



Selecting Best Technology Lineup for Designing Gas Processing Units

Saeid Mokhatab

Tehran Raymand Consulting Engineers, Tehran, Iran

Peter Meyer

CECA SA, Paris, France

ABSTRACT

Natural gas coming from the well contains hydrocarbons, CO₂, H₂S, and water together with many other impurities. Treatment of the gas is required to make it suitable for the various applications. A variety of gas processing systems are available to provide products coming up to specifications defined by the plant owner. This variety places a huge burden and challenges on owners to select the right technologies for the project circumstances to fulfill an optimized scheme meeting technological and economical targets. Given the magnitude of the investment in a gas-processing plant, it is appropriate to carry out a rigorous treating process selection study to identify the most cost effective and fit for purpose treatment package that removes contaminants in an environmentally friendly way. This paper describes the most commonly used process technologies for designing the gas processing units (commenting on some of the main developments that have taken place in the gas processing area over the last years) and shows how integration of process technologies and expert process know how make a difference.

Selecting Best Technology Lineup for Designing Gas Processing Units

1. INTRODUCTION

A typical scheme for most gas processing plants designed to produce pipeline gas from a sour gas feed is shown in Figure 1. As can be seen, field production upon arrival at processing plant will be processed in a slug catcher, which catches liquid slugs and then allows them to flow into downstream equipment and facilities at a rate at which the liquid can be properly handled. Produced gas from the outlet of the slug catcher is directed to a high-pressure (HP) separator, where final separation of liquid from gas takes place. The HP raw gas flows through to the Gas Sweetening Unit (GSU), in which acidic components like H₂S and CO₂ are removed by means of chemical solvents. Simultaneous carbonyl sulfide (COS) removal in the GSU is also desired as it facilitates the downstream processing and purification steps and contributes to the reduction of the total sulfur content of the treated gas. The enriched acid gas from the GSU is processed to produce elemental sulfur in a Sulfur Recovery Unit (SRU), consisting of a Claus unit and an associated Tail Gas Treating Unit (TGTU) if higher recovery rates are specified for the SRU itself. The final residual gas from the TGTU is incinerated.

Sweetened gas from the GSU then flows to the Gas Dehydration Unit (GDU) to reduce and control the water content of gas, to ensure safe processing and transmission. Mercaptans (RSH) are also removed in a Mercaptans Removal Unit (MRU). There are two motives for removing mercaptans in the gas-phase. The first is corrosivity. If the mercaptan content is high enough, then NACE metallurgy may be necessary. The second reason is that it will concentrate in the condensate stream and this product will not pass the copper strip test. Its further treatment will be discussed below.

Mercury can be present in natural gas and may present a problem, especially if a cryogenic process is used in the gas processing plant, as mercury can form an amalgam with aluminium (normally used as the material for the main heat exchanger in cryogenic process) resulting in corrosion problems. Therefore, mercury needs to be removed to nanogram levels. Mercury is conventionally removed using non-regenerable activated carbon or activated alumina based adsorbent.

The gas from the MRU is then sent to the hydrocarbon Dew Point Control Unit (DPCU) to recover heavier hydrocarbons in order to prevent any condensation occurring in the export system. The gas pressure (depending on the type of process used in the DPCU) may also need to be boosted by the high pressure compressors before passing through the sales gas meter and into the export line. In a gas processing plant designed to produce pipeline gas with a full range of Natural Gas Liquid (NGL) products, there is a need for an NGL recovery unit. This can include a range of options from simple hydrocarbon dewpointing (aimed primarily at gas transportation rather than NGL recovery) to complex NGL recovery processes that produce the entire range of NGL's available from natural gas to a high recovery level.

The liquids from the reception facilities are separated again into produced water and condensate. Produced water is treated and used. The condensate is combined with the hydrocarbon liquids knocked out in the DPCU. It is then processed in the Condensate Stabilization Unit (CSU) to reduce the vapor pressure to allow storage in atmospheric storage tanks. In the case of sour condensate, if there is any treatment required for the heavier sulfur components, this is likely to require complex treatment requiring hydrogen, which is generally carried out at a refinery.

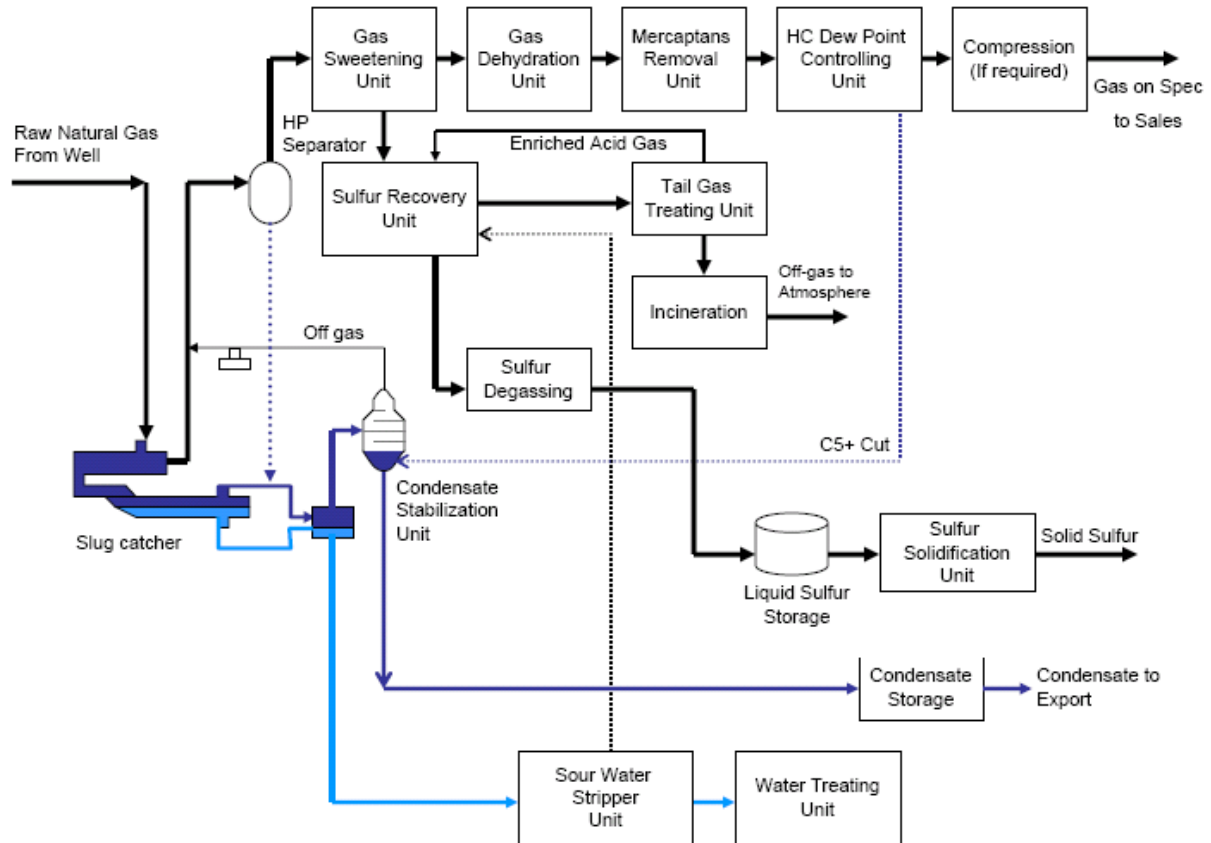


Figure 1 Typical Setup of Gas Processing Plant Producing Sales Gas

Note should be made that the illustrated arrangement for the gas-processing units in Figure 1 is typical and shows the functional blocks required to achieve the objectives of the plant designed to produce pipeline gas from a sour gas feed. The function of each of these blocks (or combinations of blocks) can be achieved in a variety of ways; some technology options may result in one or more of these functions being achieved simultaneously (thus reducing the complexity of the design). As an example, molecular sieves can be used for both dehydration and mercaptan removal reducing the two steps presented in the scheme above to one. The water and mercaptans desorbed from the bed during the regeneration can be captured by a physical absorption process to concentrate the mercaptans in a stream being sent to the SRU. The bulk of the mercaptans might be reduced this way and will limit the sulfur species being condensed in the different NGL cuts. Instead of having to use expensive caustic based processes, molecular sieves or other adsorbents could be used for the fine sweetening of the liquids (McMahon, 2004). However, operational problems and upsets of the molecular sieve unit can make the molecular sieve unit the bottleneck of the plant. Where a molecular sieve unit is a bottleneck, on-site extensive know how of molecular sieves can improve the performance of the molecular sieve unit.

2. FINDING THE BEST GAS PROCESSING ROUTE

In order to define the type of gas processing plant and its different treating units, the products to be obtained (e.g. LNG, NGL recovery, gas for pipeline...) and its specifications should be fixed. The quantity and type of impurities determine the necessary treatment steps. At this initial step it should be considered which possible units or operational steps can do the necessary partial treatment and which other technologies or further routes exist. The different options should be evaluated individually to find the best solution for the given gas composition. However, for optimal treating-package design, process selection for the individual units must be made on the basis of an integrated approach that considers interactions between units.

