Sour Gas Field Developments Strategies

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Increasing energy costs and growing demand for natural gas have driven the development of sour gas fields around the world. About forty percent or 2600 Tcf of the world's natural gas reserves are in the form of sour gas where H_2S and CO_2 compositions exceed 10% volumetric of the raw produced acid gas. In some cases the acid gas composition in these reserves is very high and economics of producing pipe line quality gas are marginal. Natural gas almost always contains contaminates or other unacceptable components, including heavy hydrocarbons, mercaptans, mercury, water and the acid gases H_2S and CO_2.

Conditioning natural gas for pipeline LNG or GTL requires the removal of these undesirable contaminants.

Emission regulations are getting tighter and there is increasing demand to achieve higher sulfur removal and recovery.

Middle East counties such as Qatar, Saudi Aramco, and Canada, China, Venezuela, Brazil and many other countries have a high demand to treat sour gas fields.

An example from the natural gas industry illustrates that, in many parts of the world, natural gas contains a substantial CO_2 component, which has to be removed before the gas can be sent to market. Both Australia and Algeria, for instance, have high CO_2 gas in some areas. Traditionally, this CO_2 is vented to atmosphere after separation without any consideration for CO_2 sequestration.

A hypothetical gas development exploiting reserves containing approximately 10% CO_2, of conventional design, at full operational capacity and venting CO_2 to atmosphere, produces approximately 7 million tonnes of CO_2 each year.

INTRODUCTION

Warnings of global climate change probably surfaced in earnest over 30 years ago. The term is ironically innocuous, but the dire predictions are by now well known – floods, drought, storms, crop failure, melting polar ice, rising sea level, species extinctions and so on. The lack of progress to date is testimony to the complexity of the issue, and resistance to the implied sacrifices which may ultimately be necessary. Yet the increasingly overwhelming consensus of the scientific community that human activity is most certainly responsible for these changes can no longer be ignored. That consensus is clearly evident in the abundance of published data,

research efforts and comprehensive reports by task forces such as the Intergovernmental Panel on Climate Change (IPCC).

The Petroleum Industry and Climate Change

The new reality is that the economics of climate change will increasingly complicate optimization of oil and as industry management strategies, compounded by the uncertainties of opposing and shifting political pressures. Legislative pressure – on local, state and federal levels – is taking many forms, ranging from mandated curtailment to subsidization of alternative technologies to a carbon tax. The EU seeks to reduce GHG emissions by 30% from 1990 level levels by 2020. Energy-rich Alberta, Canada, has only recently imposed a tax of $15/ton of CO_2e (carbon dioxide equivalent) in excess of 12% reduction targets for facilities emitting more than 100,000 ton of CO_2e_5.

Inevitably, the United States – with the world's largest economy – will have to follow suit. Exactly how it chooses to do so will greatly influence other nations' strategies worldwide. By definition, global warming requires global solutions. The oil and gas industry is obviously a major GHG emitter, and will thus be greatly impacted by any such efforts. Producing and refining activities are estimated to produce on the order of 1.2 billion tons of CO_2e annually – primarily by the generation of energy by combustion, but also by such practices as flaring and CO_2 rejection from natural gas and syngas. Many majors have implemented programs to reduce greenhouse gases. Some have gone a step further with innovative demonstration-scale projects involving such things as coal gasification and carbon sequestration. The lessons learned have been invaluable, but often one of those lessons is a reminder that carbon capture carries a price. Ultimately it is the role of government to level the playing field through legislation, and it is the role of industry to lend its insight in a non-partisan manner to best ensure the legislation is reasonably sound (if not ideal). The American Petroleum Institute (API) plays a key role in coordinating that effort, and has included GHG emissions as a key element of sustainability reporting.

The Carbon Markets

Various forms of carbon pricing have evolved. In Europe, over 1 billion tonnes of CO_2e were traded last year, worth over $24 billion USD. The EU Emissions Trading Scheme (ETS) long term phase 2 price is now on the order of $20-25 USD. The Kyoto Clean Development Mechanism (CDM) traded over 500 millions tonnes of CO2e in 2006, worth over $15 billion USD (World Bank, 2007).

