TECHNOLOGY ASSESSMENT GUIDE

NO. 2

COMBUSTION ENGINEERING LOW-BTU COAL GASIFICATION

CHAPTER ONE: EXECUTIVE SUMMARY

1.1 OVERALL PROSPECTS FOR THE TECHNOLOGY

The Combustion Engineering low-Btu coal gasification process employs an atmospheric pressure entrained flow slagging gasifier in conjunction with well characterized supporting process units to produce a gas having a heating value of approximately 110 Btu/scf. The gas is heated prior to leaving the plant as a method of enhancing plant efficiency. The low energy content of the gas together with its high distribution temperature (and low pressure) imply that the process is best suited for providing industrial or utility boiler fuel to users located adjacent to or within a short distance from the gas generation plant. Residential use of the fuel or pipeline transmission to distant users is not feasible because of the toxicity of the gas in the first case, and poor transmission economics in the second.

Utility or industrial users of this fuel who are retrofitting from natural gas or oil will require substantial boiler modification to account for differences in the way the gas burns, and will in addition experience some derating in boiler capacity.

However, under the proper circumstances such a plant could be highly desirable in light of its high thermal efficiency, ability to handle any type of coal, low pollutant emissions and reasonable gas cost. Unfortunately the system is probably a decade away from the start-up of any full commercial scale facilities.

1.2 ENGINEERING ASPECTS

Due to the fact that the end product of the gasification plant is not grossly different from the raw gas, relatively few process operations are required. This fact is responsible for reducing capital costs and operating complexities for the plant, but is more related to the fuel type produced rather than the type of gasifier employed.

Although the atmospheric pressure operation of the gasifier imposes a downstream requirement for product gas compression (an energy intensive step), the final product gas pressures are not excessive. Atmospheric gasifier pressure operation also simplifies coal feeding and ash removal operations and imposes a less severe requirement for the vessel wall thickness of downstream process vessels. The entrained flow design is capable of processing any kind of coal, and unlike fixed bed gasifiers in particular, produces no tars, oils, phenols, naphthas or hydrocarbons which foul process equipment surfaces and wastewater streams. The high operating temperature responsible for destruction of these compounds also assures that all mineral matter in the form of coal ash will be completely slagged, simplifying removal of this waste from the gasifier. By the same token, high temperature operation generally results in lower gas heating values due to a larger conversion of combustible gas components in the gasifier to provide the high operating temperatures.

Due to the short residence times in the reactor, complete carbon conversion is not obtained in one pass. Particulate collectors operating on the gasifier effluent collect this material for recycle to the first stage (combustor section) of the reactor. However, this char recycle may represent additional energy requirements (as compared to complete conversion in one pass), thermal loss and a source erosion in the system. In addition, because of low inventories of coal in the reactor at any given time, close control of coal and air feed rates will be required to prevent deterioration of raw gas quality, excessively high operating temperatures or potentially explosive mixtures.

Downstream and support equipment are all commercially available systems. Although the system components have never been assembled in an integrated system with a coal gasifier, there is no reason to suggest that unusual start-up or operating problems will be encountered.

1.3 CURRENT COSTS

The total capital requirement for this 50×10^{12} Btu/year plant is \$424 million, which is dominated by a plant capital investment of \$291 million. Interest during construction, working capital and start-up costs make up most of the difference. Other costs are incurred for paid-up royalties and the initial charge of plant chemicals.

Annual operating and maintenance costs (at a 90 percent plant capacity factor), total \$24.5 million, exclusive of coal costs. These costs are largely composed of labor, taxes and insurance, and maintenance materials. Sulfur is given a by-product credit of \$40/ton, bringing the net annual operating and maintenance costs to \$21.9 million.

Taken together with a 20 percent capital charge, these costs result in a product cost of \$2.37/10^6 Btu, which is exclusive of coal costs. At a coal cost of \$1.50/10^6 Btu, the total product cost comes to \$4.27/10^6 Btu.

1.4 RESEARCH AND DEVELOPMENT DIRECTIONS

Several areas of interest will be examined during the development of the Combustion Engineering gasifier: coal type, oxygen enriched operation, operational control and stability, and scale-up techniques.

Although many hours of operation have been logged in the 120 TPD pilot plant, relatively little testing has been done to determine the effects of coal type. In particular, highly reactive coals (particularly lower-rank coals) may be good gasification feedstocks in this system.

The air blown operational mode of the gasifier produces a combustible gas, but with a heating value which is too low for many applications. Enriching the gasification air with oxygen will raise the product gas heating value by elimination of a proportional amount of diluent nitrogen. Oxygen addition also raises new safety issues and makes control of the gasifier more sensitive. The ability to operate and control the gasifier in a smooth and predictable manner over long periods is essential to the commercial success of the system and must be demonstrated at larger scale.

The design of larger gasifiers using operating data obtained from smaller units entails a certain amount of risk. A detailed knowledge of gasification kinetics and mechanisms could play an important part in reducing the risk of reactor scale-up. It must be realized that gasification kinetics and probably mechanisms will be quite sensitive to coal composition, especially that of the mineral matter.

CHAPTER TWO: ENGINEERING SPECIFICATIONS

2.1 GENERAL DESCRIPTION OF THE TECHNOLOGY

Production of clean low-Btu gas using Combustion Engineering gasification technology is accomplished in a similar manner to that of other low-Btu gasification systems. Following gasification of pulverized coal in the two-stage entrained flow slagging gasifier, the raw gas is cooled against steam generation and unreacted carbon is collected. The cooled gas is then scrubbed for acid gas removal in a Selexol unit which selectively removes H_2S from the gas stream. The cool, clean gas is then compressed (due to the low operating pressure of the gasifier) and reheated prior to distribution.

Ancillary support systems include air blowers and preheating for gasification, ash dewatering and disposal system, power recovery and water treating.

Of the synthetic fuels processes examined for this study, this is one of the simplest in terms of process equipment and processing steps required. This is due to the fact that only minimal treatment of the raw gas is required (cooling, acid gas removal and compression); no extensive catalytic reforming, cryogenic separation or power recovery are needed. Operation of the gasifier at higher pressures (virtually all leading gasifiers are capable of elevated pressure operation) would require redesign of the current device but would allow distribution of the product without expensive recompression.

