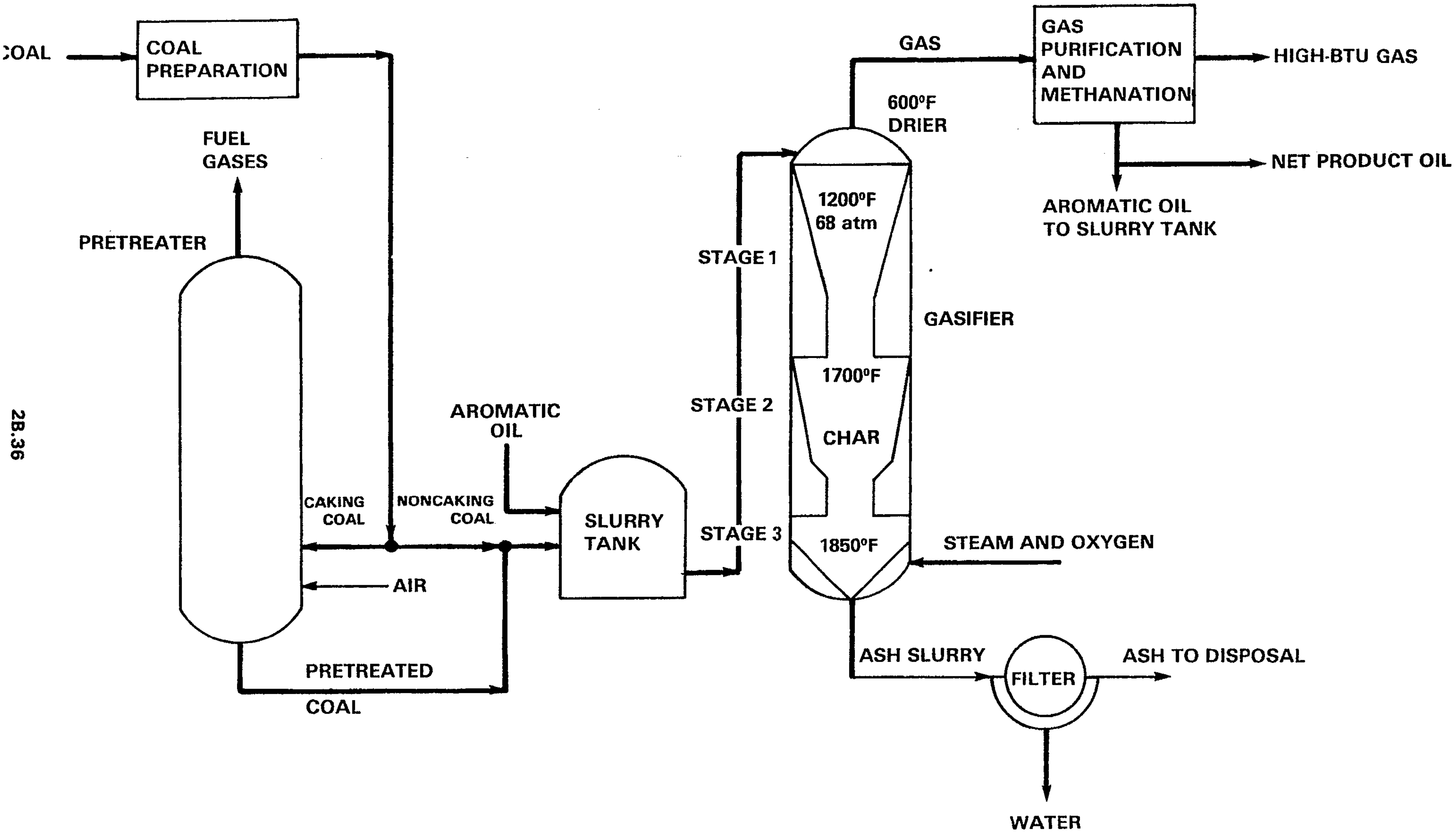
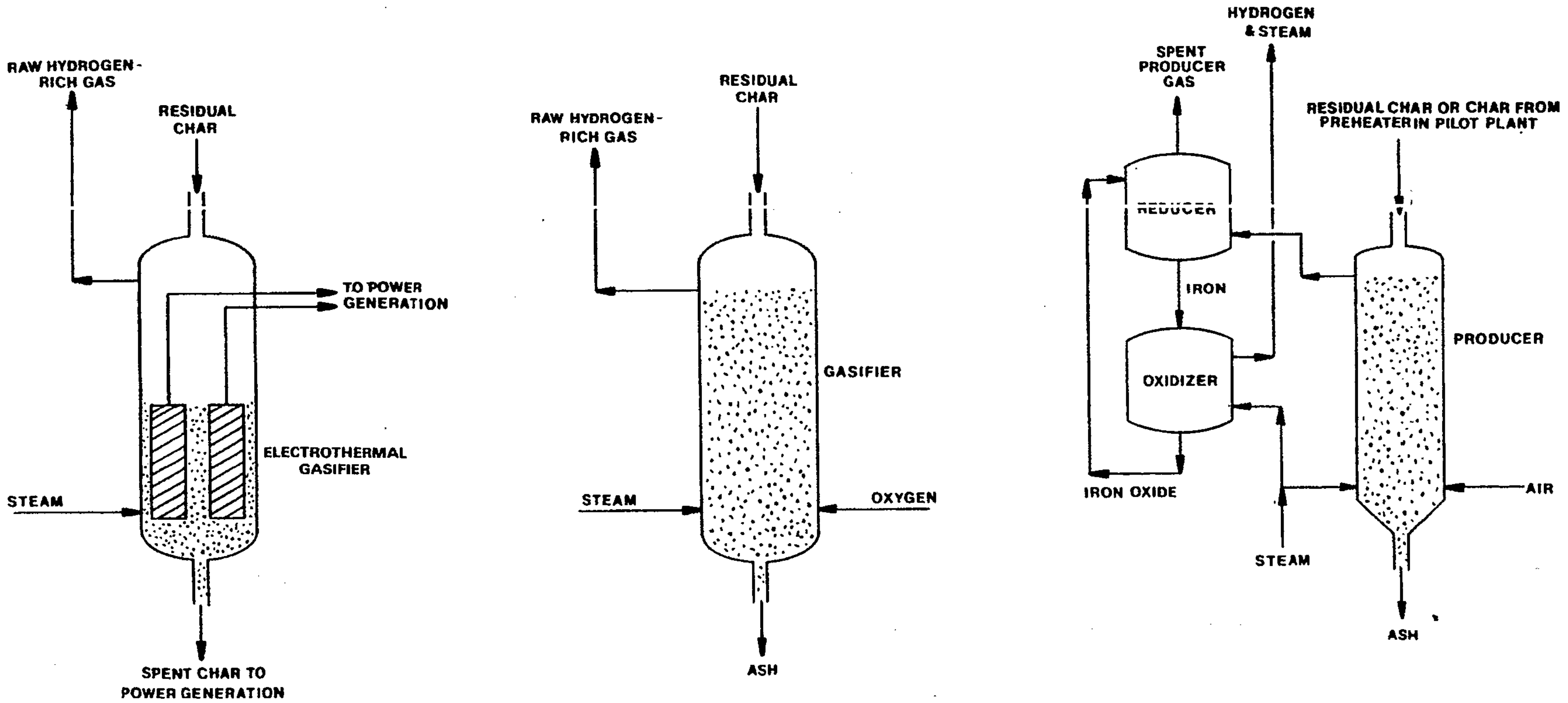


Figure 2B.9-2 Hygas Process.



ELECTROTHERMAL GASIFICATION
(DISCONTINUED IN 1974)

STEAM-OXYGEN GASIFICATION
(SELECTED)

STEAM IRON PROCESS
(DISCONTINUED IN1978)

Figure 2B.9-3 Hygas Systems For Hydrogen Production.

2B.10 SYNTHANE

Type

Fluid bed gasifier

Developer

U.S. Department of Energy
Pittsburgh Energy Technology Center
4800 Forbes Avenue
Pittsburgh, PA 15213

State of Development[1] [2] [3] pc

The concept of the Synthane gasifier was initiated in 1961 while experimenting with methods of pretreating caking coals in a fluidized bed reactor. It was observed that pretreatment of any caking coal was possible by the proper combination of oxygen content of the fluidizing gas, temperature, and residence time. Earlier gasification tests with a two fluid bed system led to the development of a single vessel construction wherein the operations of coal pretreatment, carbonization, and gasification were combined.

The first PDU scale Synthane gasifier, built at the Bureau of Mines Research Center at Bruceton, Pennsylvania, had 4 in I.D. and was 6 ft tall. It was operated at about 40 atmospheres (approx. 570 psig) and a maximum temperature of 1800°F. The gas produced had a 540 Btu/scf HHV after acid gas removal. The pretreating step operated satisfactorily to render caking coals noncaking. Among the coals tested were Pittsburgh seam coals with a Free Swelling Index (FSI) of 8 or 9 and Illinois #6 coal with a FSI of 3 to 5.

The next step in the development of the Synthane gasifier was to use the Hydrocarbon Research, Inc. (HRI) gasifier to simulate the Synthane gasifier. Tests were run on the unit during 1972-73, and results were satisfactory with regard to pretreatment and gasification.

A 72 tpd synthane pilot plant including raw processing facilities was constructed at Bruceton, PA. This plant, operated by the Lummus Co., could gasify any coal or lignite, using a pretreatment step to prevent caking of ash. Gasification started in 1976, and testing of Montana Rosebud (Western) coal at 600 psig was completed with sufficient data for scaleup to a large facility. Work continued on Illinois No. 6 coal using the pretreatment facility. The longest run was of approximately 11 days, made on Montana Rosebud subbituminous coal. Little work was done with the gas treatment facilities. The Synthane pilot plant was operated from 1976 to 1979. The project was terminated before all process problems were resolved.

Description[2]

The Synthane pilot plant was oriented toward manufacture of SNG instead of medium-Btu industrial gas, and therefore CO shift and methanation were also a part of the plant. The present description, however, is restricted mainly to manufacture of the medium-BTU gas.

The Synthane gasifier in the pilot plant is a vertical cylindrical fluid-bed reactor operating at elevated pressures and temperatures. The gasifier vessel is 101 ft high with an I.D. of 5 ft. (See Figure 2B.10-1.) Pretreated coal overflows from the pretreater into the gasifier through a nozzle on the side of the gasifier. It free falls some 20 ft in the gasifier and enters a fluidized bed maintained in the lower section of the gasifier. (A great deal of the operation was with "dip tube" feeding of the coal to the gasifier. This significantly reduced the production of tars and phenols and improved operability.) Steam and oxygen enter at the bottom through multiple orifices in a cone-shaped distributor. Approximately 65% of the carbon in the form of char is removed from the bottom. A fluidized bed type char cooler is made as an integral part of the gasifier. The entire gasifier vessel, except for the char cooler, is lined with 9 in of insulation. In the fluidized bed, provisions have been made to install baffles to maintain a temperature gradient of 1400° to 1800°F from top to bottom. Also, in the gasifier fluidized bed, provisions have been made to install Incolloy 800 shrouds of different diameters (33, 36, 39, and 42 in) to permit different ranges of fluidizing velocity.

The feed coal is dried, pulverized to 200 mesh, and transported to the pressurized feed hopper through a system of cyclones, bins, and lockhoppers. (See Figure 2B.10-2.) The coal is then entrained by high-pressure steam and a small amount of oxygen and fed into the pretreater. The pretreater is a fluid bed reactor maintained approximately at 1000 psig and 800°F. Steam and oxygen react with coal in the pretreater to nullify the caking tendencies of the coal. The pretreatment is required only for caking coals. Noncaking coals would by-pass the pretreater.

The coal from the pretreater overflows into the gasifier and is gasified in the fluidized bed with steam and oxygen. The gas produced passes up the gasifier through the free-fall zone, where it countercurrently contacts pretreated coal and devolatizes it. The gas is then passed through an internal cyclone to remove entrained particles larger than 50 microns. The particles removed return to the fluidized bed through a cyclone dipleg. The gas exits the gasifier and passes through a water-sprayed venturi scrubber. The gas, condensates, and particulate matter, such as carbon fines not removed in the cyclone, enter the scrubber surge tank, where separation of the gas and liquids takes place. The gas is then sent to a scrubbing tower. The tower contains a water wash section and an oil wash section for further cleanup.

The net condensates and carbon fines from the venturi scrubber and scrubbing tower collected in the scrubber surge tank are depressurized and sent to a decanter. In the Synthane pilot plant, the heavier-than-water tar is sent to the thermal oxidizer. The aqueous condensates will overflow from the decanter into the wastewater receiver, which also collects other process condensates. This process waste water, which contains oil, tar, and carbon fines, is also sent to the thermal oxidizer. Cooling of the recirculating liquid streams for the venturi scrubber and the gas scrubbing tower is accomplished by generation of low-pressure steam.[4]

The medium-Btu gas from the scrubbing tower is subsequently processed in a shift converter, acid gas absorber, and methanator to produce SNG with an HHV of approximately 950 Btu/scf, dry. In the pilot plant, the SNG is consumed in a high-pressure boiler.

Returning to the gasifier, the char formed in the gasifier passes down through the center of the cone-shaped distributor and into the char cooler attached to the gasifier. Spray water quenches the char here, and, as a result, high-pressure steam is produced This steam is filtered and used in the shift converter. The char is discharged via a slurry system. In a commercial plant, the char will be used to generate steam for the process. In the pilot plant, it is used as a landfill.

Feed Requirements

Pulverized coal through 200 mesh. The gasifier could handle all types of coal; caking coals require pretreatment.

The moisture content of the coal could limit operation by affecting pulverized coal flow. Coal moisture below about 14% was necessary for the coal to be free flowing. Subbituminous coal had been dried to about 7% moisture.

Operating Conditions

Temperature of coal entering the gasifier from pretreater = 800 °F
Gasifier temperature = 1500-1800 °F
Temperature of gas leaving the gasifier = 1100-1400 °F
Pressure = 1000 psig

Gas Produced

Typical gas composition (dry basis) after gas scrubbing and cooling

	O_2-Blown Operation	Air-Blown Operation[5]
Feed Coal	Illinois #6	Illinois #6
HHV of coal, Btu/lb, dry	11,695	11,695
Mole %, CO	13.2	10.1
CO_2	36.2	17.9
H_2	32.3	21.5
CH_4	15.0	5.6
C_2H_6	1.6	0.7
H_2S + COS	1.6	0.7
N_2 + Ar	0.1	43.5
HHV, Btu/scf, dry	355	165

By-Products

Tar, lb/ton of coal	94
NH_3, lb/ton of coal	16
BTX, lb/ton of coal	Not Available
Char, lb/ton of coal	600

These figures are based on Illinois #6 coal and 40 atm (570 psig) oxygen-blown operation.

Utility Requirements

O_2-Blown Operation

O_2, lb/lb of coal	0.35*
Steam, lb/lb of coal	1.25*
BFW, gal/ton of coal	Not Available
Electric Power, kWh/ton of coal	Not Available

* For caking coals. Non-caking coals consume less O_2 and steam.

Thermal Efficiency

Based on cooled and scrubbed product gas and O_2-blown operation
Cold Gas Efficiency = Not Available
Overall Thermal Efficiency = 65 to 70% for the complete plant producing SNG.

Capacity[3]

The gasifier in the Synthane pilot plant was designed to gasify approximately 72 tpd of coal at 1000 psig to produce 2 MM scfd of medium-Btu gas.

Turndown was not studied. However, the minimum gas flow required for fluidization (not determined) limited the operation.

Environmental Considerations

The char produced contained approximately 50-70% carbon. In a commercial plant, it could be used for steam generation.

The pressurizing gas used in the coal handling system was CO_2 delivered by truck. In a commercial unit, it may be obtained from the Stretford plant off-gas. The CO_2 from the Stretford would contain less than 5 ppm H_2S. Particulate matter would be removed before the lockhopper gas was vented to the atmosphere. The tar and aqueous condensates, from the gas cooling and scrubbing area could be sent to the thermal oxidizer in the pilot plant.

Remarks

The Synthane coal pretreatment and gasifier facilities portion of a 72 tpd pilot plant were operated and successfully evaluated Montana Rosebud (Western) coal processing characteristics. Illinois #6 coal was also tested. The project was terminated before all process problems were resolved. This process can produce medium- to high-Btu gas.

References

1. "Evaluation of Pollution Control in Fossil Fuel Conversion Processes, Gasification, Sec. I, Synthane Process," by Esso Research & Engineering Company, prepared for National Environmental Research Center, June, 1974.

2. Lewis, R. et al., "Update of Synthane Pilot Plant Status, October, 1977 to October 1978," presented at the 10th Synthetic Pipeline Gas Symposium, Chicago, Illinois, October, 1978.

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4. Torkos, T., and Lewis, R., "A Pictorial Tour of the Synthane Pilot Plant," U.S. Bureau of Mines Publication, Pittsburgh, Pennsylvania, January, 1974.

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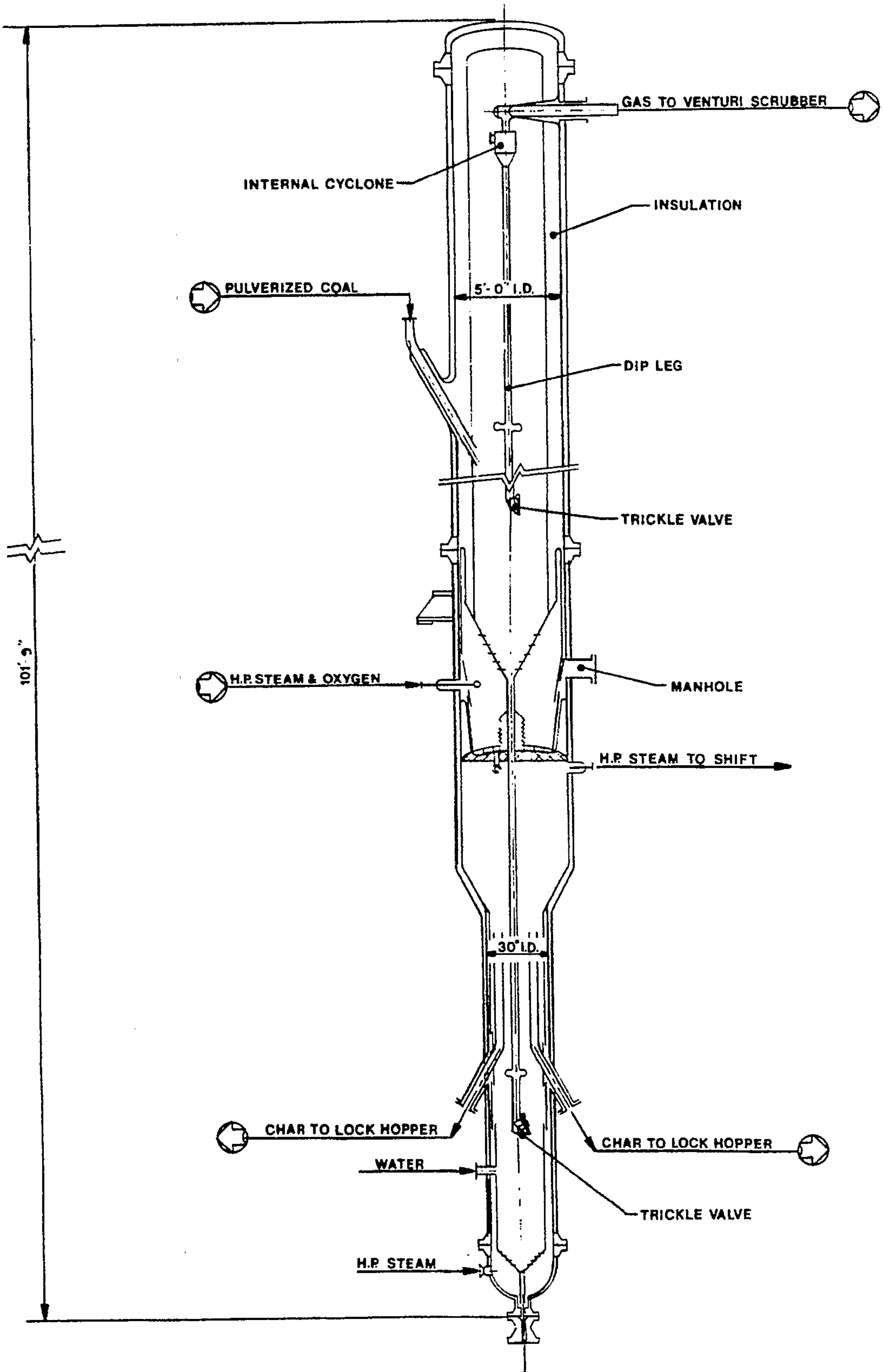

Figure 2B.10-1 Synthane Gasifier.

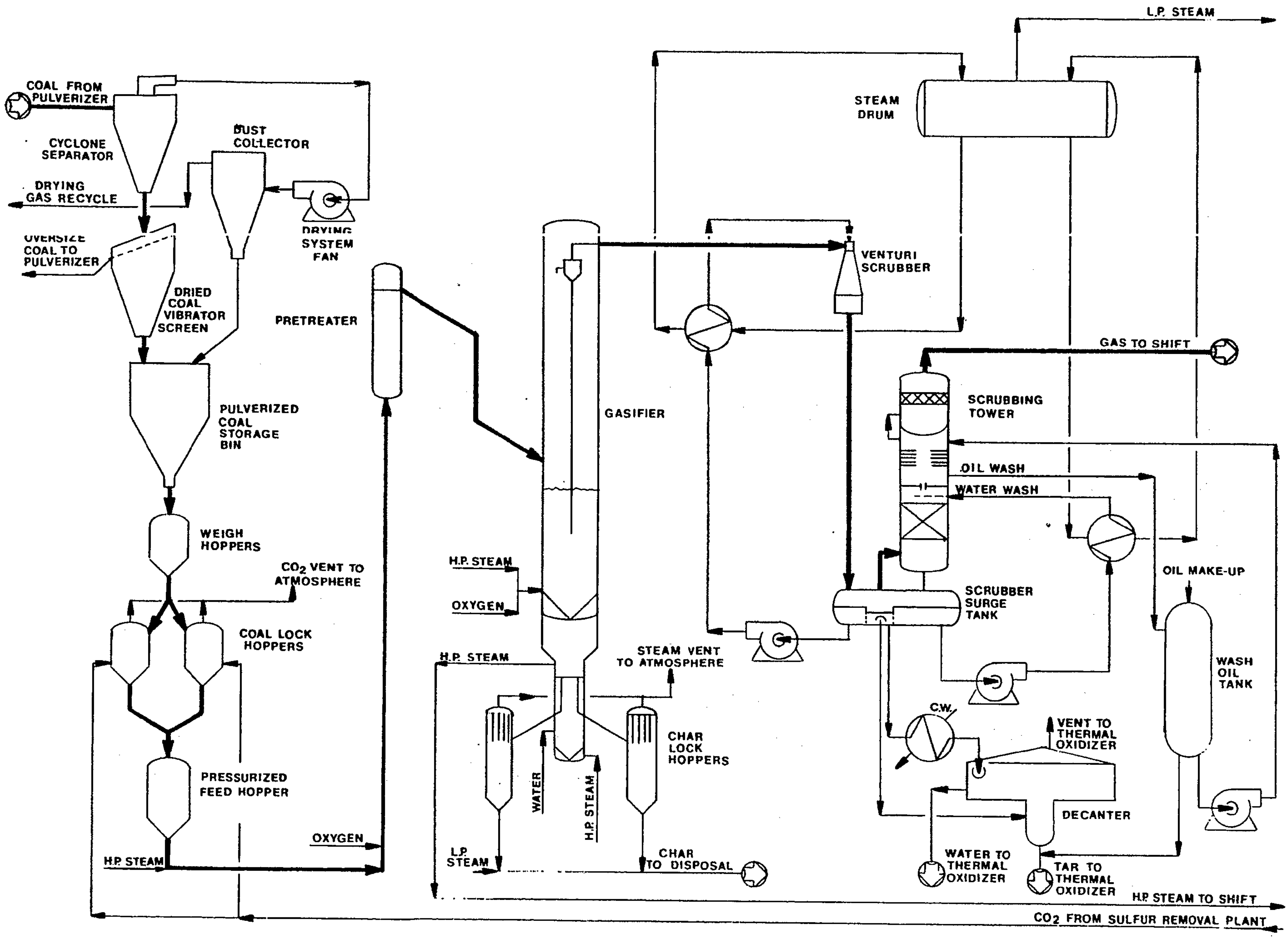

Figure 2B.10-2 Synthane Coal Gasification Process(Pilot Plant Set-Up).

2B.11 U-GAS

Type

Fluid bed, ash agglomerating gasifier

Developer

Institute of Gas Technology
13424 S. State Street
Chicago, IL 60616

State of Development[1,2]

This process is an outgrowth of studies begun in 1945, when the Institute of Gas Technology (IGT) constructed gasifiers to study the kinetics of carbon-oxygen-steam reactions at 2700 °F and at pressures from atmospheric to 750 psig. A 6-in-diameter fluidized bed reactor was built in 1947 to investigate the gasification of coal and coke fines. A pilot plant with a capacity of 18 tpd of coal that operated at 100 psig was then built in 1950.

During February 1974, a 4-ft-diameter, near atmospheric pressure gasifier operation was begun by IGT to process 6 tpd of metallurgical coke. The low-pressure gasifier was originally designed as part of the ERDA-AGA HYGAS program to test the concepts of elutriated fines return, carbon utilization, and ash agglomeration using metallurgical coke or char from the COED pilot plant as feedstock. Tests were performed in this U-Gas pilot plant during 1977 and January 1978 with air feed, using Illinois #6 caking coal and subbituminous coals. Since then, the pilot plant has been modified to perform tests for confirming the design basis of the Memphis Light, Gas, and Water Demonstration Pilot Plant for producing medium-Btu gas by using oxygen. During the 15 months following January 1978, 16 tests were conducted on Western Kentucky #9 coal.

The U-Gas process with four gasifiers (three operational, one stand-by) is being incorporated into the Memphis Light, Gas, and Water Division (MLGW) plant design, which is part of DOE's Industrial Fuel Gas Demonstration Plant Program. By 1980, the conceptual design (Phase I) was completed. During February 1980, the detailed design, procurement, and construction phase (Phase II) began. Demonstration plant operation (Phase III) is anticipated to commence during 1984. The MLGW plant is to produce 50 billion Btu/day of product gas at 270-300 Btu/scf. Forty-five billion Btu/day (approximately 135 MM scfd) are to be distributed by pipeline to commercial users, and 5 billion Btu/day (approximately 5.3 MM scfd) are to be further processed to pipeline quality (950 Btu/scf) and deposited in the Memphis natural gas distribution system.[3]

Description[1,4,5,6]

The U-Gas gasifier is a vertical cylindrical reactor with two external cyclones for returning the elutriated fines to the bed. A sloped grid at the bottom, containing an inverted cone, serves as the oxidant and steam distributor and the agglomerated ash outlet.

The U-Gas process is shown schematically in Figure 2B.11-1. Raw coal is crushed to 1/4" size. Bituminous coals, subbituminous coals, or lignite can be fed directly to the gasifier from the crusher.

Coal fed to the gasifier is gasified with a mixture of air or oxygen and steam in a single-stage fluidized bed. The residence time of the coal is about 45 minutes to an hour. Fluidizing velocity is on the order of 2.5 to 4.0 feet per second.

The key to operation of the gasifier is the agglomeration and separation of the low carbon content ash from the bed. This is accomplished, and a bed of approximately 70% carbon and 30% ash is maintained, by the grid and the fines return system in the bottom of the gasifier. The grid is sloped toward the inverted cone contained in the grid. Part of the fluidizing steam and oxidant flow through the grid, while the remaining fluidizing gas flows upward at high velocity through the throat at the cone apex. The ratio of steam to oxygen in the fluidizing gas fed to the cone is chosen so that the resulting submerged jet in the cone is hotter than its surroundings. The temperature of the jet is maintained near the softening point of the ash particles for the specific coal being gasified. The high ash-content particles preferentially stick together, and the agglomerates grow until they are heavy enough to move downward counter to the force of the gas stream in the apex of the cone and, thus, fall out of the fluidized bed.

Coal fines elutriated from the fluidized bed are collected by two external cyclones in series. Fines from the first cyclones are returned to the bed, and fines from the second cyclone are returned to the ash-agglomerating hot zone, where they are gasified, agglomerated with bed ash, and discharged with ash agglomerates. In the pilot plant, the first cyclone was internal to the gasifier, but in the MLGW demonstration plant design it has been placed external to the gasifier, thus minimizing the number of internal parts.

Feed Requirements[2]

All types of coals can be fed directly to the gasifier from the crusher. Coal is crushed to 0" x 1/4". The moisture content of coal is limited by free flowing characteristics.

Temperature in the ash agglomerating zone of the fluidized bed is influenced by the ash softening temperature and ash composition. It is controlled to maintain nonslagging conditions for the ash.

Operating Conditions[6]

Temperature in fluidized bed = 1750 to 1900 °F
Temperature of product leaving the gasifier = 1700 to 1850 °F
Pressure = 50 to 350 psig

Gas Produced[6]

Typical gas composition (dry basis) after waste-heat recovery

	Air-Blown Operation	Oxygen Blown Operation
Feed Coal	Illinois #6	Western Ky. #9
HHV of Coal, Btu/lb, dry	12,235	12,498
Mole%, CO	19.6	33.9
CO_2	9.9	20.4
H_2	17.5	41.8
CH_4	3.4	3.0
H_2S + COS	0.7	0.006
N_2 + Ar	48.9	0.9
HHV of gas, Btu/scf, dry	154	275

By-Products

Oils or tars are negligible. No provisions are included in the MLGW plant design for oil and tar. Ash is produced as ash agglomerates.

Utility Requirements[2]

	Air Blown Operation Illinois #6	Oxygen Blown Operation Western Ky. #9
Air, lb/lb of coal	2.8 to 3.3	3.4 (incl. oxygen plant)
Steam, lb/lb of coal	0.4 to 0.6	1.0
BFW, gal/ton of coal	710	451
Electric Power, kWh/ton of coal	44	15.8

Thermal Efficiency

Based on cooled and scrubbed product gas, and air-blown operation at 340 psig with Illinois #6 coal, the cold gas efficiency and the overall thermal efficiency are cited at 79%.6 One reactor is assumed to handle 3000 tons/day.

The overall MLGW Industrial Fuel Gas plant thermal efficiency is 74.8%.3 The coal gasification takes place at 75 psig and 1850 °F in three reactors.

Capacity[3]

The MLGW plant will have four (including one spare) reactors that are 13.5 ft in I.D. and 90 ft high (top to bottom cone). Each reactor will process 931 tons/ day of coal to produce 150 MM scfd of medium-Btu gas. Optimal operating pressure is indicated to be 262 psia for the medium-Btu gas.

Environmental Considerations

Fines elutriated from the bed are separated in the cyclones and returned to the gasifier. The ash produced in the gasifier contains up to 10% carbon and must be covered with dirt after landfill. At MLGW, the ash is inert and is expected to create little problems with dusting or leaching. Closed systems for coal handling and transport will keep particulate emissions to a minimum.

The MLGW plant will use approximately 2,000,000 gallons of water and discharge approximately 918,000 gallons of water each day. Liquid effluents will incur primary, secondary, and tertiary treatment. Final effluent of the MLGW plant will have no effect on the quality of the Mississippi River, into which it will be discharged.

Gaseous emissions will have no significant impact because high-efficiency gas cleanup systems are an integral part of the design of this type plant.

Remarks

The U-Gas process was originated for integration into combined-cycle power generation. It can be used to manufacture medium-Btu gas, low-Btu industrial fuel gas or synthesis gas.

References

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2. Patel, J. G., and Gray, R. W., "U-Gas Demonstration Plant Program," presented at International Gas Research Conference, Chicago, Illinois, June 9-12, 1980.

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5. Loeding, J. W., and Patel, J. G., "The U-Gas Process," Chemical Engineering Progress, 71 (4), April, 1975.

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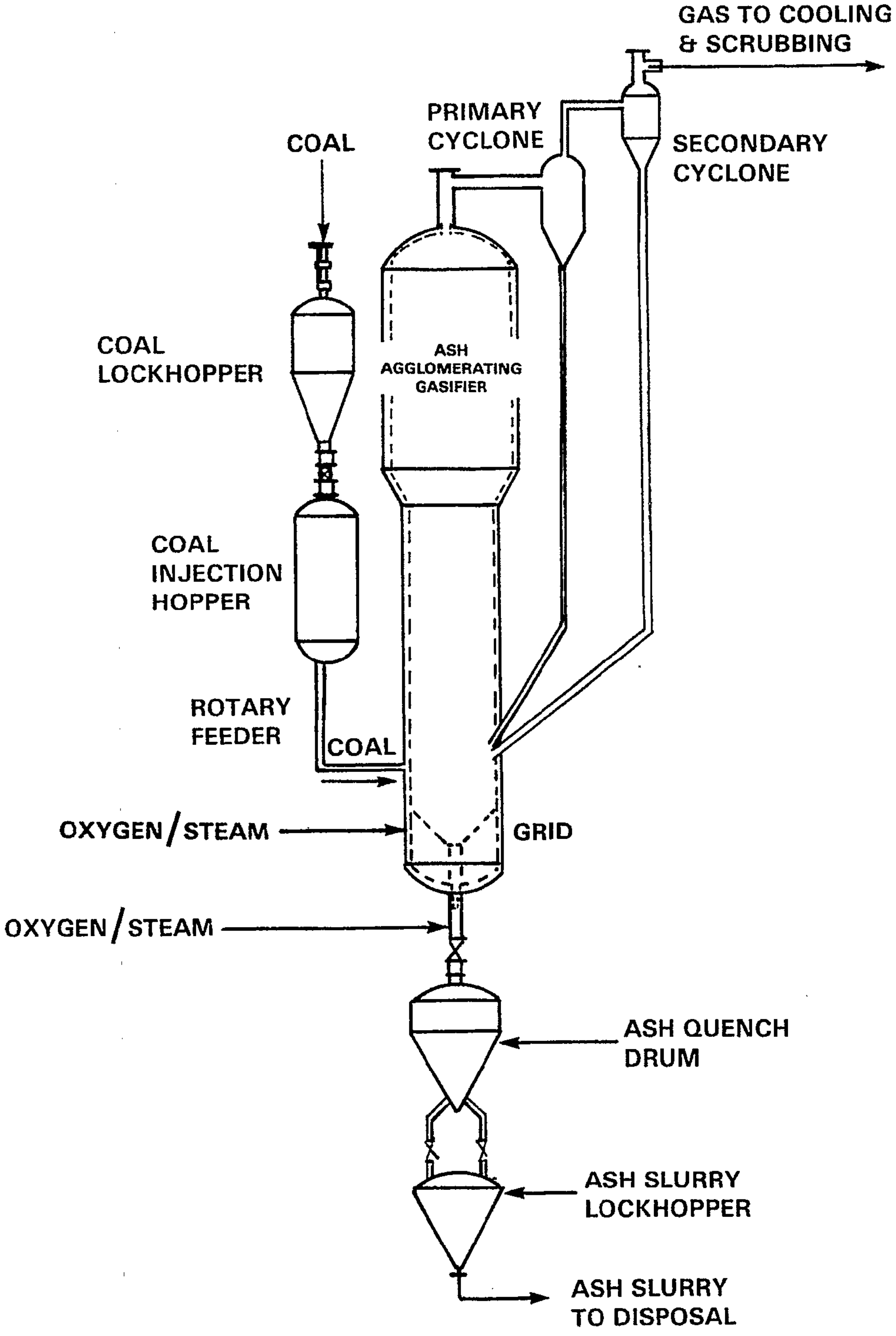

Figure 2B.11-1 U-Gas Gasification

2B.12 WESTINGHOUSE

Type

Fluidized bed gasifier

Developer

Westinghouse Electric Corporation
Synthetic Fuels Division
Madison, PA 15663

State of Development[1] pc

Development of the Westinghouse pressurized fluidized bed coal gasification process began in 1972 under the auspices of the Office of Coal Research. This developmental program is now under the sponsorship of the U.S. Department of Energy, and since 1978 has also been funded jointly by the Gas Research Institute.

During the first three years of the program, a 15 tpd process development unit (PDU) was designed and constructed, and in 1975 it commenced operation to evaluate the feasibility and operability of the Westinghouse fluidized bed coal gasification process. In the early years of the development program, the emphasis was directed primarily to a two-stage, air-blown system for direct integration with Westinghouse combined-cycle plants based on the W 501D combustion turbine.

In the next two years, from 1976 to 1978, the applications for the gasification process were expanded to include oxygen-blown experiments. To date, the single-stage fluidized bed process has been shown to be technically feasible in over 7000 hours of PDU operation at design conditions. This achievement resulted in a substantial simplification of the process and opened new areas of application.

Description[2]

The PDU process schematic is shown in Figure 2B.12-1. The conceptual commercial plant block diagram is shown in Figure 2B.12-2. Coal is dried, sized to 3/16" by 0", and fed pneumatically to the bottom of the gasifier through a lockhopper system, which provides feed control through rotary feeders.

Recycled product gas is used to transport the coal and char fines recycled from the collection cyclone downstream of the gasifier.

The fresh, unpretreated coal is fed to the gasifier along its center line, where it is combusted in a stream of oxygen (or air) fed through the central feed tube. Steam fed with the oxygen and in the grid cone of the gasifier reacts with the coal and char to form hydrogen and carbon monoxide. As the bed of char circulates through the jet, the carbon in the char is consumed by combustion and gasification, leaving particles that are rich in ash. The ash-rich particles extrude through the pores to the surface of the char, where they stick to other liquid droplets on adjacent particles. In this way, ash agglomerates are formed that are larger and denser than the particles of char in the bed. The agglomerates defluidize, migrate to the annulus around the feed tube, and are continuously removed by a rotary feeder to lockhoppers. Recycled product gas or steam is used to partially fluidize the ash and cool it as it is withdrawn.

The raw product gas, containing methane, hydrogen, carbon monoxide, carbon dioxide, and gaseous impurities exit the reactor at 1800 °F. A refractory-lined cyclone is used to remove char particles from the raw gas before it is quench-cooled in a quench scrubber that also removes most of the remaining particulate matter. The char fines collected in the cyclone are pneumatically transported to lockhoppers from which they are reinjected into the gasifier along with the fresh coal. All of the fines collected and recycled are consumed by the combustion, gasification, and agglomeration processes within the reactor.

Fuel Requirements

Coal is crushed to 3/16" x 0". The process accepts a variety of coals, including caking coals with high ash content and with no pretreatment except surface moisture removal to permit pneumatic conveying.

