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대체 발전연료의 복합발전에서의 경제성 분석연구

안 용 기

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Economics of Power Generation by Alternative Fuels in Conventional Steam Cycle and Combined Cycle Plants

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要 約

發電方式에 따른 燃料費에 대한 電力生產費의 感應度分析을 통하여 韓國에서의 輸入燃料의 經濟性을 比較 檢討하였으며 다음과 같은 一般的인 結論을 얻었다. 在來式 蒸氣發電보다 複合發電이 有利하며 排煙脫黃 없이 低硫黃炭을 수입 사용하는 것은 重油나 天然가스와 경쟁성이 있으나 資源의 確保에 유의해야 한다. 高硫黃炭을 輸入하여 가스화하여 複合發電을 하면 輸入石油나 天然가스(LNG)와 경쟁성이 있다.

INTRODUCTION

A number of factors influence the choice of fuel for future use in the generation of electric power; of significance are environmental acceptability, fuel availability, and cost.

Electric utilities comprise one of the many consuming sectors who are faced with world-wide problems of dwindling supply and escalating cost of such conventional fuels as natural gas and oil. A methodology was developed to perform an economic assessment to determine how competetive these fuels as well as coal and coal-derived fuels are for power generation. Such an assessment is especially noteworthy for a country such as Korea who has to import coal, oil and natural gas and who is faced with problems of determining which one of these fossil fuels would provide him with the most beneficial effects. The investigation does not include non-fossil fuels, nuclear and hydro-electric, and is limited to medium-Btu gas produced from high and low

Table 1. Characteristics of Fuels Selected

	High Sulfur Coal	Low Sulfur Coal	Natural Gas	No. 6 Resid Oil	No. 2 Fuel Oil
Proximate Analysis: %					
Moisture	9.7	29.5			
Volatile Matter	36.6	30.1			
Fixed Carbon	42.2	33.9			
Ash	11.5	6.5			
Total	100.0	100.0			
Ultimate Analysis: %					
Hydrogen	5.3	7.3	22.7	11.7	12.6
Carbon	63.4	45.7	69.3	86.3	87.3
Nitrogen	1.4	1.1	8.0	1.7	0.02
Oxygen	13.9	39.0	—	—	—
Sulfur	4.5	0.4	—	0.3	0.08
Ash	11.5	6.5	—	—	—
Total	100.0	100.0	100.0	100.0	100.0
HHV					
Btu/lb	11,605	8,167	—	18,000	19,430
Btu/scf	—	—	1,002	—	—
Ash Fusibility, °F					
Initial	2,330	2,163			
Softening	2,430	2,230			
Fluid	2,590	2,250			

sulfur coals in gasifiers integrated with either combined cycle or conventional steam cycle power plants; conventional coal-fired power plants with and without flue gas desulfurization (FGD); and combined cycle or conventional steam cycle plants fired by such conventional fuels as natural gas, No. 6 resid and No. 2 fuel oil.

BASIS OF DESIGN

Properties of Fuels Selected

The representative characteristics of the fuels selected for the study are shown in *Table* 1.

Power Plant Design

800MW is the base load unit size in this study. Capacity factor is 70%. Fuel storage and handling facilities provide capacity for 60 days on site storage. Only high sulfur coal burning units require FGD.

In the conventional base loaded unit, the steam generators are equipped with regenerative air heaters to reduce exit flue gas temperatures to about 300°F. The steam inlet conditions to a tandem compound turbine generator are nominally rated at 2400psig, 1000°F/1000°F. All plant auxiliary equipment is designed to support a five percent overpressure condition at the turbine inlet. Cooling is provided exclusively by mechanical draft rather than natural draft cooling towers.

For a combined cycle plant, a nominal base-rated output of 800MW is typified by a plant containing four complete 200 MW modules, each consisting of a gas turbine, a heat recovery boiler, a steam turbine, and generator. Turbine inlet temperature is limited to 1900°F. Exhaust gases from the gas turbines exhaust into the heat recovery steam generators, and then into a single exhaust stack. Inlet air filters are included. Cooling is provided by mechanical draft cooling towers.

