fall into a number of categories, these being:

1. Single phase injection conditions
2. Hydrate formation
3. Acid gas solubility in injected/in-situ water
4. Acid gas solubility in in-situ oil/condensate
5. Precipitation of elemental sulphur

Injection Conditions - The rich nature of many acid gas streams results in a phase transition from gas to liquid or supercritical liquid over the normal range of compression conditions. This can result in problems and issues associated with multiphase conditions being present in the compression system (cavitation and erosion). The appropriate temperature conditions prior to compression can ensure that the acid gas stream is supercritically compressed which may avoid a two-phase transition during injection.

Hydrate Formation - Gas hydrates are ice crystal-like compounds that can form when rich acid gas streams are contacted by water. Hydrates belong to a group of substances known as clathrates which are compounds containing two or more components joined by the complete enclosure of one compound by the other rather than a conventional chemical bond. Gas hydrates are inclusion compounds in which certain molecular mass gaseous molecules stabilize "cages" formed by hydrogen bonded water molecules at certain temperatures and pressures. Acid gases such as CO₂ and H₂S have been documented to stabilize two separate types of hydrate structures which can result in plugging of both surface and downhole equipment. The plugging nature of hydrates in natural gas and acid gas systems has long been recognized and documented. In most deeper formations, downhole temperatures may be sufficient to counteract hydrate formation resulting in this being primarily an uphole problem. Dehydration of the acid gas prior to injection or use of hydrate suppressants (ie. certain alcohols) are common solutions to this problem.

Acid Gas Solubility in Injected Water and Sour Water Injection - Acid gas injection is normally conducted in two ways: direct injection, or solubilization of the acid gas in produced or source water in a high pressure contacting tower on the surface, followed by subsequent injection of the sour water. In both cases, an understanding of the solubility of the injected gas in the injected or in-situ water phase is essential in order to quantify the speed of migration of the injected gas (in a direct injection scheme) and to design the contacting apparatus and determine injection volumes of water required to effect disposal in a sour water disposal scenario.

Sour water injection has advantages and disadvantages in comparison to direct injection. The technique results in better containment of the sour gas as it is dissolved in the injected aqueous phase and, excepting diffusive forces which act very slowly in porous media, the sour water moves only as the injected phase spreads into the reservoir. This also lessens safety concerns with respect to rate of release and volume of release in the event of blowout of a sour disposal well. Compression costs are reduced, as the effluent is pumped down the well as a liquid phase using conventional equipment (with appropriate corrosion inhibition). Disadvantages include concerns about corrosion in the surface and injection equipment, hydrate in the contacting equipment, cost and safety of the surface contacting equipment, and the fact that the phase behaviour of the sour water must be precisely determined to ensure that sour gas is not liberated from solution as temperature increases as the fluid is heated by contact with the formation. The water-contacting process also suffers from...
the fact that it is not a perfect method for removal of acid gases and preferentially tends to adsorb \( \text{H}_2\text{S} \) over \( \text{CO}_2 \). A relatively large volume of water is also required to dissolve an acid gas stream of any appreciable volume. The technique can still be advantageous in systems where a large volume of produced water is available and must be disposed in any event, and can be used as a technique to extract a large fraction of the sour gas component from a rich acid gas stream. This reduces the cost, volume and \( \text{H}_2\text{S} \) content of the remaining residual gas which subsequently will be processed by more conventional means.

**Solubility of acid gases in aqueous solution is a function of the following parameters:**

- Acid gas composition
- Contacting pressure
- Contacting temperature
- Water salinity

Solubility increases with increasing \( \text{H}_2\text{S} \) concentration and increasing pressure (although solubility generally levels out near the critical pressure of the mixture (about 7000-10000 kPa). Solubility is reduced by increasing temperature and increasing salinity of the contacted water. Figure 5 provides an illustration of the solubility of pure carbon dioxide in fresh and salt water at various pressures at 100°C. There are virtually no published data on the solubility of mixtures of acid gases in water. Table 2 provides a summary of some limited selected solubility data available for different concentrations of acid gases at various temperature and pressure contacting conditions. Detailed experimental solubility studies should be conducted prior to any acid gas injection study. This will quantify the compatibility and expected solubility of the target acid gas stream in the specific aqueous phase present in the reservoir or contemplated for co-injection.

