

DESIGN CONSIDERATIONS FOR ACID GAS INJECTION

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With growing environmental concerns, the disposal of small quantities of acid gas is a problem. In the past, producers could flare these acid gases. However, in many jurisdictions this is no longer the case. New and stricter regulations are curbing the disposal of sulfur compounds to the atmosphere. Usually a sulfur plant is not an option for these small producers. Thus, other methods must be developed to deal with the unwanted acid gas.

Acid gas injection is quickly becoming the method of choice for disposing of these gases. The acid gas is compressed and injected, usually into a non-producing formation. Recently though, some have investigated the value of using the compressed acid gas as a part of a miscible flood scheme. We would recommend against such a scheme because it will lead to a build-up of acid gas and ultimately an increased load on the amine unit. The goal is to dispose of the acid gas not to recycle it.

In addition, with the current depressed market for sulfur, some larger producers are considering acid gas injection as an alternative for dealing with unwanted sulfur.

1.0 INTRODUCTION

Acid gas injection basically involves taking the acid gas from the amine regeneration column, compressing it to a sufficient pressure, and injecting it into a suitable underground formation. Acid gas injection is essentially a zero-emission process. During normal operation, "all" of the hydrogen sulfide from the produced gas is re-injected. Only during upsets, when the acid gas is sent to flare, or if there are leaks in the system, which must be attended to, are sulfur compounds emitted to the atmosphere. Of course, there are other locations in the plant where hydrogen sulfide may be emitted, but the acid gas from the regenerator accounts for the vast majority of the produced hydrogen sulfide.

There have been several papers presented in the literature on the topic of acid gas injection. Keushnig (1995) discusses the injection of acid gas from a regulatory point of view in the province of Alberta. Wichert and Royan (1997) present an overview of the acid gas injection process from the amine regenerator to the reservoir.

We do not wish to minimize the importance of phase equilibria and physical properties in the design of acid gas injection schemes. However, these aspects were discussed in previous

papers (Carroll and Lui, 1997 and Carroll, 1998a,b) and will be discussed further in a subsequent paper (Ng et al., 1999). In addition, Clarke et al. (1997) reported some physical properties and phase equilibria of importance to acid gas injection. The reader should consult these works for additional information in this regard. However, having said that, the reader will notice in this work that these properties and calculations are presented throughout this paper. It is a fundamental part of acid gas injection design.

2.0 ACID GAS INJECTION

There are three basic components to an acid gas injection scheme. These are: (1) compression, (2) pipeline, and (3) the injection well. There is some controversy about the need for dehydration of the acid gas. This option will be addressed later.

There are several important facets to the three foregoing basic components of an acid gas injection scheme. These include, but are not limited to: (1) non-aqueous phase behavior, (2) water content of the acid gas and the possible formation of an aqueous liquid, (3) hydrate formation, and (4) the density and viscosity of the acid gas. This paper will only address these matters peripherally. A subsequent paper will examine them in more detail (Ng et al., 1999).

The reservoir engineering aspects of acid gas injection will not be covered in this paper. In this work we consider the process from the top of the amine regenerator column to the bottom of the injection well only.

3.0 COMPRESSION

The required compression scheme is dictated by two concerns. The first, and perhaps most obvious, is the wellhead pressure at the injection well. The second is an attempt to take advantage of the water holding capacity of the acid gas. A discussion of the calculation of the injection pressure for these schemes is given in the next section.

Acid gas from the amine regenerator is sent directly to the suction of the acid gas compressor. This is typically a small four-stage, four-throw reciprocating compressor designed to increase the pressure of the acid gas from approximately 5 to 10 psig to a pressure dictated by the remainder of the injection scheme, which may be a few hundred pounds up to 2000 psig or more.

Before entering the compressor, a suction scrubber will remove any residual liquids in the stream. Water will drop out in the interstage scrubbers. Since there is only a pre-set amount of water present in the gas, the gas will likely be undersaturated after the fourth stage. In order to minimize the amount of water present in the gas, it is advantageous to set the final stage suction pressure at roughly the pressure of minimum water content. The water content

of acid gas mixtures is discussed in a subsequent section of this paper, including the maximum water content effect.

By taking advantage of the thermodynamics of the acid gas mixture, one can avoid the need for dehydration of the acid gas. In all of the schemes designed by Gas Liquids Engineering, Ltd., none utilizes dehydration. This includes several years of successful operation, with no problems directly attributable to the lack of water removal have been identified. We will return to the topic of dehydration later in this paper.

As a precaution, the compressed acid gas is mixed with methanol to prevent freezing of any residual water and the formation of hydrates in the pipeline.

3.1 Compressor Design

Acid gas behaves differently from sweet gas inside the compressor. Simulation of the actual compression horsepower and temperature rise inside the compressor must be given careful consideration. Of course, the cooling is also an important consideration. Not properly accounting for water condensation and non-aqueous phase changes (especially in final stage) can result in undersized coolers.

Compressor speed is automatically controlled to ensure that the system can respond rapidly and accurately to changes in acid gas volumes. As well, the compressor is equipped with fuel gas make-up, fuel gas purge, auto-bypass, auto-recirculation of warm air, and a number of other safety/operations performance features.

The low suction pressure is not a major concern in the design of the compressor other than the need to be very conservative in sizing of piping, valves, and vessels.

“What-if” planning is very important. The compressor performance should be examined for a range of pressures around the intended suction pressure. Turndown is extremely important since predicting the acid gas volumes can at times be very difficult. In this respect, one needs to consider speed changes (minimum and maximum), compressor internal temperatures with volume pockets in operation, and possible gas recycle.

Fuel gas make-up should not be used to boost suction pressure. The effect on wellhead injection is too volatile and unpredictable. As will be demonstrated, the light hydrocarbons can significantly affect the required injection pressures.

The drains after the dump valve should be heat traced. The water content is high, and with a high acid gas content, these lines freeze easily. Hydrates readily form in acid gas mixtures.

3.2 Materials of Construction

First stage suction piping and vessels can be constructed from carbon steel since it is the same design pressure and conditions as amine regeneration reflux vessel. All other downstream piping, vessels, coolers, and equipment should be constructed from stainless steel.

The materials used in the compressor are as follows: carbon steel cylinders with Teflon piston rings, Teflon rod packing, stainless piston rod (tungsten coated), and NACE sour bolting. Of course, crankcase and packing ventilation and gas control are critical. Sometimes it can very difficult to achieve a good packing/seal on the piston rod, particularly on first stage where pressure differentials are low and a rod seal may not conform to the rod for the initial wear-in period.

Ring joint flanges seem to provide better seals than raised face flanges but getting valves and flanges apart can be difficult.

In addition, the use of stainless steel for valves, thermowells, instrument lines, manifolds, etc. is recommended. The cooler headers, bundles, tubes, connections etc., should also be constructed from stainless steel.

3.2 Water Content of Acid Gas

As explained earlier, an important consideration in the design of an acid gas compressor is the water content of the gas. This section will examine this phenomenon.

It is well known that the saturation water content of sweet gas is a continually decreasing function of the pressure. That is, as the pressure increases the amount of water in sweet gas decreases. As we shall see, the behavior is different for acid gas.