3. PROPOSED TECHNOLOGIES FOR DESIGNING GAS-PROCESSING PLANT

For a given gas processing application different process configurations are available and the choice of technologies can be vast. However, note should be made that the best practice to establish the optimum treating line-up for a gas-processing plant should be critically examined, taking all the process and environmental (CO₂ and SO₂ emissions) limitations into account within a flexible, operable and economically justified window.

3.1 Licensed Gas Processing Units

Taking the typical example of the natural gas processing set-up designed to produce pipeline gas from a sour gas feed (as shown in Figure 1), there are four main blocks, which usually means four licensors:

- Gas Sweetening Unit (GSU)
- Gas Dehydration Unit (GDU)
- Mercaptans Removal Unit (MRU)
- Sulfur Recovery Unit (SRU) + Tail Gas Treating Unit (TGTU)

Up to four license contracts are needed for each of the above mentioned steps including the guarantees and well defined border limits for the different interfaces. The large number of package vendors may give good reasons why the product specifications are not met. If one specification is not met in one unit, the other licensors cannot necessarily meet their liabilities. The other aspect is unit optimization. As each licensor is responsible for his part, he takes a certain security margin. The overall security margin is higher than the margin taking into account the concept as a whole with the strengths and weaknesses of every single unit.

This section discusses several integration aspects of the main gas treating processes involved. The technical options considered may be a combination of both open art technology and licensed processes.

3.1.1 Development of LURGI OmniSulf[®], State-of-the-Art Approach

To eliminate all the constraints discussed above, a new concept, OmniSulf[®], has been developed by LURGI for improving, but not limited to, the overall sulfur recovery rate and curbing capital investment and operating costs. This new concept is based on Lurgi's proprietary know-how as a leading technology licensor and engineering contractor and encompasses the following key processes as shown in Figure 2 (Weiss, 2002):

- Gas Sweetening with BASF activated MDEA(aMDEA[®])
- Sulfur Recovery with LURGI Claus[®], LTGT[®], AQUISULF[®]
- Gas Dehydration and Mercaptan Removal with special Zeolite technology
- Mercaptans Recovery with PURISOL[®]
- If necessary, Mercury Removal

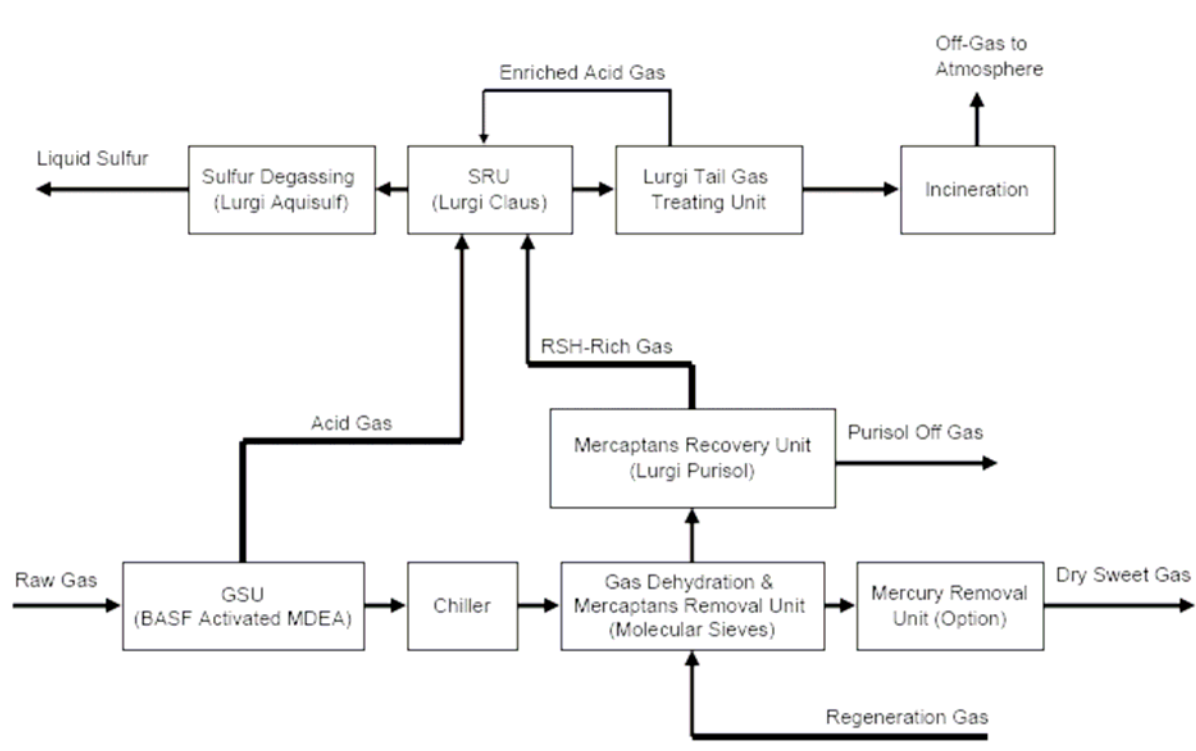


Figure 2 Overall arrangement of LURGI OmniSulf® package (Weiss et al., 2002)

The activated MDEA process removes CO₂ and H₂S to customer specifications, as well as mercaptans (RSH) and COS partially. With regard to its characteristics; very low hydrocarbon co-absorption rate, energy-efficient solvent regeneration and being non-degrading/ non-corrosive, activated MDEA acts as a benchmark for competing technologies. This triggered an ongoing development of similar solvents (Hugo and Wagner, 2000). The sweetened gas is cooled in a chiller to remove the bulk of the moisture from the sweet gas. The cleaned gas is further routed to a dehydration and mercaptan removal unit (DMRU), wherein the moisture and mercaptans are removed by molecular sieve technology. If necessary, the cleaned gas can be further routed to a mercury removal unit to remove traces of mercury using e.g. impregnated activated carbon or activated alumina.

Regeneration of the molecular sieve adsorbers is performed on a cyclic basis by means of regeneration gas coming from battery limits and/or dry-sweet gas from DMRU. The molecular sieve regeneration off-gas, rich in mercaptans, is routed to the mercaptans recovery unit utilizing Purisol technology. This is a physical gas purification technology, which uses N-Methyl-Pyrrolidone (NMP) solution, for the selective removal of sulfur components, specifically mercaptans. Other properties which make NMP a favorable choice are its high boiling point and extremely low vapor pressure, chemical and thermal stability as well as its low viscosity, with the latter ensuring good heat and mass transfer. Mercaptans from the regeneration off-gas stream are absorbed by the circulating NMP solution, thus it could be fed to the plant fuel gas system or used elsewhere. The separated mercaptan stream is processed in the sulfur recovery unit to recover the contained sulfur. The SRU consists of a modified Claus unit, a LURGI Tail Gas Treating Unit (LTGTU) and a sulfur degassing system (using Aquisulf process), all well-known, conventional and proven technologies.

The novelty in this concept is the combination of the Purisol unit for recovery of the mercaptans and the processing to elemental sulfur in the modified Claus unit with its unique LURGI Multi-Purpose Burner system. In fact, in the OmniSulf® concept, the LURGI Tail Gas Treating Unit includes an Acid Gas Enrichment (AGE) step (utilizing generic MDEA solvent for the acid gas coming from GSU) that allows an overall sulfur recovery rate higher than 99 % of all sulfur in the feed gas, indicated by a very low sulfur content in the LTGT unit's tail gas (and therefore low, environmentally friendly emissions). With this OmniSulf® concept the following is also achieved (Weiss et al., 2002):

- An ideal combination of proprietary technologies contributed by LURGI, BASF, ZEOCHEM or CECA, leaders in their respective fields.
- It can be licensed without restrictions, to practically all parts of the sales gas.
- Even if there is currently no industrial reference, all elements of the combined technologies have proven, long-term performance records in different applications. Therefore, OmniSulf[®] ensures a high on-stream factor and high reliability to provide products to specifications.

In addition, single-line project responsibility (one license contract, one overall guarantee and liability, one transparent license fee), optimized tailor-made design and customer-oriented supply from a single source (by LURGI) can result in considerable savings in investment as well as operating cost savings and enhanced flexibility of the whole plant. With the new OmniSulf[®] concept, based on proven and innovative technologies, there is a state-of-the art approach available, which simplifies technology selection.

