PROCESSING CONSIDERATIONS FOR CARBON CAPTURE & STORAGE

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ABSTRACT

As Industry and the public at large focus its attention on Carbon Capture and Storage as a means of stabilising and reducing greenhouse gas emissions, there are still only a few facilities world-wide in which this technology is actively being practiced. Operating facilities include the Sleipner, Norway and the In Salah Gas Algeria developments. In the latter in excess of 1 million tonnes per year of CO_2 is compressed and injected into a subterranean aquifer.

This paper discusses some of the features of CO_2 capture facility design that are peculiar to carbon dioxide. This includes selection of gas drying, compression and piping systems, and their optimisation.

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Introduction

Carbon dioxide is one of the most commonly found “impurities” in natural gas and associated gas feedstocks. Pipeline and bulk consumer customers require that specifications limit CO_2 content to typically 2 mol%. This requirement gives rise to two processing considerations. Firstly, carbon dioxide must be removed through what are usually energy and capital intensive gas processing units, and secondly disposal of the removed carbon dioxide.

Many papers have been published that address the processing of gas streams to meet the required CO_2 specifications. With very few exceptions these schemes give rise to a “reject stream” of low pressure, often water-wet or saturated carbon dioxide, hydrogen sulphide and other impurities. Common practice has been to vent or incinerate the stream, to recover sulphur and in relatively few cases to capture the stream.

The majority of plant experience where the CO_2 / H_2S stream has been captured are onshore USA and Canada. In some instances the carbon dioxide has been recovered, transported at pressure and used for enhanced oil recovery within oilfields often some distance away.

Recent schemes have incorporated the recovery and reinjection of carbon dioxide into non oil formations. These include the Sleipner field development of Statoil in the Norwegian North Sea and the In Salah Gas Development in Algeria. In both of these cases CO_2 is recovered at low pressure, compressed and injected into the subsurface targets.

It is anticipated that considerably more such capture / injection schemes will be designed and implemented over the next few years. This is in part due to increased public awareness and political action on carbon emissions to atmosphere, and secondly in some areas being driven by the economic benefits of recovery of carbon dioxide and its use to enhance oil recovery.

This paper considers some of the design challenges presented, including an in depth look at one unit operation – the CO_2 compression and drying unit. The case of “CO_2 recycle to surface”, which presents other challenges, has not been considered.

Examples of gas reservoirs with CO_2

BP’s involvement in oil and gas field developments throughout the world are likely to reflect the experience of many other operators – oil and gas discoveries commonly contain carbon dioxide!

For example, in Prudhoe Bay Alaska, the substantial gas resource (in excess of 20 TCF) associated with the giant Prudhoe Bay oilfield contains typically 12 mol% CO_2 and over 10 ppmv H_2S. For the Tangguh field development in Indonesia the acid gas content is similar. In Algeria, wellfluids containing up to 10 mol% CO_2 have been experienced in the development of the In Salah Gas fields south of Hassi R’Mel.

BP’s North Sea gas developments over the last forty years typically have lower wellfluid acid gas levels. However in some major gas import terminals of the UK there are substantial CO_2 removal units to bring the UK's gas into specfication. These include the terminal at Barrow and the SAGE terminal in Scotland.

In the Middle East gas streams with significant sour and acid gas content have been encountered. This includes H_2S at typically up to 3 mol% and CO_2 at approximately 5 mol%. However, it is known that these are relatively modest levels compared to some gas sources being processed today elsewhere in the region, and others in the "yet to be developed " category.

A wider survey of world gases of course shows that the full envelope of acid or sour gas compositions will span at least 0-90 mol% CO_2, and 0-60 mol% H_2S.

Injection specifications and CO_2 Product Quality

Primary CO_2 product specifications typically include a required injection pressure, temperature and composition. Table A presents an example of a CO_2 injection gas specification.

Table A
An example of CO_2 injection specification

Specification	**Value**
Gas Reinjection Pressure	Between 150 barg and 300 barg bottom hole in the aquifer, possibly varying over project life
Maximum Water Content	To avoid liquid water formation / corrosion / hydrates in the injection network
Temperature	For entry into the flowline: not to exceed 75°C

Considerations in arriving at the specification follows.

