

Zama Acid Gas Disposal/Miscible Flood Implementation and Results

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Abstract

During 1994, Pennzoil Canada, Inc. entered into an agreement with Novagas Clearinghouse Ltd. (NCL) to re-inject the waste gas produced at their newly constructed Zama gas compression/processing facility. Figure 1 highlights the project location.

This paper will provide a general overview of the design, implementation, operation, and available results of this acid gas disposal/miscible flood project. Approval to inject 70 10³m³/day waste gas was received from the EUB in March 1995. Injection limits were increased (August 1995) to 120 10³m³/day which made the Zama acid gas system the largest in Canada. The acid gas (60% CO₂ and 40% H₂S) is being injected into the Zama Keg River "X2X" Pool (a previously waterflooded reef). Re-injecting the acid gas has several significant upsides. The immediate benefit is reduced atmospheric emissions. This one project is a significant contributor to CAPP's Climate Change Voluntary Challenge Committee. Additional benefits include tertiary crude oil reserves, subsurface sulphur storage and a more effective use of capital (i.e., compression versus sulphur recovery unit). The acid gas stream (based on theoretical and laboratory work) is miscible under achievable operating conditions. Unfortunately, the use of acid gas as a miscible product has not been widely published. Laboratory work has been required to refine our understanding of the process. The key results are included. Zama has not been an area where miscible flooding was considered an economic alternative (i.e., the reefs are relatively small and isolated). The construction of NCL's plant provided an inexpensive miscible solvent to test the process. The concept has broad applications to other reefs in the Zama area and elsewhere in Alberta.

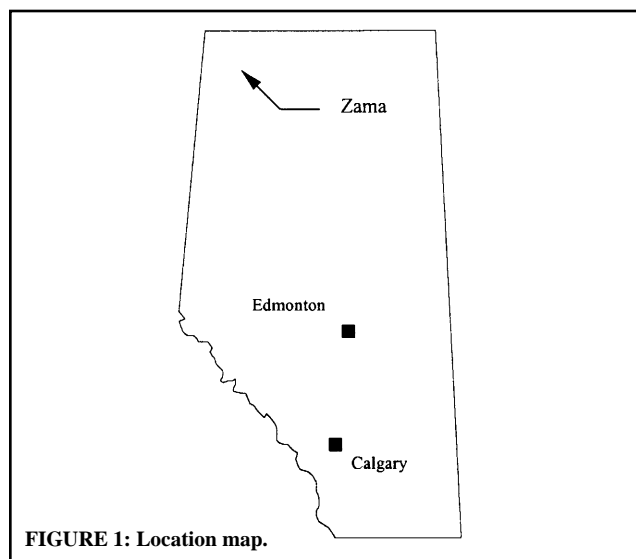


FIGURE 1: Location map.

lying Zama carbonates. Most of the larger pools were found during the early exploration phases and are now in various stages of depletion. Secondary recovery methods (waterflood, pressure maintenance) have met with mixed success. Tertiary recovery methods (gas injection, fireflood, etc.) have been attempted with no success reported to date. Pennzoil had considered miscible flooding as a potential recovery method in the Zama Basin (based on the process's application in the Rainbow Basin). Smaller reef size and miscible solvent availability made the option impractical. When NCL approached Pennzoil with the acid gas disposal concept, it was recognized as an opportunity to test the process and make available a long-term inexpensive, miscible solvent.

The discussion will be organized into three general categories.

1. Non-time specific information
2. The pre-gas injection period (Data up to April 30, 1995)
3. The post-gas injection period (Data from May 1, 1995 to January 31, 1996)

Geological Discussion

The pertinent geological section begins with the middle Devonian, Lower Keg River Platform. This formation consists of tight, dark brown, lime mudstone with scattered crinoid columnals

Introduction

The oil industry as a whole is working towards a more responsible and proactive attitude towards the environmental issues. Pennzoil Canada, Inc. stepped forward to implement a very effective method of dealing with the waste gas produced at NCL's Zama facility (13-12-116-06W6M). The general benefits as outlined previously can be applied at many existing facilities and should be given consideration during the construction of new facilities.

Potential miscibility was another key factor in Pennzoil's decision to participate in the acid gas disposal scheme. The Zama Basin contains a significant number of Keg River reefs with over-

and thin-shelled brachiopod fragments. The Lower Keg River facies is open-marine and has a thickness of approximately 45 m. For reefs without an active water drive the platform provides the lower hydraulic seal. The contact with the overlying Upper Keg River is transitional.

Overlying the Lower Keg River Platform is the light brown Upper Keg River formation which includes the organic reef member. The reef facies consists of common Devonian reef building organisms like tabular and bulbous stromatoporoids and tabulate corals. An upper Keg River reef can reach 115 m in height and is typically dolomitized with variable porosity and permeability. Principle rock types include wackestone, packstone, floatstone and rudstone. Porosity types range from intercrystalline to microfracture with varying degrees of alteration due to secondary leaching (solution enlargement) and dolomitization. Large vugs (greater than 5 cm) are not uncommon, but can be partially occluded by calcite spar overgrowths and/or bitumen. The reef flank is composed of blocks of material broken away from the reef crest. Reefs that display pressure support from an active water drive occur where the lower portion of the Upper Keg River is continuous below the spill point. This connects the oil pool to a large volume of porous, water-bearing Upper Keg River located radially beyond the reef. Well-defined original oil-water contacts (OWC) are identifiable within the Upper Keg River formation. Until monitoring proves otherwise, the original oil-water contact provides the maximum acid gas storage limits.

The Zama Member of the Muskeg formation is an extensive carbonate unit overlying the Upper Keg River pinnacle reefs and the Lower Muskeg anhydrite in off reef locations. It is a medium to dark brown laminated dolomite with relatively abundant amphipora, brachiopods and nodular stromatoporoids when overlying Upper Keg River reefs. In the off reef position, the Zama member grades into a less porous algal laminated mudstone over the Lower Muskeg anhydrite. An argillaceous zone called the "Z Marker" lies approximately within the middle of the Zama member. The carbonate unit has a northwest-southeast strike and regionally dips 6 m/km. It has a gross thickness between 20 and 30 m. On the flanks of the pinnacle reefs, where it contacts the overlying cap rock, the Zama member can drop steeply to a dip of 30 to 40 degrees.

In reef flank positions, the Zama member and the Upper Keg River reef is separated by an increasing thickness of Lower Muskeg anhydrite and dolomite as one moves away from the reef crest. The contact between the Upper Keg River and the overlying

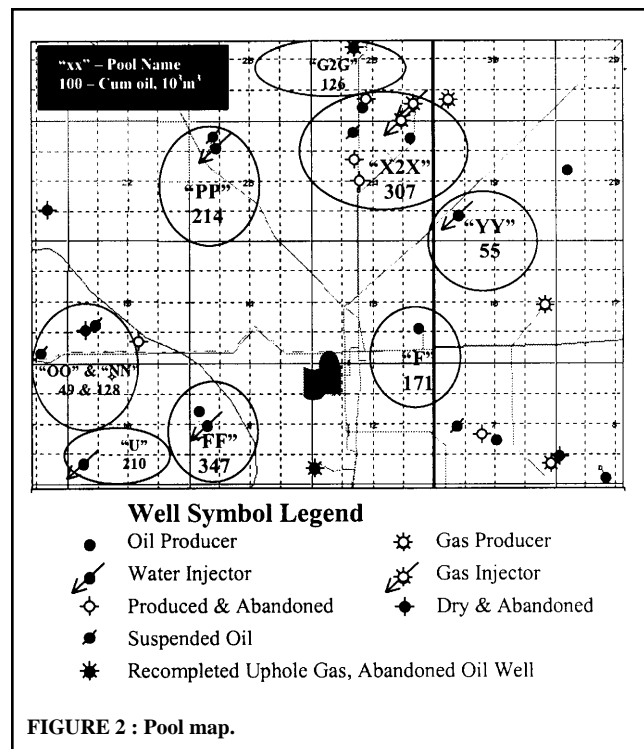


FIGURE 2 : Pool map.

cap rock of the Muskeg formation is sharp and angular. Dips in excess of 35° have been observed on dip metres. Overlying fully developed reefs, the Zama Member sits directly on top of the Upper Keg River reef.