But these are arbitrary levies, the product of political compromise. The true, or social, cost of carbon (SCC) is a measure of the damage inflicted. Assuming, logically, that the SCC is proportional to the atmospheric concentration, it follows that the eventual SCC depends on the time required to stabilize it; the longer it takes, the greater the ultimate concentration. Stern[2] calculates an SCC of $85USD/ton CO_2e, while others place it as high as $200, or worse. While painfully higher than, for example, the EU ETS price of $20-25, it is arguably what is required for timely stabilization of atmospheric GHG levels. But it must be applied globally.

Energy conservation is a logical means of GHG reduction, but such measures often fail to meet the ROI required for successful competition for limited capital dollars. Factoring the SCC into the equation is seen by many as the fundamentally sound way to shift the economics.

The Economics of Managing Change

An extension of SCC is the concept that human welfare must be improved for a project to be considered economically attractive; the benefit to society must exceed the cost to society. Damage to the environment (a publicly owned asset) by GHG emissions is a cost to society. While unrealistic to expect companies to voluntarily modify their ROI calculations on this basis, carbon taxes should be structured in an effort to achieve the same effect.

Except for the unlikely acceptance of nuclear energy, the only alternative to energy reduction is carbon capture and storage (CCS). Storage generally means deep well injection, which is contingent on reservoir availability. CCS cost estimates range from \$15-50/ton CO_2e to \$60-80/ton.   Balanced against Stern's social cost of \$85/ton, for example, the former range may be economically attractive, while the latter is marginal at best. Reduction of CCS costs is currently the goal of extensive research.

Green House Gases in Sour Gas Field Developments, Sulphur Technology & Gas Processing

Since sulphur and gas processing are in general driven by environmental, as well as economic, constraints, we need to optimize energy utilization and minimize emissions (CO_2, H_2S, SO_2, CO, NOx, VOC, etc.) to comply with new environmental regulations (and soft targets) worldwide.

Often, a fresh review of existing units can identify less-than optimum operating modes resulting, for example, from changes in operating rates or conditions over the years, lax compliance with proper operating procedures, loss of experience due to employee turnover, and so on. In many cases, operators neglect to trim energy use in turndown situations. We have the design and operating experience to evaluate the operation and provide meaningful recommendations.

Similarly, new unit designs embody the following criteria:

• Proper technology evaluation and technology selection

• Evaluate operating and capital cost for each option

• Consideration current and possible future emission regulations

• Energy optimization

- Minimization of CO_2 emissions

- Operational safety and flexibility

- Ease of operation

CO$_2$ REMOVAL AND SEQUESTRATION

Increased waste heat recovery from flue gases can minimize the capital and operating costs associated with post combustion CO_2 capture and sequestration. The cost effective technology could be evaluated to minimize CO_2 emissions to atmosphere. About 7 giga tons/year of CO_2 is emitted worldwide, and that is expected to double between 2030 and 2050. However, types of CO_2 emissions vary, and not all can be economically separated or sequestered. Examples of CO_2 sources are automobiles, natural gas enrichment, large diesel/gas internal combustion engines, coal/gas-fired boilers and turbines in power plants, and gas turbine driven machinery including compressors in refineries, chemical plants, gas plants, and others.

The CO_2 content of flue gases depend on the fuel properties. Coal generates 18-20% CO_2 (and up to 30 wt-% ash), natural gas can vary from 2 to 30% CO_2, with a pipe line specification limit of up to 3% CO_2. CO_2 sequestration requires three key operations:

- CO_2 separation from the process gas stream

- Compression of the concentrated CO_2 to a pressure ranging from 80 barg to 180 barg and conveyance to the sequestration site

- Sequestration in a proper location such as depleted oil and gas reservoirs, deep saline reservoirs or onshore underground un-mineable coal beds or others after soil evaluations