Pressure

Compressor discharge pressure (P_D) is a function of the following parameters:

$$P_D = P_{reservoir} - P_{\text{Well hydrostatic}} + P_{\text{injection loss}} + P_{\text{frictional loss}} + P_{elevation} \quad (1)$$

Although the reservoir pressure may well dominate, with a 'heavy' gas such as carbon dioxide and over geographically dispersed systems, other terms such as the hydrostatic component in the equation will be significant. The reservoir pressure may vary through the injection life. The injection loss pressure is a measure of the "driving force" to get the fluid from the bottom of the injection well into the bulk reservoir.

In order to optimise the selection of compressor discharge pressure it is necessary to consider a range of issues. In general, high discharge pressure will increase capital cost through the requirement to use higher strength / weight steels and possibly additional compression stages. Power requirements will also increase, and possibly the proven envelope of equipment will be reached or exceeded. However increased pressure can reduce well numbers if there are no other limits on injection pressure such as downhole fracture points.

A lower injection pressure, in general, provides the opposite effects, but may start to drive high well numbers and large line diameters. Well technology is important and use of horizontal injection wells has been shown to considerably reduce the total well number for the same injection pressure, or reduce injection pressure for the same number of wells.

Therefore arriving at the optimum discharge pressure requires integrated working across a range of disciplines including surface engineering designers (such as mechanical, pipeline and process) and subsurface (including completion, drilling and reservoir engineers).

Temperature

The receptor reservoir or aquifer will commonly be at the temperature driven by the geothermal gradient. Typical injection depths are likely to be 1000 – 2000m, and reservoir temperatures therefore, say, 50 – 80°C. CO_2 injection temperature is generally limited only by the available means of cooling (air and/or water) or the operating temperature limits of external or internal pipeline coatings, if these are to be applied for corrosion resistance or to reduce pipe roughness.

Water content

The water content of CO_2 must be limited by the need to avoid the formation of solid hydrates or a corrosive, free-water phase during the injection process.

Carbon dioxide's water content characteristic with pressure and temperature has been extensively reported within the literature. Test data for the water content of CO_2 vs pressure exhibits a reasonably flat minimum between approximately 55 and 70bara (GPA RR99) for all temperatures. Simplistically, this means that the water content in CO_2 mirrors the behaviour of the water content in natural gas at pressures below 55 bara i.e. for a fixed gas temperature the saturation water content decreases as pressure increases. However, with CO_2 this trend changes at approximately 55bara. If CO_2 pressure is increased beyond 55bara at constant temperature, the capacity of CO_2 to hold water initially flattens through a minimum and is vitually unchanged unitl a pressure of approximately 70bara is reached. Thereafter, the saturation water content of CO_2 increases. This unusual behavioiur translates into a reducing water dew point temperature when pressure is increased beyond 70bara and CO_2 water content is maintained constant.

By using the benefits that lie within this characteristic it is in theory possible to "dry" a CO_2 stream by water condensation alone at pressures of 55 – 70 bara, where the water content is a minimum. Subsequent recompression of the gas beyond this pressure range results in a reduction in water dew point temperature. Therefore if, for example, one has cooling medium available at 30°C, the gas may be cooled to say 40°C. If the resultant "depression" in dew point is sufficient that the gas cannot, under any operational circumstance, encounter dew-point conditions further downstream, then additional water removal by glycols or molecular sieves is unnecessary and carbon steel materials may be used for transportation and disposal.

Our assessment is that if the point of drying is reasonably close to the point of injection then it may be possible to ensure that no condensation can occur. For example if the injection wellhead is located in close proximity to the compression machinery. However, on systems where the injection point is remote from the drying, careful consideration is needed to ensure that start-up, shutdown and other operational scenarios will not result in condensation of water. If this cannot be achieved then the use of carbon steel materials may not be feasible, necessitating expensive corrosion resistant solutions or drying with molecular sieve or glycols. Once in the well, the gas is generally warmed up and the risk of condensation is reduced and this will not drive the selection.

Selection of integrated process schemes for removal and re-injection

Once the “boundary conditions” of the processing units have been defined, then the role of the process designer is in the efficient selection of the primary processing units. A “one step” generation of a high pressure carbon dioxide ‘reject’ stream together with a conditioned natural gas remains a prize that technology has not yet delivered. The design will be even more elegant if the natural gas and carbon dioxide can remain dry through the sweetening process

Although many gas processing unit operations have been studied, which include amines, membranes, lean oil absorbents, chemical and physical liquid and solid systems, perhaps the most commonly used “configuration” is that of an amine for removal of CO_2, with recovery of carbon dioxide at low pressure followed by the compression or pumping of the carbon dioxide.