Figure 1 shows the water content of five acid gas mixtures: (1) pure H₂S, (2) pure CO₂, (3) an equimolar mixture of H₂S and CO₂ (labeled 50-50), (4) a 75 mol% H₂S + 25 mol% CO₂ (75-25), and (5) a 25 mol% H₂S + 75 mol% CO₂ (25-75). All of these compositions are on a water-free basis. The curves presented in this plot were calculated with *AQUALibrium*¹. The comments in the rest of this section are observations based on this figure and thus many of them apply only for the 120°F isotherms.

At pressure less than about 450 psia the water content of the acid gas is essentially independent of the composition (the curves are essentially coincident). As well, up to this pressure the water content is a decreasing function of the pressure.

¹ *AQUALibrium* is copyright John J. Carroll.

For CO₂, which does not liquefy at this temperature, the water content follows a single curve. The curve has a minimum at approximately 1025 psia. As the pressure increases from that point, the CO₂ will hold more water.

The 25% H₂S + 75% CO₂ mixture behaves similarly to pure CO₂ in as much as it does not liquefy. It does show a minimum in the water carrying capacity, which is at about 930 psia. And at higher pressure it holds more water than the pure CO₂.

The other three mixtures will liquefy if subjected to sufficient pressure. The pressure at which they liquefy (a three-phase dew point) depends upon the composition of the mixture. As the pressure is increased, eventually all of the mixture will be liquefied (three-phase bubble point). Note that for the pure H₂S the bubble point and dew point are equal. In Fig. 1, the three-phase regions for the 50-50 and 75-25 mixtures are the trapezoids with dotted boundaries.

For pure H₂S, the water content increases by a factor of approximately 5 from the gas to the liquid. The liquid H₂S can hold significantly more water than the in the gas phase. For the other two mixtures there is a significant increase in the water-holding capacity upon liquefaction as well.

With the 50-50 and 75-25 binary mixtures, there is a range of pressure over which the three phases exist. The initial drop of the non-aqueous liquid is richer in H₂S than the overall composition. Therefore, this mixture can hold more water than once the entire mixture is liquefied. For this reason, there is a large change in the water content of the liquid as the three-phase region is traversed.

3.3 Acid Gas Liquefaction

Liquefaction of the acid gas on the interstage of the compressor should be avoided. However, if the design requires a pressure such that liquefaction cannot be avoided, then the final stage of compression could be replaced with a high-pressure pump. To the best of our knowledge, such schemes have been considered but implemented in the field.

On the other hand, liquefaction after the final stage of compression is desirable. As was shown earlier, the liquefied acid gas can hold more water than in the gaseous state. Second, the liquid is easier to inject. However, the injection conditions are ultimately dictated by the reservoir conditions.

3.4 Anderson Puskwaskau

The authors have significant experience with the acid gas injection scheme at the Anderson Puskwaskau gas plant in northwestern Alberta. This will be discussed in some detail in this

section and in the subsequent section on injection profiles. The plant was recently modified, so here we will concentrate on the original design.

The composition of the acid gas injected has varied slightly over time, but it is approximately 45% H₂S, 51% CO₂, and 4% CH₄. The volume of gas to be injected is 106 MCFD.

The original design of the acid gas compressor was for a suction pressure of approximately 7 psig and a discharge pressure of 1400 psig. This is a compression ratio of 65 or about 2.84 per stage of the four-stage unit. The interstage cooling is achieved using aerial coolers and the exit temperatures were controlled at 120°F. The final stage after cooling is controlled at 150°F.

As noted earlier, the gas enters the compressor first stage suction saturated with water. After each stage of compression the gas is cooled to 120°F and water drops out on the intersatge. This is demonstrated in Fig. 2, which shows the water content of the acid gas stage by stage.

The water enters saturated with water, but this point is off scale on Fig. 2 (approximately 4000 lb H₂O/MMCF). The gas is compressed and cooled. Following the broken line, this point is at about 60 psi and 1400 lb/MMCF. The compression/cooling process steps down the water content curve until the last stage.

The acid gas leaving the after cooler is single phase and is undersaturated with water. From Fig. 2 it can be seen that the acid gas is under saturated with water at 120°F. Since the acid gas can hold more water at 150°F, it is also undersaturated at this temperature.

4.0 PIPELINE

The acid gas is transported from the compressor to the wellhead via a pipeline. The design of the pipeline essentially follows conventional methods.

Usually the pipeline will be as short as possible. The disposal well should be near the plant, but off-site. The pipeline should therefore be from several hundred feet to two or three miles in length. Safety risks increase as the length of the pipeline increases. The line may be filled with liquefied acid gas and a break in the line would result in a large release of hydrogen sulfide.

Theoretically, carbon steel could be used for pipeline construction because of the low water content. However, public safety is of paramount importance. Usually 304/316L stainless steel is employed for best corrosion resistance. The pipeline is coated with external coating to prevent soil moisture from damaging steel. ASME code is used for the maximum design pressure to limits of pipe or flanges. The design engineer should attempt to minimize the number of connections while still giving consideration for future what-ifs for tie-ins and extra instrumentation just in case.

The pipeline is usually buried to a depth of 6 ft to minimize freezing concerns. The line should be equipped with extensive redundant instrumentation to ensure complete safety and integrity of the system. Additional safety considerations for the entire injection scheme are discussed in a subsequent section.

4.1 Hydrates

Of the components commonly found in natural gas, none forms hydrates more easily than hydrogen sulfide (Carroll and Mather, 1991). The hydrogen sulfide hydrate forms at the lowest pressures and persists to the highest temperatures. It is in the pipeline that the coldest temperatures are encountered in the acid gas injection scheme and therefore hydrates are anticipated.

There are three methods commonly employed to combat the formation of hydrates: (1) the use of inhibitors (such as methanol), (2) the application of heat and (3) dehydration. In our opinion, dehydration is not a requirement here (as will be discussed in more detail later).

In the transport of the acid gas from the compressor to the well head it is expected that the gas/liquid mixture will cool to ambient temperatures. For small injection schemes this is true even if the gas is heated (or not cooled) after the final stage of compression. Thus using heat to battle hydrates in the pipeline is usually not an option. However, the line could be heat traced to maintain a minimum temperature.

The primary method to control hydrates is to inject methanol. The methanol rates are usually quite low (1 or 2 gallons per day for a small scheme).

In the schemes that we design we do not dehydrate the acid gas, rather compression is used to reduce the water content of the gas. The water should remain dissolved in the acid gas and thus will not form hydrates (see Carroll, 1998a,b).

Hydrates are more of a problem during start up. Typically the equipment has been hydro-tested and any residual water will quickly freeze when in contact with high pressure acid gas. In these cases plenty of methanol should be on hand to thaw the line. Or preferably, precautions should be taken to remove all of the residual water from the equipment.

5.0 INJECTION PROFILES

The injection profile, and hence the injection pressure, are key parameters in the design of the system and thus they will be discussed in some detail. Furthermore, some of the potential difficulties with injecting acid gas are revealed.

