OPTIMUM DESIGN OF ONSHORE GAS PROCESSING PLANT

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Fiona George
Worley Comprimo
155 Fenchurch Street
London, EC3M 6AL, United Kingdom
Fiona.george@worley.com

ABSTRACT

This paper presents a systematic approach to selecting the optimum design for an onshore gas processing plant, emphasizing how contaminant profiles—specifically Hydrogen Sulphide, Carbon Dioxide, Carbonyl Sulphide, and Mercaptans—directly influence the selection and configuration of process units.

A case study demonstrates the evaluation of technologies for acid gas, COS and mercaptan removal. The options considered for the Acid Gas Removal Unit are a two-stage selective chemical solvent with COS hydrolysis, a deep-cut chemical solvent and a hybrid solvent. The analysis finds that the choice of technology is primarily driven by the required Sales Gas and CO_2 product specifications. Furthermore, the selection of technology for one unit has significant implications for the design and operation of downstream and upstream units, affecting overall plant integration and performance.

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Introduction

Gas processing is required to convert a raw sour gas feed stock to saleable specifications. This includes removal of impurities and hydrocarbon treatment and is achieved through the combination of different process units. The selection of each unit has an impact on other units, and an optimal design considers the integration of all units.

The key to a good design is accurate definition of the feed components, especially the contaminants as it is the contaminants that often control the selection of the units. Analysis of the reservoir fluids and in particular the levels and mercaptan species distribution is of great importance. Mercaptan removal can govern the entire gas side configuration of a processing train, and it is a significant example of the interdependence between hydrocarbon processing and impurities removal. The components which need to be removed to meet the treated gas product specification typically include H_2S, CO_2, Mercaptans, COS, H_2O, Heavy Hydrocarbons and sulphides. The required level of removal is determined by the market. For example, a CO_2 specification for sales gas could be in the range 1-4 mol% for sales gas for local or national transmission system, 50 ppmv for supply to a liquefaction facility for LNG production, or as for our case study 6.5 mol% as the gas is fed to a downstream unit for additional processing.

The CO_2 and sulphur product specifications, the required level of CO_2 and sulphur recovery and emission specifications also impact the process selection. For the selected case study there was a requirement to remove hydrogen sulphide, carbon dioxide, COS and mercaptans from the sour gas to produce Sales Gas, sulphur and carbon dioxide export streams. Key decisions included the selection of the locations for the removal of CO_2 and mercaptans and the most suitable technologies to be used.

Case Study

Feed Definition

One of the challenges for the case study was defining the design composition and flowrate of the feed gas. The H_2S and CO_2 levels vary over time and there was uncertainty regarding the levels of other sulphur species such as COS and mercaptans. An additional complication was the requirement to design for a potential future tie-in of an additional field which contained lower levels of H_2S and CO_2 but higher levels of heavier mercaptans. For the base field composition, the CO_2 varied from 12 to 18 mol%, H_2S varied from 1 to 2 mol%. The additional field contained 9 mol% CO_2 and 0.3 mol% H_2S. The level of COS was around 100 ppmv, for both fields. However, there was a significant difference in the mercaptan levels and the speciation between the two fields. The base field contained predominantly methyl mercaptan, but the additional field contained less methyl mercaptan but higher levels of ethyl, propyl and butyl mercaptans.

There was flexibility regarding the onshore feed flowrate. Decisions needed to be made considering capacity and field life. Initially the basis was for two trains with a total sales gas capacity of 1600 MMscfd. The capacity optimization study considered one train with flowrates ranging from 600 MMscfd to 1100 MMscfd. Generally, it is most cost effective to build one train at maximum capacity. However, for the case study the maximum feed gas capacity of the train varies depending on the technology selected.

Product Specifications

There was also some uncertainty regarding the product specifications as there were options for the destination of sales gas and the CO_2 reinjection location. The main destination for the sales gas was to an existing LNG plant which was designed for feed gas containing 6.5 mol% CO_2 and, as the contract was based on rate, irrespective of heating value, there was no economic benefit to remove CO_2 to less than 6.5 mol%. An added complication for CO_2 removal was a limitation on the well capacity for CO_2 injection. If more CO_2 is removed in the AGRU then the feed capacity to be processed had to be reduced accordingly.

The sales gas was required to meet an H_2S specification of less than 15 ppmv and a total other sulphur, excluding H_2S, specification of less than 15 ppmv. The sales gas is routed to an LNG plant where additional processing takes place. Initially there was a requirement to meet a water content of less than 200 ppmv however this was later relaxed to less than 600 ppmv.

Consideration was given to two wells for CO_2 injection. The required CO_2 specification was different for these wells. One well required the CO_2 to contain less than 50 ppmv H_2S and there was no specification for total sulphur. The other well had a requirement to meet 10 ppmv H_2S and also required the COS to be less than 600 ppmv and the mercaptans to be less than 100 ppmv. In the event that CO_2 injection is unavailable, the CO_2 stream can be routed to a CO_2 Thermal Oxidiser. Due to the limitations on the SOx emissions from the thermal oxidizer, consideration was given to the impact of increased levels of H_2S, COS and mercaptans in the CO_2 injection stream.

Block Flow Diagram

The block flow diagram for the case study is provided in Figure 1 showing the interaction between the units being considered for the gas plant.

