INTEGRATED SULPHUR RECOVERY METHODS IN POWER PLANTS (US Patent Pending)

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RATE has recently patented a new process for integrating sulphur recovery methods in power plants. The new innovation has superior advantages in operating and the capital cost savings over the conventional methods with fewer process units, and less equipment.

Gasification technology in power generation is in no way new, but today it has become necessary to achieve environmental and economic improvement. Typical raw materials for gasification include coal, petroleum based materials (crude oil, high-sulphur fuel oil, petroleum coke, and other refinery residuals), gases, or materials that would otherwise be disposed of as waste. The feedstock is fed to the gasifier with steam and oxygen at high temperature and pressure in a reducing (oxygen-deprived) atmosphere to generate the syngas.

The raw gasification materials enter the gasifier with oxygen to burn the gas and also to remove the slag. The gas leaving the gasifier enters the Syngas cooler to recover the heat by producing steam. The cooled Syngas enters the acid gas removal unit to remove H2S and sulphur compounds. In the conventional Integrated Gasification Combined Cycle Unit the Syngas flows to the acid gas removal using amine chemical solvents such as MDEA or similar or physical solvents such as (Selexol or similar) or Rectisol unit with large solvent circulation and large energy consumption is required to enrich the acid gas.

The new innovation is a process for recovering sulphur from the syngas streams from the power plants where the sulphur recovery is followed by the SO2 recovery unit and the gas turbines or boilers in either sequence.

RATE has a patent pending (with the application number of 13345435, filed January 2012). Some downstream processes require that the syngas be cleaned of trace levels of impurities. Trace minerals, particulates, sulphur, mercury and unconverted carbon can be removed to very low levels using processes common to the chemical and refining industries. More than 95% of the mercury can be removed from syngas using commercially-available activated carbon beds.

The clean syngas can then be sent to a boiler, internal combustion engine or gas turbine to produce power or further converted into chemicals, fertilizers and transportation fuels. This clean syngas can then be used to produce energy and valuable products, such as chemicals, transportation fuels, fertilizers, and electricity.
This paper will present all the conventional method that has been used in the power plant application and the comparison with the innovation process and compare and comparison.

BACKGROUND

Gasification of coal and other heavy feedstocks will become a larger scale source of Claus sulphur in future. Gasification has been used worldwide on a commercial scale for more than 75 years by the chemical, refining and fertilizer industries and for more than 35 years by the electric power industry. It is currently playing an important role in meeting energy needs in the U.S. and around the world. In new set-tings it is being adopted in smaller-scale applications to solve the problem of waste disposal and extract valuable energy from waste.

While most of elemental sulphur comes from oil and gas production is roughly equivalent to the other two fossil fuels. In the past sulphur was recovered downstream as FGD not a product. Now, driven market an increasing power and chemicals, which necessitate removal of sulphur from SYNGAS prior to chemical and power production. The main route from coal to chemicals can be summarized as follows.

- To ammonia and fertilizers
- To methanol which includes converting to MTO, MTG, GASOLINE, and DME
- Coal to Liquid (CTL)
- Carbon Capture
- Underground coal gasification
- Synthetic a substitute for natural gas
- Power Production

Price Comparison – Coal could be dug out at $10-60 / t equivalent to energy cost of about $0.40 – 2.12 / MMBtu, while the gas priced at $10 / MMBtu and oil is at $100-/bbl which is equivalent to $18/MMBtu, and the natural gas is about $3.5 – 4/MMBtu, then make coal very attractive especially if coal is transported from places like Inner Mongolia or China which is cheaper and easier.

The sulphur production from SYNGAS is on the rise especially in China due to high energy demand.

GASIFICATION MEANS: RESTORING ENERGY for OUR ENERGY FUTURE

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The clean syngas can then be sent to a boiler, internal combustion engine or gas turbine or boiler to produce power or further converted into chemicals, fertilizers and transportation fuels.

This clean syngas can then be used to produce energy and valuable products, such as chemicals, transportation fuels, fertilizers, and electricity.

