

**SRC-II DEMONSTRATION PROJECT.
PHASE ZERO,
TASK NUMBER 3**

DELIVERABLE NUMBER 9

VOL. 1 OF 9

**MARKET ASSESSMENT
MARKET OPPORTUNITY FOR SRC-II FUEL OIL**

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MASTER

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SECTION 1

SUMMARY

1. INTRODUCTION TO DELIVERABLE 9

This volume describes and defines the potential markets for SRC-II fuel oil from a commercial conceptual plant that is depicted as a grass-roots plant, having had the benefit of not only a successful demonstration plant experience but also the benefit of several predecessor SRC-II commercial plants.

The studies in this volume assess the opportunity for SRC-II fuel oil as boiler fuel and stationary gas combustion turbine fuel. These applications would be expected to use SRC-II fuel oil as it would be produced from a conceptual commercial plant. The boiler fuel application was studied in two parts, the utility boiler and the industrial boiler opportunities. The combustion turbine fuel market opportunity was studied exclusively as a utility market opportunity, although industrial turbine fuel opportunities for SRC-II fuel oil have been indicated in other reports, such as the GE study in Volume 4. Since there is considerable overlap in the utility studies, the two utility applications, boiler fuel and combustion turbine fuel, are presented first, followed by the industrial boiler fuel market opportunity study.

The three market assessment studies are followed by two combustion fundamentals studies which establish the validity of the potential of SRC-II fuel oil as an environmentally acceptable boiler fuel and combustion turbine fuel. Since the combustion fundamentals studies address commercially unresolved combustion technology development issues, a recommended SRC-II (fuel oil) combustion testing program is offered in the Appendix to facilitate review and planning of the coal liquids application testing development programs planned or underway. The recommended program is presented in a format identifying significant combustion technology issues with a measure of relative importance indicated by both the market studies and the combustion fundamentals studies.

For convenience of referral to product specifications questions, also offered in the Appendix of Volume 1 is a review of SRC-II fuel oil product and handling characteristics.

Several of the market studies in this volume were initiated over a year ago, with much of the critical work occurring over the last six months. For this reason, there is not uniformity in the estimated cost of SRC-II fuel oil among the studies, because the grass-roots conceptual commercial plant engineering design and economics studies have been concurrent efforts. The estimates of the cost of SRC-II fuel oil used in the market studies are, however, all within less than 10% of the most current estimated cost, \$3.76 per million Btu for all products priced for Btu content only. The conclusions made in these studies, furthermore, are not predicated upon SRC-II fuel-oil economics so finely that such small differences in the estimated cost of SRC-II fuel oil would be of any meaningful consequence.

Although the incentive to develop a coal liquefaction process such as SRC-II is to provide an economical alternative to increasingly scarce and costly petroleum fuels, the market opportunity for SRC-II fuel oil depends just as much on application economics as it does on the estimated cost of the fuel itself. The SRC-II fuel oil market opportunities indicated for each of the three application areas studied result from potentially favorable application economics. In these cases, the higher cost of SRC-II fuel oil, compared to the cost of raw coal to alternatives that would use coal at the site of application, is more than compensated for by economics of the equipment utilizing SRC-II fuel oil.

Following Volume 1 are three volumes containing outside, independent studies supporting Volume 1. Volume 2 contains SRC-II fuel oil combustion testing studies. Volume 3 contains studies by four electric utility companies providing a basis for the electric utility market studies in Volume 1. Similarly, Volume 4 contains studies by industrial companies and by Battelle Columbus Laboratories in support of the industrial boiler fuel market opportunity for SRC-II fuel oil.

Volume 5 discusses the direct heat application potential of SRC-II fuel oil in industrial furnaces and the potential for using middle distillate range SRC-II fuel oil as a medium speed diesel fuel and automotive turbine fuel.

Market opportunities for SRC-II products other than fuel oil are discussed in Volumes 6 through 8. Volume 6 presents studies on the market opportunity for the methane produced in the SRC-II process. Volume 7

contains three studies pertaining to conversion of SRC-II light hydrocarbons (ethane and propane) to ethylene. Also in Volume 7 is a study on the conversion of SRC-II naphtha to benzene, toluene and xylene (BTX), as well as a commentary of the possible long-range use of BTX conversion co-product paraffinic naphtha as fuel cell feedstock.

Volume 8 contains studies on producing transportation fuels from SRC-II. In the first part of Volume 8, conversion of SRC-II naphtha to gasoline blend stock is studied. In the second part, a study of conversion of almost all of the SRC-II liquids to gasoline, jet fuel, and diesel fuel is presented. And, in the third part of Volume 8, transportation fuels made available indirectly by use of SRC-II products is discussed.

2. SUMMARY OF VOLUME 1

Introduction

The SRC-II fuel oil market studies have focused on East Coast locations because the significant, near-term opportunity for coal liquids would be as a substitute for imported residual petroleum in large electric utility boilers, which are providing power to populous metropolitan areas. In these cases, substitution with coal directly into existing oil-fired boilers would be technically difficult and economically unattractive. Because of the ease and cleanliness of handling fuel oil, furthermore, these existing oil-fired boilers generally have been located within the metropolitan area, thereby essentially precluding the direct use of coal. In the same manner, SRC-II fuel oil would be an environmentally acceptable fuel that could be easily handled and utilized within the existing fuel distribution system and at the site of power generation.

The studies also focus on applications in the East because of the initial intended utilization of eastern bituminous coal, especially high sulfur bituminous coals, as the feedstock to the SRC-II plant.

Estimated Market

Specifically, the projected market opportunity for SRC-II fuel oil in the East Coast area of the United States is presented in the following table.

Potential SRC-II Fuel Oil Demand
Selected East Coast United States Areas ^(1,2) Thousands of Barrels per Day

<u>Year</u>	<u>Total Fuel Oil</u>	<u>Utility Boilers (1)</u>	<u>Utility Combustion Turbines ⁽¹⁾</u>	<u>Industrial Boilers ⁽²⁾</u>
1990	995	440	230	285
2000	800	130	360	310
2010	870	20	510	340

(1) Potential demand from eleven large East Coast electric utilities.

(2) Potential demand in Region 2 states: New York, Pennsylvania, Virginia, West Virginia, Delaware, and New Jersey.

This projection of market opportunity is conservative because of the limited regional scope. Demand potential could be higher as the geographical areas considered are broadened. For example, the projected demand in 1990 for SRC-II fuel oil as industrial boiler fuel for the region east of the Mississippi River is 1.02 million barrels per day and for the entire United States (48 states) would be about 1.46 million barrels per day. Utility demand for SRC-II fuel oil for the entire United States (48 states) would be about three times the amount projected on the basis of eleven large East Coast utilities. Thus, 1990 projected demand for SRC-II fuel oil could be as much as about 3.5 million B/D.

ELECTRIC UTILITY BOILER FUEL AND COMBUSTION TURBINE FUEL

A year-to-year comparison of the fuel oil demand estimates indicates that in the utility sector the boiler fuel market would be declining but

the combustion turbine fuel market would be growing. The total, after a midway decline in the time period studied, is also growing. This pattern of decline and growth would result from the more efficient and more economical utilization of coal-derived fuel oil in advanced combined cycle combustion turbines expected to be in utility service increasingly by the time of the latter half of the study period.

Electric Power Generation Trends

These changes expected in the method of generating electric power for the intermediate and base load classifications are depicted conceptually in Figure 1. Base load electric power, according to electric utility plans, will be generated increasingly from coal and nuclear compared to petroleum and natural gas, with nuclear assuming the major fraction. Direct firing of coal in pollution-controlled boilers will continue to be selected during the next decade to provide base load electric power.

Eventually new coal-related technologies will be utilized, at first in intermediate load service and eventually in base load applications, such as coal liquid fueled advanced technology gas combustion turbines with heat recovery boilers (combined cycle) and coal gasification integrated with similarly advanced gas combustion turbines. High turbine operating temperatures based on advanced technology will be used to achieve satisfactory efficiency and fuel economics with the higher cost coal-derived gas and liquids fuels. The higher combined cycle efficiencies will compensate for the thermal losses of coal conversion so that the overall efficiency will be higher than today's boiler technology efficiency.

Electric Utility Studies

The application of SRC-II fuel oil, in competition with other means of utilizing coal, was analyzed by systems studies based on the Boston Edison Company and Florida Power Corporation data bases. Energy Management Associates was subcontracted to provide system generation simulation through use of their proprietary PROMOD program, which is widely

Utilization of Generating Capacity, %

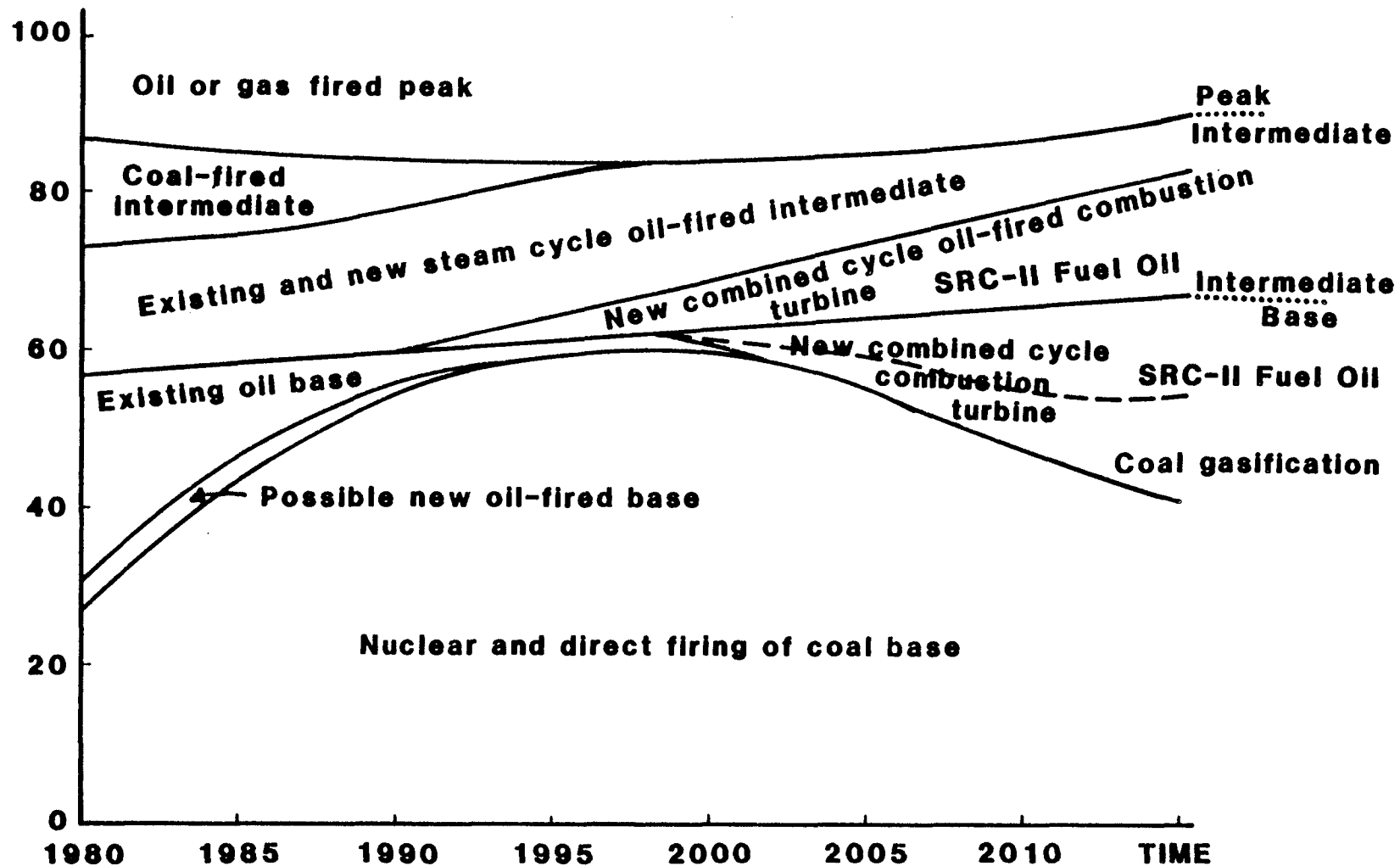


Fig. 2-1. Conceptual composition of system load with time

used and well regarded among electric utility companies. PROMOD determines the optimal dispatch of the system generating units, providing minimum variable production costs at the same state of system reliability.

Thus, different forced outage rates, depending on the type and age of the generating equipment, are taken into consideration in determining the minimum variable costs for power generation. This is important to an analysis of SRC-II fuel oil alternatives because of the higher reliability (i.e., lower forced outage rates) liquid fuel-fired units offer electric utilities.

An overall revenue requirement was also determined for each of the SRC-II fuel oil study scenarios considered, which then accounted for the fixed charges associated with the generating investment.

For the Boston Edison system, the scenarios studies and the results are:

<u>Boston Edison Scenario</u>		<u>Levelized Revenue Calculation Million of 1979 \$</u>

(Nuclear base load expansion plans remain unchanged in these scenarios.)

Base Case	Oil in Combined Cycle Turbines	218
BE Scenario 1	SRC-II fuel oil substituted for oil	225
BE Scenario 2	Cycling coal units substituted for oil units	262
BE Scenario 3	Advanced combined cycle units sub- stituted for oil units and all liquid fuel units use SRC-II fuel oil	215
BE Reburishment	Existing oil units are refurbished; retirement dates are postponed and all liquid fuel is SRC-II fuel oil	197

NOTE:

- (a) The revenue requirements were higher when SRC-II fuel oil replaced oil (This study, however, was based on the now low cost of about \$2.35 per million BTU or about \$14.70 per barrel.)
- (b) The direct firing of coal did not appear to be economically attractive when compared to SRC-II fuel oil used in boilers.
- (c) The cycling coal case required revenues about 25% higher than in the advance combined cycle case, reflecting the greater capital intensity of the coal firing technology. The estimated savings in fuel by using coal directly were not sufficient to offset the high capital cost of the cycling coal units.
- (d) When advanced combustion turbines were utilized in the combined cycle plants, the increased efficiency and lower capital cost led to favorable results. Consequently, the revenue requirements for this case and the base case were essentially the same. At oil prices that would be reflective of today's prices and using the projected SRC-II fuel oil estimates, the advanced combined cycle case with SRC-II fuel oil would be significantly preferable to the base case.
- (e) The refurbishment of existing oil-fired units to extend their useful lives and to fuel them with SRC-II fuel oil was the most attractive case. This case seemed to be somewhat insensitive to the estimated cost of refurbishment, but it is also a case for which exists little utility experience with regard to subsequent reliability of operations.

Conclusion

In conclusion, even though the refurbishment case was the most attractive, due to the uncertainty of reliability it is doubtful that a utility would plan their expansion solely on refurbishment. Instead, a combination of refurbishment and advanced combined cycles turbines, both

fired with SRC-II fuel oil, at the estimated cost, appears to be the most attractive generation expansion alternative for Boston Edison, in addition to nuclear base load.

For the Florida Power system, the scenarios analyzed and the results are:

<u>Florida Power Scenario</u>		<u>Levelized Revenue Calculation Millions of 1979 \$</u>
(Nuclear base load expansion plans remain unchanged in these scenarios.)		
Base Case	Coal-fired boilers	496
FPC Scenario 1	SRC-II fuel oil in oil-fired boilers substituted for coal-fired boilers with FGD; SRC-II fuel oil substituted for oil.	460
FPC Scenario 2	Advanced combined cycle combustion turbines substituted for coal units; all liquid fuel is SRC-II fuel oil.	376
FPC Scenario 3A	Coal gasification integrated with advanced combined cycle turbines substituted for base case coal-fired boilers.	441
FPC Scenario 3B	Combination of SRC-II fuel oil advanced combined cycle combustion turbine units and coal gasification integrated with advanced combined cycle combustion turbine units (the combination has not been optimized).	377

NOTE:

- (a) When oil-fired boilers were used instead of direct coal-fired units, the revenue requirements were somewhat lower.
- (b) When advanced combined cycle combustion turbines using SRC-II fuel oil at the projected cost was substituted for

projected direct firing of coal, a significant reduction in the revenue requirements was achieved. The sensitivity of this result to the assumed costs of constructing the advanced turbines was treated by increasing these costs. The revenue requirement remained substantially below the base case requirement.

- (c) In the scenario based upon coal gasification integrated with advanced combined cycle combustion turbines, the revenue requirements were almost 20% higher than the system with advanced combined cycle units fueled by SRC-II fuel oil at the estimated cost. This result again reflects the financial effect of the greater capital intensity of systems utilizing coal directly. The sensitivity of this result was investigated relative to the capital cost of equipment. Using the more optimistic of the estimates for coal gasification/combined cycle units and the least optimistic for liquid fuel advanced combined cycle units, the SRC-II fuel oil advanced combined cycle system maintained an economic advantage, which was, however, significantly reduced.
- (d) When the two advanced technology scenarios are combined, the revenue requirements were significantly lower than the base case and equivalent to the SRC-II fuel oil/advanced combined cycle case.

Conclusion

In conclusion, the dominant economic choices for the FPC system in this study would be advanced combined cycle combustion turbines fueled by SRC-II fuel oil, either as a stand-alone technology approach or in combination with coal gasification integrated with advanced combined cycle units. Of course, these projections are based upon the estimated cost of SRC-II fuel oil after a successful Demonstration Project. The revenue requirements of the two are essentially indistinguishable, but the mixed technology scenario offers additional expansion and fuels planning flexibility.

Effect of Reliability

The effect of the higher reliability of the SRC-II fired boilers was indicated, for example, in the Florida power study. In year 2002, in Scenario 1 as an example, the system load curve for this year indicates that the system capacity could be decreased by 901 MW and still match the loss of load hours for 2002 in the FPC base case. Thus, the 800 MW SRC-II fired boiler unit brought on line the previous year could have been dropped from the expansion plan (about 7.5% of the system capacity) and the system reliability would have still been as good as the FPC base case. This would be a savings of a capital expenditure of \$375 million (1978 \$).

Advantages of Combined Cycle Combustion Turbine Systems with SRC-II Fuel Oil

The projected market opportunity for SRC-II fuel oil in the utility sector reflects the demand from existing and new plants of current technology and from projected new plants using anticipated new technology. The Boston Edison and Florida Power studies have shown the potential advantages of SRC-II fuel oil, especially in conjunction with combustion turbine applications. The potential advantages offered by combined cycle combustion turbines fueled with SRC-II fuel oil are:

- (1) Lower heat rates or greater thermal efficiency, thereby offsetting the thermal losses in the preparation of SRC-II fuel oil; the coal pile to bus bar efficiency would be comparable to that of current direct-firing of coal technology;
- (2) Lowest capital investment electric power generating alternative;
- (3) Simple operation and maintenance;
- (4) Siting flexibility; no coal handling or coal waste problems; low land area requirements;
- (5) A comparatively short planning time requirement;
- (6) Generation expansion plan and financing flexibility because of the capability to expand in the smaller units of single combustion turbines which could later be grouped and combined with a

heat recovery boiler; this results in an expansion that would follow the load more closely and would avoid the high cost of idle capacity in very large units.

- (7) Compatibility with future integrated coal gasification systems: The combined cycle units could be installed first as peaking or intermediate load units fueled at first with SRC-II fuel oil; later, when the need for base load had developed, coal gasification units could be constructed and the combined cycle units converted to the low-Btu gas, if appropriate.

Advantages of SRC-II Fuel Oil in Utility Boilers

The Consolidated Edison Co. of New York and the Baltimore Gas and Electric Company studies have shown the potential advantages offered by SRC-II fuel oil in existing oil-fired boilers (Con Ed study) and in new SRC-II fuel oil-fired boilers instead of new coal-fired boilers with flue gas desulfurization (BG&E study).

The Con Ed study shows that a new base load SRC-II boiler unit could break even with an existing oil-fired unit, assuming only 4.4% per year greater escalation for oil than for SRC-II fuel oil in the post-1990 years. Since SRC-II fuel oil costs would be expected to escalate at not more than the rate of inflation, or less, the latter because of the large fixed capital component, it is realistic to expect that SRC-II fuel oil will be a more economical alternative than continued use of No. 6 petroleum-derived oil. In consideration of the enhanced certainty of supply and price, the ease of utilization in the existing system and the compatibility with environmental concern, the conclusion is that SRC-II fuel oil could be substantially preferable to continued use of petroleum-derived oil.

In the BG&E study, the major comparison was made between all coal-fired plants with FGD and conventional oil-fired boilers utilizing SRC-II fuel oil for future expansion. The analysis provided the minimum variable cost (fuel, operating and maintenance) dispatch of the units at the same level of system reliability, which means that the different forced outage rates of a coal plus FGD unit compared to an oil-fired unit were considered.

In addition to the capital and operating cost data, an important input to this study was the fuel cost projections of SRC-II fuel oil. It was assumed that the 1978 estimate for SRC-II fuel oil of \$3.50 per million Btu (15% DCF, 100% equity) would escalate in normal fashion, according to the coal, labor, and capital components, until 1990 by which time the first SRC-II commercial plant was assumed to be onstream. Subsequent to 1990, the price of SRC-II fuel oil was projected to escalate at a lesser rate because of an offsetting of capital investment escalation, due to assumed improved technology of successive SRC-II plants, and because of a lowering of the overall cost of capital to the successive SRC-II plants, due to assumed lessening technological and business risk.

Based upon such assumptions as to the future escalation patterns, the results of the BG&E study showed that in the direct-fired coal with FGD comparison, the SRC-II fuel oil case had much greater fuel costs than did the direct use of coal case. However, on a levelized basis, the higher fuel costs were essentially offset by the much greater fixed charge requirements of the more capital intensive direct coal with FGD case. Thus, a net benefit accrued to the SRC-II fuel oil case because of the future advantage of significantly lower incremental operating and maintenance costs. This is expected to result from the simpler-to-operate oil-fired boiler compared to a coal-fired boiler and the total absence of FGD operation, maintenance, sludge preparation, and sludge disposal cost. Over the thirty years of operation included in the study, the net present value savings in favor of the SRC-II fuel oil case was estimated to be \$380 million.

Thus, the SRC-II fuel oil option has the potential of offering the BG&E system an environmentally acceptable, operationally simpler, and economically preferable alternative to direct firing of coal. It also could offer flexibility in two areas: (1) oil-fired plants have a shorter planning span; and, (2) the lower capital cost of an oil-fired plant, about \$140 million in 1979 dollars, provides financing relief.

Petroleum Fuel Savings

In anticipation of petroleum derived oil supply becoming inadequate and of petroleum derived fuel oil prices escalating more rapidly than coal prices over the longer term, the BG&E study also investigated the extent to which petroleum derived oil could be displaced by SRC-II fuel oil. Based on the 1978 price for No. 6 fuel oil of \$2.20 per million Btu and assuming petroleum price escalation to begin to exceed that of coal in 1986, SRC-II fuel oil could become economically competitive in 1995. Subsequently, an average of five million barrels of oil per year could be saved by use of SRC-II fuel oil in the BG&E system.

Similarly, in the Con Ed system, 50 million barrels of oil were burned in 1977 in units largely having only oil- or gas-firing capability.

Overall Conclusion

In conclusion, SRC-II fuel oil is potentially attractive as a fuel for generating electric power for the following reasons:

1. SRC-II fuel oil, at presently estimated costs, would be expected to be economically competitive with replacing oil in existing oil-fired boilers, fueling new oil-fired boilers in East Coast urban locations, and fueling new combined cycle combustion turbines at today's level of technology and new advanced combined cycle combustion turbines at forecasted levels of technology regardless of utility location.
2. At the projected estimate of SRC-II fuel oil costs, SRC-II fuel oil would be expected to be economically competitive in Eastern urban areas compared to other means of coal utilization for electric power generation. This includes boilers with flue gas desulfurization, with on-site or off-site sludge disposal, and coal gasification integrated with advanced combined cycle combustion turbines.
3. The SRC-II fuel oil alternatives would have the additional advantage of being an environmentally clean method of generation which would not present waste control problems at the site of electric power generation. This is especially impor-

tant for the electric power generation demands of the populous East Coast region.

When the above considerations are combined in a utility system analysis with the higher reliability of simple to operate and maintain oil-fired generating equipment, the SRC-II fuel oil alternatives emerge having the potential to provide a lower revenue requirement to the utility system, when used in conjunction with nuclear base load power generation, by providing electric power in a broad range of load classification and for regions in addition to East Coast urban areas. In almost all cases, the dominant economic theme is the inability of the direct use of coal alternatives to offset their higher capital and operating costs with the lower fuel cost of coal, compared to the estimated cost of SRC-II fuel oil.

2.2 INDUSTRIAL BOILER FUEL

Although industrial boilers are small, compared to utility boilers, they are numerous and account for about 12% of the total United States fuel usage. The size range of interest as a potential SRC-II fuel oil market (50,000 lb/hr to 500,000 lb/hr capacity) accounts for 44% of industrial fuel usage or about 5% of the United States total. Smaller boilers could entail fuel distribution problems. Larger plants might use coal directly.

The industrial boiler fuel market opportunity projected for SRC-II fuel oil, as corroborated by Part 4 of this volume, as well as by the supporting outside studies contained in Volume 4 of Deliverable 9, is based on the important main factors of high cost for coal-fired systems and generally low utilizations of industrial boilers.

Investment and Operating Costs

Coal-fired boilers with flue gas desulfurization (FGD) cost about four times as much as an oil-fired boiler in the industrial boiler size range, primarily because of the much greater physical complexity of the coal-fired boiler and the attendant pollution control equipment. In the

smaller size ranges, about 200,000 lb/hr steam and less, oil- or gas-fired boilers are typically shipped to the customer as assembled units, whereas this is not possible with the coal-fired boiler because of its greater size. The oil-fired boiler is consequently a much less expensive "package" boiler. The coal-fired boiler, except for small sizes, is usually assembled at the user's site and is consequently a more expensive "field-erected" boiler.

The non-fuel operating cost for generating steam from a coal-fired boiler compared to an oil-fired boiler in the industrial size range is estimated to be about three times as much as for a clean liquid fuel-fired boiler. In the coal-fired case, there is the considerable solids handling with attendant requirements for operating labor and maintenance that does not exist for the oil-fired case.

The lower cost of coal fuel is not sufficient to overcome the effect of the much higher capital cost and the much higher operating costs of direct coal utilization compared to the estimated cost of SRC-II fuel oil used in an inexpensive to own and operate oil-fired boiler.

Utilization of Industrial Boilers

Industrial boiler steam economics are sensitive to the average utilization of the boiler. Generally, the more capital intensive and labor intensive coal-fired case would be favored in large boilers at high utilizations so that unit steam costs could be kept low when combined with the lower unit cost of coal. The low capital and low labor intensive SRC-II fuel oil case would be favored in smaller boilers at somewhat lower utilizations so that unit steam costs would remain low when combined with the higher unit cost of coal.

The average utilization of steam boilers in manufacturing industry is typically 41% to 46% for coal-fired boilers and 42% to 30% for oil- or gas-fired boilers, where the first figure corresponds to boilers in the 50,000 lb/hr to 100,000 lb/hr capacity range and the second figure to the 200,000 lb/hr to 500,000 lb/hr range. For the process industries, the average utilizations are 57% to 74% for coal-fired boilers and 65% to 67% for oil- or gas-fired boilers.

The lower utilizations in the manufacturing industry are reflective of the significant use of steam for seasonal space heating, which presents the need for a peak boiler capacity, and the use of steam in manufacturing industry during typically five-day, two-shift weeks, which implies a utilization of about 50%. The higher utilization of steam boiler equipment in the process industries reflects the greater use of the steam for processing in relation to around-the-clock, seven-days-a-week operations.

Figures 2-2 and 2-3 show these utilizations as well as a plot of the break-even utilization for SRC-II fuel oil in industrial boilers, according to the concepts discussed above.

Industrial Boiler Steam Generation Economics

The combination of high investment cost and comparatively low utilization cause the direct application of coal in pollution-controlled equipment to be a relatively uneconomic choice compared to SRC-II fuel oil, based on current estimated costs for SRC-II fuel oil from a commercial plant following a successful demonstration plant. The capital intensity disadvantage of the direct coal-fired options is additionally unfavorable because of the rate of return that must be earned in industry on incremental capital investment. The fuel cost savings of coal compared to the estimated cost of SRC-II fuel oil cannot justify the added investment of the direct coal alternatives compared to the SRC-II fuel oil-fired boiler.

The combination of these effects is shown in Figure 2-4 for a 15% DCF rate of return on the incremental coal-fired case investment. Figure 2-4 shows the breakdown price for SRC-II fuel oil versus boiler size at several utilization rates.

Estimated Industrial Boiler Fuel Market

It is apparent from the economics of coal-fired boilers, the expected price of SRC-II fuel oil, and the typical utilizations of manufacturing and process industry boilers that a large segment of the industrial boiler fuel market could be accessible to SRC-II fuel oil. The following data from the Battelle study (Volume 4, Part 2 of Deliverable 9) show

MANUFACTURING INDUSTRY
ENTIRE UNITED STATES

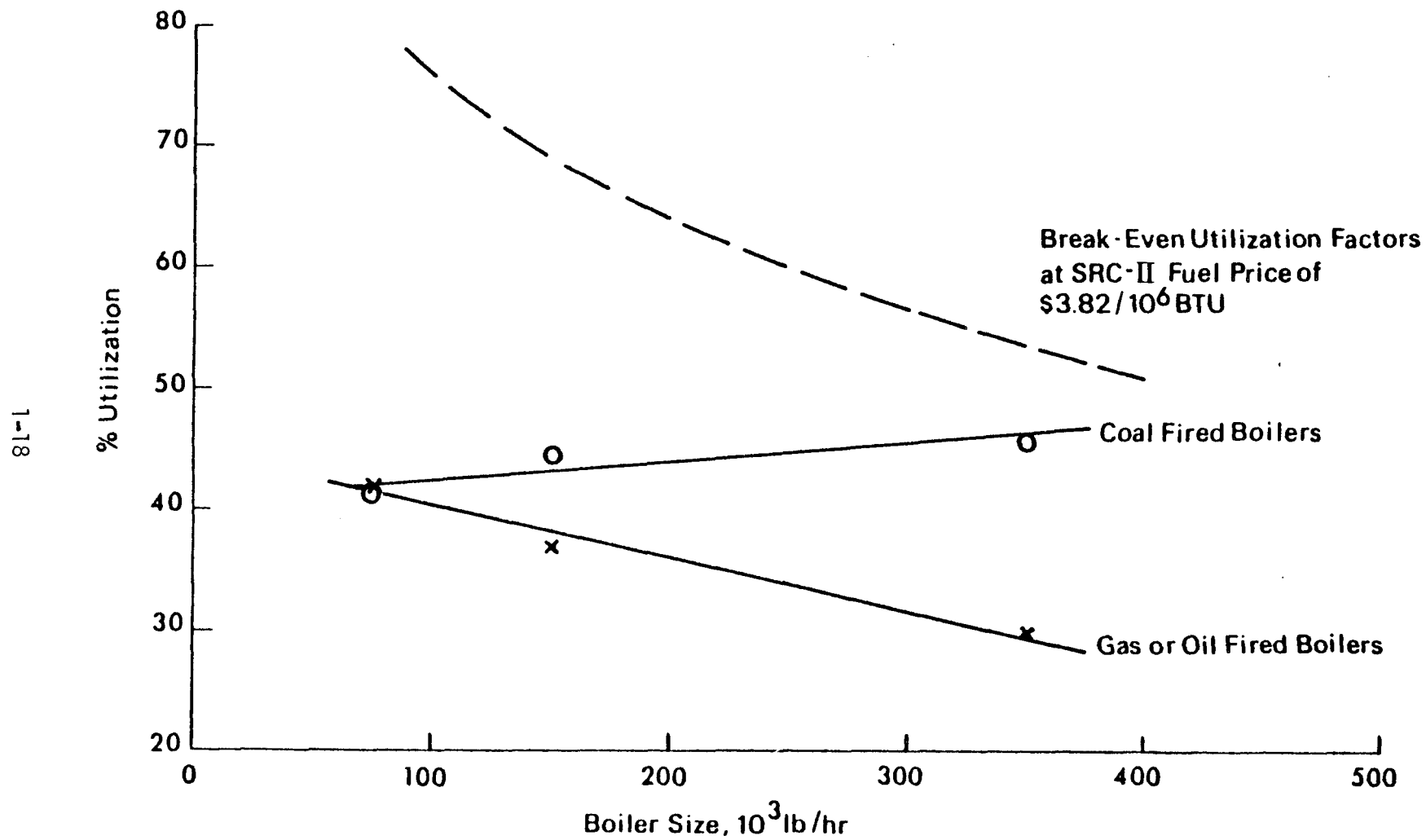


Fig. 2-2. Industrial boiler utilization rates

PROCESS INDUSTRY
ENTIRE UNITED STATES

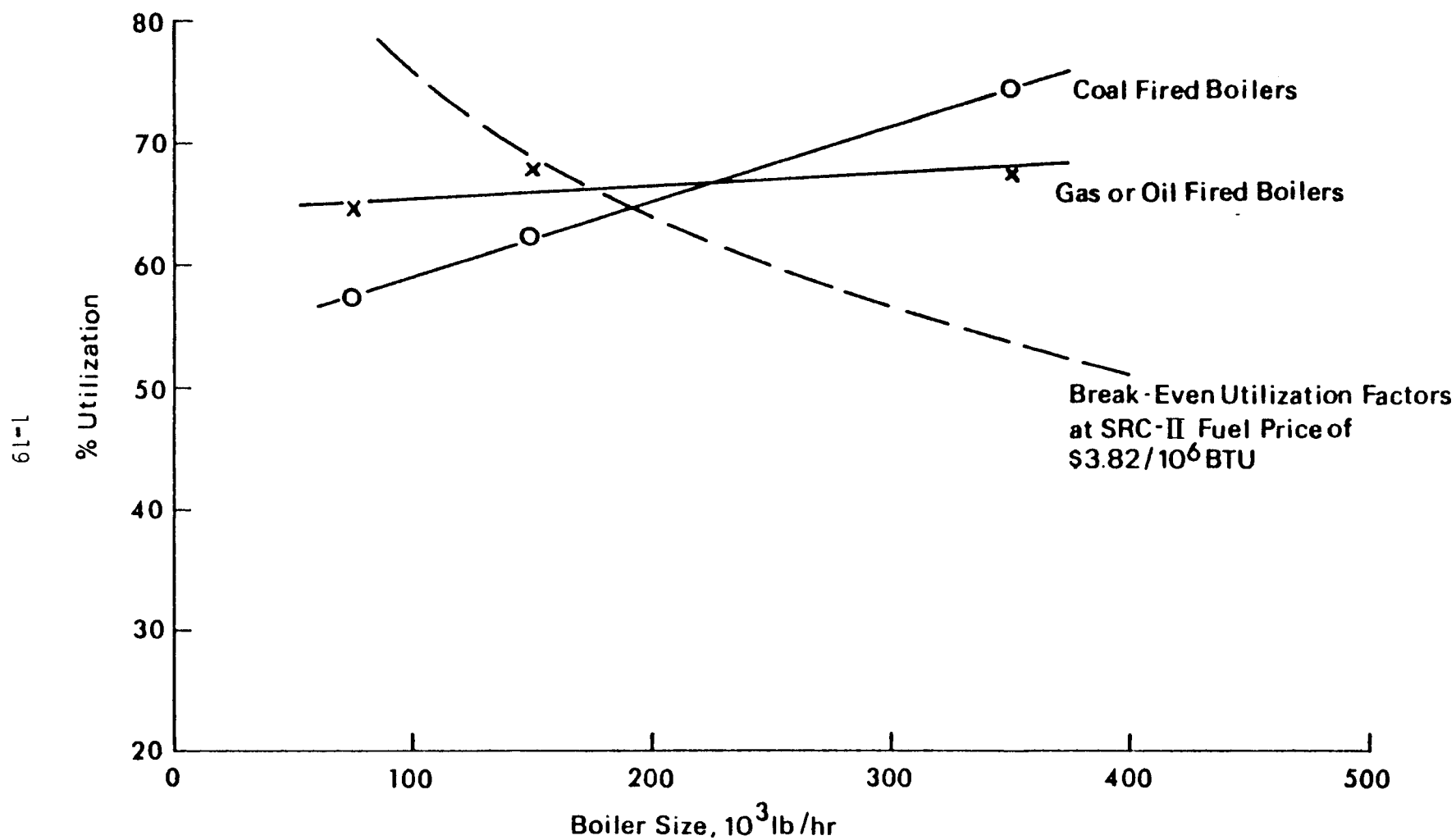


Fig. 2-3. Industrial boiler utilization rates

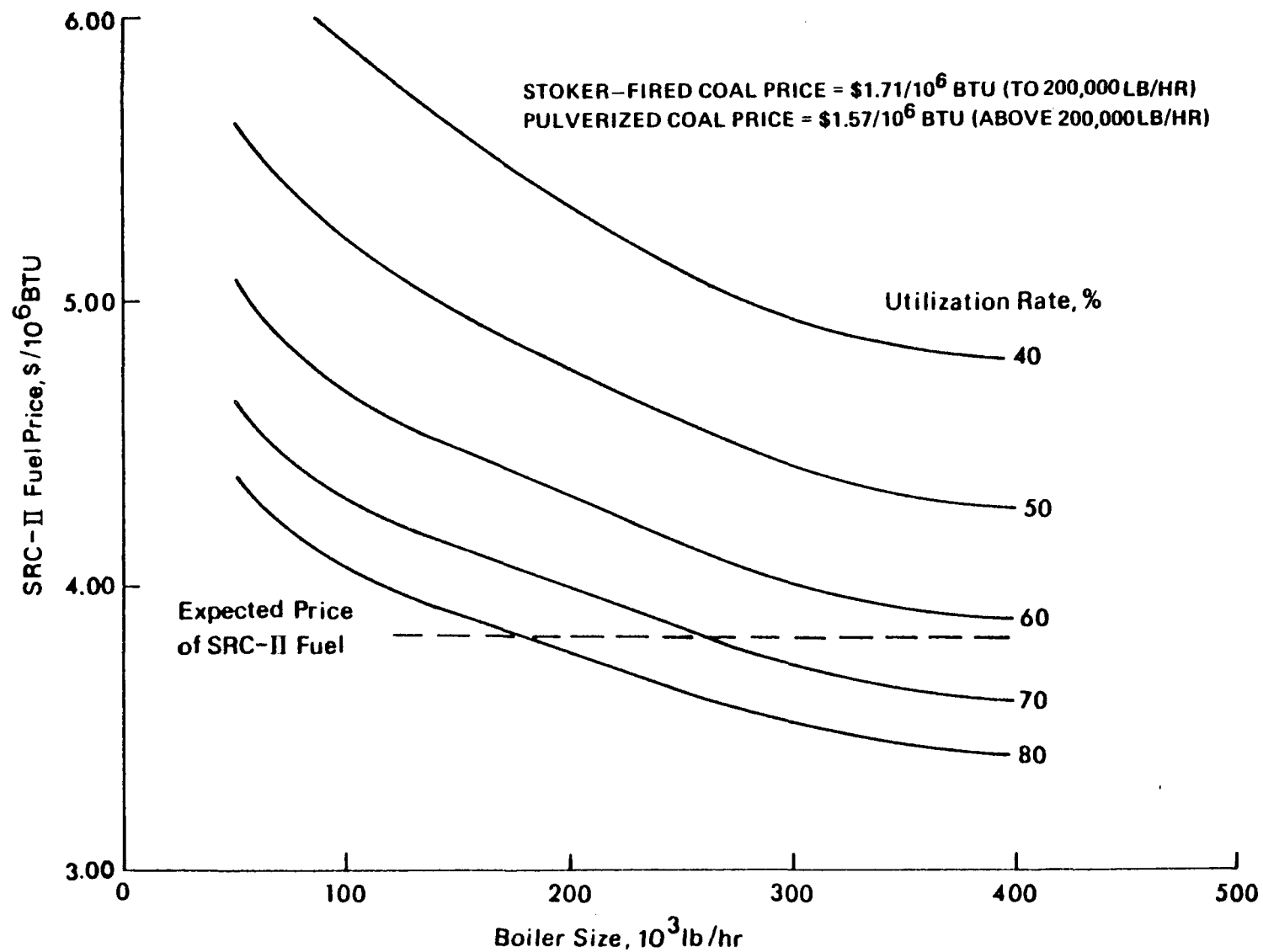


Fig. 2-4. SRC-II fuel price justified when compared to coal, based on 15% DCF rate of return on incremental investment for coal-fired boilers with FGD VS SRC-II fuel-fired boilers

that energy consumption is concentrated in oil and gas units, which cannot be converted to coal usage, and is concentrated in the smaller boilers, which are economically most accessible to the utilization of SRC-II fuel oil.

Total Energy Consumption in Industrial Boilers
By Sector and Fuel Type

Steam Boiler Design Capacity 10 ³ lb/hr Steam	Steam Generated, 10 ³ lb/hr			
	Manufacturing Industries		Process Industries	
	Coal	Oil & Gas	Coal	Oil & Gas
50-200	32,100	74,600	24,700	100,000
200-500	14,400	12,700	15,600	59,100

For the manufacturing industries, the potential market for SRC-II fuel oil would be the total fuel used. For the process industries, Figure 2-5 shows the cumulative fuel usage as a function of boiler size. From this curve the potential markets for SRC-II fuel oil up to the break-even boiler sizes from Figure 2-3 have been estimated and are also shown in the table below.

Potential Market for SRC-II Fuel Oil - Thousands of B/D, FOE

	<u>Entire U.S.</u>	<u>East of Mississippi River</u>	<u>Region 2</u>
Manufacturing Industry			
Coal-Fired Boilers	250	210	40
Non-Coal-Fired Boilers	470	280	80
Process Industry			
Coal-Fired Boilers	120	110	60
Non-Coal-Fired Boilers	<u>490</u>	<u>370</u>	<u>100</u>
TOTAL	1,330	970	280

PROCESS INDUSTRY
ENTIRE UNITED STATES

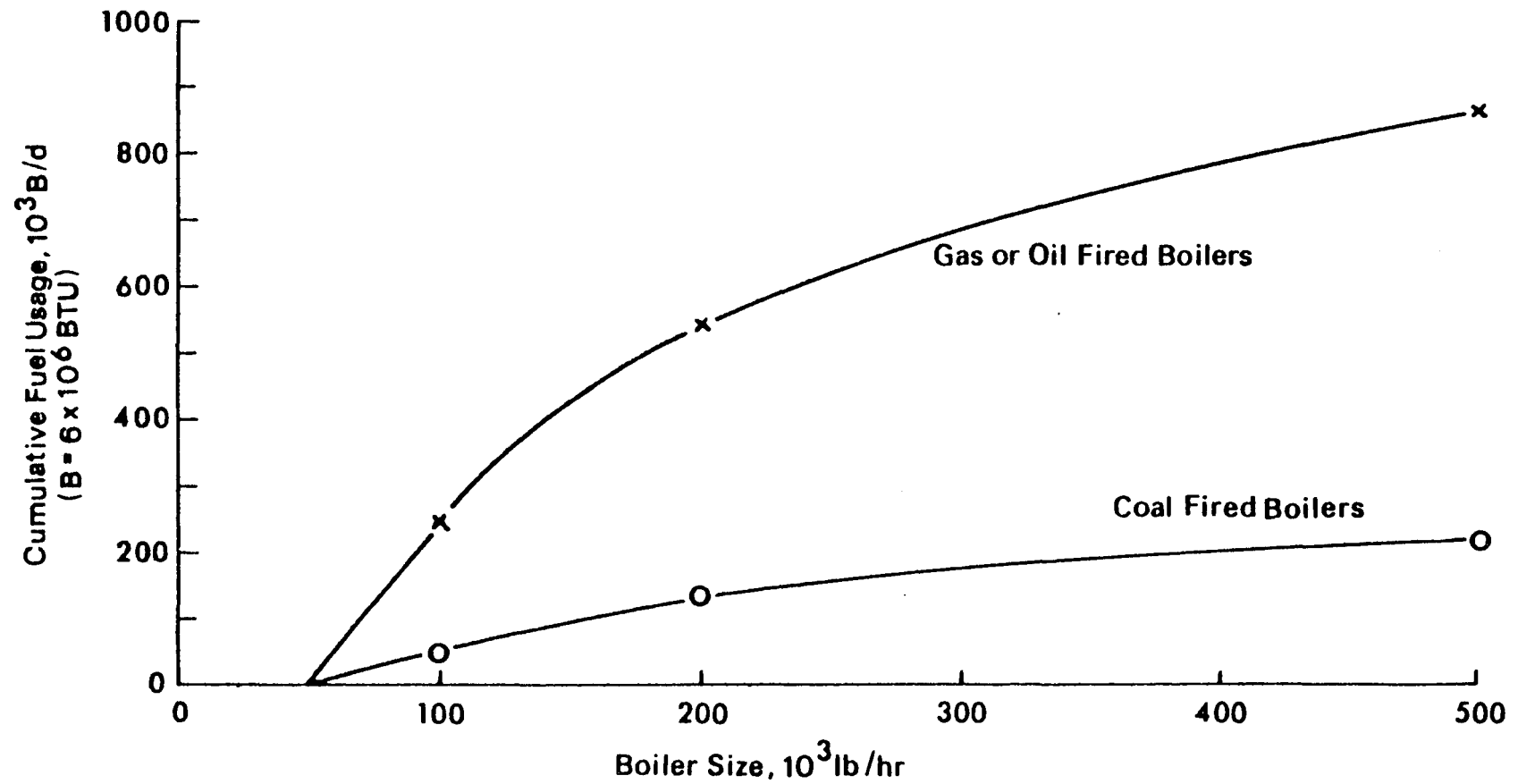


Fig. 2-5. Industrial boiler fuel usage

The most probable market for SRC-II fuel oil would appear to be those boilers which would be under pressure from DOE to convert from oil- or gas-firing because of the Fuel Use Act. The potential U.S. market for the 48 contiguous states in this case would be 960,000 B/D based on 1977 usage. Because SRC-II fuel oil would initially be expected to be available in the Eastern U.S., the market may be largely in this area where most industries are located. In this area, the potential market by displacing oil and gas would be 650,000 B/D. In the more limited Region 2, the market would still be 180,000 B/D.

Because many of the coal-fired boilers used in industry are presently not yet in conformance with environmental laws, it is probable that at least part of this market would find the use of SRC-II fuel oil to be an attractive alternative to flue gas treatment. If 25% of the present usage were converted to SRC-II fuel oil, it would amount to an additional SRC-II fuel oil market of 90,000 B/D for the entire U.S., 80,000 B/D east of the Mississippi River, and 25,000 B/D in Region 2.

The Battelle Columbus Laboratories (BCL) data base computer program prepared for this study can also be used to project future growth in industrial boiler systems and usage. Total fuel requirements are expected to increase by 13.6% by 1985 (about 245,000 B/D) and by 22.9% by 1990 (about 410,000 B/D) and all of this increase would be potential SRC-II fuel oil market. The most likely potential SRC-II fuel oil market in 1977, 1985, and 1990 are summarized in the table below.

Likely Industrial Boiler SRC-II Fuel Oil Market Volumes - Thousands of B/D, FOE

	<u>1977</u>	<u>1985</u>	<u>1990</u>
Entire U.S.	1,050	1,295	1,460
East of Mississippi River	730	900	1,015
Region 2	205	255	285

The fuel oil market volumes in the above table are those which were derived from calculations using the BCL data base. As pointed out earlier, the data base covers the size range from 50,000 to 500,000 lb/hr of steam, and fuel usage in smaller industrial boilers and those not

otherwise included in the inventory may be another 50 to 100% of that shown. These numbers may be, therefore, a conservative estimate of the SRC-II fuel oil market.

Capital Formation and Allocation

The average size of all boilers in the BCL data base is 116,000 lb/hr of steam and the average fuel usage is 327 B/D. Based on a DOE requirement to convert oil- and gas-fired boilers to alternate fuels and using the intermediate estimate of new and replacement boilers east of the Mississippi having a fuel requirement of 900,000 B/D in 1985, it can be estimated that about 2,750 boilers of average size would be required. The cost of coal-fired boilers is about \$7 million greater than the cost of SRC-II fuel oil-fired boilers in this size range so that the added capital cost for coal-firing for 2,750 boilers would be about \$19.3 billion in 1978 dollars.

For an SRC-II plant producing 57,000 B/D of SRC-II fuel oil, the capital cost is estimated to be \$1.56 billion. The \$19.3 billion that could be saved by building SRC-II fuel oil-fired boilers should provide sufficient capital to build SRC-II plants with a total fuel oil capacity of about 720,000 B/D. The total fuel output of the SRC-II plants, however, would be about 1,260,000 B/D. This is provided at the same investment of capital as required incrementally for the coal-fired boilers, which saves only 900,000 B/D of oil or gas. Thus, the SRC-II fuel oil alternative results in a lesser capital formation requirement, or, in other words, capital invested in SRC-II plants is better utilized than capital invested in coal-fired industrial boilers.

2.3 COMBUSTION FUNDAMENTALS SRC-II FUEL OIL AS BOILER FUEL

In the anticipated configuration of a conceptual commercial SRC-II plant, a middle distillate fraction (about 400°F to 550°F distillation range) and higher boiling distillate (550°F to about 900°F) will comprise the fuel oil range product. In terms of viscosity, the middle distillate resembles No. 2 fuel oil and the heavy distillate resembles a No. 5 fuel oil. SRC-II fuel oil, various blends of the middle and heavy

distillate, is a low sulfur fuel oil containing only about 0.3% sulfur. The ash content of the middle distillate is less than 0.001%, and the ash content of the heavy distillate is about 0.03-0.1%.

SRC-II fuel oil, however, is high in nitrogen, about 1.0%, and has a high aromatics content. Thus, in regard to most current or proposed environmental regulations, combustion of SRC-II fuel oil in boilers would not cause excessive sulfur oxides or particulates emissions, but there is the possibility of high NO_x and unburned hydrocarbons emissions because of the comparatively high nitrogen and aromatics content of the SRC-II fuel oil. Hydrogenation of the SRC-II fuel oil could decrease nitrogen and aromatics, thereby making the product more similar to petroleum fuels, but this would add substantial cost. The SRC-II fuel oil might just as well be used in compliance with environmental regulations by making adjustments of the combustion conditions at far less cost than fuel hydrogenation. Part 5 of this volume describes modified combustion techniques employed in testing SRC-II fuel oil and reviews boiler fuel combustion development in terms of both fundamentals and testing programs.

Although several combustion modification methods have been developed to suppress NO_x derived from nitrogen in the combustion air ("thermal NO_x "), only one of these methods, staged combustion, suppresses fuel-derived NO_x . Suppression of fuel-derived NO_x , via a fuel-rich flame zone, has been optimized by reduction of the stoichiometric combustion air fed to the first zone, by interstage cooling, and by longer residence time and higher temperature in the first zone. In such testing a lower fraction of the fuel nitrogen emerged as NO_x as fuel nitrogen increased. Staged combustion of nitrogenous residual fuel oils is now widely accepted in utility boilers, and recently, 2% nitrogen shale oil was burned in combination with a petroleum oil with only 270 ppm NO_x emitted.

A very successful EPRI-sponsored field demonstration of SRC-II combustion was conducted in a 44 MW utility boiler of Consolidated Edison, with KVB, Inc., participation. Conventional staged combustion was conducted by feeding more fuel to the lower burners than the upper burners. Further staging, or delayed fuel-air mixing, was also accomplished by shifting part of the air flow away from each burner ("burner staging"), which was significantly more effective, decreasing NO_x emis-

sions to 175 ppm. Particulates emissions were less than the proposed EPA New Source Performance Standards, and operational problems (flame stability, coking, etc.) were negligible.

Utility boilers have shown great adaptability to clean burning of SRC-II fuel oil. In contrast, industrial boilers which require No. 6 or even No. 2 fuel oil and have at most four burners, cannot conduct staged combustion by multiple burner manipulation, as in utility boilers. Instead, industrial boilers must have their burners replaced by low-NO_x burners which are now being developed by several organizations.

Of these new burners, the staging distributed mixing concept of Energy & Environmental Research, Inc., in an EPA contract, is the most successful, being based on detailed chemical and aerodynamic modeling. Tests of commercial-scale burners with nitrogenous residual oils have been very successful, and tests of SRC-II fuel oil will be conducted. There are several other burner designs in development, some of which incorporate principles other than fuel-rich staging; further testing may show some of these approaches to also be effective.

2.4 COMBUSTION FUNDAMENTALS - SRC-II FUEL OIL AS STATIONARY COMBUSTION TURBINE FUEL

Fractions of SRC-II fuel oil resemble petroleum distillate fuel oils in distillation range, viscosity, ash and sulfur content. Therefore, stationary combustion turbines appear to be an appropriate utilization of this fuel, especially SRC-II middle distillate fuel oil. SRC-II fuel oil, however, is more aromatic (lower hydrogen content) and contains more nitrogen than comparable petroleum distillate fuels. Although the nitrogen could be removed with a hydrotreater added to an SRC-II plant, such emissions might well be more economically suppressed by new combustion turbine combustor designs or post-combustion NO_x removal.

The ASTM specification, D2880, for stationary gas combustion turbine fuels was examined for other problems with SRC-II fuel oil use in turbines. The following properties were satisfactory: viscosity, flash point, heat of combustion, fuels compatibility, compatibility with materials of construction, and carbon residue. Although the low hydro-

gen content of SRC-II fuel oil leads to the expectation of the overheating of conventional combustor liners, the new emissions combustor designs are also solutions to this potential problem.

The metals contents of SRC-II fuel oil from present pilot plant operations is somewhat less than 100 ppm ash and less than 1 ppm of Na+K, near the present specification. Further improvements in ash content are expected with installation of a new vacuum tower in the pilot plant specifically designed for the SRC-II process, and corrosion and deposition in combustion turbines using SRC-II fuel oil should be no more problematic than with conventional fuels. Long-term corrosion tests on turbine blade materials would be required since the trace metal composition of SRC-II fuel oil differs from that of conventional fuels.

Through these preliminary considerations of SRC-II fuel oil properties, combustion turbine fuel specifications and emissions regulations, NO_x and soot emissions and combustor liner overheating were identified as the greatest potential technical barriers to SRC-II fuel oil use in stationary gas turbines. A review was conducted in order to understand whether solutions to these problems would best come from advances in combustion equipment or from more intensive processing of SRC-II fuel oil. The combustion chemistry behind pollutant emissions, of gas turbine combustor designs and their potential for emissions reduction, high temperature and advanced cycle turbines, and postcombustion NO_x removal were studied.

The suppression of NO_x formed by oxidation of molecular nitrogen (N_2) in the combustion air ("thermal NO_x ") in gas turbines has received extensive chemical and engineering study. The elementary chemical reactions involved are relatively simple and can be suppressed by reducing the peak flame temperatures occurring in the combustor. This has been successfully engineered and widely applied, being achieved by increasing the air/fuel ratio in the primary flame zone of the combustors, or by water injection at a one-to-one water/fuel weight ratio. However, the latter approach suffers a trade of increased emissions of CO and unburned hydrocarbons.

The nitrogen chemically bound in fuel oil is converted to NO_x ("fuel NO_x ") if oxygen is readily available in the flame, but otherwise converts to molecular nitrogen, N_2 . Fuel- NO_x formation in fuel oil

flames in boilers has been suppressed very successfully by excluding excess oxygen from the primary flame zone or first stage of the boiler, termed "staged combustion"; this also results in the formation of large amounts of CO, hydrogen, and soot, since the flame is fuel-rich. Downstream admission of the rest of the combustion air readily consumes the CO and hydrogen, but care must be taken to assure oxidation of all the soot.

The N_2 -formation process in the first stage (rich) and the soot oxidation process in the second stage (lean) both require long residence times, which exist in boilers, but which tend to be too short in gas turbine combustors. Nevertheless, detailed studies of the chemistry of these very complex reactions is revealing possible approaches to sufficiently accelerating them to make staged combustion in gas turbines effective (termed "rich-lean" combustion in gas turbines).

The suppression of fuel- NO_x is not very dependent on the types of nitrogen molecules in the fuel, but is facilitated by rapid fuel vaporization and high temperatures in the fuel-rich zone. This suggests that SRC-II fuel oil is a favorable candidate for the rich-lean approach, especially because of its high volatility compared to, for example, the nitrogenous compounds in No. 6 residual petroleum fuel oil.

Soot emissions are the combined result of soot formation in the primary flame zone and subsequent incomplete soot burnout in the secondary zone. Many sub-steps have been found to be involved in the formation of soot particles. These include pyrolysis of the fuel molecules to precursors, most importantly aromatic molecules, which explains why aromatic (and thus low-hydrogen) fuels tend to produce more smoke, and also why hotter flames smoke more. Another soot-forming substep is the agglomeration of precursor molecules together into soot particles, which explains why soot formation increases with combustor pressure.

Although SRC-II fuel oil has the disadvantage of being highly aromatic, as are other coal-derived liquids, flame chemistry studies have suggested that the very highest boiling fractions of SRC-II fuel oil contribute to soot formation far out of proportion to their concentration.

A set of coal-derived liquid (CDL's) has been tested in conventional half-scale and full-scale single combustors by Westinghouse in an

EPRI-sponsored program. The CDL's had hydrogen contents between 7.7% and 12.25%, and the smoke and liner heating followed a correlation which aligned well with a correlation involving a more conventional hydrogen range in another combustor. Fuel-NO_x yields paralleled other fuel-NO_x results mentioned above. Although the NO_x and soot emissions from these coal liquids appeared to be an approximate extension of experience with conventional fuels, attempts to find petroleum-derived aromatic refinery streams ("surrogates") to closely mimic the soot and NO_x emissions of the CDL's were unsuccessful, suggesting that the surrogate approach should be used with caution.

All new combustor design concepts to suppress fuel-NO_x incorporate a fuel-rich zone. Rich-lean concepts have been proposed since 1976, for example (among others), in the Westinghouse ECAS Phase II work and in a chemical kinetic modeling study of advanced cycle combustor concepts for ammonia-contaminated low-Btu gas for EPA by Energy and Environmental Research, Inc. (EER). This concept is embodied in a combustor configuration now widely known, which contains a rich primary reactor, a quick-quench section rapidly admixing the rest of the gas turbine dilution air, and a CO burnout section.

Substantial experimental success in implementing this configuration has been reported in an EPA project by Pratt & Whitney Aircraft Group. Their work utilized engineering methodology developed in their aircraft combustor design work. With No. 2 oil doped to 0.5% nitrogen as pyridine, the bench-scale combustor produced 75 ppm NO_x and acceptable CO using a variable-geometry air inlet vane to the primary reactor to keep the fuel/air ratio at 30% excess of fuel over air while the load was varied. The critical physical and chemical sub-processes occurring in this configuration have been modelled for the full-scale unit, which has been fabricated, and full-scale testing is now commencing.

Although in conventional combustors SRC-II fuel oil will produce higher liner temperatures than conventional fuels, particularly at the primary zone where most of the combustion is completed, these rich-lean designs distribute the heat-releasing combustion more evenly over the entire length of the combustor, and should prevent liner overheating when SRC-II fuel oil is used. This should obviate an otherwise important barrier to SRC-II fuel oil utilization in gas turbines.

Work by four or five gas turbines manufacturers as contractors in the DOE-NASA-Lewis "Low NO_x Heavy Fuel Combustor" program will begin in mid-1979. Since the rich flame principle will be widely utilized in this program, and since SRC-II fuel oil will be used in the testing, this program appears likely to successfully generate a low-emissions retrofittable combustor for CDL.

In addition to the rich-lean concept, there have recently appeared other promising concepts for clean CDL combustion. Some of these approaches involve recirculation of some of the flame gas to the fuel injection area, an approach which would also benefit No. 6 oil burning. Heat removal by an external steam generator between the rich reactor and the quick quench zone is also proposed (by EER, Inc.) for suppressing thermal NO_x generation in the CO burnout reactor. Finally, honeycomb catalysts in the combustion chambers are being widely explored, and could have certain benefits in rich flame reactor sections. The basic chemistry of soot formation, burnout, and nitrogenous fuel combustion is receiving vigorous research, which should lead to further improvements in combustor design approaches.

Post-combustion NO_x removal appears to be a very viable and important alternative to low- NO_x combustors. In this process, ammonia is injected into the turbine effluent as it passes through a honeycomb catalyst. This approach would be especially opportune in a combined cycle plant, where the catalyst would be installed in the heat recovery boiler. The operating and capital costs have been evaluated by a turbine manufacturer to be modest increments, and EPRI is supporting some pilot-scale verification of this approach.

Advanced cycles with increased thermal efficiency are expected to financially permit the consumption of more costly fuels, which will be the case for SRC-II fuel oil and conventional fuels in the mid-1980's. Advanced cycle plants also present some unique opportunities for clean CDL combustion. One of these is ammonia injection NO_x removal, and another approach is the inter-stage heat removal outside the combustor, both mentioned above. Another possibility involves an auxiliary firing of the heat recovery boiler in a staged fashion so as to suppress NO_x from the nitrogen in both the gas turbine and boiler fuels. This has also been shown to be possible in repowering an existing boiler. Finally,

combustors suppressing fuel- NO_x from CDL's can be compatible with the firing of ammonia-contaminated low-Btu gas.

Conclusion

In conclusion, SRC-II fuel oil is very likely to make a good technical fit into the future stationary combustion turbine market. This conclusion is based on the following facts:

1. The low viscosity and distillation range of SRC-II fuel oil meets the requirements of all stationary gas turbines.
2. Its content of corrosive trace metals is below present requirements.
3. The NO_x and soot emissions expected because of its nitrogen and aromatics content can be prevented. Basic combustion chemistry shows the potential effectiveness of fuel-rich combustion conditions in achieving low emissions.
4. On this basis, Pratt & Whitney has engineered and built a successful low-emissions combustor in an EPA-sponsored project.
5. Alternatively, NO_x removal from the flue gas by selective catalytic reduction will be feasible in most systems, if needed, but may have slightly higher costs.
6. High efficiency systems (high turbine inlet temperatures and advanced combined cycles) will offset the price of SRC-II fuel oil and, in addition, will provide unique opportunities for further emissions-suppression combustor technology.

**GULF SCIENCE AND TECHNOLOGY COMPANY
PITTSBURGH, PENNSYLVANIA**

**THE MARKET OPPORTUNITY FOR
SRC-II FUEL OIL AS UTILITY BOILER FUEL**

P. G. COOPER

**CHEMICALS AND MINERALS DIVISION
REPORT NO. 633RK104
JULY, 1979**

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SECTION 1

PREFACE

The market opportunity for SRC-II fuel oil in electric utility applications is discussed in two parts of this volume. The boiler fuel oil market is discussed in this Part 2. The stationary gas combustion turbine and combined cycle fuel oil market is discussed in Part 3.

SECTION 2

SUMMARY

The method of generating base load and intermediate load electric power is expected to change in the future, with base load generated increasingly from nuclear and coal units and use of petroleum and natural gas decreasing. Direct firing of coal will be used heavily in the near term, but eventually new coal-related technologies will be utilized, such as high efficiency combined cycle units fueled with coal-derived liquid or gas fuels.

Technologies involving the use of coal or the conversion of coal to another fuel at the generating station site have a number of disadvantages from the electric utilities' point of view. In comparison with coal-derived liquid fuels such as SRC-II fuel oil in which the coal and all process wastes can be handled elsewhere, the above technologies involve the complexity and associated unreliability of handling solid fuel and solid waste, space requirements for the handling and storage of coal (and perhaps lime) and for the handling and disposal of solid waste, and the various environmental problems which complicate site selection and involve long lead times for obtaining permits and licenses. For some urban areas with severe environmental problems and limited space, these problems may rule out or severely limit consideration of any direct coal utilization technologies.

A detailed study has been completed on how the expected changes in electric utility systems may take place. In order to provide realistic results, the study was carried out in cooperation with four electric utilities, Boston Edison Company (BE), Florida Power Corporation (FPC), Consolidated Edison Co. of New York (Con Edison), and Baltimore Gas and Electric Co. (BG&E). The data bases for the first two of these utility systems have been the primary basis for the study calculations and projections. To ensure the proper scope, economic factors and operating parameters for present and

developing technologies have been incorporated in a series of seven scenarios of utility system expansion and operation covering a study period of 1990 to 2010. With the aid of a subcontractor, Energy Management Associates, economic system dispatch simulations and revenue requirement calculations were carried out for these seven scenarios and for the two utility system base cases.

The results of these studies indicate that some utilities in large eastern urban areas, i.e., New York City, Connecticut, and Boston, may use advanced technology combined cycle units which would be fueled with SRC-II fuel oil for most of the part of their base load not supplied by nuclear units and for almost all of their new intermediate load and peaking requirements. Most other utilities will use other coal technologies for non-nuclear base load, but will use combined cycle units for most of their intermediate load and peaking.

The availability of SRC-II fuel oil at an acceptable supply and price level would prolong the useful economic life of most existing liquid fuel-fired boilers. There may also be some further installation of liquid fueled steam boiler units in urbanized areas by utilities who wish to take a conservative approach to new or developing technologies and who find it impractical to use direct firing of coal for various reasons. However, such installations will require exemptions from existing federal law.

For the near term, during which proposed advanced technologies are being developed and demonstrated, two of the main utility options are direct coal-fired steam boilers with flue gas desulfurization (FGD) and liquid fuel-fired steam boilers. Studies of the Con Edison, BG&E, and FPC systems show that an SRC-II fuel oil fired boiler system would be economically competitive or better than coal-fired boilers with FGD. For the FPC system, levelized revenue requirements were 7% lower (and system reliability higher) when SRC-II fuel oil fired boilers were substituted for planned coal-fired units with capacity, number, and start-up dates of the units kept the same. The economic effect of the projected higher reliability of the SRC-II fuel oil-fired boilers was indicated by taking one of the SRC-II fired units (800 MW) out of

the planned system with a potential capital savings of \$375 million (1978 \$). The system reliability was still equal to the base case (with the coal plus FGD units) after making this change.

A projection of the demand for SRC-II fuel oil as steam boiler fuel and of the total demand for eleven large east coast utilities has been derived from the simulations and analysis of the Boston Edison and Florida Power Corporation systems and from the studies of the Con Edison and BG&E systems. These projections are summarized by the following:

Potential SRC-II Fuel Oil Demand,
U.S. East Coast
(millions of barrels per year)

<u>Year</u>	<u>Boiler Fuel</u>	<u>Total Demand*</u>
1990	159	244
1995	74	182
2000	46	177
2005	13	182
2010	7	193

*Includes use in gas combustion turbines and combined cycle units.

The potential demand for SRC-II boiler fuel is estimated to be 159 million barrels (435 000 barrels per day) in 1990. The potential demand for SRC-II boiler fuel decreases rapidly during the first five years of the study period, with total demand also decreasing, due to the retirement of boiler units. Boiler fuel demand then decreases at a slower rate and total demand holds about constant as efficient combined cycle units with relatively low fuel requirements, using SRC-II fuel oil, are installed. Total demand increases slightly toward the end of the study period.

An approximation of the SRC-II fuel demand for the U.S. (48 states) indicates that boiler fuel demand for the country will be about twice that for

SECTION 3

INTRODUCTION

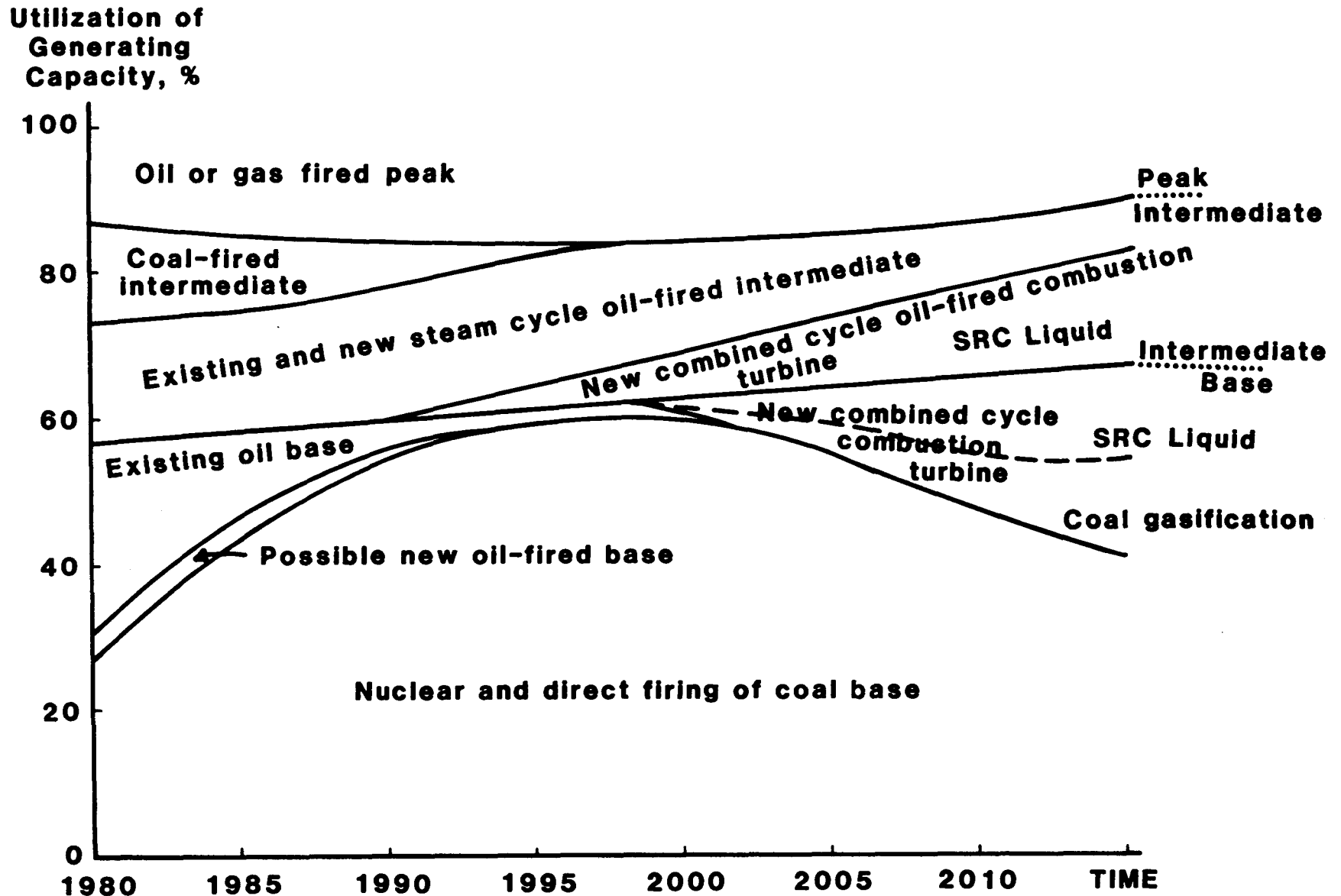
The method of generating electric power for the intermediate and base load classifications is expected to change with time (see Figure 1). Base load electric power, according to electric utility plans, will be generated increasingly from coal and nuclear compared to petroleum and natural gas, with nuclear assuming the major fraction. Direct firing of coal in pollution-controlled boilers will continue to be selected during the next decade to provide coal-derived base load electric power. Eventually new coal-related technologies will be utilized, in base load power generation, such as coal liquid fueled advanced technology gas combustion turbines with heat recovery boilers (combined cycle) and coal gasification integrated with similarly advanced gas combustion turbines. High turbine operating temperatures based on advanced technology will be used to achieve satisfactory efficiency and fuel economies with the higher cost coal-derived gas and liquids fuels. The higher combined cycle efficiencies will compensate for the thermal losses of coal conversion so that the overall efficiency will be better than today's boiler technology efficiency.

