ACID GAS INJECTION: AN OPERATOR'S PERSPECTIVE

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Devon Canada Corporation (Devon) currently operates five acid gas injection systems within North Central Alberta. While there are a number of similarities, each one is slightly different in nature. Differing injection requirements, new developments, and increasing facility experience has allowed for three (3) differing generations of acid gas injection equipment and technology. This paper will present four schemes illustrating some of the design aspects, problems, and solutions that were unique to each project.

INTRODUCTION

Devon Canada Corporation is based in Calgary, Alberta, Canada. Devon and its predecessor Anderson Exploration Ltd., operate five acid gas injection projects in North Central Alberta. Each of these projects is based in the Peace River Arch area, a significant production area for Devon. As acid gas injection technology and understanding has developed extensively, Devon and Gas Liquids Engineering (GLE) have each responded in order to ensure the highest level of safety, on-line time, and system performance. Each project has developed in slightly different ways, however, a number of common factors have become evident for the success of any acid gas injection process.

CASE STUDIES

Puskwaskau

The Puskwaskau production facility is located approximately 55 km northwest of Grande Prairie, Alberta. This development project was planned simultaneously with Devon's Dunvegan acid gas injection project.

The original project, due to low acid gas volumes, was initially deemed to be a candidate for acid gas flaring. The low volume of acid gas, at 0.995 tonnes/day, was less than the Alberta Energy Utilities Board (AEUB) mandated maximum of 1 tonne for flaring. Regulatory compliance was still required with regards to dispersion of SO_2 within the area.

During the public consultation process, it became obvious that immediate approval of the facility would not be forthcoming, with several area residents expressing concern about acid gas flaring. After a series of public meetings and information sessions, Anderson Exploration agreed to study the merits of acid gas injection and a decision was made to incorporate Acid Gas Injection (AGI) at the Puskwaskau facility to dispose of the acid gas from the amine regeneration facility. Subsequently, a revised Application was sent to the AEUB in late 1995.

The facility received AEUB approval in early 1996. Design criteria for the main facility is as follows:

Main Feed Gas:	21.16 MMSCFD
H_2S Content:	2385 ppm
Inlet Sulphur:	1.9382 tonnes

Inlet gas, water and condensate is gathered at the main location, and separated. Water is sent to the Produced Water Tanks for storage. Condensate is sent via level control to a condensate stabilizer. Inlet gas is compressed to an interstage pressure, and sweetened in a conventional amine sweetening plant using 20 USGPM of 35wt% diethanolamine (DEA). Sweet gas exiting the amine plant is refrigerated in a propane based system and 80 wt% EG is injected for simultaneous hydrate and water dewpoint control. Any condensed liquids from the Low Temperature Separator are also sent to the Condensate Stabilizer and an atmospheric RVP product was produced. Warm, dry sales gas is then compressed to sales pressure, metered, and sent to the pipeline for use on consumer and industrial sites.

Early reservoir work and geology identified that the Leduc reservoir would be an excellent candidate for the injection process. It is a depleted gas zone with a large amount of water present. The injection zone was determined to be 2670 meters (8759') below surface. This zone was excellent due to a number of features:

- Deep zone prevents nearby producers/operators from drilling through the injection zone searching for production.
- Good cap rock integrity
- Good extent for dispersion of acid gas fluid
- No longer a producing zone

A search of nearby wellbores showed that an abandoned well existed 500 meters from the plant to the southeast.

An in-depth study of the zone was undertaken to determine the depth and extent of the zone, as well as to establish cap rock and casing integrity. A cement bond log was completed to illustrate the integrity of the cement/casing bond to ensure that no cross-contamination occurred.

Design Aspects

Amine regenerator acid gas at a rate of 0.106 MMSCFD would be directly compressed in a four stage reciprocating compressor to the required injection pressure. The composition of the acid gas injected has varied slightly over time; but it is approximately 45% H_2S, 51% CO_2, and 4% CH_4. The volume of gas to be injected at the time of design was 106 MCFD.

Wellbore parameters are as follows:

Depth:	2670 m
Pressure:	29.5 MPa
Temperature:	82°C

The original design of the acid gas compressor was for a suction pressure of approximately 7 psig and a discharge pressure of 1400-1600 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 to 150°F.

Gas enters the compressor first stage suction fully saturated with water. After each stage of compression the gas is cooled to 120°F and water drops out on the interstage. This is demonstrated in Fig. 1, which shows the water content of the acid gas stage by stage.

The acid gas enters saturated with water at 4000 lb H_2O/MMSCF. The gas is compressed and cooled. Following the broken line, this point is at about 60 Psia and 1300 lb/MMSCF. The compression/cooling process steps down the water content curve until the last stage.

The acid gas fluid leaving the after cooler is single phase and is under saturated with water. From Fig. 1 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 under-saturated at this temperature.

Dehydration would not be necessary due to the natural "auto-dehydration" effect of acid gas within this type of system.

As is shown below, fluid exiting the compressor package at point D will be under-saturated and will have a much lower hydrate point than fluid at point C. For example, the above fluid at 450 Psia will have a hydrate point of 76°F while the same fluid at 1477 Psia will have a hydrate point of 31°F.

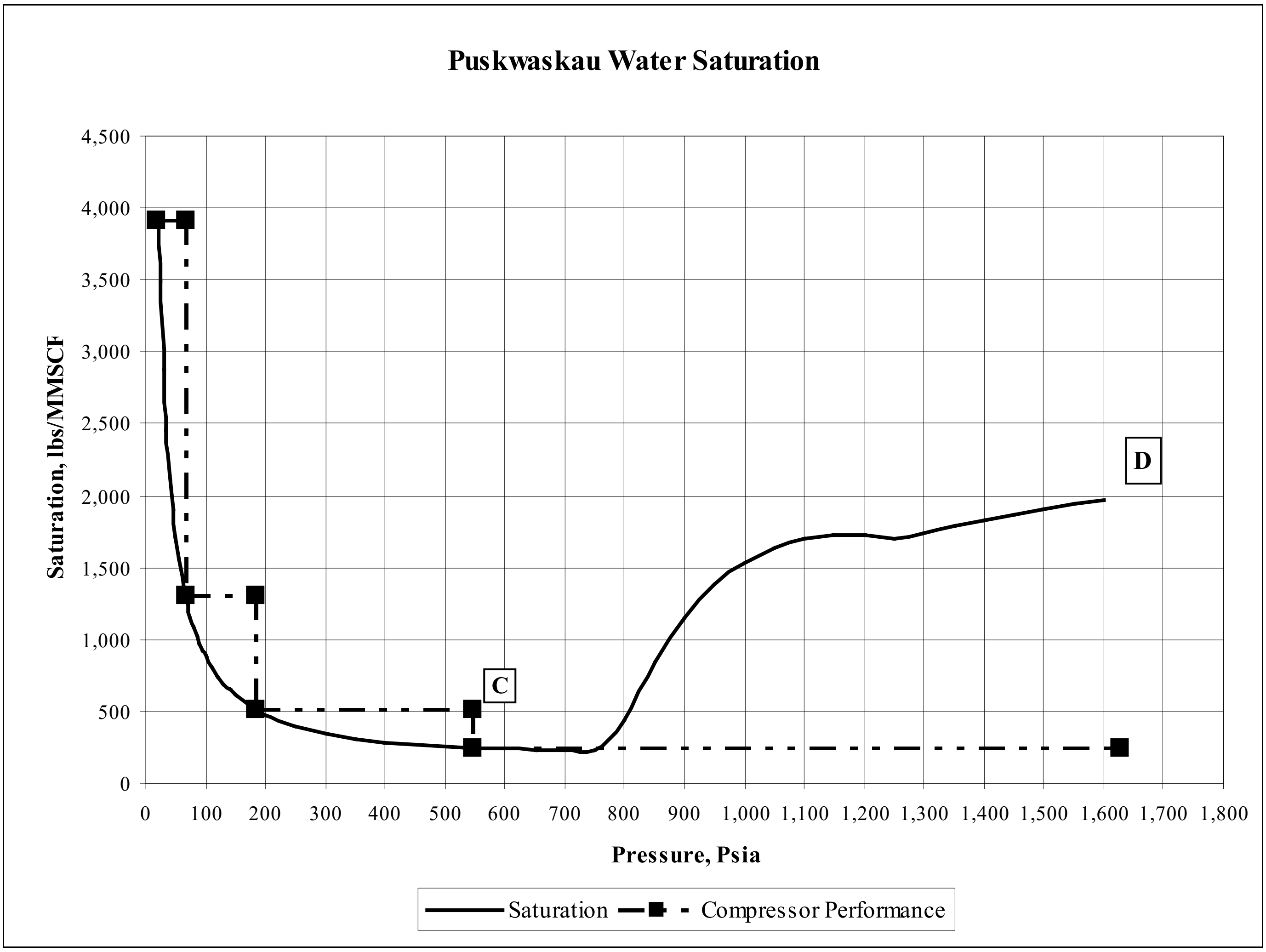


Figure 1

Much of the early Puskwaskau design work was based upon the author's experience with the Canrock Fourth Creek acid gas injection facility. At the time the Canrock facility was designed and constructed, acid gas injection technology was in its infancy. The Canrock facility incorporated a number of unusual process modifications, including fuel gas suction pressure makeup, injection of amine flash tank overheads, and auto-purge technology among other things.