Gasification is an environmentally sound way to transform any carbon-based material, such as coal, refinery byproducts, biomass, or even trash, into energy without burning it. Instead, gasification produces a gas by creating a chemical reaction that combines those carbon-based materials (feedstocks) with air or oxygen, breaking them down into molecules and removing pollutants and impurities. What’s left is a clean “synthesis gas” (syngas) that can be converted into electricity and valuable products, such as transportation fuels, fertilizers, substitute natural gas, or chemicals.

**IGCC Gasification Flow Diagram**

It is known that in gasification plants there are number of steps are to be taken to produce the syngas as shown in the following diagram-1.

**Diagram -1 – Simplifies IGCC Block Flow Diagram**

Gasification is a process that converts carbon-containing materials, such as coal, petroleum coke (pet coke – a low-value byproduct of refining), biomass, or various wastes, to a syngas, which can then be used to produce electric power and valuable products such as chemicals, fertilizers, substitute natural gas, hydrogen, and transportation fuels.
Gasifier- The core of the gasification system is the gasifier, a vessel where the feedstock reacts with oxygen (or air) at high temperatures. There are several basic gasifier designs, distinguished by the use of wet or dry feed, the use of air or oxygen, the reactor's flow direction (up-flow, down-flow, or circulating), and the syngas cooling process. Currently, gasifiers are capable of handling up to 3,000 tons/day of feedstock throughput and this will increase in the near future. After being ground into very small particles or fed directly (if a gas or liquid) — the feedstock is injected into the gasifier, along with a controlled amount of air or oxygen. Temperatures in a gasifier range from 1,000-3,000 degrees Fahrenheit. The conditions inside the gasifier break apart the chemical bonds of the feedstock, forming syngas.

The syngas consists primarily of hydrogen and carbon monoxide and, depending upon the specific gasification technology, smaller quantities of methane, carbon dioxide, hydrogen sulfide, and water vapor. The ratio of carbon monoxide to hydrogen depends in part upon the hydrogen and carbon content of the feedstock and the type of gasifier used, but can also be adjusted or “shifted” downstream of the gasifier through use of catalysts. This ratio is important in determining the type of product to be manufactured (electricity, chemicals, fuels, hydrogen). For example, a refinery would use a syngas consisting primarily of hydrogen, important in producing transportation fuels. Conversely, a chemical plant uses syngas with roughly equal proportions of hydrogen and carbon monoxide, both of which are basic building blocks for the broad range of products that they produce. These include consumer and agricultural products such as medications, fertilizer, and plastics. This inherent flexibility of the gasification process means that it can produce one or more products from the same process. Typically, 70–85% of the carbon in the feedstock is converted into the syngas.

Some of the gasifier licensors are noted below.

- GE gasifiers with full or partial water quench provide best CO2 capture economics for bituminous coals
- COP partial slurry quench (PSQ) design (ala Wabash) includes some water quench and lower CH4 production
- Shell gasifiers offer high efficiency over wide range of feed stocks. Water quench design is in development.
- Siemens gasifiers include partial water quench and handle wide range of feedstocks

Oxygen Plant - Most gasification systems use almost pure oxygen (as opposed to air) to help facilitate the reaction in the gasifier. This oxygen (95–99% purity) is generated in a plant using proven cryogenic (ultra-low temperature) technology. The oxygen is then fed into the gasifier at the same time as the feedstock, ensuring that the chemical reaction is contained in the gasifier.

SYNGAS - The raw syngas produced in the gasifier contains trace levels of impurities that must be removed prior to its ultimate use. After the syngas is cooled, virtually all the trace minerals, particulates, sulphur, mercury, and unconverted carbon are removed using commercially proven cleaning processes common to the chemical and refining industries. For feedstocks (such as coal) containing mercury, more than 90% of the mercury can be removed from the syngas using relatively small and commercially available activated carbon beds.
Carbon Dioxide - Carbon dioxide can also be removed in the syngas clean-up stage using a number of commercial technologies. In fact, carbon dioxide is routinely removed with a commercially proven process in gasification-based ammonia, hydrogen, and chemical manufacturing plants. Gasification-based ammonia plants already capture/separate approximately 90% of their carbon dioxide and gasification-based methanol plants capture approximately 70%. The gasification process offers the most cost-effective and efficient means of capturing carbon dioxide during the energy production process.