5.1 The New Model

The model presented in this work is an extension of the one that was presented earlier (Carroll and Lui, 1997). The wellhead pressure at an injection well can be calculated as the sum of several contributions:

$$\begin{aligned} \text{Wellhead pressure} &= \text{reservoir pressure} \\ &+ \text{pressure drop due to formation porosity and permeability} \\ &+ \text{pressure drop due to skin damage} \\ &+ \text{pressure drop through the perforations} \\ &- \text{static head of tubing fluid} \\ &+ \text{frictional pressure drop} \end{aligned} \quad (1)$$

For most small injection schemes the reservoir pressure and static head terms are the only ones of significance. In particular, it is assumed that the pressure drop due to friction is not important, although the design engineer is advised to review these factors in each case. In order to calculate the injection pressure, one integrates the differential hydrostatic equation from the reservoir conditions to the surface. The hydrostatic equation is:

$$\frac{dP}{dh} = -\rho g \quad (2)$$

The density of the acid gas is calculated using the volume-shifted Peng-Robinson (1976) equation of state (see Carroll and Lui, 1997). This may not be the most accurate method for this application, but it is satisfactory for our purposes.

The temperature profile along the well is assumed to be linear and the fluid is assumed to be instantaneously at the temperature of the surroundings. It will be shown that the temperature has a dramatic effect on the calculated profiles, so this effect cannot be taken lightly.

Carroll and Lui (1997) used a simple Euler method for integrating the hydrostatic equation. Further investigation of this method revealed some problems. Even with relatively small step sizes there could be significant error in the integration. Thus, to achieve accurate integration fairly small step-size, and thus increased computation, was required. Furthermore, as the phase boundary is approached, the integration became highly unreliable, even though the scheme did not enter the two-phase region.

In this work, the hydrostatic equation is integrated using the Runge-Kutta-Fehlberg (Gerald and Wheatley, 1989) integration method, with automatic step size adjustment. Usually the method has no difficulty integrating the equation, however, in the region near the phase boundary, and in particular near a critical point, step size adjustment is required. Frequent adjustment of the step size is indicative of larger problems, such as a phase transition.

The resulting program is called the *AGIPProfile* and is copyright John J. Carroll. A sample output (in SI Units) is appended to this paper.

Phase Envelope. The first step in calculating the injection pressure is the calculation of the phase envelope. The intersection injection profile and the phase envelope can have a dramatic effect, as will be shown. In all cases presented here, the phase envelopes were calculated using the Peng-Robinson equation of state.

5.2 Hypothetical Examples

To begin, two relatively simple cases will be considered. In each of these cases the acid gas composition is 82% carbon dioxide, 15% hydrogen sulfide, and 3% methane. In these cases the depth of the injection well is 3900 ft, the reservoir temperature is 120°F, and the wellhead temperature is 32°F. Other conditions will be stated for each particular case.

The purpose of these two cases is to show: (1) How the reservoir conditions have a significant effect on the injection. (2) That, if the reservoir pressure is sufficiently low, the acid gas can be injected as a gas (or gas-like fluid).

Case 1. In this case the reservoir pressure is assumed to be 1740 psia. The estimated injection pressure is 591 psia. The injection profile, along with the phase envelope are shown in Fig. 3. The injection profile starts with the wellhead, in the lower left, and terminates in the reservoir, upper right.

In this case the fluid remains single phase over the entire injection profile. For the portion of the injection profile on the left of the diagram, the fluid is clearly a liquid since the pressure is greater than the bubble point. At the wellhead conditions, the fluid density is estimated to be 51.5 lb/ft³. At high pressure, to the right on the diagram, the fluid is supercritical. However, there was no phase transition. At the reservoir conditions, the estimated density of the fluid is 31.3 lb/ft³, which is also liquid-like.

Note the density of the fluid remains liquid-like over the entire injection profile. It does, however, change significantly – by 20.3 lb/ft³.

In this case, if you incorrectly assumed that the density was constant and equal to the density at reservoir conditions (this is a convenient reference point because both the temperature and the pressure are known), then the estimated injection pressure is 883 psia which is significantly higher than that obtained by the more rigorous model. Using a density of 51.5 lb/ft³, which is the density at the wellhead as calculated using the rigorous model, this predicts that the well would be under vacuum (i.e., wellhead pressure less than zero). First, this prediction is significantly less than that from the rigorous model. Second, the well would not be under vacuum; the injection fluid would vaporize. Unlike water injection wells, which

are commonly operated under vacuum, the acid gas has a large vapor pressure. This effect is discussed in more detail later.

Case 2. In this case the reservoir pressure is 580 psia and the estimated injection pressure is 450 psia. The injection profile and phase envelope are plotted in Fig. 4. Note, the phase envelope is the same as in the previous case but it has a different appearance because of the change to the scale of the y-axis.

In this case, the injection fluid is gas-like at reservoir conditions (estimated density of 4.7 lb/ft³). At the wellhead, the fluid is a gas (i.e., at a pressure less than the dew point pressure). The estimated density of the acid gas at wellhead conditions is 4.8 lb/ft³. It is interesting to note that although the fluid is gaseous, the density is approximately constant.

Comparison. In the first case the fluid is liquid and has a relatively high density. This high density fluid provides a significantly larger hydrostatic head. In Case 1 the reservoir pressure is 1160 psi larger than Case 2 (1740 vs. 580 psia), yet there is only about 141 psi difference in the calculated wellhead pressures.

We usually assume that gases are compressible and that liquids are incompressible. However, it is demonstrated that assuming the liquid is incompressible (i.e. constant density) can lead to a serious error in the estimated injection pressure. On the other hand, assuming that the gas is of constant density is a good approximation in this case, even though we know that the density of a gas is a strong function of both the temperature and the pressure.

In these two cases, the wellhead is approximately at saturated conditions. In Case 1, at the wellhead the fluid is a saturated liquid and for Case 2 it is a vapor and just slightly superheated. We can anticipate that for reservoir pressures greater than 1740 psia the injection fluid will remain liquid for the entire injection profile. For reservoir pressures less than 580 psia, the injection fluid will remain a gas. However, for pressure between 580 and 1740 psia, the injection profile will intersect the phase envelope. Again, this is discussed further later in this paper. At this point it is sufficient to note the importance of the phase equilibrium in these injection schemes.

5.3 Chevron Injection Wells

Complete details of acid gas injection schemes in the literature are rare. Lock (1997) gives details of two injection schemes operated by Chevron Canada Ltd. These are the most completely described schemes available in the open literature. Other schemes are described, but too much important information is omitted to do a reasonable job of calculating the profile.

West Pembina. From Lock (1997) the disposal well at the Chevron West Pembina site has a depth of 9186 ft and the composition of the acid gas injected is approximately 21.93%

carbon dioxide, 77.17% hydrogen sulfide, and 0.90% methane (dry basis). Keushnig (1995) gives the reservoir pressure of 4177 psia. Lock (1997) gives this as “about 30 000 kPa” (4351 psia), so the value from Keushnig (1995) will be used here. It was further estimated that the reservoir temperature was 230°F and the injection temperature was 32°F.