A number of significant issues arose throughout the design phase and construction phases:

A) Acid Gas Compression Volume

Although selective sweetening technology was well known, there was considerable concern among the design group that the success of the selective sweetening process would have a huge impact on the potential size of the compressor. If the amine extracted higher than anticipated levels of CO_2 from the inlet gas, the compressor could conceivably be under-sized.

Due to the nature of the permitting process, the acid gas compressor was considered essential to the success of the facility - that is, if the compressor failed to inject acid gas, then the facility production would firstly be scaled back, then shut-in. Long-term flaring, due to the inability to inject, would not be permitted under the facilities operating license. It became critical to establish a design rate for the acid gas compressor

In order to achieve the highest level of confidence in the system, we chose to proceed with a DEA design to allow for the highest amount of acid gas possible. This allowed for a considerable degree of future flexibility to increase plant capacity with a selective amine based process.

B) Amine Flash Tank Overheads

As stated previously, much of the Puskwaskau design work was based on work completed during the previous summer (1995) for Canrock at their Fourth Creek facility. During the commissioning and operation of the Fourth Creek facility, injection of the acid gas failed due to a buildup of non-condensable components within the wellbore. This design incorporated re-injection of the Amine Flash Tank gas. It became obvious that the presence of hydrocarbons and other non-condensable gas within the acid gas would drastically impair the "injectability" of the fluid. The Amine flash tank gas was removed from the Puskwaskau compression scheme to ensure the required injection of the acid gas.

C) Capacity Control

The original design for Puskwaskau was to utilize a complex capacity control system for the acid gas compressor. Bypassing acid gas compressor discharge fluid was not practical for a number of reasons:

- Bypassing cool liquid acid gas into the suction header would generate cryogenic temperatures colder than –90 F. These temperatures would require expensive metallurgy, plus the fluid would be entering the 1st stage with liquid present potentially causing considerable machine damage.

- These low temperatures would result in hydrate formation.

The original design used a number of capacity control methods:

- Variable speed drive for infinite suction pressure control with 5:1 turndown.
- Variable volume pockets within the compressor
- Hot gas bypass for settings below minimum speed
- Fuel gas make-up for settings below minimum speed

Based on the work completed during the commissioning and troubleshooting of the Fourth Creek facility in 1995, it became apparent that the concept of fuel gas suction pressure makeup could not be tolerated by the injection scheme. As well, the auto-purge technology was deemed too "risky" and was subsequently removed to safeguard against the introduction of methane into the wellbore.

D) Prediction of Injection Profile

One of the key parameters within the design of any acid gas injection scheme is the calculation of wellbore injection pressure. Obviously over-designing the compressor and associated equipment for excessive discharge pressures has both economic and process implications.

Design of this project was completed prior to the development of GLE's AGIProfile software. This software utilizes a volume shifted "equation of state" based calculations to predict liquid density. Consequently, early methods relied on computer predictions of fluid density and hand calculations of "backwards" integration up the wellbore from the injection pressure and temperature. Thus it was necessary to calculate the density of fluid at injection conditions and assume that this density was constant for a finite depth of tubing. Using 10 to 15 iteration points was fairly common and the designer could then calculate the density up the wellbore using a linear temperature approach. This calculation method, while relatively accurate, relied upon traditional equation of state methodology. Calculations were completed based on the assumption that the acid gas fluid would arrive at the wellbore at ground temperature (3°C). At one point in the construction of the project, the decision was made to insulate and heat trace the pipeline to prevent the formation of hydrates during long term shutdowns. While the logic was valid and sound, the addition of insulation meant that the fluid now arrived at the wellbore much warmer than anticipated. This necessitated much more detailed calculations. The original calculations were based on Hysim generated fluid densities over a wide range using few points. The detailed design work used curves generated with many more points. These curves showed a disturbing trend to lowered fluid densities surrounding the critical point. Ironically enough, the Puskwaskau fluid actually passed through the critical point in the wellbore further complicating the calculations. During the detailed calculation work, it became obvious that, based on the information available, there was a probability that the injection scheme discharge pressure would be much higher than anticipated – in fact, exceeding the design pressure of the 4th stage equipment and pipeline.

While we inherently believed that fluid densities did not obey the Hysim predictions, the decision was made prior to startup to install an acid gas chiller to ensure that the fluid reached the wellbore at the appropriate cool temperature. This would ensure a high density and thus a lower wellhead injection pressure.

Project Aspects

While acid gas injection had been done before, it was relatively unknown technology for Devon Canada. The safety of the public and Devon's operation staff was considered to be a paramount importance. The facility was expected to be constructed to the highest quality standards, with rigorous inspection procedures, engineering reviews, and input from all affected groups. A number of resident meetings were held to ensure that local residents and landowners understood the nature and timing of the project and to ensure that all groups were well informed. Safety and equipment integrity were considered to be the most important aspects and it was realized that the control system is an inherent part of any AGI system. Vendor inspections were numerous, and rigorous drawing reviews were held, particularly with the compressor vendor.

Equipment Aspects

A number of equipment design parameters were selected early in the project for maximum operability, safety, and ease of performance. These were:

1. Designing for lower than anticipated suction pressure

   - Variable speed drive for infinite suction pressure control with 5:1 turndown.
   - Variable volume pockets within the compressor
   - Hot gas bypass for settings below minimum speed
   - Fuel gas make-up for settings below minimum speed

2. Designing for low speed operation

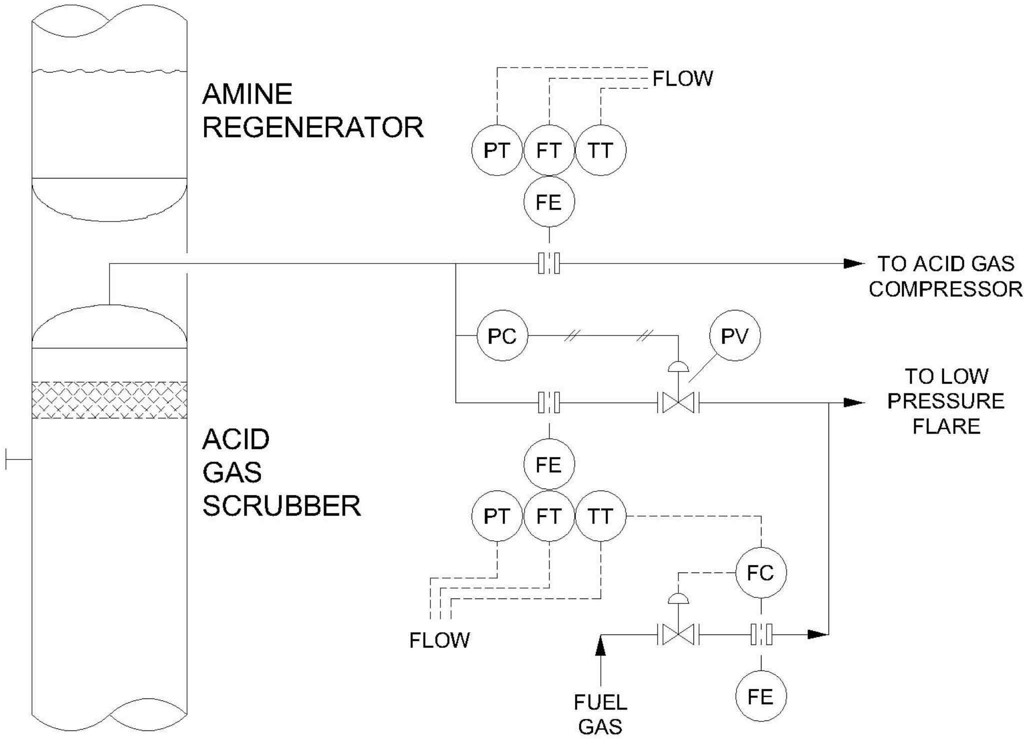
   Due to cost and schedule constraints, this compressor received high priority consideration. It was very critical that the compressor operate well, consistently, and with a very high on-line time. Consequently, a number of equipment parameters designed to ensure this were chosen:

   - 900-RPM electric motor – compressor speed was recognized to be a significant factor in unit maintenance and low speed was considered a desirable attribute. As well, should future process requirements change, the motor and cooler could be changed to 1200 RPM and a 33% increase in capacity achieved.
   - Vacuum pump and purge system on crankcase vapours.
   - Full winter cooler design with variable speed electric motor, pseudo- independent cooler louver controls (stages 1/3, and stages 2/4), over-the-end warm air recirculation, heat medium bundle, and manual louvers.

