POTENTIAL FOR ACID GAS INJECTION AT KHARG ISLAND

N. Rahimi
Iranian Offshore Oil Company

P.J. Griffin, Ph.D., P.Eng.
Gas Liquids Engineering Ltd.

ABSTRACT

The proposed Kharg Island Gas Gathering and NGL Recovery Project in Iran is designed to process 600 MMscfd of sour natural gas and produce 460 MMscfd of sweet gas and 48,000 bbl/d of hydrocarbon liquids.

The planned acid gas removal facilities will generate an acid gas stream of approximately 85 MMscfd containing 33-64% H_2S and 29-57% CO_2. Gas Liquids Engineering is undertaking conceptual design, and front-end engineering and design (FEED) studies to evaluate the implementation of acid gas injection.

The preliminary design requires the compression of the acid gas to 180 bara in a manner to maximize interstage dehydration and avoid interstage liquids formation with a relatively wide range of acid gas compositions prior to injection into multiple wells.

The complete initial design is scheduled for completion early in 2005.

1. INTRODUCTION

The proposed Kharg Island Gas Gathering and NGL Recovery Project is a grass roots facility and will consist of the simultaneous development of two separate gas treatment and NGL recovery plants sharing common utilities and liquid export systems. Gas will be gathered from both onshore and offshore sources.

Onshore gas will be gathered, compressed and piped from the existing Aboozar, Dorood I, Dorood II, Dorood III and Foroozan oil processing facilities. Dorood I, Foroozan and Aboozar are physically adjacent to each other and located approximately 6 km from the proposed site of the new NGL facility. Dorood II is approximately 3 km from the site of the new NGL facility. Dorood III will be a new facility located adjacent to Dorood II.

Offshore gas will be gathered from the planned new Aboozar, Bahregansar, Foroozan, Nowrooz and Soroosh oil production facilities. Gas from the Aboozar pipeline and the Foroozan pipeline will be routed to reception facilities at the NGL recovery facility as shown in Figure 1.

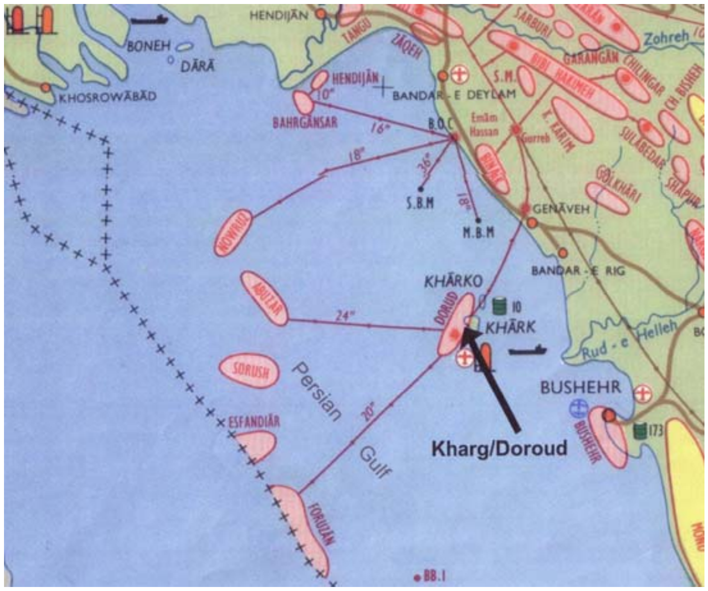

Figure 1: Kharg Island Field

The onshore and offshore gas will be compressed and treated in separate Acid Gas Removal Units before being blended into a single gas stream. The gas stream will then be split and the gas processed in two identical NGL recovery trains.

The facility is planned to handle a raw gas feed stream of 600 MMscfd and produce products including ethane, propane, butane and pentane.

The original FEED (front-end engineering and design) study for the entire project was completed in 2002 by John Brown Hydrocarbons Limited. At that time the facility incorporated a sulfur plant with a capacity of 1,200 t/d.

The Acid Gas Removal units have been designed by Shell Global Solutions.

In 2003 Gas Liquids Engineering (GLE) undertook a conceptual design study of the potential for acid gas injection at Kharg Island and earlier this year GLE commenced a FEED study of an acid gas injection facility to replace the original sulphur plant.

In support of the Acid Gas Injection FEED study, injection zone core analysis has been undertaken by Hycal Energy Research Laboratories (Calgary) and reservoir studies have been undertaken by Tehran Energy Consultants and Fekete Associates Inc (Calgary).

The Acid Gas Injection FEED study is scheduled for completion early in 2005.

2. INJECTION RESERVOIR

A preliminary reservoir study of non-hydrocarbon bearing formations at Kharg Island was undertaken in Tehran which identified the Dhruma formation in the Dorood field as the best potential candidate for acid gas injection.

Normally, an assessment of a formation considered for acid gas injection includes:

- The depth and size of the potential disposal zone to ensure that it will hold the injected gas over the life of the project.
- Thickness, fractures and extent of the caprock to confirm that it will contain the acid gas.
- Reservoir containment ability is also assessed by the determination of the caprock threshold displacement pressure and fracture pressure; the lower of the two should be used to set the maximum allowable injection pressure.
- The location and extent of other formations to determine if other wells in the area are likely to be impacted by the disposal scheme.
- Folding and faulting of the formation to determine seismic risk.
- Reservoir properties analysis to determine if injection can be undertaken at reasonable pressures and conditions.

The additional driving forces for the initial selection of the Dhruma formation included:

- Formation should be ideally accessible from wells drilled from Kharg Island.
- Formation must have "no" risk of communicating with existing or future production zones. Due to the high number of existing producing wells in the region, some of which have extremely limited drilling and completion data, it was decided that the injection zone must be located below any existing production zones.

The Dhruma formation is predominately a limestone with chalky and intergranualar porosity. Minor horizontal fracturing is observed in the core. The Dhruma is folded and potentially faulted in the study area, forming an anticlinal feature.

2.1 Core Properties

A core sample from the formation (well D-21) was obtained and examined to evaluate its properties. A typical core section is shown in Figure 2. The primary reservoir properties determined from the formation core and available logs were:

- Dhruma Zone: 4016-4150 m
- Net Pay: ~125 m
- Typical injection zone porosity: 15-23 %
- Typical injection zone permeability: 10-600 mD

Figure 2: Dhruma D-21 core - 4046.9 m native reservoir {Hycal}

Analysis of a D-21 drill stem test (DST) generated data comparable to core results and showed no indication of high permeability from fracture flow.

2.2 Reservoir Injectivity

Initial reservoir injection modeling was undertaken employing Fekete's WellTest™ software with a radial composite cylindrical reservoir model. Fekete's VirtualWell™ software also was used to compute the total pressure drop from the sandface to the wellhead.

The preliminary results in Figure 3 show the changes in reservoir pressure (P_r), sandface pressure (P_{sf}) and wellhead pressure (P_{wh}) over a 10-year period at injection rates of 80 MMscfd.