2.2 PROCESS FLOW, ENERGY AND MATERIAL BALANCES

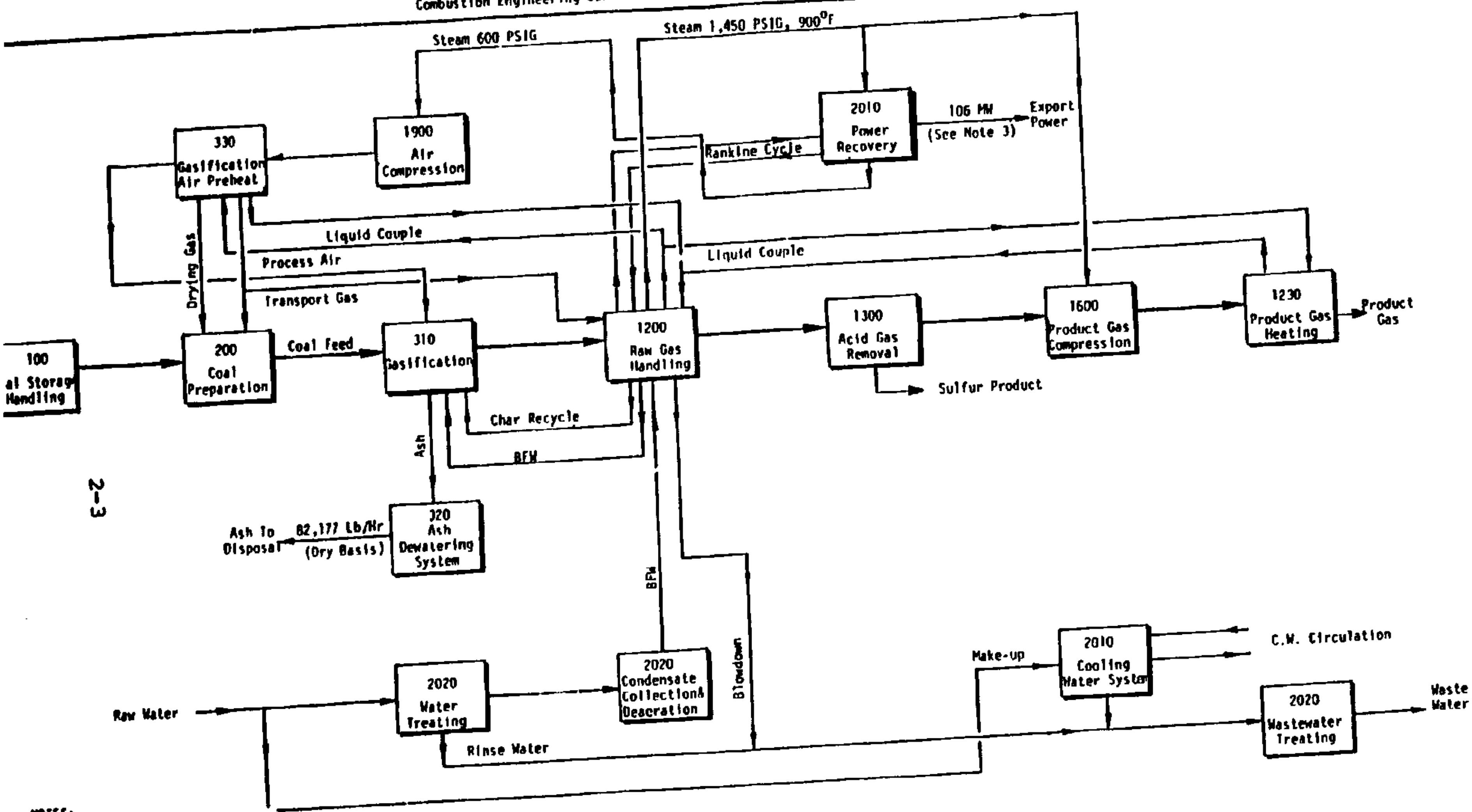
An overall conceptual block flow diagram for the Combustion Engineering low-Btu coal gasification process is given in Figure 2-1. Groupings of chemical process units integral to the process are represented by the block segments and are assigned Plant Area numbers according to function in Table 2-1.

Washed, 1-1/2 x 0 coal is received at the plant site by unit train. No breaking and refuse disposal systems are included. The coal feed stock is unloaded from bottom dump 100 ton cars into an unloading hopper, withdrawn from the hopper by four vibrating feeders and transported by belt conveyors to a tripper conveyor. The tripper is attached to a traveling belt stacker. The stacker travels on tracks and forms storage piles on either side. The unloading and stacking system is designed to handle a three day supply in eight hours.

Coal is reclaimed from storage piles by a bridge type bucket wheel reclaimer rated at 500 tons per hour. This machine is a rail mounted bridge which supports a rotating bucket wheel and belt conveyor. The wheel moves across the face of the pile, making a vertical cut across the many layers of coal. At the end of one cut, the reclaimer moves ahead a small, predetermined distance and the wheel makes another cut in the opposite direction. The excavated coal is carried by a series of conveyors to a pulverizer feed hopper.

Coal is ground to 70 percent passing a 200 mesh screen, classified and dried simultaneously in the pulverizers. The drying gas is 325°F process air from the primary air heater.

Figure 2-1
Combustion Engineering Low-Btu Coal Gasification Process



NOTES:
[1]Flows shown are for 100% of capacity operation.
[2]Stream heat contents include higher heating value and sensible heat above 60°F.
[3]Export power is gross power recovered less plant power consumption.

Table 2-1

Relevant Plant Area Numbers for Combustion Engineering Low-Btu Coal Gasification

100	COAL STORAGE AND HANDLING
	110 Coal Storage
	120 Coal Handling and Transportation
200	COAL PREPARATION
	220 Coal Pulverization
	240 Drying
300	COAL GASIFICATION
	310 Gasification
	320 Ash Dewatering System
	330 Gasification Air Preheat
1200	RAW GAS HANDLING
	1210 Particulate Removal
	1220 Gas Quenching and Cooling
	1230 Product Gas Heating
1300	ACID GAS REMOVAL
	1310 H_2S Removal
1600	PRODUCT GAS COMPRESSION
1900	AIR COMPRESSION
2000	UTILITIES AND SUPPORT SYSTEMS
	2010 Cooling Water System and Power Recovery
	2020 Wastewater Treating and Water Supply
	2030 Solids Disposal
2100	OFFSITES AND MISCELLANEOUS

The pulverized coal is conveyed by the drying gas to a separation cyclone. From the separation cyclone, coal falls into four 400 ton storage silos and the drying gas is recycled to the pulverizer. Water is removed from the system by venting a slip stream of the drying gas from the cyclone to the atmosphere through a bag filter.