Above the Zama member the Muskeg formation ranges in thickness between 60 and 90 m. The formation consists of white to clear dolomitic nodular and bedded anhydrite with fine to medium crystalline dolostone and laminated dolostone interbeds. Caliper logs show a very competent rock with no indication of fractures, unstable sloughing or permeability (filter cake). Off-reef thickness can increase sharply to over 135 m. The bounding Muskeg formation is laterally continuous and tight with no indication of facies variation or mechanical incompetence. The Muskeg has a northwest to southeast strike and a regional dip of 6.5 m per kilometre.

TABLE 1: Zama oil reservoir comparative summary.

Pool	Locator	Wells	km From Plant	Gross Pay m	Current Oil Rate m ³ /day	Remaining Oil Nov. 1994 10 ³ m ³	Estimated Ultimate Recovery Factor	Minimum Acid Gas Storage No mixing 10 ⁶ m ³	Maximum Acid Gas Storage Miscible mixing 10 ⁶ m ³
KR "X2X"	16-24-116-06W6	2	4.0	28.8	6.7	9.9	36%	157.8	226.1
KR "NN"	05-15-116-06W6	2	3.6	37.4	0.0	0.0	20%	58.0	107.0
KR "OO"	01-16-116-06W6	1	3.8	31.0	0.0	0.0	33%	28.0	67.0
Muskeg "L"	14-01-116-06W6	1	2.0	63.8	0.0	0.0	19%	44.6	75.8
KR "U"	04-10-116-06W6	1	4.0	51.4	0.0	0.0	24%	93.7	179.4
KR "F"	08-13-116-06W6	1	0.8	51.4	0.0	0.0	19%	82.6	179.4
KR "Z3Z"	05-34-115-06W6	1	5.6	57.2	0.0	0.0	30%	73.9	109.9
KR "Und"	10-33-115-06W6	1	6.8	57.2	0.0	0.0	30%	73.9	109.9
Muskeg "AAA"	04-27-116-06W6	1	6.4	105.7	0.0	0.0	28%	67.3	123.5
KR "T4T"	14-26-116-06W6	1	5.6	87.3	0.0	0.0	33%	47.7	76.3
KR "E"	05-02-116-06W6	1	3.2	47.5	0.0	0.0	23%	44.5	86.5
KR "XX"	08-18-116-05W6	1	4.0	67.3	0.0	0.0	19%	43.6	99.0
KR "B2B"	07-07-116-05W6	1	2.4	51.4	3.2	6.9	25%	97.2	179.4
KR "JJJ"	07-10-116-05W6	1	7.2	46.1	7.2	20.2	41%	87.6	91.0
KR "FF"	12-11-116-06W6	2	2.0	86.5	13.5	29.7	29%	158.7	275.3
KR "PP"	13-23-116-06W6	2	4.8	94.3	17.5	40.6	33%	105.1	173.1
KR "VV"	02-35-115-06W6	1	4.0	92.7	9.5	49.1	33%	175.6	290.1
KR "S"	16-09-116-05W6	2	7.2	90.1	19.1	50.6	18%	94.9	180.0

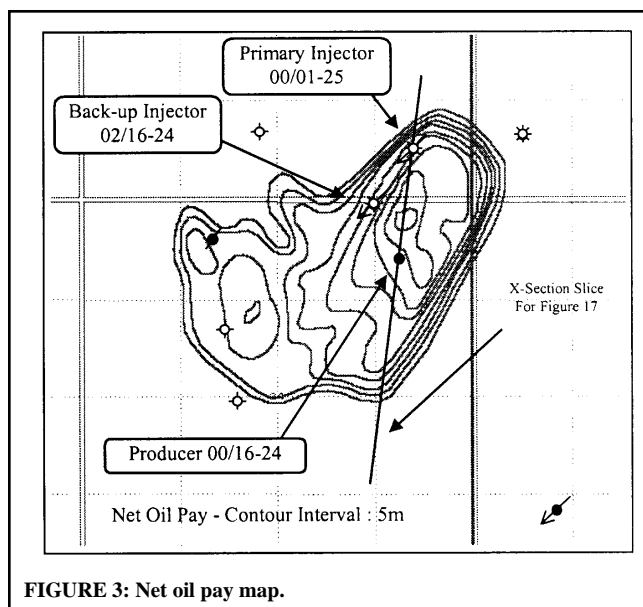


FIGURE 3: Net oil pay map.

Candidate Selection

A number of key factors went into selecting a candidate pool for this acid gas disposal project. Pennzoil required a large reef with multiple wellbores, minimal conversion losses [i.e., primary and secondary (waterflood) reserves have already been produced], 100% ownership, high initial pressures above the minimum miscibility pressure (MMP), within a reasonable radius of the plant site and close to several other reef candidates. Table 1 and Figure 2 outline the main prospects.

A large percentage of candidate reefs were quickly eliminated based on current reservoir pressures. The bigger reefs (in general) do not appear to have full aquifer support and have as a result experienced pressure depletion. Preliminary calculations suggested that the MMP would be somewhere near initial reservoir conditions (subsequently confirmed with laboratory work and discussed later). The Keg River "X2X," "NN," "OO," "F," and "FF" Pools remained after preliminary pressure screening. The Keg River "NN" and "OO" Pools were considered primary candidates but had unresolvable ownership issues and a risk that the pools could not be pressured to the MMP. These were the only pools with strong aquifer support. The Keg River "F" Pool was another excellent candidate but requires additional wellbores to properly operate the acid gas disposal scheme. Water injection had been initiated in the Keg River "FF" Pool to bring reservoir pressures up to the MMP. In the end the Keg River "X2X" Pool was the only pool that satisfied enough criteria. Pennzoil was forced to sacrifice some existing production to properly implement the disposal system. However, the upside benefits of a successful miscible flood were forecast to offset any lost production and reserves.

Zama Keg River "X2X" Pool

The Zama Keg River "X2X" Pool net pay map is shown in Figure 3. Refer to Figure 17 for a stratigraphic cross-sectional view. Net pay was based on porosity and water saturation cut-offs of 3% and 45% respectively. A weighted net to gross ratio of 0.72 was derived from the three deepest wells in the pool. The pool was discovered with an oil-water contact at -1122 mSS and contains under-saturated oil. A 3D seismic program (conducted in 1991) was used to map the pool's structure and produce the net pay map. The pool has an irregular plan with an area of approximately 106 hectares at the oil-water contact. East and west lobes were identified, separated by a north-south trending saddle running through LSDs 10 and 15-116-06W6M. Volumetric original oil-in-place (OOIP) is approximately 844 10³m³. Approximately 80% of the pool's OOIP and virtually all production are contained within the eastern lobe.

TABLE 2: Fluid properties.