Operating Conditions[2]

Gasification temperature = 1900 °F
Raw gas temperature before quench = 1850 °F
Raw gas temperature after quench = 400 °F
Gasification pressure (PDU) = 130 - 230 psig
Gasification pressure (projected for large scale) = 220 to 600 psig depending on coal gas application: 220 psig for combustion turbine fuel gas, 340 psig for a methanol plant, and 600 psig for an SNG plant.

Gas Produced[2]

Typical single-stage oxygen-blown PDU results and projected commercial plant data

	PDU	COMMERCIAL
Feed Coal	Pittsburgh #8	Pittsburgh #8
HHV of coal, Btu/lb	12,400	12,400
Mole %, CO	49.05	51.14
CO_2	17.17	9.90
H_2	29.81	25.79
CH_4	3.16	10.22
N_2	0.30	0.44
H_2S	0.50	1.74
HHV, dry, Btu/scf	285	350

By-Products[2]

The projected data for oxygen-blown commercial SNG plant

Sulfur (lb/ton of coal) = 82.4
Ammonia (lb/ton of coal) = 25.0
Tars and oils = Minimal

Utility Requirements[2]

Utility requirements for an oxygen-blown single-stage PDU and projected commercial SNG plant (Pittsburgh coal)

	PDU	COMMERCIAL
Oxygen (lb/lb of MAF coal)	1.04	0.69
Steam (lb/lb of MAF coal)	0.55	0.38
Electric Power (kWh/ton of MAF coal)	Not Available	Not Available

Thermal Efficiency[2]

Overall efficiencies for entire projected commercial SNG plant (Pittsburgh coal)

Cold Gas Efficiency = 63.1%
Thermal Efficiency = 65.4%

Capacity[2]

The projected commercial SNG plant will have capacity of 662.8 tph of Eastern coal. It will contain three trains, each containing a 16-foot, 10-inch ID gasifier.

Environmental Considerations

A multi-stage system is used in the commercial SNG plant design to remove particulates from the hot product gases. The system may include cyclones and/or granular filter beds.

Remarks

The effect of pressure on gasification is currently being evaluated in the PDU by going from 130 psig to 230 psig.

References:

1. U.S. Department of Energy Quarterly Report on Coal Gasification, July 1980.
2. Salvador, L. A., et al., "The Westinghouse Coal Gasification Process," presented at First International Coal Research Conference, Chicago, Illinois, June 1980.

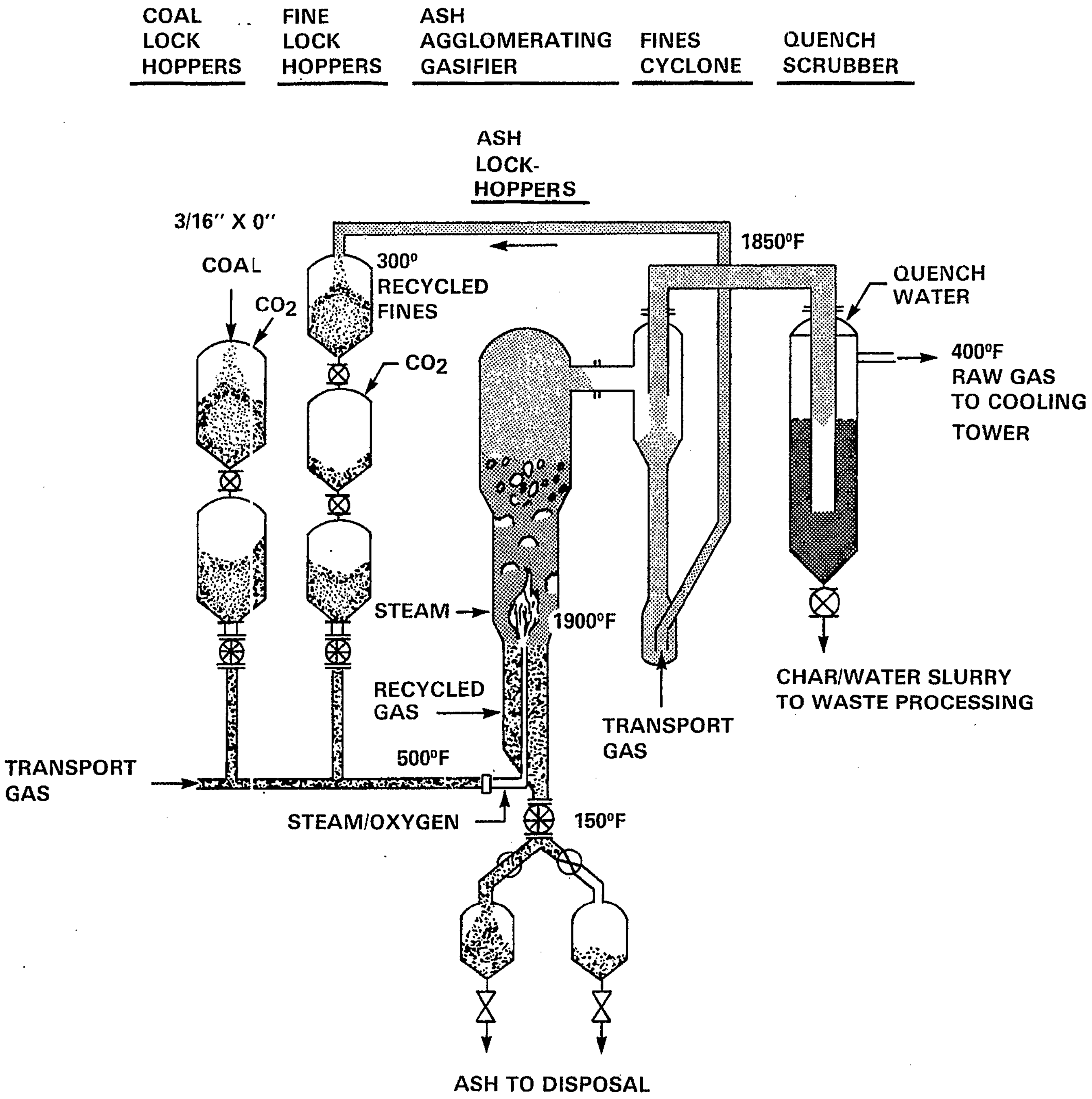

Figure 2B.12-1 Westinghouse PDU Process Schematic

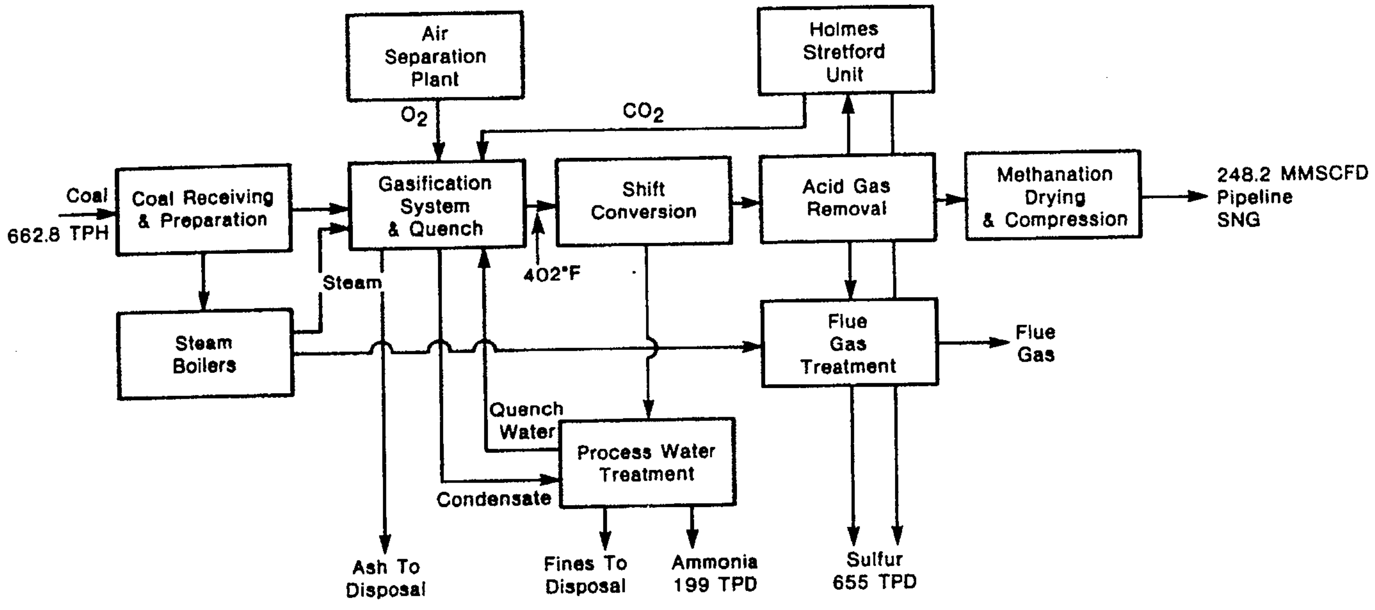

Figure 2B.12-2 Conceptual SNG Plant Design Using the Westinghouse Gasifier

2B.13 WINKLER

Type

Fluidized bed gasifier

Licensor

Davy McKee Corporation
6200 Oak Tree Blvd.
Cleveland, Ohio 44131

State of Development[1] [2]

The Winkler process is a commercially proven process for manufacturing synthetic gas from coal with low-to-medium Btu heating value. Initial development work was completed in the early 1920s. The first commercial plant was put into operation at Leuna, Germany, in 1926. Since then, 16 commercial plants have been installed in European and Asian countries.[1] The locations and capacities of these plants are listed in the Table 2B.13-1. In the plants installed, both air and oxygen have been used as the gasification medium.

American high volatile C bituminous (HVCB) coal from Illinois was tested in a commercial Winkler gasifier at Magdeburg, Germany in the late 1920s. Results indicated that the Winkler process could accept this type of U.S. soft coal. However, the process has not been demonstrated on U.S. HVAB coal.

In 1972, the Winkler gasifier was successfully operated at pressures up to 7 psig. Currently, the Davy McKee development program calls for testing U.S. coals in a 50 tpd pilot plant with operating pressure up to 150 psig.

Description[1] [3] [4]

The Winkler gasifier is a vertical cylindrical type with a steel shell lined on the inside with refractory. The coal feed inlet is located in the lower portion of the gasifier. (Figure 2B.13-1.) The steam and oxygen (or air) are charged through nozzles located at several levels in the fluid bed. The fluidized bed occupies only part of the gasifier volume; the remainder serves as a disengaging zone. Secondary steam and oxygen injection is provided above the bed level to gasify unconverted carbon leaving the bed.

Feed coal is crushed to 0 x 3/8" size and transported to the feed bunker. Variable-speed screws then feed the coal from the bunker into the gasifier (Figure 2B.13-2). The screw feeders control the coal feed rate and also serve as a seal to prevent steam in the gasifier from wetting the coal in the bunker.

Steam and oxygen (or air) are introduced into the gasifier to fluidize the bed of coal particles. The coal particles react with oxygen and steam in the bed to form H_2, CO, CO_2, and CH_4. Since the reactants are intimately mixed, uniform temperature is quickly reached between the solids and the gases, and coal gasification reactions approach equilibrium in a short time. The main reactions occurring in the reaction zone are combustion and water gas reactions, and since they occur at a relatively high temperature, the tars and heavy hydrocarbons are also gasified.

The residual ash particles are segregated in the fluidized bed according to size and specific gravity. The heavier particles drop through the fluidized bed and pass into the ash discharge unit at the bottom of the gasifier, while the lighter particles are carried up through the bed with the product gas.

Unconverted carbon carried over with the lighter ash particles is gasified with steam and oxygen (or air) in the space above the fluidized bed. Accurate control of steam and oxygen flow is necessary at this point to secure optimum process thermal efficiency. Underfiring causes an increase in unconverted carbon loss, while overfiring results in a loss of product gas.

Maximum temperature in the gasifier occurs in the space above the fluidized bed, and some of the ash particles melt. To prevent these molten particles from forming deposits in the exit duct, a portion of the waste heat in the gas is recovered in a radiant heat boiler installed inside the gasifier. As a result, the gas temperature is reduced by approximately 350° to 400°F, which is sufficient to resolidify the particles.

The ash particles and gas leaving the gasifier pass through a refractory-lined duct to the waste heat train. Here the gas is first cooled in a waste heat boiler, where high pressure superheated steam is generated. The gas then passes through an oxygen (or air) preheat section for further cooling and into a separator. A decrease in velocity of approximately 60% and a change in direction of flow causes 30-40% of the ash to separate at the bottom of the waste heat train. Cyclones following the waste heat train eliminate an additional 45-50% of the entrainment. The ash removed in the waste heat train and cyclones is then mixed with ash leaving the gasifier and is transferred to a bunker. The conveying medium can be either nitrogen in a pneumatic system or water in a slurry system; both have been used in the past. In most cases, ash from the waste heat boiler and cyclone can be used as boiler fuel.

Residual ash in the gas leaving the cyclones is separated in a direct contact wet scrubber and an electrostatic precipitator. (The scrubber-precipitator combination is now replaced with a high-efficiency venturi-type scrubber.) The solids contained in the scrubber bottoms are separated in a settler. The overflow water is recycled through a cooler and returned to the scrubber. If a pneumatic dry ash handling system is used, the slurry from the settler is mixed with the dry ash from the dry ash bunker, and the mixture is sent to disposal. The water in the slurry cools and wets the dry ash, and thus prevents dusting problems during ultimate disposal.

Feed Requirements[5]

Coal is crushed to 0 x 3/8" size. In Europe and Asia, the gasifier has been operated mainly with lignite and subbituminous type coals. It is expected that bituminous coals with free swelling indices less than 4 would be acceptable as feed coals; coals with free swelling indices higher than 4 may require pretreatment. The limit on moisture content is estimated at 25-30% for lignite and less for less reactive (higher grade) coals.

Operating Conditions[1]

Maximum temperature in fluidized bed:

For lignite = 1850 °F
For hard coals = 2000 °F
Temperature of gas leaving the gasifiers = approximately 350 °F lower than the maximum gasifier temperature
Pressure = atmospheric to 4 atmospheres

Gas Produced[1]

Typical gas composition (dry basis) after gas scrubbing, cooling, and acid gas removal

	O_2-Blown Operation	Air-Blown Operation
Feed Coal	Lignite	Western U.S. Subbitum. Coal
HHV of coal, Btu/lb, dry	10,200	10,300
Mole %, CO	48.2	22.0
CO_2	13.8	7.0
H_2	35.3	14.0
CH_4	1.8	1.0
N_2 + Ar	.9	56.0
HHV, Btu/scf, dry	288.0	126.0

By-Products

High pressure steam generated = 1650 lb/ton of coal.

Utility Requirements

Requirements for oxygen-blown operation

O_2 (98%), lb/lb of coal	0.5
Steam, lb/lb of coal	0.2 to 0.3
BFW, gal/ton of coal	198
Electric Power, kWh/ton of coal (includes cooling and scrubbing)	12

Thermal Efficiency

Based on cool and scrubbed product gas, and Illinois #6 coal

Cold Gas Efficiency = 72%
Overall Thermal Efficiency = 69%

Capacity

A typical commercial Winkler gasifier with an 18-ft I.D. and 75 ft tall can gasify approximately 1100 tpd of coal at atmospheric pressure and 1800 tpd of coal at 4 atmospheres.

Turndown will be limited by the minimum gas flow required for fluidization. Expected turndown ratio = 4:1.

Environmental Considerations

The ash made is wetted sufficiently in the ash handling scheme to prevent dusting problems during disposal. It is estimated that the ash would contain approximately 15-30% unconverted carbon.

Remarks

The radiant waste heat boiler installed inside the gasifier is a relatively new development. It permits higher reaction temperatures in the gasifier so that higher ash carbon conversion and thermal efficiency may be obtained.

References

1. Banchik, I. N., "Power Gas from Coal Via the Winkler Process," presented at the Symposium on Coal Gasification, Liquefaction, and Conversion to Electricity, Pittsburgh, Pennsylvania, August 1974.
2. Odell, W., "Gasification of Solid Fuels in Germany by the Lurgi, Winkler, and Leuna Slagging-Type Gas-Producer Processes," Bureau of Mines Information Circular 7415, November 1947.
3. "Power Gas from Coal via the Winkler Process," Publication by Davy Powergas, Inc., 1974.
4. Grimm, H.G., "The Gasification of Fine Grained Coals in the Winkler Gas Producer," presented at the Third International Conference on Bituminous Coal, Carnegie Institute of Technology, Pittsburgh, Pennslyvania, Proceedings Volume I, 1931, pp. 874-892.
5. Banchik, I. N., Davy Powergas, Inc., "The Winkler Process for the Production of Low-Btu Gas from Coal," 1974.

Table 2B.13-1 DAVY McKEE WINKLER COAL AND COKE FLUID BED GASIFICATION PLANTS

PLANT NO.	PLANT	PRODUCT	CAPACITY PER GASIFIER 1000 SCFH	NUMBER GASIFIERS	OPERATING DATES
1	BASF, Ludwigshaven W. Germany	Pilot Plant	75	1	1925-58
2	Leuna-Werke, Merseburg	Fuel Gas and Synthesis Gas for MeOH and NH_3	3,730 1,870	4 1	1926-70
3	BRABAG, Bohlen, E. Germany	Hydrogen	1,120	3	1938-Present
4	BRABAG, Magdeburg, E. Germany	Hydrogen	1,230	3	1938-45
5	Yahagi, Japan	Ammonia	330	1	1937-60
6	Dai-Nihonyinzo-Hiryo, Japan	Ammonia	520	2	1937-59
7	Nippon Tar, Japan	Ammonia	520	2	1937-60
8	Toyo Koatsu, Japan	Ammonia	750	2	1938-69
9	*Fushum, Mandschukko Japan	Syn. Gas for F.T. Fuel	750	4	1939-?
10	BRABAG, Zeit East Germany	Hydrogen	840	3	1941-Present
11	Treibstoffwerke, Brux (now Most), Czechoslavakia	Hydrogen	1,120 *1,200	5 2	1943-73 1954-73
12	**Salawad, USSR	Medium Btu Gas	860	7	?-Present
13	**Baschkirien, USSR	Medium Btu Gas	860	4	?-Present
14	**Dimitroffgrad, Bulgaria	Medium Btu Gas	670	4	1951-Present
15	**Stara Zagora, Bulgaria	Medium Btu Gas	1,120	5	1962-Present
16	Fabrika Azotnih, Jendinjenja, Gorazce, Yugoslavia	Ammonia	260	1	1952-Present
17	Calvo Sotelo I, Puertollano, Spain	Ammonia	350	1	1956-70
18	Calvo Sotelo II	Ammonia	350	1	1950-70
19	UKW, Wesseling I, W. Germany	Synthesis Gas for MeOH and NH_3	630	1	1958-67
20	UKW, Wesseling II, W. Germany	Synthesis Gas for MeOH and NH_3	630	1	1962-67
21	Azot Sanayii TAS, Kytahya, Turkey	Ammonia	450	2	1959-Present
22	Neyveli Lignite Corp. India	Ammonia	745	3	1961-78
	Total (Including Pilot Plants)			63	
	THOSE IN OPERATION AT PRESENT			29	

*Replica Winkler plants built by others

**Plants in the Soviet Bloc which were built as replicas of existing plants

As of September, 1980

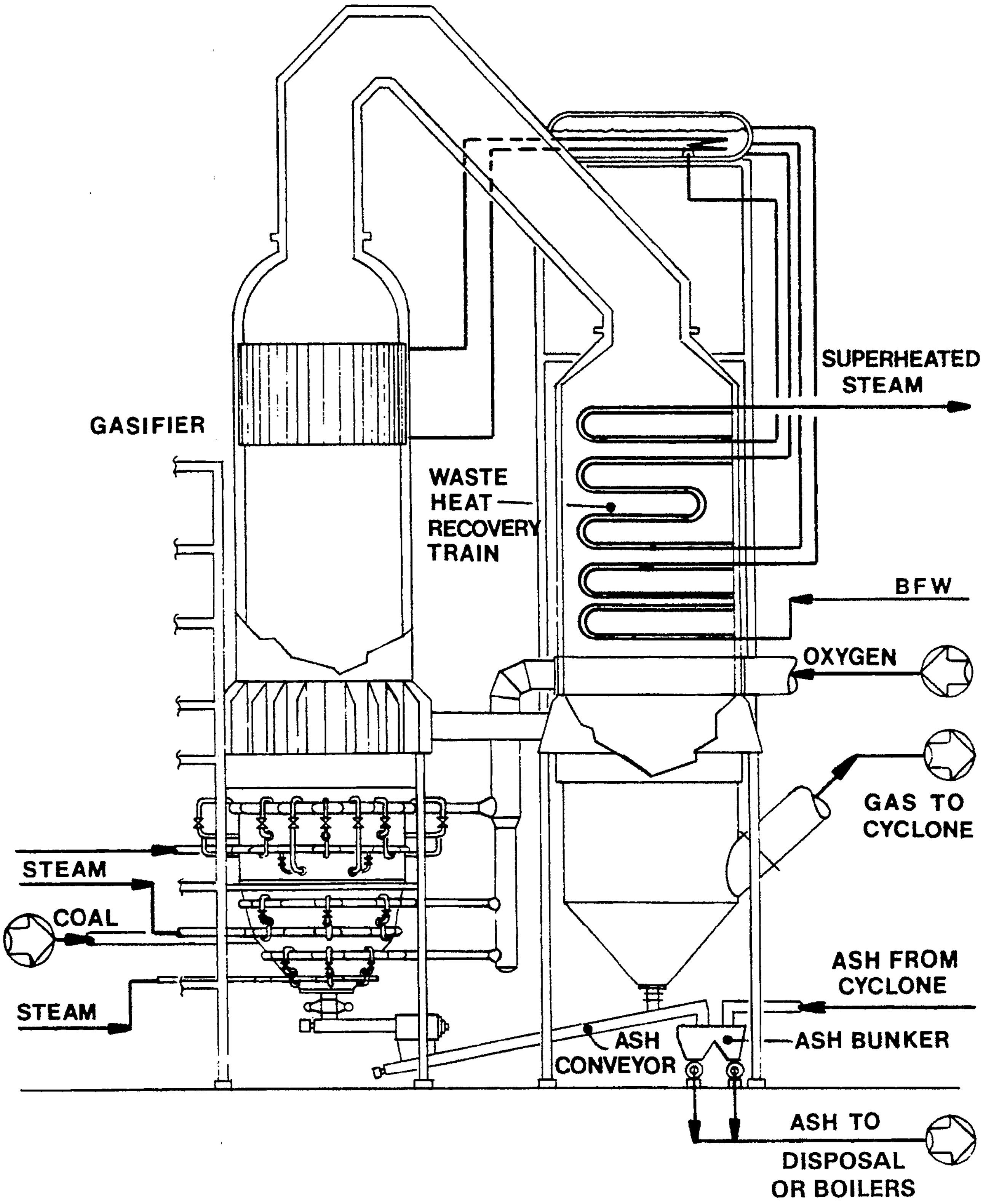

Figure 2B.13-1 Winkler Gasifier.

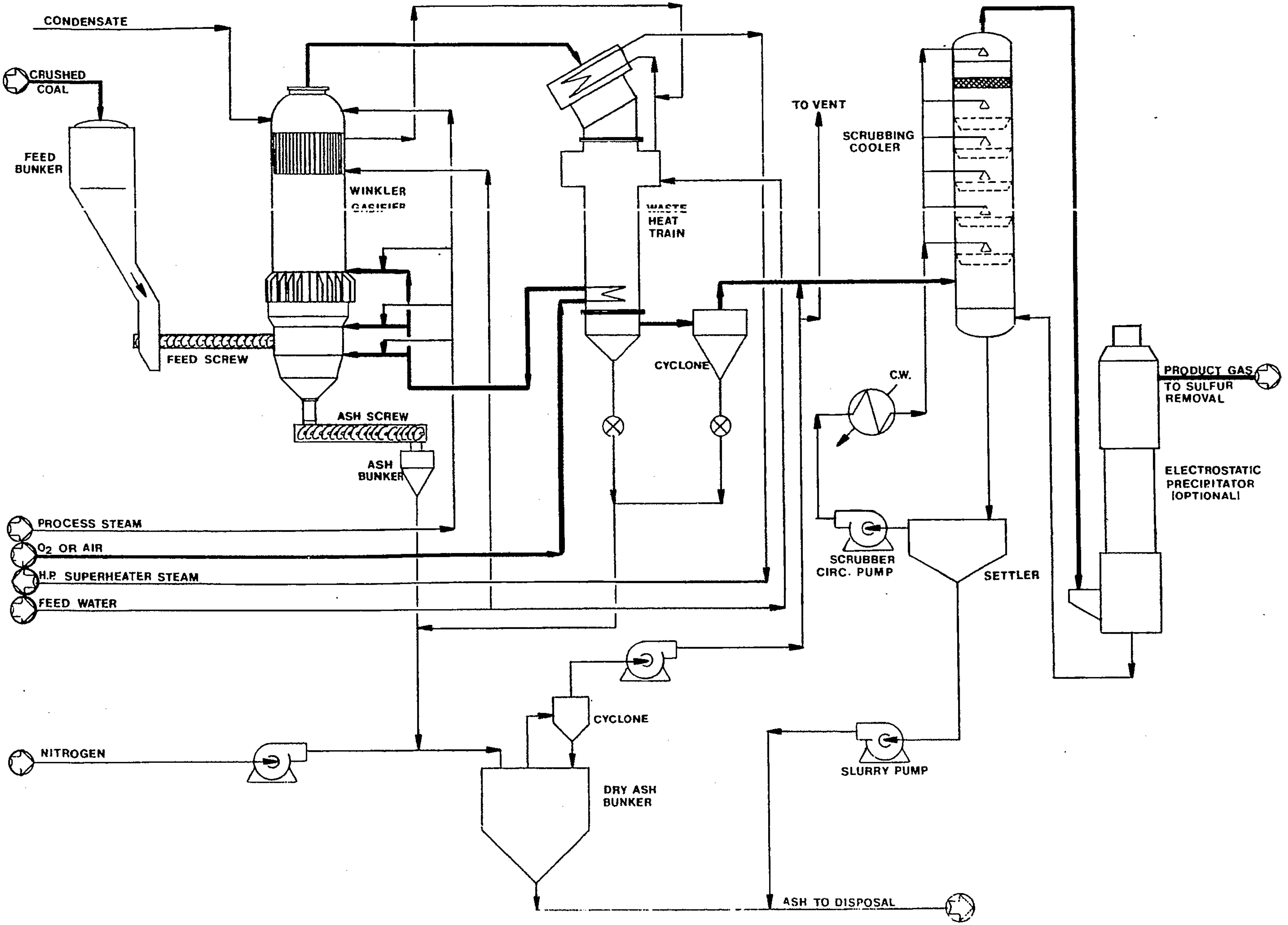

Figure 2B.13-2 Winkler Coal Gasification Process

2C.1 BELL AEROSPACE HIGH MASS FLUX GASIFIER

Type

Entrained flow slagging gasifier

Developer

Bell Aerospace Textron
P.O. Box 1
Buffalo, NY 14240

State of Development[1] [2]

In January 1976, the Energy Research and Development Administration (now the Department of Energy) awarded a contract to Bell Aerospace Textron to investigate the feasibility of using an entrained flow slagging gasifier, operating at very high mass throughputs, to convert coal into gas using air or oxygen as the gasifying medium. A program was initiated in October 1979, under joint sponsorship of the Department of Energy and the Gas Research Institute, to develop the process for the production of synthesis gas using oxygen as the principal gasifying medium in a 0.5 tph PDU. A feature of this specific application of the Bell High Mass Flux (HMF) gasifier is the addition of secondary coal injection to produce a methane rich gas. PDU buildup was funded by DOE and GRI. Gasifier testing has been funded by Bell.

To date (March 1981), a total of 86 air and oxygen blown gasification tests have been conducted, using 3 types of coal. For all tests, including 17 tests of between 30 and 60 minutes duration, the operation of the reactor was reported smooth and stable, with no reactor malfunctions. Twenty-four oxygen-blown tests (without secondary coal) were conducted with Pittsburgh #8 bituminous coal. Carbon conversion efficiencies in the 85%-90% range and nitrogen and moisture free heating values in the 290 Btu/scf range were obtained. Two tests conducted with North Dakota lignite yielded 95% carbon conversion efficiency and higher heating values of 295 Btu/scf. During the oxygen-blown program, the effects of reactor variables upon performance and operation were evaluated.

Description[1]

The High Mass Flux gasifier (HMF) may be classified as a pressurized, entrained flow, slagging gasifier. It shares the advantages commonly ascribed to other entrained flow gasifiers in its class - simplicity, no moving parts, rapid dynamic response, and ability to handle a wide range of coals.

The features of the High Mass Flux gasifier are its small size, high mass throughput per unit of reactor volume, and short reactant residence time. The high mass throughput and short superficial residence time are achieved by the use of injectors designed to promote intense mixing and uniform particle distribution over the reactor cross section. The intense mixing results in high particle heating rates, promotes coal devolatilization, and creates short-lived active sites on small carbon crystallites that greatly accelerate heterogeneous surface reactions and the overall gasification process. Much of the technology for the injector designs was derived during Bell's 30 years experience as a developer of rocket engines. Of particular value was work performed during the development of a rocket engine that operated on fluidized powder propellants. The test gasification facility is shown in Figure 2C.1-1, and details of the gasifier are shown in Figure 2C.1-2.

In the synthesis gas mode (Zone A/Zone B only) the gasifier output has a broad range of applicability, such as fuel gas, feedstock for methanol and chemicals combined cycle power generation, etc. When secondary coal is added, the primary application is the production of methane-rich feedstock for producing SNG. This latter process is carried out in a single downward-flowing reactor operating at pressures of up to 50 atmospheres and may be considered as taking place sequentially in four reaction zones, as shown in Figure 2C.1-2. Separation of the zones is a consequence of the location of the reactor injector elements and their resulting mixing patterns.

Into Zone A (the upper reaction zone), dry pulverized coal (70% - 200 mesh) and gaseous oxygen are injected. A fast, highly exotheric reaction results, producing CO and CO_2 at a combustion temperature of approximately 3000 °F. In addition, rapid devolatilization of the coal particles and the formation of carbon char with chemically active sites also takes place.

At the entrance of Zone B, steam is injected into the Zone A reaction products, and endothermic gasification reactions occur between the active char, steam, and carbon dioxide to produce a synthesis gas rich in hydrogen and carbon monoxide.

Secondary coal is then injected into the hot synthesis gas at the entrance to Zone C. The secondary coal is uniformly mixed with the gas and is rapidly heated and devolatilized to produce a chemically active char that reacts with the gases from Zone B. Methane is produced during the devolatilization process. In addition, methane is also formed in a kinetically controlled nonequilibrium reaction between hydrogen in the gas and the active sites of the char particles.

To minimize decomposition of the methane produced in Zone C, water is injected into the gas stream at the entrance to the water quench zone (the fourth zone), reducing the gas temperature rapidly. The injected quench water both freezes the methane decomposition reactions and provides the steam required for shift conversion of the hydrogen and carbon monoxide to methane. It should be noted that the use of dry feed results in low oxygen and steam consumption. Only sufficient steam is used to complete the Zone B reaction.

Feed Requirements[1]

All types of coal dried and pulverized to 70% minus 200 mesh size can be gasified.

Operating Conditions

Temperature in Zone A = 3000 °F
Temperature in water quench zone = 500 °F
Maximum operating pressure = 735 psig

Gas Produced[pc]

Typical gas composition from Zone B with oxygen gasification projected for Illinois #6 coal

HHV of Coal, Btu/lb		12771
Mole, %	CO	56.8
	CO_2	4.3
	H_2	30.1
	$CH_4 + C_nH_m$	0.1
	N_2	0.6
	H_2O	6.9
	H_2S	1.2
HHV, Btu/scf (dry, H_2S free)		306.5

By-Products

The raw gas is free of tars, phenols, or heavy hydrocarbons.[pc] The byproducts are slag containing char, and sulfur in the case of high sulfur coal. The project is in the preliminary phase, and data on byproducts are not available.

Utility Requirements[1]

Typical utility requirements for oxygen gasification of Illinois #6 coal

Oxygen, lb/lb of coal	0.722
Steam, lb/lb of coal	0.2

Thermal Efficiency

Gasifier cold gas efficiency is projected to be about 81%. This becomes 74% if a methanator is added for SNG production.

Capacity

The HMF gasifier used during initial gasification tests has a 5-in internal diameter and is 42-in long. The internal diameter of the current PDU reactor remains the same. Reactor modules are 3 ft in length and can be configured to produce a gasifier between 3 ft and 12 ft in length.

Environmental Considerations

The project is still in the small scale developmental stage, and the environmental impact of the effluents is not representative of that of the effluents from a large plant.

Remarks

The HMF gasifier has potential advantages of reduced gasifier size and of promoting methane formation, which is important for SNG production. Features of the PDU are advanced instrumentation, data acquisition, and data analysis capabilities together with an on-line mass spectrometer. The PDU utilizes a programmable logic control system with integrated high response safety monitoring systems.

References

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2. Simpkin, A. J., "High Mass Flux Gasifier," presented at Fifth Annual International Conference on Commercialization of Coal Gasification, Liquefaction and Conversion to Electricity, Pittsburgh, Pennsylvania, August 1-3, 1978.

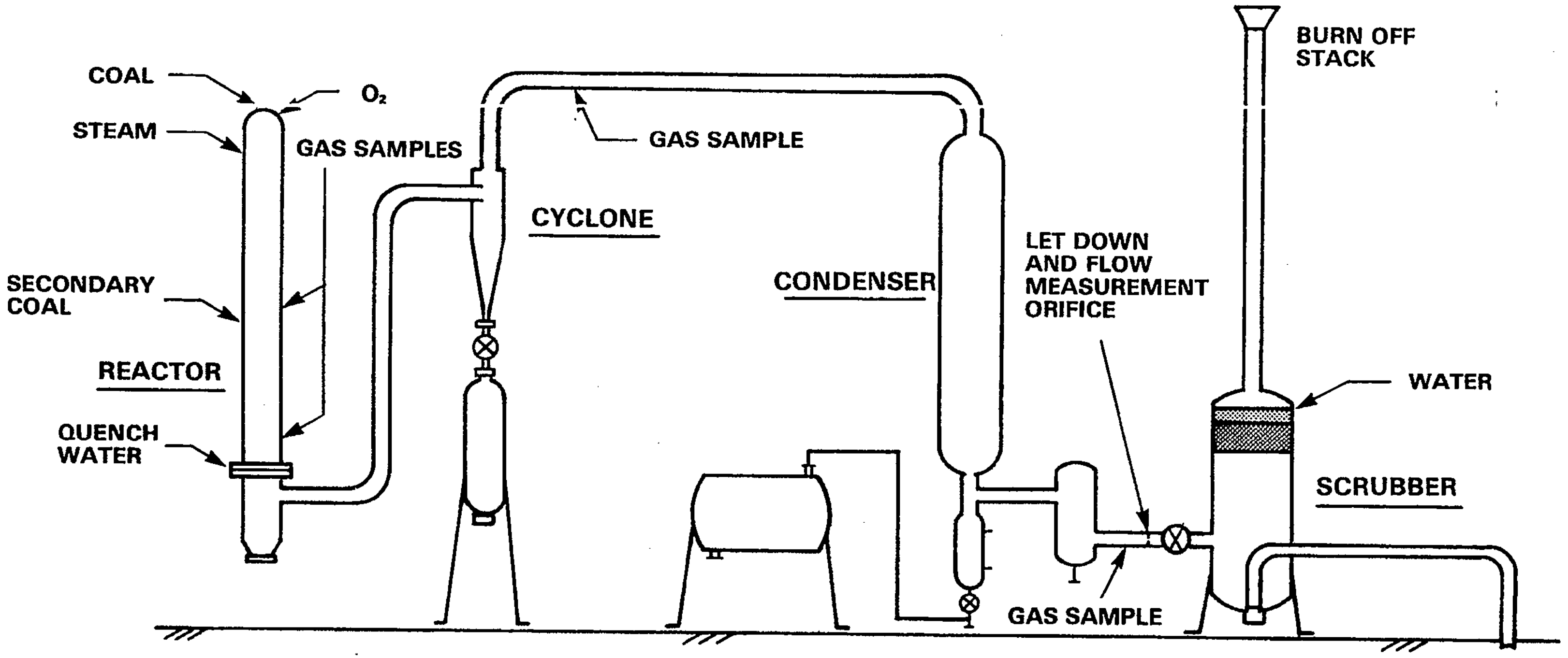

Figure 2C.1-1 High Mass Flux Gasification Experimental Unit.

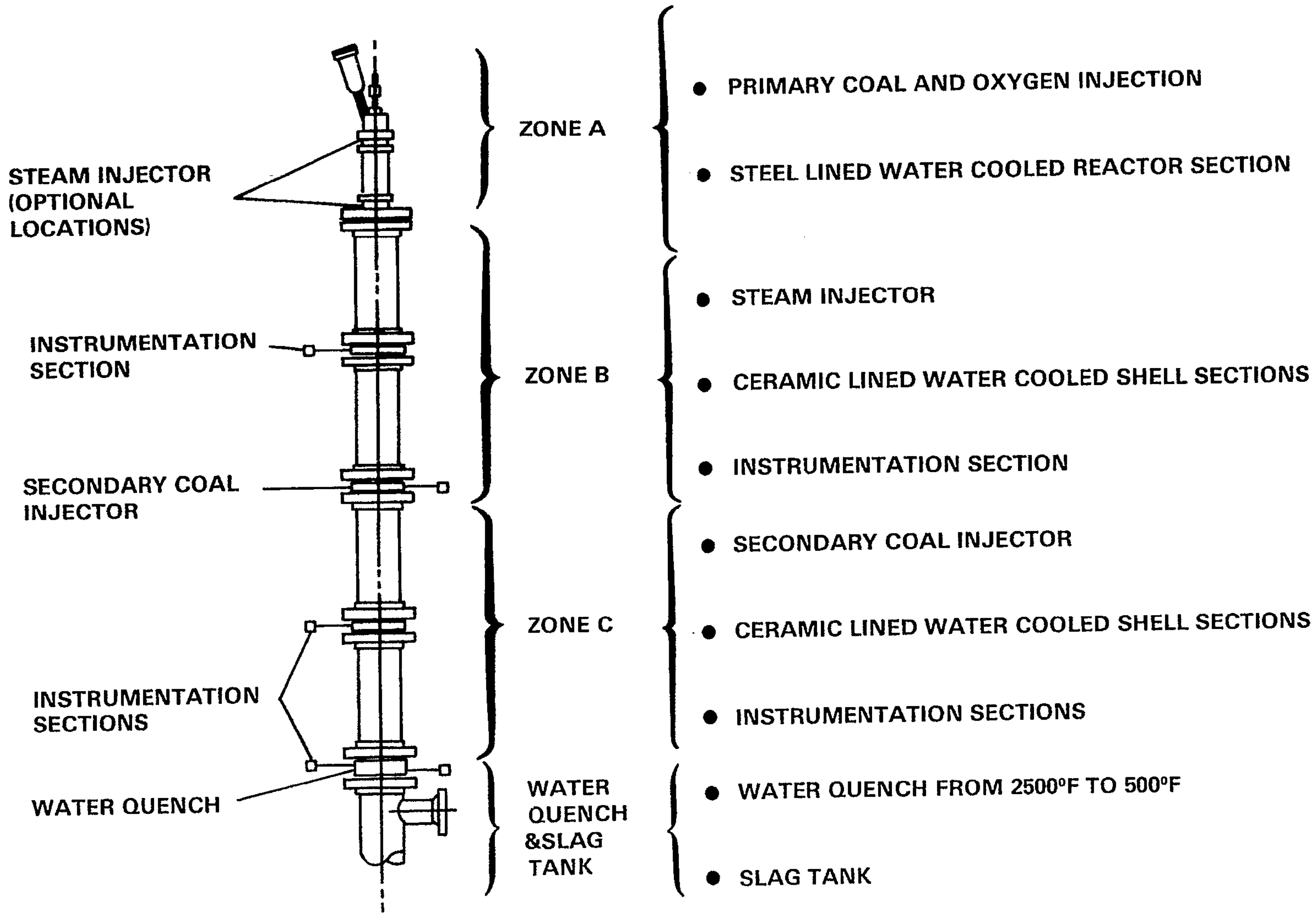

Figure 2C.1-2 High Mass Flux Experimental Gasifier.