Integrated Gasifier/Power Plant Design

Among many gasifiers either commercially available or under development, for application to power plants of both conventional and combined cycle configuration, a gasification process with a high throughput and a high degree of reliability is desirable. Gasifier turndown capability is of less importance for base load units. In a combined cycle, high pressure gasifiers are desirable, whereas low pressure gasifiers are satisfactory for conventional cycle. A review of gasifier specifications indicates that an entrained-bed gasifier meets the criteria, i.e., pressurized, single stage for combined cycle applications and low pressure, two-stage for conventional cycle application.

When gasifiers are integrated with either a conventional or combined cycle power plant, the net station system efficiency is higher than the cold gas efficiency, but lower than the hot gas efficiency. Auxiliary power produced in the power plant, and sensible heat recovered during the gas cleanup, can be used as a part of the gasification system energy requirement. In general, integrating a gasification system with a power plant will improve the efficiency of heat recovery and provide opportunities to optimize the overall cycle.

Integration gasifiers with the combined cycle plant provides higher gasifier system efficiency than those with conventional power plants because of increased potential for cycle optimization. Additionally, for integration with the same power plant configuration, medium-Btu gas provides a higher gasifier system efficiency than low-Btu gas. Therefore, an integrated medium-Btu gas/power plant configuration was selected for the coal-derived fuels.

PERFORMANCE DATA

Performance data for the power generation systems considered are presented in *Table* 2. The tabulation represents combination of published data and Gilbert's in-house design data.[1,2] It was interesting to note that even with the installation of a FGD the efficiency of high sulfur coal-fired conventional cycle plant is higher than that of the low sulfur coal without FGD. The reason for this was that the higher boiler efficiency for high sulfur coal compensates the higher auxiliary power requirement for the FGD.[3] This is not true for all the cases involving other high sulfur or low sulfur coals.

ECONOMICS OF POWER GENERATION

Capital and operating costs were developed for the selected power plant configurations and are summarized in *Table* 3. Bus bar power generation costs were calculated by the utility financing method using the financial parameters listed below[1,2]

Table 2. Performance Data for Various Power Generation Configurations

(Basis: 800MW Capacity, 70% Load Factor)

	Med-Btu Gas Integrated with Combined Cycle Plant		Med-Btu Gas Integrated with Conventional Cycle Plant		Coal Fired Conventional Cycle		Natural Gas Fired		No. 6 Resid Fired		No. 2 Fuel Oil Fired Combined Cycle
	High Sulfur Coal	Low Sulfurl Coa	High Sulfur Coal	Low Sulfur Coal	High Sulfur Coal W/FGD	Low Sulfur Coal W/O FGD	Combined Cycle	Conventional Cycle	Combined Cycle	Conventional Cycle	
Gasifier Type	Pressurized Entrained Bed		Low Pressure Entrained Bed		—	—	—	—	—	—	—
Gasifier Efficiency, %											
Hot Gas	92	92	91	91	—	—	—	—	—	—	—
Cold Gas	76	76	75	75	—	—	—	—	—	—	—
Gasifier System											
Efficiency, %	84	84	80	80	—	—	—	—	—	—	—
Power Plant Efficiency, %	38.5	38.5	36.0	36.0	—	—	—	—	—	—	—
Fuel to Electricity											
Efficiency, %	32.3	32.3	28.8	28.8	35.1	34.0	45.2	35.0	41.8	36.7	44.5
Heat Rate, Btu/kWh	9,947	9,947	11,851	11,851	9,726	10,025	7,560	9,750	8,160	9,302	7,670
Fuel Required											
Coal, TPD	8,740	12,420	9,802	13,929	8,279	11,764	—	—	—	—	—
Others, MM Btu/Day	—	—	—	—	—	—	145,152	187,200	156,672	178,598	147,264

Table 3. Economics for Various Power Generation Configurations

(Basis: 800MW Capacity, 70% Load Factor, Jan. 1979 Price)