Parameter	Value
Initial Pressure	14,479 kPa
Temperature	76 °C
Saturation Pressure	11,928 kPa
Formation Volume Factor	1.281 Rm ³ /m ³
Crude Oil Viscosity	0.801 centipoise
Solution Gas-oil Ratio	57 m ³ /m ³
Stock Tank Oil Density	844 kg/m ³
C ₇₊ Molecular Weight	225 kg/kg-mole

TABLE 3: Reservoir properties.

Parameter	Value
Initial OWC	-1,122 mSS
Latest OWC	-1,102 mSS
Gross Pay	38 m
Average Net/Gross Ratio	0.72
Area at original OWC	106 hectares
Initial Water Saturation	19.2 %
Porosity	7.6 %

Fluid inflow was a problem in the west lobe. Initial rates were economic. However, as reservoir pressure dropped, production quickly became uneconomic. Horizontal technology was being considered to improve the area's productivity, access better porosity reservoir (as indicated on seismic), add a second pressure sink and improve horizontal sweep. The pool's performance was being monitored closely to determine an appropriate time to implement this option.

The "X2X" Pool is interpreted to be a large Keg River complex with the Zama draped over top. The fluid (Table 2) and mechanical rock properties (Table 3) of this complex are similar to other area pinnacles. However, since the relief is gentler, any strain-related fracturing of the Zama member would likely be reduced in the "X2X" Pool. The Zama drape over individual pinnacle reefs is more pronounced and prone to fracturing.

The "X2X" Pool has many characteristics that distinguish it from most other pools in the area. The key differences are outlined below:

- The pool is a Keg River complex versus the typical individual pinnacle reefs common to the Zama Basin.
- The pool has been successfully waterflooded. The estimated recovery factor is ± 36% of OOIP (versus typical primary recovery of ± 25%). Recovery within the eastern lobe is actually ± 42%.
- Disposal operations significantly over-pressured the pool. Reservoir pressure peaked at 26,890 kPag and was gradually reduced to 18,970 kPag prior to additional water injection (in 1991). When acid gas injection commenced, reservoir pressure was approximately 21,550 kPag.
- Most of the hydrocarbons are contained within the Zama member. As a result, the pool has a relatively thin gross oil pay column. The pool's large area (relative to separate pinnacles) compensates for the thinner pay and yields a high OOIP.
- The pool can be configured for both vertical and horizontal miscible flooding. The initial scenario is set up for vertical flooding.
- A total of four wellbores were available for the acid gas disposal scheme.

Pool Production History

The Keg River "X2X" Pool was discovered in late 1968 with the 00/16-24-116-06W6/0 wellbore. Additional drilling added producing wells at 00/14-24 in 1983 and 00/01-25 in 1990. Both

TABLE 4: Production summary.

Cumulative (pre-gas injection)	to April 30, 1995	
Oil Production	307,450	m ³
Gas Production	24.14	10 ⁶ /m ³
Water Production	385,134	m ³
Water Injection	1,330,220	m ³
Gas Injection	0.00	10 ⁶ /m ³
Cumulative (post-gas injection)	May 1/95 – Jan. 31/96	
Oil Production	102	m ³
Gas Production	0.04	10 ⁶ /m ³
Water Production	57,280	m ³
Water Injection	0	m ³
Gas Injection	9.763	10 ⁶ /m ³
Cumulative (combined)	to January 31, 1996	
Oil Production	307,552	m ³
Gas Production	24.18	10 ⁶ /m ³
Water Production	442,414	m ³
Water Injection	1,330,220	m ³
Gas Injection	9.763	10 ⁶ /m ³

wells encountered severely over-pressured zones. By 1990, the oil-water contact had risen 26 m to -1,102 mSS (based on the 00/01-25 well logs). Productivity was high at both wells but dropped off quickly as pressures declined. The 02/16-24 wellbore was drilled in August 1991 as a pilot hole for a horizontal well. Waterflooding had flushed the zone and the wellbore was subsequently abandoned. The pool's production is detailed in Figure 4 and Table 4. To April 30, 1995, the pool had produced 307.5 10³m³ of oil, 385.1 10³m³ of water and 24.1 10⁶m³ of gas. Total offsetting water injection reached 1,330.2 10³m³. The oil cut averaged 6.9% over the last 9 months production.

Pool Pressure History

The Keg River "X2X" Pool has had an interesting pressure history (Figure 5). Original reservoir pressure (at pool discovery in 1968) was approximately 14,700 kPag. Pressures dropped quickly to just over 10,000 kPag. Water injection in an offsetting pool (00/04-19-116-05W6/2, the Keg River "YY" Pool) began in 1970. The "X2X" pressures leveled and began rising around 1975. Pressures peaked in 1988 at 26,890 kPag. Injection was suspended at that time and pressures began declining. Injection was resumed in late 1991 for roughly 1 1/2 years. In addition to the obvious pressure communication with 00/04-19, the "X2X" Pool is also in communication with 00/11-25-116-06W6/0 (the Keg River

TABLE 5: Acid gas properties (60% CO₂).

Parameter	Value	
Specific Gravity	1.38	
Formation Volume Factor	3.0	Rm ³ /10 ³ m ³
Viscosity	0.04	centipoise
Density	490	kg/m ³
Gas Deviation Factor	0.4	

"G2G" Pool) to the north. Material balance calculations confirm the three pinnacles are hydraulically isolated from other reefs in the area.

General Waterflood History

The production/pressure histories outline the positive effects of offsetting water injection [i.e., pressure maintenance/enhancement and incremental recovery (± 11% of OOIP)]. Unfortunately, the water injection at 04-19 has historically been viewed as water disposal. An in-depth analysis of water flow patterns within the reservoir is not available. Regardless, establishing waterflood sweeps/flow paths in these Zama/Keg River complexes is extremely difficult. The Zama and Keg River formations are separate zones that in some areas are in communication. The degree of communication varies from 0 – 100% within the basin. Since the Zama formation is laminated by nature, water will preferentially flow along the laminae (i.e., horizontally). The OOIP (within the "X2X" Pool) is contained primarily in the Zama formation. As a result, horizontal displacement should play a major role in any displacement scheme. Lateral displacement through deep saddles [like the one that exists between 04-19 (the injection well) and the "X2X" Pool] is questionable. The Zama formation tends to be non-reservoir in the lows. This point provides a geological reason suggesting Keg River/Zama pressure communication.

Pressure/production information also points toward Keg River and Zama pressure communication. Injection was limited to deep within the Keg River formation between September 1970 and September 1976 [i.e., the 04-19 well was dually completed as a producer (from the Zama) and injector (in the Keg River) during this period]. Pressure declines were still arrested in both 00/16-24 and 04-19. The Keg River and Zama have to be in pressure communication for this to occur. The peak oil production also occurred during this period. The oil production profile reacts more like bottom water drive than a waterflood (i.e., an oil bank formation is not evident). Changes in oil production are just reflecting changes in overall fluid production. As water cuts increase, fluid rates are increased and the oil production is maintained or declines are minimized. The increasing reservoir pressure is directly responsible for the rising fluid rates.