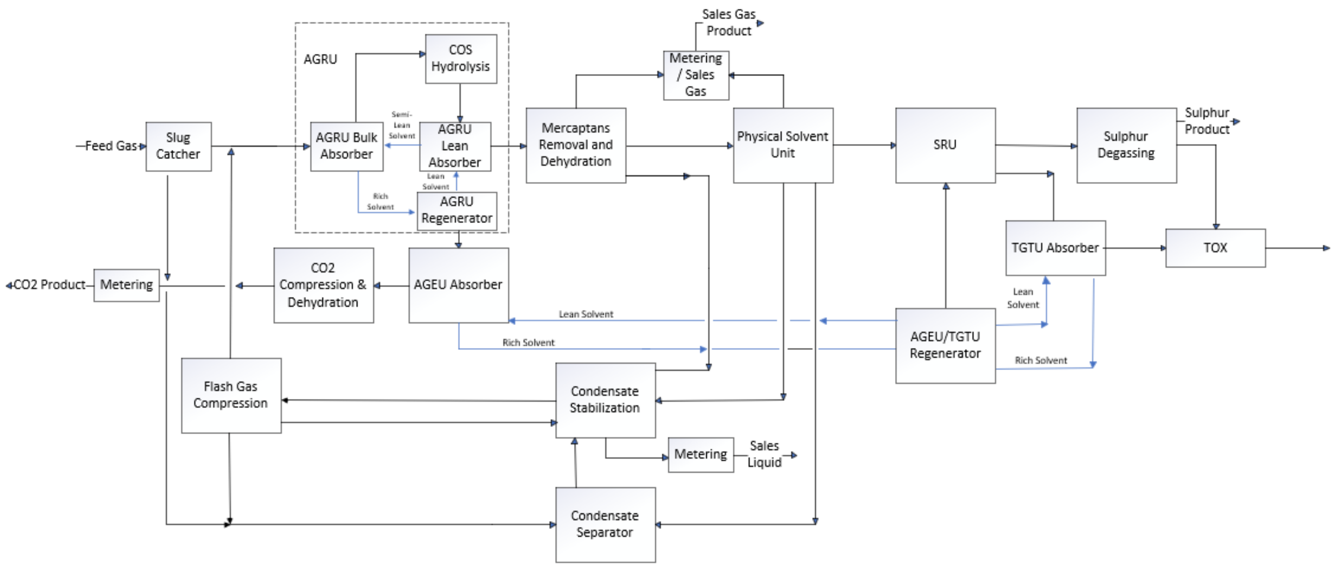

Figure 1 - Block Flow Diagram for Case Study

Acid Gas Removal Unit (AGRU) Technology Options

Three options were considered for the AGRU, and this paper will show how the feed composition and product specifications impact the technology selection for the AGRU and the downstream units.

AGRU Option 1- Two-Stage AGRU using selective chemical solvent with COS Hydrolysis

Two AGRU Absorbers with an intermediate COS Hydrolysis Reactor are required for high level removal of H_2S and COS whilst optimizing the level of CO_2 removal. A proprietary selective chemical solvent is used to remove H_2S preferentially and slip less CO_2 to the treated gas. The AGRU Bulk Absorber is required for bulk removal of H_2S and CO_2. The gas from the AGRU Bulk Absorber is routed to the COS Hydrolysis Reactor where COS reacts with water, present in the stream, to form CO_2 and H_2S.

$$\boldsymbol{COS + H_2O \Rightarrow H_2S + CO_2}$$

The process is carried out at a temperature of 300°F (~150°C) in a reactor with an aluminum oxide catalyst. The reaction is an equilibrium reaction. With high levels of H_2S in the gas, the equilibrium position could convert H_2S to COS. It therefore needs to be carried out after most of the H_2S in the feed gas has been removed and so the COS reactor is located downstream of the AGRU Bulk Absorber.

The gas from the COS Hydrolysis Reactor then enters the AGRU Lean Absorber where CO_2 and H_2S are removed to meet the required sales gas specifications. The AGRU is not designed to remove mercaptans which minimizes the sulphur species in the Acid Gas to the AGEU and therefore in the CO_2 stream. There is a requirement to remove mercaptans downstream. AGRU option 1, Figure 2, removes the CO_2, H_2S and COS to meet the treated gas specifications for these components.

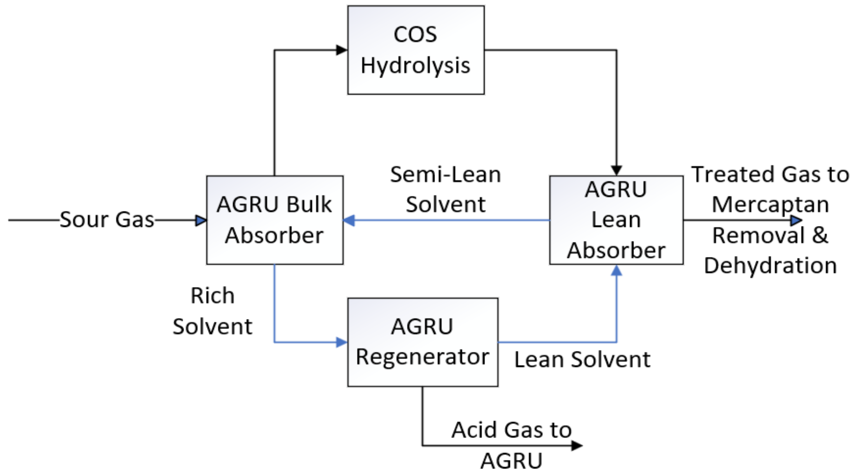

Figure 2 - AGRU Option 1 – 2 stage AGRU with selective chemical solvent and COS Hydrolysis

AGRU Option 2- Chemical solvent – Deep cut CO_2 Removal

AGRU option 2, Figure 3, is based on using a single AGRU Absorber and a chemical solvent. By targeting a deeper CO_2 product specification of less than 50 ppmv, COS can be removed to meet the required treated gas specification without the requirement for a separate COS Hydrolysis reactor. The chemical solvent will only remove ~10% of methyl mercaptan so mercaptan removal is still required downstream to meet the sales gas total sulphur specification. This AGRU configuration removes the CO_2, H_2S and COS to meet the treated gas specifications for these components.