3. Designing for bumpless transfer of pressure control in the event of compressor shutdown.

   This process design criteria attempted to minimize the potential upsets due to an AGI system shutdown. The compressor was equipped with a suction ESD valve and this valve was a permissive for operation. Thus, on any compressor shutdown, the valve would close. One of the critical aspects of acid gas compression is the extremely low suction pressure that is available.

   The system is set up as shown, with automatic transfer of control from the acid gas compression unit to the back pressure based control loop as shown.



4. Maximum use of stainless steel materials and equipment to minimize sour gas leaks.

   The nature of the acid gas compression process involves the continuous reduction of water content. The resulting sour water that is condensed in the inter/aftercoolers is very corrosive. Although the first stage of compression (suction side) is carbon steel, the remainder of the compression equipment is stainless steel construction. Theoretically, carbon steel could be used for pipeline construction because of the low water content. The pipeline was constructed of 2" Schedule 80 316 stainless steel for the best corrosion resistance. The pipeline is externally coated to prevent soil moisture from damaging the steel. The ASME code is used for the maximum design pressure to limits of pipe or flanges. The line was buried at a 6' depth to minimize the risk of freezing. Although our calculations showed that the gas would be under-saturated upon exiting the compressor, connections were added to allow for future installation of an interstage acid gas dehydration unit if it became necessary.

5. Maximum use of control systems

   The nature of the process required utilization of electronic controls to the greatest extent possible. The system was equipped with the following control system features:

   - Local control panel based PID loop for variable speed control; auto spillover for bypass. This is explained by using the full 5:1 turndown for compressor speed control. If the suction pressure continued to drop, the auto-bypass would become active allowing for some hot 4th stage discharge gas to bypass back into 1st stage suction.

- Local control panel based PID loop for compressor 4th stage backpressure control. Compressor backpressure was maintained at a pre-set level to ensure that the compressor quickly reached operating pressure. This allowed quicker start-ups, faster response time, and accelerated compressor testing.
- Local control panel based PID loop for automatic over-pressure to flare. While this was initially considered redundant, it became a valuable control loop during compressor function testing and fuel gas commissioning.
- Plant control panel based suction ESD valve.
- Plant control panel hi and low discharge pressure switches (located at compressor discharge after the back pressure valve and check valve).
- Local panel based fuel gas control valve for auto purging of compressor and associated equipment. Initially the capacity control system also bled fuel gas into the compressor suction to maintain suction pressure. Injectivity problems at a previous job required removal of this feature from the control system. This fuel gas addition became strictly used for purging and testing of the compressor.

The Puskwaskau design utilized panel mounted transmitters with multiple tubing runs to the hookup points. It was decided that panel mounted transmitters would be easier to work on and provide better wiring access. This design was changed in later compression schemes to minimize tubing runs and potential leak points.

6. Maintain control of possible leakage of acid gas

   The highly toxic nature of acid gas required rigorous control over possible leak points within the system. Most new start-ups of natural gas processing equipment are prone to leaks of some type. Often these are instrument leaks, valve body leaks, level gauges, and minor connections. Consequently a nitrogen helium test during the commissioning phase of the start-up was incorporated. While this sounds simplistic, it should be noted that compression equipment inherently has some leaks due to seals, rings, VVCP (variable volume clearance pockets), and controls. Even the smallest leaks in an acid gas system are hazardous and could be deadly for the operations staff.

Start-up Aspects

While any start-up is a new and often demanding event, it seemed like this one had more than it's share of problems. These included:

- Winter conditions at the time of the start-up were unusually harsh. Snow fell virtually every day throughout the entire start-up. Temperatures varied from -25°C to +10°C in a single day. With minimal hours of daylight, and difficult conditions, it was nearly impossible to maintain staff morale.

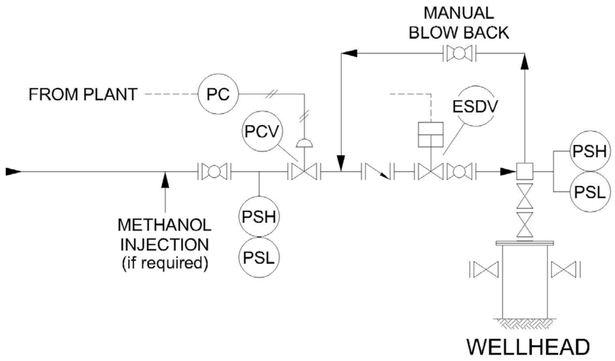
- The facility, and consequently, the entire acid gas system was prone to random facility Emergency Shutdowns (ESD's) and blowdowns at the most inopportune times. Eventually it was realized that the Arctic-style Nomex parka's that the staff was wearing were snagging the ESD buttons at the entrance to the doors and triggering blowdowns. Of course, each blowdown occurred at the worst possible time and was accompanied with a multitude of other problems.

- Timing of the various start-up functions became logistically difficult. It was necessary to run the compressor for some time on fuel gas at near operating pressures to allow for some differential pressure and to ensure that the compressor rod seals had some heat, time, differential, and lubrication to seal prior to the N_2/He test. In essence, this required that the compressor and all associated equipment must be ready to run. Problems then occurred late in the day and often required service personnel, parts, or new equipment.

- While the nitrogen helium test was designed to illustrate smaller leaks, the test showed a number of huge leaks were costing large volumes of helium and nitrogen (and time) and invalidating the test. Even small leaks that would be considered a nuisance in a normal natural gas application were certain to become a problem. Leaks such as valve stem packing, check valve seal rings, and level gauge packing glands were numerous and required the replacement of parts and seals, often requiring halting the test and forcing staff to wait for replacement parts to be delivered in the snowstorm.

- With this being Devon's first foray into acid gas systems, a large number of technical and operations staff wanted to be involved and were offering assistance. While this is usually appreciated, it became a burden for this type of project. For anyone involved in sour gas start-ups, they often go smoother and faster with fewer people involved. Obviously the intent was to minimize possible personnel risk and it became necessary to restrict access of all un-necessary people to the acid gas compressor area.

- There was uncertainty as to how to achieve the required liquid head in the well bore during start-up and it was decided to precharge the injection well with water. While this may have had some merit at the time, the problems it introduced at -20°C ambient temperatures were numerous. Knowing the possible problems with the injection of fuel gas into the wellbore, serious precautions were taken to ensure that the line never had fuel gas in it. During commissioning and testing, it was deemed critical that the system run up to operating pressure with fuel to test the control systems at the wellhead, and this left a large amount of non-condensable gas within the system. The system was equipped with a wellhead ESD valve and a wellhead PCV valve as well as a check valve at the wellsite. The wellhead also had a small bypass assembly to allow for backflowing of the wellbore to the plant in the event of a non-condensable build-up. This wellbore required flare-backs and blowdowns at least six times due to a buildup of non-condensables in the system. While this may sound excessive, it is a relatively simple procedure, and is a manual operation. The release of fuel gas or methane from the wellbore is observed quite easily at night - as the methane content is decreased in the flared stream, the yellowish tinged flare becomes a more pronounced blue.



- The entire control system was tested on fuel and the compressor PID loops commissioned on fuel and confirmed to be active. This was a fundamental step that must be completed on fuel gas. We cannot emphasize this enough; commissioning controls on acid gas is a very complex and time-consuming procedure. If the system is setup properly, it is quite simple to simulate the flow of acid gas from the amine plant to witness and fine-tune the performance of the unit.

