

TECHNOLOGY ASSESSMENT GUIDE
NO. 10
ICI COAL TO METHANOL

DRAFT

CHAPTER ONE: EXECUTIVE SUMMARY

1.1 OVERALL PROSPECTS FOR THE TECHNOLOGY

Methanol is a valuable industrial commodity with a variety of uses including chemical synthesis and fuel applications in addition to its use in many manufacturing processes. The ability to produce methanol from coal rather than from natural gas or petroleum sources could be an important means for reducing the consumption of these resources. The decline in consumption would result for two reasons: 1) these sources would no longer be required to produce methanol, and 2) additional methanol production above current levels would result in fuel and non-fuel uses for methanol which would further offset consumption of natural gas and petroleum.

The ICI coal to methanol process is based upon Lurgi dry-ash gasification technology, which proves very low risk due to its considerable operating history, but also is noted for its poor thermal efficiency. Overall process efficiency is approximately 64 percent, which could be improved with a second (or third) generation gasifier. The ICI methanol process is well established commercially, but the same cannot be said of the catalysts for raw gas shift and purge gas methanation. Improvements in process efficiency (by the use of an advanced generation gasifier) should produce lower product costs, allowing the methanol, SNG and naphtha products of the plant to become more competitive, and thereby over time help to increase the acceptability of this method of coal utilization.

1.2 ENGINEERING ASPECTS

The heart of the ICI coal to methanol process lies in the chemical synthesis step where synthesis gas (carbon monoxide and hydrogen) is reacted catalytically to produce methanol. The gasification unit used to produce the synthesis gas is the conventional dry-ash Lurgi system, described in Technical Assessment Guides No.3 and No. 5.

Several by-products are produced from the Lurgi gasification system. Tars, diesel-range oils, crude phenols and ammonia are sold directly without further treatment. The light naphtha fraction recovered from the acid gas removal section is hydrotreated prior to sale to improve product quality. Hydrogen for the hydrotreating operation is obtained from a slipstream of the purge gas resulting from methanol synthesis. This slipstream is recombined after hydrogen removal with a purge gas stream from methanol fractionation. The combined purge gas streams are then upgraded through methanation, acid gas removal and drying to the third plant output, a high-Btu SNG-type product.

Conceptually, this process is designed in an efficient manner (except with regard to the choice of gasifier), but several potential technical difficulties remain. The gas shift catalysts used on the gasifier effluent have not been proven at a commercial scale and involve some risk. Multiple trains will be used to minimize the risk of emergency shutdown of these units. Similarly, the methanation catalysts operating on purge gases are not well known commercially and present the possibility of thermal runaway due to the highly exothermic nature of the methanation reactions.

1.3 CURRENT COSTS

The total capital requirement for this 125×10^{12} Btu/year plant is \$3.6 billion, which is dominated by a plant investment of \$2.1 billion, working capital of \$218 million, and interest during construction of \$200 million. These costs are quite high relative to other planned synthetic fuels plants, and reflect the degree of complexity associated with this process.

Annual operating and maintenance costs (at a 90% plant capacity) total \$172 million, which are offset to \$166 million net from ammonia by-product credits.

Taken together with a 20 percent capital charge, these operating costs result in a product cost of $\$7.87/10^6$ Btu, which is exclusive of coal costs. However, it must be remembered that this is an average cost on a Btu basis for all three plant products. The methanol is by far the highest value product, and would be sold at a price considerably above this level. Depending on the naphtha quality, the SNG will most likely be the intermediate product in price, followed by the naphtha. Inclusion of coal costs (at $\$1.50/10^6$ Btu) into this estimate results in a product cost of $\$10.20/10^6$ Btu.

1.4 RESEARCH AND DEVELOPMENT DIRECTIONS

Improvements in the Lurgi gasification system were addressed in section 1.4 of TAGS 3 and 5.

Portions of the process which have not been commercially proven must gain a sufficient degree of operational experience at large scale before widespread commercial

acceptance can be expected. One technique for bringing this about at minimum risk is the use of a larger number of process trains which minimizes the impact to process operation when an individual train goes down.

Large-scale operation may indicate the need for catalyst development, not only for raw gas shift and purge gas methanation catalysts, but also for methanol synthesis catalysts. Catalyst improvements may include better selectivity, higher specific rates under lower severity conditions, better heat transfer or thermal stability, and longer life.

CHAPTER TWO: ENGINEERING SPECIFICATIONS

2.1 GENERAL DESCRIPTION OF THE TECHNOLOGY

The ICI process described converts coal to methanol using indirect liquefaction technology. Lurgi Mark IV gasifiers first convert the coal solids into a raw gas, which then undergoes a water-gas shift reaction to increase the hydrogen to carbon monoxide ratio. Once cooled, the shifted gas stream separates into a liquid condensate and a cleaned gas. Crude diesel oil, phenols, tars, and ammonia are recovered from the condensate prior to wastewater treatment; the cooled, cleaned gas is treated to remove acid gases and then sent to methanol synthesis reactors. Remaining gases are converted to pipeline quality SNG.

The process described in this TAG is designed to produce high quality methanol suitable for gasoline blending. A significant feature of this process is the large amount of non-methanol substances produced; less than one-half of the total product slate heating value is represented by the methanol product. This product diversity is attributed to the use of Lurgi dry-ash gasifiers, which normally produce a number of materials other than syngas.

2.2 PROCESS FLOW, ENERGY, AND MATERIAL BALANCES

Plant area numbers designating process units integral to the ICI process are listed in Table 2-1. A conceptualized process flow diagram showing the relationships of the various process units is illustrated in Figure 2-1, and significant stream flows are quantified in Table 2-2. The following discussion summarizes major processing steps for the ICI conversion of coal to methanol.