The pulverized coal storage silos are blanketed with an inert gas to preclude oxygen. The silos are sized for an eight hour outage of a pulverization unit. Coal is pneumatically conveyed from the silos to the gasifiers by process air.

Air for gasification is compressed to 19-1/2 inches water gauge pressure in a single stage blower. Each of the four parallel blower trains requires 625 hp which is supplied by a topping turbine driven by 600 psig steam exhausting at 50 psig.

The primary process air heater preheats air from the blower to 325°F against condensing 50 psig and 240 psig steam. Approximately 35 percent of the preheated process air is used to transport coal and char to the gasifier and to dry the pulverized coal. The balance of the process air is further preheated to 600°F in the secondary process air heater before being fed to the gasifier. Final heating is against condensing 600 psig steam and Hitec heat transfer salt.

Pulverized gasification coal, oxidant and recycle char tangentially enter an atmospheric pressure entrained bed gasifier, through water cooled nozzles at two levels near the bottom of the gasifier. The first stage is a combustor section where all the recycle char and a portion of the coal are reacted with the oxidant. The coal split is controlled to maintain 3200°F in the combustor section. About 32 percent of the pulverized coal is consumed in the combustor section.

The balance of the coal is injected at the higher level (the reductor section) into hot gases leaving the combustor section. Devolatilization of the reductor coal and cracking of the volatile matter occurs in the lower level of the reductor. The gases cool to 1700°F as they flow up through the reductor section as a consequence of endothermic reactions that occur in this section.

Complete gasification of the coal is not obtained in one pass through the gasifier. Unreacted char is swept out of the gasifier in the hot crude gas and recovered in the gas cooling unit. Entrainment amounts to about 27 pounds char per 100 pounds coal feed.

The gasifier is enclosed with water cooled, fin-welded, studded, refractory-covered walls. Boiler feedwater is pumped through the walls and high pressure steam is generated. Of the total high pressure steam generated approximately 79 percent is from the water cooled gasifier walls.

Molten slag collects on the combustor walls and drains from the gasifier into a cooling water filled slag quench vessel where it is quenched and fragmented under controlled conditions. The resultant slurry is educted to a common transfer tank using recycle process water as the motive fluid. Slag grinders prevent large chunks of slag from plugging transfer lines and a slag breaker disintegrates slag icicles at the gasifier tap hole. The slag slurry is dewatered in dewatering bins producing an ash ready for disposal. Final cleaning of the water overflowing the dewatering bin is accomplished in a settling tank where slag fines settle and are pumped back to a dewatering bin. A portion of the clarified water is recycled for slag quenching after cooling in an induced draft type cooling water tower. The balance of the clarified water is pumped to the slag slurry transfer eductors to serve as motive fluid.

Hot gasifier effluent is cooled to 200°F in a waste heat boiler by heat exchange with other fluids in a series of coils. The effluent is at slight vacuum. In the first coil, high pressure steam generated in the gasifier walls and the third coil is superheated to 900°F. Hitec salt is heated from 670°F to 850°F in the second coil. High pressure boiler feedwater is heated from 250°F to near its boiling point in the fourth coil. Energy is recovered by an isobutane Rankine cycle system in the fifth coil. Final gas cooling in the sixth coil is against condensate.

The Hitec heat transfer salt is a heat transfer medium marked by DuPont Company. It is a eutectic mixture of potassium nitrate, sodium nitrite and sodium nitrate. It has been used for process heat transfer applications in the 300-1000°F temperature range for a number of years. The mixture is nonfouling, nonflammable, and has a low degree of corrosivity toward commonly used materials of construction.

The cooled crude effluent gas-char stream flows through a spray drier into which a char slurry from the secondary char recovery unit is sprayed. The slurry is 33 percent by weight char. The purpose of the spray drier is to dry and agglomerate the solids which are collected in the wet secondary char recovery unit before they are recycled to the combustor section of the gasifier. Some of these solids are collected in the hopper bottom of the spray drier and the rest are collected in a char recovery cyclone through which the drier effluent gas passes. Recovered char is pneumatically transported to the gasifier with process air. About 85 percent of the char entrained in the gasifier is recovered in the drier and cyclone.

The cooled crude gas stream from the char recovery cyclone flows through a venturi scrubber where it is washed with water to remove the remaining particulate matter. Scrubber water, approximately 2 wt. percent char, is pumped from the bottom of the scrubber knockout vessel, combined with slurry streams from parallel trains, and fed to a secondary char recovery unit. Hydroclones thicken the 2 wt. percent bottom to 33 wt. percent slurry. The filtrate from the recovery unit is recycled back to the venturi scrubbers. The underflow from the recovery unit is sprayed into the top of the spray driers where the hot gas dries the atomized slurry to a dry, free flowing, powder.

Raw water makeup maintains the scrubbing system in water balance. The scrubbed char free crude gas from the scrubber knockout vessel flows to the acid gas removal system.

The Stretford process is used for removal of hydrogen sulfide (H_2S) because other processes (such as Selexol which is used in the other cases) are not suitable or efficient at atmospheric pressure operation. Stretford is a direct oxidation process which absorbs H_2S from the gas stream and converts it to elemental sulfur. The sulfur content of the gas is reduced to an equivalent of 1.0 pounds SO_2 per million Btu (HHV) coal feed to the gasifiers.

The char free crude gas flows up through a H_2S absorber, where the H_2S is absorbed by countercurrent contact with an alkaline solution. About 89 percent of the entering sulfur is absorbed. The desulfurized gas leaves the top of the absorber and flows to the product gas blower.

Active chemicals (sodium meta vanadate and anthraquinone disulphonic acid) in the solution oxidize absorbed H_2S to elemental sulfur. The absorber provides sufficient retention time to allow the reactions to elemental sulfur to go essentially to completion. The reacted solution flows from the bottom of the absorber to oxidizing tanks where it is regenerated with air sparged into the tanks. The air also provides a medium for flotation of the sulfur to the top of the oxidizers where it overflows into a slurry tank. The underflow from the oxidizers flows to a pump tank, from which it is pumped back to the absorber.