Figure 2 – Amine Absorption of CO$_2$ from Flue Gas
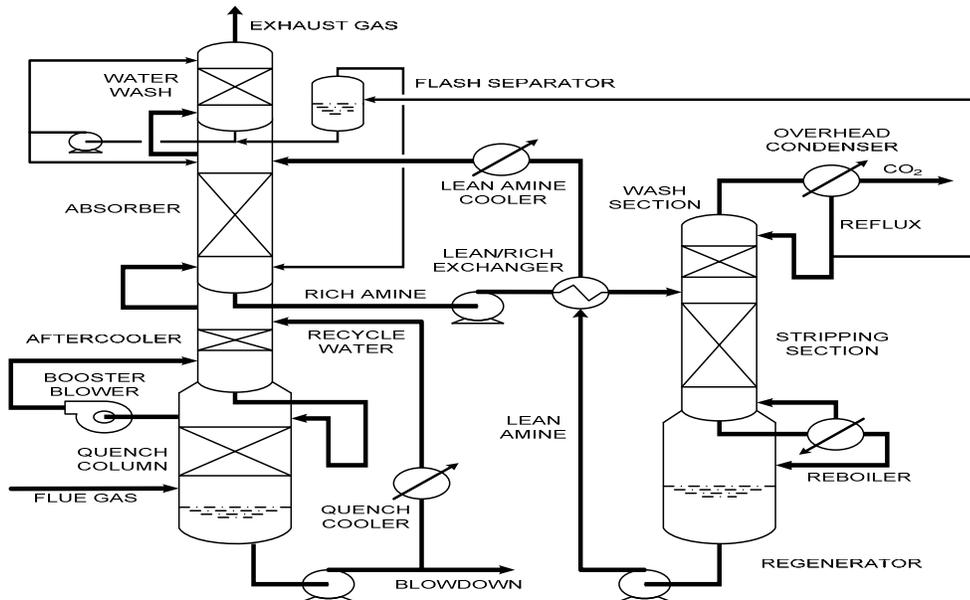
CO_2 removal technologies can be classified as absorption, adsorption, membrane separation and cryogenic processes. Selection depends on the CO_2 concentration and pressure. Chemical absorption is the most economical technology. Solvents for CO_2 removal are used for natural gas treaters, landfill gas facilities with high CO_2 feed, ammonia and hydrogen plants, and natural gas or LNG facilities with downstream cryogenic facilities.

CO_2 is a difficult gas to compress because it behaves like a liquid at its supercritical conditions of about 73 barg, which are encouraged during compression.

CO_2 storage pressures vary from 80 to 180 barg, depending on the reservoir properties. Up to nine stages of compression are required.

Sequestration of CO_2 requires a complete evaluation of geological structure of the soil formation. This includes storage capacity, properties of the reservoir for holding CO_2 for a long period such as 500 years or more, estimated maximum sustainable reservoir pressure, water level below the earth cap, static or dynamic behavior, chemical reaction, mechanical stress/strain and optimum injection point (at the top into the gas cap or below the water table).

TGU LOW TEMPERATURE CATALYST

We offer low temperature hydrogenation catalyst if requested by the client, and suitable for the emission requirements. Low temperature catalyst permits substitution of an indirect heating system, typically HP steam, for the conventional reducing gas generator. Such catalyst are reportedly capable of operating at inlet temperatures of 210-240°C (410-464°F).

The primary advantage (in a new unit) is elimination of the RGG, translating to (1) lower capital cost, (2) operating simplicity, (3) improved turndown, (4) reduced TGU tail gas volume, (5) reduced CO_2 recycle to the SRU, and (6) elimination of risk of catalyst damage by RGG misoperation.

Historically, Claus tail gas treating units (TGTU) have required reactor inlet temperatures of ~ 550°F for appreciable hydrolysis of COS, CS_2 and CO, typically requiring preheat by inline firing or heat exchange with hot oil or heat transfer fluid.

Vendor claims of energy savings are questionable since they tend to (1) assume the plant is long on LP steam, and (2) disregard the cost of HP steam. Long term performance of low-temperature catalysts is still uncertain. The following considerations should be taken into account:

▶ A steam reheater will limit the ability to compensate for normal catalyst activity loss with age, potentially limiting its useful life.

▶ A bottom layer of titania in the first Claus converter may be required for COS/CS_2 hydrolysis.

▶ Higher residual CO levels could mean operating the incinerator at 1500°F (~ 800°C) instead of 1200°F (~ 650°C).

▶ Incomplete CS_2 destruction, and hence methyl mercaptan formation, can result in serious nuisance odors if the TGU tail gas is discharged without incineration.

Reactor inlet temperatures are only half the story; outlet temperatures are the other half. Any catalyst will probably initiate SO_2 hydrogenation at 400-450°F (~ 205-230°C) and, with sufficient temperature rise and excess catalyst, will subsequently achieve virtually complete hydrolysis.