2C.2 BI-GAS

Type

Entrained flow slagging gas fier

Developer

Bituminous Coal Research, nc.
350 Hochberg Road
Monroeville, PA 15416

State of Development[1] [pc]

A 120 tpd Bi-Gas pilot plant has been in operation since 1976. This process is being developed to produce high-Btu gas.

Initial process development work started in 1965 and has proceeded from batch-type experiments in rocking autoclaves through continuous flow experiments in a 5 pound per hour externally heated gasifier and through operation of a 100 pound per hour PDU. The results of these experiments and PDU operation were used to design the fully integrated 120 tpd pilot plant at Homer City, Pennsylvania. Since the beginning of operations, the major developmental effort has been on the coal slurry feed system and the gasifier. The shift reactor and methanation system have not yet been activated. Subbituminous coal has been gasified at elevated pressures and temperatures.

Description[2 3 4]

The Bi-Gas gasifier is shown in Figure 2C.2-1. The gasifier consists of three elements in a single vessel: slag quench zone in the bottom; Stage I, where the char burners are located; and Stage II, where the coal feed is injected.

The walls of Stage I are made of vertical, closely spaced, water-cooled tubes covered with dense refractory. The tubes are bent inward and form a throat that aids in separation of the molten slag formed in Stage I. The throat also produces a high enough gas velocity to prevent unreacted coal or char from dropping from Stage II into Stage I. The walls of Stage II consist of an inner layer of precast dense refractory and an outer layer of lightweight insulating refractory to minimize heat losses. Just inside the outer pressure shell is a row of vertical wall tubes. Water is circulated through these tubes by external pumps to maintain the temperature of the outer shell at a level low enough to minimize H_2S corrosion, hydrogen damage, and hot spots.

The Bi-Gas pilot plant uses a high-pressure slurry feed system to feed pulverized coal to the gasifier. Feed coal is slurried and pulverized in water at a 25-35 wt% concentration. It is then centrifuged, repulped, and, if required, mixed with a flux to provide the desired feed concentration. A reciprocating type high-pressure pump picks up the slurry and pumps it through a preheater to a spray dryer. (See Figure 2C.2-2.) Here it is contacted with hot recycle gas, and the coal is separated in a cyclone. Recycle gas is washed and cooled to condense the steam, then recompressed and reheated before it returns to the spray dryer. The coal, now at a higher pressure than the gasifier operating pressure, flows by gravity into two coal eductors.

Recycle conveying gas transfers coal from the eductors into the two coal injection nozzles of the gasifier. (See Figure 2C.2-3.) Steam is also introduced into the nozzles through a separate annulus. The two streams combine at the tip of the nozzle and join the rising hot gas from Stage I, converting the coal to synthesis gas, methane, and char. Gas and char leaving the gasifier are quenched by atomized water and fed to a cyclone separator. Raw gas leaves the cyclone separator for further processing, and the char is recycled to the gasifier.

Steam is used to transport char to the three char burners in Stage I. Here recycled char is partially oxidized with preheated oxygen and steam to produce a hot gas, which enters Stage II to gasify and entrain the incoming coal. The char burners are arranged to fire cyclonically, causing a swirling motion that promotes slag separation as well as gasification. Molten slag, separated in this manner, flows down the Stage I walls into the quench zone.

The slag quench zone, located at the bottom of the gasifier, contains cooled recirculating water. As the molten slag from Stage I falls into the water, it is shattered to a granular form. Granular slag settles to the bottom of the zone, and there high-pressure water jets agitate and move it to the outlet nozzles. The slag is then sent to one of the two slag lockhoppers prior to disposal.

Raw gas and uncollected char from the outlet of the cyclone separator enter the raw gas scrubber and pass upward through a curtain of downward flowing water. The water scrubs the char dust, cools the gas, and condenses the moisture. Water is circulated by reflux pumps, and heat is recovered with an air cooler. A slip stream of the water is let down in pressure to an atmospheric, vent gas washer. Here the dissolved gases are released and vented to a thermal oxidizer, and the slurry is drained to a waste pond.

The char-free cooled gas leaving the raw gas washer is the medium-Btu product gas. If air is used in lieu of oxygen in the gasifier char burners, a low-Btu gas is produced that is further processed for CO-shift, acid gas removal, methanation, etc., to yield SNG.

Feed Requirements[3]

Coal is pulverized to 5% + 10 mesh size. Pulverized coal is slurried with water to pump it through the high-pressure slurry feed system. Thus, feed coal of virtually any moisture content can be handled.

Operating Conditions[4]

Temperature in Stage I = 2700 to 3000 °F
Mixing temperature in Stage II = 2200 °F (estimated)
Temperature of gas leaving Stage II = 1500 to 1700 °F
Pressure = 750 to 1500 psig

Gas Produced[4]

Typical gas composition (dry basis) after gas scrubbing and cooling, oxygen-blown operation

Feed Coal	Pittsburgh seam coal
HHV of coal, Btu/lb, dry	14,090
Mole%, CO	29.3
CO_2	21.5
H_2	32.0
CH_4	15.7
H_2S + COS	0.8
N_2 + Ar	0.7
HHV, Btu/scf, dry	356

By-Products

Oils or tars are negligible.

Utility Requirements

Basis: West Kentucky Coal - 13,460 Ztu/lb HHV, oxygen-blown operation

O_2 (99.5%), lb/lb of coal	0.5
Steam, lb/lb of coal	0.4
BFW, gal/ton of coal	140
Electric Power, kWh/ton of coal*	65

* (From receiving coal from storage to gas cooling and scrubbing.)

Thermal Efficiency[4]

Based on cool, scrubbed gas, oxygen-blown operation

Cold Gas Efficiency = 69%
Overall Thermal Efficiency = 65%

Capacity

A single commercial size two-stage Bi-Gas gasifier (Stage I - 5.5 ft I.D., Stage II - 16 ft I.D., overall 40 ft high) would have a projected capacity of 3750 tpd of Eastern HVAB coal.

Turndown of the gasifier has not been studied. It will be determined by the ability to maintain slagging conditions in Stage I and by the gas quantity necessary to entrain the coal in Stage II.

Environmental Considerations[2]

The char formed in Stage II is separated from the gas and returned to Stage I for gasification under slagging conditions. Slag generated in this manner contains a minimal amount of unconverted carbon, and, in the pilot plant facility, it will be disposed of by landfill. A slip stream of the slurry recirculating in the raw gas scrubber is depressurized in the atmospheric vent gas washer. In the pilot plant, the dissolved gases released are vented to the thermal oxidizer. The slurry is drained from the atmospheric vent gas washer to a waste pond.

Remarks

It is projected that the Bi-Gas gasifier will accept all types of coal. The Bi-Gas pilot plant is oriented toward production of SNG and is complete with facilities for CO-shift and BCR's fluidized bed methanation. Approximately half of the methane in the SNG product is made in the gasifier. By-products such as tars and oils are not produced during gasification.

References

1. "Bi-Gas Pilot Plant Program," BCR Inc., DOE/FE-1207-T7, 1979.

2. Hull, D.E., "Status of the Bi-Gas Coal Gasification Pilot Plant," presented at the Seventh Synthetic Pipeline Gas Symposium, Chicago, Illinois, October 27-29, 1975.

3. "Engineering Study and Technical Evaluation of the BCR Two-Stage Super Pressure Gasification Process," Contract No. 14-32-001-1204, Research and Development Report No. 60 prepared for OCR, Department of the Interior, Washington, DC 20240, Air Products and Chemicals, Inc., 1970.

4. Grace, R. J., "Development of the Bi-Gas Process," presented at the Symposium on Clean Fuels from Coal, Chicago, Illinois, September 1973.

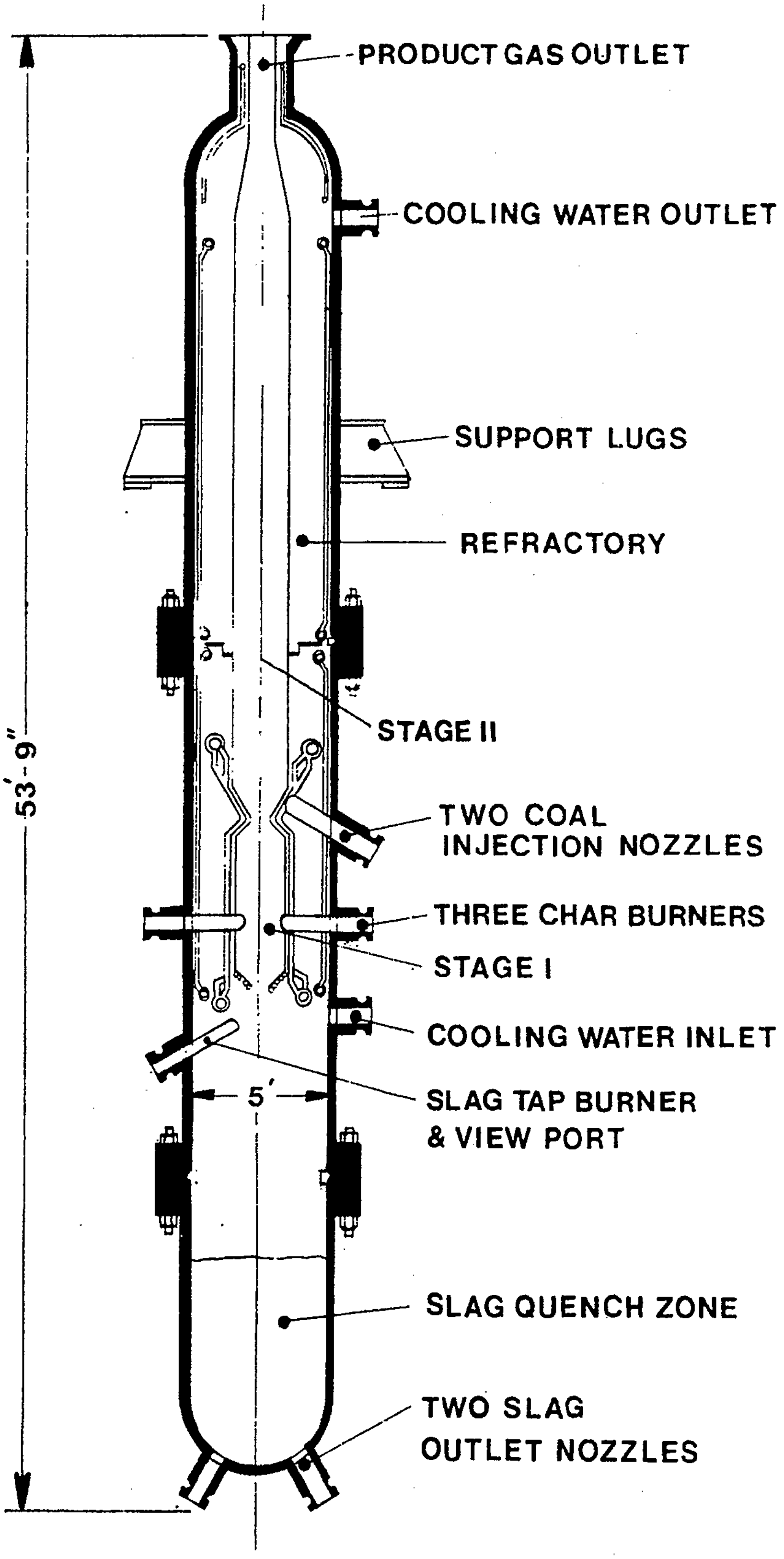

Figure 2C.2-1 Bi-Gas Gasifier.

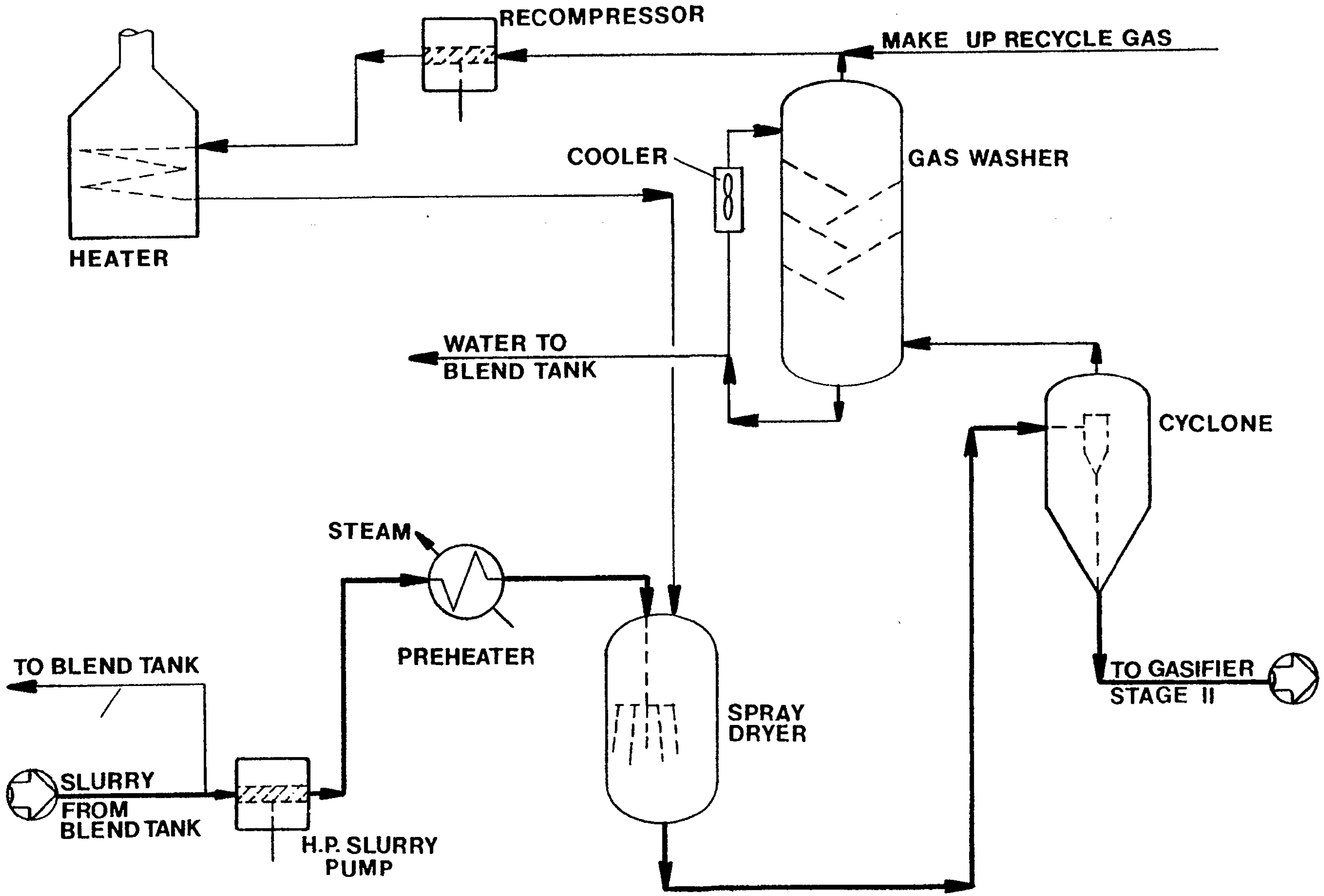

Figure 2C.2-2 Bi-Gas High-Pressure Slurry Feed System

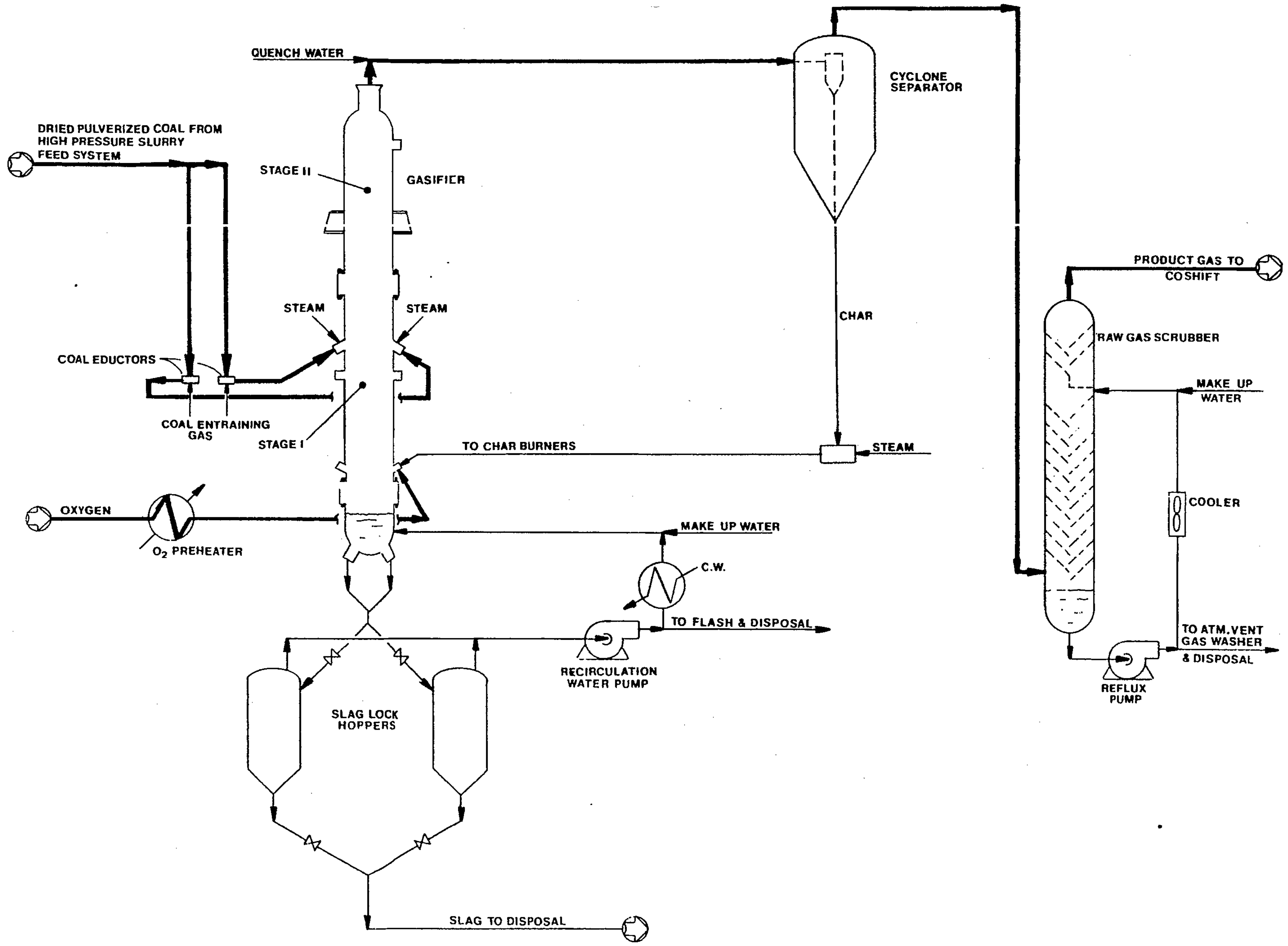

Figure 2C.2-3 Bi-Gas Coal Gasification Process (Pilot Plant Set-Up)

2C.3 COMBUSTION ENGINEERING

Type

Entrained flow gasifier

Developer

Combustion Engineering, Inc.
1000 Prospect Hill Road
Windsor, CT 06095

State of Development[1] [pc]

Development of the Combustion Engineering (C-E) coal gasification process for producing low- to medium-Btu gas began in the early 1970s as a three-phase program. Phase I consisted of an evaluation of technologies that had potential for producing a clean fuel gas from coal. An atmospheric pressure, entrained flow gasifier was selected because of its simplicity, clean fuel gas production, and favorable economics.

Since 1974, C-E has been involved with Phase II of this program. A 5 tph (4.5 metric tph) PDU was constructed at C-E's Windsor, Connecticut site. Funding for design, construction, and operation of the plant has been shared by the U.S. Department of Energy (DOE), the Electric Power Research Institute (EPRI), and C-E. The PDU began operation in June 1978. Prior to it's shutdown in June 1981, more than 3,700 hours of gas-making operation in 12 runs had been logged. Total gas production from 12 runs had been approximately 2.7 billion scf with a heating value ranging from 50 to 140 Btu/scf. Most of the operation had been in the air-blown mode with Pittsburgh #8 seam coal (a highly caking coal with 2-1/2% sulfur content). Limited operation was achieved in the oxygen enriched air blown mode on Pittsburgh #8 seam coal. Heat and mass balances around the gasifier and other major plant components were achieved within 1% to 5%. Periods of continuous gas-making for more than 13 days had been logged.[2]

Another major phase of this program as originally planned, was design, construction, and testing of a 150 mW demonstration plant.[2] C-E received a DOE contract in 1980 to begin the design of a gasifier for this demonstration plant. The contract was reduced in scope in 1981. This plant was to consume 75 tph, and its output fuel gas was used to fire a 150 mW existing boiler at the Gulf States Utilities Company, Nelson Station, in Lake Charles, Louisiana.

Description

The Combustion Engineering gasifier is designed for operation at atmospheric pressure (see Figure 2C.3-1). A combustor section, having tangentially oriented fuel nozzles, is at the bottom of the structure. Directly above it is the reductor section, where additional coal is fed into the gasifier. Hot gases in the combustor and reductor sections entrain and gasify the feed coal as it passes vertically through the unit. Water-cooled, refractory-lined walls around the gasification reactor produce steam.

Pulverized coal and recycle char are fed through the combustor fuel nozzles and oxidized in the combustor zone with a near stoichiometric quantity of air (see Figure 2C.3-2). The resulting hot gases rise into the reductor section, and the molten slag formed in the combustor is removed from the bottom and quenched.

Pulverized coal is injected tangentially through the reductor fuel nozzles into the hot gases rising from the combustor section. Feed coal is devolatilized, and the volatiles are cracked in the lower, high-temperature section of the reductor. As the gases rise through the remainder of the gasifier, they are cooled to 1700 °F by the endothermic gasification reactions.

Gases exiting the top of the reductor section are directed into a waste heat recovery unit, where their temperature is reduced over tubular heat-transfer surfaces. These transfer surfaces recover heat in the form of preheated feedwater, saturated steam, superheated steam, sensible heat in a transfer medium or other, depending on the applications. The cooled gas then flows sequentially to a spray drier, a cyclone, and a scrubber that remove the particulate matter. Other particulate removal systems could work as well. Char and ash thus collected are recycled to the combustor. Product gases are then sent to a sulfur removal unit, resulting in a low-Btu fuel gas. By substituting oxygen for air in the gasification, a medium-Btu synthesis gas with a heating value of approximately 285 Btu/scf can be produced.

Feed Requirements[3]

Coal is pulverized to about 70% through 200 mesh. The gasifier can accept all types of coal.

Drying during pulverization produces a coal of approximately 1% to 2% moisture content in the case of bituminous coal. Raw coals of virtually any moisture content can be adequately dried and handled.

Operating Conditions[2]

Temperature in combustion zone = 3200 °F
Temperature of gas leaving the gasifier = 1700 °F
Pressure = Atmospheric

Gas Produced[1] [4]

Typical gas composition (dry basis) after gas scrubbing and cooling and air-blown operation

Feed Coal	Pittsburgh Bituminous (caking)
HHV of coal, Btu/lb, dry	13,160
Mole %, CO	22.9
CO_2	4.4
H_2	10.0
CH_4	0.0
$N_2 + Ar$	62.7
H_2S	100 ppm
Other hydrocarbons	0.0
HHV, Btu/scf, dry	106

By-Products

Quantities of elemental sulfur and slagged ash produced are not available.

Utility Requirements[4] [5]

For gasification of Pittsburgh coal in air-blown operation

Total Air, lb/lb of coal	4.9
Steam, lb/lb of coal	None
BFW, Gal/ton of coal	Varies with application
Electric Power, kWh/ton of coal	Varies with application

Thermal Efficiency

Based on cooled and scrubbed product gas

Cold Gas Efficiency = up to 75%
Overall Thermal Efficiency = up to 98%

Capacity

The pilot gasifier, 9 ft I.D. and 78 ft tall, can gasify 120 tpd of coal to produce about 16 MM scfd of low-Btu gas.
Turndown Ratio = Not Available

Environmental Considerations

Entrained char in the gas leaving the gasifier is separated and recycled to the slagging combustor. The slag produced contains about 2% unconverted carbon. It is disposed of by landfill.

Remarks

The gasifier is in a developmental stage, and the 120 tpd atmospheric pressure pilot plant has been operated. This 120 tpd gasifier could be used to develop the design basis for scale-up to a demonstration plant capable of providing sufficient low-Btu gas to generate about 150 mW of electric power.

The gasifier can handle all types of coal. The gasification system design is oriented toward producing a low- to medium-Btu gas for combustion in an electric power generating station, but it is also suitable for other applications.[6]

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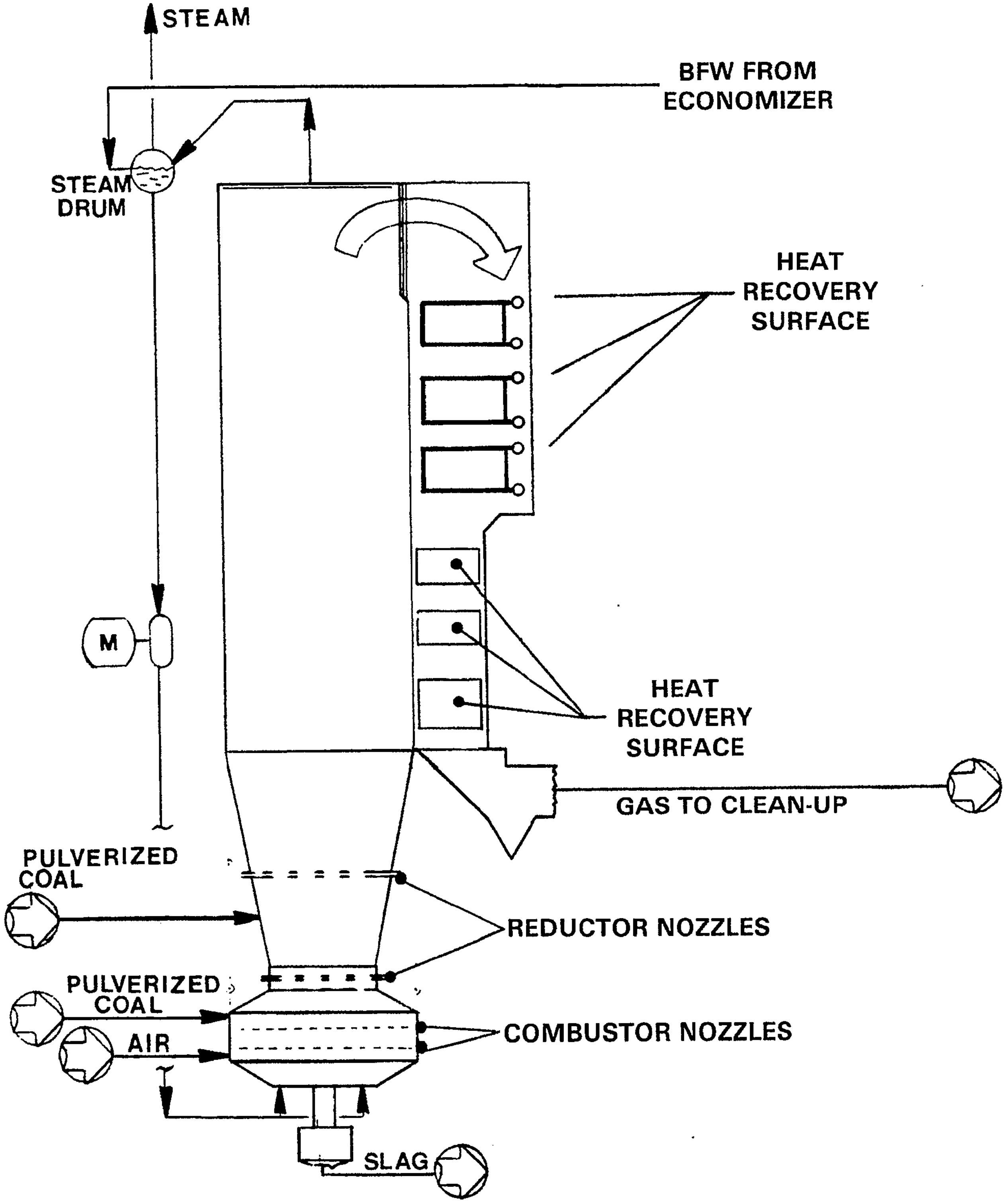

Figure 2C.3-1 Combustion Engineering Gasifier.

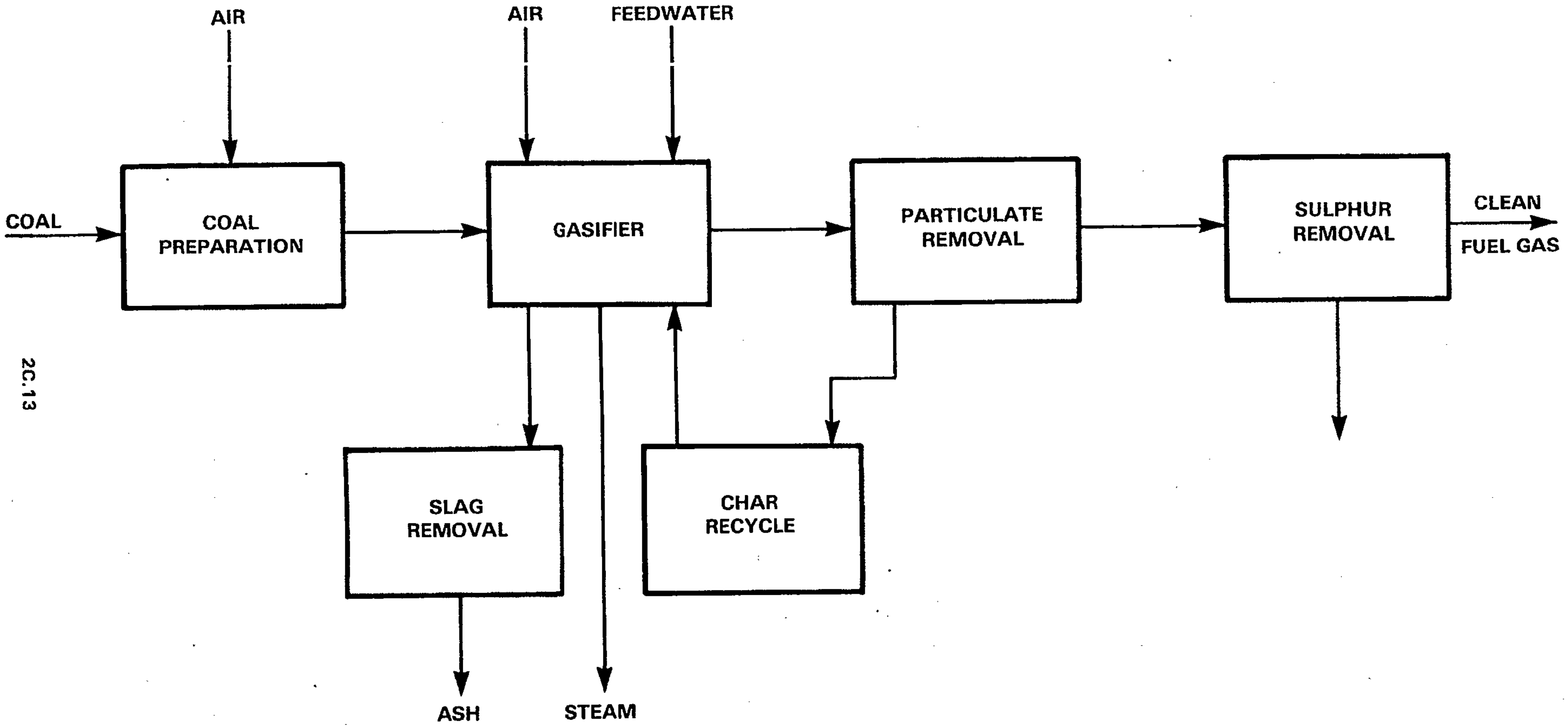

Figure 2C.3-2 Combustion Engineering Coal Gasification Process

2C.4 FOSTER WHEELER

Type

Two-stage, entrained flow, slagging gasifier

Developer

Foster Wheeler Energy Corporation
110 South Orange Avenue
Livingston, NJ 07039

State of Development[1] pc

A research and development program for this process was initiated in August 1972. The process is based on work performed by Bituminous Coal Research, Inc. A 480 tpd pilot plant was planned to be located near Sioux Falls, South Dakota, but was not constructed. No significant progress on this process has been reported since 1978. This process produces a low-Btu gas and is oriented toward combined cycle electric power generation.

Description[1]

The Foster Wheeler gasification process is shown schematically in Figure 2C.4-1. The gasifier is a vertical cylindrical vessel with upper and lower gasification stages. Each stage has its own coal or char and steam and air injection nozzles.

Coal is delivered to the plant site and after passing through the live storage pile is pulverized and dried. The coal is next fed to a lockhopper system that increases pressure to that required for feeding to the gasifier, which operates at about 450 to 500 psig to meet the requirements of the gas turbine.

Coal is fed into the upper stage where it is contacted by a hot gas stream from the lower stage. The coal in the upper stage is devolatilized to form char, as well as CO, H_2, CH_4, etc., then entrained upward and out to a series of cyclones. Recovered char is partially oxidized in the lower stage of the gasifier to produce heat plus fuel gas. The lower stage operates at temperatures sufficient to slag the ash. The hot gases from the lower stage devolatilize the coal in the upper stage.

Molten slag is thrown out against the walls of the lower gasification vessel and runs down through a tap hole into a quench system for cooling and conversion into frits. The slag is then discharged through a lock system and delivered to battery limits for use as landfill.

The gaseous effluent, at a temperature slightly over 1700 °F, flows from the gasifier to the sulfur removal system. The sulfur contained in the original coal is converted mainly to H_2S and COS by a reactor-regenerator fluidized bed system that circulates dolomite for sulfur removal. (Figure 2C.4-2)

The raw gas, after contacting the dolomite, during which time is has been cooled to about 1580 °F, passes through a series of several cyclones for dolomite recovery. The gas stream still contains particulate matter, and the conceptual design of the process uses a high-pressure, high-temperature, electrostatic precipitator to purify the gas to the specification required by the gas turbine. Fines recovered from the precipitator system are returned to the process for complete coal utilization.

The purified fuel gas is next split into two streams, one of which serves as fuel for the gas turbine, while the other (smaller) portion, after heat recovery, is divided into a number of streams for various purposes throughout the plant. A portion is used for cooling the precipitators, for char fluidization gas, for transport gas, for fuel to operate an inert gas generator, and for fuel for coal drying. The major portion of the purified gas flows directly to the gas turbine, which it enters at a temperature of approximately 1580 °F and at a pressure of about 320 psig.

Spent stone from the desulfurizer is sent to a fluidized bed regenerator, which operates at a temperature of about 1300 °F and at a pressure approximately the same as that of the desulfurizer vessel. The regenerator uses CO_2 and H_2O to reverse the direction of the reaction and regenerate the stone. Limestone is constantly fed to the system for makeup; approximately 1.0 percent of the circulating limestone is constantly removed from the system, stabilized, and discarded. The regenerated off-gas, which is a mixture of water vapor, CO_2, N_2, and H_2S, is sent to a liquid Claus system. This system is a circulating stream of sulfurous acid, and the H_2S reacts with the H_2SO_3 to form liquid elemental sulfur and water. These two compounds are separated in a decantation system that removes liquid water from the system and produces a liquid sulfur stream, part of which is combusted and used to reconstitute the acid in an SO_2 absorption column. The bulk of the sulfur is recovered and removed as a liquid product.

A certain amount of stone is removed from the system. This material must be stabilized before it can be discharged from the plant. This is accomplished by slurrying the material with water and passing this through several reaction stages. A certain amount of H_2S is recovered in this system, and this gas stream is compressed and sent to the liquid Claus reactor. The stabilized limestone is discharged as a 40 weight percent water slurry.

The high temperature desulfurization system requires makeup CO_2. Several schemes for CO_2 makeup were designed. The one selected as most economical was to take a portion of the gas turbine exhaust and run this thmough an amine system for CO2 recovery.

Feed Requirements

Pulverized coal 70% through 200 mesh and dried to 2% moisture level. The gasifier can handle all types of coal with ash fusion temperatures of less than 2800 °F. Fluxing agents may allow handling of coals with higher ash fusion temperatures.

Operating Conditions

Temperature in upper stage = 1800 to 2100 °F
Temperature in lower stage = 2500 to 2800 °F
Pressure = 350 psig

Gas Produced

Typical gas composition (dry basis) after air gasification, gas scrubbing, and cooling

Feed Coal	Illinois #6
HHV of coal, Btu/lb, dry	12,800
Mole %, CO	29.3
CO_2	3.3
H_2	14.5
CH_4	3.5
H_2S + COS	0.7
N_2	48.7
HHV, Btu/scf, dry	177

By-Products

Oils and tars are negligible.
Steam Generated = Not Available.

Utility Requirements

Not Available.

Thermal Efficiency

Power station applications have an expected efficiency of 45% with advanced gas turbine designs.

Capacity

Projected pilot plant capacity = 480 tpd of coal.
Turndown Ratio = Not Available.