The extent of base load electric power generated from oil or natural gas boilers will decline because of the high cost and scarcity of these fuels. The availability of SRC-II fuel oil at an acceptable supply and price level, however, would prolong the useful economic life of most existing oil-fired boilers. In some expansive metropolitan areas, there may well be installation of new oil-fired boilers, eventually to use SRC-II fuel oil, because of the high cost and waste disposal difficulties associated with direct firing of coal, as well as the greater financing burdens imposed on the utility because of the greater capital cost of the coal using system and the associated pollution control equipment.

Although coal gasification integrated with advanced gas combustion turbines is expected to generate electric power at a somewhat lesser cost than coal liquids with advanced gas combustion turbines, there would be base load

FIGURE 1

CONCEPTUAL COMPOSITION OF SYSTEM LOAD WITH TIME



utilization of coal liquids in combined cycle turbines for the same environmental and regional reasons that oil-fired boilers continue to be of importance.

For intermediate load or cycling power generation, the use of coal-fired boilers will decline because of the high cost and operational inflexibility of newer coal-fired boiler systems, whether coal with flue gas desulfurization or coal in atmospheric fluidized bed combustion. With the availability of coal liquids such as SRC-II fuel oil, economics will favor the continuing use of oil-fired (petroleum or SRC-II) steam cycle generation of intermediate load electric power. In considerably less time than for the base load case, application of appropriate coal liquids in gas combustion turbines with combined cycle will begin to grow and eventually dominate intermediate load generation. Because the utilization of intermediate load equipment is less compared to base load, the economics are less sensitive to fuel costs and more sensitive to capital costs. Thus, the low capital cost liquid-fueled gas combustion turbine alternative would be especially attractive for intermediate load power generation. This technology will be economically attractive sooner for the same reasons: because of reduced sensitivity to fuel cost and greater capital cost sensitivity, turbine technology and the associated efficiency does not need to advance as much. Less efficiency will mean somewhat higher fuel cost but capital cost will still be low.

Peak load power will continue to be supplied largely by combustion turbines. The deployment of turbine technology throughout the load classifications offers an attractive alternative approach to traditional generation expansion. New major plants are usually designed for base load. In the past, these new plants have been larger and more efficient than predecessor plants and therefore more economical. The smaller, older units were conveniently "downgraded" to intermediate load service. This trend in boiler technology has matured now, and furthermore, new units have the added cost and operating complication of flue gas desulfurization units. These units, in modules of approximately 150 MW of related boiler capacity, need to operate near steady-state to be effective. Cycling load demands will consequently aggravate the

already difficult operation of these units. In atmospheric fluidized bed systems, operation seems to be too complex and to possess too much inertia to facilitate cycling.

A turbine-based electric power generation system, however, could provide considerably greater financing and operating flexibility. Turbines could first be added as peaking units and later clustered and combined with heat recovery boilers to provide intermediate or base load service, depending on factors such as the number and output of the units and the size of the electric power generating system. Thus, the generation expansion plan could follow the forecasted load curve more closely without the attendant costs and problems of long lead-time commitment to large units, which, when initially onstream, can cause under-utilization of system capacity.

This report describes the analyses of these complex trends which Gulf has carried out with the cooperation and assistance of the electric utility industry. In this, we have tried to shed some useful light on the way in which SRC-II fuel oil, a coal liquefaction distillate, can contribute to supplying the electricity needs of the nation. We have not tried to portray SRC-II fuel oil as the solution to every fuel problem or fuel need of the electric utility industry. However, we believe we have shown how it can very definitely fill certain pressing needs in an effective and economic fashion.

The next two sections of this report, Nos. 4 and 5, are background discussions on combustion chemistry, especially as related to environmental considerations, and on environmental regulations which might affect the boiler fuel market. In Section 6, the important economic and operating parameters for liquid fueled steam boiler power plants and for competing technologies are discussed. Section 7 describes the utility systems which have been studied and summarizes results for Consolidated Edison Company and for Baltimore Gas and Electric Company while Section 8 analyses the results of the study which Consolidated Edison Company did of using SRC-II fuel oil. The economic dispatch simulations and financial analysis done for nine cases for the Boston Edison Company and Florida Power Corporation are discussed in detail in

Section 9. The resulting SRC-II fuel oil demand projections are presented in Section 10. A discussion of the price projections used for SRC-II fuel oil, petroleum, and coal is given in Appendix A.

SECTION 4

BOILER FUEL COMBUSTION BACKGROUND

The purpose of this section is to provide a background summary of the information gathered on boilers and means for emissions suppression in burning alternative fuels, and to present conclusions about utilization of SRC-II fuel oil in the utility and industrial boiler market.

4.1 SRC-II FUEL OIL PROPERTIES

The SRC-II process, which is based upon the catalytic properties of recirculated coal mineral matter, is being developed at a 150 bbl/day pilot plant at Ft. Lewis, Washington. In the present operation of the process distillation units, separating the product into a middle distillate fraction (350-550°F distillation range) and a heavy distillate (550-930°F), the middle distillate resembles No. 2 fuel oil in its viscosity, and the heavy distillate resembles a No. 5 fuel oil in its viscosity. The only problematic properties of these SRC-II fractions are their high contents of nitrogen and aromatics, implying excessive NO_x and soot emissions.

4.2 COMBUSTION MODIFICATION

Although several combustion modification methods have been developed to suppress NO_x derived from nitrogen in the combustion air ("thermal NO_x "), only one of these methods, staged combustion, suppresses fuel-derived NO_x , via a fuel-rich flame zone. In tests of nitrogeneous residual fuel oils in laboratory-size boilers staged with fuel-rich first zones, the parametric dependence of the NO_x emissions was studied. Suppression of NO_x was optimized by 80% of the stoichiometric combustion air fed to the first one, by inter-stage cooling, and by longer residence times and higher temperatures in the first stage; furthermore, with increasing fuel nitrogen content, a lower fraction of that nitrogen emerged as NO_x . Staged combustion of nitrogeneous residual fuel oils is now widely applied in utility boilers, and recently, in

combination with a modification termed dual-fuel firing, 2%-nitrogen shale oil was burned with only 270 ppm NO_x emitted.

In tests of SRC-II fuel oil with staged combustion in a laboratory boiler at KVB, Inc., the response of the NO_x emissions to boiler conditions paralleled that of residual oils. In another laboratory furnace, MIT is beginning studies of soot and PNA formation and burnout within the furnace, and the alteration of the radiative heat transfer to boiler tubes which the soot may possibly cause.

A very successful field demonstration of SRC-II combustion was then conducted in a 44 MW utility boiler of Consolidated Edison, with KVB participation. Conventional staged combustion was conducted by feeding more fuel to the lower burners than the upper burners, but further staging, or delayed fuel-air mixing, was also accomplished by shifting part of the air flow away from each burner ("burner staging," for reference), which was significantly more effective, reaching 175 ppm NO_x. Particulates emissions were less than the proposed EPA New Source Performance Standards, and operational problems (flame stability, coking, etc.) were negligible.

Utility boilers have shown great adaptability to clean burning of SRC-II fuel oil. The high quality of SRC-II fuel oil could be used to additional advantage in the industrial boilers which require No. 6 or even No. 2 fuel oil. Although such boilers, having at most four burners, could not conduct staged combustion by multiple burner manipulation, as in utility boilers, their burners instead could be replaced by low-NO_x burners which are now being developed by several organizations.

Of these new burners, the staging distribution mixing concept of Energy & Environmental Research, Inc., in an EPA contract, is the most successful, being based on detailed chemical and aerodynamic modeling. Tests of commercial-scale burners with nitrogeneous residual oils have been very successful, and tests of SRC-II fuel oil will be conducted. There are several other burner designs in development, some of which incorporate principles other than fuel-rich staging; further testing may show some of these approaches to also be effective.

Thus, staged combustion has been successfully demonstrated at a range of boiler sizes to be effective in controlling NO_x emissions without causing unacceptable emissions of unburned hydrocarbons or particulates. For industrial boilers, new low NO_x burners will enable NO_x control.

SECTION 5

ENVIRONMENTAL REGULATION BACKGROUND

5.1 INTRODUCTION

This section deals with clean air regulations that apply to large fuel burning facilities, encompassing industrial boilers and utility steam boilers. The requirements for these types of facilities deal principally with emission limitations for sulfur oxides (SO_x), total suspended particulate matter (TSP), and nitrogen oxides (NO_x). Although specific, quantitative emission factors are given, there are other federal and state regulatory requirements which may require more stringent limitations than are implied by the emission factors. In other words, the emission limits represent a ceiling and this upper limit may require downward adjustment based on local (or regional) conditions.

In order to understand the possible effects of local conditions on emission limits, it is necessary to give a brief exposition of the statutory and regulatory requirements imposed by the Clean Air Act Amendments (CAAA) of 1977. Unfortunately, these requirements cannot be listed in absolute terms because, as will become apparent, the "actual" emissions from major facilities must be kept within limits that will not cause exceedance of the National Ambient Air Quality Standards (NAAQS) or the incremental ambient air quality limits imposed by the Prevention of Significant Deterioration (PSD) of air quality to be exceeded. In both instances, local meteorological conditions play an important role in the distribution of pollutants at ground level and consequently, these local conditions may require greater emissions control.

The effects of local conditions may be gleaned, to some extent, by examining the SO_x emission limits currently imposed in some of the regions of interest, e.g., East Coast metropolitan regions. Existing ambient air quality and local meteorological patterns have been responsible for developing the

resulting variability of emission limits given in Section 5.5. Even in these instances, however, site-specific factors may necessitate more control than is implied by the general limitations.

The projections for future emission limits are in a state of flux at this time. The CAAA of 1977 require that all states must revise their State Implementation Plans (SIP) to determine their NAAQS compliance status and to impose new procedures aimed at achieving and maintaining the NAAQS by the 1982 deadline. These requirements apply equally to the "tertiary" ambient air standards, described below, imposed by the PSD statute. Although the SIP were required to be submitted to the U.S. Environmental Protection Agency (EPA) by January, 1979, very few states have met this deadline. The SIP process is further complicated by the requirement that they be approved by the EPA. It is doubtful that any state's SIP will complete the process before the Fall of 1979. Until the SIP have been submitted and approved, the future emission limitations for any state, or region within a state, must remain in doubt. In a qualitative way, however, it is almost certain that regions where the NAAQS are exceeded will require more stringent emission limitations than those now required.

The following sections deal with the portions of the CAAA which control procedures used in determining emission control requirements in all parts of the U.S. This information is essential in order to understand the complexity involved in developing emission limits and their variability in different regions. The final section lists the emission limits required in certain East Coast metropolitan regions and for Chicago, IL, and Detroit, MI.

5.2 NATIONAL AMBIENT AIR QUALITY STANDARDS

These standards have been promulgated by the EPA. The NAAQS form an important basis for determining the requirements for emission limitations. The CAAA requires that each Air Quality Control Region (AQCR) achieve the primary standards for SO_x , TSP, and NO_x by 1982. The primary standards refer to the ambient air concentrations required for the protection of public health

and the secondary standards, for protection of public welfare (i.e., vegetation, wildlife, visibility, etc.). The standards are summarized in Table 5-1.

TABLE 5-1
NATIONAL AMBIENT AIR QUALITY STANDARDS

<u>Pollutant</u>	<u>Primary Standards</u>	<u>($\mu\text{g}/\text{m}^3$)</u>		<u>Secondary Standards</u>
SO _x	80	Annual Avg.	--	
	365*	24 hr Avg.	--	
	--	3 hr Avg.		1300*
TSP	75**	Annual Avg.		60**
	260*	24 hr Avg.		150*
NO _x	100	Annual Avg.		100

* Not to be exceeded more than once a year.

**Geometric mean.

As required by statute, the EPA is examining the validity of the NAAQS to determine whether they are adequate to protect "public health and welfare." The CAAA also directs the EPA to assess the need for a short-term standard (one- to three-hour average) for NO_x. In a qualitative way, we suspect that the EPA will effect the following changes in the referenced standards over the next two years:

- SO_x - relaxation of the SO₂ concentration and the addition of a "sulfate" ambient air limit.
- TSP - relaxation of the "total" particulate standard and the addition of a "respirable suspended particulate" concentration.

- NO_x - addition of a short-term standard which will be more restrictive than that of the current "annual average" standard.

5.3 ATTAINMENT/NON-ATTAINMENT STATUS OF AQCR's

The emission requirements listed in the succeeding sections are heavily dependent on whether the air quality of a region is better (attainment) or worse (non-attainment) than the NAAQS. These determinations are made on a pollutant-by-pollutant basis, i.e., a region may be in attainment for SO_x but non-attainment for TSP. Since an AQCR covers a wide geographic area (see Figure 5-1) and since some AQCR have attained the ambient air standards, except in small highly-industrialized portions, Congress eased the severity of the CAAA limitations by permitting the states to classify AQCR into smaller segments for attainment or non-attainment status. In some instances, the states have isolated individual counties and even downtown areas of cities, for classification purposes.

The ambient air quality of an AQCR, or portions thereof, is determined by air monitoring using methods specified by the EPA. In some instances, an inventory of emission sources together with modeling of the distribution of pollutants by prescribed "diffusion models" is acceptable for classifying an area or region. In many regions, however, neither monitoring nor modeling are adequate to assess the compliance status for a specific pollutant. In these cases, the status is listed as "cannot be classified." A summary of the attainment status of the selected East Coast metropolitan areas is given in Table 5-2.

5.4 STATE IMPLEMENTATION PLANS (SIP)

SIP constitute the basic provisions which the states intend to follow in order to attain and maintain the ambient air standards in each of

EPA AIR QUALITY CONTROL REGIONS (AQCR)

FIGURE 5-1

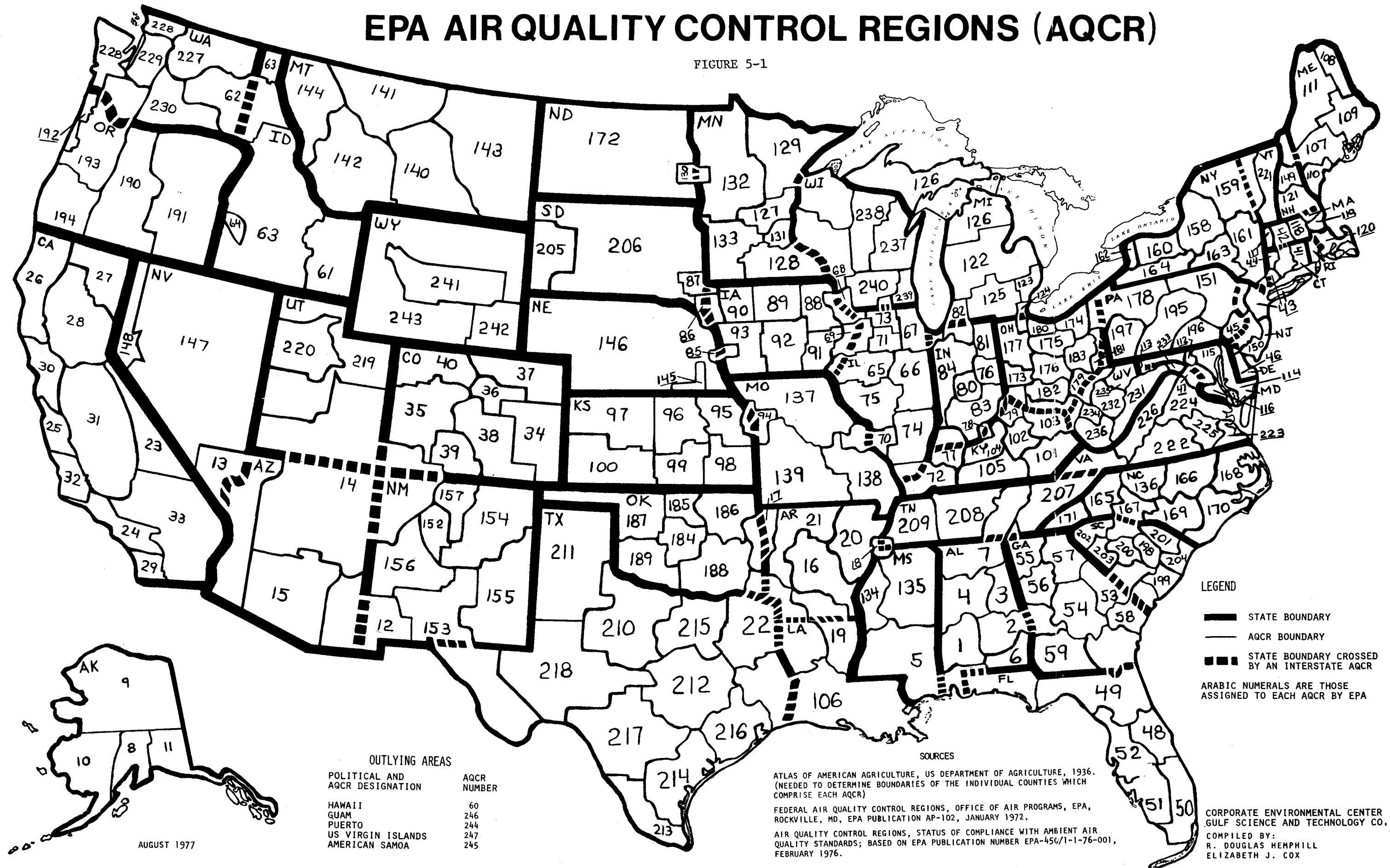


TABLE 5-2

ATTAINMENT STATUS FOR SO_x, TSP, NO_x

<u>State/AQCR No. & Name</u>	<u>City/County</u>	<u>SO_x</u>	<u>TSP</u>	<u>NO_x</u>
47 DC National Capital Interstate	Washington	Better than National Standards	*	Better than National Standards
47 MD National Capital Interstate	Portions of Prince Georges & Montgom- ery Counties	Better than National Standards	Better than Standards	Cannot be Classified or Better than National Standards
47 VA National Capital Interstate	Portions of Arling- ton & Fairfax Counties	Better than National Standards	Cannot be Classified	Cannot be Classified or Better than National Standards
FLORIDA				Entire State: Cannot be Classified or Better than National Standards
49 Jacksonville- Brunswick Interstate (FL-GA)	Jacksonville- Duval	Cannot be Classified	Downtown area: Does not meet secondary standards	
52 W. Central Florida Interstate	Tampa Hills- Borough	Cannot be Classified	Circle, 12 km radius, center at intersection of US 41 & State 60: Does not meet secondary standard	
	St. Petersburg- Pinellas	Attainment; (NW corner does not meet primary or secondary standards)	Better than National Standards	

TABLE 5-2 (Cont'd.)

ATTAINMENT STATUS FOR SO_x, TSP, NO_x

State/AQCR No. & Name	City County	SO _x	TSP	NO _x
50 Southeast Florida Interstate	Miami/Dade	Better than National Standards	Better than National Standards	
ILLINOIS 67 Metro Chicago Interstate (IL-IN)	Chicago/Cook	*	*	Central Core Area of Cook County Wacker Dr. on N & W Michigan Avenue on E, and Harrison St. on S: does not meet primary standards Remainder of Cook County Better than National Standards
MASSACHUSETTS 119 Metro Boston Interstate	Boston-Suffolk	Better than National Standards	Boston & Danvers: Do not meet standards	Cannot be Classified or Better than National Standards
MARYLAND 115 Metro Baltimore	Baltimore: Balti- more City, Balti- more County	Better than National Standards	Do not meet Standards	Cannot be Classified or Better than National Standards
MICHIGAN 123 Metro Detroit-Port Huron Interstate	Detroit/Wayne	Better than National Standards	*	Cannot be Classified or Better than National Standards

TABLE 5-2 (Cont'd)

ATTAINMENT STATUS FOR SO_x, TSP, NO_x

<u>State/AQCR No. and Name</u>	<u>City/County</u>	<u>SO_x</u>	<u>TSP</u>	<u>NO_x</u>
NEW YORK 43 NJ-NY-CT Interstate	New York City, New York County, Borough of Manhattan	Borough of Manhattan: Cannot be Classified	Borough of Manhattan: Cannot be Classified	Cannot be Classified or Better than National Standards
PENNSYLVANIA 45 Metro Philadelphia Interstate (DE-NJ-PA)	Philadelphia- Philadelphia County	Parts of inner city: Do not meet Primary Standards Balance of City: Better than National Standards	*	Cannot be Classified or Better than National Standards
VIRGINIA 223 Hampton Roads Interstate	Norfolk, Norfolk City Hampton Roads, Nansemond	Better than National Standards	Better than National Standards	Better than National Standards

* Too detailed for simple listing. Portions of the designated geographic unit are better than National Standards; others do not meet standards.

the AQCR. The SIP also must address the manner in which the state will control the "Prevention of Significant Deterioration" (PSD) of air quality in attainment regions. Finally, all SIP must be approved by the EPA.

The CAAA of 1977 permits very limited increases in the ambient air concentrations for particulate matter and sulfur oxides in those regions which are in compliance with the NAAQS for these two pollutants. The incremental increases allowed for the regions, above the baseline concentrations occurring in August, 1977, are listed in Table 5-3. If the full increments will result in violations of the ambient air standards, only that amount which will raise the baseline to the secondary standard will be allowed.

TABLE 5-3

PSD INCREMENTS ALLOWED FOR ATTAINMENT REGIONS

	$\mu\text{g}/\text{m}^3$		
	Class I*	Class II	Class III
<u>Particulate Matter</u>			
Annual geometric mean	5	19	37
24-hour maximum	10	37	75
<u>Sulfur Oxides</u>			
Annual arithmetic mean	2	20	40
24-hour maximum	5	91	182
2-hour maximum	25	512	700

Class I - Minor air quality deterioration; includes specified national parks, wildlife refuges, etc.

Class II - Moderate deterioration and growth permitted; most AQCR's are in this class.

Class III - Deterioration up to primary and secondary standards for industrial growth areas.

* Figure 5-2 is a map of mandatory Class I areas. For the metropolitan regions under discussion, the Everglades National Park is the only Class I area which may be close enough to be affected by a major emitting source.

Some of the more demanding provisions which must be included in an approvable SIP are listed below for attainment (PSD) and non-attainment regions or area. These statutory requirements apply to "major emitting facilities" (MEF). MEF are identified by the following criteria:

- Sources which have the "potential to emit"* 100 tons per year of any regulated pollutants if the source falls into one of 28 industrial categories identified by Congress. Two of the 28 categories are "fossil fuel-fired electric plants of more than 250 million BTU/hr heat input" and "fossil-fuel boilers of more than 250 million BTU/hr heat input."

Attainment (PSD) Region

- One-year monitoring--before seeking a permit for a new or modified facility the air quality for all regulated pollutants must be monitored for one year. This requirement may be reduced if air quality data are available from other sources. The monitoring data may show that the region is mis-classified and that it falls into the non-attainment class. In such a case, the plans for the new facility must be redesigned to satisfy the requirements for non-attainment regions.

* The application of this phrase has been in dispute. EPA has interpreted it to mean the quantity of emissions projected in the absence of pollution control equipment. In a recent per curiam opinion by the U.S. District Court of Appeals for the District of Columbia Circuit (Alabama Power Company, et al., vs. EPA), the court has determined that "potential to emit" refers to the total controlled emissions when the facility is operated at full capacity. The opinion also states that fugitive emissions from material storage areas, loading docks, truck traffic between loading and storage areas, etc., may also be subject to this regulation, i.e., coal storage piles at a facility.

- Construction permit application--an application for construction must contain the one-year monitoring data, dispersion modeling of the projected emissions showing the effects on air quality, and the engineering requirements for pollution control. The EPA or state must grant or deny the permit with one year of application.
- New source performance standards (NSPS) or best available control technology (BACT)--the control of emissions must fit the most demanding of the technologies defined by these terms. For the present, NSPS and BACT for large utility boilers are equivalent (see NSPS section).
- Allowable increment above baseline--the increase in concentration of ambient particulates and sulfur oxides must not exceed the increments listed in Table 5-3. When the increment has been consumed by new facilities, no further growth will be allowed unless an equivalent reduction in emissions from existing sources can be effected.

Non-Attainment Region

- Emission offsets--New or modified facilities may not be permitted unless the emissions from existing sources are reduced by an amount in excess of the projected new source emissions. Offsets are pollutant-specific and they vary with the extent of non-attainment of the region. Offset requirements to date have run as low as 1.1 to 1 and as high as 3 to 1 in different areas of the country.
- Lowest achievable emission rate--the most stringent, demonstrated control requirements imposed by any state will be required for new or modified facilities in non-attainment regions in all other states.

- Industrial growth--if a state does not have an approved SIP for achieving the NAAQS by 1982, no new or modified facility will be permitted in any of that state's non-attainment regions after July 1, 1979, and the prohibition will remain in effect until an SIP is submitted and approved. In some areas, reductions of existing emissions for the offset requirements may eventually reach a point where all potential offsets have been used up; new construction will then be prohibited pending the build-up of new sources for emission offsets, e.g., abandonment of existing facilities.
- Reasonably available control technology (retrofit)--in order to show progress toward achievement of the NAAQS, additional proven control measures will be required for existing facilities in non-attainment regions. Flue gas desulfurization for SO_x, more efficient electrostatic precipitators or baghouses for TSP and fuel burner modifications for NO_x are among the candidates for retrofitting of existing sources.

5.5 NEW SOURCE PERFORMANCE STANDARDS (NSPS)

The CAAA directs the EPA to set NSPS for a number of source categories; the list includes industrial and utility boilers greater than 250 million BTU/hr heat input. A NSPS applies to all new or modified sources in all regions of the country.

In 1971, the EPA promulgated NSPS for fossil-fuel steam generating units greater than 250 million Btu/hr heat input. These standards limited emissions from new or modified sources as follows:

- Particulate matter: 0.10 lb/million BTU
- Sulfur Dioxide: 0.80 lb/million BTU for liquid fuels and
1.2 lb/million BTU for solid fuels

- Nitrogen Oxides: 0.20 lb/million BTU for gaseous fuels,
0.30 lb/million BTU for liquid fuels,
0.70 lb/million BTU for solid fuels, and
0.80 lb/million BTU for lignite.

These standards are still in effect for non-utility furnaces and boilers "for the purpose of producing steam by heat transfer." The EPA is considering the need for modifying the non-utility NSPS in the near future. A new set of standards have been promulgated, on June 11, 1979, for utility boilers.

The newly promulgated NSPS for new or modified utility boilers and combined-cycle gas turbines fired with fossil fuels and with heat inputs greater than 250 million BTU/hr are summarized in Table 5-4. It is important to note that "...the standards do not apply to existing facilities... that are modified to fire shale oil, coal/oil mixtures, coal/oil/water mixtures, solvent refined coal, liquefied coal, gasified coal, or any other coal-derived fuel" (emphasis added).

The sulfur dioxide standards bear further explanation. The upper limits of SO₂ emissions, for the fuel listed, are given in the second column of Table 5-4. If the total emissions that would result from the uncontrolled burning of these fuels are less than the upper limits listed, then the emissions must be controlled to the extent shown in column 3. The relationship of emission limits and emission reductions to the sulfur content of coals is given in the simplified graph of Figure 5-3 which was published by the EPA. In essence, the figure indicates that SO₂ emissions from coals with less than 1% sulfur must be reduced by 70% of the "uncontrolled" emissions and SO₂ emissions from coals with more than 3% sulfur must be reduced by 90% of the "uncontrolled" case. Coals with sulfur contents between these two limits will require a sliding scale of SO₂ emissions (between 70 and 90% reduction) with an upper limit of 0.6 lb SO₂ per million BTU.

Special note is made of two features in the NSPS regulations which apply to SRC-II. The first feature deals with SO₂ emissions. The sulfur content of the coal processed to produce SRC-II is guiding with respect to the

Figure 5-3

Percentage Reduction Requirement by Percent Sulfur Coal

Controlling Element of Standard		1%*		3%*	
	70% minimum		0.6 lb/10 ⁶ Btu		90% Removal
Percent Reduction Required	70%		70% - 90%		90%

* % sulfur coal

TABLE 5-4

NEW STATIONARY SOURCES PERFORMANCE STANDARDS
ELECTRIC UTILITY STEAM GENERATING UNITS

SULFUR DIOXIDE				PARTICULATE MATTER	NITROGEN OXIDES	
Fuel Type	Emission Limits	Reduction in Potential Emissions	Determined by	All Fuel Types	Fuel Type	Emission Limit (lb/10 ⁶ Btu) Heat Input
Solid and solid-derived fuels (Except SRC 1)	1.20 lb/10 ⁶ Btu	90%	Continuous monitoring to obtain 30-day rolling avg.	0.03 lb/10 ⁶ Btu	Gaseous Fuels	
	--when emissions are less than	70%			Coal-derived fuels	0.50
	0.60 lb/10 ⁶ Btu				All other fuels	0.20
		85%			Liquid Fuels	
Gaseous and liquid fuels not derived from solid fuels	0.80 lb/10 ⁶ Btu	90%	Opacity, 20% Max.		Coal derived fuels	0.50
	--when emissions are less than				Shale Oil	0.50
	0.20 lb/10 ⁶ Btu	0%			All other Fuels	0.30
					Solid Fuels	
Anthracite Coal					Coal-Derived fuels	0.50
	1.20 lb/10 ⁶ Btu	exempt			Subbituminous Coal	0.50
					Bituminous Coal	0.60
					Anthracite Coal	0.60

limits on SO₂ emissions. However, "The percent reduction is computed on the basis of overall SO₂ removed by all types of SO₂ and sulfur removal technology, including flue gas desulfurization (FGD) systems and fuel pretreatment systems (such as coal cleaning, coal gasification and coal liquefaction)." (emphasis added) The second feature permits higher NO₂ emissions for SRC-II than for other liquid fuels "because coal-derived fuels have fuel-bound nitrogen contents that approach the levels found in coals rather than those found in petroleum oil and natural gas."

5.6 EMISSION LIMITATIONS FOR EXISTING FACILITIES

As noted earlier, emission limits for existing facilities reflect, to some extent, the magnitude of non-compliance from the NAAQS in a region. Most of these limits were set in SIP during the 1972-1974 period. Where air quality data have shown that these limitations have not resulted in achievement of the NAAQS, more stringent requirements will be imposed in the 1979 revised SIP. Reference to Table 5-2 will indicate some of the compliance Metropolitan areas which are so affected. Unfortunately, the exact future emission requirements for these regions will not be known until the new round of SIP approvals by the EPA is completed.

The existing SO₂ emission limits for fuel burning facilities of the selected Metropolitan areas is given in Table 5-5. Some of the limits are expressed in terms of the maximum sulfur content of the fuels, others in terms of SO₂ or S emissions per million BTU heat input. The intercomparison of these factors can be made by referring to the ordinates of the graph in Figure 5-4. (Note that the sulfur contents given in the abscissa refer to liquid fuels only.) Although not listed in the table, it should be realized that any fossil-fuel fired steam generator greater than 250 million BTU/hr heat input which was modified or constructed since December 1971 was required to meet the NSPS in effect at that time.

TABLE 5-5

FUEL SULFUR OR SO_x EMISSION LIMITS

<u>City/County</u>	<u>Breakdown of Geographia Area, if any</u>	<u>Fuel-Using Source, if Given</u>	<u>Fuel Type</u>	<u>% Sulfur or SO_x Emission Limits</u>
DISTRICT OF COLUMBIA	Include MD and VA portions within AQCR Boundary		oil-all types coal-all types	1.0 1.0
JACKSONVILLE, FL	northern Duval County remainder of Duval County entire County		oil oil coal	2.5 lb SO ₂ /10 ⁶ Btu 1.65 lb SO ₂ /10 ⁶ Btu 6.1 lb SO ₂ /10 ⁶ Btu
TAMPA, FL			oil coal	1.1 lb SO ₂ /10 ⁶ Btu 2.25 lb "
ST PETERSBURG, FL			oil coal	2.75 lb " 6.1 lb "
MIAMI, FL	Miami other areas of Gulf Coast Entire Dade County		oil oil coal	1.1 lb " 2.75 lb " 6.1 lb "
CHICAGO, IL			oil-all types coal-all types	1.0 1.0
BALTIMORE, MD			distillate oil residual oil coal-all types	0.3 1.0 1.0

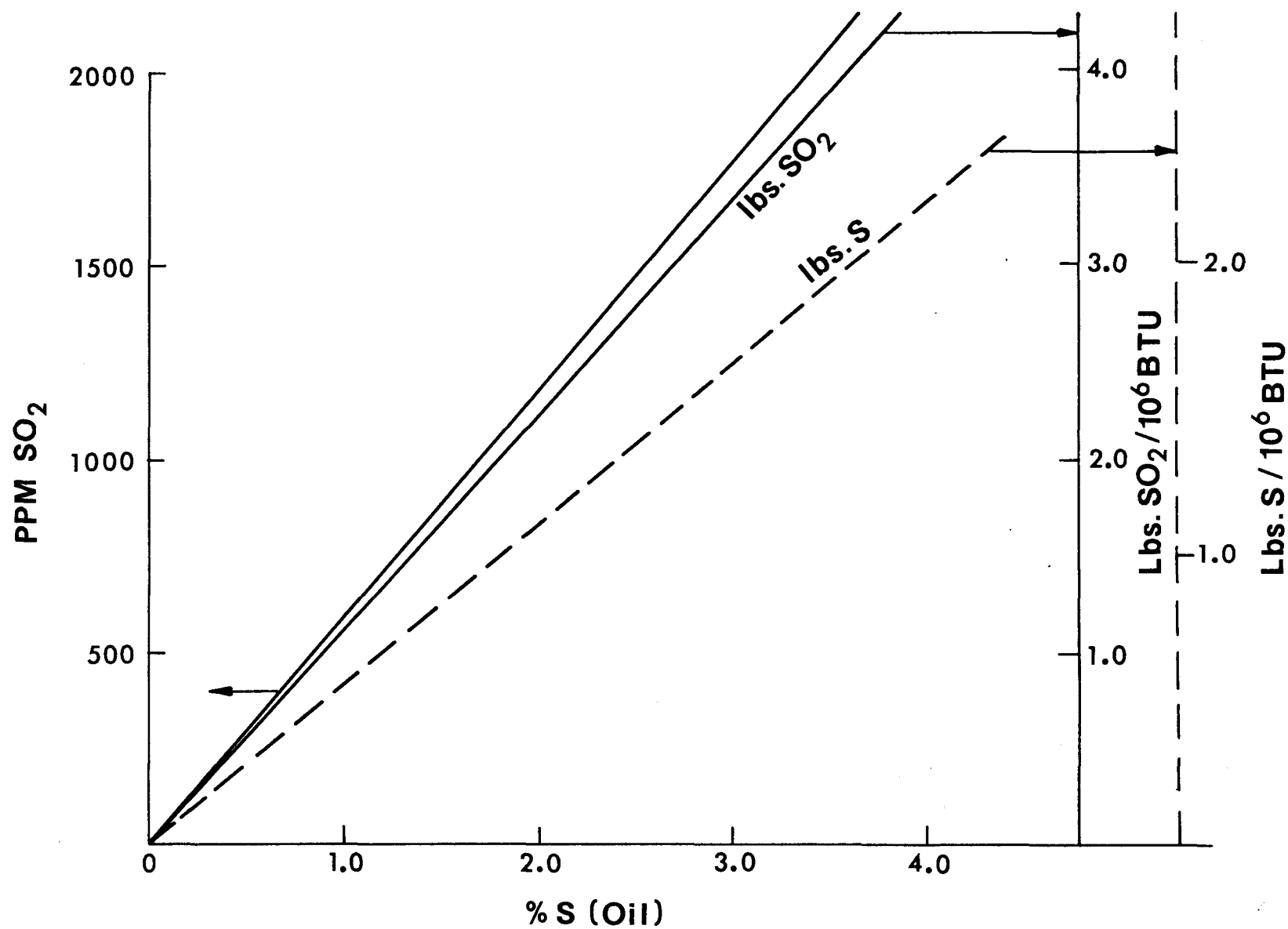
TABLE 5-5 (Cont'd)
FUEL SULFUR OR SO_x EMISSION LIMITS

City/County	Geographic Area, if any	Fuel-Using Source, if Given	Fuel Type	% Sulfur or SO _x Emission Limits
BOSTON, MA	Core Area - 13 cities: Arlington, Belmont, Boston, Brookline, Cambridge, Chelsea, Everett, Malden, Medford, Newton, Somerville, Waltham, Watertown	Sources over 250 x 10 ⁶ Btu/hr heat input	No. 6 oil	1.1
			coal	0.7
		Sources less than 250 x 10 ⁶ Btu/hr heat input	distillate	0.3
			No. 6 oil	0.5
	Metro Boston outside the core area, i.e., remainder of AQCR	Sources over 100 x 10 ⁶ Btu/hr heat input	coal	0.35
			distillate	0.3
		Sources under 100 x 10 ⁶ Btu/hr input	No. 6 oil	2.2
			coal	1.5
DETROIT, MI Wayne County		Electric power plant and central steam generation	distillate	0.3
			No. 6 oil	1.0
			coal	0.7
			distillate	0.3
			pulverized coal	1.0
			other coal	0.75
			distillate oil, Nos. 1 & 2	0.30
			crude & heavy oil, Nos. 4,5,6	1.0
		Residential, commer- cial, space & water heating	coal	0.30
			distillate oil, Nos. 1 & 2	0.30
			crude & heavy oil, Nos. 4,5,6	1.0
			All other uses not specified above	1.0
			coal	0.75
			distillate oil, Nos. 1 & 2	0.30
			crude & heavy oil, Nos. 4,5,6	1.0

TABLE 5-5 (Cont'd.)

FUEL SULFUR OR SO_x EMISSION LIMITS

<u>City/County</u>	<u>Breakdown of Geographic Area, if any</u>	<u>Fuel-Using Source if given</u>	<u>Fuel Type</u>	<u>% Sulfur or SO_x Emission Limits</u>
NEW YORK CITY, NY			residual oil	0.3
			distillate	0.2
			coal	0.2 lb S/10 ⁶ Btu
PHILADELPHIA, PA			residual oil	0.5
			distillate oil	0.2
			coal-all types	0.3
NORFOLK-HAMPTON ROADS, VA	Entire AQCR		residual oil	2.5
			distillate oil	2.6
			coal-all types	1.8

Figure 5-4 S AND SO₂ EMISSIONS VS S CONTENT OF OILS

Not applicable to coal

SECTION 6

UTILITY BOILER CAPITAL AND OPERATING COSTS

6.1 ECONOMIC AND OPERATING FACTORS

The critical economic and operating factors used in this study for new steam boiler electric power plants are given in Table 1. The data for liquid fuel-fired boilers are derived from units designed for the combustion of petroleum. As described in the next Volume, SRC-II Fuel Oil Combustion Test Program, Supporting Reports, it has been demonstrated that SRC-II fuel oil can be utilized without major modification of the equipment design and no significant change is expected in the operating factors. Costs for flue gas desulfurization are included for the coal-fired boiler, and details on this component of the costs are given in Table 2. These data were obtained from a study done by Bechtel for EPRI,⁽¹⁾ from the Stearns-Roger Power Division, and from Tennessee Valley Authority.⁽²⁾

6.2 ADVANTAGES OF LIQUID FUELS-FIRED SYSTEMS

The capital costs for the liquid fuels-fired system are about 60% of those for the coal-fired flue gas desulfurization system. For either kind of system, the capital costs for the southeast region are 75-80% of those for the same system built in the northeast region. For the liquid fuel-fired system this is due only to regional differences in construction costs, since the system designs are identical. For the coal-fired system, there are some small differences due to a different coal being used, but most of the variation is, again, due to regional construction costs differences. Operating and maintenance costs for a liquid fuel-fired boiler are relatively low, and are assumed

(1) "Coal-Fired Power Plant Capital Cost Estimates," Bechtel Power Corporation, EPRI Report AF342, January 1977.

(2) Letter from F. A. Sudhoff, Tennessee Valley Authority, Muscle Shoals, Alabama, May 3, 1979, to P. G. Cooper, Gulf Research & Development Company, Pittsburgh, PA.

Table 1

ECONOMIC AND OPERATING FACTORS FOR NEW INSTALLATIONSSTEAM BOILER POWER PLANTS, LIQUID FUEL FIRED
1978 \$

Costs

Capital, \$/kW	
Northeast	604
Southeast	461
Operating and Maintenance, mil/kW·h	
Northeast	1.8
Southeast	1.8

Operating Parameters^(3,4)

Heat rate, Btu/kWh	9000
Planned outage, % of year	10
Forced outage rate, % of time not on planned maintenance	5

Unit Size, Nominal
MW

2 @420 (840)

(3) "Market Potential for New Coal Technologies," Dwain Spencer and Oliver Gildersleeve, EPRI J., May 1978, pp. 19-26.

(4) "Pricing Scenario for Coal-Derived Synthetic Fuels for Electric Utilities," EPRI, April 24, 1979, Stanley Vejtasa and Oliver Gildersleeve.

Table 2

FLUE GAS DESULFURIZATION (FGD) COSTS FOR COAL-FIRED ELECTRIC POWER PLANT

1978 \$

Capital Cost, \$/kW

Northeast	187
Southeast	152

Operating and Maintenance,
mils/kWh

Main FGD unit

Northeast	2.0
Southeast	2.0

Sludge Disposal

Northeast ^(a)	2.4
Southeast ^(b)	0.8

(a) Truck 30 miles to landfill

(b) On-site landfill

to be the same in both regions. For a coal-fired system with FGD, operation and maintenance expenses are two to three times higher. This higher value for the northeast region is due to the assumption that the FGD waste had to be trucked 30 miles to a land-fill site.

Compared to a coal-fired boiler with FGD, a liquid fuel-fired steam boiler system involves fewer equipment items, is less complex, requires much less manpower, and is easier to start up. Elimination of the handling of solid fuel or solid waste makes a liquid-fueled boiler system much more reliable, as shown by the 13% forced outage rate for a coal unit with FGD (used by Florida Power Corporation), compared to the two to five percent forced outage rate for liquid fueled systems. The lower capital cost of the liquid fueled boiler tends to offset the higher fuel costs, and also simplifies the planning and financing of the expansion of an electric utility system. The lower amount of capital reduces the risk of the project, and also reduces the utility's debt burden and cash flow problems.

Planning is also simplified with regard to site selection and development; much less space is required for a unit of given capacity, since there is no need for a FGD unit or for sludge and ash handling and disposal. No coal storage and handling area, and no lime storage and handling area are required. The great reduction in environmental problems obtained by the elimination of handling dusty coal and ashes, and of FGD sludge, also eases site selection problem and reduces the time required for obtaining licenses and permits. The resulting reduction in required lead time reduces the risk due to commitment for capacity needed in the future.

Finally, a liquid-fueled boiler system is more flexible in its operation, and can respond readily to changes in the system load. In contrast, a coal-fired system with FGD is restricted in the frequency and range of load changes, because of the sluggish response and critical operating parameters of the FGD system.

6.3 COMPARISONS WITH COAL AND NUCLEAR PLANTS

Economic and operating factors for other power generating techniques with which liquid fuel fired boilers have to compete are given in Table 3. Nuclear power is included in this table only for completeness. It is generally recognized that nuclear power plants have the lowest cost of electricity of any available technology, but are considered suitable only for base load service. The high investment required for a nuclear plant and the long lead time involved in construction generally makes it impractical for a utility to rely completely upon nuclear facilities for expansion of their base load capacity. Therefore, other technologies are also needed.

Quite a number of possible technologies have been reviewed in recent years, such as magnetohydrodynamics or closed cycle gas turbines using helium or carbon dioxide as the working fluid. While some of these have promise for the future, the technologies for utilization of coal listed in Table 3, coal gasification integrated with combined cycle, combustion of coal in atmospheric or pressurized fluidized beds, appear to have the best near-term potential among the direct coal alternatives. Since these methods utilize coal directly, their fuel costs are a good deal lower than for a liquid fuel fired boiler. Their cycle efficiency is as good as or better than that of the liquid fuel fired system. Estimates for the capital costs for these technologies given in the literature cover quite a range, with the lower end of the range being about the same as the capital costs for a liquid fuel fired boiler system. However, even at the higher estimates of capital costs, electricity generated by these methods can be expected to be less expensive than that from a liquid fuel fired boiler system.

Although these technologies can compete better economically than the direct combustion of coal with flue gas desulfurization, they still suffer from most of the same practical problems as coal firing with FGD: the complexity and associated unreliability of handling solid fuel and solid waste, space requirements for the handling and storage of coal and lime and for the handling and disposal of solid waste, and the various environmental problems

Table 3

ECONOMIC AND OPERATING FACTORS FOR NEW INSTALLATIONSELECTRIC POWER PLANTS, COAL OR NUCLEAR FUEL
1978 \$

	<u>Coal Plus FGD</u>	<u>Coal Gasification Integrated with Combined Cycle</u>	<u>Nuclear</u>	<u>Atmospheric Fluidized Bed</u>	<u>Pressurized Fluidized Bed</u>
Costs					
Capital, \$/kW					
Northeast	958	590-868	960	620-785	585-898
Southeast	761	544-801	867	589-623	539-714
Operating and Maintenance, Variable, mils/kWh					
Northeast	5.2	2.6	0	4.6	4.6
Southeast	3.7	2.6	0	3.0	3.0
Fixed, \$/kW-week					
Northeast	0	0.22	0.19	0.03	0.03
Southeast	0	0.22	0	0.03	0.03
Operating Parameters					
Heat Rate, Btu/kWh,	9500	7760-8610	9750-11,360	9190	8720
Higher Heating Value					
Planned Outage, % of year	10	10	12	10	-
Forced Outage Rate, % of time not on planned maintenance	13	11	15	9	-
Unit Size, MW	2 @420 (840)	1200	1000	814	904

which complicate site selection and involve long lead times for obtaining licenses and permits. For urban areas with severe environmental problems and limited space, these problems may rule out any direct coal utilization technologies in utility expansion planning. Thus, if government restrictions can be eased, liquid fuel fired steam boiler plants will probably be given serious consideration for at least the near term expansion plans of urban utilities. The construction of a base load liquid fuel fired steam boiler power plant would represent a significant market opportunity for SRC-II fuel oil. For example, a 660 MW liquid fuel fired boiler operating at a yearly average capacity factor of 0.52 would use around 13,000 barrels/day of SRC-II fuel oil.

In addition, utilities without severe site and environmental limitations may also wish to install liquid fuel fired boilers until development of the other technologies is completed, and pioneer commercial scale units have been started up and their operation fully demonstrated. However, after this point, the significantly lower cost of electricity which can be obtained by coal gasification integrated with combined cycle or by atmospheric or pressurized fluidized bed technologies will bring about the selection of these technologies for base load electric power generation by many utilities.

SECTION 7

UTILITY SYSTEMS STUDIED

7.1 DESCRIPTION OF UTILITY SYSTEMS

The boiler fuel market for SRC-II fuel oil has been studied in co-operation with four utilities: Consolidated Edison Company of New York (Con Edison), Baltimore Gas and Electric Company, Boston Edison Company, and Florida Power Corporation. Con Edison supplies electric power to most of New York City and most of Westchester County, New York. Its generating capability as of January 1, 1977, was 9880 MW. Peak demand in 1976 was 7579 MW, and 32.0 million MW-hr were generated by the Con Edison system. They have one nuclear station, and also use both coal and petroleum fuels.

Baltimore Gas and Electric Company (BG&E) supplies electric power to a 2300 square mile area in central Maryland, with about 1/3 of its load concentrated in the city of Baltimore. Their total generating capability, as of January 1, 1977, was 4215 MW, and their 1976 peak load was 3234 MW. They generated 14.8 million MW-hr in 1976. They also have one nuclear plant with both oil and coal also being used in the system.

Boston Edison supplies electricity to an area of approximately 590 sq miles within 30 miles of Boston, encompassing the city of Boston and 39 surrounding cities and towns. Its generating capability at the end of 1978 was 2806 MW while peak load was 2031 MW. 13 billion kW hours were generated during 1978. The peak load for the Boston Edison system is projected to grow at 3.35% per year. Boston Edison is a member of the New England power pool interchange system.

The Florida Power Corporation (FPC) provides service to 375 cities, towns, and rural communities in Florida as well as rural areas in 32 of Florida's 67 counties in the central and northwest portions of Florida, including part of the Florida panhandle, covering a total area of 20,600 sq miles. Major cities in their service territory are St. Petersburg and

Orlando. Peak load for the 1978-79 winter season was projected to be 4450 MW with a projected generating capability of 5300 MW. Power sales for the FPC system in 1978 were 17 billion kW hours. Peak load for the system is expected to grow at a rate of 5-7% over the next several years.

7.2 EXPANSION PLANS

The generation expansion plans and projected demands for BE and FPC are given in Tables 4, 5, and 6.

All four of the utility systems include oil-fired boilers, some of which are relatively new and can be expected to be in service during at least part of the study period 1990-2010. There is, of course, considerable interest on the part of the utilities in continuing to use these units to the end of their normal service life, if a suitable liquid fuel is available at a reasonable price. In addition, there is some interest in the possibility of installing new liquid fuel-fired steam boilers. This would require an exemption from certain Federal regulations based on the premise that the unit would be switched to the use of coal liquid as a fuel as soon as it was available. Liquid fuel-fired steam boiler power plants are currently available, with no technology development required. Their operation is familiar, and their reliability is excellent. Therefore, liquid fuel-fired steam boiler power plants may be given serious consideration in the generation expansion plans of the utilities.

For the Con Edison and the Baltimore Gas and Electric Systems, the analysis of the need for SRC-II fuel oil in liquid fuel-fired steam boiler power systems was done by the utilities themselves. For the Boston Edison and Florida Power Corporation systems, the analysis has been carried out by Gulf, through subcontract with Energy Management Associates, Atlanta, Georgia.

The Con Edison study compared the economics of power plants, using SRC-II fuel oil, with the economics of coal, oil, and nuclear base load generating stations. Con Edison's main conclusion was that the use of SRC-II fuel oil in existing oil-fired units can be expected to be more economic than

Table 4

GENERATION EXPANSION PLAN - BOSTON EDISON COMPANY

The following numbers of new units are on line:

As of November of:	<u>64 MW Gas Combustion Turbines</u>	<u>365 MW¹ Combined Cycle Units</u>	<u>690 MW² Nuclear Units</u>	<u>Summer Peak Loads³</u>
1989	0	0	0	-
1990	1	0	0	3003
1991	4	0	0	3102
1992	1	1	0	3204
1993	3	1	0	3310
1994	0	2	0	3419
1995	0	2	1	3532
1996	0	2	1	3649
1997	3	2	1	3769
1998	0	3	1	3894
1999	3	3	1	4022
2000	0	5	1	4155
2001	4	5	1	4292
2002	2	6	1	4434
2003	0	7	1	4580
2004	0	7	2	4731
2005	0	7	2	4887
2006	3	7	2	5048
2007	1	8	2	5215
2008	4	8	2	5387
2009	2	9	2	5565
2010	(a s s u m e n o c h a n g e)			5749

¹ Four gas combustion turbines and one heat recovery steam generator

² These units are 60% of 1150 MW jointly owned units.

³ Extrapolated at 3.3%

Note: The Pilgrim II nuclear unit is expected to come on line in December of 1985. Boston Edison will own 60% of this 1150 MW unit. No other changes to the current system are planned until 1990.

Table 5
GENERATION EXPANSION PLAN -
FLORIDA POWER CORPORATION

<u>Year</u>	<u>Size Addition, MW</u>	<u>Type</u>
1980	150	Combustion Turbine
1981	300	Combined Cycle
1982	670	Coal
1983	100	Combustion Turbine
1984	670	Coal
1985	660	Coal
1986	-	-
1987	660	Coal
1988	-	-
1989	660	Coal
1990	-	-
1991	-	-
1992	780	Nuclear
1993	-	-
1994	780	Nuclear
1995	-	-
1996	800	Coal
1997	-	-
1998	800	Coal
1999	-	-
2000	-	-
2001	800	Coal
2002	-	-
2003	-	-
2004	800	Coal
2005	-	-
2006	-	-
2007	800	Coal
2008	-	-
2009	-	-
2010	800	Coal

Table 6

FLORIDA POWER CORPORATION

DEMAND AND ENERGY 1990-2010

<u>Year</u>	<u>Demand, MW</u>	<u>Energy, GWH</u>
1990	6870	29137
1991	7110	29963
1992	7150	30733
1993	7370	31482
1994	7400	32214
1995	7620	32915
1996	7730	33533
1997	7930	34101
1998	8090	34760
1999	8240	35230
2000	8370	35780
2001	8510	36300
2002	8650	36800
2003	8800	37280
2004	8950	37710
2005	9160	38150
2006	9200	38600
2007	9350	39000
2008	9470	39400
2009	9600	39800
2010	9750	40170

continuing to burn residual oil in these units. This study is discussed in more detail in the next section, and Con Edison's report of their study is given in Part 3 of Volume 1.

The BG&E study was an economic analysis of the use of SRC-II fuel oil as an alternate to petroleum oil or coal for electric power generation. Revenue requirements, operation and maintenance expenses, and purchased fuel and energy expenses, were considered, along with reliability and financial considerations for various scenarios thru the year 2019. BG&E concluded that using SRC-II fuel oil instead of coal with flue gas desulfurization would result in a savings to BG&E, in spite of the higher costs of the fuel. They concluded that financing problems would be eased, and pointed out that additional benefits of SRC-II fuel oil would be that its supply would be more dependable, and its price more stable, than that of petroleum oil. They concluded that fuels cleanup, as in SRC-II fuel oil, is preferable to flue gas scrubbing. This conclusion was based not only on the economics of the alternatives, but also on other considerations, such as scrubber sludge storage problems. The report prepared by BG&E on their study is contained in Part 3 of Volume 1.

The studies of the Boston Edison Co. and the Florida Power Corporation systems are described in Section 9.

SECTION 8

ANALYSIS OF CONSOLIDATED EDISON STUDY

8.1 JOINT STUDY WITH CONSOLIDATED EDISON

Joint studies were made by Gulf with Consolidated Edison Company of New York, Inc. (Con Edison) on use of SRC-II fuel oil as an alternate fuel for electric power generation. These studies were done in a very limited time period in support of development of the DOE coal liquefaction program. It was the general conclusion that the use of SRC-II fuel oil in existing oil-fired units can be expected to be more economic than continuing to burn residual oil in these units. Additionally, a promising opportunity for SRC-II fuel oil compared to coal with FGD was indicated.

The Con Edison study compared the economics of power plants using SRC-II as a fuel with the economics of coal, oil, and nuclear base load generating stations. Assuming the availability of SRC-II fuel oil in 1990, costs of electricity were developed through levelized annual costs for the period 1990-2024. An inflation rate of 5.5% and a cost of capital of 8.4% were assumed. Comparing the cost of electricity from a new 840 MW coal-fired plant (with FGD) in the New York City area with that from a new SRC-II fuel oil-fired plant of the same capacity at the same location, the Con Ed analysis indicated that the levelized SRC-II fuel oil price would have to be \$6.72/million Btu or lower to achieve break-even or more favorable economics for the SRC-II fueled plant. The break-even price of SRC-II fuel oil as given above is somewhat lower than the projected 1990 price of \$6.77/million Btu and the levelized price of \$8.17/million Btu (1990-2009) developed by Con Edison.

The text of the study done by Con Edison is contained in Volume 3. Since the study was conducted in limited time and utilized external studies for FGD investments, Con Edison did not have the benefit of having a more recent capital cost estimates of a coal-fired plant with FGD and of an SRC-II fired plant all on a consistently prepared basis. The Con Edison study

assumed a differential capital investment of \$240/kW (1990 basis) for a coal-fired plant with FGD compared with an oil-fired plant.

8.2 STEARNS-ROGER STUDY

Stearns-Roger developed cost data for Gulf for these technologies as follow-up to a joint study by Con Edison and Gulf. The Stearns-Roger results are for a New York City setting and should be roughly applicable to other East Coast urban areas.

The capital costs for the coal plus FGD case were based on vendor quotes for the boiler (Babcock and Wilcox and Combustion Engineering) and on an EPRI report prepared by Bechtel¹ (Table 7). Modifications were made by Stearns-Roger to reflect: (1) a change to eastern bituminous coal, (2) a slight change in the size of the plants, and (3) higher construction costs for the New York City area. Incremental coal-fired capacity that would be required to achieve the same system reliability as an oil-fired boiler would give was not taken into account (see below). Stearns-Roger prepared the oil-fired boiler costs aiming at providing a consistent and comparable alternative case. Quotes were again obtained from the same boiler manufacturers. The gross power plant capacity was adjusted to give the same net capacity. The boiler house and site related factors were modified in an appropriate manner to reflect the lesser requirements of an oil-fired generating station. No adjustment was made in the investments to reflect the higher reliability of the oil-fired system. This is provided for in the calculation of the electric power costs discussed below.

Electrostatic precipitation costs (ESP) were prepared by Stearns-Roger. Stearns-Roger had prepared an ultra-high particulates recovery study for EPRI and was ideally suited for this task. No ESP costs are shown for the SRC-II fuel oil case based on our experience at the Con Edison 74th Street

¹ Coal-fired Power Plant Capital Cost Estimates, EPRI AF342, Final Report, January 1977, prepared by Bechtel Power Corporation, San Francisco.

Table 7

ESTIMATED CAPITAL COSTS

Electrical Power Generation from SRC-II Fuel Oil and
Direct Combustion of Coal with Flue Gas Desulfurization

840 MW Net, \$/kW, 1978 Dollars

<u>Case</u>	<u>Eastern Coal Plus FGD</u>	<u>SRC Fuel Oil</u>
Boiler, 880 MW Gross	-	65.5
Boiler, 915 MW Gross	94.0	-
Electrostatic Precipitators ^a	33.0	-
Remainder of Steam Plant and Electrical Generation, per EPRI Study, Adjusted for New York City Labor Costs	<u>319.0</u>	<u>302.5</u>
Subtotal	446.8	368.0
Indirect Field Costs, Engineering, Contingency	175.0	152.6
FGD	147.4	-
Other Owner's Cost (7%) and AFDC (16%)	<u>185.5</u>	<u>130.7</u>
TOTAL	954.7	651.3

^a Clear stack, 0.025 lb particulates/10⁶ Btu.

Station test burn. Capital costs for both the coal-fired plus FGD case and the oil-fired case are summarized in Table 7.

8.3 ECONOMICS: COAL PLUS FGD VS SRC-II FUEL OIL BOILER

Electric power costs using the capital costs developed by Stearns-Roger are given in Table 8. The capital charge factor of 19.54% and the capacity factor of 65% used for both cases are the factors used by Con Edison for an in-city plant in their SRC study. The capital charge factor is the same as the figure supplied to us by Boston Edison (19.56%).

The coal price used, \$1.50/million Btu, is the value developed by Con Edison for delivered coal and used in their study. It should be noted that Boston Edison Company used \$1.56/million Btu (1978) for coal in recent planning studies. A heat rate of 9500 Btu/kWh was used for coal and 9000 Btu/kWh for SRC-II fuel oil.² Operating and maintenance for coal includes 1.2 mils/kWh for the coal plant alone (taken from an EPRI study)³ and 1.8 mils/kWh for FGD (not including waste disposal or sludge fixation).

Since a New York City location is assumed, on-site disposal of FGD waste is not possible. Therefore, a revenue requirement of 0.6 mils/kWh is added to the coal case for sludge fixation and transportation (10 miles, truck) to a remote site. This is derived from information provided by TVA for the conditions of this study.⁴ Operating and maintenance for SRC-II fuel oil is 1.8 mils/kWh, the figure used by Boston Edison Company for a 380 MW base load oil-fired unit. It should be noted that Con Edison used 0.9 mils/kWh

² Dwain Spencer and Oliver Gildersleeve, "Market Potential for New Coal Technologies," EPRI Journal, May 1978, pp. 19-26.

³ EPRI Report PS-445SR, "Coal and Nuclear Generating Costs," April 1977.

⁴ Letter from F. A. Sudhoff, Tennessee Valley Authority, Muscle Shoals, Alabama, May 3, 1979, to P. G. Cooper, Gulf Research & Development Company, Pittsburgh, PA.

Table 8

ELECTRIC POWER COSTS

(Based on Investments by Stearns-Roger)

All Amounts in 1978 Dollars

<u>Case</u>	<u>Eastern Coal Plus FGD</u>	<u>SRC-II Fuel Oil</u>
Investment, \$/kW	954.7	651.3
Fuel Price, \$/T	35	-
\$/million Btu	1.50 ^a	3.56 ^b
	<u>Electric Power Cost, \$/MWh</u>	
Capital @19.54% per year, 65% capacity factor	32.80	22.40
Fuel	14.20	32.00 ^a
Operating and Maintenance	3.00	1.80
FGD Sludge Fixation and Transportation	<u>0.60</u>	<u>-</u>
Subtotal	50.60	56.20
Uncertainty Items		
FGD Costs (Capital, O&M), +20%	2.40	-
Adjustment for Equivalent Generating Reliability (Capital), +10%	<u>2.50</u>	<u>-</u>
Total	55.50	56.20

^a Delivered.^b SRC fuel oil price includes 10% contingency on plant investment.

(1.6 for 1990, adjusted to 0.9 to 1978) for oil or SRC-II fuel oil operating and maintenance.

The above items total \$50.60/MWh for the coal case and \$56.20/MWh for the SRC-II fuel oil case, with the difference of \$5.60/MWh being less than the uncertainty range of the figures. The uncertainty includes two components, one of which is due to lack of knowledge and will be resolved by time and experience. The other component is the difference in reliability between the two systems. The forced outage rate for liquid fuel systems can be estimated reliably from past experience. Coal burning systems will be discussed further below, but are known to have higher forced outage rates even without FGD. The latter adds very significantly to the rate.

8.4 UNCERTAINTIES AFFECTING THE ECONOMICS

The lack of knowledge for the coal case applies to the capital charge for the FGD system (\$8.60 out of \$32.80/MWh) and to operating and maintenance costs and sludge fixation and transportation costs. In the SRC-II fuel oil case, the lack of knowledge applies to the cost of the fuel. As an example of the current uncertainty in capital cost for FGD units, Pennsylvania Power Company is in the process of replacing (at their Bruce Mansfield station) the fan housings (originally rubber lined steel) of all of twelve 9000 HP induced draft FGD fans, with Incoloy housings.

The total portion of the electric power cost for the coal case subject to major uncertainty is \$12.20/MWh. A reasonable escalation for this uncertainty is 20% or \$2.40/MWh.

Spencer and Gildersleeve² indicate a substantial difference in forced outage rate between a liquid fueled boiler, with an estimated availability of 85%, and a coal unit without FGD (low S coal) with estimated availability of 77%. With the addition of limestone scrubbing ("mature") to the coal unit, availability drops to 73% (corresponding forced outage rate of 18%). We have not calculated the effect of this for this particular study but

as shown in Section 9 in the discussion of the FPC base case and FPC Scenario 1, an availability difference of this sort can make a 7.5% difference in the required system capacity to maintain the same effective system generating reliability. Therefore, an increase in capital charges for the coal plus FGD case of 7.5% or \$2.50/MWh is a rough approximation of this effect. Adding both this amount and the amount due to uncertainty in FGD costs to the subtotal for the coal plus FGD case indicates that the total electric power cost could be as high as \$55.50/MWh.

The capital charges and O&M costs for the SRC fuel oil case have relatively little uncertainty. The major uncertainty is in the cost of the SRC-II fuel oil. The expected cost of \$3.56/million Btu includes a 10% capital investment contingency.

Addition of both uncertainty items to the coal plus FGD case and adding another 10% fuel cost increase to the SRC-II fuel oil case (over and above the current 10% capital investment contingency) maintains very close economic equivalence. Overall, we can conclude that utility planners would probably choose between coal plus FGD and a SRC-II fuel oil-fired boiler on the basis of non-economic factors.

8.5 OTHER FACTORS

The effect of non-economic factors depends greatly on local conditions in the area where the plant is to be built. A plant fueled with SRC-II fuel oil requires a minimum of land and has little or no environmental problems. Transportation, transfer, and storage of the fuel is convenient and clean. In congested urban areas where land is scarce and expensive and where environmental problems are usually severe, these factors make SRC-II fuel oil very attractive compared to coal plus FGD. The latter requires a greater amount of land for the plant such as for coal storage and for the FGD system. Even with off-site sludge disposal, a disposal area on the order of several hundred acres is required to accommodate the plant for its operating lifetime.

In addition, the relatively simple and reliable operation of an SRC-II fuel oil-fired plant is attractive compared to the complex and difficult to operate coal plus FGD plant with a 13 percentage point lower availability. The coal plus FGD plant requires transport, transfer, and storage or disposal of coal, limestone, flyash, and sludge. In a congested urban area especially stringent requirements must be faced with regard to coal and limestone dust, with leakage or spillage of sludge from trucks, and with contamination of plant storm water with all these materials.

Since the economics of these two cases are about equivalent, the non-economic factors would probably cause planners for an urban utility, or any utility with difficult site problems, to choose SRC-II fuel oil over coal plus FGD.

On the other hand, for situations where one has available rural plant sites with ready access to a coal supply such as the Appalachian area, coal plus FGD is probably the best choice. Land cost and availability are not a severe problem and construction costs may be lower, reducing the plant cost difference. "On-site" waste disposal will be possible, minimizing operating and maintenance costs, and these factors will make coal plus FGD more economically attractive. Environmental problems can probably be dealt with more readily.

It should be noted that this discussion is comparing only a SRC-II fuel oil-fired boiler with a coal-fired boiler with FGD. Other technologies such as combined cycle combustion turbines are covered elsewhere. The two technologies discussed in this section are relatively well developed. It can be concluded that each would have its area of application in base load electric power generation if they are the only technologies being considered.

In reference to the Con Edison study, Table 7 shows that for an 840 MW unit the differential between an oil-fired and a coal-fired unit with FGD, as estimated by Stearns-Roger using the Bechtel/EPRI study, is \$303/kW (1978 basis). When Con Edison's escalation rate of 5.2%/yr is used to adjust to 1990, the comparable capital investment differential would amount to

\$557/kW. Thus the economics of an SRC-II fuel oil fired plant in the Con Edison study would be improved somewhat relative to the economics of the coal-fired plant with FGD because of the lower FGD capital investments used in the previous study.

Using the capital investment estimates from the Stearns-Roger modification of the EPRI study and the comparable capital charge and other levelized cost factors used by Con Edison, the SRC-II fuel oil break-even price is \$7.87/million Btu as opposed to an SRC-II fuel oil break-even price of \$6.72/million Btu indicated in the Con Edison study (see Table 9). The break-even SRC-II fuel oil cost based on the Stearns-Roger capital investment estimate is now only about 4% below the projected levelized SRC-II fuel cost of \$8.17/million Btu for the period of 1990-2009 developed by Con Edison.

The total costs given for coal fired units in Table III are the total cost of electricity while the totals for SRC-II fuel oil fired units do not include the cost of the fuel. Using Con Edison's projected levelized fuel price of \$8.17/million Btu, the fuel portion of the cost of electricity is \$77.5/MWh. The total cost of electricity for a SRC-II fuel oil fired unit is, therefore, \$125.8/MWh using Con Edison's investment figures or \$126.8/MWh using Gulf's investment figures. The cost of electricity is only 3% higher for the SRC-II fuel oil case compared to the case burning coal with FGD. In terms of capital investment savings, there is considerable advantage. An 840 MW SRC-II fueled plant could achieve a 30%, or \$468 million (1990 \$), reduction in capital investment over a comparable coal-fired plant with FGD.

Table 9

SRC-II FUEL OIL BREAK-EVEN PRICE

Con Edison Results vs Revised Investments

Data Source	Coal in City			SRC-II Fuel Oil in City	
	Con Edison	Gulf		Con Edison	Gulf
Particulates Control, lb/10 ⁶ Btu	0.1	0.1	0.025	-	-
Fuel Type	----- Eastern Coal -----			----- SRC-II Fuel Oil ---	
Site	New York City			New York City	
Fuel Cost, \$/10 ⁶ Btu					
1978	----- 1.50 -----			----- 3.68 -----	
1990	----- 2.76 -----			----- 6.77 -----	
Unit Size, MW	----- 840 -----			----- 840 -----	
Unit Capital Cost, 1990 \$/kW	1405	1743	1754	1165	1196
Annual Cost, \$/MWh, Levelized (1990-2024)					
Generation	48.2	59.8	60.2	40.0	41.1
Transmission	5.3	5.3	5.3	5.3	5.3
Fuel	48.9	48.9	48.9	-	-
O&M	<u>9.6</u>	<u>9.6</u>	<u>9.6</u>	<u>3.0</u>	<u>3.0</u>
TOTAL	112.0	123.6	124.0	48.3 ^(a)	49.4 ^(a)
Break-Even Price of SRC-II Fuel Oil, \$/10 ⁶ Btu				6.72	7.87
Levelized Cost of SRC Fuel Oil, \$/10 ⁶ Btu			8.17	8.17	

(a) Total does not include fuel cost.

SECTION 9

ANALYSIS OF BOSTON EDISON CO. AND FLORIDA POWER CORP.

9.1 INTRODUCTION

In order to study the electric utility market opportunity for SRC-II fuel oil in more detail, the Boston Edison and Florida Power Corporation systems have been studied in detail by Gulf and our subcontractor, Energy Management Associates (EMA).

9.2 METHOD OF ANALYSIS

A representative set of current technologies and developing technologies for electric power generation have been selected, and the most reliable and consistent possible set of economic factors and operating parameters for all these technologies have been assembled from the current literature. Extensive discussions with Boston Edison, Florida Power Corporation, other utilities, and EMA have been carried out to acquire the necessary background knowledge to assess the quality of the input data and of the method of analysis. Data bases have been set up describing the current expansion plans of the two utilities and also describing three alternate scenarios for expansion by each utility.

In these scenarios, the interactions of the various technologies being developed with existing equipment, and with each other, were explored. This was done by simulating the dispatch of the utility systems for these cases using EMA's PROMOD program. The dispatch of each system was simulated over a 20-year study period from 1990 to 2010. Capacity was expanded to satisfy the expected growth in load for each utility as specified in the data base, and the dispatch of all units was determined by PROMOD, based on fuel cost and reliability requirements. The data on operation indicated by the PROMOD run, including fuel requirement and operating and maintenance costs, were then used in the next step, which was calculation of revenue requirements.

Revenue requirements for each scenario were calculated, taking into account the above factors plus return on equity, interest charges, depreciation, taxes, and allowance for funds used during construction, using financial parameters supplied by the two utilities. For the Boston Edison cases, capital expenditures for all units coming into service during the 1990-2010 study period were taken into account in the calculations. No capital costs for existing units were included. For the Florida Power Corporation cases, capital expenditures for all new units installed from 1985 (beginning with the first coal unit with FGD in the base case) through 2010 were included in the calculations. Construction costs were spread over an appropriate period for each project. Operation and maintenance costs and fuel costs were calculated for all of the utilities' units for the 1990-2010 study period. Investments and the various costs were escalated at appropriate individual rates. The present worth of net cash flow and levelized revenue requirements were calculated for each scenario, permitting ready comparisons of the various technological options and combinations.

