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When Oxbow purchased the project in 1985, the NC gas and H₂S concentrations in the reservoir were not known with any certainty, and therefore the plant emission rates and H₂S abatement requirements were unknown. To answer these questions, obtaining accurate NC gas analyses of the produced fluid became one of the first priorities during the initial stages of well testing and field development. Preliminary calculations of possible H₂S emissions were in the range of 180 to 230 tons/year at gross outputs of 55 to 62 MW. Any emission rate above 250 tons/year would require a full PSD review.

Further well sampling in the summer and fall of 1986 and pilot plant testing in the summer of 1987 confirmed that plant emissions would be below 250 tons/year. In October 1987, Oxbow petitioned the Nevada Environmental Commission for adoption of a State Implementation Plan (SIP) source specific emission limit of H₂S to less than 250 tons/year. Compliance with this emission limit insures that the Dixie Valley power plant will not be a PSD source and would not potentially require retrofitting the plant with the "best available control technology" at a future date. The SIP was approved in May 1988 and to date, this is the only geothermal power plant in Nevada operating under a SIP.

Initial NC Gas Sampling and Measurements

At Dixie Valley, the first accurate NC gas analyses from most of the wells were obtained in 1986 from two-phase flow lines during extended flow tests of eight wells with fluid-entry temperatures ranging from 430°F to 480°F. These 8 wells documented the total range of temperature and chemistry known from the initial testing of the reservoir.

In 1989, an additional NC gas sample was collected from the 402°F well 25-5 which was specifically drilled as a relatively shallow (6000') injection well (Benoit, 1992). Prior to collecting this sample, the reservoir had been produced for about 1-1/2 years and injection had occurred in well 45-5, located about 400 feet away for one year.

A total of 31 NC gas samples were collected in evacuated glass bombs during the 1986 testing for analysis of the total NC gas content and composition. These samples were collected from a mini-separator attached to a variety of sample ports on the top, sides, and bottoms of straight runs of two-phase flow lines. Samples were also collected from ports at or near elbows in the pipelines. Another 74 total NC gas contents were measured on site with a Wet Test Meter (gas volume meter). These results are summarized in Table 1, wherein averages are presented for all the combinations of wells and various sample ports. A few obviously questionable individual analyses, defined as NC gas contents above 2600 ppm or below 1400 ppm, are not included in the data presented in Table 1.

More extensive brine sampling and analyses indicate there was no detectable change in the chemistry of any of the wells during this 1986 testing. For this reason, potential chemistry changes over this short time frame are not addressed.

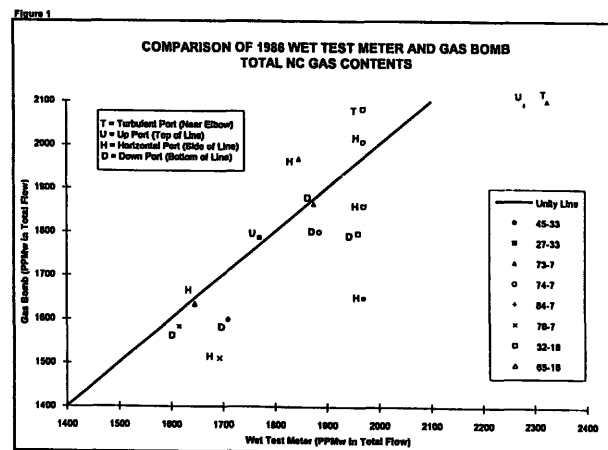
The evacuated glass bombs tended to give the most consistent results. This may reflect the simple sampling process of partially filling the glass bomb with steam

condensate and gas versus the more involved process of utilizing a Wet Test Meter under field conditions. Also, numerous correction factors, such as those accounting for gas solubility in the condensate and the water vapor content of the gas, are required to convert the raw gas volumes measured to mass and concentration units. There is generally good correlation between the total NC gas measured by the two methods. Averaged values agree to within 200 ppm of total NC gas in the total flow (Fig. 1) for samples collected from the same port. Overall, the Wet Test Meter results tended to give slightly higher contents than the glass bombs.