Problems may be associated with solubility of hydrogen sulphide into water. Water solutions containing \( \text{H}_2\text{S} \) are not stable and reaction with adsorbed oxygen can cause the precipitation of elemental sulphur\(^2\) and turbidity. This may result in plugging of the injection zone by the suspended solid precipitate. The turbidity can be reduced by filtration or stabilized with various inhibitors (ie. glycol), but both techniques may increase the cost of the injection operation significantly thus reducing the economic viability of the sour water injection operation.

**Acid Gas Solubility in In-Situ Hydrocarbons** - Rich acid gases exhibit extreme solubility in liquid hydrocarbons at elevated pressures (gas-oil ratios of acid gases in hydrocarbons, particularly light condensates, can be in excess of 300 \( \text{m}^3/\text{m}^3 \)). Solubility of pure \( \text{CO}_2 \) in 40° API gravity oil at 100°C is provided in Figure 5. Many potential injection zones contain a residual mobile or immobile liquid hydrocarbon saturation. This would include depleted oil reservoirs, transition zones containing an immobile oil saturation, waterflooded zones at a residual oil saturation, depleted gas reservoirs containing an initial irreducible or sub-irreducible oil saturation, and depleted retrograde condensate gas zones containing a trapped irreducible or sub-irreducible critical condensate saturation. Two potential concerns arise with respect to the contact of these hydrocarbon liquids with the acid gas as follows:

**Compatibility** - Many oils may de-asphalt when contacted with diatomic gases such as \( \text{CO}_2 \) and \( \text{H}_2\text{S} \). The precipitation of granular solid asphaltene can lead to plugging of the pore system and restricted injectivity in the near wellbore region. If injection into a zone containing liquid hydrocarbons is contemplated, detailed compatibility testing should be conducted between the live hydrocarbon liquid and the proposed injection gas over the range of expected downhole injection conditions to ensure that destabilization asphaltene from the liquid hydrocarbon phase does not occur.

**Swelling** - Due to the extreme solubility exhibited by rich acid gases in most hydrocarbons a large formation volume factor increase (expansion of the size of the liquid hydrocarbon phase) occurs when the acid gas contacts the insitu oil. If pressure is sufficient, the acid gas may actually be miscible with the insitu crude which will result in miscible displacement of the residual oil saturation away from the wellbore area, potentially creating an advantageous increase in relative permeability to the injected acid gas and an increase in injectivity. In many situations, the composition of the acid gas, liquid hydrocarbon gravity and downhole temperature and pressure conditions are not conducive to the establishment of miscibility. In this situation, a portion of the injection gas is absorbed into the trapped liquid hydrocarbon phase,
causing a large increase in formation volume factor of the oil. Figure 6 provides a pressure-composition diagram for a typical insitu retrograde condensate phase with a molecular weight of approximately 110 when contacted with a 50% H2S/50% CO2 acid gas stream at 10000 kPa and 60°C. It can be seen at the saturation point (ie. point where the saturation pressure of the liquid is equivalent to the injection pressure of 12000 kPa representing the maximum degree of swelling expected to occur) that an increase in condensate volume of over 27% occurs due to solubility effects.

If the expanded oil saturation is already at the irreducible level, the problem may not be significant. When the oil saturation expands, it is basically akin to increasing the oil saturation, and the portion of the increased liquid hydrocarbon saturation in excess of the irreducible value should be mobilized and displaced deeper into the formation. Problems may occur if the original oil saturation is relatively small and is at a subirreducible level. This often occurs in depleted gas condensate reservoirs or some gas reservoirs which have been created by gas migration over geological time into previously oil bearing strata. As the liquid saturation increases in value, it still remains below the irreducible value and hence is not mobilized, but expands and occludes space previously available for gas to be injected. The end result can be a significant reduction in gas phase injectivity if the configuration of the gas phase relative permeability curve is very steep at low liquid saturation values. Figure 7 provides an illustration of this phenomena.