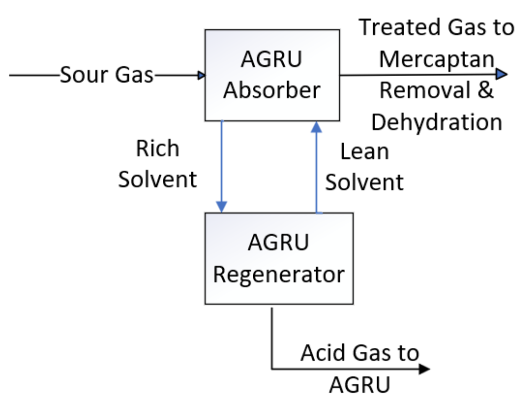

Figure 3 - AGRU Option 2- Chemical solvent with deep cut CO_2 removal

AGRU Option 3 - Hybrid Solvent

AGRU option 3, Figure 4, is based on using a single AGRU Absorber and a hybrid solvent. Hybrid solvents are a mixture of a physical solvent, a chemical solvent and water. The physical solvent permits higher acid gas loadings at high acid gas partial pressures, which provides the bulk removal capacity while the chemical solvent helps achieve the desired gas purity.

Hybrid solvents have the ability to remove mercaptans in the AGRU, avoiding the requirement for mercaptan removal downstream. This AGRU configuration can remove CO_2, H_2S, COS and mercaptans to meet the treated gas specifications for these components.

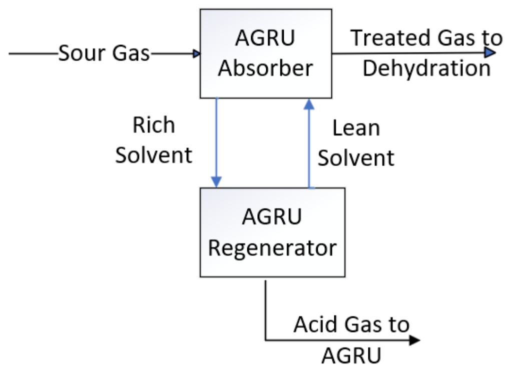

Figure 4 - AGRU Option 3- Hybrid solvent

AGRU Comparison

Table 1 provides a comparison of the composition of CO_2, H_2S, COS and mercaptans in the treated and acid gas from the AGRU for the three AGRU options considered. All options were based on the feed composition case containing 14 mol% CO_2, 2 mol% H_2S, 100 ppmv COS and 38 ppmv Mercaptans.

Table 1 - Comparison of AGRU Treated Gas and Acid Gas for the different AGRU options

	AGRU Treated Gas Composition			**AGRU Acid Gas Composition**		
	Option 1	**Option 2**	**Option 3**	**Option 1**	**Option 2**	**Option 3**
CO_2	6.2 mol%	< 50 ppmv	< 50 ppmv	76.2 mol %	81.7 mol %	81.8 mol %
H_2S	<5 ppmv	<5 ppmv	<5 ppmv	17.9 mol %	11.6 mol %	11.6 mol %
COS	<2 ppmv	<2 ppmv	<2 ppmv	2 ppmv	582 ppmv	582 ppmv
Mercaptans	37 ppmv	31 ppmv	10 ppmv	43 ppmv	74 ppmv	180 ppmv

The option considered for the AGRU has an impact on the treated and acid gas compositions. All three options meet the requirement of the CO_2 to be less than 6.5 mol% and the H_2S to be less than 15 ppmv. However, options 2 and 3 both result in recovery of higher levels of CO_2 than required to meet the sales gas specification which results in a more dilute acid gas with a lower H_2S/CO_2 ratio.

With option 1, COS is converted to H_2S and CO_2 by hydrolysis and then the CO_2 and H_2S are removed in the lean absorber. For options 2 and 3, COS is removed from the treated gas and so leaves the AGRU in the acid gas stream. Therefore, the acid gas stream for option 1 will only contain 2 ppmv COS but the acid gas for options 2 and 3 will contain over 580 ppmv.

There is also a difference in the levels of mercaptan removal between the three options. Option 3 will remove sufficient mercaptans to meet the sales gas specification, Option 2 will remove approximately 10% methyl mercaptans but there will be no mercaptan removal in option 1.
Any mercaptans removed in the AGRU will leave the unit in the acid gas. There is therefore a difference in the levels of mercaptans in the acid gas between the three options considered.

Table 2 - Comparison of key flowrates and exchanger duties for the different AGRU options

	AGRU Option 1 Two stage AGRU with COS Hydrolysis	AGRU Option 2 Chemical solvent deep cut CO2 Removal	AGRU Option 3 Hybrid Solvent
Treated Gas Molar Flow	100 %	94 %	93 %
Acid Gas Flow Molar MMscfd	100 %	154 %	154 %
Flash Gas Flow Molar MMscfd	100 %	162 %	392 %
Hydrocarbon Losses Mass Basis	100 %	137 %	1159 %
Solvent Mass Circulation rate	100 %	142 %	211 %
Reboiler Duty	100 %	153 %	157 %
Lean Cooler Duty	100 %	171 %	202 %

Table 2 provides a summary of the key flowrates and heat exchanger duties for the different AGRU options. All values are shown as a percentage compared to AGRU Option 1. AGRU Options 2 and 3 have higher CO_2 recovery and therefore higher acid gas rates and lower treated gas flowrates than for option 1.

Option 1 has the lowest solvent circulation rate and regenerator reboiler duty as the AGRU is designed for selective removal of H_2S with optimized removal of CO_2. The solvent regeneration circuit will therefore be smaller for this option than the other two. However, a COS Hydrolysis loop is required for COS removal. Thus, the option 1 scheme has more equipment than the other two options.

Options 2 and 3 do not require a COS loop for removal of COS but remove more CO_2 than required to meet the sales gas specification. Higher solvent circulation rates are required to remove higher levels of CO_2. An increase in circulation rate leads to an increase in the size of the solvent regeneration circuit which includes the solvent flash drum, lean solvent pumps, exchangers, tank and reboiler in addition to the regenerator column. Option 3, with a hybrid solvent, also removes mercaptans so requires a higher solvent circulation rate, and therefore increased size of regeneration circuit compared to option 2.

The physical component in the option 3 solvent leads to higher hydrocarbon absorption, resulting in an increase in hydrocarbons in the flash and acid gas streams. Hydrocarbon losses into the flash gas are recovered as the flash gas is compressed and recycled back to the inlet to the AGRU. The downside of increased hydrocarbons in the flash gas is an increase in flash gas compression. Hydrocarbon losses in the acid gas result in a reduction in sales gas revenue. The hydrocarbon losses are the lowest for option 1 and highest for option 3 with option 2 in between.