Table 1 COMPARISON OF TOTAL NC GAS FROM WET TEST METER AND GAS BOMB TESTS

WELL	PORT	WET TEST METER		GAS BOMB	
		average ppm	no. of samples	average ppm	no. of analyses
45-33	H	1970	2	1649	1
45-33	D	1710	2	1599	1
27-33	U	1770	12	1787	7
73-7	H	1847	3	1955	1
73-7	T	2325	6	2101	1
73-7	D	1875	2	1865	2
73-7	U	1778	4		
74-7	H	1970	1	2007	1
74-7	D	1886	5	1801	1
84-7	U	2280	1	2053	5
76-7	H	1693	3	1510	1
76-7	D	1615	6	1583	1
32-18	H	1970	1	1860	2
32-18	T	1970	4	2082	1
32-18	D	1960	1	1797	3
65-18	H	1647	3	1634	1
65-18	T	2118	5		
65-18	D			1526	1

T = Turbulent Port (Near Elbow on Side of Line) H = Horizontal Port (Side of Line)
 U = Up Port (Top of Line) D = Down Port (Bottom of Line)



The position of the sampling port on the flow line caused a significant bias in the NC gas content (Fig. 1). The highest NC gas contents were measured in samples collected from the top of the flow lines and samples from "turbulent ports" on the side of the lines near 90 degree elbows where flow turbulence was greatest. Samples collected from the bottom of the flow lines tended to have the lowest NC gas contents. Samples from the sides of straight sections of pipe were intermediate in NC content. The total variation between the sampling ports

was as high as 550 ppm (Table 1), which is substantial considering the total quantities are between 1500 and 2300 ppm.

The primary engineering conclusion from an evaluation of NC gas measurements was that the average preflash NC gas concentrations of the individual wells deemed capable of long-term production ranged between 1800 and 1900 ppm. With this information, the gas ejection equipment was sized.

Comparison of NC Gas Measurements from Two-Phase and Single-Phase Lines

In May 1988, the first NC gas samples were collected from single-phase lines downstream of the high-pressure production separators. This presented the first opportunity to check the previous analyses from the two-phase lines. Table 2 contains data for all individual production well samples collected prior to September 1988 when injection commenced. Prior to September 1988, there are no chemical data which indicate any time changes or trends in individual well chemistry.

Table 2 COMPARISON OF H₂S AND CO₂ CONTENT FROM 1986 SINGLE-PHASE AND 1988 TWO-PHASE LINE SAMPLES

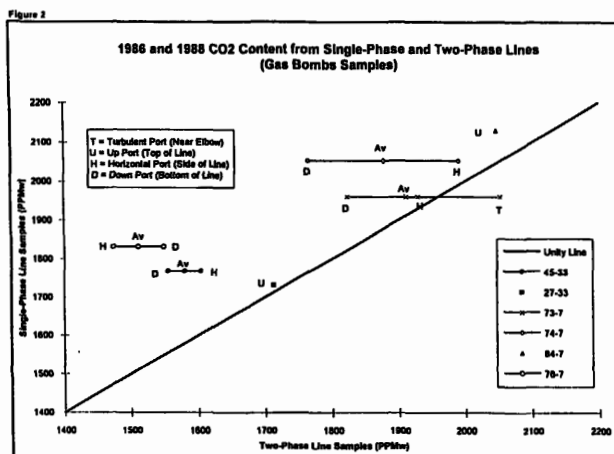
WELL	PORT	2 Phase CO ₂		1 Phase CO ₂		2 Phase H ₂ S		1 Phase H ₂ S	
		ppm	no. of analyses	ppm	no. of analyses	ppm	no. of analyses	ppm	no. of analyses
45-33	H	1604	1			16	1		
45-33	D	1555	1						
45-33	NA			1768	2	16.7	1	17.4	2
27-33	U	1713	7			15.3	7		
27-33	NA			1732	1			16.4	1
73-7	H	1912	1			13.1	1		
73-7	T	2053	1			13.5	1		
73-7	D	1824	2			13.2	2		
73-7	NA			1960	1			13.3	1
74-7	H	1991	1			13	1		
74-7	D	1766	1			12.8	1	14.3	1
74-7	NA			2053	1				
84-7	U	2047	5			13	5		
84-7	NA			2131	1			13.6	1
76-7	H	1474	1			9.4	1		
76-7	D	1549	1			10.2	1	9.9	1
76-7	NA			1832	3				
65-18	H	1600	1			1.9	1		
65-18	D	1490	1			2.2	1		
32-18	H	1825	2			6.9	2		
32-18	T	2040	1			7.2	1		
32-18	D	1753	3			6.9	3		
25-5	?	86	1			2.2	1		