Table 2-1

Relevant ICI Coal-to-Methanol Plant Area Numbers

100	COAL STORAGE AND HANDLING
	110 Coal Storage
200	COAL PREPARATION
	210 Coal Crushing
	250 Coal Sizing
300	GASIFICATION
	310 Gasification
	320 Ash Handling
400	HYDROGENATION/METHANOL SYNTHESIS
500	PRODUCT SEPARATION
	510 Methanol Fractionation
	520 Naptha Stabilization
1300	ACID GAS REMOVAL AND GAS CLEANING
	1310 Acid Gas Removal
	1320 Ammonia Recovery
	1330 Tar and Oil Separation
	1340 Phenol Recovery
1700	SHIFT CONVERSION
1800	METHANATION AND OTHER CATALYTIC REFORMING
1900	AIR SEPARATION
2000	UTILITIES AND SUPPORT SYSTEMS
	2020 Wastewater Treatment
2100	OFFSITES AND MISCELLANEOUS

Figure 2-1
 ICI Coal-to-Methanol Conceptualized Process Flow Diagram

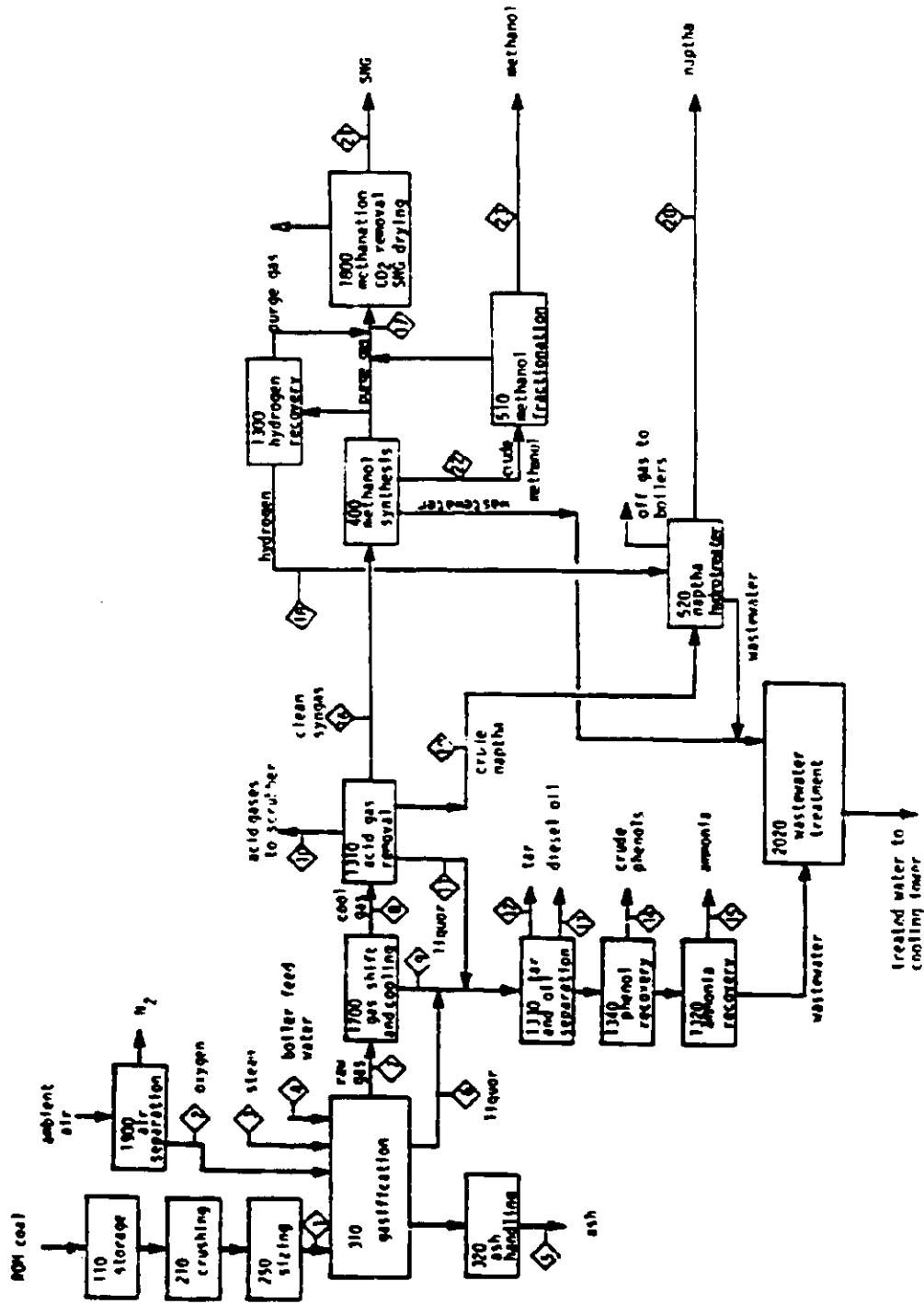


Table 2-2
ICI Coal-to-Methanol Detailed Process Stream Descriptions

Stream Description Temperature, °F Pressure, PSIG	1 Coal Feed		2 Oxygen		3 Steam		4 BFW to Gasifier Jacket		5 Ash		6 Gas Liquor		7 Raw Gas		8 Shifted & Mixed Gas		9 Gas Liquor	
	klb/hr	wt %	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %
H ₂																		
N ₂																		
CO			2.15	0.437														
CO ₂																		
H ₂ O																		
CO ₂																		
methane																		
ethylene																		
ethane																		
propylene																		
propane																		
i-butane																		
butenes																		
n-butane																		
i-pentane																		
pentenes																		
n-pentane																		
hexanes																		
methanol																		
water																		
oxygen																		
HC ₁																		
Coal	617.36	29.356	488.27	99.563	1841.62	100.000	211.13	100.000										
Minerals	1300.39	61.540																
Gill	175.23	5.004																
Par																		
NH ₃																		
Hepta																		
Crude phenols																		
Sulfur																		
Fatty Acids																		
Nitrogen organic																		
TOTALS	2102.98		490.47		1841.62		211.11		117.94		291.14		4741.87		2788.76		1453.61	