This problem is very difficult to diagnose without direct field or lab testing. Conventional gas-liquid relative permeability curves can provide some insight, but the parameters and configuration of normal gas-liquid relative permeability curves are generally significantly altered when considering an acid gas-oil or acid gas-water system. Dissolution of the acid gas in the liquid phase significantly reduces its viscosity (by an order of magnitude or more for some hydrocarbon liquid systems) and also can substantially reduce interfacial tension between the gas and liquid phases.

POTENTIAL SIDE BENEFITS

Acid gas re-injection may have potential side benefits in addition to the direct disposal of unwanted sour gas. Some of these factors have been alluded to previously, but will now be discussed in greater detail. They include:

Potential Stimulative Nature Caused By Carbonate Dissolution - In the absence of adverse precipitation effects and dissolution induced fines mobilization and plugging, long-term acid injection may actually improve injectivity in some disposal wells due to low pH induced dissolution effects.

Desiccation - In most direct acid injection projects, the injected acid gas will have been dehydrated to minimize hydrate problems at surface. Due to higher downhole temperatures, hydrate formation will likely not be problematic, but the dry nature of the injection gas may result in a gradual desiccation of the trapped irreducible or connate water saturation from the region adjacent to the injection zone. This is analogous to a phenomenon which often occurs during injection of conventional dry gas into gas storage reservoirs. The reduction in initial water saturation can cause an increase in injectivity due to a lessening of adverse relative permeability effects associated with the presence of the initial water saturation in the porous media. This effect may also be damaging if the insitu water being desiccated is highly saturated with soluble salts (for example, in a typical deep carbonate formation). Desiccation of fluid by the injection gas results in precipitation of these soluble salts within the pore system which may have a counteracting effect on the expected increase in permeability due to water saturation removal, depending on the location of the re-precipitation within the pore system.

Limited Or Full Miscibility with In-situ Oil - Most acid gas streams represent excellent miscible injection solvents (from a phase behaviour point of view) and very low or zero interfacial tension can be obtained with these gases with many oils at relatively low pressures. This makes these gases potential EOR injectant candidates for the miscible displacement of oils (which are generally in and of themselves already sour). Due to the supercritical nature of the gas, actual volume available for injection is usually too small to be an effective consideration for voidage
replacement for an EOR process. Situations do exist, however, where the rich acid gas, extracted from produced solution gas from a large oil reservoir or directly from a sour gas reservoir, could be used to miscibly inject into adjacent smaller oil pools or isolated zones of the source oil pool. Detailed lab and numerical studies would be required in this situation to confirm miscibility with the in situ crude, pressure required to maintain low IFT/miscibility and potential compatibility concerns with the gas-crude system and injectivity issues as discussed previously. Contingency plans for premature ultra-sour gas breakthrough at a producing well are also a necessity in this situation.

SCOPING PROCEDURES FOR THE DESIGN AND IMPLEMENTATION OF AN ACID GAS INJECTION PROJECT

This section of the paper discusses the specific tests which should be conducted to quantify acceptability of an proposed injection or disposal zone for acid gas injection. The tests fall into three categories:

1. Phase behaviour/fluid-fluid compatibility
2. Rock-injection fluid compatibility
3. Reservoir containment and mobility

Concerning Sour Acid Gas Laboratory Studies

For any acid gas experimental procedure extreme safety precautions are required due to the corrosive and toxic nature of the gas. Hastelloy or Monel equipment is required to obviate corrosion problems, and the tests should be conducted in a sour rated isolation lab with floor level suction, incineration of the produced gas stream from the lab, continuous H₂S monitoring, remote camera sensing and equipment operation, self-contained or umbilical breathing apparatus for test operators. All personnel should be fully trained with respect to the handling of toxic and lethal H₂S gas.

Phase Behaviour and Fluid-Fluid Compatibility

Water Solubility

Figure 8 provides a schematic of the apparatus used to determine acid gas solubility in aqueous solutions. Because acid gases are preferentially soluble in aqueous solutions over other natural gas components, a specialized continuous contact procedure must be evaluated to ensure that the maximum solubility number is evaluated, rather than simply attempting to compress a given volume of whole injection fluid into a set volume of water.