Sulfur from the slurry tank is pumped to the primary centrifuge which produces a wet sulfur cake that is reslurried and fed to a secondary centrifuge. The filtrate from the two centrifuges is recycled to the primary oxidizer through a filtrate tank. The sulfur cake from the secondary centrifuge is reslurried and pumped through an ejector mixer where the sulfur is melted by the injection of steam. The molten sulfur is separated from the slurry medium (water) in a sulfur separator. From the separator, sulfur is pumped to the loading facilities. The water portion is recycled to the reslurry tanks.

The desulfurized product gas from the H_2S absorber is compressed by a product gas blower and heated to 700°F across three coils in a product gas reheat vessel. Condensing 240 psig and 600 psig steam supply 25 percent and 22 percent of the reheat duty in the first two coils, respectively. Final heating is against Hitec salt. The reheat vessel is a series of cross flow coils mounted in a rectangular duct.

Excess heat and steam generated in the fuel processing units are converted into electric power. Thus, although the primary purpose of the plant is production of fuel gas, 137 MW of power is generated in at 100 percent operating load factor. This power figure is expressed as work extracted from the process and do not include losses associated with generator inefficiency. (Generator efficiency is approximately 97 percent.) Most of the power is generated by the expansion of steam. However, some power is developed in the operation of a low level heat recovery scheme utilizing an organic fluid in a Rankine cycle.

From Steam, MW	87.9
From Low Level Heat, MW	2.3
TOTAL	90.2

The steam system operates at four pressure levels:

High Pressure Superheated	-	1450 psig
Medium Pressure	-	600 psig
Low Pressure	-	240 psig
Low Pressure	-	50 psig

Major steam generation is at 1450 psig. Fresh high pressure boiler feedwater from the deaerator is pumped through the fourth coil of the waste heat boiler to the high pressure steam drum. Boiler feedwater from the high pressure steam drum is circulated through the gasifier walls and the third coil of the waste heat boiler. The high pressure steam generated is separated in a steam drum, superheated to 900°F in the first coil of the waste heat boiler and fed to the high pressure steam header.

Total high pressure steam production at 100 percent capacity is 1,208,200 lb/hr. About 12 percent of the high pressure steam is used to drive the product gas blowers which are condensing turbine drivers.

The rest of the high pressure steam feeds a condensing steam turbine driving a generator. There is extraction at 600 psig and 240 psig to supply steam requirements at these pressure levels. Approximately 60 percent of the 600 psig steam is used to drive pumps and turbines. This steam exhausts into the 50 psig systems. The rest of the 600 psig steam is used for product gas and process air heating.

Steam at 240 psig is used for heating product gas, air to the gasifiers and melting sulfur in the acid gas removal unit. Steam at 50 psig is supplied by turbine exhausts and condensate and blowdown flashes at this pressure level. This steam is used for air heating and boiler feedwater deaeration. There is excess 50 psig steam which is expanded in a condensing steam turbine. This turbine is part of the same drive train turning the electric power generator.

Overall material and energy flows are shown in Table 2-2. Energy flows and losses as percent of coal higher heating value are shown in Table 2-3. Process water and steam flows are omitted for simplicity (and account for the difference between input and output flows). The Combustion Engineering gasifier is one of the few gasifiers, including both commercial and advanced generation, which uses no steam or water injection as part of the gasification process.

As indicated in Table 2-3, sensible heat is a large component of the product gas heating value. This is due to primarily to the reheating of the product gas to 700°F prior to distribution. Some latent heat is also included due to the presence of moisture in the gas, but just as the latent heat from the water of combustion is not available for use (as reflected in the HHV figure), so is this latent heat unavailable. Thus, although it is a plant output which is not directly useful to the user, it is included in the estimate of plant output and energy efficiency by convention.

2.3 PLANT SITING AND SIZING ISSUES AND CONSTRAINTS

The grass roots plant examined in this technical assessment guide is designed to produce 50 x 10^{12} Btu/year assuming operation at 100 percent plant capacity for 365 days per year. The plant is large enough to provide fuel gas for a large industrial park. Due to the nature of the fuel gas, specifically its low heating value and low distribution pressure (making it uneconomical to transport long distances) and its high temperature (excessive cooling would result in pipeline transportation), the plant must be located in very close proximity to users of the gas. Since the gas is toxic, it is unsuitable for residential use and in most cases would be suitable only as an industrial or utility boiler fuel.

Table 2-2

Overall Material and Energy Flows For the Combustion Engineering Low-Btu Gasification System

Input	Unit Higher Heating Value	Mass Flow Rate, TPD	Btu Content, MM Btu/day
Coal Feed	12,235 Btu/lb	6,570	160,770
Gasification Air		28,014	—
	Totals	34,584*	160,770
Output			
Product Gas	1,757 Btu/lb (113 Btu/SCF)	34,709 (1080 MM SCFD)	121,980**
Sulfur	3,970 Btu/lb	203	1,620
Ash	—	630	—
Electric Power	9,000 Btu/Kwh	70 MW	15,040
	Totals	35,542*	138,640

NOTE:

*Process water flows are not indicated in this table and account for differences in input and output material flows.

**Product gas Btu content includes sensible and latent heat as well as HHV.

$$\text{Overall Plant Energy Efficiency} = \frac{138,640}{160,770} \times 100\% = 86.2\%$$

Table 2-3

Energy Balance as Percent of Coal HHV

Input	Percent
Coal	100.00
Output	
Product Gas HHV	67.86
Product Gas Sensible	8.01
Product Gas Latent	2.38
Net Power	3.75 (converted at 3413 Btu/Kwh)
Sulfur and Ash HHV and Sensible	1.83
Stretford Sensible and Latent	1.76
Pulverization Sensible and Latent	0.92
Gasifier Heat Losses	1.50
Sensible Heat Gain	(0.78)
Latent Heat Gain	(0.46)
Rejected at Condensers	12.22
	99.49

NOTE:

The discrepancy in output vs. input results from approximations used for calculating heat loads for some process units.

In addition to these constraints, a potential site must be several hundred acres in size, relatively flat and of sufficient integrity to support heavy foundations and processing vessels. It must also be located for economical delivery of coal and water, and disposal of ash and other solid wastes. It is desirable that the plant site be in or near an active market for elemental sulfur. Environmental permitting may be difficult, because most users of the low-Btu product gas will be located in non-attainment areas.

2.4 RAW MATERIAL AND SUPPORT SYSTEM REQUIREMENTS

2.4.1 Coal Quantities and Quality

For the purposes of this assessment, Illinois #6 coal is used as a gasifier feedstock. Table 2-4 summarizes the ultimate and proximate analyses of the coal feedstock. Washed coal 1-1/2" x 0 is to be shipped to the plant by unit train and received at the rate of 6,570 tons per day (2.4 million tons per year). Long term contracts covering the life of the plant (20 years) would be required to secure a steady and reasonably priced coal source.