Environmental Considerations

The slag generated is expected to contain very little carbon and can be disposed of by landfill. Vent gases are free of sulfur and ammonia. The reaction temperatures in the gasifier are high enough to ensure that tars or heavy hydrocarbons contained in the product gas exiting the top of the gasifier are negligible.

Remarks

The Foster Wheeler gasifier is oriented toward producing a clean low-Btu gas for use in combined cycle electric power generation. The process has not yet been proven on a pilot plant scale.

References

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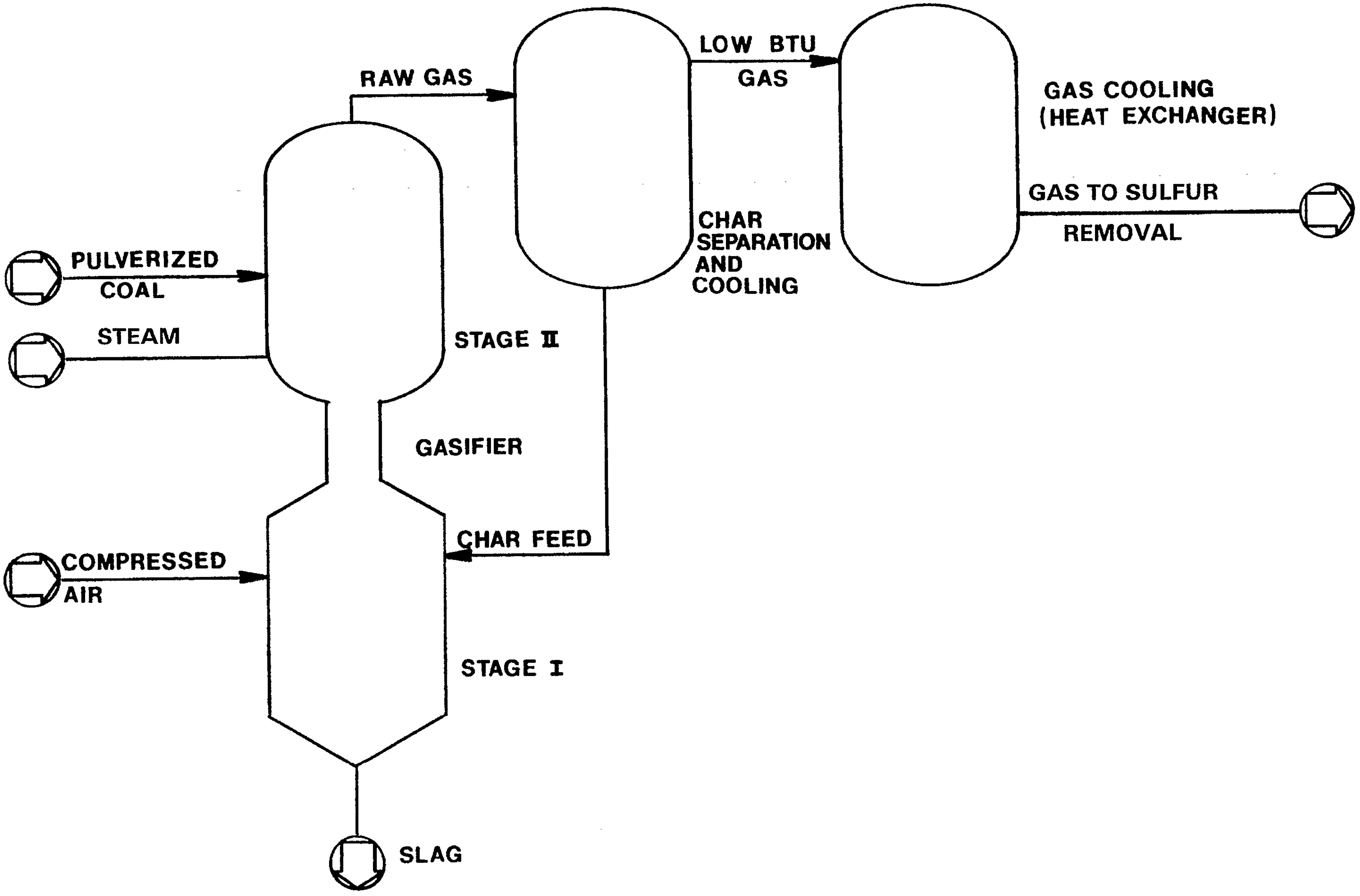

Figure 2C.4-1 Foster-Wheeler Coal Gasifier.

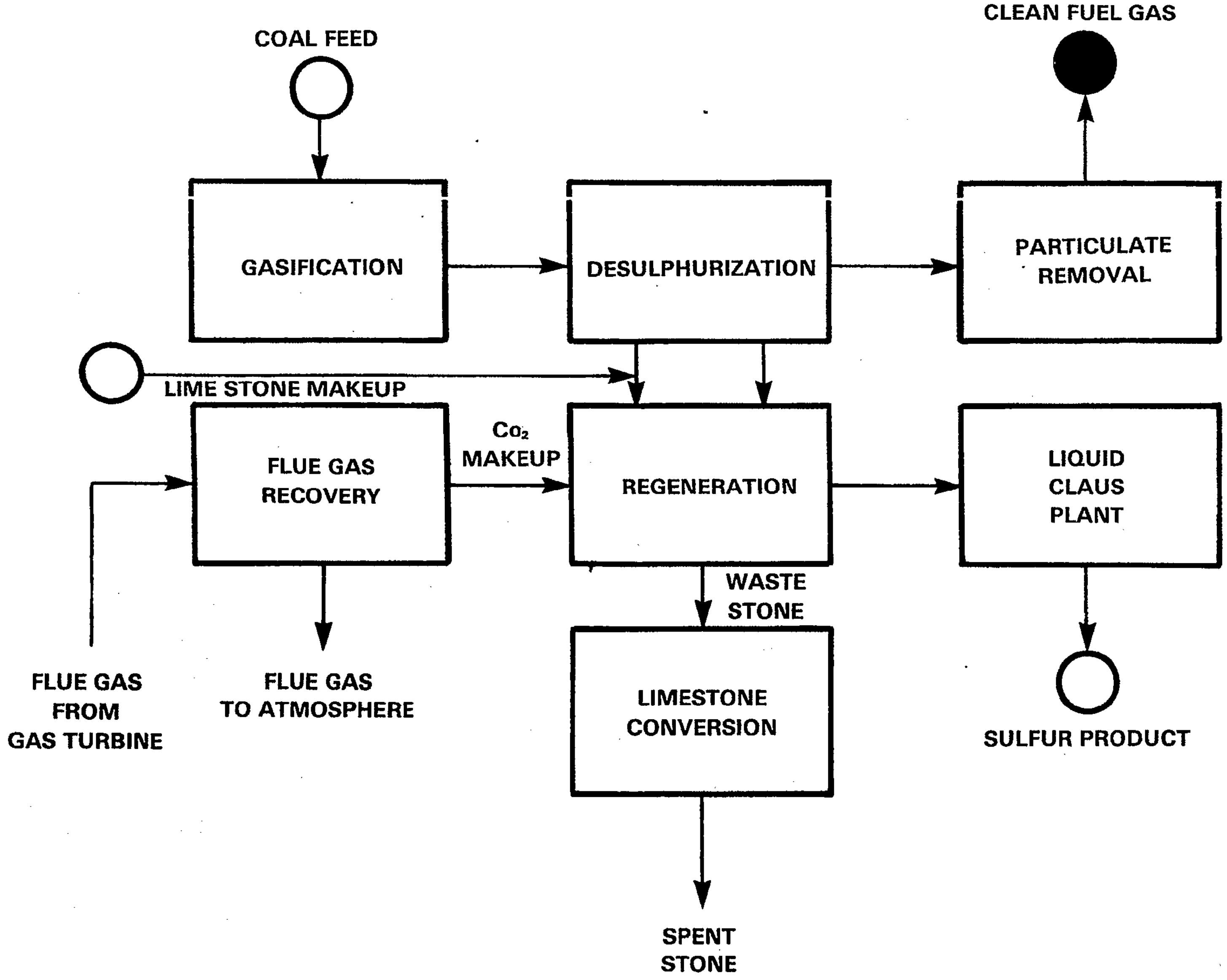

Figure 2C.4-2 Foster-Wheeler Coal Gasification Process

2C.5 KBW

Type

Entrained Flow Slagging Gasifier

Licensor

KBW Gasification Systems, Inc.
1403 Chamber of Commerce Bldg.
Pittsburgh, PA 15219

State of Development[1] PC

In October 1980, the Koppers Company, Inc., and the Babcock & Wilcox Company (an operating unit of McDermott, Inc.) formed a joint venture, KBW Gasification Systems, Inc., to engineer, design, market, fabricate, construct, and service coal gasification systems worldwide. KBW is offering an atmospheric pressure, oxygen-blown, slagging, entrained flow commercial gasification system.

The entrained flow gasification process was first demonstrated in the United States about 30 years ago. In 1948, Koppers built a demonstration plant for the U.S. Bureau of Mines at Louisiana, Missouri. In 1951, the Babcock & Wilcox Company supplied two entrained flow gasifiers (one atmospheric, one pressurized) to the U.S. Bureau of Mines at Morgantown, West Virginia. Also in 1951, Babcock & Wilcox designed and installed an entrained flow gasifier for DuPont at Belle, West Virginia. Based upon the successful operation of this installation, Babcock & Wilcox built a large scale (17 tph of coal) entrained flow gasifier for DuPont at Belle, West Virginia, in 1955. For further information on B&W gasification, see References 2, 3, 4 and 5. Coincidentally, the ready availability of natural gas made coal gasification economically impractical in the United States. However, in Europe the need for expansion and modernization of agriculture required the use of coal to produce ammonia. In 1952, the first commercial size entrained flow gasification plant (see chapter 2C.6 for details) was installed in Finland. Since then, 16 commercial size entrained flow gasification plants have been installed by others in the Eastern Hemisphere.

By today's standards, these initial plants were small in size, inherently simple in design, and lacking in the areas of overall thermal efficiency and coal throughput capacity. They employed long residence times and small internal volumes, had limited flexibility to operate efficiently with a wide variety of coals, and experienced refractory erosion problems. During the 1960s and 1970s, several design and hardware modifications were implemented to improve the earlier gasification systems. As a result, several commercial, entrained flow gasifiers utilizing steam generating cooling jackets, shorter residence times, larger internal volumes, and improved refractories were designed and installed.

Description[1]

The KBW gasification process can be described in terms of three major stages (Figure 2C.5-1); Coal Preparation and Feeding; Coal Gasification and Heat Recovery; and Gas Cooling and Cleaning.

Coal Preparation and Feeding: Coal crushed to 1-1/4 in x 0 in is conveyed to a bunker, which feeds the pulverizer. The pulverizer is air-swept to provide drying and transport of the coal. From the pulverizer, the pulverized coal passes to a storage bin having a cyclone separator at the inlet. The cyclone separator removes the pulverized coal from conveying air and discharges it into the bin. The moisture laden air is vented to the atmosphere through a bag filter to remove traces of pulverized coal from the vented air.

From the storage bin, the dried pulverized coal is transported with nitrogen to the service bins located adjacent to each gasifier. Each service bin is equipped with a cyclone separator and a bag filter to remove the pulverized coal from the conveying nitrogen. The nitrogen is vented to the atmosphere, and the pulverized coal is stored under an inert atmosphere in each service bin.

From each service bin, the pulverized coal passes through two parallel weigh feeders to two smaller feed bins, where it is stored under an inert atmosphere. The feed bins maintain a constant supply of coal at the inlet of variable speed screw feeders, which regulate the flow of pulverized coal to each burner of the gasifier. There is one feed bin and one screw feeder for each of the eight burners in the KBW gasifier. At the exit of the screw feeder, the pulverized coal is picked up by a stream of oxygen and steam and transported a short distance to the burner in the gasifier wall. The velocity of the coal, oxygen, and steam mixture is maintained above the flame propagation velocity at all times, and the screw feeder is designed to maintain a gas-tight plug of pulverized coal to prevent back-flow of oxygen into the coal feed system.

Coal Gasification and Heat Recovery: The KBW gasifier (Figure 2C.5-2) is a square column nominally 15 ft on a side and 61 ft high. The premixed reactants enter the gasifier through eight burners located two each toward the bottom of each side wall. The burners are arranged vertically, one over the other, and are offset from the center of the wall so that the gases form a vortex in the gasifier to promote good mixing. The gasification reactions take place as the pulverized coal entrained in the hot gas passes upward through the gasifier. The temperature in the gasification zone is above the ash fluid temperature, so the ash in the coal is melted, finds its way to the gasifier walls, and runs down as a molten slag to the sloping hearth floor. It then drains continuously through a slag drain opening in the floor. Below this opening is a water filled slag quench vessel, where cold water shatters the molten slag into a solid granular material resembling black gravel. This material is removed continuously from the slag quench vessel by a conveyor for disposal.

The gasifier shell consists of water-cooled, membraned, tubular walls continuously welded to form a gas-tight enclosure. The tubes are typically 2-1/2-in O.D. on 3-in centerline to centerline. The individual tubes are continuous from bottom to top. All the tubes begin at headers at the bottom of the gasifier and are arranged to form the floor or hearth and the slag outlet. They are then bent to form the vertical gasifier walls. And finally, they are bent in to form the top of the gasifier and the gas outlet before being terminated in headers at the top of the gasifier.

Water enters the tubes through the lower headers. As the water flows upward through the tubes, it boils and a portion of the water turns to steam. The steam water mixture is collected in the upper headers and flows to the steam drum, where steam is separated from the water and sent to a superheater located in the heat recovery boiler. The saturated water is returned through downcomers to recirculating pumps where it is pumped to the lower headers to make another pass up through the gasifier tubes. Boiler feed water makeup is supplied to the steam drum through an economizer section in the heat recovery boiler.

The temperature of the furnace face of the refractory is kept below the ash fusion temperature and a layer of frozen slag forms on the refractory. The molten slag flows down over this layer of frozen slag. The frozen slag offers protection to the refractory and tubes while minimizing the heat loss from the gasification zone.

The gasification reactions are essentially completed at an elevation approximately 15 ft above the upper row of burners, where the gas temperature is 200 °F above the ash softening temperature. Above this elevation, the gasifier walls are bare membrane welded tubular walls. The gas is cooled by radiation to the walls in this cooling zone as the gas temperature passes from where the ash is clearly molten to approximately 1800 °F, where it is dry particulate fly ash. At intermediate temperatures, the ash is plastic and can form deposits. In this temperature range, it is handled best with cold bare steel, from which the ash tends to shed off spontaneously. In addition, retractable wall sootblowers are located throughout the upper portion of the gasifier to assist in dislodging any deposits that may build up. These deposits fall to the floor of the gasifier, where they melt and flow out through the slag drain opening with the rest of the molten ash from the coal.

The gas and some unreacted char and fly ash at approximately 1800 °F leave the gasifier and pass through the crossover flue to enter the top of the waste heat recovery boiler. It flows downward over the banks of the horizontal convection surface comprising the superheater and economizer. The gas leaves the heat recovery boiler at the bottom at approximately 450 °F and flows to the gas cooling and cleaning equipment downstream. The walls of the heat recovery boiler are of bare, membraned, tubular wall construction identical with that of the upper portion of the walls of the gasifier.

Gas Cooling and Cleaning: Each gasifier is equipped with a gas cooling and cleaning train. Gas from the heat recovery boiler enters a multicyclone dust collector, which removes about 90% of the entrained particulates.

Gas leaving the cyclone dust collector flows through a saturator cooler, where the entrained particulate loading in the gas is reduced to about 0.01 grains per standard cubic foot (24 mg. per normal cubic meter). The gas then enters a spray type final cooler, where it is cooled to about 105 °F by direct contact with water.

From the final cooler, gas flows to a gas blower that maintains the pressure in the system. From the blower, the gas passes through an electrostatic precipitator. The precipitator reduces the entrained particulate loading to about 0.0001 grains per standard cubic foot (0.24 mg. per normal cubic meter). A gas holder is provided to absorb systems surges. Gas from the precipitator flows to the plant battery limits.

Feed Requirements

Feeds from peat through all ranks of coal to petroleum coke can be gasified. Coal is crushed to 1-1/4 in x 0 in. With Eastern bituminous coal, the typical sized feed to the gasifier has a fineness of 70-85% through 200 mesh (74 microns) and a moisture content of approximately 2%.

Operating Conditions

Temperature in the gasification zone = 200 °F above the ash softening temperature
Temperature of the gas leaving the gasifier = 1800 °F
Temperature of the gas leaving the heat recovery boiler = 450 °F
Gasifier Pressure = Atmospheric

Gas Produced[1]

Typical gas composition (dry basis) is

Feed Coal	Eastern Bituminous
HHV of coal, Btu/lb; dry	Not Available
Mole %, CO	53-65
CO_2	8-11
H_2	25-35
Trace Compounds	1-2
HHV, Btu/scf, dry, acid gas free	290-300

By-Products

Not available.

Utility Requirements

Oxygen, lb/lb of coal	0.76-0.88
Steam, lb/lb of coal	0.12-0.20
BFW, lb/lb of coal	Not Available
Electric Power, kWh/ton of coal	Not Available

Thermal Efficiency

Cold Gas Efficiency	60% to 70%
Overall Thermal Efficiency	Depends on the overall scope of the plant

Capacity

The gasifier is standardized with a square internal cross section 14 ft - 3 in on a side. Typical coal feed rate is 800-1200 tpd and gas production rate is 32,000-45,000 scfm. Typical carbon conversion is 86% to 98%. Turndown capacity depends on ash fusion characteristics, but typically is 2:1.

Environmental Considerations

The gas cleaning train reduces the entrained particulate loading in the gas to about 0.0001 grains per scf. At high temperatures, phenols and tars are not produced. No major environmental constraints expected.

Remarks

The gasifier is based on technology that has been commercial. Membrane walls of the gasifiers are constructed of vertical, water cooled tubes similar to those used in boilers. Thin refractories are used in the gasification zone instead of thicker ones, which have erosion problems in slagging gasifiers. The square cross section permits higher throughputs for the same residence time.

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5. May, M. P., "Suspension Gasifier Offers Economies of Scale," Iron & Steel Engineer, November 29-December 3, 1953.

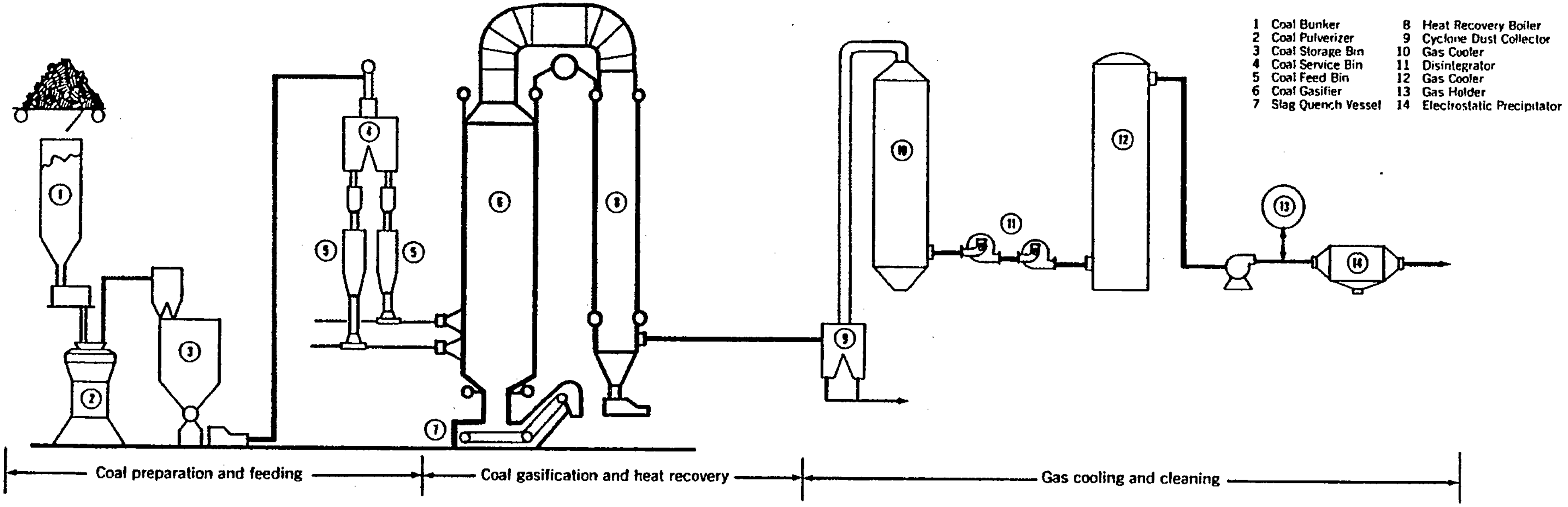

Figure 2C.5-1 KBW Gasification Process.

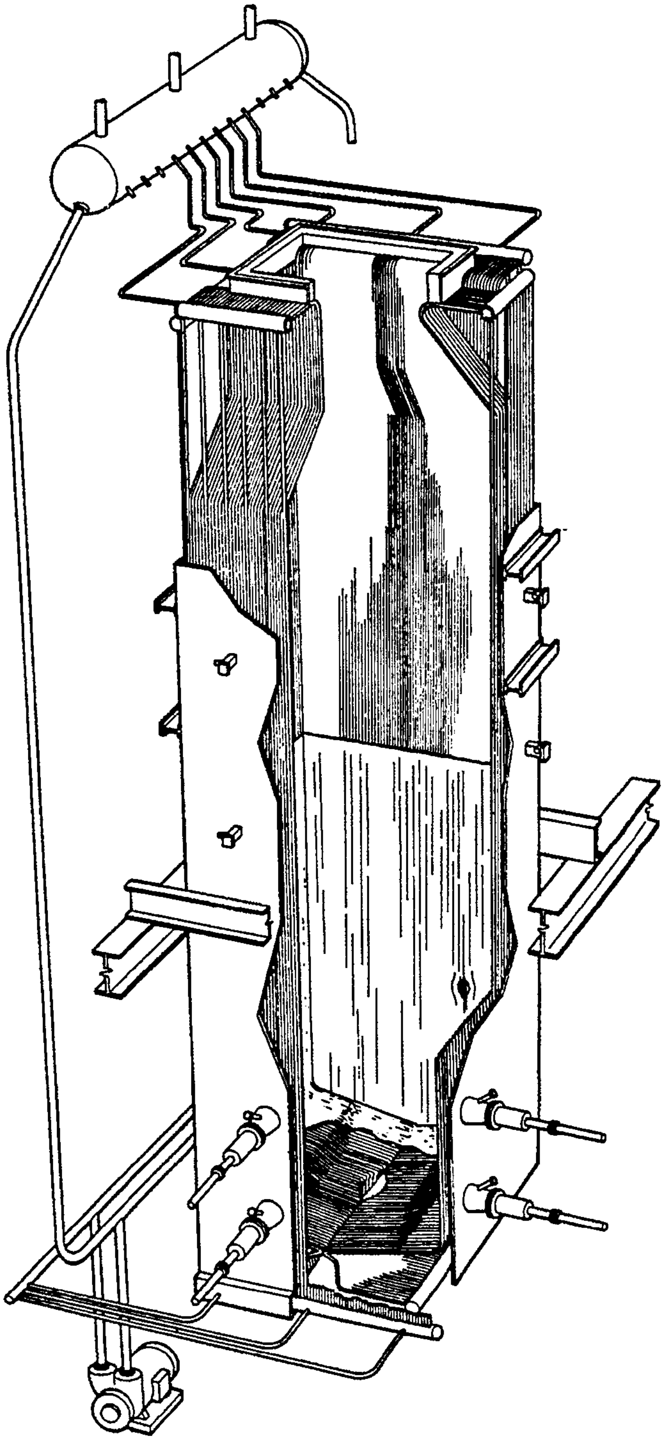

Figure 2C.5-2 KBW Gasifier.

2C.6 KOPPERS-TOTZEK

Type

Entrained Flow Slagging Gasifier

Contact:

GKT Gesellschaft fuer Kohle-Technologie mbH
c/o Krupp Wilputte
152 Floral Avenue
Murray Hill, NJ 07974

State of Development[1 2 3]

The Koppers-Totzek (K-T) process is a commercially proven, oxygen blown, low-pressure process for producing synthesis or fuel gas from solid or liquid carbonaceous feeds.

The process was developed by Dr. Friedrich Totzek in Germany in the late 1930's/early 1940's. Three pilot plants were operated from 1938 to 1944 at various locations in Germany.

In 1948, Heinrich Koppers GmbH of West Germany, the parent company of GKT, designed the first small scale demonstration unit which was built by Koppers Company, Inc., USA and jointly operated by the two companies at Louisiana, Missouri under a contract to the Bureau of Mines. It was designed to generate synthesis gas for the production of liquid hydrocarbons via Fischer-Tropsch.

The first commercial two-headed K-T gasifier was installed in France in 1949/ 1950 by GKT's parent company. Since then, 25 plants in total have been designed, engineered and constructed or are under design, engineering, and construction in Europe, Asia, Africa, and America. From 1952 to 1956, six plants were installed in Finland, Japan, Spain, Belgium, and Portugal. Each gasifier produced approximately 4.5 MM scfd of gas (CO + H_2). Between 1959 and 1969, seven more plants were installed in Greece, Egypt, Thailand, Turkey, East Germany, and Zambia with an average capacity of approximately 10 MM scfd of (CO + H_2) per gasifier.

Between 1963 and now eleven plants were contracted, two of them in the USA. Since the introduction of the four-headed gasifier in 1969, the capacity has been increased to approximately 45 MM scfd per unit.

Description[4 5]

Coal is oxidized in the gasifier, producing a temperature in the flame zone of approximately 3500 °F. Steam generation in the double-shell gasifier reduces the temperature of the gas mixture to about 2700 °F. Ash in the coal is liquefied because the gasifier temperature is maintained at a level higher than the ash fluid temperature. About 50% of the ash flows down the gasifier walls as molten slag and drains into a slag quench tank. The slag, quenched by circulating water, shatters to a granular form. The remainder of the ash leaves the gasifier as fine ash particles entrained in the exit gas.

Gas leaving the waste heat boiler is washed and cooled by water in a scrubber. The particulate matter is reduced here to a negligible amount. Water from the gas cooling and cleaning system is sent to a clarifier. The separated sludge is sent to disposal along with the slag from the gasifier.

The water is cooled and then recirculated to the scrubber system. The scrubbed and cooled gas is processed in a sulfur removal system, resulting in medium-Btu product gas.

Feed Requirements[4]

Coal is pulverized to about 70-90% through 200 mesh. The gasifier will accept all types of coal.

The moisture content of the coal can limit operation by affecting pulverized coal flow. Therefore, simultaneously with the pulverization, the coal is dried in the coal preparation unit, which reduces the moisture content between 8% (lignite) and 1% (bituminous coal).

A wide range of ash fusion temperatures can be handled in the K-T gasifier. Fluxing agents may be required in certain cases to lower the fusion temperature.

Operating Conditions[4]

Temperature in combustion zone = 3500 °F
Temperature of gas leaving the gasifier, prior to the water spray = 2700 °F
Pressure = Slight Positive

Gas Produced[4]

Typical gas composition (dry basis) after gas scrubbing and cooling, oxygen-blown operation:

Feed Coal	Pittsburgh #8
HHV of coal, Btu/lb, dry	12,640
Mole%, CO	59.2
CO_2	7.5
H_2	29.9
H_2S + COS	2.4
N_2 + Ar	1.0
HHV, Btu/scf, dry, sulfur-free	298

By-Products

Oils and tars = none
Steam generated, saturated, up to 1500 psig = 3000 lb/ton of coal
Low-pressure steam generated = 1000 lb/ton of coal

Utility Requirements[4]

O_2 (98%), lb/lb of coal	0.80
Steam, lb/lb of coal	0.16
Electric Power, KwH/ton of coal	34

Thermal Efficiency

Cold gas efficiency = 75% - 78%

Capacity

A two-headed gasifier can produce up to 21 MM scfd of gas; for a four-headed unit, this figure is about 45 MM scfd. The capacity can be adjusted (four-headed gasifier) between 30 and 100 percent.

Environmental Considerations

Approximately half of the ash in the coal leaves the gasifier as fine slag particles. These particles contain the bulk of unconverted carbon. The weight of carbon in the slag is dependent upon the carbon conversion and the ash content of the feedstock. The carbon is occluded in the particles that have been fused, and no serious disposal problems are expected. In landfill disposal, the slag would be covered with soil to support vegetation growth, thereby meeting environmental regulations.

Pressurized nitrogen from the oxygen plant is used as pulverized coal transport gas. It is vented to the atmosphere through bag filters.

Remarks

The K-T gasification process is commercially proven. The gasifier accepts all kinds of coal and does not produce undesirable by-products. High pressure operation of this process has been demonstrated in pilot plant.

References

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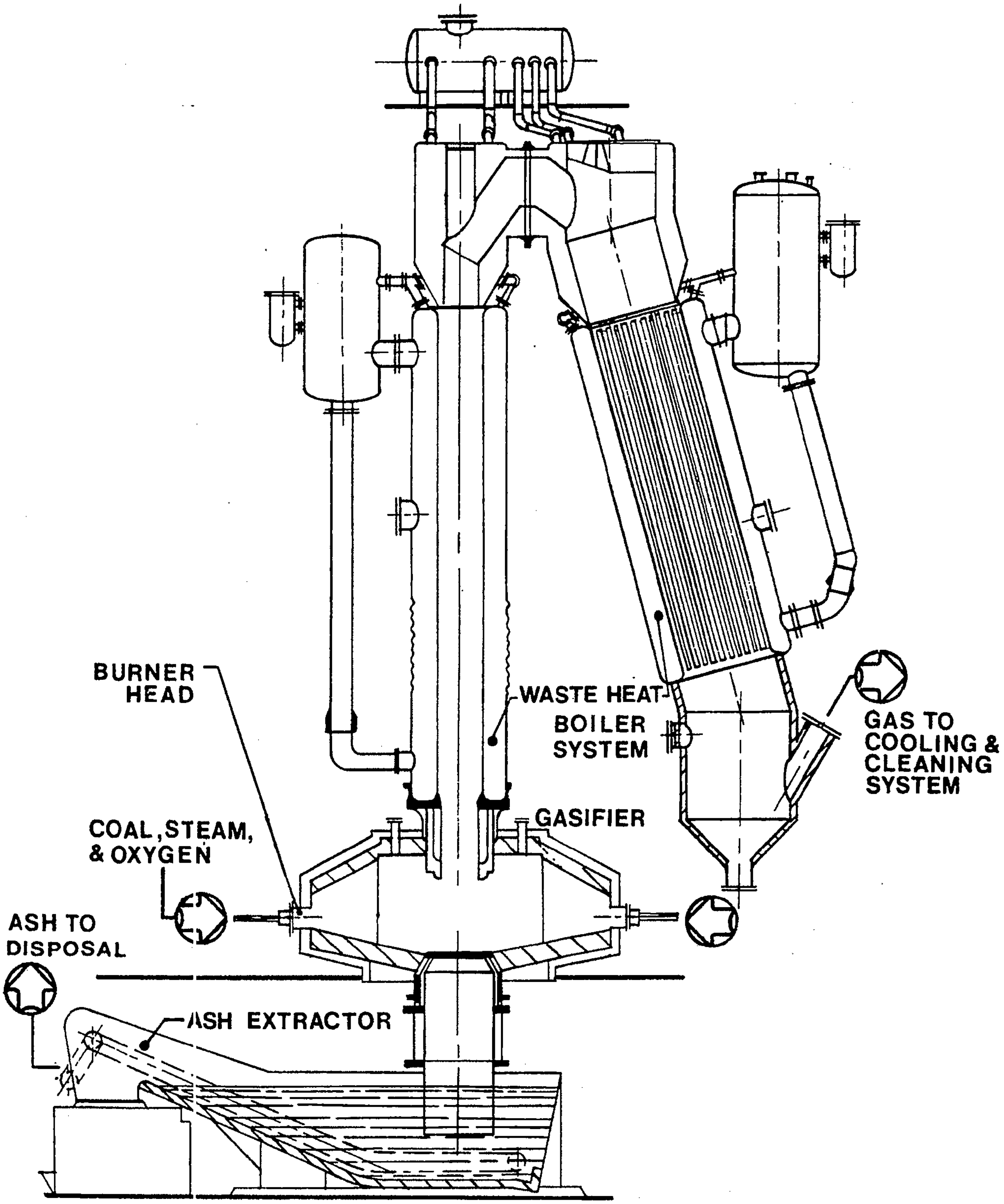

Figure 2C.6-1 Koppers-Totzek Two-Headed Gasifier.

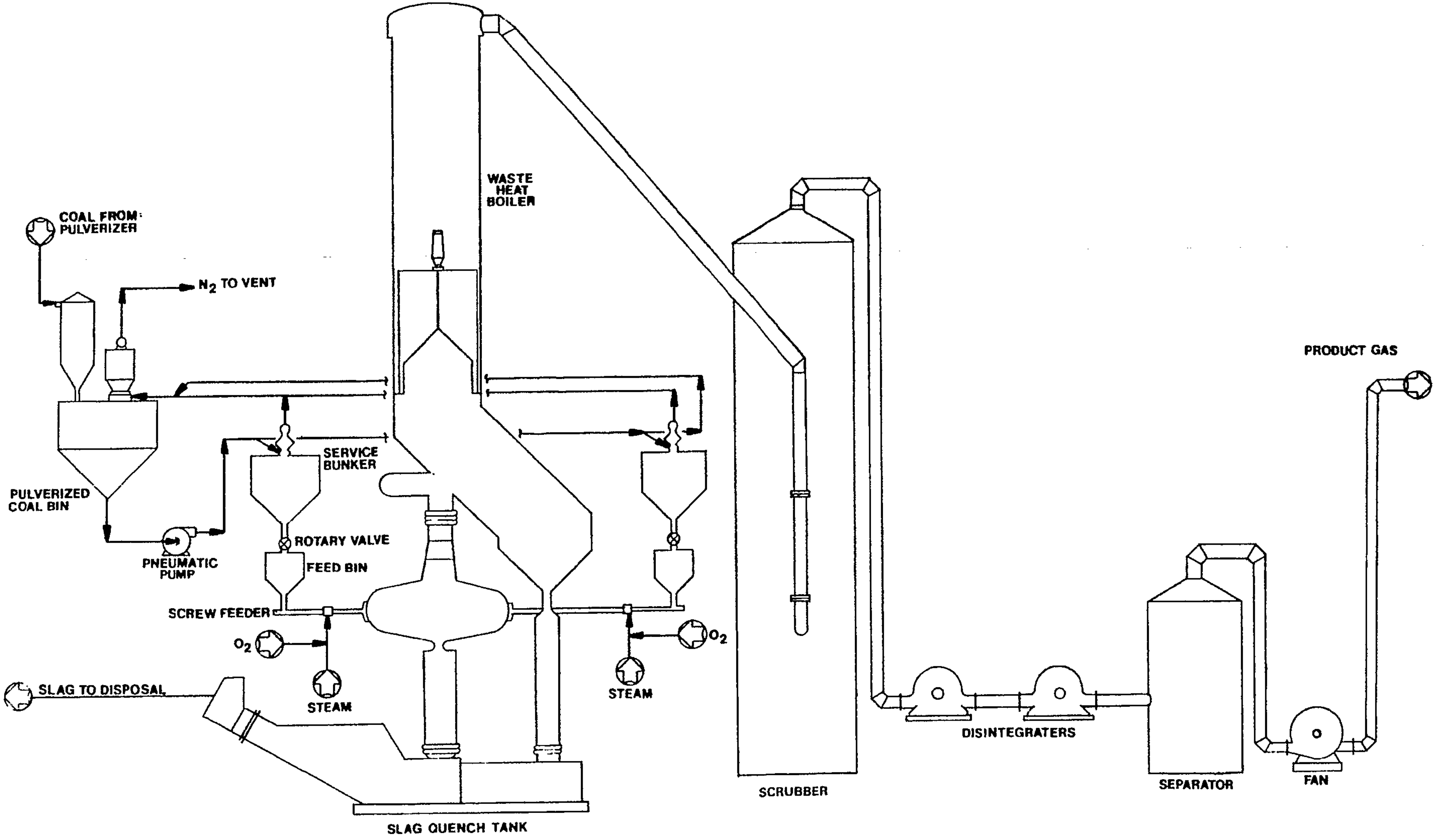

Figure 2C.6-2 Koppers-Totzek Coal Gasification System.

2C.7 MOUNTAIN FUEL RESOURCES

Type

Pressurized entrained flow gasifier

Developer

Mountain Fuel Resources, Inc.
180 East First South St.
Salt Lake City, UT 84139

State of Development[1 2]

Mountain Fuel Resources (MFR) development of a pressurized, entrained flow gasification process has proceeded from extensive laboratory testing to the detailed design of a 30 tpd Process Development Unit (PDU) and to process design studies of a 600 tpd commercial unit.

Pressurized gasification of coal in experimental entrained flow gasifiers was studied extensively from 1953 to 1962 at the U. S. Bureau of Mines, Morgantown, WV. Tests were conducted at pressures up to 300 psi with a unit having feed rates up to 1500 pounds per hour. This work demonstrated that the reaction of pulverized bituminous coal with oxygen and steam could be efficiently carried out at gasifier throughput rates as high as 500 lb coal/hr/ft^3 of reaction-zone volume. This rate is more than an order of magnitude greater than that of existing commercial gasifiers. The practical implication of high throughput rates is that the reaction vessels can be made much smaller and at a substantially lower cost.

Research leading to a design with some similarity to the Bureau of Mines unit was begun at the Eyring Research Institute in 1974. This work was supported originally by the U. S. Office of Coal Research and later by the U. S. Energy Research and Development Administration. The unit at the Eyring Research Institute has been operated at pressures up to 150 psi, and it has a feed rate capacity of 0.5 tpd.

In the late seventies, MFR and Ford, Bacon, and Davis, Utah Inc. initiated a detailed design of a 30 tpd process development unit based on the research done at Eyring Institute.[2 3 4] In addition, process design studies for a 600 tpd unit have also been carried out. The objective of the process design studies was to investigate variations in coal feeding methods, effluent cooling methods, coal composition, and steam/coal feed ratio.

Description[4 5]

The pulverized coal is fed to the top of the gasifier and is entrained in a stream of recycled product gas. It is reacted at a temperature above the melting point of the ash with preheated oxygen and superheated steam in a refractory-lined downflow reaction chamber. The reaction products are partially cooled by radiant heat transfer to the walls of a primary heat exchanger located immediately below the reaction chamber. An abrupt increase in flow area at the entrance to this heat recovery unit is provided to cause the slag flowing down the walls of the reactor to separate from the refractory surface and fall as droplets through the radiant heat recovery unit into a slag accumulation chamber. The slag and larger ash particles are quenched with a water spray, accumulated, and periodically discharged from the bottom through a lockhopper vessel. The gases, entrained soot, and fly ash pass through a convective exchanger and into a scrubber, where the particulates are removed by water scrubbing. The final product is a cooled, clean fuel of intermediate heating value that is suitable, after sulfur removal, for firing industrial boilers and furnaces or for use as a synthesis gas.