The project was designed as a disposal project first and a misci-

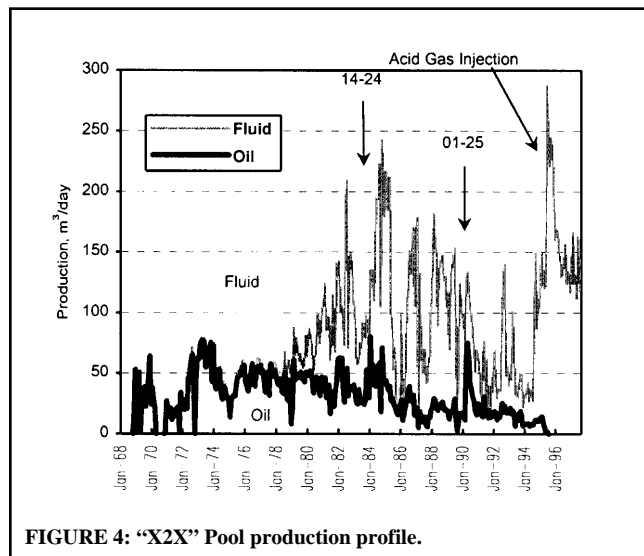


FIGURE 4: "X2X" Pool production profile.

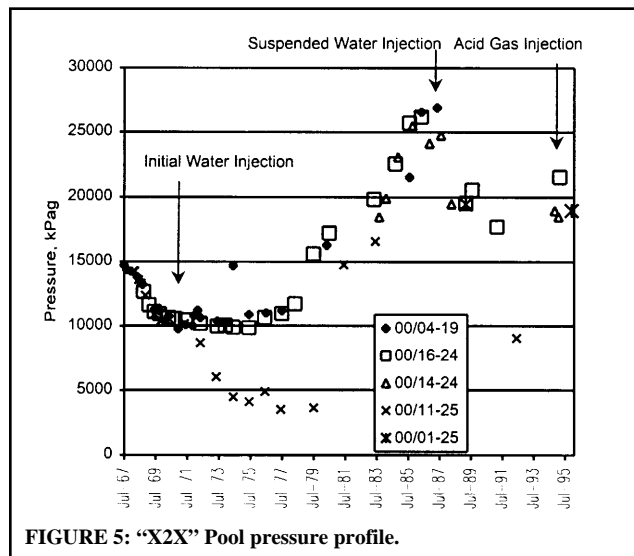


FIGURE 5: "X2X" Pool pressure profile.

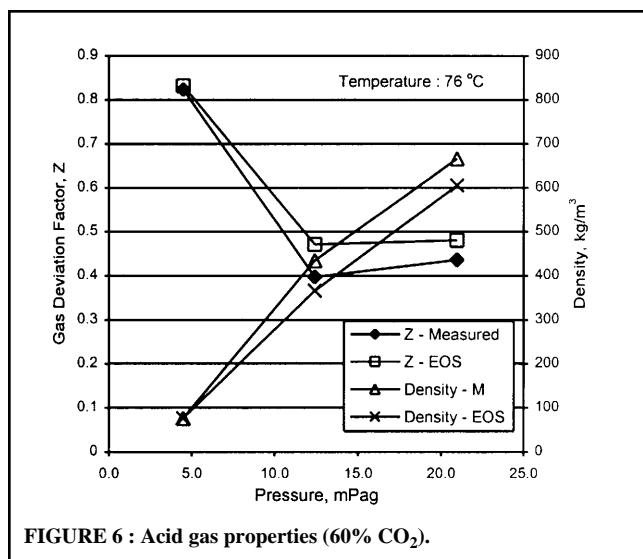


FIGURE 6 : Acid gas properties (60% CO₂).

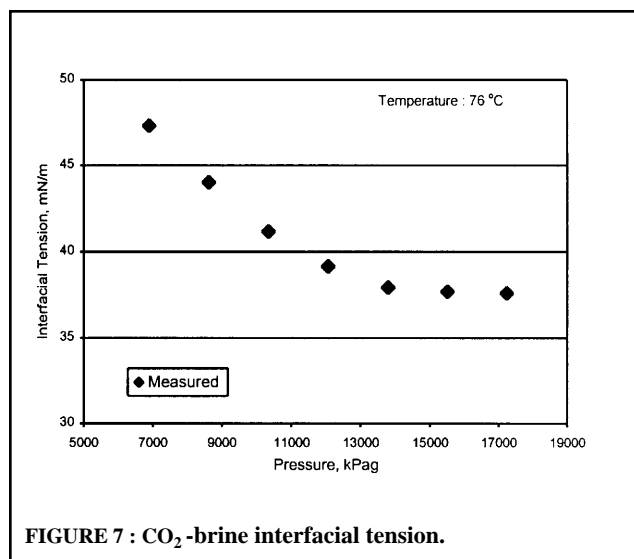


FIGURE 7 : CO₂-brine interfacial tension.

ble flood second. Vertical displacement would be the most efficient and cost effective alternative if technically feasible. The vertical flood was being monitored to determine vertical displacement efficiency. A lateral displacement scheme was contemplated and was to be considered at a future date (if necessary).

Literature Search

A literature search uncovered only two projects where acid gas has been used as a solvent in a tertiary recovery project. The literature contained no Canadian analogues.

The Slaughter Estate Unit in West Texas operated by Amoco Production Company⁽¹⁾ began in 1976. After a search for pure CO₂ was unsuccessful, an available feed consisting of 72% CO₂ and 28% H₂S was proven to be miscible in the laboratory and an eight well, water alternating gas (WAG) pilot was initiated. Tertiary miscible response was noted the following year. A 26% hydrocarbon pore volume slug was immediately followed by a similar volume of nitrogen chase gas (commencing in November 1979). Incremental tertiary recovery was estimated between 20 and 25%. No additional information regarding the termination of chase gas or the final recovery could be obtained.

At the Amoco operated Elk Basin Plant in Northwest Wyoming, an unknown mixture of carbon dioxide and hydrogen sulphide was injected into the Elk Basin Madison oil field over a period of two years⁽²⁾. The two project objectives were to reduce emissions from a forty year old sour service gas plant and to attempt enhanced recovery in the target zone. No performance information was available regarding the success of the operation. Following the termination of injection into the Madison, the acid gas was injected into the Elk Basin Tensleep reservoir in an effort to arrest natural production decline. Again, no details about the operation could be uncovered.

Laboratory Results

Acid gas disposal is not a widely published subject (as shown above). The properties of Pennzoil/NCL's acid gas stream had to be measured and/or verified with laboratory work. The various tests are outlined along with some of the empirical relationships that were also required.

1. Acid Gas PVT Study
2. CO₂-Brine Interfacial Tension Study
3. Cap Rock Capillary Threshold Study
4. Miscible Displacement Study
5. Pressure Temperature Phase Behaviour
6. Acid Gas Solubility in Brine

Acid Gas PVT Study

The acid gas properties are detailed on Figure 6. These plots assume an acid gas composition of 60.9% CO₂ and 38.1% H₂S plus small concentrations of methane, ethane, and propane. At the proposed operating conditions of 14,500 kPag and 76° C, the acid gas would have the properties outlined in Table 5.

CO₂-Brine Interfacial Tension Study

The Petroleum Recovery Institute (PRI) was commissioned to measure the interfacial tension between pure CO₂ and "X2X" Pool formation brine. Pure CO₂ was used because PRI was not set up for sour experiments. The laboratory work was conducted at the reservoir temperature of 76° C over a range of pressures. At the target operating pressure of 14,500 kPag, the interfacial tension of CO₂ in saturated brine is approximately 38 dynes/cm. The CO₂ interfacial tension was required to finalize the test results obtained in the Cap Rock Capillary Threshold Study. The solubility of CO₂ in brine is higher than H₂S. Therefore, the results obtained here (Figure 7) provided a conservative estimate.