Impact of AGRU technology on Acid Gas Enrichment unit (AGEU)

The Acid Gas Enrichment unit is required to remove CO_2 from the Acid Gas from the AGRU to concentrate the level of H_2S in the feed to the SRU. The CO_2 which is removed, is compressed, dehydrated and reinjected into the well. The amount of H_2S and CO_2 in the SRU feed gas affects the performance and capacity of the SRU. Very lean acid gases with high CO_2-to-H_2S ratio will result in an unstable acid gas flame with low temperatures in the Claus thermal reactor. An unstable flame is typically observed at H_2S concentrations below 45mol% in the acid gas. For low H_2S feeds, co-firing with natural gas or operation with oxygen enriched air is recommended which makes the operation of the SRU more complex.

High CO_2 content in the feed stream, besides hydraulically loading the entire SRU/TGTU train, causes excessive COS formation in the thermal reactor. For the case study, enrichment to a minimum of 62 mol% H_2S (dry basis) is required to avoid co-firing in the SRU. Consideration was given to using generic MDEA, chemical solvents and sterically hindered solvents. The sterically hindered solvent was selected for the AGEU as it was the only solvent that could achieve the required level of enrichment. It also had the lowest heating duty, smallest column sizes, lowest solvent circulation rate and lowest CAPEX and OPEX.

The feed to the AGEU is dependent on the design of the AGRU. Some of the AGRU options result in removal of more CO_2 from the treated gas than required to meet the treated gas specification. If more CO_2 is removed from the treated gas, then more CO_2 will be in the Acid Gas and therefore in the feed to the AGEU. The level of H_2S will be lower in these cases and it will therefore be more difficult to achieve the H_2S level required by the SRU. The levels of mercaptans and COS in the Acid Gas to the AGEU are dependent on the choice of solvent for the AGRU. If mercaptans and COS are present in the feed to the AGEU it is expected that the majority will leave in the CO_2 stream. Therefore, if a hybrid solvent is selected for the AGRU the majority of the mercaptans and COS that are removed by the AGRU will end up in the CO_2 stream and could result in exceeding the required CO_2 specification. If there are minimal Mercaptans or COS removal in the AGRU then there will be minimal mercaptans or COS in the feed to the AGEU and therefore minimal levels in the CO_2 stream. Higher removal of CO_2 in the AGRU also leads to an increase in the size of the AGEU and CO_2 Compression and Dehydration units.

Table 3 provides a comparison between the different AGRU options.

Table 3 - Comparison of AGRU technologies

	AGRU Option 1 Two-stage AGRU using selective solvent with COS Hydrolysis	**AGRU Option 2 Chemical solvent – deep cut CO_2 Removal**	**AGRU Option 3 Hybrid Solvent**
H_2S removal	✓	✓	✓
CO_2 removal	✓	✓	✓
COS removal	✓	✓	✓

	AGRU Option 1 Two-stage AGRU using selective solvent with COS Hydrolysis	AGRU Option 2 Chemical solvent – deep cut CO_2 Removal	AGRU Option 3 Hybrid Solvent
Mercaptan removal	X	✓Partial Removal of methyl mercaptan	✓ Dependent on solvent & mercaptans levels
Minimise CO_2 removal to meet Sales Gas spec	✓	X	X
COS, mercaptans in CO_2 stream	Minimal	Majority of COS, some methyl mercaptan	Majority of COS & mercaptans
Equipment count	Highest due to requirement for COS loop	Lower as no COS loop but may need multiple regenerators	Lower as no COS loop but may need multiple regenerators
Solvent rate & reboiler duty	Lowest	Middle	Highest
Hydrocarbon & solvent losses	Lowest	Middle	Highest
Flash gas rate	Lowest	Middle	Highest
AGEU	Smallest	Larger	Larger
CO_2 Dehydration & Reinjection	Lowest	Highest	Highest

AGRU Cost Comparison

Table 4 - AGRU Cost Comparison

	AGRU Option 1 Two-stage AGRU using selective chemical solvent with COS Hydrolysis	AGRU Option 2 Chemical solvent – deep cut CO_2 Removal	AGRU Option 3 Hybrid Solvent
AGRU	100%	93%	104%
AGEU	100%	116%	116%
CO_2 Compression/ Dehydration	100%	153%	153%
Offshore CO_2 Injection	100%	112%	112%

Table 4 shows the comparative costs for the AGRU, AGEU and CO_2 Reinjection compared to the two-stage AGRU with COS Hydrolysis. This was based on designing with one AGRU train. The deep cut chemical solvent option has the lowest relative cost, hybrid solvent the highest and two-stage with COS Hydrolysis in between. The solvent circulation is lowest for the selective CO_2

option, but this has the additional cost for the additional Absorber and the COS loop. The deep cut chemical and hybrid solvent cases only require one absorber and no COS loop. However, the required solvent circulation rate for the deep cut chemical and hybrid cases are higher and therefore, due to equipment size restrictions, there was a requirement for an additional regenerator column for these cases.

It is also interesting to see the impact that the CO_2 slip has on the size and therefore cost of the AGEU and CO_2 Reinjection. The two-stage AGRU using a selective solvent can achieve 6-6.5 mol% CO_2 in the treated gas. The deep cut chemical and hybrid solvents are designed to remove the CO_2 to ppm levels. This additional removal of CO_2 increases the cost of the AGEU by 16% and the CO_2 compression and dehydration units by over 50%.

Options for Mercaptan Removal & Dehydration unit

If mercaptans are not removed in the AGRU then there is a requirement for mercaptan removal downstream to meet the total sulphur specification in the sales gas. Mercaptan removal can be achieved using a Temperature Swing Adsorption (TSA) unit with adsorbent beds. The case study was based on using beds filled with an aluminosilicate adsorbent material which provides superior performance compared to molecular sieves. The TSA can be designed to include dehydration if there is a sales gas specification for water content. The design of the Temperature Swing Adsorption (TSA) is dependent on the feed levels and speciation of mercaptans, product specification and the AGRU selected option. The case study considered three different TSA options and an alternative option to meet a relaxed water specification.