- All the scrubbers were equipped with stainless steel check valves and were piped under the grating of the compressor building with electric heat tracing to a drain tank equipped to de-gas the water and send the resulting vapours to LP flare. The high pressure water from the 4th stage suction scrubber was prone to freezing in the line due to the cold air below the grating in the building. Eventually, after a number of shutdowns requiring steam trucks to be called in, a heater was installed below the grating to keep the piping and valving above freezing.

- The injection line had leftover water in it from the hydrotest and thus a number of hydrates were formed prior to injection proceeding. Again, under normal applications, methanol is applied to dissolve the hydrate. However, once acid gas was in the line, the injection of methanol became much more complex. It was a "mask" job, requiring safety staff, dedicated experienced operations, and the addition of methanol into a severely sour line. With a large majority of the work taking place with plant light during dark conditions, each operation became an event in it's own right.

- Although the nitrogen/helium test allowed for checking of all flanged and most NPT connections right up to the wellhead, it was almost impossible to check all the tubing connections from the process line up the panel mounted transmitter. In actual fact, a number of tubing leaks were causing significant releases of sour gas in the building requiring tracing, leak checking and replacement of some connections. Over-tightening tubing connections became a concern. The tubing leaks became a serious concern and some tubing runs were abandoned for local mounted transmitters, now a standard design item.

- An interesting and often overlooked fact is that the acid gas compressor is expected to handle the waste gas from the facility. This means that the AGI system is often the last thing to be commissioned and started up. Minor plant upsets in upstream compression, processing, or even utilities affected the acid gas system in every way. It became obvious that attempting an AGI compressor start-up was a waste of time until all the necessary process units upstream were functioning well. This included amine regeneration cooling, achieving specification sales gas, and properly functioning control systems. Attempting to accelerate steps in an AGI start-up can waste time and manpower.

- Planning is critically important. A number of acid gas start-ups since this Puskwaskau job have shown the need for rigorous planning for equipment, people, and parts. A what-if scenario is necessary to ensure that the facility has the ability to deal with the situations that may arise. This can be as simple as spare gaskets to as complicated as having crews on standby, compression spares, provision of extra helium/nitrogen testing, and extra transmitters in the event of failures.

Project Summary

While the above listing of start-up issues seems extensive, the injection proceeded with relative ease once obvious issues were overcome. The use of the acid gas chiller was never necessary, and once past commissioning, was never put into service. The original scheme also incorporated methanol injection as a hydrate safeguard. Methanol is not being injected during normal current operations.

Injection is currently active at the Puskwaskau facility and wellhead tubing pressure is at 9100 kPa. Tubing pressure has varied as low as 9,100 kPa to as high as 9,800 kPa. Early in 1998, the compressor was re-cylindered and a new motor installed to increase the injection rate from 0.1 MMSCFD to a maximum of 0.30 MMSCFD. The motor was changed from 50 HP to 100 HP and a new drive installed as part of an electrical upgrade at the facility. The acid gas injection compressor is continuing to work well and is experiencing no unusual problems.

2.1 North Normandville

Devon's North Normandville facility is located approximately 35 km southwest of Peace River. This production facility is also located within Devon's Peace River arch production area. Design for this facility began in early 1997 with site selection and simultaneous development of the acid gas injection facilities. Site selection was based on the successful conversion of an abandoned wellbore in the nearby area. Devon's reservoir group was reasonably confident that they could inject the acid gas into the Normandville D1 zone. This well was roughly 330 meters from the plant site allowing for minimal risk and ease of operations.

Design criteria for the central 03-36 facility varies widely as a number of possible zones including Debolt, Wabamun, Montney and BlueSky are produced to the plant. The design of the acid gas compression scheme was intended to roughly model the Puskwaskau design with the noted improvements. The design-specific criteria is as follows:

Main Feed Gas:	20 MMSCFD
H_2S Content:	2500 ppm
Inlet Sulphur:	1.91 tonnes/day
CO_2 Content:	0.15%

The plant, similar to the original Puskwaskau facility, utilized a non-selective amine (DEA) to reduce total CO_2 and H_2S content. Again, due to the possibility of future un-determined production, it was decided to leave the possibility of CO_2 slip for future processing or debottlenecking requirements.

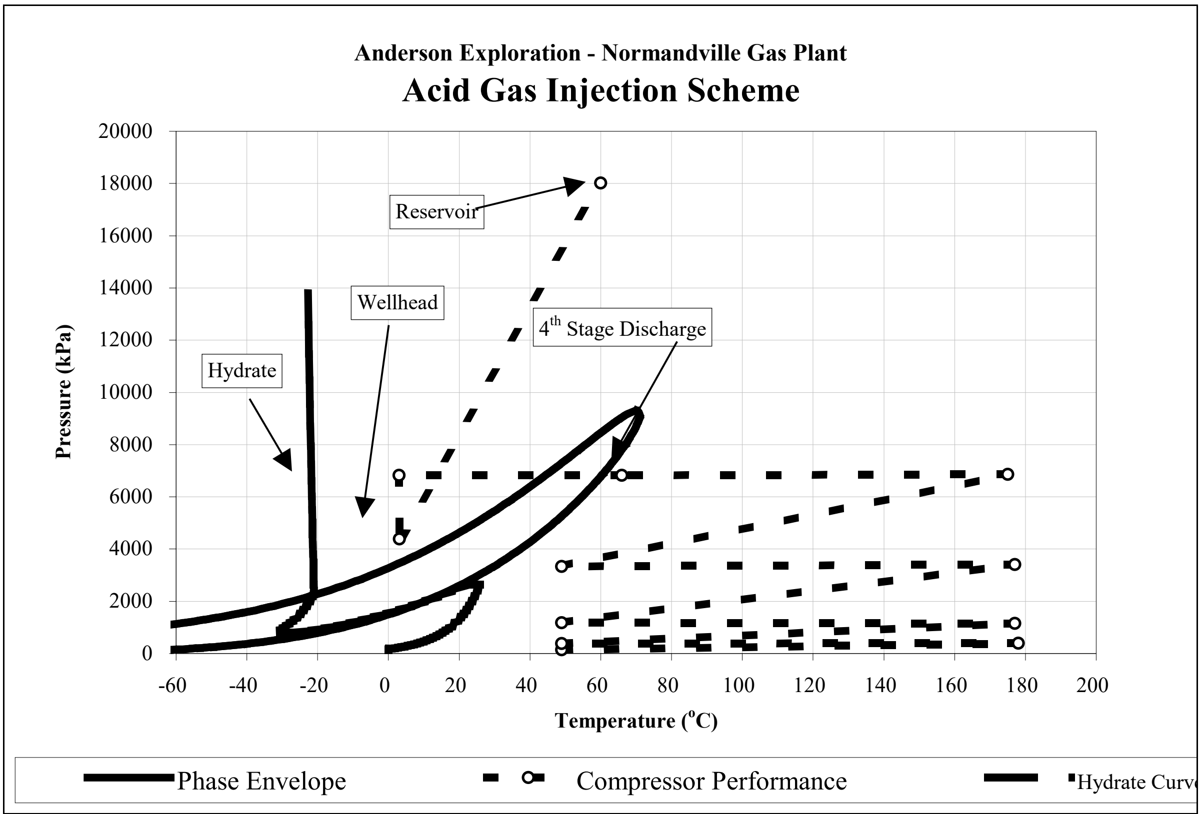
Design Aspects

The resulting acid gas was 67% H_2S, with the balance being primarily CO_2, and small amounts of methane, nitrogen and heavier hydrocarbons. Design flow was 0.08 MMSCFD although the compressor selection and permitting was set at 0.1 MMSCFD. The wellbore characteristics were as follows:

Depth:	1858 m
Pressure:	19.014 MPa
Temperature:	60°C

As can be seen, the injection well on this facility is much shallower than Puskwaskau's with a correspondingly lower reservoir pressure and injection temperature. In order to predict the acid gas injection pressure, a pseudo-integration of wellbore fluid density was again started at the wellbore and worked up the hole. Surface fluid temperature was assumed to be 3°C due to the un-insulated acid gas pipeline and the low fluid velocity. Line pressure drop was calculated to be minimal with such a low velocity. The wellhead injection pressure is calculated to be 4,380 kPa (650 Psia) using the recently developed proprietary program developed by John Carroll to calculate a shifted PR equation of state for fluid density prediction.