Table 2-2
ICI Coal-to-Methanol Detailed Process Stream Descriptions Page 2 of 3

Stream	Description	10		11		12		13		14		15		16	
		lb/hr	mole %	lb/hr	mole %	lb/hr	mole %	lb/hr	mole %	lb/hr	mole %	lb/hr	mole %	lb/hr	mole %
	Acid Gases 95 1)														
	Flow	0.47	0.533												
	H ₂	0.01	0.001												
	N ₂	3.00	0.273												
	CO	1660.85	96.396												
	CO ₂														
	H ₂ S	5.82	0.437												
	CS ₂	0.13	0.006												
	CH ₄	7.08	1.130												
	C ₂ H ₆ ethylene	1.96	0.179												
	C ₂ H ₄ ethane	11.02	0.938												
	C ₃ H ₆ propylene														
	C ₃ H ₈ propane														
	i-butane														
	n-butane														
	n-pentane														
	hexane plus														
	methanol														
	water														
	oxygen														
	HC														
	Sulfurals														
	oil														
	tar														
	HI ₂														
	naphtha														
	crude phenols														
	TOTALS	1690.96		3.14		39.50		55.90		16.49		9.49		1076.88	

Table 2-2
ICI, Coal-to-Methanol Detailed Process Stream Descriptions
Page 3 of 3

Stream Description Temperature, °F Pressure, PSIG	17 Purge Gas		18 Hydrogen		19 Crude Naptha		20 Product Naptha		21 SMG		22 Crude Methanol		23 Product Methanol	
	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %
H ₂	21.98		0.21	100.000					0.52	1.500	0.29	0.635		
N ₂	29.12								1.42	0.580	0.46	0.074		
CO	31.37								0.05	0.010	0.76	0.121		
CO ₂	75.90								0.77	0.100	13.74	1.366		
H ₂ S														
CO ₂														
CH ₄	163.09								273.24	97.800	6.66	1.842		
C ₂ H ₆	0.47										0.04	0.007		
C ₂ H ₄	6.93										0.60	0.088		
C ₂ H ₂	0.28													
C ₃ H ₈	5.35													
C ₃ H ₆	3.41													
1-butane	0.34													
butenes	0.68													
n-butane	0.77													
1-pentane	0.16													
pentenes														
n-pentane	0.05													
hexane plus	0.05													
methanol	3.10				0.17	100.000			0.03	0.010	579.94	80.395	633.99	99.900
water	0.11										62.67	15.452	0.63	0.010
oxygen														
coal														
minerals														
oil														
tar														
NH ₃														
naptha														
crude phenols					17.02		16.87							
sulfur organic					0.08									
nitrogen organic					0.01									
TOTALS	343.12		0.21		17.28		16.87		276.03		665.16		634.62	

Run of mine coal is first crushed to minus 2 inch mesh, dry screened for removal of the 2" x 1/2" sized coal, and wet screened for separation of 1/4" x 0" size from the 1/2" x 0" size coal. The 1/4" x 0" coal cannot be fed to the Lurgi gasifiers and is therefore used as boiler feed. Extra coal required for the boilers is removed from the gasification unit coal feed stream.

The well-sized coal is fed into Lurgi Mark IV gasifiers (210) from top-mounted coal lock hoppers. While traveling down through the gasifier, the coal is dried, devolatilized and gasified by a mixture of oxygen and steam which is introduced into the bottom of the gasifier through a rotating grate. Ash is removed by this grate and discharged to the ash handling unit (320). The addition of steam moderates the gasifier temperature to below the ash melting point.

The hot raw gas leaving the gasifier is cooled and scrubbed with recycled gas liquor. By this operation the crude gas is saturated with steam and the dust and heavy tars are removed. After further cooling, the raw gas is then sent to the raw gas shift (1700) and cooling unit.

The dusty gas liquor leaving the wash cooler is sent to the gas liquor separation unit for recovery of tars and light oil (1320), phenol (1340), and ammonia (1320).

The raw gas shift unit increases the H₂/CO ratio in the raw synthesis gas to meet the requirements of methanol

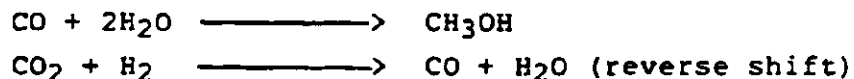
synthesis. Carbon monoxide concentration is reduced and additional hydrogen is produced by the following exothermic shift reaction:



Reaction steam is provided by the normal steam content of the raw gas. Only a portion of the raw gas from the gasifiers is fed to the raw gas shift unit. The remaining raw gas is cooled, then later mixed with the shifted gas prior to acid gas removal.

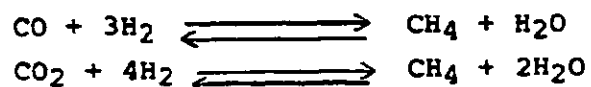
The acid gas removal unit (1310) removes sulfur compounds (primarily hydrogen sulfide) to less than 0.1 ppm in order to protect the downstream methanol synthesis unit catalyst. The unit also removes CO₂ from the gas, as well as naptha and HCN. A non-selective Rectisol unit with a naptha pre-wash section is used in this process.

Cleaned synthesis gas enters the Imperial Chemical Industries (ICI) low pressure methanol synthesis unit (400), where the following two major reactions occur:




Crude methanol containing about 88 wt% methanol, 10 wt% water, and dissolved gases leaves the synthesis unit and enters the methanol fractionation unit (510). In this process, crude methanol is distilled to gasoline blending quality using two fractionating columns, one operating at higher pressure than the other. The two tower fractionation system allows the overhead from the high pressure tower to reboil the bottoms of the low pressure tower, thereby reducing total steam requirements for the unit.