2.4.2 Catalysts and Other Required Materials

No catalysts other than that naturally occurring in the coal mineral matter are used in the gasification reactor. The primary use of chemicals in the process is for the Stretford acid gas removal system and process water treatment. Sodium metavanadate and anthraquinone disulphonic acid used in the Stretford system are regenerated, but need continual replenishment due to degradation in the process. Demineralizers, clarifiers, bacterial and antibacterial agents are used in large quantities for water treatment and are either largely one-use chemicals

Table 2-4

Coal Analysis for Illinois #6 Feedstock

Ultimate Analysis	Weight Percent
(moisture and ash free)	
Carbon	77.26
Hydrogen	5.92
Oxygen	11.14
Nitrogen	1.39
Sulfur	4.29
	100.00

Proximate Analysis	
Moisture	4.2
Ash	9.6
Fixed Carbon	52.0
Volatile Matter	34.2
	100.0

Heating Value - As Received	
Higher Heating Value (HHV)	12,235 Btu/lb
Lower Heating Value (LHV)	11,709 Btu/lb

or are lost in process blowdown. Due to the widespread use of these chemicals in utility and industrial operations, commercial availability or cost escalation should not pose a great problem to economical plant operation.

2.4.3 Water Requirements

Although water or steam is not used as a feed to the gasifier itself, the low-Btu gas process will require a continual supply of process water for use in steam generation and power recovery, acid gas removal and process heat transfer. A source of potable water will also be required. Total plant water requirements are approximately 3,125,000 gallons of raw water per day (2170 gpm).

2.5 EFFECT OF COAL TYPE

As with other gasifiers of the entrained flow design, the Combustion-Engineering gasifier is capable of accepting all coal types. Caking coals do not present an agglomeration problem because of the large interparticle distance in the reactor, allowing relatively few particle interactions.

The C-E gasifier is not as efficient at overall carbon conversion as is other gasifiers, even within the entrained flow class. Thus, due to the short period of time available for reaction, coal reactivity is an important factor. The higher reactivity of the lower-rank coals may be an important factor in attaining high single pass carbon conversions, thus limiting the amount of char recycle required. However, the higher moisture content of these coals will require either more drying air or more gasification air to achieve slagging conditions.

Slag characteristics, particularly leachability, will vary with the specific coal used, but accurate generalizations cannot be made. Individual feedstock evaluations will have to be made in this area as well as for coal storage and preparation requirements.

The effect of coal type on process equipment downstream of the gasifier is limited to its effect on determining gas composition. High sulfur coals will place a greater load on the H_2S removal system; higher moisture coals will produce more condensate. High temperature gasifier operation results in the destruction of virtually all C_1 and higher hydrocarbons, thereby erasing any effect of coal type on the composition of wastewater organics. Gas competition with respect to N_2, CO1 CO_2, H_2, and H_2O can be controlled by gasifier manipulation well enough that variations in coal composition will not adversely affect that operation of downstream equipment or final product gas heating value.

2.6 AIR POLLUTION CONTROL TECHNOLOGY

2.6.1 Ability of Existing Technology to Meet Regulations

The coal gasification complex described in this technology assessment guide is capable of meeting both present and projected air quality standards. Two principal contaminants are of concern in addressing air pollution technology for the C-E process: particulates and sulfur.

Particulate emissions arise primarily from coal handling operations, ash handling and char recovery from the gasifier effluent stream. Procedures for dealing with dusting from coal and ash handling are well known and will be employed on an as needed basis for each individual plant. These include the use of wetting agents and covered vessels and equipment. Particulate control in the raw gas stream is especially important, not for only environmental control but mainly for recovery of unreacted carbon. High recovery of particulate matter (mostly carbon) from this stream is integral to achievement of acceptable process efficiencies.

Sulfur emissions result primarily from the H_2S component of gaseous process streams, which is generated from coal sulfur in the reducing portion of the gasifier. Carbonyl sulfide (COS) is also present to a small extent, but is unaffected by the chemistry used for H_2S removal. The Stretford process has been selected for selective removal of these sulfur compounds from the raw, cooled gasifier effluent. This system was chosen on the basis of its ability to operate at the low pressures which prevail in the CE design. The Stretford absorber lowers the H_2S concentration from 0.52 mol percent to 0.06 in the product gas. Carbonyl sulfide remains at a constant 0.03 mol percent. A very slight extension of current technology for acid gas removal will be required in order to approximately double the size of the Stretford vessels. The Stretford process has not been used at this scale in previous chemical and petrochemical plant applications; an extension of this nature can be accomplished with only very minor risk.

2.6.2 Impacts on Process Efficiency

The removal of particulates and sulfur compounds from the low-Btu fuel gas stream is required to produce a gas which can be burned in an environmentally acceptable manner. Effective removal of particulates is of particular importance to prevent damage to turbine blades if the fuel gas product is to be combusted in a gas turbine. In addition, particulate removal is important for the recycle of unreacted char to the reactor, contributing significantly to the overall process efficiency.

However, sulfur removal is employed entirely for environmental reasons, since it is highly unlikely that the product gas will find an end use involving sensitive catalysts. According to Table 2-3 (presented earlier), latent and sensible heat losses due to Stretford unit operation account for approximately 1.76 percent of coal HHV. This translates to an approximate overall process efficiency loss of 1.5 percent. Taken together with the approximate 1 percent loss of sulfur HHV from the product gas, the total efficiency loss due to sulfur removal activities is of the order of 2.5 percent.

2.7 WATER POLLUTION CONTROL TECHNOLOGY

2.7.1 Ability of Existing Technology to Meet Regulations

Because of high gasification temperature typical of many entrained flow gasification systems, the production of tars, oils, phenols, naphthas and heavy hydrocarbons by the C-E gasifier is minimal or zero. For the same reason, ammonia production is minor, but that which is produced appears in process condensate streams. These streams become part of a wastewater stream which includes other organic and inorganic compounds produced by gas cleaning, ash dewatering, process condensate blowdown and water treating rinse activities.