IGCC Power Plants - An Integrated Gasification Combined Cycle (IGCC) power plant combines the gasification process with a “combined cycle” power block (consisting of one or more gas turbines and a steam turbine). Clean syngas is combusted in high efficiency gas turbines to produce electricity. The excess heat from the gas turbines and from the gasification reaction is then captured, converted into steam, and sent to a steam turbine to produce additional electricity.

Byproducts – Most solid and liquid feed gasifiers produce a glass-like byproduct called slag, composed primarily of sand, rock, and minerals contained in the gasifier feedstock. This slag is non-hazardous and can be used in roadbed construction, cement manufacturing or in roofing materials. Also, in most gasification plants, more than 99% of the sulphur is removed and recovered either as elemental sulphur or sulphuric acid.

IGCC Environmental Attributes

The new environmental regulations require the IGCC units to comply with critical emissions limits such as sulphur recovery to 99.99% (zero SO2 emission).

- The NOx emissions are controlled by removal of nitrogen-containing species from the syngas and by flame temperature moderation in the gas turbine with a downstream SCR possible.
- Particulates are removed from the syngas by filters and water wash prior to combustion so emissions are negligible Current IGCC design studies with SCR plan ~3ppmv each of SOx, NOx and CO
- Mercury and other HAP’s are removed from the syngas by adsorption on activated carbon bed
- Water usage is lower than conventional coal
- Byproduct slag is vitreous and inert and often salable
- CO2 under pressure takes less energy to remove than from PC flue gas at atmospheric pressure, which could be mostly removed in the acid gas removal 3-tower configurations

COS is one byproduct that requires hydrolyzation to improve emissions and overall sulphur recovery. Traditionally using titanium in the first Claus reactor will improve the hydrolysis of COS up to 98% and then the remaining COS is expected to be hydrolyzed in the tail gas hydrogenation reactor. However, sometimes due to different feed compositions from the upstream units, it may be required to have a separate COS hydrolysis reactor. Diagram 2 represents the scheme of the hydrolysis system. As discussed above, mercury is another impurity where the conventional method is using activated carbon. Diagram 3 represents the activated carbon for mercury removal scheme.
Diagram 2 – COS Hydrolysis

COS Hydrolysis / Simplified PFD

Diagram 3 – Mercury Capture in IGCC

**Mercury Capture in IGCC**

- Capture on sulfur impregnated activated carbon
- Standard natural gas application for LNG plants
- In syngas service at Eastman Chemical Co. since 1984
- Capture rate ~94% of vapour phase mercury
- Bed life ~ 2 years
- Spent carbon to hazardous landfill

Source: Trapp, 2002
Acid Gas Removal - The gas leaving the gasifier enters the Syngas cooler to recover the heat by producing steam. The cooled Syngas enters the acid gas removal unit to remove H2S and sulfur compounds. In the conventional Integrated Gasification Combined Cycle Unit the Syngas flows to the acid gas removal using amine chemical solvents such as MDEA or similar or physical solvents such as (Selexol or similar) or Rectisol unit which may require large solvent circulation and large energy consumption to enrich the acid gas.

The conventional acid gas removal processes are carried out by one of the following solvents. It is important to mention that the acid gas removal selection is based on the IGCC feed compositions, and the syngas specification. Selexol physical solvent, and methanol-based Rectisol are the most common solvents for the acid gas removal for the IGCC units followed by MDEA and other listed processes.

- MDEA
- DGA
- UOP / DOW - Selexol
- Linde - Rectisol
- Developmental Physical Solvent Absorption
- GTI & Uhde – Morphysorb Solvent Absorption
- Developmental Membrane CO2/H2 Separation
- Other Developmental Technologies (NETL + Other Research Organizations)

Acid gas removal using chemical or physical solvents consists of one absorber and one regeneration column to selectively remove H2S. However, due to new regulations in some countries in regard to CO2 reduction emission (Green House Gases) an additional absorber maybe added to all of these processes for the purpose of CO2 removal.

The following diagram 4 and 5 represent the acid gas removal using the MDEA solvent for H2S removal only and H2S and CO2 removal respectively.

The following diagram 6 and 7 represent the acid gas removal using the SELEXOL solvent for H2S removal only and H2S and CO2 removal respectively.

The following diagram 8 represents the acid gas removal using the RECTISOL solvent for H2S and CO2 removal.