New catalysts by Criterion and Axens require lower activation temperatures achievable by indirect reheat by 600# steam, thus reducing investment cost, operating complexity and, in some cases, energy consumption. In addition, lower reactor outlet temperatures may obviate the downstream waste heat boiler.

While reduced investment and complexity are a given, whether the claimed energy savings is real is site-specific. Reduced feed preheat energy only constitutes a savings if the plant is already long on low-pressure waste heat steam (40-70 psig). Otherwise, incremental heat input is fully recovered. Furthermore, in the absence of a steam surplus, elimination of the waste heat boiler may have forfeited recoverable BTUs.

Relative COS, CS_2 and CO conversion efficiencies need to be compared. It is not necessarily sufficient to achieve regulatory compliance.

COS, CS_2 and CO Hydrolysis using low temperature catalyst

Relative COS, CS_2 and CO conversion efficiencies can be critical. It is not necessarily sufficient to achieve regulatory compliance.

▶ Regulations could become more stringent in the future.

- ▶ Some plants must also buy emission credits per pound of SO_2 discharged.

- ▶ Excessive CO residuals could require higher incinerator temperatures, or require incineration otherwise obviated in units able to achieve TGTU absorber H_2S emissions < 10 ppm by the use of acid-aided MDEA.

Hydrolysis of COS, CS_2 and CO typically requires higher temperatures than hydrogenation of SO_2 and S_x. Perhaps accordingly, COS, CS_2 and CO conversion efficiencies are the first to suffer as conventional catalysts lose activity with age. Higher reactor inlet temperatures will tend to compensate for deactivation, thus extending catalyst life considerably. Depending on the design limits, temperatures can generally be increased by 50-150°F (28-83°C).

Assuming the same holds true for the low temperature catalysts, a steam reheater will substantially limit the extent to which temperatures can be increased, in effect potentially shortening catalyst life. The lower initiation temperature of the Criterion 734 at start-of-run is thus significant, as it affords the greatest margin for increase.

At 464°F (240°C) – generally the limit of a 600# steam reheater – hydrolysis of CO, COS and CS_2 approaches that of conventional high temperature catalysts. At 428°F (220°C), however, Axens concedes that COS/CS_2 conversion must be accomplished in the 1st Claus stage by (1) supplementing the alumina bed with a bottom layer of expensive titania catalyst, or (2) increasing the inlet temperature to 550-600°F (288-316°C). The latter will nominally

- ▶ reduce Claus recovery efficiency from

- ▶ increase SRU tail gas rate

- ▶ increase TGTU sulphur load

However, the 1st stage will not effect CO conversion.

Conventional cobalt-moly catalyst will generate minor, but significant, levels of methyl mercaptan by the reaction of CS_2 and hydrogen at 480°F (249°C) when in good condition, and at much higher temperatures if the catalyst is aged or damaged. While the manufacturers claim no residual mercaptans with the low temperature catalysts, there is some uncertainty – in the author's view – as to whether that will remain true a few years into the run.

Hydrogen Balance using low temperature catalyst

Compared with firing the feed heater at stoichiometric air and importing H_2, a steam reheater will of course have no impact on the H_2 balance. However, many plants avoid the need for supplemental H_2 by the use of a reducing gas generator (RGG), typically burning natural gas sub-stoichiometrically to generate H_2 and CO.

In the absence of an RGG, the alternative is to operate the SRU more air-deficient as necessary to maintain, say, 2% residual H_2 downstream of the TGTU reactor. This will nominally

- reduce Claus recovery efficiency

- increase SRU tail gas rate

- increase TGTU sulphur load

CO_2 Balance using low temperature catalyst

Eliminating the inline burner has the benefit of reducing the TGTU tail gas volume (for the assumed basis with an RGG). Assuming 85% CO_2 slip, the acid gas load on the TGTU amine is reduced.

Energy Balance using low temperature catalyst

A steam reheater will not only eliminate the following natural gas required by the RGG, but will also reduce incinerator fuel by virtue of the reduced tail gas rate:

- RGG fuel savings

- Incinerator fuel savings

Assuming H_2S/SO_2 = 2 in the SRU tail gas, of supplemental H_2 will be required to maintain a 2% residual in the TGTU tail gas. As a rule-of-thumb, the value of relatively pure (non-reformer) H_2 is four times that of natural gas.