In anticipation of future regulations governing coal conversion plants, a detailed process design would probably include the concept of zero liquid discharge to surface waters. This technique employs cooling towers extensively to evaporate process waste waters, concentrating the wastes so that subsequent steps can convert them into solids for burial. Some deep well discharge of process waters is usually part of such a system. Regardless of the design chosen for wastewater treating, this and other entrained flow gasification processes studied in this report will probably represent the cleanest operating systems of both current and advanced technologies alike.

2.7.2 Water Recycling Systems

Extensive water recycling will be required to meet the no discharge requirement, or in cases where raw water availability is limited. The extent of recycling used in each case will be customized to the particular constraints of the situation in question.

The simplest plant water system to effect a large water recycling program is in the boiler feedwater and condensate system. Deashed water and process condensate from the CE process can also be treated with relative ease for recycling to the process. A certain amount of make-up water will be required to supplement cooling tower losses, except perhaps in cases where a very high moisture feedstock (such as lignite) is used which can supply a significant amount of process water through gas condensation. The importance of this source is limited by moisture content limitations on gasifier feedstock.

2.7.3 Impacts on Plant Efficiency

Treatment of wastewater streams is necessary in order to remove suspended solids, trace elements and organic matter for reuse of water in plant processes. Much of the treated water is fed back to the gasification water walls, process boilers and acid gas removal plant operations. The treatment of these wastewaters requires electrical energy and steam which has an impact on process efficiency, albeit a minor one. Water recycling promotes the efficient use of water resources and will be in many cases worthwhile in its own right aside from environmental considerations.

2.8 SOLID WASTE HANDLING

2.8.1 Disposal Requirements

No regulations governing the disposal of solid waste currently apply at the federal level for coal gasification plants.

The primary solid waste of the Combustion Engineering low-Btu coal gasification process is the molten slag produced from the gasifier itself. Particulates collected from the raw gas stream are entirely recycled within the process. Some residual solids also result from wastewater treating operations.

The large quantities of slag generated by the gasifier are quenched in a water bath arrangement which fragments the solidified slag agglomerates. The slag is dewatered primarily for the removal of excess (surface) moisture. A portion of the water removed from the slag slurry is recycled to the quench vessel, the remainder being processed in wastewater treating. Disposal of the ash may in the most severe case be in a classified landfill; however, it may be entirely feasible to return the material to the mine for ultimate disposal.

2.8.2 Leachate Problems

Because the coal is in the form of solidified slag upon its disposal, the leaching of trace metals from the ash is minimized. ASTM leaching tests on slags produced in other gasifiers have been performed (see TAG 4B) and this is an area under active investigation. Complete characterization of leaching characteristics of a specific coal feedstock slag produced by the CE gasifier would be required prior to and would be the basis of the selection of a solid waste disposal option.

2.9 OSHA ISSUES

The coal storage and preparation areas will present occupational hazards to workers. Coal dust which can be present in storage and milling areas can cause respiratory illness such as black lung or cause fires. Coal pulverization is a noisy operating during which ears should be protected.

The high operating temperature of the gasifier will pose a danger of burns from gas leaks or during slag handling.

2.10 PROCESS PERFORMANCE FACTORS

2.10.1 Product Characteristics and Marketability

The composition of the product gas from the Combustion Engineering low-Btu gasification process when using an Illinois No. 6 feedstock is presented in Table 2-5. The gas heating value is quite low, due to large amounts of diluent nitrogen in the gas. The use of such a fuel in a boiler designed for oil or natural gas would require combustor redesign, possibly tube reorientation, and most likely some boiler derating. The strongest markets for the gas will be found among utility and large industrial energy users. Due to the toxicity of the gas, its direct use in residential applications would not be feasible.

One possible additional use for the gas is as a feedstock for activated carbon production, or pipeline gas production via a solid carbonaceous intermediate such as is used in TRW's BEACON process.

2.10.2 Capacity Factors, Flexibility and Reliability

The Combustion Engineering low-Btu coal gasification process is designed to operate at a 90 percent capacity factor. Although the turndown capability of the gasifier itself is limited (as are most entrained flow gasifiers), the use of multiple process trains (four in this design) gives the plant a high degree of flexibility in throughput. In addition, the CE gasifier is capable of accepting a wide variety of coals, none of which require pretreatment (except for drying in some cases).

Table 2-5

Expected Synthesis Gas Composition from Illinois No. 6 Coal

Gas Component	Mole % (Vol %)
CH_4	0.00
H_2	10.83
CO	21.46
CO_2	4.91
H_2O	7.31
H_2S	0.06
COS	0.03
N_2	55.40
NH_3	0.00
	100.00

Cold Gas Heating Value, HHV	104 Btu/SCF
Gas Heating Value as delivered (including sensible and latent heat)	113 Btu/SCF

Due to the developmental nature of the gasifier, the reliability of the CE design is yet to be proven in larger scale and longer duration tests.

2.11 TECHNOLOGY STATUS AND DEVELOPMENT POTENTIAL

2.11.1 Current Status

In late 1975, construction began at CE's Windsor, Connecticut site for a 120 TPD pilot plant system. Construction was completed in 1977 and experimental operation began in June 1978. Most of the testing has been with Pittsburgh No. 8 seam coal, although some testing on Texas lignite, Montana subbituminous, Western subbituminous and Midwestern bituminous coals has been done. CE had plans for performing gasification runs using oxygen enriched air, but did not reach this phase of the test program before the unit was shut down in June, 1981 due to DOE funding problems and necessary equipment modification and maintenance studies.

Combustion Engineering has also executed a $4.9 million contract with the Department of Energy to design a coal gasification plant at Gulf States Utilities Company's plant in Westlake, Louisiana. This is the first phase of a project to design, construct and operate a gasification system to be integrated with the 150 MW Unit 3 boiler. Gulf States has signed an agreement confirming their participation and Ford, Bacon and Davis has been selected for the architect/engineer subcontract work.[2-2] Uncertainties in DOE funding now make the future of the project uncertain.

2.11.2 Key Technical Uncertainties

An important aspect of this process is that, with the exception of the gasifier itself, no major equipment items in the system require development effort. Although the various major components have never been assembled in a single system equivalent to the proposed system, all but the gasifier are commercially available and have been used successfully in sizes and throughputs which approximate the needs of this system. The principal R and D effort required to successfully produce and operate such a system is the development of an understanding of the gasification kinetics involved in this process so that full-scale gasifiers can be properly sized to produce the desired quantity and quality of gas at the gasifier exit. It also will be necessary to develop a viable mode of operation and control of the system on a size scale which permits direct translation of the results to large-scale equipment.