The reaction chamber of the 0.5 tpd laboratory unit at the Eyring Research Institute has a 3-in I.D. and is 11 in long. It is encased in a 10-inch diameter carbon steel pressure shell. It has produced efficient conversion at throughput rates of 1000 lb/hr/ft^3. It differs from the Bureau of Mines design principally in the incorporation of an integral heat recovery system to generate steam from the waste heat. The system also employs a unique procedure for using recycled product gas as the entraining medium for feeding the coal.

The process flow shown in Figure 2C.7-1 is that for the 600 tpd conceptual gasifier. Also, the data presented subsequently in this chapter are computed from the design study of this 600 tpd gasifier.[5]

Feed Requirements

All types of coal can be gasified. Three reference coals have been selected in the design study. These are Western bituminous (Deseret), western subbituminous (Rosebud), and lignite (North Dakota). Data presented below are based on the design study and hence labeled as "predicted."

Operating Conditions[6]

Reaction temperature = 2850 °F
Raw gas temperature prior to heat exchange = 1850 °F
Reaction pressure = 185 psig

Gas Produced[5]

Predicted gas composition (dry basis) with oxygen gasification:

Feed Coal	Bituminous	Sub-bituminous	Lignite
HHV of coal, Btu/lb, dry	12,783	11,869	11,112
Mole %, CO	55.72	58.63	55.5
CO_2	6.95	7.89	11.31
H_2	35.46	31.79	31.65
CH_4	0.50	0.39	0.23
H_2S + COS	0.20	0.27	0.23
N_2	1.17	1.03	1.08
HHV, Btu/scf, dry	300	297	285

By-Products[5]

Tars, phenols, and heavy hydrocarbons are negligible. Sulfur is a by-product, as is the export steam that is produced in the heat exchangers. Approximately 1.4 lb of export steam per lb of coal is produced (or about 20% to 25% of the heating value of coal).

Utility Requirements[5]

Predicted requirements with oxygen gasification

Feed Coal	Bituminous	Sub-bituminous	Lignite
Oxygen, lb/lb coal	0.77	0.76	0.75
Steam, lb/lb coal	0.21	0.17	0.17
Additional Mech. Energy, Btu/lb coal	697	792	766

Thermal Efficiency[5]

Predicted efficiencies with oxygen gasification

Utility Requirements[5]

Predicted requirements with oxygen gasification

Feed Coal	Bituminous	Sub-bituminous	Lignite
Cold Gas Efficiency (%)	78	80	78.2
Overall Efficiency (%)	73.9	75.5	72.9

Capacity

The reactor dimensions for the 30 tpd PDU are not available.

Environmental Considerations

As in other high-temperature entrained gasifiers, tars, phenols, and heavy hydrocarbons are negligible. Slag, acid gases, and fines require proper handling to meet environmental standards. Current emphasis of the design study is on the gasifier and related systems. Downstream systems are to be studied laterK

Remarks

The parametric studies on the 600 TPD unit have yielded the following results:

- Dry feeding of the coal offers a significant efficiency advantage over feeding the coal as a water slurry. The overall efficiency can be as much as 13% greater.
- Large variations in ash content produce only small variations in the overall efficiency.
- Heat loss to the reactor walls in the ranges typical for laboratory-scale equipment can cause substantially higher CO_2 formation and 5% to 10% lower efficiency than might be expected in large-scale equipment.
- For a western bituminous coal, the optimum steam/MAF coal ratio is about 0.2.

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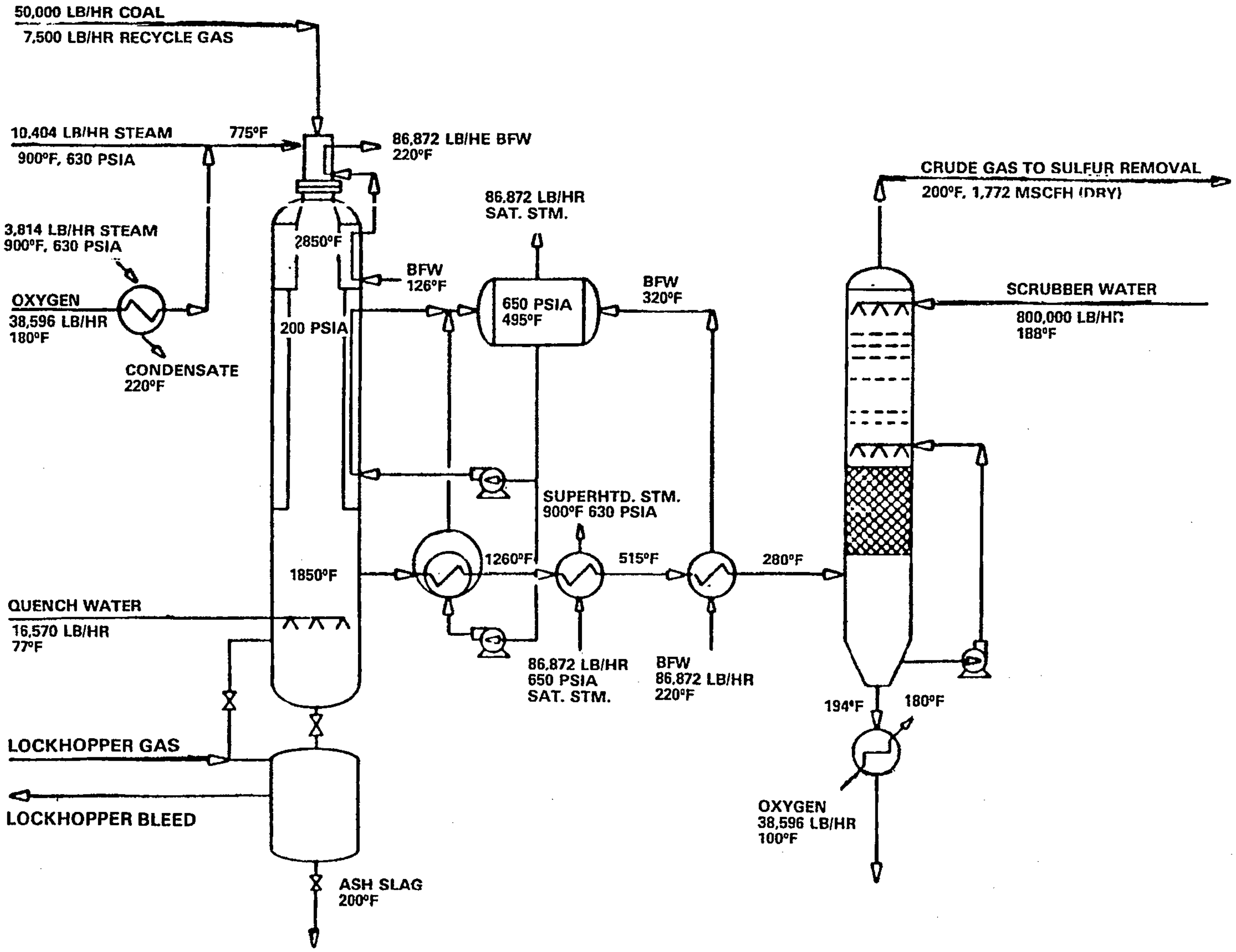

Figure 2C.7-1 Mountain Fuel Resources Conceptual Gasification System.

2C.8 ROCKWELL HYDROGASIFIER

Type

Entrained flow hydrogasifier

Developer

Rockwell International Corporation
Energy Systems Group
8900 De Soto Avenue
Canoga Park, California 91304

State of Development[1 2 3]

The Rockwell Hydrogasifier has been under development at Rockwell International Corporation since early 1977. It is a single-stage, short-residence-time, entrained flow reactor for the production of methane by the direct hydrogenation of bituminous and subbituminous coals.

The application of the Rockwell hydrogasifier concept to a commercial SNG plant is being pursued jointly with Cities Service Company and hereafter will be referred to as the Cities Service/Rockwell (CS/R) Process. Through July 1980, a series of short-duration tests was completed in an engineering-scale test unit at a coal throughput of 3/4 tph.

The CS/R Process was initially conceived and developed under private funding. Further development and optimization of the process were initiated in March 1977 under contract from the Department of Energy (DOE) to Rockwell International to perform engineering-scale tests at 1/4 tph. This effort was supported by bench-scale testing at 2 to 4 lb of coal per hour at Cities Service Research and Development Company, a major subcontractor.

In October 1978, a 3-year follow-on to the first DOE hydrogasification contract was initiated; the scope of this program involved an integrated combination of design, construction, and operation to demonstrate the large-scale, long-term feasibility of applying the Rockwell hydrogasifier reactor in a viable SNG from coal process. Short-duration testing at 1/4 tph performed under the predecessor contract was continued during the follow-on period through December 1978 for additional expansion of the data base.

The first phase of the current program consisted of building a new engineering-scale facility to perform batch tests for longer duration runs (up to 1 hour) at 3/4 tph. Testing at this newly-built facility was initiated in July 1979 and continued through June 1980. During this period, considerable useful data were generated, which are now being used for the conceptual design of a commercial plant.

The second phase of the program is to involve the design, construction, and operation of a 3/4 tph IPDU, with extended runs being made for various durations up to 30 days.

Description[1 2]

The CS/R Process employs a rapid noncatalytic coal hydrogenation technique, termed flash hydropyrolysis (FHP), in an entrained flow reactor to produce the coal/hydrogen reaction. Major process considerations are as follows: First, as a direct hydrogenation scheme, the FHP process is theoretically capable of producing approximately 20% more high-Btu gas per ton of coal than a process using an intermediate synthesis gas step.[4] Second, because FHP operates in a regime of rapid kinetics, it allows the use of an entrained flow reactor system. An entrained flow hydrogenation reactor uses pulverized coal with a large active surface area and can operate at high enough temperatures (1600-1900°F) so that the reactions occur in milliseconds. The kinetics are sufficiently rapid at these conditions and allow the development of a compact reaction system. Further, the rapid kinetics make it possible to process highly caking coals without pretreatment to eliminate agglomeration.

In the Rockwell hydrogasifier, pulverized coal in dense-phase is intimately and quickly mixed with hot hydrogen by an injector, the design of which is based on the design of rocket engines. A diagram representing the hydrogasifier to be used in the 3/4 tph IPDU is shown in Figure 2C.8-1. Here, the reactor train consists of two sections, the first of which is the injector-reactor tube section. The flash hydropyrolysis of coal occurs immediately downstream of the injector, and the reactor tube provides the residence time for additional reactions, namely, the hydrogenation of liquids and char. The reactor tube, which runs hot during operation, is pressure-balanced by a reactor shell gas purge that maintains the differential pressure between the inside and the outside of the reactor tube within the strength limits of the tube at operating temperatures. The purge gas, which has been nitrogen in the engineering-scale tests and will be hydrogen in the IPDU, joins the main product stream at the interface between the flow splitter cones and individual tubes of the recuperator. The second section is the recuperator and is composed of two stages. In the first stage, the heat in the products of hydrogasification is transferred by counterflow heat exchange to the hydrogen used as input to the injector. This hot hydrogen is internally connected to a preburner in which the hydrogen is raised to a higher operating temperature by combusting it with a trickle flow of oxygen. The resulting hot hydrogen is then fed to the injector. The products exiting the H_2-cooled first-stage recuperator are further cooled in a water-cooled second stage to temperatures that assure safe operation of the downstream process components.

All engineering-scale tests conducted before September 1980 were performed in test units similar in configuration to the first section in Figure 2C.8-1, but without the two-stage recuperator. In these units, the hot products of hydrogasification were directly quenched by internal water sprays to safe temperatures. The engineering scale tests were performed typically at 750 to 1500 psig reactor pressure and 1100 to 2000°F reactor exit gas temperature. Residence times were on the order of 0.5 to 6.0 seconds.

A simplified block flow diagram of the CS/R Process for SNG production from coal is presented in Figure 2C.8-2. A typical commercial-scale plant would be designed on a grass-roots basis to produce 250 MM scfd of SNG at 1000 psig outlet pressure. The plant consists of two major subsystems--a direct hydrogasification system to produce SNG and a steam-oxygen gasification system to produce the makeup hydrogen requirement from coal and/or char. Excess hydrogen in the product stream from the hydropyrolysis reactor is recovered cryogenically and recycled. The plant also includes provisions for the production and recovery of light aromatics, consisting predominantly of nearly pure benzene, although it can be designed specifically to produce a 100% gaseous product. Sulfur is recovered from the effluent gas streams in the form of hydrogen sulfide, which is subsequently converted to elemental sulfur for commercial sales.

Because of the high overall carbon conversion achieved in the hydrogasifier, exceeding that required for a balanced plant operation without excess char, several options exist for the optimum utilization of the char. There is approximately enough char to satisfy the utility needs for steam and power generation. Alternatively, the char can be used exclusively for hydrogen production. In this latter scheme, a small amount of pulverized raw coal must be added to the char to satisfy the total plant H_2 demand. Optimization studies are in progress to determine the most economic route to follow.

Feed Requirements

Pulverized coal is sized to 70 wt% through 200 mesh. The gasifier can accept caking and noncaking coals, dried peat, and other solid fuels that can be pulverized.

Operating Conditions[2]

Among the many tests conducted at the engineering-scale test facilities, one particular test appeared to give an attractive product slate from the standpoint of a commercial-scale process. (This test condition was replicated twice to confirm the data from the first test.)

Reactor pressure = 985 psig
Gas residence time = 1.8 seconds
Reactor exit gas temperature = 1800 °F

Gas Produced[2]

For the operating conditions given above, typical gas composition at the outlet of the hydrogasifier on a hydrogen- and moisture-free basis

Feed Coal	Kentucky #9, HVAB
HHV of Coal, Btu/lb, dry	13,430
Mole %, CH_4	82.5
CO	7.8
CO_2	0.6
C_2H_6	0.3
H_2S + COS	2.1
N_2 + Ar	3.1
NH_3	0.2
BTX	3.4
HHV, Btu/scf, dry	1008

By-Products[2]

The main by-product is BTX containing greater than 99% benzene. Negligible quantities of other light oils are produced at the cited operating conditions. Carbon conversion to benzene is nominally about 11.0%.

Utility Requirements[2]

Net Hydrogen, lb/lb MF coal	0.087
Oxygen to hydrogasifier, lb/lb MF coal	0.15
Oxygen to char-steam-oxy-gasifier, lb/lb MF coal	Not Available
Steam, lb/lb MF coal	Not Available
Electric Power, kWh/ton of coal	Not Available

Thermal Efficiency

Overall plant efficiency for a commercial scale plant is estimated at 65%.

Capacity

The engineering-scale tests conducted to date were performed at coal feed rates of 1/4 and 3/4 tph in 15-ft long reactor tubes ranging in diameter from 2 to 6 in. The IPDU reactor tube will be 6 to 10 in diameter and 15 ft long, having a throughput of 3/4 tph. The variable tube diameter will provide added flexibility in selecting reactor operating conditions, including reactor residence time (0.5 to 4.0 seconds) and pressure (500 to 1500 psia).

A commercial-scale Rockwell hydrogasifier will consist of a clustered arrangement of nominally 4 tph injector elements and will have the capacity to process 150 to 175 tph of coal. As in the smaller engineering-scale reactors, each commercial-scale injector element handles a central coal feed stream with several surrounding hot hydrogen jets impinging on it. Single reactor dimensions are envisioned to be 6 ft in diameter and 15 ft in length.

Environmental Considerations

Since only negligible quantities of heavy hydrocarbons, such as tars and other oils, are produced, these less desirable hydrocarbons may be absorbed on the char and disposed of by using them as if they were char. The nitrogen in the coal is converted to predominantly ammonia, which is removed by conventional means. The sulfur in the coal is converted to predominantly H_2S, which is removed from the product stream and recovered as elemental sulfur. The handling of BTX will require special consideration to maintain low exposure levels conforming to OSHA regulations. Wastewater from the process will be treated and recycled. Inorganic solids, such as slag or ash from the char gasifier, may be used as landfill material. More detailed analyses of the environmental aspects involved in the CS/R Process are planned as part of a comprehensive preliminary commercial design study in progress.

Remarks

Development effort is continuing on the Rockwell hydrogasifier with emphasis on shifting from gasifier development per se to process development and optimization. It is now apparent that the most attractive process option is the coproduction of methane and benzene.

Testing, mainly with bituminous coal, has generated a data matrix covering the major reactor parameters, namely, the reactor exit temperature, residence time, pressure, and hydrogen-to-coal weight ratio. These data have been correlated by applying nonlinear multiple regression techniques to hydropyrolysis kinetics represented by a set of phenomenological reactions. A 3/4 tph IPDU is now being built based on the most attractive conditions selected from the recent tests.

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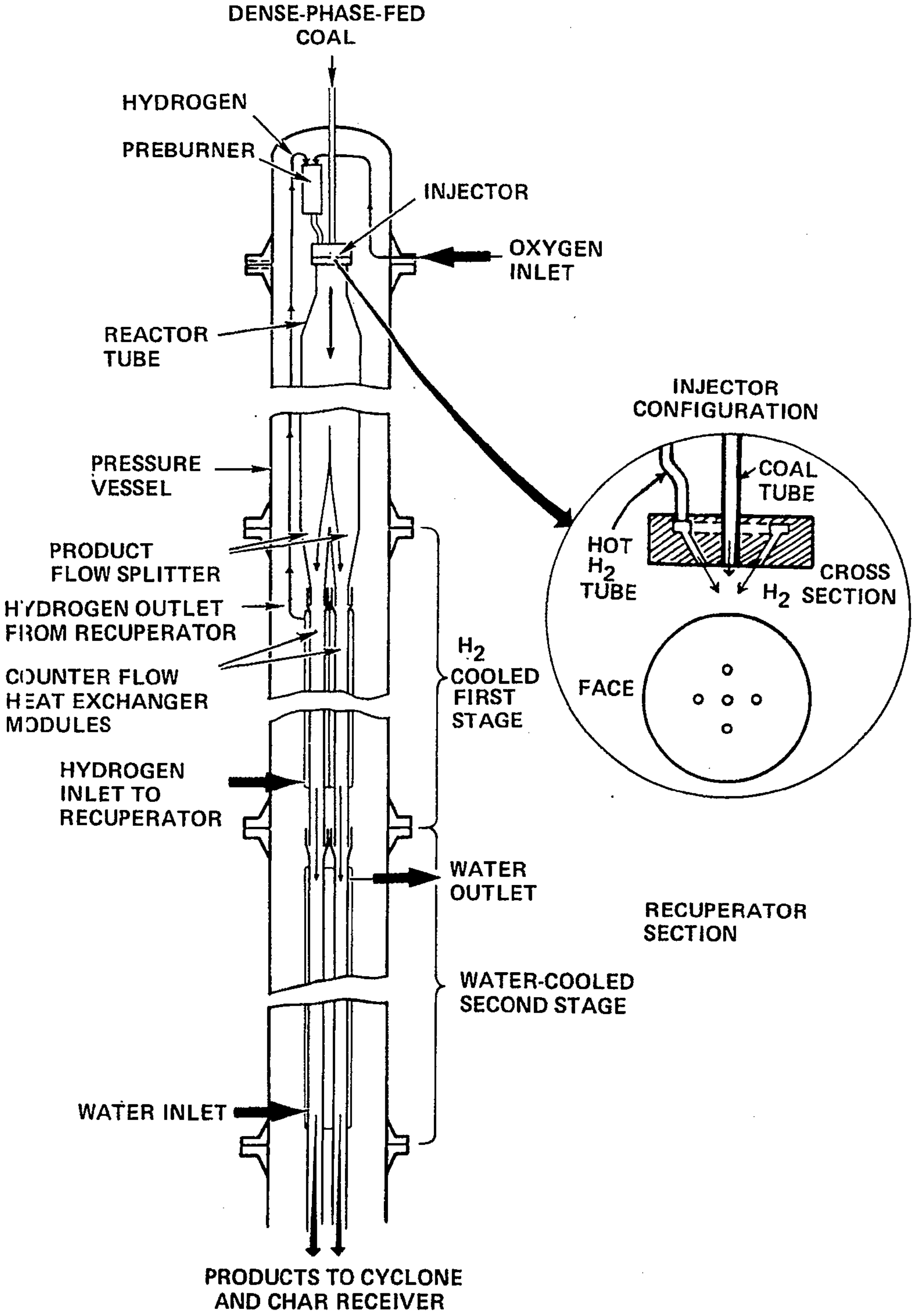

Figure 2C.8-1 Rockwell Hydrogasifier To Be Used In ¾-TPH Integrated Process Development Unit.

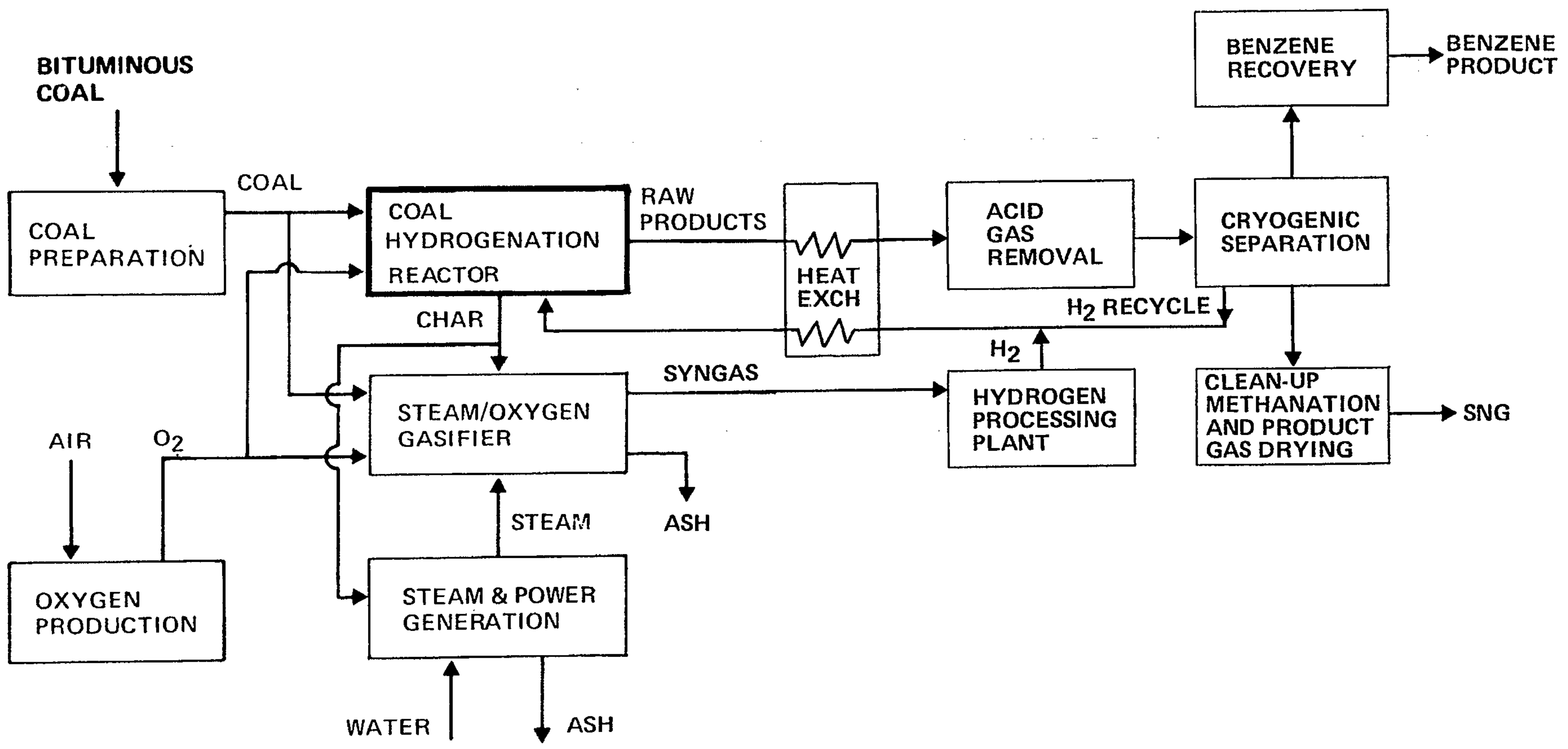

Figure 2C.8-2 Simplified Flow Schematic Of The Rockwell Hydrogasification Process.

2C.9 RUHRCHEMIE RUHRKOHLE COAL GASIFICATION PROGRAM

Type

Entrained flow (Texaco type) gasifier integrated with specialized ancillary units.

Developer

Ruhrchemie AG
D-4200 Oberhausen - Holten
West Germany

Ruhrkohle Oel und Gas GmbH
D-4250 Bottrop
West Germany

State of Development[1]

The Ruhrchemie Ruhrkohle (RCRK) coal gasification is an extension of the Texaco coal gasification process (the Texaco gasifier is discussed in this handbook in Chapter 2C.11). The development of this process, sponsored by the West German Federal Ministry of Research and Technology, began in 1975. Combining the experimental results of the Texaco coal gasification facility in Montebello, California, with RCRK's own engineering developments, planning of a 6 tph coal gasification plant began in mid 1975. The construction of this plant in Oberhausen, West Germany, was started in April 1977.

Operation of the coal gasification plant commenced at the end of January 1978. By March 1981, several runs had been conducted for a total of more than 7,500 hours.[2] [3] [pc] Several test runs demonstrated continuous operation for periods in excess of 800 hours. Approximately 40,000 metric tons of different Ruhr area coals of varying volatility have been gasified at pressures ranging from 300 to 600 psig. Approximately 3 billion scf of syngas have been produced. Further development and process optimization are being carried out in this program. Included activities are evaluation of alternate components, testing of alternate concepts for heat recovery, and gasification of a wider range of coals. The total program is planned to provide sufficient information for the design of large-scale second-generation coal gasification plants using the Texaco process. Plans have been made to utilize the operational results of this 6 tph plant to design a 50 tph unit in 1981.

Description[2]

The objective of RCRK's coal gasification program is to develop a coal gasification process that would (1) operate at high pressure so that high throughputs could be achieved, (2) operate at high temperatures so that high carbon conversion could be achieved and tar and methane formation could be suppressed, (3) use coal fines as feedstock, and (4) accept coal feed suspended in a liquid.

To achieve these objectives, RCRK decided to use the Texaco coal gasifier and integrate it with its own developmental work and knowledge to complete the system.

As shown in Fig. 2C.9-1, the main features of the Ruhrchemie/Ruhrkohle technical version of the Texaco Coal Gasification Process (TCGP) are:

- coal grinding and slurry preparation
- gasification
- heat recovery
- slag/ash treatment

The first, third, and fourth steps are based mainly on RCRK's own developments. The second step, gasification, uses the principle of the Texaco entrained gasifier.

According to Figure 2C.9-1, the run-of-mine-coal is stored as dry coal or as a slurry and is fed together with either recycle water or optimally with fresh water into a wet mill, adding additives if necessary. The resulting homogeneous slurry of high solid content is stored in a suspension vessel and pumped up to gasification pressure.

When oxygen is introduced into the gasifier, the coal is partially combusted ("autothermal gasification"), thus supplying energy to heat the reactants and to cover the enthalpy requirements of the reaction. On leaving the gasifier, the gas stream is deflected, thereby separating most of the liquid slag present in the gas. The separated slag is granulated in a water bath at the bottom of the first heat recovery vessel and removed via a lockhopper system.

The gas is cooled in a two-stage gas cooling system, consisting of both a radiant and a convection cooler. The energy released is used for steam generation. The remaining solid matter - the dust content after passing through the heat recovery system - is removed by scrubbing water in a cooler/scrubber.

The solid-charged scrubbing water is separated in a settler into a clarified phase (to be reused as scrubbing water) and a settler underflow, which may be recycled to the grinding section and the gasifier, as it still contains combustible materials. A water purge removes water-soluable inorganic impurities of the coal from the system. The detailed description of each of the process features except the gasifier is given below.

Coal Grinding and Slurry Preparation: A wet grinding system is used because it eliminates a costly preliminary coal drying step. Because of its hydrophobic behavior, dry coal dust is difficult to suspend in water, and its handling and processing require extreme - and highly expensive -safety precautions. A coal grinding unit of proprietary design is used.

Heat Recovery: Heat recovery from the hot reaction mixture is essential because the sensible heat of the mixture contributes approximately 20% to the thermal efficiency of the whole process. The process produces saturated or superheated steam for heating. This reaches temperatures on the heat transfer surfaces, thus making it possible to use low-alloy steels as long as the steam pressures are below approximately 1500 psig.

A proprietary two-step cooling system is used at the Oberhausen plant that separates the slag from the gas without any contact with a radiation cooler. Small amounts of flue dust then pass the convection cooler, which is similar to corresponding vessels in power stations or in chemical plants. Further information on heat recovery is not available.

Slag/Ash Treatment: Attention has been given to the corroding and/or eroding attack of the liquid slag on the reactor lining. This could be controlled either by noncooled ceramic linings of special composition or by water-cooled metallic walls. In special test zones incorporated in the lining of the reactor jacket, some fifty different ceramic materials from various manufacturers have been tested. The materials first tested proved to have short lifetimes as reactor lining, but, after a year of experimental work, ceramic linings having expected lifetimes of 5000 hours or more were found. Water-cooled metallic walls have also been tested and found to be suitable. It is expected that the solution of the problem of protecting the reactor walls will eventually involve a combination of ceramic linings, as in oil gasification units, supplemented by water cooling in the more exposed regions.

As mentioned earlier, the coarse slag/ash is removed via a water bath at the bottom of the radiation cooler. The ash removal system contains valves that resist even strongly eroding solids. They are part of a programmable lockhopper unit. The latter operates in such a way that an eroding attack from a streaming ash suspension is avoided. The electronically controlled switching sequence prevents gas escapes during the batchwise ash removal steps by providing continuous control and synchronizing of all working parameters. The removal of the fine ashes by separation and depressurizing of the solid-charged washing water is ensured in a similar manner.

Feed Requirements

Slurries with solid contents over 70% have been employed. The grain size of the coal is adjusted to between 14% and 60% greater than 90 microns. Low and high volatile bituminous coals having up to 45% of volatiles and coal sludges from the coal washing having up to 30% of ash have been gasified.

Operating Conditions[2] [3] [pc]

During operation, the temperature has been varied between 2450 °F and 2800 °F. The gasification pressure has a design limit of 600 psig.

Gas Produced

Typical gas composition (dry basis)[2] [4]

Feed Coal	Not Available
HHV of Coal, Btu/lb, dry	Not Available
Mole %, CO	55.0
CO_2	11.0
H_2	33.0
CH_4	0.1
$H_2S + COS$	0.3
$N_2 + Ar$	0.6
HHV, Btu/scf, dry	Not Available

By-Products

By-products, such as tars, phenols, and ammonia, are negligible because of high operating temperatures. Rate of steam production is 15 tph at 600 psig.

Utility Requirements

Not available.

Efficiency

Cold gas efficiency = 74%

Capacity

Reactor dimensions and turndown ratio not available.

Environmental Considerations

The wastewater streams from the plant have been found to contain very low levels of Cl, NH_3, Cn, As, Cd, Ni, and P. This can be attributed to high reaction temperatures. In addition, environmental problems such as coal dust and slag handling are not present because of the system described above.

Remarks

RCRK reports that its objectives for a coal gasification system are being achieved. Very little technical data are available on their process at the present time.

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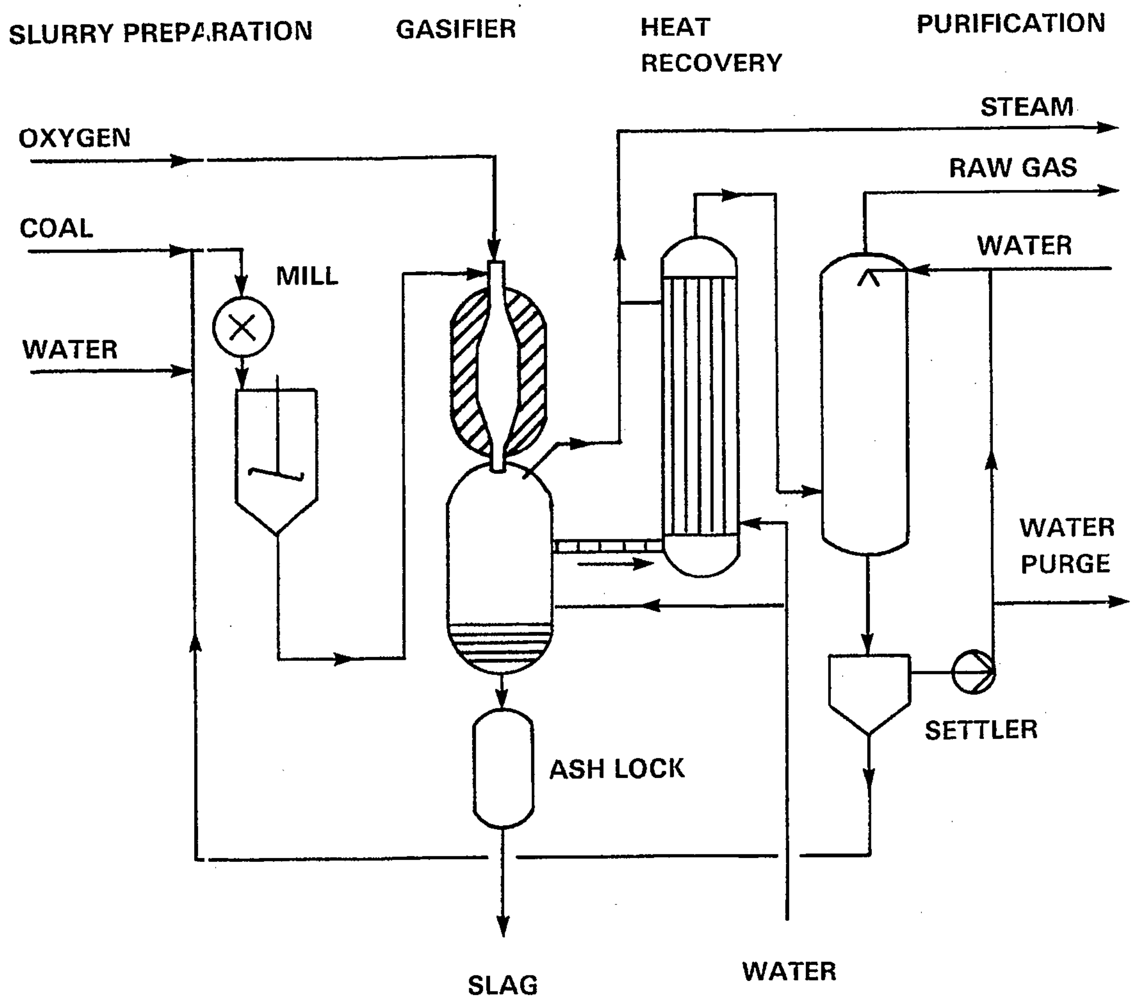

Figure 2C.9-1 Ruhrchemie-Ruhrkohle Coal Gasification

2C.10 SHELL COAL GASIFICATION

Type

Pressurized entrained gasifier

Developer

Shell Internationale Petroleum Maatschappij B.V.
Manufacturing Development Division
Carel van Bylandtlaan 30
The Hague
Netherlands

State of Development[1]

Shell Internationale Petroleum Maatschappij B.V., The Hague, has been working since 1973 on the development of a high-pressure slagging coal gasification process. A pilot plant of 6 tpd intake capacity has been in operation at Shell's Amsterdam Laboratories since December 1976. As part of further development, Deutsche Shell AG decided to set up a larger experimental plant employing this process. The firm Krupp-Koppers GmbH (formerly Heinrich Koppers GmbH) made contributions to the development by making its experience on the atmospheric pressure Koppers-Totzek Process available and by acting as the main engineering and construction contractor for the 150 tpd pilot plant in Germany.

A series of runs ranging from a few to over 200 hours duration has been made in the pilot plant since its commissioning in November 1978.[2] [3] Designs based on experience with the pilot plant are being developed for two 1000 tpd prototype units, one in Moerdijk, Holland, and one in Germany, which are scheduled for commissioning in 1984 and 1985 respectively. The capacities of subsequent fully commercial units will be increased stepwise to about 2500 tpd toward the end of the eighties.

Description[1]

The Shell process (Figure 2C.10-1) is based on the principle of entrained bed gasification at elevated pressure under slagging conditions (i.e., at a temperature sufficiently high to ensure that the ash is in the molten state). The coal is normally crushed and ground to a size (90% less than 90 microns) and dried. The drying is required to ensure the free-flowing characteristics needed for the pulverized coal and to limit the burden of liquid water in the gasifier. As a consequence, hard coal is generally dried to 2-3% moisture, and brown coal, to 6-8% moisture. The pulverized dried coal is pressurized and fed into a reaction chamber of the gasifier through opposed diffuser guns and reacts with the blast, consisting of oxygen or air and steam, in a flame-like reaction. The flame temperatures can be as high as 3300 to 3600 °F, but reactor outlet temperatures normally do not exceed 2550 to 2700 °F. The wall temperature in the reactor is controlled by means of an intricate cooling system. An alternative insulating brick wall reactor is also being investigated at present.

The reactor is equipped with two diametrically opposite burners and consists essentially of a pressure shell that is protected from the hot gases by a tube wall in which saturated steam of 700 psia is raised. The tube is, in turn, protected by a thin layer of a refractory material. The slag, which leaves the reactor via a hole in the bottom, is quenched in water, crushed in a submerged mill, and then lockhoppered out to atmospheric pressure.

The gas leaving the reactor at about 2700 °F and 410 psig is quenched with solids-free recycled synthesis gas at 200 °F to 1450 to 1650 °F. This is to solidify entrained slag particles before they enter the waste heat boiler. The gases leave the waste heat boiler at a temperature of 600 °F. In the waste heat boiler, superheated steam of 930 °F at 700 psia pressure is raised.

The waste heat boiler and the reactor tube wall have a common forced circulation system. About 90% of the solids in the gas are separated in a cyclone. The remainder of the solids is washed out with water in a series of scrubbers and separators after the gas has been further cooled in two economizers. The gas leaving the scrubbers has a solids content of approximately 1 ppm and a temperature of 100 °F. The solids in the circulating water used in the scrubbers are concentrated in a slurry that is reinjected upstream of the cyclone. The water then evaporates, and all solids leaving the waste heat boiler are eventually separated in the cyclone. A small part of the slurry is purged in order to prevent build-up of contaminants. This system has already run successfully in a 6 tpd pilot plant at Shell's Amsterdam Laboratories.