There are various well publicised process schemes that have been proposed and in some cases used that, for example, allow slightly higher reject pressure of the majority of the carbon dioxide, though in the main, carbon dioxide is released at low pressure.

Case Study Process Conditions

The scheme discussed is based on a desert location. Water is not available in sufficient quantities for cooling services, so air cooling is to be used throughout. Summer maximum ambient air temperature is +40^{o}C, limiting process stream temperatures to 55^{o}C for design purposes. Minimum winter temperature has been taken as +1^{o}C.

Specifications, as defined earlier, apply and the recovered CO_2 will be reinjected into an aquifer. Carbon dioxide is recovered from comingled process gas in two, parallel absorption / regeneration trains, employing a closed loop, aqueous activated-amine removal system.

CO_2 is produced at a rate of 80 tonnes/hr, as a water-saturated gas stream at near atmospheric pressure (1.5 bara) and 55^{o}C temperature from the reflux drum of each regenerator tower. Hydrogen sulphide in the incoming well streams (15 ppmv design) is concentrated into the carbon dioxide and achieves a design level of 200 ppmv. Trace amounts of hydrocarbons, predominantly methane (<0.1mol%), are also contained in the CO_2 product stream as a result of co-absorption from the process gas in the amine absorber columns, together with amine from carryover / vapour – liquid equilibrium. If HP flash vapour from the amine circuit is produced and routed here then higher methane levels will result.

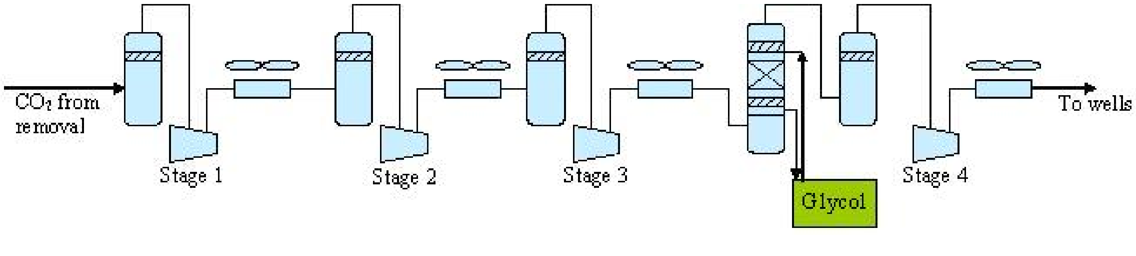

Figure 1 - Process Flow Schematic for Injection

A schematic diagram of the concept arrangement is given in the preceding Figure 1. Inter-stage pressures are 5 barg, 28 barg & 60 barg when a discharge pressure of 200 barg is required for injection.

Design Issues

From CO_2 removal through to ultimate disposal there are a wide range of design considerations. These include surface plant, drilling and completions and reservoir engineering aspects. This paper introduces and discusses a selection of these from the surface plant perspective.

Design Safety

Most natural gas developments will identify the major accident events to arise from the hydrocarbon processing activities. Whilst carbon dioxide is itself inert, the processing of it presents risks of its own. These include asphyxiation, pressure hazard and hazard from the contaminants present in the stream, principally toxic H_2S. Great attention must therefore be paid to the concept safety aspects (such as plant location and proximity to people, volumes of fluid, uncontained release events). As engineering develops there is also much in the engineering detailing, such as in the gas detection and warning, system isolation philosophies, etc. The operating philosophy must go hand-in-hand with the design to prescribe where, for example, breathing apparatus will be required, and where other risks must be managed such as confined space access or pressure source isolation.

A further feature of carbon dioxide, common to natural gas, is Joule-Thompson (J-T) cooling on reduction of pressure. In the case of carbon dioxide, very low temperatures may be produced at pressure let-down points, requiring careful engineering and detailing of metallurgy. Cold thermal creep upstream of the pressure let-down point is one example.

A fuller discussion of these issues is not the primary area of discussion within the paper and warrants a whole paper in their own right.