T = Turbulent Port (Near Elbow on Side of Line)
 U = Up Port (Top of Line)
 ? = Port not Documented
 H = Horizontal Port (Side of Line)
 D = Down Port (Bottom of Line)

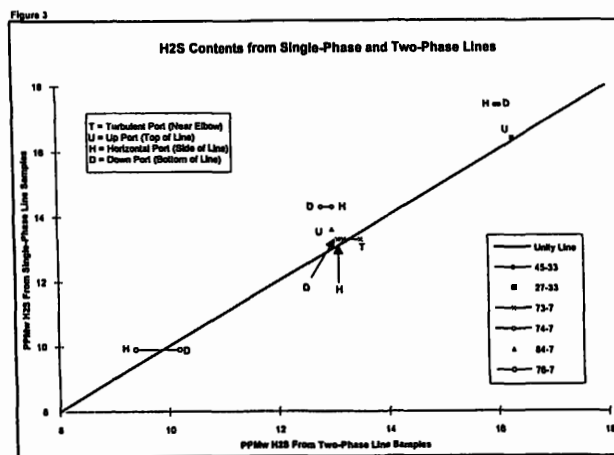
The comparison of CO₂ data from single and two-phase lines (Fig. 2) shows that there is best agreement between the single-phase CO₂ content and those from sample ports highest on the two-phase flow lines. In all but one instance, the turbulent port of 73-7, the analyses from single-phase lines showed higher CO₂ contents than from the two-phase lines. The lowest overall CO₂ concentrations were measured in samples collected from the bottom ports on two-phase lines.

The observed sample bias with port orientation on the two-phase flow lines for Dixie Valley wells is consistent with the potential errors expected for this type of sampling. The bulk of the two-phase flow stream was stratified in straight pipe runs where most of the sample ports were located. The fluid was well mixed at the turbulent ports located at or near

pipe elbows. The fluid extracted from the bottom of straight pipe runs was enriched in brine and deficient in steam. The type of mini-separator used to separate the two phases was connected to the flow line by approximately six feet of flexible 1-inch hose. In an effort to obtain sufficient steam from the separator for sampling, the operator apparently increased the flow rate through the separator until a significant pressure drop occurred through the flexible hose, resulting in additional flashing of brine. The steam thus formed diluted the small quantity of original steam in the separator, causing a reduction in the total NC gas concentration. A review of the sampling data confirms that the separator pressure was significantly lower when connected to bottom ports compared to the top, horizontal and turbulent ports where steam was not as scarce.



The comparison between H₂S analyses from single and two-phase lines (Fig. 3) shows very good correlation. The H₂S content of NC gas samples is not as adversely affected by additional flashing of brine in the separator due to the much greater solubility of H₂S in brine compared to CO₂. Secondary flashing of Dixie Valley brine results in steam containing substantial quantities of H₂S (see section below on pilot plant testing). The H₂S data in Table 2 and Figure 3 represent total H₂S in the reservoir water and are corrected to reflect the fraction remaining in the brine after flashing.