The cool gas, thus treated, still contains sulphur compounds that must be removed. The process used for their removal depends on the particular application of the gas produced. Units for the removal of H_2S, COS, and, if necessary, CO_2 can be hooked up to the gasification plant.

Feed Requirements[1]

The process is suitable for the gasification of almost all types of coal and petroleum coke. Fuels with a high ash content (up to 40% wt) and high sulphur content (up to 8% wt) can be used. High water content in the coal does not pose a technical problem, but on economic grounds (to reduce the oxygen requirement and to improve the quality of the gas) the coal is in most cases dried to a moisture content of 1% - 6% by weight. Coal is normally crushed to 90% below 90 micron size.

Operating Conditions

Flame temperature in the combustion zone can be as high as 3300° to 3600 °F.
Reactor exit gas temperature = 2540° - 2700 °F
Pressure = 410 psig

Gas Produced[1]

Typical raw gas composition based on oxygen gasification of two different types of coal

Feed Coal		Illinois #6	Wyodak
LHV of Coal, Btu/lb		11095	7380
Mole %,	CO	64.0	62.8
	CO_2	0.8	1.3
	H_2	31.6	32.5
	CH_4	0	0
	H_2S + COS	1.4	0.3
	N_2 + Ar	0.7	0.5
	H_2O	1.5	2.6
HHV, Btu/scf, dry		296	292

By-Products

The operation at very high temperatures ensures the formation of a high-quality synthesis gas essentially consisting of hydrogen and carbon monoxide (93 - 98% vol. for oxygen gasification). As a rule, methane concentrations in the gas do not exceed 0.2% vol. Sulphur and ash are produced in varying amounts, depending on the coal type. Tars and oils are negligible.

Utility Requirements[1]

Based on oxygen gasification of the two coals

	Illinois #6	Wyodak
Oxygen, lb/lb coal to gasifier	0.84	0.81
Steam, lb/lb coal to gasifier	0.075	0.024

Thermal Efficiency[1]

Based on oxygen gasification of the two coals:

	Illinois #6	Wyodak
Gasifier proper (LHV basis)%	83.0	83.0
Overall plant (LHV basis)%	78.0	77.0

Capacity

Gasifier dimensions are not available.

Environmental Considerations

The requirements for both process and cooling water have been minimized in the gasification and the solids removal sections. The gas produced contains negligible tars, phenols, condensable hydrocarbons, or organic sulphur compounds. Physical and chemical means are available for removing hydrogen sulphide and traces of cyanide, carbonyl sulphide, and ammonia from the synthesis gas. The only major by-products from the process are elemental sulphur and the unavoidable ash from the coal, of which the bulk becomes available as a non-leachable and inert slag. Depending on the application, the production of wastewater is very low.

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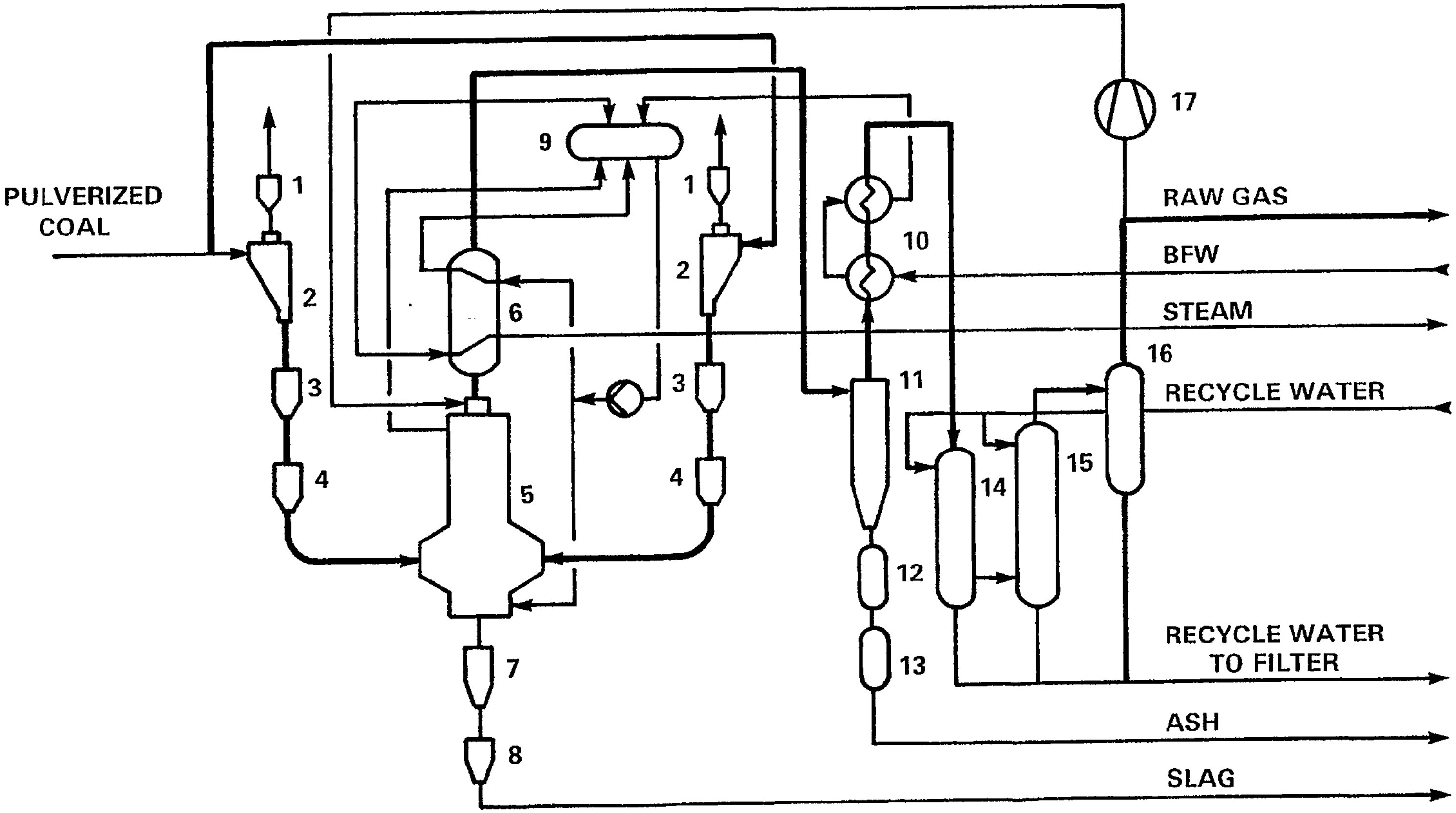
2. Van Oorsouw, F., "The Prospects of Shell-Koppers Gasification in a Power Plant," VGB Conference, Dortmund, West Falenhalle, March 27-28, 1979.

3. Vogt, E. V., and Van der Burgt, M. J., "Status of the Shell-Koppers Process," CEP, March 1980, pp. 65-72.



1 COAL FILTER
2 CYCLONE HOPPER
3 LOCK HOPPER
4 FEED HOPPER
5 GASIFIER
6 WASTE HEAT BOILER
7 SLAG BREAKER
8 SLAG LOCK HOPPER
9 STEAM DRUM
10 BFW PREHEATER
11 CYCLONE
12 ASH HOPPER
13 ASH LOCK HOPPER
14 VENTURI
15 SCRUBBER
16 H.P. SEPARATOR
17 RECYCLE GAS COMPRESSOR

Figure 2C.10-1 Shell Coal Gasification Process.

2C.11 TEXACO

Type

Entrained flow gasifier

Developer/Licensor

Texaco Development Corporation
2000 Westchester Ave.
White Plains, New York 10650

State of Development[1, 2, 3]

The Texaco coal gasification process (TCGP) is a pressurized, entrained flow process for producing synthesis gas from solid carbonaceous feedstocks. Demonstration projects are presently in operation for coal gasification.

The TCGP was developed from the commercial Texaco Synthesis Gas Generation Process (TSGGP). Since the early 1950s, the TSGGP has produced medium- or low-Btu synthesis gas from a wide variety of liquid and gaseous hydrocarbon feeds. The first commercial TSGGP plant was placed in operation in 1953. Since then, at least 75 plants with a total capacity in excess of a billion cubic feet per day have been built in 22 countries. Early plants were relatively small, producing 5 to 10 MM scfd of synthesis gas in several parallel trains. Recent plants can produce more than 100 MM scfd of gas in a single train.

TSGGP technology experience was used in developing the TCGP. Testing was performed on a 100 tpd, 300 psig pilot plant at Morgantown, West Virginia to test West Virginia coals during 1956-1958. Currently Texaco's development work on coal gasification is being done at its Montebello Research Laboratory in California with two pilot gasifiers, each capable of processing 15 to 20 tpd of coal at pressures ranging from 300 to 1200 psig.

Commercial and demonstration projects underway include a 165 tpd coal gasification unit at the Ruhrchemie Chemical Plant Complex in Oberhausen-Holten, West Germany, which has been in operation since 1978.[1] (See Chapter 2C.9) Synthesis gas from this plant can be used for hydrogen manufacture or as a feed stock for chemical manufacture. Carbon conversion of more than 98% was used as a design basis for this plant, based on Montebello pilot unit tests with the Ruhr region (Germany) coal.

The Tennessee Valley Authority has selected a 190 tpd Texaco coal gasifier to produce synthesis gas. This unit replaces an existing natural gas reformer used to manufacture ammonia. W. R. Grace is assessing the feasibility of a 50,000 Bbl/day coal-to-methanol-to-gasoline plant using Texaco gasifiers. Texaco and Southern California Edison, with support from the Electric Power Research Institute, General Electric Co., Bechtel Power Corp., Japan Cool Water Program Partnership and the Empire State Electric Energy Research Corp. are constructing a 1000 tpd coal gasification combined cycle demonstration plant near Barstow, California.[3]

In addition, Tennessee Eastman has a commercial plant under construction at Kingsport, Tennessee, to manufacture photographic chemicals from coal. This plant, scheduled for startup in 1983 will gasify 900 tpd coal.[4]

Description[1, 5]

The TCGP reactor is a pressurized, entrained flow gasifier with a low residence time and a slurry feed. It is a non-catalytic process involving the reaction of hydrocarbonaceous materials with oxygen at high temperatures and pressure under conditions of insufficient oxygen for complete combustion. The rapid flame-type reactions that take place with this deficiency of oxygen produce a gaseous product consisting primarily of hydrogen and carbon monoxide and lesser amounts of water vapor, carbon dioxide, hydrogen sulfide, methane, and nitrogen.

The temperatures are high enough to produce a slagging mode of operation. Tars, phenols, or other heavy hydrocarbons are nearly absent. The temperature is limited to that which the refractory-lined vessels can withstand and is controlled by using slurry water as a moderator.

The process can be operated in the following two basic modes: (1) direct quench with internal steam generation; and (2) gas cooler with external steam generation. The type of downstream processing and end use of the syngas determine the mode of operation.[3]

The direct quench mode, shown in Figure 2C.11-1, is preferred for the production of high purity hydrogen and ammonia. The coal is ground and mixed with water to form a pumpable slurry, which is fed to a burner together with the oxidant-high purity oxygen. The gasifier consists of a steel vessel with an internal refractory lining and no internal moving parts. The carbon conversion, which is controlled by the amount of oxygen fed to the system, is generally maintained above 90%. The hot gas and molten slag leaving the combustion chamber are contacted with water, thus quenching the raw synthesis gas and saturating it with steam. The solidified slag, which normally has a carbon content below 1% by weight, is removed through a lockhopper and taken away for disposal. The quenched synthesis gas contains small amounts of particulate matter, which are removed by water scrubbing.

The various water streams containing ash and soot are sent to a settler, where clarified water is recovered for recycle. The settler bottoms can be discarded but is normally recycled back to the gasifier by blending it with the coal slurry. A water blowdown stream prevents the buildup of dissolved solids. This stream does not contain tars or phenols.

When the direct quench mode is used, the raw synthesis gas goes directly to a shift converter, since it already contains the steam required for conversion of the carbon monoxide to hydrogen. Since the hydrogen sulfide has not yet been removed from the synthesis gas, a sulfur-resistant shift catalyst, such as the cobalt-molybdenum catalyst developed by BASF, must be used. This approach avoids the need for two acid gas removal steps, one before the shift converter to remove the hydrogen sulfide and the carbon dioxide produced in the gasifier, and another to remove the carbon dioxide produced in the shift converter.

The gas cooler mode of operation is similar except that the raw synthesis gas is not quenched but is sent to a gas cooler, where steam suitable for other uses is produced.

The gas cooler option is used when there is no need for steam in the synthesis gas, such as in the production of clean fuels. The remainder of the TCGP system is the same except for a different routing of some of the water streams. This is necessary because the gas leaving the cooler contains a higher level of particulates, and a more thorough water scrubbing is required.

Feed Requirements[1]

Pulverized coal is required. The process is capable of gasifying a wide variety of caking and non-caking bituminous and subbituminous coals as well as petroleum coke. Pulverized coal is slurried in water and pumped to the gasifier; thus, feed coal of virtually any moisture content can be handled.

Operating Conditions

Temperature of the gas leaving the gasifier = 400° to 500 °F (direct quench mode).
Pressure = 300 to 1200 psig.

Gas Produced

Typical gas composition (dry basis) after gas scrubbing and cooling, oxygen-blown operation

Feed Coal	Illinois #6 Coal
HHV of Coal, Btu/lb, dry	13,150
Mole %, CO	37.6
CO_2	20.8
H_2	39.0
CH_4	0.5
H_2S	1.5
N_2 + Ar	0.6
HHV, Btu/scf, dry	253

By-Products

As a result of high gasification temperature, by-product tars, phenols, and hydrocarbons heavier than methane are negligible.

Utility Requirements

Not Available.

Thermal Efficiency

Cold Gas Efficiency = Approximately 75%

Capacity

The 1000 tpd coal gasification combined cycle demonstration plant near Barstow, California is being designed to generate 100 MW net electric power.

Environmental Considerations[2]

The Texaco coal gasification process exhibits a low pollution level. The fuel gas stream contains a minimal number of by-products. H_2S is removed from the gas stream by conventional acid gas removal and sulfur recovery processes. Most of the water streams are recycled within the process to form the coal slurry or to cool the gas in the gasifiers or the scrubber. Coal ash recovered as granular slag contains less than 1% carbon and shows very low levels of leachability. Thus, it can be disposed of by landfill.

Remarks

The Texaco gasifier has been proven on a commercial scale with liquid and gaseous hydrocarbons for many years. Currently, several demonstration and commercial plants that plan to use the Texaco coal gasifier are in the engineering design phase.

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3. Cool Water Coal Gasification Program - First Annual Progress Report, Electric Power Research Institute, Palo Alto, California, AP-2487, July 1982.

4. Coover, W.H. and Hart, R.C., "Turn in the Road; Eastman Chemicals from Coal," presented at the Annual Meeting of the American Institute of Chemical Engineers, New Orleans, Louisiana, November, 1981.

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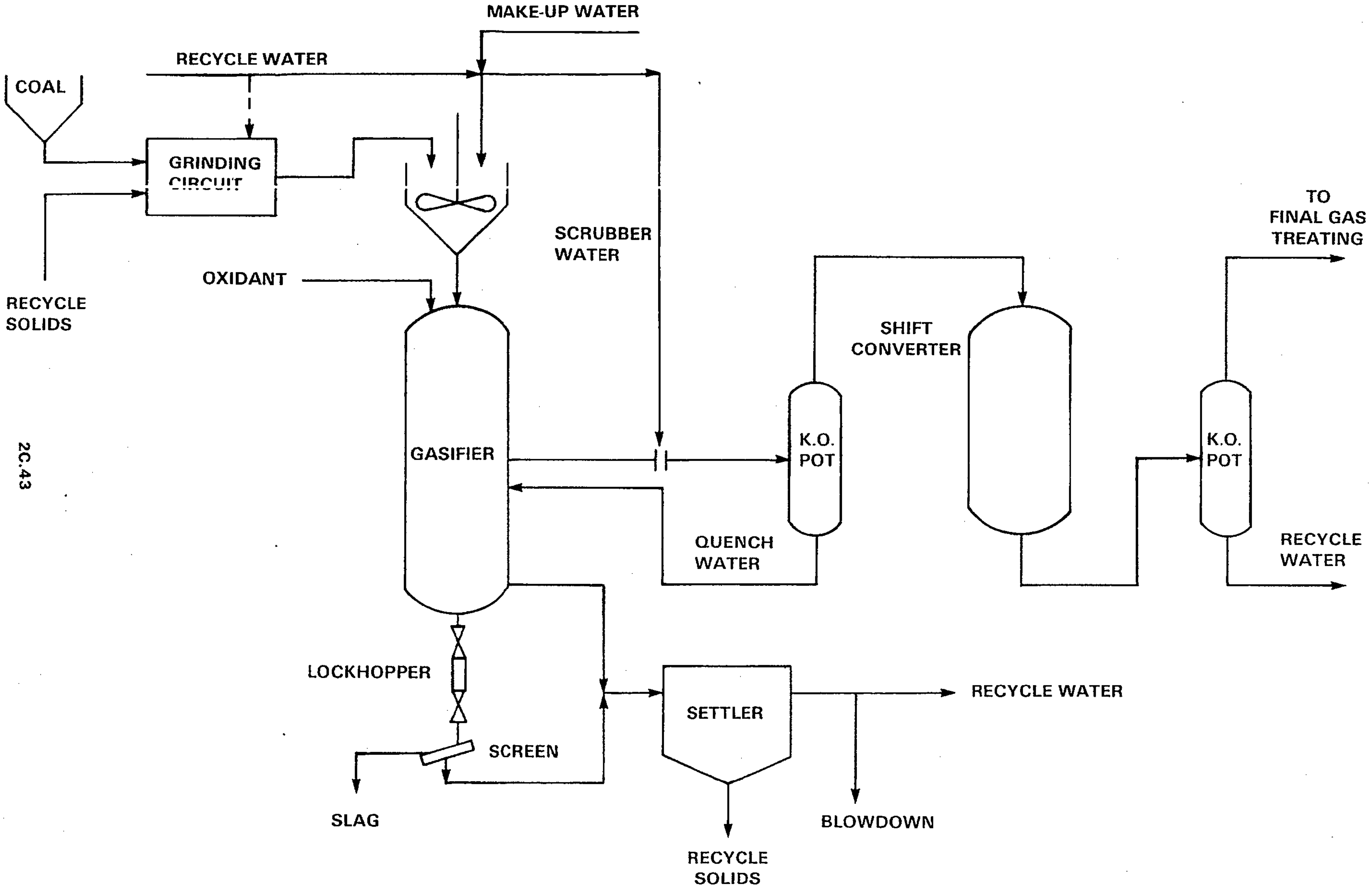

Figure 2C.11-1 Texaco Coal Gasification Process.

2D.1 ALLIS-CHALMERS KILNGAS COAL GASIFICATION

Type

Rotary kiln type gasifier

Developer

Allis-Chalmers Corporation
P.O. Box 512
Milwaukee, Wisconsin 53201

State of Development[1] [2] [pc]

The Kilngas system has been under development by Allis-Chalmers since 1971. Beginning in 1976, eleven electric utilities joined Allis-Chalmers in sponsorship of a 3-year Basic Engineering Program that was designed to evaluate commercial viability and to mitigate process and equipment risks associated with demonstration, particularly those risks relating to pressurized operation.

By mid-1978, the results of the Basic Engineering effort were showing evidence of probable success, which led the sponsoring utility team and Allis-Chalmers to commission a new phase termed "Demonstration Assessment." This phase had several objectives: 1) to conduct an independent economic and technical review of the technology development and commercial forecasts by an eminently qualified process engineering firm; 2) to assess risks and readiness for demonstration; and 3) to prepare business and technical plans for a demonstration program. During this 2-year planning and assessment phase, five additional utilities and an architect/engineer, Gilbert/Commonwealth Company, joined the charter utilities in active participation and financial commitment.

The Electric Power Research Institute also initiated its own formal study of the technology during this period.

The KILNGAS Commercial Module at the Wood River Generating Station of Illinois Power Company will process up to 600 tons per day of 12,500 Btu/lb high-sulfur Illinois coal and will produce 409 million Btu per hour of clean, low-Btu gas at rated output.

Description[2] [3]

The process flow scheme is shown in Figure 2D.1-1, and the gasifier details are shown in Figure 2D.1-2.

Raw coal is fed to the feed end (left end in Figure 2D.1-2) of the rotating kiln, which is sloped to cause the coal to flow through the four process zones. Entering coal is first dried by the exiting hot gases. The coal fines are driven into the bed by the tumbling action of the coal.

After drying, the coal is pre-heated by the exiting gases. Swelling and agglomeration of the coal occur naturally in this stage. Expansion space for free swelling is provided by loading the kiln only partially, and the agglomerates are physically broken down by the tumbling action of the bed.

The pre-heated coal then enters the devolatilization zone, where an air/steam mixture is injected under the bed. This raises the bed temperature and releases volatile matter from the coal. Again, the tumbling bed mixes the coal particles and exposes all of the coal to the devolatilization process.

Finally, the devolatilized coal enters the gasification zone, where the steam-air mixture reacts with the devolatilized coal, or char, and produces the principal combustible products, carbon monoxide and hydrogen.

Some of the remaining ash is removed from the discharge end of the kiln. This ash can be considered generally similar to bottom ash recovered from a conventional power plant boiler. Most of the ash is entrained in the product gas and is recovered by physical separation. This ash is similar to power plant fly ash.

Moderate amounts of hydrocarbon compounds are present in the fuel gas. These compounds are removed from the fuel gas by use of technologies developed to remove similar compounds from coke oven emissions. Other potential pollutants, such as H_2S and NH_3, are also present in the fuel gas. These compounds are removed by conventional methods.

The kiln is operated at moderate temperatures and pressures. Typical kiln temperatures are well below those for iron ore pelletizing or direct-reduction processes. Kiln pressures are higher than those used for other chemical processes using rotary kilns. The product gas, which has a heating value on the order of 150 Btu/scf, is delivered to a combustion unit at pressures of 50 to 250 psig, depending upon the application.

Varying kiln size, operating speeds, and operating temperatures permit virtually any coal type to be processed in the rotary ported kiln. The principal coals used in the development program are Illinois #6 and Pittsburgh #8.

The large kilns always have a considerable inventory of coal in residence at reaction temperature, regardless of gas flow rates. As a result, gas production rates are primarily a function of reactant injection rates. Because of the simplicity of controlling flow rates of the reactants (steam and air), gas production can be quickly increased or decreased, providing load-following capability with inherent process stability. This characteristic is especially valuable for electric utility applications. Single kilns operating in iron ore pelletizing plants can process coal at rates in excess of 6000 tons per day.

Feed Requirement

Almost any type of coal can be gasified. The coal does not require grinding or pre-drying.[1]

Operating Conditions[4]

Kiln temperature = 2000 °F
Designed demonstration plant pressure = 60 psig

Gas Produced[2]

The projected composition of product gas from the demonstration plant, after tar, particulate, and sulfur removal[1]

Feed Coal	High Sulfur Illinois #6
HHV of coal, Btu/lb	12,500
Mole %, CO	20.0
CO_2	10.0
H_2	18.9
$CH_4 + C_nH_m$	1.8
N_2	47.8
H_2O	1.4
Sulfur Compounds	0.1
HHV, Btu/scf, dry	158

By-Products

Ash and sulfur are the by-products.

Utility Requirements[2]

Projected for the demonstration plant

Air, scf/lb of coal	28.2
Steam, lb/ton of coal	50.0

Thermal Efficiency

Cold gas efficiency = 68%

Capacity

The demonstration plant kiln is approximately 200 feet long and 13 feet in diameter. Its projected turndown capacity is 10:1.

Environmental Considerations

Small amounts of condensible hydrocarbons/tars are produced by the KILNGAS System. Condensible hydrocarbons are removed from the gas stream with conventional technology currently being practiced in the coke industry. Tars may be separated and recycled to the gasifier. The net condensate from the gas streams is blown down to the wastewater pretreatment system for oil separation and steam stripping. Fuel-bound nitrogen is converted to ammonia in the gasification process. Ammonia is removed from the product gas in the cleaning systems. A Stretford hydrogen sulfide removal system has been selected for sulfur removal.

Remarks

The process can gasify various types of coal, including fines, without pretreatment - caking coals on a continuous basis, and large quantities of coal in a single unit.

References

1. McWhorter, R. J., et al., "Large-Scale Clean, Low Btu Gas from Coal via the KILNGAS System," presented at American Power Conference, Chicago, Illinois, April 24-26, 1978.
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3. Womeldroff, P. J., et al., "Retrofit of Oil- and Gas-Fired Generating Plants - An Analysis of Alternative Strategies," presented at American Power Conference, Chicago, Illinois, April 21-23, 1980.
4. Ahn, Y. K., et al., "Analysis of Gasifier Pressure Versus Gas Transmission Distance for Single Stage Fixed-Bed Gasifiers," presented at Coal Technology '79 Symposium, Houston, Texas, November 6, 1979.

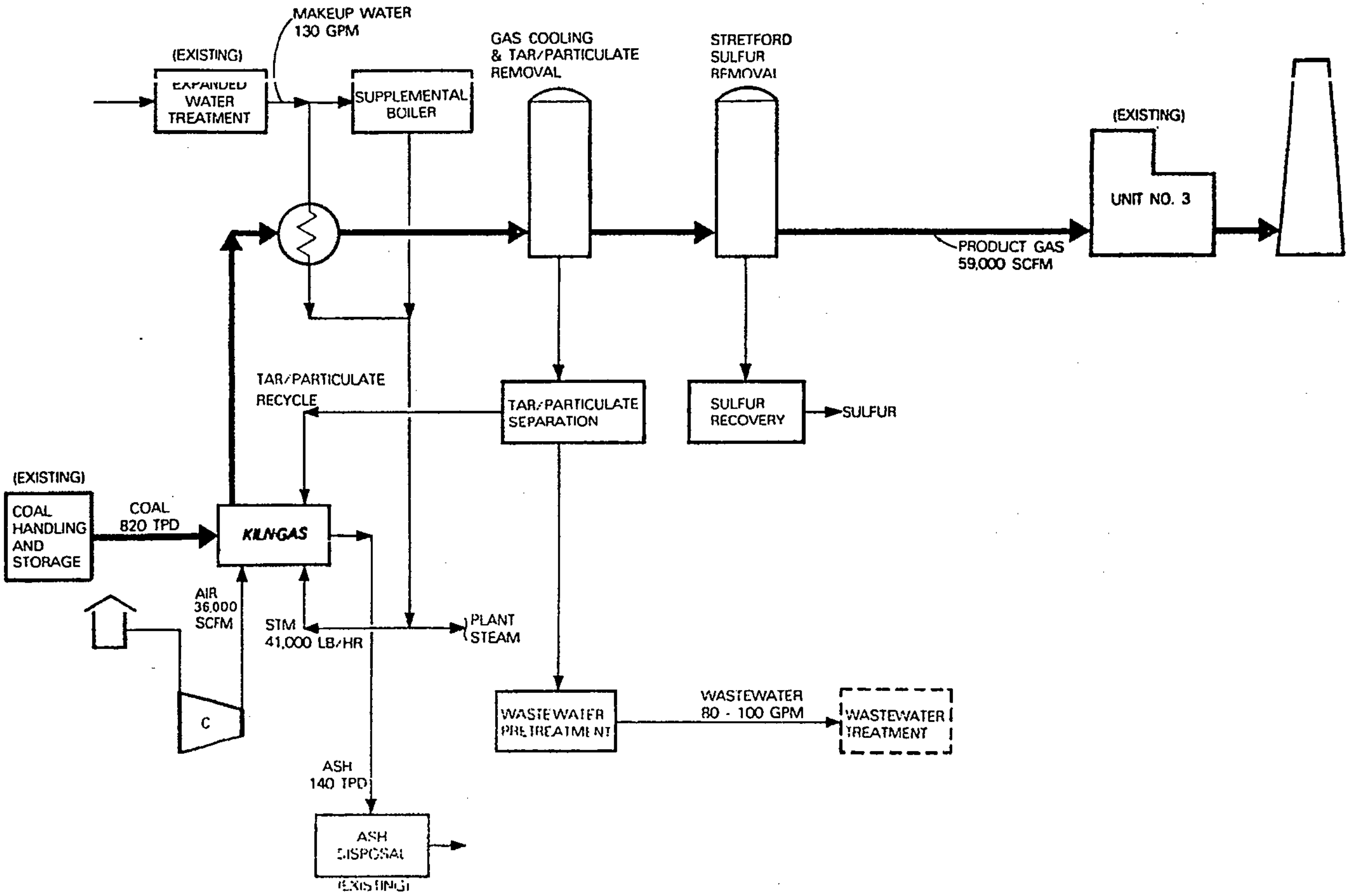

Figure 2D.1-1 Allis-Chalmers Kilngas Gasification Demonstration Plant.

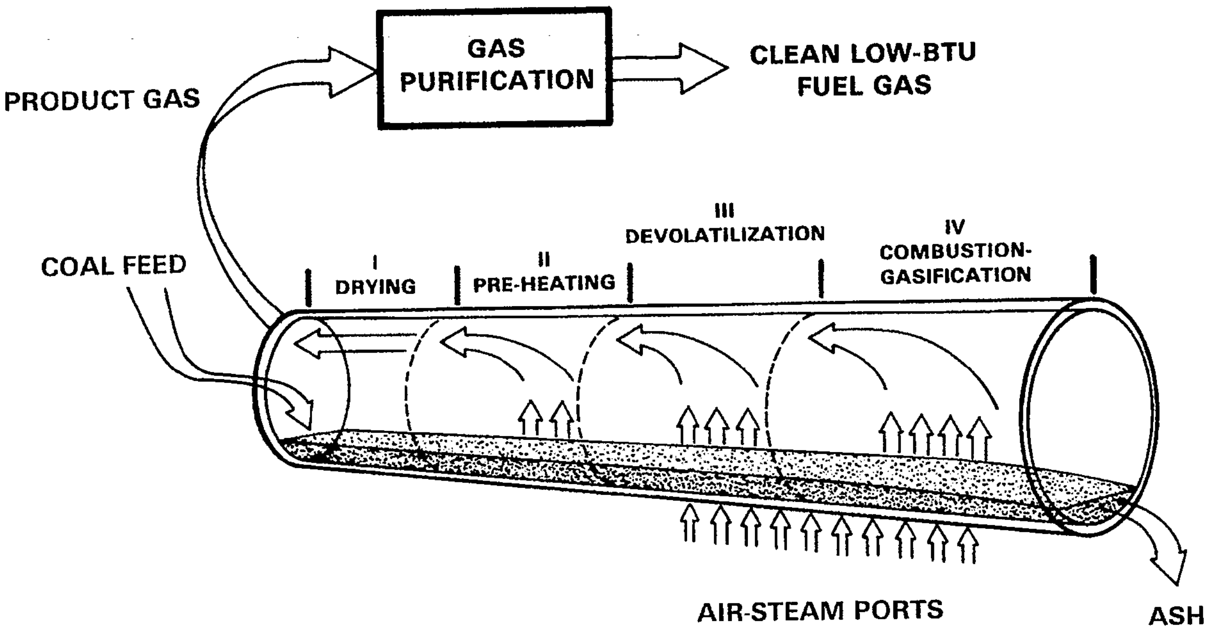

Figure 2D.1-2 Allis-Chalmers Kiln Gasifier.

2D.2 ROCKWELL MOLTEN SALT

Type

Molten salt gasifier

Developer

Rockwell International Corporation
Energy Systems Group
8900 DeSoto Avenue
Canoga Park, CA 91304

State of Development[1,3]

The Rockwell Molten Salt coal gasification process has been operated at bench scale, pilot plant, and in a PDU. The process is being developed for low-Btu gas but is also applicable to medium-Btu gas.

In December 1974, Rockwell was awarded a contract by ERDA (now DOE) for the design, construction, and operation of a 120 tpd pilot plant to produce approximately 15.8 MM scfd of low-Btu gas. The pilot plant size Molten Salt Test Facility (MSTF) consisted of a reactor vessel and supporting equipment for feeding coal and air and combusting the product gas. The reactor vessel was a 4-ft O.D. (3-ft I.D.), 10-ft high stainless steel vessel lined with fused cast alpha-alumina refractory. In a typical pressurized coal gasification test, 1800 lb of Kentucky #9 coal (15% ash, 4% sulfur) was gasified at an average coal feed rate of 470 lb/hr, generating 520 scfm of low-Btu gas with a heating value of 130-160 Btu/scf. Process conditions were 32 psig pressure, with a melt bed temperature of 1900-2000 °F.

This contract was redirected to design and construction of a 1.0 tpd PDU located at Santa Susana, California. This plant has been in operation since November 1978. Integrated process testing at atmospheric pressure was achieved in May 1979. Results to date have been close to those predicted from small-scale tests. The PDU is operating with air feed to the gasifier, producing low-Btu gas.

Description[1,3]

In molten salt gasification, the gasification reactions occur within a pool of molten sodium carbonate. The sodium carbonate melt (1) acts as a dispersing medium for both the coal being gasified and the air used for the gasification; (2) acts as a heat sink, with high heat transfer rates, for absorbing and distributing the heat of oxidation; (3) acts as a heat source for the pyrolysis and distillation of the volatile matter of the coal; (4) reacts chemically with and absorbs the sulfur from the coal; (5) provides an environment in which the sulfur compounds formed act as catalysts for the partial oxidation of the coal; and (6) retains physically the ash present in the coal

The process diagram for the PDU is shown in Figure 2D.2-1. Air is supplied by twin compressors at rates up to 8035 lb/hr, which corresponds to a maximum coal rate of 2000 lb/hr. Dry coal is milled to -8 mesh and transported to a silo. Sodium carbonate is stored in a separate silo, which receives both makeup material delivered by truck and recycled sodium carbonate from the regeneration system. Coal and carbonate are withdrawn from their silos, metered at a ratio of 38% carbonate to coal (at reference design conditions), and injected into the gasifier through four nozzles fed by pressurized lockhoppers. The gasifier (Figure 2D.2-2) is a refractory lined vessel within which the coal-air reaction takes place in an 1800 °F pool of molten salt.

The product gas exits the gasifier vessel from the top, is cooled to 350 °F in a spray cooler, and is then reduced in pressure. A small stream of melt is continuously withdrawn through a side overflow port for ash removal, sulfur removal, and sodium carbonate regeneration. The hot melt stream falls into the quench tank, where soluble components are dissolved and insoluble ash is suspended in the resulting aqueous slurry. The aqueous slurry from the quench tank passes through pressure reduction valves into a flash tank, where steam and liquid are separated. Steam produced in the flash tank is used in a subsequent H_2S stripping step, and the liquid product is pumped to a precarbonator.

The aqueous solution is sparged with CO_2 in the precarbonator to enhance ash settling and prepare the solution for H_2S stripping. The solids are removed from the system by settling and filtration. The clarified green liquor is pumped to a tank that provides surge capacity at this point in the system. Green liquor is then pumped from the storage tank to the top of the H_2S stripper tower, where it is contacted countercurrently with an upflowing stream of steam. Water is condensed from the H_2S-rich gas exiting the stripper.

In a commercial plant, this H_2S stream would then go to a Claus sulfur plant. In the PDU, the H_2S gas is burned in an incinerator, giving a dilute sulfur dioxide gas stream. The SO_2 is reacted with a sodium-carbonate solution in the spray drier to produce a dry powder consisting primarily of sodium sulfite and sodium sulfate. The dry powder is removed from the gas stream by a bag filter and collected for disposal. The liquid from the H_2S stripper is pumped through a carbonator, where CO_2 is absorbed to convert the sodium carbonate to sodium bicarbonate crystals. These crystals are separated from the solution, dried, and decomposed in a calciner to produce regenerated sodium carbonate. The remaining liquid is recycled to the quench tank to dissolve additional melt.

Feed Requirements

The process can gasify all types of coal. It also allows the use of a complete range of coal particle sizes from 1/4 in. down to the fines. There is no requirement for close sizing of coal, removal of fines, or pulverization. The only requirement is crushing to facilitate pnuematic conveying.

The coal should be dried to less than 10% moisture, primarily to prevent plugging or bridging in the solids feed system. The coal feedstock ash fusion temperatures will not be a major consideration, since the gasification temperature (1800 °F) is below the ash softening temperature of virtually all coals.

Operating Conditions[4]

Melt bed temperature = 1800 °F
Gas outlet temperature = 1700 °F
Gasifier pressure = 0 to 280 psig

Gas Produced[1]

Average gas composition (dry basis) based on air gasification of Illinois #6 coal in the PDU for two different runs

Pressure (psig)	0	140
HHV of coal, Btu/lb	12,950	12,950
Mole %. CO	16.4	24.80
CO_2	11.4	5.77
H_2	10.4	5.23
CH_4	0.9	1.84
N_2	60.1	62.35
O_2	0.8	0.01
H_2S (ppm)	Not Available	60
HHV, Btu/scf	96.2	115

Bench scale experiments with O_2 have produced a product gas with a heating value of approximately 300 Btu/scf.

By-Products

H_2S is recovered from the salt in the salt regeneration step. In a commercial plant, it will be fed to a Claus plant, where elemental sulfur will be produced.

Utility Requirements[1]

Based on gasification of Illinois #6 coal and the same PDU runs as above

Pressure, psia	0	154
Air, scf/lb of coal	75	54.1
Salt feed, lb/lb of coal	Not Available	0.17
Electric power (kWh/ton of coal)	Not Available	Not Available

It is estimated that a 207.1 tph commercial plant will produce approximately 500 mW (net) of electric power. It will require 150,000 gpm of cooling water with a 20 °F rise.

Thermal Efficiency

Based on cooled product gas and air-blown operation

Cold Gas Efficiency = 78%

It is projected that a 500 mW combined cycle commercial power plant will have an overall net station efficiency of 37.2% at a gas turbine inlet temperature of 2000 °F.[5]

Capacity[5]

It is projected that a 500 mW combined cycle power plant will have three molten salt gasifiers, each with a capacity of 1440 tpd of coal. Each gasifier will be 19 ft in outside diameter and 50 ft high and will operate at 280 psig. Gas will be produced at 146 Btu/scf.

Environmental Considerations

The sulfur in the feed coal is removed by reaction with the molten salt and subsequently recovered in elemental form from a Claus plant. The product gas, therefore, does not require further sulfur removal for most applications.

The ash is removed as a moist filter cake. It is washed to remove all but a trace of soluble salts, so disposal is not expected to be a problem.

Remarks

The process allows the use of a complete range of coal particle sizes from approximately 1/4 in down to fines, and it accepts all types of coal. Practically all the sulfur and ash of the coal are retained in the melt, thus minimizing the requirements for product gas cleaning. The sulfur is recovered in elemental form using a Claus plant.