The final phase envelope is shown below for this injection scheme:



The final predicted hydrate temperature is approximately -22°F (-30°C), substantially colder than the line would get during normal injection operations.

This project proceeded more smoothly than Puskwaskau, due in part to the large number of startup issues, and the considerable acid gas processing technology had taken place.

Devon and Gas Liquids understanding of acid gas behavior and system performance had jumped a generation by this time. Since the Puskwaskau project, Dr. John Carroll of GLE developed a proprietary program titled AGIProfile to calculate injection densities and injection profiles. With the application of AGIProfile, the injection profile was more completely understood and sensitivities could be examined easily. As well, the Normandville application had substantially lower reservoir pressure, thus removing some of the inherent risk associated with Puskwaskau. As mentioned above, the predicted acid gas wellhead tubing pressure was 4,380 kPa or 650 Psia. The fluid density in the wellbore varied from 670 kg/m^3 at the surface to 822 kg/m^3 at the bottom of the tubing.

At the time this project was complete, accurate hydrate prediction was still proving difficult. Again, while it was believed that hydrates would not form, the possibility of hydrate formation remained unacceptable. Methanol injection was recommended at a rate of approximately 2.5 gallons per day.

Project Aspects

We experienced a large number of problems at the previous Puskwaskau AGI facility and attempted to address the majority of these in the design of the facility and the equipment. The acid gas injection line was again constructed from stainless steel and insulated and traced per the Puskwaskau design.

Equipment Aspects

A number of equipment design parameters were modified in the Normandville project.

1. Maximum use of control systems

   The panel was modified from Puskwaskau's pseudo-electronic design to a fully integrated electronic panel using Amot Hawk technology. Multiple Hawk units were required for maximum I/O capability. Transmitters were mounted as close as possible to the process hook-up and wired back to the panel.

   The system was equipped with the following control system features:

   - Local control panel based PID loop for variable speed control and auto spill over for full bypass. This system was identical to the one employed at Puskwaskau with some tuning necessary for PID parameters.

   - Local control panel based PID loop for compressor 4th stage backpressure control. Compressor backpressure was maintained at a pre-set level to ensure that the compressor quickly reached operating pressure. This allowed quicker start-ups, faster response time, and accelerated compressor testing.

   - Local control panel based PID loop for automatic over-pressure to flare. While this was initially considered un-necessary, it became a valuable control loop during compressor function testing and fuel gas commissioning.

   - Plant control panel based suction ESD valve.

   - Plant control panel high and low discharge pressure switches (located at compressor discharge after the back pressure valve and check valve).

   - Local panel based fuel gas control valve for manual purging of compressor and associated equipment. This fuel was to be used only for testing and purging.

Start-up Aspects

If Puskwaskau was a difficult start-up, then Normandville proved to be well planned, cooperative, and relatively straightforward. Some of the more unusual quirks included:

- Again, Canadian winter conditions at the time of the start-up were extremely harsh. While snow wasn't a major factor (only 1 meter!), temperatures seldom exceeded –25 to -30°C during the day and often were colder than -40°C at night. Working in these conditions during a start-up is difficult, with even simple tasks taking long times and requiring that heat be applied to equipment. Obviously, plant utility heat was a major priority and no other start-up function could take place without heat; even compressor/motor alignments can't be done properly at these temperatures.

- The nitrogen/helium test proceeded with test pressures set at 80% of MAWP pressures to reveal the majority of leaks. During the testing of the 4th stage piping and vessels, it was noticed that some of the piping bolting was unusually small. A review of the entire compression unit showed that virtually all the 4th stage bolting had to be replaced with the correct size and bolting specification.

- With temperatures hovering at –25 to -30°C, having excess personnel on site was not an issue. Maintenance staff was much closer to this site, and previous experience at Puskwaskau proved valuable during this start-up. Sufficient gaskets, valves, bolting, and service crews were available. At the first sign of difficulty, response with the necessary parts and people was quickly undertaken.

- The wellbore was not precharged during commissioning and uncertainty existed as to how the injection would proceed during the initial "kick-start" of the injection well. Again, due to unforeseen reasons, the injection pressure started out higher than initially expected and several plant blowbacks to the flare system were necessary. One of the valuable lessons learned during Puskwaskau (and Normandville) was that short blowdowns were more effective than long ones.

- Due to exceedingly cold temperatures and logistics of trying to start the plant up several days before the holiday season, the decision was made to defer the start-up of the acid gas compression equipment until after the Christmas break. During the introduction of acid gas into the wellbore, the acid gas managed to contact wet saturated gas during the pressure build-up phase. Consequently a hydrate developed in the wellbore. Several barrels of methanol were pumped into the system and then chased with the acid gas to dissolve the hydrate and push the mixture into the formation. Since that time, the Normandville facility has experienced no hydrate issues.

- The compressor bypass valve proved to be oversized and was difficult to tune. A smaller trim was installed and the bypass loop became much more effective at low compressor loads.

- During the start-up, the acid gas cooler motor began drawing high amperage from the system. Upon discussion with the vendor (in the southwest USA), the vendor admitted that they had not sized the motor for extreme Canadian winter air at -40°C. The cooler was so small that the fan blades were a fixed pitch and unchangeable. The motor was upsized, and the cooler worked well.

- Unit leaks were few and far between. Again, the majority of system leaks were on tubing hook-ups, level gauge cocks, valve stems, and level switch hook-ups.

- The Amot Hawk panel is somewhat difficult to work with. Although it was considered high-tech at the time, compressor panel technology has since improved. Viewing operating pressures and temperatures is only possible one variable at a time; consequently, it was time consuming to view all possible unit parameters. However, since the unit continues to function well, there is little justification for a panel change.

- Once injection was proceeding, it was noticed that a small leak had developed at the wellbore. During the inspection, it was realized that the leak was coming from an internal body steel gasket plate inside the wellhead ESD valve. Once the parts were replaced, injection continued uninterrupted.

- This new design incorporated underfloor heating - no freeze ups in the underskid piping was noticed and the building remained warm.

Project Summary

Injection at the North Normandville site was a straightforward process. Problems were relatively simple and injection was initiated quite smoothly. This restored confidence in the injection design as well as assuring Devon that AGI was a viable, operable process that allowed for the disposal of nuisance volumes of H_2S.

Injection is currently active at Devon's North Normandville facility and wellhead tubing pressure is at 4300 kPa. Tubing pressure seldom varies. The acid gas injection compressor is continuing to work well and is experiencing no unusual problems. The plant has since been upgraded twice to incorporate LPG recovery, condensate stabilization, and the addition of a flash tank to ease separation problems with the condensate/glycol system. No upgrades have been made to the acid gas scheme.

2.2 West Culp

The next candidate in Devon's acid gas injection projects, was entitled West Culp. This area of development had been active for some time as an oil producing area. Again, similarly to the Normandville project, plant site location was based on a combination of factors:

- Close proximity to producing wells, areas and possible areas of future development
- Minimal interaction with area residents and landowners
- Close proximity to abandoned wellbores that were likely candidates for injection wells.
- Close proximity to existing access roads, the existing oil battery, and the local production office.

During project development, it was realized that the plant could incorporate processing of the solution gas from Devon's West Culp oil battery. This is a sweet oil battery that was flaring solution gas. It was felt that the plant would be approved more quickly if solution gas recovery were incorporated into the design.

The West Culp facility was chosen to be adjacent to Devon's oil battery located approximately 40 km southwest of Peace River, Alberta. Preliminary reservoir engineering showed that the abandoned wellbore at 6-34 (approx 500 m away) was an excellent candidate for injection.

Design criteria for the West Culp facility was expected to encompass several design analyses including either a Wabamun gas stream or a blended analysis. The design specific criteria is a dual one as follows:

Case	Blended	Wabamun Only
Composite Volume	21.3 MMSCFD (600.106 10^3m^3/day)	9.07 MMSCFD (255.54 10^3m^3/day)
Inlet H_2S/CO_2	1.324%/1.149%	4.111 %/0.9315%
Acid Gas Volume	.5852 MMSCFD (16.5 10^3m^3/day)	.5031 MMSCFD (14.17 10^3m^3/day)
Acid Gas Composition	48% H_2S/42% CO_2	74% H_2S/17% CO_2
Inlet Sulphur	10.8 tonnes/day	14.3 tonnes/day
Inlet Oil/Condensate	359.6 BBLS/Day (57.2 m^3/day)	265.5 BBLS/Day (42.2 m^3/day)
Inlet C3+ Content	4.52%	10.6%
Sales LPG	220.8 BBLS/Day/35.1 m^3/day	439.3 BBLS/Day (69.8 m^3/day)

As is shown, the "Wabamun Only" case is considerably richer in C_{3+} components, thus taxing the limits of the refrigeration compressor system. The equipment was sized for maximum flexibility, thus allowing for potentially higher processing rates than design depending on the blend of gas entering the facility.