Purge gas from the ICI methanol synthesis unit is sent to the hydrogen recovery unit (1300) and to the methanation unit (1800) to produce SNG. Separated hydrogen is used to hydrotreat crude naphtha in a fixed catalytic bed (520). Hydrotreatment of the naphtha stream removes any sulfur and nitrogen, improves odor, stabilizes the naphtha, and produces a stream suitable for gasoline blending. The stabilized product naphtha is then sent to storage. The purpose of the methanation unit is to produce pipeline quality SNG from the methanol synthesis purge gas. In the presence of a catalyst, hydrogen is combined with carbon monoxide and carbon dioxide to form methane and water by the following reactions:



Hydrocarbons other than methane are cracked and hydrogenated to form methane. The product gas is then contacted with a circulating stream of monoethanolamine (MEA) to remove carbon dioxide down to a concentration of 0.1 mole percent. Water is removed from the SNG to a concentration of 4 lb/MMSCF by contact with a circulating solution of triethylene glycol (TEG).



An overall ICI coal-to-methanol plant material and energy balance is shown in Table 2-3. A total coal input of 31,275 tons per day is necessary to generate 125×10^{12} Btu/yr of liquid and gaseous fuel products. Methanol produced by the ICI process accounts for only 46 percent of the product slate's energy content. Much of the remaining energy value (48%) is contained in the produced SNG.

The plant thermal efficiency, based on the product slate shown in Table 2-3, is 64.3 percent. Ammonia is considered a by-product of the ICI process and is therefore not included in calculating the overall thermal efficiency.

Table 2-3
Overall ICI Coal-to-Methanol Material and Energy Balance

<u>Input</u>	<u>klb/Day</u>	<u>High Heating Value 10⁹ Btu/Day</u>
Coal to plant	62550 ^a	532.2
Oxygen	12423	
Water (makeup)	58350	
<u>Output</u>		
Methanol	15231	148.5
Naphtha	405	7.7
SNG	6624	157.0
Crude phenol	396	6.0
Crude diesel oil	<u>1341</u>	<u>23.2</u>
Total Products	23997	342.4
<u>Byproduct</u>		
Ammonia	228	2.2
<u>Overall Thermal Efficiency</u>		64.3%

^aRepresents ROM coal. MAF Coal = 41850 Klb/day

2.3 PLANT SITING AND SIZING: ISSUES AND CONSTRAINTS

The ICI Coal-to-methanol process assessed in this study is designed to produce the equivalent of 125×10^{12} Btu/yr of coal-derived methanol, SNG, and other liquid fuel products. Related process needs will include a captive coal source, wastewater treatment facilities, sludge and ash treatment and disposal areas, air separation and compression, process cooling towers, and a source of fresh water.

Subbituminous coal resources must be provided at a secured rate of 11.4 million tons per year for the life of the plant. Coal preparation facilities at the plant site include a railyard capable of receiving and dumping over 315 coal hopper cars a day. Other preparation facilities include a long term crushed coal storage pile (60 day supply), a 4.5 million gallon water reservoir for the wet screening unit, and various intermediate coal storage hoppers and silos.

Nearly 11 million tons/yr (approximately 7800 acre-feet) of fresh makeup process water are required. Fresh water is needed for the cooling tower, coal preparation, flue gas desulfurization, steam generation, and general services. Fresh water makeup is not readily available in large quantities in northeastern Wyoming. Therefore, the plant design minimizes fresh water consumption by utilizing recycle water streams and as much air cooling as possible. Water is obtained from deep water wells situated at 1000 foot intervals along the facility plot site. This water is pumped to a two million gallon reservoir for surge control.

Solid waste disposal facilities must safely store ashes from the gasifiers, gypsum sludge from flue gas desulfurization, and concentrated waste water sludges. Approximately 860 acres must be devoted to landfill for the generated solid wastes. The landfill is lined with a compacted bentonite/soil layer for permeability control. No leachate collection system should be needed due to the relatively high evaporation rate in northeastern Wyoming.

2.4 RAW MATERIALS AND SUPPORT SYSTEM REQUIREMENTS

2.4.1 Coal Quantities and Quality

It has been assumed that this methanol production plant is located in northeastern Wyoming and uses subbituminous coal similar in composition to coal from the Wyodak deposit. Proximate and ultimate analyses for the design coal are listed in Table 2-4. Approximately 25 percent of the incoming coal is used as boiler feed for steam generation. Well-sized coal (1/4" x 2") is fed to the gasifiers at a rate of approximately 25,000 tons/day.

2.4.2 Catalysts and Other Required Materials

No quantified information is available concerning catalyst makeup requirements throughout the facility.

Table 2-4
Coal Composition

Proximate Analysis (as received), wt %	
Moisture	28.0
Ash	5.1
Fixed Carbon	33.8
Volatile Matter	<u>33.1</u>
Total	100.00
Ultimate Analysis (MAF basis) wt %	
Carbon	74.45
Hydrogen	5.10
Oxygen	19.22
Nitrogen	0.75
Sulfur	0.45
Chlorine	<u>0.03</u>
Total	100.00
Ash Softening Temperature, °F	2335
Ash Flow Temperature, °F	2430
Hardgrove Grindability Index	60

2.4.3 Water Requirements

The ICI coal-to-methanol facility will require approximately 7.0 million gallons (21.5 acre-feet) of fresh water every day. This quantity represents a minimum requirement when water conservation and recycle techniques are used. Wet cooling tower makeup is a major user of fresh water; other processes requiring fresh water makeup include: coal preparation, flue gas desulfurization, boiler feed water, and general services.

Section 2.7.2 discusses several of the water recovery and recycling systems proposed for the plant site. Fresh water is provided by deep water wells situated at 1000 foot intervals along the plot site.

2.5 EFFECT OF COAL TYPE

The design coal used for this plant is a subbituminous coal feedstock similar in composition to the Wyodak deposit in northeastern Wyoming. Other coal types may be used, although certain parameters may require modification, as discussed below.