TSA Option 1 - TSA with Physical Solvent Unit (PSU) for Regeneration Gas Treatment

TSA Option 1 consists of four adsorbent beds with two beds in adsorption mode and two beds in cooling and heating respectively, as shown in Figure 5. The beds operate cyclically to desorb water, mercaptan species and hydrocarbons from the adsorbent. The beds are regenerated by a side stream of the treated gas, which is heated, flows upwards through the saturated beds, is cooled in an air cooler and condensate liquids are separated and are routed to a condensate stabilization unit. The gas is then compressed and routed to the Regeneration Gas Treatment unit which uses a Physical Solvent Unit to remove sulphur species, so the treated regeneration gas meets the sales gas specification. The Acid Gas from the Regeneration Gas Treatment unit is routed to the SRU. HP and LP Flash Gas are routed to the Flash Gas Recovery unit.

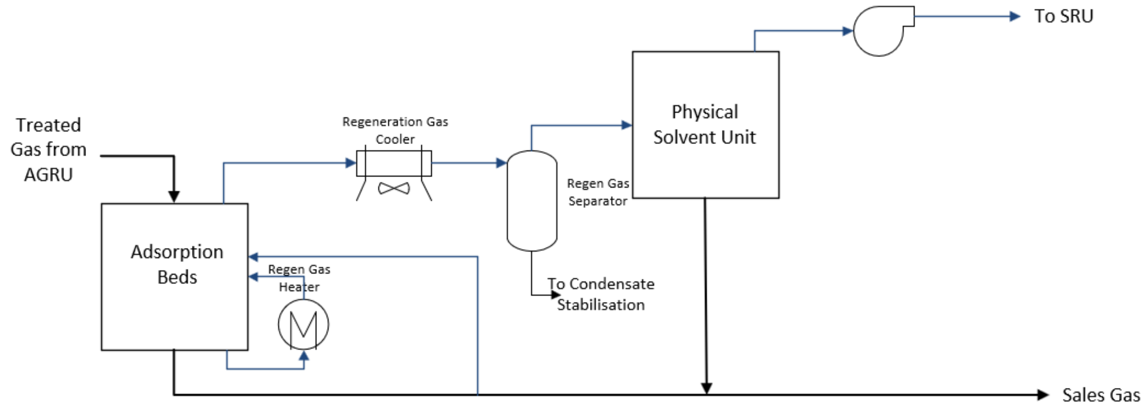

Figure 5 - Open loop TSA

TSA Option 2- Closed loop TSA with Regeneration Gas Recycle

TSA Option 2 consists of four adsorbent beds with two beds in adsorption mode and two beds in cooling and heating respectively as per TSA option 1. However, the beds are regenerated using a closed loop regeneration system without a Physical solvent unit to treat the regeneration gas as shown in Figure 6. For the closed loop scheme the beds are regenerated with a slip stream of feed gas, containing water and mercaptans, and the regenerated gas is cooled, some water, mercaptans and hydrocarbons are condensed. The regeneration gas is recycled back to the inlet to the unit, and the condensate is routed to the condensate stabilization unit. A forcing valve is used to avoid the requirement for a regeneration gas compressor.

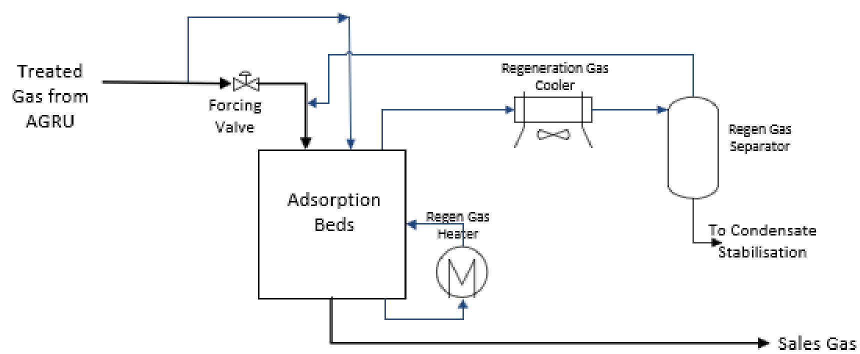

Figure 6 - Closed Loop TSA

TSA Option 3- TSA for Dehydration only

TSA Option 3 is designed for dehydration only. It is based on using a closed loop scheme with a forcing valve as per TSA option 2. However, the adsorbent beds are designed for water removal only. The number of beds can be reduced to three with two in adsorption mode and one in regeneration mode. The bed cycle times can be increased for this option as only water is removed.

Option 4- no TSA- cooler and separator- for relaxed water specification

If the sales gas does not need to be dehydrated, then the requirement for a TSA to dehydrate the gas can be removed. For the case study a water specification of <600 ppmv could be achieved simply by cooling the gas to 68°F (20°C) (based on a 9°F (5°C) margin above the hydrate point) and then using a vertical separator to knock out the liquid condensate phase.

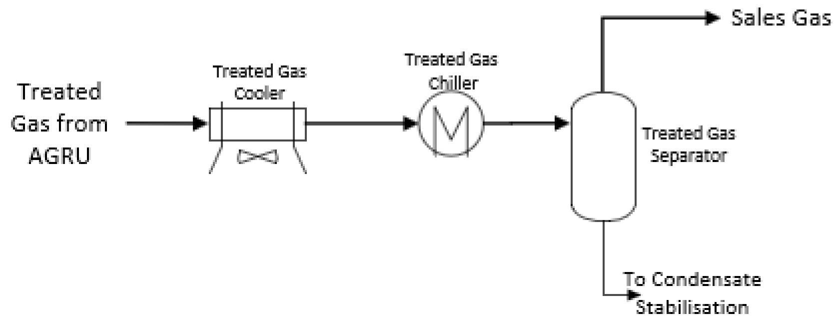

Figure 7 - No TSA- Simple Cooler & Separator

Cost Comparison TSA Options

Table 5 provides a comparison of the number of items of equipment required in each unit for the different TSA options.