Figure 5 shows the injection profile and the phase envelope for this case. This is a relatively simple case since the fluid does not change phase in the wellbore. The calculated injection pressure is 1272 psia, which is about 17% larger than the value of 1080 psia given by Lock (1997).

Part of the reason for the higher than expected estimation of the injection pressure is because of the assumed reservoir temperature. If the reservoir is assumed to be 212°F, then the estimated injection pressure is 1211 psia (10% error) and at 194°F it is 1150 psia (6% error). This demonstrates the strong effect of the temperature on these calculations.

Of course, another source of the error is that the volume-shifted Peng-Robinson equation of state may be in error by as much as 10 or 15%. Neglecting the additional terms in Eq. (1) also contributes to this error.

Acheson. From Lock (1997), the disposal well at the Chevron Acheson site has a depth of 3610 ft and the acid gas injected is 89.8% carbon dioxide and 10.2% hydrogen sulfide (dry basis). Keushnig (1995) gives the reservoir pressure of 1349 psia and this will be used here, although some of the other data in this paper are in conflict with those given by Lock (1997). It was further estimated that the reservoir temperature was 118°F and the injection temperature was 32°F.

Using the injection program described in this paper, the injection profile is calculated. The integration scheme has problems with this well indicating a potential problem – probably a phase change.

At reservoir conditions, the fluid is supercritical (density approximately 24.0 lb/ft³) and as we move up the injection well the fluid becomes a liquid (the pressure is greater than the bubble point pressure).

At a temperature of about 52°F the injection profile intersects the phase envelope. From this point to the surface, the fluid remains in two phases. In this self-regulating system, any heat transfer from the surroundings to the fluid will condense or evaporate the liquid and thus the pressure will return to the equilibrium value.

Based on this calculation, for the first 820 ft, or so, in the well the mixture is two phase. At greater depths the mixture has completely liquefied and remains liquid down to the reservoir.

According to this theory the injection pressure is estimated to be about 479 psia, which is in excellent agreement with the observation from the field that “the actual injection pressure upon start-up was only 3 500 kPa (508 psia) and remains at that level today” (Lock, 1997). Also according to this theory, the pressure will remain steady at about 508 psia, even though the reservoir pressure is increasing. According to the calculation, once the reservoir pressure reaches about 1624 psia, then the surface pressure should begin to rise. At that point the fluid will be liquid for the entire length of the well. This should also serve as a warning. Just because the wellhead pressure does not change over time (even over a fairly long period of time), one should not interpret this as “no problems” injecting into the reservoir.

The injection profile for this well is shown in Fig. 6. Notice how the injection profile intersects the phase envelope.

This well demonstrates two things clearly. First, phase equilibrium can play a significant role in calculating the injection pressure. Second it shows that just because the wellhead pressure remains unchanged over a period of time does not mean that the operator can assume that there is no pressure build-up in the reservoir.

5.4 Anderson Puskwaskau

This well has a depth of 8800 ft and a reservoir pressure of 4134 psia and temperature of 180°F. The composition of the acid gas injected has varied over time, but it is approximately 45% H₂S, 51% CO₂, and 4% CH₄. It was assumed that the wellhead temperature was 40°F. From the program outlined in this paper, the injection pressure is estimated to 1340 psia, which is in excellent agreement with the actual pressure of about 1230 to 1280 psia. This is an error of about 5 to 9%.

5.5 Further Comments

Presented in this paper is a method for calculating the injection pressure for acid gas disposal systems. The accuracy of this method is demonstrated by comparing it to field data.

It is further shown the importance of the phase equilibria on acid gas injection. The phase transition region provides a self-regulating effect on the pressure that is beyond the simple hydrostatic head calculation.

It was noted by Carroll and Lui (1997) that the presence of methane in the acid gas can dramatically increase the required injection pressure. This model predicts that as well. However, this paper more clearly demonstrates the effect of the phase behavior on the injection process. The presence of methane in the acid gas makes the fluid more volatile (or more difficult to compress, depending upon your point of view). This can be a further impairment to the injection process.

In all the cases discussed above, both the hypothetical ones and those based on field data, the injection profile are at temperatures near the mixture critical point. This region is notorious for accurate physical property predictions. Not only do the calculations of the physical properties tend to be inaccurate, in the critical region they are strong functions of the temperature and the pressure. This makes these calculations more difficult.

6.0 SAFETY CONSIDERATIONS

In a typical acid gas injection scheme, the pipeline and wellbore are filled with liquefied acid gas. If released to the environment this could pose significant environmental hazard and would be a threat to the lives of humans and animals in the vicinity of the leak. Hydrogen sulfide is very toxic.

A typical system is equipped with the following emergency shut down (ESD) valving:

1. Acid Gas Compressor Suction ESDV - Shuts automatically on any compressor shutdown
2. Acid Gas Compressor Discharge ESDV - Shuts automatically on any compressor shutdown
3. Acid Gas Injection Wellhead PCV - Controls compressor discharge pressure to ensure proper phase behavior
4. Acid Gas Wellhead ESDV - Shuts automatically on any system malfunction or compressor shutdown

In addition, the system is continuously monitored for:

1. High Pressure/Low Pressure at discharge, injection and wellhead
2. Casing pressure trending for tubing/packer failure
3. Tubing pressure trending for unexpected system responses
4. Wellhead H₂S ambient exposure levels
5. Discharge Pressure trending for unexpected process responses

It is very important to have contingency plans for virtually any situation that can occur. You should be prepared for anything. Check all systems again and again to ensure compliance so that when sour gas is in operation, there are no surprises. Good understanding of instrumentation principles, a good practical sense, extreme unwillingness to compromise safety are all

hallmarks of a good acid gas injection system program. The installation should include multiple blowdowns, blowbacks, purges, etc. for additional safety.

In order to combat problems arising from hydrate formation, one should keep plenty of methanol on hand.

7.0 PROCEDURES FOR START-UP

Throughout the initial portion of the start-up, the sour gas inlet is spectacle blinded for safety. The spectacle blind should be removed only when you are prepared to bring the acid gas into the system.

Before beginning the pressure testing, a full flowsheet check confirming check valves, port sizes, PSV set points, bypasses, and overall piping assembly is required. Re-check compressor cylinder sizes against the process specification

Next, do a pre-start-up check of the compressor. Confirm the torque on the valve bolts and ensure that pistons, valves, and cylinders are installed correctly.

As a part of the leak testing procedure, all flanges should be taped and electronically sniffed through a small vent hole.

A full N₂/He test should be done to check tightness of the connections. Ensure that the leakage rate is below the 5 scf/year tightness criteria. Once again, check all flanges, cylinders, valve stems, and miscellaneous connections for leaks. All level gauges should be bagged and checked for leakage. Even with the N₂/He test, it can be difficult to find the source of a leak. The bags should be left in place in place for the sour service test.

Next, the pipeline should be pressure tested up to the ESDV. For this test, use pressures as high as possible without popping PSV's. Beware of the fact that compressor valves may not hold back pressure.

Once all of these tests have been successfully completed, the compressor can be pressurized. The unit should be fully purged on sweet fuel gas and all connections should be rechecked for leaks.