Startup Blower

We provide a start up blower on the contact condenser overhead to eliminate flaring large quantities of H2S to atmosphere and to prevent violation of the emission. For those cases that a booster blower required then booster blower will have dual function as a start up blower and as a booster blower.

Booster Blower

Many of the Claus units that are in operation do not have enough pressure to handle a new tail gas unit in other words the provision of operating the Claus unit at the higher pressure was not considered, if the source pressure changed the existing amine unit requires higher reboiler duty and in most cases required significant changes in the amine unit. We have been offering a booster blower in the tail gas unit to overcome the pressure limitation.

Retrofit Tail Gas Units will typically require a booster blower downstream of the Contact Condenser to overcome the additional pressure drop. The blower is located after the Contact Condenser to minimize the actual volume (by virtue of cooling and condensation), and before the Absorber to take advantage of the higher pressure.

With proper design and operation, booster blowers are inherently very reliable, requiring minimal maintenance. Typically, the case is cast iron or carbon steel, with an aluminum impellor. N_2-purged tandem shaft seals

(typically carbon rings) eliminate process leakage to atmosphere on the discharge end as well as air aspiration into the process on the suction end, which is typically at a vacuum.

Though often viewed as a liability by clients, booster blowers arguably improve operability in several ways:

- By recirculating tail gas, the TGU can be started up and shut down independent of the SRUs.

- Tail gas recycle ensures process stability at high SRU turndown by (1) avoiding undue RGG burner turndown potentially conducive to sooting due to poor mixing or air/gas flowmeter inaccuracy, and (2) diluting potentially high SO_2 levels often typical of high SRU turndown. With advance warning, tail gas recycle can avoid RGG shutdown in the event of an SRU trip.

- By routing the SRU and TGU tail gas to the incinerator via a common header, a vacuum can be maintained at the RGG without risk of leaking air from the incinerator back into the TGU, thus potentially further increasing SRU capacity. In the event that the tail gas bypass valve leaks, clean TGU tail gas is recycled to the RGG rather than SRU tail gas bypassing the TGU (as when the RGG pressure is positive). Any such reverse flow will improve bypass valve reliability by excluding sulphur vapor, and the valve can be partially stroked periodically to verify operability without increased emissions.

RGG Vacuum Operation
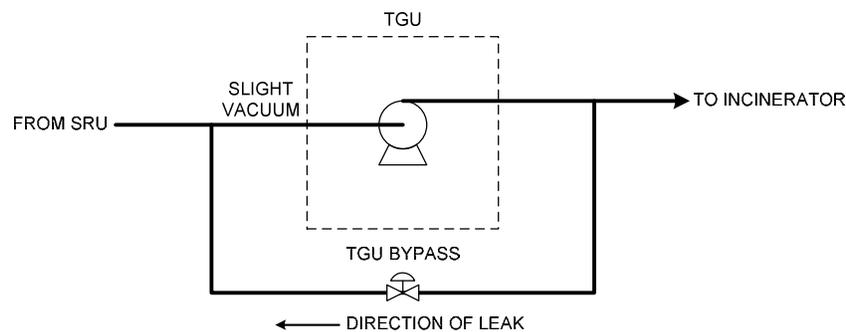
In the absence of a booster blower a single startup blower recycle is usually provided for tail gas recycle. While these machines tend to be less sophisticated, N_2-purged tandem shaft seals are still required.
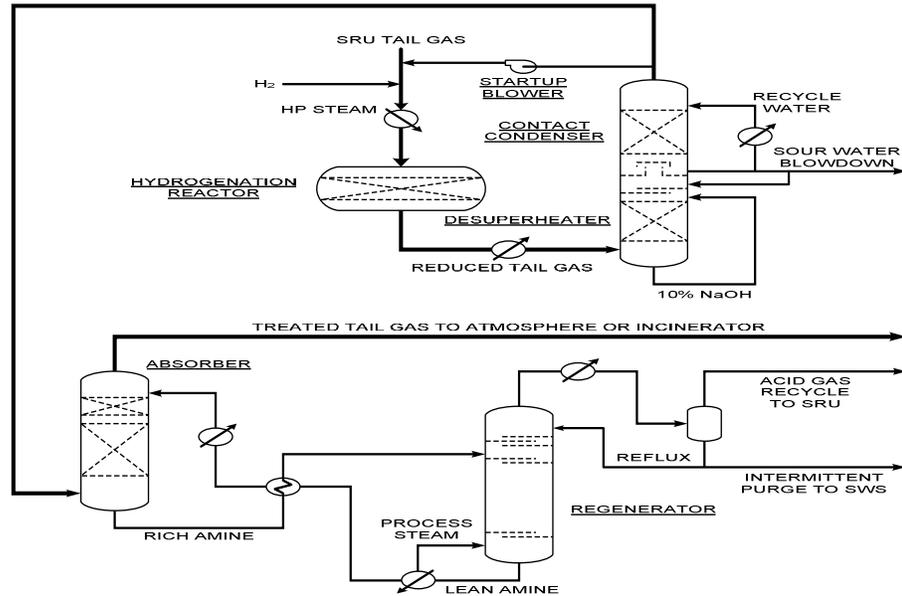
The primary advantage (in a new unit) is elimination of the Inline Burner, translating to