The following diagram 9 represents the solubility of Selexol versus Murphysorb solvents.
Diagram -4 – MDEA Process for IGCC – H2S Removal

Diagram 6- Selexol Process – H2S Removal

Diagram 7- Selexol Process – H2S & CO2 Removal
Diagram 8 – Rectisol Process for H2S & CO2 Removal

Linde Rectisol for IGCC
Process Flow Diagram: H2S and CO2 Capture (3 tower design)


Diagram 9 – Solubility of Morphysorb vs. Selexol

Morphysorb Solvent Process
H2S & CO2 Solubility – Morphysorb vs. Selexol (DMPEG)
RATE Zero Emission in IGCC Design Scheme

In this section, we will talk about a unit is recently designed by RATE and all the features are considered. This project is a Coal to Chemical project where 3 process stream had to be processed in the sulphur recovery/ tail gas treating unit to achieve 99.9% overall sulphur recovery unit, and to achieve 10 pmmw of H2S for sulphur degassing.

<table>
<thead>
<tr>
<th>Composition (%vol)</th>
<th>Stream 1</th>
<th>Composition (% vol)</th>
<th>Stream 2</th>
<th>Stream 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>H₂</td>
<td>0.20</td>
<td>H₂</td>
<td>4.28</td>
<td>18.34</td>
</tr>
<tr>
<td>CO</td>
<td>0.27</td>
<td>CO</td>
<td>2.00</td>
<td>27.12</td>
</tr>
<tr>
<td>CO₂</td>
<td>51.03</td>
<td>CO₂</td>
<td>48.39</td>
<td>20.44</td>
</tr>
<tr>
<td>H₂S</td>
<td>40.4</td>
<td>H₂S</td>
<td>1.2</td>
<td>0.09</td>
</tr>
<tr>
<td>COS</td>
<td>0.09</td>
<td>COS</td>
<td>0.03</td>
<td></td>
</tr>
<tr>
<td>N₂</td>
<td>7.91</td>
<td>H₂O</td>
<td>11.00</td>
<td>33.74</td>
</tr>
<tr>
<td>Ar</td>
<td>-</td>
<td>NH₃</td>
<td>32.77</td>
<td>0.04</td>
</tr>
<tr>
<td>CH₃OH</td>
<td>0.1</td>
<td>CH₄</td>
<td>0.01</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>N₂</td>
<td>0.02</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Ar</td>
<td>0.01</td>
<td></td>
</tr>
</tbody>
</table>

- The acid gas removal scheme was Selexol or Rectisol (confidential).
- The sulphur recovery is designed based on 100% oxygen enrichment
- The tail unit contains an additional reactor for COS HYDROLYSIS and to process one the feed stream directly to maintain high temperature in the SRU
- The tail unit is designed to recycle the quench overhead to the acid gas removal (Selexol, Rectisol) where the tail gas amine portion is eliminated and to achieve ZERO EMISSION SULPHUR DESIGN.

RATE developed an exclusive scheme, where 100% oxygen enrichment is used to achieve stable combustion temperature. For a coal to chemicals application where to properly process several lean streams, some streams are routed to the tail gas unit and an additional hydrolysis reactor is also added in the tail gas unit.

We processed one of the lean streams in the SRU by using 100% oxygen enrichment. We had other streams where the rate was high with a very small amount of H2S. Processing such streams in the SRU would reduce the combustion temperature significantly due having ammonia present in the gas, in order to maintain the adequate combustion temperature for ammonia destruction, we processed some of the lean acid gas in the tail gas unit. In addition due to lean acid gases, significant COS & COS produced in the reaction furnace having TI catalyst in the SRU converters would not have 100% conversion. The remaining COS /CS2 were hydrolyzed by providing an additional hydrolysis reactor after the tail gas hydrogenation reactor. The lean acid gas is combined with the hydrogenation reactor.
outlet and is routed to the hydrolysis reactor. The quench overhead is routed to the acid gas removal via a blower or eductor, where is shown in diagram 10.

**Diagram 10- RATE ZERO EMISSION SCHEME**

This is a typical tail gas configuration for the tail gas treating unit to represent the concept.