Design Aspects

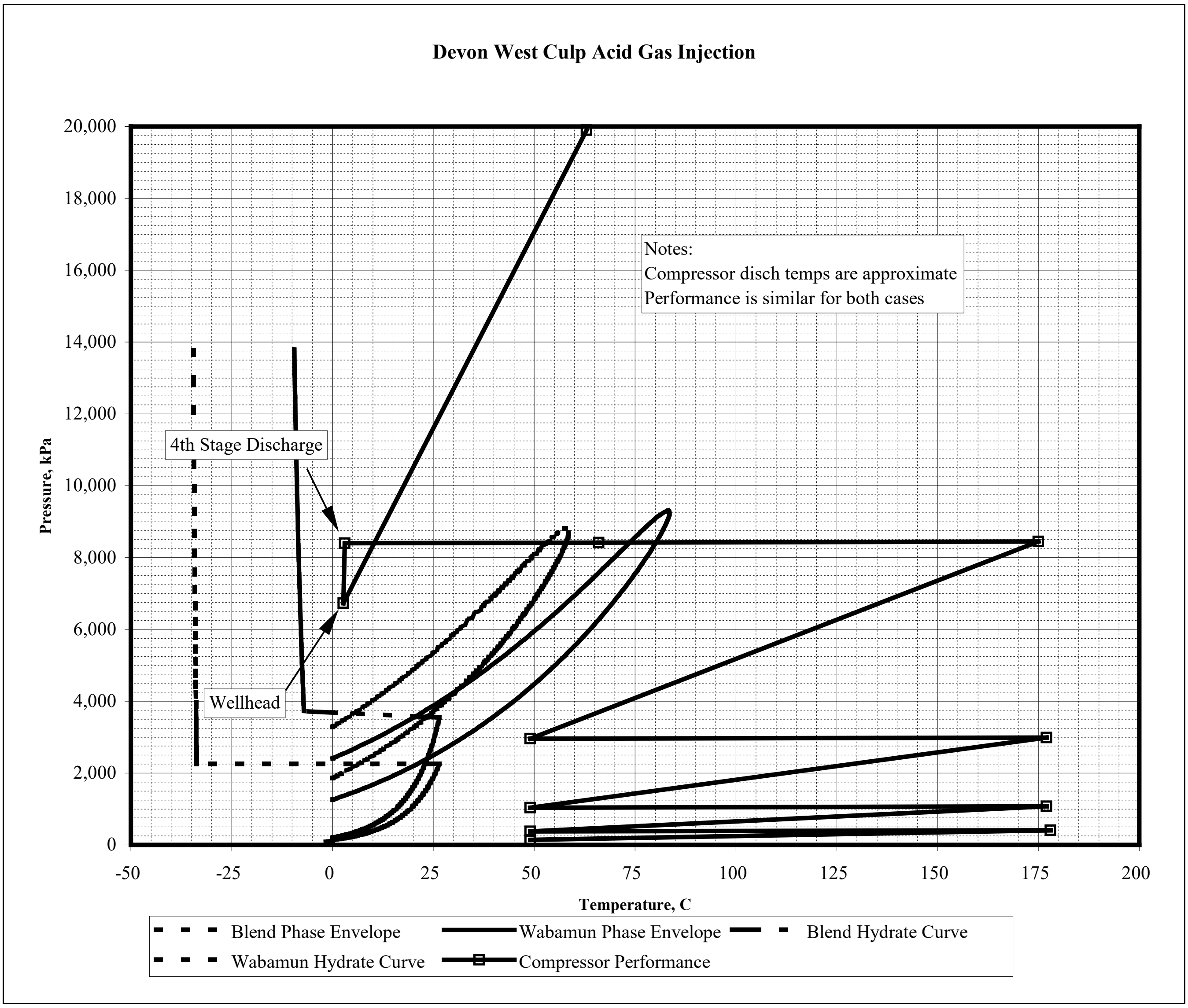
The resulting acid gas mixture varies widely from a low of 48% H_2S to over 74% H_2S depending on the amount of Wabamun gas that will enter the facility. Since the plant was expected to perform at either case, it was important to check and verify the design under all conditions. Design acid gas flow for the compressor was 0.585 MMSCFD although the compressor selection allowed for 0.63 MMSCFD. The wellbore characteristics were as follows:

Zone:	Wabamun (isolated)
Depth:	1943 m
Pressure:	20.220 MPa
Temperature:	63°C

Based on the differing analyses, the injection well experiences different injection pressures.

For the blended case, the wellhead injection pressure is predicted to be 6,730 kPa or 976 Psia. Once the analysis moves to the Wabamun case, the injection pressure decrease to 5,599 kPa or 812 Psia.

The final phase envelope is shown below for this injection scheme:



Again, based on the previous generation of acid gas injection projects, this one had extensive planning for personnel, logistics, timing, and parts. Other segments of the startup, including the power generation, amine sweetening, and refrigeration were essentially on line within about 10 days of commissioning. Exceedingly cold temperatures hindered the startup, but utilizing people with AGI experience and understanding eliminated a large number of "rookie" difficulties.

The compressor selected for this application was an Ariel JG/4 equipped with 4 throws and 4 stages of compression. It was driven with a 250 HP electric motor. The motor was equipped with a variable speed drive (5:1 turndown) to achieve maximum unit flexibility.

Project Aspects

Again, solutions to historical problems noted in previous facilities were incorporated into the design and operation of the Normandville facility.

Equipment Aspects

A number of equipment design parameters were again modified in the West Culp facility.

1. Due to the increased knowledge of acid gas systems and performance, the decision was made to install the acid gas pipeline without insulation. Although recent projects had speculated about the need for stainless steel, it was felt that the short distance and inherently low risk of stainless steel made the marginal cost adder acceptable. Removing the insulation made for a less costly and faster installation.

2. Maximum use of control systems

   Control systems and acid gas leaks continued to be the prime concern. The compressor panel was again modified to a fully electronic PLC based system using a touch screen specifically designed and programmed for compression equipment. The unit utilized full PID controls. The speed control for the motor was incorporated into the panel so that the PLC based variable speed drive received a 4-20 mA signal from the control panel. In this way, the compressor panel became much more powerful. Transmitters were again mounted as close as possible to the process connection and wired back to the panel. Additional transmitters were added to show rod loads, and utility equipment conditions.

   The system was equipped with the following control system features:

   - Local control panel based PID loop for variable speed control and auto spill over for full bypass. Easy access for PID parameters with built-in offset of compressor suction pressure was also provided. The panel incorporated auto spill from the discharge back to suction in the event that the injection pressure rose beyond a preset value. This proved to be very useful in that, should injection fail due to a blockage or hydrate, the suction pressure would rise and the excess gas would spill to flare via the amine regeneration loop back pressure valve. This would alert operations staff to a problem as well as adding sufficient fuel for dilution purposes.

   - Local control panel-based PID loop for compressor 4th stage back pressure control. Compressor backpressure was maintained at a pre-set level to ensure that the compressor quickly reached operating pressure. This allowed quicker start-ups, faster response time, and accelerated compressor testing.

   - Local control panel based PID loop for automatic over-pressure to flare. While this was initially considered un-necessary, it became a valuable control loop during compressor function testing and initial fuel gas commissioning.

   - Plant control panel based suction ESD valve.

- Plant control panel high and low discharge pressure switches (located at compressor discharge after the back pressure valve and check valve).

- Local panel based fuel gas control valve for manual purging of compressor and associated equipment. This fuel was to be used only for testing and purging.

Start-up Aspects

As our experience in acid gas technology grew in leaps in bounds, so did our ability to cope with start-up issues. Few problems were noted during this start-up. Some of the more unusual issues included:

- The nitrogen/helium test proceeded with test pressures set at 80% of MAWP pressures to illustrate the majority of leaks. During the testing of the equipment, piping, and vessels, it was noticed that there were a significant number of leaks that needed to be addressed. Fixing these leaks took up to 24 hours with multiple crews and replacement of gaskets, RTJ rings, and seals.