Reservoir parameters of 417 bara (6048 psia) and 121°C were obtained from the D-21 DST (drill stem test). The reservoir was assumed to be water saturated and the initial sandface injection pressure was calculated to be 622 bara (9020 psia) as shown in Figure 3.

The preliminary forecast assumed a limited reservoir, no gravity override effects and full displacement of the native water with acid gas. As a result, reservoir pressure is predicted to rise over time and the sandface pressure differential is predicted to decrease as relative mobility effects are overcome. This injection model assumed no dissolution in brine.

The anticipated wellhead pressure from this model is 4,000-5,000 psia (275-345 bara).

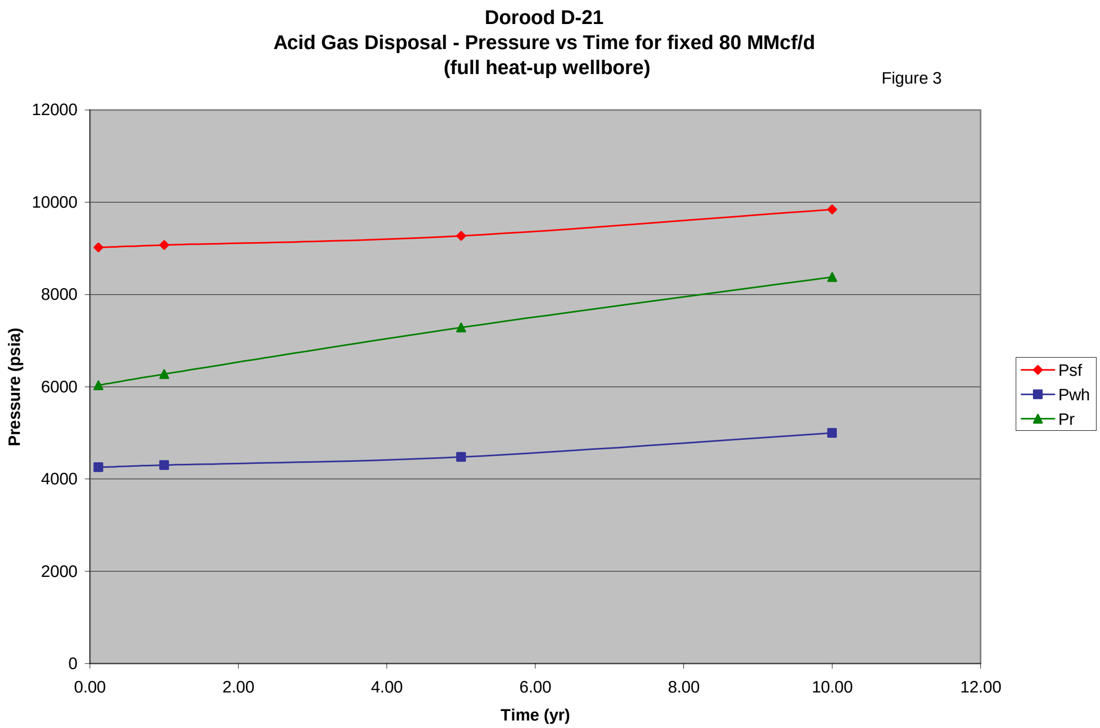

Figure 3: Reservoir Pressure vs. Time {Fekete}

Due to the relatively high wellhead pressure, subsequent modeling evaluated the impact on reservoir and wellhead pressure of multiple injection wells as shown in Figure 4.

The wellhead injection pressure is reduced to 2,400 psia (165 bara) when the acid gas injection stream is distributed amongst three injection wells.

Further reservoir simulation incorporating core flood data undertaken by Hycal is currently underway to evaluate such factors as:

- Areal displacement of acid gas in variable permeability layers.
- Gravity effects.
- Relative permeability effects on injection pressure.
- Injection well spacing.

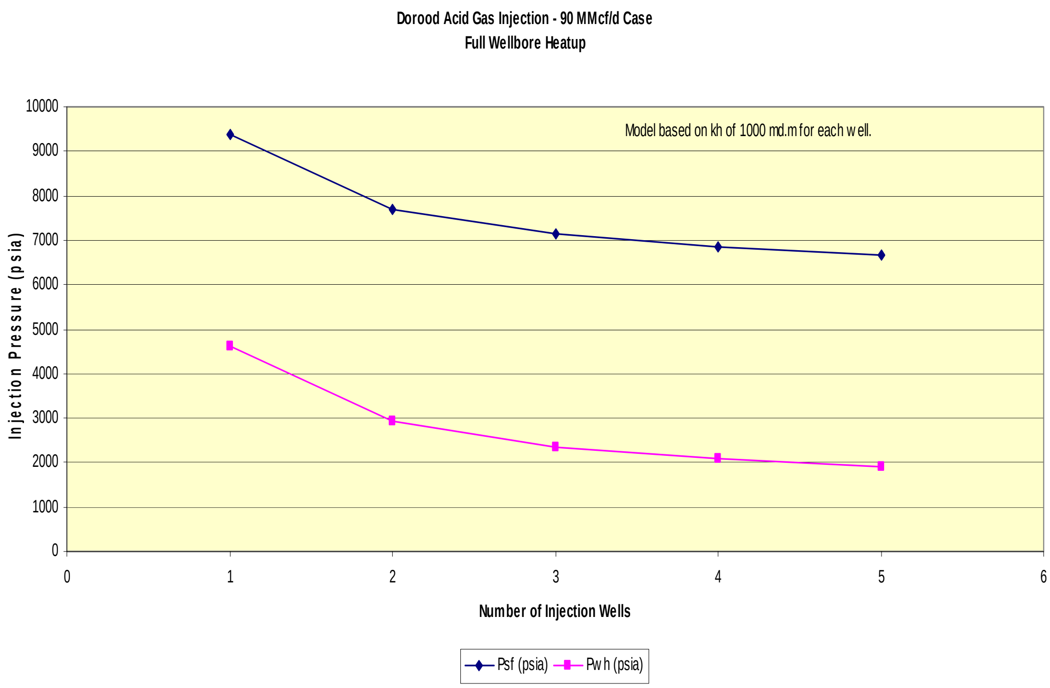

Figure 4: Impact of multiple injection wells on pressure {Fekete}

Additional injectivity modeling will be undertaken in subsequent stages of the Acid Gas Injection FEED Study after confirmation of the reservoir caprock integrity, wellhead locations, downhole locations and wellbore design. The final wellbore modeling will also include analysis with Neotec's Wellflo™ and AGIProfile™ from Gas Liquids Engineering.

2.3 Reservoir Capacity

Cumulative injection of 394 Bscf (injecting 85.8 MMscfd for 12.5 years), which is equivalent to 168 million bbl at reservoir conditions, occupies a reservoir volume of 2,700 ha.m in an ideal situation. Liquid acid gas will ideally reside above a level of –3,700 mSS (Figure 5).