	Med-Btu Gas Integrated with Combined Cycle Plant		Med-Btu Gas Integrated with Conventional Cycle Plant		Med-Btu Gas Conventional Cycle		Natural Gas Fired		No. 6 Resid Fired		No. 2 Fuel Oil Fired Combined Cycle
	High Sulfur Coal	Low Sulfur Coal	High Sulfur Coal	Low Sulfur Coal	High Sulfur Coal W/FGD	Low Sulfur Coal W/O FGD	Combined Cycle	Conventional Cycle	Combined Cycle	Conventional Cycle	
Capital Cost, MM $											
Total Plant Investment (TPI)	538.9	470.7	645.1	561.6	615.5	486.3	249.5	285.5	295.9	287.5	274.7
Working Capital (W)[a]	20.0	20.9	22.9	23.8	22.4	18.0	28.6	36.6	26.8	33.4	33.5
Interest During Construction (IDC)[b]	129.3	113.0	154.8	134.8	147.7	116.7	59.9	68.5	71.0	69.0	65.9
Total Capital	688.2	604.6	822.8	720.2	785.6	621.0	338.0	390.6	393.7	389.9	374.1
Operating Cost, MM $/Yr											
Fixed Cost	25.1	24.6	28.4	27.6	23.5	7.1	12.8	2.5	16.4	2.8	13.3
Depreciation (5% of TPI)	27.0	23.5	32.3	28.1	30.8	24.3	12.5	14.3	14.8	14.4	13.7
Taxes & Insurance (2.5% of TPI)	10.8	9.4	12.9	11.2	12.3	9.7	5.0	5.7	5.9	5.8	5.5
Fuel Cost[c]	62.3	69.1	69.8	77.4	59.0	65.4	111.3	143.5	114.1	130.1	130.9
Gross Operating Cost	125.2	126.6	143.4	144.3	125.6	106.5	141.6	166.0	151.2	153.1	163.4
Sulfur Q $25/ton	(2.5)	(0.3)	(2.5)	(0.3)	—	—	—	—	—	—	—
Net Operating Cost	122.7	126.3	140.9	144.0	125.6	106.5	141.6	166.0	151.2	153.1	163.4
Bus Bar Power Cost, ₵/kWh	3.95	3.85	4.61	4.45	4.21	3.52	3.60	4.21	3.92	3.95	4.13

a Includes cost for 60 days fuel inventory and 1% of TPI

b 12%/Yr interest on TPI for 2 years

c Fuel costs were based on $27.88/ton for high sulfur coal ($1.2/MM But), $31.76/ton for low sulfur coal ($1.33/MM Btu), $3.00/MM Btu for liquefied natural gas, $2.85/MM Btu for No. 6 resid, and $3.48/MM Btu for No. 2 fuel oil.