The importance of CO_2 Density

The critical pressure of carbon dioxide is 73.77 bara. CO_2 therefore becomes supercritical in the high pressure, fourth stage of the compressor, as well as in the reinjection pipeline and wells.

To establish the necessary compressor discharge pressure, with the required downhole pressure defined by specification, accurate prediction of supercritical CO_2 density is important in order to calculate friction losses in long reinjection pipelines and, in particular, pressure gain due to static head between the surface wellhead and the injection aquifer. Typically the aquifer will be1000m or more below ground.

Commercial simulators offer the user a bewildering variety of thermodynamic packages and property calculation methods which can yield significantly different predictions of physical properties. Table B illustrates the variation in predicted CO_2 supercritical densities, when using 'equation of state' property calculation methods.

Table B
Simulation Results – CO_2 Density

	Simulator 1				Simulator 2			
E-O-S	C-S	P-R	SRKKD	SRK	BWRS	P-R	SRKKD	SRK
Pressure, barg	200	200	200	200	200	200	200	200
Temperature, °C	75	75	75	75	75	75	75	75
Density, kg/m^3	591.3	592.7	548.4	548.7	598.3	594.2	549.8	549.7
Well depth, m	1850	1850	1850	1850	1850	1850	1850	1850
Static pressure, bara	107.1	107.4	99.3	99.4	108.4	107.6	99.6	99.6
ΔP, bar	Base	+0.3	-7.8	-7.7	+1.3	+0.5	-7.5	-7.5

Incorrect selection of the thermodynamic package or property calculation method for modelling the CO_2 reinjection system can therefore result in a difference in required compressor discharge pressure of as much as 8 bar, when considering only the column of supercritical carbon dioxide.

The Mollier chart for CO_2 indicates a specific volume of ~0.0016m^3/kg (620kg/m^3) at 200 barg and 75°C, yielding a static pressure gain of 112 bar. The margin for error in compressor discharge pressure could therefore be even larger than that tabulated above depending on the basis selected for predicting CO_2 density. The temperature changes in the CO_2 will require factoring in for deeper systems, or where the geothermal gradient is unusual.

CO_2 streams that originate from natural gas processing, or streams in pre-combustion removal technologies recovered using amine solutions will contain small quantities of light hydrocarbons (< 0.5mol%) as a result of co-absorption in the absorber column. Generally these low 'contaminant' levels have negligible impact on the predicted density of CO_2, though they "lighten" the overall mix.

Compressor Inter & After Coolers

Due to the unavailability of adequate volumes of cooling water, air coolers are assumed for this application. With the exception of the first stage of compression, suction air coolers were provided on the 2nd, 3rd and 4th compressor stages to remove the heat of compression, with a final aftercooler on the 4th stage discharge to condition the injection stream to a temperature of 75°C.

Due to the day-night and seasonal variations in ambient air temperatures, stages 2, 3 & 4 recycle gas streams are taken off directly from the compressor discharge and let down from stage discharge pressure to the preceding stage suction pressure before cooling in the suction air cooler to ensure that liquid or even solid CO_2 cannot be produced by overcooling during compressor recycle operations. This effect is illustrated for winter and summer conditions for stage 3 of the compressor on the CO_2 Mollier chart of Figure 2.