Based on the results of the revenue requirement calculation and on a number of non-economic considerations, the most likely scenario for each utility has been selected. The fuel usage indicated by these most likely scenarios has then been used as a basis for the projection of the market opportunity for SRC-II fuel oil for eleven large east coast utilities. The ratios of liquid fuel use to coal use and of turbine fuel use to boiler fuel use for liquid fuel for the two utilities has been compared to the projected load and energy for the eleven utilities and their projected fuel use distribution to arrive at a reasonable market opportunity estimate for the use of SRC-II fuel oil as a turbine fuel.

The scenarios for which economic dispatch simulations and financial analyses were carried out are listed in Table 10.

Table 10
UTILITY SCENARIOS

<u>Scenario</u>	<u>Description</u>
Boston Edison Company	
BE Base Case	Base Case = Current technology combined cycle units utilizing petroleum fuel.
BE Scenario 1	SRC-II fuel oil substituted for petroleum. Base expansion plan.
BE Scenario 2	Cycling coal units substituted for combined cycle units.
BE Scenario 3	Advanced combined cycle units substituted for base case combined cycle units. All liquid fuel units use SRC-II fuel oil.
BE Refurbishment	Modification of Scenario 2. Existing oil units are refurbished, retirement dates are postponed and all liquid fuel is SRC-II fuel oil.
Florida Power Corporation	
FPC Base Case	Base Case. Expansion by coal with FGD and nuclear.
FPC Scenario 1	SRC-II fuel oil fired boiler units substituted for coal units.
FPC Scenario 2	Advanced combined cycle units substituted for coal units. All liquid fuel is SRC-II fuel oil.
FPC Scenario 3A	Coal gasification/combined cycle units substituted for base case coal units.
FPC Scenario 3B	Combination of SRC-II fueled advanced combined cycles and coal gasification/ combined cycle unit scenarios.

9.3 DISCUSSION OF EMA RESULTS

For all the utility scenarios except for the base cases, it has been assumed that SRC-II fuel oil is used in all liquid fuel fired units throughout the study period of 1990 to 2010. Even for scenarios in which the maximum use of coal is being studied, the usage of SRC-II fuel oil is significant in the early part of the study period. For example, in Boston Edison's Scenario 2, where expansion is accomplished with nuclear units and with cycling coal units, the liquid fuel fired boilers in the system still require 35,000 barrels per day of SRC-II fuel oil in 1990 (Table 11). This drops steadily throughout the study period until in 2010, it is down to 6,500 barrels per day.

For FPC Scenario 3A, where system expansion is accomplished with nuclear units and with coal gasification units integrated with combined cycle turbines, 18,700 barrels per day of SRC-II fuel oil is used in 1990 by the existing liquid fuel fired boilers (Table 12). This drops to a much lower level shortly thereafter due to nuclear units coming on-line and continues to drop slowly until in 2010, usage is down to 700 barrels per day.

9.3.1 Boston Edison Refurbishment Case

The Boston Edison Refurbishment case is based upon BE Scenario 2 which is discussed in detail in Volume 1, Part 3. In Scenario 2, it is assumed that the BE base case combined cycle units are replaced by 400 MW cycling coal units. In the refurbishment case, it is assumed that appropriate liquid fuel fired units have their life extended beyond their normal 30-year retirement date by refurbishment to extend their lives another 15 years. Stearns-Roger did a study of the cost of doing this refurbishment and their report is given in Appendix B. They determined that to refurbish an oil-fired unit would cost \$9.30/kW (1979 \$). For the run, it was assumed that three 150 MW units were refurbished in 1995 replacing the 400 MW cycling coal unit scheduled for 1994 in Scenario 2. A 380 MW unit was refurbished in 2000 taking the place of one of the 2 cycling coal units scheduled for 2000 and

Table 11

SUMMARY OF SCENARIO RESULTS FOR
BOSTON EDISON COMPANY

(\$ in millions)

	<u>1990</u>	<u>1995</u>	<u>2000</u>	<u>2005</u>	<u>2010</u>
ANNUAL RESULTS FOR					
<u>BE Base Case:</u>					
Production Costs	582.2	1016.2	1682.5	2319.2	3849.8
Oil (1000 BBLs/yr)	12841	14616	14559	13629	18606
Combined Cycle Capacity Factor	N/A	31%	31%	36%	39%
<u>BE Scenario 1:</u>					
Production Costs	753.3	1102.9	1535.8	2047.7	3433.1
SRC-II (1000 BBLs/yr)	12849	14314	14182	13035	17768
Combined Cycle Capacity Factor	N/A	51%	40%	36%	39%
<u>BE Scenario 2:</u>					
Production Costs	753.3	989.0	1365.1	1679.0	2773.8
Coal (1000 Tons/yr)	N/A	1429	1936	3233	4753
SRC-II (1000 BBLs/yr)	12849	9775	7972	2544	2396
Cycling Coal Capacity Factor	N/A	47%	39%	31%	35%
<u>BE Scenario 3:</u>					
Production Costs	751.9	1023.6	1428.0	1731.9	2832.4
SRC-II (1000 BBLs/yr)	12843	13118	13091	10332	13759
Advanced Combined Cycle Capacity Factor	N/A	57%	54%	37%	40%
<u>BE Refurbishment:</u>					
Production Costs	753.3	1067.7	1432.1	1841.6	3020.0
Coal (1000 Tons/yr)	N/A	817	1409	2082	3343
SRC-II (1000 BBLs/yr)	12849	11998	10062	6975	7711
Cycling Coal Capacity Factor	N/A	54%	43%	35%	37%

Table 12

SUMMARY OF SCENARIO RESULTS FOR
FLORIDA POWER CORPORATION

(\$ in millions)

	ANNUAL RESULTS FOR				
	<u>1990</u>	<u>1995</u>	<u>2000</u>	<u>2005</u>	<u>2010</u>
<u>FPC Base Case:</u>					
Production Costs	1182.9	1397.1	2110.1	3145.8	4581.0
Coal HS (1000 Tons/yr)	6877	5924	8386	10270	11485
Coal LS (1000 Tons/yr)	2878	2346	1291	549	300
Oil (1000 BBLs/yr)	4477	1763	857	792	729
Capacity Factor of New Coal Units	62%	55%	49%	44%	42%
<u>FPC Scenario 1:</u>					
Production Costs	1453.0	1605.8	2457.9	3673.8	5327.2
Coal HS (1000 Tons/yr)	2339	1831	1777	1719	1883
Coal LS (1000 Tons/yr)	3808	3566	3578	3538	3430
SRC-II (1000 BBLs/yr)	16141	11004	14913	18922	21986
Capacity Factor of New SRC-II Units	48%	36%	30%	27%	27%
<u>FPC Scenario 2:</u>					
Production Costs	1386.2	1465.3	2112.1	3050.3	4287.4
Coal HS (1000 Tons/yr)	2457	2092	2183	2174	2369
Coal LS (1000 Tons/yr)	4012	3742	3880	3922	3875
SRC-II (1000 BBLs/yr)	14100	7700	9000	11000	12200
Advanced Combined Cycle Capacity Factor	-	-	50%	44%	36%
<u>FPC Scenario 3A:</u>					
Production Costs	1219.9	1321.1	1772.7	2559.8	3677.5
Coal HS (1000 Tons/yr)	5183	5406	6705	7970	9207
Coal LS (1000 Tons/yr)	3325	2010	1469	949	449
SRC-II (1000 BBLs/yr)	6838	1081	618	471	267
Coal Gasification Capacity Factor	73%	49%	45%	43%	40%
<u>FPC Scenario 3B:</u>					
Production Costs	1212.2	1290.4	1916.2	2700.4	3943.1
Coal HS (1000 Tons/yr)	5184	4231	4478	6322	6777
Coal LS (1000 Tons/yr)	3321	2775	3060	2448	2543
SRC-II (1000 BBLs/yr)	6682	2696	3624	2092	2882
Capacity Factor - Coal Gasification	73%	60%	63%	58%	62%
Capacity Factor - Advanced Combined Cycle	N/A	20%	18%	11%	11%

Note: Coal HS, LS = High, low sulfur.

another 380 MW unit was refurbished in 2003 replacing the cycling coal unit added in that year. A total of 1,210 MW of capacity was refurbished.

The electricity production costs are slightly higher in the refurbishment run, compared to Boston Edison's Scenario 2, because more SRC-II fuel oil is being used (Table 11). However, the levelized revenue requirement (LRR) for the refurbishment scenario has dropped dramatically, to \$197 million, from the \$262 million from Scenario 2, a drop of 25% (Table 13). In the year 2010, 21,000 barrels per day of SRC-II fuel oil are being used in contrast to Scenario 2 where the usage has dropped to 6,500 barrels per day (Table 14). This refurbishment study demonstrates the important effect of avoiding large capital expenditures.

9.3.2 FPC Scenario 1

In FPC Scenario 1, it is assumed that instead of installing coal fired units after 1985, FPC would install SRC-II fuel oil fired boilers of the same capacity in accordance with the base case schedule. As expected, this increases the production costs of electricity due to the higher costs of the fuel. Surprisingly, the LRR for Scenario 1 drops to \$460 million in contrast to the \$496 million LRR for the base case, a drop of about 7% (Table 12). The capital costs of the SRC-II fuel oil fired units are much lower than for the coal fired units with FGD, the liquid fuel fired units being 60% of the capital cost of the solid fuel units.

The explanation for the lower LRR for Scenario 1 versus the base case is that the SRC-II fuel oil fired boilers installed in Scenario 1 do not run at as high a capacity factor as the new coal units installed in the base case. Instead, the four existing (before 1985) coal units in the FPC system are at much higher capacity factors. For example, in 1990 Crystal River units 1 and 2 run at an average capacity factor of .74 in Scenario 1 while they only ran at 0.54 in the base case. In the year 2010, the same units run at a 0.59 capacity factor in Scenario 1 while they ran at a capacity factor of only 0.35 in the base case. The contrast is even greater for Crystal River units 4 and

Table 13

LEVELIZED REVENUE REQUIREMENTS
BOSTON EDISON COMPANY SCENARIOS

	<u>Total Levelized Revenue Requirement (millions of 1979 \$/year)</u>
Base Case	\$211
Scenario 1	\$217
Scenario 2	\$255
Scenario 3	\$207
Refurbishment	\$190

Table 14

LEVELIZED REVENUE REQUIREMENTS
FLORIDA POWER CORPORATION SCENARIOS

	<u>Total Levelized Revenue Requirement (millions of 1979 \$/year)</u>
Base Case	\$496
Scenario 1	\$460
Scenario 2	\$378
Scenario 3A	\$441
Scenario 3B	\$377

5 which run on low sulfur coal. The capacity factor for these units in 2010 in the base case was only 0.05 whereas in Scenario 1, it is 0.60. The capacity factors of the new SRC-II fuel oil units in Scenario 1 are from 0.14 to 0.19 lower than the capacity factor of the new coal units in the base case (Table 12).

Thus, the production costs in Scenario 1 are not much higher than the production costs of the base case as would be expected from a one to one replacement of coal fired capacity with SRC-II fuel oil fired capacity. A considerable amount of coal is still used in Scenario 1 through better utilization of the existing coal fired units. The resulting electricity production costs, although higher than for the base case, are more than offset by the lower capital costs for the SRC-II fuel oil fired units, resulting in a lower LRR. It is, thus, not unreasonable to consider the installation of liquid fuel fired boilers in the 1985 to 1990 time frame. If needs for reliability and other considerations are met, a considerable savings in capital expenditures over those for coal fired units with FGD would be obtained and overall revenue requirements and costs of electricity would tend to be lower. In the case of the FPC system, this would result in 44,000 barrels per day of SRC-II fuel oil being used in 1990.

The effect of the higher reliability of the SRC-II fired boilers used in Scenario 1 (5% forced outage rate) as compared to the coal fired units in the base case (13% forced outage rate) can be determined from the equivalent load curve produced by the economic dispatch program (PROMOD, Energy Management Associates). Taking the year 2002 in Scenario 1 as an example, the curve for this year indicates that the system capacity could be decreased by 901 MW and still match the loss of load hours for 2002 in the FPC base case. Thus, the 800 MW SRC-II fired boiler unit brought on line the previous year could have been dropped from the expansion plan (about 7.5% of the system capacity) and the system reliability still would have been as good as the FPC base case. This would be a savings of a capital expenditure of \$375 million (1978 \$).

SECTION 10

BOILER FUEL DEMAND ESTIMATES

10.1 PROJECTED DEMAND FOR LARGE EAST COAST UTILITIES

The scenarios in which turbine technology is studied in detail are discussed in Volume 1, Part 3 on the turbine fuel market opportunity. Based on the analysis of these scenarios and on the levelized revenue requirement results given in Tables 13 and 14, BE Scenario 3 and FPC Scenario 3B were selected as the basis for projecting SRC-II fuel oil demand. In BE-3, generation expansion is accomplished with nuclear and advanced combined cycle technology. In FPC-3B, it is accomplished with nuclear, coal gasification integrated with combined cycle, and advanced liquid fuel combined cycle technology.

Demand was projected for the eleven large U.S. East Coast utilities listed in Table 15. Data on projected fuel use and energy production were obtained from each of these utilities. This information was then compared with the results of BE-3 and FPC-3B scenarios. From this comparison, it was decided to group Consolidated Edison Co. and Northeast Utilities Co. with Boston Edison Co. for projection of demand based on Scenario B-3. The projection for the other eight utilities was based on Scenario FPC-3B and on the data for five utilities (marked with an asterisk in the list) in the Middle Atlantic area.

The nuclear generation projected by the utilities was used as given or extrapolated to the end of the study period. For Consolidated Edison and Northeast Utilities, the projected petroleum-based oil consumption was assumed to be the projected demand for SRC-II fuel oil. This demand then was distributed between use in boilers, combustion turbines, and combined cycle units as in BE-3.

In FPC-3B, the percentage of generation based on SRC-II fuel dropped from 1990 to 1995 as boiler units were retired and then held roughly constant from 1996 to 2010. A steep drop in oil used from 1990 to 1995 also is projected by most of the other utilities which we are relating to FPC-3B. The drop in oil use then continues at a much slower rate to 2010. This latter

Table 15

U.S. EAST COAST UTILITIES USED IN
PROJECTING SRC-II FUEL OIL DEMAND

Boston Edison Company (+)
New England Electric System
Northeast Utilities Company (+)
Consolidated Edison Company (+)
Public Service of New Jersey (*)
Philadelphia Electric Company (*)
Potomac Electric Company (*)
Baltimore Gas and Electric Company (*)
Virginia Electric Power Company (*)
Florida Power Corporation
Florida Power and Light Company

+ Grouped for projection based on Scenario B-3.

* Middle Atlantic area utilities grouped for projection.

drop should not occur if SRC-II fuel oil is available. Therefore, the SRC-II fuel oil demand for 1990 to 2010 was held as a constant percentage based on the percentage of oil used in 1996. Distribution among boilers, turbines, and combined cycle units was based on FPC-3B.

The projected demand for each type of equipment and the totals were summed for all eleven utilities. The results of this are given in Table 16 and shown graphically in Figure 2. Projected demand for SRC-II fuel oil as boiler fuel is 159 million bbls/year (435,000 bbls/day) in 1990 dropping to 74 million bbls/year (200,000 bbls/day) in 1995 and to 7 million bbls/year (19,000 bbls/day) in 2010 as older units are retired. Total projected demand for the eleven electric utilities is 244 million bbls/year (670,000 bbls/day) in 1990, dropping to 172 million bbls/year (470,000 bbl/day) in 1999 because of the drop in boiler fuel use. As is shown in Figure 2, the drop in boiler fuel demand is largely offset by the increase in combined cycle fuel demand. Total use then gradually increases to 193 million bbls/year in 2010 (530,000 bbls/day) as combined cycle unit demand continues to increase. A scale is included in Figure 2 for converting the barrels of SRC-II fuel oil consumed by each technology to GWh of electricity generated.

The lighter dashed lines in Figure 2 represent how SRC-II fuel oil use as a boiler fuel might be increased by the refurbishment of existing liquid fuel fired boilers as studied in the Boston Edison refurbishment scenario (see Section 9). It is assumed in the figure that the refurbished units are used instead of new combined cycle units being built and that total SRC-II fuel oil demand unit is not affected. However, refurbishment could partly displace other technologies such as coal gasification also and thus might increase total SRC-II fuel oil use.

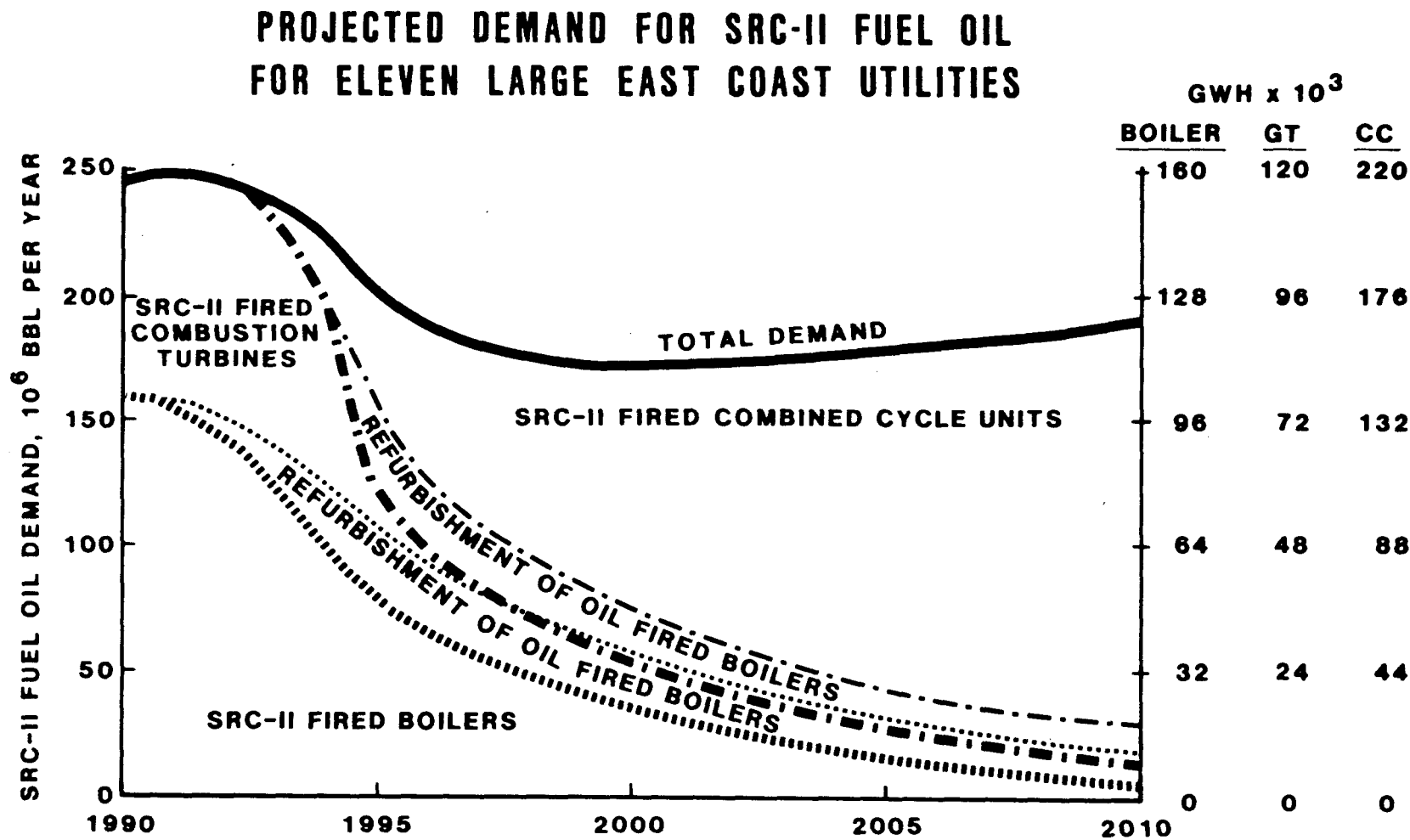
Table 16

PROJECTED DEMAND FOR SRC-II FUEL OIL
ELEVEN LARGE EAST COAST UTILITIES

Millions of Barrels/Year

<u>Year</u>	<u>Steam Boilers</u>	<u>Combustion Turbines</u>	<u>Combined Cycle</u>	<u>Total</u>	<u>Projected Percent of Total Power Generation Based on SRC-II Fuel Oil</u>
1990	159.4	84.2	0	243.6	33.2
1991	159.8	90.5	0	250.3	32.8
1992	142.1	106.0	0	248.1	30.8
1993	134.1	94.9	9.5	238.5	29.2
1994	91.0	34.4	69.7	195.1	27.3
1995	73.7	15.1	92.9	181.7	26.4
1996	73.3	22.9	90.1	186.3	25.7
1997	58.0	31.7	87.3	177.0	23.3
1998	52.0	31.7	91.7	175.4	22.6
1999	48.4	12.8	110.3	171.5	22.6
2000	46.1	14.4	116.4	176.9	22.8
2001	29.3	12.4	133.5	175.2	22.8
2002	24.5	15.3	132.5	172.3	21.7
2003	24.4	14.4	138.0	176.8	21.8
2004	15.4	10.9	150.3	176.6	21.8
2005	13.3	19.4	149.1	181.8	21.4
2006	11.9	16.9	156.7	185.5	21.6
2007	10.1	5.3	161.8	177.2	20.8
2008	9.3	9.8	164.4	183.5	20.8
2009	9.5	13.8	168.1	191.4	21.0
2010	7.0	8.8	176.8	192.6	21.0

Figure 2



10.2 PROJECTED DEMAND FOR TOTAL U.S.

An approximation was made of the total electric utility U.S. demand for SRC-II fuel oil. The total generation was projected from DOE figures.⁽¹⁾ The percentage of generation from SRC-II fuel oil was then calculated from the fraction projected for oil by the five Middle Atlantic utilities as was explained previously. This figure was then reduced by 50% since conditions for supply and use of SRC-II fuel oil will not be as favorable for some parts of the U.S. as they are for the east coast. The resulting demand projection is given in Table 17. The patterns of use with time are similar to those for the east coast.

(1) "Annual Report to Congress, Volume II, 1977, Projections of Energy Supply and Demand and Their Impacts," Energy Information Administration, U.S. Dept. of Energy.

Table 17

Projected U. S. (Contiguous) Demand for SRC-II Fuel Oil

Millions of Barrels/Year

<u>Year</u>	<u>Steam Boilers</u>	<u>Combustion Turbines</u>	<u>Combined Cycle</u>	<u>Total</u>
1990	375.0	354.0	0	728.0
1991	383.0	347.0	0	731.0
1992	336.0	416.0	0	752.0
1993	308.0	360.0	44.3	713.0
1994	133.0	61.9	298.0	493.0
1995	121.0	67.2	304.0	492.0
1996	110.0	98.5	289.0	498.0
1997	81.4	143.0	306.0	530.0
1998	73.3	129.0	336.0	538.0
1999	51.2	27.5	429.0	508.0
2000	54.1	37.3	442.0	533.0
2001	43.0	45.1	468.0	556.0
2002	43.0	45.3	491.0	579.0
2003	45.9	48.5	512.0	607.0
2004	46.3	55.2	531.0	633.0
2005	39.7	95.1	543.0	677.0
2006	31.4	81.6	581.0	694.0
2007	24.5	15.8	650.0	690.0
2008	22.7	29.1	675.0	727.0
2009	21.6	52.4	695.0	769.0
2010	16.1	50.8	731.0	798.0

APPENDIX A

DISCUSSION OF FUEL PRICE PROJECTIONS

The SRC-II fuel oil prices used in the electric utility study include transportation to the utility service territory by pipeline and tanker and are escalated to reflect real cost increases for feed coal, for operating and maintenance expenses, and for capital cost escalations up to the point at which the first plant is built and on stream. A plant price of \$3.56/million Btu of SRC-II fuel oil in the fourth quarter of 1978 is the basis. A 20-inch pipeline 1000 miles long costing \$250,000 per mile to construct is assumed to transport the fuel oil to Baltimore. The SRC-II fuel oil is then transported either to Boston or to Tampa in 37,000 ton dead weight tankers. The resulting 1978 transportation cost to Boston was 21¢/million Btu and to Tampa was 27¢/million Btu. The plant cost of SRC-II fuel oil was escalated using the factors given in Table 18.

It was assumed that no real escalation in construction costs occurred for SRC-II fuel oil production facilities after the first plant came on stream. This was based on the expectation of improved designs of subsequent plants based on what is learned in constructing and operating the first plant, and on the expectation of lower cost of financing because of reduced project risk after the completion and successful operation of the first commercial plant. The escalated SRC-II fuel oil prices were also inflated to current dollars. The resulting prices shown in Tables 19 and 20, were used in the simulations and financial analyses of the electric utility systems.

A definitive analysis of the above effects was done after the study was nearly complete and is reported in Deliverable 8, Volume 5 of the Commercial Conceptual Plant-Economics Analysis. The effects of technology improvements and operating experience upon the cost of a series of SRC-II plants were considered. The more liberal financial parameters appropriate after several plants have been built and operated were taken into account, such as when long-term purchase contracts will probably be coming into effect for a large proportion of the production.

TABLE 18

ESCALATION FACTORS

SRC-II Fuel Oil Price

<u>PERIOD</u>	<u>PRICE COMPONENT</u>	<u>% DUE TO COMPONENT</u>	<u>ESCALATION RATE, % OVER GENERAL INFLATION</u>
Before plant is built	Coal Feed	35.1	1.0
	Operation & Maintenance	13.3	0.5
	Capital Charges	51.6	1.5
After plant is built (1989 start-up)	Coal Feed	35.0	1.0
	Operation & Maintenance	27.0	0.25
	Capital Charges	38.0	0 (No Escalation)

TABLE 19

BOSTON EDISON FUEL COSTS

(Inflated dollars, ¢/million Btu)
Used in Economic Dispatch Calculations

<u>Year</u>	<u>Coal</u>	<u>SRC-II Fuel Oil</u>
1978	155.3	377.0
1979	167.0	404.3
1980	179.9	434.0
1981	193.4	465.0
1982	206.7	495.3
1983	220.7	527.2
1984	235.2	560.0
1985	250.7	594.9
1986	267.1	632.0
1987	284.7	671.4
1988	303.4	713.3
1989	323.4	757.7
1990	344.6	798.6
1991	367.3	842.1
1992	391.4	888.1
1993	417.2	936.6
1994	444.6	987.8
1995	473.8	1042.0
1996	505.0	1099.0
1997	538.2	1159.0
1998	537.6	1222.0
1999	611.3	1289.0
2000	651.5	1360.0
2001	694.3	1434.0
2002	740.0	1513.0
2003	788.6	1596.0
2004	840.5	1683.0
2005	895.7	1775.0
2006	954.6	1873.0
2007	1017.0	1976.0
2008	1084.0	2084.0
2009	1156.0	2199.0
2010	1232.0	2319.0

TABLE 20

FLORIDA POWER CORPORATION FUEL COSTS
(Inflated dollars, ¢/million Btu)
Used in Economic Dispatch Calculations

<u>Year</u>	<u>Coal HS*</u>	<u>Coal LS*</u>	<u>Residual Fuel Oil</u>	<u>No. 2 Fuel Oil</u>	<u>SRC-II Fuel Oil</u>
1978	170.3	-	235.3	-	383.0
1979	181.1	-	253.1	311.0	410.8
1980	195.0	-	270.6	331.0	440.9
1981	209.6	-	292.3	352.0	472.3
1982	224.0	259.7	314.0	375.0	503.2
1983	239.2	277.3	336.9	403.0	535.5
1984	254.9	295.5	260.8	434.0	568.9
1985	271.7	315.0	386.5	468.0	604.3
1986	289.5	335.6	418.6	512.0	641.9
1987	308.6	357.8	452.8	555.0	681.9
1988	328.8	381.2	489.6	608.0	724.4
1989	350.5	406.4	529.6	671.0	769.6
1990	373.5	433.0	572.7	744.0	811.1
1991	398.1	461.5	625.6	802.0	855.5
1992	424.2	491.8	683.1	865.0	902.2
1993	452.1	524.1	746.0	939.0	951.6
1994	481.9	558.7	814.6	1022.0	1004.0
1995	513.6	595.4	889.5	1115.0	1059.0
1996	547.3	634.5	981.1	1232.0	1117.0
1997	583.3	676.3	1082.0	1346.0	1178.0
1998	621.7	720.8	1193.0	1457.0	1242.0
1999	662.5	768.1	1315.0	1562.0	1310.0
2000	706.1	818.6	1450.0	1652.0	1382.0
2001	752.5	872.4	1597.0	1749.0	1458.0
2002	802.0	929.8	1762.0	1837.0	1538.0
2003	854.7	990.9	1886.0	1929.0	1623.0
2004	910.9	1056.1	1981.0	2025.0	1712.0
2005	970.8	1125.1	2080.0	2126.0	1806.0
2006	1035.0	1199.9	2184.0	2233.0	1905.0
2007	1103.0	1278.8	2293.0	2344.0	2010.0
2008	1175.0	1362.2	2407.0	2462.0	2120.0
2009	1252.0	1451.5	2528.0	2585.0	2237.0
2010	1335.0	1547.7	2654.0	2714.0	2360.0

*HS, LS: High, low sulfur

The effect of using an SRC-II fuel oil price projection such as this in the electric utility study instead of the price projection actually used can be evaluated. Financial comparisons in the electric utility study were made by discounting the revenue requirements for each year during the study back to 1979, using a discount rate of 10%. Using the same discount rate, the present values for each of the two series of SRC-II fuel oil prices can be calculated. Taking a ratio of these two present values indicates that substituting the new set of prices would increase the present value of the fuel cost used in the financial calculations by 11%. The expenditures for SRC-II fuel oil are only a fraction of the total expenditures (which also include other fuel, operation and maintenance costs, and capital expenditures) used to calculate the levelized revenue requirements (LRR) for the scenarios. Therefore, the effect of the above cost increase on the LRR for the scenarios will be less than 11%. The increase will vary from scenario to scenario depending upon the amount of SRC-II fuel oil used, but it would not affect the conclusions reached in this study to any great extent.

In addition, the SRC-II fuel oil market projections are not affected by the change in the SRC-II fuel oil price. The projection could be affected in two ways. One effect would be on the economic dispatch calculations. However, since SRC-II fuel oil was already the highest price fuel in all the scenarios, the economic dispatch calculation gave the minimum SRC-II fuel oil usage. A further price increase has no effect on the dispatch. The other effect would be on the selection of the scenarios on which to base the projection. Boston Edison Scenario 3 (BE-3) and Florida Power Corporation Scenario 3B (FPC-3B) were used for the projections. The only alternative selection to BE-3 would be the cycling coal scenario (BE-2) which has a LRR 18% higher than BE-3. FPC Scenario 2, a possible alternate to FPC-3B would be significantly and adversely affected by the price increase but has already been ruled out since it is unlikely that utilities serving territories similar to that of Florida Power Corporation will want to base all their non-nuclear expansion on liquid-fueled, combined-cycle units. Direct coal firing with flue gas desulfurization, and coal gasification integrated with advanced combined cycle will also be used. FPC Scenario 3B represents this situation best.

A relatively small amount of SRC-II fuel oil is used in FPC-3B, so it will not be affected significantly by the price increase. The LRR will, therefore, remain about 15% below that for FPC Scenario 3A, in which expansion is accomplished using only coal gasification and nuclear units.

Boston Edison and Florida Power Corporation supplied 1979 delivered coal prices of \$1.67/million Btu and \$1.81/million Btu respectively. These prices were escalated from 1979 to the end of the study period at an annual rate of 1-1/2% over general inflation. The mine-mouth coal used as feed for the SRC-II plant is assumed to cost \$1.25/million Btu in 1978. This component of the SRC-II fuel cost is escalated at 1% over general inflation. The higher escalation rate for the delivered coal was meant to reflect an expected greater increase in transportation costs because of escalating transportation fuel costs and anticipated deregulation. A portion of the coal delivered to an SRC-II commercial plant was assumed to be essentially mine-mouth.

Residual fuel oil prices used for the base case scenario were projected by assuming a 1979 price of \$15.50/bbl of 0.3 wt % S fuel (same sulfur content as SRC-II fuel oil) and then escalating the price (before general inflation) by the following schedule until it reached a limit of about \$36/bbl.

1979-80	1%
1981-85	2%
1986-90	3%
1991-95	4%
1996 and after	5%

The limit reflects competition from synthetic fuels and increased petroleum recovery at the higher prices. While the study was in progress, petroleum prices increased very rapidly, making the above projection possibly low. This increases the likelihood that SRC-II fuel oil will be less costly than residual fuel oil by 1990.

After escalation in "real" or constant dollars, all the fuel prices were then adjusted for general inflation using the factors given in Table 21. The resulting prices used in the utility studies are given in Tables 19 and 20. The No. 2 fuel oil and No. 6 fuel oil prices given for Florida Power Corporation were also used for Boston Edison Company.

The revised SRC-II fuel oil prices (delivered) reflecting the more realistic capital costs and financing parameters are given in Table 22.

TABLE 21

GENERAL INFLATION RATES

<u>YEAR</u>	<u>%</u>
1978	6.3
1979	6.1
1980	6.1
1981	5.9
1982	5.3
1983	5.2
1984 and beyond	5.0

TABLE 22
REVISED SRC-II FUEL OIL PRICE PROJECTION
(Inflated Dollars, \$/Million Btu)

	<u>Delivered to</u>	
	<u>Boston</u>	<u>Tampa</u>
1978	4.17	4.23
1979	4.46	4.52
1980	4.81	4.88
1981	5.12	5.20
1982	5.44	5.52
1983	5.83	5.91
1984	6.16	6.25
1985	6.53	6.63
1986	6.97	7.07
1987	7.38	7.49
1988	7.81	7.92
1989	8.36	8.48
1990	8.82	8.94
1991	9.34	9.47
1992	9.97	10.11
1993	10.56	10.71
1994	11.07	11.23
1995	11.67	11.84
1996	12.36	12.54
1997	13.09	13.28
1998	13.56	13.76
1999	14.50	14.71
2000	15.35	15.58
2001	16.22	16.46
2002	16.83	17.09
2003	17.82	18.09
2004	18.83	19.12
2005	19.93	20.24
2006	21.10	21.42
2007	22.38	22.72
2008	23.68	24.04
2009	25.06	25.45
2010	26.47	26.88

APPENDIX B
STEARNS-ROGER REFURBISHMENT REPORT

Stearns-Roger
SERVICES INC.

June 26, 1979

Mr. John Koenig
The Pittsburgh & Midway Coal Mining Co.
1720 South Bellaire
Denver, CO 80222

Dear Mr. Koenig:

Reference: SRC-II Demonstration Plant
P&M/ET-78-C-01-3055
S-R Project C-21500
SR/PM Letter No. 79-146

Subject: Task 3, Power Station Refurbishment
Costs to Extend Its Productive Life
Gulf Mineral Resources
June 1979

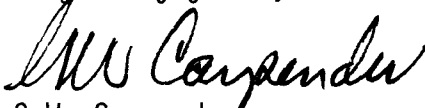
We are pleased to submit our report "Power Station Refurbishment Costs to Extend Its Productive Life", dated June 1979.

The report is self-explanatory and was developed without discussions with Baltimore Gas & Electric and Florida Power Corporation as previously planned.

If you have any questions concerning the above, contact either myself or Hugo Wangelin in our Denver office.

Thank you for your time and consideration.

Very truly yours,


G.W. Carpender

GWC:jdb

Enclosure

cc: R.B. Rice
H. Wangelin
C.E. Wysocki
R.B. Yale
C.E. File No.: 1.01
G.W. Carpender
(All with enclosure)

POWER STATION REFURBISHMENT
COSTS TO EXTEND ITS PRODUCTIVE LIFE
GULF MINERAL RESOURCES

Stearns-Roger Engineering Corporation

June 1979

C-21500, X00007

Phase 0 Task 3

FORWARD

As part of the subject Task 3, Gulf requested Stearns-Roger to develop the capital costs for refurbishing a thirty year old 400 MW fossil fired utility plant in order to extend its life another 15 years. This was to be a hypothetical plant built to today's standards and costs were to be developed in today's dollars.

Three sets of costs were developed as follows:

- (1) A 400 MW coal fired plant refurbished to fire coal for another 15 years.
- (2) A 400 MW coal fired plant refurbished to change from coal firing to oil firing for an additional 15 years.
- (3) A 400 MW oil fired plant refurbished to fire oil for another 15 years.

In order to accomplish this, certain assumptions had to be made. The primary assumption is that this is a unit in a well maintained plant where maintenance procedures have kept the plant in good condition which is normal procedure in the Utility industry today. The costs developed are not necessarily our time costs that occur at the beginning of the 15 year period but are costs over and above normal maintenance costs due to extending the life of the unit.

A description of this work and tables of costs are attached hereto.

OBJECTIVE

The objective of this study is to determine the estimated costs which could reasonably be expected to refurbish a hypothetical 30 year old 400 MW fossil fired electric generating plant in order to extend its productive life for an additional 15 year period. The hypothesis supposes that this plant is built to today's standards. Costs are based on today's dollars.

STUDY PARAMETERS

In the absence of having an actual unit to work with, certain assumptions had to be made to define the basis for the hypothetical plant as follows:

1. It is assumed that this plant is and has been an operable facility normally found in the electrical power industry.
2. It is also assumed that as an operating facility the maintenance of the equipment was again normal to the utility power industry in that the equipment when it has been maintained it was returned to "whole" or "as good as new" which is the normal maintenance philosophy of the electrical industry in as much as each unit is expected to operate for a period of 35 years.
3. Under the above conditions it is believed that a "sudden investment in refurbishment" is not called for. Rather, a continuation of normal scheduled and, at times, unscheduled, maintenance be continued only as necessary.
4. Consequently, the study was predicted on the following premises:

A. (Column #1)

Original design of the boiler was for coal only.

The costs shown in column No. 1 are for refurbishing the plant to extend its life for 15 years and continue coal firing.

The renewal of superheater and reheater loops will no doubt be necessary during the 15 year period.

The turbine will be overhauled at regular 5 year periods.

The mill overhaul will occur every time some 200,000 tons of coal is pulverized by each mill.

The bags will require replacement every 2-3 years with the present technology.

Turbine blades at the last stages will require replacement at least once during the 15-year period.

Condenser tubes will need to be replaced during the next 15 years.

Cooling towers will need a new fill during the 15 year period.

Fans (ID) will require rebuilding, whether the boiler continues on coal, or as the result of having been on coal prior to the new period.

High pressure heater banks will need re-tubing during the period under consideration.

Condenser tubing will need at least 50% replacement, especially in the air removal section.

Miscellaneous items will be refurbished as needed at the estimated costs shown in column No. 1.

B. (Column #2)

Original design of the boiler was for coal and now we wish to refurbish for use of SRC-II for the next 15 years. The same logic applies to each common item except such items as pulverizers, ash systems, sootblowers, etc., which would not be active when firing SRC-II. However, oil firing equipment would have to be installed.

C. (Column #3)

Boiler was originally designed for regular fuel oil and now it is to continue on SRC-II oil.

In addition to the reasoning applied to the major power plant equipment, the same considerations were given to each of the smaller cost items in determining the cumulative costs for each of the assumed parameters during the 15 year period under consideration.

As stated before, if this facility has been and is still operating the estimated costs and items requiring repairs or replacements would not all be performed at the initial phase of the 15 year period, but would be dispersed over several years except for such necessary items as oil burning equipment where there was none before as in case number 2 etc.

Table No. 1

BOILER ISLAND

	Original Boiler Coal Fired to Continue on Coal	Original Boiler Coal Fired to SRC-II Oil	Original Boiler Oil Fired to SRC-II Oil
	COAL	OIL SRC-II	OIL SRC-II
Retube SH Loops	50,000	50,000	50,000
Retube RH Loops	50,000	50,000	50,000
Burners - add oil burner equipment	----	700,000	----
Replace furnace seals	10,000	10,000	10,000
Rebuild Pulverizers	220,000	----	----
Coal Handling System (belts- crushers)	50,000	----	----
Soot Blowers 50% replacement	94,000	----	----
ID Fans rebuild rotor & cones	200,000	200,000	----
Air Heater replace cold end baskets	165,000	165,000	165,000
Air Compressors (Soot Blower) rebuild	12,000	----	----
Ash disposal piping + replace 5000 ft.	300,000	----	----
Ash hopper reline	50,000	50,000	----
Clinker grinders rebuild	10,000	----	----
Coal Scale Feeders belts and bearings	12,000	----	----
SO ₂ Scrubber Gen. Maintenance	200,000	----	----
SO ₂ Scrubber By-Pass	----	350,000	350,000
Baghouse New Bags	585,000	----	----
Rotary Dump Apron feeders Rebuild	20,000	----	----
Chimney Gunite Lining	135,000	135,000	135,000
SUB-TOTALS	2,163,000	1,710,000	760,000

Table No. 2

BALANCE OF PLANT

	Original Boiler Coal Fired to Continue on Coal	Original Boiler Coal Fired to SRC II Oil	Original Boiler Oil Fired to SRC II Oil
	COAL	OIL SRC II	OIL SRC II
D A Heater Replace Spray Valves	1,000	1,000	1,000
Stage Heater Retube HPs	282,000	282,000	282,000
BFP - Replace one rotor and seals	60,000	60,000	60,000
Cond. - Pump - Replace one rotor and seals	3,000	3,000	3,000
House Service Pumps - Replace one rotor and seals	3,000	3,000	3,000
Circ. Water Pumps - Replace one rotor and seals	35,000	35,000	35,000
Ash Pumps - replace two rotor	6,000	----	----
I.A. Compressors - rebuild	4,000	4,000	4,000
Main Turbine Replace last stage buckets	306,000	306,000	306,000
Main Turbine Rework incl. admission valves	500,000	500,000	500,000
Condenser retube 50%	825,000	825,000	825,000
Generator Retie winding	5,500	5,500	5,500
Generator Exciter brushes, rings, etc.	2,000	2,000	2,000
Cooling Tower - gear boxes - fill	920,000	920,000	920,000
Overhead Crane - New Cables	10,000	10,000	10,000
Demineralizer - replace resins	5,000	5,000	5,000
SUB-TOTALS	2,967,500	2,961,500	2,961,500
TOTALS	5,130,500	4,671,500	3,721,500

**GULF SCIENCE AND TECHNOLOGY COMPANY
PITTSBURGH, PENNSYLVANIA**

**THE MARKET OPPORTUNITY FOR SRC-II FUEL OIL
AS STATIONARY GAS COMBUSTION TURBINE FUEL**

P. G. COOPER

**CHEMICALS AND MINERALS DIVISION
REPORT NO. 633RK106
JULY, 1979**

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SECTION 1

PREFACE

The market opportunity for SRC-II fuel oil in electric utility applications is covered in two parts of this volume. Boiler fuel applications are covered in Part 2, while Part 3 covers use in gas combustion turbines and combined cycle units.

SECTION 2

SUMMARY

The method of generating base load and intermediate load electric power is expected to change with time, with base load generated increasingly from nuclear and coal units and use of petroleum and natural gas decreasing. Direct firing of coal will be used heavily in the near term but eventually new coal-related technology will be utilized such as high efficiency combined cycle units fueled with coal-derived liquid or gas fuels.

Technologies involving the use of coal or the conversion of coal to another fuel at the generating station site have a number of disadvantages from the electric utilities' point of view. In comparison with coal-derived liquid fuels such as SRC-II fuel oil in which the coal and all process wastes can be handled elsewhere, the above technologies involve the complexity and associated unreliability of handling solid fuel and solid waste, space requirements for the handling and storage of coal (and perhaps lime) and for the handling and disposal of solid waste, and the various environmental problems which complicate site selection and involve long lead times for obtaining permits and licenses. For some urban areas with severe environmental problems and limited space, these problems may rule out or severely limit consideration of any direct coal utilization technologies.

A detailed study has been completed on how the expected changes in electric utility systems may take place. In order to provide realistic results, the study was carried out in cooperation with four electric utilities, Boston Edison Co. (BE), Florida Power Corporation (FPC), Consolidated Edison Co. of New York (Con Edison), and Baltimore Gas and Electric Co. (BG&E). The data bases for the first two of these utility systems have been the basis for the study calculations and projections. To ensure the proper scope, the economic factors and operating parameters for present and developing technologies have been incorporated in a series of seven scenarios of utility system expansion and operation covering a study period of 1990 to 2010. With the aid of a subcontractor, Energy Management Associates, economic

system dispatch simulations and revenue requirement calculations were carried out for these seven scenarios and for the two utility system base cases.

The results of these studies indicate that some utilities in large eastern urban areas, i.e., New York City, Connecticut, and Boston, may use advanced technology combined cycle units which would be fueled with SRC-II fuel oil for almost all of the part of their base load not supplied by nuclear units and for most of their new intermediate load and peaking requirements. Most other utilities will use other coal technologies for non-nuclear base load, but will use combined cycle units for most of their intermediate load.

Comparison of scenarios in which SRC-II fuel oil fired combined cycle units would be used for system expansion with those in which coal with FGD or coal gasification units would be used shows the SRC-II fuel oil combined cycle units to have equal or better economics than the other technologies using coal directly. The higher cost of SRC-II fuel oil is offset by 1) the lower capital, operating, and maintenance costs; 2) the higher efficiency; 3) the higher reliability; and 4) the smaller unit sizes of the liquid fuel-fired combined cycle units.

The use of both coal gasification and SRC-II fuel oil fired combined cycle units in the same system was found to have potentially favorable economics compared to base case economics of using coal directly in boilers. Optimization of the interaction between the two technologies and achievement of the coal gasification capital cost goals mentioned in the literature would improve the economics of combined use further. However, the advantage is not expected to be large compared to exclusive use of SRC-II fuel oil fired combined cycle units. In addition to the siting and other problems mentioned above for the use of coal, coal gasification will involve the utility in a very complex chemical processing plant which up to now has been outside the realm of utility experience.

For utilities where coal gasification would be an attractive option, an interesting possibility would be to install the combined cycle units as peaking and intermediate load units and run them at first with SRC-II fuel oil. Later, when the base load need has grown to be large enough, coal

gasification units could be constructed and the combined cycle units converted to the low Btu gas. This would reduce the problem of having a large base load unit producing no revenue during construction and low revenue during the initial period of operation at low utilization.

A projection of the demand for SRC-II fuel oil as gas combustion turbine (GCT) and combined cycle (CC) fuel and of the total demand for eleven large east coast utilities has been derived from the simulations and analysis of the Boston Edison and Florida Power Corporation systems and from the studies of the Con Edison and BG&E systems. These projections are summarized by the following:

Potential SRC-II Fuel Oil Demand,
U.S. East Coast
(millions of barrels per year)

<u>Year</u>	<u>GCT and CC Fuel</u>	<u>Total Demand</u>
1990	84	244
1995	108	182
2000	131	177
2005	169	182
2010	186	193

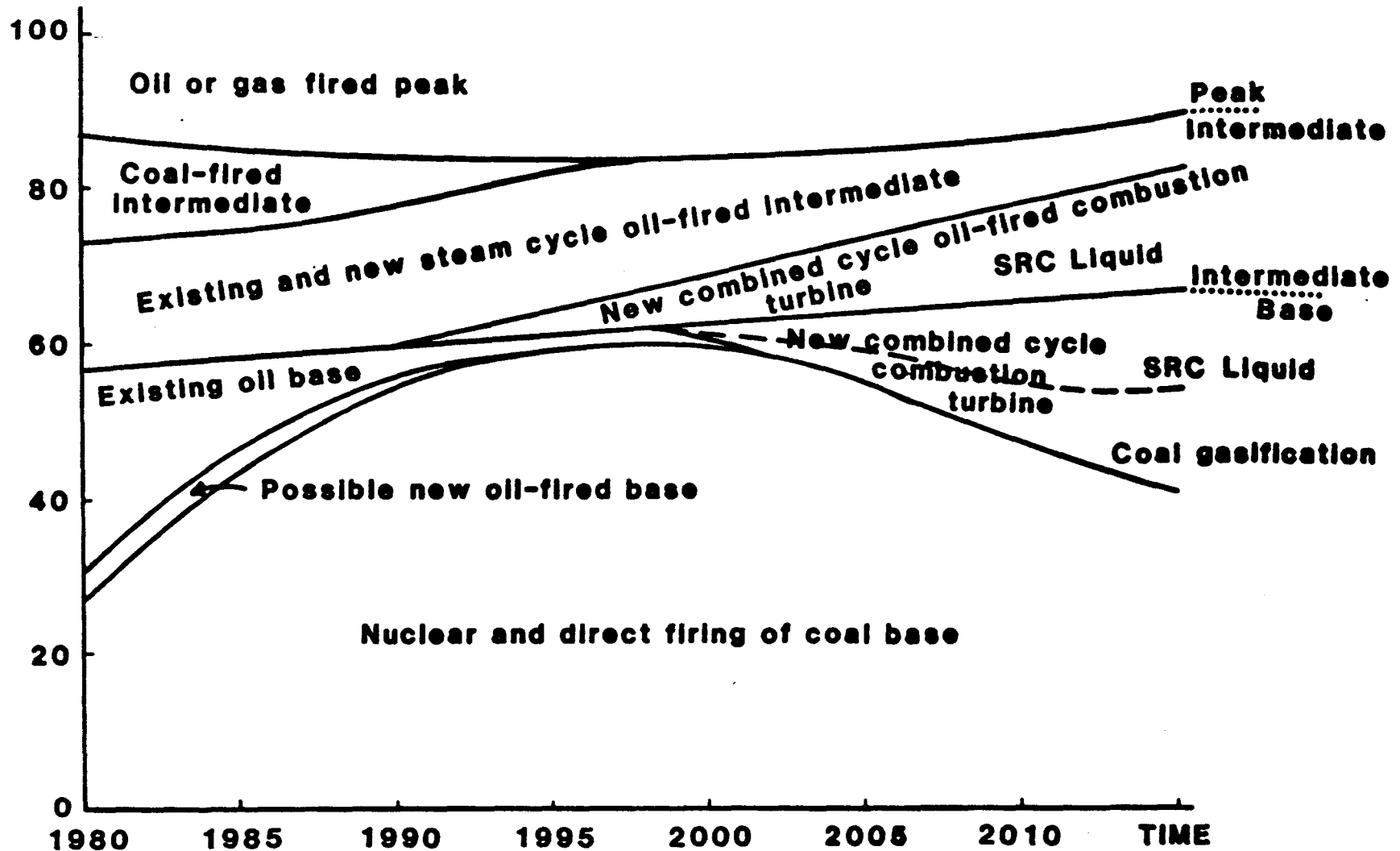
The potential turbine fuel market increases steadily from 84 million barrels per year (230,000 barrels per day) in 1990 to 186 million barrels per year (510,000 barrels per day) in 2010, thus offsetting the decline in the projected SRC-II boiler fuel market for utilities. Boiler fuel demand decreases rapidly during the first five years of the study period, with total demand also decreasing, due to the retirement of boiler units. Boiler fuel demand then decreases at a slower rate and total demand holds about constant as efficient combined cycle units with relatively low fuel requirements are installed. The net result is that total demand increases slightly toward the end of the study period.

An approximation of the SRC-II fuel demand for the U.S. (48 states) indicates that GCT and CC demand for the country will be about three times that for the east coast while total demand may be three to four times that for the east coast.

FIGURE 1

CONCEPTUAL COMPOSITION OF SYSTEM LOAD WITH TIME

Utilization of
Generating
Capacity, %



SECTION 3

INTRODUCTION

The technologies and fuels for electric power generation are expected to change more rapidly over the next several decades than in the recent past. The rapid increase in petroleum costs and the high costs of sulfur dioxide control by recently developed flue gas desulfurization (FGD) methods have interacted with and accelerated the development of improved or new generation technologies.

These trends are illustrated in Figure 1 which depicts how the various technologies and fuels will interact over the next three or four decades. Over the next decade, most new base load capacity will be nuclear and coal with FGD units although installation of some new liquid fueled fired steam boilers cannot be ruled out. Nuclear units will continue to be installed for base load but coal with FGD technology will be displaced by combined cycle combustion turbine units fueled either with low Btu gas or SRC-II fuel oil beginning around 1990 and becoming quite significant soon after.

Much of the intermediate load will be provided by currently existing liquid and solid fuel-fired boilers which will be downgraded from base load service. Combined cycle units (and possibly new steam boilers) fired with SRC-II fuel oil would be installed as needed to cover remaining growth in intermediate load. Peak load needs will be provided by smaller downgraded liquid fuel steam boilers and by combustion turbines and combined cycle units. A more detailed discussion of these interactions between current and developing technologies is given in the Introduction (Section 3) of Part 2 of this volume in which the use of SRC-II fuel oil in boilers is discussed.

This report describes the analyses of these complex trends which Gulf has carried out with the cooperation and assistance of the electric utility industry. In this, we have tried to shed some useful light on the way in which SRC-II fuel oil, a coal liquefaction distillate, can contribute to

supplying the electricity needs of the nation. In this Part, its use as a fuel in gas combustion turbines and in combined cycle units is emphasized.

The next Section gives a background summary on the combustion of SRC-II fuel oil in stationary gas turbines, especially in relation to environmental concerns. A discussion of environmental regulations which may affect the use of SRC-II fuel oil is contained in Part 2 of this volume (mentioned above) as Section 5.

Background information on advanced combustion turbine technology is given in Section 5 of this Part. Economic and operating parameters for combined cycle combustion turbine systems and competing technologies are discussed in Section 6. The economic dispatch and revenue requirement analyses for the Boston Edison Co. and Florida Power Corporation systems are covered in Section 7 and the turbine fuel demand projections for large East Coast utilities in Section 8.

SECTION 4

TURBINE FUEL COMBUSTION BACKGROUND

The purpose of this section is to provide a background summary of the information obtained and the conclusions drawn about the combustion of SRC-II fuel oil in stationary gas turbines.

4.1 SRC-II FUEL OIL PROPERTIES

The SRC-II coal liquefaction process is based on the discovery that recycled mineral matter from the coal catalyzes the liquefaction of coal. The fuel oil fraction is removed from the ash-laden reactor effluent stream by distillation instead of filtration as in earlier processes and the result is fuel oil containing very little ash, metals, or non-volatile fractions. SRC-II fuel oil resembles No. 2-5 fuel oils in its distillation range, viscosity, ash and sulfur content. Therefore, gas turbines or small boilers seemed to be an appropriate utilization of this fuel, as well as utility boilers, where coal could also be used.

SRC-II fuel oil is more aromatic (lower hydrogen content) and contains more nitrogen than comparable petroleum distillate fuels. Although the nitrogen could be removed with a hydrotreater added to an SRC-II plant, Gulf expects that such emissions resulting from fuel bound nitrogen will be more economically suppressed by new gas turbine combustor designs or post-combustion NO_x removal.

ASTM specification D2880 for stationary gas turbine fuels was examined for potential problems with SRC-II fuel oil use in turbines. The following fuel oil properties were found satisfactory: viscosity, flash point, heat of combustion, fuels compatibility, compatibility with materials of construction, and carbon residue. Although the low hydrogen content of SRC-II fuel oil leads to the expectation of the overheating of conventional combustor liners, the new low-emissions combustor designs are also solutions to this potential problem.

Through these preliminary considerations of SRC-II fuel oil properties, gas turbine fuel specifications and emissions regulations, NO_x and soot emissions and combustor liner overheating were identified as the greatest potential technical barriers to SRC-II fuel oil use in stationary gas turbines. In order to understand whether solutions to these problems would best come from advances in combustion equipment or from more intensive processing of SRC-II fuel oil, a review of the combustion chemistry behind pollutant emissions was conducted, of gas turbine combustor designs and their potential for emissions reduction, high temperature and advanced cycle turbines, post-combustion NO_x removal, and alternative fuels to coal liquids.

4.2 GAS TURBINE COMBUSTION CHEMISTRY

The suppression of NO_x formed by oxidation of molecular nitrogen (N_2) in the combustion air ("thermal NO_x ") in gas turbines has received extensive chemical and engineering study. The elementary chemical reactions involved are relatively simple and can be suppressed by reducing the peak flame temperatures occurring in the combustor. This has been successfully engineered and widely applied, being achieved by increasing the air/fuel ratio in the primary flame zone of the combustors, or by water injecting at a one-to-one water/fuel weight ratio. However, this approach suffers a trade of increased emissions of CO and unburned hydrocarbons.

The nitrogen chemically bound in fuel oil is converted to NO_x ("fuel- NO_x ") when oxygen is readily available in the flame; otherwise it converts to molecular nitrogen, N_2 . Fuel- NO_x formation in fuel oil flames in boilers has been suppressed successfully by excluding excess oxygen from the primary flame zone or first stage of the boiler, termed "staged combustion"; this also results in the formation of large amounts of CO, hydrogen and soot, since the flame is fuel-rich. Downstream admission of the rest of the combustion air readily consumes the CO and hydrogen, but care must be taken to assure oxidation of all the soot.

The N_2 formation process in the first stage (rich) and the soot oxidation process in the second stage (lean) both require the long residence times which exist in boilers, but which tend to be too short in gas turbine combustors. Nevertheless, detailed studies of the chemistry of these very complex reactions are revealing possible approaches to sufficiently accelerating them to make staged combustion in gas turbines effective (being termed "rich-lean" combustion in gas turbines). This work has shown that the suppression of fuel- NO_x is not very dependent on the types of nitrogen molecules in fuel, but is facilitated by rapid fuel vaporization and high temperatures in the fuel-rich zone. This suggests that SRC-II fuel oil is a favorable candidate for the rich-lean approach, especially because of its high volatility compared to, for example, the nitrogenous compounds in No. 6 residual petroleum fuel oil.

Soot emissions are the combined result of soot formation in the primary flame zone and subsequent soot burnout in the secondary zone. Many sub-steps have been found to be involved in the formation of soot particles. These include pyrolysis of the fuel molecules to precursors, most importantly aromatic molecules, which explains why aromatic (and thus low-hydrogen) fuels tend to produce more smoke, and also why hotter flames smoke more. Another soot-forming substep is the agglomeration of precursor molecules into soot particles, which explains why soot formation increases with combustor pressure. Although SRC-II fuel oil has the disadvantage of being highly aromatic, as are other coal-derived liquids, flame chemistry studies have suggested that the very highest boiling fractions of SRC-II fuel oil contribute to soot formation far out of proportion to their concentration.

Aircraft engine smoke emissions (most severe at low power) and high-power combustor liner overheating have been found to correlate very well with the hydrogen contents of the jet fuels, and jet fuel specifications have become based on hydrogen content, requiring at least 13.0% hydrogen. Aircraft-derived stationary power gas turbines, having smaller combustors than heavy-duty machines, may have a higher smoking tendency with aromatic fuels. They might, for example, require a lower distillation fraction of SRC-II fuel oil. Heavy-duty stationary gas turbines have been fired successfully with

fuels having low-quality viscosities and hydrogen contents (11% unofficially required) extensively during the last twenty years; however, in these cases suppression of fuel-NO_x was not attempted.

Some interesting observations of fuel-NO_x formation at gas turbine conditions had been obtained before coal liquids became available. The fraction of fuel-nitrogen converted to NO_x (the "fuel-NO_x yield") decreased to only 20-40% for the most nitrogenous (0.8%N) fuels, and in a very large single-combustor power turbine with an apparently fuel-rich primary zone, the fuel-NO_x yield was 5-10%. Faster fuel-air mixing, sometimes done in some designs in order to reduce smoke, and water injection, which reduces thermal-NO_x formation, both greatly increased the fuel-NO_x emissions. This empirical information from conventional combustors has been useful in seeking new design approaches.

4.3 GAS TURBINE COMBUSTOR DESIGN CONCEPTS

All new combustor design concepts to suppress fuel-NO_x incorporate a fuel-rich zone. Rich-lean concepts have been proposed since 1976, for example (among others), in the Westinghouse ECAS Phase II work and in a chemical kinetic modeling study of advanced cycle combustor concepts for ammonia-contaminated low-Btu gas for EPA by Energy and Environmental Research, Inc. (EER). This concept is embodied in a combustor configuration now widely known, which contains a rich primary reactor (fuel equivalence ratio $\phi = 1.3$, or 30% excess of fuel over air), a quick-quench section rapidly admixing the rest of the gas turbine dilution air and a CO burnout section. Substantial experimental success in implementing this configuration has been reported in an EPA project by Pratt & Whitney Aircraft Group; whose work utilized engineering methodology developed in their aircraft combustor design work. With No. 2 oil doped to 0.5% nitrogen as pyridine, the bench-scale combustor produced 75 ppm NO_x and acceptable CO using a variable-geometry air inlet vane to the primary reactor to keep the fuel/air ratio at $\phi = 1.3$ while the load was varied. The critical physical and chemical sub-processes occurring in this configuration have been modelled for the full-scale unit, which has been fabricated, and full-scale testing is now commencing.

Although in conventional combustors SRC-II fuel oil will produce higher liner temperatures than conventional fuels, particularly at the primary zone where most of the combustion is completed, these rich-lean designs distribute the heat-releasing combustion more evenly over the entire length of the combustor, and should prevent liner overheating when SRC-II fuel oil is used. This should obviate an otherwise important barrier to SRC-II fuel oil utilization in gas turbines.

Work by four or five gas turbine manufacturers as contractors in the DOE-NASA-Lewis "Low NO_x Heavy Fuel Combustor" program will begin in mid-1979. Since the rich flame principle will be widely utilized in this program, and since SRC-II fuel oil will be used in the testing, this program appears likely to successfully generate a low-emissions retrofittable combustor for coal-derived liquids (CDL). The program goal is for the combustor to also be capable of burning No. 6 oil cleanly and without operating problems. Such a design would then also be capable of burning SRC-II fuel oil cleanly.

In addition to the rich-lean concept, there have recently appeared other promising concepts for clean CDL combustion, which are described briefly in the following. Some of these approaches involve recirculation of some of the flame gas to the fuel injection area, an approach which would also benefit No. 6 oil burning. Heat removal by an external steam generator between the rich reactor and the quick quench zone is also proposed (by EER, Inc.) for suppressing thermal NO_x generation in the CO burnout reactor. Finally, honeycomb catalysts in the combustion chambers are being widely explored and could have certain benefits in rich flame reactor sections. The basic chemistry of soot formation, burnout and nitrogenous fuel combustion is receiving vigorous research, which should lead to further improvements in combustor design approaches.

Post-combustion NO_x removal appears to be a very viable and important alternative to low- NO_x combustors for solving the fuel- NO_x problem of SRC-II fuel oils, although the latter would be less expensive. In this process, ammonia is injected into the turbine effluent as it passes through a

honeycomb catalyst. This approach would be especially opportune in a combined cycle plant, where the catalyst would be installed in the heat recovery boiler. The operating and capital costs have been evaluated by a turbine manufacturer to be modest increments and EPRI is supporting some pilot-scale verifications of this approach.

Advanced cycles with increased thermal efficiency are expected to financially permit the consumption of more costly fuels which will be the case for SRC-II fuel oil and conventional fuels in the mid-1980's. Advanced cycle plants also present some unique opportunities for clean CDL combustion. One of these is ammonia injection NO_x removal. Another approach is the inter-stage heat removal outside the combustor, both mentioned above. Another possibility involves an auxiliary firing of the heat recovery boiler in a staged fashion to suppress NO_x from the nitrogen in both the gas turbine and boiler fuels. This has also been shown to be possible in repowering an existing boiler. Finally, combustors suppressing fuel- NO_x from CDL's can be compatible with the firing of ammonia-contaminated low-Btu gas.

4.4 PROSPECTS FOR SRC-II FUEL OIL IN GAS COMBUSTION TURBINES

SRC-II fuel oil is likely to make a good technical and economic fit into the future stationary gas turbine market, for a number of reasons:

- (1) The low viscosity and distillation range of SRC-II fuel oil meets the requirements of all stationary gas turbines.
- (2) Its content of corrosive trace metals is below present requirements.
- (3) The NO_x and soot emissions expected because of its nitrogen and aromatics content can be prevented. Basic combustion chemistry shows the potential effectiveness of fuel-rich combustion conditions in achieving low emissions.

- (4) On this basis, Pratt & Whitney has engineered and built a successful low-emissions combustor in an EPA-sponsored project.
- (5) Alternatively, NO_x removal from the flue gas by selective catalytic reduction will be feasible in most systems, if needed, but may have slightly higher costs.
- (6) High efficiency systems (high turbine inlet temperatures and advanced combined cycles) will offset the price of SRC-II fuel oil and, in addition, will provide unique opportunities for further emissions-suppression combustor technology.

SECTION 5

ADVANCED STATIONARY GAS COMBUSTION TURBINE TECHNOLOGY

5.1 BACKGROUND

Gas combustion turbines operate under the Brayton cycle which is similar to the Rankine cycle except that no change of phase occurs in the working fluid. The combustion air for the turbine system is compressed by an axial compressor driven by the system. After combustion takes place in a pressurized chamber, the hot gas mixture expands through an axial reaction turbine producing the power to both drive the desired load and to compress the combustion air. Typically, for a turbine with a 20,000 HP rating, air compression takes 80,000 HP, while the power turbine generates 100,000 HP, yielding a net power of 20,000 HP. As for any thermodynamic cycle, raising the temperature at which the driving energy is available increases ideal cycle efficiency. A relatively large amount of excess air is used in combustion of the turbine fuel to limit the combustion temperature and protect the metal system components from damage.

Considerable research and development effort is being expended on ways to permit raising the allowable turbine temperature (by lowering the excess air) and obtain higher cycle efficiency. Higher compression ratios (ratio of turbine inlet pressure to outlet pressure) also increase cycle efficiency if the inlet temperature is high enough, as indicated in Figure 3. At a given combustor temperature, increasing the compression ratio (by increasing the number of compressor stages) lowers the turbine outlet temperature which can be achieved since more gas expansion occurs. Lowering the temperature at which heat is "rejected" increases the ideal cycle efficiency since the difference between inlet and outlet temperatures have been increased.

Simple cycle combustion turbines (GCT) have been used extensively by electric utilities for peaking power generation. Improvements in operating

efficiency by increasing temperature and pressure of operation will not be sufficient to make GCT's suitable for intermediate or base load operation. However, a further large improvement in efficiency is obtained by using the waste heat in the turbine exhaust gas in a heat recovery boiler to generate steam for a steam turbine generator unit. This "combined cycle" has an excellent efficiency and is suitable for intermediate generation and, in some circumstances, for baseload generation.

5.2 PROJECTED DEVELOPMENTS IN TURBINE TECHNOLOGY

In a report prepared by Bechtel Power Corporation for the Electric Power Research Institute⁽¹⁾ it is stated that "the present generation of industrial utility turbines operate at a 10:1 compression ratio and a 2000°F turbine inlet temperature." The heat rate corresponding to these conditions for a combined cycle unit is about 8400 Btu/kWh (higher heating value). In a section on projected future technology, Bechtel discusses the desirability of going to a higher inlet turbine temperature and higher compression ratio. Increasing the turbine inlet temperature to about 2400°F lowers the turbine heat rate. Further increases in temperature have little effect on heat rate but increase the capacity of the machine, thereby lowering capital costs. Increasing the turbine compression ratio also lowers the heat rate and for temperatures of 2400°F or above, improvements are still being obtained up to and beyond the 25:1 compression ratio point. These effects are illustrated in Figures 2 and 3 taken from the Bechtel study. Studies of advanced combustion turbine technology⁽²⁾ assume a turbine inlet temperature of 3000° and a compression ratio of 16:1. The Bechtel study projected a heat rate of 6400 Btu/kWh (lower heating value) for a combined cycle unit for 1990, assuming a 3000°F inlet temperature (Figure 4).

(1) Bechtel Power Corporation, "Combined Cycle Power Plant Capital Cost Estimates," EPRI Report AF-620, December 1977.

(2) "Comparative Study and Evaluation of Advanced Cycle Systems," General Electric Company, EPRI Report AF-664, February 1978.

Evaporative water cooling⁽²⁾ of the turbine components or advanced air cooling⁽³⁾ are expected to allow this high inlet temperature to be achieved. Such cooling could keep the surface temperature of the components as low as 1000°F, substantially lessening the rate of hot corrosion and possibly eliminating it⁽⁴⁾. This will allow the use of a low cost alloy for the core of the turbine buckets with only a cladding of nickel base alloy required. Therefore, going to the higher turbine inlet temperature in units employing advanced design concepts such as these may not require large amounts of exotic materials for the construction of the machines. This, combined with the higher capacity achieved by the higher temperature and compression ratio, tends to lower the capital cost of these machines according to projections given⁽²⁾. See Figure 3.

The Department of Energy is sponsoring a High Temperature Turbine Technology development program. Two of the participants, General Electric⁽⁵⁾ and Curtiss-Wright,⁽⁶⁾ were contacted to determine the status of this program. The main objective at present is to develop turbines suitable for low Btu gas generated from coal. However, a capability to use coal liquids as the turbine fuel is a secondary objective and much of the work on gas is applicable to coal liquids service. Demonstration runs with a prototype turbines or "technical readiness vehicles" are scheduled for the period 1980 to 1985. It is expected that commercial high temperature turbines will be available around 1990.

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- (3) "A High Temperature Turbine for Operation on Coal Derived Fuel," V. M. Mogul, et al., ASME paper 79-GT-173, San Diego, March 1979.
 - (4) "Overall Plant Design Description Coal Derived Liquid Electric Power Plant," Department of Energy Report No. FE-1806-24, July 1977 (General Electric Company).
 - (5) Personal communication from J. W. Hickey, General Electric Co., Schenectady, NY, to R. C. Amero, Gulf R&D Co., Harmarville, PA, June 21, 1979.
 - (6) Personal communication from T. R. Koblish, Curtiss-Wright Co., Wood-Ridge, NJ, to P. G. Cooper, Gulf R&D Co., Harmarville, PA, June 17, 1979.