The volume is a small fraction of reservoir capacity and reservoir capacity exceeding 25 years of injection is easily available. The acid gas will essentially be located in a small area of the reservoir under the north-east corner of Kharg Island (Figure 6).

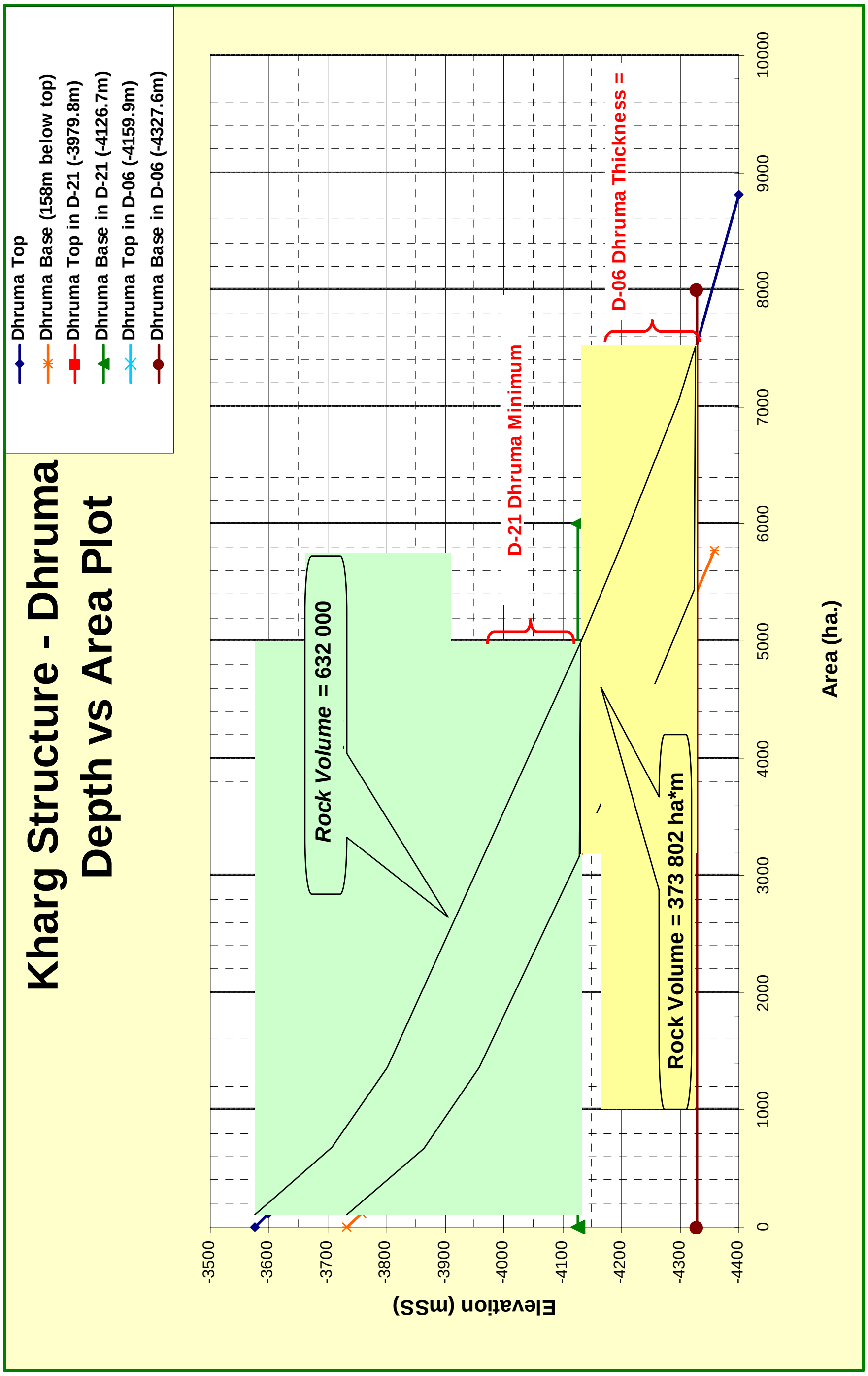

Figure 5: Dhruma Formation Data {Fekete}

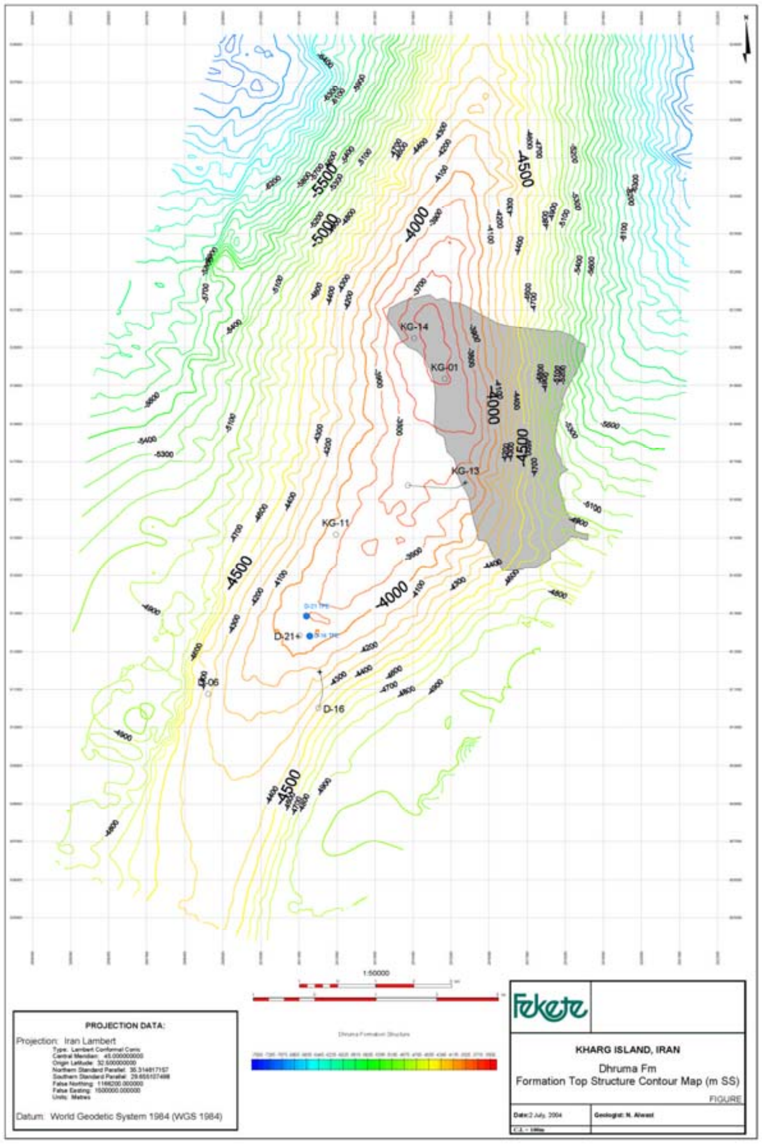

Figure 6: Dhruma Formation Top Structure Contour {Fekete}

2.4 Injection Zone Containment

The evaluation of the caprock containment is not yet complete. The highly folded nature of the formation has required additional analysis of caprock integrity.