However, in the actual design, instead of tail gas inline burner, low temperature hydrogenation catalyst is used. The design of the quench system could be one or two stages depending on the availability of ammonia for injection or caustic for neutralization.

As was mentioned due to recycling quench overhead to the acid gas removal unit there is no tail gas amine treating unit which will have a significant operating and capital savings.

Diagram 11 and 12 represent the details for the sulphur recovery unit using 100% oxygen enrichment and the exclusive tail gas configuration including COS hydrolysis reactor accordingly.
Diagram 11- RATE 100% OXYGEN ENRICHMENT
Diagram 12 – RATE EXCLUSIVE TAIL GAS CONFIGURATION DETAILS
Catalytic Coal Gasification Application

We had an application in catalytic coal gasification where the H2S concentration was very low, oxygen was not always available as there was no Air Separation Unit in the catalytic Gasification. The SRU unit is fairly small compare to other type of gasification process.

The feed composition is provided below.

<table>
<thead>
<tr>
<th>Description</th>
<th>Acid Gas to SRU</th>
</tr>
</thead>
<tbody>
<tr>
<td>Comp mole fraction</td>
<td>1</td>
</tr>
<tr>
<td>CO2</td>
<td>0.856</td>
</tr>
<tr>
<td>H2O</td>
<td>0.05</td>
</tr>
<tr>
<td>METHANE</td>
<td>0.002</td>
</tr>
<tr>
<td>H2S</td>
<td>0.092</td>
</tr>
</tbody>
</table>

RATE exclusively developed the following scheme for this application.

**SRU Section**

The acid gas will be washed in the water wash K.O. Drum to remove the ammonia in the acid gas. The acid gas is preheated before entering the direct oxidation catalyst such as Selectox oxidation catalyst or similar using direct oxidation recycle such as Selectox recycle to control the temperature and then followed by one conventional catalytic Claus stage.

**Tail Gas section**

Since the unit is very small and it should be cost effective. We have proposed a catalytic incineration using direct oxidation catalyst such as Selectox catalyst or similar followed by a small venturi caustic scrubber to absorb the un-recovered sulphur that is converted to SO2. Using Catalytic incineration will save fuel consumption in the incinerator since it is operate at lower temperature and also this configuration requires less equipment compare to conventional tail gas unit. This configuration will meet 99.9% + recovery. The sulphur in a form of SO2 that is absorbed by caustic will not be recovered.

The following diagram 13 presents catalytic coal gasification scheme.
Diagram 13 – Catalytic Coal Gasification Scheme
RATE New Innovation- Integrated Sulphur Technology in Power Plants

We received some application to process SYNGAS including the acid gas removal and the sulphur recovery unit. The feed composition is provided below.

<table>
<thead>
<tr>
<th>Compositions</th>
<th>Mole percent</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO</td>
<td>24.67</td>
</tr>
<tr>
<td>CO2</td>
<td>36.47</td>
</tr>
<tr>
<td>H2</td>
<td>30.11</td>
</tr>
<tr>
<td>H2O</td>
<td>NG</td>
</tr>
<tr>
<td>CH4</td>
<td>4.97</td>
</tr>
<tr>
<td>C2H6</td>
<td>NG</td>
</tr>
<tr>
<td>N2</td>
<td>1.48</td>
</tr>
<tr>
<td>H2S</td>
<td>2.3</td>
</tr>
<tr>
<td>COS</td>
<td>TRACE</td>
</tr>
<tr>
<td>NH3</td>
<td>TRACE</td>
</tr>
<tr>
<td>HCN</td>
<td>TRACE</td>
</tr>
<tr>
<td>TOTAL</td>
<td>100</td>
</tr>
</tbody>
</table>

We started the evaluation and the technology selection using the conventional method for the acid gas removal followed by the sulphur recovery unit. Referring to the feed gas composition, even though the H2S concentration is a typical range for the syngas, with high volumetric gas rate, the acid gas removal required a high circulation rate of the solvent and was not very economical. We decided to use our new technology by eliminating the acid gas removal and using the SO2 recovery unit instead and as the results the tail gas treating unit is also eliminated and the design will be ZERO EMISSION.