Subbituminous and other low-rank coals are highly reactive in gasification processes, compared to higher-ranked coals. When utilizing a dry bottom fixed-bed gasifier (as in this plant design), reaction rates for low-rank coal gasification remain high even at the lower temperatures required to maintain dry ash conditions.

Moisture content of the feed coal is not a significant concern in Lurgi dry ash gasifiers. In fact, large amounts of steam are injected into the gasifier to maintain temperature levels below the ash melting point.

Since the chemical composition of the feed coal determines CO, CO₂, and H₂ proportions in the synthesis gas, operating conditions in the shift conversion unit may require adjustment to account for variations in coal composition. Given the proper mixture of reactant gases, methanol synthesis and conversion processes can operate without adjustment.

Variations in coal composition, even when successfully controlled by way of process modifications, may alter the product slate proportions estimated for this design. The devolatilization of oils, phenols, naphthas, and other components will require different separation and treatment systems for higher-rank coal feedstocks due to differences in composition and feed rate.

2.6 AIR POLLUTION CONTROL TECHNOLOGY

2.6.1 Ability of Existing Technology to Meet Regulations

This plant is designed to meet existing environmental requirements for atmospheric discharges. The only discharges to the atmosphere anticipated throughout the ICI facility result from the steam generation coal-fired boiler and from various process vent streams.

A flue gas desulfurization (FGD) unit is used to remove sulfur dioxide and residual fly ash from the steam boiler stack gas. Flue gases from the high and medium pressure boilers are treated separately by limestone slurry scrubbing.

An incinerator is used at the plant site to combust sludge cake from the wastewater treatment unit, as well as combustible plant trash. Raw diesel oil from the liquor separation unit is used to fire the solids in the incinerator. Atmospheric discharges from this unit may include particulates and various unburned hydrocarbons. Emissions have not been quantified, although the use of a baghouse may be necessary to control particulate discharges. No other significant pollutants are anticipated.

2.6.2 Impacts on Process Efficiency

The use of flue gas desulfurization as a means of sulfur control has been selected in conjunction with the selection of the non-selective Rectisol acid gas removal

process. When a non-selective Rectisol unit is used to treat synthesis gas, and the sulfur content of the feed coal is very low (0.45 wt %, MAF basis), FGD systems can be considered an alternative to a selective Rectisol-Claus/SCOT sulfur recovery unit. The use of FGD requires less overall water consumption, and represents the favorable choice for process efficiency, especially since an FGD unit is already required for control of emissions from the process steam boilers.

2.7 WATER POLLUTION CONTROL TECHNOLOGY

2.7.1 Ability of Existing Technology to Meet Regulations

Although no aqueous effluent standards relating specifically to coal conversion plants have been established, standards do exist for similar non-process conventional sources (e.g. coal-fired boilers blowdown, cooling tower blowdown, etc.). Projected and existing effluent standards for coal liquefaction processes are listed in Table 2-5. The facility is designed to meet all existing effluent standards and regulations.

2.7.2 Water Recycling Systems

Water conservation is a major environmental concern in the west, and is a significant design consideration throughout this plant. Wherever possible, water usage has been eliminated, reduced, or recycled, as the following examples illustrate.

Table 2-5

Liquid Effluents-Coal Liquefaction Facilities

Source/Pollutant	Existing Requirements ^a	Projected 1990 Requirements (Base Case)	Stringent 1990 Requirements
<u>PROCESS</u>			
• Sour Water	N/A		Zero discharge
BOD ₅		5.0 mg/l	
TDC		10.0 mg/l	
COD		25.0 mg/l	
Oil and Grease		20.0 mg/l	
pH		6.0-9.0	
Priority Pollutants		0.5 mg/l ^b	
• Acid Gas Removal/Sulfur Recovery Blowdown	N/A	Zero discharge of water from acid gas or sulfur removal process.	Zero discharge
• Ash Sluicing Water	N/A	Zero discharge of ash transport water	Zero discharge
<u>NONPROCESS</u>			
• Boiler Blowdown			
TSS	100 mg/l ^c	Zero discharge	Zero discharge
Oil and Grease	20 mg/l ^c		
Copper, Total	1.0 mg/l ^c		
Iron Total	1.0 mg/l ^c		
• Once-Through Cooling Water Free Available Chlorine	0.5 mg/l	0.5 mg/l ^e	(0.1 Total Residual Chlorine) ^d
• Cooling Tower Blowdown-Recirculating Type Free Available Chlorine	0.5 mg/l	0.5 mg/l of priority pollutant discharge on a case by case basis.	(0.1 Total Residual Chlorine) ^d Zero discharge of priority pollutants.
• Bottom Ash transport			
TSS	100 mg/l ^c	100 mg/l ^c	Zero discharge of bottom ash transport water.
Oil and Grease	20 mg/l ^c	20 mg/l ^c 0.4 mg/l of priority pollutant discharge on a case by case basis.	
• Fly Ash Transport			
TSS	100 mg/l	100 mg/l	No discharge of fly ash water.
Oil and Grease	20 mg/l	20 mg/l	
Priority Pollutants		0.5 mg/l priority pollutants on a case by case basis	
• Low Volume Wastes ^d			Zero discharge
TSS	100 mg/l ^a	100 mg/l	
Oil and Grease	20 mg/l ^a	20 mg/l	

^aThe pH of all discharges, except for Once-Through Cooling Water, shall be within a range of 6.0 to 9.0.

^bOn a case-by-case basis.

^cMaximum for any one day.

^dIncludes coal pile runoff and leachate, fireside cleaning wastes.

^eTotal residual chlorine.

Source: Reference 2-1

Process condensate from the Lurgi gasifiers is treated and reused as makeup for the 550 psig steam generation system. By using less extensive treatment processes, the water can be used as cooling water makeup. Most other wastewater streams, following treatment, are routed to the cooling tower. Even after maximizing the practical usage of air cooling (dry cooling) techniques, cooling water requirements remain a major water consumer in the plant.