3.1.2 Shell Global Solutions' Treatment Technologies

Shell Global Solutions' processes team offers customers the benefits of the knowledge and experience that the Royal Dutch/Shell Group has accumulated in over 100 years of operation. Some Shell technologies are protected by patent; other technologies are unique to Shell. Their processes team have developed innovative processes to meet emerging needs for designing a gas-processing plant :

- Sulfinol solvent, which is a mixture of Sulfolane, water and DIPA (diisopropanolamine) or MDEA (methyldiethanolamine), Sulfinol-D and Sulfinol-M, respectively. These remove hydrogen sulfide, carbon dioxide, carbonyl sulfide, mercaptans and organic sulfur components from natural gas. Sulfinol is known to have a significantly higher removal capability for organic sulfur because of the higher physical solubilities for these components, due to the presence of the Sulfolane. However, the removal of all organic sulfur in only one absorber requires high Sulfinol circulation rates compared to cases where only H₂S and CO₂ are removed (Bruijn et al., 2002). When mercaptans are present in the feed gas, the Shell Sulfinol process is strongly preferred as the acid gas removal step. Formulated MDEA solvents have a comparable capital cost to Sulfinol, but lack the mercaptan removal capabilities, one exception being the Flexsorb formulation (from Exxon) also containing Sulfolane. Although, Sulfinol is more efficient in removing mercaptans, it has the disadvantage of relatively poor hydrocarbon selectivity, resulting in hydrocarbon losses in the separated acid gases, where combustion of the hydrocarbons in the SRU will result in an increase in CO₂ emissions (Rajani, 2003). However, this higher hydrocarbon solubility is still far less than that of a purely physical solvent and is normally considered acceptable (Klinkenbijn et al., 1999).
- Sulfur process: Shell no longer possesses proprietary technology for the familiar Claus process, but in other areas of sulfur processing Shell does have a number of successful processes such as SCOT (Shell Claus Off-gas Treatment), Sulfur Degassing and Catalytic Incineration (Hoksberg, et al., 1999). The SCOT process enhances sulfur recovery from Claus plants (typical traditional recovery is about 95%) to levels over 99.8% and can help to meet the most stringent environmental limits (Brand, 2002; Rajani, 2003). The SCOT tail gas technology can readily be integrated with the main gas treatment, with or without an acid gas enrichment step, and if necessary, treatment of sour gas from molecular sieve regeneration (Klinkenbijn et al., 1999). Sulfur Degassing (licensed with Jacobs Netherlands) removes hydrogen sulfide and polysulfides from liquid sulfur produced in Claus sulfur recovery units. The process eliminates potential explosion and odor hazards, and the risk to human health. It provides a high quality sulfur product.
- Shell's molecular sieve package (e.g. with molecular sieves of CECA or UOP) helps gas plants improve operating cost, bed life, reliability and availability of Molecular Sieve Unit (MSU). As an example, molecular sieves ageing know how can be translated by Shell Global Solutions into operational procedures that maximize the lifetime of the molecular sieve, thus reducing the OPEX on adsorbents. The know how may also be used to increase the natural gas plant revenue by optimizing the amount of regeneration gas (to a minimum) while preventing cake formation. For some plants, a reduction of the amount of regeneration gas also saves OPEX on fuel gas. The MSU regeneration gas is treated to remove the mercaptans from this stream by a second, smaller Sulfinol absorber before recycling the gas to the inlet of the main absorber. To reduce the

hydrocarbon coabsorption from this process, a source of regeneration gas that is very low in heavy hydrocarbons can be used. The bed configuration selected for the MSU design offering by Shell minimizes the risk of hydrocarbon coadsorption on the molecular sieves without affecting the mercaptan-removal capacity of the beds (Grootjans, 2005). Though Shell has its own knowledge for molecular sieves design, they get their designs confirmed by molecular sieve suppliers to guarantee the performance of the adsorption process. Nevertheless, taking into account the differences between the different adsorbent product, the end-customer should be aware that optimized designs are possible depending on the specific strengths of the adsorbents. As an example, a high density adsorbent would allow small vessel designs with smaller regeneration gas quantity and flow rate leading to significant investment and operating savings. CECA proposes this with its OPTISIEVE concept.

It should be noted that the presented know how of Shell Global Solutions has been shown to improve the performance of the MSU (Bruijn et al., 2002; Carlsson et al., 2005).

As stated before, when the GSU is based on Sulfinol solvent, the solvent can be designed to remove all mercaptans. This specification is also easily met when the CO₂ has to be removed to deep specification and the solvent circulation is high. Subsequently, MSU has only to meet the water specification. Generally this option will result in an expensive GSU design with a hydrocarbon co-absorption that is too large to be acceptable. In the aqueous-amine-solvent treating option, which removes only H₂S and part of the CO₂, although the coabsorption effect will be very low, however the complexities of all mercaptans removal using molecular sieves can affect the net present value of an investment due to operational difficulties resulting in unplanned downtime, or a failure to meet design capacity for a certain period (Carlsson et al, 2007). The optimisation of the line-up between the solvent-based step and the molecular sieves is very dependent on the level of mercaptans in the feed gas (Klinkenbijn et al., 1999). If the mercaptan content of the feed gas is high, use of an aqueous solvent for the GSU will require construction of a very large MSU, which would make this option uneconomic. However, if the mercaptan content is less than approximately 400 to 500 ppm, both processes offer advantages and disadvantages (Grootjans, 2005). The optimum solution in many cases is the distribution of the mercaptan removal capabilities over the mixed solvent in the GSU as well as the MSU. In this design, as shown in Figure 3, the regeneration of the MSU gas can be integrated with the GSU, using shared regeneration. The treated molsieve regeneration gas can either be recycled to the inlet of the molsieve unit, or the inlet of the main absorber (Bruijn et al., 2002). An advantage of a dedicated Acid Gas Enrichment Unit (AGEU) is the possibility to separate the H₂S/CO₂ stream from the mercaptan stream, where the AGEU treated gas is directly routed to the incinerator to ensure that small traces of H₂S and hydrocarbons are properly combusted. However, this stream contains mercaptans and heavy hydrocarbons removed in the GSU by the mixed solvent and hence the mercaptans are lost from the sulfur recovery. The enrichment with this heated flash mechanism is not as efficient, but can in some cases be sufficient. An aqueous amine unit, which is best choice for economic reasons, will be used for increasing the H₂S/CO₂ ratio in the SRU feed gas. The selective enrichment absorber can be integrated with the Tail Gas Treating Unit (TGTU) absorber with a common regenerator for optimization of capital and operating expenses (Klinkenbijn et al., 2005). The configuration described will ensure a sulfur recovery system with a recovery greater than 99.5% and also will ensure that the system will perform efficiently during feed-gas-composition variations.

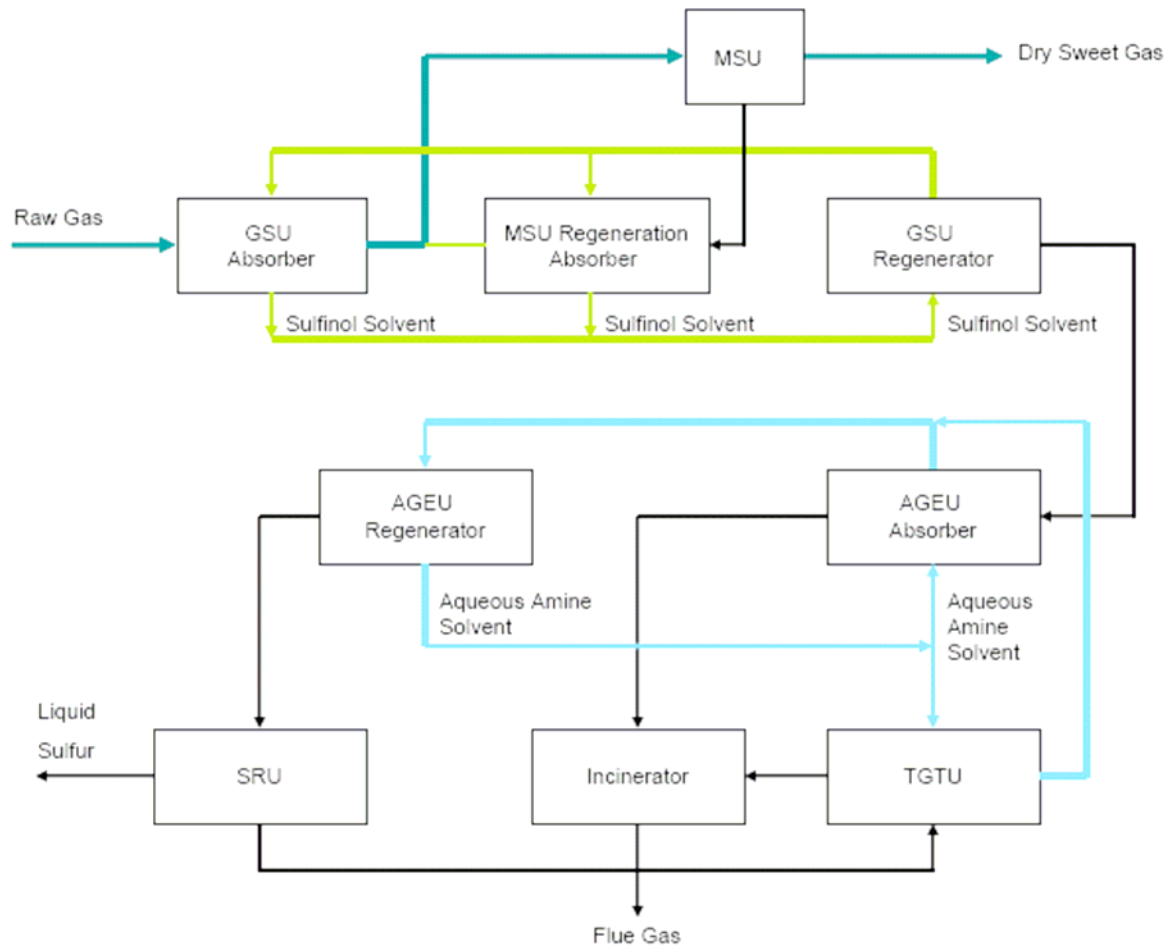


Figure 3 Overall arrangement of the Shell optimized solution with respect to maximization of treating train operability and flexibility (Klinkenbijl et al., 2005)