The compressor is initially run on sweet fuel gas at its lowest speed. At this point, check all bypasses, speed controls, ramping bypass controls, etc. It is important that the unit be fully operational on fuel before switching to sour gas. Confirm all auto-purge systems and check all lubrication systems. Run unit up to operating pressure and pressurize entire acid gas pipeline to operating pressure. Throughout this test, continue to check and recheck for leaks.

Sour gas may now be brought into the compressor. Full safety concerns should be in place: masks, breathing air, H₂S detection on bypass, doors open, windows open, and safety personnel nearby at the ready to assist in an emergency. After the acid gas enters the system, start another set of checks for leaks.

Once satisfied that there are no leaks, the compressor can be run at its lowest speed. Check to see how machine responds and once satisfied begin increasing the operating pressures. Continue to monitor how the compressor responds and watch the pressures on interstage. Pressurize the system to full operating conditions. As the pressure rises, continue to check all flanges and fittings for leaks.

8.0 DEHYDRATION

Since water can be a significant problem, many have suggested the use of a dehydration unit to remove water from the acid gas.

8.1 Glycol Dehydration

One of the most common methods for dehydrating natural gas is a glycol dehydration unit. The problem with this approach is that the glycol has a high affinity for the acid gases.

Consider the Puskwaskau case that has been discussed in some detail up to this point. The design remains basically unchanged except, on the interstage between the third and fourth stages one assumes that a dehydration unit will be used to dry the gas. The dehydration unit was modeled using the *GRI-GLYCalc* program and the results are summarized in Table 1.

The dehydration unit can dry the gas to less than 4 lb water/MMCFD. However, one can expect emissions on the order of 25 lb H₂S/day – a very odorous glycol unit. There is no alternative but to deal with these emissions, such as flaring or incineration. Although the volume of gas flared is small, it results in a plant that is no longer “zero-emission”. Plus, in this example the acid gas stream is very small – only 106 MCFD. Larger units would have significantly larger emissions.

In addition, Lock (1997) details the operation problems with the dehydration units operated by Chevron. These include deposition on the trays of the contactor, higher than anticipated water dew point of the gas, and difficulties dealing with the regenerator still off-gas.

Furthermore, the glycol dehydration has a large operating expense and produces a large volume of semi-condensed sour water that must be managed.

8.2 Other Means of Dehydration

The acid gas can also be dehydrated using mole sieves. The mole sieve must be selected such that it has a high affinity for water but as low an affinity for the acid gas as possible. Regardless, the mole sieve must be regenerated and this produces a sour regeneration stream that must be managed.

Some have proposed using cooling as a means of dehydrating the acid gas. A slipstream from the propane refrigeration unit is used to cool the acid gas to a temperature lower than can be achieved in an aerial cooler. The lower temperature will result in more water condensing out. With this method you must be cautious because hydrates can be formed in acid gas mixtures at temperatures as high as 85°F, depending upon the pressure (Carroll and Mather, 1991).

9.0 CARBON DIOXIDE SLIP

Among the new technologies in the gas processing industry are amine-based solvents that allow for slippage of carbon dioxide. That is, some of the carbon dioxide is left in the sales gas. All of the major vendors offer solvents that are designed to maximize CO₂ slip.

Although this application is directed mainly at plants with large quantities of CO₂, they can also play a significant role in plants with acid gas injection. Increasing the CO₂ slip reduces the volume of acid gas and ultimately the required compression horsepower.

10.0 SUMMARY

There are many factors in the design of an acid gas injection scheme. The most important is concern for safety. The extensive use of stainless steel and NACE materials is recommended. An acid gas injection project is not the place to save a little money when leaks of any kind can be catastrophic.

An intimate understanding of compression performance, especially under adverse conditions, is also of paramount importance in the design and operation of an acid gas injection scheme.

Good understanding of fluid phase behavior is important in the design of an acid gas injection process. This includes the phase equilibrium in the acid gas mixtures, the formation of aqueous phase, and the precipitation of hydrates. The phase behavior and physical properties are important in all aspects of the injection scheme.

As much as possible, keep light hydrocarbons and nitrogen out of the fluid to be injected. These light components will increase the required injection pressure and thus the horsepower of the compressor.

In our opinion, glycol dehydration is more trouble than good. The glycol exhibits high hydrogen sulfide pickup and consequently must be dealt with in the still vent gas. There is considerable potential exposure to operating staff with piping, valves, filters, pumps, etc. The dehydration unit provides many additional places for possible leakage of hydrogen sulfide.

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Table 1 Summary of GRI-GLYCalc Runs for the Dehydration of an Acid Gas

		Case 1	Case 2
Feed Gas			
Rate	MCFD	106	106
Temperature	°F	120	120
Pressure	Psia	470	470
Concentration			
H ₂ S	mol %	45.0	45.0
CO ₂	mol %	51.0	51.0
CH ₄	mol %	4.0	4.0
water		sat'd	sat'd
TEG			
Circulation	gal/lb H ₂ O	1.0	2.0
Rich Concentration	wt %	99.0	99.0
Regenerator Still Gas			
Temperature	°F	212	212
Pressure	Psia	14.7	14.7
Rate	SCFH	34.2	50.7
H ₂ S	lb/hr	1.08	2.28
Stripping Gas		none	none
Absorber			
Number of Ideal Stages		4.68	3.27
TEG Circulation	gal/hr	0.91	1.82

APPENDIX Sample Output from AGIProfile

```

*****
*
*              AGI Profile              *
* ACID GAS INJECTION PRESSURE CALCULATION *
*              Version 1.3              *
*              Copyright 1997           *
*
* J.J. Carroll                          Mar. 1998 *
*
*****

```

RUN DATE: Dec. 22, 1998

PROJECT: Anderson Puskwaskau

WELL PROFILE:

Depth (m)	Pressure (kPa)	Temperature (deg C)	Density (kg/m**3)
2682.0	2.8500E+04	8.2200E+01	6.4688E+02
2547.9	2.7645E+04	7.8312E+01	6.5029E+02
2413.8	2.6780E+04	7.4424E+01	6.5731E+02
2279.7	2.5905E+04	7.0537E+01	6.6460E+02
2145.6	2.5021E+04	6.6649E+01	6.7218E+02
2011.5	2.4127E+04	6.2761E+01	6.8004E+02
1877.4	2.3221E+04	5.8873E+01	6.8817E+02
1743.3	2.2305E+04	5.4985E+01	6.9658E+02
1609.2	2.1377E+04	5.1098E+01	7.0526E+02
1475.1	2.0438E+04	4.7210E+01	7.1420E+02
1341.0	1.9486E+04	4.3322E+01	7.2339E+02
1206.9	1.8522E+04	3.9434E+01	7.3282E+02
1072.8	1.7545E+04	3.5546E+01	7.4246E+02
938.7	1.6555E+04	3.1659E+01	7.5231E+02
804.6	1.5553E+04	2.7771E+01	7.6233E+02
670.5	1.4536E+04	2.3883E+01	7.7252E+02
536.4	1.3506E+04	1.9995E+01	7.8284E+02
402.3	1.2463E+04	1.6107E+01	7.9328E+02
268.2	1.1405E+04	1.2220E+01	8.0381E+02
134.1	1.0334E+04	8.3318E+00	8.1440E+02
.0	9.2487E+03	4.4440E+00	8.2505E+02