It is likely that the development effort on the gasifier will reveal shortcomings in selected materials of design for the gasifier, particularly the refractories with respect to their compatibility with various types of slag and ash, method of support, and ability to withstand thermal cycling. Materials problems will be common to all types of gasifiers because of the severe service condition to which the gasifier walls are exposed. No significant materials problems are anticipated for the balance of the system.

2.11.3 Availability for Commercial Production

The extent of operating experience with the Combustion-Engineering gasifier has been limited to the 120 TPD pilot plant at CE's Windsor, Connecticut facility. A demonstration plant is planned which will fire a 150 MW boiler, but this facility will not be on line until 1985 at the earliest. This facility will represent a 15 to 1 scale up in capacity from the current pilot plant. A commercially sized plant would be a factor of approximately five larger than the 150 MW demonstration plant. Although risk for the commercial plant would be low by virtue of the use of multiple process trains similar to that used in the demo plant, design and construction of a full-sized facility would have to be based on experience gained in the demonstration unit. Start-up of such a plant is therefore probably at least a decade away.

2.11.4 Unit Design and Construction Times

The design of a fully commercial-scale low-Btu gas plant based on Combustion Engineering gasification technology does not represent any unusual challenges aside from the developmental or risk nature of assumptions which form the design basis and underlie engineering calculations. A design period of one to two years could be anticipated. Similarly, the same comment applies to the length of time required for construction once environmental and other regulatory permits have been obtained. Approximately five years from initiation of construction to start-up could be expected and would allow time for custom fabrication of the gasifier, the only non-commercial equipment item in the plant.

2.12 REGIONAL FACTORS INFLUENCING ECONOMICS

2.12.1 Resource Constraints

The Combustion Engineering gasification facility requires approximately 2.4 million tons of coal per year, and approximately 3,500 acre feet of water per year. These resources must be available on a long-term basis to assure continuous plant operation during its 20 year life. Other materials required for plant operation (process chemicals) are readily available in the quantities needed and will not pose a problem to plant operation.

2.12.2 Environmental Control Constraints

Proper operation of the Stretford sulfur removal system should reduce product gas sulfur concentrations to a range acceptable in all attainment areas. Unfortunately the very nature of the product gas suggests that most users will be located in a highly industrial and therefore probably non-attainment area. Construction of a plant in these areas may require the shutdown or other such tradeoff of some existing sources in the area, at some cost to the low-Btu gas facility. Special permits covering air. water, and solid waste may also be required. Each situation is unique however, and must be assessed individually.

2.12.3 Siting Constraints

A suitable site for the C-E gasification plant must be several hundred acres of fairly level ground with good access to rail or barge service, and within a relatively close proximity (less than 3 miles) to all users of the low-Btu gas. Such sites in industrial areas are usually well equipped for rail and barge transportation (for coal in this case), but may be difficult or expensive to obtain within a reasonable distance of users due to the size involved. The ideal and most likely situation for the first commercial plant would locate the plant in part or wholly on the grounds of the user, or at least adjacent to the user's plant battery limits.

References

2-1. Kimmel, S., E.W. Neben, G.E. Pack. Economics of Current and Advanced Gasification Processes for Fuel Gas Production, Electric Power Research Institute Report No. AF-244, July 1976.

2-2. "Coal Gasification Demo Plant for Gulf States," CEP, May 1981.

CHAPTER THREE: ECONOMIC ANALYSIS - COMBUSTION ENGINEERING

3.1 INTRODUCTION AND METHODOLOGY

3.1.1 Economic Analysis Methodology

The economic analysis relies on a commercial-size conceptual design for a low-Btu gasification plant using Combustion Engineering technology (3-1). The data presented in the report were scaled to a size of 50 trillion Btu per year and were corrected from 1976 to 1980 dollars; the adjusted data were used to compute product costs for the process.

3.1.2 Scaling Exponents

The reference report (3-1) contained a plant with a capacity of 77.05×10^{12} Btu per year including low-Btu gas (67.77×10^{12} Btu/year) and electricity (9.28×10^{12} Btu/year evaluated at 10,000 Btu/kWh). This was scaled down to a plant size of 50×10^{12} Btu per year using the formula presented in the Background section.

Scaling exponents of 0.7 were used for the Coal Preparation (200) and Utilities and Support systems (2000) areas because these areas were composed of one or two trains (3-2). The use of one or two trains implies that equipment sizes must be changed, and so economies of scale apply. Scaling exponents of 1.0 were used for the Gasification (300), Acid Gas Removal (1300) and Product Gas Compression (1200) areas because these areas employed four or more

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trains. Scaling down plants of multiple trains simply implies removing one or more train, so no economies of scale apply.

A scaling factor of 0.6 was used for operating labor.

3.1.3 Price Indices

Costs presented in reference 3-1 were in 1976 dollars. These were corrected to third-quarter 1980 dollars using the indices listed in the Background section.

3.1.4 Economic Criteria

The standard economic criteria described in the Background section were employed. The schedule of investments over the three-year construction period was 25 percent, 50 percent, 25 percent.

3.1.5 Contingencies

A project contingency of 15 percent was applied to the sum of all area costs to cover unanticipated increases in costs during final design and construction. A process contingency of 25 percent was added to the cost of Area 300, Gasification, because this technology has not been proven beyond the pilot plant stage. The costs of Area 300 also include Area 1200, Raw Gas Cooling.

3.2 CAPITAL COSTS

3.2.1 Itemized Capital Costs

The total plant investment for a 50 trillion Btu per year Combustion Engineering gasification system would be $290.8 million in third-quarter 1980 dollars, or $5.82 per million Btu capacity. Highly detailed cost information was not available for this system. However, Table 3-1 shows that the Gasification and Raw Gas Cooling areas together would cost $84.9 million of 37 percent of the total. The other largest components of costs are Utilities and Support Systems (Area 2000) and Offsites and Miscellaneous (Area 2100), which together would cost $74.9 million. Substantial savings are achieved in this system because the recovery of gasifier heat in the form of electric power reduces the necessary size of components.

Besides the total plant investment, other funds are needed to complete the total capital requirements, as is shown in Table 3-1. Paid-up royalties, at $1.5 million, are fees to technology owners. Working capital adds $17.7 million and Start-up $17.4 million. Interest During Construction is the largest of these extra expenses at $95.7 million. The total capital requirement amounts to $423.6 million.