3. Acid Gas Compression

3.1 Primary Design Parameters

3.1.1 Acid Gas Compressor Feed

- Design acid gas feed rate: The normal operating acid gas rate from the acid gas removal units is expected to be 78 MMscfd. The design rate for the acid gas feed stream to the acid gas injection facility is currently 85.8 MMscfd which includes 10 % contingency.
- Minimum acid gas feed rate: The current design preference is to be able to maintain operation of the acid gas compression units with an acid gas feed rate as low as 18 MMscfd.
- Acid gas feed pressure: The current design has a minimum compressor suction pressure of 1.7 bara.
- Acid gas feed temperature: Normal operating temperature will be 45 °C.
- Acid gas composition: The feed stream composition will vary dependent upon production streams and prior processing activities. The range of operating data is expected to include:

Component	Mol. %
H_2S	33-64
CO_2	29-57
CH_4	0.3-1.3
C_{2+}	0.5-2.2
Mercaptans	0.1-0.2
Other hydrocarbons	0.2-0.3
H_2O	4-5

Under certain operating scenarios the hydrocarbon content (C_{2+}) may increase to 6 %.

3.1.2 Acid Gas Compressor Discharge

In the standard design of an acid gas injection project the required acid gas compressor discharge pressure would be back-calculated from the facilities and reservoir downstream of the compressor. Namely, reservoir studies would determine the formation injection pressure requirement for the design rate and then a bottom hole pressure would be determined. Wellbore studies would then determine the applicable wellhead pressure. Finally pipeline analysis would determine pipeline pressure loss and therefore the design acid gas compressor discharge pressure.

The current status of the Kharg Island Acid Gas Injection project does not permit this rigorous analysis, namely:

- Cap rock integrity has not yet been confirmed.
- Simulation studies have not determined downhole well spacing.
- Multiple injection wells will be required for the design injection rate. Additional injection wells will decrease the required discharge pressure but will increase project costs.
- A facility location study is currently underway that may result in alternate locations of acid gas injection compressors and injection wellheads thereby delaying pipeline design activities.

The existing Acid Gas Injection FEED study is proceeding with a design compressor discharge target of 180 bara. The prior Conceptual Design Study indicated that this discharge pressure is the maximum achievable with the anticipated range of available compressor/driver options. Additionally this discharge pressure should provide sufficient wellhead injection pressure for the preliminary three injection well scenario at 165 bara (Figure 4) with an allowance for pipeline pressure loss and other factors.

Figure 7 shows the presently proposed location of the facility on Kharg Island. If the injection wells can be drilled and operated at the southern end of the facility lease, as currently anticipated, the injection pipeline will be less than 100 m and the injection wells will be near vertical. (see Figure 6)

Figure 7: Kharg Island Schematic

3.2 Process Design

3.2.1 Phase Envelopes

As a first stage of the investigation of the acid gas injection facility, phase envelopes were constructed. The phase diagrams are very important in the design primarily because the two-phase region must be avoided during the compression of the acid gas. Formation of liquefied acid gas during compression will pose a significant problem.

As stated previously a range of potential feed stream compositions may be presented to the acid gas injection facility dependent upon the operation of the wells and the processing units. At this time the specific stream data and options are covered by various confidentiality agreements and detailed data cannot be released.

Figure 8 shows the calculated phase envelopes for the six primary flow scenarios to the acid gas compression facility. As shown in Figure 8, compositions with higher hydrocarbon content tend to be “shorter” and “broader”.

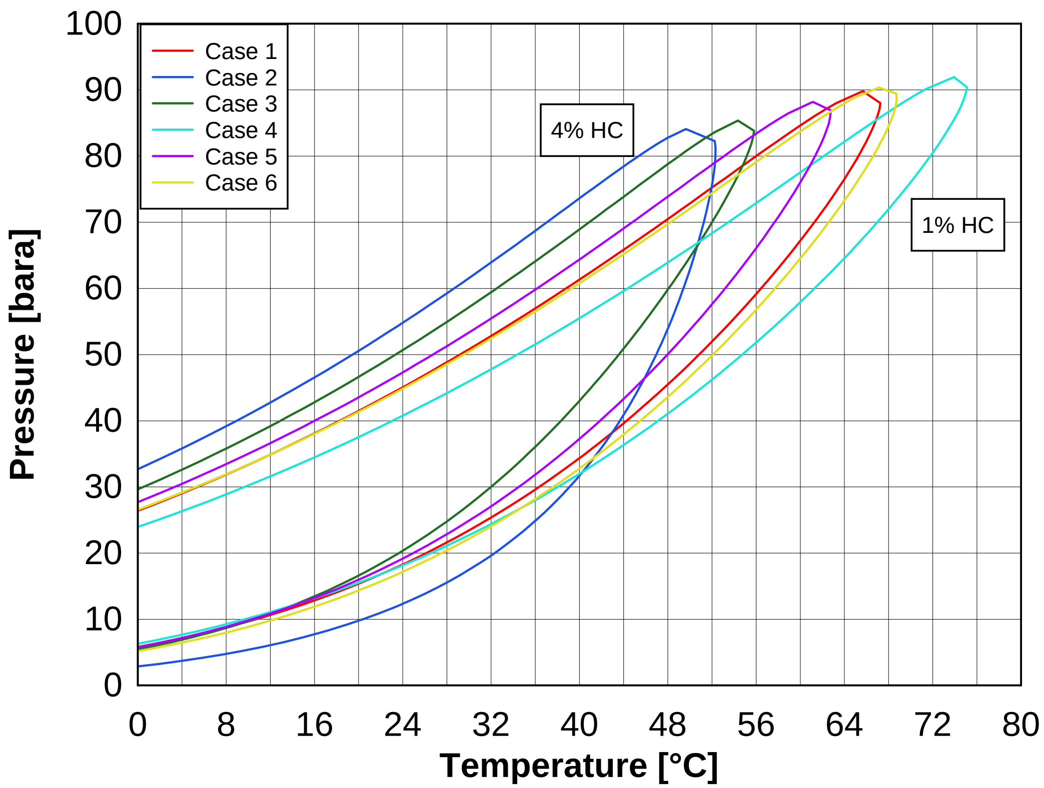

Figure 8: Acid Gas Phase Envelopes for Kharg Island AGI

Figure 9 demonstrates the effect of increasing hydrocarbon content on specific flow regimes. Cases 5 & 7 represent the same base composition but with increased hydrocarbon content in Case 7; Cases 6 & 8 represent similar effects under different operating schemes. As the hydrocarbon content increases the phase envelopes expand significantly towards the low pressure, high temperature region. The area within the phase envelopes which represents the formation of a multiphase fluid, increases with increasing HC content and thereby the area that must be avoided during compression is increased.