Following the guidelines to design a "zero-discharge" facility, wastewater streams are treated and sent to the cooling tower as makeup. The estimated water analyses for each of these treated streams indicate that these streams are of good enough quality to be used as cooling water. If these treated waters are later found to be unsuitable as cooling tower makeup, either more treatment will be necessary or the waters will be routed to evaporative ponds.

A storm sewer system is provided to process rain and wash water from the plant for further use. Rain water drained from the plant surface is held in a storm holding pond and then pumped to an oil separation facility. After removal of contaminants, the clean water is sent to the cooling tower as makeup.

2.7.3 Impacts on Plant Efficiency

Overall plant efficiency would be theoretically improved if every water-related process unit utilized a once-through water loop. However, such an approach is not feasible in any location, and especially in the semi-arid climate of northeastern Wyoming. The increased costs and reduced efficiencies of extensive water recycling must be compared to the option of long distance water shipments (surface pipelines) or numerous water wells. In this comparison, plant efficiency is most likely maximized by using extensive recycling.

2.8 SOLID WASTE HANDLING

2.8.1 Disposal Requirements

Onsite solid waste disposal procedures have been designed to meet the regulations outlined in the Resource Conservation and Recovery Act (RCRA). The solid wastes generated consist of ash from the gasifiers and boilers, gypsum sludge from flue gas desulfurization, and concentrated waste water sludges.

Two solid waste disposal options have been considered for use with this indirect coal liquefaction plant. Both are in conformance with baseline projected future EPA standards for solid waste disposal. The first alternative is a clay-lined landfill; the second alternative uses chemical fixation prior to disposal.

The landfill would require approximately 860 acres of land, and approximately 930,000 tons of bentonite for use in the clay/soil liner. Approximately 20 percent of the landfill would be soil used to cover waste at intervals prescribed by proposed EPA standards.

Chemical fixation circumvents the need for a clay liner, yet necessitates the addition of a fixation process facility and the purchase of quicklime and supplemental flyash.

2.8.2 Leachate Problems

It is estimated that no leachate system is required for either landfill alternative, since the mean evaporation rate exceeds the mean precipitation rate by more than 20 inches per year.

2.9 OSHA ISSUES

Storage and handling of coal will expose the workers to coal dust and noise. Coal dust can cause black lung disease. Coal piles can also spontaneously combust. Danger from both dust and spontaneous combustion can be controlled by wetting coal piles.

No special occupational hazards exist in synthetic gas to methanol production. Methanol is toxic but not a known carcinogen and is not considered particularly dangerous. Coal tars from the gasification process, however, are high in carcinogenic benzene and benzo(a)pyrene and co-carcinogenic in phenols. Exposure to these tars may occur during maintenance and cleaning operations. Leaks from gasifier lines may release tar vapor or droplets into plant ambient air. Exposure to this tar must be prevented.

2.10 PROCESS PERFORMANCE FACTORS

2.10.1 Product Characteristics and Marketabilities

The two principal coal-derived products produced by the ICI facility are high quality methanol and pipeline quality SNG. These two products account for approximately 90 percent of the total fuel energy output of the facility. Other products include naphtha, phenols, and crude diesel oil. Ammonia is also generated but is considered a process by-product with no profitable market. The characteristics of these products are described below.

- Methanol: Methanol produced by the ICI coal-to-methanol facility is a highly refined alcohol that meets gasoline blending stock specifications. The composition consists of 99.9 wt % methanol with small amounts of other alcohols, and maximum of 0.1 wt % water.

- SNG: Substitute natural gas produced by the ICI plant has a heating value of 991 Btu/scf and consists of the following components:

<u>Compound</u>	<u>Mole %</u>
H ₂	1.5
CH ₄	97.8
CO	0.01
CO ₂	0.1
Inerts (N ₂ + Ar)	0.58
H ₂ O	<u>0.01</u>
	100.00

The SNG is within acceptable American Gas Association (AGA) standards for natural gas properties, and is interchangeable with pure methane.

- Naphtha: The composition of the stabilized product naphtha is not available due to the proprietary status of the technology. Many licensed commercial hydrotreating processes are available, and the ultimate naphtha product composition would depend on the process and operating conditions selected.

- Crude Phenols: No compositional information is available due to the proprietary nature of the licensed phenol recovery unit.

- Crude Diesel Oil: No compositional information is available due to the proprietary nature of the licensed oil separation unit.

2.10.2 Capacity Factors, Flexibility, Reliability

This ICI Coal-to-Methanol plant is designed to operate with a 91 percent capacity factor (8000 hrs/yr) and to produce

coal-derived liquid fuels at 64.3 percent overall thermal efficiency. It has been designed for minimal risk and high service factor, largely due to redundant process trains. All major reactor systems have been proven commercially. The overall plant service factor is estimated to be 84 percent for the first one to two years. After one to two years, instrument and electrical system problems will be overcome, better data will be available for methanation, and unscheduled down time will be minimized. After two years a 95 percent service factor is estimated.

Commercialization of the design as well as determination of the flexibility of the plant will require development work on both the individual plant units and their overall compatibility.

2.11 TECHNOLOGY STATUS AND DEVELOPMENT POTENTIAL

2.11.1 Current Status

The indirect liquefaction process uses gasifiers and major reactor systems that are available commercially, and all auxiliary subprocesses have been demonstrated in test operators of substantial duration in at least pilot plant facilities.

2.11.2 Key Technical Uncertainties

Although the plant design represents a minimum technical risk, there are several areas that should be studied in order to optimize reliability and efficiency. Three specific areas are discussed below.

- Gas Shift Catalysts: Lurgi has developed technology to shift the H_2/CO ratio to a value necessary for methanol production using commercial catalysts for CO conversion. Although Lurgi guarantees the process, it

has been used at the demonstration scale only. Some risk is involved due to the lack of commercial plant experience. In this and other examples where processes have not been commercially proven, multiple trains are provided to improve reliability.