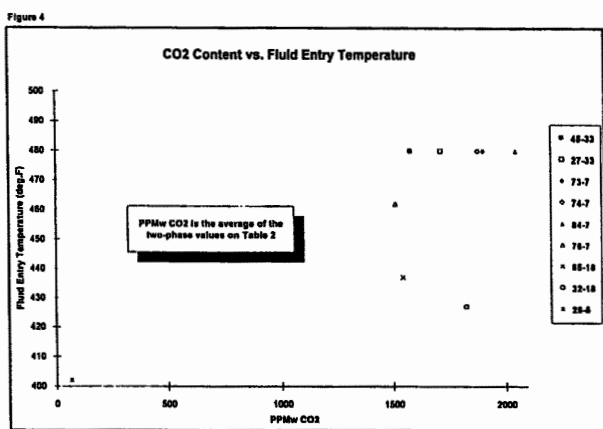
A requirement of representative two-phase sampling is to operate the mini-separator at the maximum flow rate possible without causing a pressure drop of more than 1 to 2 psi through the separator. This insures that the relative heat loss from the separator is minimized without significant additional flashing that would change the composition of each phase. Since the relative proportions of steam and brine passing through the separator are not known, additional flashing cannot be corrected for by heat and mass balance equations.

To obtain a sufficient quantity of steam, the separator should be connected to the top port of a horizontal two-phase flow line for steam and NC gas samples. Conversely, the separator should be connected to the bottom port of a horizontal two-phase flow line for brine samples. The separator should also be connected directly to the sample port, not by a length of flexible hose, to minimize pressure drop and heat loss.

The initial two-phase sampling was performed in Dixie Valley before these methods had been widely used and standardized. Subsequently, these sampling techniques have been documented and standardized with a draft procedure currently under review by ASTM subcommittee E44.15 (Standard Practice for Sampling Two-Phase Geothermal Fluids for Purposes of Chemical Analysis).

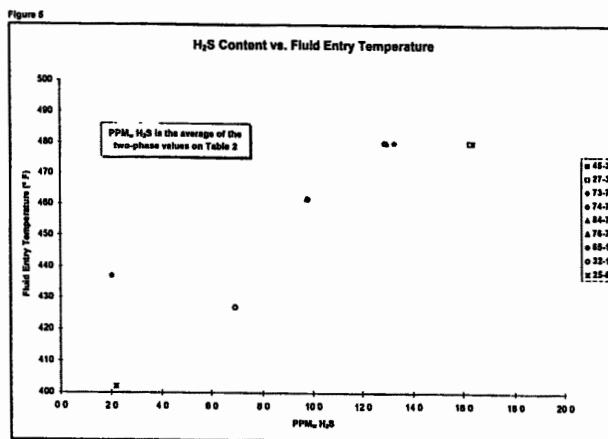
Initial State Reservoir Chemistry

The CO₂ content showed no strong correlation with fluid-entry temperature (Fig. 4). The Section 7 wells, which within limits of temperature tool precision had the same temperature as the Section 33 wells, showed a slightly higher CO₂ content than the Section 33 wells. The sole sample from injection well 25-5 contained only 66 ppm of CO₂. By itself, this may be indicative of the 25-5 fluid consisting largely or all of injectate. However, the brine chemistry was clearly distinct from the injectate chemistry. Perhaps some other process has been active in lowering the CO₂ content. The initial NC gas was comprised of about 98% CO₂.



The initial H₂S contents showed considerable variation ranging from 2 to 16 ppm and presented a strong increasing trend with fluid-entry temperature (Fig. 5). Again, there are significant differences between the Section 7 and 33

production wells, except this time the Section 33 wells have the higher content. The data from well 65-18 stand out as being anomalously low for its fluid-entry temperature.



It was these data from the Section 7 and 33 production wells that indicated total H₂S production to the power plant could be as high as 275 tons/year at a total mass flow rate of 4,336,500 lbs/hr (56 MW gross). This value was well above the 250 tons/year PSD applicability level, but did not account for the fraction of H₂S remaining in the brine after two stages of flash. The Dixie Valley brine has a relatively high pH after flashing, 9.1 or 9.2 units at 20°C, and retains a substantial amount of H₂S in solution which is ultimately injected back into the reservoir.