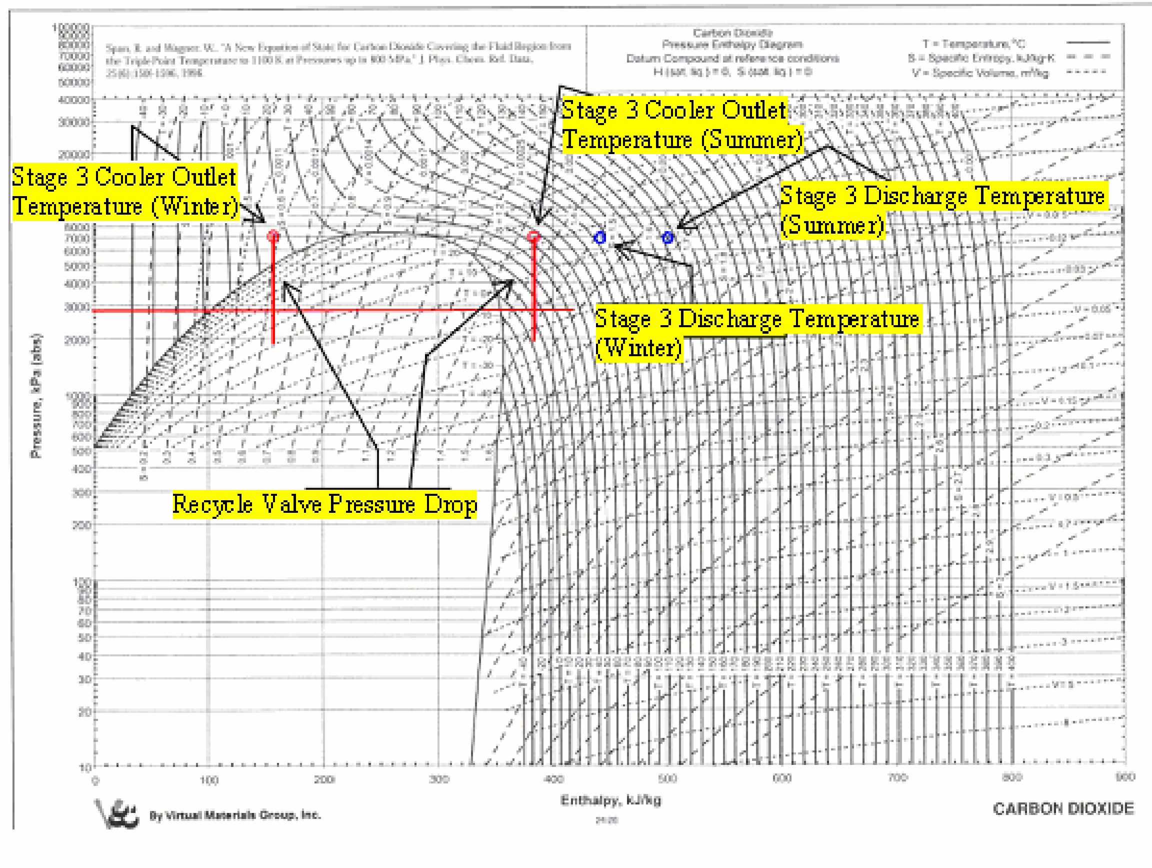

Figure 2
3rd Stage – Suction Cooling

The red vertical line to the right illustrates a typical cooling path across the recycle valve with a relatively warm gas. The red line on the left illustrates the path of a gas that has been over-cooled and on pressure reduction shows the formation of liquid carbon dioxide.

First-stage suction temperature is determined by operation of the upstream CO_2 stripper air-cooled condenser. Condensing temperature is generally minimised to reduce amine vaporisation losses into the CO_2 injection stream. Automatic temperature control can be effected by means of autovariable pitch fans, variable speed fan motors and by switching fans on/off.

The requirement for suction temperature control on the remaining compressor stages can be assessed by a review of the compressor stage performance curves. Compression stages that exhibit a sharp peak on the efficiency curve around the rated capacity point of operation may benefit from automatic temperature control. By this means, tighter control of compressor efficiency and hence power consumption can be practised more effectively than is possible by manual intervention, particularly when interstage air cooling is preferred and when ambient air temperature can vary widely, as is the case for this concept study.

CO_2 disposal during plant upsets

The concept design considered the case of unavailability of injection capacity, due, for example, to loss of motor power, injection well capacity or some other upset event. If the event is of short duration it is likely that production will continue, to avoid other major interruption to plant throughput from the wellhead to the market-place. In this event diverting of the excess CO_2 may be practiced. The designer must then give consideration to selection of a flare, a vent or an incineration system.

Considerations that need to be studied include:

- Local, national and international regulations
- Contaminants in the stream, particularly H_2S, sulphur components, light hydrocarbon components such as methane and other heavier components such as Benzene, Toluene and Xylenes (BTX)
- Duration and frequency of events
- Dispersion scenarios including a range of atmospheric conditions and considering, in particular, location of population centres

Incineration or flaring obviously involves an assisted combustion, thus adding to the atmospheric emissions of CO_2 and loss of valuable natural gas. Longer-term incineration scenarios are usually combined with heat recovery but these schemes are normally not considered appropriate for short-term use. Hence unincinerated venting of excess CO_2 was adopted for this concept design for normal upset scenarios.