The optimization is based on reducing the MSU size by addition of mercaptan removal capacity in the GSU. This option therefore represents the most flexible, operable and cost efficient solution at the expense of increased hydrocarbon co-absorption (van de Graaf and Klinkenbijl, 2003; Rajani and Bowerbank, 2004). Shell optimized line-up is usually considered a cost effective solution, requiring the lowest capital investment, for an existing plant to be converted to one that meets tight sulfur specifications for gas and liquid products, while offering some flexibility in the feed-gas-composition (Klinkenbijl et al., 2005).

3.1.3 PROSERNAT Total Solution

PROSERNAT offers a range of proprietary technologies that answers the issues of cost reduction, efficiency improvement and environment protection. These proprietary technologies include:

- AdvAmine™ technology portfolio developed by TOTAL and licensed by PROSERNAT offers a wide range of solvents and configurations, all based on the use of widely available open market chemicals for gas sweetening applications (Streicher et al., 2004):
 - **HiLoadDEA** for complete CO₂/H₂S removal, a process based on the use of the well known DEA, which differentiates itself from open-art DEA technology by its advantageous proprietary features:
 - Use of a higher DEA concentration (up to 40 wt %) and for very sour gases of high acid gas loadings (mol absorbed acid gas / mol amine) to reduce solvent flowrates,
 - Special process configurations to minimize energy consumptions,

- Proprietary process configuration to achieve up to 95 % COS hydrolysis.
- **MDEA**max for selective H₂S removal, a process to get the maximum benefit of the selectivity properties of aqueous solutions of MDEA, **MDEA**max selectively removes H₂S down to very low levels, and maximizes CO₂ slippage to produce H₂S rich gas for direct Claus treatment, while advantageous by reducing energy consumption.
- Energized**MDEA** for controlled/complete CO₂/H₂S removal, a process using MDEA formulated with the addition of molecules, called “energizers”, able to accelerate the CO₂ capture by MDEA based solutions. This process achieves complete removal of CO₂, while getting the benefits of using MDEA, a solvent easier to regenerate and less sensitive to degradation. A key benefit of Energized**MDEA** is for the removal of CO₂, where some flash procured regeneration can be obtained, leading to very low regeneration energy consumption. The type and amount of energizer can also be tailored to meet specific requirements and achieve for instance controlled CO₂ removal.

The AdvAmine™ portfolio is based on impressive know-how as well as the extensive industrial and operational experience of TOTAL as developer and user of these technologies (Streicher et al., 2004). Accumulated industrial experience has made AdvAmine™ a versatile gas sweetening technology portfolio meeting the industrial needs for:

- All types of natural gas sweetening applications
- Reduced cost through optimal solvent use and improved process configurations (mainly high loading concept)
- Tight treated gas specifications on H₂S, CO₂, but also COS (in order to reach very low levels of total sulfur), and some mercaptans
- Ease of operation (avoiding corrosion/foaming)
- Molecular sieves technology (PROSERNAT has had very good experience with Axens or CECA) for gas dehydration and mercaptans removal unit.

The proposed unit consists of adsorption on molecular sieve, enabling simultaneous removal of water and mercaptans. The regeneration off-gas from the molecular sieve unit is loaded with mercaptans, which in turn must be treated to separate the mercaptans. The amount of mercaptans in the regeneration off-gas varies according to the molecular sieve regeneration cycle, which then requires oversize of some items of the Claus unit equipment and may impair the overall sulfur recovery efficiency, when these mercaptans are recovered to be sent to a Claus unit (Lallemand et al., 2008). In some case, incineration of the off-gas with peak RSH content can be proposed and the off gas used as fuel gas when RSH levels are acceptable. It should be noted that PROSERNAT proposes a combination approach for removal of mercaptans from regeneration gas, in which the regeneration gas is firstly washed with aqueous DEA to remove the CO₂ (in order to minimize caustic consumption through irreversible reactions with CO₂). The acid gas obtained after regeneration of the DEA, contains small amounts of H₂S and can be either sent directly to the thermal incinerator or at the inlet of the Claus. The regeneration gas is then washed with caustic solution to remove the mercaptans. The caustic solution loaded with mercaptans could then possibly be regenerated, for instance with Axens' (PROSERNAT's sister company) Sulfrex technology. If this option is selected it is possible to send the Disulfide Oil (DSO) obtained after regeneration of the caustic to a refining plant, or to use other means to convert the DSO in order to minimize the SO_x emission of the whole plant. Producing DSO exported to an oil refinery also avoids to send a stream of mercaptans with a high hydrocarbon content to the Claus unit (Streicher, 2009).

- AdvaSulf™ technological toolbox covering all SRU steps and options, and including (but not limited to) proprietary know-how and processes with an impressive track record of industrial experiences.
 - Claus technology including TOTAL's experience, IFP's R&D support and AXENS' CATALYSTS' know-how.
 - Claus Tail Gas Treatment (TGT) technologies including IFP's Clauspol II®, TOTAL/LURGI's Sulfreen™ (for some applications) and PROSERNAT's Sultimate™. Basically two main concepts can be used for tail gas treating:

- Continuation of the Claus reaction at such lower temperatures that liquid sulfur will condense (sub-dewpoint technologies): Clauspol II (the cheapest TGT technology available on the market from 99.4 to 99.8% sulfur recovery), and Sulfreen™ (best fit for large capacities sulfur plants).
- Conversion of all Sulphur species present in the Claus Tail Gas into H₂S followed by selective H₂S absorption and recycle at Claus inlet: Sultimate™ (can achieve the highest levels of sulfur recovery up to 99.9+%).
- Acid Gas Enrichment (AGE) process for Claus feed stream quality upgrade: TOTAL's AdvAmine™ (MDEAmax).
- Liquid Sulfur degassing non catalytic, or catalytic with TOTAL's Aquisulf™

AdvaSulf™ is therefore PROSERNAT's answer to the key challenges of today's sulfur plants: reduced costs, higher sulfur recoveries, higher flexibilities and reliabilities, possibility to treat dilute H₂S gas streams. Its applications include:

- Complete H₂S extraction (with AdvAmine™) and conversion (with AdvaSulf™) treatment chain
- All types of H₂S containing gas streams
- High conversions (99.9+%) achievable with TGT unit, contributing to keep AdvaSulf™ technologies at the forefront of today's environment protection technologies.

The PROSERNAT total solution is described in Figure 4, which is a simplified diagram showing mainly the technology architecture.

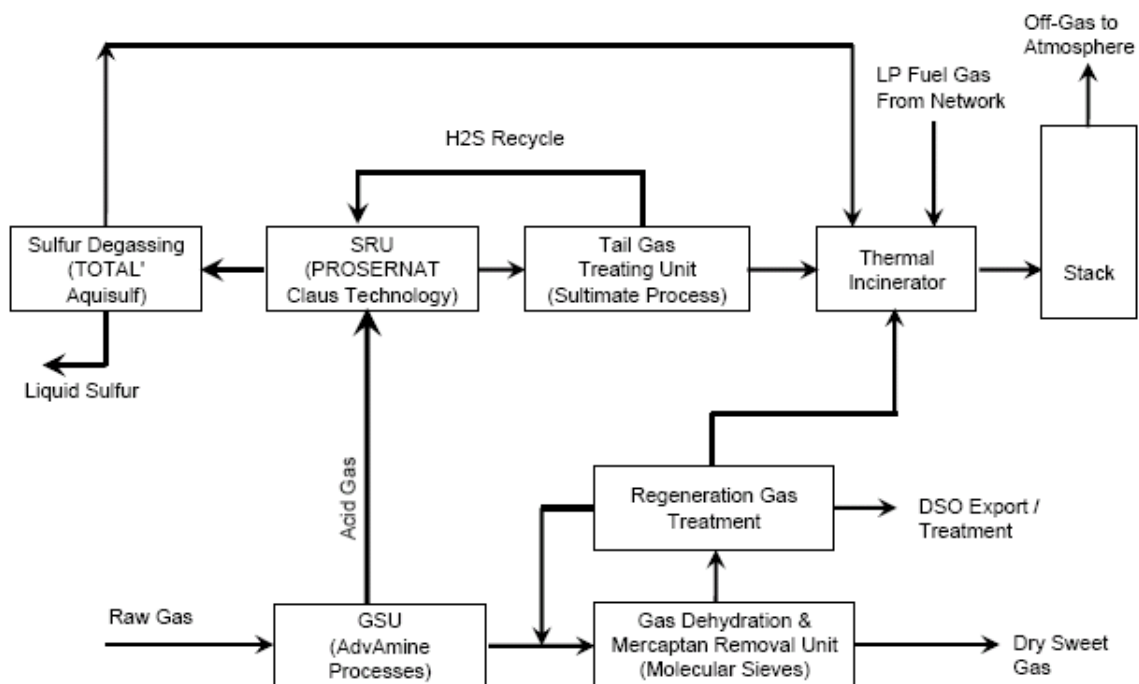


Figure 4 Technology architecture of PROSERNAT' total solution (Streicher, 2009)

For all its technologies, PROSERNAT provides high-quality fit-for-purpose designs, comprehensive training and effective troubleshooting for customer in order to achieve successful long-term operation as well as single source supply of fully guaranteed process-equipment packages.