To estimate the quantity of H₂S that would remain in the brine after the second flash, a chemical computer modeling program was utilized (Thermochem, Inc., 1987). The program calculates the vapor/liquid distribution of the various geothermal gases, accounting for the effects of major acid/base species such as H₂S, CO₂, HCO₃, CO₃, and H₄SiO₄ on the pH and ionization of dissolved electrolyte gases. The modeling program was first validated by computing the partitioning of H₂S in systems where the concentrations of H₂S in brine and steam were accurately known, such as other geothermal power plant separators and individual well test flow lines. The model accuracy was within 5% for these comparisons. Inputting the Section 7 and 33 well test data into the program, it was estimated that 15.6% of the total produced H₂S would remain in the brine after two stages of flash, and 232 tons/year would be emitted from the plant. This was uncomfortably close to the 249 ton/year limit where H₂S abatement could be required and left no margin for error if the plant were to be operated at higher megawatt output.

Pilot Plant Testing for H₂S Partitioning

With the possibility of having to install an H₂S abatement system at the power plant, a pilot plant test was conducted on well 45-33, one of the wells with the highest concentration of H₂S. This test was required to precisely evaluate the partitioning of H₂S between the brine and vapor phases through the dual-flash process and to check the results of the computer modeling performed to estimate this partitioning. The pilot test involved flowing the well 45-33 at line pressures

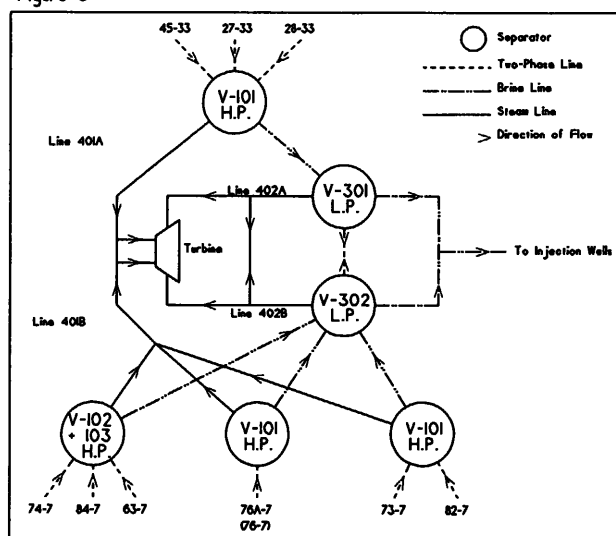
close to the first stage flash pressure (100 psia) designed for the plant. A side-stream of this flow was passed through a small cyclone separator operated at the line pressure to simulate first stage flash conditions. Brine from this primary separator was passed through another cyclone separator operated at the second stage flash pressure (22 psia) designed for the plant. Samples of steam and brine were collected from each separator for complete analyses of the NC gas and brine at each stage of flash.

The results of this testing indicated that 15.4% of the total H_2S would remain in the brine after second flash, which confirmed the chemical computer modeling performed prior to the field test that predicted partitioning of 15.6%. After the first stage of flash, 42.7% of the total H_2S was still dissolved in the brine. The second stage flash steam H_2S concentration was 63% of the first stage flash concentration.

Power Plant and Wellfield Design

There are four high pressure separators located in the wellfield V-101, V-102 + 103, V-104, and V-105 (Fig. 6). Two-phase fluid from the individual wells flows into these separators and single-phase fluids flow out of the separator to the power plant. The high-pressure steam flows directly to inlets on both sides of the turbine. The high-pressure steam from the north and south parts of the wellfield is not well mixed or homogenized prior to entering the turbine. Consequently, flow rates and the NC gas content between the two high-pressure steam lines can vary considerably, depending upon which wells are flowing. The high-pressure 401A line primarily brings in steam from the Section 33 wells, and consequently has a higher H_2S content than steam in the 401B line.