Cap Rock Capillary Threshold Study

These tests were requested by the Alberta Energy & Utilities Board (EUB) and conducted by Core Laboratories to ensure that the reservoir has a competent cap rock. The "X2X" Pool has been subjected to reservoir pressures significantly greater than the original reservoir pressure. The tests were designed to establish the threshold pressure of the cap rock. The tests involved saturating cap rock core samples with representative brine and exposing a surface to acid gas at disposal pressure. The first tests failed because the core could only be saturated along a very thin exterior skin. The applied pressure caused the liquid to distort allowing the acid gas to shoot through the air-dried porosity. This methodology was abandoned and replaced with mercury injection testing.

TABLE 6: Mercury injection results.

Sample Number	Depth <i>mKB</i>	Threshold Pressure <i>mPag</i>	
		Mercury	CO ₂
1	1509.3	129.0	17.5
2	1517.6	161.2	21.9
2A	1517.6	103.0	14.0
3	1518.4	82.4	11.2
4	1518.8	308.9	42.0

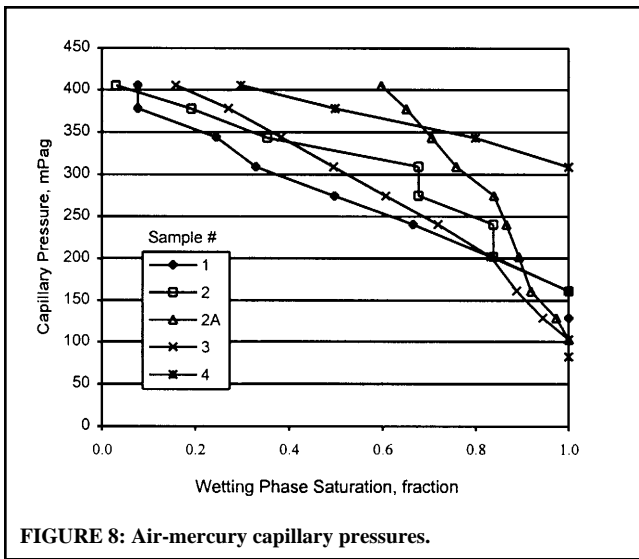


FIGURE 8: Air-mercury capillary pressures.

Mercury is applied at high pressure (up to 100 mPa) to a confined core specimen until threshold entry pressure is observed. The capillary retention pressure of pure CO₂ can then be derived by an equation which ratios the interfacial tensions.

The mercury injection testing yields an average field adjusted threshold differential pressure of 22,300 kPag. At initial conditions, the normal differential pressure across the Muskeg formation is approximately 7,000 kPag (i.e., the pressure immediately above the Muskeg is 7,700 kPag). The maximum operating pressure is therefore 30,000 kPag (i.e., 22,300 plus 7,700 kPag). The CO₂/H₂S mix will have a larger interfacial tension pressure than the CO₂ owing to its relative solubility. Accordingly, the field-adjusted estimate represents a low-end minimum of containment threshold differential pressure. The relevant data is included as Table 6 and Figure 8.

Miscible Displacement Study

Core Laboratories conducted the miscible displacement tests over a range of pressures detailed in Table 7. As shown, the recovery factors were all significant, indicating a similar miscible recovery was taking place. It is important to remember that the tests were run in a packed column using glass beads (mesh size: 100 – 120). The recovery factors are significantly higher than an actual core flood or field tests would yield. Figure 9 compares the produced fluid density versus Pore Volumes Injected (PVI) at two pressures. The last test (at 14,286 kPag), reacted differently than the three higher pressured tests despite having a similar recovery. At 14,286 kPag the fluid density began behaving erratically (i.e.,

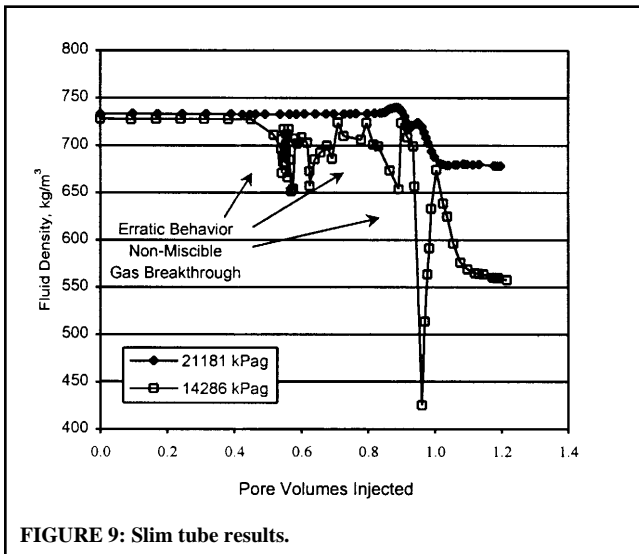


FIGURE 9: Slim tube results.

TABLE 7: Slim tube results.

Slim Tube Number	Recovery Factor %	Run Pressure kPag	
1	98.62	23249	kPag
2	98.13	21181	kPag
3	97.98	17733	kPag
4	97.88	14286	kPag

gas breakthrough) at ± 0.45 PVI. The lower produced densities suggest that the test is very close to the MMP. Once the system is operating below the MMP, the acid gas is no longer miscible and a portion will be produced as free gas.

Pressure Temperature Phase Behaviour

The critical temperature and pressure of the 60/40 acid gas mixture are 47.7° C and 8,038 kPag, respectively. Equations of State (EOS) calculations were used to estimate these values. EOS calculations compared closely to Core Laboratories' derived values (i.e., refer to Figure 10). The acid gas disposal system was designed to operate above its isothermal bubble point in single phase. The expected operating conditions are well above the phase envelope.

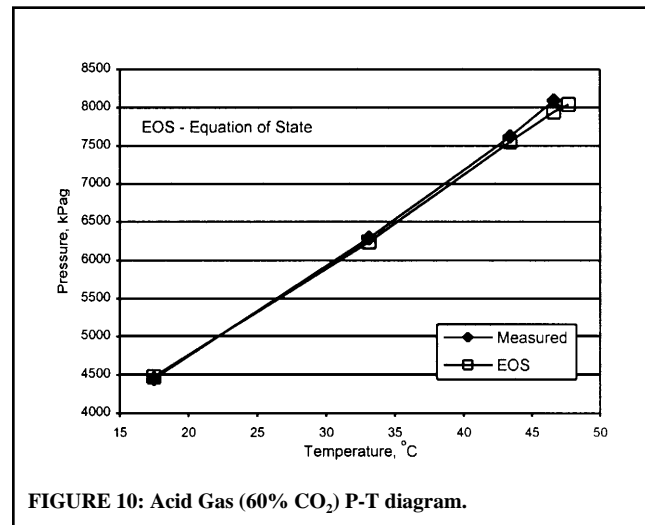


FIGURE 10: Acid Gas (60% CO₂) P-T diagram.

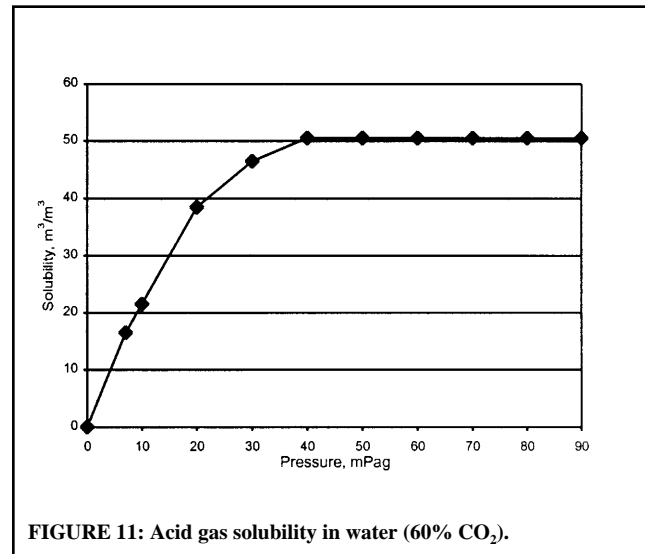


FIGURE 11: Acid gas solubility in water (60% CO₂).