Curtiss-Wright currently has designs for combined cycle systems with a heat rate of 7200 Btu/kW (lower heating value) which they feel they would be able to guarantee.⁽⁷⁾ Westinghouse projects a heat rate of 6966 Btu/kWh (higher heating value) for a liquid fuel combined cycle power plant being developed in the High Temperature Turbine Technology program.⁽⁸⁾

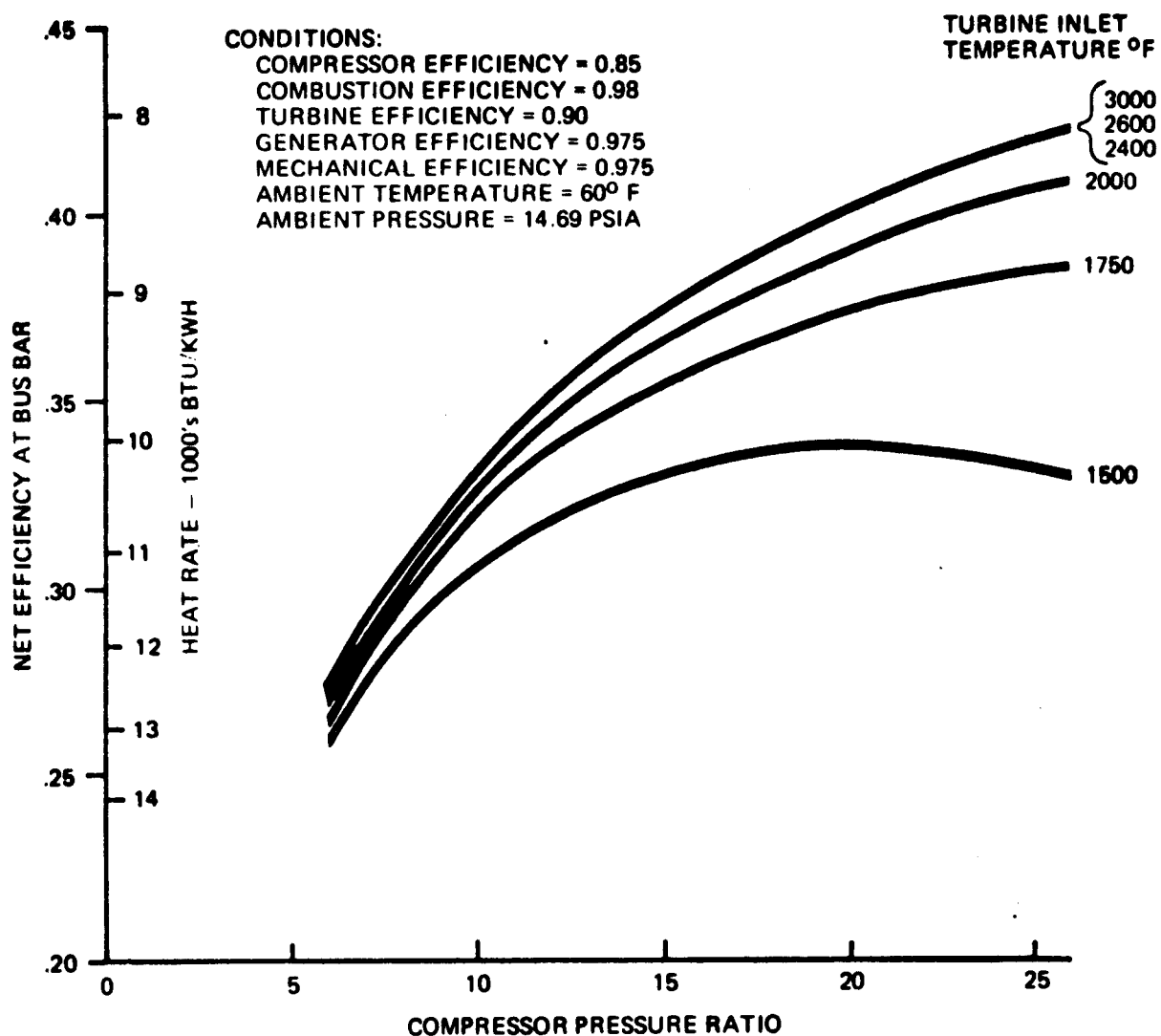
General Electric projects a capital cost of \$343/kW (1979 \$) for an advanced (high temperature and high compression ratio) combined cycle system using a liquid fuel. This figure includes catalytic destruction of nitrogen oxides in the stack gas.⁽⁹⁾ A capital cost of around \$400/kW has been assumed in this study.

The projected improvements in heat rate and the relatively low, possibly decreasing, projected capital cost for gas combustion turbines in combined cycle units will make this type of unit very attractive economically. While a relatively expensive liquid fuel will be required, the low heat rate offsets this to a large degree and the low capital cost provides another substantial offset.

(7) Op. cit., July 5, 1979.

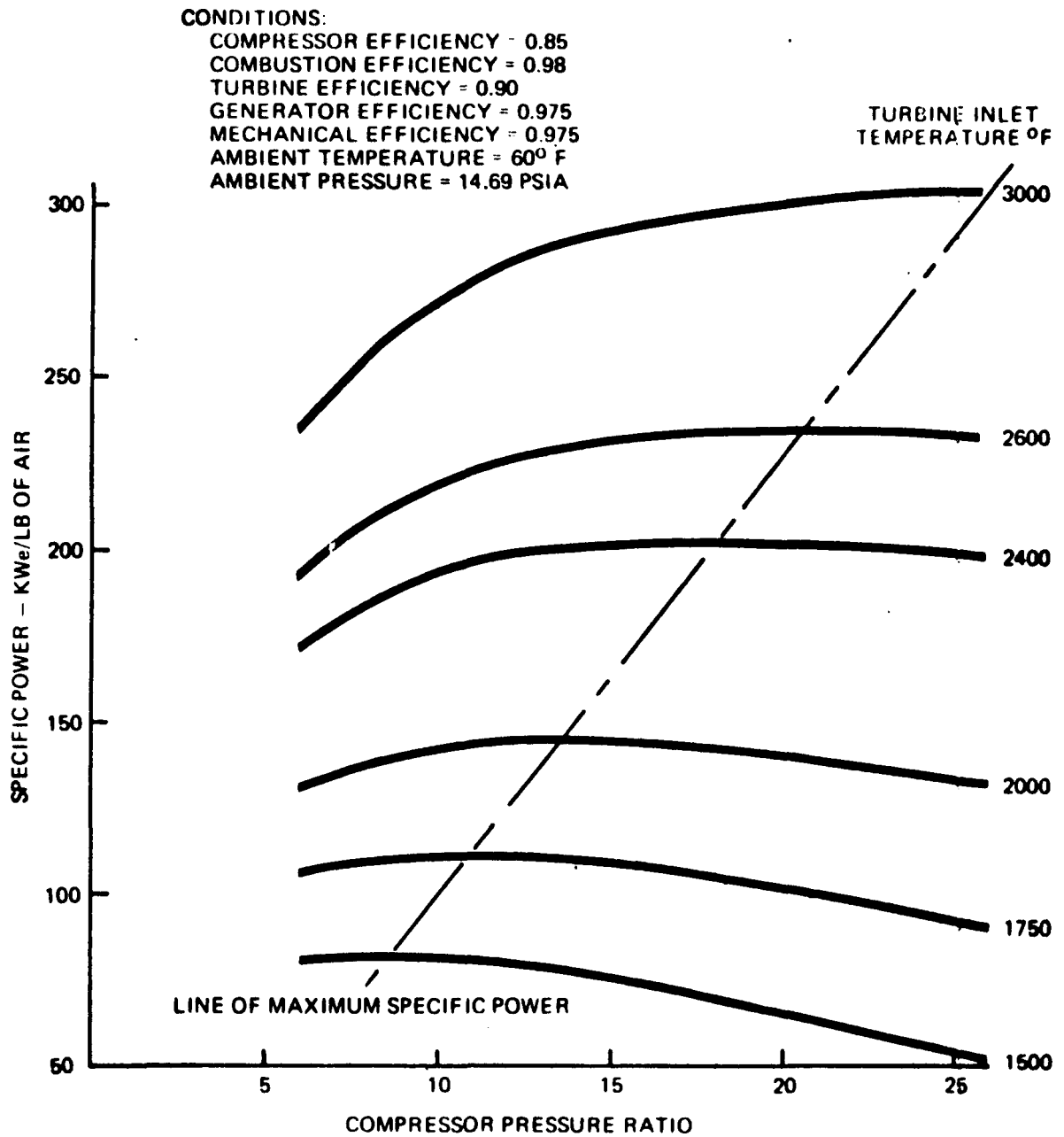
(8) R. E. Strong, "Combined Cycles for Operation on Coal Derived Fuels with High Temperature Combustion Turbines," ASME paper 77-WA/Ener-14, Atlanta, GA, November 27-December 2, 1977.

(9) Personal communication to P. G. Cooper by D. M. Todd, Gas Turbine Division, General Electric Company, Schenectady, NY, June 25, 1979.



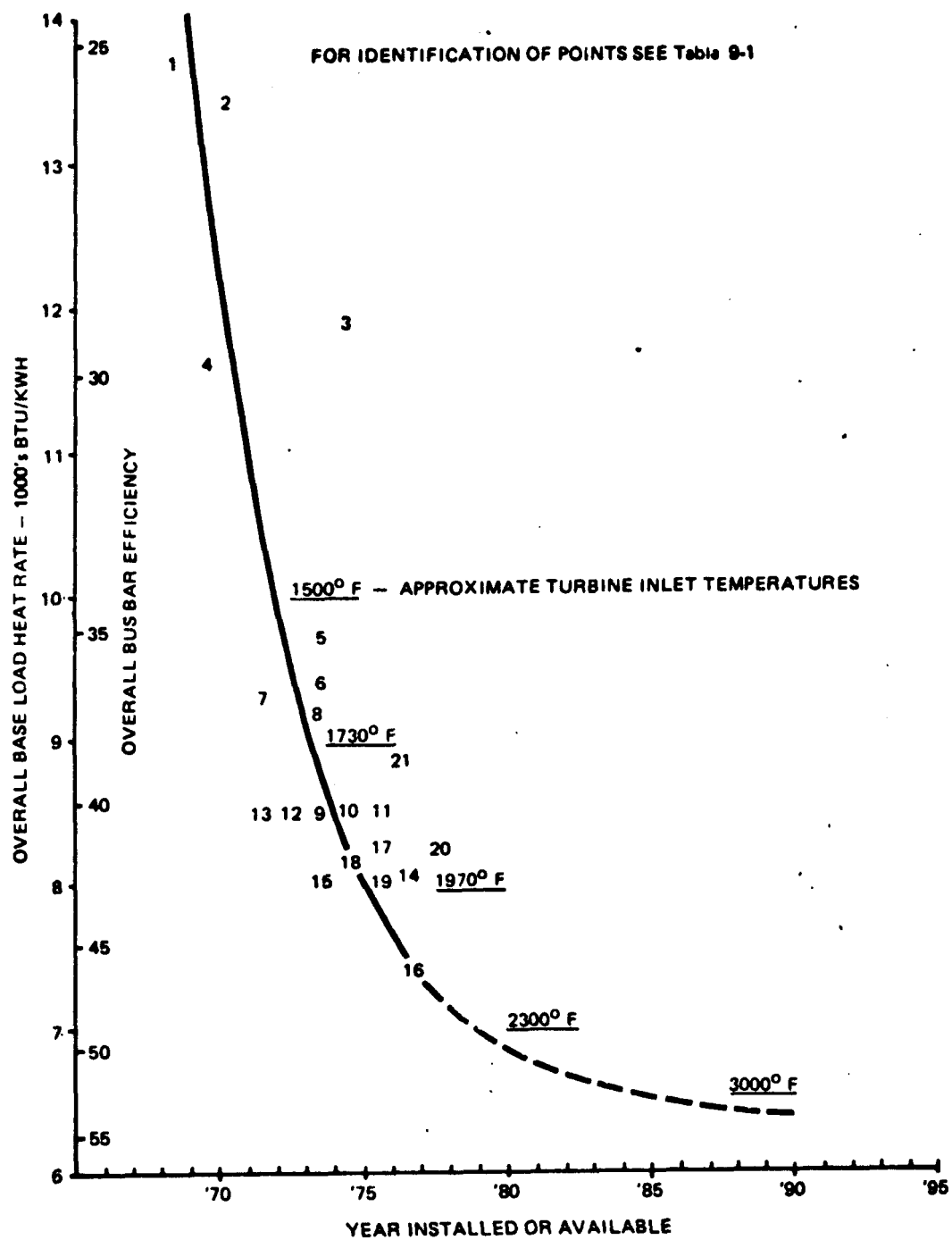
SIMPLE OPEN-CYCLE GAS TURBINE NET EFFICIENCY VARIATION WITH COMPRESSOR PRESSURE RATIO FOR VARIOUS TURBINE INLET TEMPERATURES

Figure 2



SIMPLE OPEN-CYCLE GAS TURBINE SPECIFIC POWER VARIATION WITH COMPRESSOR PRESSURE RATIO FOR VARIOUS TURBINE INLET TEMPERATURES

Figure 3



TREND OF COMBINED-CYCLE HEAT RATES

Figure 4

SECTION 6

STATIONARY GAS COMBUSTION TURBINE CAPITAL AND OPERATING COSTS AND OTHER SYSTEM DESIGN FACTORS

6.1 ECONOMIC AND OPERATING FACTORS

The critical economic and operating factors used in this study for new combustion turbine and combined cycle units are given in Table 1. These data are derived from units designed for the combustion of petroleum. Combustion turbine manufacturers have indicated that design modifications required for SRC-II fuel oil combustion will be minor and will not raise the unit cost. The data are shown for three time periods with the values selected from various sources, and in some cases interpolated, to reflect the expected technological improvements in this field. The capital costs are adjusted for regional construction cost differences based on a study by Bechtel.⁽¹⁾

6.2 ADVANTAGES OF GAS COMBUSTION TURBINES

SRC-II fuel oil burning combined cycled gas combustion turbines have both a primary, and a potential, financial advantage for electric utilities. First of all, the capital cost per unit of capacity for these units is expected to be substantially lower than that for almost any other future technology. For example, the cost will be one-half to two-thirds of that for a unit involving coal gasification integrated with combined cycle gas combustion turbines and will be about one-third of that for units burning coal with flue gas desulfurization.

A less general but still potentially important advantage is the adaptability of these units to installation of relatively small increments of capacity. The merit of this and the strategy involved will depend upon the

(1) Bechtel Power Corporation, "Combined Cycle Power Plant Capital Cost Estimates," EPRI Report AF-620, December 1977.

TABLE 1-A

**ECONOMIC AND OPERATING FACTORS FOR NEW INSTALLATIONS
COMBUSTION TURBINE AND COMBINED CYCLE UNIT SPECIFICATIONS
1978 \$**

	<u>1985-1990</u>	<u>1990-2000</u>	<u>2000-2010</u>
Capital Cost, \$/kW^(1,2)			
Northeast (Boston Edison)	396	388	372
Southeast (Florida Power Corp.)	357	351	336
Operating and Maintenance Cost⁽²⁾			
Fixed, \$/kW-week	0.025	0.025	0.025
Variable, mils/kWh	1.40	1.40	1.40
Heat Rate, Btu/kWh	8070 ^(a)	6900 ^{(1)*}	6400 ^{(1)*}
Planned Outage, % of time	10	10	10
Forced Outage Rate, % of time not on planned maintenance (mature)^(3,4)	9.2	6.3	6.3
Unit Capacity, MW			
4 Combustion Turbines @ 64 MW	192	—	—
1 HRSG ^(b) @ 109 MW	109	—	—
Total	<u>365</u>	—	—
3 Combustion Turbine @ 190 MW	—	570	570
1 HRSG ^(b) @ 276 MW	—	276	276
Total	—	<u>846</u>	<u>846</u>
Combustion Turbine Characteristics			
Heat Rate, Btu/kWh	11,310 ^(c)	9450	8950
Capital Cost, \$/kW	297	297	297
Forced Outage Rate, ⁽⁴⁾ %	7.9	5.9	5.9

(a) GE Model STAG 407E, higher heating value

(b) Heat recovery steam generator

(c) GE Model PG-7981 Turbine

(*) Lower heating value

(1) Op. cit.

(2) "Comparative Study and Evaluation of Advanced Cycle Systems," General Electric Company, EPRI Report AF-664, February 1978.

(3) "Market Potential for New Coal Technologies," Dwain Spencer and Oliver Gildersleeve, EPRI J., May 1978, pp. 19-26.

(4) "Pricing Scenario for Coal-Derived Synthetic Fuels for Electric Utilities," EPRI, April 24, 1979, Stanley Vejtasa and Oliver Gildersleeve.

Table 1-B
Combined Cycle Component Capital Costs

\$1979

Current Technology (Use for Case BE-1 (only) throughout study period)

	<u>\$/kW</u>
64 MW combustion turbines	320
109 MW HRSG*	688
365 MW combined cycle unit	430

Advanced Technology (Use for Cases FPC-2, FPC-3B, and BE-3)

<u>Time Period</u>	<u>Region</u>	<u>Combustion Turbine</u>		<u>HRSG*</u>		<u>Combined Cycle Unit</u>	
		<u>MW</u>	<u>\$/kW</u>	<u>MW</u>	<u>\$/kW</u>	<u>MW</u>	<u>\$/kW</u>
1985- 1990	NE	64	318	109	683	365	427
	SE	64	287	109	616	365	385
1990- 2000	NE	190	296	276	669	846	418
	SE	190	268	276	605	846	378
2000- 2010	NE	190	284	276	641	846	401
	SE	190	257	276	579	846	362

*Heat recovery steam generator.

size of the utility, its growth rate, and its relative amounts of base, intermediate, and peaking load. For example, a large growing utility with a relatively high peaking power requirement might install one or two 190 MW combustion turbines for peaking with the intention of very soon adding a heat recovery steam generator and then a third combustion turbine a little later. Thus, the simple cycle units will be converted to a combined cycle unit with a total capacity of 846 MW, suitable for intermediate or base load operation. A small utility or one with a low growth rate might install just one combustion turbine and then later, depending upon the need for peaking or for efficiency, might add a second combustion turbine or the heat recovery steam generator, possibly adding a third combustion turbine before finally adding the heat recovery unit.

Therefore, a utility can maintain the utilization of its generating system at a relatively high level, avoiding the financial burden of excess generating capacity over that needed to meet reliability criteria. Combustion turbine or combined cycle capacity can be installed for base, intermediate, or peaking requirements shortly before need. Plans can be altered easily and more frequently, reducing the risks of planning many years into the future. At the same time, there is no substantial loss of economy of scale or of efficiency.

The operation and maintenance expense for a combined cycle unit using SRC-II fuel oil is expected to be relatively low (exclusive of fuel costs) compared to other coal alternatives for generating electric power. The use of a low sulfur liquid fuel containing virtually no ash and with a convenient viscosity will make it possible for these systems to be relatively simple compared to direct coal or coal gasification alternatives. Besides yielding low operating and maintenance costs, these same characteristics will contribute to good unit reliability with forced outage rates expected to be about 6% of time not on planned maintenance and planned maintenance about 10% of the year.

Combined cycle gas combustion turbine units using SRC-II fuel oil also are attractive because of favorable system reliability effects and

relative ease of site selection. They can be located close to the load (which improves system reliability) because they require relatively little area, are modular in nature, have minimal emission problems, and have a low cooling water requirement. In addition, they do not require as much fuel storage area and handling space as for a coal using unit or for the waste handling for the ash and FGD or atmospheric fluidized bed wastes. Many of these same factors will make these systems a contender for base load applications even where a simple economic comparison would favor other technologies. For intermediate and peak load applications, quick startup capability and load response characteristics are favorable compared to, for example, coal with FGD or coal gasification integrated with combustion turbines.

6.3 COMPARISONS WITH COAL AND NUCLEAR PLANTS

Economic and operating factors for electric power plants based on coal or nuclear fuel are given in Table 2 for comparison with gas combustion turbine units. Nuclear power plants are included only for completeness. It is generally recognized that the cost of electricity from a nuclear generating plant is less than that from any other technology. Nuclear plants are always designed for base load applications. The high investment and the long lead times required for construction of a nuclear facility usually make it impractical for a utility to depend completely upon nuclear technology for their base load capacity expansions. For this reason, a number of other technologies have been reviewed recently for base load application.⁽²⁾ These include magnetohydrodynamics and closed cycle gas turbines using helium or carbon dioxide as the working fluids. Some of these show promise for the future, but the technologies given in Table 2, coal with flue gas desulfurization, coal gasification integrated with combined cycle, and coal burned in an atmospheric or pressurized fluidized bed, are the ones which seem to have the best near-term potential.

In the case of the firing of coal with flue gas desulfurization, the capital cost is about twice that for liquid fuel fired combined cycle systems. For the utilization of coal in gasification or in fluidized beds, the capital costs given in the literature cover a broad range and are from 35% to 80%

Table 2

ECONOMIC AND OPERATING FACTORS FOR NEW INSTALLATIONSELECTRIC POWER PLANTS, COAL OR NUCLEAR FUEL
1978 \$

	<u>Coal Plus FGD</u>	<u>Coal Gasification Integrated with Combined Cycle</u>	<u>Nuclear</u>	<u>Atmospheric Fluidized Bed</u>	<u>Pressurized Fluidized Bed</u>	
Costs						
Capital, \$/kW						
Northeast		958	590-868	960	620-785	585-898
Southeast		761	544-801	867	589-623	539-714
Operating and Maintenance,						
Variable, mils/kWh						
Northeast		5.2	2.6	0	4.6	4.6
Southeast		3.7	2.6	0	3.0	3.0
Fixed, \$/kW-week						
Northeast		0	0.22	0.19	0.03	0.03
Southeast		0	0.22	0	0.03	0.03
Operating Parameters						
Heat Rate, Btu/kW,		9500	7760-8610	9750-11,360	9190	8720
Higher Heating Value						
Planned Outage, % of year		10	10	12	10	-
Forced Outage Rate, % of time not on planned maintenance		13	11	15	9	-
Unit Size, MW		2 @420 (840)	1200	1000	814	904

higher than liquid fuel fired combined cycle systems. Operating and maintenance (O&M) costs are not a decisive factor for any of these technologies. However, all of the technologies involving direct use of coal have relatively high O&M costs compared to liquid fuel fired systems and those systems using limestone to capture the sulfur in the coal, such as atmospheric and pressurized fluidized beds, are all assumed to have higher operating and maintenance costs than coal gasification in which the sulfur is produced as a by-product. This reflects the high cost of disposing of the large volumes of waste for processes utilizing limestone.

The heat rate for liquid fuel fired combined cycle units is expected to improve with time as shown in Table 1. Typical or projected heat rates for other technologies are shown in Table 2. The values for combined cycle units run about 65 to 85% of the other technologies. The relative simplicity and reliability of a liquid fuel system is reflected in the 6.3% forced outage rate for the combined cycle units compared to the 9-13% values for the units utilizing coal. While the cost of a liquid fuel such as SRC-II fuel oil will be considerably higher than the cost of a coal fuel, this expense will be largely offset when SRC-II fuel oil is used in combined cycle units due to their lower capital cost, lower operating and maintenance cost, superior heat rate, and lower forced outage rate.

The heat rates given for the combined cycle liquid fired units are based on the liquid fuel itself and do not reflect the approximately 75% efficiency of the coal liquefaction plant. Also, it should be noted that the values given in Table 1 for the periods 1990 to 2000 and 2000 to 2010 are based on lower heating value of the fuel whereas all the other heat rates are based on higher heating values. The difference between higher heating value and lower heating value is not as large for SRC-II fuel oil as it is for petroleum fuels (4.7% vs 5.7% to 6.9%) due to the lower hydrogen content of SRC-II fuel oil. This small difference would not significantly affect any of the conclusions of this study.

Table 3

FLUE GAS DESULFURIZATION (FGD) COSTS FOR COAL FIRED ELECTRIC POWER PLANT

1978 \$

Capital Cost, \$/kW

Northeast	187
Southeast	152

Operating and Maintenance,
mils/kWh

Main FGD unit	
Northeast	2.0
Southeast	2.0
Sludge Disposal	
Northeast ^(a)	2.4
Southeast ^(b)	0.8

-
- (a) Truck 30 miles to landfill
 (b) On-site landfill

SECTION 7

SYSTEM ANALYSIS OF BOSTON EDISON CO. AND FLORIDA POWER CORPORATION

7.1 DESCRIPTION OF STUDY

The Boston Edison Company (BE) of Boston, Massachusetts, and the Florida Power Corporation (FPC) with headquarters in St. Petersburg, Florida, participated in the market opportunity study for east coast electric utilities by allowing their systems to be used for detailed studies of how SRC-II fuel oil would be used by an actual utility, and how it would compete with other fuels such as coal or low Btu gas generated from coal in meeting the needs of actual electric utilities. The generation expansion plans for BE and FPC are given in Tables 4 and 5.

7.2 DISCUSSION OF INTEREST IN GAS COMBUSTION TURBINES OR GAS COMBUSTION TURBINES IN COMBINED CYCLE SYSTEMS FOR THESE UTILITY SYSTEMS

The current Boston Edison system includes one nuclear unit with the rest of the system being based on petroleum fuels. These units consist of oil-fired boilers and combustion turbine peaking units. BE believes that the construction and operation of coal fired units for their system would be very difficult. For the near term, they expect to expand capacity by the construction of a second nuclear unit. For the study period of 1990 to 2010, they project the addition of two more nuclear units supplemented by the addition of combustion turbines and combined cycle combustion turbine systems. The combustion turbines will be added as needed for peaking and then integrated into combined cycle systems as the need for intermediate and base load grows. At the end of the study period, they expect to have nine 365 MW combined cycle systems.

On the other hand, the FPC system includes both coal and oil burning units; their current expansion plans are heavily dependent on the use of coal. The units currently burning coal are two 400 MW units at their Crystal River site which were originally constructed to use oil but now have been converted to coal. They have one nuclear unit, also located at Crystal River, and they

Table 4

GENERATION EXPANSION PLAN - BOSTON EDISON COMPANY

The following numbers of new units are on line:

	64 MW	365 MW ¹	690 MW ²
As of November of:	<u>Gas Combustion Turbines</u>	<u>Combined Cycle Units</u>	<u>Nuclear Units</u>
1989	0	0	0
1990	1	0	0
1991	4	0	0
1992	1	1	0
1993	3	1	0
1994	0	2	0
1995	0	2	1
1996	0	2	1
1997	3	2	1
1998	0	3	1
1999	3	3	1
2000	0	5	1
2001	4	5	1
2002	2	6	1
2003	0	7	1
2004	0	7	2
2005	0	7	2
2006	3	7	2
2007	1	8	2
2008	4	8	2
2009	2	9	2
2010	(a s s u m e n o c h a n g e)		

¹ Four gas combustion turbines and one heat recovery steam generator.

² These units are 60% of 1150 MW jointly owned units.

³ Extrapolated at 3.3%.

Note: The Pilgrim II nuclear unit is expected to come on line in December of 1985. Boston Edison will own 60% of this 1150 MW unit. No other changes to the current system are planned until 1990.

Table 5

GENERATION EXPANSION PLAN -
FLORIDA POWER CORPORATION

<u>Year</u>	<u>Size Addition, MW</u>	<u>Type</u>
1980	150	Combustion Turbine
1981	300	Combined Cycle
1982	670	Coal
1983	100	Combustion Turbine
1984	670	Coal
1985	660	Coal
1986	--	--
1987	660	Coal
1988	--	--
1989	660	Coal
1990	--	--
1991	--	--
1992	780	Nuclear
1993	--	--
1994	780	Nuclear
1995	--	--
1996	800	Coal
1997	--	--
1998	800	Coal
1999	--	--
2000	--	--
2001	800	Coal
2002	--	--
2003	--	--
2004	800	Coal
2005	--	--
2006	--	--
2007	800	Coal
2008	--	--
2009	--	--
2010	800	Coal

are currently constructing two additional coal units at the same site. A combustion turbine peaking unit is planned for the year 1980 and another for 1983.

Two additional coal units of 660 MW capacity are planned for a new central Florida site in the 1987-1989 period. During our study period of 1990 to 2010, two 780 MW nuclear units and six 800 MW coal burning units are planned. Since FPC's expansion plan does not show any installation of combustion turbine capacity during the study period, the question is whether this plan is likely to change if the performance and cost factors for combustion turbines and combined cycle combustion turbine systems develop as projected. Florida Power is definitely interested in this possibility. Their particular interest would be for intermediate and peak load service.

7.3 METHOD OF ANALYSIS

The market opportunity for SRC-II fuel oil in gas combustion turbine applications has been analyzed in detail, using the two utility systems discussed above to provide a realistic basis for the analysis. A representative set of current technologies and developing technologies for electric power generation have been selected, and the most reliable and consistent possible set of economic factors and operating parameters for all these technologies have been assembled from the current literature. The simulations of the utility systems and the analysis were then carried out as described in Section 9 of Part 2 of this volume, "The Market Opportunity for SRC-II Fuel Oil as Utility Boiler Fuel."

Based on the results of the above analysis and on a number of non-economic considerations, the most likely scenario for each utility has been selected. The fuel usage indicated by these most likely scenarios has then been used as a basis for the projection of the market opportunity for SRC-II fuel oil for eleven large east coast utilities. The fuel use patterns for the two utilities have been compared to the projected load and energy for the eleven utilities and their projected use of the various fuels to arrive at a

reasonable market opportunity estimate for the use of SRC-II fuel oil as a turbine fuel.

7.4 DISCUSSION OF RESULTS

The first study of gas combustion turbine use in an electric utility system was for the Boston Edison Company (BE) generation expansion plan. This plan, shown in Table 4, assumes that expansion will be accomplished with nuclear units and with liquid fueled gas combustion turbines and combined cycle units. The Pilgrim II nuclear unit is expected to come on line in December of 1985. No other changes to the current system are planned until 1990. One combustion turbine is added in 1990, three more in 1991, and one in 1992, with the four previous combustion turbines being incorporated into a 365 MW combined cycle unit in 1992. This process of installing combustion turbines and converting them to combined cycle units continues throughout the study period, pausing only when nuclear units are added in 1995 and 2004.

7.4.1 Boston Edison Base Case and Scenario 1

In this BE base case scenario, it is assumed that petroleum fuels are used throughout the study period. Petroleum prices were projected by Gulf. See Appendix A of Part 2 for a discussion of fuel prices. Boiler units were fired with residual fuel oil (No. 6) and combined cycle and combustion turbine units were fired with No. 2 fuel oil. Next, in BE Scenario 1 SRC-II fuel oil was substituted for all petroleum fuels. The Gulf projected SRC-II fuel oil price and the heating value for SRC-II fuel oil were substituted into the data base used in BE's base case. SRC-II fuel oil was used for boiler units and also for combustion turbines and combined cycle units. The capacities and heat rates of the combustion turbines and combined cycle units used in the Boston Edison's base case expansion plan are based on currently available General Electric units. This is a conservative assumption since it is expected that larger units with improved heat rates will be available in the future.

In the BE base case, the requirement that the combustion turbine units and the combined cycle units utilize the more expensive No. 2 fuel oil causes the economic dispatch program to run the boiler units (which utilize the less expensive No. 6 fuel oil) at a high capacity factor. Thus, the combined cycle units run at only an average of 31% capacity factor in 1995 and 2000 for the base case (Table 6), while in Scenario 1 where SRC-II fuel oil is used in both boilers and combined cycle units, the combined cycle average capacity factors are 51% for 1995 and 40% for 2000, with the boiler usage dropping proportionately. This difference does not appear in 2005 and 2010 because of the planned retirement of boiler units and the continued addition of combined cycle units. The latter dominate the intermediate load operation for the utility in this period.

The amount of SRC-II fuel oil used in 1990 is very slightly higher than the barrels of oil used in the base case due to the somewhat lower heating value of SRC-II fuel oil compared to petroleum fuels. The actual number of BTU's used is lower due to the higher usage of the more efficient combined cycle units in Scenario 1. In 1995 and after, the volume of SRC-II fuel oil drops significantly below the volume of oil that was used in the base case. Under the price projections assumed in this study, electricity production costs are higher when using SRC-II fuel oil than when using petroleum fuels until 1998. However, as the study was being brought to a conclusion oil prices rose to a level considerably above that which had been projected for this study. In addition an independent consultant has provided us with price projections for oil indicating that crude will cost \$30.00/barrel (1979 dollars) in the early 1990's. Thus petroleum fuel will probably cost more than SRC-II fuel oil before 1990.

Levelized revenue requirements (LRR) for the Boston Edison base case were calculated using the low estimate of petroleum fuel costs, giving a value of \$211 million. The LRR for Scenario 1 is \$217 million or only 3% over that for the base case (Table 7).

Table 6

SUMMARY OF SCENARIO RESULTS FOR
BOSTON EDISON COMPANY

(\$ in millions)

	<u>1990</u>	<u>1995</u>	<u>2000</u>	<u>2005</u>	<u>2010</u>
ANNUAL RESULTS FOR					
<u>BE Base Case:</u>					
Production Costs	582.2	1016.2	1682.5	2319.2	3849.8
Oil (1000 Bbls/yr)	12841	14616	14559	13629	18606
Combined Cycle Capacity Factor	N/A	31%	31%	36%	39%
<u>BE Scenario 1:</u>					
Production Costs	753.3	1102.9	1535.8	2047.7	3433.1
SRC-II (1000 Bbls/yr)	12849	14314	14182	13035	17768
Combined Cycle Capacity Factor	N/A	51%	40%	36%	39%
<u>BE Scenario 2:</u>					
Production Costs	753.3	989.0	1365.1	1679.0	2773.8
Coal (1000 Tons/yr)	N/A	1429	1936	3233	4753
SRC-II (1000 Bbls/yr)	12849	9775	7972	2544	2396
Cycling Coal Capacity Factor	N/A	47%	39%	31%	35%
<u>BE Scenario 3:</u>					
Production Costs	751.9	1023.6	1428.0	1731.9	2832.4
SRC-II (1000 Bbls/yr)	12843	13118	13091	10332	13759
Advanced Combined Cycle Capacity Factor	N/A	57%	54%	37%	40%
<u>BE Refurbishment:</u>					
Production Costs	753.3	1067.7	1432.1	1841.6	3020.0
Coal (1000 Tons/yr)	N/A	817	1409	2082	3343
SRC-II (1000 Bbls/yr)	12849	11998	10062	6975	7711
Cycling Coal Capacity Factor	N/A	54%	43%	35%	37%

Table 7

LEVELIZED REVENUE REQUIREMENTS
BOSTON EDISON COMPANY SCENARIOS

	<u>Total Levelized Revenue Requirement (millions of 1979 \$/year)</u>
Base Case	\$211
Scenario 1	\$217
Scenario 2	\$255
Scenario 3	\$207
Refurbishment	\$190

7.4.2 Boston Edison Scenario 2

In Boston Edison Scenario 2, the 365 MW combined cycle units assumed in the BE base case and in Scenario 1 are replaced by 400 MW cycling coal units with an average heat rate of 9800 Btu/kWh. In this scenario, the use of coal is studied under worst case conditions: a congested urban setting in which flue gas desulfurization (FGD) wastes and ashes have to be trucked thirty miles to a landfill for disposal on prime commercial land costing at least \$10,000 an acre. In this setting, the already high capital costs of a solids handling unit with FGD are raised further by the high construction costs of an urban area. Also the use of nuclear units for generation of base load relegates the coal units to intermediate load service. Their capacity factor ranges from 35 to 47%, a rather low utilization for a high capital cost installation.

In addition, the practicality of this application of the technology is somewhat doubtful. Coal fired boiler designs are under development for cycling or intermediate load service. However, operating experience to date with FGD systems would indicate that such systems are fairly difficult to operate even under base load operating conditions and that operation in a cycling mode will aggravate operating and maintenance difficulties. A forced outage rate of 13% has been assumed for these units which is the same as that specified by Florida Power Corporation for their coal units with FGD. This forced outage rate is lower than some others published^(1,2) and reflects improvements in design and operating knowhow as operating history accumulates for FGD units and the number of units in service increases. While this factor may drop by some additional amount for base load coal units, it seems reasonable to assume that this value will apply to future cycling coal units.

(1) "Market Potential for New Coal Technologies," Dwain Spencer and Oliver Gildersleeve, EPRI J., May 1978, pp. 19-26.

(2) "Pricing Scenario for Coal-Derived Synthetic Fuels for Electric Utilities," EPRI, April 24, 1979, Stanley Vejtasa and Oliver Gildersleeve.

It has been proposed that coastal utilities dispose of their FGD sludge in the ocean. A method which would seem to be reasonably acceptable and technically possible would be to form the sludge into stable blocks which could be dumped into the ocean to form reefs as a habitat for sea animal life. The blocks would be stabilized sufficiently to avoid any noticeable discoloration of the ocean or any significant migration of the sludge. However such methods are still under development, their environmental acceptability has yet to be evaluated, and their costs are unknown and could be rather high.⁽³⁾

In urban settings such as that of Boston Edison where disposal costs are very high, another possibility is regenerable FGD with the production of sulfur or sulfuric acid as a by-product. This eliminates the need for a large land-fill site for disposing of the FGD sludge but it raises capital and operating and maintenance costs, even compared to this worst coal plus FGD case. Capital costs for FGD would increase about \$41/kW (from \$199/kW to \$240/kW) and O&M costs for FGD would increase by 1.5 mils/kWh (from 4.4 to 5.9). Income from the by-product sulfur or sulfuric acid would only be about 0.5 mils/kWh.

At the beginning of Scenario 2, SRC-II fuel oil is being used at a rate of about 35,000 barrels/day (Table 6). Ninety-five percent of this is used in liquid fuel fired boilers and the other five percent is in peaking units. As the liquid fuel fired boilers are retired and the peaking units are replaced by more efficient units, usage drops, until in 2010 it is down to 6500 barrels of SRC-II fuel oil per day. In contrast to this in Scenario 1, SRC-II fuel oil use builds up throughout until in 2010 it is around 49,000 barrels per day. Since SRC-II fuel oil costs about two and one-half times as much as raw coal, electricity production costs are considerably higher in Scenario 1 compared to Scenario 2 where coal is being used. However, the much lower capital cost of the combined cycle units and their higher capacity

(3) "Current Alternatives for FGD Waste Disposal," C. J. Santhanam, et al., A. D. Little, Inc., FGD Symposium, Las Vegas, March 5-8, 1979.

factor offsets this. As a result, the LRR of \$217 million for Scenario 1 are exceeded by the LRR of \$255 million for Scenario 2 by about 18% (Table 7).

7.4.3 Boston Edison Scenario 3

In Boston Edison Scenario 3 the effect of advanced gas combustion turbine technology was studied. Addition of advanced units was started in 1990 as in the base case. Projected unit sizes, efficiencies and capital costs as shown in Table 1 for the periods 1990-2000 and 2000-2010, were used appropriately. Since these units are larger than those assumed for the base case, they are added less frequently in Scenario 3 and the final number of units added is fewer. It should be noted that the capital costs and heat rates assumed for these units are conservative in that the projected overall improvements in these values are assumed not to be reached until the year 2000. It is possible that they will be reached by the beginning of the study period 1990.

The improved heat rate results in a higher combined cycle unit capacity factor for the first decade in Scenario 3 than in Scenario 1 (Table 6). Since this is at the expense of the operation of the steam boilers the reduction in the fuel usage and electricity production costs is magnified over that obtained directly just by the improvement in the efficiency of the combined cycle units themselves. In 2005 the electricity production costs in Scenario 3 is only 3% higher than for the Scenario 2 in which cycling coal units are being used and coal is the main fuel. In 2010 this same comparison shows Scenario 3 only 2% higher than Scenario 2. This, combined with the much lower capital cost for the combined cycle units, gives an LRR for Scenario 3 of only \$207 million (Table 7) or 19% below the \$255 million for the cycling coal Scenario 2. In the year 2010 the use of advanced combined cycle technology results in a SRC-II fuel oil usage which is 22% lower than that for Scenario 1 where current combined cycle technology is assumed.

7.4.4 Florida Power Corporation Base Case and Scenario 2

The Florida Power Corporation (FPC) generation plan used in the base case study of their system for the years 1980-2010 is given in Table 5. FPC has two units designed for oil which have been converted to burn coal and they are adding two more coal burning units in 1982 and 1984 which will burn low sulfur coal. In 1985, the first unit will come on line which will burn high sulfur coal and will have FGD. The seven more coal units added after this up to 2010 will also have FGD units.

The FPC system is mainly oil burning currently, aside from its one nuclear unit. By 1990, the start of the study period, the projected addition of coal units will increase the use of coal considerably and drop the use of oil to a relatively low level. This drop continues out to the year 2000 when less than a million barrels of oil will be used. FPC Scenario 2 is a study of the substitution of SRC-II fuel oil fired combined cycle units for the projected high sulfur coal units with FGD. The capital costs, heat rates, and unit sizes given in Table 1 for the periods 1985-1990, 1990-2000, and 2000-2010 are used appropriately.

In the FPC base case, the heat rates for the coal units with FGD specified by FPC in their data base were used. These are somewhat higher than those assumed for the cycling coal units in Boston Edison Scenario 2. As a result, the difference in efficiency between FPC Scenario 2 and the FPC base case with coal units is greater. The electricity production cost for Scenario 2 is higher than the FPC base case only for 1990 and 1995 (Table 8). For 2000 and after, the greater difference in efficiency just mentioned results in a lower electricity production cost for Scenario 2. Thus, when the additional effect of the lower capital cost of the combined cycle units as compared to the coal units is considered in the calculation of LRR, there is a rather large advantage for the combined cycle units with a LRR of \$378 million (Table 9) as compared to that for the base case of \$496 million, or a 24% advantage for the combined cycle Scenario 2.

Table 8

**SUMMARY OF SCENARIO RESULTS FOR
FLORIDA POWER CORPORATION**

(\$ in millions)

	ANNUAL RESULTS FOR				
	<u>1990</u>	<u>1995</u>	<u>2000</u>	<u>2005</u>	<u>2010</u>
<u>FPC Base Case:</u>					
Production Costs	1182.9	1397.1	2110.1	3145.8	4581.0
Coal HS (1000 Tons/yr)	6877	5924	8386	10270	11485
Coal LS (1000 Tons/yr)	2878	2346	1291	549	300
Oil (1000 BBLs/yr)	4477	1763	857	792	729
Capacity Factor of New Coal Units	62%	55%	49%	44%	42%
<u>FPC Scenario 1:</u>					
Production Costs	1453.0	1605.8	2457.9	3673.8	5327.2
Coal HS (1000 Tons/yr)	2339	1831	1777	1719	1883
Coal LS (1000 Tons/yr)	3808	3566	3578	3538	3430
SRC-II (1000 BBLs/yr)	16141	11004	14913	18922	21986
Capacity Factor of New SRC-II Units	48%	36%	30%	27%	27%
<u>FPC Scenario 2:</u>					
Production Costs	1386.2	1465.3	2112.1	3050.3	4287.4
Coal HS (1000 Tons/yr)	2457	2092	2183	2174	2369
Coal LS (1000 Tons/yr)	4012	3742	3880	3922	3875
SRC-II (1000 BBLs/yr)	14100	7700	9000	11000	12200
Advanced Combined Cycle Capacity Factor	-	-	50%	44%	36%
<u>FPC Scenario 3A:</u>					
Production Costs	1219.9	1321.1	1772.7	2559.8	3677.5
Coal HS (1000 Tons/yr)	5183	5406	6705	7970	9207
Coal LS (1000 Tons/yr)	3325	2010	1469	949	449
SRC-II (1000 BBLs/yr)	6838	1081	618	471	267
Coal Gasification Capacity Factor	73%	49%	45%	43%	40%
<u>FPC Scenario 3B:</u>					
Production Costs	1212.2	1290.4	1916.2	2700.4	3943.1
Coal HS (1000 Tons/yr)	5184	4231	4478	6322	6777
Coal LS (1000 Tons/yr)	3321	2775	3060	2448	2543
SRC-II (1000 BBLs/yr)	6682	2696	3624	2092	2882
Capacity Factor - Coal Gasification	73%	60%	63%	58%	62%
Capacity Factor - Advanced Combined Cycle	N/A	20%	18%	11%	11%

Table 9

LEVELIZED REVENUE REQUIREMENTS
FLORIDA POWER CORPORATION SCENARIOS

	<u>Total Levelized Revenue Requirement (millions of 1979 \$/year)</u>
Base Case	\$496
Scenario 1	\$460
Scenario 2	\$378
Scenario 3A	\$441
Scenario 3B	\$377

Except for the heat rate assumed, the coal units for the FPC base case represent a near best case for coal plus FGD technology. A rural setting is assumed and this allows on site land-fill disposal of FGD sludge. Also construction costs are lower in general in the southeast region than in the northeast and the rural setting allows elimination of the premium for urban construction costs. These factors aid high capital cost technologies relative to those with lower capital costs.

7.4.5 Florida Power Corporation Scenario 3A

In FPC Scenario 3A, coal gasification units integrated with combined cycle combustion turbines were substituted for the high sulfur coal units added after 1984 in the base case. An EPRI study of coal gasification conducted by Fluor Engineers and Constructors, Inc.⁽⁴⁾ was used as a basis. This was a fairly detailed study of six different gasification processes currently in various stages of research, development, and demonstration. The sensitivity of the results to factors developed in other less detailed studies⁽⁵⁾ was also considered and is discussed below. The Texaco process and the British Gas Council (BGC) process were selected from the Fluor study as the most likely to be commercialized in the near future. Capital costs, operating and maintenance costs, and overall system heat rate were averaged for these two processes for use in FPC Scenario 3A.

Five low Btu gasification units of 1200 MW capacity each were substituted into FPC's generation expansion plan in place of the nine coal fired plus FGD units slated to come on line from 1985 through 2010. In 1990, the first year of the study, production costs for Scenario 3A are higher than for

(4) "Economic Studies of Coal Gasification Combined Cycle Systems for Electric Power Generation," EPRI Report AF-642, January 1978 (Fluor Engineers and Constructors, Inc.).

(5) "Comparative Study and Evaluation of Advanced Cycle Systems," General Electric Company, EPRI Report AF-664, February 1978.

the base case (Table 8). This is because only one gasification unit has been installed at this point and the system is still relying heavily upon liquid fuel fired boilers. SRC-II fuel oil is assumed to be used as the only liquid fuel in all scenarios other than the base case. For the fuel prices used in this study, SRC-II fuel oil is more expensive than petroleum in the year 1990. However, by 1995 the two nuclear units have come on line as well as an additional low Btu gasification unit. The use of SRC-II fuel oil in fired boilers has dropped by 80% and the electricity production cost in 1995 is lower than that in the base case. This trend continues on out through 2010. Production costs for Scenario 3A are also lower than for Scenario 2 where SRC-II fuel oil is being used heavily in combined cycle units.

The coal units used in the base case after 1985 have a forced outage rate of 13% due to the FGD units. This requires the installation of 6,780 MW of coal fired capacity from 1985 to 2010 (besides nuclear capacity) to maintain reliability. EPRI⁽⁴⁾ indicates a forced outage rate of 11% for coal gasification units. The large (1200 MW) size of the gasification units requires that more capacity be installed to maintain reliability than would be necessary for smaller units. The net effect of larger unit size and lower forced outage rate is that only 6,000 MW of low BTU gasification capacity is installed in Scenario 3A for the 1985-2010 period. EPRI⁽²⁾ indicates a forced outage rate for advanced technology combined cycle units of 6.3%. In Scenario 2, this low forced outage rate, along with the 846 MW combined cycle units size, allows the reliability criteria to be met with the installation of only six 846 MW units for a total of 5,076 MW over the period. Thus while the LRR for Scenario 3A of \$441 million is 11% below the \$496 million of the base case (Table 9), it does not match the 24% reduction of \$276 million achieved in Scenario 2 with advanced combined cycle units. Thus the higher cost of SRC-II fuel oil is overcome by its utilization in low capital cost, highly reliable combined cycle units.

7.4.6 Florida Power Corporation Scenario 3B

The effect of using both SRC-II fuel oil fired combined cycle units and coal gasification integrated with combined cycle units was tested in FPC Scenario 3B. Two coal gasification units and three liquid fuel fired combined cycle units with a total capacity of 4,938 MW were installed over the period of 1985-2010. During the study period of 1990-2010, the coal gasification units run in a very high capacity factor range (58% to 73%). On the other hand, the SRC-II fuel oil fired combined cycle units run in the low intermediate or peaking load range (11% to 20%). The LRR for Scenario 3B is \$377 million, a considerable improvement over the \$441 million of Scenario 3A where coal gasification is used exclusively. However, LRR for Scenario 3B is equal, within the precision of the results, to that for Scenario 2 where SRC-II fueled combined cycle units were used exclusively for expansion (Table 9). The schedule of additions of gasification units and of SRC-II fuel oil fired combined cycle units in Scenario 3B was somewhat arbitrary and was designed mainly to give the same overall system reliability as for the FPC base case. It is a reasonable first case for a study of the use of these two technologies together. However, optimization of the relative number, size, and timing of each type of unit might give improved LRR.

The relatively high capital cost and the large size assumed for coal gasification units integrated with combined cycle will be a financial burden on a utility during the seven year construction period and initial period of operation for such a unit. The large size of the unit tends to make it underutilized during the early years of operation. However, almost all the coal gasification processes under development involve multiple trains (typically six trains) and theoretically at least, one could install less than a full 1200 MW plant at first, adding the rest as needed. We have not explored what economy of scale might be lost by this technique. For utilities where coal gasification does seem to be an attractive option, an interesting possibility would be to install the combined cycle units as peaking and intermediate load units but run them at first with SRC-II fuel oil. Later, when the base load

need has grown to be large enough, coal gasification units could be constructed and the combined cycle units converted to the low Btu gas. This would reduce the problem of having a large base load unit producing no revenue during construction and low revenue during the initial period of operation at low utilization.

7.4.7 Sensitivity Analysis

The projected capital costs used for the various technologies considered in this study are a major source of uncertainty in the results. Recent years have illustrated the difficulty of forecasting capital costs, especially for a new technology. Since relatively low capital costs are one of the major advantages of SRC-II fuel oil fired combined cycle units and since a rather wide range of capital costs is indicated in the literature for coal gasification units integrated with combined cycle, the sensitivity of the results to variations in these capital cost estimates has been studied. For FPC Scenario 2 where advanced cycle units are used for expansion of the system, it was assumed that the capital cost for the advanced technology units installed in the 1990 to 2010 period was increased by \$100/kW or about 25%. This raised the LRR from \$378 million to \$382 million (Table 10), an increase of only 1%.

For coal gasification, the capital cost was lowered from \$863/kW, the average for the Texaco process and the BGC process, to around \$800/kW which was the approximate capital cost for the BGC process. This lowered the revenue requirement from \$441 million to \$430 million, a drop of only 2.5%. Next, the capital cost for coal gasification was dropped to \$600/kW, which is approximately the lowest value mentioned in the literature. This decreased the revenue requirement to \$396 million, about a 10% drop. The combined effect of increasing capital cost in FPC Scenario 2 and decreasing capital cost in Scenario 3A still leaves the advanced combined cycle units with a slight economic advantage over the gasification units (\$382 million vs \$396 million, Table 10).

Table 10

SENSITIVITY TESTS ON CAPITAL COSTS

Florida Power Corporation Scenarios

	<u>Levelized Revenue Requirement (millions of 1979 \$/yr)</u>
Scenario 2 (+\$100/kW for Combined Cycle Units)	382
Scenario 3A (\$800/kW Coal Gasification/Combined Cycle Units	430
Scenario 3A (\$600/kW Coal Gasification/Combined Cycle Units	396

It does not appear likely that a utility will obtain a large financial advantage by the use of coal gasification integrated with combined cycle. The advantage may be large enough to induce some utilities to use this technology, but for others, particularly those in an urban environment, the requirements to transport, handle, and store coal and the resulting residue from the gasification process may make coal gasification unattractive because of the space requirements and the environmental problems it would cause. In addition, when embarking upon a coal gasification project, a utility is getting involved in very complex chemical processing which up to now has been outside the realm of its usual operation. Although disposing of the ash residue from the coal gasification process would be a much smaller problem than that of disposing of FGD sludge, the coal gasifiers and other processing units are potential sources of air and water pollution.

One possible solution to the site and environmental problems for coal gasification units and other coal using technologies would be to locate the coal gasification and power generating units outside the urban area and use high voltage transmission lines to carry the power to the point of need. Construction of high voltage transmission lines involves right of way and environmental problems in urban areas. In addition they are an additional capital cost which will offset the already fairly small financial advantage of gasification. However, these negative factors would not apply to either Florida Power Corporation or Boston Edison. In BE's case, suitable transmission lines already exist, and in the near term at least, the location of FPC's new generating units will not be affected by the type of generating technology selected; therefore transmission costs will be the same for all technologies.

SECTION 8

TURBINE FUEL DEMAND ESTIMATES

8.1 PROJECTED DEMAND FOR LARGE EAST COAST UTILITIES

Based on the above analysis of scenarios and on the levelized revenue requirement results given in Tables 7 and 9, BE Scenario 3 and FPC Scenario 3B were selected as the basis for projecting SRC-II fuel oil demand. In BE-3, generation expansion is accomplished with nuclear and advanced combined cycle technology. In FPC-3B, it is accomplished with nuclear, coal gasification integrated with combined cycle, and advanced liquid fuel combined cycle.

Demand was projected for the eleven large U.S. East Coast utilities listed in Table 11. Data on projected fuel use and energy production was obtained from each of these utilities. This information was then compared with the results of BE-3 and FPC-3B scenarios. From this comparison, it was decided to group Consolidated Edison Co. and Northeast Utilities Co. with Boston Edison Co. for projection of demand based on Scenario B-3. The projection for the other eight utilities was based on Scenario FPC-3B and on the data for the five utilities (marked with an asterisk in Table 11) in the Middle Atlantic area.

The nuclear generation projected by the utilities was used as given or extrapolated to the end of the study period. For Consolidated Edison and Northeast Utilities, the projected petroleum-based oil consumption was assumed to be the projected demand for SRC-II fuel oil. This demand then was distributed between use in boilers, combustion turbines, and combined cycle units as in BE-3.

In FPC-3B, the percentage of generation based on SRC-II fuel dropped from 1990 to 1995 as boiler units were retired and then held roughly constant from 1996 to 2010. A steep drop in oil used from 1990 to 1995 also is projected by most of the other utilities which we are relating to FPC-3B. The drop in oil use then continues at a much slower rate to 2010. This latter drop will probably not occur if SRC-II fuel oil is available. Therefore, the SRC-II fuel oil demand for 1990 to 1995 was projected from the 1990 to 1995 oil usage, and the SRC-II fuel oil demand to 2010 was held as a constant

Table 11

U.S. EAST COAST UTILITIES USED IN
PROJECTING SRC-II FUEL OIL DEMAND

Boston Edison Company (+)
New England Electric System
Northeast Utilities Company (+)
Consolidated Edison Company (+)
Public Service of New Jersey (*)
Phildadelphia Electric Company (*)
Potomac Electric Company (*)
Baltimore Gas and Electric Company (*)
Virginia Electric Power Company (*)
Florida Power Corporation
Florida Power and Light Company

+ Grouped for projection based on Scenario B-3.

* Middle Atlantic area utilities grouped for projection.

percentage based on the percentage of oil used in 1996. Distribution among boilers, turbines, and combined cycle units was based on FPC-3B.

The demand for each type of equipment and the totals were summed for all eleven utilities. The results of this are given in Table 12 and shown graphically in Figure 5. Projected demand for SRC-II fuel oil as combustion turbine fuel is 84 million bbls/year (230,000 bbls/day) in 1990, dropping to 15 million bbls/year (41,000 bbls/day) in 1995 as combustion turbines are replaced by or converted to combined cycle units. It then holds roughly constant till 2010. The expansion plans of Boston Edison Co. and Florida Power Corp. and the scenarios selected for this projection interacted in a way causing no combined cycle units to come on line until 1993. Thus no combined cycle SRC-II fuel oil demand is projected for 1990 to 1992. This is unrealistic and a more likely occurrence would be a gradual increase starting before 1990.

Combined cycle demand is shown as increasing from 70 million bbls/year (191,000 bbls/day) in 1994 to 116 million bbls/year (318,000 bbls/day) in 2000 and to 177 million bbls/year (485,000 bbls/day) in 2010. Total projected demand for the eleven electric utilities is 244 million bbls/year (670,000 bbls/day) in 1990, dropping to 172 million bbls/year (470,000 bbl/day) in 1999 because of the drop in boiler fuel use. As shown in Figure 2, the drop in boiler fuel demand is largely offset by the increase in combined cycle fuel demand. Use then gradually increases to 193 million bbls/year in 2010 (530,000 bbls/day) as combined cycle unit demand increases.

Total demand for the period is at a peak at the beginning, falling off, and then beginning to gradually increase. In 2010 the total demand is less than 80% of the previous peak demand. However, due to the increased efficiency of the combined cycle units, the SRC-II fuel oil consumed in 2010 is generating about 35% more electricity than was generated by the SRC-II fuel oil at the peak demand. A scale is included in Figure 6 for converting the barrels of SRC-II fuel oil consumed by each technology to GWH of electricity generated.

Table 12

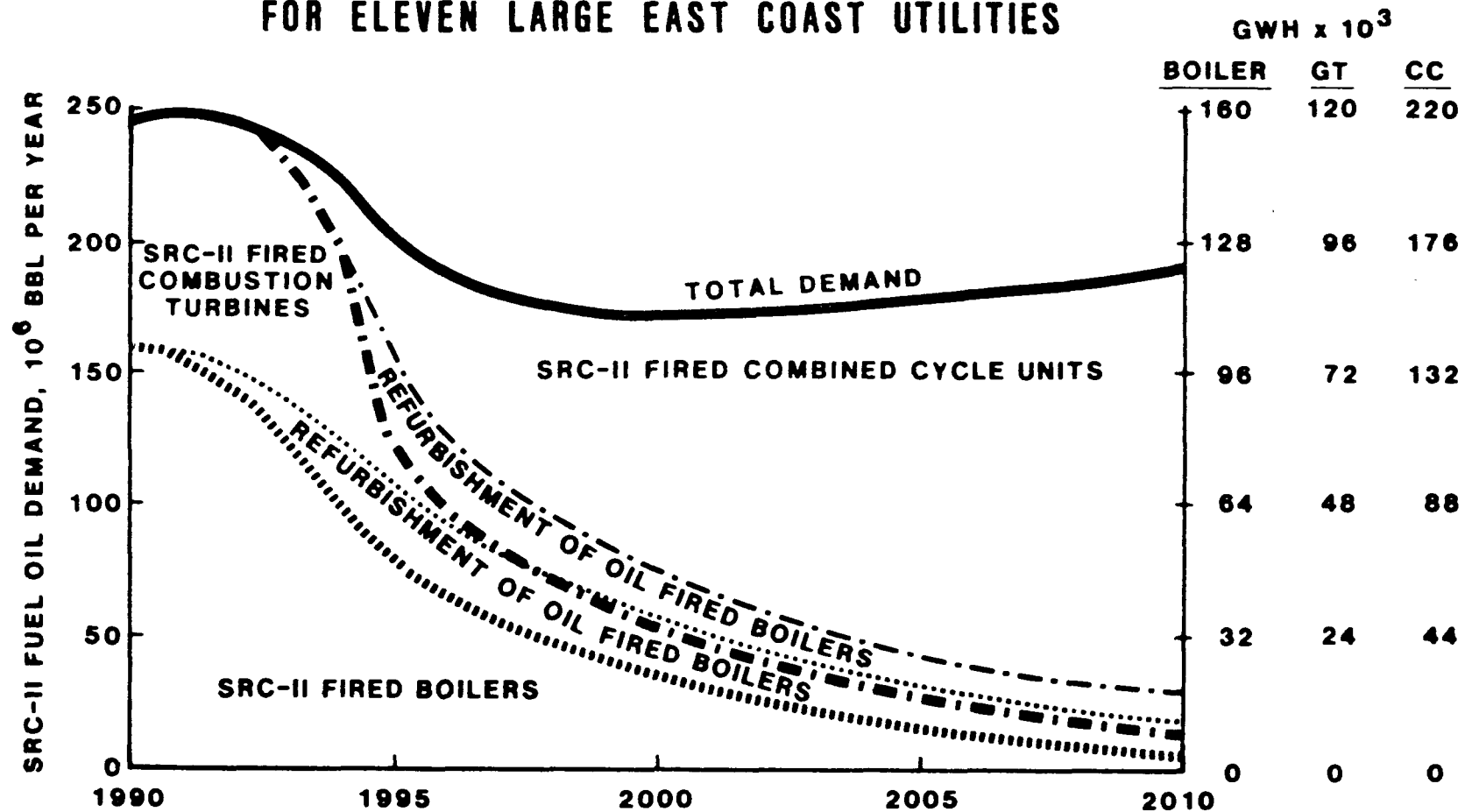
PROJECTED DEMAND FOR SRC-II FUEL OIL
ELLEN LARGE EAST COAST UTILITIES

Millions of Barrels/Year

<u>Year</u>	<u>Steam Boilers</u>	<u>Combustion Turbines</u>	<u>Combined Cycle</u>	<u>Total</u>	<u>Projected Percent of Total Power Generation Based on SRC-II Fuel Oil</u>
1990	159.4	84.2	0	243.6	33.2
1991	159.8	90.5	0	250.3	32.8
1992	142.1	106.0	0	248.1	30.8
1993	134.1	94.9	9.5	238.5	29.2
1994	91.0	34.4	69.7	195.1	27.3
1995	73.7	15.1	92.9	181.7	26.4
1996	73.3	22.9	90.1	186.3	25.7
1997	58.0	31.7	87.3	177.0	23.3
1998	52.0	31.7	91.7	175.4	22.6
1999	48.4	12.8	110.3	171.5	22.6
2000	46.1	14.4	116.4	176.9	22.8
2001	29.3	12.4	133.5	175.2	22.8
2002	24.5	15.3	132.5	172.3	21.7
2003	24.4	14.4	138.0	176.8	21.8
2004	15.4	10.9	150.3	176.6	21.8
2005	13.3	19.4	149.1	181.8	21.4
2006	11.9	16.9	156.7	185.5	21.6
2007	10.1	5.3	161.8	177.2	20.8
2008	9.3	9.8	164.4	183.5	20.8
2009	9.5	13.8	168.1	191.4	21.0
2010	7.0	8.8	176.8	192.6	21.0

FIGURE 5

PROJECTED DEMAND FOR SRC-II FUEL OIL FOR ELEVEN LARGE EAST COAST UTILITIES



A possible shift in the proportions of SRC-II fuel oil used due to refurbishment of existing liquid fuel fired boilers is indicated in Figure 6 by the light dashed lines. It is assumed in the figure that the refurbished units are used instead of new combined cycle units being built and that total SRC-II fuel oil demand is not affected. However, refurbishment could partly displace other technologies such as coal gasification also and thus might increase total SRC-II fuel oil use.

8.2 PROJECTED DEMAND FOR TOTAL U.S.

An approximation was made of the total electric utility U.S. demand for SRC-II fuel oil. The total generation was projected from DOE figures⁽¹⁾. The percentage of generation from SRC-II fuel oil was then calculated from the fraction projected for oil by the five Middle Atlantic utilities as explained previously. This figure was then reduced by 50% since conditions for supply and use of SRC-II fuel oil will not be as favorable for some parts of the U.S. as they are for the east coast. The resulting demand projection is given in Table 13. The patterns of use with time are similar to those for the east coast.

(1) "Annual Report to Congress, Volume II, 1977, Projections of Energy Supply and Demand and Their Impacts", Energy Information Administration, U.S. Dept. of Energy.

Table 13

PROJECTED U.S. (CONTIGUOUS) DEMAND FOR SRC-II FUEL OIL

Millions of Barrels/Year

<u>Year</u>	<u>Steam Boilers</u>	<u>Combustion Turbines</u>	<u>Combined Cycle</u>	<u>Total</u>
1990	375.0	354.0	0	728.0
1991	383.0	347.0	0	731.0
1992	336.0	416.0	0	752.0
1993	308.0	360.0	44.3	713.0
1994	133.0	61.9	298.0	493.0
1995	121.0	67.2	304.0	492.0
1996	110.0	98.5	289.0	498.0
1997	81.4	143.0	306.0	530.0
1998	73.3	129.0	336.0	538.0
1999	51.2	27.5	429.0	508.0
2000	54.1	37.3	442.0	533.0
2001	43.0	45.1	468.0	556.0
2002	43.0	45.3	491.0	579.0
2003	45.9	48.5	512.0	607.0
2004	46.3	55.2	531.0	633.0
2005	39.7	95.1	543.0	677.0
2006	31.4	81.6	581.0	694.0
2007	24.5	15.8	650.0	690.0
2008	22.7	29.1	675.0	727.0
2009	21.6	52.4	695.0	769.0
2010	16.1	50.8	731.0	798.0

**GULF SCIENCE AND TECHNOLOGY COMPANY
PITTSBURGH, PENNSYLVANIA**

**THE MARKET OPPORTUNITY FOR
SRC-II FUEL OIL AS INDUSTRIAL BOILER FUEL**

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**CHEMICALS AND MINERALS DIVISION
REPORT NO. 633RK105
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SECTION 1

SUMMARY

The production of steam for use in industry is one of the essential elements of our complex society. Steam production requires large expenditures of capital for equipment and large costs for fuel and operation. The lowest possible steam cost is one of industry's goals, but steam production can also be a source of environmental degradation and added costs must be incurred to minimize pollution either by burning non-polluting fuels or by adding pollution control equipment to the boiler system. SRC-II fuel oil from the SRC-II coal liquefaction process appears to be an attractive alternative to replace diminishing supplies of increasingly expensive oil and gas or pollution-controlled coal. This volume discusses various aspects of industrial steam boiler systems, costs of generating steam in industrial boilers, the size of the market for alternate fuels, and specific typical opportunities for SRC-II fuel oil.

Industrial boiler technology has been developed over the years until it has become a highly complex field in itself even though it is an adjunct to the main manufacturing process. Coal-fired boilers have the longest history, and coal presently is normally the lowest cost major fuel. At various times, oil and particularly gas have actually been less costly than coal; and since World War II gas- and oil-fired industrial boilers have relegated coal-fired boilers to a minority position. Recent events have engendered legislation to promote a return to the use of coal, but other legislation on environmental protection has greatly increased the capital and operating costs of coal burners.

Studies of the economics of producing steam using coal-firing show that the high costs of coal-fired boilers and the attendant pollution-control equipment result in steam costs which are quite high, particularly for moderate-sized boilers up to about 200,000 lb/hr of steam and at utilization rates of 60% or less. Below these rates, it is more economical to install and

operate oil-fired systems using SRC-II fuel oil at its estimated price of \$3.82/million Btu than it is to burn Northern Appalachian coal priced at \$1.71/million Btu. In fact, at the average boiler size (106,000 lb/hr steam) and utilization factor (40%) for all U.S. manufacturing industries, SRC-II fuel oil prices of \$5.73/million Btu (50% higher than expected) would result in the incremental capital for coal-fired systems using coal at \$1.71/million Btu showing a DCF rate of return of only 14%. Other alternate systems of using coal, such as burning in a fluidized bed or gasifying the coal, result in higher steam costs than those calculated using SRC-II fuel oil.

A data base was developed for U.S. industrial boilers ranging in size from 50,000 to 500,000 lb/hr of steam. Process industry boilers have an average size (130,000 lb/hr steam) somewhat higher than those in the manufacturing industry and operate at a higher utilization factor (66%). By combining information from the data base with steam generation economics, it was calculated that the possible market for SRC-II fuel oil might be as much as 1.46 million B/D for the entire U.S. by 1990. For the region east of the Mississippi River, the market was projected to be 0.9 million B/D by 1985. If SRC-II fuel oil were used to this extent instead of coal, there would be a capital savings in steam boilers of about \$19.3 billion or about 73% of the capital required for the SRC-II plants, from which about 60% of the output would be fuel oil. Thus, the SRC-II fuel oil alternative is also preferable from the point of view of capital formation.

Joint studies with Rohm and Haas and with General Electric for typical processing and manufacturing industrial boiler applications in the northeast U.S. have been made. The results of both studies indicate a significant opportunity for SRC-II fuel oil to generate the steam requirements in the plants studied, based on economics, operating simplicity and environmental considerations as compared to the options of firing coal either with added flue gas desulfurization or in a fluidized bed combustion system.

SECTION 2

INTRODUCTION

The industries of our country require large quantities of steam, and the production of this steam consumes about 6 to 8% of our entire fossil fuel usage for all purposes. Coal has been a mainstay for steam production since the start of the industrial revolution; but coal burning as practiced in the past was the source of unacceptable environmental pollution, and in recent years gas and oil have largely replaced coal in industrial steam boilers. The availability of gas and oil is limited and their cost is ever increasing as is the cost of providing and operating equipment to burn coal in an environmentally acceptable manner. These factors have stimulated efforts to develop technologies to produce from our abundant coal resources clean-burning substitutes for gas and oil. One of these technologies which is aimed at producing liquid fuels from coal is the SRC-II process, and the distillate SRC-II fuel oil which it produces appears to show particular promise as an industrial boiler fuel.

SECTION 3

TECHNICAL CLASSIFICATION OF SRC-II FUEL OIL

SRC-II fuel oil is a low-sulfur distillate. The ash content of SRC-II middle distillate is less than 0.001%; the ash content of SRC-II heavy distillate is 0.03-0.10% in pilot plant production, with expectation of lower ash content with the more efficient fractionation that can be expected in commercial production.

It is feasible to hydrogenate SRC-II distillate and effect significant upgrading in terms of increased hydrogen content, and decreased sulfur and nitrogen contents. In its present (raw) form, SRC-II fuel oil has the prospect of serving as a satisfactory boiler fuel without the significant added cost of hydrogenation.

Physical properties and inspection data in Table I indicate that SRC-II middle distillate can be handled and burned like No. 2 fuel oil, and SRC-II heavy distillate can be handled and burned like No. 5 fuel oil. The full-range distillate, comprised of middle and heavy distillates in the proportions formed in the SRC-II process, are intermediate in properties as might be expected. The significant differences between petroleum and SRC-II distillates are:

1. Higher nitrogen content of SRC-II fuel oil which indicates a tendency towards more NO_x formation in combustion.
2. Lower hydrogen content of SRC-II fuel oil which suggests a tendency towards formation of more soot and smoke in combustion.

Full-scale combustion tests in a 45,000 lb/hr package boiler "...suggested strongly that SRC-II fuel oil would burn similarly to No. 2 fuel oil;" that "... NO_x emissions...limit could be met...by the use of two-stage combustion and by the proper matching of burner and atomizer designs;" and that "SRC fuel

Table I

INSPECTIONS OF SOME RAW SRC II PRODUCTS^a
FROM A VARIETY OF COALS AND TWO PETROLEUM FUEL OILS

Product:	SRC II		Petroleum Fuels	
	Middle Distillate	Heavy Distillate	No. 2 Grade	No. 5 Grade ^b
<u>Inspections:</u>				
Gravity: °API	13.8	0.4	>30	19
Density (15°C): kg/dm ³	0.974	1.072	<0.876	0.940
Color	dark	dark	light	dark
Viscosity: cSt				
100°F	3.1-3.4	49.6-90.2	2.0-3.6	26-194
210°F	-	4.0-5.1	-	2.9-48
Viscosity: SUS				
100°F	36.3-37.3	231-418	32.6-37.9	124-900
210°F	-	39.8-42.7	-	36-224
Flash Point, P-H: °F	>160	>180	>130	>150
Pour Point: °F	<-45	<+45	<+5	-15 - +80
Carbon Residue, Con.: %W				
10% Bottoms	<1.2	-	<0.35	-
Total Sample	-	<1.5	-	2 - 10
Nitrogen: %W	0.9-1.1	1.2-1.4	<0.02	<0.3
Oxygen: %W	3.6-4.3	1.4-1.8	<0.09	<0.4
Sulfur: %W	<0.2	0.37-0.47	0.04-0.48	0.07-1.9
Carbon: %W	86.0	89.1	87.0	88.3
Hydrogen: %W	9.1	7.5	12.8	10.7
Hydrocarbon Groups (HPLC): %W				
Saturates	35-38	-	>65	-
Aromatics & Polar Compounds	62-65	-	<32	-
Asphaltenes, IP143: %W	<0.1	0.9-2.7	<0.1	<5.0
Phenolics: %W	3-20	-	0	-
Naphthalenes: %W	14-19	-	<6	-
Smoke Point: mm	5-8	-	>14	-
Ash, D482: %W	<0.001	0.03-0.1	<0.003	<0.05
Nickel: ppm	<0.1	0.3-0.9	<0.1	46 ^c
Vanadium: ppm	<0.1	<0.1-1.1	<0.1	180 ^c
Sodium: ppm	-	2-11	<0.5	2-20
Neut. No (Ian), D664	0.27-0.42	0.25-0.57	<0.30	<0.45
Copper Strip Corrosion, D130	1-3	1	1	1
Heat of Combustion, Gross, D240				
BTU/Lb	16,900	17,000	19,300	18,700
BTU/Gal	137,100	151,800	136,700	146,600
Cetane No., D613	<20	-	40-55	-
Autoignition Temperature: °F	925	895	595	600-700
Thermal Stability, NDTL (D1661)				
Thimble Rating				
Unwashed	1	1	1	1
Washed	1	1	1	1
Washed and Wiped	1	1	1	1
Rating of Tube	1	1	1	1
Accelerated Stability, D2274				
Deposit Weight: mg/100 ml	<0.8	<3.5	<1.0	-
Stability Test, 64 hr @ 210°F				
Insolubles: mg/100g	<0.3		<0.5	-
Distillation: °F	D86	D1160; 760mm	D86	
Over point	338-396	538-554	369-389	-
10%	386-406	568-584	422-445	-
50%	425-444	640-656	498-516	-
90%	483-500	785-820	580-593	-
End Point	538-553	923-939	630-640	-

Notes:

a - Preliminary values based on Pilot Plant production. Values of commercial product may vary. Reprocessing is also capable of altering product properties.

b - Product is a blend of distillate and residual fuels.

c - Metals content subject to considerable variation depending on crude source.