Figure 6



The separated high-pressure brine flows to two low-pressure separators a short distance from the turbine. Again, the high-pressure brine from the north and south portions of the wellfield is not homogenized before entering the separators and consequently the steam in the low-pressure line 402A is primarily from the Section 33 wells and has a higher H_2S content.

NC gas from the direct contact condenser is removed with the aid of steam ejectors and dispersed to the atmosphere through the seven cell counter flow cooling tower. The plant design called for approximately 90,000 lbs/hr of high-pressure motive steam to operate the ejectors.

Exhausted steam from the turbine is condensed by approximately 30,000 gallons per minute of cooling tower circulating water that is sprayed into the condenser and then pumped back through the cooling tower. On an annual basis, about 500 gallons/minute of excess water overflows the cooling tower basin and is either discharged to the surface or pumped into the injection line.

Unflashed brine from the low-pressure separators is pumped back into the reservoir via the 8 currently operating injection wells.

Since plant startup in July 1988, no NC gas samples have been collected from the individual two-phase lines supplying the high-pressure separators.

V-101 is supplied by the three northern production wells, 27-33, 45-33, and 28-33 (Fig. 6). Well 28-33 was placed in service in July 1990 and has a brine chemistry very similar to 27-33 and 45-33 so it is unlikely that the addition of 28-33 to the system resulted in any significant changes in NC gas content or chemistry from V-101.

V-102 + 103 are two interconnected separators that were supplied by wells 84-7, 74-7, and 73-7 from June 1988 through July 1989. In August 1989, the wellfield was modified so that wells 63-7, 84-7, and 74-7 now supply V-102+ 103. As was the case for V-101, all of these wells are closely spaced and while there is some modest and consistent variation in brine chemistry between them (they can be chemically distinguished from each other), they are treated as a single group with very similar NC gas chemistry.

V-104 is the only single separator servicing a single well, 76-7, at Dixie Valley. However, even this simple arrangement has been complicated by changes to well 76-7. In the spring of 1993, well 76-7 was reworked, deepened and renamed 76A-7. It now produces from the same deep fault environment as all the other Section 7 wells. From 1986 through early 1992, well 76-7 produced a cooler fluid from a shallower basaltic aquifer which had a significantly different brine and NC gas chemistry.

V-105 has been supplied only by wells 73-7 and 82-7 since it was placed into service in early 1989. Again, these two wells are located close to each other, have similar brine chemistries and have been treated as a single entity.

Changes in CO_2 and H_2S Contents with Time

Within the first 15 months of power plant operation, there were substantial measured declines in CO_2 and H_2S contents (Table 3, Figures 7 and 8) for all separators except V-105 which was not operational for most of that time period. V-104 had by far the greatest and most rapid decline, followed by V-101 and then V-102. Tracer test results showed a relatively rapid return of injectate to V-104 (Adams, et al., 1989). The declines in CO_2 content are complimented by ongoing declines in total carbonate in the brine chemistry (Fig. 9).

Table 3 SUMMARY TABLE OF DIXIE VALLEY H₂S AND CO₂ EMISSION RATES

	1988	1989	1990	1991	1992	1993
Gross Megawatts (at time of sampling)	60.2	62.7	63.3	55.8	62.1	62
Average CO ₂ Content of Pre-Flash Fluid from H.P. Separator Data (ppm)	1863	1647	1388	1283	1070	998
Total CO ₂ Production Rate from H.P. Separator Data (bs/hr)	9061	8731	7756	6082	5424	5171
Lbs. of CO ₂ Produced per Megawatt Hour from H.P. Separator Data	150.5	139	122.5	109	87	83.4
Total CO ₂ Production Rate from Power Plant Data (bs/hr)	9134	8873	7377	5167	4719 (7)	--
Lbs. of CO ₂ Produced per Megawatt Hour from Power Plant Data	151.7	141.5	116.5	92.6	76 (7)	--
Average H ₂ S Content of Pre-Flash Fluid from H.P. Separator Data (ppm)	13.3	11.8	11.1	10.1	9.8	9.4
Total H ₂ S Emission Rate from H.P. Separator Data (bs/hr)	54.3	50.6	51.8	41.7	39.3	39
H ₂ S Oxidized in Circulating Water (bs/hr)	2.48	3.14	1.52	1.47	3.53	--
H ₂ S Injected (bs/hr)	8.02	8.9	8.17	4.72	6.89	--
Lbs. of H ₂ S Produced per Megawatt Hour from H.P. Separator Data	0.9	0.81	0.82	0.75	0.83	0.62
Total H ₂ S Emission Rate from Power Plant Data (bs/hr)	49.2	52	48.3	37.3	29.2 (7)	--
Lbs. of H ₂ S Produced per Megawatt Hour from Power Plant Data	0.82	0.83	0.76	0.67	.47 (7)	--