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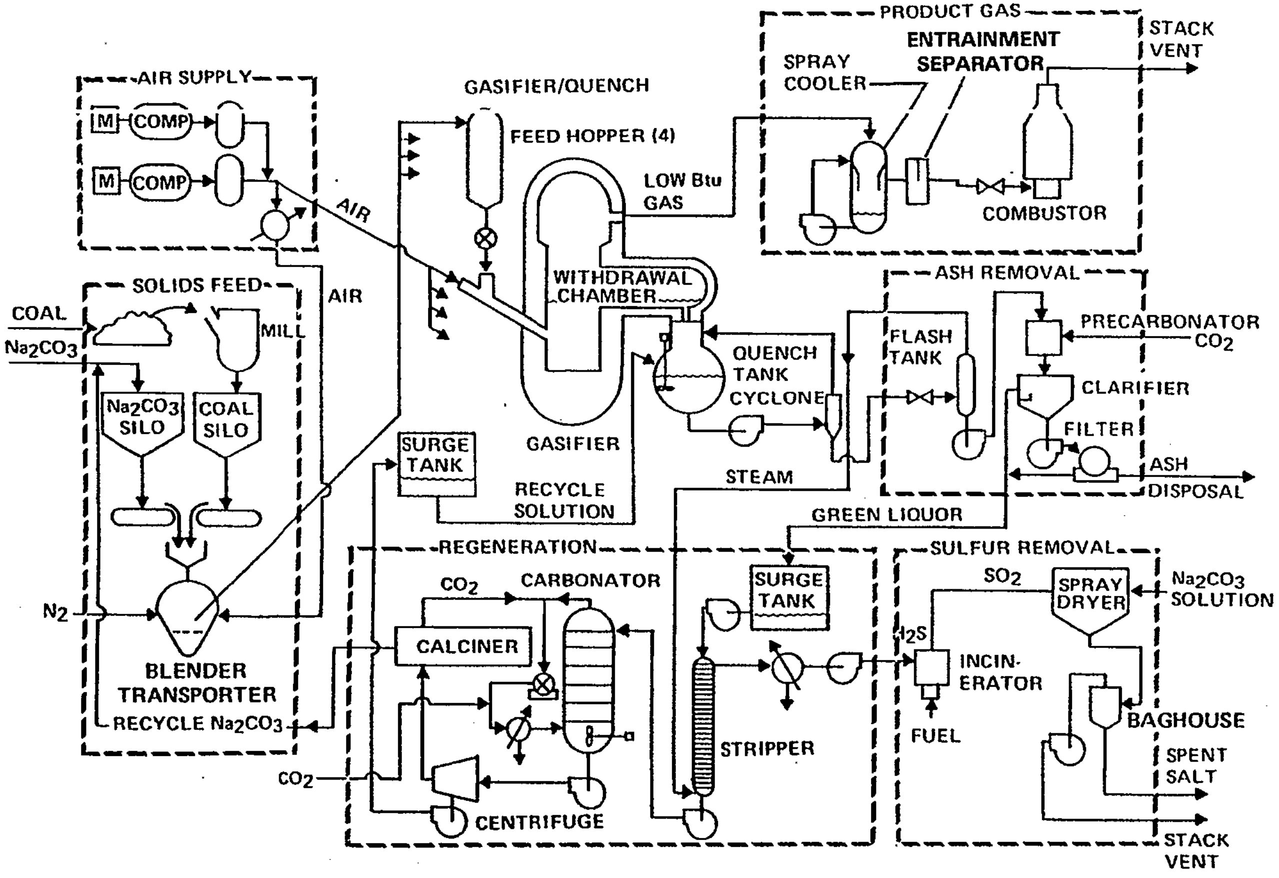


Figure 2D.2-1 Rockwell Molten Salt Coal Gasification PDU.

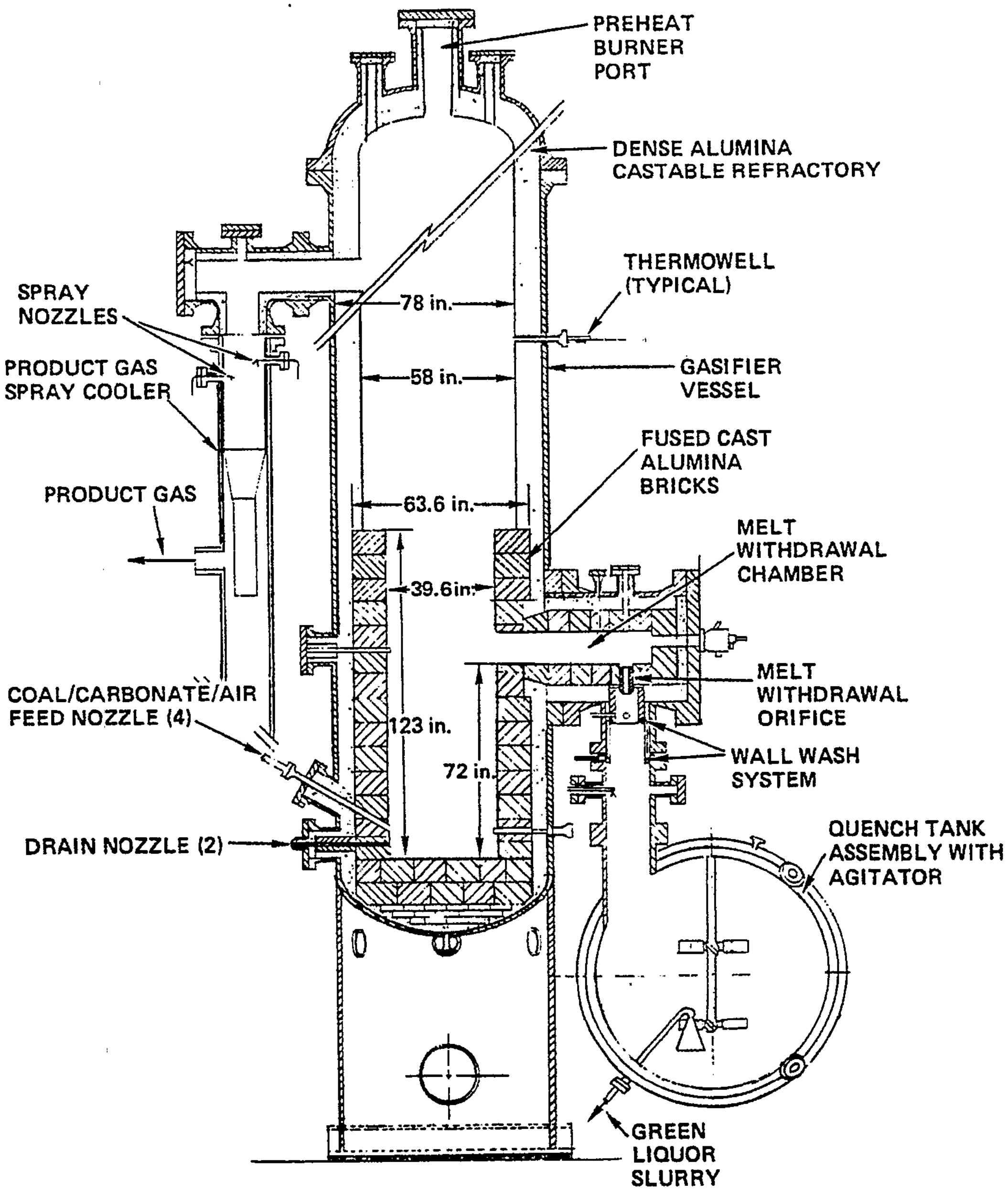


Figure 2D.2-2 Rockwell Molten Salt Gasifier/Quench Assembly.

2D.3 SAARBERG-OTTO

Type

Entrained flow, slag bath gasifier

Developer

SAARBERG + DR. C. OTTO
Gesellschaft fur Kohledruckvergasung mbH
Kokereistrasse
6620 Volklingen-Furstenhausen
West Germany

State of Development[1] [pc]

Since the autumn of 1975, Saarbergwerke AG, Saarbrucken, and Dr. C. Otto & Comp. GmbH, Bochum, have been engaged in the development and testing of a new process for the gasification of coal under pressure. Experience gained with the Rummel/Otto slag bath gasifier in the fifties and sixties has been used in the development of this process.

The two companies agreed to test the entrained flow pressure gasification process on a 11 tph demonstration unit. Design was begun in 1976, and the construction of the plant was completed in 1979. Since December 5, 1979, the plant has been in operation. It is designed for an operating pressure of 350 psig, a coal throughput of 11 tph, and a gas production of approximately 780,000 scfh. The cost of this development project will be shared, with the Western German Ministry of Research and Technology contributing 75%.

The main purposes for the development of this process are investigation of a high-temperature and high-pressure entrained bed gasification technology; improvement of the gasification efficiency; improvement of critical equipment, such as the coal feeding system, the cooling system, slag removal system, and the particulate matter removal system; parallel development of hot gas cleaning systems; and characterization of process effluents.

Description[1] [2]

The Saarberg-Otto gasifier is a high-temperature entrained-flow gasifier of the slag bath type comprising three stages:

Stage I: Primary gasification zone
Stage II: Post gasification zone
Stage III: Cooling zone

Figure 2D.3-1 shows the flow sheet of the Saarberg-Otto process. The feed coal is ground to a grain size of less than 3 mm and dried to approximately 2% (lignite coal to approximately 12%) moisture in the grinding and drying plant indicated by (1) in the flow diagram. It is then pneumatically transported to the storage bin (2). In the lockhopper (3), the coal is pressurized and fed to the feed tank (4). Recycled product gas carries coal dust through four feed pipes into the gasifier (5).

Fuel and gasifying media (steam and oxygen or oxygen enriched air or air) are injected into the gasifier through a system of nozzles and react at temperatures of about 3000-4350 °F. Air or oxygen is preheated, using part of the saturated steam from the waste heat system; superheated steam from the high-pressure system serves as process steam. The nozzles are oriented in a downward and tangential direction toward the surface of the molten slag bath.

The primary gasification zone and post gasification zone, Stages I and II of the gasifier, have an outer pressure shell and an inner shell of water-cooled, closely spaced tubes. Initially the tube wall construction is protected by castable refractory, which quickly becomes replaced by slag when the gasifier is operated. Stage III is refractory-lined. Excess slag flowing off through a central tap hole is granulated in a water bath and discharged through a lockhopper (6). The granulated slag contains less than 1% unconverted carbon.

The slag and coke particles entrained in the rising, rotating gas stream are partially removed in a throat between the primary gasification zone and the post gasification zone. These particles are thrust against the layer of solid slag sticking to the cooling system and flow back to the bath. The rotational velocity is reduced when the gas has passed the throat, so undesirable deposits are avoided in the post gasification zone. The heat requirement for post gasification in the second stage is met by the sensible heat of the incoming gas, which has a temperature of approximately 2700-3100 °F.

In the cooling zone of the gasifier, the gas is cooled from 2200-2700 °F to between 1500-1700 °F. The liquid slag droplets in the gas stream are thus solidified. Fly coke and ash particles are separated in the cyclone (8), the waste heat boiler (11), and dedusters of the fibrous filter type (12). The recovered dust is returned to the gasification process. The raw gas is cooled to 460-550 °F in the waste heat boiler, where it produces high-pressure steam, and to 100 °F in the spray cooler (13). The cooled gas is further processed in a desulfurization plant.

In the Saarberg-Otto gasifier, high spot temperatures are possible. The slag bath acts as a heat shield and ensures safe combustion. The injection mechanism effects a high turbulence in the rotating mixture of particles and gas above the slag bath and so, in conjunction with the high temperature, increases the velocity of the reaction. The slag bath allows the gasification of relatively big particles.

Feed Requirements[1] [2]

All types of coal (with ash content up to 40% by weight) can be gasified. In addition, residues of coal hydrogenation plants and refineries can also be gasified. Solid and liquid fuels can be simultaneously gasified.

Operating Conditions

Maximum reaction zone temperature = 3000-4350 °F
Temperature of gas leaving the gasifier = 1500-1700 °F
Design pressure = 350 psig

Gas Produced[1]

Typical raw gas composition (dry basis) on the basis of gasifying a bituminous coal (ash content = 8% by wt MF coal and sulfur content = 1% by wt MF coal)

Feed Coal	Bituminous
HHV of coal, Btu/lb, dry	13,500
Mole%, CO	58
CO_2	10
H_2	31
CH_4	0.5
N_2	0.2
H_2S	0.3
HHV, Btu/scf, dry	284
Production rate, scf/lb of coal	34

By-Products

Very high temperatures cause complete destruction of tars, phenols, and other heavy hydrocarbons. The only significant by-products are sulfur compounds and granulated slag containing less than 1% carbon.

Utility Requirements[1]

On the basis of gasifying the same bituminous coal

O_2, lb/lb of coal = 1.0
Steam, lb/lb of coal = 0.15

Thermal Efficiency

On the basis of gasifying the same bituminous coal

Cold gas efficiency = 73%
Overall thermal efficiency = 88-94%

Capacity

The demonstration plant can gasify 264 tons per day of coal. The gasifier has a 4-ft, 10-in I.D. and is about 50 ft high.

Environmental Considerations

The environmental impact caused by the Saarberg-Otto process is not a major concern. The gas produced is free of tars, phenols, condensable hydrocarbons, and organic sulfur compounds. For the removal of hydrogen sulfide and carbonyl sulfide, proven processes are available. The only by-products are sulfur and granulated slag, the latter being an environmentally inert material. The wastewater, with very low content of ammonia and cyanide, amounts to less than 0.2 lb per lb coal input.

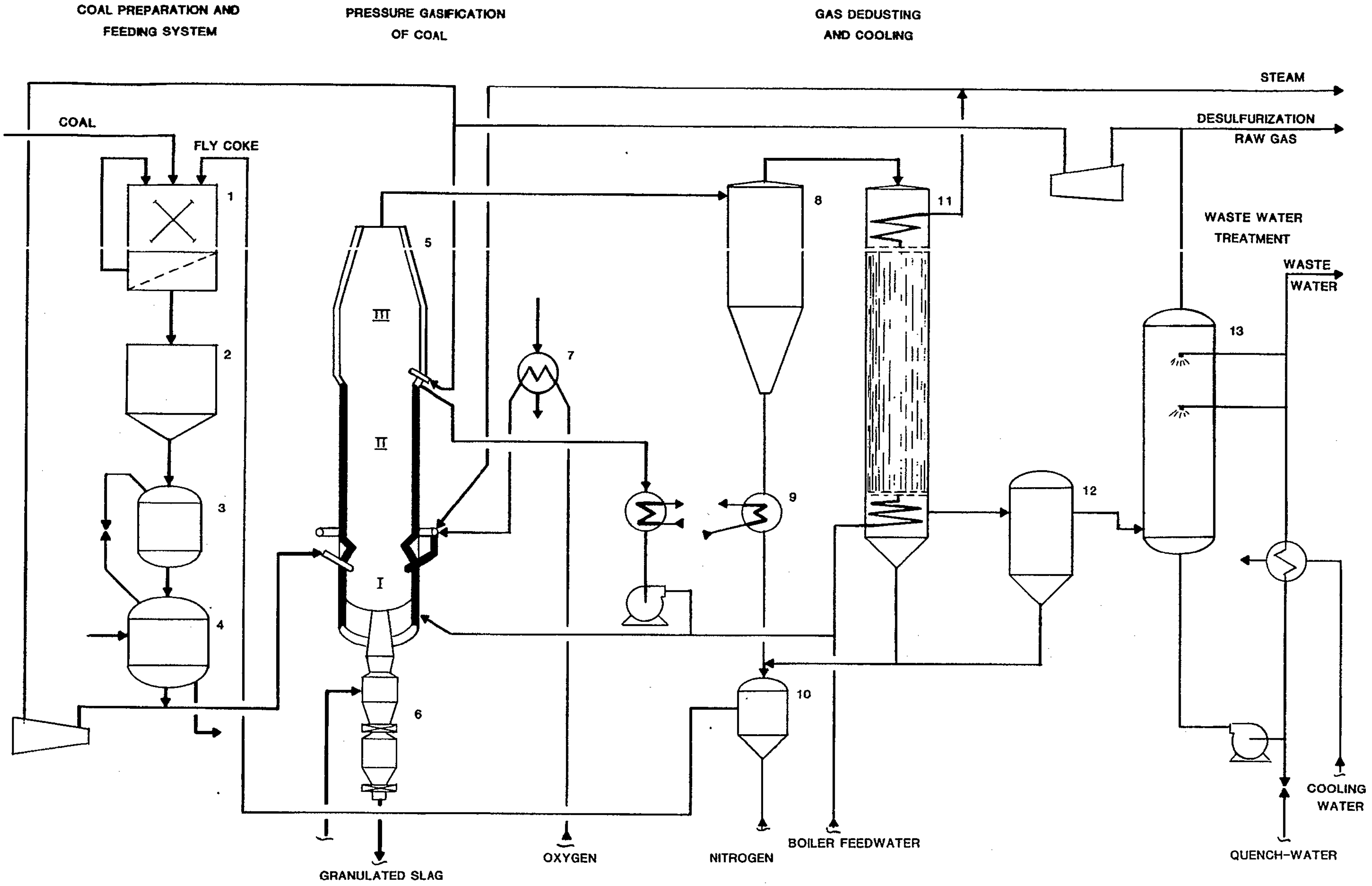
Remarks

Because of very high gasification temperatures, a sophisticated cooling system is necessary. The water cooling system works well. The tube walls, initially protected by castable refractory, are then covered by molten slag freezing on the cooled tubes, thus providing further protection. The particulates in the gas are removed by a cyclone, waste heat boiler, and fibrous filters.

References

1. Brocke, W., and Rossbach, M., "Saarberg-Otto Gasification Process," presented at the First International Gas Research Conference, Chicago, Illinois, June 9-12, 1980.

2. "Saarberg-Otto-Pressure Gasification of Coal," Bulletin, Saarberg and Dr. C. Otto.



1 GRINDING AND DRYING PLANT	6 SLAG REMOVAL SYSTEM	10 CHAR LOCK HOPPER
2 STORAGE BIN	7 OXYGEN PREHEATER	11 WASTE HEAT BOILER
3 LOCK HOPPER	8 CYCLONE	12 BAG FILLER
4 FEED TANK	9 FLY COKE COOLER	13 SPRAY COOLER
5 GASIFIER		

Figure 2D.3-1 Saarberg-Otto Gasification

3A.1 ACTIVATED CARBON ADSORPTION

Suppliers

1. Calgon Corporation
   Activated Carbon Division
   Calgon Center
   Box 1346
   Pittsburgh, PA 15230

2. United Catalyst, Inc.
   P. O. Box 32370
   Louisville, KY 40232

State of Development[1] pc

The activated carbon adsorption process was developed by I. G. Farben Industries in the 1920s. Since that time, it has been used extensively for the removal of H_2S and other low molecular weight sulfur compounds from industrial gases. More than 60 commercial plants using the process are in operation in the United States.

Process Description

Feed gases, containing low molecular weight sulfur compounds, enter the top of the adsorber tower and flow downward through a bed of activated carbon. The activated carbon, chemically adsorbs H_2S and physically adsorbs mercaptans. The purified gas then exits the bottom of the tower. When COS is present in the gas, the use of activated carbon is not recommended.

After the bed of carbon becomes fully loaded with sulfur compounds, it must be regenerated before further use. This is accomplished by raising the temperature of the carbon bed to 450°-500°F with superheated steam at or near atmospheric pressure. More efficient regeneration can be accomplished by injecting the steam countercurrently to the flow of gas during adsorption. Condensate formed in the steaming operation usually contains liquid hydrocarbons and must be removed via a drain valve. After the carbon bed reaches 350°F, the steaming is continued for 4 to 6 hours. During this time air is added in incremental amounts until the oxygen concentration in the steam-air mixture reaches about 0.5 vol%. In this regeneration step, metallic sulfides from H_2S absorption are converted back to the oxide form, while elemental sulfur is formed and accumulates in the bed. The physically adsorbed mercaptans are desorbed and removed with the regenerated gas steam.

Most installations have parallel adsorber towers so that one can be regenerated while the other is in use. (See Figure 3A.1-1.) With care, it is possible to change towers with a negligible effect on process flow. Depending upon the flow and adsorption requirements, two parallel trains with two series flow towers each may be required.

The bed of activated carbon gradually loses its adsorption capability as the particle surfaces are covered and the pores are plugged with elemental sulfur or other materials, such as heavy hydrocarbons. As much as 10-20 pounds of elemental sulfur per 100 pounds of activated carbon can be accumulated before it becomes necessary to replace the carbon bed with fresh material.

Chemical Description

Activated carbon itself is manufactured from selected grades of bituminous coal, coconut shell char, or other carboniferous materials. Following high temperature activation under rigidly controlled conditions, the carbon is specially impregnated with 5-10% of metallic oxides. Activated carbon materials are available in several mesh sizes and can be tailored to specific uses.

The actual mechanism of sulfur removal by activated carbon has not been clearly established. It is believed that desulfurization of the gas is accomplished by a combination of chemical absorption and physical adsorption. Thus, the H_2S in the gas reacts with the metal oxide activators in the carbon to form metal sulfides. Other low molecular weight sulfur compounds, such as CH_3SH and COS, are probably physically adsorbed on the carbon particles.

Operability Limits

Apparently, there is no pressure limitation for operation of the activated carbon process.

Lower gas feed temperatures favor adsorption of sulfur compounds. The upper temperature limit for the feed gas is about 150°F.

Activated carbon can be used to remove fairly high concentrations of H_2S and other low molecular weight sulfur compounds. However, there is a practical limitation on these concentrations, since activated carbon can adsorb only a fixed quantity of sulfur compounds before regeneration is required. Generally, bed regenerations more frequent than once every three days are not recommended for commercial operations. For this reason, the activated carbon process is considered most applicable for desulfurizing gas streams containing up to 2 grains/100 scf of total sulfur (approximately 30 ppm H_2S).

High molecular weight hydrocarbons in the gas stream will have an adverse effect on the desulfurizing capacity of the carbon, since they will tend to plug the pores of the carbon particles and are relatively difficult to remove during regeneration.

Purification Limits

Natural gas can be purified to a breakthrough value of 0.2 ppm of sulfur. Until breakthrough is reached, the sulfur content of the gas will be essentially nil. When breakthrough occurs, the sulfur concentration in the exit gas will increase rapidly to that of the feed gas. Increasing the breakthrough limit from 0.2 ppm to 1 ppm will not increase the sulfur removing capacity of the carbon significantly.

Utility Requirements

The main utility requirement for the activated carbon process is the energy required during regeneration to heat the carbon bed and desorb the sulfur compounds. Superheated steam (400-500°F) at or near atmospheric pressure is usually used. The quantity of steam required averages 8 to 10 pounds of steam per pound of adsorbed material. Steam requirements of 50-100 pounds per cubic foot of carbon for an average regeneration have also been reported.

Carbon eventually becomes fouled and must be discarded. The life of the carbon varies considerably, but in most applications a useful life of greater than two years may be expected. The actual amount of carbon used is dependent upon the specific process.

Environmental Considerations

The sulfur in the H_2S may be recovered in the form of elemental sulfur after regeneration. Low molecular weight sulfur compounds other than H_2S are removed with the regeneration steam and may require some form of treatment before disposal.

Remarks

Although the activated carbon process is capable of removing high concentrations of sulfur from various gas streams, it is usually used for desulfurizing gas streams having up to about 30 ppm of sulfur. High sulfur concentrations require either frequent regenerations of the activated carbon or large bed volumes. High molecular weight hydrocarbons have an adverse effect on bed capacity.

Sulfur is deposited on the carbon in elemental form and discarded with the carbon when the bed is replaced.

There appears to be no limitation on the pressure at which activated carbon can be used, but the operating temperature should not exceed 150 °F.

References

1. Risenfeld, F. C. and A. L. Kohl, "Gas Purification," 2nd Edition, Gulf Publishing Co., Houston, Texas, 1974.

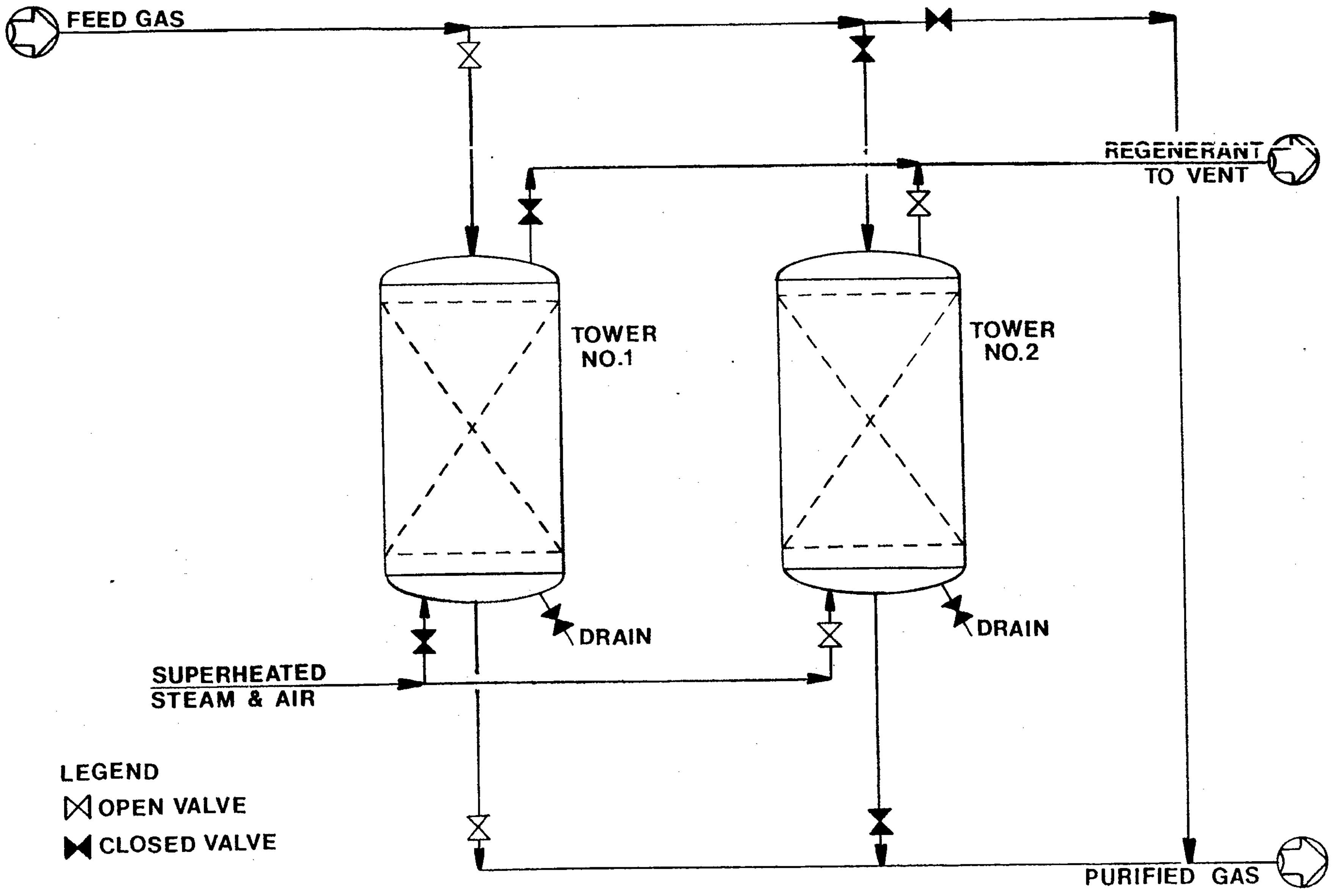


Figure 3A.1-1 Activated Carbon Adsorption.

3A.2 ADIP PROCESS

Licensor

Shell Development Company
One Shell Plaza
P.O. Box 2463
Houston, TX 77001

State of Development

The ADIP process as developed by Shell uses an aqueous solution of di-isopropanol-amine (DIPA) to remove H_2S from industrial gases. The process is used for treating LPG and NGL streams to selectively reduce H_2S and COS concentrations to low levels. The process has been applied to natural gas, refinery gas, synthetic gas, and liquid hydrocarbons. More than 150 of these plants have been constructed worldwide since 1959.[1] [pc] The plant capacity may range from a few MM scfd to over 100 MM scfd.[2]

Description[3] [4]

The ADIP process is shown schematically in Figure 3A.2-1. Sour gas to be cleaned enters the bottom of the absorber, and an aqueous solution of DIPA is pumped to the top. The lean solution absorbs H_2S and some of the CO_2 and COS as it passes countercurrently to the gas. The purified gas exits at the top of the absorber.

Rich solution from the absorber bottom is heated by interchange with the hot lean solution and flows to the regenerator. Here the absorption reactions are reversed by heat supplied by stripping steam generated in the reboiler. As the steam passes countercurrently to the rich solution, regenerated acid gases are driven overhead. Steam is condensed and separated from the acid gases and refluxed to the regenerator, while the gases go to sulfur recovery.

Hot lean solution is pumped from the regenerator bottom and cooled by interchange with the cool rich solution. It then passes through a water cooled exchanger and returns to the absorber to continue the absorption process.

Chemical Description[4]

The ADIP solution contains the chemical absorbent di-isopropanol-amine (DIPA) with the structural formula: $[CH_3CH(OH)CH_2]_2NH$. The absorption/regeneration reactions of H_2S and CO_2 with DIPA can be expressed as:

$$R_2NH + H_2S \longleftrightarrow R_2NH_2 \bullet HS$$
$$R_2NH + CO_2 + H_2O \longleftrightarrow R_2NH_2 \bullet HCO_3$$

In the above equations, R_2NH is DIPA.

DIPA reacts with COS to form thiocarbamates, just as monoethanol-amine (MEA) does. MEA, however, reacts further to form di-ethanol urea or cyclic compounds of the oxazolidone or imide type. The latter type of compounds is not regenerable under normal process conditions, and MEA losses occur. In the case of DIPA, the reaction does not proceed beyond the thiocarbamates formation. This reaction, along with the absorption reactions with H_2S and CO_2, is reversed in the stripper endothermally to form CO_2, H_2S, and DIPA. However, in the ADIP process, a long residence time is required for COS absorption, which is normally feasible in liquid treaters, but not in gas treaters.

Operability Limits[4]

The absorber operates at a 100 to 140 °F temperature, which is established by the heats of reaction and the regenerated solvent cooling. The absorber will operate at pressures up to 3000 psig. Normal operating pressure is 255 psig. Higher-pressure operation favors the absorption reaction rate. The regenerator operates at lower pressures, usually near atmospheric, and higher temperatures in the range of 250 to 275 °F. The process can be adapted for treatment of various feed gas contents and rates by selecting proper operating conditions.

Purification Limits[1]

The process can reduce H_2S content in natural gas to less than 5 ppm by volume, in synthesis gas to less than 100 ppm by volume, and in LPG to less than 1 ppm by weight. Other acid gases, in addition to COS, are removed depending on their concentrations and the operating conditions. Selective amounts and rates of absorption for H_2S, CO_2, COS, and other gases can be achieved by proper selection of operating pressure, DIPA concentration, flow rates, etc., to suit the feed gas.

Utility Requirements[4]

Typical utility requirements per MM scf when treating a gas containing 10 vol% H2S, and 2.5 vol% CO_2 at 255 psig, with 2 ppm H_2S and 0.2 vol% CO_2 in the purified gas, are estimated at

Steam, lb/MM scf	22,000
Cooling Water, gal/MM scf	Not Available
Electric Power, kWh/MM scf	85

DIPA losses are normally limited to mechanical leakages.

Environmental Considerations

H_2S and COS in the acid gases exiting the stripper require further processing in a sulfur recovery unit, such as a Claus.

Remarks

The ADIP solution is not corrosive, and carbon steel construction is employed. The ADIP process uses a dialkanol amine chemical absorbent (DIPA) for the acid gas removal, and it is not degraded by COS. Therefore, the ADIP process is suitable for regenerative COS removal. However, when used in an aqueous solution, as is the case in the ADIP process, DIPA requires a long residence time for COS removal, which is difficult to achieve for gases. In processes such as the Sulfinol process (Section 3A.23), where DIPA is dissolved in Sulfolane, a more effective contact between DIPA and COS is possible because COS has a higher solubility in Sulfolane.

When compared with the traditional amine solutions, the solvent has not only a high kinetic selectivity for H_2S with respect to CO_2 but also a well-balanced alkalinity resulting in low steam consumption. Amine losses by degradation and volatility are negligible.

References

1. "Gas Processing Handbook," Hydrocarbon Processing, April 1979, p. 104.
2. ADIP Process, Brochure by Shell Development Co., 1980.
3. Ouwerkerk, C., "Design for Selective H_2S Absorption," Hydrocarbon Processing, Vol. 57, No. 4, April 1978, p. 89.
4. Environmental Assessment Data Base for Low/Medium-Btu Gasification Technology, Vol. II, EPA Report #600/7-77-1256, November 1977, p. B-40.

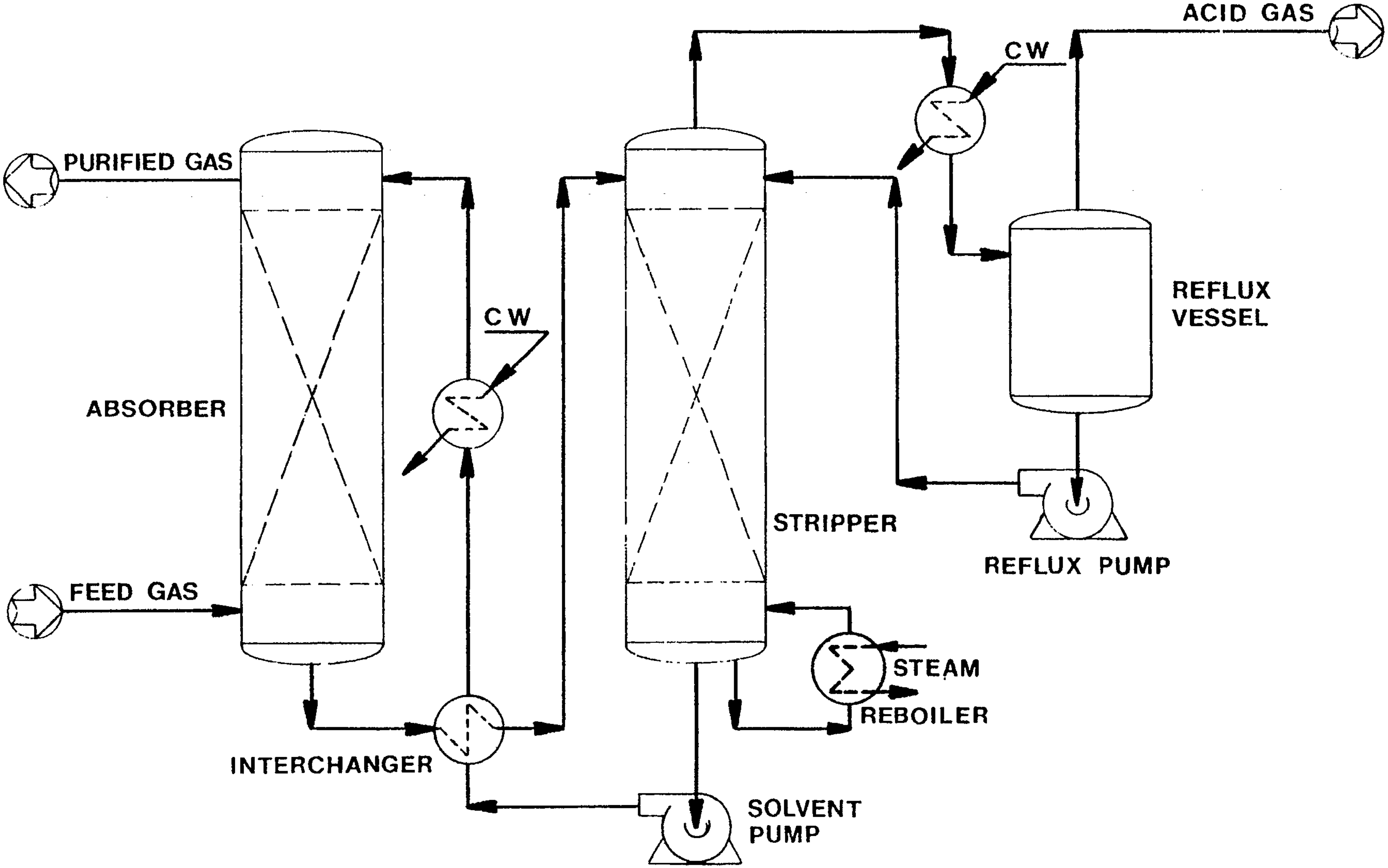


Figure 3A.2-1 Adip Process.

3A.3 ALKAZID

Licensor

Davy McKee AG
5 Koln-Braunsfeld 41
Postfach 45 02 80
West Germany

State of Development

The Alkazid (alka-acid) process was originally developed in Germany by the BASF Corporation in 1935. As an absorption medium, the process uses an aqueous solution (approx. 25%) of alkali salts of weak nonvolatile amino acids. Two different absorption solutions, Alkazid M and Alkazid DIK, are used commercially, each having a specific field of application. Alkazid M solution is used for removal of H_2S and CO_2 simultaneously. The Alkazid DIK solution is used for the selective absorption of H_2S. More than 100 plants are operating in Europe, the Middle East, and Japan.[1] [pc] The process is suitable for treating synthesis gas, water gas, natural gas, and hydrocarbon liquids at atmospheric and elevated pressures.[pc] No commercial installations are known to exist in the United States, although pilot scale units have been used to study the process.

Process Description[1]

The Alkazid process is shown schematically in Figure 3A.3-1. Sour feed gas to be purified enters the bottom of the absorber, and the Alkazid solution is pumped to the top. This lean solution absorbs H_2S and/or CO_2 from the feed gas as it passes countercurrently to it. The purified gas exits at the top of the absorber.

The rich solvent, containing the absorbed acid gases, is pumped (if required) from the absorber, heated by interchange with hot lean solvent, and enters the top of the stripper. Here the absorption reactions are reversed by heat and the regenerated acid gases are driven overhead. Steam is condensed and separated from the acid gases, which are then sent to sulfur recovery. Hot lean solvent is pumped from the stripper and cooled by interchange with the cool rich solvent. It is then further cooled with water and returned to the absorber to continue the absorption process.

Chemical Description[2]

The two types of absorbents primarily used in this process are (1) Alkazid M, which is an aqueous solution of a potassium salt of methyl-amino-propionic acid, and (2) Alkazid DIK, which is a potassium salt of dimethyl-amino-acetic acid. The DIK solution is the more selective absorbent for H_2S in the presence of CO_2, CS_2 and/or HCN. Pilot plant studies were conducted by the U.S. Bureau of Mines to evaluate the Alkazid DIK solution as a selective absorbent for H_2S in the presence of CO_2. Results indicated that the solution has the capability of absorbing large amounts of H_2S, particularly at low CO_2:H_2S ratios in the feed gas. Some degradation of the solvent has been observed when HCN and O_2 are present in the feed gas.