11/30/78

oil produced no significant smoking tendencies. Flame appearance, as well as stack opacity, with SRC-II fuel oil was slightly better than with No. 5 fuel oil." The report by Babcock & Wilcox Company, from which these conclusions have been extracted, is presented in Volume 2 of this series.

In considering the technical aspects of SRC-II fuel oil as an industrial boiler fuel, it can be regarded as resembling No. 2 fuel oil from the viewpoint of equipment needed for transportation, storage, and combustion. No emissions control equipment seems indicated if proper burners are used to control NO_x formation.

SECTION 4

INDUSTRIAL BOILER DESIGN FACTORS

4.1 Introduction

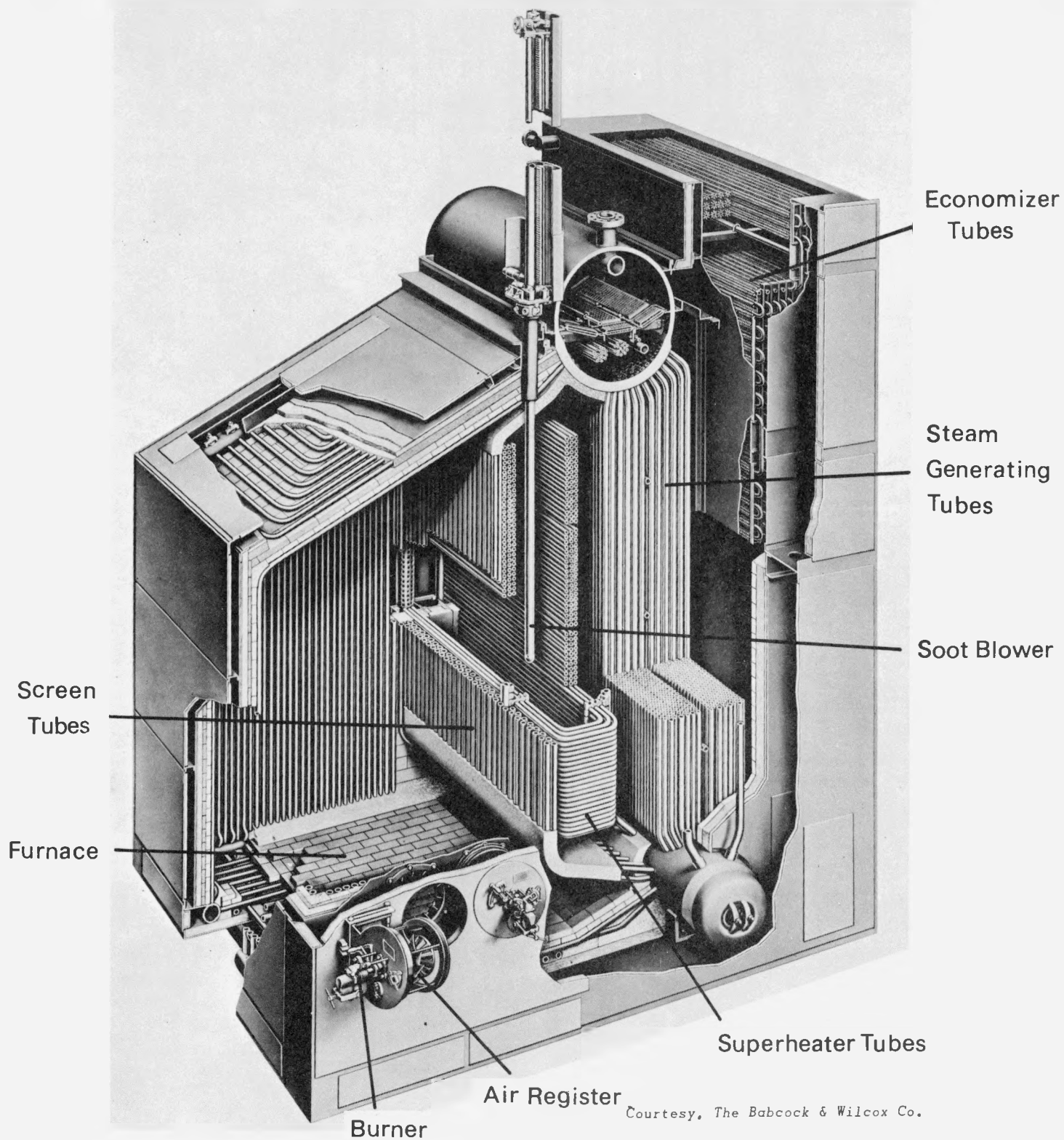
The major single use for fuel in the United States is to generate steam. In 1977, 4.2 quads (4.2×10^{15} Btu) of energy in the form of coal, oil, and gas were consumed in generating steam for industrial use, excluding the steam used by public utilities for generating electricity. Industrial utility engineers in each company have the responsibility of providing this steam at the lowest possible cost within the local limitations of labor and maintenance charges, fuel availability and pricing, and environmental regulations.

4.2 Boiler Technology

The boiler itself has become a complex device, as shown in Figures 1 and 2, in the effort to burn the fuel completely and efficiently, and then transfer the heat from the combustion gases through the walls of the boiler tubes into the water and steam. The effort to recover all of the heat from the combustion gases must be tempered by the knowledge that, below about 175°C, moisture and sulfur oxides will condense from the gases to deposit a corrosive liquid on economizer and preheater tubes (see Figure 3). The lowest temperature to which the gases should be cooled depends on the amount of air used for combustion and the sulfur content of the fuel, as shown in Figures 4 and 5.

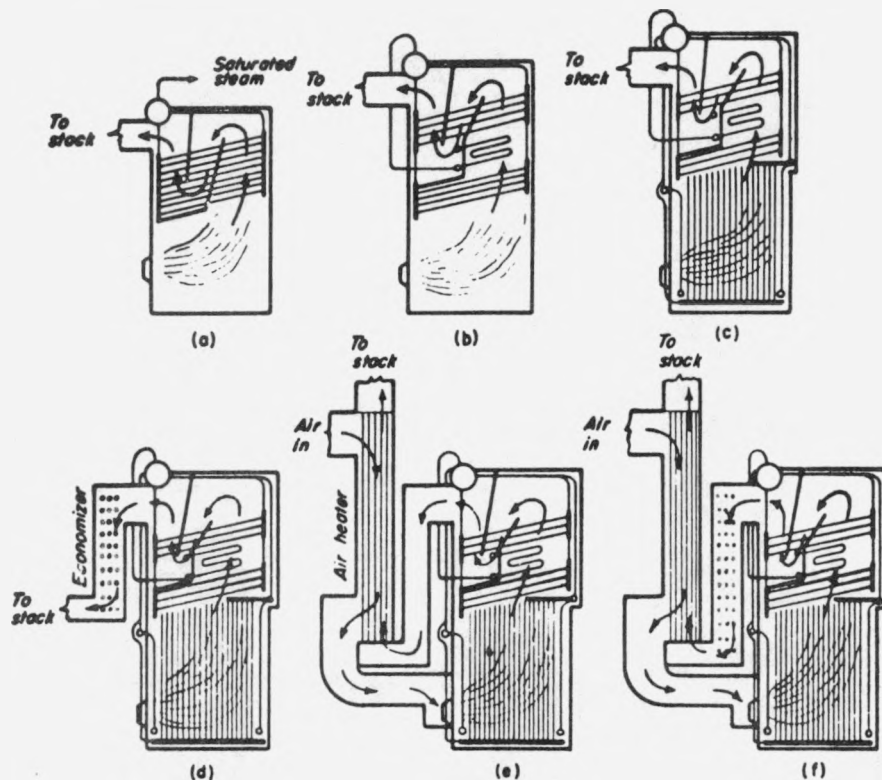
4.3 Solids Fuel Firing

Coal is normally cheaper than oil or gas in terms of dollars per million Btu delivered to the power plant. However, coal is a solid with variable ash content, typically around 10%. Furthermore, coal is not a single entity, but a range of products with different heat contents, slagging, and fouling tendencies. The boiler size and geometry relate to the classification



BABCOCK & WILCOX TWO-DRUM MARINE BOILER

Figure 1



To increase efficiency economically special forms of surface suited to the heat-transfer conditions in the various sections of the unit may be added to the simple boiler of

(a): superheater may be added at (b), waterwalls at (c), economizer at (d) or air heater at (e). Unit of (f) employs all the forms of surface.

Figure 2

**METHODS OF INCREASING EFFICIENCY BY
MORE COMPLETE HEAT EXTRACTION FROM COMBUSTION**



Courtesy, R. S. Norris Associates

**Figure 3 TYPICAL "COLD-END" CORROSION OF TUBES CAUSED BY
CONDENSATION OF WATER AND OXIDES OF SULFUR ON COLD METAL SURFACES**

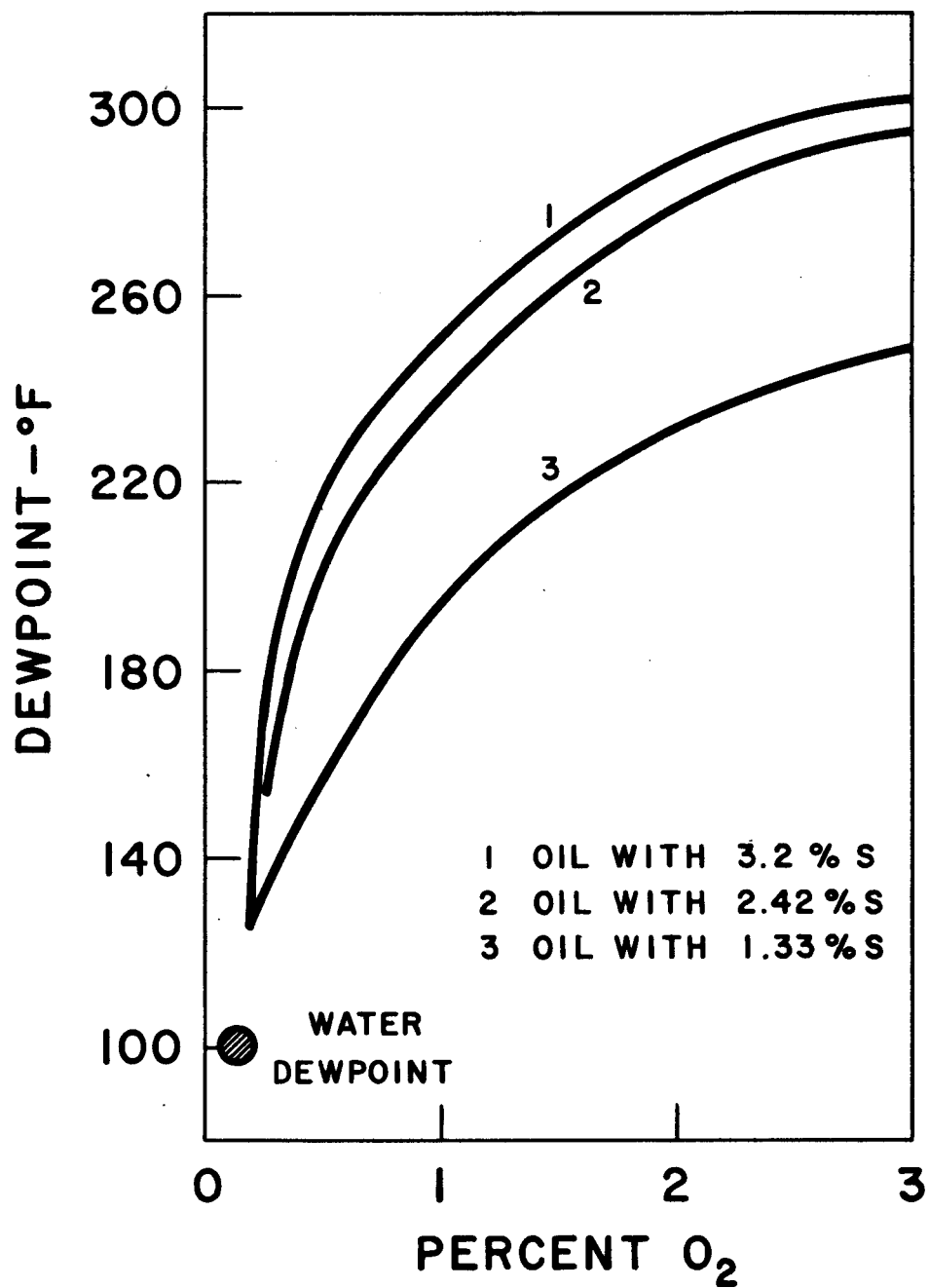
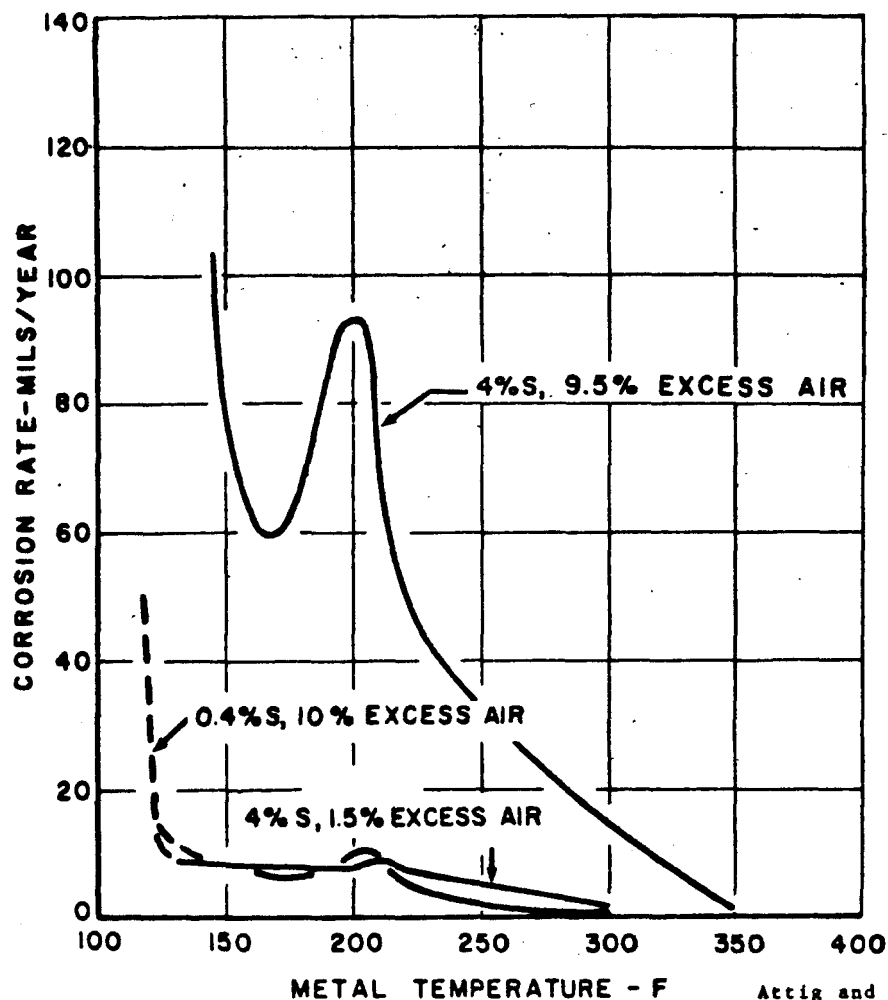


Figure 4 EFFECT OF LIMITED EXCESS AIR ON DEWPOINT OF STACK GASES FROM AN OIL-FIRED REFINERY BOILER



EFFECT OF EXCESS AIR
AND SULFUR ON CORROSION OF CARBON STEEL

Attig and Sedor, "A
Pilot Plant Investigation
of Factors Affecting Low-
Temperature Corrosion in
Oil-Fired Boilers," American
Power Conference, Chicago,
Illinois, April 14-16, 1964

Figure 5

of coal fired, and substitutions cannot be made lightly,⁽¹⁾ as illustrated in Figures 6 and 7.

Space, labor, and equipment are required for storage piles, for conveying, and crushing the fuel,⁽²⁾ and for disposing of the remaining one tenth (the ash) that is not combustible. In the boiler, part of the ash coats the boiler tubes, interfering with the flow of combustion gases between the tubes and acting as insulation to prevent the heat of the fire from flowing through the tube walls into the water and steam. "Soot blowers" are used to clean off the tubes, sometimes three or more times a day, with jets of steam or compressed air to maintain the boiler capacity and efficiency. Otherwise, the space between the tubes become clogged, restricting the flow of combustion gas and reducing the size of the fire that can be maintained; such combustion gas as is generated leaves the stack at too high a temperature because it is unable to properly transfer heat into the steam or water to accomplish useful work.

The combustion gases from coal carry some of the ash out of the furnace, particularly during the soot blowing operation. The gases also contain sulfur oxides and nitrogen oxides formed by combustion of impurities in the coal. (This is in addition to the nitrogen oxides formed by the heat of the flame from the nitrogen which comprises 4/5 of the air around us). Equipment as large as the boiler might be required on the outlet of the boiler to remove these components from the combustion gases in accordance with environmental regulations. If limestone is used as the treating agent to remove the sulfur oxides from the combustion gas, at least 65 lb of limestone is required for each percent sulfur liberated from a ton of coal. With coal

-
- (1) For an overview of coal properties as related to boiler requirements, refer to Smith, V. L., "Coal Firing and Industrial Boiler Design - the Modern Approach," ASME Paper 75-IPWR-14, which is Appendix A in this section.
- (2) For an overview of coal storage and handling, refer to Harris, E. R., Connell, G. F., and Dengiz, F., "Coal Handling Equipment and Storage (For Industrial Plants)," ASME Paper 75-IPWR-1, Appendix B in this section.

FURNACE SIZE COMPARISONS

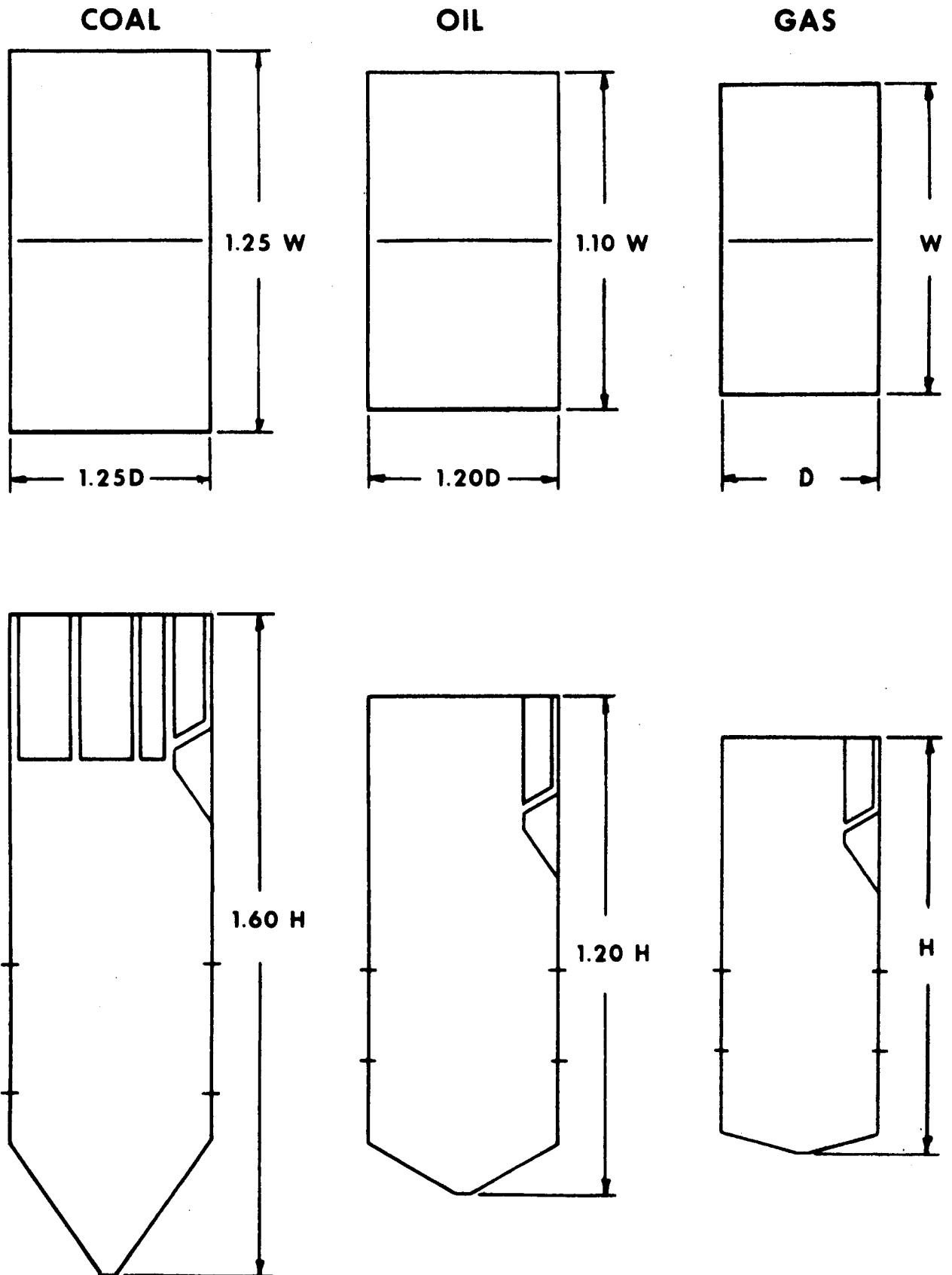


Figure 6

From Richards, C. L., "Conversion to Coal - Fact or Fiction",
Combustion Magazine, April, 1978.

FURNACE SIZE COMPARISONS

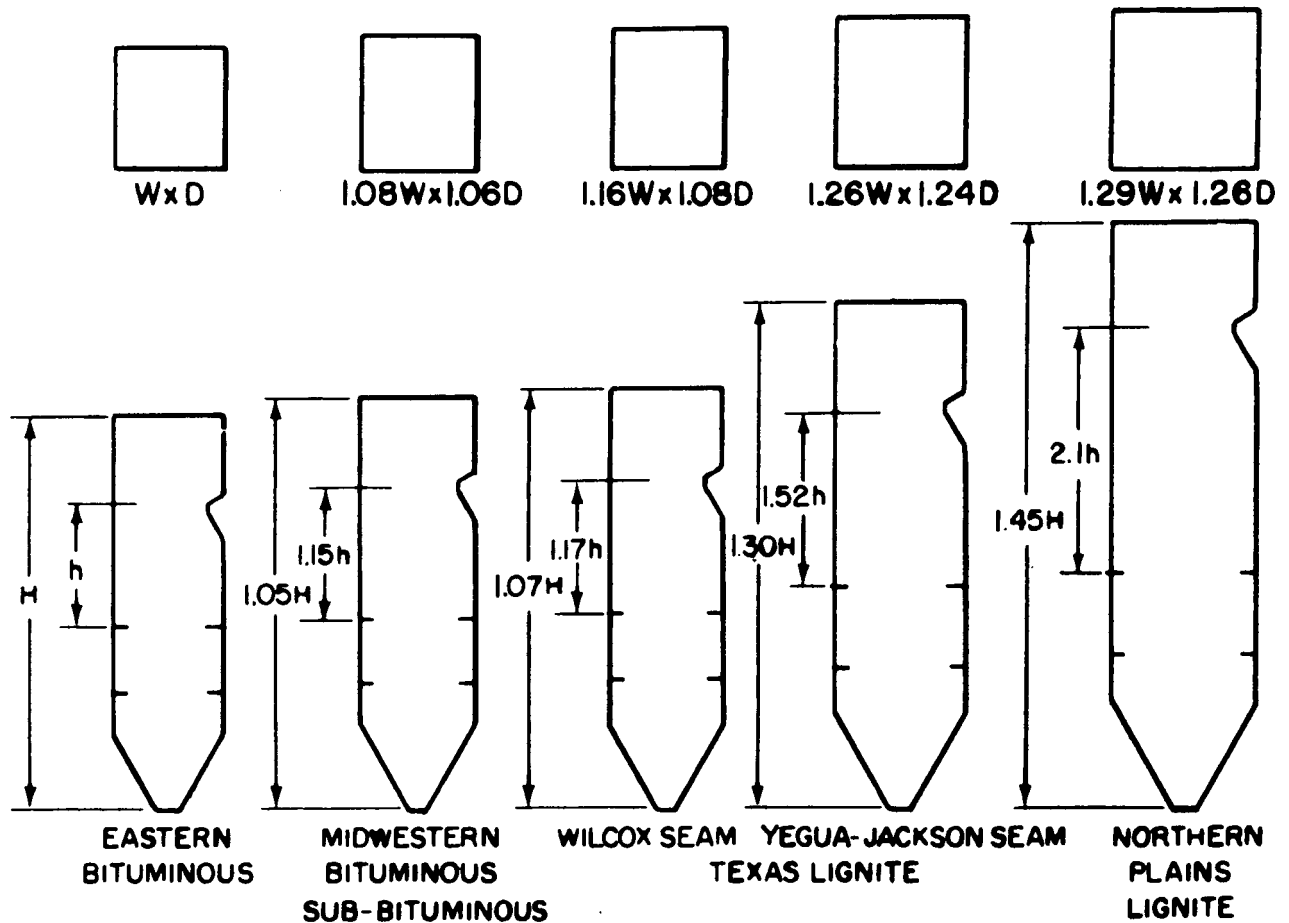


Figure 7

Furnace sizes needed for the various coals to operate with various properties that influence slagging.

From Richards, C. L., "Conversion to Coal - Fact or Fiction", Combustion Magazine, April, 1978.

of 3 to 4% sulfur content, the spent limestone can exceed the weight of the ash, thus doubling the problem of solid waste disposal.

The question of burning waste fuel arises frequently and, indeed, this is common in many industries. Bagasse, sawdust, coffee grounds, sulfite liquor, and old rubber tires⁽³⁾ are among the materials successfully handled. Municipal waste is occasionally used, especially in Europe, as an endless supply of "free" low-sulfur fuel. However, with municipal waste, the maintenance and operation are sufficiently formidable that the cost of steam generation is usually greater than when burning purchased fossil fuels.⁽⁴⁾

4.4 Liquid Fuel Firing

Oil is much more convenient than coal, since it can be stored in tanks and transferred by pumping. Switches, valves, and controls take the place of the conveyors, bulldozers, and crushers - and labor - required with coal. But oil must be considered in two categories: residual and distillate.

A residual is a petroleum fraction that did not vaporize during distillation in the refinery. If the refinery employed only atmospheric distillation at about 700°F, the residual might be half of the crude oil. Much foreign and imported residual fuel is made in this manner. However, modern American refinery practice requires high temperature vacuum distillation of this residue, followed by severe heating and catalytic treatments to convert more of the residue into distillates. The residue from this treatment is a highly viscous tar that contains resins, ash, asphaltenes, and coke in a cracked, viscous oil. In 1954, residual fuel yields in the United States represented 16.4% of the average barrel of crude oil, but refiners reduced

(3) In Appendix C, see ASME Paper 75-IPWR-10 by Moats, E. R., "Operating Experience with a Tire-Fired Boiler."

(4) See Appendix D, ASME Paper 71-WA/Inc. 2 by Sommerlad, R. E., et al., "Systems Evaluation of Refuse as a Low Sulfur Fuel," also Appendix E which is ASME Paper 68-PWR-3 by Sebastian, F. P., et al., "Modern Refuse Incineration in Dusseldorf - A Composite of the Best European Practices."

this to 8.6% in a decade. The residue can be further reduced to a solid coke, and an increasing number of American refineries are adopting this practice.

Sometimes the liquid residue is kept hot ($>200^{\circ}\text{C}$) and burned directly in an industrial furnace. If the residue is to be sold as commercial fuel, it must be diluted with distillate to reduce the viscosity. With minimum dilution, viscous No. 6 fuel oil is obtained which must be heated for pumping and handling, and must be heated even more to reduce the viscosity sufficiently for proper atomization and burning. Ash content of No. 6 fuel oil averages around 0.03 to 0.05%, so the dust load in an oil-fired furnace is obviously less than 5% of what it is in a coal furnace. Still, there is a need for soot blowers to clean the outside of the boiler tubes regularly, and there may be need for flue gas treatment to capture sulfur oxides, particulates, and/or nitrogen oxides. Also, the fuel oil ash contains vanadium pentoxide which, above its melting point, is extremely corrosive to high temperature alloy metals.⁽⁵⁾

On the other hand, distillate fuel, which is best exemplified by No. 2 diesel fuel or No. 2 home heating oil, remains free flowing at temperatures of -15°C or lower and has an ash content measured in parts per million. With no need for preheaters, soot blowers, or stack gas cleanup, only minimum costs are involved in equipment, operation, and maintenance.

Blends of No. 2 and No. 6 fuel oils are also widely marketed. A mixture of 80% No. 6 and 20% No. 2 will give No. 5 fuel oil, which can be pumped and handled without heating, but requires preheating for proper atomization. This compromise is often convenient for industrial use. No. 4 fuel oil is typically a 50-50 blend of No. 2 and No. 6 fuel oils and can be handled and burned without preheat. No. 4 fuel oil is often used in commercial boilers in apartments, dry cleaners, greenhouses, etc., where the

⁽⁵⁾ The nominal melting point of V_2O_5 is 690°C , but this can be lowered at least 100° by fluxes in the ash (salt, caustic, etc) or raised 500° by neutralization with magnesia, lime, or alumina.

building custodian might clean ash deposits out of the boiler on a quarterly or yearly basis.

4.5 Gaseous Fuel Firing

The ultimate fuel for low operating costs is, of course, natural gas. It does not even require the fuel tanks, pumps, and atomizing nozzles needed for No. 2 fuel oil. Good combustion is achieved with minimal attention and, except for precautions to avoid the formation of nitrogen oxides, there is no environmental concern over stack emissions.

Most natural gas is supplied through long distance pipelines which must operate continuously at high load factor to achieve reasonable economy. Three different approaches have been highly developed to match variable demand with steady supply:

1. Underground Storage. Old gas fields in Pennsylvania and Ohio serve as summer repositories for gas from the southwestern states. The stored gas supplements pipeline deliveries in winter months.
2. Special Rate Structures. Utilities and industries burn gas at reduced prices in warm weather and switch to alternate fuels on short notice when gas is needed for home heating. This arrangement has been extremely satisfactory for canneries who process foods during the harvest season and are virtually shut down before cold weather.

Some municipal gas utilities who buy gas from the pipeline wholesale "at the city gate" find it economical to start up their own gas manufacturing plants in the coldest weather. Using their own gas for "peak shaving" can be more economical than paying the excess demand charges established by the pipeline.

3. Liquefied Storage. First used commercially in Cleveland, Ohio, in 1940, the summer liquefaction of pipeline gas for storage and later

use during periods of peak demand is now receiving renewed attention in New England.

4.6 Fuel Transportation

With coal and oil, as well as with gas, it is easy to overlook the miracle of materials handling that is involved in transporting fuel to industrial boilers. By definition, industrial boilers range from about 50,000 to 500,000 lb of steam per hour. For a simple example, consider the fuel requirements for a boiler of 100,000 lb per hour steam generating capacity. That 18-wheel coal truck lumbering down the turnpike can carry only enough fuel to keep the boiler going for 5-1/2 hours. If there is a typical 60-day fuel reserve at the plant, there are 260 truckloads like that one, piled near the boiler house. And there will be three truckloads of ash per week to dispose of. The 18-wheel tank truck that is trying to pass the coal truck is hauling enough oil to keep the boiler going about eight hours. If it is No. 6 fuel oil, the ash will be less than a truckload per year. Fueled with No. 2 fuel oil or with natural gas, there will be no ash problem, but the boiler will consume enough each year to heat 8500 homes for the same period of time.

Trucks afford easy visualization, of course, but the total coal distribution system includes rail and water transportation as well as a few pipelines where coal is transported in slurry form. The same is true for residual fuel: deep draft marine, lake tankers, barges, railroad tank cars, and a few short pipelines provide the major means of transportation between refineries, terminals, and users.

A different pattern is found for the non-viscous refined petroleum products (gasoline, kerosene, distillates). Pipeline systems from the refineries to consuming areas are the backbone of the transportation-distribution system, supplemented as required by water, rail, and highway transport. Petroleum pipelines are currently the cheapest way to transport large quantities of energy overland; cheaper than gas pipelines, unit trains for coal, or high voltage electrical transmission lines. In the last 15 years, pipelines

have even displaced tankers for bulk deliveries from the Gulf Coast to the East Coast north of Norfolk. Jet fuel goes by pipeline from refineries in Port Arthur, Texas, to Kennedy Airport in New York entirely by pipeline. Looking at the overall petroleum system, refined products move by pipeline or water transport to storage terminals from which they are handled by truck, rail, or barge to customers or, in a few instances, to wholesalers or redistribution points before final delivery.

Natural gas is, of course, handled entirely by pipeline except for recent ventures into transportation as a cryogenic liquid. Economical and efficient as they are, gas pipelines require more pumping energy per Btu per mile than the refined petroleum products. For gases of substantially lower heating value than natural gas, the cost of long distance pipelining becomes prohibitive.

4.7 The Changing Fuel Situation

In the last six years, the industrial utility engineer has been faced with a widely vacillating fuel supply situation. Today, coal might be unavailable because of a strike, tomorrow oil might be unavailable because of an embargo, the next day gas might be unavailable because of governmental edict or cold weather. At the same time, the environmental control regulations have grown relentlessly more severe, restricting the fuel options. Early in this decade, Pennsylvania launched a program to convert boilers at all state institutions - universities, prisons, hospitals, governmental buildings - from coal to gas and oil firing in the interest of air quality control. Only five institutions had accomplished the change before the program was abandoned because of fuel shortages.

Several companies have developed detailed plans for firing more than one fuel at the same time, to achieve the lowest cost steam while meeting the environmental requirements. At the Pittsburgh plant of H. J. Heinz Company, this is called "ratio firing."

The Heinz plant in Pittsburgh is unique in the food industry, not only in having a fairly constant load but also in having been designed originally for coal firing. There are five 40,000 lb/hr Babcock & Wilcox chain grate jet ignition boilers connected to one stack with no dust collector. There are also two Combustion Engineering boilers with spreader stokers and mechanical dust collectors exhausting through a second stack. Heinz rates the C-E boilers at 60,000 lb/hr. When air pollution control regulations required operational changes, gas-oil burners were added to six of the boilers without removing the coal-firing capability, even though this approach was novel and quite difficult. Now two or three fuels are fired simultaneously to achieve the lowest overall fuel cost while complying with regulations on particulates emissions. They are currently firing 55% low sulfur, low ash Kentucky coal (0.6% sulfur, 5-7% ash), 35% natural gas, and 10% low sulfur No. 6 fuel oil (about 0.4% sulfur). Retention of the coal-firing capability, coupled with the use of the premium grade coal, has saved \$4 million in fuel costs over the past six years as compared with 100% conversion to oil-gas firing.

In the future, the fuel options promise to become even more restrictive as natural gas and petroleum are diverted from industrial boilers to other uses. A report by the American Boiler Manufacturers Association states that current trends in boiler purchases indicate decreased reliance on natural gas and emphasis on waste fuel and coal for industrial units.⁽⁷⁾ To this should be added the option of burning coal-derived liquid. As discussed in Section 5, coal firing promises better economy for larger boilers with a high utilization factor because the low unit cost of fuel becomes more important than the cost of labor, equipment, and maintenance. Conversely, smaller plants, or large plants operating at a low utilization factor, can afford to pay a higher unit cost for fuel to save on other charges.

⁽⁷⁾ See Appendix F, "Shift in Boiler Fuel Usage Patterns," by W. H. Axtman, Executive Director, ABMA.

Utilization factors can be defined as the quantity of steam a boiler actually produces as compared with how much it would produce if operated continuously at rated capacity. The boilers in a cannery might operate at full load night and day for two months and be on standby or shut down the rest of the year. For example, a tomato processing plant in California used 0.68×10^{12} Btu of natural gas in 1977, of which 0.48×10^{12} (70%) was used in August and September. A machine shop might work two shifts a day; the demand for heating steam will fluctuate with the plant activity as well as with the seasonal demand for space heating. Studies by Battelle-Columbus, discussed later, show an overall utilization factor of 40% for boilers in the manufacturing industries. In contrast to this, the Battelle-Columbus data show an overall utilization factor of 67.3% in the process industries such as rubber and chemicals.

4.8 Boiler Economics

The preceding discussion on equipment, maintenance, operation, and labor requirements must be converted to economics to be fully appreciated. The subject is covered in Section 5, Steam Generation Economics. For orientation, the following may be helpful:

1. Boilers using distillate fuel oil (petroleum or SRC-II) will need oil receiving facilities, storage tanks, and piping.
2. Boilers using No. 5 or No. 6 fuel oil, or SRC-II heavy distillate, will need similar oil handling facilities except they must be heated.⁽⁸⁾ In addition, soot blowers will be required, and equipment to control particulate emissions may be required with the petroleum fuels but not with SRC-II fuel oil.

⁽⁸⁾ Fuel-handling facilities for residual oil are discussed in Appendix G, a paper on "Heavy Oil Pumping, Heating," by A. J. Poole.

3. Boilers using coal fall into two categories:

- a. Units up to about 250,000 lb steam per hour use screened grades of lump coal burned on grates. This requires coal receiving, storage, and conveying facilities, plus soot blowers, emissions controls; and means for collecting, storing, and disposing of ash.
 - b. Units above 250,000 lb steam per hour use cheaper, run-of-mine coal which is pulverized on-site and burned as a coarse dust suspended in air. Pulverized coal units require the same basic equipment as the stoker units, except that the grate is omitted and a crusher, grinding mill, and airveying system are added. Also, a pilot fuel system must be added so the furnace can be started by burning gas or distillate oil. (The stoker units are usually started by building a fire with scrap wood on the grate.)
4. New schemes under consideration include: (1) on-site gasification of coal, or (2) burning of coal in a fluidized bed at atmospheric pressure (AFB) with limestone added to trap sulfur oxides as they are formed. The AFB option is considered in a companion report in Volume 4 on the boiler plant at a Rohm and Haas facility. Without a detailed consideration of economics, both of these plans fall in the same general category as direct coal burning, i.e., they require equipment and labor for on-site handling of solid fuel and ash, and would be more competitive in large, high load factor boiler installations.

Boilers in sizes up to 125,000 lb per hour are generally shop assembled. This is the most economical, efficient means of construction, but the overall size is limited by railroad shipping clearances. In capacities from 125,000 to over 200,000 lb per hour, boilers might be field assembled; i.e., they are built in two pieces that are joined on-site. Larger sized units are built in the field from tubing, drums, and other basic components.

When plotting costs versus boiler size, as discussed below in Section 5, Steam Generation Economics, there is a discontinuity in the curves at the transition from stoker coal-firing with graded coal to powdered coal-firing using the cheaper run-of-mine coal.

Space requirements for coal storage and for flue gas desulfurization, or for equipment to collect particulate emissions can raise problems in siting or retrofiting. Existing plants may not have access to a rail siding for coal deliveries nor space for coal handling and storage. Even for plants which had been coal fired at some time in the past, it is not uncommon to have no room because the former coal yard was converted to other use when oil burning was adopted (see Appendix B). Also, in urban areas, any limestone sludges or other spent reagents from flue gas desulfurization would have to be disposed of at an off-site location, which involves hauling and dumping costs. In densely populated, environmentally conscious areas, such as typically found in the populous East Coast areas of the United States, siting of such a dumping location can be difficult.

Investment, operating, and maintenance costs for coal-fired boilers are three to four times as high as for oil-fired units, as will be discussed in Section 5, Steam Generation Economics. Labor is one important component; 13 to 15 men might be required for 24-hour operation of a coal-fired unit as compared with 5 for oil firing. Another factor is the greater physical size of the coal-fired boiler plus the additional auxiliary equipment it requires, as illustrated in Figures 8, 9, 10, and 11.

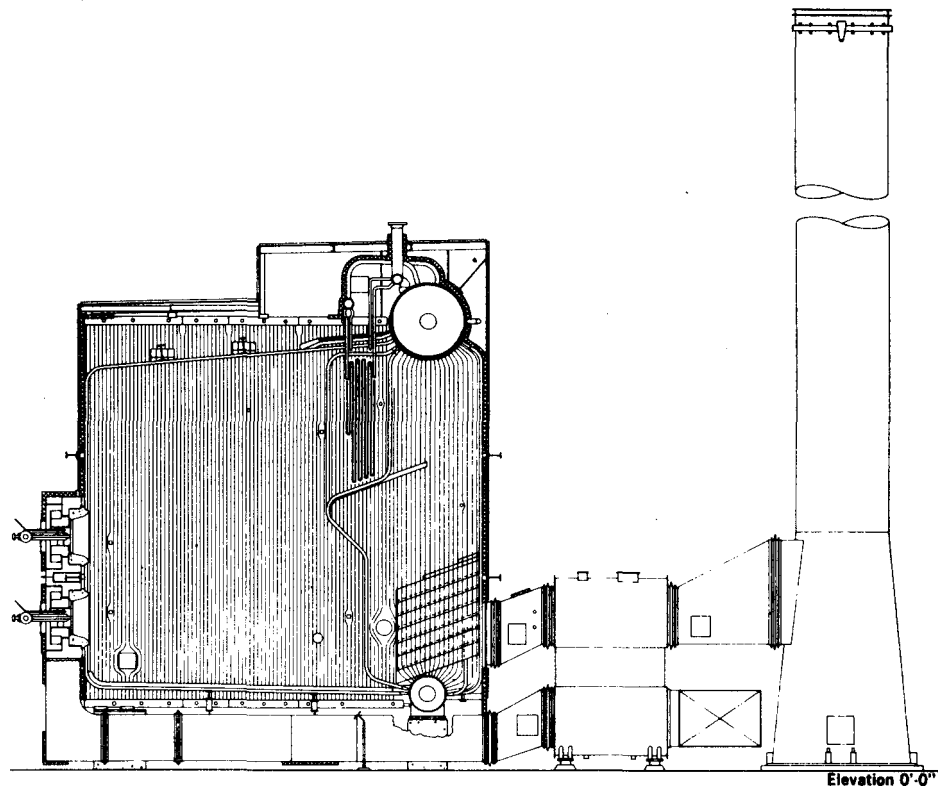


Figure 8 BOTTOM SUPPORTED UNIT DESIGNED FOR OIL AND GAS FIRING

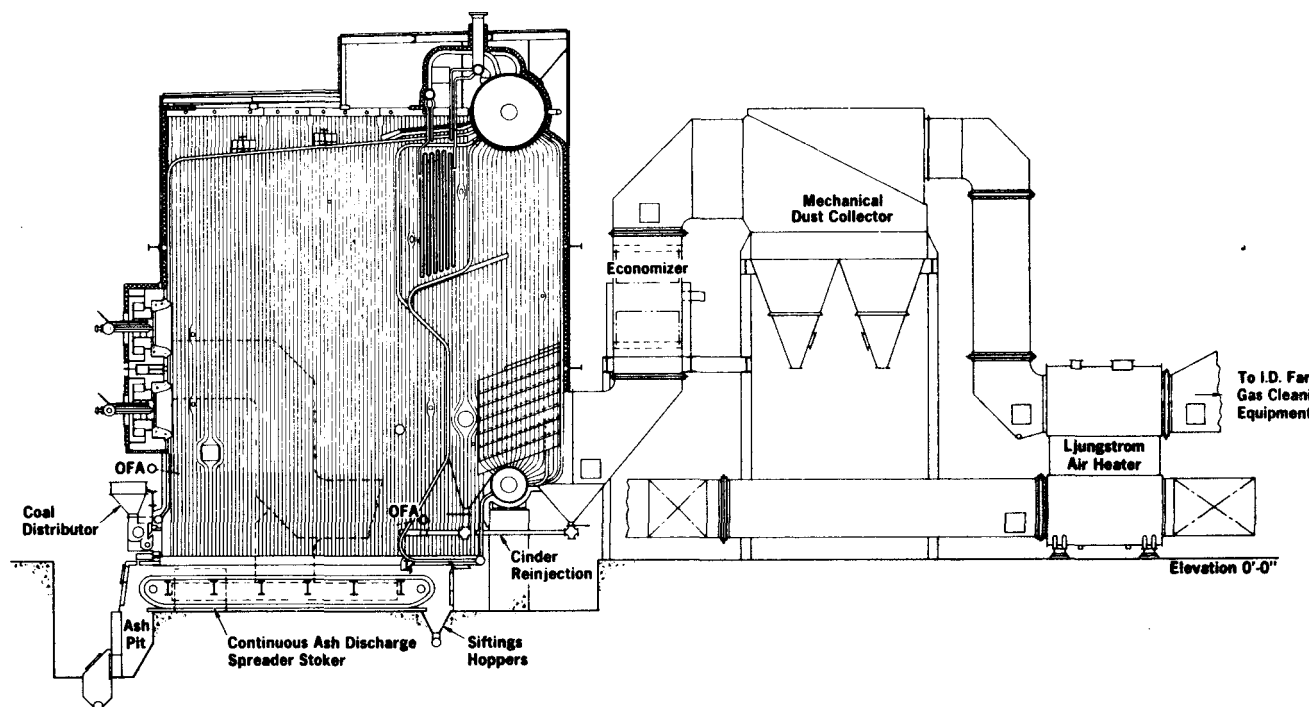
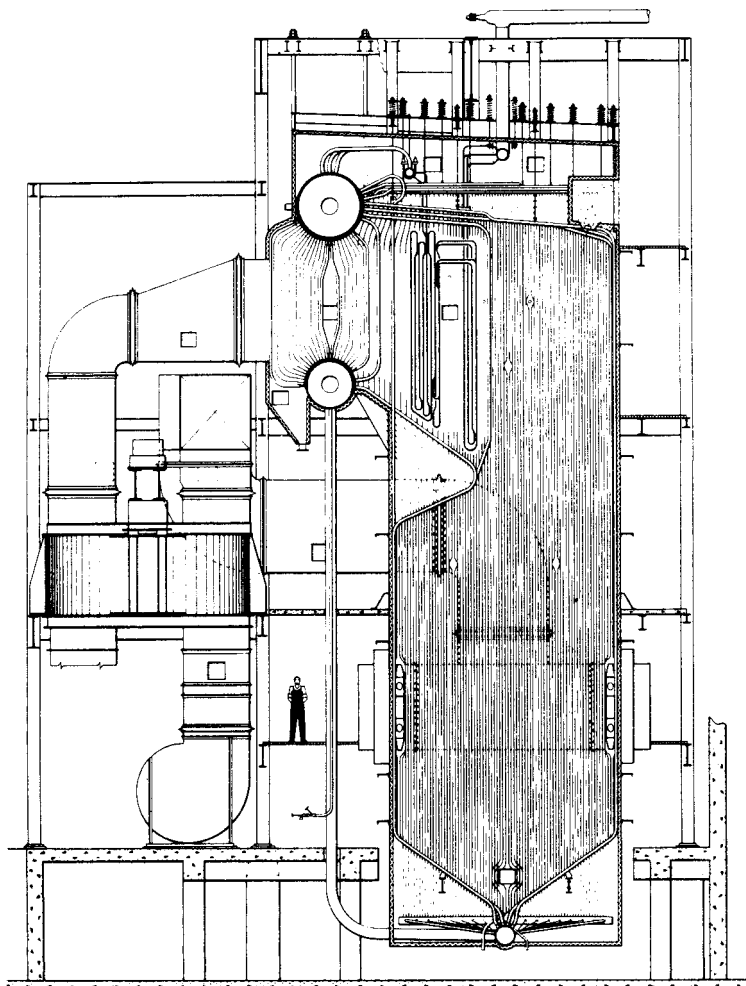


Figure 9 BOTTOM SUPPORTED UNIT CONVERTED TO SPREADER STOKER COAL FIRING

FROM RULNICK, S. N. AND SMITH, B. H.,
 "CONVERSION OF OIL AND GAS-FIRED
 INDUSTRIAL BOILERS TO COAL FIRING"
 ASME INDUSTRIAL POWER CONF., MAY, 1976
 (CE POWER SYSTEMS PAPER T1S-4931)



FROM RULNICK, S. N. AND SMITH, B.H.,
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 INDUSTRIAL BOILERS TO COAL FIRING"
 ASME INDUSTRIAL POWER CONF., MAY, 1976
 (CE POWER SYSTEMS PAPER TIS-4931)

**Figure 10 TOP SUPPORTED UNIT DESIGNED FOR
 OIL AND GAS FIRING**

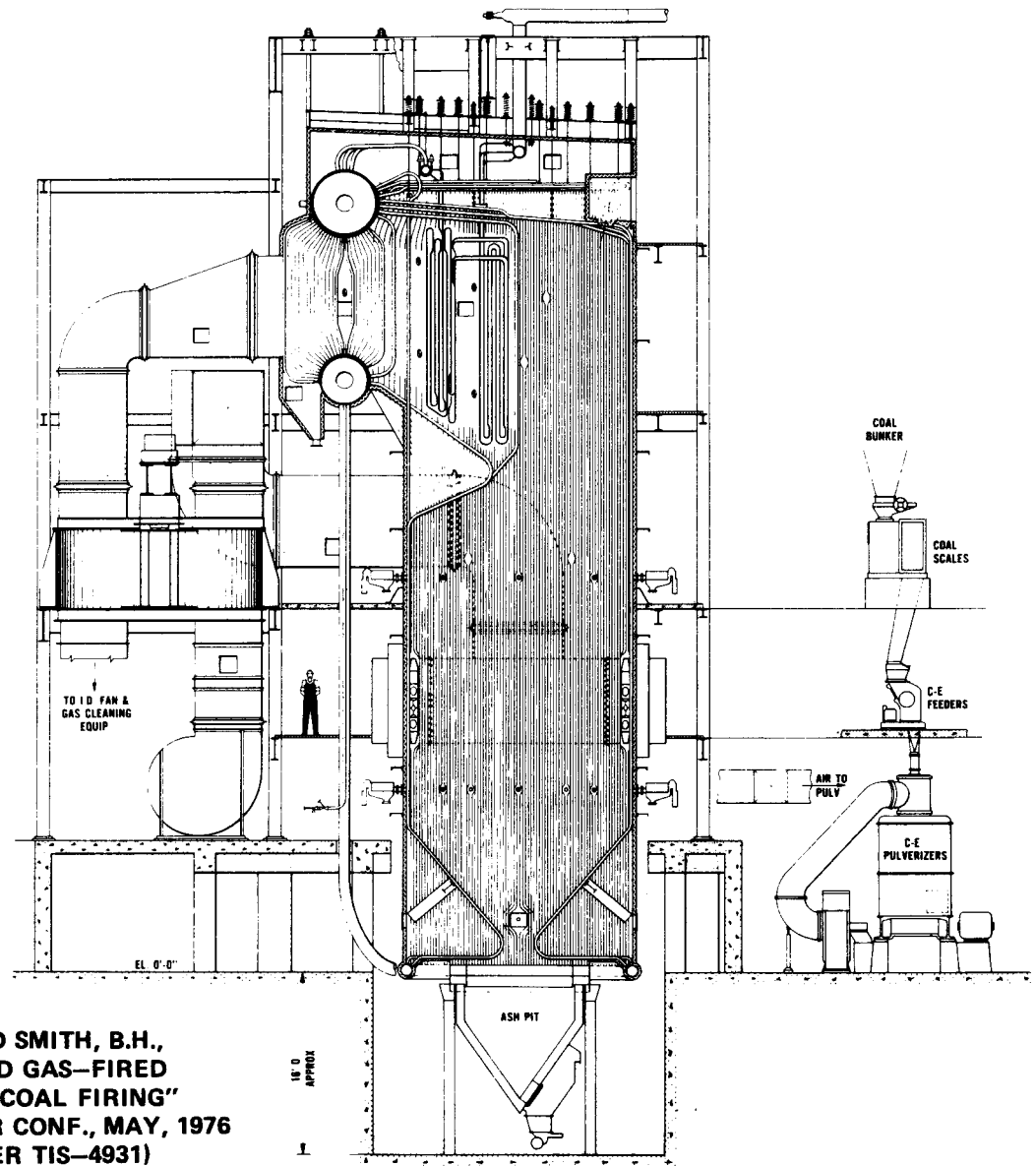


**Figure 11 TOP SUPPORTED UNIT CONVERTED TO
 PULVERIZED COAL FIRING**

APPENDIX A

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Coal Firing and Industrial Boiler Design—the Modern Approach

Coal is becoming increasingly more favorable as a fuel due to petroleum becoming too valuable to be used as one. The technology of firing coal has advanced tremendously as a result of new coal source discoveries and higher pressure and temperature steam generation. This paper defines the modern classifications of the different coals found in the United States and presents the respective design parameters for each classification. The varying design parameters in conjunction with the coal classifications are then related to modern industrial boiler design.

Introduction

Coal was once the primary source of energy for the commercial as well as the residential section of the American economy. The surplus and then seemingly inexhaustible supply of petroleum and natural gas set up a definite trend away from the use of coal between the early 20's and the early 60's. Environmental protection legislation acts of 1963 and 1970 further reduced the use of coal in favor of cleaner, less troublesome fuels.

After World War II, the United States could no longer satisfy its ever increasing appetite for petroleum with domestic production. This resulted in the importing of greater amounts of crude oil. The United States was no longer independent of the rest of the world.

American industry has finally realized its dependence on potentially hostile governments. Coupled with the current energy crises and the fluctuating value of the dollar, a major turnaround is now occurring. Industry is again utilizing a fuel abundant in this country—coal.

In these earlier years, nearly every industrial plant operator and designer associated with the power generation field was familiar with and knowledgeable of coal and its design parameters. Today's industrial plant operator generally does not have this experience. The following bulk of this text is intended to present a brief exposure in an attempt to create an awareness of the complexities involved when coal is used as a primary energy source. The reader should acquaint himself with the glossary of terms listed at the beginning of the Appendix.

Coal—A Fuel

Coal is probably the most abundant and most economical source of energy for industrial boilers used to generate both process and

power steam. The coal reserves have long been "estimated from drillings, outcroppings, operating mines, and explorations for minerals and oil" [1].¹ Millions of years under moisture, heat, and pressure were required to convert the wood and vegetation to carbon and hydrocarbons. The procession of change probably was as follows: peat, brown coals, lignite, subbituminous, bituminous, and anthracite.

Coal, however, is also the dirtiest (i.e., high ash content) of all fuels commercially burned or fired in industrial boilers. The ash of a coal sample can be identified as intrinsic—in the vegetation from the beginning—and extraneous—mud deposits of shale and pyrites which were mixed in with the vegetation from external sources.

The boiler furnace acts as a large chemical reactor where the coal is intimately mixed with air and burned producing gas temperatures up to the 3000 deg range. Although the resulting ash constituents are many and varied there are only approximately eight or nine that are found in the United States in major amounts. These constituents determine the physical and chemical characteristics of the coal ash. The compounds forming the ash constituents and their interaction with each other determine the behavior of the ash in the boiler furnace.

The proper utilization of Eastern bituminous type coals as an energy source was a long-term process taking many years. Knowledge of the coal preparation and burning characteristics was acquired on relatively small units where fuel supply could be varied depending on operating results. In contrast, fuel supply and units' size designed to fire Western coals has grown at a rapid rate. The majority of the Western coals come from undeveloped seams where the knowledge of its characteristics is limited to core samples. These geologically young coals have wide variations from seam to seam and within seams thus limiting the usefulness of core sampling programs.

The selection of a coal or a plant to handle available coal is actu-

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Copies will be available until February, 1976

¹ Numbers in brackets designate References at end of paper.

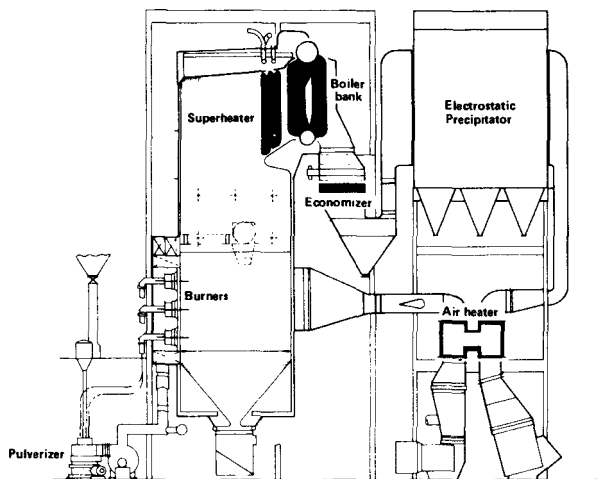


Fig. 1 PC fired system

ally a function of economics. The owner desires to generate steam at the lowest overall cost which includes cost at the mine, shipping charges, storage, handling, initial capital expenditures, operating, and maintenance costs.

Energy Conversion

Differentiating from oil and gas, coal is not a processed fuel in the same sense of the word. Petroleum products are refined to an essentially homogeneous fuel from coast to coast. An oil fired boiler is not significantly different for one part of the country as compared to another. Coal fired units within one state may vary drastically in size, performance, etc. Some cleaning may be performed at the mine, but there is not any commercially available refinement of the chemical constituents of coal. Coal gasification may refine the fuel but at an added cost. Why not replace natural petroleum products by firing coal in its raw form in lieu of oil or gas?

To reduce this paper to a printable volume, pulverized coal systems are the only type of boilers discussed. A typical modern pulverized coal unit is illustrated in Fig. 1. Only furnace, superheater, and boiler design are touched upon.

Pulverized coal is introduced into the boiler furnace with hot air and is ignited at a very high temperature. The mineral matter in the coal is released from its organic matrix and either (1) remains solid (fly ash), (2) melts and becomes liquid sticking to boiler surfaces, (3) remains liquid and flows easily on boiler surfaces, or (4) volatilizes and condenses on surfaces in the convection zone of the boiler and also on suspended fly ash particles. This combustion process is depicted pictorially in Fig. 2.

The ultimate analysis establishing the elemental chemical composition coupled with the heating value provides sufficient data for combustion calculations and predicting boiler performance. The proximate analysis provides a breakdown of the volatile matter, fixed carbon, moisture, and ash content. With the proximate analysis, the behavior of a particular coal in the boiler furnace can be predicted. A burning profile reflects the volatile matter portion of a coal. This portion consists of combustible and noncombustible gases. The profile therefore provides a graphic picture of the rate of ignition which is essential in burner and furnace design. Typical burning profiles per ASTM rank are presented in Fig. 3. The foregoing, however, offers little knowledge to estimate the severity of ash deposition on boiler furnaces.

Coal Ash

Why be concerned with ash deposition on boiler surfaces? The following list is intended to demonstrate the significance of coal ash without considering its affect on boiler surfaces. Coal ash must be:

- 1 Paid for—a price per pound of coal also includes ash which

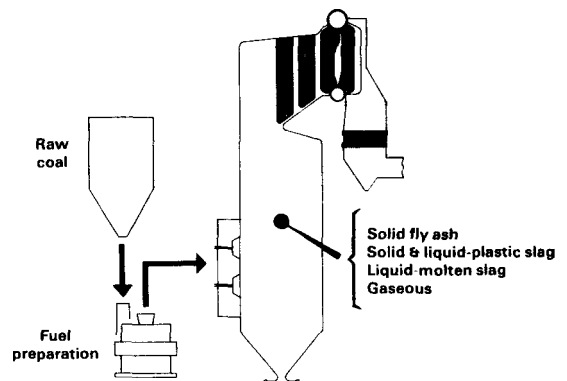


Fig. 2 Combustion process

has a zero heating value.

- 2 Shipped—transportation charges per Btu are increased as ash content increases.

- 3 Conveyed—more coal must be delivered from the stock pile to pulverizer as ash content goes up.

- 4 Pulverized—in the same sense, more pounds of coal must be crushed to a powder with increased ash content.

- 5 Heated—the ash particles are heated to very high temperatures.

- 6 Collected—the ash that does escape the boiler furnace, economizer, and air heater must be collected by some means to comply with emission standards.

- 7 Disposed of—the bottom and fly ash collected must then be economically and ecologically done away with.

Coal ash has been demonstrated to be of significant importance or concern to the plant designer or operator. Why is coal ash, its chemistry and quantity, of importance to the design of the boiler and furnace? Answer to this question will be found in the remaining portion of this paper. Briefly, however, ash accumulation on furnace, superheater, and boiler surfaces result in the following:

- 1 A layer of ash reduces heat transfer by conduction which in turn raises the outside surface temperature reducing heat transfer by radiation.

- 2 Accumulations of ash in the furnace may break away in large chunks and fall from a sufficient distance possibly damaging pressure parts, stoker if applicable, ash hopper, etc.

- 3 Lower heat transfer in the furnace can raise gas temperatures in superheater (higher steam temperatures) and boiler exit (loss efficiency).

- 4 Possible plugging of convection surfaces, (boiler, superheater, economizer, and air heater) reducing steam output.

The usefulness of a coal's heating value, ultimate and proximate analyses have been touched upon. The information provided by these parameters provide no means of predicting the severity of ash deposition on boiler surfaces. The molecular formations and interaction of coal ash is the result of an extremely complex chemical reaction. To predict the coal ash characteristics when a particular coal is burned in a coal furnace, empirical relationships were developed using an analysis of the coal ash constituents. To supplement, ash fusion temperatures and the viscosity-temperature relationships are also used. Fuel test data of units firing similar coals but in differing designs have been correlated to expand and refine boiler design technology. Before design technology and parameters are presented, the ash deposition mechanisms must first be defined.

A Fused Slag Deposits—Slagging. One ash characteristic of particular importance to boiler designers is slagging. Slagging is the deposition of solid and molten ash particles on heat transfer surfaces. Slagging takes place primarily in the boiler furnace but may be precipitated into the superheaters by upset conditions. The ash or mineral matter in coal is a complex mixture of clays,

shells, pyrites, calcite, dolomite, quartz, etc. When subjected to the intense heat and radiation in the boiler furnace, these mixtures become molten. When the molten ash comes into contact with the relatively cool boiler surface, the molten ash forms a sticky base for fly ash particles to stick to. When gas temperatures are above the melting temperature of ash, the ash will remain fluid and run down the furnace walls. This molten ash is rarely thick enough to hinder or impair the heat transfer, thereby creating minor problems in boiler design. As the ashes are further cooled by the furnace surface primarily through radiation, temperatures decrease and the viscosity of the fluid increases resulting in a slower moving, thicker liquid. This mixture of liquid and solid particles is called plastic slag.

The Babcock & Wilcox Company has developed a slagging index utilizing the ratio of the basic to the acidic ash constituents in bituminous coal ash. The combustion of bituminous coals result in a Fe_2O_3 content in the ash (percent by weight) greater than the $\text{CaO} + \text{MgO}$ content. For lignite or subbituminous coals with a lignitic type ash, the reverse is true. This index has been proven successful for predicting the slagging potential of coals mined east of the Mississippi River. The amount of sulphur in the ultimate analysis of the coal is also a factor even though the ash contains little if any sulphur. This is true because approximately one-half of the sulphur is in the form of FeS_2 . During the combustion of coal the sulphur is released as SO_2 and the iron is oxidized to Fe_2O_3 or FeO depending on the furnace conditions, i.e., oxidizing or reducing atmosphere. In a reducing atmosphere, more FeO is generated thus lowering the melting temperatures. The influence of iron (Fe) content in the coal ash is demonstrated in Fig. 4.

The foregoing slagging index is sufficiently accurate for designing boilers to fire bituminous coals. The best information, however, is obtained from the viscosity-temperature relationship of the coal ash establishing melting and flow characteristics and is applicable for both bituminous and lignite coals. The plastic zone discretely defined enables wall blowers to be situated where the slag accumulates while maintaining slag in the burner zone. This slagging index is usually not employed because of the high cost of the required laboratory studies and other indices which accomplish the same purpose are available.

Statistical methods have been applied to empirical data to develop a means of calculating the viscosity-temperature relationships from coal ash analyses. Unfortunately, this method has not been found accurate for coal ashes with a Na_2O content higher than 2 percent or those different than the more common coal

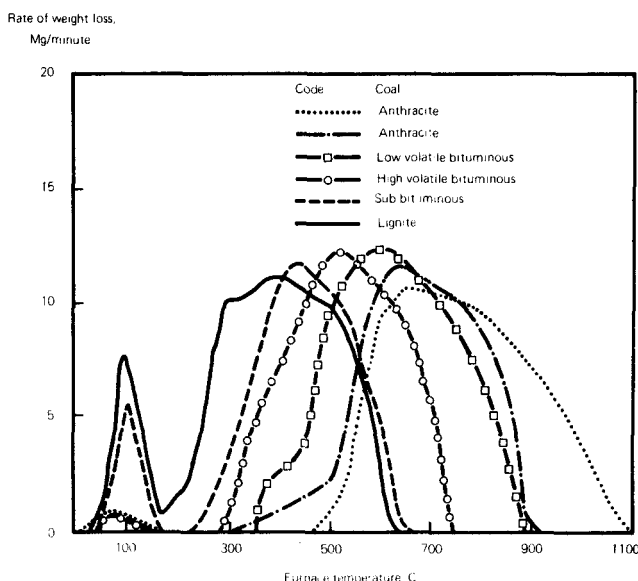


Fig. 3 Comparison of burning profiles for coals of different rank

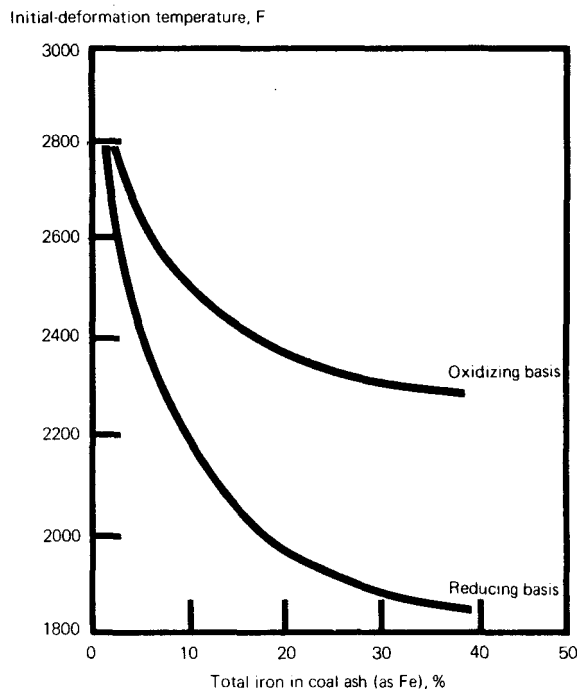


Fig. 4 Influence of iron on coal ash fusion temperatures

ashes. An index for Western coals with Na_2O content higher than 2 percent in the ash has not been developed entirely from empirical data. With some special lignite coals the units must be designed using objective and/or subjective parameters.

A slagging index based on ash fusion temperatures has been found to be the most accurate with both lignite and subbituminous type coals. Both of these types are considered to result in lignitic type ashes when fired in a boiler furnace. The ash fusion temperatures are used as an indication of slag viscosity characteristics to identify the plastic zone. The low ash fusion temperature normally associated with the subbituminous-lignitic type ash coals presents an interesting phenomenon. Normal ash constituents in the majority of coals found in the United States are Si, Al, Fe, Ca, Mg, Na, K, and Ti. When oxidized these constituents exhibit relatively high melting temperatures (3000–5000°F). Interaction of these constituents with one another has been acknowledged to have a substantial effect at elevated temperatures on their characteristics. Complex salts are formed that have entirely different physical properties. Among other changes, melting temperatures of these compounds are usually lowered to an eutectic temperature (lowest possible melting point). Sodium oxides present in the coal ash act as a catalyst for the rate of deposition and increase the bonding strength thus making the deposit most difficult to remove. Calcium silicate has also been shown to have a positive correlation with the fouling potential.

B High-Temperature Bonded Deposits—Fouling. A second type of high temperature ash deposition occurring on the gas side surfaces of steam generators is fouling. Fouling is high-temperature bonded deposits that form on superheater and convection bank tubes. These deposits can form at temperatures appreciably below the fusion temperatures of the ash. The different type of fouling deposits are normally identified by their principle bonding agent such as alkali, calcium, sulphate, phosphate, or silica.

Sintering strengths have been used for many years to measure how tight the bonded deposits adhere to the boiler tubes and how difficult it is to remove them. As was the case with the viscosity-temperature relationships, the sintering laboratory tests are expensive. To avoid the high costs of these tests, an index has been developed which relates these sintering strengths of a coal ash to

its ash constituents for bituminous-Eastern coals. The fouling index found statistically superior for coals of the bituminous type involves the basic and acidic constituents of the coal ash as well as the Na_2O content in predicting fouling tendencies.

Coals which produce a lignitic type ash after combustion have a bonding mechanism which results from the sulphating of the alkali and alkaline earth constituents in the coal ash. The amount of Na_2O in the ash is the primary fouling predicting index. Again as with the slagging indexes, statistical methods have been used to relate empirical data obtained from field tests to correlate the characteristics of particular coal ash to its constituents. The fouling indexes for bituminous and lignitic coals have been based on empirical data relating chemical composition of the coal ash to the sintering strength of laboratory prepared coal ash. The problems caused by fouling are correlated to the strength of bonded deposits in the superheater sections and convection passes. Time and temperature are important factors to be considered. A slagging fuel in the furnace can contribute to fouling problems by elevating the temperatures in both the superheater and convection passes.