The test procedure consists of dynamically contacting a large volume of injection acid gas of the specified compositions with water of the salinity proposed for injection, or to be contacted in the injection interval. The contact test is conducted at either the surface contacting pressure and temperature (if scoping for an acid water injection scheme is contemplated), or at estimated average bottomhole injection conditions that will occur in the injection or disposal zone if a direct injection technique is contemplated. This contacting generally occurs for several hours/days by flow through the aqueous phase in a countercurrent fashion in a packed column assembly with subsequent evaluation of the solubility of the resulting equilibrium saturated brine phase.

Once a saturated condition is achieved, the acid gas saturated aqueous phase can be evaluated for:

- total acid gas solubilized (m³/m³)
- composition of the acid gas components which are selectively absorbed
- turbidity and compatibility
- size and concentration of any destabilized precipitates
- pH for dissolution, corrosion and scaling calculations

Hydrocarbon Solubility

If a sample of the liquid hydrocarbon phase which is present in the reservoir can be obtained, a multiple contact swelling test should be conducted on the hydrocarbon liquid to evaluate:

- degree of solubility of the acid gas in the hydrocarbon phase at downhole temperature and pressure conditions
transitions or precipitation points which would not normally be apparent with conventional normal visual observations. New state-of-the-art acoustic resonance equipment is currently being developed to assist in these measurements which will provide an new level of technology for detecting difficult phase transitions associated with some of these phenomena.

Rock-Fluid Interactions

A major concern in any acid gas or acid water injection operation is ensuring that we maintain sufficient injectivity to dispose of the volume of fluid required, and this injectivity is not compromised over a period of time by incompatibility issues. Reductions in injectivity will lead to increased injection pressures which increase costs and safety concerns at the surface. In addition, if injection pressures are increased to fracture levels, containment of the acid gas or water in the zone of interest may be compromised with potentially disastrous results. Therefore, it is essential that proper design and evaluation of the efficacy of the injection operation into the zone of interest is evaluated prior to implementing the process. This is generally conducted through a series of laboratory coreflow tests using preserved or restored state core material from the zone of interest for injection.

Figure 9 provides a schematic illustration of a typical multiple contact sensitivity apparatus used to determine these parameters. The measurement of acid gas-liquid hydrocarbon interfacial tensions at downhole conditions may also be of interest to quantify the degree of miscibility obtained. This apparatus is illustrated in Figure 10.

Acid Gas Phase Behaviour and Stability

These tests are normally conducted to ensure that over the range of conditions expected during the compression and injection operation, the acid gas stream remains in a single phase and the precipitation of elemental sulphur does not occur. Figure 11 provides a schematic of a typical visual cell laser system used for these types of tests. Gas of a specific composition is charged into the visual cell system, and the pressure and temperature then varied over the range of potential operating conditions. If phase transitions or precipitation occurs, the optical refraction and dispersion characteristics of the acid gas phase are altered. This can be detected with the laser to pinpoint phase transitions or precipitation points which would not normally be apparent with conventional normal visual observations. New state-of-the-art acoustic resonance equipment is currently being developed to assist in these measurements which will provide an new level of technology for detecting difficult phase transitions associated with some of these phenomena.

It is essential that the core material be at the correct initial saturation and wettability conditions. Preserved core (if such can be obtained with unaltered original saturations) is preferred but, in most cases, restored state core material must be utilized due to a lack of available preserved state core. If restored state core is used, documented wettability restoration and saturation institution procedures should be
utilized. The core is azeotropically cleaned prior to restoration (to remove any residual salts or oxidized hydrocarbons), and the correct initial oil and water saturations are instituted and uniformly dispersed in the media, and appropriate aging time is allowed for wettability equilibria to be established. Offcut end sections of the core plugs being tested are generally subjected to the pre-test thin section, scanning electron microscope and XRD analysis to characterize the "pre-injection" unaltered rock matrix. If a significant increase or decrease in injectivity is noted, the use of post-test petrography on the actual post-injection stack can quantify the exact mechanism of the permeability alteration through comparison with pre-test analysis.