It is important to carry out momentum and/or heavy gas based dispersion modelling to establish whether the excess CO_2 flow results in a CO_2 plume that could slump to grade and, depending on wind direction – potentially become a hazardous event. Typically as the feed gas $CO_2 : H_2S$ ratio is preserved into the plume stream, a feed gas of 7.5 mol% CO_2 / 15 ppmv H_2S, will result in a plume with H_2S levels of 200 ppmv, the balance being CO_2.

If plume slump is determined to be an occasional, potential problem, for example as a result of reduced plant throughput and stream momentum, then fuel gas (methane) can be injected to dilute the CO_2 content to a volume ratio of $CO_2 : CH_4$ of approximately 3.4, to yield a combustible mixture. Ignition will increase plume buoyancy and raise the plume, eliminating nuisance or hazard.

CO_2 Dehydration

For this study, the reduction in water dew point temperature of the CO_2 stream by air cooling alone could not provide year-round guarantee that, under all ambient conditions and operating scenarios, free water would not form in the injection piping. Of particular concern was a prolonged shutdown of the pipeline system in cooler winter conditions and consequent corrosion.

Carbon dioxide, at or below its water dew point, can form a Type I hydrate whether or not a free-water phase is present. Above approximately 40 bara, CO_2 will form a hydrate if the stream temperature is below 9 – 12°C. Provision of temperature-controlled suction cooling protects against gas temperatures falling below the hydrate formation temperature in both recycle and normal (forward flow) operating modes. The dehydration facilities provided between the 3rd and 4th compression stages reduce the water content and dewpoint temperature to ensure that water and hydrate formation cannot occur in the high pressure discharge equipment and distribution piping.

Refrigeration, molecular sieves and triethylene glycol (TEG) can all be considered for dehydration service. As the plant requires TEG facilities for dehydration of other gas streams, then some economy of scale through using a “slip-stream” of lean glycol and combined returns made it a good choice. Such decisions are not always so easily made and a techno-economic study would normally be required to optimise the technology selection.

For this concept a dehydration absorber was located between the 3rd and 4th stages of compression where the pressure was held below the critical pressure of CO_2 (73.8bara), at approximately 60-65bara. Also, with this pressure the actual volume flow of gas is reasonable, thus reducing equipment size.

Design water content is reduced from 75400 kg/MSm^3 at the CO_2 injection compressor first stage suction to 3800 kg/MSm^3 at the inlet to the TEG dehydration facility at the suction of the fourth stage of compression.

At the 3rd stage operating pressure, water removal from CO_2 is maximised by cooling with ambient air in the compressor inter-coolers, thus minimising the duty and load imposed on the TEG dehydration plant.

Further dehydration of CO_2, beyond that achievable by air cooling alone, is essential to reduce the water level in CO_2. In this case, with compression to 200 barg injection pressure with a CO_2 water content of 3800 kg/MSm^3 a water dew point temperature of approximately 37^{o}C would result, which is well above the minimum design ambient air temperature (1^{o}C) and winter ground temperature (15^{o}C). Without TEG drying, in the shut-in condition it would therefore be possible for free water to condense in the carbon steel injection pipeline leading to possible severe corrosion.

Because TEG dehydrators can be prone to foaming and consequent solution entrainment into the gas stream, high removal efficiency internals have been considered for the separator downstream of the glycol contactor to exclude, as far as possible, TEG solution from the 4th compression stage. Stage discharge temperatures are predicted to be in the range of 150^{o}C to 210^{o}C, depending on ambient air temperature and 4th stage compression ratio. Apart from the erosive potential of liquid droplets on compressor internals, literature recommends that TEG is not heated above 204^{o}C due to its accelerated degradation and by-products, so exclusion of TEG from the CO_2 compressor is doubly important.

Blowdown

The inert nature of CO_2 makes it a non-contributory factor to a major fire event in the compression area. Nevertheless a compressor blowdown facility is provided to enable wet CO_2 gas to be evacuated to a controlled destination, if an emergency arises or if a prolonged shutdown becomes inevitable, with the consequent possibility of water condensation.

Selection of blowdown destinations is important. Lower pressure stages of the CO_2 injection compressors can be depressured into the acid gas vent/ignitable system. Higher pressure stages of the compressors are depressured to atmosphere due to the risk of formation of solid 'dry ice' during blowdown which could lead to blockage in the acid gas vent.