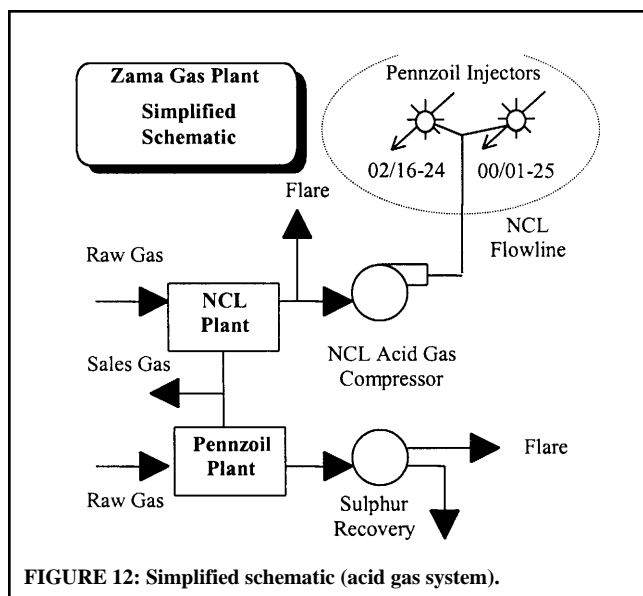


FIGURE 12: Simplified schematic (acid gas system).

Acid Gas Solubility in Brine

The Zama, Keg River and Muskeg Formations naturally contain significant percentages of both CO₂ and H₂S. Re-introducing additional volumes of acid gas to the reservoir is not expected to cause severe formation damage through deterioration. The probability of dissolution and re-precipitation of reservoir rock is small. Long-term dissolution tests were initiated by re-saturating Zama, Keg River and Muskeg core samples with formation water, followed by an acid gas flush. The samples were visually monitored for several months with no evidence of formation damage. The formation water-acid gas solubility was estimated using empirical correlation, combined with independent work conducted by Hycal Energy Research Laboratories Ltd. related to acid gas projects. Figure 11 details the acid gas solubility in water for a range of pressures.

Operations Summary Start-up

The acid gas disposal system schematic is laid out in Figure 12. The acid gas stream is a by-product of NCL's facility at 13-116-06W6M. The acid gas stream is injected into the Keg River "X2X" Pool using the 00/01-25 well as the primary injector and the 02/16-24 well as the back-up injector. The original discovery well (00/16-24) is used as a producing well to maintain the

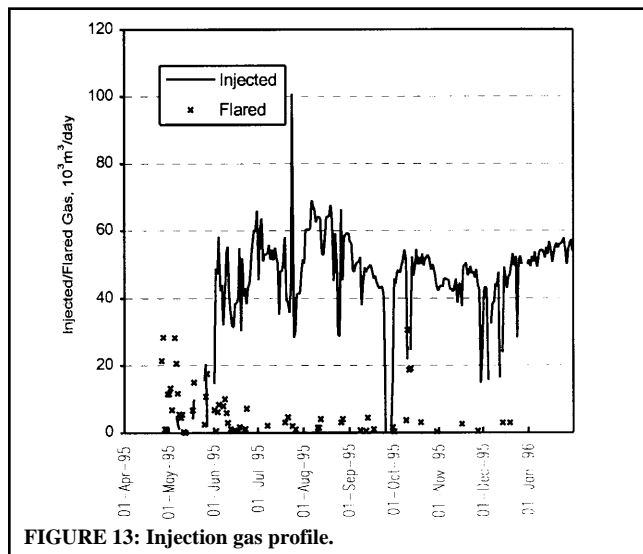


FIGURE 13: Injection gas profile.

TABLE 8: Completion summary.

Primary Producer 00/16-24	Relief Injector 02/16-24	Primary Injector 00/01-25
Pre-Gas Injection Completion		
Open Hole 1466.0-1482.0 mKB	Drilled and Abandoned n/a	Perforated 1487.0-1488.5 mKB 1489.5-1491.5 mKB
Post-Gas Injection Completion		
Set Liner and Perforated 1506.9-1510.0 mKB	Re-entered, Deepened, Set Liner and Perforated 1492-1498 mKB	Perforated 1487.0-1488.5 mKB 1489.5-1491.5 mKB Open Hole 1495.0-1501.0

desired voidage. A fourth well (00/14-24) could also be used for voidage balance. The three active wells had to be re-completed to conform to the acid gas development scenario. The initial and current completions are detailed in Table 8.

Initial disposal was hampered by poor injectivity. The injectivity problem was not specifically reservoir related. Under initial start-up conditions, the acid gas stream was behaving like a gas (rather than a critical fluid) due to methane content. The gas column formed in the wellbore resulted in higher pressures throughout the disposal system. In a critical state, the acid gas density is liquid in magnitude (i.e., the fluid column has a much higher head and wellhead pressures are reduced). Some modifications to the system and a revised start-up procedure were developed to overcome these problems.

Scheme Performance

Acid gas injection commenced on May 3, 1995, but was sporadic during the month of May. Continuous injection began June 1, 1995. The injection profiles are detailed in Figure 13. The only shut down related to the acid gas disposal system occurred on October 10, 1995. The subsurface safety valve (SSV) failed and equalized pressures across the tubing and casing. The 01-25 well was immediately taken out of service. The back-up injector was quickly commissioned to restore injection capacity. The SSV was pulled and sent to Safety Systems Consulting Services of Broken

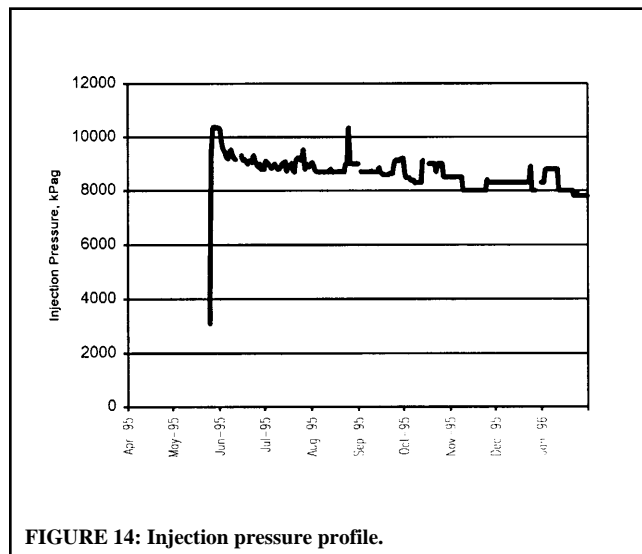


FIGURE 14: Injection pressure profile.

TABLE 9: Acid gas composition.

Component	
CO ₂	78.18%
H ₂ S	19.66%
Methane	2.03%
Ethane	0.03%
Propane	0.03%
n-Butane	0.01%
Other Hydrocarbons	Trace
N ₂	0.06%
Relative Density	1.432

Arrow, Oklahoma for evaluation. A crack was found in the valve housing. During assembly, the valve body is subjected to significant stresses. Applying sufficient torque to actually plastically deform the threads creates the seal. The applied stress, although within design parameters, did not provide the safety margin needed for this high H₂S environment. The original valve was manufactured from 410 stainless steel. The replacement valve was upgraded to Incoly 925 (I-925). The SSV was replaced in November and the well was returned to active injection on December 21, 1995. Total injection to the end of January 1996 was 9.763 10⁶m³ (347 mmscf). Injection rates peaked in early August 1995 at ± 65 10³m³/day then fell back to ± 50 10³m³/day. Approvals to inject up to 120 10³m³/day are in place.