Table 5 - TSA comparison of number of items of equipment

	TSA Option 1 - TSA with Physical Solvent Unit (PSU)	**TSA Option 2 - Closed loop TSA with Regeneration Gas Recycle**	**TSA Option 3- TSA for Dehydration only**	**Option 4- cooler and separator- for relaxed water specification**
TSA	12	12	11	3
PSU	27	0	0	0

Table 6 - Cost Comparison TSA options

	TSA Option 1 - TSA with Physical Solvent Unit (PSU)	**TSA Option 2- Closed loop TSA with Regeneration Gas Recycle**	**TSA Option 3- TSA for Dehydration only**	**Option 4- cooler and separator- for relaxed water specification**
TSA	100 %	106 %	87 %	47 %
PSU	100 %	Not required	Not required	Not required

Table 6 includes the comparative costs of the different options considered for the TSA. TSA Options 1 and 2 are both designed for mercaptan removal. TSA option 1 is an open loop so has a lower cost for the TSA but requires a PSU to treat the regeneration gas. TSA option 2 does not need a PSU unit so that is a cost-saving. However, as the regeneration gas is recycled round to the inlet to the beds, the size of the beds and the regeneration gas rate and therefore the cost of the option 2 TSA is higher than for option 1. TSA option 3 is for dehydration only, so the number of beds and regeneration gas rate are lower, and therefore the cost is lower than for the options which also include mercaptan removal. TSA option 4 just consists of a simple cooler and separator for bulk water knock out. This is the cheapest option but will not achieve the same level of dehydration as TSA option 3.

Impact of AGRU technology and mercaptan levels and speciation on selection of TSA

The open loop TSA option with a physical solvent to treat the regeneration gas is the most robust solution as it is a suitable option for all mercaptan levels and speciation. A key benefit of this system is that once the mercaptans in the regeneration gas are removed they leave the system and are sent to the SRU. The disadvantage of the open loop system is the requirement for a physical solvent unit and the additional cost of that unit.

The closed loop TSA option for mercaptan removal can only be selected if the feed stream contains predominantly methyl mercaptan. It is unsuitable if the feed contains higher levels of heavier mercaptans. As the molecular weight of the mercaptan increases, so does the boiling temperature. Higher levels of heavier mercaptans in the feed will result in higher levels of heavier mercaptans being present on the adsorbent beds that boil at higher temperatures and can become subject to thermal cracking and coke formation in the beds.

For the case study, the hydrocarbon condensate liquids knocked out in the TSA separator are routed to the condensate stabilization unit as shown in the block flow diagram in Figure 1. Due to the vapor pressure and total sulphur specifications for the hydrocarbon condensate, the majority of the mercaptans that are knocked out into the condensate end up in the condensate stabilizer overhead stream and are recycled back to the inlet to the AGRU. This results in a build-up of mercaptans in the system, increasing the load to the adsorbent beds and therefore the size and cost of the unit. The suitability of using a closed loop TSA system for removal of methyl mercaptan is therefore also dependent on the choice of solvent in the AGRU. If a selective chemical solvent is used in the AGRU then there will be minimal removal of mercaptans in the AGRU and therefore there will be a build-up of mercaptans in the system. Operating the AGRU with a chemical solvent and deep cut removal of CO2, will result in ~10-30% methyl mercaptans being removed. 10% removal of methyl mercaptans in the AGRU is sufficient to avoid mercaptans building up in the system. Therefore, if the feed stream contains predominantly methyl mercaptans the closed loop TSA system can be selected, provided the solvent selected in the AGRU will remove at least 10% mercaptans in the feed to the unit.

If a hybrid solvent is used in the AGRU or if there are no mercaptans in the feed, then there is no requirement for mercaptan removal in the TSA. If there is a requirement to meet a sales gas water specification, then TSA for dehydration only should be selected. If there is no sales gas water specification, then the simple cooler and separator is the most cost-effective option.

Table 7 summarizes the suitability of the TSA option based on the solvent used in the AGRU and the level and speciation of mercaptans in the feed.

Table 7 - TSA Comparison with respect to mercaptans

	TSA Option 1 TSA with Physical Solvent Unit (PSU) for Regeneration Gas Treatment	**TSA Option 2 Closed loop TSA with Regeneration Gas Recycle**	**TSA Option 3 TSA for Dehydration only**
No mercaptans in feed	✓	✓	✓
Mainly methyl mercaptan in feed	✓	X Selective Chemical ✓ Chemical Deep cut ✓ Hybrid	X Selective Chemical X Chemical Deep cut ✓ Hybrid
Higher levels of heavier mercaptans in Feed	✓	X	X Selective Chemical X Chemical Deep cut ✓ Hybrid

Table 8 provides a summary of the AGRU options showing which impurities are removed in the AGRU and which in the downstream TSA. The table shows the impact which the mercaptan speciation has on the selection of the TSA option.

Table 8 - Location of removal of impurities

	AGRU Option 1 Two-stage chemical solvent with COS Hydrolysis	**AGRU Option 2 Chemical solvent with deep CO_2 removal**	**AGRU Option 3 Hybrid solvent**
H_2S	AGRU	AGRU	AGRU
CO_2	AGRU-selective removal	AGRU – Removal to lower level than required	AGRU –Removal to lower level than required
COS	Two-Stage AGRU with COS Hydrolysis	AGRU- Deep Cut CO2 Removal Chemical Solvent	AGRU- Hybrid Solvent
Methyl Mercaptans	TSA with physical solvent unit to treat regeneration gas	AGRU - Partial Removal. TSA with closed loop recycle of regeneration gas	AGRU- Hybrid Solvent
Ethyl/Methyl/Propyl/ Butyl Mercaptans		TSA with physical solvent unit to treat regeneration gas	
H_2O	TSA	TSA	TSA or simple cooler & separator for relaxed water specification

Sulphur Recovery Unit SRU

For all AGRU options a 2 stage SRU & TGTU was selected for sulphur recovery. This met the requirement to achieve over 99.9% sulphur removal efficiency and over 99.9% sulphur recovery as the sulphur removed from the gas streams is recovered as elemental sulphur.