Boiler design and boiler operation affect the fouling as well as ash composition. The mechanisms of fouling are vastly different from those of slagging. Different indexes must be used to predict fouling for the various possible bonding mechanisms. Thus, the reader should be aware of the many variables under consideration in designing a modern coal fired boiler. The complex chemical reactions and interactions which take place in a boiler furnace will probably never be fully understood. The importance of field test data involving a particular coal in an actual operating unit is imperative. When compared to designing boiler units to fire commercially obtainable oil and gaseous fuels, the complexities of coal and its use in generation of steam for power and process must be appreciated.

C Low-Temperature Deposits. Formation of deposits in the low temperature zones (air heater and economizer) is usually associated with condensation of acid or water vapor when the metal surfaces of the air heater or economizer are cooled below acid or water dew point. These deposits are of three general types of material:

- 1 A corrosion product due to the acid attack depending on the amount of acid available, temperature, and type of metal.
- 2 Trapped fly ash particles on the wetted surfaces.
- 3 Sulphates created by the reaction of acid with such fly ash constituents as iron, sodium, and calcium (CaSO_4 deposits are nearly insoluble and are thereby difficult to remove by washing).

Design

Ash removal from boiler surfaces is extremely important to its successful operation. Deposits act initially as insulation retarding heat transfer and thereby upsetting the overall thermal balance within the boiler. Large accumulations in the upper furnace may fall and damage pressure components. In the convection tubes of the superheater and boiler, accumulations may block gas passes thereby increasing the draft loss and limiting output. Ash deposits have been seen to be the function of the type and to a minor extent of the quantity of mineral matter in the coal while other factors such as boiler design and operation also are significant. An example of increased slagging potential is lower ash fusion temperatures caused by a reducing atmosphere resulting from either flame impingement on boiler furnace walls, or nonuniform coal supply, or high coal/air ratios.

A coal ash with a very high fusion temperature may remain dry with little or no deposit forming on the boiler surfaces. Minor changes in the operation or type of coal received could result in an entirely different outcome. A thorough and accurate coal selection—i.e., mine, seam, ash analyses, etc.—is the first step in the complex and technical process. A burner-furnace design combination which results in minimizing the occurrence of reducing atmospheres will enable the coal with very high oxidizing but low reducing fusion temperatures to operate successfully (normally bituminous coals).

A poor design may result in unsuccessful troublesome operation even with the good coal.

Furnace slag deposits may remove themselves by gravity when they reach a thickness of 3–6 in. The bond that holds the initial ash deposit is weak. A small portion of that deposit, however, remains on the tube and by constant repetition of this mechanism the ash will grow. This ash forms a hard deposit that adheres to the boiler tubes very tightly with bond strength increasing constantly with time. The outside surface of this deposit becomes several hundred degrees hotter as this hard deposit grows. These types of deposits resist removal by conventional soot blower methods. Substantial deposits may be formed in this manner which could result in a unit shutdown.

Coal ash slagging and fouling can have a significant effect on boiler operation and performance as well as such phases as ash removal, air pollution control equipment, fuel preparation equipment, plant efficiency, to name a few. Concentrating on the coal ash deposits on boiler surfaces has resulted in the following conclusions:

- 1 Deposits affect heat transfer.
 - (a) Conductive heat transfer is reduced by slag accumulations.
 - (b) The resulting higher temperatures on the outside surface of the slag accumulation reduces the temperature differential thereby reducing radiant heat transfer.
- 2 Furnace radiation and conductance are inter related.
- 3 Furnace heat absorption is dependent on size and chemical composition of the coal ash as well as temperatures.
- 4 Melting of the coal ash can increase heat transfer by conductance thus lowering the outside surface temperature and increasing the radiant heat transfer.

A properly designed burner-furnace combination performs two functions: (1) burns fuel completely and (2) cools the combustion products. The coal ash then encounters three phases (1) liquid-molten slag, (2) semiliquid slag known as the plastic region, and (3) solid and "dry" fly ash. The liquid slag has little deterrent effect on furnace operations as it does not accumulate significantly. Dry fly ash is necessary in the convection section of the boiler—i.e., superheater, boiler bank, air heater, and economizer. The plastic slag region, however, does affect boiler operation and therefore receives primary attention in furnace design. Slag at a viscosity of 250 poise just barely runs on an inclined plane while at a viscosity of 10,000 poise the slag has solidified. Below 250 poise, the coal ash is molten and above 10,000 poise the ash is solid. In between is defined as the plastic zone. Fig. 5 illustrates the plastic zone in terms of a particular coal's viscosity-temperature curve and where this zone should be in terms of the boiler furnace. Soot blowers are positioned in the plastic slag region to periodically remove the semi-molten slag buildups. Once the coal ash is solidified and enters the convection surfaces, soot blowers can again be used periodically to remove the high temperature deposits of fouling.

Fig. 6 demonstrates just why one coal is classified to be of higher slagging potential [3]. A severely slagging coal has a certain ash which remains in the plastic zone over an extended range of temperatures. This means a larger portion of the boiler furnace which must be equipped with cleaning devices—soot blowers. A low slagging coal experiences only a small temperature range where the coal ash is semimolten thus the ash solidifies at higher temperatures allowing for a small number of soot blowers and a relatively small furnace with a higher exit gas temperature while still cooling the ash to a solid state.

The slagging potential of a coal influences such furnace design parameters as furnace size, cross-sectional area, burner clearances, number and location of furnace wall blowers, and furnace exit gas temperatures. In addition, burners must be designed to provide thorough mixing of the fuel and air to assure an oxidizing atmosphere. The fouling potential of a coal can affect such boiler design parameters as furnace exit gas temperatures, gas temperatures in convection zone, back and side spacing of tubes, gas distribution

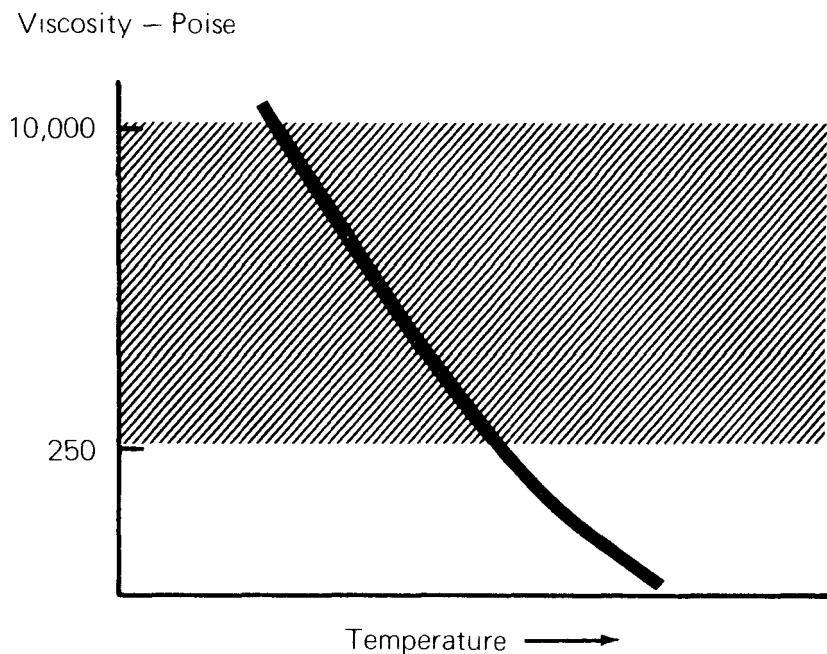
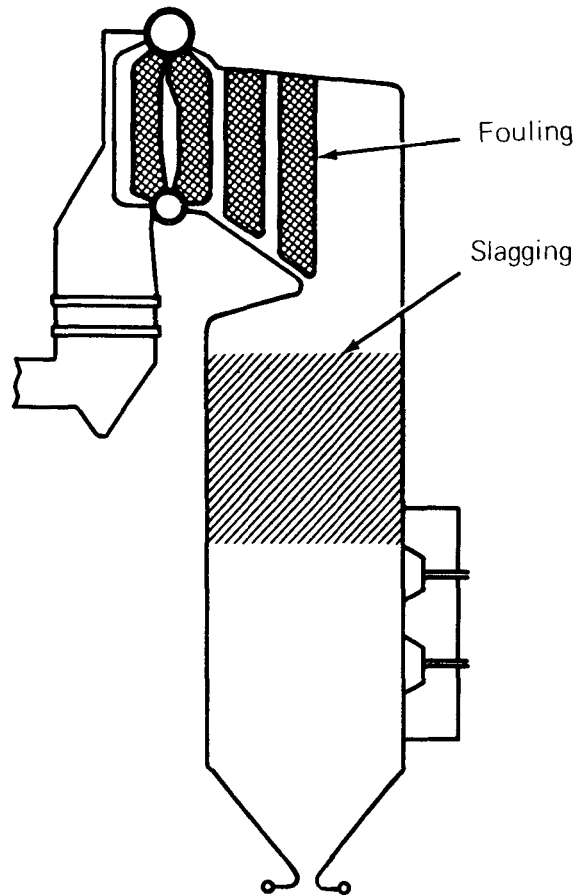


Fig. 5 Slagging and fouling zones

through superheater, arch slopes, furnace nose size, number and location of soot blowers, cleaning radius of soot blowers, and tube bank depths.

Coal Classification

As stated, routine coal analysis such as the ultimate and proximate and the Btu value are of little value in estimating the severity

of ash deposition. Ash fusion temperatures are utilized but again are not sufficient. It therefore is essential to devise techniques to provide means of predicting the behavior of ash in the boiler. This has been accomplished by analyzing the inorganic constituents which make up the coal ash. The coal ash originated as mineral matter associated with the coal formation and inorganic constituents inadvertently added during mining.

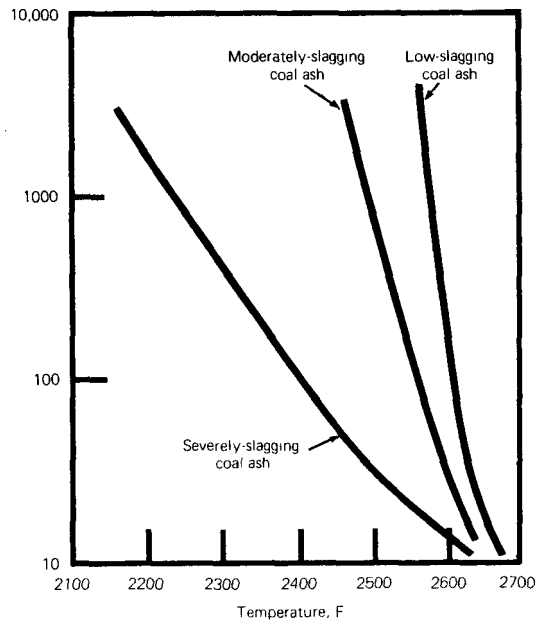


Fig. 6 Viscosity of wall slags (oxidizing atmosphere)

This paper is primarily concerned with the two high temperature ash deposition mechanisms of slagging and fouling. The low temperature deposits were presented only to round out the presentation. Slagging and fouling are independent and are classified separately as low, medium, high, and severe. Table 1 lists the typical elements of coal ash received in the United States and their oxidized form. The ash constituents are then further categorized as acidic or basic. Using the ash analysis in conjunction with the elemental analysis and ash fusion temperatures, a specific coal can be classified as bituminous or lignitic, low to severe slagging, and low to severe fouling. The classification is presented in Table 2. If the reader desires specifics, he is referred to the paper by Gray and Moore [2] for lignitic type ash coals and a paper by Attig and Duzy [3] for bituminous ash coals.

Affect of Coal Classification on Boiler Sizing

Slagging and fouling mechanisms of coal ash have been presented. Classifications of low to severe were established. What effect does firing a coal classified as having a low versus severe slagging or fouling potential have upon boiler sizing? Why be concerned about the type of coal when planning a new pulverized coal fired steam generator or analyzing a new coal source for an existing

Table 1 Ash analysis

As rec'd.	Oxidized form by spectrographic analysis	
S_i	S_iO_2	Acidic
Al	AlO_3	
T_i	T_iO_2	
Fe	Fe_2O_3	
Ca	CaO	Basic
Mg	MgO	
Na	Na_2O	
K	K_2O	

unit? The purpose of this paper was to demonstrate there are significant differences among coals and these differences necessitate special consideration in burner design and fuel input, flame clearances, wall blower locations, gas temperatures, furnace geometry, convection tube spacing and arrangement, etc.

To qualify, Fig 7 portrays three pulverized coal units of the same width designed to generate the same steam capacity of same steam conditions. In general, increased fouling potential requires a larger furnace to lower the gas temperatures entering the superheater while increased slagging potential requires a larger furnace cross section, lower burner inputs, increased furnace depth, larger furnace due to decreased heat transfer resulting from slag buildups, and a greater number of wall blowers. Boiler A is designed to fire a West Virginia bituminous coal classified as having a low fouling and low slagging potential. The slightly larger Boiler B is designed to fire an Alabama bituminous coal classified as having a medium fouling and medium slagging potential. Boiler C, the largest, is designed to fire a Wyoming, subbituminous lignitic type ash coal classified as having medium fouling and severe slagging potential.

The increased size of Boiler B versus Boiler A can be attributed primarily to the increased fouling potential of the coal and indirectly to the increased slagging potential. The furnace exit gas temperature had to be decreased for the given superheater tube side spacing in order to allow adequate cleanability. In general, high slagging coals have lower ash softening temperatures. The furnace exit gas temperature then must also be lowered in order to have "dry" fly ash entering the convection surface of the superheater (or screen). The slightly smaller economizer and larger air heater is due to the slightly higher moisture content of the bituminous Alabama coal.

With the same fouling potential, the subbituminous coal fired

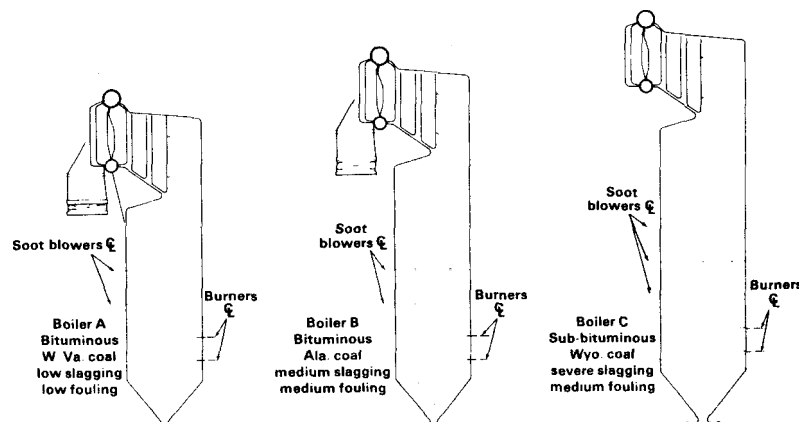


Fig. 7 Influence of ash characteristics on furnace size

Table 2 Classification of ash

ASH TYPE	BITUMINOUS	LIGNITIC
Classification		
Criterion	$\text{Fe}_2\text{O}_3 > \text{CaO} + \text{MgO}$	$\text{Fe}_2\text{O}_3 < \text{CaO} + \text{MgO}$
Fouling	$\text{B/A} \times \% \text{Na}_2\text{O}$	$\% \text{Na}_2\text{O}$
Slagging	$\text{B/A} \times \% \text{S of dry coal}$	Adjusted ash softening temperature

Where, B = Basic constituents, %; e.g., Fe_2O_3 , CaO , MgO , Na_2O , K_2O

A = Acidic constituents, %, e.g., SiO_2 , Al_2O_3 , TiO_2

by Boiler C can be seen to be substantially larger than Boiler B firing a bituminous coal. This increased unit size is entirely attributable to the severe slagging potential of the Wyoming coal as compared to the medium slagging potential of the Alabama coal. The furnace must be larger because the heat transfer effectiveness of the furnace walls is reduced by the greater slag accumulations and the lower ash fusion temperatures. A considerably greater number of wall blowers are also required to provide adequate cleanability of the lignitic type ash buildups. The economizer is completely eliminated and air heater size increased as high secondary air to the burners must be maintained for ignition and high primary air temperature to sufficiently dry the coal for transport and ignition due to the vastly greater amount of both inherent and surface moisture of the subbituminous coals. The size differentials are further quantified in Table 3.

Lignitic as Compared to Bituminous Coals

The low ranked lignitic type ash coals from west of the Mississippi River have come into their own in recent years. Today's air pollution restrictions on sulphur content have created a demand for these low sulphur Western coals. The reserves are abundant with "many of the deposits close to the surface and in thick enough seams to be very economical to mine" [4]. Most of these coals, however, are high in moisture and volatile matter but low in heating value. These lower ranked coals have good emission characteristics and are fairly easy to burn but impurities can be variable and extremely troublesome.

Lignite coal found in the Northern Great Plains area is the lowest rank. This fuel is categorized as having widely varying characteristics in ash properties. Hardgrove grindability may vary from a low of 25 to a high of 65. The single most important factor in the design of steam generators is the variation in the amount, type, and characteristics of mineral matter. Substantial commercial deposits of lignites exist in the Texas Gulf Coastal Plain area. Many of their lignites exhibit low ash viscosity characteristics providing

the potential for heavy slagging in the boiler furnace. Although the sodium content (used as an index of convection surface fouling tendencies) is low for these lignite coals, the calcium sulphate concentrations in the ash still produce bonded deposits that are difficult to remove.

Next up in the rank of the low sulphur-Western coals is the subbituminous type. Considerable deposits of the subbituminous type coals are found in Montana and Wyoming. The percent by weight of Na_2O in the ash may range from 0.5 to 9.0. The unusually high abrasiveness has a profound affect on pulverizer life. Abrasiveness of a coal depends largely upon the amount of grain quartz or other hard materials associated with mineral matter. Since it is a function of ash content, the varying nature of subbituminous coals is again shown by the wide variation in abrasiveness. The subbituminous coals like the lignite have low sulphur content but these younger coals have even lower ash viscosity characteristics which tend to cause greater furnace slagging. When this low ash viscosity is combined with a high sodium or calcium sulphate content, the coal becomes the most difficult to handle in a boiler furnace and superheater. Eastern bituminous coals contain sodium from salt sources enabling the chloride content to indicate its amount. North Dakota lignites can have Na_2O contents up to 15 percent by weight in the ash but its source is from the humic acids. Subbituminous coals with medium and high sodium content have still other sources of this sodium.

To summarize, coal with lignitic type ash when compared to those with bituminous ash in general have the following characteristics:

- 1 Higher moisture content.
- 2 Lower heating value.
- 3 Higher volatile matter thus faster ignition rates.
- 4 Lower sulphur content.

Specifically, lignitic type ash versus bituminous ash coals have:

- 1 Lower grindability but require lower fineness for combustion (degree of reducing the coal to a powder form).
- 2 A greater variation of ash chemistry since these coals are young. Wide variations will exist even within the same team.
- 3 A greater potential of slagging due to its lower ash viscosity characteristics.
- 4 A higher Na_2O and calcium sulphate content for the subbituminous classification resulting in tightly bonded fouling deposits.
- 5 A greater tendency to be more abrasive thereby increasing pulverizer wear.
- 6 A greater portion as volatile matter but an increased moisture content that necessitates a longer combustion zone and time.

Ash Removal

To remove the slag and high temperature bonded deposits on boiler surfaces, soot blowers utilizing steam as the blowing medium have been successful in units firing bituminous and subbituminous coals. Peak impact pressure (PIP) is defined as the energy at the point of impact of the jet stream from the soot blower nozzle. This parameter is of prime importance in designing a soot blowing system to effectively clean and detach coal ash deposits from boiler

Table 3 Boiling size versus coal classification

Boiler Coal rank Source	A Bit. W. Va.	B Bit. Ala.	C Sub-Bit. Wyo.
Slagging	Low	Med.	Severe
Fouling	Low	Med.	Med.
Furnace surface	1.0	1.1	1.3
Furnace vol.	1.0	1.04	1.34
Furnace plan area	1.0	1.0	1.13
Superheater surface	1.0	1.04	1.04
Boiler surface	1.0	1.0	1.0
Economizer surface	1.0	0.8	0.0
No. furnace wall sootblowers	16	16	36
Air heater	10	1.1	1.5

surfaces. The range or distance from the soot blower nozzle to the boiler surfaces is critical as the energy delivered is inversely proportional. High temperature bonded deposits which are characteristically dry are easier to remove than the plastic or similar like plastic deposits normally found in the boiler furnace as the blowing medium (steam) must first solidify the slag deposit before it can be removed. Thus the slagging classification of the coal (low to high) has the greatest influence on the number and positioning of wall blowers in the boiler furnace where the plastic region of molten and semimolten ash occurs. Higher fouling type coals result in progressively wider convection and superheater tube spacings. Via fuel tests, soot blower positioning and nozzle sizing have been correlated with the slagging and fouling characteristics of the types of coal to be fired.

Conclusion

Unlike such processed or refined fuels as oil and gas, coals vary from coast to coast and even within the same seam of the same mine. Physical properties—grindability, size, abrasiveness, etc.—chemical properties of the coal—heating value, burning profile, ultimate and proximate analysis, and the chemical properties of the coal ash-oxidized ash analysis—all are important to the successful design and operation of a boiler unit.

The coal ash is significant as a physical commodity for economic reasons and as a chemical commodity for its effect on boiler design. The ash melts in a furnace and has a tendency to adhere to heat transfer surfaces. The basic functions of an adequate design are to keep molten ash off boiler surfaces, to solidify the ash before leaving the furnace and entering convection surfaces, and to provide for cleanability.

When a proposed or existing plant is "locked in" to a long term coal contract, specifying not only the heating value, grindability, ash fusion temperatures, proximate and elemental analyses but also the oxidized ash analysis is required to ensure an adequate design. Proposals from various vendors can then be evaluated on the same basis.

When the coal source is not as well defined over the expected operating life of the unit, the area coal concept should be applied. The eventual purchaser must request from the coal company (with whom he has or plans to get a coal contract) analyses of near and possible long term coal supplies. The boiler manufacturers can then apply their own experience to that area of the country which the plant and/or his coal source make up. Ranges of heating value, required fineness, pulverizer power, theoretical air (for combustion calculations), grindability and surface moisture are established based on both utility and industrial experience. In this manner an overall plant design can be developed for a reasonable range of expected coals.

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APPENDIX

Glossary of Terms

Coal Rank. Ranking according to geological age and degree of coalification.

Fouling. "Bonded deposits caused by condensation of volatile constituents in the coal ash (i.e., Na_2SO_4) on fly ash particles and boiler tubes at temperatures such that they remain liquid and react chemically with fly ash, existing deposits, and SO_2 in the flue gas" [2].

Slagging. Molten slag particles entrained in the gas stream solidify as they come into contact with the cool furnace walls. "Strength of attachment is influenced by the temperature and physical contour of the surface and by the direction, force of impact, and wetting characteristics of the slag" [2].

Eutectic. Mixture of two or more compounds "such that it has the lowest possible melting point" [2].

Elemental Analysis. Fuel constituents are reduced to percentages of elements—i.e., a percentage of methane (CH_4) is broken down to percentages of C and H_2 .

Proximate Analysis. Fuel constituents are reduced to percentages of volatile matter—portion of coal which evolves to a gaseous form, fixed carbon, ash, and water.

Ash. Intrinsic—in the vegetation from the beginning; extraneous—mud deposits of shale and pyrites which were mixed in with the vegetation from external sources.

Bituminous Ash. $\text{Fe}_2\text{O}_3 > \text{MgO} + \text{CaO}$

Lignitic Type Ash. $\text{Fe}_2\text{O}_3 < \text{MgO} + \text{CaO}$

APPENDIX B



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Coal Handling Equipment and Storage (For Industrial Plants)

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In today's energy environment manifested by decreasing availability of liquid and gaseous fuels, the industrial user is forced to turn once again to coal as an energy source to provide heating and cooling for his buildings and supply steam for processing. The purpose of this paper is to describe equipment, materials and systems available to accomplish the unloading, storing and handling of coal in an industrial facility and to define some of the parameters involved in systems design and component selection.

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Coal Handling Equipment and Storage (For Industrial Plants)

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GENERAL

Coal handling systems, as discussed herein, pertain essentially to the potential industrial plant user.

An industrial plant for purposes of this paper is defined as one large enough to require mechanized and automated or semi-automated coal unloading and handling facilities, but not exceeding about one million pounds per hour (pph) steam generating capacity.

It is further assumed that boilers may range in size from 25,000 to 250,000 pph stoker fired and up to 500,000 pph for pulverized coal fired units.

It is not the purpose of this paper to develop detail concepts and engineering calculations for the design of coal handling systems. Many good books and catalogs are available for this purpose. Moreover, it is recommended that the engineer work closely with manufacturers' representatives when preparing system and equipment layouts and specifications.

We will provide some general guidelines and design parameters which can be useful for system and component selection. We will also describe some of the equipment and systems available for this purpose.

DELIVERY

Coal is generally delivered to industrial plants by truck or rail. Although some larger plants located on waterways may receive coal by barge, by far the majority of coal for industrial use is transported by railroad hopper bottom cars. This discussion will concern itself only with that mode of delivery.

ON-SITE STORAGE

One of the early considerations in the development of a coal handling system is a determination of the amount and type of on-site coal storage to be provided.

Several factors should be analyzed includ-

ing:

- Plant size
- Steam load characteristics
- Source reliability
- Mode of shipment
- Coal type and characteristics
- Number of days of full load steaming capacity required
- Power house siting
- Land available for storing and handling.

Also, the economics of invested capital, taxes and the maximum and minimum tons of storage which are economically and operationally justifiable must be resolved.

Availability and reliability of supply are generally overriding considerations. Sufficient storage must be provided to assure continuity of operation.

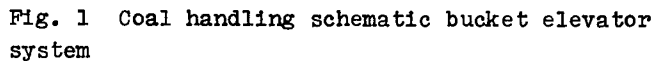
Sixty days on-site storage based on maximum anticipated steaming conditions is a commonly applied guideline.

Adequate space should be allocated to permit future expansion for unloading, handling, and storage facilities. Quite often, insufficient attention is given to power house siting with the consequence that after a few years, the manufacturing buildings completely encircle the power house seriously impairing the ability to economically expand capacity.

COAL STORAGE FACILITIES

Coal is stored for immediate use (active) or placed in dead storage (reserve) for future use.

When a shipment of coal is received, generally, the coal is conveyed to live storage to the extent of available capacity, overflow is then directed to reserve storage. The extent of reclaim or transfer from reserve storage is dependent on frequency and amount of coal delivered, capacity of live storage facilities,



Insofar as possible, coal supply to the boilers is provided from live storage while coal in dead storage is retained for emergency use.

Depending on boiler size and firing arrangement, active or live storage coal is usually supplied by gravity to the stoker or pulverizing mill from an overhead bunker or silo.



One of the commonest ways for storing coal is to place it in piles on the ground. The pile can be exposed to the outside atmosphere (open) in which case certain precautions must be taken, or the pile may be enclosed and protected from the elements.

The pile may be active mode that is in continuous use supplying coal to the boilers under manual, automatic, or semi-automatic control, or simply dead storage arranged for reclaim on demand or conceivably a combination of the two.

The construction of open piles is a major consideration in avoiding potential fire hazards and is discussed later under "Spontaneous Combustion."

Estimating the ground area required to provide a given number of days storage involves evaluation of several factors and may be calculated using the formulas shown in the Appendix.

Coal is "stocked out" or placed on the pile by several methods. In the case of truck delivery, this may simply mean dumping the coal on ground and bulldozing onto the pile. Rail delivery by hopper bottom cars with coal discharging to track hoppers where the coal is then elevated to grade by belt or apron conveyors and pushed

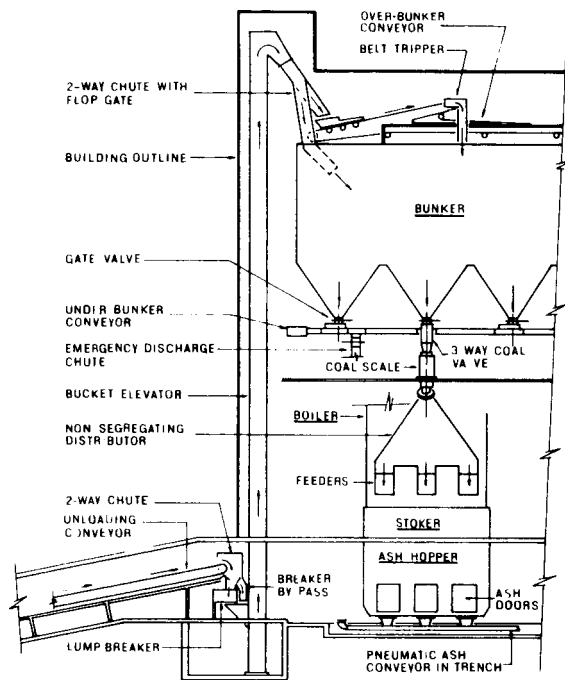


Fig. 4 Over-bunker conveyor arrangement

into place by bulldozer or end loaders is commonly used. Quite often, coal is elevated to overhead bunkers and silos by bucket elevators, the discharge head of which is fitted with a two-way flap gate permitting coal discharge either to the bunker or by chute to the outdoor coal pile. Larger installations may employ a system of belt conveyors arranged to elevate the coal to overhead bunkers and silos (Fig. 1).

One element of the system is a stocking out conveyor which may be equipped with a telescoping chute at the discharge head, which can be raised or lowered depending on pile height, and thereby reduce dust emission. The conveyor is sometimes pivoted from a central supporting stanchion and can discharge coal along the length of the pile depending on its limit of arc or swing. This arrangement can help to reduce the effect of segregation by layering the pile. However, the high cost for this equipment can generally be justified only for larger plants utilizing active storage piles.

When active piles are employed, coal is discharged directly over a reclaim hopper. Feeders discharge coal from the hopper at a constant flow rate onto a system of transport conveyors which deliver the coal to overhead bunkers or silos which then feed the boiler firing equipment by gravity.

Details of the various types of equipment used in these systems will be reviewed later in the report.

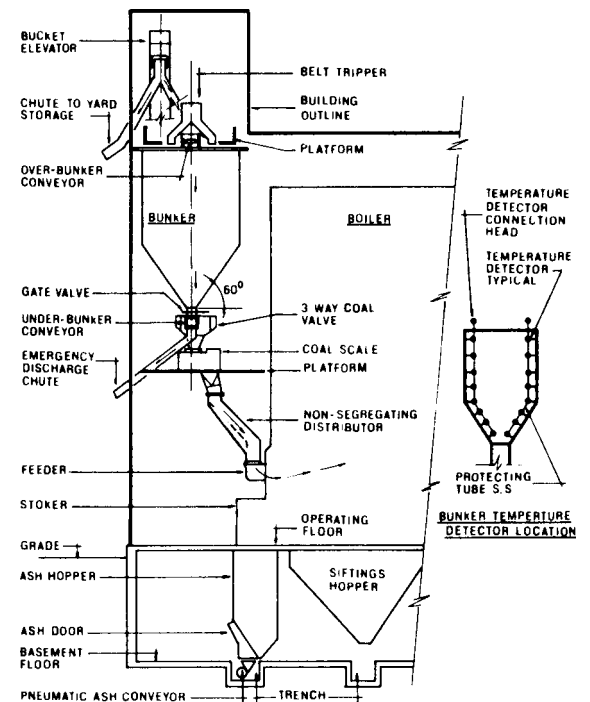


Fig. 5 Over-bunker coal feed to boiler

SILOS

Coal silos provide maximum storage volume per square foot of ground space utilized. This can be an important consideration when space is not available for ground storage piles, particularly in existing plants. They obviously protect the coal from weathering and inherently provide a cleaner environment around the plant by reducing the coal dust associated with handling coal on an open pile operation (Figs. 2 and 3).

Silo floors can be sloped for gravity discharge through the side or bottom of the silo. Often silos are constructed with inside shelves set at angles to permit both active and reserve storage. In such arrangements, coal is introduced to the silo through gates in the silo top. The coal fills the active section of the silo first and then overflows to the reserve section from which coal can be reclaimed.

To assure satisfactory coal flow, silo floors made of concrete should be sloped at not less than 60 deg or should be lined with stainless steel. Exposed outlet gates should be provided with steam jackets to prevent freezing.

When coal is fed to a silo, there is a tendency for segregation of the coal to occur. To reduce this effect, coal should be delivered to the top of the silo at multiple locations. Silos may be circular or rectangular cross

section with circular being the least expensive and most common. Silos are constructed using various materials including poured reinforced concrete, hollow tile, and steel. Usually erected from grade on concrete foundations, they may also be supported from elevated steel structures.

BUNKERS

In power house parlance coal storage bunkers usually refer to overhead storage bins arranged for gravity coal flow to the boiler fuel firing equipment.

Although bunkers may be constructed of concrete, they are practically always fabricated from steel plate and lined with concrete or gunnite. Steel bunkers can be classified into three categories according to their shape.

Cylindrical bunkers are vertical circular bins. They are low in first cost, self-cleaning, and generally problems are not experienced with segregation. The configuration lends itself to a unitized boiler bunker arrangement. Discharge hopper sides should slope at a minimum 60-deg angle.

Rectangular bunkers with multiple bottom hoppers: These bunkers are equipped with multiple outlet gates and the configuration is suitable for feeding a battery of boilers. Careful attention should be exercised in the design of the bunker to assure that no valley angles within the bunker hoppers are less than 60 deg.

Hopper sides are sometimes clad with stainless steel to improve coal flow characteristics. All coal flow surfaces must be kept free from protruding edges or obstructions which could impede coal flow or cause static accumulations of coal and result in bridging or arching at the hopper outlets (Figs. 4 and 5).

Hopper outlet gates should permit full free flow, be self-cleaning design preferably fabricated of stainless steel.

Bunkers are subject to large internal static loads. Careful attention must, therefore, be given to the design of structural reinforcing, supporting structures, and foundations.

Provisions for emergency discharge of coal from the bunker must be included in the system design. In the event of fire developing in the bunker from spontaneous combustion, there must be a fast, safe way to remove hot coal from the bunker.

Depending on system arrangement, it is sometimes possible to run the coal out of the hoppers via the underbunker conveyor discharging

to the bucket elevator and then outside to the yard.

Where this is not feasible and particularly when high sulfur coal will be used, emergency gates or doors are provided in the sides of each bunker hopper and arranged so that a chute may be attached and the hot coal can then be discharged via the chute through the building wall to the yard.

Suspension or catenary is another bunker configuration. Although lower in first cost than the rectangular bunker, this shape is not self-cleaning. Careful operational care must be exercised to assure that pockets of coal do not remain undisturbed for long periods of time.

These bunkers are provided with multiple outlets, and this configuration is suitable for feeding a battery of boilers.

SPONTANEOUS COMBUSTION

When coal is placed in reserve, certain precautions must be taken to assure that fires will not occur in the coal pile and that weathering will be reduced to a minimum.

Fires are generated in improperly compacted coal piles due to spontaneous combustion which occurs when the proper amount of oxygen is present to cause oxidation of the coal with a rise in temperature to the combustion point.

Iron pyrite and iron sulfides in the coal combine with water and oxygen to form iron sulfate and sulfuric acid in an exothermic reaction. This reaction then triggers carbon and hydrocarbon reactions with oxygen already in the coal and especially from air in immediate contact with the heated coal. If there is sufficient air available, the process of oxidation increases rapidly and results in spontaneous combustion.

To reduce the potential for spontaneous combustion in plants using open ground storage, the coal pile must be constructed and coal compacted so as to prevent air infiltration through the pile. The problem is more severe when unsized coal containing a large percentage of fines is used which is the case for most industrial plants burning bituminous and subbituminous coals.

When coal is discharged onto a pile, segregation takes place; i.e., the coarse large lumps roll to the outside of the pile while the fines stay in the middle, thereby effectively producing lanes where air can circulate in some areas and not in others, thus permitting localized heating and "hot spots" to develop.

To avoid this condition, the coal should be

piled in layers one to two feet thick and compacted so that air cannot pass through the pile. The sides and top of the pile should be sloped to permit water run off.

Spontaneous combustion is most prevalent with high sulfur coals having high ash content and low fusion temperature, i.e., coal in excess of one percent sulfur. Coal ranging up to 3.5 to 4 percent sulfur such as Indiana and Illinois bituminous, may require special attention, such as use of continuously monitored temperature detectors in the pile to provide an early warning of excessively high temperature buildup. These devices are often employed in bunkers, bins, and silos (Figs. 2 and 5).

When fires develop, especially in an enclosed storage area, use of water may lead to serious explosions due to methane gas generation when hot coal reacts with water. Carbon dioxide or dry ice may be of some value in controlling hot spots or fires; however, removal of the hot coal itself is the preferable procedure.

COAL SYSTEM UNLOADING CAPACITY

Desirable unloading rates are determined by evaluating a number of variables, such as plant steaming rate, average and maximum daily and weekly coal usage, labor and demurrage costs, active and reserve storage capacity, size and frequency of deliveries and first cost or capital investment for unloading and handling facilities.

High labor costs and demurrage justify using higher unloading rates and less manual supervision of coal handling than may have been customary in the past.

Coal is received in railroad hopper bottom cars in net capacities ranging between 50 and 100 tons with 50- and 70-ton cars being most common.

Because cars require time for spotting and moving on the siding, coal is actually delivered to storage for only a portion of the unloading time. Thawing of frozen coal and car shaking also tend to reduce actual delivery. True unloading rate may be as low as 50 percent of the continuous flow capacity of the handling system. Therefore, the design coal handling rate of the conveyor system should be approximately two times the desired unloading rate.

As a general rule, unloading rate should be approximately nine times the maximum total plant burning rate. For example, a steam plant with a total steam output capacity of 100,000 lb steam per hour should have a system capable of unloading not less than 47.5 tons per hour (tph)

determined as follows:

$$Ur = (9) \frac{(W)}{(Ev) (2000)}$$

$$Ur = \frac{9 \times 100,000}{(9.47) (2000)}$$

$$Ur = 47.5 \text{ Tons/hr (43.1 metric tons/hr)}$$

The coal handling rate of the conveyor system in this example should be two times the unloading rate, to allow for car spotting. The conveyor system capacity will then be:

$$2 \times 47.5 = 95 \text{ tons/hr}$$

This will assure that at least six rail cars of 60-ton average capacity will be emptied in an 8-hr shift or about 360 tons/day.

The maximum hourly coal burning rate for this example is:

$$Br = \frac{(W)}{(Ev) (2000)}$$

$$Br = \frac{1000,000}{(9.47) (2000)}$$

$$Br = 5.28 \text{ tons/hr (4.79 metric tons/hr)}$$

The maximum daily usage will be:

$$(5.28) (24) = 127 \text{ tons/day}$$

Therefore, the normal handling of coal, from rail car delivery during the day shift, will accumulate about three days peak use during an 8-hr shift. If larger than normal shipments arrive, the conveyor system can be operated more than 8 hr per day to reduce demurrage charges.

RAILROAD TRACK ARRANGEMENT

Adequate provision must be made for the storage and movement of both full and empty hopper cars. One or more spur tracks must be provided for this purpose.

General arrangement and mode of handling cars will depend on several factors: number and orientation of main railroads serving the site, anticipated size and frequency of shipments, switch engine availability, and unloading system capacity.

In general, sufficient straight length of spur track must be available to accumulate a full shipment of full hopper cars and to store the empties plus providing space for car thawing, track hoppers, and shaking equipment. Coal car spur tracks should never be used for other plant operations, such as, shipping, receiving, scrap

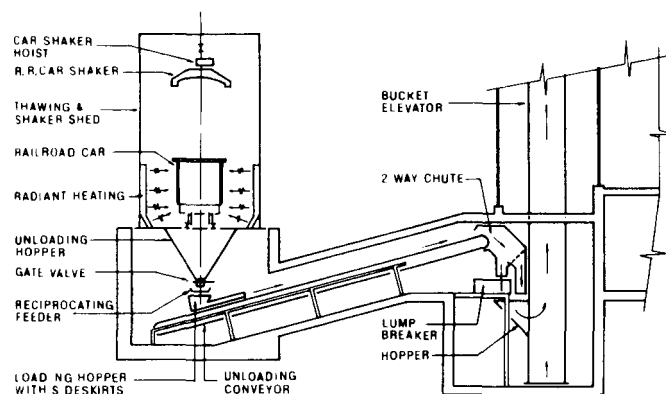


Fig. 6 Coal unloading to bucket elevator

unloading, hauling, etc.

CAR PULLER AND CAR SPOTTER

Once the full hopper cars are moved into place by the switch engine, spotting and repositioning cars for thawing and dumping is usually accomplished using a car puller or car spotter.

A car puller is usually used with small industrial plants of 100,000 lb steam/hr or less and consists of a capstan (vertical rope winch) and a manually applied tow rope. This arrangement can handle up to two railroad cars per hour by one man. This arrangement will not work well if the track is on any grade other than level because the tow rope can pull in only one direction and cannot be used to stop a car on an incline.

A car spotter is usually used with plants of greater than 100,000 lb/hr capacity, or where the track is on an inclined grade. The car spotter consists of a cable winch system with anchored pulleys about 100 to 400 ft apart alongside the railroad track. The winch is reversible and can be remotely controlled. The cable is a continuous loop through the winch and is provided with tow rings and short tow cables for attachment to the railroad car. The winch can be operated in either direction to accurately spot the car over the track hopper. A car derailling installation should be provided when track inclination is excessive.

CAR THAWING

Frozen coal in hopper bottom cars can be a major problem for the industrial user. Coal loaded in Kentucky, Tennessee, and Virginia, having excessive moisture or absorbing moisture during rainy weather and transported north in unprotected cars, will probably freeze depending

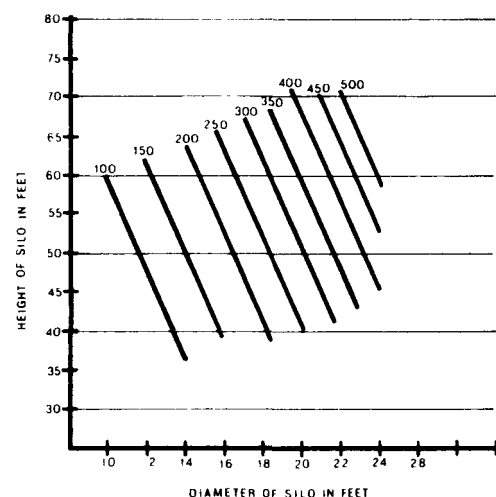


Fig. 7 Coal silo capacities (based on coal weighing 50 lb/cu ft)

on temperature and wind conditions. Coal can freeze in transit even on relatively short hauls.

Some procedures which may help to alleviate the freezing problem would include thorough drying of the coal at the mine, storage in covered or weather-protected facilities, plus rapid transit time and fast unloading. Use of calcium chloride, spraying oil on hopper car interiors, insulation of various types, and in-transit heating all can contribute to reducing or preventing freezing.

Frozen coal is especially difficult to unload, particularly when a large percentage of slack, screenings, and fines are present.

Since all of these provisions to prevent freezing are beyond the direct control of the plant operator, positive means must be provided at the unloading point to assist in removing frozen coal from hopper cars.

Occasionally, a car will be frozen solid, more often a layer 12 in. or more thick may be frozen around all sides of the car.

Several types of equipment are available for "car thawing" from simple steam jets and hand torches to sophisticated permanently installed car heating. Hand torches are considered hazardous and rather ineffective.

Simple installations of permanently installed heaters may consist of oil or gas fired burners installed in refractory tile and mounted between the tracks. Radiant heat from the burner flame and refractory heats the car hoppers.

More elaborate systems employ banks of radiant heaters deployed along the sides of the car which heat both sides and car hoppers. These radiant heaters may use electricity, natural gas, or light fuel oil. Some installations provide wind break barriers along the length of the

car heating area to increase the thawing effectiveness and partially protect personnel.

In larger and more sophisticated installations, car thawing sheds large enough to house two or three cars are built along the track adjacent to or including the track unloading hopper. Permanently installed radiant heating systems are used, and maximum effectiveness in car thawing and unloading is obtained (Fig. 6).

CAR SHAKERS

Bottom dump hopper cars of the manually locked door, sawtooth hopper design are the most common car types for delivering coal to industrial steam plants. A car shaker is usually required to insure a fast and complete discharge, especially when the coal is wet or frozen (Fig. 6).

The two basic types of car shakers are the side-mounted and the top-mounted arrangement.

The side-mounted type is suspended from a jib pole alongside the track and can be manually attached to the side of the railroad car or removed and swung out of the way of railroad traffic by one man. A chain operated, pneumatic or electric hoist is used with the jib pole to elevate the car shaker for attachment to the side of the railroad car. The side-mounted type will provide for dumping up to two cars per hour.

The top-mounted type is a heavy-duty shaker suspended by hoist from a structural frame over the railroad track. The shaker can be positioned and operated by remote control. The top-mounted type will provide for dumping six to eight cars per hour. This unit rests over the rim angles along the top side of the car. The shaking motion is transmitted through the sides to the bottom hoppers.

Both side-mounted and top-mounted shakers operate on the principle of vibration caused by an eccentrically mounted, rotating weight. The rotating weight is belt driven to minimize shock loads on the drive motor. The drive motor and rotating weight are spring mounted on a steel frame which transmits the vibration to the railroad car.

Noise is a major problem with car shakers. When noise from this operation could cause a nuisance to neighbors, the shaker should be enclosed in a sound conditioned building or enclosure and every effort made to operate the equipment when least obtrusive to the neighborhood.

TRACK HOPPERS (Fig. 6)

Hopper bottom cars are arranged for dis-

charge to the coal handling system through a track unloading hopper. A single track hopper 12 x 12 ft may be employed particularly for 50-ton cars which can be completely discharged without respotting. Larger cars 70- and 100-ton capacity have three or four discharge hoppers and must be respotted when single track hoppers are used. Therefore, double track hoppers 12 x 25 ft are normally provided when the larger cars can be expected. Hoppers should be 14 x 30 ft when a majority of 100-ton cars are anticipated.

Track hoppers are fabricated of minimum 1-in.-thick steel plate supported on a reinforced concrete structure. Hopper sides should slope at a minimum 50-deg angle and preferably not less than 60 deg. Hoppers fabricated of stainless steel provide less friction for coal flow and last longer than mild steel. Type 410 stainless has given good results. Bar grating is placed over the hopper and should have openings 6 x 6 in. between the tracks and 8 x 3 in. along the sides adjacent to the tracks.

RECLAIM HOPPERS

Coal placed in yard storage may be reclaimed by bulldozer or front end loader to the track unloading hopper or to a separate reclaim hopper if provided. When a live pile reclaim system is employed, and independent hopper or hoppers must be provided. Reclaim hopper should be conical shape with side slopes 60 deg or greater with cast steel plate installed around the top of the concrete supporting structure to guard against bulldozer damage. Sometimes poke holes are provided in the bottom section of the hopper to provide access for unplugging (Fig. 1).

COAL FEEDERS

The coal transport system removes coal from the track hopper and delivers it to storage or directly for use in the boilers. In order for the conveyors to function properly and efficiently, they must be fed coal at a uniform rate. A coal feeder is used for this purpose and there are several types. Feeders must be designed as an integral part of the overall hopper and feeder system, and the hopper outlet must be properly dimensioned to allow passage of the coal at the maximum discharge rate without arching or ratholing. A feeder is used to control the flow and provide uniform discharge rate.

VIBRATING FEEDERS

This type feeder moves coal along a trough

by mechanically vibrating the feeder plate or trough. Drives for vibrating feeders may be motor driven eccentrics or electromagnets. Power requirements for these feeders are low, but they are limited in application to relatively short lengths and generally horizontal discharge.

BELT FEEDERS (Fig. 1 and 6)

This feeder has the advantage of low initial cost, dependable operation, and automatic control. The belt is usually kept flat and equipped with side skirting to retain the material. When located under track hoppers, belts must be properly protected and supported to withstand high impact loads. Belt speeds can be readily varied to control flow rate.

APRON FEEDERS (Fig. 6)

Apron feeders are composed of interlocking metal pans forming a continuous belt. They are recommended for use where impact conditions or lump sizes prevent the application of belt feeders which would be damaged by this material. The initial cost and power consumption for these feeders is higher than for belt feeders, but they are usually recommended for use under track hoppers and where severe impact conditions are expected. Apron feeders may be any length and can be installed at inclines up to 25 deg.

RECIPROCATING FEEDERS (Fig. 6)

An oscillating plate carries the coal forward and is driven by shaft mounted eccentric, connecting rod, and motor drive. These feeders are generally limited to short horizontal runs; however, they are simple, inexpensive, and commonly used under track hoppers.

COAL CRUSHERS (Fig. 6)

At some point in the handling system prior to storage, provision is usually made for installation of a coal crusher.

When Run-Of-Mine (ROM) coal is purchased for stoker fired boilers, the coal must be crushed to the proper size to assure satisfactory distribution and burning on the fuel bed. Size reduction may also be required for pulverized coal installations.

In industrial practice, sized coal of suitable dimensional characteristics is generally obtained from the mine; however, a crusher or lump breaker may still be desirable for breaking up large frozen lumps of coal.

Several configurations of crushers are available: crushing between two rolls; between a roll and plate; gravity impact on a rotating drum and hammer mills using swinging or ring type hammers.

These machines will crush ROM or frozen lump coal to the desired size say 1 1/2 x 1/4 in. in one operation. They can be furnished with a metal trap for removal of tramp iron. A two-way flap gate bypass is installed so that the crusher is used only when ROM or frozen coal is encountered.

The crusher or lump breaker is commonly located after the track unloading hopper so that the largest size lump handled is 6 x 6 in. or 8 x 3 in. Breaker motor horsepower is determined by capacity and lump size.

The crusher is fed at uniform rate using a belt or apron feeder.

BUCKET ELEVATORS (Figs. 2 and 4)

Bucket elevators are commonly employed in industrial practice to carry coal vertically to elevated storage and overhead conveyor systems.

There are two basic types of bucket elevators, centrifugal discharge and continuous gravity discharge.

The centrifugal discharge elevator is applicable to free flowing, consistently fine and dry material.

The continuous gravity discharge type is usually specified for industrial steam plants because the coal is sometimes wet, sticky, and of variable lump size. The continuous discharge elevator releases the material into the discharge chute by gravity and is less likely to be affected by wetness or material size.

The continuous bucket elevator is usually sized for 75 tons/hr or greater capacities with chain speeds between 100 and 110 fpm. The buckets are mounted on a double strand chain. The coal is fed to the buckets by a loading leg above the bottom or boot of the elevator. The buckets are heavy-duty continuously spaced for maximum capacity. The buckets are designed to form a chute as the buckets start down over the head shaft pulley, thus guiding the material into the discharge chute.

BELT CONVEYORS (Figs. 1, 4, and 5)

Belt conveyors are used to transport coal smoothly and efficiently over both long and short distances and to elevate coal to overhead bunkers and transfer systems. Coal conveyor belts are carried on troughing idlers shaped to

contain the coal and minimize spillage.

Materials used in the construction of conveyor belting have been significantly improved with the introduction of rubber polymers and synthetic fibers.

One form of belt construction consists of a heavy-duty top rubber cover usually 3/16 in. thick on the carrying side and 1/16 in. thick bottom side. Sandwiched between top and bottom covers is the carcass which consists of several plies or layers of high strength nylon mesh. Two plies are commonly specified for coal service. Between the two carcass plies is a thick rubber support layer.

The primary purpose of the carcass is to carry the tension force necessary to move the loaded belt and absorb the impact of the material being loaded on the belt. The cover protects the belt carcass against damage by the material being conveyed.

Belting is made endless by use of mechanical fasteners or by vulcanized splices. The vulcanized splice provides the strongest connection and longest service. Belt speed varies depending on belt width and capacity required. Speeds ranging from 50 to 300 fpm are common in coal handling systems.

Generally speaking, wider belts and lower speeds provide longer life and less maintenance, but with the penalty of increased first cost. Belt conveyors are usually driven by motor reducers and sometimes provided with variable speed control.

When belts are used for elevating coal, the maximum practical angle of inclination is 23 deg; however, incline should normally not exceed 15 to 18 deg.

When belts are used to convey coal outdoors exposed to freezing weather, enclosures are usually provided. Several types of enclosures are available such as:

- 1 Half covers — semi-circular in shape, made of sheet metal, fastened to the belt conveyor support, frequently hinged on one side to permit servicing of belt and idlers from the walkway alongside.

- 2 Galleries — rectangular or circular in cross section provided with walk-through service-ways and completely enclosing the belt conveyor and support structure provide the ultimate in weather protection and accessibility for maintenance personnel. Galleries are constructed with structural steel frames and metal siding and roofs. First cost is high, but often pays off in reliability of operation.

FREEZE PROTECTION

Accumulation of water, ice, and snow between the belt and drive can prevent a belt conveyor from starting up if the belt has frozen to the drive surfaces. This problem can be avoided by continuing to run the belt slowly when not actually delivering coal or by providing heat at the head and tail drive pulleys to prevent freezing. If the conveyor is enclosed in a galley or building that is unheated, infra-red heaters could be used, but they must be properly designed and enclosed to prevent explosion. Steam unit heaters directed at potential problem areas are commonly used.

MAGNETIC SEPARATORS

Magnetic separators are often provided on belt conveyors to remove tramp iron. A magnetic pulley at the discharge end will retain the tramp iron until after the coal has been discharged. The tramp iron then drops into a collection box.

Another method commonly used is to suspend an electromagnet over the belt. Tramp iron is pulled out of the coal bed as the belt passes under the magnet.

OVERBUNKER CONVEYOR SYSTEMS

Once the coal has been elevated to the top of the bunker, it must then be transported the length of the bunker and so discharged from the conveyor system as to uniformly fill the bunker while preferably minimizing segregation in the case of stoker fired installations (Figs. 1, 4, and 5).

Several types of conveyors are employed for this purpose. Two common arrangements are flight conveyors and belt conveyors.

A flight conveyor usually consists of a double strand steel chain to which is attached steel plates or flights. The chain and flights travel in a rectangular steel plate enclosure, closed on both sides and the bottom and open on top. Discharge gates located uniformly along the length of the conveyor usually actuated by rack and pinion gears and operated manually from above discharge coal along the centerline of the bunker. The flights drag the coal along the bottom plate of the conveyor until an open gate is encountered. The sequence of gate openings can be varied in an attempt to place the coal in layers in the bunker and, thereby, reduce segregation. Although segregation may take place

in each layer, segregation throughout the bunker is avoided (Fig. 2).

The gates can be motorized to permit semi-automatic operation. Flight conveyors are suitable for relatively small installations and are lowest in first cost.

Belt conveyors in combination with a belt tripper are generally used in larger installations. To discharge coal at any point along the length of a belt, a belt tripper must be used. The tripper consists of a series of pulleys over which the belt rides and in so doing changes directions. The coal discharges from the belt into a hopper and discharge chute mounted on the tripper. The chutes, in turn, discharge to the bunker on each side of the belt (Figs. 4 and 5).

Belt trippers can be hand-propelled, self-propelled, and arranged for manual or automatic operation.

The hand-propelled type is moved by means of a hand crank and roller chain drive to the axle. The self-propelled type is moved by power transmitted from the conveyor belt itself, through a friction drive from the pulley shafts. The direction and travel is limited by manual control.

The automatic type is similar to the self-propelled except that the direction and travel limits are automatically controlled by limit stops mounted on the tripper tracks, which engage the tripper and reverse the travel direction.

Motor-propelled belt trippers are used for service where the discharging stations or spotting are far apart, where frequent moving is required, or for continuous travel when "bedding" or layering is desired. Propulsion is provided by a gear head motor. Travel speed is usually 30 fpm.

SHUTTLE CONVEYORS

Motor-propelled track mounted shuttle belts can be used to discharge coal along the length of a bunker and are sometimes used for coal pile stacking as well.

UNDERBUNKER COAL HANDLING

Coal is placed in overhead bunkers to provide gravity coal flow to the boiler firing equipment. When the bunkers are designed as silos or rectangular units for unitary feed to a single boiler, coal flow is dependent only on keeping the bunker supplied from the overbunker coal handling system. This arrangement is com-

monly used in pulverized coal fired installations. However, in many industrial plants, a common suspension-type bunker serves a bank of boilers. A series of outlet gates along the length of the bunker can be used to supply coal to anyone or all of the boilers. When a boiler is located directly below an outlet gate, that boiler can be supplied by gravity so long as coal level is maintained in the bunker (Figs. 1, 4, and 5).

WEIGH LARRY

In many plants, weigh larries are used to collect coal from any point in the bunker and supply coal to each of the boiler stoker hoppers.

The larry consists of a self-cleaning steel hopper with attached chute and swivel discharge gate. The larry travels on and is usually suspended from overhead tracks. Larries vary in capacity from 1000 to 10,000 lb and can be hand or motor-propelled. A beam scale weighs the coal in the hopper and can be a recording or indicating type. The disadvantages of a weigh larry are labor required to operate and coal dust resulting from its use. There are practical limits to the size and numbers of boilers which can be serviced by a larry.

When weigh larries are used, extension hoppers are provided on the stoker feed hoppers. These hoppers should hold, if possible, two to three hours' supply of coal to reduce the number of trips required by the larry. Hoppers are constructed with 3/16-in. 410 stainless-steel plate suitably reinforced and supported.

UNDERBUNKER CONVEYORS

For those plants desiring a fully enclosed dust-free installation suitable for automatic operation, underbunker conveyor systems are commonly employed (Figs. 1, 4, and 5).

Basically, underbunker conveyors are used for the following reasons:

- To feed coal to stokers or pulverizers which are so located that they cannot be fed by gravity from the bunker outlets
- To reclaim coal from the dead spots which exist between bunker outlets, particularly in suspension bunkers
- To quickly and easily empty any section of the bunker for repairs or for prevention of bunker fires
- To permit operation of the boiler plant for a maximum period in the event of

breakdown in the bunker filling conveyor system.

Basically then, the underbunker conveyor is not intended as a primary, continuous operation feed system for the boilers, but rather as a backup for gravity feed.

There are several types of underbunker conveyors. One type commonly employed is a dust-tight steel box enclosure fitted with a drag flight double strand chain. Coal is fed from the bunker through coal gates or valves to the top strand of the chain which rides on an intermediate plate. Coal is discharged through outlets in the lower strand and bottom plate to the point of use. Leveling bars are installed at each point of coal inlet to the conveyor to regulate depth of coal in the conveyor.

AUTOMATIC WEIGH SCALES

Automatic weigh scales are used to weigh and record continuously coal flowing by gravity from bunkers or underbunker conveyors and discharging to each boiler. The scales are enclosed in a dust-tight housing provided with service doors for access to belts and weighing mechanism. A quick-acting bypass is provided so that coal may be fed direct from bunker to stoker should the scale become inoperative (Figs. 1, 3, 4, and 5).

These scales range in capacity from 15 to 40 tons/hr with hopper capacities 200 to 500 lb. Essentially, the scale consists of a continuous belt onto which coal flows by gravity through a coal gate from the bunker above. When the weigh hopper is empty, a limit switch starts the belt which discharges coal into the weigh hopper until the preset weight is satisfied. The weigh beam raises tripping a limit switch and stopping the belt. The hopper is provided with a pivoted bottom plate held in position by an electrically actuated latch. When the hopper is full, the plate is released and the contents are dumped to a discharge hopper. Coal usage is recorded on a digital counter.

THREE-WAY GATE (TRIPLE VALVE)

A built-up steel plate enclosure containing coal valves, space for underbunker conveyor discharge, gravity bypass and surge hopper mounted above and discharging to the coal scale (Figs. 1, 4, and 5).

NON-SEGREGATING DISTRIBUTOR

To complete the path of coal flow to the

boiler stoker hopper, a chute must be provided between the scale outlet and the stoker hopper inlet. The conventional flared chute has a tendency to deliver the fines in the center of the stoker while the lumps roll to the outside, causing an uneven burning bed of coals and reduced boiler efficiency (Figs. 1, 3, 4, and 5).

To obtain an even distribution of fines and lumps over the entire width of the stoker, a non-segregating distributor of conical design is provided. This is a specially designed chute which gives a constant rate or velocity of coal flow so that the same volume of coal is delivered into the stoker hopper at every point across its full width, thereby eliminating the cause of segregation.

DUST CONTROL

Maintaining cleanliness in a coal fired powerhouse is difficult at best; however, careful equipment selection and system design can measurably reduce this problem. Modern plants utilize fully enclosed dust-tight coal conveying equipment between the bunker outlet and firing equipment which is normally within the confines of the building enclosing the boilers, firing equipment, control systems, and auxiliaries.

Customarily, coal bunkers and the conveyor systems feeding them are not covered or enclosed. This usually results in an extremely dusty, dirty operation in the coal bunker area.

Some industrial plants have endeavored to reduce the coal dust nuisance by covering the bunkers with concrete floors. To increase dust control effectiveness of a totally enclosed bunker, a slight negative pressure is maintained in the bunker by fan systems equipped with high efficiency collectors. Exhaust fans should be heavy duty, static electricity-free and spark-proof construction to avoid the possibility of explosion. Velocities in the dust collecting system range from 3000 to 3500 fpm. The exhaust air must be passed through a high efficiency dust collector before discharge to atmosphere.

An exhaust system may also be installed to remove dust at conveyor transfer points.

Vacuum cleaning systems are sometimes installed in the powerhouse and consist essentially of a vacuum exhauster, dust storage bin, air filter and a permanently installed collection tubing system to which a hose and vacuum cleaning device may be conveniently attached at various points throughout the powerhouse. The dust storage bin can be arranged for discharge to the

boiler ash handling system.

Dust associated with coal unloading and outdoor storage can be reduced by using various surface wetting and dust control agents.

AUTOMATIC CONTROL

Coal handling and transport systems generally comprise a large number of individual conveyors, feeders, elevators, directional flow control gates, valves, belt trippers, motor drives, etc., all arranged to unload, handle, and transport coal to storage and to the boiler firing equipment in one fully integrated system. These various equipment components can be started, stopped, and operated manually.

However, the normal system complexity involved and the desire to reduce operating manpower generally dictate provision for semi-automatic control of system operation.

By simply positioning a selector switch and push button, the system can start automatically and deliver coal from track hoppers to the desired destination in the plant such as bunker or yard storage. Retrieval from yard storage via live pile reclaim system and automatic positioning of belt trippers can provide a virtually automatic coal supply to the bunker.

Any arrangement of coal transport conveyors should incorporate certain control features. To avoid jamming the system on start-up or shutdown, the individual components must be started and stopped in a prescribed sequence. For instance, the last conveyor in the system must be started first followed by each preceding system component. On shutdown, a reverse order procedure is followed in which the conveyor or feeder nearest to coal infeed, such as the feeder under the track hopper, is stopped first.

Sequencing can be accomplished by interlocking the control circuits in each system component motor starter. Relays may consist of position switches and zero speed switches on the conveyors, elevators, valves, gates, etc. These devices provide a direct positive indication of equipment status and the most reliable operation. Sequencing can also be accomplished indirectly by auxiliary contacts on motor starters interlocked electrically with the various system components.

When the system is shut down and the coal supply to the first feeder is shut off, it is desirable to allow the conveyors to continue to run long enough to purge all coal from the system. This will permit restarting the conveyors later in an unloaded condition.

At each transfer point in the conveyor system, paddle switches or other devices are installed to detect abnormal piling of coal which would indicate a malfunction of some component such as stopping or breakdown of a conveyor. Activation of the paddle switch will immediately stop all conveyors prior to that point in the system.

To facilitate operator control and monitoring of the system, a central control panel is often provided, including a graphic display showing schematically the system and its components. Operational status is indicated by running lights. Push buttons and selector switches are provided to permit semi-automatic or manual mode of operation. Trouble lights and alarms are provided to give warning of off-normal conditions.

GENERAL

Mild steel is the principal construction material used in fabrication of coal handling equipment; however, use of stainless steel can reduce maintenance and increase life for those parts subject to severe wear or a combination of repeated corrosion and erosion. A 410 stainless is often used in lining track hoppers, silo live shelves, bunker hopper outlets, and other areas where reduced corrosion and improved flow are desirable.

Coal valves (gates) should be self-cleaning design with 410 or equivalent stainless steel used for all parts which come in direct contact with the coal. Valves located where they are subject to freezing should be fitted with steam jackets.

All electrical equipment and control devices in a coal dust atmosphere must comply with national electrical standards—Class II, Group F, Division I.

CONCLUSION

There is a wide variety of coal handling and transporting equipment available for assembly in the simplest to the most complex of systems.

Many types of equipment and devices not mentioned in this paper are available and may be most attractive for a particular installation.

To assure reliable, satisfactory operation, careful attention must be given to system design and equipment selection. Each project must be evaluated on its own merits so as to provide an arrangement matched to the operational characteristics of the plant.

APPENDIX

Equations:

$$A = \frac{(W) (24 \text{ hrs.}) (LF) (N)}{(Ev) (d) (Ht)}$$

$$Ev = \frac{(Hv) (Eff)}{He}$$

$$Br = \frac{(W)}{(Ev) (2000)}$$

$$He = Hg - Hf$$

$$Ur = \frac{(9) (W)}{(Ev) (2000)}$$

where:

- A = square foot of ground area (square meters)
 Br = maximum hourly coal burning rate
 d = density of coal, lb/cu ft (kg/cu m)
 Eff = overall thermal efficiency of boiler
 Ev = average boiler evaporation rate, lb steam/lb coal (kg steam/kg coal)
 He = total heat absorbed by steam, Btu/lb (J/g)
 Hf = enthalpy of feed water entering boiler, Btu/lb (J/g)
 Hg = enthalpy of steam leaving boiler, Btu/lb (J/g)
 Ht = average height of coal storage pile, ft (M)
 Hv = higher heating value of fuel in Btu/lb (J/g)
 LF = steam plant load factor
 N = number of days storage required
 Ur = coal unloading rate, tons/hr (metric tons/hr)
 W = peak steam plant capacity, lb/hr (kg/hr)

Examples:

1 Find the ground area required for the following conditions:

- W = 100,000 lb steam/hr (45,360 kg/hr)
 LF = 0.6 (winter load factor)
 N = 60 days storage
 hg = 1195.6 Btu/lb (sat. steam at 150 psig) (2781 joules/gm at 11.36 Bar)
 hf = 188.2 Btu/lb (feed water at 220 F) (437.7 J/g at 104.4 C)
 He = hg - hf = 1195.6 - 188.2 = 1,007.4 Btu/lb (2343.3 J/g)
 Hv = 11,500 Btu/lb (higher heating value of coal) (26,749 J/g)
 d = 50 lb/cf for coal (800.9 kg/cu m)
 Eff. = 83 percent (with economizer)

$$Ev = \frac{(Hv) (Eff.)}{He} = \frac{(11,500) (0.83)}{1007.4} = 9.47 \text{ lb steam/lb coal (kg steam/kg coal)}$$

$$Ht. = 20 \text{ ft (average storage pile height) (6.096 m)}$$

Solution:

$$A = \frac{(W) (24) (LF) (N)}{(Ev) (d) (ht)}$$

$$A = \frac{(100,000) (24) (0.6) (60)}{(9.47) (50) (20)} = 9123 \text{ sq ft (847.64 sq m)}$$

2 Find the maximum hourly coal burning rate with the above conditions:

$$Br = \frac{(W)}{(Ev) (2000)}$$

$$Br = \frac{100,000}{(9.47) (2000)} = 5.28 \text{ tons/hr. (4.79 metric tons/hr.)}$$

Maximum daily usage will be:

$$5.28 \times 24 = 127 \text{ tons/day}$$

3 Find the unloading rate with the above conditions:

$$Ur = \frac{(9) (W)}{(Ev) (2000)}$$

$$Ur = \frac{(9) (100,000)}{(9.47) (2000)} = 47.5 \text{ tons/hr (43.1 metric tons/hr)}$$

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APPENDIX C



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Operating Experience with a Tire-Fired Boiler

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Though scrap tires constitute less than one percent of the nation's solid waste, they present a unique disposal problem since, without subdivision, they are unsuited for land-fill operations. One potential solution to this problem is the use of scrap tires as fuel. The tire-fired boiler designed to burn whole tires requires a higher initial capital investment than do comparable oil- or coal-fired boilers, but affords appreciably lower total operation costs. The tire-fired boiler thus meets the needs of American society today; it generates cheaper steam at no drain on fossil fuel sources while contributing a most viable solution to the disposition of a troublesome solid waste component.

Contributed by the Fuels Division of The American Society of Mechanical Engineers for presentation at the Industrial Power Conference, Pittsburgh, Pennsylvania, May 19-20, 1975. Manuscript received at ASME Headquarters February 14, 1975.

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Operating Experience with a Tire-Fired Boiler

E. R. MOATS

OPERATING EXPERIENCE WITH A TIRE-FIRED BOILER

The disposal of worn-out tires and other rubber products is a problem that has challenged engineers for years. Ironically, the outstanding advantage of rubber contributes to its disposal disadvantage: Rubber does not decay or change state, but remains in the same form indefinitely.

Because of this, landfilling rubber products -- particularly tires -- has not been a satisfactory answer. Not only do tires not decompose, but they are extremely difficult to cover properly because of their basic shape.

Until recent years, burning tires -- either in incinerators or simply in piles at disposal areas -- was a means of disposal. Burning, however, generated heavy, acrid smoke and recent air quality laws prohibit such methods.

Yet, rubber does have a high Btu value and under properly controlled combustion, it is an excellent heat energy source. Recognizing this, several companies have experimented with the mixing of rubber with coal as a fuel for spreader stoker boilers. The rubber, however, must be ground or cut into cubes compatible with the fuel feeding mechanism. Generally, the ratio that has proved most satisfactory is 1 lb of rubber to 10 lb of coal.

Goodyear believes it has another more satisfactory answer in the tire-fired boiler it elected to install at its Jackson, Mich., tire plant. The system was developed to burn whole tires, thus eliminating the cost of grinding or shredding. The furnace is designed to provide air in the proper pattern for the proper time to burn all the combustible material in the tires with an absolute minimum of smoke and without odor.

The furnace operates continually without supplementary fuel at a temperature high enough to melt all the non-combustible material such as bead wire and fiber glass. The non-combustible material flows in the liquid state to an ash discharge port.

An investigation of tire-fired boiler equipment suppliers was made in 1971 by Goodyear's

Corporate Engineering Department. Based on design analysis and tests run on a smaller unit in England, Lucas American Recyclers was selected as the equipment supplier.

The basic furnace design was developed by Lucas Furnace Development Ltd. of England. Engineering design and construction was rendered by Lucas American Recyclers and by Fluor Utah. The design included a furnace with the capacity of burning 3000 lb of tires per hr and a boiler to generate 25,000 lb of steam at 250 psi. Stack gas cleaning equipment was incorporated as a contingency to reduce particulate and SO₂ emissions to comply with possible air pollution standards, if required. The vendor's illustration (Fig. 1) depicts the original proposed unit, complete with buildings and conveyors.