Cumulative production between May 1, 1995 (the initial injection month) and January 31, 1996 was 102 m³ of oil, 47,079 m³ of water and 30.0 10³m³ of gas.

Reservoir Pressure

Reservoir pressure at 00/16-24 on March 25, 1995 (i.e., just prior to acid gas injection) was 21,546 kPag. These pressures were much higher than the MMP. The 00/16-24 wellbore was re-completed at the original oil-water contact and was produced at rates designed to ultimately lower overall operating pressures to design levels near 14,500 kPag. By December 21, 1995 reservoir pressures had declined to 18,969 kPag.

The production and pressure responses are in line with Pennzoil's expectations. High water production and a net withdrawal characterize the initial production phase. Small uneconomical amounts of oil could be produced since the 00/16-24 production perforations are located near the original oil-water contact. The major oil response will occur once the oil bank reaches the perforations. A delayed oil production response is preferred. The longer the miscible bank has to form, the more competent the bank will

become. The overall sweep efficiencies are also improved.

The declining reservoir pressure has resulted in declining injection pressures (Figure 14) at 00/01-25 and declining production rates at 00/16-24. The severely over-pressured reservoir had allowed the well to flow large volumes of water. However some form of artificial lift will soon be required at 00/16-24 to maintain sufficient voidage. Over time, the dominant reservoir drive is gradually changing from high residual waterflood pressures to the current acid gas miscible flood.

Acid Gas Composition

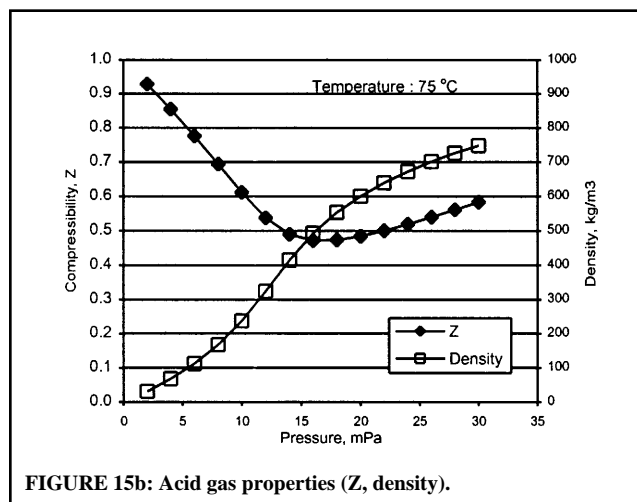
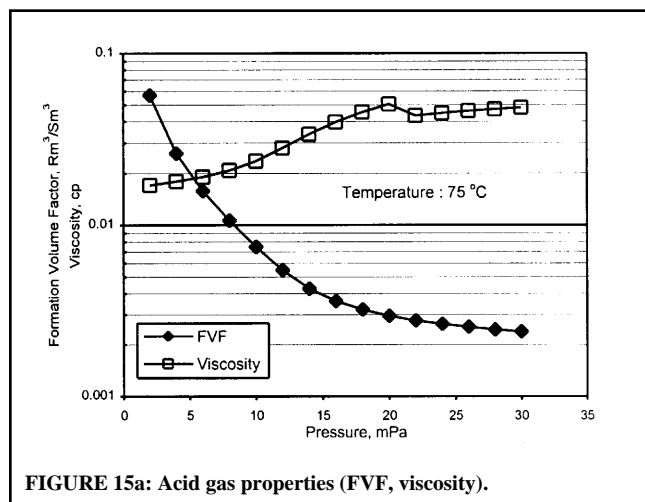
The acid gas composition is actually higher in CO₂ than original design parameters. The rough split is 80% CO₂ and 20% H₂S. Table 9 details the actual composition (as sampled on November 21, 1995). The original design assumed that the gas supply would include Keg River/Zama production (i.e., high H₂S concentrations) to supplement the Sulphur Point/Slave Point producers. Over time the H₂S concentrations will rise as Keg River/Zama gas percentages rise. The acid gas PVT properties are affected by concentration changes. The new estimated acid gas properties are detailed in Figures 15a and 15b. The critical temperature and pressure of the 20% H₂S acid gas mixture are 42° C and 7,642 kPaa, respectively.

The presence of H₂S in the acid gas stream is both a benefit and a drawback. The obvious drawback is the potential risk factors that H₂S represents. Handling H₂S properly is critical to the safety of employees and the public. Since the Zama area is characterized by high H₂S concentrations, procedures already exist to handle acid gas production (and injection). An H₂S concentration benefits a miscible flood operation by reducing the minimum miscibility pressure (MMP). The miscible flood scheme can be operated at lower pressures, which results in lower operating costs and a safer operating pressure. In situations where aquifer support limits the maximum reservoir pressure, H₂S (in some situations) could be used to reduce the MMP below that reservoir pressure. H₂S concentrations also benefit operating conditions due to swelling effect [i.e., the total volume of hydrocarbon gas mixtures increases with the addition of H₂S (given a constant pressure)]. As a result, injection pressures can be reduced and/or production rates increased without reducing reservoir pressure below the MMP.

Corrosion Monitoring

Given the corrosive nature of the acid gas, corrosion was a major concern. The key to eliminating corrosion in the disposal system is to ensure that no free water is present. To that end a continuous dew point analyser was installed. Acid gas dew points were initially -20 to -25° C. With some minor process modifications, the dew point was lowered to -30 to -40° C. As an added precaution, an inhibitor is continuously injected into the carbon steel pipeline.

Pipeline corrosion is monitored using X-ray shadow shot sur-



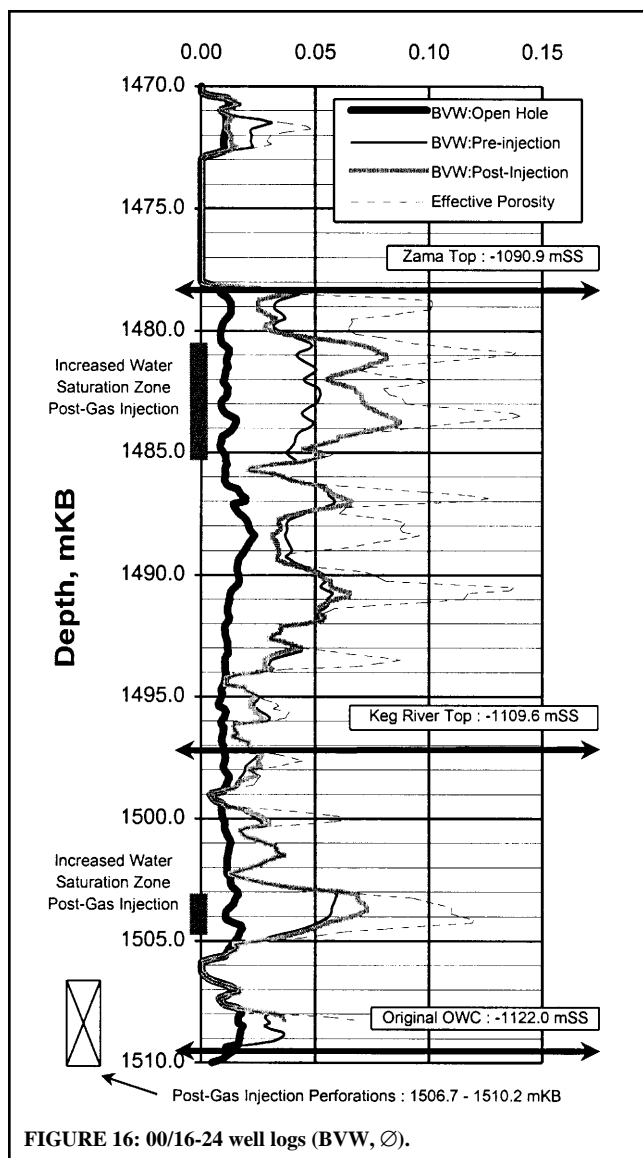


FIGURE 16: 00/16-24 well logs (BVW, Ø).

veys. A survey (conducted in November 1995) showed that corrosion was not occurring in the pipeline. To evaluate corrosion levels in the tubing string, tubing pup joints directly above and below the SSV were removed for inspection. The evaluation of these tubulars was still in progress.