3.1.5 Combining Different Technology Licensors

The value-added contributions of competing process technologies are sometimes compromised by not properly defining the inside and outside boundary limits. Each technology possesses its unique set of operating conditions where its performance excels. Likewise, each project is different and offers its own challenges to the available process technologies whereby a previously utilized technology may not be cost-effective. However, in this case, there are a few license contracts, guarantees and liabilities, and license fees. There are also multiple design margins internal to each package, which can result in significant CAPEX and OPEX increasing.

3.1.6 Integration of Open-Art Processes

Typically contractors use equipment standards and process simulations, and, together with equipment vendor consultations, they are able to design gas processing units without the need to use licensed technologies.

Licensed technologies, however, are mainly for specific unit processes where design has been optimized or proprietary materials (treating chemicals and solvents) are used. Work on process optimization has included increased control over the gas specification, reduction in energy consumption and waste generation, and reduction of capital costs through improved technologies and design. In fact, the investment in units utilizing proprietary/licensed "state of the art" technology pays off in a very short time resulting in a cost effective and efficient unit.

A proposed scheme for designing a gas-processing plant utilizing the open-art technologies will be as:

3.1.6.1 Gas Sweetening

Three main process technologies utilizing different amines (Diethanol Amine, DEA; Diglycol Amine, DGA; and Methyldiethanol Amine, MDEA) can be investigated during process screening. All of these processes are able to meet the sales gas H₂S specification of 4 ppmV. The key difference between those processes is the amount of CO₂ removed from the sour feed gas. Some processes remove virtually all of the CO₂ while others are designed to minimize CO₂ removal. When the CO₂ content in the sour gas is very low and deep NGL recovery does not follow, CO₂ slippage with the sales gas stream is not a major concern, so selective processes can be employed to treat the sour gas. Considering the pros and cons of those above-mentioned gas-sweetening processes, as presented into Table 1; design of gas sweetening unit will be usually based on the MDEA solvent. But in order to be able to use MDEA based solvents for complete and simultaneous H₂S and CO₂ removal, additives must be mixed into the MDEA solution. Such additives are usually primary or secondary amines which will speed-up or energize CO₂ capture. Another key advantage of MDEA base solvents is that CO₂ can be partially released from the solvent by simple flash. It is therefore possible to reduce the amount of solvent sent to the thermal regenerator, which can have a considerable impact on treatment costs for gases with high CO₂ content and high CO₂ partial pressure (Lallemand and Minkinen, 2001). For controlled CO₂/H₂S extraction, when some CO₂, but not all, must be removed, specific additives shall be used to tailor the respective removal rates of H₂S and CO₂ (Streicher et al., 2004). In this case, finding an optimum concentration for mixed amines strongly depends on the H₂S and CO₂ content of the sour gas, operating pressures and sale gas specifications.

Table 1 - Gas Sweetening Processes Pros and Cons

	DEA	DGA	MDEA
Pros	<ul style="list-style-type: none"> • Low solvent vapor pressure, and hence lower solvent losses. • Low solvent cost 	<ul style="list-style-type: none"> • Low circulation rate • High reactivity at low pressure and high temperature • Excellent thermal conductivity • Ability to remove CS₂, COS, and mercaptans 	<ul style="list-style-type: none"> • Selectivity of H₂S over CO₂, CO₂ can be slipped. • Lowest circulation rate • Low vapor pressure • Less corrosive • High resistance to degradation • Activator can be added to control selectivity
Cons	<ul style="list-style-type: none"> • Lower reactivity compared to DGA • Non-selective • High circulation rate • High regeneration heat requirements • May require supplemental lean amine cooling to meet sales gas specification • Co-absorb BTX • Non-reclaimable by conventional reclaiming techniques. 	<ul style="list-style-type: none"> • Non-selective • Co-absorb BTX • Require reclaimer to keep degradation products in check • Higher solvent cost compared to DEA • High solvent vapor pressure 	<ul style="list-style-type: none"> • Co-absorb some BTX • Highest solvent cost compared to DGA and DEA • Slightly more complex to operate as circulation rate is controlled on H₂S pickup as well as CO₂ slip. • Non-reclaimable by conventional reclaiming techniques.

Note, the alkanolamine technologies generally used, do not provide a satisfactory technological solution for the elimination of significant quantities of mercaptans and COS. The performance of alkanolamines used for such purpose not only depends on the type of amine considered (Kohl and Nielsen, 1997) but also on the absorber design that shall be achieved taking into account the specific chemistry of COS, especially the kinetics of the reaction between COS and alkanolamines (Cadours et al., 2006).

3.1.6.2 Gas Dehydration

Four well-established dehydration processes can be investigated during process screening for a gas dehydration unit in order to meet sales gas water content of 7 pounds per million standard cubic feet of gas. These dehydration processes are:

- Monoethylene Glycol (MEG) injection
- Triethylene Glycol (TEG) system
- Molecular Sieve system
- Silica Gel Technology

However, considering the pros and cons of those above-mentioned dehydration processes, as presented into Table 2; design of gas dehydration unit will be usually based on conventional TEG dehydration process when deep NGL recovery does not follow. However, there are a few items utilizing this conventional method (i.e. minimization of emissions and carbon footprint, dehydration of gases containing significant quantities of non hydrocarbons, etc) that will require slightly different design and operating considerations.

Table 2 - Gas Dehydration Processes Pros and Cons

Process	Pros	Cons
MEG Injection	<ul style="list-style-type: none"> • Simple process • Low capital cost • Low maintenance and operating cost • Not dependent on high glycol concentration to meet water dew point spec • Flexible on circulation rate • Regeneration can be done at low temperature using low-pressure steam 	<ul style="list-style-type: none"> • Completely dependent on propane refrigeration. When propane system goes down, there is no dehydration. • Co-adsorb some BTX that ends up in the regeneration vapor stream. • Requires slightly more refrigeration duty • MEG and condensed water/hydrocarbons mixture has high viscosity and needs to be heated to ensure good separation. • Requires a downstream three-phase separator to recover the MEG. • Uncertainty in composition and the extent of hydrocarbon absorption in the MEG may cause operational difficulties.
TEG	<ul style="list-style-type: none"> • Simple process • Moderate capital and maintenance cost • Low operating cost 	<ul style="list-style-type: none"> • Dry gas water content is completely dependent on glycol concentration and circulation rate. • Co-absorb significant amounts of BTX • Regeneration requires elevated temperature • Represents an additional step in the gas treatment, could be replaced by molsieves in case of further purification (other than water removal) by molsieves
Molecular Sieve	<ul style="list-style-type: none"> • Can achieve very low water dew point • No vent streams to be incinerated • Drying and purification could be done in one unit • Unmanned operation possible (robust and flexible system) • Small utility demand 	<ul style="list-style-type: none"> • High capital and maintenance cost • High operating cost • The sieve is exposed to deactivation, should be replaced every 3-5 years
Silica Gel	<ul style="list-style-type: none"> • Lower regeneration gas energy (temperature or flow rate) necessary compared to molecular sieves • Use of untreated feed gas possible for regeneration 	<ul style="list-style-type: none"> • Hydrocarbon coadsorption • water dew point not as low as for molecular sieves • special waterstable silica gel necessary

Selection of the drying process must consider mercaptans removal. If drying and mercaptans removal is necessary, another step or processing unit for the removal of mercaptans is often necessary. The only process capable of simultaneously drying and removing mercaptans is molecular sieves. The molecular sieves are able to concentrate the water and the mercaptans in the relatively small quantity of regeneration gas used to regenerate the sieves. All the impurities will be desorbed from the sieves

in peaks, the mercaptans first and then the water. Unless the water can be isolated by cooling the regenerated gas it is not easy to concentrate the mercaptans in a stream to be able to treat them. The hydrocarbons possibly coabsorbed in the physical absorption must be separated prior to sending the mercaptans to a sulfur recovery unit (SRU) unless the full regeneration gas quantity is burned for heat recovery or flared. This is often not possible as the regeneration flow is too high for the fuel gas balance and the SO₂ emissions limits are more and more stringent (environmental aspects).