- Lower capital cost

- Operating simplicity

- Improved turndown

- Reduced TGU tail gas volume

- Reduced CO_2 recycle to the SRU

- Elimination of risk of catalyst damage by INLINE BURNERmis-operation

- Elimination of natural gas consumption in the INLINE BURNERwith resultant reduction of CO_2 emissions

- Support of GHG reduction criteria.

Solvent Selection Criteria in the Tail Gas Unit

The most common solvent is 40-45 %-wt MDEA, (HS-101, or similar) designed for a maximum rich loading of 0.1 mol acid gas (H_2S + CO_2) per mol amine with typical emission reduction to ~ 100 ppmv H_2S. Cooling of the lean amine to at least 100°F (38°C) is important for minimization of emissions and amine circulation rate. Specialty TGU amines are essentially pH-modified MDEA to facilitate stripping to lower residual acid gases for treatment to < 10 ppm H_2S, potentially obviating incineration. CO_2 slip is also improved. These products are variously marketed as

- Dow UCARSOL HS-103

- Ineos Gas/Spec TG-10

- Huntsman MS-300.

An alternative to MDEA is ExxonMobil's Flexsorb SE, a proprietary hindered amine patented by Exxon. The main advantage is a 20-30% reduction in circulation rate. The solvent is much more stable than MDEA, but is also more expensive. Flexsorb SE Plus is also available for treatment to < 10 ppmv H_2S. Both solvents require a license agreement with ExxonMobil.

It used to be assumed that TGU carbon filtration was not required in view of the absence of hydrocarbons. For MDEA-based solvents, at least, this has proven untrue, presumably due to the generation of surfactant amine degradation products.

- Solvent Applications

- FLEXSORB® SE Selective removal of H_2S

- FLEXSORB® SE Plus Selective removal of H_2S to less than 10 ppm

- FLEXSORB® SE Hybrid Removal of H_2S, CO_2, and sulphur compounds (mercaptans and COS)

- In sulphur plant tail gas applications, FLEXSORB® SE solvents can use as little as one half of the circulation rate and regeneration energy typically required by MDEA based solvents. CO_2

- Rejection in TGTU applications is very high, typically >90% rejection.

- Flexsorb solvents offer other advantages compare to the other amine solvents for instance, most of applications requires no reclaiming, have good operating experience, low corrosion, and low foaming due to low hydrocarbon absorption, by providing water wash of treated gas at low pressure system amine losses are minimum.

In general acid gases could be treated using generic solvents such as DGA, DEA, MEA, or MDEA or using proprietary solvents such as aMDEA, Sulfinol, Selexol, Ucarsol, Flexsorb, or other processes from Ryan Homes, BASF, IFP, ADIP, membranes, or molecular sieves options depending on the acid gas compositions and the product specifications considering optimization for affordable capital and operating costs.

For Dew Point Control, water has to be removed to meet the pipe line specifications, by using Glycols, Membranes, or molecular sieves according to the project specification, application, and cost.