A general description of the major equipment components follows:

Rotating Hearth Furnace

The furnace is of the rotary hearth type. The diameter of the rotating hearth is 16 ft - 4 in. with a central ash discharge aperture 2 ft 3 in. in dia. The hearth is sloped toward the

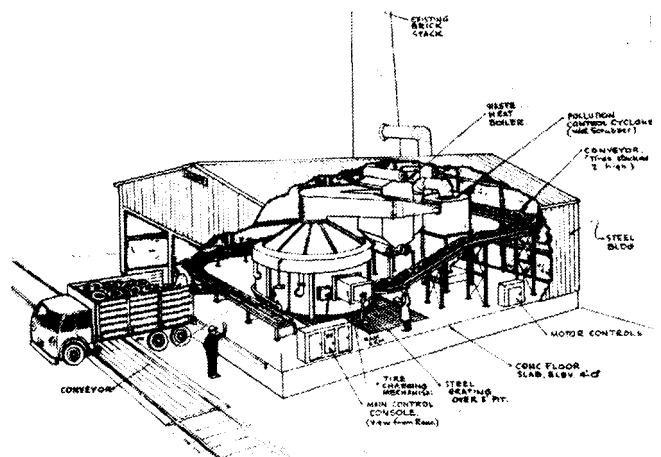


Fig. 1 Vendor's illustration of original proposed unit

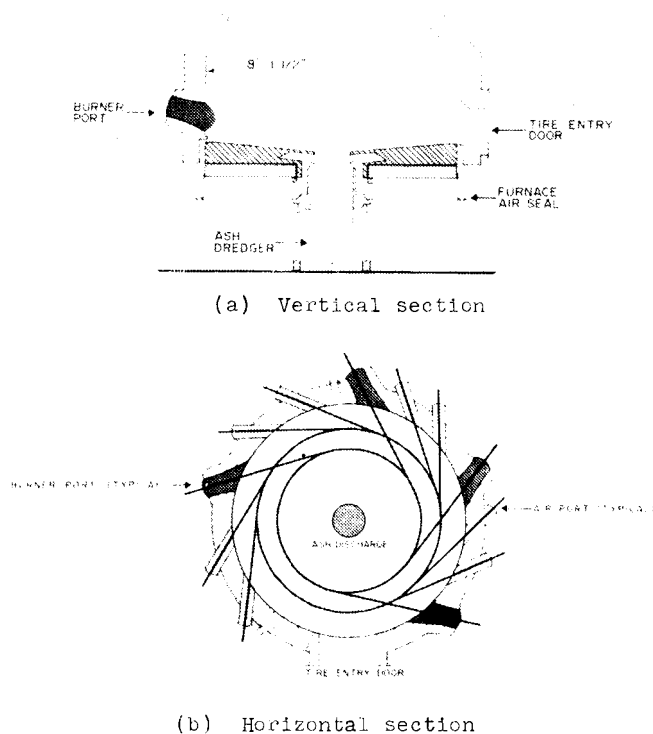


Fig. 2 Cross section tire-fired furnace

center facilitating movement of the unburned ash toward the central discharge opening. The rotating hearth is refractory lined and water cooled around the center to insulate the metallic body of the hearth from the high temperatures developed inside the furnace.

The hearth refractory consists of an outer refractory ring 6 in. wide and 16-1/2 in. deep anchored to the hearth frame with stainless steel anchors. The main refractory from the outer ring to the 7 ft -0 in. dia steel cooling tank consists of 10-1/2 in. of insulating firebrick mounted on in. asbestos mill board.

A top layer of 60 percent Al_2O_3 castable refractory 6 in. thick on the outer edge tapering to approximately 2 in. thick adjacent to the water cooled area covers the hearth. Two 1/2 in. expansion joints filled with spun refractory wool packing are located to separate the main hearth refractory area from the 6 in. outer ring and from the water cooled area.

A horizontal section and a vertical section of the furnace is shown in Figs. 2 and 3.

The hearth metallic shell area 7 ft -0 in. dia is subjected to direct water quenching by spray water from a circular spray ring inside the inner seal tank. The cooling water is pumped to the spray nozzles from the hearth coolant tank.

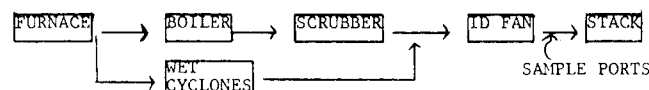


Fig. 3

Water hits the metallic surface and drips back to the inner-seal-tank. It is returned to the hearth-coolant-tank using a pump via a water strainer to separate entrained fine particles and a heat exchanger to cool it back to the original temperature before reuse.

The outer edge of the rotating hearth is sealed around its circumference with a metallic skirt immersed in the outer seal water trough. The water level in this tank is maintained with makeup water. Excess water overflows into the ash dredger tank. Some of the unburned ash collects in the outer seal trough when the ash pusher returns from the center of the furnace back towards the outside edge via the skirt. The ash is swept with fixed metallic rakes on the metallic skirt in the outer seal trough. As the hearth rotates, the ash is discharged from an opening in the bottom of the trough into a mini-dredger underneath the opening. The ash is partly dewatered in the mini-dredger as it is conveyed upward and discharged into the ash dredger tank. It is then discharged together, with the ash dropping from the center of the hearth via a drag conveyor into a hopper for final disposal outside the plant.

Most of the ash is removed through the central ash discharge aperture which is arranged with a water seal similar to that in the outer seal tank.

The entire flat hearth with its refractory is supported on an anti-friction ring bearing about 5-ft-in-dia which in turn sits on a structure spanning the main ash dredger tank. The hearth revolves about the stationary sprays and circular spray ring. The ash dredger tank is on rollers and can be rolled out of the way to allow maintenance work on the sprays and ring bearing.

Furnace Walls and Conical Roof

The furnace diameter to the inside of the metal shell is 19 ft. The furnace has four natural gas burner ports and eight tire combustion air ports symmetrically located around the circumference of the furnace. They enter at an angle 3 ft 5 in. from the bottom. Combustion air enters the furnace tangentially from the air ports producing a high velocity cyclonic flow.

This assures adequate contact between the oxygen in the air and tires on the rotating hearth. Gas burners are used to heat the furnace to the desired temperature prior to feeding tires and starting the incineration process. Combustion air for natural gas is supplied from a separate 4000 scfm air fan, whereas air for tire combustion is supplied from an 18,000 scfm forced draft fan. Refractories around the air and burner ports are made of castable plastic refractory. The rest of the wall is made of high Alumina bricks and mineral wool insulation blocks against the metal plate.

The thickness of the refractory and insulation in the cylindrical portion of the furnace is 16 in. on the average. The height of the cylindrical section of the furnace is 6 ft 9 in. The conical dome is also lined with 16 in. of refractories. The surface refractory is Kruzite backed by mineral wool insulating bricks. The height of the conical section is 6 ft 0 $\frac{1}{2}$ in.

Combustion Air

Combustion air is supplied from a 18,000 scfm forced draft fan rated at 5 in. SP driven by a 25 hp electric motor. Air is fed into the furnace via a ring main duct with eight tangential ports into the furnace. Each inlet is fitted with a manually preset butterfly damper to regulate the flow of air to each port. The motor driven combustion air damper is on the suction side of the air fan and has two normal operating positions, one fully closed if the furnace is warming up and one fully open when the furnace is at normal operating temperature.

Auxiliary Burner System

The furnace is equipped with four natural gas burners for start up and for supplementary use. The Pyronics burners are rated at 6 million Btu/hr per burner.

A 4000 scfm fan rated at 16 in. SP driven by a 20 hp motor supplies combustion air for the gas burners. Air is fed into the burners via a square ring duct built inside the main combustion air ring duct and distributed from this duct into the four gas burners. The air to gas ratio is preset for gas combustion in each burner and the total amount of air delivered from the fan to the four burners is regulated by a motor operated damper located on the discharge side of the fan.

Furnace Temperature Control

The furnace exhaust gas temperature is measured with a thermocouple which is installed in the hot duct leaving the top of the furnace.

Temperature is recorded and automatically starts or stops the gas burners at preset temperatures. The tire feeding cycle is interrupted if the maximum preset furnace temperature level is exceeded. When the furnace temperature drops to normal operating temperature, the tire feeding cycle is automatically resumed. If the tire feeding cycle is interrupted and the furnace temperature drops below the minimum operating temperature the gas burners are automatically lighted and the burners are operated until normal furnace temperatures are attained. The gas burners then automatically shut off.

Waste Heat Boiler

The waste heat boiler is designed to generate steam at 250 psi. The boiler is the conventional two drum design with bare tubes in the first section and finned tubes in the second section. The boiler was designed to generate 25,000 lb/hr of steam with flue gas entering at 2102 F and leaving at 550 F with a gas flow of 62,500 lb/hr.

A retractable soot blower is located in the gas inlet to the boiler. Two soot blowers are located between the bare tube and finned tube sections.

DESCRIPTION OF OPERATION

Hearth Rotation, Tire Feeding, and Ash Pushing

Hearth Rotation. Hearth rotational speed is set manually to suit the tire burning rate. The range of hearth speed at normal burning rates is 2.7 to 6.0 revolutions per hr, although the mechanism can turn the hearth at 8-1/2 to 1/4 revolutions per hr. There is no indication or recording of hearth rotational speed.

Tire Feed System. Tires enter the feed system from a gravity roller conveyor. Tires enter the vestibule through the vestibule door which starts the timed feed cycle. The tires enter the vestibule laying flat and move on rollers into position to be fed into the furnace by the tire pusher ram. The vestibule door closes as the furnace door opens. When the furnace door is fully open the pusher rams the tires into the furnace. The pusher retracts, the furnace door closes and the feed cycle is ready for another tire.

Ash Pushing. The ash pusher is located to the left of the tire entry door when facing the furnace. The hearth rotation is set manually for complete combustion of tires in two revolutions. The rate of the ash pusher operation is set by a timer for approximately 30 operations for each revolution of the hearth.

Table 1

	No. 1	No. 2	No. 3
Burning rate, lb/hr	2600	2800	2650
Furnace outlet temp, deg F	1125	1600	1525
Furnace wall temp, deg F	1165	1165	1165
Boiler exit, deg F	800	852	830
Gas to desulfurizer, deg F	755	810	790
Desulfurizer exit, deg F	125	127	130
Steam generated lb/hr	14,500	15,500	14,500
Total gas flow, acfm	16,486	17,051	17,048
Stack flow rate dry, scfm	11,382	11,476	11,635
Percent excess air	113.3	101.2	83.3

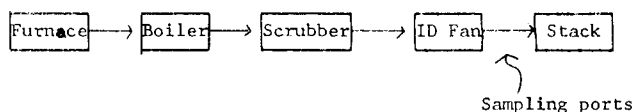


Fig. 4

The ash pusher is water cooled and the internal end of the rod and pushing plate is replaceable.

To minimize ash being pulled back into the outer seal by the pusher while it is being withdrawn, a short hydraulic cylinder raises the supporting roller after the pushing stroke and during the withdrawing stroke.

The original installation was completed in 1973. Trial operation revealed unsatisfactory furnace performance (hearth and air pattern), and a decision was made to redesign the furnace and auxiliary equipment. Lucas American Recyclers contracted Fluor Utah to engineer and construct the redesigned unit.

The reconstructed unit was completed and the first tire burned in March 1974. Trial operations continued over the next four days and totaled 14 hr of actual operation. The unit was then shut down and the furnace cooled for an inspection of the refractory. Minor changes to the control system and the hearth cooling system were recommended and the work completed.

Tire burning operations were resumed in May 1974. Various tire burning rates were carried out to determine the maximum burning rate of the furnace and the optimum burning rate. The furnace performed well at a burning rate of 4400 lb of tires per hr, (1400 over design), so it was decided to carry out stack gas tests at this rating.

The stack gas tests were performed June 5,

1974, by Entropy Environmentalists Inc. Three separate 1 hr tests were performed to measure gas flow rate, particulate emissions and sulfur dioxide emissions. All tests were carried out according to the procedures and recommendations of the Michigan Department of Natural Resources.

The gas flow during the test is illustrated as shown in Fig. 3.

The gas flow was split with 70 percent through the boiler and desulfurizer, the remaining 30 percent passing through the wet cyclones. The furnace was operating with eight 11-in.-dia air ports. The tire feeding rate averaged 4400 lb/hr during the test periods.

The desulfurizer was operated by circulating water without chemical addition of NaOH through the sprays.

Operational data for the test periods were:

Burning rate	4,400 lb/hr
Dry gas flow rate	17,827 scfm
Actual gas flow rate	33,638 acfm
Gas temp ahead of stack	233 F
Percent moisture in flue gas	28.6 percent
Percent excess air	213.9 percent

The sulfur dioxide emissions were approximately 1/3 of the maximum permissible emission rate for solid fuel-fired boilers. Based on this test data, a desulfurizer unit is not required for reduction of sulfur dioxide emissions. Since tires contain less than 1 percent sulfur by weight they can be considered a low sulfur fuel. (The Michigan sulfur limitation for this size boiler is 2.0 percent.)

The particulate emissions were above the maximum permission emission rate which was expected due to the high firing rate of 4400 lb/hr of tires.

During July the furnace was shut down for inspection. Refractory damage was found at the outer edge of the rotating hearth and at the center water cooled section. The damaged refractory on the outer edge was replaced with air set castable material. A minor redesign and change in material from stainless steel to carbon steel was made in the water cooled section of the hearth. A decision to reduce the firing rate to the 3000 lb/hr rate was made and the air nozzle size reduced to 8 in. dia. This was done to maintain the air velocity at a lower air flow rate.

The unit was fired up again on August 7, 1974, and burning operations were carried out with various air flow rates.

Goodyear took over complete control of boiler operations in September. Tire burning operations were carried out on a 24 hr schedule starting September 16.

Maintenance and operating problems recorded and conditions observed during inspection periods were:

1 Ash Dredger Jams. These jams were caused by chunks of slag or sections of partially burned tires being discharged from the furnace.

Observations indicated the tire feeding cycle and furnace temperature controls were causing the majority of the problems. Corrective steps have eliminated most of the ash dredger jams.

2 Furnace Temperature Control Failures. The thermocouple sensing the furnace temperature is very sensitive and has a short life. The thermocouple has been relocated to the gas duct ahead of the boiler out of the radiant heat zone of the furnace.

The furnace temperature proportional type controller is subject to frequent electrical failures. This unit has been replaced by a more reliable on-off controller.

3 Jams in the Tire Feeding Cycle. Jams in the tire feeding cycle were caused by tires not properly positioned on the conveyor at the entrance to the vestibule and by mechanical and electrical malfunctions of the tire feeding mechanism.

This problem was eliminated by conveyor changes that reduce the possibility of tires (stacked two high) not being properly positioned for the feeding operation.

The electrical control system for the tire feeding mechanism has been redesigned for maximum reliability. It also permits greater flexibility in controlling the feeding operation when a mix of passenger tires and truck tires is involved.

Limit switches on vestibule door, tire feed ram, and furnace door have been replaced with switches with internal overtravel.

4 Slag Build Up On The Hearth. During normal furnace operation slag from melted wire and glass does not build up on the outside of the hearth. The slag forms on the inner section of the hearth and flows in a liquid state into the central ash discharge aperture. However, when tire feeding is interrupted for a long period and the furnace temperature drops, the gas burners are lighted. The angle and location of the gas burners directs the heat at hearth locations that melt slag outside of the normal slag pool.

This slag flows toward the outer edge of the hearth but cools and solidifies before reaching the outside edge. Slag build-up near the outer edge of the hearth must be removed manually. This problem has been minimized by correcting the furnace temperature control problems and the tire feeding problems.

5 ID Fan Vibration. Solids and moisture carry over from the desulfurizer deposit on the fan rotor resulting in an out of balance condition. Regular cleaning of the fan rotor is required to remedy the situation.

The second stack emissions test was made by Entropy Environmentalists, on October 16. Only particulate emission rate determinations were made since the unit was in compliance with sulfur dioxide emissions. The unit also was tested closer to its designed burning rate of 3000 tires per hr. The gas flow during this test was as shown in Fig. 4.

Operational data during the three 1 hr test periods was as shown in Table 1

The particulate emission were 0.634 lb/1000 lb dry gas corrected to 50 percent excess air and 12 percent carbon dioxide. This is less than the maximum allowable emission rate of 0.65 for boilers. A request for an operating permit has been made to the Michigan Air Pollution Control Commission. All tests were observed by a member of the Michigan Air Pollution Control Commission and performed in accordance with state procedures.

The tire-fired boiler is functioning as well as a conventional steam boiler unit would function provided the conventional unit was equipped with comparable accessory equipment for handling the supply and feeding of fuel, and for the special requirements of ash raking, hearth cooling, and ash disposal. At the same time, it is reducing the number of discarded tires piling up on the nation's scrap heap by a million or more yearly.

APPENDIX D



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Systems Evaluation of Refuse as a Low Sulfur Fuel:

Part 2—Steam Generator Aspects

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This paper is part of a series which summarizes results of a study to assess the extent to which municipal refuse, when used as a fuel to generate steam for power generation, can aid in reducing the atmospheric emission of sulfur dioxide. In this part, the basic premise is that refuse is a low sulfur, low grade fuel which imposes rather restrictive limitations on steam generator design, and it is shown that it is technically possible to burn refuse in combination with fossil fuels to generate power with substantial benefits to the environment. The basis of the work in this study derives to a large extent from European experience, especially from Germany, that was applied to U. S. conditions in a design study. Preliminary designs prepared for new steam generators and modifications of existing steam generators represented various combinations and refuse-burning systems.

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Systems Evaluation of Refuse-as a Low Sulfur Fuel:

Part 2—Steam Generator Aspects

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R. W. BRYERS

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INTRODUCTION

This is one part of a three part series summarizing the results of a study of burning municipal refuse for power generation and deals with the steam generator aspects. The first part summarizes resource recovery values and the third deals with air pollution aspects (1, 2).¹ When one thinks of refuse the usual descriptive terms are "rubbish," "food wastes," and "noncombustibles." The basic premise of this study is that refuse is a fuel. As a fuel, it compares favorably with other fossil fuels that have been successfully applied for power generation as shown in Table 1. Refuse is not as good as premium fuels, such as oil or natural gas. However, it is a volatile fuel with a heating value of about half that of bituminous coal, and it has a relatively low-sulfur content of about 0.15 percent sulfur (3×10^{-5} lb/Btu).

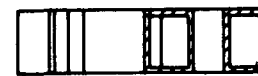
Large urban areas have high levels of sulfur dioxide in the atmosphere, derived in large part from power plant emissions. These same areas typically have solid waste disposal problems. In many areas, the present practice for waste disposal is landfill — sanitary or unsanitary. In many cities, there are incinerators which are the worst point sources of air pollution.

In this study, refuse was treated as a fuel and its heat content utilized in generating steam to be delivered to a turbine. As with other solid fossil fuels, the heat-transfer surface formed the furnace enclosure. On this basis, it became more appropriate to describe the combustion process as burning, i.e., giving forth heat during combustion, rather than incinerating, i.e., burning to ashes or consuming without heat utilization. With this distinction, the priority was the production of heat with the mass and volume reduction of refuse being secondary. This is not to imply that other characteristics of refuse,

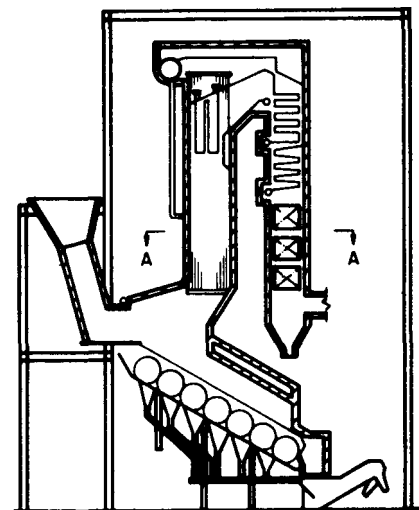
such as nonhomogeneity and potential corrosive aspects, were ignored. Much emphasis was placed on the undesirable aspects of burning refuse as a fuel.

EUROPEAN EXPERIENCE

The concept of burning refuse to recover heat is not a new one. In recent years, the trend to this concept has become a reality in Europe where many such plants are in operation. The plants in the Federal Republic of Germany (West Germany) are most worthy of mention because they



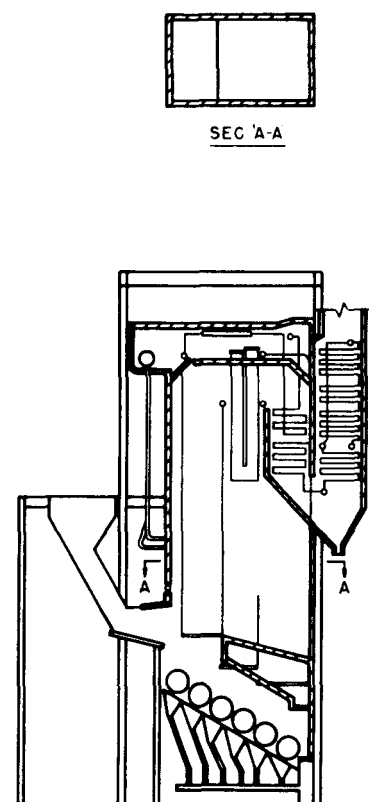
SEC A-A'



DÜSSELDORF-FLINGERN

Fig.1

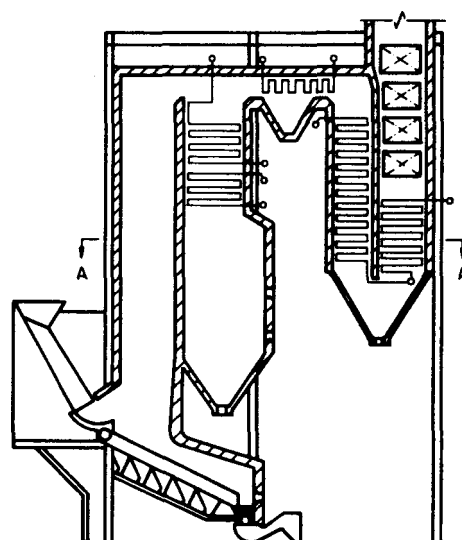
¹ Numbers in parentheses designate References at end of paper.



STUTTGART-MÜNSTER
UNIT NO. 29

SCALE IN FEET
0 10 20 30 40 50

Fig. 2



MUNICH NORTH
UNIT NO. 1A

SCALE IN FEET
0 10 20 30 40 50

Fig. 3

epitomize the overall European art. The waste disposal technique practiced on a commercial basis in Germany includes pulverization combined with landfill, composting, and refuse burning (Müllverbrennung). Since 1960, but especially since 1964, a series of refuse burning installations have gone into operation, generally with relatively high disposal capacities, and these plants provide some rather surprising statistics. As of February 1969 (the most recent data available during the study period), 13 refuse burning installations were in operation with seven more under construction with 1971 service dates. All are equipped with steam heat-recovery systems. The 13 plants handle the refuse of about 7.5 million inhabitants, i.e., about 12.5 percent of the total population. This amounts to 37 percent of the refuse in the large cities where the plants are located. With the seven new installations, as well as two installations in the planning stages, the number of inhabitants whose refuse is burned will be increased to more than 11 million. This number could easily reach 14 to 15 million by the mid 1970's. This will correspond to almost a

quarter of the total population of Germany (3).

The majority of the German units burn refuse and recover the heat by generating steam. The utilization of the steam varies considerably, ranging from running plant auxiliary equipment to district heating and power generation (4). In considering steam generating power plants, economic considerations dictate high steam pressures (>1000 psig) and high superheat temperatures (>950 F). The number of plants burning large amounts of refuse and generating high-pressure steam for power generation are relatively few and are found mainly in Germany (5). Refuse is either fired in a separate furnace cell or in the same furnace, or refuse is burned to heat only a portion of the feedwater-steam loop. These plants have one thing in common: Whenever high pressure steam is used in generating power with refuse firing, fossil fuel is always used somewhere in the steam cycle. Because of the nonhomogeneity of refuse combustion, gas temperature and composition fluctuate rapidly and erratically within the furnace. Outside the furnace, these fluctuations are manifested by variations in steam pressure,

Table 1 Fuel Properties

Fuel	Bituminous Coal	Anthracite	Lignite	Peat	Refuse
Proximate Analyses, Per Cent					
Moisture	7.8	18.3	36.4	40.0	27.1
Volatile Matter	41.1	5.0	28.7	18.4	44.5
Fixed Carbon	41.1	56.5	28.0	35.4	6.7
Ash	10.0	20.2	6.9	6.2	21.7
Higher Heating Value (HHV), 12,022 Btu/lb		8,845	6,750	5,290	4,460

Table 2 Summary of 15 Test Conditions Used for Detailed Study of Five Units

Plant	Unit No.	Refuse	Fossil Fuel	Refuse + Fossil Fuel
"Düsseldorf	1	1	-	-
Stuttgart	28	-	1	2
Stuttgart	29	-	1	2
Munich North	1A	1	1	1
Munich North	2	1	1	3

temperature, and flow. By combining the contribution of the nonhomogeneous fuel (refuse) with the homogeneous fuel (fossil fuel), the effect of these fluctuations is minimized. Shown later are the various, specific techniques by which this is accomplished.

One of the aspects of this program was to select several of these units for detailed study. In choosing these plants, nonagitating grates (e.g., horizontal traveling grates) and units previously firing fossil fuel, modified to burn refuse, were excluded. The five units selected assure consideration of the best examples of inclined grate and boiler design, and include "Düsseldorf-Flingern Unit No. 1, Stuttgart-Münster Unit Nos. 28 and 29, and Munich North Unit Nos. 1 and 2.

"Düsseldorf-Flingern

The four identical units of this plant were put into service in late 1965. Each natural circulation steam generator is designed to deliver 25,500 to 35,200 lb/hr of steam at 1280 psig and 932 F as shown in Fig. 1. (Figs. 1 through 4 and Fig. 6 depict general arrangement drawings of the various units and are all shown to the same scale). Refuse is fired on a roller grate at a rate of 22,050 lb/hr (260 tpd). The roller grate was developed by the City of Düsseldorf in conjunction with manufacturers (6). Auxiliary oil guns are used for start-up. The steam is used in conjunction with the Flingern Power Plant located nearby.

Steam from the four refuse-burning steam generators is delivered to a header to which four coal-fired steam generators are also connected. The steam is then delivered to two high- and low-pressure turbo-generators. Steam can also be taken from the outlet of the high-pressure turbine and delivered to a district heating system. The four refuse units comprise only 13.5 percent of the steam generating capacity of the system. The steam pressure and temperature of the refuse-fired units are controlled uniformly, but the steam flow variation is quite erratic. The four refuse units, connected in parallel, comprise only a small percentage of the total steam capacity, resulting in negligible variations in total steam flow at the inlet to the turbines. Space for these additional units was provided in the original plant planning.

"Stuttgart-Münster

The two refuse burning units at this plant are nearly identical (differing only in the type of grate used to burn the refuse) and were put into service in 1965. Both units have an oil-fired furnace and a refuse-fired furnace with flue gases combining before entering the convection sections as shown in Fig. 2. Unit No. 28 is equipped with a backward reciprocating grate (Martin) and Unit No. 29 with a roller grate (VKW). Each of these natural circulation steam generators is designed to deliver 204,600 lb/hr steam at 925 psig and 977 F. The refuse is burned at a rate of

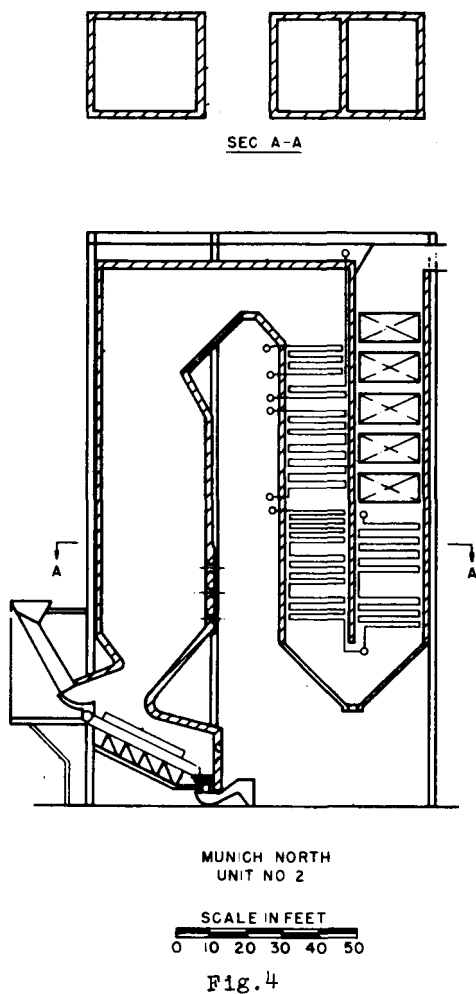


Fig. 4

40,920 lb/hr (490 tpd) which constitutes about 40 percent of the heat input.² Steam from the two combined fired steam generators is delivered to a header to which several coal-fired steam generators are also connected. The steam is then delivered to seven turbo-generator sets (155 MW) with extraction points for a district heating system. The refuse-fired portion of these two combined units comprise less than 15 percent of the steam generating capacity of the system. The steam pressure and temperature of the combined units is uniformly controlled, but there is considerable variation in steam flow. The amount of steam generated by the combined-fired units comprise a small percentage of the total steam capacity, resulting in negligible variations in total steam flow at the inlet to the turbines. One additional combined-fired unit is being added to the plant. As in Dusseldorf, initial plans provided space for this additional unit.

² Heat input is based on United States practice of using higher heating value, contrary to European use of lower heating value.

Munich North

Unit No. 1. This unit consists of two identical steam generators (Boiler Nos. 1A and 1B) in parallel connected directly to a turbine and was placed in service in 1964. Each steam generator has a pulverized coal-fired furnace and a refuse-fired furnace with the flue gases combining before entering the convection sections as shown in Fig. 3. Each of these forced circulation steam generators is designed to deliver 220,000 lb/hr steam at 2600 psig and 1004 F/1004 F superheat and reheat temperatures, respectively. Refuse is fired on each backward reciprocating grate (Martin) at a rate of 55,000 lb/hr (660/tpd), which constitutes about 54 percent of the heat input. Steam is delivered directly to a 68-MW turbo-generator with extraction points for district heating. The steam pressure and temperature of each unit is controlled uniformly, and there are only slight variations in steam flow. Some damping of flow variations is obtained by the parallel arrangement of the twin steam generators. The remaining fluctuations are also present in the electric generator output, but are small in comparison to the system generation (550 MW).

Unit No. 2. This unit, first put into service in 1966, consists of a single steam generator connected directly to a turbine. The steam generator is a forced circulation type designed to deliver 800,000 lb/hr steam at 2600 psig/1004 F/1004 F. It has a single furnace with separate refuse and pulverized coal-firing equipment as shown in Fig. 4. Refuse is fired on a single backward reciprocating grate (Martin) at a rate of 88,500 lb/hr (1060 tpd) which constitutes about 30 percent of the heat input. Full load can be achieved firing only coal, or refuse and coal in combination. Refuse alone may be fired for district heating but not for power generation. The steam pressure and temperature and flow are controlled uniformly, permitting the plant to operate on system demand.

TUV PERFORMANCE TESTS

Performance test data for the steam generator and accessory equipment of each of the selected plants were made available. These tests were performed by the Technischer Überwachungs-Verein. The TÜV was organized about 100 years ago by boiler owners at the request of local authorities to provide test certificates for steam generators. Presently, there are TÜV offices in each of the principal industrial regions. They provide expert certification service for industrial equipment. Both plant owners and manufacturers bear the expense of the performance tests. There is

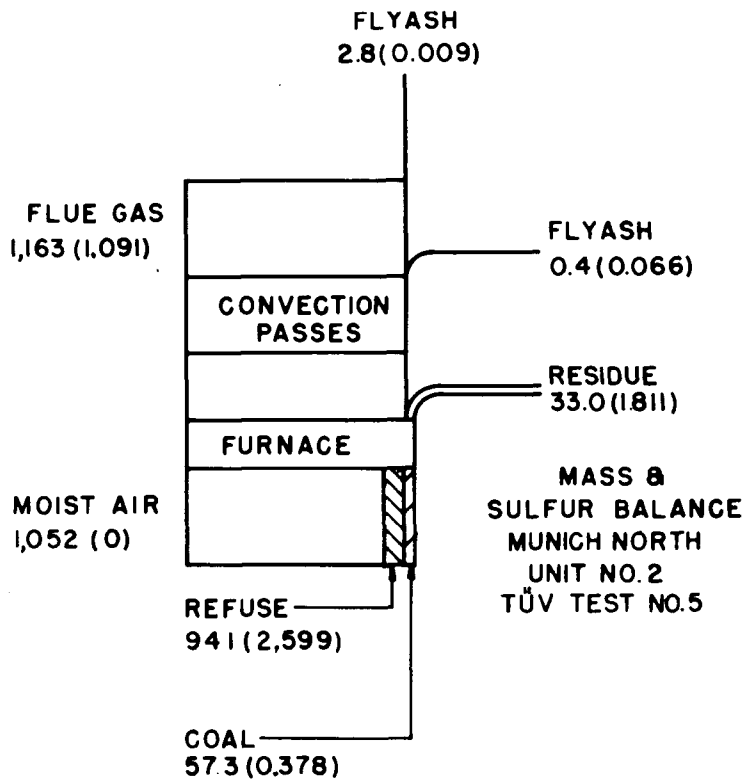


Fig.5 Mass and sulfur balance, Munich North,
Unit No. 2, TÜV Test No. 5

Table 3 Summary of Performance Data from Munich North, Unit No. 2
(TÜV TEST NO. 5)

Steam	M lb/hr	774.8
Pressure superheater outlet	Psig	2688
Temperature steam superheater outlet	F	1000
Temperature steam reheater outlet	F	1004
Temperature air entering unit	F	37
Temperature air leaving air heater	F	513
Temperature gas entering air heater	F	618
Temperature gas leaving air heater	F	329
Excess air entering air heater	%	38*
Wet gas entering air heater	M lb/hr	1163
Air leaving air heater	M lb/hr	1047
Fuel fired (Refuse)	M lb/hr	94.1
Fuel fired (Coal)	M lb/hr	57.3
Efficiency	%	81.69

* TÜV Method

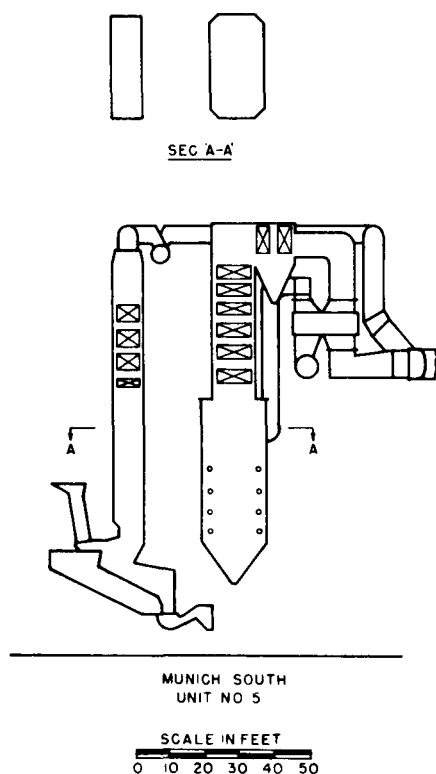


Fig. 6

no comparable service available in the United States. Use of these performance test results for this study required approval of the plant owners and all manufacturers, to whom a great debt of gratitude is extended.

The TUV conducted thorough evaluations of the performance of the five selected units at various test conditions. Table 2 is a summary of the 15 test conditions used for detailed study, firing either fuel alone or in combination. Several tests with fossil fuel only at partial loads were also included in the original TUV reports.

The original intent of these reports was to demonstrate whether the equipment tested had met guaranteed specifications. In the context of this study, these reports were used as documentation to determine the feasibility of using refuse as a fuel and to determine what effect such a process would have on air pollution, specifically on the emission of sulfur oxides.

That the equipment met specifications is a tribute to the designers, manufacturers, and operators. The first large refuse-fired installation (264 tpd) was put in service in 1960 at the Essen Karnap Plant. This was a re-vamp of existing pulverized coal-fired steam generators to include combined refuse fossil-fuel firing (7). It is quite remarkable that by 1964-1966, combined refuse fossil-fuel plants were being put into service on a performance-guaranteed basis. The

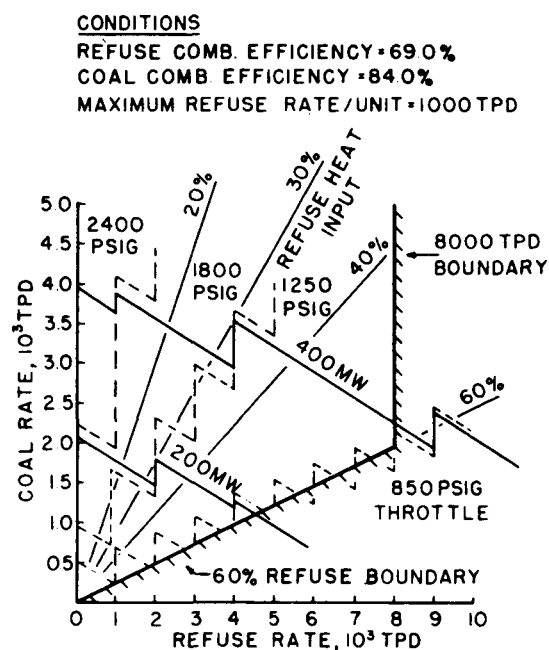


Fig. 7 Fuel requirements blended flue gases

TUV reports presented a unique opportunity to evaluate performance data. Of course, their practical value for United States conditions required not only translation from German and the conversion from metric units, but also the conversion of heat liberation from the lower heating value (LHV) basis to the higher heating value (HHV) basis. This is the first time such an evaluation has been made on the higher heating value basis. An evaluation of the sulfur oxides emission was made by sulfur balances. Results of one particular TUV test are summarized in Table 3. Fig. 5 illustrates the mass and sulfur balance. The results of Fig. 5 are summarized in Table 4.

The data in Table 4 are encouraging, because they indicate that a small amount of the sulfur in the refuse is carried out in the flue gas. Most of the sulfur is retained in the residue.

Tube Wastage

An especially important part of the program was a study of refuse fireside deposition and corrosion. This involved a comprehensive examination of the literature on ash deposits and corrosion in conjunction with laboratory analyses and physical examination of ash deposits on tubes from the five selected units, and an evaluation of their relationship to corrosion in waterwall refuse-fired units (8). The corrosion and deposition problem was initially brought out as a result of the publication of a series of articles in Europe in 1966-1967, describing severe corrosion in the furnace and high-temperature gas passes of refuse-fired steam generators (primarily the new German

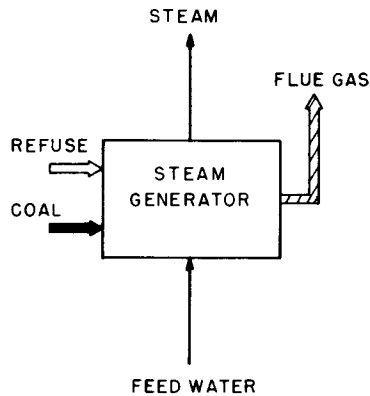


Fig.8 Blended flue gas system

units) shortly after being put into operation. The initial rather disturbing reports were followed by numerous papers which now indicate that corrosion, although still understood only to a limited degree, has subsided or been brought under control (9-11).

As a result of this detailed study and discussions with plant designers and operators, the present situation may be summarized as follows:

1 The exact mechanism of corrosion in refuse-fired steam generators is not fully known, and the proposed explanations are based upon surmise.

2 Corrosion in refuse boilers is mainly a nuisance at present, rather than a critical problem, and poses no serious threat in Europe to existing installations. As a result, only minor attention is being given to elucidating the causes of corrosion.

These comments should counteract the unfortunate impression, still widespread in the United States, that high-performance, refuse-fired steam generators in Europe continue to experience intolerable corrosion problems. From a design point of view, it must be acknowledged that more detailed information is desirable. However, as a result of this study, the main danger points have been established which permit the designer to avoid the persistent problems incurred in Europe. For example, the experience indicates that corrosion occurs in convection passes when tube metals exceed threshold temperatures between 850 and 950 F, in almost all cases in the presence of ash deposits. In addition to fouling, and like ash corrosion from fossil fuels at comparable temperatures, corrosion due to refuse appears to be accelerated by the presence of sodium, potassium, chlorine, zinc, and lead (12, 13). Localized reducing conditions can lower these threshold temperatures. This effect can be remedied by proper design and also by operating procedures. Full

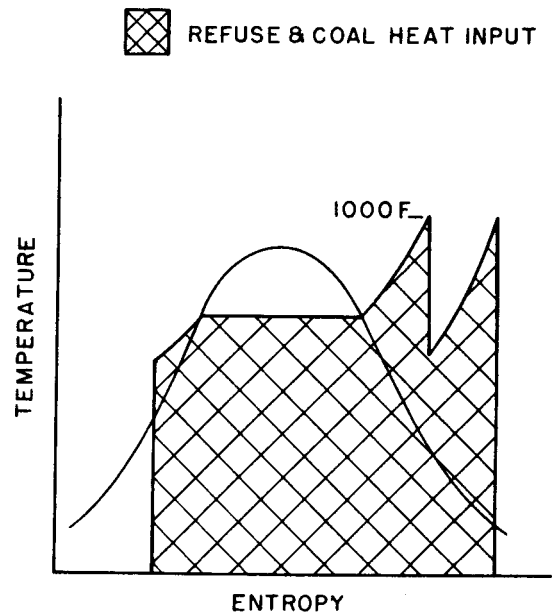


Fig.9 Steam T-S diagram for blended flue gas system

cognizance of this wealth of information was taken in the design of units for domestic conditions illustrated later in this paper.

Munich South

No survey of European experience on burning refuse for power generation would be complete without including the Munich South Plant. This is the most recent installation, having been put into service in late 1969. At the time the European plants were evaluated, no TÜV reports on this plant were available, and there most likely will not be a formal performance test because the unit has been so successful.

Unit No. 5 (Fig. 6) consists of a refuse-fired economizer and a natural gas- and/or oil-fired steam generator. Feedwater heated in the refuse-fired economizer is transferred to the steam generator which is designed to deliver 805,000-lb/hr steam at 2600 psig and 1004 F/1004 F. Refuse is fired on a backward reciprocating grate (Martin) at a rate of 84,000 lb/hr (700 tpd) which constitutes about 20 percent of the heat input. Steam from the main steam generator is delivered directly to a 124-MW turbo-generator extraction points for district heating. Regulation of steam pressure, temperature, and flow is controlled uniformly, comparable to a unit fired only with fossil fuel. Provision has been made for the future addition of coal pulverizers. Room has been provided for a duplicate unit (Unit No. 4), tentatively planned for a 1971 service date.

The work of Dr. M. Andritzky, formerly the

Table 4 Summary of Results in Fig. 5

Refuse Only	-	15 to 30 per cent of the entering sulfur appears in the flue gas.
Combined Firing	-	With (high sulfur) oil, 13 to 18 per cent of the entering sulfur appears in the flue gas. With (low sulfur) coal, 32 to 36 per cent of the sulfur appears in the flue gas.
Fossil Fuel Only	-	Over 92 per cent of the entering sulfur appears in the flue gas.

Table 5 Steam Pressures and Nameplate Ratings Corresponding to Various Regions in Fig. 7

<u>Steam Conditions</u>	<u>Turbine Nameplate Rating</u>
<u>Throttle (Psig)/Superheat (F)/Reheat (F)</u>	<u>MW</u>
2400/1000/1000	216-500
1800/1000/1000	86-215
1250/950/-	41-85
850/900/-	≤ 40

Director of the Munich Electricity Works (now retired and a consultant to this program), and his successors is a model of planning, construction, and operation (14-18). In the coming years, refuse burning will ultimately provide about 10 percent of the total power requirements of the City of Munich. However, the success in Munich has only been achieved because the city administration and the utility are partners in a joint venture with financial benefits accruing to both partners (17).

DOMESTIC EXPERIENCE

In the United States, there are presently no refuse burning plants designed and built for power generation. The first modern refuse-fired steam generator in the United States was built at the U.S. Naval Base at Norfolk, Virginia (19, 20). This unit and subsequent units at Montreal, Chicago, Harrisburg, Braintree, Hamilton (Ontario), and Rochester are industrial size steam generators with the steam being used for industrial purposes or simply being condensed. The planned modification to Unit No. 1 at the Meramec Station of Union Electric in St. Louis is the first large-scale refuse burning demonstration for power generation (21). However, by comparison to the European plants and the designs developed in this program, the refuse rate is small — amounting to only about 10 percent of the heat input.

An additional challenge imposed on domestic applications is that the heating value of municipal refuse is increasing each year as is the total

amount of refuse produced. A steam generator is essentially designed for a fixed heat input. As the refuse heating value increases, the amount of refuse fired must be decreased to provide a constant heat input. Steam generator design is also based on fuel characteristics. If the fuel varies either by degradation or improvement, performance can be adversely effected. In Europe, refuse heating value has increased and, to some degree, has been a contributing factor to some of the operational difficulties reported.

CATALOG OF CANDIDATE SYSTEMS

An important task of this program has been the development of engineering and cost data on possible steam generator configurations fired by refuse. The catalog of such candidates was then systematically analyzed to identify those design forms which offer favorable bases for optimization. The selection of such systems was based on a state-of-the-art survey of steam generator designs and a detailed analysis of the characteristics of refuse. The aim in developing the catalog was to propose two classes of designs, one for new plants and one for modifying existing plants to accommodate refuse burning. Ten candidate designs were developed for new plants and five for existing plants.

Design Parameters

In order to develop the catalog, certain assumptions and design constraints were imposed. Typical analyses and heating value were assumed

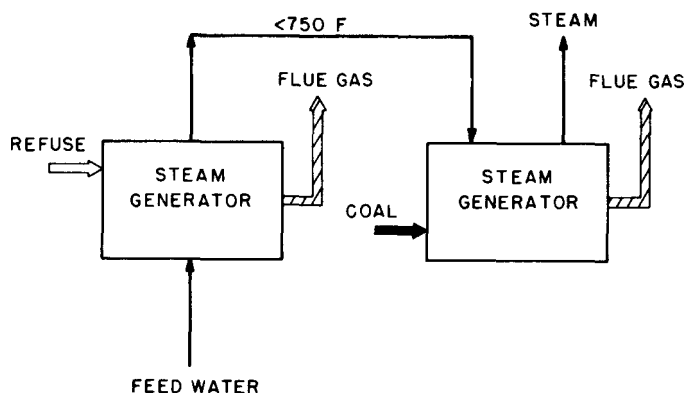


Fig.10 Separate flue gas system

for refuse and coal. Candidate systems using grates were limited to a refuse rate of 1000 tpd. Those not using grates were limited to 2000 tpd. Refuse rates of 20 to 60 percent of the total heat input were generally sought. Plant economy is adversely affected at lower refuse proportions, especially for new plants, while at levels above 60 percent, steam fluctuations become increasingly difficult to control. An upper limit of 500 MW was used. Four steam conditions were used in different plant sizes based on a survey of utility equipment purchasing over a three-year period ending in 1968. Only natural circulation steam generators were considered, based on the economy of this type compared to forced circulation. (Here there is a basic difference between United States and European practice). The flue gas exit temperature for firing refuse alone or in direct combination with coal firing was set at 450 F. It was chosen on the basis of electrostatic precipitators being a viable candidate for dust collection. Another design parameter was that when burning refuse only (especially on a grate without size reduction), the maximum allowable steam temperature would be 750 F.

Fuel Rate Requirements

For a given unit nameplate rating, the fuel requirements were determined for the appropriate steam conditions by evaluating steam generator efficiencies and auxiliary loads. One example of the fuel requirements is shown in Fig. 7. This case is for blended flue gas system (similar to Munich North, Unit Nos. 1 or 2). This has a regenerative cycle with or without reheat. The various regions labeled by steam pressures correspond to the following steam pressures and plant nameplate ratings in Table 5.

The pressure regions, plant nameplate ratings, and the allowable refuse rate per furnace determined the number of steam turbines and the number of steam generators. The discontinuities

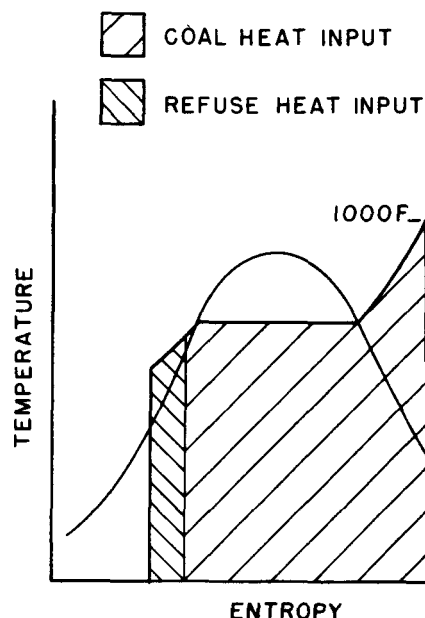


Fig.11 Steam T-S diagram for separate flue gas system (refuse-fired economizer)

of fuel requirements at steam pressure region boundaries are basically due to differences in cycle efficiencies, the number of turbines and steam generators for a given nameplate rating, and the maximum allowable refuse rate per steam generator. Also shown is a boundary following 60 percent refuse heat input and 8000-tpd refuse rate. This system includes a grate and, therefore, the 1000 tpd per refuse furnace limit. Therefore, the refuse rate in 1000 tpd corresponds to the number of refuse furnaces. Thus, at a plant rate of 8000 tpd, there would be eight refuse furnaces in parallel. If burning more than 60 percent refuse, the number of refuse furnaces required was significantly increased. In addition, many multiple furnaces firing less than 40 percent coal required extremely costly duplication of fossil-fuel burning equipment. The catalog of candidate systems consists of combinations of various heat-absorption methods and various refuse-firing methods.

Heat-Release Methods

One method of burning refuse to generate steam would be to burn refuse only and generate superheated steam delivered directly to a steam turbine. However, this presents difficulties in the control of fluctuations in steam flow and would result in steam temperature above 750 F with correspondingly higher metal temperatures and the potential of tube wastage. Such a method could be used in parallel with coal-fired units, where the amount of steam generated by refuse would be small

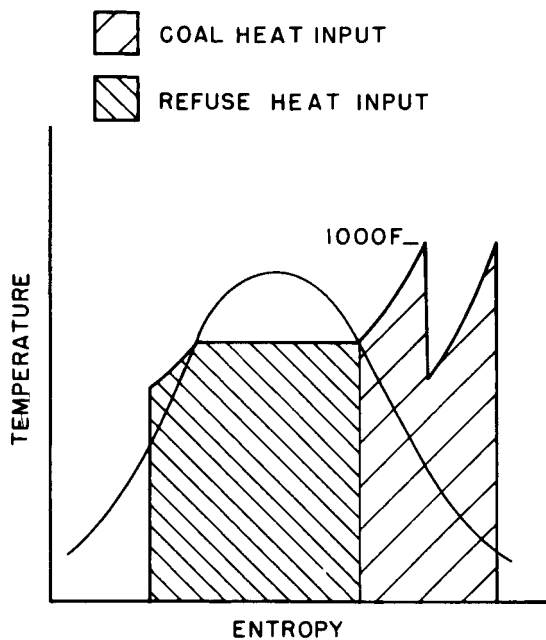


Fig. 12 Steam T-S diagram for separate flue gas system (refuse fired to saturated steam)

enough so that variations in steam flow would be minimized, e.g. as at Dusseldorf. However, for the reheat cycle, the potential of tube wastage was sufficient to delete this method from the catalog.

Another method consists of firing refuse and coal in combination (blended flue gas) as shown schematically in Fig. 8. On a temperature-entropy plot, the area under the path of state is approximately the heat input as shown for a reheat cycle in Fig. 9. In this method, refuse and coal could be fired in separate furnaces (Stuttgart, Munich North, Unit No. 1) or in the same furnace (Munich North, Unit No. 2).

Yet another method would be to fire refuse only with the steam temperature held below 750 F as shown in Fig. 10. This method permits the designer a wide latitude. The refuse may be used to merely heat feedwater, normally the duty of the economizer of a conventional steam generator as shown in Fig. 11 (Munich South). The refuse may be used to heat steam to saturated vapor as shown in Fig. 12 (22) or to partially superheat steam (750 F) as shown in Fig. 13. In these instances, superheating and reheating would be accomplished in a separate coal-fired superheater (reheater). Such a method has been used for nuclear plants where saturated steam from the steam generator of the reactor was superheated in a separate, oil-fired superheater (23). It has also been considered for a combined refuse-oil firing system where steam is used for industrial purposes (24).

A method combining the last two methods is

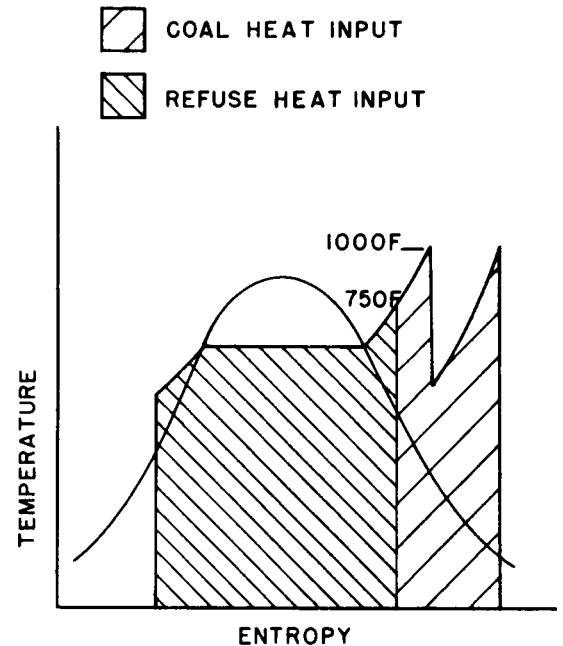


Fig. 13 Steam T-S diagram for separate flue gas system (refuse fired to partial superheated steam)

shown in Fig. 14. Such a method would be used to generate saturated steam as shown in Fig. 15 or may be used to generate superheated steam. As shown in the following, this method is dependent on the firing method to some degree.

Refuse-Firing Methods

The method of firing refuse considered in the catalog has been summarized in Fig. 16. Various manufacturers' equipment may vary in detail. For optimum service, each method requires size preparation. Size reduction of bulky waste is required even for agitating grates. In Europe, this procedure is built into the collection system either by preventing bulky refuse from entering the plants (Munich) or by having separate receiving and shredding facilities for bulky refuse (Dusseldorf and Stuttgart). Metals can be passed through the furnace and separated from the ash for scrap. However, at the Essen Karnap plant, metals are removed prior to firing. It is noted this plant has had no tube wastage and deposition problems. Prior removal of magnetic metal, which also removes most of the lead and zinc, may be the reason. Lead and zinc are two of the suspected temperature-dependent deposition and corrosion accelerators.

Just as commercial coal firing has progressed from grate to suspension firing, there is a real incentive to apply suspension firing to burning refuse for power generation. Grates have structural limitations, and hence a single furnace enclosure is limited to about 1000 tpd. Firing

Table 6 Synthesized Steam Generator Design Candidates

<u>Case</u>	<u>Designation</u>
1	Separate Furnace
2	Combined Furnace
3	Separate Refuse-Fired Economizer
4	Saturated Steam Unit with Separate Superheater
5	Partial Superheater Unit with Separate Superheater
6	Suspension Furnace
7	Spreader Stoker
8	Slagging Furnace
9	Arch Furnace
10	Arch Furnace with Separate Superheater

Table 7 Summary of Performance Data for Case 3 — Separate Refuse-Fired Economizer (Design Data)

<u>Refuse</u>				<u>Coal</u>	
Feedwater	M lb/hr	933	Steam	M lb/hr	2800
Pressure at outlet	Psig	2600	Pressure superheater outlet	Psig	2520
Temperature feedwater outlet	F	657	Temperature steam superheater outlet	F	1000
Temperature feed entering unit	F	470	Temperature steam reheater outlet	F	1000
Temperature air entering unit	F	80	Temperature air entering unit	F	80
Temperature air leaving air heater	F	316	Temperature air leaving air heater	F	764
Temperature gas entering air heater	F	766	Temperature gas entering air heater	F	825
Temperature gas leaving air heater	F	575	Temperature gas leaving air heater	F	325
Excess air entering air heater	%	50	Excess air entering air heater	%	18
Wet gas entering air heater	M lb/hr	435.5	Wet gas entering air heater	M lb/hr	3004
Air entering air heater	M lb/hr	368.9	Air leaving air heater	M lb/hr	2740
Fuel fired	M lb/hr	232.6	Fuel fired	M lb/hr	250.7
	tpd	930		tpd	3008
Efficiency	%	66.22	Efficiency	%	87.42
Combined Efficiency % 81.93					

pulverized refuse in suspension certainly would eliminate the need for cumbersome grates and, hence, would permit greater amounts of refuse to be fired. For such a system, a limitation of 2000 tpd was imposed in the catalog. This resulted in a significant change in the fuel requirements map in comparison to grate firing (Fig. 7). The basic difficulty to be resolved is to assure complete burnout of the refuse. One such method is illustrated later in this paper.

New Plants

A total of ten different candidate steam generator designs that were synthesized are shown in Table 6.

Cases 1 through 4 involve the use of a conventional agitating grate, such as the backward reciprocating, forward reciprocating, roller or

tilting grate. Cases 5 through 10 require special refuse-firing equipment. These cases were subjected to preliminary designs and cost estimates in sizes up to 500 MW and, where applicable, over the complete range of refuse rates (percentage heat input) with a total of over 80 separate cost estimates being derived. Team members (Envirogenics Co. and Cottrell Environmental Systems, Inc.) generated other plant cost data and the cost analysis resulted in the selection of two optimal candidate systems for detailed study: Case 3 — Separate Refuse Fired Economizer (400 MW) and Case 10 — Arch Furnace with Separate Superheater (100 MW). The results of the detailed design and cost estimate are given in the final report. Only a summary of Case 3 is given here.

Case 3 — Separate Refuse Fired Economizer.
This case is similar to the Munich South plant.

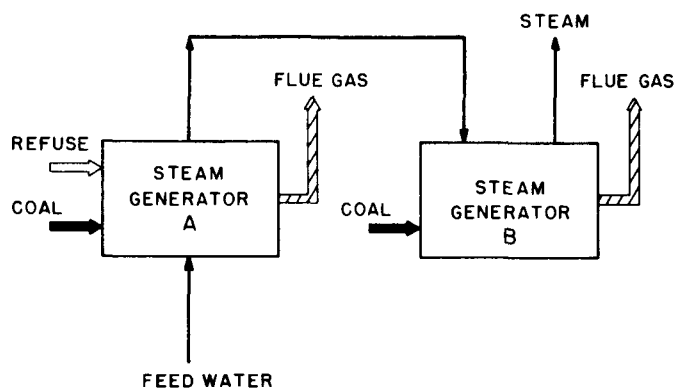


Fig. 14 Blended-separate flue gas system

The cycle schematic, Fig. 17, shows three refuse-fired economizers (limited by 1000 tpd/grate) connected in parallel heating feedwater for a natural circulation coal-fired steam generator. The latter is a conventional unit with the exception that the economizer surface has been omitted. Also shown in Fig. 17 are the turbo-generator and feedwater heaters for a regenerative-reheat system. The fuel map requirements for this case developed in the catalog of candidates are shown in Fig. 18, along with the design point resulting from the detailed design. A cross-sectional arrangement of the economizers and steam generator is shown in Fig. 19, and the summary performance is shown in Table 7.

Existing Plants

Modifications to candidate plants followed the procedures used for new plants. Obviously, there was a limit to the heat absorption and firing methods that could be employed. The obvious modifications consisted of conversions to Cases 1 and 2 type furnaces with agitating grates or spreader stokers. Suspension firing was considered appropriate for a unit recommended by others for combined refuse and coal firing (21). Steam conditions for this 300-MW unit are 2200 psig/1010 F/1010 F. It was placed in service in 1961. The unit is front wall fired, with the furnace divided into three sections by division walls as shown in Fig. 20. Refuse would be injected into each of these sections through nozzles located above the top row of burners. There would be two nozzles per section on the front and rear walls. The refuse would be injected between counterrotational coal burners tending to give the refuse an extremely turbulent burning path. In the event that there is insufficient burnout of refuse while in suspension, the furnace hopper could be modified to provide a surface for additional burning. The hopper tubes would be replaced by a slightly al-

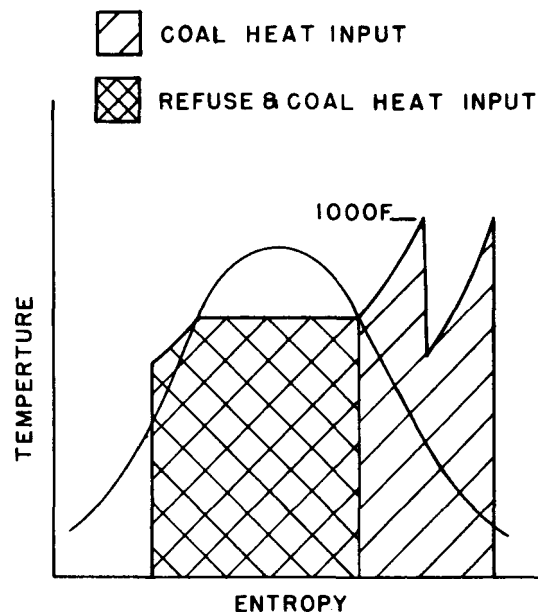


Fig. 15 Steam T-S diagram for blended-separate flue gas system

tered tube arrangement so that the stationary grate bars could be attached as illustrated in the insert in Fig. 20. The header enclosure under the furnace hopper would be converted into a plenum chamber for the underfire air. An array of steam jets on the hopper would be operated periodically to remove ash deposits from the grate bars. The refuse rate has been set at 775 tpd, which is equivalent to 10 percent of the heat input. At this rate, existing fans could be used. Additional soot blowers have been included, but at this refuse rate and with magnetic metals removed from the refuse, no fouling would be anticipated.

CONCLUSIONS

It has been shown that the European experience of burning refuse in combination with fossil fuel for power generation is fully developed and based on a sound engineering approach. The more recent plants are well planned and are virtually operated with the same availability and reliability as conventional fossil-fuel-fired plants. Their confidence is well documented by the continued commitment of new units. It has also been shown that the European experience is applicable to the United States conditions. The companion papers to this paper demonstrate that there are economic and environmental incentives to generate power from refuse. What is required here in the United States is the same approach that has been applied in Europe, the cooperation of the public, municipal governments, and electric utility companies to burn refuse to produce kilo-

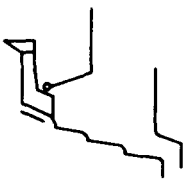
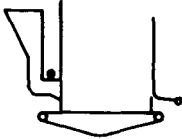
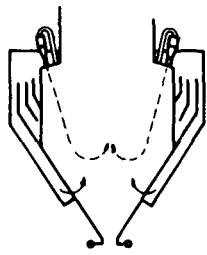
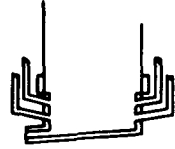
TYPE	AGITATING GRATES	AIR BLOWN SPREADER	SUSPENSION	SLAGGING
SCHEMATIC				
REFUSE PREPARATION	AS RECEIVED	4" SHREDDED	2" SHREDDED	2" SHREDDED
MAXIMUM ALLOWABLE REFUSE RATE PER GRATE TPD	1000	1000	2000	1000

Fig.16 Firing methods

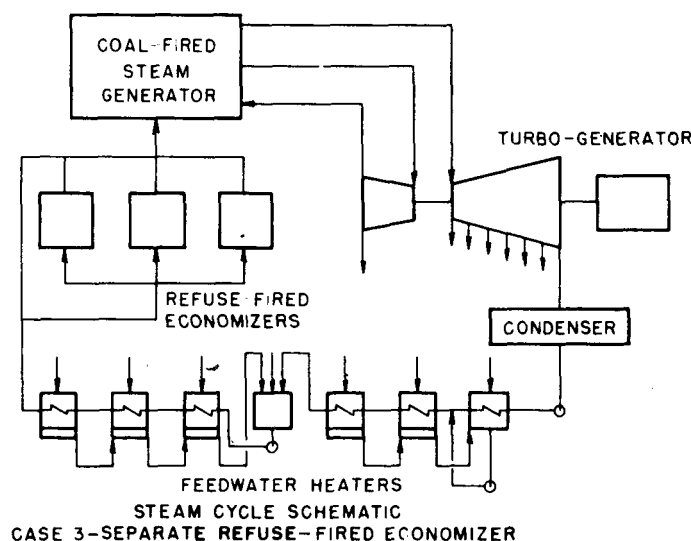


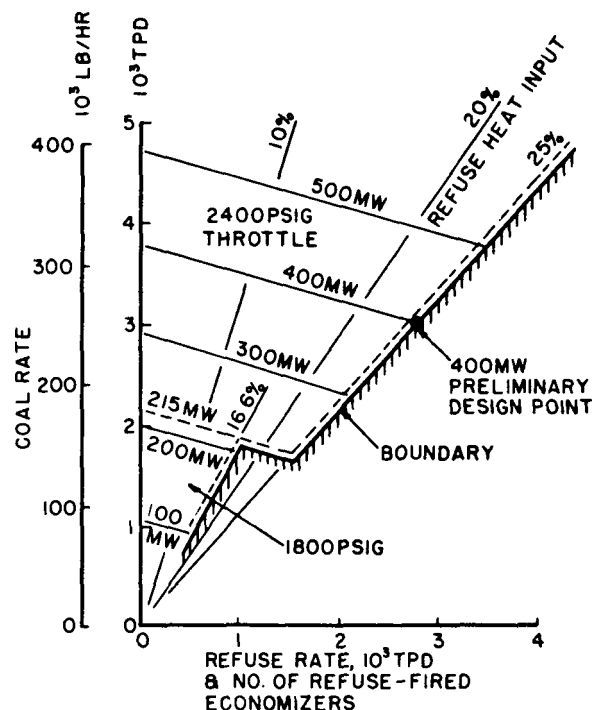
Fig.17

watts — a reasonable challenge.

ACKNOWLEDGMENTS

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The contributions of the following private consultants is also acknowledged; Mr. L. P. Flood, New York; Dr. M. Andritzky, Munich, Germany; and Dipl.-Ing. F. Nowak, Stuttgart, Germany. Space does not permit a listing of various European plant operators, manufacturers, governmental agencies, and independent research laboratories who contributed to this program, but special acknowledgment is given to Vereinigte Kesselwerke AG, Düsseldorf, whose assistance in this program was invaluable.



PLANT FUEL REQUIREMENTS
CASE 3-SEPARATE REFUSE-FIRED ECONOMIZER

Fig.18

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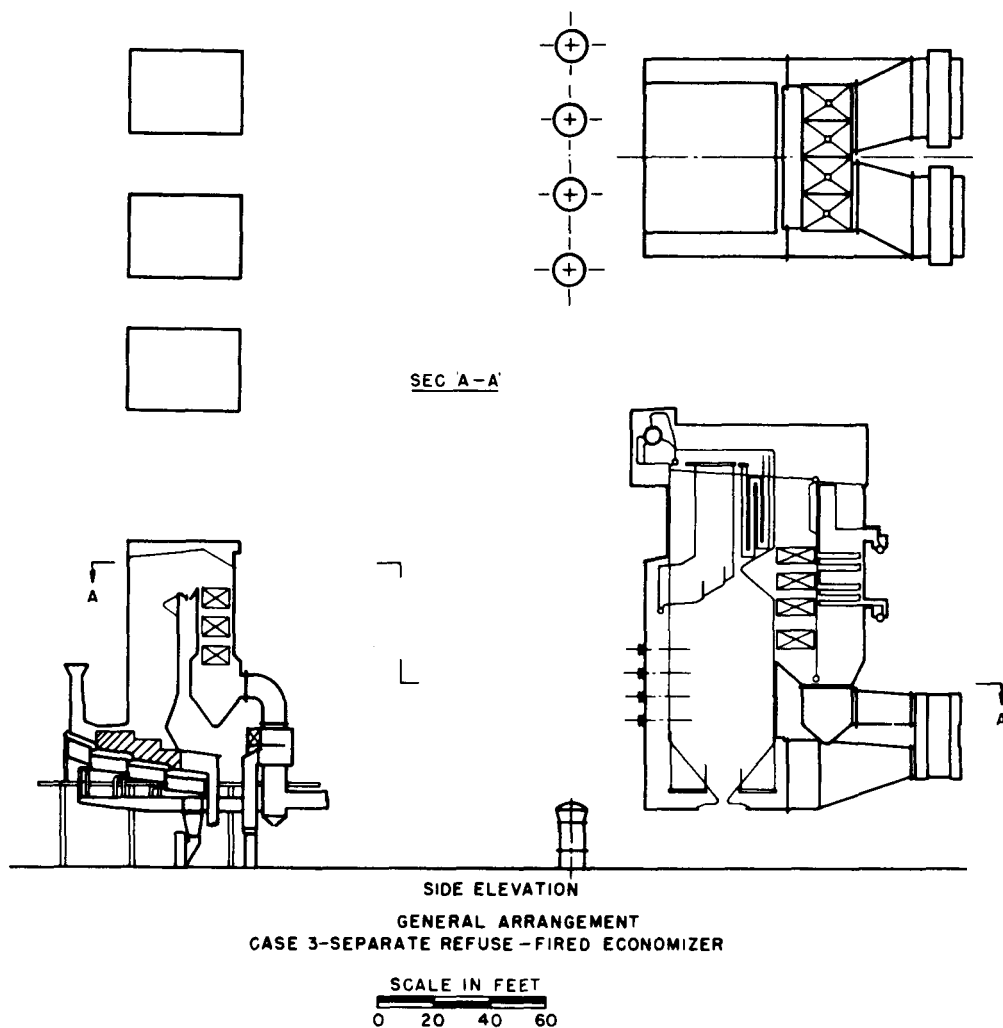


Fig.19

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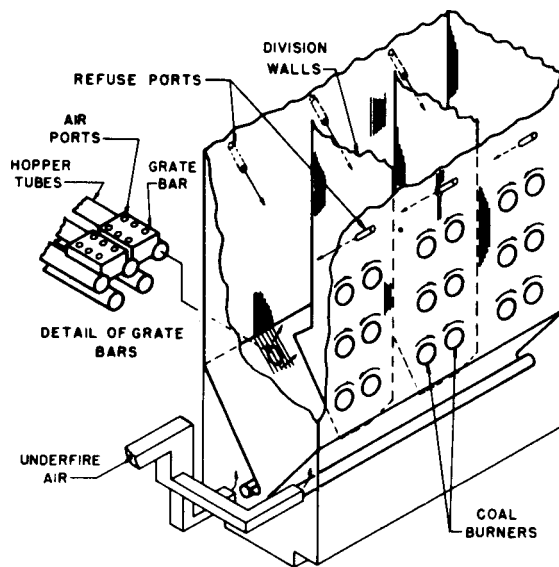


Fig.20 Existing unit modified for suspension firing of refuse

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APPENDIX E



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Modern Refuse Incineration in Düsseldorf—A Composite of the Best European Practices

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Eleven European incinerator plants were inspected and studied by the authors during the recent tour that provides background for the paper. Of the installations they visited, the authors deemed the Düsseldorf plant the most promising for additional study because it came closest to having all the features they considered to be the best. They examine thoroughly the characteristics that they believe make the plant outstandingly representative of the best European practices.

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Modern Refuse Incineration in Düsseldorf—A Composite of the Best European Practices

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HISTORY AND BACKGROUND

A new generation of refuse incinerators has made West Germany the leader in the technology of solid waste disposal. Perhaps the most representative of these new plants is at Düsseldorf, serving a Metropolitan area of 61.1 square miles and a population (1966) of over 698,000.