Silica gel allows the treated gas to meet the dew point pipeline specs for water and hydrocarbons by requiring less regeneration gas compared to molecular sieves due to the lower adsorption enthalpy of the contaminants on the silica gel. The adsorbed products are more loosely bound to the adsorbent. Untreated gas is used for the heating and cooling and recycled to the inlet of the unit after partially condensing the water and the heavy hydrocarbons. The adsorption capacity is typically exhausted in the range of dozen of minutes up to 2-3 hours, which increases the number of absorption cycles and reduces the life of the silica gel. Mercaptans can be partially adsorbed (Kane et al., 2004).

3.1.6.3 Mercaptans Removal

Molecular sieve technology can be used to remove mercaptans. However, there is no open-art process for removing mercaptan (RSH) from the molecular-sieve regeneration off-gas. So, the off-gas can sometimes be incinerated when the off-gas RSH content is unacceptable for fuel gas purposes. Special designs for molecular sieve units can allow a reduction in the regeneration gas flow rate. Nevertheless, these designs should be based on proven technology (see point 5.3.2). In general it is recommended to compare designs of at least two different vendors and check for references. As the molecular sieve design has a huge influence on the whole plant design it is important to involve molecular vendors from the beginning of the FEED (front end engineering design) study.

3.1.6.4 Sulfur Recovery

The conventional Claus process has become the “workhorse” of the sulfur processing industry for the conversion of H₂S into elemental sulfur. The Claus process operates best at higher concentrations of H₂S in the acid gas. There is a lower limit of H₂S concentrations in the acid gas, between 15 mole% - 20 mole%, below which the Claus process may not achieve acceptable sulfur recovery levels. Hence, the choice of sulfur recovery process must be made in conjunction with the selection of a gas treating process because the upstream process selection is the primary determinant of plant size and cost of the SRU. Evaluating the SRU design in isolation would not necessarily lead to the most cost effective overall design that meets the processing criteria. Benzene, Toluene, and Xylene (BTX) in the sour gas poses another difficulty in the process selection because sulfur recovery catalysts are prone to deactivation in the presence of aromatic hydrocarbons.

The design of a complete sulfur plant requires a technological know-how which goes far beyond the Claus unit itself: Claus feed pre-treatment (like acid gas enrichment), Claus tail gas treatment, exhaust gas incineration, sulfur degassing and forming, steam recovery, etc. An optimal design of a sulfur plant therefore requires both extensive and robust industrial experience and the access to a wide range of technologies and process configuration options.

Sulfur disposal by acid gas injection, which would eliminate the capital cost of the SRU and any tail gas unit, is an option that eliminates the need to handle and market the sulfur. Generally, this is found to be a more economical choice if a host reservoir is available and the acid gas can be safely transported to the reservoir. The only treatment necessary is drying before compression. Since the acid gas is used for regeneration special acid gas resistant molecular sieves from suppliers such as CECA or UOP should be used to insure a minimum life time.

3.1.6.5 Design Concerns

Applying the open-art technologies for designing a gas-processing plant should be compared to the life cycle costs of licensed process units. The plant owner may wish to accept the risks for design and operation of the plant and possible off-specification products. Otherwise, insist on a performance guarantee for a licensed process that provides an adequate payback to offset the plant owner's risk.

3.2 Hydrocarbon Dew Point Controlling Unit

Table 3 presents the advantages and disadvantages of the most commonly-used technologies for DPCU. Twister, membrane and silica gel can achieve water and hydrocarbon dew point in one unit. Other technologies are primarily hydrocarbon removal technologies and require dehydration / hydrate inhibition by methanol or MEG typically.

Table 3 - HC Dew Point Controlling Technologies Pros and Cons

Process	Pros	Cons
Low Temperature Separation (LTS)	<ul style="list-style-type: none"> • Simple and compact process • Ease in operation • Low capital cost • Low maintenance cost 	<ul style="list-style-type: none"> • Hydrocarbon dew point control is directly related to the pressure reduction across Joule-Thomson (J-T) valve • Higher recompression horsepower • Off-spec gas during start up • Sensitive to feed gas composition
Refrigeration	<ul style="list-style-type: none"> • Simple process • Lower energy • Low operating cost • Little pressure loss through the chiller 	<ul style="list-style-type: none"> • May occupy a large area with heavy equipments • More maintenance cost and issues • Efficiency reduced when large percentage of inerts presented in the feed gas • CO₂ may become a concern • Sensitive to feed gas composition • Need refrigerant storage (potentially hazardous)
Lean Oil Absorption	<ul style="list-style-type: none"> • Little pressure loss through the absorber • Flexible for feed gas containing higher amount of CO₂ 	<ul style="list-style-type: none"> • High operating and capital costs • Need a large area • Tower height becomes a concern in windy area such as offshore • Inefficient when feed gas pressure is high – lose light hydrocarbons to rich oil • Need to process unstable condensate
Twister	<ul style="list-style-type: none"> • Could achieve dehydration and dew point control simultaneously • Remove more hydrocarbons than J-T valve for the same pressure drop • Compact and module design • Ease of installation and operation • Low maintenance 	<ul style="list-style-type: none"> • High recompression horsepower • Limited commercial test experience and performance relies on proprietary information • Limited turndown without operator involvement
Membrane	<ul style="list-style-type: none"> • Use smaller space • Light and compact module design • Ease of installation and operation • Low maintenance • Could achieve dehydration and dew point control simultaneously 	<ul style="list-style-type: none"> • Loss of methane in low-pressure permeate • May need a compressor to recompress the permeate, but operating and capital costs significantly increased • Not economically competitive for larger plants • Limited commercial test experience • Membrane can be fouled by heavier hydrocarbon so may need pretreatment or regular replacement
Silica Gel	<ul style="list-style-type: none"> • Could achieve dehydration and dew point control simultaneously • Low pressure drop • Ease in operation • On-spec gas during start-up • High flexibility with respect to gas properties and composition 	<ul style="list-style-type: none"> • Problems with T>50°C • Can be high cost • Need fired heater (capex & opex) • May need refrigeration for regeneration gas conditioning

Twister shares similar benefits of simplicity, robustness and ease of operation as the LTS (J-T valve). Two studies have shown that Twister can recover more hydrocarbons than the J-T valve for the same pressure drop (Genesis Oil & Gas Ltd, 2007; Schinkelshoek and Epsom, 2008). Therefore, it could potentially be operated at a reduced pressure drop for the same performance as a J-T valve. This reduces the sales gas compression power and cost. It can be particularly interesting for de-bottlenecking or upgrading existing gas plants. An additional benefit of Twister is the ability to remove water and hydrocarbons simultaneously in its tubes. Twister technology also offers environmentally-friendly, chemical-free operation within a small footprint. Recently Twister BV introduced the Twister SWIRL valve, which improves HC dewpointing performance of existing LTS plants by improving the separation of two-phase flow across a pressure reduction valve, such as a choke valve, JT valve or control valve. This in turn significantly improves the liquid separation efficiency of downstream separators. This improved separation can be used to either increase flow capacity of existing LTS plants, or to reduce the pressure drop required for JT cooling, or to lower the HC dew point and also to reduce glycol carry-over.

Membrane systems are very versatile and are designed to process a wide range of feed conditions. With very compact footprint and low weight, these systems are well suited for offshore applications. Membranes could potentially remove water and heavier hydrocarbons simultaneously, thus making it an attractive alternative to replace the conventional dehydration and DPCU design (Baker, 2002). However, more commercial testing is needed to gain industrial acceptance. The other issue with this technology compared to more standard dew point control methods is that when something goes wrong, the user is totally dependent on the vendor for troubleshooting and this is typically expensive, time consuming and sometimes futile.

Silica gel can achieve a simultaneous reduction of the hydrocarbon and the water dew point. More than 200 silica gel units are installed in natural gas applications under different conditions worldwide, on- and offshore. Usually, an adsorptive hydrocarbon recovery unit consists of three or more vessels, where adsorption and regeneration takes place in parallel. The installation costs depend on the case itself as they vary with the composition and the flow rate. They are often competitive to other technologies or redeem quickly due to long lifetimes and low operation costs. One of the most interesting points concerning adsorption of hydrocarbons and water with silica gel is the flexibility of these units in view of operating parameters and gas compositions. If the amount of water or hydrocarbons changes in the feed gas, the cycle time of the adsorption plant can be varied easily in order to achieve continuously low dew points (Schultz and Laukart, 1995; Brands and Rajani, 2001; Daiminger and Lind, 2004).