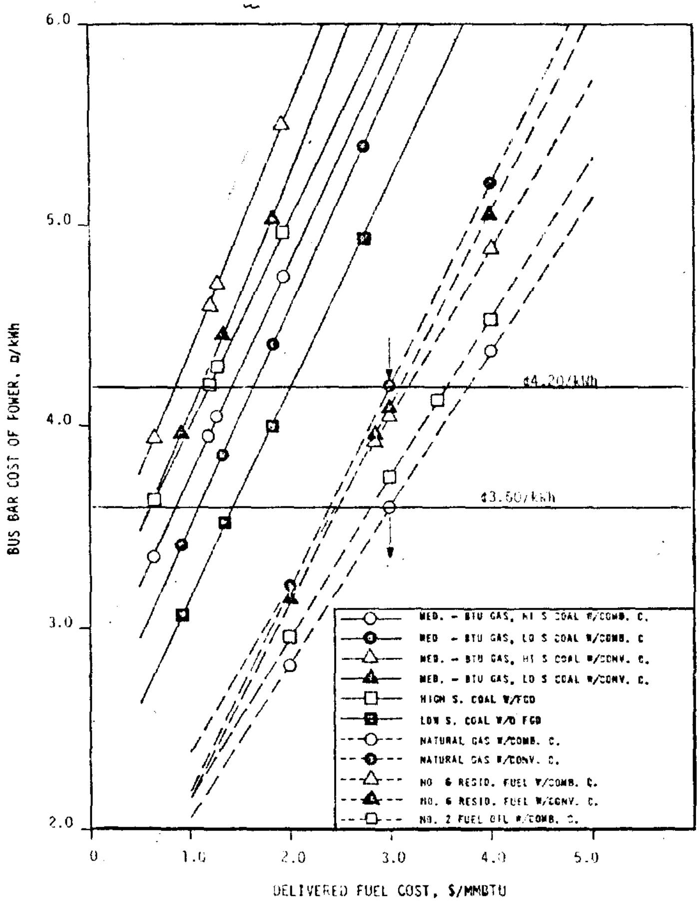

Fig. 1. Sensitivity of Power Cost to Fuel Cost

Table 4. Financial Parameters Used to Develop Power Generation Cost

Plant Life	20 Years
Depreciation (Based on Total Capital Less Working Capital)	5%/Year Straight Line
Fraction Debt	0.75
Return on Equity	15%/Year
Interest on Debt	12%/Year
Load Fcator	70%
Working Capital Coal	Inventory for 60 Days and 1% of Total Plant Investment
Interest During Construction	Interest on Debt×Total Plant Investment×2
Federal Income Tax Rate	48%

RESULTS AND DISCUSSION

In order to make a proper selection of a fuel for use in power generation, it would be desirable to establish the sensitivity of power cost to fuel cost for various power plant configurations. Since Korea has to import all forms of fossil fuels (coal, oil and gas), a fuel cost sensitivity curve, as shown in *Figure* 1, can be a useful guide for preliminary selection of a fuel type for a given power plant configuration. For example, an import of LNG from Japan is stipulated for power generation according to a recent Korean newspaper article. What price can Korea pay for the LNG and still maintain a competitive edge of the LNG over fuels produced from imported petroleum oil and/or coal? *Figure* 1 can be used to answer some of these questions.

Let us first look at the existing oil or coal-fired conventional steam cycle power plants. Retrofitting oil-fired or coal-fired boilers to LNG has been performed in the United States from the 1940's to 1960's, and no technical problems are anticipated. How about economics? Let us assume for the purpose of illustration that Korea pays Japan $3/MM Btu for the LNG delivered to the conventional cycle plant sites. The corresponding bus bar power cost from *Figure* 1 is ₵4.21/kWh. At this price, one can afford to pay between $1.14~2/MMBtu ($18 to $33/ton) for low sulfur coal, $0.86~1.20/MMBtu ($20 to $28/ton) for high sulfur coal and $3.10/MMBtu for No. 6 resid ($18/Bbl) when conventional cycle plant is used. No. 2 fuel oil is considered only for combined cycle plant. The fuel prices indicate that low-sulfur coal, high sulfur coal, and No. 6 resid are all within competitive ranges of the LNG if conventional cycle plants are considered. It should also be noted that both high and low sulfur coals can also be considered in competition with LNG whether they are used in direct fired boilers with or without FGD or are converted to medium-Btu gas in an integrated gasification/conventional cycle plant.

Let us next look at the combined cycle power plant. The design and economics for the study are based on the state-of-the-art turbine technology with an inlet temperature of 1900°F. A considerable improvement is expected if an advanced turbine technology with the inlet temperature of up to 2700°F is utilized. At $3.00/MMBtu for the delivered LNG, the bus bar cost from *Figure* 1 is ₵3.60/kWh. At this power cost, coals will be competitive with the LNG if high and low sulfur coals were used in an integrated medium-gas plant and if low sulfur coal is used in direct-firing without FGD. The price ranges for the coal would be $1.1 to 1.5/MMBtu ($18 to $25/ton) and $0.86/MMBtu ($20/ton) for the low and high sulfur coals respectively. For petroleum based fuels, the prices would have to be $2.5/MMBtu ($14/Bbl) and $2.8/MM Btu ($18/Bbl) for No. 6 resid and No. 2 fuel oil respectively.

CONCLUSION

A methodology was presented for the preliminary selection of fuel types to be used in various power plant configurations. The economics are based on the labor and material costs in the United States. *Figure* 1 will, of course, have to be revised by incorporating many site-specific cost factors such as land cost and availability, environmental regulations, varying labor and maintenance costs, financial parameters, and other institutional problems. However, referring to *Table* 2 and *Figure* 1, the following conclusions were observed:

1. Combined cycle configuration is better than conventional steam cycle plant.
2. Low sulfur coal without FGD appears to be competitive with oil and gas fired conventional or combined cycle plants. However, due to the high demand of low sulfur coal to meet the environmental regulations, reliable supply of the low sulfur coal at competitive prices will be difficult to achieve.
3. High sulfur coal, if used in an integrated medium-Btu gas/combined cycle power plant, will also be competitive with the imported natural gas and oil.

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