(7) Results are known to be low due to malfunctioning analyzer

Figure 7

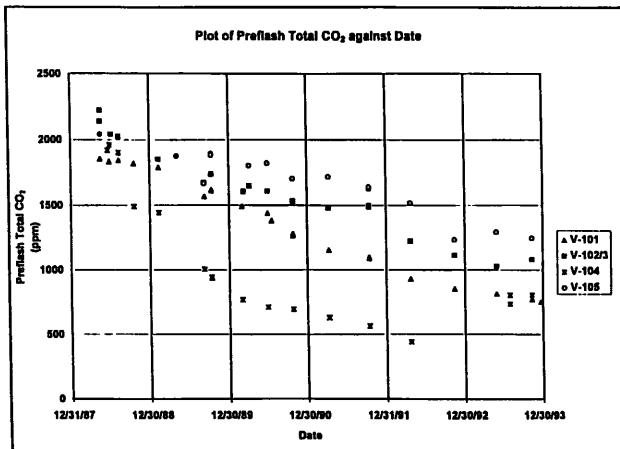


Figure 8

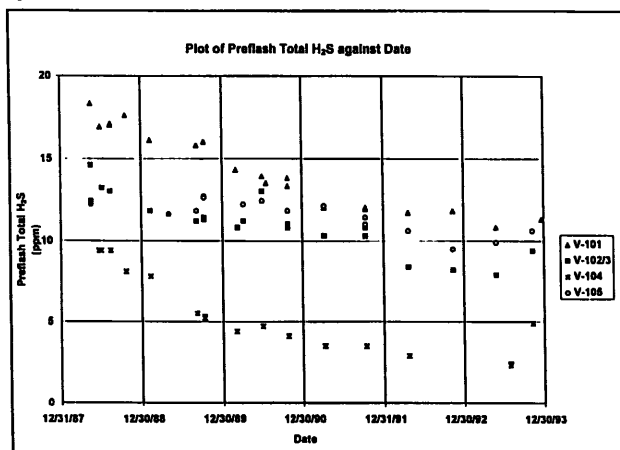
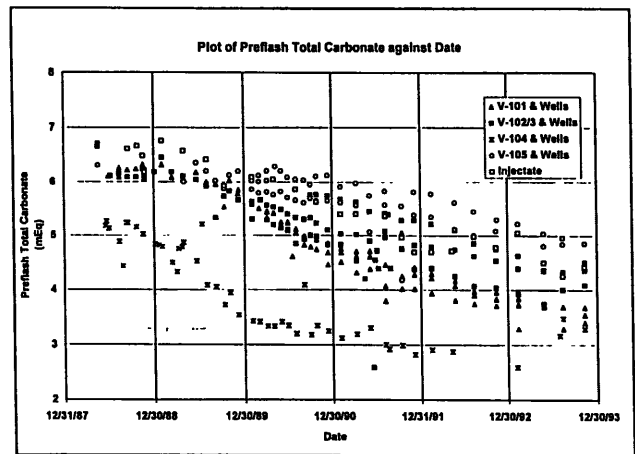


Figure 9



Longer term monitoring of chloride contents confirmed the return of major quantities of injectate to all production wells (Benoit, 1992). Unpublished stable isotope results show both the production and injection fluids are becoming "heavier" with time. These three chemical indicators combine to strongly indicate the chemical changes seen in the production fluid chemistry are predominately the result of recycling injectate that has been concentrated by the flashing process and stripped of NC gas.