Choosing a best hydrocarbon dew point controlling technology requires consideration of a broad range of factors. The main variables that affect the choice of the best process for a given application include inlet conditions (gas pressure, richness, and contaminants), downstream conditions (i.e. residue gas pressure), and overall conditions (i.e. utility costs and plant location). In addition to the feed gas composition and operation mode, the most decisive technical characteristics of any process are the feed gas pressure and permissible unit pressure drop (Mokhatab et al., 2006). Pressure loss across the DPCU affects the sales gas delivery pressure. Higher pressure loss leads to increased sales gas recompression horsepower, and may even affect the compressor's number of stages.

4. TECHNOLOGY SELECTION CRITERIA

The earlier chapters have given an overview over the different treatment steps with its advantage and disadvantages. To design the full processing plant this information together with well defined selection criteria for the different technologies and their interfaces is necessary.

For selecting a certain technology it is important to take into account the interaction between this technology and the other treatment steps. Depending on the technology chosen, different schemes might be developed. They have to be evaluated taking into account the following characteristics: CAPEX and OPEX (lifecycle cost), license availability and fee, environmental and operational aspects, process safety, maintenance, utility needs, etc (McMahon, 2004).

5. MERCAPTAN REMOVAL WITH MOLECULAR SIEVES

Overview of the major process technology options (described above), illustrates the particular application of the molecular sieves in the natural gas processing plant, which can be used for both dehydration and mercaptan removal simultaneously. The new functionality of the molecular sieve units increases the importance to understand the principles and operation of such unit in order to prevent it to be the bottleneck of the plant. It is therefore desirable to take precautions against operational upsets for preventing unplanned shut-downs.

5.1 History

Units using molecular sieves for removal of mercaptans and other sulfur species go back to around 1978 with several treatment plants in Orenburg, Russia. Other unit where started up in 1988 in the Netherlands. In 1996-1999 very huge units where started up in Qatar while the first unit in Iran has been started up in 2003. Since then more than a dozen of other plants where started up mainly in the Middle East. Depending on the design of the molecular sieve unit, determined by the supplier, and the treatment of the regeneration gas the units faced more or less start-up problems and work in the meantime in general properly.

Contrary to drying units there are not so many existing units for the application of mercaptans removal in gas phase and not all molecular sieve suppliers do have the know how to design the units properly. In rare cases the designs are under designed in terms of adsorption capacity, more often there are issues of under designed regeneration procedure (flow rate), poor plant conception (number of adsorbers in adsorption and regeneration) and issues with the coadsorption of BTX on the molecular sieves which then will be in the regeneration gas where it causes separation problems in the physical absorption used to again concentrate the sulfur species before they are send to the Claus unit.

CO₂ is not removed by molecular sieves in general as this will lead to very huge units. Only for rather small feed flow rates or very low CO₂ concentrations (and drying and CO₂ removal only) molecular sieve technology could be interesting (Meyer, 2009).

5.2 BTX Issue

Benzene, Toluene and Xylene (BTX) components are an important issue in mercaptan (RSH) removal with sieves, but this can be handled. Two options are possible for a particular design of the gas dehydration and mercaptans removal unit with molecular sieves (MS):

- A) complete mercaptans removal with 4A, 5A and 13X molecular sieves
- B) partial, but bulk removal of mercaptans with 4A and 5A molecular sieves

For both options, the 4A MS is used for drying as the 4A is the most water resistant molecular sieve of the 4A, 5A and 13X types. In general, its density is higher, too, which offers an advantage for the vessel sizing. 5A MS is used for trace removal of H₂S, by limiting the COS formation (reaction of CO₂ and H₂S forming COS and water) and mainly for the removal of methyl-, ethyl- and n-propyl-mercaptans. These mercaptans represent in general the bulk mercaptan content of a Natural Gas. 13X MS is used for the adsorption of branched and C₄+ mercaptans. Heavier mercaptans, sulfides, disulfides and BTX can be adsorbed on 13X, too. COS is not removed with molecular sieves in such a system. Even if it can be adsorbed on zeolites its adsorption kinetics is very poor and it will very fast slip through the vessel. In general it is adsorbed by a doped alumina usually in liquid phase taking into account that this alumina type is not selective for COS, but will adsorb CO₂, too. Its very low adsorption capacity would lead to very huge vessels and enormous regeneration gas flow rates.

Solution A would allow a complete sweetening of the gas, including the sweetening of the C₅⁺ cut recovered from the DPCU. On the other hand, the BTX competition with the heavy mercaptans on the 13X should be taken into account. The overall design (bed size) would be higher than the Solution B resulting in a higher regeneration gas flow rate. Assuming a correct design the BTX will not turn the RSH removal by MS impossible. But the coadsorbed BTX will be in the regeneration gas. As the most common treatment of the regeneration gas is a physisorption they will be captured, too, and will have to be separated from the mercaptans before their treatment in the Claus unit. Solution B would have the advantage of no BTX coadsorption with additionally a lower regeneration gas flow rate. Most of the

mercaptans will be removed from the gas; the heavier mercaptans will be knocked down with the C5+ cut which is commonly treated with the liquid from the Condensate Stabilizer containing in any case other sulfur species which should be addressed by a further treatment in a refinery.

5.3 Maximizing Molecular Sieve Performance

The following sections review a number of problems that can affect the proper operation of the molecular sieves unit and the procedures that can be used to avoid or deal with those problems. It is concluded that the presented molecular sieve know how of CECA can sustain or improve your plants competitiveness and profitability.

5.3.1 Liquid Carry-Over

Liquid carry over to molecular sieve unit treating gas should be prevented in general. Whether it is water or hydrocarbon phase both will lead to a faster aging or almost immediate failure of the sieves.

- Liquid water will reduce the adsorption performance significantly due to the limited adsorption capacity of the sieves. It may lead in extreme cases to local, thermal temperature peaks resulting in powdering of the sieves.
- Caustic soda is probably the worst as it will react with the sieves and form concrenite (agglomerate), very often present in form of a "piston" or plate on the bed. Immediate consequence is increase of pressure and mal-distribution leading to premature breakthrough.
- Liquid hydrocarbons will lead to coking during the regeneration step with the result of blocking the pores of the adsorbent. This leads to loss of adsorption capacity.

5.3.2 Liquid Condensation on Molecular Sieve

Sometimes depending on the gas composition, some heavy hydrocarbon may be coadsorbed during the adsorption in a MRU, desorbed during the regeneration and form liquid hydrocarbons (being condensed on the cold parts of the bed) to again reduce the efficiency of the molecular sieves used for such purpose. This effect was observed on an untypical scheme using three adsorbers in series in regeneration, two adsorbers in heating and one in cooling. However, the fact to have hydrocarbon liquid condensation on the sieves during the regeneration procedure is a result of poor design and not due to the fact of using molecular sieve technology.

5.3.3 Thermal Degradation of the Molecular Sieve

Applying a special regeneration procedure can help to avoid hydrothermal degradation. This happens in general in drying units where the water being desorbed from the bottom layers of the bed is condensed on the cold layer to the top and boiling them in liquid water. Pore closure, attack of the crystal structure of the zeolites and weakening of the binder will be the consequence leading to premature failure of the bed due to loss of adsorption capacity or too high pressure drop (Meyer, 2003).

6. CONCLUSION

This extreme utilization of natural gas represents a worldwide increase in consumption against the background of dwindling natural resources, which ultimately leads to an increase in the significance of natural gas purification technologies. The requirements of a strategic important technology with respect to competitive forces for a gas-processing plant dictates that the most effective treatment process technology should (1) be able to comply with sulfur specifications for gas and liquid products, (2) be able to process different feeds, and (3) be cost effective compared to other alternatives. Added to this are other considerations such as reliability record, corrosion performance, quality of process guarantees and availability of professional after sales technical service.

It is important to see the full concept of the processing plant and identify the interactions between the different units. The optimization of a single unit should be secondary to the best overall processing scheme. For this, it is necessary to understand the constraints and limits of every single unit or

technology chosen. Product specifications (gas for pipeline, NGL, LNG ...), availability of utilities and environmental issues will drive the process design. Proprietary processes may have advantages, but the experience and knowledge of the application of open art solutions will impact the technological and final commercial risk.

Five alternatives have been described for design of licensed gas-processing units. Among the alternatives, integrated solutions (Lurgi OmniSulf[®] package, Shell and Prosernat total solutions), which are tailored to customer needs, will be the only comprehensive technology options where these integrated concepts offer the following advantages:

- One license contract, one overall guarantee and liability, and one license fee.
- Tailor-made solution to avoid multiplying internal design margins; which can result in significant CAPEX and OPEX savings.
- These integrated concepts are based on Lurgi/Shell/Prosernat' proprietary know-how as leading technology licensors and engineering contractors that takes the feed stream and deliver the required end product in an optimal manner.
- The scope of engineering services continues to detailed engineering as well as assistance at commissioning and start-up and after sales services (technical assistance, training, and revamp studies).