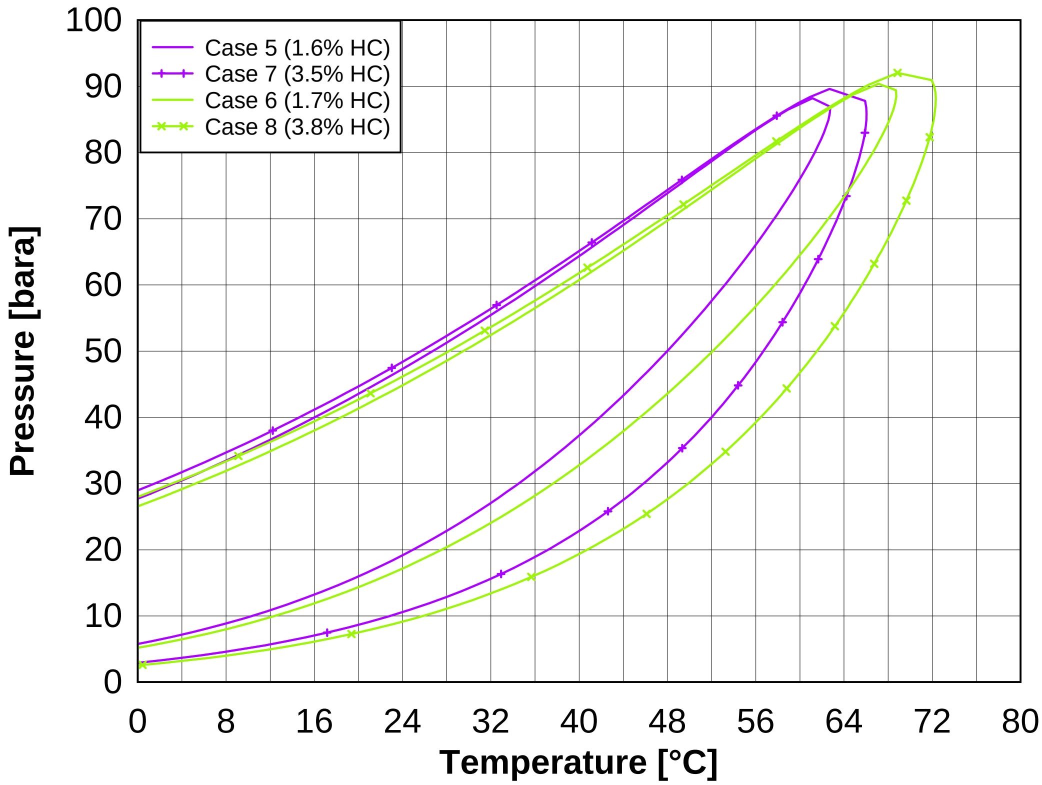

Figure 9: Acid Gas Phase Envelopes for Kharg Island AGI - Increased HC

Perhaps the most important impurity in an acid gas stream beside water is methane; methane presence can generate several effects:

- Methane is significantly more volatile than the acid gas components. Thus, it tends to broaden the phase envelope. The presence of a few percent of methane in the gas can significantly increase the bubble point pressures. Usually the presence of a small amount of methane (up to a few mole per cent) does not have a significant effect on the dew point pressures of the mixture.

- Methane has an effect on the water capacity of the acid gas. At high pressure, a hydrocarbon rich stream can hold less water than an acid gas stream. The presence of methane in the acid gas reduces the water holding capacity of the stream.

- The presence of methane reduces the density of the gas. Since the injection pressure is related to the density of the injection fluid, the presence of the methane increases the required injection pressure.

- In some situations, where there is a significant amount of volatile hydrocarbons (i.e. methane and ethane) in acid gas, there is a potential for phase separation in the injection well. The first necessary condition for this to occur is that the fluid must enter the two-phase region. If the fluid is at a pressure and temperature such that it is outside of the two-phase region then a bubble will not form. Secondly, in a low flow regime it is possible that the buoyancy of the gas can overcome the flow of the mixed fluid and gas bubbles may rise instead of flowing with the mixture. At higher superficial liquid velocities, the gas bubbles are typically carried with the momentum of the liquid.

In a typical aqueous alkanolamine sweetening process, hydrocarbons heavier than methane are usually only picked up in small quantities. However, if a physical solvents or mixed solvents are used, significantly heavier hydrocarbons may be absorbed in the sweetening process and released with the acid gas.

Based solely on boiling points, components heavier than methane but lighter than about n-butane are neutral; that is they have little effect on the phase envelope of the acid gas mixture. The heavier hydrocarbons can be both more volatile than the acid gas components and less volatile. Fortunately the available model for vapor-liquid equilibrium, based on cubic equations of state, can accurately predict the phase behavior in these systems.

The light hydrocarbons (up to about heptane or so) tend to reduce the density of the acid gas mixture. Again, the lower density results in higher injection pressures.

In addition to hydrogen sulfide there are several sulfur compounds that are found in natural gas. There are simple compounds such as carbon disulfide (CS_2) and carbonyl sulfide (COS). In addition, there are the mercaptans (more correctly called “thiols”), which are the sulfur analogues to alcohols. The simplest of the mercaptans are methanethiol (CH_3SH), ethanethiol (C_2H_5SH), and n-propanethiol (C_3H_7SH).

Unfortunately it is difficult to model the effect of these sulfur components because they have not been studied in much detail. Specifically, the vapor pressure of these components has not been studied in detail (most of the vapor pressure information that appears in the literature for these compounds are based on generalized correlations). In addition, there is very little equilibrium data for mixtures of these components, which are necessary to make accurate predictions. Most of the commonly used process simulation software packages include these sulfur compounds in their component lists. However, the lack of information regarding these sulfur compounds makes predictions from these packages of limited value.

Finally, the densities of these sulfur compounds are comparable to the acid gas components. Therefore the presence of these components should have little effect on the required injection pressure.

3.2.2 Compression Profile

The compression profiles have been generated by plotting the suction, discharge and interstage pressures and temperatures to meet the following parameters:

- Initial suction pressure: 1.7 bara
- Initial suction temperature: 45 °C
- Final discharge pressure: 180 bara
- Final discharge temperature: 40 °C
- Phase envelope margin: 5 °C or more
- Maximum interstage temperature: 70 °C (after cooling)
- Maximum interstage temperature: 200 °C (prior to cooling)

The preferred additional parameters include:

- Interstage cooling to: 40 °C
- Maximum interstage temperature: 180 °C
- Interstage pressure to maximize dehydration

The final discharge temperature and interstage temperatures are based on the cooling capacity of existing utilities. Interstage temperatures could be increased within the 180 °C/200 °C limits stated above and the final discharge temperature could be raised to 60 °C.

At the current design stage, the interstage pressures are:

		Stage 1	Stage 2	Stage 3	Stage 4
Suction Pressure	bara	1.7	5.2	19.3	60.0
Discharge Pressure	bara	5.9	20.0	60.7	180.0

Subsequent equipment design may modify these interstage conditions and the final discharge pressure.