Estimated injection pressure = 9.2487E+03 kPa

STREAM DIAGNOSTICS:

DENSITY CORRELATION: Peng-Robinson equation of state -
volume-shifted
(SiPPS Version 2.0 -- (C) J.J. Carroll, 1993)

SPECIFIED PHASE: liquid

MIXTURE MOLAR MASS: 38.423 kg/kmol

ESTIMATED VISCOSITY:

Bottom hole conditions: 6.117E-05 Pa.s
Bottom hole conditions: 6.117E-02 centipoise
Surface conditions: 9.150E-05 Pa.s
Surface conditions: 9.150E-02 centipoise

DENSITY RANGE:

Maximum Density: 8.250E+02 kg/m**3
Minimum Density: 6.469E+02 kg/m**3

STREAM COMPOSITION (mole %):

CARBON DIOXIDE	51.00
HYDROGEN SULFIDE	45.00
METHANE	4.00

INTEGRATION DIAGNOSTICS:

Maximum integration error: 1.287E-05 kPa/m
Number of integration steps: 20
Initial step size: 1.341E+02 m
Maximum step size: 1.341E+02 m
Minimum step size: 1.341E+02 m
Step size halved 0 times
Step size doubled 0 times

Integration completed without step-size modification

Fig. 1 Water Content of Acid Gas Mixtures at 120°F
(Dashed trapezoids are three-phase regions)

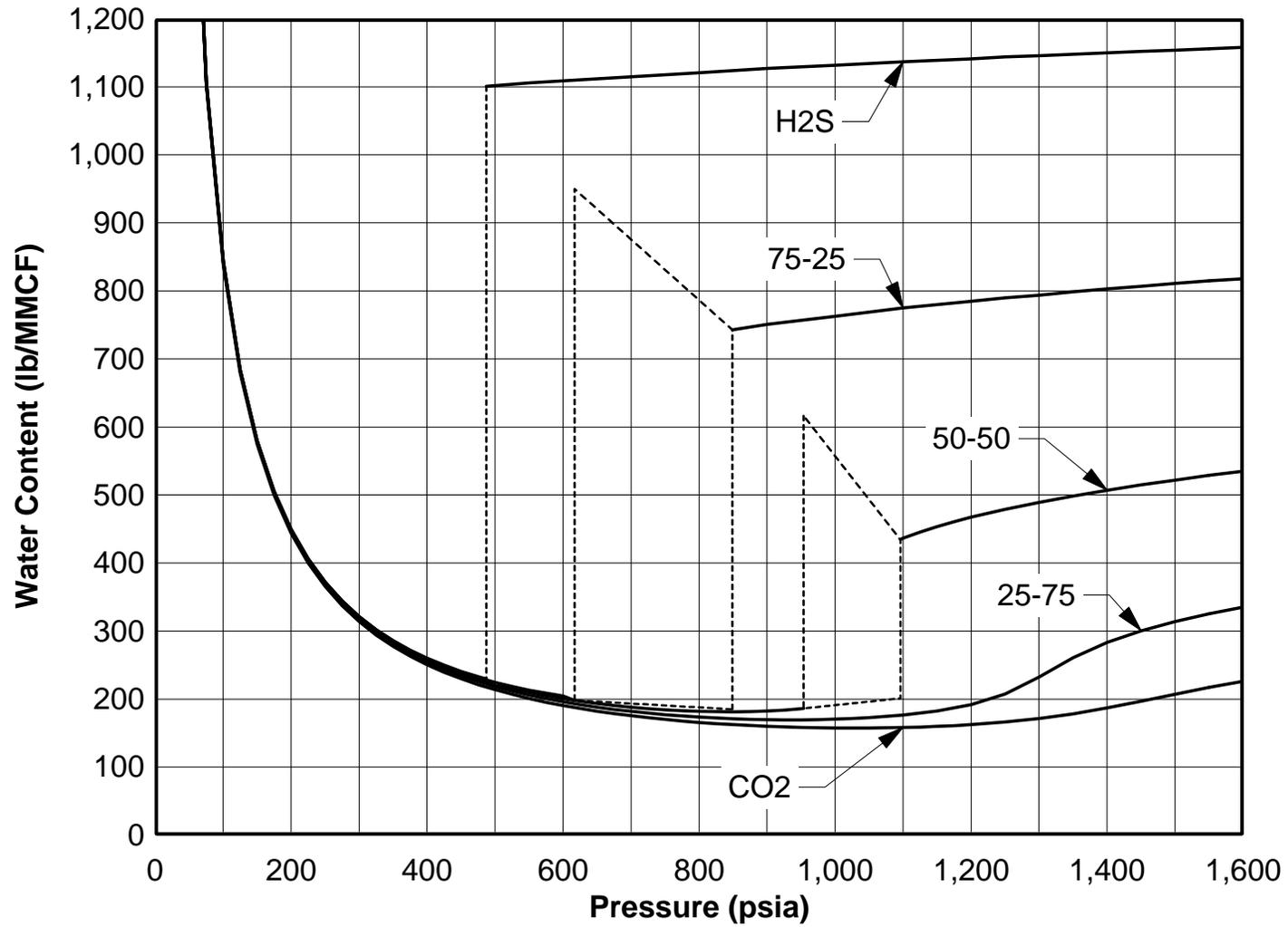


Fig. 2 Compression of Acid Gas at Puskwaskau Gas Plant (120°F)