From the work conducted to date, corrosion is not considered a problem in the injection system. However, produced fluids when combined with the acid gas will need to be handled carefully. As mentioned previously, the Zama basin already produces hydrocarbons with high acid gas concentrations. Procedures to work in a corrosive environment are in place. The operators are well equipped and trained in the handling of sour gases. Some additional training was required to handle critical fluids.

Cased Hole Logs

To assist in monitoring fluid movement within the Keg River "X2X" Pool, cased hole logs were run in the 00/16-24 production well prior to acid gas injection. These cased hole logs (Figure 16) showed a typical waterflooded reservoir. The bulk volume water had risen uniformly throughout the Keg River and Zama formations. To establish the progress of the acid gas injection, a second log was run on October 16, 1995. At that point in time, cumulative injection volumes were sufficient to form a gas cap at 00/16-24 (provided the acid gas was not forming a miscible product). These logs indicated that fluid movement was occurring within the reservoir. The bulk volume water at the top of the Zama formation had increased significantly with no evidence of increased gas saturations. This bulk volume water profile indicates that a miscible bank is being formed. The high bulk volume water is caused by water banking in front of the miscible bank. The pool's structural and injection configurations produce the high bulk volume water at the top of the Zama. The injection point, 00/01-25 is not at the "X2X" Pool's structurally highest point. Injected fluids migrate up structure along the laminated permeability trends present in the Zama formation. As the crest of the structure begins to fill with acid gas, displacement of reservoir fluids will become vertical. The general cross-sectional schematic highlights the above discussion (Figure 17).

The logs also showed fluid movement was occurring near the oil-water contact (although not as pronounced as in the Zama). Higher bulk volume water is expected since the 00/16-24 perforations are at the oil-water contact and water production rates were in the 250 m³/day range.

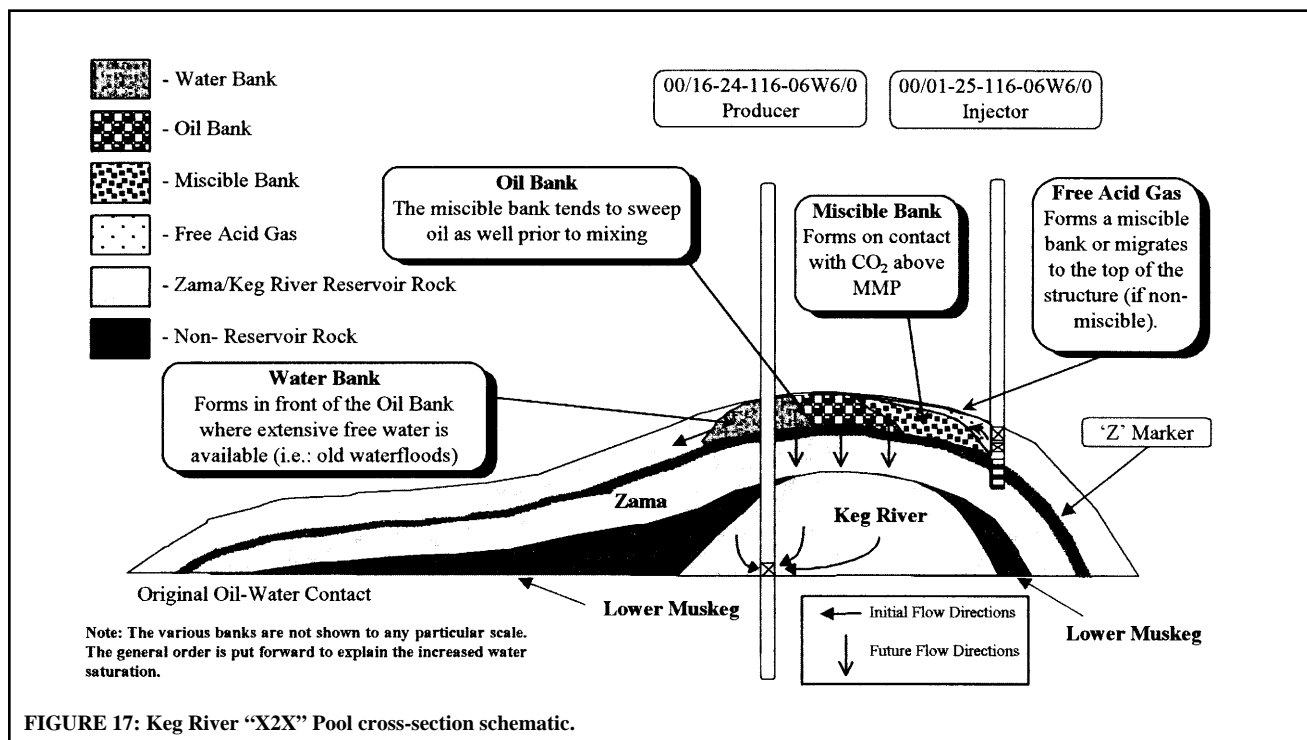


FIGURE 17: Keg River "X2X" Pool cross-section schematic.

Conclusions

1. Implementation of acid gas disposal schemes can be a viable alternative to:
 - a) flaring waste gas and
 - b) blocking sulphur.
2. The process has several environmental upsides:
 - a) reduced greenhouse gas emissions,
 - b) reduced acid rain emissions and
 - c) reduced surface sulphur contamination.
3. The process benefits everybody
 - a) the producers (Pennzoil, etc.),
 - b) the processors (NCL, etc.),
 - c) the province and
 - d) the general public.
4. Acid gas has some significant upside potential as a miscible solvent. The CO₂ component is a natural miscible solvent. The H₂S enhances the process by introducing a swelling effect and reducing the minimum miscibility pressure. Early data indicates that the injected acid gas is forming a miscible bank.
5. The disposal scheme is showing that a highly corrosive, poisonous gas stream can be handled safely and efficiently. The key factors in a safe operation are:
 - a) water free acid gas,
 - b) proper material selection,
 - c) well trained operators and
 - d) proper monitoring.
6. This acid gas disposal scheme does have its own unique characteristics. However, this scheme is not an isolated opportunity. Combined with other acid gas disposal schemes (both in operation and in planning), the industry is making a significant impact to reduce its share of the emission problem. With some dedication, proper planning (i.e., all situations have to be analysed on their own merits) and joint effort from all parties further gains will be realized.
7. The overall process is not well documented in the public domain. Additional information needs to be brought forward. Ultimately everyone will benefit.

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