This disclosure relates generally to processes for the production of elemental sulfur from Syngas, in the power plant, more particularly to processes the mixture of the 100% syngas stream with the 100% SO2 recycle gas; with an additional stream comprising oxygen such as air, oxygen-enriched air, or substantially pure oxygen is added to the SO2 recycle stream prior entering the Claus reactor for producing elemental sulfur. The combination of innovation schemes comprises the sulfur recovery unit, the SO2 recovery unit and the gas turbines or boilers to promote a cost effective options by reducing the number of steps in an efficient manner and to achieve near 100% sulfur recovery with significant cost and energy saving. The SO2 gas is recycled from the SO2 recovery unit to the sulfur recovery unit by using one of the regenerable solvent. With further aspects of the present invention, the innovation scheme is a combination of the 3 process units; where the Claus unit scheme, followed by two units in any sequence order of the SO2 recovery unit and the gas turbines or boilers.

In accordance to the new invention, the syngas will not be processed in any acid gas removal, in other words some steps such as acid gas removal, tail gas treating, syngas coolers, and the tail gas incineration units are eliminated. The following diagrams summarize the two schemes of the new innovation.

In the first option the SO2 recovery is located after the sulphur recovery where it is recycled back to the SRU and the treated gas is sent to the gas turbine boilers to generate the electricity.
In the second option the SO2 recovery is located after the gas turbine boilers and again the SO2 stream is recycled to the SRU. In this case, the gas turbine material has to be selected to tolerate the acid gas properties and there are vendors that can design such turbines.

The detailed scheme of the SRU and the SO2 recovery is provided in the following pages.

**Figure a- Option 1- RATE INNOVATION SCHEME**

![Diagram 1](image1)

**Figure b- Option 2- RATE INNOVATION SCHEME**

![Diagram 2](image2)

**SO2 Recovery Unit** - The SO2 regenerable unit could be a chemical or physical solvent or water based system such as ClausMater, Cansolv, Labsorb, Elsorb, TurboSox, Well-man Lord and ENFI Organic solvent, or similar. Diagram 14 and 15 present the SO2 Recovery using chemical or physical solvent respectively.

As discussed in the conventional acid gas removal that adding an additional absorber could be added for the CO2 removal where CO2 emissions has to be controlled,, in this new innovation, the same logic
will be applied where the regenerable SO2 Solvent has been used for CO2 removal and carbon capture, while the SO2 is recycled to the sulphur recovery unit, the ZERO EMISSION will be achieved.

Diagram 14- SO2 Recovery Chemical Solvent
**Diagram 15- SO2 Recovery Physical Solvent**

**Sulphur Recovery Section**- More particularly the 100% syngas and the 100% SO2 recycle gas are mixed first plus air, oxygen or enriched air is added to the SO2 recycle stream and flow directly to a Claus reactor. The SO2 gas is recycled from the SO2 recovery unit using one of the commercial regenerable solvent. Key advantages are some steps such as the acid gas removal unit, syngas coolers, tail gas treating and the tail gas incineration units are eliminated, reduced energy significantly and reasonable operating and capital costs with overall near 100% sulfur recovery with SO2 recycled to the sulfur plants and to meet the new environmental regulations.

In this section the syngas is heated indirectly with HP steam or any type of heaters to about 450°F before entering the reactor to avoid condensing the sulfur product on the catalyst. The Claus reaction is exothermic and creates a temperature rise across the catalyst bed. In order to maintain a reasonably low reactor outlet temperature (less than 650°F), cooled tail gas is recycled to the inlet with an ejector that uses the high-pressure sour feed gas as the motive fluid or by recycle blower. If the feed contains heavy hydrocarbon, some polishing unit may be required upstream of the sulphur recovery unit.

the activated catalyst in the Claus reactor(s) is an alumina, titania, or a mixed bed with alumina on the top and a layer of titania and/or direct oxidation catalyst such as Selectox or similar which promotes a Claus reaction in the reactor, and by supplying oxygen to the reactor.
If in the reactor inlet, Light hydrocarbons (C1-C3) present in sour feed gas will not react in the relatively low temperature of the Sulfur Converter. However, heavy hydrocarbons, especially aromatics such as BTX, if present, may crack and deactivate the catalyst. To account for the possibility of some heavy hydrocarbon contamination, it is recommended to provide polishing units such as activated carbon bed or similar units to capture the hydrocarbon impurities.