- Injection was initiated and, with the exception of a plugged flowline, preceded as expected. Initially, the plug was thought to be hydrates. After some time injecting methanol and attempting blowbacks, the line was disassembled and the line plug was found to be newspaper. Presumably it was stuffed into the line during construction to prevent snow and mud from fouling the line and was not noticed during the boltup.

- Injection into the reservoir proceeded almost immediately. A slight increase in wellhead tubing pressure was noticed, and then it decreased slightly and steadied out. No wellbore blowback was necessary.

- Subsequent increases in tubing pressure were suspected to be wax. A wax solvent was injected with no change in performance. After changing pressure and operating conditions a number of times, the conditions were set back close to design and the methanol injection rate was increased slightly. The system settled down. Methanol injection remains active today at 7-10 gallons/day.

- Several leaks were noticed during start-up, specifically from control valve packings and stems. It seems that until the valve has stroked a few times and seated the packing against the stem, that the valves are prone to slight stem leaks. Unfortunately, even slight leaks in acid gas systems cause concerns amongst operations and engineering staff.

- A number of cooler plugs leaked after start-up, and eventually all the cooler plugs were replaced with a gasketed design. The new plugs were lubricated and retorqued to the correct values.

- No unusual maintenance issues have been observed. Obviously maintenance activities within this unit constitute a significant safety concern and some activities like valve changes and piston rod packing replacements must be done under mask. Nonetheless, both Devon's maintenance staff and vendor mechanics are familiar with acid gas compressor equipment.

Project Summary

A large number of the Devon staff was now experienced in AGI equipment, acid gas operations, and the thought processes involved in an AGI project. The start-up proved to be relatively straightforward and with a few problems, was complete in 14 days. The plant remains on line today and injection is proceeding with tubing pressure at roughly 5,800 kPa. During low flow cases, the injection pressure rises to as high as 6,000-6,300 kPa, and then settles down as the flow increases. It is suspected that, during low flow cases, slight quantities of methane and nitrogen are rising to the top of the wellbore and slightly depressing the fluid level to force an increase in discharge pressure. The plant liquid handling system has been upgraded for better slug handling and liquid separation equipment improved. No upgrades have been made to the acid gas scheme.

2.3 Rycroft

Devon's latest candidate for acid gas injection is the Rycroft facility located some 80 km northeast of Grande Prairie. This development remains within Devon's core area of the Peace River arch. Development of this producing area proved to be challenging. In order to be close to a possible acid gas candidate well, the plant location was selected very close to Kakwa Lake. While this lake was quite small, the area surrounding the lake was environmentally protected for ducks and other water based wildlife. Extensive consultations with area residents were undertaken and approval was achieved.

The Rycroft facility was chosen to be constructed on the north side of the lake, relatively close to most of the producing wells. As well, the location was only several miles away from the pipeline receipt point, requiring a small sales pipeline to tie-in. Reservoir development work showed that the candidate injector well, located 200 m to the west, had potential to inject into the Kiskatinaw formation.

The plant and associated equipment are designed to process a blend of inlet gas from Gething, Doig, Charlie Lake, Montney, and Debolt zones. The facility is designed and constructed for 679.3 $10^3 m^3$/day raw inlet gas, although it is licensed for 747.6 $10^3 m^3$/day. Table 1, shown below, lists some key parameters:

Table 1 Design Parameters

Inlet Gas Volume	679.3 10^3m^3/day 24 MMSCFD
Inlet Conditions	1300 kPa (a) & 4.4°C 175 Psig & 40°F
Inlet H_2S/CO_2	2.07%/1.099%
Acid Gas Volume	22.24 10^3m^3/day (Stage 1 suction) 790,000 SCFD
Acid Gas Composition	64% H_2S/26% CO_2 (Stage 1 suction)
Inlet Sulphur	20.412 tonnes/day
Inlet Oil/Condensate	18.68 m^3/day 118 Bbls/day
Inlet Water	40.5 m^3/day 255 Bbls/day
Sales Gas	648.5 10^3m^3/day 23.02 MMSCFD
Sales Condensate	29.57 m^3/day 186 Bbls/day

Maximum Injection (07-02 W/H) Pressure	5500 kPa
Maximum Acid Gas Injection Rate	24.5 10^3m^3/day

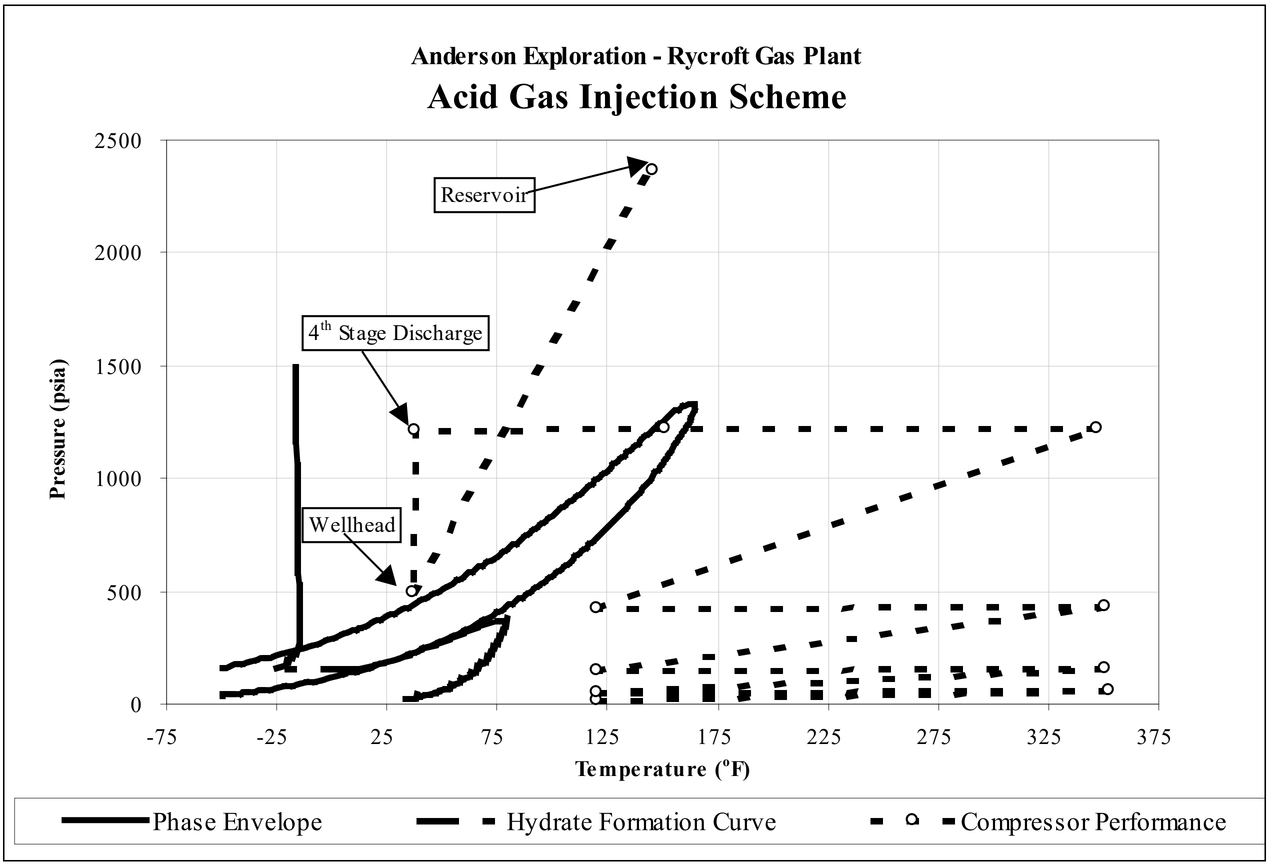
Design Aspects

The resulting acid gas mixture has an H_2S content of roughly 64%. This tends to vary depending on the production scenario and which high H_2S wells will be producing. Design acid gas flow for the system was 0.78 MMSCFD, with a compressor selected for 0.83 MMSCFD. The selected wellbore characteristics were as follows:

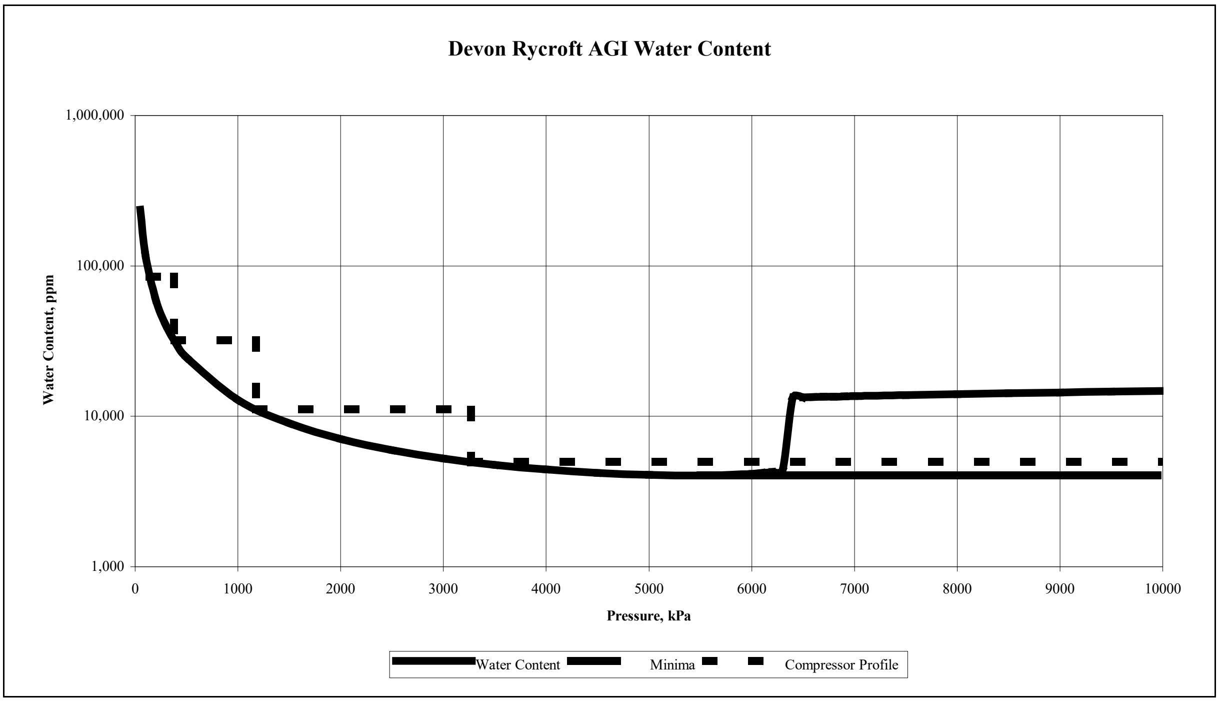
Zone: Kiskatinaw
Depth: 1780 m
Pressure: 16.331 MPa
Temperature: 63.3°C

For the original case, the wellhead injection pressure is predicted to be 3,450 kPa or 500 Psia.

The final phase envelope is shown below for this injection scheme:



The high H_2S content leads to excellent water performance, as is shown below on the water content curve. The water offset between actual water content and potential water content is quite high. The water content of the acid gas fluid exiting the compressor is slightly over 4000 ppm, while the capacity of the fluid to hold water could be as high as 14,000 ppm. Thus the fluid going to the 7-2 wellbore is under-saturated. The compressor 3rd stage discharge pressure is 3,270 kPa.



Since this facility was almost a carbon copy of West Culp, similar planning, personnel, and logistics were utilized. Again, with winter temperature dipping below -30°C for several weeks, startup activities focused on heating systems and tracing. For the first time, Devon departed from using Ariel frames and chose a Gemini frame. This compressor, based on its predecessor Energy Industries, was a similar air cooled, high speed reciprocating compressor. The selection for this application was a Gemini A354-4 frame, equipped with a 15.5" stage 1 cylinder. The compressor is equipped with a 250 HP, 900 RPM motor for maximum flexibility, power, and performance. Like the preceding units, this package is equipped with a 5:1 turndown, allowing the compressor speed to reduce to as low as 180 RPM. As well, with a motor and cooler change, this frame can be adapted up to 1200 RPM or higher as necessary.

Project Aspects

The wellbore was very close to the plant site, at roughly 200 m from the acid gas compressor. Access was simple and the well was located just outside the plant fence on it's own fenced access site. This acid gas injection scheme even though it experienced a few problems on start-up, has operated for three years now with little or no problems.

Equipment Aspects

With the exception of the compressor frame and some packaging details, the system was virtually unchanged from the West Culp unit.

Start-up Aspects

Although the system has run well for some time, it did have some problems during commissioning.

- The nitrogen/helium test proceeded with some difficulty. VVCP vent lines were tubed together to allow for excess vent gas to flow to flare in the event of a VVCP packing failure. In order to test each stage sufficiently high enough, the plan was to use the cylinder valves to hold the pressure from each stage as progression was made in pressure stages. With the VVCP packing leaking slightly, it became very difficult to achieve test pressures without the test medium leaking back and repressuring the lower pressure cylinders. After a number of disassemblies, VVCP port vents were plugged and the test proceeded without incident. A number of leaks were noted and fixing them became time consuming, considering that most of the leaks were under the skid grating and were on the 1500# ANSI bolted flange sets.

- Injection was initiated and preceded without a problem. Methanol injection was provided for but proved to be un-necessary.

- Again, as injection was started, the tubing pressure increased slightly and then decreased and steadied out. No wellbore blowback was necessary and has never been required since. Methanol has never been required.

- Tubing pressure remains at 3,300-3,600 kPa with the prediction of 3,450 kPa (g) proving to be very accurate. Pressure varies slightly depending on compressor load and speed.

- Again, several leaks were noticed during start-up, specifically from control valve packings and stems.

- Valve head cover gaskets remain a constant leak problem with this particular scheme. Installation of the gaskets remains a delicate operation and leaks have proven troublesome.

- Compressor rings on the 4^{th} stage cylinder were replaced shortly after start-up. While the reason is unclear, the failure occurred very soon after start-up. No further problems have been noted to date.

- Operations reports minimal corrosion concerns during annual inspections of the coupons.

- Suction temperature on 4^{th} stage must be maintained above 40-50°C to prevent freezing of the 4^{th} stage scrubber dump valve. This has been an occasional problem during cold winter nights or when ambient temperatures vary widely.

Project Summary

The latest acid gas project at Devon's Rycroft facility has proven to be an unqualified success. A fast efficient start-up, minimal problems, and highly experienced operating staff have proven the success of small-scale acid gas injection projects. Subsequent development work on this facility has required a re-licensing of the facility as the H_2S content of the acid gas is projected to increase. With the H_2S increasing to as high as 90%, injection pressure is expected to decline slightly. The higher H_2S content should provide a larger offset for water capacity as well.

SUMMARY & RECOMMENDATIONS

Early involvement of residents and proper site selection is of paramount importance. No AGI project can proceed without adequate public involvement and understanding. In developing and implementing an acid gas injection project, a number of critical parameters need to be addressed:

- Realizing throughout the project that the acid gas injection process is unique.
- Thorough selection of reservoir zone and injection parameters – involve reservoir staff immediately.
- Selection of wellsite location and/or acquisition of the proposed injection well.
- Immediate involvement of operating personnel in the design process.
- Thorough development of phase behaviour and understanding of the injection process.
- Scheduling and budgeting of proper equipment.
- Close interaction with equipment suppliers.
- Engineering support throughout construction, commissioning, start-up and operating.
- Continued technical support through the facility operating life.

Engineering and designing an acid gas compression scheme requires paying particular attention to details:

- Detailed process simulation of the acid gas system with approximate interstage conditions.
- Full phase envelope development.
- Hydrate prediction, water behaviour, and water handling.
- Engineering review of alternative process gas analyses.
- Discussion with equipment vendors ensuring that they understand the project objectives.
- Detailed equipment bid specifications and drawing reviews.
- Verify process simulations with predicted compressor interstage conditions.
- Thorough drawing reviews with field operating staff and instrument/controls engineering groups.
- Very detailed commissioning and start-up planning, looking at contingencies, spare parts, vendor service technicians, and 3rd party tech services.
- Careful control of services, personnel, and timing during start-up.
- Subsequent post-start-up audits and review of operations.
- Continued operations and process support for life of facility.

Acid gas injection has proven itself to be a successful, long term, safe method for dealing with small volumes of previously unmanageable acid gas. Residents, landowners, and operators are comfortable with the technology - it is strong, robust, and relatively resistant to the wear and tear of the oil/gas industry. In semi-populated areas and projects with larger acid gas flaring requirements than regulated flaring will permit, acid gas injection is a valid and highly encouraged way of dealing with nuisance acid gas.