The primary differences in process by using generic amines are in solution concentrations. MEA is ordinarily used in a 10 to 20 percent by weight in the aqueous solution. DEA is also used in the 10 to 30 percent by weight in the aqueous solution. DIPA, DGA, and MDEA are used in higher concentrations. Typical concentration ranges

for DIPA and MDEA are 30 to 50 percent by weight in the aqueous solution. DGA concentrations range from approximately 40 to 50 percent by weight.

As the results of the new revolutions in challenging the various solvents and different process configurations, gas processing in gas industries and refineries has become more complex. In response to this trend and to comply with the product specifications, more equipment and more processing upstream or downstream of gas processing should be implemented.

The selection criteria for gas processing is not limited to the selection of gas treating configurations by itself; it is expanded to the selection criteria of more side process / downstream configurations, to complete the gas processing in order to meet the product specification and to satisfy environmental regulatory agency requirements.

Acid gas removal is the removal of H_2S and CO_2 from gas streams by using absorption technology and chemical solvents. Sour gas contains H_2S, CO_2, H_2O, hydrocarbons, COS/CS_2, solids, mercaptans, NH_3, BTEX, and all other unusual impurities that require additional steps for their removal.

There are many treating processes available. However, no single process is ideal for all applications. The initial selection of a particular process may be based on feed parameters such as composition, pressure, temperature, and the nature of the impurities, as well as product specifications. The second selection of a particular process may be based on acid/sour gas percent in the feed, whether all CO_2, all H_2S, or mixed and in what proportion, if CO_2 is significant, whether selective process is preferred for the SRU/TGU feed, and reduction of amine unit regeneration duty. The final selection could be based on content of C_3^+ in the feed gas and the size of the unit (small unit reduces advantage of special solvent and may favor conventional amine).

Final selection is ultimately based on process economics, reliability, versatility, and environmental constraints. Clearly, the selection procedure is not a trivial matter and any tool that provides a reliable mechanism for process design is highly desirable.

Selection of the right tools is very crucial. Establishing and conducting all the elements together at the same time, would generate such a beautiful art in gas treating.

Natural Gas Processing

Natural gas is one of the common sources of gas treating, with a wide range in CO_2/H_2S ratios and high pressure treating. If natural gas is not an LNG application, it could be treated with selective H_2S removal if significant CO_2 is present. If C_3^+ is present, the desirability of using physical or mixed solvents is reduced. If organic sulfur is present, the desirability of using physical or mixed solvents is increased.

It is favored to use proprietary solvents if natural gas has significant CO_2 and /or H_2S for large units/ and to use conventional solvents for small units particularly with modest acid /sour gas levels.

Petroleum Refining

Petroleum refining is another source of gas treating with low CO_2 content, unless the refinery has catalyst cracking unit, in which case the gas may contain COS, organic sulfur, cyanides, ammonia, and organic acids. The acid gas from hydrotreating and hydrocracking essentially contains H_2S and ammonia. The gas treating pressures and H_2S specifications vary for individual applications, and MEA/DEA/MDEA/DGA or formulated amines are the typical solvents. The refinery typically has multiple absorbers and a common regenerator as listed below:

- Fuel gas treating
- Hydrotreater product/fuel gas
- Hydrotreater recycle gas
- Hydrocracker product/fuel gas
- Hydrocracker recycle gas
- LPG liq-liq contactor
- Thermal/catalyst cracker gases
- Services independent or combined as practical

Synthesis Gas Treatment

Synthesis gas treatment is characterized by high CO_2 and low (or no) H_2S. If the amount of CO_2 is limited, it is preferred to use selective H_2S treating via formulated/hindered amine, mixed solvent or physical solvent. If H_2S is not present and there is modest or essentially complete CO_2 removal, it is preferred to use activated MDEA, hot potassium, mixed amine, and physical solvent.

Case Studies

The following cases recently are evaluated different schemes and solvent for bulk acid gas removal versus selective solvent. Sour Gas Field Developments normally includes amine unit or sulfur removal unit, Dehydration, SRU, TGU and incineration. A typical flow diagram and the process flow diagram for the Case 2 are provided on the following pages.

Two schemes will be described.