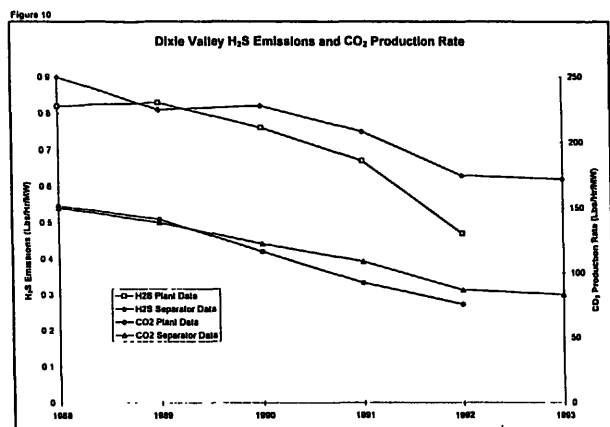
Over the longer term, the declines in CO₂ and H₂S contents have continued to the point that each separator now produces a distinctive and easily identifiable NC gas chemistry. V-105 produces the highest NC gas content now and also has had the least increase in chloride content (Benoit, 1992) which indicates V-105 is producing the smallest fraction of injectate of all the separators. The V-101 and V-102 separators produce a fluid which has an intermediate NC gas composition between that of V-104 and V-105.

Power Plant Emissions

Two methods have been used at Dixie Valley for determining power plant emissions. They are largely independent of each other in terms of sampling locations and flow rate instrumentation and therefore can independently determine the emissions. The first method (plant method) relies on analysis of the high and low-pressure steam entering the turbine with corrections for the amount of H₂S naturally oxidized in the cooling tower circulating water. The remaining H₂S is discharged to the atmosphere through the steam ejectors and cooling tower cells (Table 3). This method utilizes instrumentation in the immediate vicinity of the turbine for flow rates. The second method (separator method) is to measure the amount of H₂S that flows through the high and low-pressure separators with corrections for the H₂S that is naturally oxidized in the cooling tower circulating water (Table 3).

The power plant method was utilized annually for permit compliance from 1988 through 1992. The separator method was utilized twice a year from 1988 through 1993, primarily to give information on the reservoir chemistry. Generally, both methods are in good agreement (Fig. 10). However, there are

discrepancies in the 1991 and 1992 values which are caused by a malfunctioning annubar under-reporting the amount of high pressure steam entering one side of the turbine. As this annubar cannot be repaired while the plant is on line, the power plant sampling was not performed in 1993. The trend of declining emissions with time (Fig. 10) corresponds with the results previously presented in Figures 7 and 8.



Overall, the H₂S and CO₂ production rate per megawatt hour have declined by 31% and 45% respectively during the first 5-1/2 years of plant operation. This has allowed one of the three trains of steam ejectors to be shut down, conserving about 30,000 lbs/hr of high pressure steam.

Conclusions

- Comprehensive sampling and analysis of NC gas contents, in addition to chemical modeling and pilot plant testing prior to power plant design and construction at Dixie Valley, have resulted in a project that has had no noteworthy problems with NC gases.
- Sampling of various ports on two-phase flow lines demonstrates that samples should be collected from the top of the line and mini-separators attached directly to the sample ports to minimize potential bias in the results. By comparing the analysis results of samples collected from two-phase well test lines to single-phase production separator discharge lines, it is clear that representative gas samples can be obtained from two-phase flow streams with the proper sampling techniques.
- The amount of H₂S and CO₂ produced and emitted from the plant have declined markedly with time due to the recycling of injectate as confirmed by changes in the general brine chemistry and stable isotope ratios.

Acknowledgements

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