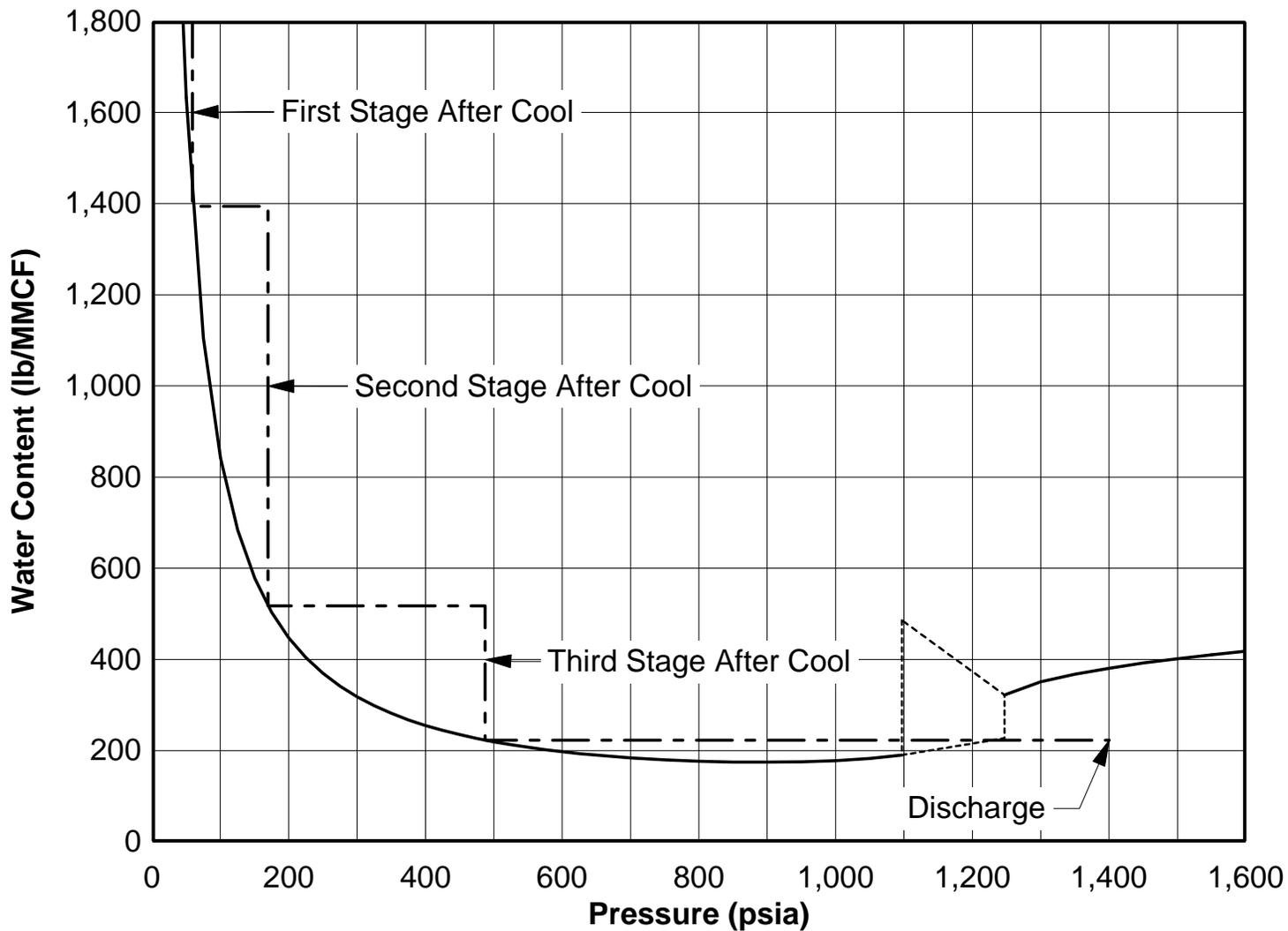


Fig. 3 The Calculated Injection Profile for Case 1

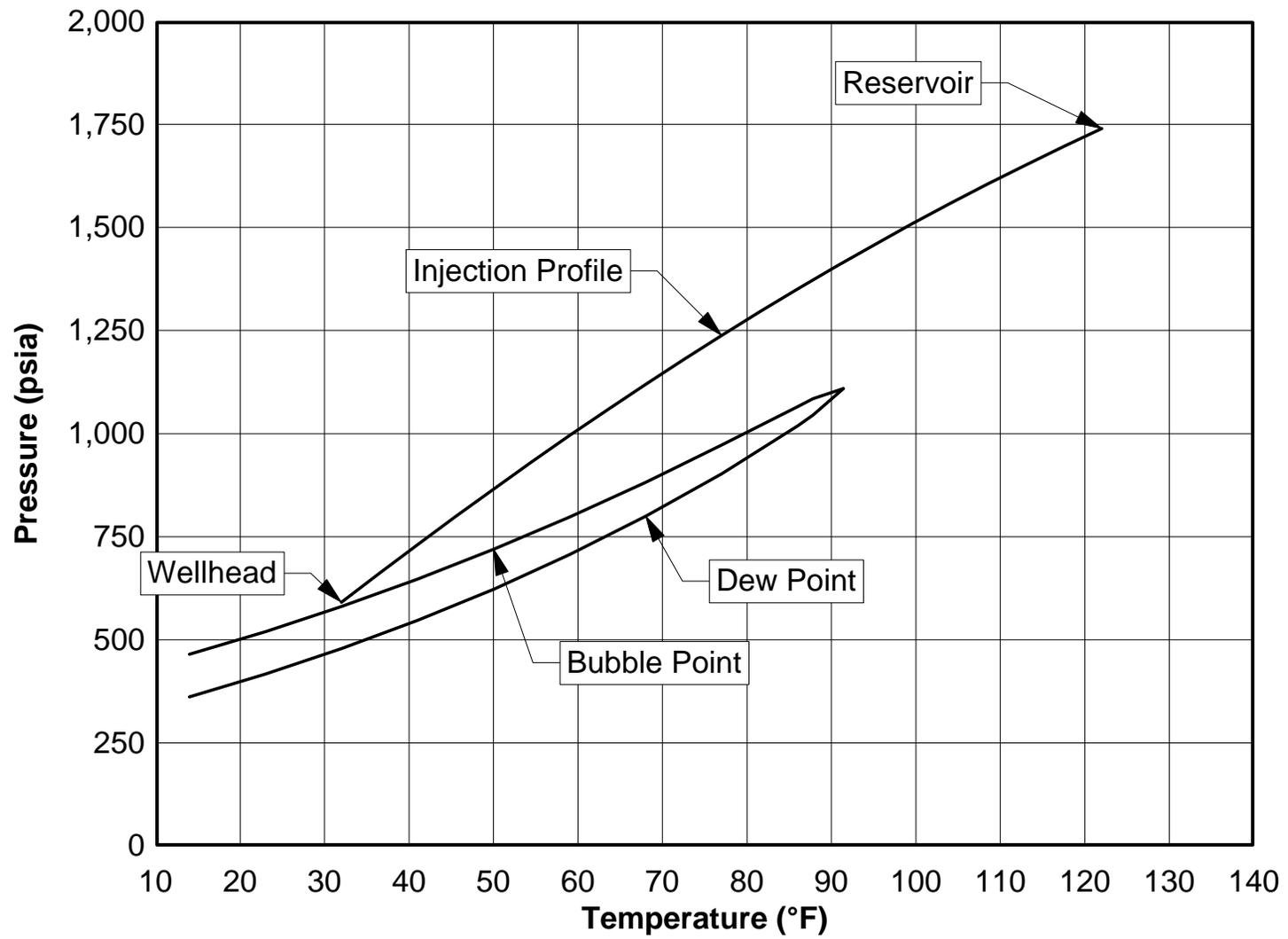


Fig. 4 The Calculated Injection Profile for Case 2