Case 1 – our evaluation for new Upgraders and Oil Sands mostly in Canada dealing with a lot of high content H2S and CO2 in sour gas indicates that using DGA solvent in the amine unit will meet the product specification. There will be more CO_2 and H_2S to the sulfur recovery unit since DGA absorbs most of the H_2S and CO_2. The Claus unit is then followed by the TGU-amine tail gas treatment unit. MDEA solvent is selected in the tail gas unit and the evaluation of potential benefits of using selective solvent such as Flexsorb or similar is in progress. In this application amine unit uses DGA solvent follows by SRU Claus sulfur recovery unit, and TGU/amine and sulfur degassing.

Case 2 - Our evaluation indicates that using common regeneration unit for the amine unit and the tail gas unit is very cost effective in reducing capital and operating cost. The amine unit is designed with a special features of

split flow configuration and using turbine to save the electricity where the pressure from the absorber bottom will let down to a lower pressure. TEG is selected for the dehydration unit.

1. Common Regeneration unit lower operating and capital cost

2. Absorber with split flow configuration

3. Smaller reboiler duty

4. Recover the majority of horse power required by recovering the energy from absorber bottom

5. One solvent, less operating cost

6. Easier to operate

(Sulfur Removal) Amine Process Description

The amine unit is an integrated split flow configuration and a common regeneration with the tail gas unit. MDEA flows into the Amine absorber where H_2S is preferentially absorbed by the MDEA solution. The MDEA solution reduces the H_2S content in the absorber overhead stream to less than 4 ppmv. A 50 wt% MDEA solution is used to treat the acid gas.

TEG Dehydration Process Description

The Sales gas from the Amine Unit is sent to the Dehydration Unit, for which we have slected TEG as the drying solvent. There are other dehydration processes that could be selected.

For Case 2 application, the following are the typical feed gas compositions and the product specification for natural gas application in the gas plant.

Component	Composition (% mol)
He	0.01
H_2	0.02
N_2	0.552
CO_2	8.63[2]
H_2S	14.14[1]
CH_4	76.52
C_2H_6	0.12
C_3H_8	0.008
Organic S	<150 mg/Nm^3

Component	Composition (% mol)
Total	100
Critical Temperature, K	227.65
Critical Pressure, Mpa (a)	5.496
Temperature, °C	25~30
Pressure, Mpa (a)	8.3

It was Assume: H_2S content: 13-18%, CO_2 content: 8-11%, and Sour feed gas also contains organic sulfur compounds: content of organic sulfur compounds <150mg/m3. Sour feed natural gas is saturated with water and also contains some solid particles (maximum average of 0.2 mg / m3). The treated natural gas will contain less than 6mg/Nm^3(20C, $1.013×10^5$Pa) of H2S, less than 3vol % of CO2 and less than 200mg/Nm^3(20℃, $1.013×10^5$Pa) of sulfide.

The typical specification of the water dew point of treated natural gas will be -10°C. The Sulfur Recovery Unit shall recover essentially minimum 99.9 wt. percent of the sulfur contained in the feedstock. The vent gas leaving the absorber of the Tail gas treating section shall contains no more than 150 ppmv of sulfide. The liquid sulfur shall contain no more than 10 ppmv of H_2S.

Case -3 – Our experience on LNG application indicates using activated MDEA is a very cost effective solvent to meet pipeline specifications and followed by dehydration unit to meet the water specifications. A typical LNG feed composition is provided below.

LNG Typical Feed Gas Composition

COMPONENT	Composition (mol %)
CO2	12.76
N2	0.59
CH4	78.86
C2H6	5.50
C3H8	1.92
n-C4	0.18
i-C4	0.12

C5	0.04
C6	0.01
C7	0.00
C8	0.00
C9	0.00
H2S	0.01
Total	100
PROPERTIES	
Temperature C	60
Pressure Bara	50

CONCLUSIONS

Despite the inevitable controversies and uncertainties surrounding climate change, management of GHG emissions will be a key focus for the petroleum industry in the years to come. Often, improved profitability resulting from reduced operating costs is a welcome byproduct. But only by considering whole life-cycle economics, and the projected value of GHG emissions, either as damage avoided or as some form of carbon tax, can the petroleum industry fully understand the implications of investment decisions, and better manage its operations in this period of profound change.

However, to unlock a wider range of revenue positive sustainability options, companies must be willing to evaluate these costs and benefits within the context of the rising cost of carbon, and its impact on the internal rates of return of sustainability options.

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