The core displacement tests are conducted at downhole conditions of temperature, pore pressure and overburden pressure so that the correct solubility and dissolution effects of the acid gas contact on the matrix and insitu fluids are duplicated.

Most tests are initiated with a reservoir condition baseline measurement of unimpaired injectivity. If an acid water project is evaluated, permeability at full reservoir conditions to formation water is measured on the sample. If an acid gas injection scheme is evaluated, permeability to a non-reactive gas (generally humidified methane or nitrogen) is determined to obtain the baseline injectivity. In addition to providing the baseline permeability value, these measurements also provide a good estimate of true insitu permeability of the matrix in the proposed injection zone for injectivity calculations. Obviously, if fractures or high permeability laminations are present in the injection zone, overall injectivity may be underestimated using this technique, but in general it provides a conservative approach to the evaluation of the potential injectivity of the target zone.

Sensitivity to the acid gas or water is then evaluated by switching the injection fluid over to either the sour gas or water stream and continuously injecting 100-500 PV of this fluid through the sample over an extended (2-10 day) period while continually tracking injectivity. In most tests, once the injection has been completed, the displacement fluid is switched back to the non-reactive baseline fluid, and the permeability remeasured to obtain a final value with a fluid of rigidly known parameters to confirm a stimulation or reduction in permeability. In some cases, to evaluate extended contact of the acid gas/water, a shut-in period in a static mode of several days/weeks is used midway in the exposure period of the test.

Table 3 provides a normalized dataset for the results of several direct acid gas injection experiments in sandstone and carbonate (dolomite) formations. Some of these tests were conducted in the presence of irreducible condensate saturations in the rock. Figure 13 provides a plot of the transient permeability profiles for the acid gas injection phases for the various tests.

In general, it can be seen that in most cases significant problems with reduced injectivity were not apparent and in many cases, slight increases in permeability were observed. These increases in permeability were mostly due to a desiccation of a portion of the connate water saturation from the injection zone by the large volume of desiccated acid gas injected.

In the cores which had condensate saturations, some transient permeability reductions were observed due to expansion of the condensate saturation, but it appears that subsequent vaporization/displacement or pH induced dolomite dissolution counteracted this initial effect, negating the majority of the effect in the long-term. It is expected in a lower permeability matrix that this damage would be more severe.

For the two samples which exhibited significant damage, post-test petrography indicated that the plugging mechanism was the migration of insoluble pyrobitumen flakes which had been apparently loosened by acid gas contact, possibly by dissolution of carbonate based cements in the matrix by the acid gas contact. This would possibly indicate some sensitivity of zones containing pyrobitumen to acid gas injection, but the available dataset is too small to come to a definitive conclusion in this aspect.

In general, when reductions in permeability occurred the majority of the change occurred in the first 10-20 PV of injection, suggesting that in the field, rapid reductions in injectivity could potentially occur if a situation of incompatibility existed.
Reservoir Containment and Mobility

Tests must be conducted to verify that the injected acid gas will be entirely contained in the injection/disposal zone of interest. This normally involves documented procedures to quantify the sealing capacity of the caprock above the zone (vertical fluid permeability of less than 10^-4 mD and a threshold entry pressure for gas in excess of 7000 kPa). Detailed geological studies may also be required to ensure that natural fractures or high permeability laminae will not result in the rapid migration of the acid gas/water out of or to undesired locations in the injection/disposal zone.

CONCLUSIONS

Acid gas or water injection has proven to be a viable technology for the disposal of large volumes of waste acid gas. Detailed studies need to be undertaken to quantify the proper process and location of the injection/disposal zone and to minimize risk due to poor containment of the acid gas or impaired injectivity. Potential concerns with fluid phase behaviour, solubility and compatibility with the injection zone matrix can be evaluated in the laboratory to optimize the acid gas injection process and reduce operator risk.

ACKNOWLEDGEMENTS

The authors express appreciation to Maggie Irwin and Vivian Whiting for their assistance in the preparation of the manuscript and figures.