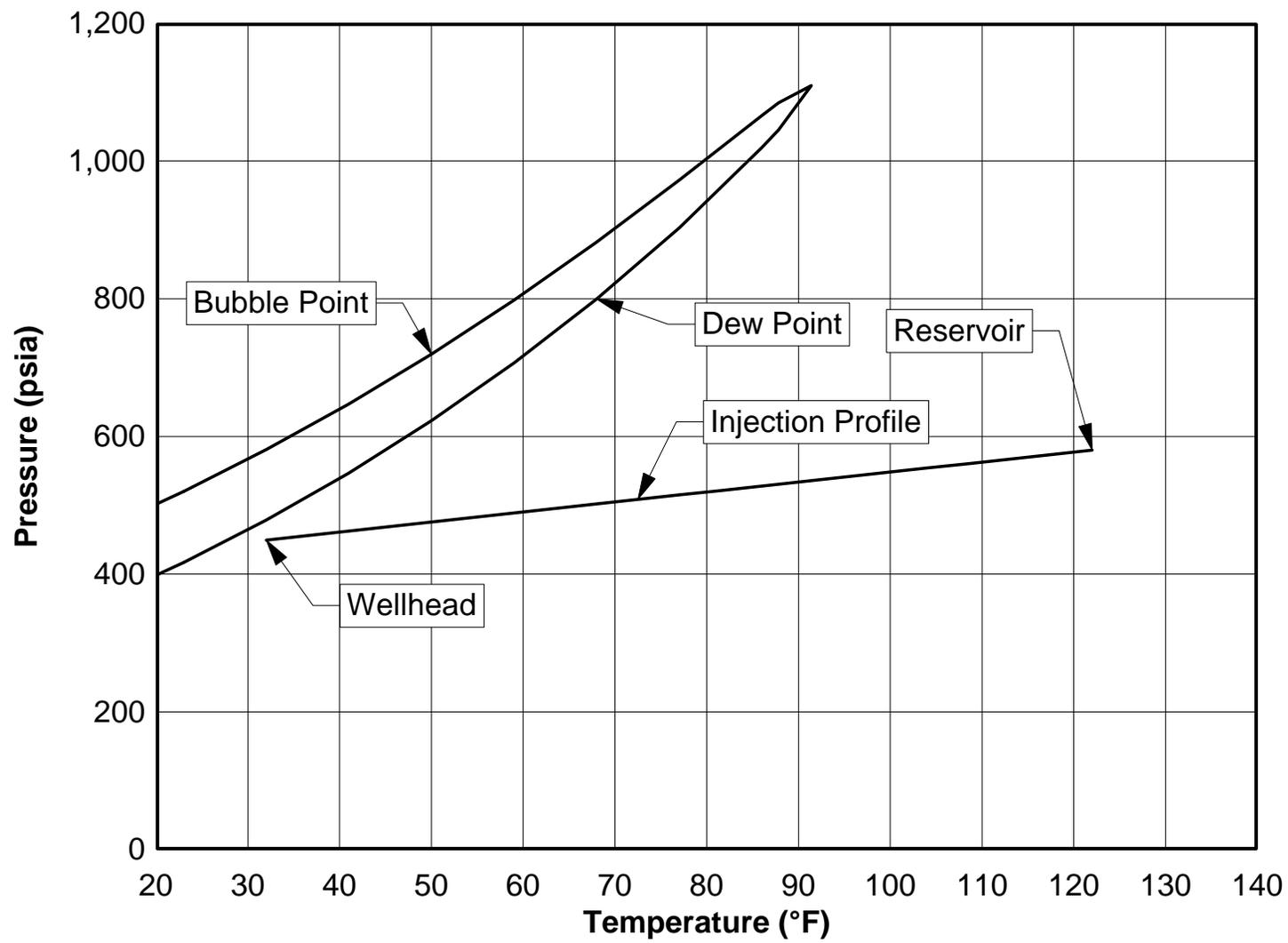


Fig. 5 The Calculated Injection Profile for the Chevron West Pembina Well

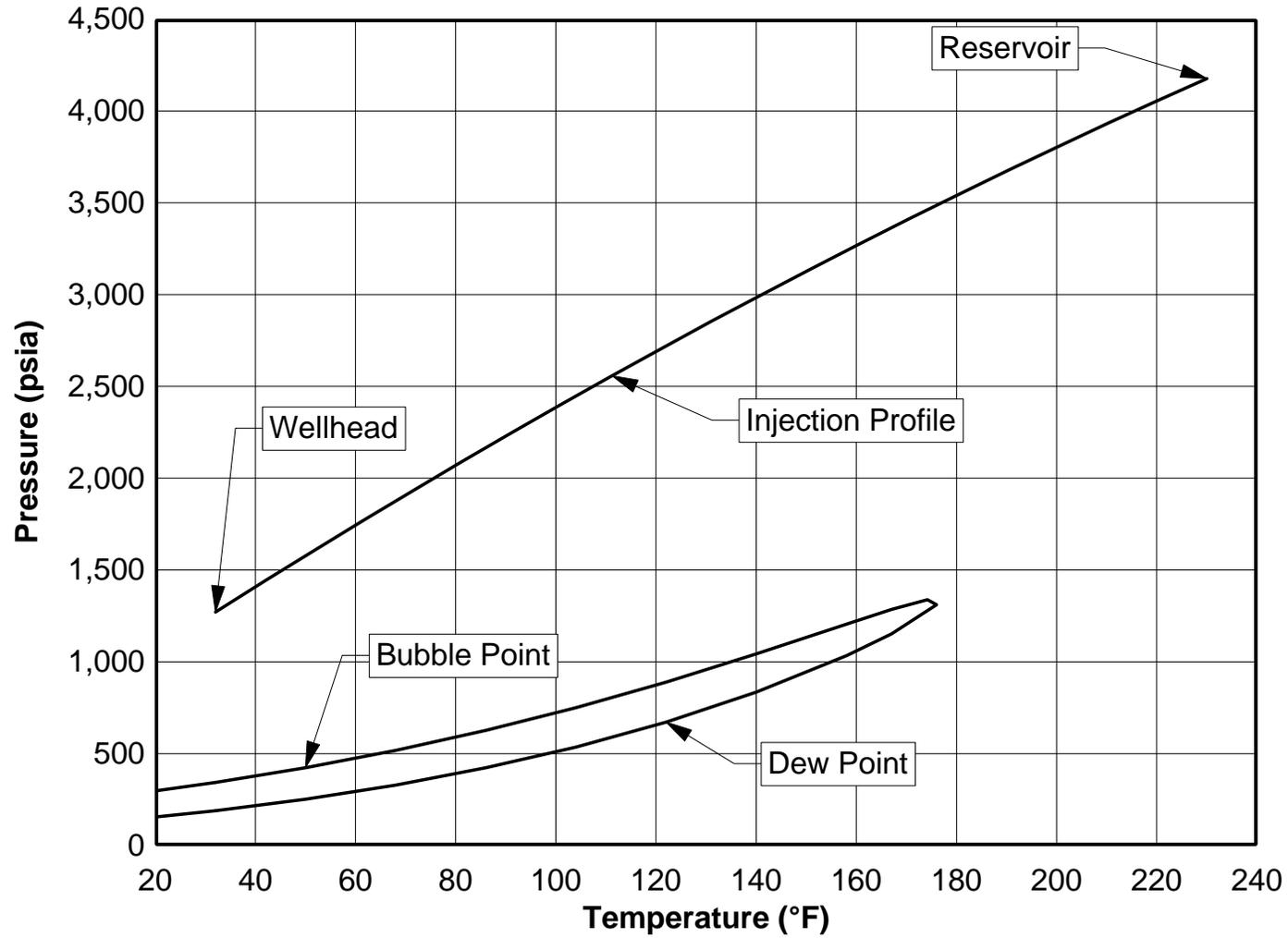


Fig. 6 The Calculated Injection Profile for the Chevron Acheson Well