Figure 10 shows the compression profile overlaid on the phase envelope from Case 1 (previously shown in Figure 8).

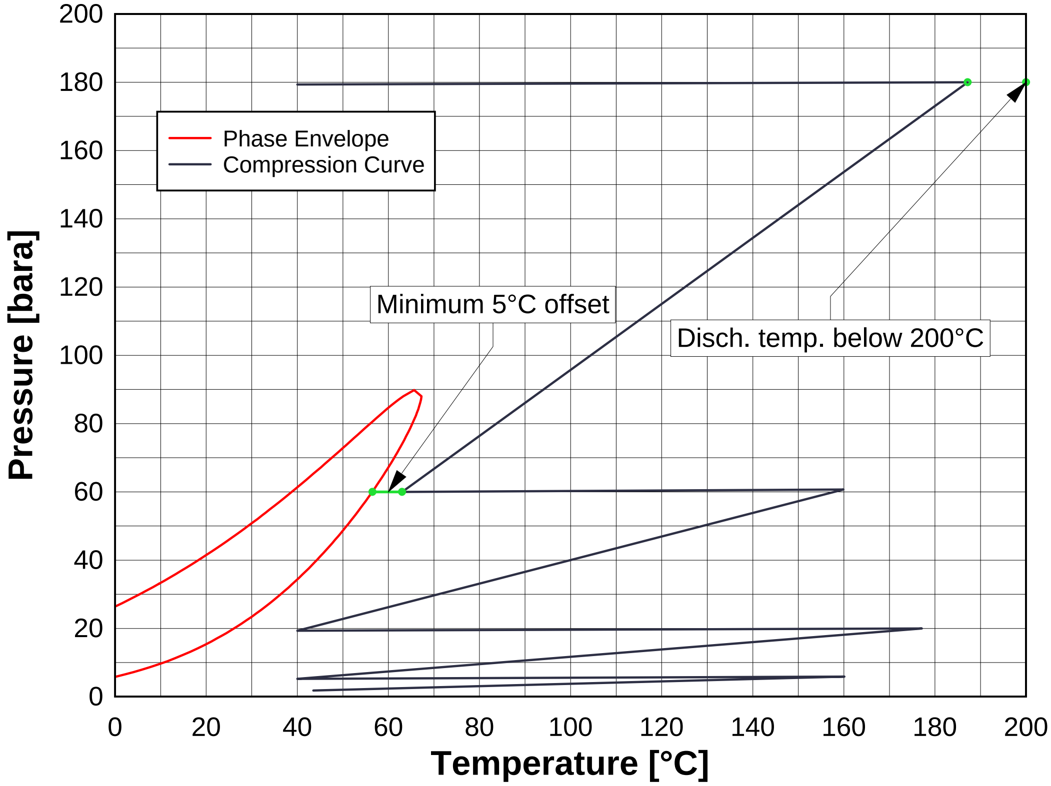

Figure 10: Compression Profile for Case 1

The actual phase envelope offset is:

Stage 1	Stage 2	Stage 3	Stage 4
63.4 °C	42.1 °C	14.8 °C	6.6 °C

As shown, the compression profile for Case 1 meets all the requirements with a minimum phase envelope offset of 6.6 °C.

Ideally the compression profile should be selected to remain constant and operate outside the phase envelope and within the limits of any additional constraints for all operating scenarios. However as shown in Figure 11, the base compression profile when overlaid on the Case 8 will likely enter the multiphase region at second and third stage interstage conditions.

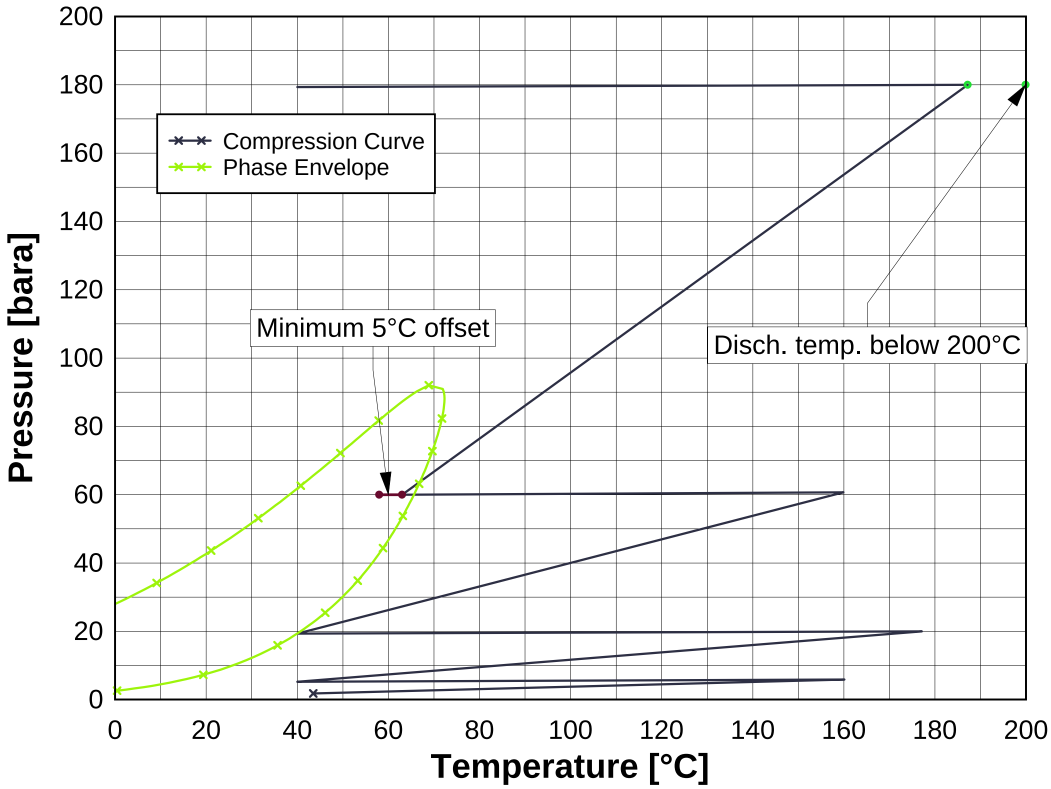

Figure 11: Default Compression Profile for Case 8

The current Kharg Island AGI design has approximately 15 alternate stream compositions and operating scenarios which are driven by different field production schemes and alternate plant operating scenarios. Design of the compression profiles for these scenarios requires balancing of the various design parameters and targets stated earlier for the compression units.

Figure 12 shows the preliminary compression profile for Case 8 with an alternate interstage temperature regime to move the compression profile a suitable distance from the phase envelope. At these conditions the interstage cooling is reduced and as a result the discharge temperature approaches the current 200 °C maximum.

Preferred compression profiles have been selected for all scenarios; these profiles are currently under review to determine actual operating feasibility and control methodology.