However, the results of an economic analysis will clearly indicate which alternative would be economically preferred. Determining the best process is very much dependent on the initial feed gas conditions, the treated gas specifications and environmental requirements. Before the treating line-up is selected, it is strongly recommended that an optimization study is carried out to obtain the lowest Capex/Opex and largest operating window with respect to feed gas composition (Klinkenbijn et al., 1999). In fact, the right technology, which results in a cleaner environment, improved reliability, and higher margins, has to be chosen on the basis of the environment of each individual project on a case by case basis, addressing the drawbacks and advantages of each option. Selecting the right technology and tailoring the right process design for a given application also requires both extensive industrial experience and the possibility to choose among various technologies and process options. For instance, whereas deep removal of mercaptans from a sour gas is a concern, the use of amine solvents followed by a specific treatment for mercaptans, such as soda wash or molecular sieves, induces relatively complicated treatment schemes with high investment costs, while physical or hybrid solvent processes entail higher hydrocarbons co-absorption (Warsame and Al-Hatou, 2005; Grant et al., 2007). This means, the investment in a high quality engineering consultant to provide process selection study will be well rewarded with a reliable fit for purpose and cost effective treatment package.

ACKNOWLEDGMENTS

The authors would like to thank Mr. Adrian Finn of Costain Oil, Gas & Process, Dr. Guang Lee and Dr. Douglas Elliot of IPSI LLC, Mr. Christian Streicher of Prosernat, Dr. Judith Schulze-Schlarmann and Dr. Waldemar Lind of BASF, and Mr. Hugh Epsom of Twister BV for the kind assistance and comments received from them during the preparation of this paper.

7. REFERENCES CITED

- Baker, R.W., "Future Directions of Membrane Gas Separation Technology", Ind. Eng. Chem Res. 41, 1393-1411 (2002).
- Brand, K., "Shell's New, Low Cost SCOT Process", paper presented at Brimstone Sulfur Recovery Symposium, Vail, CO, USA (September 2002).
- Brands, D.S., and Rajani, J.B., "Comparison between Low Temperature Separation (LTS) and SORDECO Process for Hydrocarbon Dewpointing", paper presented at the GPA Europe Annual Conference, Amsterdam, Netherlands (Sept. 26-28, 2001).
- Bruijn, J.N.H., Huffmaster, M.A., van de Graaf, J., Grinsven, P.F.A., and Grootjans, H., "Maximizing Molecular Sieve Performance in Natural Gas Processing", paper presented at the 81st Annual GPA Convention, Dallas, TX, USA (March 11-13, 2002).

- Cadours, R., Magné-Drish, J., Normand, L., Roquet, D., and Perdu, G., "COS Removal from Natural Gases by Absorption in Alkanolamine Solutions", paper presented at the 85th Annual GPA Convention, Grapevine, TX, USA (March 5-8, 2006).
- Carlsson, A.F., Rajani, J.B., and Kodde, A.J., "Finding the Fountain of Youth for a Mol Sieve Dehydration Unit", paper presented at the GPA Europe Annual Conference, Provence, France (Sept. 22-24, 2004).
- Carlsson, A.F., Last, T., and Rajani, J.B., "How to Avoid Excessive Mol Sieve Deactivation When Used for Mercaptan Removal", paper presented at 84th Annual GPA Convention, San Antonio, TX, USA (March 13-16, 2005).
- Carlsson, A.F., Last, T., and Smit, C.J., "Design and Operation of Sour Gas Treating Plants for H₂S, CO₂, COS, and Mercaptans", paper presented at the 86th GPA Annual Convention, San Antonio, TX, USA (March 11 - 14, 2007).
- Daiminger, U., and Lind, W., "Adsorption Processes for Natural Gas Treatment", paper presented at the GPA Europe Meeting, London, UK (Feb.26-27, 2004).
- Genesis Oil and Gas Consultants, "Twister NGL Recovery Study", London, UK (Dec.2007).
- Grant, J., Sourisseau, K., and Weiss, M., "Conversion of Sulfinol-D to MDEA at the Shell Canada Burnt Timber Facility", paper presented at the 57th Annual Laurence Reid Gas Conditioning Conference, Norman, OK, USA (Feb. 2007).
- Grootjans, H., "Sustained Development in the Pearl GTL Treating Design", IPTC 10682, paper presented at the 2005 International Petroleum Technology Conference, Doha, Qatar (Nov. 21-23, 2005).
- Hoksberg, C., et al., "Sulfur Recovery for the New Millennium", Hydrocarbon Engineering, (November 1999).
- Hugo, S., and Wagner, R., "Deep COS Removal with New Formulated MDEA Solvents", paper presented at the 50th Annual Laurence Reid Gas Conditioning Conference, Norman, OK, USA (Feb.27 –March 01, 2000).
- Kane, A., Shelenko, L., and Kauders, P., "Co-adsorption of Mercaptans using Silica Gel in Sour Gas Dewpointing Applications", paper presented at the GPA Europe Meeting, London, UK (Feb. 26-27, 2004).
- Klinkenbijn, J.M., Dillon, M.L., and Heyman, E.C., "Gas Pre-Treatment and Their Impact on Liquefaction Processes", paper presented at the 78th Annual GPA Convention, Nashville, TN, USA (March 1-3, 1999).
- Klinkenbijn, J., Grootjans, H., and Rajani, J.B., "Best Practice for Deep Treating Sour Natural Gases (to LNG and GTL)", paper presented at the GasTech 2005 Conference and Exhibition, Bilbao, Spain (March 14-17 , 2005).
- Kohl, A.L., and Nielsen, R.B., Gas Purification, 5th Edition, Gulf Professional Publishing, Burlington, MA, USA (1997).
- Lallemand, F., and Minkinen, A., "Highly Sour Gas Processing in An Ever-Greener World", paper presented at the 80th Annual GPA Convention, San Antonio, TX, USA (March 12-14, 2001).
- Lallemand, F., Roquet, D., and Weiss, C., "Development and Industrial Validation of A New Hybrid Solvent for Improved Mercaptan Removal", paper presented at the 87th Annual GPA Convention, Grapevine, TX, USA (March 2 - 5, 2008).
- McMahon, D, "Navigating the Technical Minefield of Gas Processing Options", paper presented at the GPA Europe Meeting, London, UK (Feb. 26-27, 2004).
- Meyer, P.B. Chr., "Hydrothermal Damaging of Molecular Sieves and How to Prevent It", paper presented at the GPA Europe Meeting, Paris, France (Feb. 21. 2003).
- Meyer, P.B. Chr., "How Molecular Sieves Design Can Answer to Amine Unit Performance", paper presented at the GPA Europe Meeting, London, UK (Feb. 19. 2009).
- Mokhatab, S., Poe, W.A., and Speight, J.G., Handbook of Natural Gas Transmission & Processing, 1st Edition, Gulf Professional Publishing, Burlington, MA, USA (2006).
- Rajani, J.B., "Treating Technologies of Shell Global Solutions for Natural Gas and Refinery Gas Streams", paper presented at the 12th International Oil, Gas and Petrochemicals Congress, Tehran, Iran (Feb. 24-26, 2003).
- Rajani, J.B., and Bowerbank, G., "Integrated and Optimised Treating Configurations for Mercaptan Removal from Natural Gas Streams", paper presented at the Sour Oil & Gas Advanced Technology 2004 International Conference, Doha, Qatar (Nov 22 – 24, 2004).
- Schinkelshoek, P., and Epsom, H.D., "Supersonic Gas Conditioning-Commercialization of Twister Technology", paper presented at the 87th GPA Annual convention, Grapevine, TX, USA (March 2-5, 2008).

- Schultz, T., and Laukart, A., “Natural Gas Treatment – The Adsorption Process in Comparison with Glycol Dehydration“, paper presented at the 45th Laurence Reid Gas Conditioning Conference, Norman, OK, USA (1995).
- Streicher, C., Lallemand, F., Minkkinen, A., and Lecomte, F., “A New Look at Amines: Extending the Gas Industry “Workhorse” to New Limits”, paper presented at the 83rd Annual GPA Convention, New Orleans, LA, USA (March 14-17, 2004).
- Streicher, C., Private Communications, Prosernat, Paris, France (2009).
- Van de Graaf, J., and Klinkenbijn, J., “Optimized Treating Configurations for the Combined Removal of H₂S, CO₂ and Mercaptans from Natural Gas for LNG and GTL Applications”, paper presented at the 82nd Annual GPA Convention, San Antonio, TX, USA (March 10-12, 2003).
- Warsame, A.F., and Al-Hatou, O.I., “Qatargas Experience – Acid Gas Enrichment Solves Lean Acid Gas with BTX Problems”, paper presented at the 55th Laurence Reid Gas Conditioning Conference, Norman, OK, USA (Feb. 27-March 02, 2005).
- Weiss, M.M., Hearn, J., and Hawes, P., “Sulfur Management in Natural Gas Treating Plants: A one-stop-shop for pipeline gas and LNG Plants”, paper presented at the GPA Europe Annual Meeting, Rome, Italy (Sept. 26-27, 2002).
- Weiss, M.M., “Sulfur Management – The Lurgi Concept”, paper presented at the AIChE Process Industries Congress, Mexico City (March 18-20, 2002).