3.2.2 Variability of Capital Costs

The conceptual design of the gasification system included all major equipment items. The design was specific enough to allow a confidence interval of approximately ±30 percent. That is, major equipment items were specified and costed, but no plant-specific costing was attempted.

TABLE 3-1

TOTAL CAPITAL REQUIREMENT - COMBUSTION ENGINEERING[a]

AREA	ITEM	COST (10^6 \$)	PERCENT OF SUBTOTAL
100	Coal storage and handling	(in 200)	--
200	Coal preparation	30.0	13.1
300	Gasification	84.9	37.0
1200	Raw gas cooling	(in 300)	--
1300	Acid gas removal	21.6	9.4
1600	Product gas compression	18.1	7.9
2000	Utilities and support systems	74.9	32.6
2100	Offsites and miscellaneous	(in 2000)	--
	Subtotal	229.5	
	Process contingency	21.2	
	Project contingency	34.4	
	Sales tax	5.7	
	Total plant investment	290.8	
	Paid-up royalties	1.5	
	Initial catalysts and chemicals	0.5	
	Interest during construction	95.7	
	Working capital @ 6.1%	17.7	
	Start-up @ 6.0%	17.4	
	Total capital requirement	423.6	

[a]Source: 3-1, updated to third-quarter 1980 dollars and scaled to 50 trillion Btu/year by ERCO.

At the time this estimate was made, the Combustion Engineering pilot plant had not yet been operated. Subsequent operation of the pilot plant demonstrated that the economic assumptions of this report were substantially correct.

3.3 OPERATING AND MAINTENANCE EXPENSES

3.3.1 Itemized Operating and Maintenance Expenses

Annual operating and maintenance expenses are presented in Table 3-2. An operating factor of 90 percent is assumed. Gross expenses total $24.5 million. These are offset by a credit for by-product sulfur of $2.6 million, so net operating and maintenance (O&M) costs total $21.9 million.

The largest single O&M cost is Local Taxes and Insurance at $7.3 million. The plant would have labor costs of $8.2 million. Administration and general overhead would absorb $3.8 million.

3.3.2 Variability of Operating and Maintenance Expenses

The confidence interval of the operating and maintenance costs should be within the ±30 percent of the capital cost estimates. No major annual cost item was deleted from the estimate. Maintenance costs and local taxes and insurance were factored directly from the capital cost estimates using the conservative methods outlined in 3-1. Other costs are essentially process dependent, so without major design revisions they will lie within the ±30 percent confidence interval.

TABLE 3-2

NET OPERATING AND MAINTENANCE COSTS - COMBUSTION ENGINEERING[a]

ITEM	COST (10^6 $)[b]	PERCENT OF TOTAL[c]
Administration and general overhead	3.8	15.5
Local taxes and insurance	7.3	29.8
Labor		
Operation	3.6	14.7
Maintenance	2.7	11.0
Administrative and support	1.9	7.8
Total	8.2	33.5
Maintenance materials	4.1	16.7
Catalysts and chemicals	0.2	0.8
Solids disposal	0.3	1.2
Utilities	0.6	2.4
Total	24.5	100.0
By-Product Credit	(10^6 $)	
Sulfur	(2.6)	
Net O & M Costs	(10^6 $)	
Gross O & M costs	24.5	
By-product credit	(2.6)	
Total	21.9	

[a]Source: (3-1), adjusted to 50 trillion Btu/yr by ERCO. 90 percent operating factor.

[b]Third quarter 1980 dollars.

[c]Column does not add to 100 percent because of rounding.

3.4 EFFECT OF TECHNOLOGY DEVELOPMENT ON COSTS

The Combustion Engineering gasifier technology is not yet mature. Further technology development could reduce costs in real dollars as better methods are learned. The immature gasification system accounts for approximately 46 percent of the total plant investment. With a maximum experience factor of 10 percent on new energy technologies, the experience factor on Combustion Engineering technology would be 46 percent of 10 percent, or 4.6 percent. Each doubling of Combustion Engineering gasifier capacity would result in a 4.6 percent reduction in real costs.

3.5 PRODUCT COSTS

The product costs have three discrete components: capital charges, operating and maintenance (O&M) costs, and coal costs. A non-fuel product cost can be computed with the capital charges and O&M costs, and the formula given in the background section.

The total capital requirement of the plant is $423.6 million from Table 3-1, and net O&M costs are $21.9 million from Table 3-2. Therefore, the non-fuel product cost is:

$$P = \frac{(\$423.6 \times 10^6 \times 20\%) + \$21.9 \times 10^6}{(50 \times 10^{12}\ \text{Btu}) \times 90\%\ \text{capacity}}$$

$$= \underset{\text{(capital charges)}}{\$1.88/10^6\ \text{Btu}} + \underset{\text{(O\&M charges)}}{\$0.49/10^6\ \text{Btu}}$$

$$= \underset{\text{(non-fuel product cost)}}{\$2.37/10^6\ \text{Btu}}$$

The non-fuel product cost can be combined with a coal cost to yield a total product cost. The overall coal-to-product efficiency of the process is 78.8 percent[1]. With coal assumed to be $1.50/10^6 Btu, the coal cost would be $1.90/10^6 Btu. Therefore the total energy cost would be:

$$E = \underset{\text{(Coal)}}{\$1.90/10^6\ \text{Btu}} + \underset{\text{(Capital and O\&M Costs)}}{\$2.37/10^6\ \text{Btu}}$$

$$= \$4.27/10^6\ \text{Btu}$$

The average product cost would be $4.27/10^6 Btu. This price of $4.27/10^6 Btu assumes that electricity is valued at 10,000 Btu/kWh and the product gas at its higher heating value. Electricity has a theoretical heat content of 3,412 Btu/kWh. Ten thousand Btu/kWh is used here to account for energy losses normally associated with electricity generation. Use of 3,412 Btu/kWh would increase the product costs by less than 20 percent.

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[1]Assuming the product gas is valued at its higher heating value, and electricity at 10,000 Btu/kWh.

References

3-1. Chandra, K., B. McElmurry, and S. Smelser (Fluor Engineers and Constructors), "Economics of Fuel Gas From Coal - An Update Including the British Gas Corporation's Slagging Gasifier." Electric Power Research Institute AF-782, May 1978.

3-2. Kimmel, S., E.W. Nelson, and G.E. Pack (Fluor Engineers and Constructors), "Economics of Current and Advanced Processes for Fuel Gas Production." Electric Power Research Institute AF-244, July 1976.