REFERENCES


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### TABLE 2
**ACID GAS SOLUBILITY IN INJECTION/FORMATION BRINES**

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</tr>
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<td>30 % CO₂</td>
<td>70 % CO₂</td>
<td>15</td>
<td>500</td>
</tr>
<tr>
<td>30 % H₂S</td>
<td>70 % CO₂</td>
<td>15</td>
<td>7000</td>
</tr>
<tr>
<td>70 % H₂S</td>
<td>30 % CO₂</td>
<td>45</td>
<td>14000</td>
</tr>
</tbody>
</table>
TABLE 3
NORMALIZED INJECTIVITY RATIOS FOR POROUS MEDIA
ACID GAS INJECTION TESTS
(Tests conducted at representative reservoir temperatures ranging from 40-80°C using acid gases containing 30-65% H₂S)

<table>
<thead>
<tr>
<th>Pore Volumes of Acid Gas Injected (Cuml)</th>
<th>Injectivity Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>T#1</td>
</tr>
<tr>
<td>0.5</td>
<td>1.00</td>
</tr>
<tr>
<td>1.0</td>
<td>1.07</td>
</tr>
<tr>
<td>1.5</td>
<td>0.93</td>
</tr>
<tr>
<td>2.0</td>
<td>0.94</td>
</tr>
<tr>
<td>4.0</td>
<td>0.65</td>
</tr>
<tr>
<td>6.0</td>
<td>0.54</td>
</tr>
<tr>
<td>8.0</td>
<td>0.45</td>
</tr>
<tr>
<td>10.0</td>
<td>0.42</td>
</tr>
<tr>
<td>15.0</td>
<td>0.40</td>
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<tr>
<td>20.0</td>
<td>0.37</td>
</tr>
<tr>
<td>30.0</td>
<td>0.37</td>
</tr>
<tr>
<td>50.0</td>
<td>0.37</td>
</tr>
<tr>
<td>100.0</td>
<td>0.35</td>
</tr>
</tbody>
</table>

Legend

Test 1 - Sandstone sample containing pyrobitumen, moderate permeability at initial Swi with no oil saturation, permeability reduction believed to be due to dissolution of carbonate cements and mobilization and plugging by pyrobitumen fines.

Test 2 - Sandstone sample, moderate permeability, simulating an oil saturated zone. Permeability to gas increases rapidly as oil is miscibly displaced from the sample by the low IFT acid injection gas.

Test 3 - Very low permeability intercrystalline carbonate at initial water saturation with no oil present. Dissolution and plugging effects were caused gradually by acid gas injection.

Test 4 - Carbonate, moderate permeability, initial water saturation present, oscillations in permeability indicate some potential dissolution and migration effects, final slight stimulation likely due to desiccation of the initial water saturation caused by long-term acid gas injection.

Test 5 - Carbonate, moderate permeability, contained initial water and irreducible retrograde condensate saturation. Transient reduction in permeability at low PV of gas injected believed to be due to expansion and subsequent mobilization of the portion of the trapped condensate saturation.

Test 6 - Sandstone, moderate permeability, initial water saturation with no oil present, slight stimulative effect may be due to desiccation effects caused by long-term acid gas injection.
FIGURE 5
SOLUBILITY OF CARBON DIOXIDE vs PRESSURE FOR WATER, OIL, AND SALT WATER @ 100°C

FIGURE 6
SOLUBILITY OF ACID GAS IN IN-SITU OIL

Test Conducted on 50/50 H2S/CO2 Mix
@ 9500 kPa & 75°C

FIGURE 7
ILLUSTRATION OF PERMEABILITY REDUCTION DUE TO THE EXPANSION OF A SUBULTRAREDUCTIBLE LIQUID HYDROCARBON SATURATION DURING AN ACID GAS INJECTION PROCESS

FIGURE 8
ACID GAS SOLUBILITY IN AQUEOUS SOLUTION APPARATUS

SI = Initial Permeability
SF = Final Permeability
SI = Initial Permeability after saturation of the oil phase by acid gas contact

To Gasometer
Oven

Injection Piston
Collection Piston

Contacting Column

Gauge

Hg injection to displace contacted water for analysis
FIGURE 13
EFFECTIVE INJECTIVITY RATIO (K/K)
INJECTIVITY RATIO vs PV OF GAS INJECTED