Further aspects of the present invention, the two process units after the sulfur recovery unit can be in any sequence order, it is preferred to have the SO2 recovery unit as the second process unit and the gas turbines or boilers as the third process unit where the gas turbines or boilers are commercially standard.

If the second unit are the gas turbines or boilers and since the gas stream is still contains sulfur compounds such as H2S, the material of construction of the boilers should be adequate to handle the tail gas streams. The tail gas stream is combusted and all the sulfur compounds are converted to SO2 and the combusted heat is recovered by producing high pressure of steam. If the boilers are employed as the third unit, since all the sulfur components are recovered, then the material of the construction for the boilers are industry standard.

In the first innovation scheme, the final condenser is followed by the quench system. The effluent from the quench system flows to the SO2 recovery system and finally to the gas turbines or boilers.

In the second innovation scheme the last condenser flows to the gas turbines or boilers without any quench system and then flows to the SO2 recovery system.

The diagram 16 and 17 present the detailed scheme of this innovation consisting both schemes.
Diagram 16- RATE New Innovation for Sulphur Recovery – Scheme 1

Diagram 17- RATE New Innovation for Sulphur Recovery – Scheme 2
Advantages

The new innovation has the following advantages.

100% of the sour gas (Syngas or Low BTU Gas) and 100% of the SO2 recycle streams are mixed prior entering the Claus reactor, in other words, in the new invention, the gas stream is not split, some steps such as the reaction furnace and the tail gas treating and the tail gas incineration units are eliminated and the employed equipment are smaller size, as the results, the new invention provides significant energy and cost saving in both capital and operating costs.

- In accordance to the new invention, the syngas will not be processed in any acid gas removal, in other words some steps such as acid gas removal, tail gas treating, syngas coolers, and the tail gas incineration units are eliminated. The acid gas removal is eliminated.

- The tail gas from the sulfur recovery is processed in the regenerable SO2 removal where the SO2 gas is recycled to the sulfur recovery unit and the treated gas enters the gas turbines or boilers to generate electricity. The treated gas leaving the third process unit can be emitted to the atmosphere if it is safe or other units. The tail gas treating is eliminated.

- An SO2 recovery unit has dull function as the acid gas removal and tail gas treating.

- The SO2 regenerable unit could be ClausMater, Cansolv, Labsorb, Elsorb, TurboSox, Well-man Lord and ENFI Organic solvent, or similar.

- ZERO EMISSION, means by recycling the SO2 to the SRU, the overall recovery of near 100% will be achieved.

- By adding an additional absorber and common regeneration, CO2 could be removed where it is applicable

- Finally, the new innovation could also be used for gas fields for low BTU gas applications

- Much lower operating and capital cost, with less equipment, and less plot space, less complicated unit

Conclusions

In this paper we discussed the integrated sulphur recovery methods in the power plants by using the conventional method versus the new innovation patent pending process by RATE. RATE has extensive experience in all kind of gasification including catalytic coal gasification and any other gasification system. As the results, RATE has developed a new technology among expertize in all current technologies to offer full spectrum in this field.

The stream containing H2S and other components are not the same and it depends on type of gasification process and the source are used could be coal, coke or any other source of energy.
Depending on the feed compositions, availability of utilities, source of oxygen, H2S concentration, other impurities like ammonia, other flue gas streams, type of gasification and gasifier the most economic and the most feasible technology has to be selected considering emissions of SO2 and CO2, COS NOx and any other impurities and ultimately to achieve ZERO EMISSION.

As we discussed the technology selection for the acid gas removal in the conventional method depends on the feed composition of the SYNGAS. As it was discussed it is worthwhile to perform a preliminary technology screening for the acid gas removal before any process gets selected and compare the operating and capital cost.

There are some cases that the conventional scheme is not economical. RATE has patented a new scheme where it has significant saving over the conventional method by eliminating the acid gas removal, tail gas treating and possible tail gas incineration as well as large SYNGAS cooler which are very costly in most cases, an SO2 recovery is added instead to achieve near 100% recovery or zero emission.

As far as CO2 recovery, if it is required, in both conventional acid gas removal and new RATE innovation the CO2 can be removed by adding an additional absorber and using the same regeneration system.