- Purge Gas Methanation: The methanation reaction is highly exothermic and runaway reactions are possible, resulting in damage to the catalyst. High pressure operation with the selected catalyst (unspecified) has not been commercially proven, although the methanation process in general is a proven technology.

- Water Consumption/Power Consumption Tradeoffs: All possible design steps were utilized to minimize the consumption and net discharge of water in this plant. A more thorough analysis of all process areas is required in order to optimize plant efficiency and water usage.

It was discovered in reference 2-1 that the actual saving in cooling water is smaller than initially estimated, and that significant penalties in efficiency and operating cost result by using medium pressure boilers for gasification steam. Another efficiency penalty may be the extensive use of air coolers instead of water coolers.

2.11.3 Availability for Commercial Production

The ICI Coal-to-Methanol plant described in this report utilizes commercially available and, for the most part, commercially proven technologies. The likelihood of actual construction and operation of this plant will depend

on a number of factors involving both engineering and economic considerations. Assuming favorable regulatory, financial, and market conditions exist, the ICI plant would be available for commercial production at any location close to sufficient coal land and water resources.

2.11.4 Unit Design and Construction Times

Start-up of the ICI facility is estimated to occur within five years from the initiation of final engineering design; four years from actual site preparation.

2.12 REGIONAL FACTORS INFLUENCING ECONOMICS

2.12.1 Resource Constraints

As described in section 2.4, the coal feedstock must be supplied at a secured rate of 11.4 million tons per year for the life of the plant. In addition, nearly 11 million tons (7800 acre-feet) of ground water are required per year as makeup water for the plant processes. It is difficult to obtain both resources in sufficient quantities at any one location in the U.S. The plant described in this TAG is sited for convenient access to abundant coal resources; water supply and its conservation represent major technical and economic design considerations due to the relative scarcity of this vital process feedstock.

References

- 2-1. Wham, R.M., J.F. Fisher, R.C. Forrester III, and others. Liquefaction Technology Assessment - Phase 1: Indirect Liquefaction of Coal to Methanol and Gasoline Using Available Technology, Oak Ridge National Laboratory, ORNL-5664, February 1981.

CHAPTER THREE: ECONOMIC ANALYSIS

This section contains information on the costs of the ICI methanol process, based on Lurgi coal gasification.

3.1 Methodology and Introduction

3.1.1 Economic Analysis Methodology

The economic analysis relies on a conceptual commercial plant design for a full-scale coal to methanol plant. The information presented in the report was adjusted for inflation, contingencies were calculated, and the data were scaled to a plant size of 125 trillion Btu per year using the methodology explained in the Background section.

3.1.2 Scaling Exponents

The reference plant produced 120.7 trillion Btu per year, which was scaled up to 125 trillion Btu. Different scaling exponents were applied to different plant areas according to the amount of scale economies within each area. Scaling exponents were derived from a comparison of the costs of the reference plant and a plant one-quarter its size presented in the same volume (3-1). The scaling exponents used are presented in Table 3-1.

TABLE 3-1

SCALING EXPONENTS

PLANT AREAS OR UNITS	SCALING EXPONENT
100, 1330, 1800, 2000	0.6
400, 1700	1.0
300, 1200, 1310	0.9
1320	0.8
1900	0.93

3.1.3 Price Indices

Costs for the reference plant were presented in mid-1979 dollars. These were corrected to 1980 dollars according to the methods described in the Background section.

3.1.4 Economic Criteria

The standard economic criteria described in the Background section were employed. The schedule of plant investment was 9.2 percent, 24.2 percent, 42.0 percent, 22.3 percent and 2.3 percent in years one, two, three, four and five of construction (3-1).

3.1.5 Contingencies

Two contingencies were added to the capital cost estimate: a process contingency and a project contingency. The process contingency covers technical uncertainties which

might cause costs to increase. The Methanation and Raw Gas Cooling sections were each assigned a 10 percent process contingency because further technical development in these sections is possible.

A 15 percent project contingency was applied to the total of all area and unit costs (not including the process contingency). The project contingency allows for unanticipated cost increases which may occur as the plant design is made more complete.

3.2 Capital Costs

3.2.1 Itemized Capital Costs

Plant investment by area and unit number is shown on Table 3-2. Steam generation and power recovery (unit 2010) account for the largest section of plant costs, at \$329 million or 17.9 percent wastewater of plant investment not including contingencies. Unit 2020 adds \$200.8 million, or 11 percent. The methanol synthesis and product separation units are contained in Area 400, and would cost 11.1 percent of the subtotal, or \$202.1 million. The total plant investment, including contingencies, sums to \$2,113.2 million.

The total capital requirement of the facility would be \$3,591.2 million, as is shown in Table 3-3. After the plant investment costs, interest during construction is the largest contributor to the capital requirement, at \$1,200.8 million.

Interest during construction is high because of the long 5-year construction period. Working capital start-up

and catalysts and chemicals add \$128.8 million, \$126.8 million and \$22.2 million respectively to the capital requirement.

3.2.2 Variability of the Capital Cost Estimate

The reference capital cost estimate was targeted to be within a range of +30 percent (3-1, page 213). The level of detail of the estimate was high, with most equipment prized from published lists. Therefore, the estimate can be assumed to be accurate enough to lie within the +30 percent range.

3.3 Operating and Maintenance Costs

Annual gross operating and maintenance (O&M) costs total \$172.2 million, as is shown in Table 3-4. The largest component of these costs is local taxes and insurance, at \$58.7 million, or 22.7 percent. Maintenance materials add \$37.8 million, or 22 percent of the total. Ammonia production will net a by-product of the total. A credit of \$5.8 million, \$166.4 million, as is shown in Table 3-4.

3.3.1 Variability of Operating and Maintenance Costs

The O&M cost estimate was detailed and did delete any important cost factors. Therefore, it can be considered as accurate as the capital cost estimate, +30 percent.