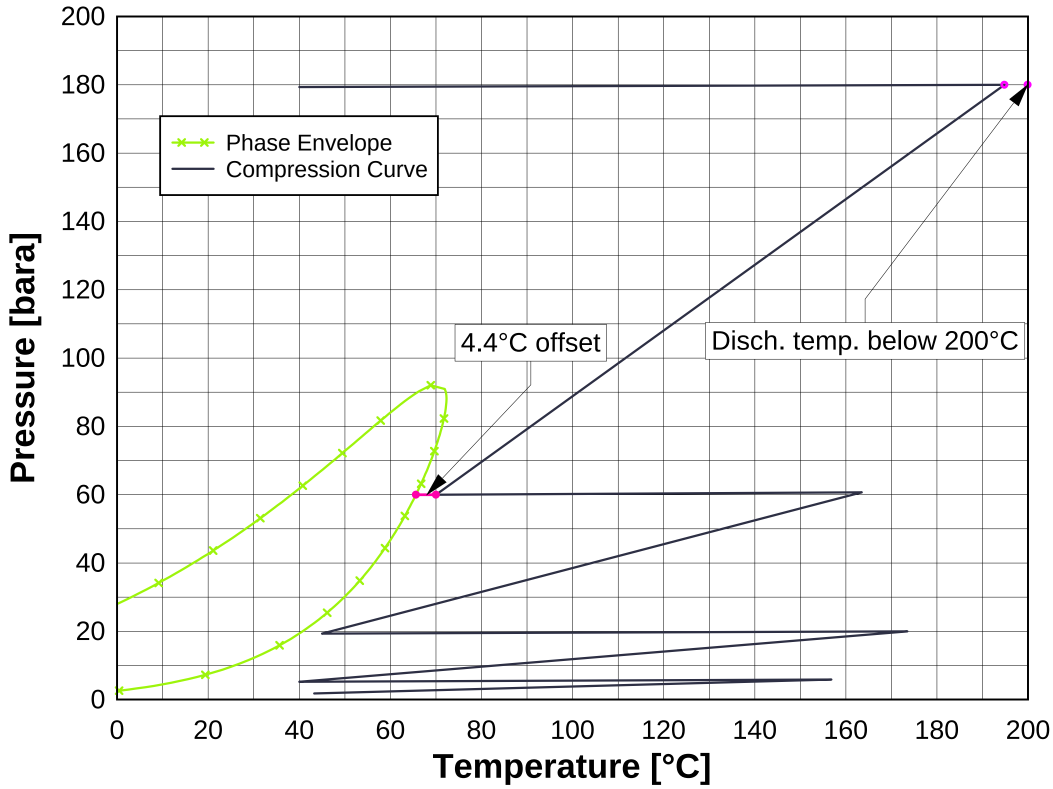

Figure 12: Alternate Compression Profile for Case 8

3.2.3 Water Removal

Water in acid gas can lead to corrosion and formation of hydrates. To avoid free water formation, water content must be controlled so that the acid gas leaving the compressor is under-saturated. This can be achieved by refrigeration, glycol or dry desiccant dehydration, or simply in some cases by setting the optimum compressor interstage conditions to promote water removal.

The water content of sweet gas is a well-behaved function of pressure and temperature. As the temperature increases so does the water content. As the pressure decreases, the water content increases. In addition, when light hydrocarbons are liquefied, their ability to hold water decreases.

Acid gas behavior is slightly different. At low pressure the water content behavior is similar to that of sweet gas inasmuch as the water content increases with increasing temperature and decreasing pressure. However, with acid gas as the pressure is further increased the water content reaches a minimum, beyond which the water content increases as shown in Figure 13. Furthermore the liquefied acid gas holds more water than the vapor, which is contrary to light hydrocarbons.

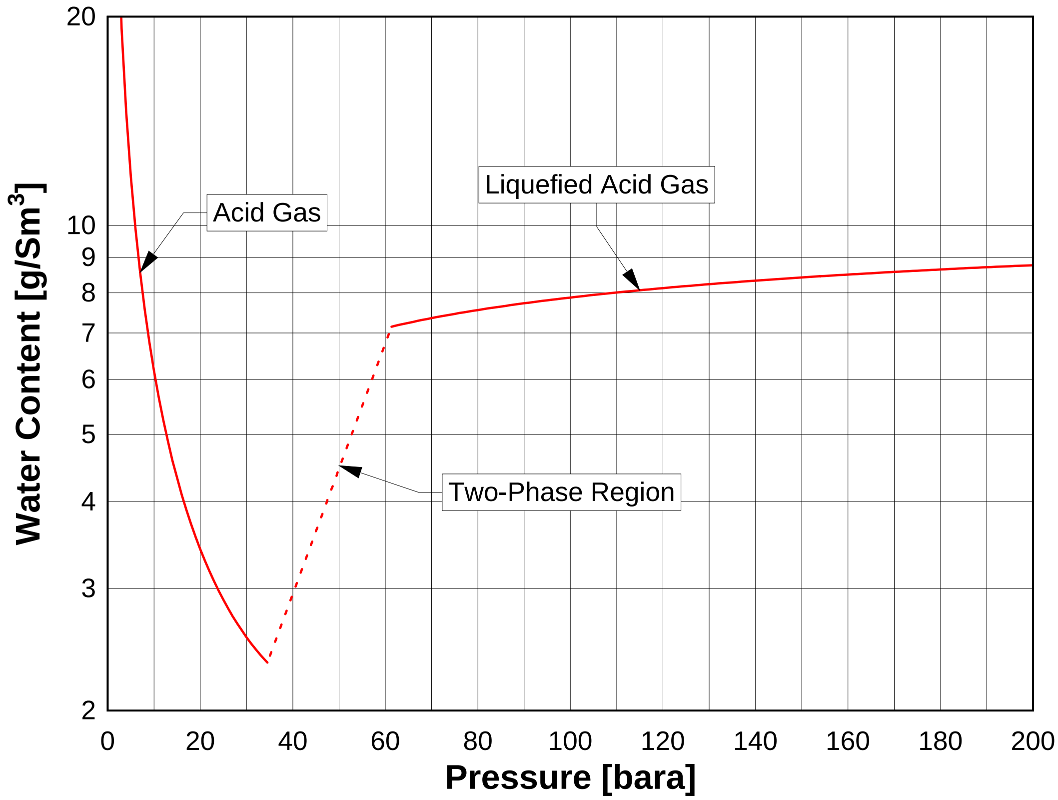

Figure 13: Kharg Island Acid Gas Case 1 Water Content at 40°C

In acid gas injection it is common to use the minimum in the water content to reduce the water content of the injection stream below saturation. Thus the formation of both a free-water phase and hydrates can be avoided in the injection scheme.