The discharge of solid CO_2 necessitates careful location of the vent discharge away from normally manned areas whilst at the same time minimising the number of bends in the outlet piping which will be subject to impact by solids.

If transportation infrastructure exists, in order to protect carbon steel injection pipework from excessively low temperatures during depressurisation, a staged blowdown strategy can be considered for the pipeline. For example, in the first stage, pipeline pressure could be reduced from settleout to a moderate pressure, say 30barg (equivalent to a fluid temperature of about -5°C) and then allowed to warm up to ambient temperature by heat gain from atmosphere. After warming-up blowdown is continued so that the pipeline system pressure is further depleted. In this manner, the bulk pipeline temperature never falls below a typical temperature of -40°C sufficient for the system to be designed for impact tested carbon steel with its minimum design temperature of -48°C. Since decommissioning of the injection pipeline is likely to be an extremely infrequent, carefully planned event, the time constraints typically imposed for hydrocarbon blowdown events do not apply and stage-wise depressurisation can be allowed over a much longer time period.

Machinery Selection

In our case study approximately 1.4 million tonnes of CO_2 per year is produced at low pressure and warm temperature from the stripper overhead of the amine unit. At the suction conditions, a total CO_2 volume flow of 75,000Am^3/h is calculated.

To allow selection of compressors within a proven size range, two identical 50% compressors were chosen to deliver the CO_2 flow.

With this machine capacity and the required 200 barg discharge pressure, suppliers offered centrifugal machines with four stages of compression. Typical stage compression conditions are depicted in Figure 3:

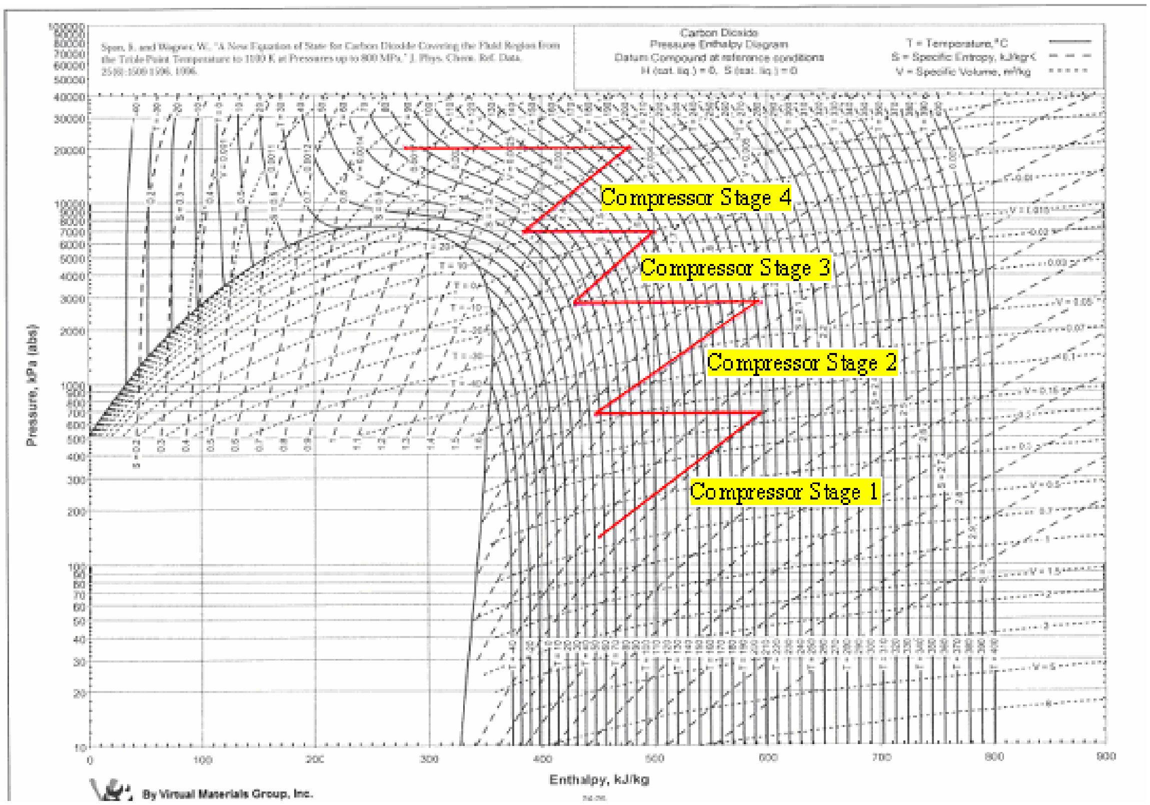

Figure 3
Typical Stage Compression Conditions

It can be observed that this is a typical ‘compression path’ for achieving gas at 200 barg. An alternative path is to select an intermediate pressure and to liquefy the gas. Subsequent pumping of the liquid will then allow a pressure of 200 barg to be achieved, which for the carbon dioxide stream alone results in addition of less energy. However, when the cooling / refrigeration duty is added in, the difference is reduced. In this case, the principal disadvantage of the pumped scheme is the necessity for an additional process system, and hence increased capital cost and operating complexity. Also, the design will have to consider contaminants that will not liquefy and will require purging from the CO_2 stream.

Material Selection

For robust protection against corrosion, ‘wet’ CO_2 should be processed in stainless steel equipment and piping. Conventional carbon steel will corrode rapidly. Although coatings and/or inhibition are sometimes considered, inhibitor effectiveness would need to be very high and high demand would be placed on operational and inspection measures. In a normal industrial system it is hard to assure this. After dehydration, carbon steel materials may be specified for the ‘dry’ CO_2 stream subject to assessment of reliability and mitigation measures.

Consideration can be given to the use of carbon steel piping on the discharge of each compressor stage, where the CO_2 is greatly superheated as a result of compression work. Off-line fittings and connections need to be corrosion resistant as the superheating here cannot be assured. Precautions, such as a blowdown system may be required to ensure that free-water is always excluded from these areas during upset operations.

Stainless steel clad vessels can also be considered although it has been our recent experience that solid stainless steel vessels are a more robust, lower cost solution.

Corrosion resistant materials for compressor internals such as stainless steel will be the robust choice, although alternative coated materials have been used for this service. If coated materials are specified, particular attention must be paid to the coating application process in the supplier's workshop and to subsequent compressor operations to exclude gas stream contaminants that may diminish the long-term effectiveness of the coating.

Depending on the distance between the CO_2 compression facilities and the final point of injection, stainless steel or carbon steel materials may be selected for the main injection pipeline. Over shorter distances of a few hundred meters, stainless steel pipework is an economic solution, particularly if this selection permits a CO_2 dehydration plant to be eliminated from the flowscheme.

For injection pipelines of several kilometres length or more, carbon steel materials with CO_2 drying is likely to be a more economic solution.

Summary

Greater public awareness of greenhouse gas emissions and their contribution to global warming is driving political and industrial action for gas processing and future pre- and post-combustion projects which capture and store carbon dioxide. The results of a gas processing scheme for a desert location where CO_2 is removed from process gas using an amine solvent, compressed to 200 barg and reinjected into a subsurface aquifer, have been reported in this paper.

As these processing units become more commonly required by commercial, environmental and tertiary oil recovery schemes, it is likely that the scale and fluid envelope will be increased.

Although today's technology has demonstrated that a solution can be achieved, advances in technology will be beneficial in seeking optimal integrated removal / recovery process schemes that will further reduce energy consumption and equipment size and complexity. Whilst it is hard to predict where these advances will come from, it is likely that high pressure regeneration will play its part. Equally solid beds, solvents or membrane-type equipment that can act as a better 'molecular knife' will be attractive in reducing slip of methane and other valuable components.

As ever, there will be no 'one-size-fits-all' solution to the problem of CO_2 capture and storage and site specific conditions such as location, ambient air temperature, availability of cooling medium, etc. will play a large part in determining the optimum configuration of the facilities.

For the designer, the importance of understanding the behaviour of water-CO_2 mixtures, having the tools to accurately model this behaviour and predict physical and thermodynamic properties cannot be overemphasised, if the resultant design is to meet the strategic objectives.

Acknowledgements

The authors wish to thank the Gas Processors Association for their kind permission to reproduce the Mollier Chart for CO_2, Figure 24-23 from GPSA Engineering Data Book, 12th Edition which was used to illustrate examples in this paper.