TABLE 3-2

TOTAL PLANT INVESTMENT - COAL TO METHANOL, ICI PROCESS^a

AREA	UNIT	ITEM	COST (10 ⁶ \$)	PERCENT OF SUB- TOTAL ^b
100		Coal Storage and Handling	(in 200)	-
200		Coal Preparation	174.9	9.5
300		Gasification	183.6	10.0
400		Hydrogenation		
	410	Reaction	178.8	9.8
	420	Primary Separation	23.3	1.3
1200		Raw Gas Cooling	14.2	0.8
1300		Acid Gas Removal and Gas Cleaning		
	1310	H ₂ S and CO ₂ Removal	126.3	6.9
	1320	Ammonia and Phenol Recovery	39.6	2.2
	1330	Tar and Oil Separation	29.7	1.6
1700		Shift Conversion	49.2	2.7
1800		Methanation	32.2	1.8
1900		Air Separation	149.1	8.1
2000		Utilities and Support Systems		
	2010	Steam Generation and Power Recovery	329.0	17.9
	2020	Wastewater Treating and Water Supply	200.8	11.0
	2030	Solids Disposal	23.3	1.3
	2040	Plant and Instrument Air	0.6	0
2100		Offsites and Miscellaneous		
	2110	Flare and Incineration	5.1	0.3
	2120	Tankage, Shipping, and Receiving	87.2	4.8
	2130	Other Support Facilities	186.7	10.2
		Subtotal	1,833.7	100.0
		Project Contingency	275.1	-
		Process Contingency	4.4 ^c	-
		Total Plant Investment	2,113.2	-

^aSource (3-1) corrected to 1980 dollars and scaled by ERCO.

^bColumn does not add to 10 percent because of rounding.

^cTen percent of areas 1200 and 1800.

TABLE 3-3
TOTAL CAPITAL REQUIREMENT^a

ITEM	COST (10 ⁶ \$)	PERCENT OF TOTAL
Total Plant Investment	2,113.2	58.8
Interest During Construction @ 15%	200.8	33.4
Working Capital	218.8	3.6
Start-Up	126.8	3.5
Catalysts and Chemicals	22.2	0.6
Total	3,591.9	100.0

^aSource (3-1) corrected to third-quarter 1980 dollars and scaled by ERCO.

TABLE 3-4

NET OPERATING AND MAINTENANCE COSTS, ICI METHANOL^a

ITEM	ANNUAL COST (10 ⁶ \$)	PERCENT OF TOTAL
Administration and General Overhead	36.7	21.3
Local Taxes and Insurance	58.1	33.7
Labor		
Process	7.3	4.2
Maintenance	8.0	4.7
Supervision	10.1	5.9
Maintenance Materials	37.8	22.0
Catalysts and Chemicals	13.5	7.8
Solids Disposal	0.7	0.4
Total	172.2	100.0
By-Product Credit	<u>(10⁶ \$)</u>	
Ammonia	(5.8)	--
Net O&M Costs	<u>(10⁶ \$)</u>	
Gross O&M Costs	172.2	--
By-Product Credit	(5.8)	--
Total	166.4	--

Source: (3-1), updated and scaled to 125 trillion Btu per year by ERCO.

3.4 Effect of Technology Development on Costs

After the first methanol plant is built, future plant costs, in constant dollars, will decline because of experience. The primary route to cost reductions will be through better understanding of the engineering requirements of the plant. The conceptual plant design was most notably over-engineered in the steam generation unit, Water Supply and Wastewater Treating Gasification sections, and Methanol Synthesis areas. In future plants, less equipment will be purchased as capacity factors are better understood. In addition, design costs will be reduced as engineering firms gain experience designing these plants.

Fluor, the conceptual plant designer, notes that the potential capital cost reduction is in the range of 10 to 20 percent (3-1, p.353). There are relatively few areas where technology improvement will reduce costs because the Lurgi gasification and ICI methanol synthesis systems are already commercialized.

3.5 Total Energy Costs

The total cost of the products has three discrete components: capital charges associated with plant capital costs, plant operating and maintenance (O&M) costs, and fuel (coal) costs. Both a total product cost and a non-fuel cost can be computed using the formulae given in the Background section.

Non-fuel costs have a capital charge component and an O&M charge component. Based on the total capital requirement of \$3,591.9 million from Table 3-3, and the yearly net O&M cost of 166.4 million from Table 3-4, the non-fuel product cost is:

$$\begin{aligned}
P &= \frac{\$3,591.9 \times 10^6 \times 20\% + \$166.4 \times 10^6}{125 \times 10^{12} \text{ Btu} \times 90\%} \\
&= \$6.39 \times 10^6 \text{ Btu} \quad + \quad \$1.48 \times 10^6 \text{ Btu} \\
&\quad \text{(capital charges)} \quad \quad \quad \text{(O\&M costs)} \\
&= \$7.87 \times 10^6 \text{ Btu} \\
&\quad \text{(total non-fuel cost)}
\end{aligned}$$

Capital charges amount to \$6.39/10⁶ Btu and O&M costs to \$1.48/10⁶ Btu. The total non-fuel cost will be \$7.87/10⁶.

The non-fuel cost, combined with a coal cost, yields a total product cost for the plant's outputs. The overall coal-to-hydrocarbon output efficiency of the plant is 64.4 percent. With coal assumed to be \$1.50/10⁶ Btu, the fuel component of energy costs would be \$2.33/10⁶ Btu. When combined with the non-fuel cost, this yields an average product cost of \$10.20/10⁶ Btu.

The figure of \$10.20/10⁶ Btu is only an average cost. Methanol, because it is suitable for transportation fuel, will have a higher selling price per million Btu than will the SNG produced by the plant.

References

- 3-1. Wham, R.M. et al., "Liquefaction Technology Assessment - Phase I, Indirect Liquefaction of Coal to Methanol and Gasoline Using Available Technology," Oak Ridge National Laboratory, ORNL-5664, February 1981.