No claim is made that the gas is dehydrated in a conventional sense – it still contains approximately 3.7 g/Sm³ at 180 bara in Case 1, which is substantially higher than the typical 0.065 to 0.115 g/Sm³ specification for natural gas. But at this water concentration the fluid leaves the final stage of compression under saturated with respect to water. Saturated water content of acid gas for Case 1 at 180 bara is 8.6 g/Sm^3.

AQUAlibrium™ 3.0 software was used to calculate saturated water content data.

3.2.4 Hydrate Formation

Hydrates are solid crystalline substances composed of water and small molecules (hydrate former). They form at temperatures where a solid phase of water would not otherwise be expected. That is they form a temperatures greater than 0 °C (32 °F).

There are three criteria that must be met in order to form a hydrate [1]:

- The exact combination of pressure and temperature
- The presence of a hydrate former: methane, ethane, propane, CO_2, H_2S
- The proper amount of water – not too much, not too little.

Of all the components commonly found in natural gas, none forms a hydrate more readily than hydrogen sulfide. The hydrogen sulfide hydrate forms at the lowest pressure and persists to the highest temperatures. In addition, the presence of H_2S in a gas mixture tends to have a disproportionately large effect on the hydrate forming conditions.

Among the ways to combat hydrate formation is to use dehydration. If there is no water then there is no hydrate. In addition, if there is reduced water then the temperature at which a hydrate is formed is also reduced.

Figure 14 shows the hydrate curve for Case 1 for a water-reduced case. The designer of the acid gas injection scheme has to make sure that the lowest anticipated temperature in the injection scheme is above the hydrate formation temperature.

The hydrate curves were generated using BR&E's Prosim software. Hydrates are expected to form under the conditions on the left side of the hydrate curve. The predicted hydrate temperatures never exceed about 25 °C. Since the lowest anticipated temperature in this injection scheme is just below 40 °C, hydrates are not expected to form.

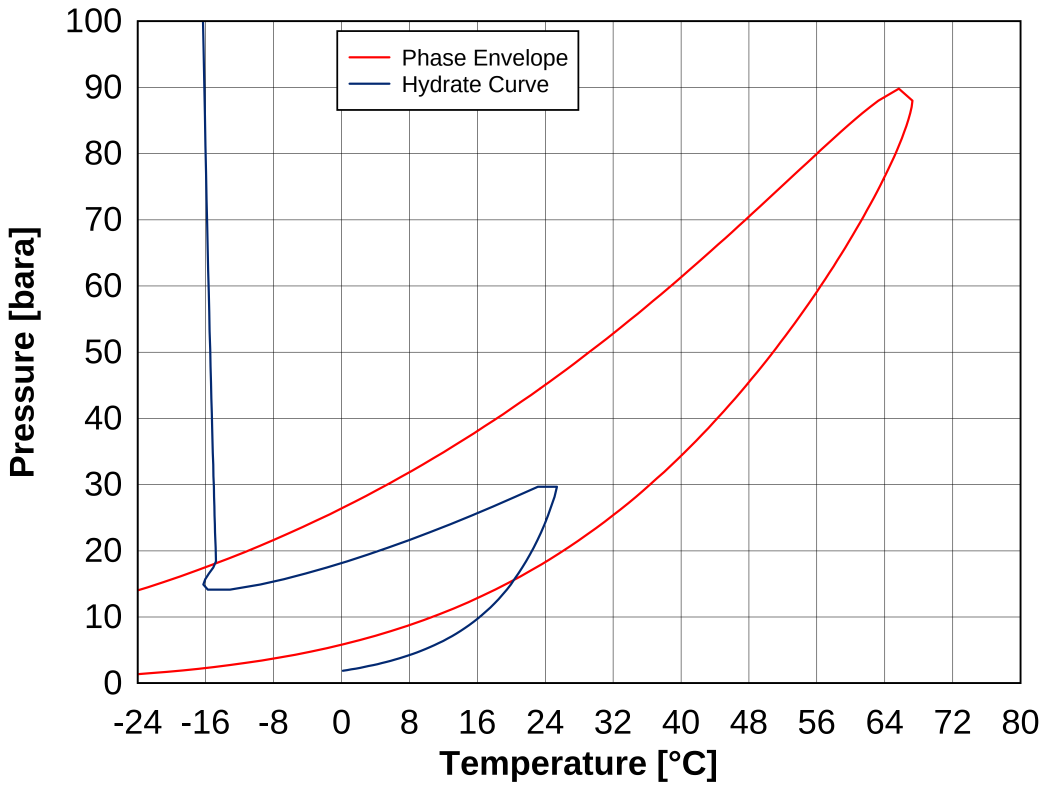

Figure 14: Kharg Island Case 1 Hydrate Formation Conditions

3.2.5 Acid Gas Properties

The properties of the acid gas at discharge from the acid gas compression facility are currently expected to be:

- Pressure: 179 bara
- Temperature: 40 °C
- Flow: 160,000 kg/h, 4,700 m^3/d
- Density: 810-830 kg/m^3
- Viscosity: 0.09-0.11 cP

4. Equipment Design

Compression design is currently under development within the following parameters:

- Compression equipment, maintenance and spare parts must be reliably available to the end user.
- Preliminary design is based upon 3x50% centrifugal compressors driven by natural gas-fired turbines. Each driver will require a site rating of approximately 11,500 kW to generate the required compression.
- Interstage conditions will be designed to provide adequate interstage dehydration, to avoid interstage dense or liquid acid gas phase formation, and to avoid discharge temperatures higher than 200 °C.
- Interstage dehydration is achieved by setting interstage pressure at a value as close as possible to the pressure at which acid gas contains minimum amount of water.
- To avoid formation of liquefied acid gas, the compression curve will be kept 5 °C or more from the phase diagram.
- The system will be able to handle any acid gas rate between maximum and minimum, using a combination of compressor trains, gas turbine speed control and gas recycle.
- Compression feed streams may vary extensively and the system will be designed to handle such variations with minimum control variations.

5. Future Developments

Final initial design, P&ID development and control system methodology for the facility components are currently under development in conjunction with all parties for completion by the end of 2004.

Pipeline, wellhead and wellbore design were suspended until reservoir studies were completed; however these design components recently commenced based upon assumptions in regard to facility locations and reservoir parameters. Conceptual design should be complete of these components early in 2005 although final design will be dependent upon additional reservoir studies which will likely not be completed until mid-2005.

Safety and environmental impact are critical issues in the design of any acid gas injection facility and especially in a facility with high rates of high pressure acid gas. The original facility FEED studies completed in 2002 contains specifications for all safety systems and specifications for environmental and risk assessments. As a component of the Kharg Island AGI FEED study, all the safety and environmental components of the original plant design are being reviewed to insure that the specifications, procedures and philosophies are applicable to the Acid Gas Injection facility. A full HAZOP of the initial AGI FEED will be undertaken early in 2005; additional risk and environmental impact assessments will be scheduled during subsequent project phases.

References:

1 Carroll, J.J. *Natural Gas Hydrates: A Guide for Engineers*, Gulf Professional Publishers, Amsterdam, the Netherlands, (2003).