The AGEU uses a sterically hindered solvent to selectively remove H_2S. This same solvent can be used in the TGTU and therefore a common regeneration system can be used which reduces the number of items of equipment which are required and therefore reduces the CAPEX.

Schemes Considered Based on Selection of Options for AGRU & TSA

Five different schemes were considered based on the three AGRU options and four TSA/ Dehydration options. These were:
Scheme A- Two stage selective chemical solvent with COS Hydrolysis AGRU & Open loop TSA with Physical Solvent Unit (PSU)
Scheme B1- Chemical solvent with deep CO2 removal AGRU & Open loop TSA with Physical Solvent Unit (PSU)
Scheme B2- Chemical solvent with deep CO2 removal AGRU & Closed loop TSA with regeneration gas recycle
Scheme C1- Hybrid solvent AGRU & TSA for Dehydration only
Scheme C2- Hybrid solvent AGRU & Cooler and Separator

Destination of Contaminants Based on Unit Selection

Table 9 - Destination of impurities based on the line up of units

Scheme	**A**	**B1**	**B2**	**C1**	**C2**
AGRU	**Two stage chemical solvent with COS Hydrolysis**	**Chemical solvent with deep CO_2 removal**		**Hybrid solvent**	
TSA	**Open loop TSA with Physical Solvent Unit (PSU)**		**Closed loop TSA with regeneration gas recycle**	**Dehydration only TSA**	**Cooler & Separator**
H_2S	Liquid Sulphur				
CO_2	52% of feed CO_2 to CO_2 Reinjection	91% of feed CO_2 to CO_2 Reinjection			
COS	Converted to H_2S/ Liquid Sulphur	CO_2 Reinjection			
Mercaptans	Combusted to SO_2 in SRU	Partial CO_2 Reinjection/ Combusted to SO_2 in SRU	CO_2 Reinjection/ Condensate	CO_2 Reinjection	

For all the schemes the H_2S leaves the plant in the liquid sulphur stream. It is the destination of the COS and mercaptans where there is a significant difference between the options. Scheme A is based on a two-stage selective chemical solvent in the AGRU to maximize the CO_2 level in the Sales gas at 6-6.5 mol%. For this scheme there is less CO_2 removed in the AGRU so only 52% of the inlet CO_2 is re-injected. This scheme had much lower capital costs for the AGEU and CO_2 reinjection. For schemes B and C, the AGRUs are designed to remove CO_2 to ppmv levels, leading to recovery of 91% of CO_2 in the feed being recovered and re-injected.

Scheme A has a COS Hydrolysis reactor so all the COS in the feed is converted to H_2S and the converted H_2S leaves the plant in the liquid sulphur stream. Schemes B and C are designed for removal of COS in the AGRU with the COS leaving the AGRU in the Acid Gas stream. The Acid Gas from the AGRU is routed to the AGEU and the COS leaves in the CO_2 reinjection stream.

Schemes A and B1 are based on an open loop TSA with a PSU. For scheme A, there is no mercaptan removal in the AGRU so all mercaptans are removed in the TSA with regeneration gas treated by the PSU and routed to the SRU. For scheme B1 there will be partial removal of methyl mercaptans in the AGRU, so any mercaptans removed in the AGRU with end up in the CO_2 reinjection stream. For scheme B1 the heavier mercaptans are removed in the TSA and then routed to the SRU via the PSU and destroyed in the thermal reactor. Scheme B2, has some mercaptan removal in the AGRU which ends up in the CO_2 stream and some removal in the TSA which leaves in the condensate. Schemes C1 and C2 are based on using a hybrid solvent for mercaptan removal in the AGRU so the mercaptans leave the plant in the CO_2 reinjection stream. This is summarized in Table 7.

Table 10 - Overall plant unit selection

<table>
<tr><th>Scheme</th><th>A</th><th>B1</th><th>B2</th><th>C1</th><th>C2</th></tr>
<tr><td>Mercaptan speciation in feed</td><td colspan="2">Methyl/Ethyl/Methyl/ Propyl/Butyl</td><td>Predominantly Methyl</td><td colspan="2">Methyl/Ethyl/Methyl/ Propyl/Butyl</td></tr>
<tr><td>Sales Gas water spec</td><td colspan="4">≤ 200ppmv</td><td>No spec</td></tr>
<tr><td>AGRU</td><td>2 stage chemical solvent with COS Hydrolysis</td><td colspan="2">Chemical solvent with deep CO2 removal</td><td colspan="2">Hybrid solvent</td></tr>
<tr><td>TSA</td><td colspan="2">Open loop TSA with Physical Solvent Unit (PSU)</td><td>Closed loop TSA with regeneration gas recycle</td><td>Dehydration only TSA</td><td>Cooler & Separator</td></tr>
<tr><td>Relative CAPEX %</td><td>100</td><td>105.5</td><td>99.6</td><td>100.8</td><td>97.5</td></tr>
</table>

Table 10 provides a cost comparison of the different line-ups for the AGRU and TSA which could be selected. The relative CAPEX also includes the CAPEX of the inlet facilities, condensate stabilization, Sulphur systems, CO_2 Reinjection, utilities and pipeline. The differences between the estimates of the different line-ups are negligible considering the accuracy of the cost estimate is on a basis of +/-40%. Therefore, the decision on the line up could not be made purely on a cost basis.

Other factors to consider

When selecting a process line-up there are also additional factors to consider.

Scheme A is the most complex scheme with the most units as it is based on an AGRU with a two-stage absorber and a COS loop and a TSA open loop with a PSU. This scheme will require multiple shut down valves to manage the inventory and quantitative risk assessment. It will require the largest plot space and has the most items of equipment and requires management of COS catalyst and TSA adsorbent consumables. There are also limited references for the two-stage AGRU with COS absorber.