Operability Limits

The process can be operated over a wide pressure range, typically 0 to 1000 psig. The stripper is usually operated at low pressure, about 5 psig. The absorber is normally operated at near ambient temperatures, but in some applications the operating temperatures are below ambient, and chilled water is required. Operating conditions can be varied to meet the feed and purified gas requirements.

Purification Limits

The acid gas content of the purified gas depends upon the operating pressure and temperature, the ratio of CO_2:H_2S in the feed gas, and any requirements regarding the acid gas composition. Low-pressure operation in the absence of CO_2 in the feed gas produces a gas containing 85 ppm H_2S Low-pressure operation with high CO_2 content in the feed gas produces a gas containing 320 ppm H_2S, which is desirable if the recovered acid gas is to be further processed in a Claus unit. With a smaller H_2S:CO_2 ratio in the recovered acid gas, and thus with less selectivity, a gas containing less than 5 ppm H_2S can be produced in high-pressume operation.

Utility Requirements

Typical requirements per MM scf of feed gas containing 0.7 vol% H_2S and 30 vol% CO_2, at 1100 psig and 77 °F, with 5 ppm H_2S in the purified gas, are

Steam, lb/MM scf	15,500
Cooling Water, Gal/MM scf	93.500
Electric Power, kWh/MM scf	230

The Alkazid solution has essentially no solvent vapor pressure. This accounts for the zero loss factor of the reagent during the desorption cycle. Reagent losses are limited to mechanical leakages and any degradation caused by HCN and O_2, if present in the feed gas.

Environmental Considerations

H_2S and CO_2 in the acid gas require further processing in a sulfur recovery unit, such as a Claus.

Waste effluent solution will be generated if O_2 or HCN is present in the feed gas. Final disposal must be determined for each installation.

Remarks

The Alkazid process selectively removes H_2S from feed gases containing H_2S and CO_2, particularly at low CO_2:H_2S ratios. The Alkazid solution has essentially no solvent vapor pressure and none of it is lost in the desorption step. Loss of the Alkazid reagent is limited to mechanical leakages and degradation by HCN and O_2, if present.

It is reported that the Alkazid solutions are relatively noncorrosive; however, it is German practice to use aluminum and special alloys for the hot solution pumps and lines, stripper, and reboiler.

The low solubility of hydrocarbons in Alkazid solutions results in minimum loss of hydrocarbons in the feed gas.

References

1. "Gas Processing Handbook," Hydrocarbon Processing, April 1979, p. 106.
2. Riesenfeld, F. C., and A. L. Kohl, "Gas Purification," 2nd Edition, Gulf Publishing Company, Houston, Texas, 1974.

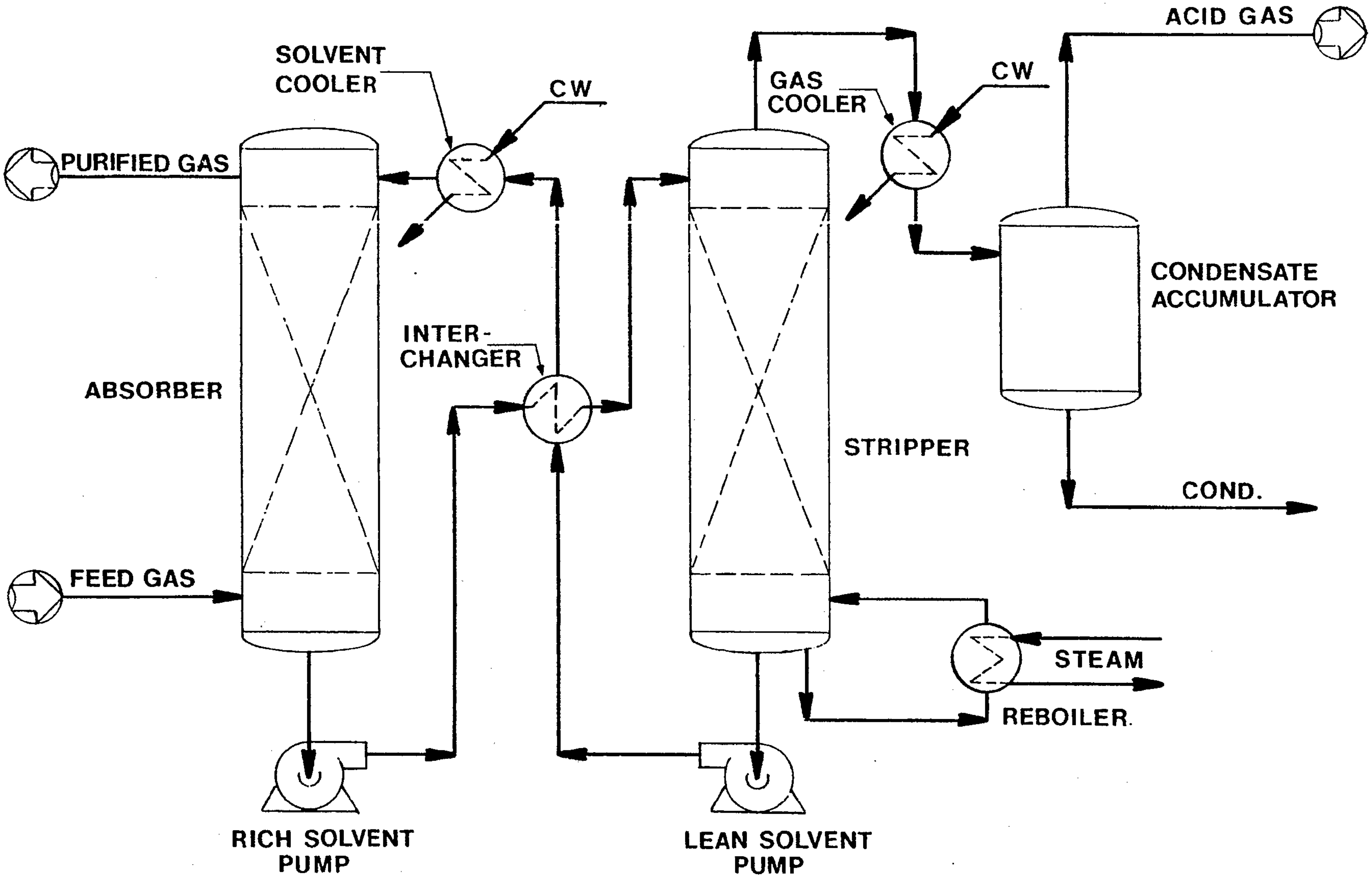


Figure 3A.3-1 Alkazid Process.

3A.4 AMISOL

Licensor

Lurgi Kohle und Mineraloeltechnik GmbH
Bockenheimer Landstrasse 42
Postfach 119181, D-6000
Frankfurt Am Main 1
West Germany

State of Development

The Amisol process is a combination of physical/chemical absorption of acid gases. It was developed by the Lurgi Company for the complete removal of CO_2, H_2S, COS, and other organic sulfur compounds from synthesis gas. The process uses a mixture of alkanolamine (MEA, DEA) with methanol as a solvent.

At present, one commercial plant is in operation and one under construction, with a total throughput of 61 MM scfd.[1]

Process Description

The Amisol unit consists mainly of three columns - absorber, regenerator, and methanol distillation columns. As shown in Fig. 3A.4-1, feed gas is scrubbed in the absorber by countercurrent contact with the solution mixture. The purified gas is washed by water at the top of the absorber to recover the methanol vapor. Acid-gases-laden rich solution flows directly to the regenerator without heating. In the regenerator, the rich solution is flashed to atmospheric pressure and then stripped by the rising methanol vapor. A low-pressure steam reboiler generates methanol vapor by heating the solvent mixture. After cooling the solvent mixture with water, the regenerated solvent returns to the absorber. Methanol vapor in the acid gases from the overhead of the regenerator is recovered by water washing and further condensing and reflux of the acid gas stream. Dilute methanol-water mixtures from the top sections of both absorber and regenerator are fed to the distillation column, where the methanol is purified. The methanol vapor is fed to the regenerator as additional stripping vapor.

Chemical Description

A combination of methanol and amines removes acid gases by both physical and chemical absorptions. The bulk acid gases are removed chemically by the amine constituents and by physical absorption in the methanol in the solvent mixture.[1] The physical absorption of acid gases is favored by low temperature and high pressure.

The typical amine chemical absorption of acid gases can be expressed as follows:

$$RNH_2 + H_2S \longleftrightarrow RNH_3 \bullet HS$$
$$RNH_2 + CO_2 + H_2O \longleftrightarrow RNH_3 \bullet HCO_3$$

R denotes alkanol group(s).

Operability Limits

The desirable operating pressure is above 200 psia.[2] Absorber top temperature is normally 90 °F. Regenerator pressure is a few pounds above atmospheric. Regeneration temperature is below 212 °F. The methanol distillation column operates at low pressure and within the temperature range of the boiling points of methanol and water.

Purification Limits

The Amisol process removes CO_2, H_2S, COS, and other organic sulfur compounds from synthesis gas, reformed gas, or natural gas having low to medium acid gas content (up to 6-7%). The attainable purity is 0.1 ppm sulfur and 5 ppm CO_2.

Utility Requirements

The typical utility requirements per MM scf of feed gas containing about 6% acid gases[1]

Electricity, kWh/MM scf	2600
Cooling water, M gal/MM scf	370

Environmental Considerations

Acid gases from the regenerator require further processing, as in a Claus or Stretford unit, to recover sulfur. The solvent blowdown stream consists of traces of degradation products and other components that are scrubbed from the feed gas stream. The disposition of the blowdown stream will be determined by the nature of impurities. In some cases, further treatment of the stream to recover solvents and to provide a desirable disposable product would be required.

Remarks

The Amisol process is a combined physical and chemical absorption process developed by the Lurgi Company for synthesis gas purification. Typical application is to remove acid gases from the synthesis gas produced from residue oil by partial oxidation or from coal gasification processes.

References

1. "Gas Process Handbook," Hydrocarbon Processing, April 1979, p. 107.

2. "Environmental Assessment Data Base for Low/Medium Btu Gasification Technology," Vol. 2, EPA-600/ 7-77-1256, November 1977, pp. B58-B61.

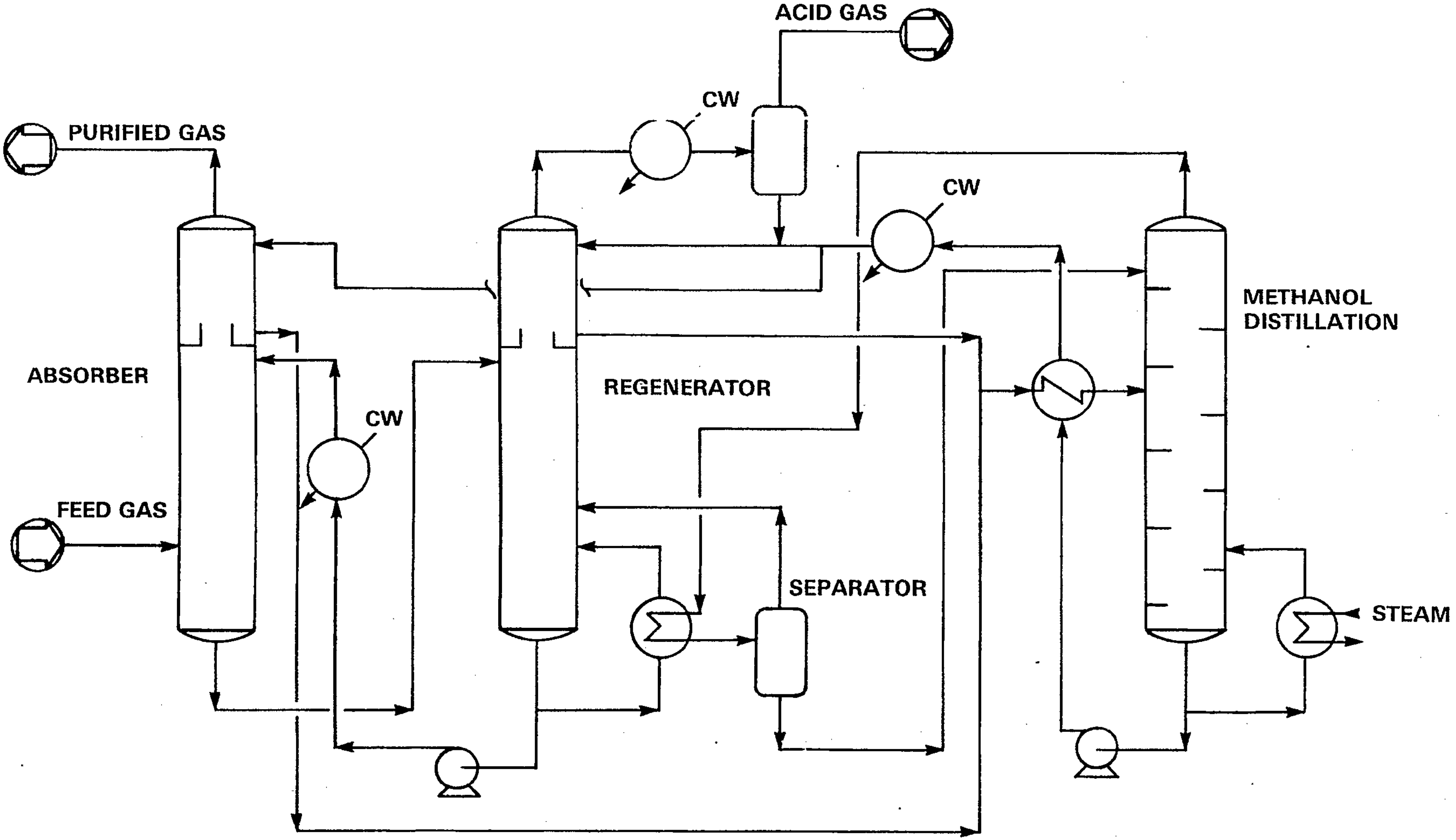


Figure 3A.4-1 Amisol Process

3A.5 BEAVON STRETFORD (BEAVON)

Co-Developer/Licensor

Ralph M. Parsons
100 W. Walnut St.
Pasadena, California 91120

Licensor/Co-Developer

Union Science and Technology Division
Union Oil Co. of California
P.O. Box 76
Brea, California 92621

State of Development

The Beavon process is a tail gas cleanup process based on the catalytic conversion of sulfur species to H_2S (via hydrogenation and hydrolysis) followed by recovery of the H_2S as elemental sulfur in a Stretford unit. This process is commercial, and more than 36 plants are in operation, in construction, or in design phase at 37 locations in U.S. and Japan.[1]

Process Description[2][3][4][5]

The Beavon process, shown in Figure 3A.5-1, consists of two steps. In the first step, all sulfur compounds in the Claus tail gas (SO_2, S_x, COS, CS_2) are converted to H_2S. The second step is the removal of H_2S from the hydrogenated tail gas in a Stretford unit.

In the first step, the tail gas is heated to reaction temperature by mixing it with the hot combustion products of fuel gas and air. If the tail gas does not contain sufficient H_2 and CO to reduce all of the SO_2 and S_x to H_2S, the fuel gas is combusted with a deficiency of air. The heated gas mixture is then passed through a catalyst bed, where all sulfur compounds are converted to H_2S by hydrogenation and hydrolysis. The hydrogenated gas stream is cooled by direct contact with a slightly alkaline buffer solution before entering the H_2S removal portion of the process.

The second step (Stretford Process) involves absorption of the H_2S in an oxidizing alkaline solution. The oxidizing agents in the solution convert the H_2S to elemental sulfur, then are regenerated by air oxidation, which floats the sulfur off as a slurry. This sulfur slurry is then heated and separated to recover the Stretford solution and produce a high-purity molten sulfur product. For further details, see the description of the Stretford Process in Chapter 3A.21.

Chemical Description[2][3]

Sulfur species are converted to H_2S in the catalytic reactor by the following reactions.

$$S + H_2 \longrightarrow H_2S \quad \ldots\ldots\ldots\ldots \quad (1)$$
$$SO_2 + 3H_2 \longrightarrow H_2S + 2H_2O \quad \ldots\ldots\ldots\ldots \quad (2)$$
$$COS + H_2O \longrightarrow H_2S + CO_2 \quad \ldots\ldots\ldots\ldots \quad (3)$$
$$CS_2 + 2H_2O \longrightarrow 2H_2S + CO_2 \quad \ldots\ldots\ldots\ldots \quad (4)$$

The hydrogen for the first two reactions can be supplied by substoichiometric combustion of fuel gas (which also supplies heat for the above reactions) if sufficient hydrogen is not present in the feed gas. No undesirable side reactions occur in the catalytic converter. Since trace elements are normally not present in the Claus tail gas, the catalyst should remain active for extended periods of time.

The effectiveness of the Beavon process for removing sulfur species is dependent upon two factors: the conversion efficiencies obtained in the catalytic reactor, and the removal efficiency of the Stretford unit. The equilibrium constants for Reactions (1) and (2) are very high, and hence essentially complete conversion of S and SO_2 occurs. The extent of hydrolysis of COS and CS_2 (Reactions 3 and 4) is also very high. Normally less than 100 ppm by volume of non-H_2S sulfur compounds are present in the reactor effluents. The Stretford process is capable of reducing the H_2S content of a gas to less than 1 ppm by volume.

Operability Limits

The pressure drop for the treated gas is 2 to 3 psi; all pressures are near atmospheric. Operating temperatures are 550 to 750 °F for the hydrogenation reactor and 90 to 120 °F for the Stretford section. Equipment is essentially all carbon steel.

Purification Limits[5]

Typical compositions of Claus tail gas to be treated in the Beavon process and of the treated gas from the Beavon process

		Tail Gas	Treated Gas
Mole %	H_2	0.5-2	variable
	CO	0.2-2	500 ppm
	CO_2	5.0-15.0	7.0
	N_2	58.0-61.0	90.0
	H_2O	33.0-36.0	5.0
	S_8	0.01-0.02	Less than 1 ppm
	H_2S	0.3-0.6	Less than 10 ppm
	SO_2	0.15-0.3	Less than 1 ppm
	COS	0.02-0.33	Less than 50 ppm
	CS_2	0.02-0.33	Less than 1 ppm

Utility Requirements[6]

Typical utility requirements for treatment of the tail gas from a 100 long tpd Claus sulfur plant

Fuel gas = 125,000 scfd
Electrical power = 283 kWh
Boiler feed water = 12,000 gpd
Steam (credit) = 2500 lb/hr
Recovered sulfur = 5 long tpd

Environmental Considerations

The gaseous discharge streams are treated tail gas and the oxidizer vent. Liquid effluents are by-product sulfur, Stretford sorbent blowdown, and the condensate. Incineration of treated gas is not required.

The treated tail gas contains less than 100 ppm total sulfur. The oxidizer vent contains N_2, O_2, H_2O, and CO_2 and is odorless.

The sulfur stream is normally more than 99.5% pure. Stretford blowdown contains salts such as $Na_2S_2O_3$,

$NaVO_3$, ADA, $NaHCO_3$ and Na_2CO_3. These streams are treated prior to discharge (see Chapter 3A.22). The condensate stream containing dissolved H_2S is treated in biological ponds, and water is reused.

Remarks

The process is well suited for removal of organic sulfur such as COS, CS_2 and S_x. It can use an existing Stretford plant if available.

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3. Beavon, D. K., and Vaell, R. P., "Tte Beavon Sulfur Removal Process for Purifying Claus Plant Tail Gas," Proceedings of American Petroleum Institute Division of Refining, New York, New York, 1972, p. 267.
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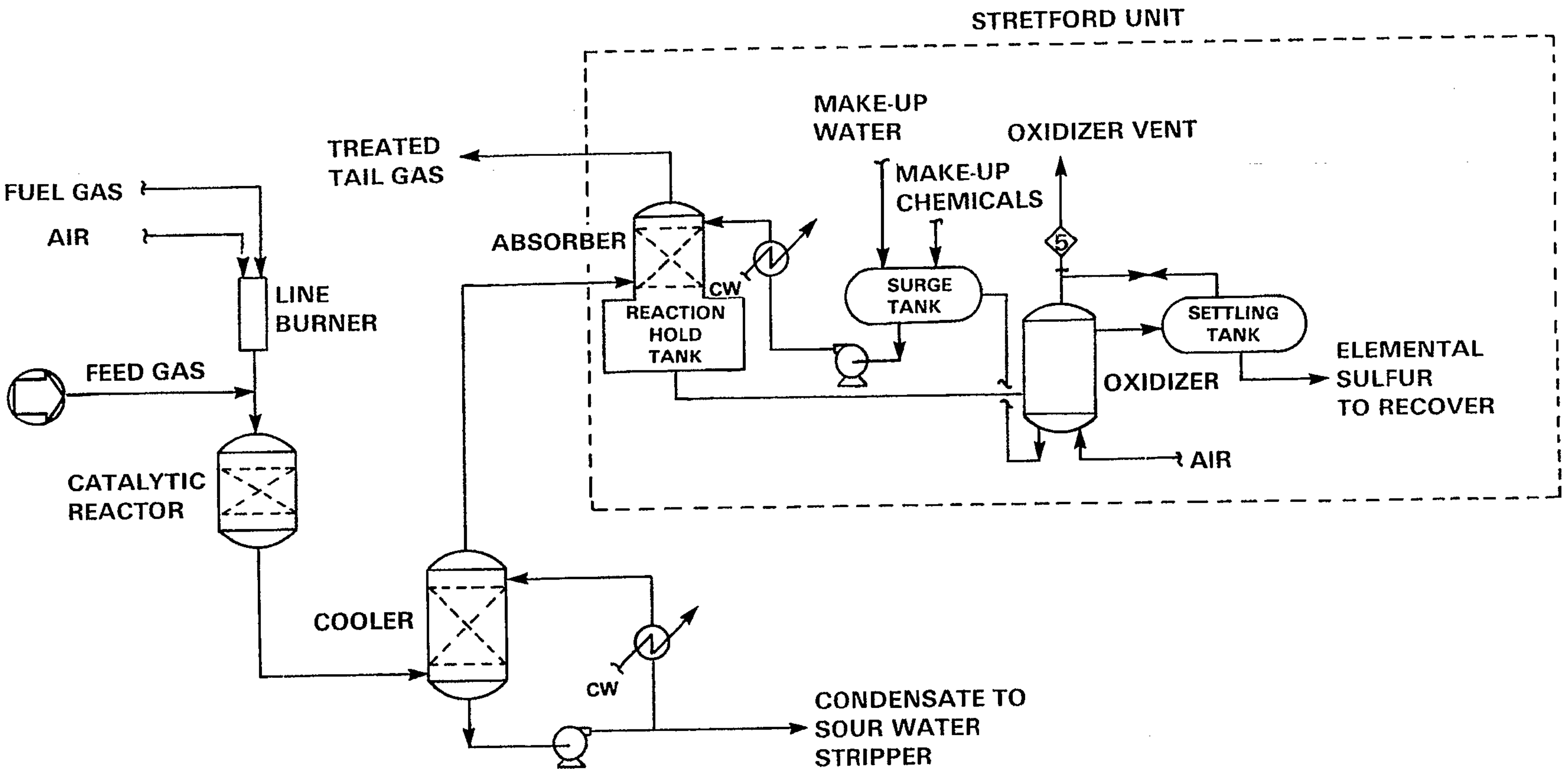

Figure 3A.5-1 Beavon Tail Gas Treating Process.

3A.6 BENFIELD

Licensor

The Benfield Corporation
615 Washington Road
Pittsburgh, PA 15228

State of Development[1] pc

The Benfield hot potassium carbonate process was developed by Benson, Field and coworkers at the U.S. Bureau of Mines, Bruceton, Pennsylvania, in the early 1950s. Their work has since been widely used for scrubbing of CO_2 and H_2S from industrial gases at moderate to high pressures.

Currently, over 500 Benfield-designed purification systems are in the design phase, in operation, or have been operated in the past. Of these, about 300 employ activated solutions or other innovations, and about 15 use the Benfield HiPure process.[1] Commercial Benfield applications include desulfurization of synthesis gas generated by partial oxidation of heavy oils and natural gas purification. It has also been used to purify synthesis gas generated from coal in the Lurgi process at Westfield, Scotland and in demonstration coal gasification units in the United States and Japan.[1] Contaminants in the gas have not been harmfully reactive with the solution, and there has been no undue foaming or corrosion. Efficient removal of both H_2S and organic sulfur has been achieved.

As a result of research conducted by the Benfield Corporation on a laboratory, pilot plant, and semicommercial scale, certain proprietary activators have been developed. These improve the kinetics and advantageously alter equilibria relationships. The net results are reduced tower sizes, a greater degree of purification, and improved thermal efficiency. As a result of technical innovations, an improved process version called Benfield HiPure was developed. The Benfield HiPure process has extended the capability of activated, hot potassium carbonate scrubbing to the point where purified gas with less than 1 ppm H_2S and 10 ppm CO_2 can be obtained.

Process Description[1] [2]

The Benfield activated, hot potassium carbonate process employs conventional gas-liquid absorption technology. A single-stage process configuration is depicted in Figure 3A.6-1, in which the basic characteristics of the process are shown. Both absorber and regenerator operate at a temperature of about 230 °F. The recommended maximum practical operation temperature is 280 °F.

Gas to be purified is introduced into the absorber below a packed section. It blows upward through the packed bed and is contacted with lean Benfield solution flowing countercurrently downward. Purified gas is collected at the absorber top, and rich solution is withdrawn at the base of the absorber. The rich solution is regenerated while passing downward through the second tower against a rising flow of steam. Direct process steam and/or the reboiler vapors are used as the stripping media. Steam is condensed and separated from the regenerated acid gas and refluxed to the stripper, and the acid gas goes to sulfur recovery if H_2S is present.

Some variations of the process are described below.

Single-Stage, Split-Stream Design: The bulk of the hot regenerated solution is introduced at an intermediate point in the absorber, while a small portion is cooled and sent to the top of the absorber. This yields a higher degree of purification because of lower equilibrium pressure of CO_2 and H_2S over the cooled solution.

Benfield HiPure Process: This system is presented in Figure 3A.6-2. The scheme employs two independent countercurrent circuits utilizing multiple effects of stripping steam. The scheme effects bulk removal of CO_2 and H_2S in the first stage of the absorber, while the second stage provides final purification to reduce the sulfur concentration of the product gas to ppm level.

Chemical Description

The absorption-regeneration reactions of H_2S and CO_2 with activated hot potassium carbonate solution can be represented as:

$$K_2CO_3 + H_2S \longleftrightarrow KHCO_3 + KHS$$
$$K_2CO_3 + CO_2 + H_2O \longleftrightarrow 2KHCO_3$$

Equilibrium pressures of H_2S and CO_2 over the solution increase with temperature and concentrations of KHS and $KHCO_3$. Because $KHCO_3$ is formed during absorption of H_2S and CO_2, the acid gas equilibriium pressures and the $KHCO_3$ concentration are interdependent and must be carefully evaluated in designing the process. When the CO_2:H_2S ratio of the feed gas is greater than 8, a reasonable estimate of capital cost and utility requirements can be made by assuming total acid gas to be only CO_2. Since H_2S is more soluble than CO_2, the H_2S content of purified gas will be reduced to a greater extent than CO_2, and thus nearly complete removal of H_2S can be obtained.

Just as H_2S is more soluble in the carbonate solution than is CO_2, it is absorbed and stripped at a faster rate. If the operating conditions are selected properly, an H_2S absorption rate 50 times that of CO_2 can be achieved. Generally, H_2S removal of 90 to 98% is possible, while restricting the CO_2 removal to 10 to 40%.[1]

Typical trace components observed in coal derived gases are COS, CS_2, thiophene, mercaptans, ammonia, HCN, BTX, and other miscellaneous light hydrocarbons. Removal of these components by the Benfield process is discussed below.[1]

COS: This component hydrolyzes in activated, hot potassium carbonate to form H_2S and CO_2 as follows:

$$COS + H_2O \longleftrightarrow H_2S + CO_2$$

With proper selection of processing scheme and operating temgerature, nearly complete removal of COS can be achieved.

CS_2: This component is hydrolyzed in two stages to H_2S as follows:

$$CS_2 + H_2O \longleftrightarrow COS + H_2S$$
$$COS + H_2O \longleftrightarrow CO_2 + H_2S$$

Because of the additional step involved, CS_2 is absorbed slower than COS. In an activated Benfield pilot plant, 71% of CS_2 was absorbed, while COS absorbed was 99.4%. Limited experience at Westfield, Scotland, indicates up to 75% CS_2 removal.

Thiophene: Normally, removal of this compound is not expected, although removal of up to 85% has been reported on a commercial unit.

Mercaptans: Methyl mercaptan is more readily absorbed than higher hydrocarbons, and an absorption of 68% was observed in the activated Benfield pilot plant when 99.4% COS was removed. The HiPure process increases mercaptan absorption to 92%.

Ammonia: Absorption rate of ammonia is high, but the solution capability is low. The degree of removal is dependent on the concentration of ammonia in the feed gas and the solution circulation rate.

HCN: Because of the strong acidic nature of HCN, its removal is expected to be as high as that for H_2S or greater.

Hydrocarbons: No reaction is expected, nor is any degradation of solution reactivity.

Operability Limits

High-pressure operation favors the absorption/desorption scheme, and utility requirements are lowered at elevated pressures. The practical limit of operating temperature is visualized as 280 °F for economical operation. The feed gas composition is not considered critical for effective operation. A processing scheme can be designed for various feed gas compositions and corresponding outlet acid gas concentrations. Purification Limits By appropriate selection of design criteria, COS, H_2S, and CO_2 can be removed to ppm levels from H_2S concentrations as high as 10% and CO_2 concentrations as high as 25 to 45%. The process is not guaranteed for removal of thiophene, as its absorption has not been proven with duplicate results in any commercial unit.

Utility Requirements[pc]

Typical utility requirements for the activated Benfield process per MM scf of feed gas at 250 °F and 615 psig containing about 1.5% H_2S and 5.4% CO_2, with 2 ppm H_2S and 0.01% CO_2 in the purified gas

Steam @ 50 psig, saturated, lb/MM scf	10,500
Cooling Water, Gal/MM scf	21,000†
Electric Power, kWh/MM scf	70

† Based on acid gas leaving the condenser at 200 °F.

Typical utility requirements for the activated Benfield process per MM scf of feed gas at 250 °F and 615 psig containing about 45% CO_2, with 0.1% CO_2 in the purified gas

Steam @ 50 psig, saturated, lb/MM scf	31,200
Cooling Water, Gal/MM scf	24,500†
Electric Power, kWh/MM scf	300

† Based on acid gas leaving the condenser at 200 °F.

Environmental Considerations

Acid gases exiting the stripper require further processing in a sulfur recovery unit, such as a Claus or Stretford. The process does not produce effluents caused by solvent degradation.

Remarks

The Benfield process can purify feed gases at temperatures up to 280 °F. It removes most of the COS and HCN and substantial proportions of CS_2. The Benfield solution does not dissolve hydrocarbons present in the feed gas. Only mechanical losses of the solution must be replaced, since solvent degradation does not occur.

The process is most economical when acid gas partial pressures exceed 25 psi. It is not guaranteed for removal of thiophene.

References

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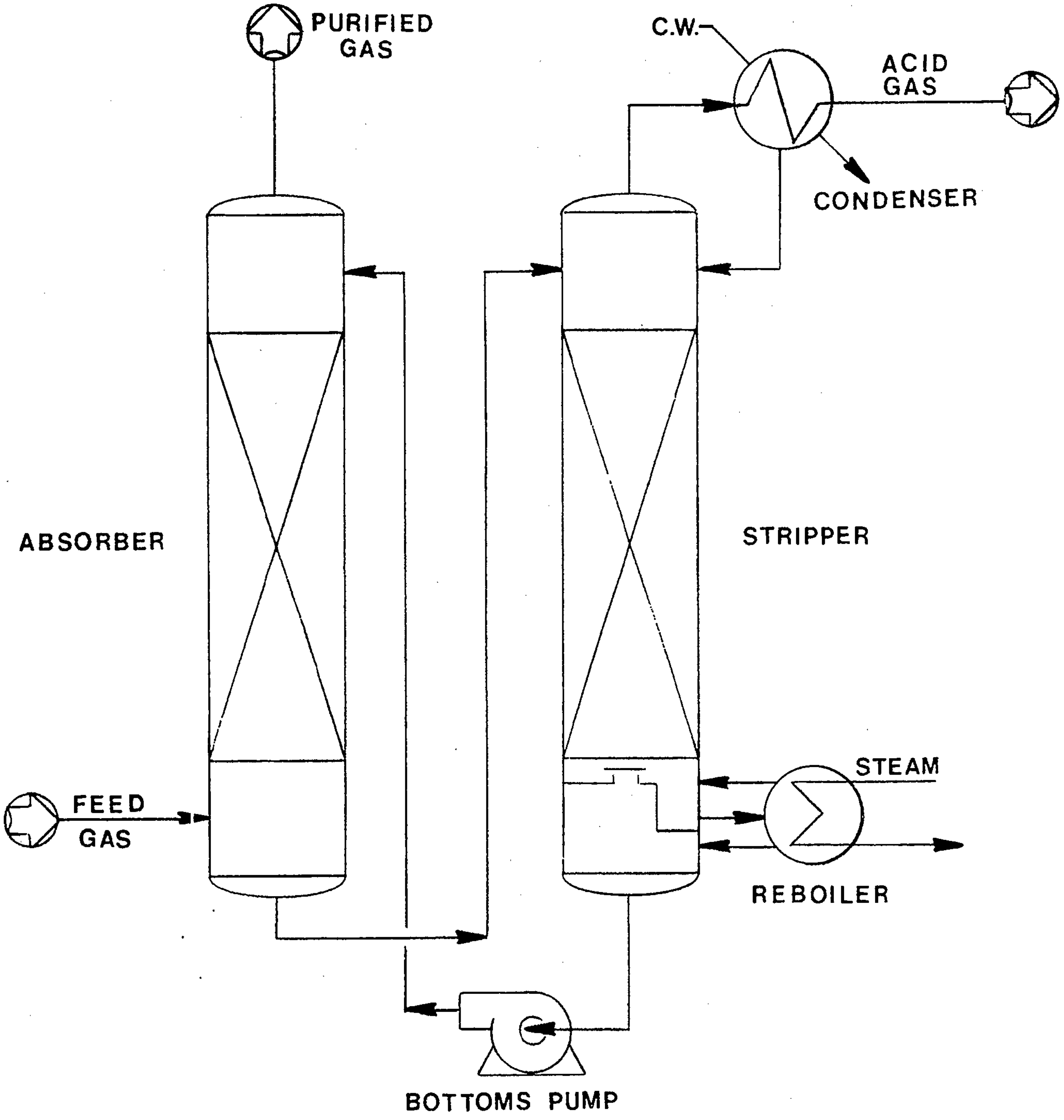

Figure 3A.6-1 Benfield Process.

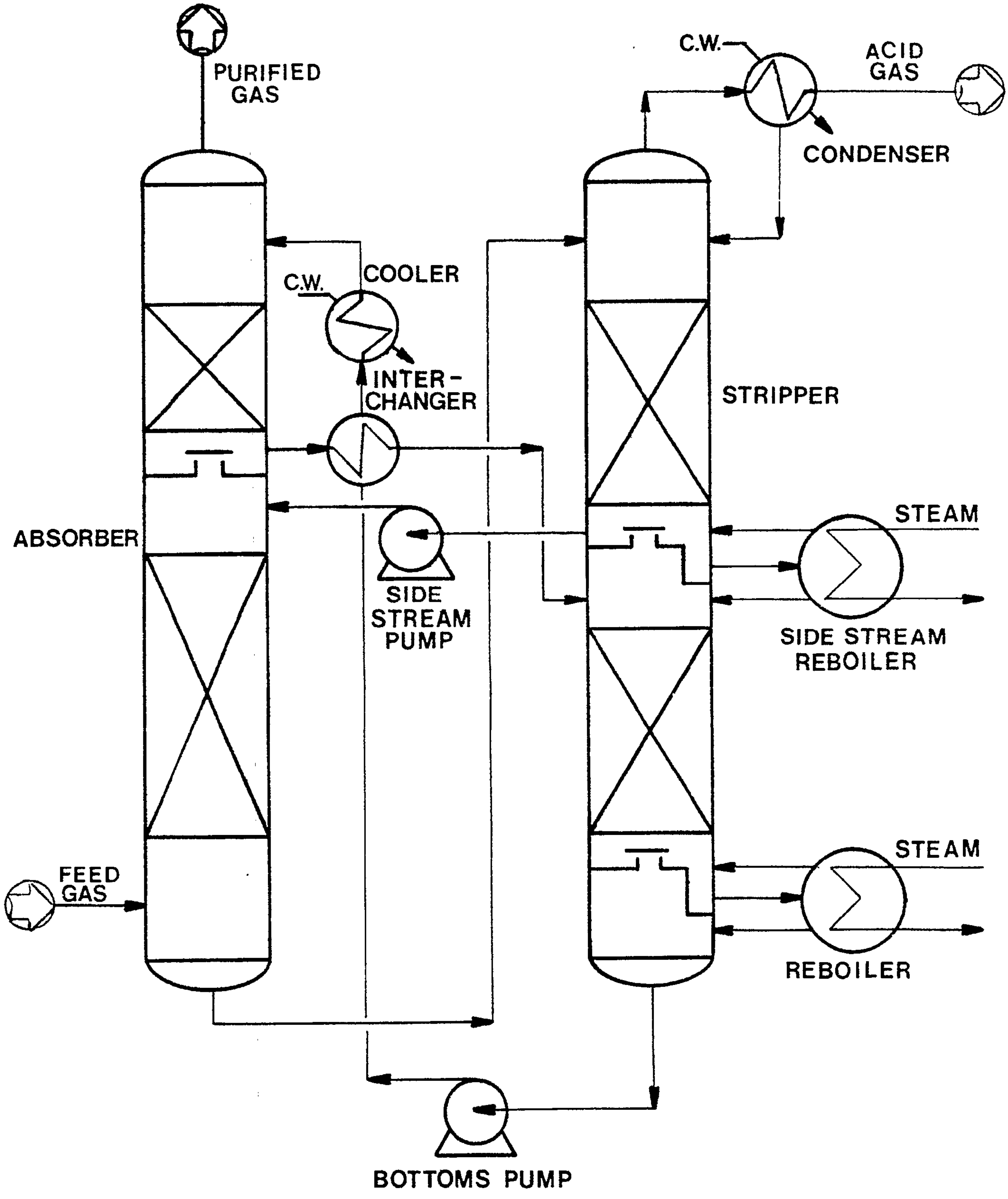

Figure 3A.6-2 Benfield HiPure Process.