Scheme B has moderate complexity as it is based on a standard AGRU and TSA. There are multiple references for this line-up. Scheme B2 with the closed loop TSA has fewer items of equipment and consumables but can only be considered if the mercaptan speciation is predominantly methyl mercaptan. Scheme B1 with an open loop TSA is a more robust solution as it is suitable for heavier mercaptans.

Scheme C is based on mercaptan removal using a hybrid solvent in the AGRU and so there is no requirement for mercaptan removal in the TSA. There are multiple references for hybrid solvents for mercaptan removal. Scheme C1 is similar in complexity to scheme B2 except the TSA is only designed for dehydration not mercaptan removal. Scheme C2 is the simplest scheme as there is no requirement for a TSA. It has the lowest equipment and only the AGRU solvent to be managed.

Case Study Conclusion

For the case study, the decision on which scheme to select ultimately was based on the product specifications. Initially there was a requirement to meet a total sulphur specification in the CO_2 reinjection stream and so the two-stage AGRU with COS Hydrolysis option looked to be the most suitable option for the AGRU. On many CO_2 reinjection projects there is uncertainty as to the specification of the level of impurities in the CO_2 stream. This is largely due to the CO_2 specification often being based on a sales CO_2 product composition rather than for reinjection. A metallurgy assessment concluded that the initial sulphur specification was too conservative and that it would be acceptable for the COS and mercaptans to be routed to the CO_2 reinjection stream.

With the change in CO_2 specification, the other schemes were then considered. The chemical deep cut AGRU option with TSA with closed loop regeneration had the benefit of fewer items of equipment than the open loop TSA. However, there is uncertainty regarding the mercaptan speciation in the feed stream. If the TSA was designed with a closed loop system and then the feed stream contained high levels of heavier mercaptans then this could result in a build-up of heavier mercaptans in the system and the beds could be subject to thermal cracking and coke formation. The open loop TSA system with a PSU is a more robust solution but increases the number of items of equipment and complexity.

The scheme based on using a hybrid option in the AGRU is designed for mercaptan removal in the AGRU. The TSA is only required to dehydrate the gas. The sales gas from this plant is routed to a downstream LNG plant for further processing. Initially there was a requirement to dehydrate the gas to meet a water dewpoint due to concerns with water being knocked out in the line. After much discussion and assessment this specification was then relaxed so that there was no requirement for dehydration. Once there was no requirement for dehydration then there was a significant advantage in selecting the hybrid option for the AGRU. An acceptable level of water could be knocked out by cooling and water separation at 68°F (20°C).

There was still concern regarding the uncertainty of mercaptan speciation. Well tests suggested that initially the sour gas would contain predominantly methyl mercaptans but with time the gas stream would contain lower levels of CO_2 and H_2S but higher levels of heavier mercaptans. The sensible solution therefore was to start with one blend of hybrid solvent and then increase the level of the physical component as the level of heavier mercaptans increased. Scheme C2 was selected for the case study as it was the simplest design that could meet all the required product specifications. A hybrid solvent in the AGRU and a cooler and separator for water knock out. The block diagram for the selected scheme is provided in Figure 8.

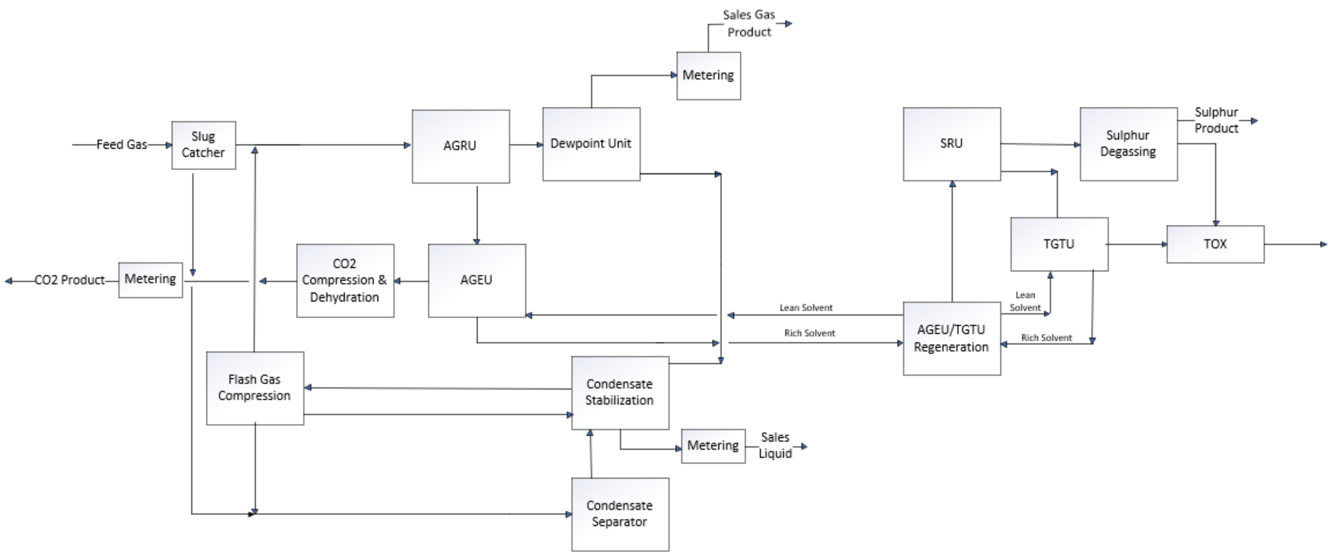

Figure 8 - Selected option based on AGRU with hybrid solvent and simple dewpoint unit

Summary

The optimum design for an onshore gas processing plant is driven by the required sales gas and CO_2 product specifications. The choice of technology for one unit affects the design and operation of all other units, emphasizing the need for integrated decision-making. The final scheme selected for the case study was a hybrid solvent in the AGRU with a cooler and separator for water knock-out, balancing simplicity, flexibility, and compliance with evolving feed compositions and product specifications.

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