The initial decision to incinerate the ever growing volume of refuse, and to thus relieve the rapidly disappearing landfills, was made in 1960. There followed an intensive study and survey of current practices, both domestic and foreign, resulting in plans for a pilot plant incorporating a grate of novel design. After building the experimental plant and operating it for one year, the City of Düsseldorf commenced planning the full-scale facility. Certain delays ensued due to objections from neighbors of the 7²/₃-acre site. Construction was started by November 1963, however, and the first boiler was operating by November 1965.

GENERAL DESCRIPTION OF OPERATION

The structural housing has a capacity for six incinerator/boilers (Fig.1). The initial construction, however, included only four units. Each unit has a capacity of 10 metric tons per hr (11 short tons), or a total for four units of 960 metric tons (1058 short tons) per 24-hr day. One unit typically serves as standby or undergoes maintenance while the other three are in use. On occasion, the four units may fire simultaneously to meet certain operating requirements.

Unsegregated municipal refuse is brought directly to the Düsseldorf plant from as far away as eight miles, and 500 truckloads are deposited daily into the storage pit. Tipping is limited to an 8-hr period and occurs at a maximum rate of 120 trucks per hr. These figures do not include private, industrial, and commercial sources which account for about 15 percent of the total volume.

Operating requirements which dictated the design of the plant included:

- 1 Safe operation using refuse of constantly changing composition and density.
- 2 High combustion efficiency to obtain fur-

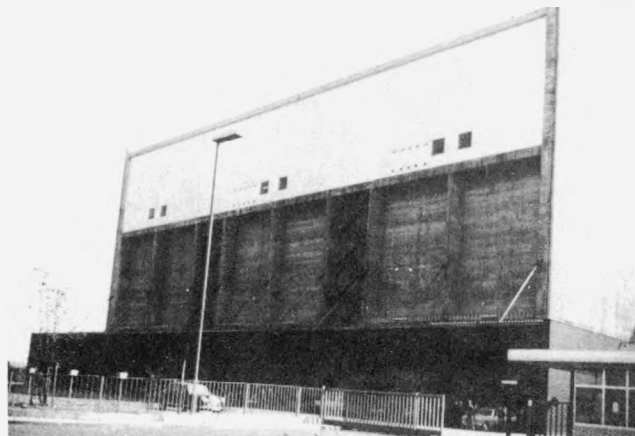


Fig.1 Exterior view of plant. Truck tipping area beyond fence, with visitor's gate at right

nace temperatures between 1650 F and 1850 F, which in turn will insure:

- (a) Elimination of odor and combustible pollutants from the stack gases.
- (b) Sterile ash containing only traces of putrescible matter.

3 Minimum of dust in the flue gas at the furnace outlet.

4 High boiler efficiency in order to maximize steam production, and thus helping to offset operating costs.

Operating incinerators are manned by personnel on four shifts. A shift crew includes one shift engineer, one chief foreman, two firemen, one crane operator, and one ash handler. During the day shift, there are one extra crane operator, one truck scale operator, and one truck spotter. Four men operate the ash reclamation plant during the regular shift.

COMBUSTION AND STEAM GENERATION

The average calorific content of the Düsseldorf refuse is reportedly 2600 Btu/lb. This average will be higher in the summer months, but lower in winter due to the large amounts of coal ash from residential heating units.

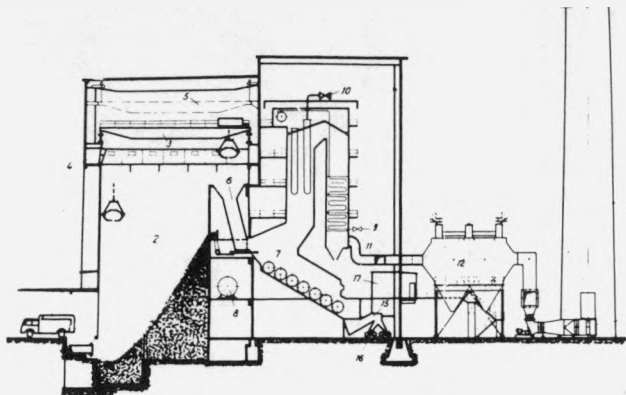


Fig.2 Cross-section diagram, showing process from truck discharge at left to stack at right

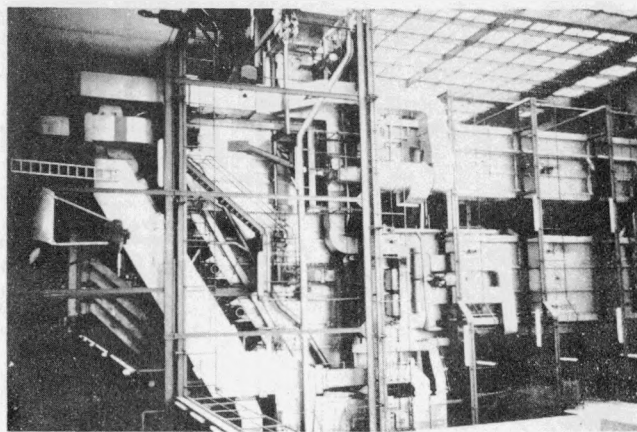


Fig.3 Exterior elevation of incinerator/boiler

Mixing of the fuel elements charged into the incinerators has been found important in meeting output requirements. Mixing is accomplished by directing the trucks to predetermined tipping positions at the storage pit, and then by using the crane grapple bucket to selectively feed various types and amounts of refuse into the incinerators in a definite sequence.

The Düsseldorf grate consists of a series of contiguous, independently driven, rotary drums. The drums are positioned so that a tangent to their upper surfaces forms an incline down which gravity, assisted by the motion of the drums, tumbles, and agitates the refuse. Fig.2 shows a cross section of the grate in relation to the remainder of the incinerator plant. Grate drum rotation is varied from four revolutions per hr down to one revolution per hr, and can be reversed to break very rare jams caused by wire or other material wedged between a drum and its scraper plate. Excellent experience has been obtained with the grey cast iron grate bars, attributable in part to their intermittent exposure to the 1800 F furnace temperatures. The life expectancy of grate bars has been estimated at five years, after which they will require replacement because of mechanical wear over the entire drum surface.

An analysis of the ash has established the following properties:

<u>Material</u>	<u>Initial Deformation at deg F</u>	<u>Softening at deg F</u>	<u>Fluid at deg F</u>
Air Dry Ash	1922	2048	2120
Fly Ash	2012 to 2120	2066 to 2354	2120 to 2228

From this it is apparent that the low initial deformation temperature of the fly ash could lead to severe coating of the boiler tubes if the furnace temperature becomes too high. On the other hand, temperatures must be maintained above the odor limit, considered to be 1650 F minimum. As furnace temperatures are to be maintained within these limits (at about 1850 F) regardless of the refuse composition, the following provisions were made to obtain firing flexibility:

- 1 Supplementary firing of heavy fuel oil from two sidewall burners.
- 2 Adjustable air preheating in two stages, operated by (a) 300 F boiler feed water, and (b) extraction steam.
- 3 Flue gas recirculation into the last three drums of the grate.
- 4 Light fuel oil firing from an overhead burner for startup, in order to quickly achieve the required minimum furnace temperature of 1650 F.

When the heating value for the refuse is in the low range of 1550 to 1800 Btu/lb, supplementary heavy fuel oil firing and maximum air preheating are used to obtain the required 1850 F furnace temperature. With a refuse heating value of 1800 to 2300 Btu/lb, the heavy oil firing is discontinued and the air preheating reduced proportionately. Within the range of these heat values, the steam generation remains almost constant. A refuse heat value in excess of 2300 Btu/lb eliminates the need for air preheating, and operation is with ambient air. The last three drums of the grate are then supplied with recirculated flue gas, according to the refuse heat value, and steam generation is increased accordingly. Control problems are minimal because refuse combustion reactions are unusually slow compared to reactions for oil or coal. Combustion air is drawn through the boiler by induced draft fans downstream of the electro-

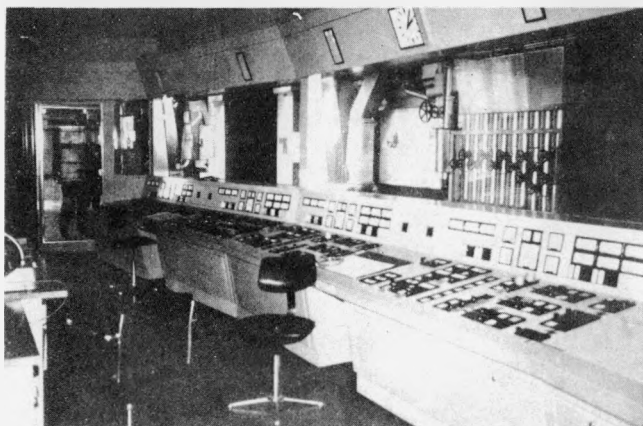


Fig.4 Control room; incinerator control bench boards

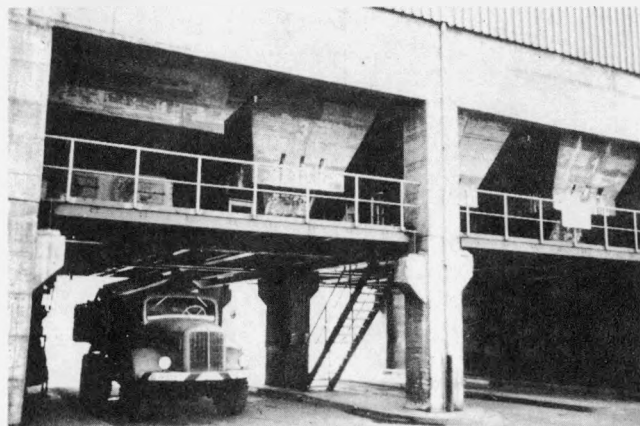


Fig.6 Classified ash loading area. Truck is loaded with oversized metal scrap

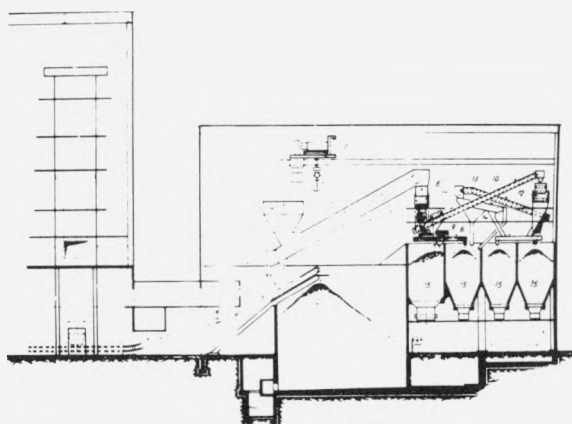


Fig.5 Ash classifying plant

static precipitator. Secondary air is introduced at the furnace outlet.

The boiler fireside has two furnace passes with two pendant superheaters in the upper portion of the furnace (Fig.3). The steam side of the boiler is of the single-drum natural recirculation type. Feedwater enters the triple economizer at 302 F. Water wall recirculation is provided in the furnace and convection pass. Steam leaving the drum passes through a horizontal superheater in the convection pass, and the two pendant superheaters in the upper section of the furnace, and leaves the boiler at 932 F. Operating pressure of the drum is 1422 psig. Based on burning eleven short tons of refuse per hr per unit, the steam generation is between 35,300 and 38,600 lb/hr per unit, depending on the heat value of the refuse. The average boiler efficiency is reported to be 69 percent. This low value is attributed to the high waste gas temperature and the large amounts

Table 1 Miscellaneous Properties and Composition of Ash

Component or Property	Raw Ash	Air Dry Ash	Fly Ash
Water Content (%)	9.7-27.5	0.1-0.8	0.1-0.2
Mineral Content (%)	65.7-86.0	89.9-96.2	94.7
Combustibles (%)	3.2-7.9	3.3-9.6	5.1-5.2
Unburned Carbon (%) (Fraction of Combustibles)	70.9-89.9	97.0-99.4	98.7-98.9
Volatiles (%)	0.4-1.6	0.5-2.2	1.0-1.1
Lower Heating Value (BTU/lb.)	275-720	513-1115	306-441
Putrescible Matter (%)		0.02-0.045	

of excess air. See Fig.4 for a view of the main control room.

BYPRODUCT UTILIZATION

In 1966, approximately 203,000 tons of refuse produced 330,000 tons of steam, 120,000 tons

of ash, and 4000-5000 tons of scrap metal, with resultant volume reduction to about 15-20 percent of the original. Steam is sold to a power plant 2300 ft from the incinerator and is utilized for power generation, as well as for a district heating system. Condensate is deaerated, heated, and returned to the boiler.

Table 2 Chemical Composition of Ash (Percent by Weight) From Winter Refuse

Silica as Si O ₂	49.6
Iron as Fe ₂ O ₃	12.2
Aluminum as Al ₂ O ₃	8.0
Calcium as Ca O	9.1
Magnesium as Mg O	1.9
Sulfur as SO ₄	2.2
Remainder (Alkalines)	<u>17.0</u>
	100.0
PH of Water Solution	8.8

Table 3 Typical Flue Gas Analysis

Excess Air	1.4 - 1.5
CO ₂ (Mean) (%)	12
CO ₂ (Max.) (%) (Determined from refuse analysis)	18.5 (Approx.)
O ₂ (Mean) (%)	7.4
SO ₂ (Without supplementary fuel) (grains/scf)	0.192 - 0.337
SO ₃ (Without supplementary fuel) (grains/scf)	0.00149 - 0.00227
SO ₂ (Light oil supplement)* (grains/scf)	0.236 - 0.349
SO ₃ (Light oil supplement)* (grains/scf)	0.00166 - 0.00284
SO ₂ (Heavy oil supplement)* (grains/scf)	0.367 - 0.519
SO ₃ (Heavy oil supplement)* (grains/scf)	0.00087 - 0.00183
Dewpoint (° F.)	170 - 190

*Equivalent to 10% of heating value.



Fig.7 Metal scrap baling equipment and conveyor to a truck loading platform. Sebastian on left, Arley on right

In addition to reclaiming heat energy in the form of steam from the refuse, the burned out residue is processed to recover ferrous metals and usable inert materials. Properties of the ash are given in Table 1. A chemical analysis of oven dry ash minerals is shown in Table 2.

Ashes are collected in a water filled hopper after the last and lowest grate drum. A screw conveyor collecting siftings from the grates also feeds into this hopper. The ashes are then sluiced into belt conveyors for transport to the ash processing plant. In Fig.5, a conveyor (1) moves the ash to a 1600 m³ stockpile (2). A travelling crane (3) grapple deposits raw ash into a hopper (4) which feeds it onto a belt (5) and moves it to a primary screen (6). The plus 1.2-in. fraction passes through a crusher (7) and is conveyed (8) to the product hopper (Grobasche 15). A magnetic separator (9) removes ferrous metals, mostly tin cans, from the conveyor and deposits this crushed scrap into the product hopper (Schrott 15). Another magnetic separator (11) also removes ferrous metals from the fines belt (10) and chutes it into the product hopper with the crushed scrap. The fines are screened (12) and the fraction passing a 3/8-in. mesh are routed to one of the fine ash storage bins (Feinasche 15). The plus 3/8-in. material is conveyed (13) to still another screen, where a final separation (14) is made between the fine ash and the coarser fragments of ash, clinker, and ceramics. Fig.6 shows the loading area for the product bins. Processing results in approximately 8 percent ferrous metal scrap, and the balance in nearly equal parts of fine and coarse ash. Ferrous scrap may be discharged from the bin directly to trucks, or onto a conveyor feeding the scrap press line (Fig.7).

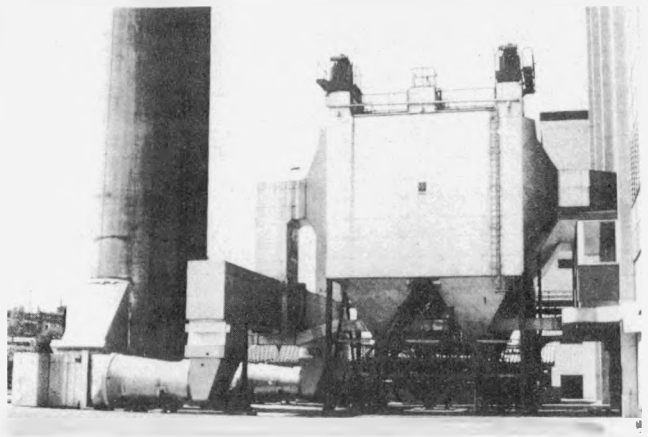


Fig.8 Electrostatic precipitator, induced draft fan, and base of stack

AIR POLLUTION CONTROL

The German code requires that:

- 1 Gases must pass through a zone of 800 C.
- 2 The stack plume must read less than No. 2 Ringelmann.
- 3 Particulates must be less than 150 mg per normal cubic meter, corrected to 7 percent CO₂.
- 4 Exhaust gas contains less than 1 mg per normal cubic meter of SO₂.

The completed Düsseldorf plant will consist of six incinerator/boiler units, with their flue gases distributed by a duct header to three electrostatic precipitators (Fig.8). The precipitators are of a size as to guarantee that the stack discharge does not exceed 0.066 grain of dust per standard cubic ft. Very advantageous in maintaining this value is the low dust generation on the grates, with approximately 0.44 grain/scf in summer and 1.3 grains/scf in winter operation. Three induced draft fans will draw the effluent from the precipitators and discharge into the stack; an additional fan is on standby. The observed stack discharge is barely visible.

The stack is 100 m high, and has an acid resistant brick liner covering the entire inner surface, and extending down the exterior at the top for 20 m. Construction is of reinforced concrete, with the lower 80 m having a double shell.

Due to fluctuations in the composition of the refuse, flue gases are carefully monitored. A typical flue gas analysis is shown in Table 3.

ECONOMICS OF OPERATION

The Düsseldorf plant cost approximately \$7,500,000, exclusive of the cost of the land. This was for four incinerator/boiler units, but

with attachments and auxiliaries for the future two units. It was estimated that the complete six-unit plant would cost \$8,500,000. The annual operating payroll for 60 persons is about \$250,000, and another \$250,000 is required for utilities and maintenance. It is estimated that power consumption is 40 kwh/ton of refuse; the water requirement of 1 m³/ton is met by their own well.

Private industrial and commercial users are charged \$3 per ton, delivered at the plant. Householders' rates include both collection and disposal.

Steam is sold to another department within the city for \$1.80 per ton of steam. In 1966 the revenue from steam was \$595,000, or \$2.93 per ton of refuse. The price of steam is based on replacement cost at the power plant, and is tied to the cost of coal. The 1967 cost of Ruhr coal was \$16.25 per ton (metric).

Scrap iron is sold in the open market for anywhere from \$12.50 to \$25.00 per metric ton. The 1966 income from scrap was about \$83,000, or about \$0.41 per ton of refuse. Through the use of an annual contract, one third of the ash residue is sold for \$0.19/ton, a second third is optionally bought by the contractor at \$0.11/ton, and the contractor may have the remaining third at no cost, if desired. While this arrangement represents substantial progress in developing a market for the ash, it is still necessary for the plant to dispose of as much as two thirds of the residue if the contractor does not exercise his options.

Using 1966 figures, it is seen that the total revenue is about \$3.40 per ton of refuse. Extending this over the reported 203,000 tons of refuse, the total would suffice to meet all operating costs, with an appreciable balance which could be applied to the amortization of capital costs.

APPENDIX F

SHIFT IN BOILER FUEL USAGE PATTERNS

W. H. Axtman
Executive Director
American Boiler Manufacturers Association

INTRODUCTION

There have been a number of changes affecting the fuel usage pattern of boiler sales in the past fifteen years. The changes have been brought about largely by the following pressures:

1. Environmental regulations
2. Fuel costs vs. equipment costs
3. Fuel availability patterns
4. Energy conservation requirements

The current weather conditions, fuel strikes and conditions in the Middle East have emphasized availability problems affecting fuel supply and will, perhaps, accelerate the shifting fuel patterns that have already started to emerge. Various pronouncements by public officials and energy "experts" have added to the confusion.

In analyzing changing fuel patterns, it is useful to consider fuel changes by boiler use category.

INDUSTRIAL BOILERS

An analysis of fossil fuel utilization patterns for industrial boilers for the period 1961 to 1978 shows coal reaching a high point of 19.8% of sales in 1963. Coal declined steadily from that point and with the passage of the Clean Air Act in 1970 reached a low of 1.0% in 1971. Since that time the market has had a modest recovery to 8.7% in 1975. In 1977, with a projected shortage of gas and imminent energy legislation, coal unit sales spurted to 21.9%. However, 1978 sales declined to 9.4% - about the historic level of recent years.

In contrast, natural gas went from 31.5% in 1961 to a high of over 60% in the late 60's. Pressures from projected shortages of natural gas and rate changes for industrial customers have caused this to drop steadily from the high of 61.3% in 1969 to a current 18.0% in 1978.

Oil dropped from 39.5% in 1962 to a low of 17.1% in 1969. With pressures on gas supply, oil has rebounded to 39.9% in 1978 showing an almost inverse curve to that of gas. It is important to realize that the majority of gas-fired units sold in recent years have been equipped to burn oil as an alternate fuel.

If one examines the total fossil curve (Figure 1), a steady decline can be seen since 1970 when fossil fuels represented 87.2% of industrial boiler sales. The area above this curve, then, represents non-fossil or waste fuel utilization which amounted to 32.7% in 1978. If you add this to coal percentage of 9.4% then units using fuels other than gas and oil totaled 41.1% in 1978, up from 16.3% in 1970. This healthy increase shows a strong trend for industrial units away from dependence on scarce gas and oil.

An analysis of selected waste fuels may also be of interest. Sales of industrial boilers fired with waste wood products has increased dramatically since 1966 when a low of 0.1% was realized. Since that time, sales of waste wood units climbed to 6.5% of the industrial market. In contrast black liquor boilers have been more cyclic ranging from a high of 7.7% to a low of 1.2%. Current sales of these boilers amount to 4.0%. Bagasse boilers are also somewhat cyclic ranging from a low of 0.0% in 1967 to a high of 5.0% in 1975. In recent years heat recovery boilers have been increasing in importance amounting to 8.6% of sales in 1976. Some interest in burning municipal waste is also shown but at present is spotty and spasmodic.

It may be interesting to look at these figures in the light of what is happening to the industrial boiler market. Figure 2 shows sales of industrial boilers since 1961. You will note that the market peaked in 1973 at 98.5 million pounds of steam. Since that time the market has declined to 37.7 million pounds of steam.

Figure 3 shows the average size of these boilers since 1961. The average size of industrial units has been relatively constant, ranging between 70 and 80 thousand pounds per hour. In contrast (Figure 4), the average size of coal-fired units has been somewhat larger being around 125 thousand pounds per hour over the 18 year period.

Pulverized coal units represent only a small fraction of the industrial coal market with various types of stokers filling the balance of sales. In the early 1960's, pulverized fuel units averaged about 250,000 pounds per hour capacity. By the middle 70's, the average size had grown to about 350,000 pounds per hour. However, in the last few years, small pulverized coal units are again becoming evident.

COMMERCIAL-INDUSTRIAL BOILERS

Boiler units in the commercial-industrial size ranges, although less interesting to this group, show a similar pattern with respect to oil and gas. These boilers are used for HVAC installations and also for small process applications.

Packaged firetube boiler sales for oil-fired units started with 48.7% of the market in 1963, dropped to a low of 32.7% in 1970 (the year of the Clean Air Act) and have since rebounded to 47.3% in 1976. In contrast gas units went from 28.6% in 1963 to 36.9% in 1969. In 1976 gas units dropped to an all-time low of 13.8%. Combination gas-oil units held steady between 23 to 28% until 1969 when they started to climb to a high of 41.6% in 1975. This reflects desires of purchasers to utilize any fuel available for this class of units.

Data on sales of other design types in the commercial-industrial market is not as well defined with oil accounting to about 20 to 25% of the market and combination units covering 15%. Gas units declined from 69% in 1971 to 21.6% in 1975 but rose to 45.4% in 1976 reflecting easing gas supplies in some areas and demands for replacement units.

There has been some interest in coal and waste fuel fired units in the commercial-industrial market but unit costs, environmental contracts and fuel handling problems have made use of these fuels viable only on a highly selected basis.

CONCLUSION

As we have seen, pressures from government regulation, fuel shortages and equipment costs have affected the fuels available for boilers, resulting in the changing of fuel patterns. Current trends indicate decreased reliance on natural gas and emphasis on waste fuels and coal for industrial units.

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INDUSTRIAL BOILERS

Fossil Fuels
(Domestic & Export)

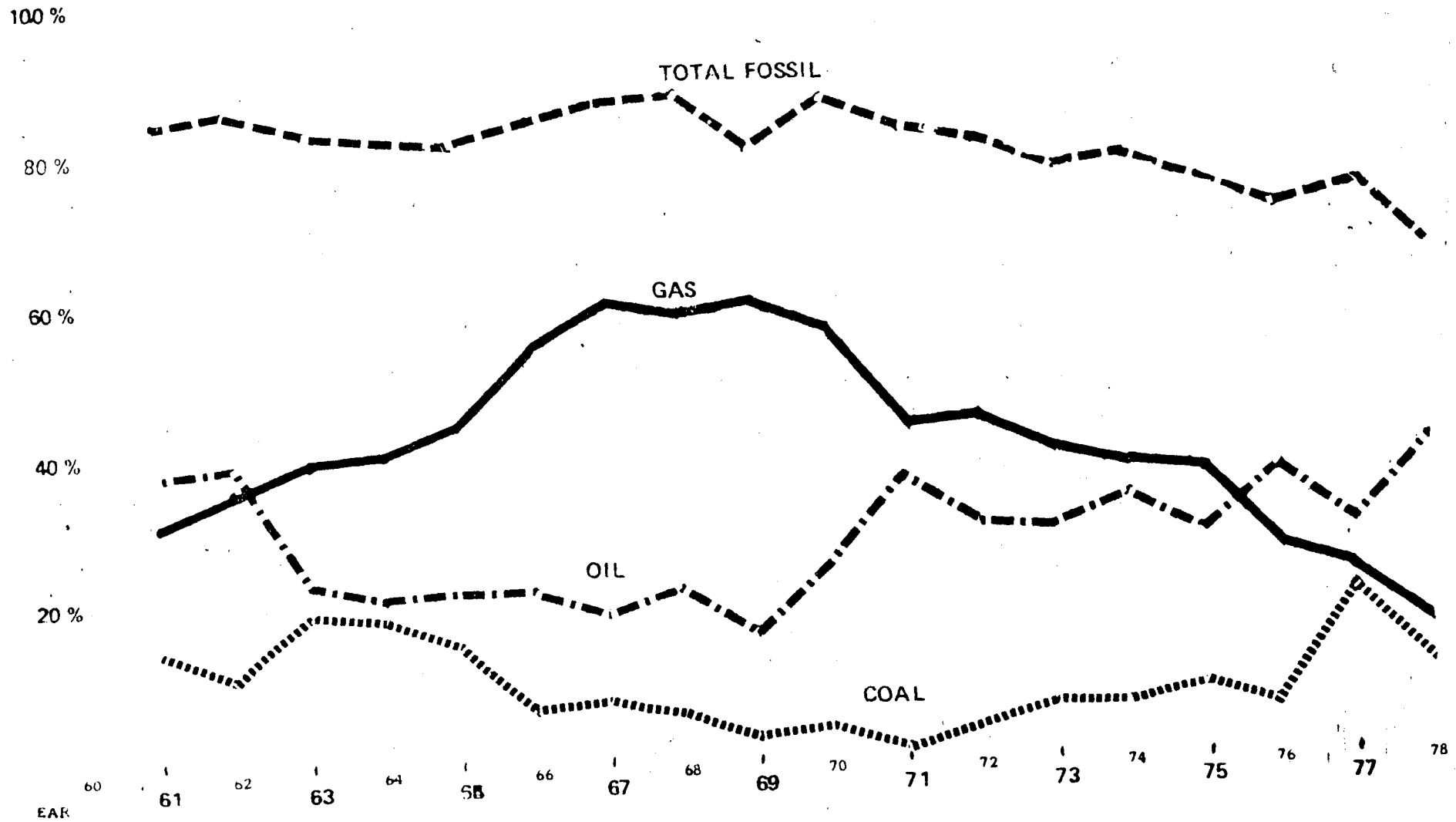
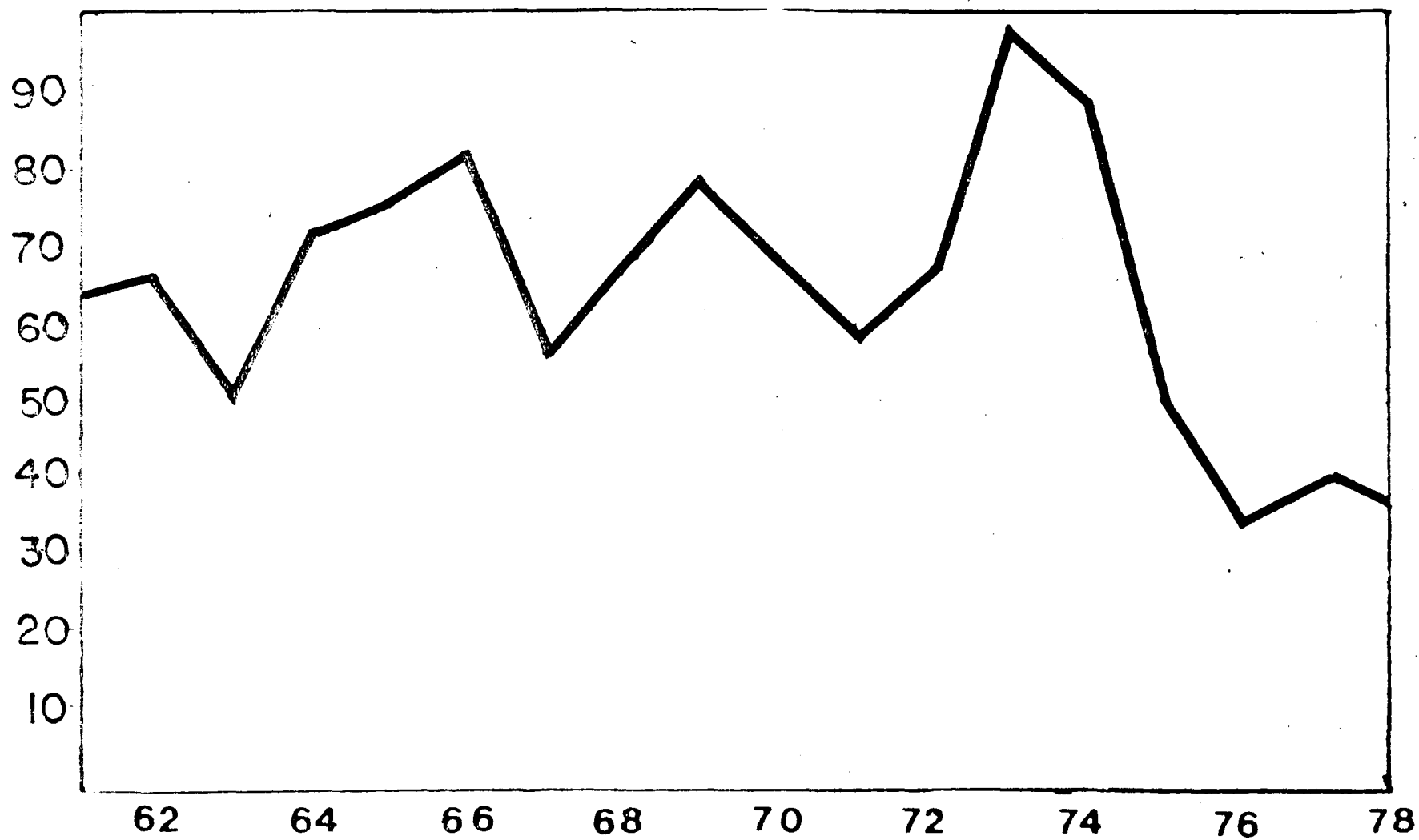


Figure 1

INDUSTRIAL BOILER SALES

million PPH



AVERAGE SIZE OF INDUSTRIAL BOILERS

thousand PPH

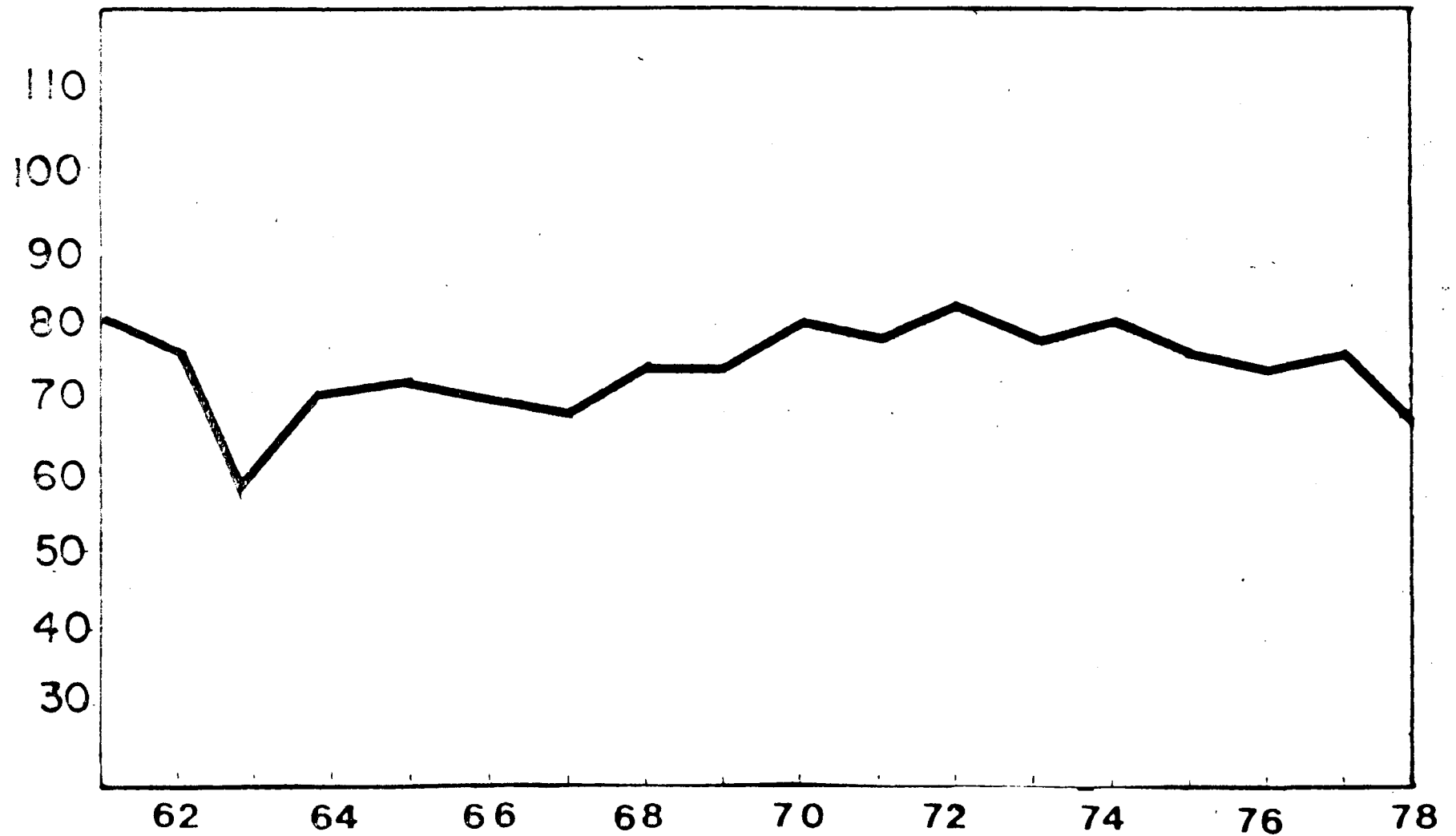


Figure 3

AVERAGE SIZE COAL FIRED BOILERS

thousand PPH

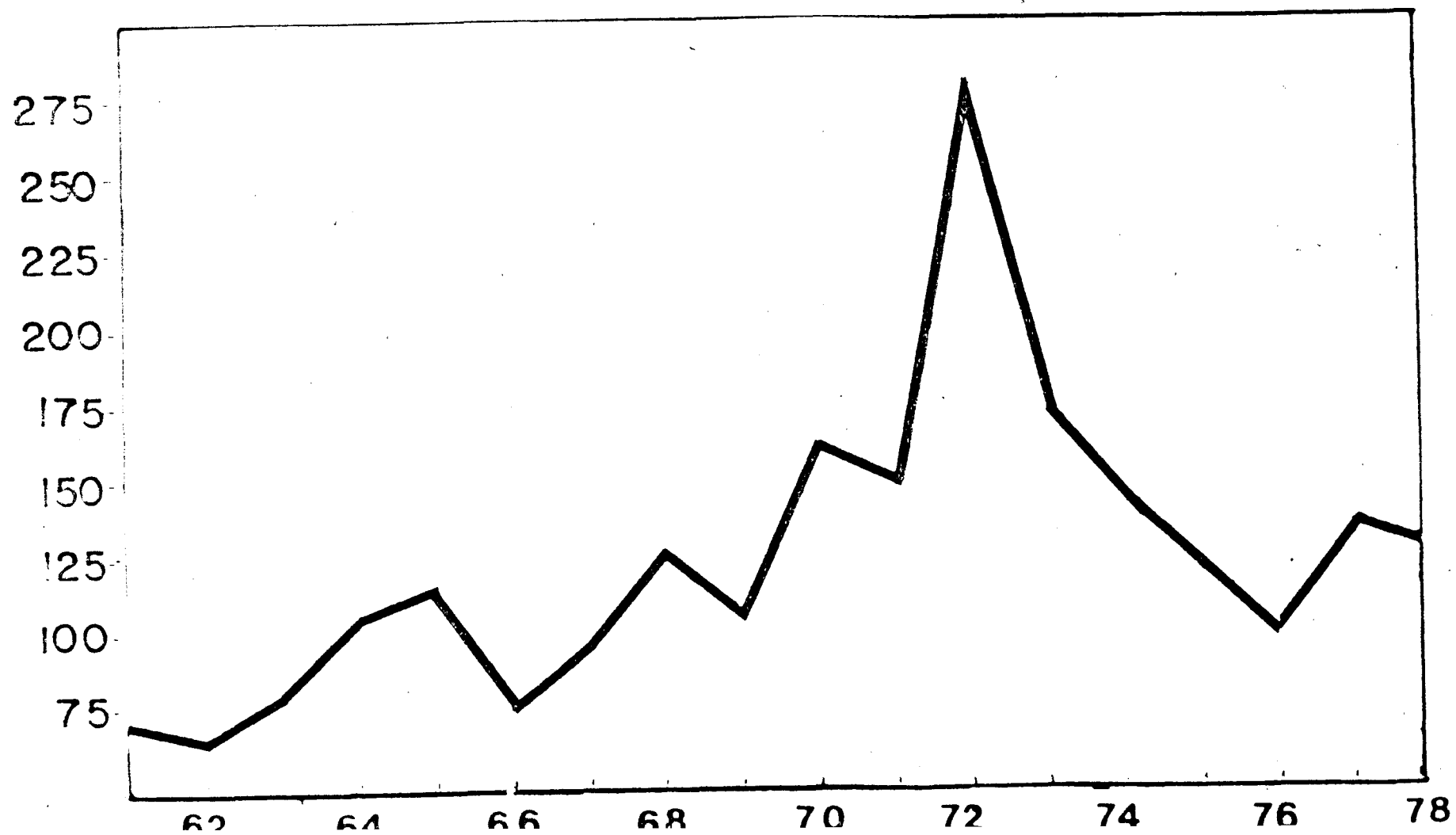


Figure 1

COMMERCIAL - INDUSTRIAL BOILERS

Packaged Firetube

70 %

50 %

40 %

30 %

20 %

10 %

62

63

64

65

66

67

68

69

70

71

72

73

74

75

76

77

78

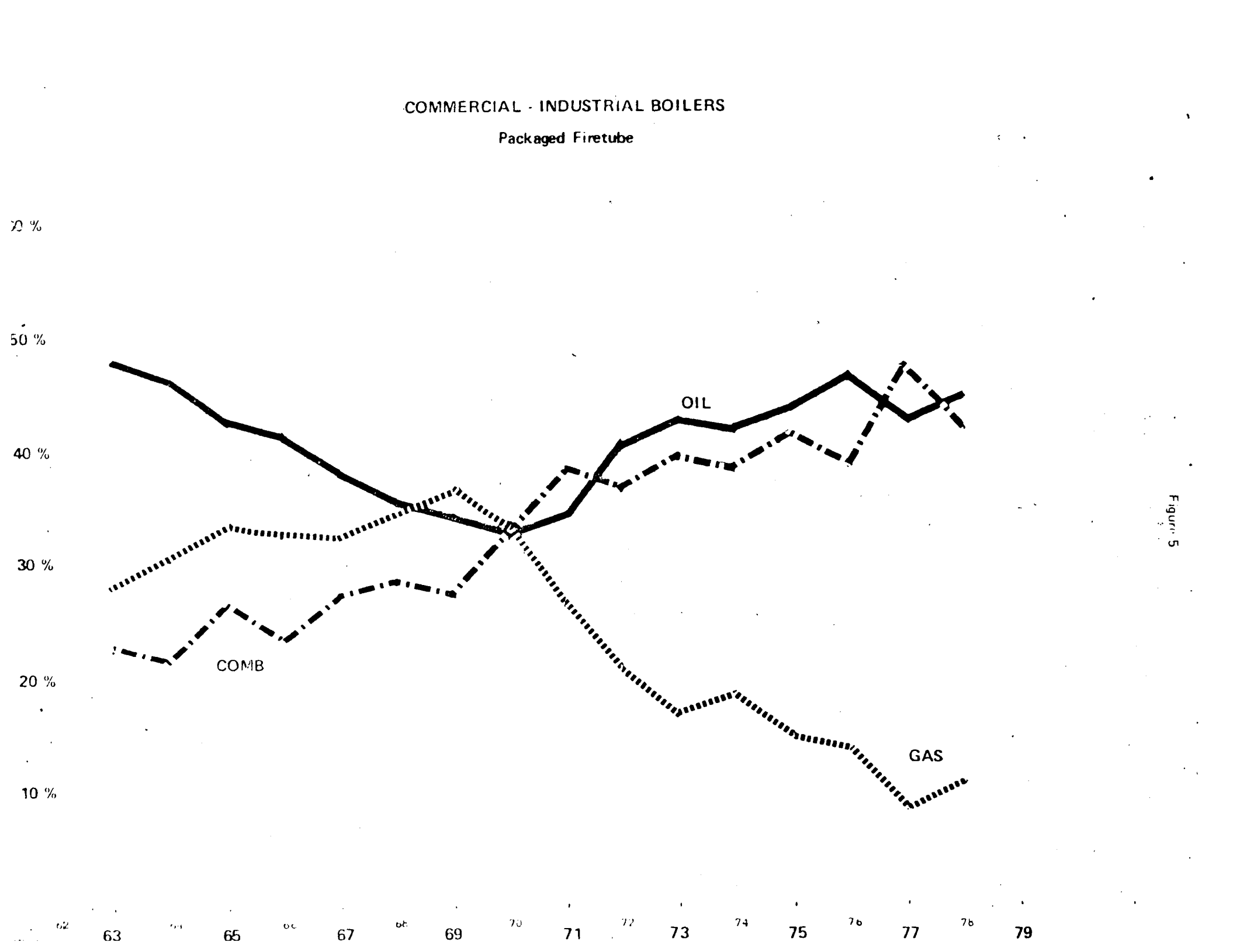
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COMB

OIL

GAS

Figure 5



COMMERCIAL - INDUSTRIAL BOILERS

Small watertube, Firebox, Misc. designs

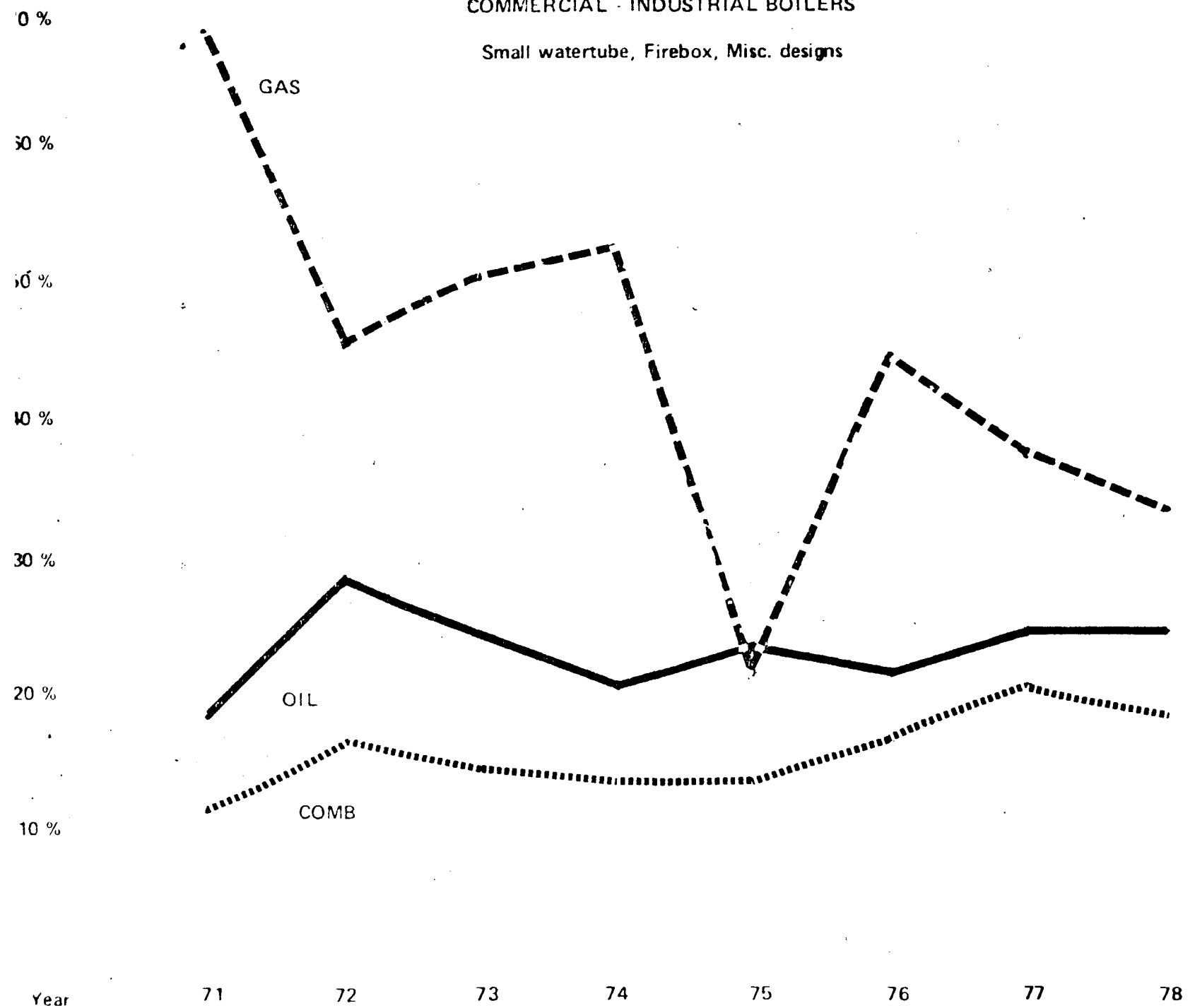


Figure 15

APPENDIX G

Heavy oil Pumping, Heating

Oil Heaters, Pumps, Piping and other Equipment used with No. 6 Fueloil

by
A. J. Poole*

IN THE INDUSTRIAL OILBURNING FIELD the fueloil generally burned is grade No. 6, usually called Bunker C. This oil is the last major marketable end product in refining and as such is less expensive than the lighter fueloils. It carries a minimum of specifications—a minimum flash point, and an upper limit on viscosity so that the user can handle it without difficulty. These facts dictate a different design of oil pumping and heating equipment than is required for the lighter fueloils.

As the range of capacities of oil pumping and heating equipment for this fueloil extends from as low as 15 gph to upward of 20,000 gph depending upon the plant requirements, this article cannot be too specific. However, in general the requirements are the same—only the details differ.

The first consideration is oil storage. Usually local conditions dictate whether the storage tank will be located above or below grade and whether the

tank will be vertical or horizontal. Local ordinances generally dictate the structural features. An excellent treatise on the subject has been issued by the National Board of Fire Underwriters; a copy may be procured from them by requesting NBFU pamphlet No. 30. This deals with details as to how the tank should be arranged, its construction, and requirements for preventing the spread of fire resulting from a tank leak. This treatise is highly recommended to supplement local ordinances.

The next item is oil storage capacity. Factors that influence this are:

1. Space available for the tanks.
2. Size of deliveries.
3. Proximity of the nearest oil supply depot.
4. Weather conditions.
5. Future expansion of the plant.

Where infrequent, large deliveries of oil are less expensive than frequent, small deliveries, large storage capacity is desirable. Hence the largest feasible storage capacity may be most economical in the long run.

Oil may be delivered by tank truck, rail tank cars, and barge. An investiga-

From this article by a power plant expert, dealers new to big-job technicalities can gather dozens of points of information—bland mention of oilheating and pumping rates up to 20,000 gph, oil pressures of 100 to 300 lbs. as the usual thing for power plants and the general advice on being able to heat oil to 240° F. for jobs using mechanical-atomizing or steam-atomizing burners.

On the other hand, readers already versed in large-job engineering, will discover interesting points and will be able to compare their experience with those of this oil-fired boiler expert. Where the author does things differently than they do, they may get a kick out of realizing there is more than one way to skin a cat!

tion into the methods of delivery possible for the particular installation should be made, and provisions made to handle several days' reserve in the tanks plus a full delivery. For example, if the size of installation warrants oil deliveries in 2500 gallon tank trucks, the storage capacity should be at least 2500 gal. plus the quantity normally burned in 3 or 4 days.

The proximity of the nearest oil depot and severity of weather conditions should receive consideration. Where the depot is remotely located and severe snow storms may be experienced, the fueloil reserve should be considerably greater than for a plant situated more favorably.

For the most favorable supply and weather conditions there should be a storage equivalent to at least two weeks consumption of fueloil at maximum plant capacity, and at least three weeks for plants located in unfavorable weather areas, or where the oil depot is distantly located.

If the oil is to be used as a standby for another fuel or if there is an available supply of some other fuel that can be burned in place of the fueloil,

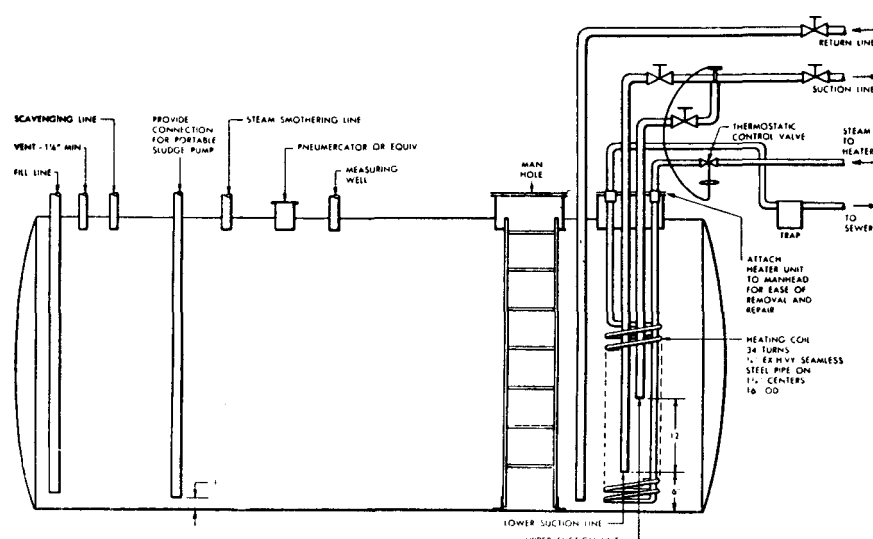


Fig. 1. Tank attachments, including gauge openings, fill and vent pipes and fire protection devices. Piping immersed in the oil tank should be of black steel, with all fittings of the flanged type—no packed joints. The lower suction line shown is the one normally used; the upper suction line is used in emergencies to forestall shutdowns when water collects to the level of the lower suction line. Before installation, the arrangement shown above should be checked against local Code regulations and revised, if necessary.

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then some reduction in the amount of storage can be considered. However, it would be well to determine if the auxiliary fuel will be available always. For example, in some localities natural gas is available at certain times of the year but usually during the winter it is not available to industrial users.

Future expansion of the power plant also should be considered; one large tank is cheaper than two smaller ones installed several years apart.

The tank should be equipped with certain attachments which are shown diagrammatically in Fig. 1, for determining the amount of oil in storage at any time, for fire protection, and the usual fill and vent needs.

Tank Heater

Generally speaking it is necessary to have Bunker C oil at a temperature of about 90° F. in order to be certain of being able to pump it, although in some warm climates the oil refineries apparently blend enough light stock with the heavy oil to permit pumping it if the temperature does not drop below 70° F. and thereby obviate the need for the tank heater except during abnormal weather conditions. Certainly, anyone designing a heavy oil system should provide for heating the oil in the storage tank.

There are two methods for accomplishing this: (1) recirculate enough returned hot oil to keep the oil in the tank at the proper temperature, or (2) supply heat to the oil tank by an auxiliary heater. The latter usually is the preferred method. The auxiliary heat is usually obtained by providing a coil of pipe around the suction stub in the tank and supplying low pressure steam or hot water to the coil. A more recent method uses electric heating. The choice is largely dictated by the cost of the heat source. The oilheating unit should be controlled to maintain the proper temperature for pumping the oil.

Where steam is used as the heating medium, the recommended practice is to discharge the condensate from the oilheater to the sewer and not return it as feed water to the boiler. The reason for this is that a leak in the heating coil can contaminate the condensate and the consequences of oil

getting into a boiler unit, resulting in failure of the heat absorbing surfaces, are entirely too costly to take the risk. Where hot water is used for this purpose as is the case in many small plants, the amount of water required is of such magnitude as to warrant returning the water to the system to avoid wasting it. When this is done provisions should be made to permit checking the returned water from the tank heater for any oil contamination before it goes to the main hot water system.

Location of Heater

A tank heater should be located close to the suction line so its effect on the oil suction will be fast. To heat the entire tank of oil is not necessary. Similarly, the return oil line should be close to the tank heater. In starting up after a long shutdown the oil can be circulated through the system to purge it of cold oil. Returning the purged oil close to the tank heater reduces the work the heater must do to raise the

oil temperature to that desired for pumping.

Transfer Pumps

Bunker C oil at a temperature of about 90° F. has an appreciable resistance to flow. Unless the storage tank is located at a level higher than the main oil pumps and is favorably disposed toward obtaining flow to the main pumps under adverse conditions, a transfer pump, or pumps should be located adjacent to the oil storage tank. The pumps may be electrically or steam driven. A popular arrangement is to use one electric and one steam powered pump and size each pump to deliver about 25% more oil than is required so that either steam or electric power can be used over the full load range. The pump need not be expensive. It merely lifts the oil out of the storage tank and delivers it into the boiler house at 5 to 10 psi.

The pipe line from the transfer

FUEL OIL AND ATOMIZING STEAM PIPING SIZES

The following oil pipe sizes are recommended for the discharge* side of heater where pumping and heating sets are located within 100 ft of the burners. Atomizing steam

header piping sizes are also given.

These values can be used for headers serving one or more boilers by totaling the oil flow to all units.

TYPE OF PIPING	OIL VISCOSITY, S.S.U.	OIL FLOW, lb/hr	APPROXIMATE STEAM FLOW FROM UNIT, lb/hr	SIZE OF EXTRA-HEAVY PIPE, in.
Suction, (Storage to pump and pump to heater)	5000	1000 to 1500	14,000 to 21,000	2
		1501 to 3000	21,001 to 42,000	2½
		3001 to 7000	42,001 to 98,000	3
		7001 to 12,000	98,001 to 168,000	3½
		12,001 to 20,000	168,001 to 280,000	4
*Discharge, (Heater to burners)	135	20,001 to 50,000	280,001 to 700,000	5
		50,001 to 100,000	700,001 to 1,400,000	6
		1000 to 8000	14,000 to 112,000	1½
		8001 to 15,000	112,001 to 210,000	2
		15,001 to 25,000	210,001 to 350,000	2½
Atomizing Steam Header		25,001 to 50,000	350,001 to 700,000	3
		50,001 to 80,000	700,001 to 1,200,000	3½
		80,001 to 150,000	1,200,001 to 2,100,000	4
		Up to 6000	—	1
		6001 to 12,000	—	1½
		12,001 to 16,000	—	2
		16,001 to 27,000	—	2½
		27,001 to 39,000	—	3
		39,001 to 60,000	—	4
		60,001 to 100,000	—	4

Pipe sizes are based on the use of oil having a viscosity of 135 S.S.U. and saturated steam at 125 psi for atomizing purposes.

For locations other than given above, use larger pipe sizes. In calculations, pressure drop between pump and burners, including allowances for heaters and fittings, should be limited to about 60 psi.

The average pump has a maximum lift of about 15 feet. Piping must be of a size that will not use up the entire lift of the pump in pressure drop. The actual lift from the tank to the pump plus the pressure drop in the piping should not exceed the rated lift of the pump. As a precaution it is recommended

that the total pressure drop should not exceed 75 per cent of pump lift. Oil temperature at pump suction for No. 6 oil will normally be from 90 to 120 F which will give a viscosity of approximately 5000 S.S.U. to 3000 S.S.U. Pump lift must be obtained for both conditions and checked against the sum of actual lift from tank to pump plus pressure drop in piping. If suction lift is exceeded, consideration must be given to a transfer pump preferably located at the storage tank.

Fig. 2. Suggested pipe sizes for various parts of the system.

pumps to the boiler house may be buried or placed in a trench with a removable cover. Depending upon the distance between the boiler house and the storage tanks and the severity of weather, it may be necessary to heat this line. An electrical heating system accomplishes this easily; one or more heating units may be used along the line, or a steam or hot water line to heat the storage tank oilheater can be located adjacent to the oil lines and all the lines insulated together. Where these lines are placed in a trench they should be wrapped with a waterproof covering over the insulation. Where freezing weather may be encountered provisions should be made to prevent freezing of the steam and condensate lines and traps. Fig. 2 shows suggested pipe sizes for various parts of the system—the lines carrying the more viscous 90° F. oil, and the lines carrying the "hot" oil.

Service Pump

As the vast majority of oilburners used in power plant applications require oil pressures from 100 to 300 psi and temperatures from 165° to 200° F., the next phase of the pumping and heating equipment is to increase the pressure and temperature to the required value from the 90° F. and 5 to 10 psi provided by the tank heater and transfer pump.

Practice varies as regards service pumps, and no hard and fast rules can be laid down. Usually boilers installed in factories that use process steam for the products will use steam-driven auxiliaries throughout—for fans for drafting the boilers, for feed-water pumps, and for fueloil pumps. Some large industrial plant boilers have two means of driving auxiliary equipment, steam only for standby, and electric for economical normal operation. Still others use electrically driven equipment throughout. The diagram in Fig. 3 indicates both steam and electric type pumps.

The motor-driven pumps may be either a gear or screw type and while such pumps can be driven only by steam turbines, in most installations where a steam-driven pump is used the type selected is the duplex. While this uses much more steam than an efficient

turbine driven pump, the slow speed and traditional reliability of the duplex pump make it a favorite.

Reciprocating type fueloil pumps must have large air chambers to dampen out the fluctuations in oil pressure that without this occur at the ends of the pump strokes. Most pumps come equipped with air chambers inadequate for the service. The air trapped in the top of the chamber in time is absorbed by the oil and an oil-filled chamber does not steady the oil pressure. Small chambers cause the oil pressure at the burner to fluctuate violently and produce a pulsating flame. Where an automatic combustion control of the modulating type is used, as is usual with this type of equipment, the fluctuating oil pressure affects the control of the combustion air and starts it hunting. Furthermore the wear of the delicate parts of the controls and pressure gages becomes excessive.

Therefore, an additional air chamber is needed in these systems. A good air chamber can be made from a 6' to 10' length of 6" or 8" pipe connected in the oil line after the reciprocating pump as indicated in Fig. 3. This will dampen oil pressure fluctuations of 25 psi down to less than 5 psi, which is quite acceptable. After some time the pressure will start to fluctuate. Before the fluctuations become excessive for the particular installation, the air chamber can be drained by isolating it and opening the pipe plug at the top and drain valve at the bottom, thereby restoring the steady oil pressure.

Oil Heaters

To obtain the desired oil temperature, oilheaters using either steam or hot water as the heating medium are required. These heaters should be designed to heat the oil to 240° F. so they will be suitable for any unusual fuel condition that may develop, and should have a capacity of about 25% more than that required for full output of the boiler equipment. The heaters generally are arranged in banks so that individual heaters may be cut in or out of service manually to match the number of boilers in use at the time.

Because of the maldistribution within the heaters and the occasional poor operation of the temperature control-

ling element, trouble may be experienced from time to time with carbonization of the fueloil with resulting deposits on the heating surfaces and loss of heater capacity. This requires occasional cleaning of the heaters and if the required reduction in plant capacity during the heater cleaning period cannot be tolerated, spare heaters should be incorporated in the system.

Heater surfaces should be arranged for ready removal and easy cleaning, with space around the heaters provided for the necessary access. Any extended heating surface in the form of fins on the elements should be of such construction that deposits may be removed easily. Generally fins arranged lengthwise of the pipe and radial thereto, so a section through a heating element when viewed from the end appears like the spokes of a wheel, give the maximum facility for cleaning. It must be remembered that the deposit on the surface will be largely of carbon which is not dissolvable; the deposits must be removed by mechanical means.

Thermostatic Control needed

The service heaters should be equipped with a thermostatic control. A steam atomizing burner performs well with the oil temperature 15° F. or so off from the desired value whereas a mechanical (pressure) burner requires closer regulation. If you adjust the number of heaters in service, even a rather crude temperature control will hold the temperature within acceptable limits. Using only one of four boilers in a plant, much better regulation of the oil temperature is obtained with a corresponding number of oilheaters.

As in the case of tank heaters the accepted practice is to discharge the condensate from steam oilheaters to the sewer to avoid contamination of boiler feedwater that might occur from a heater leak. Where recirculated hot water is used for this purpose on unusual installations, take pains to check on the possibility of fueloil contamination in the returns.

In the smaller plants where the boiler plant may be shut down for the weekend, getting started again the following Monday may be a problem.

SUGGESTED TYPICAL PIPING ARRANGEMENT FOR OIL FUEL SYSTEMS

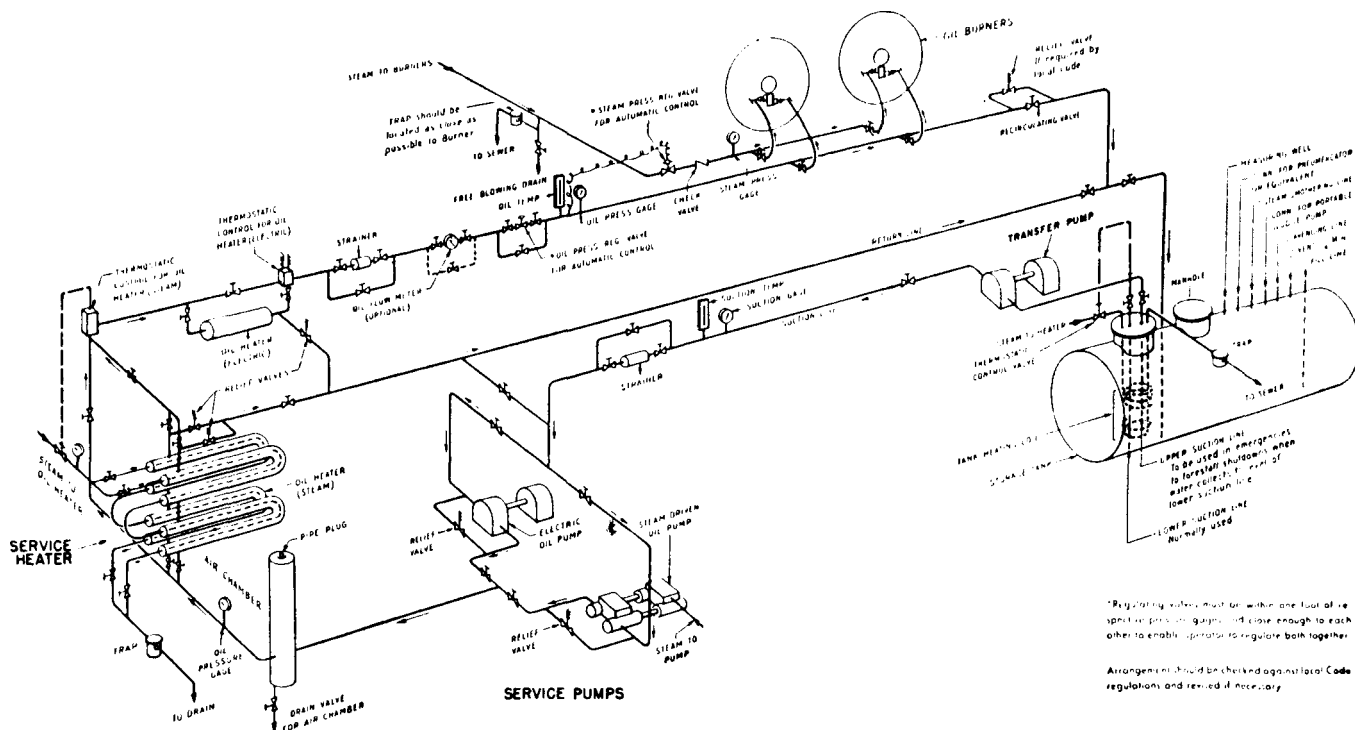


Fig. 3. Typical arrangements for piping to pumps, oilheaters, strainers, valves, instruments and controls.

One method for coping with this is to have an auxiliary oil supply using light fueloil not needing heating; by using either the main oil pump set or a special one for the light oil, a boiler can be fired until steam is available for the heavy fueloil heaters.

In some plants of this type the cold-start problem is solved by electric oil heaters in the main oil system. Where the cost of electric power is somewhat high, it is normal to size the electric heaters for enough capacity to heat the oil to the required temperature at the minimum firing rate required to bring a cold boiler into service. This would be equivalent to the minimum rate of a rotary cup type burner or about 15% of the full load requirements of the boiler fired by a pressure or steam atomizing type burner. Low output burner tips often are used for the steaming up interval.

Electric heaters should have thermostatic controls or equivalent protection to avoid oil too cold to burn properly or overheated to the point of coking in the heaters.

Strainers

Provide a strainer in the oil system just ahead of the service pumps and one following the oilheaters. The first

removes much foreign matter in the fueloil as it received, and the second not only prevents foreign matter that gets past the first strainers from entering the burners but also removes any carbon that forms in the heaters. Several types of strainers are suitable for this service, but the basket type is used generally. Usual practice is to have 1/16" or 1/32" dia. holes in the strainer ahead of the service pumps, and 1/16" dia. holes in the strainers following the service heaters. The total area of the perforations in each strainer should be about six times the area of the connecting pipe.

Where continuity of service is of paramount importance and there is no auxiliary fuel available, the duplex strainer should be used. Single strainers often are acceptable in small installations, if the load permits an interruption in firing at weekly intervals to permit strainer cleaning.

Relief Valves

At several locations in the oil system, relief valves as shown in Fig. 3 are needed to protect the equipment against excessive pressures that might result from improper operation. In small systems a pressure regulating valve at the pump maintains steady

pressure and avoids damaging pumps of the constant displacement type. A preferred arrangement, whose cost generally can be justified in larger installations, is to provide a separate control valve following the service heaters. This is regulated automatically from the oil header pressure to bleed excess oil back to the storage tank and maintain the desired header pressure, and is better than an ordinary spring-loaded valve for this function. While the latter will do the job within the limits usually required of smaller installations, it lacks the refinement of control that the more expensive pressure control valve possesses.

In selecting relief valves for oil systems, use only valves intended for this service. Ordinary safety valves are not suitable as they are designed to relieve gas under pressure. If a gas type safety valve is used, severe pounding of the piping may result. The liquid type relief valve is so designed to bleed off the pressure fairly constantly with no tendency for intermittent opening and closing which causes the piping shocks.

Instruments

Fig. 3 shows recommended gages and thermometers for a simple heavy fueloil pumping, heating, and storage

system. These permit tracing trouble quickly to its source and isolating the offending piece of equipment. The thermometers and pressure gages should be of the highest quality and should be maintained in accurate calibration. Pressure gages and controls should be mounted with short large connections on the oil pipe itself, or if the reading must be transmitted to another location, use a fluid that will not become sluggish, from the point of pressure measurement up to the pressure gage. In a long pressure gage line, heavy fueloil will cool to the point where its movement is very sluggish, and indicate erroneous pressures.

Controls

The diagram in Fig. 3 shows a minimum of controls for the small installation. Large plants entirely dependent upon fueloil can afford to spend con-

siderable more money for more efficient operation. As an example, if the oil temperature in a small industrial installation varies 20° from the desired value this may be of little consequence. It may not adversely affect burner performance. On the other hand, a large public utility should hold the fueloil temperature within plus or minus 5° of the desired value for more accurate metering of the fuel, and since overheating the oil represents a loss in heating steam and gives the possibility of fouling the heaters from coking.

Where the load on the boiler unit fluctuates widely, a better and more responsive control of oil temperature is warranted than in a plant that operates for hours at a time at a substantially constant load. Similarly for reliability and continuity of service, the small industrial plant may keep ready one more pump than is required for

the load, whereas a public utility might spend considerable money to obtain automatic starting of additional pumps to save the power cost of operating continuously any more equipment than is absolutely necessary. The determination of what should be done can be established only by a consideration of the initial cost for the equipment as compared to the possible saving.

An article on the subject of heavy oil pumping and heating equipment is not complete without a word of caution to those making their first installation. This fuel differs considerably from light fueloils—it is much more viscous at a given temperature, and contains more sulphur, water and sediment. In order to keep out of operating troubles the customary good practice is to select only equipment that has been proved in the field, or is backed by a reliable manufacturer.

SECTION 5

STEAM GENERATION ECONOMICS

5.1 Introduction

The cost of steam from industrial boilers is comprised of capital costs, operating and maintenance costs, and fuel costs. The ultimate cost will, of course, be completely dependent on the multitudinous requirements of each individual case, and general statements as to the most economical boiler fuel for all cases can be inappropriate. However, it is possible to develop economics for some fuel and boiler systems in a general fashion and discern trends which should be helpful to the industrial boiler users and fuel suppliers in making decisions regarding future actions which will be necessary to meet the requirements of the Fuel Use of Act of 1978 in regard to reducing the use of natural gas and petroleum fuels in industrial boilers.

Coal per se or fuels derived from coal are expected to be the first choice to replace natural gas or petroleum fuels in industrial boilers. SRC-II fuel oil is a liquid product derived from coal which has qualities comparable to, and in many respects superior to, those of petroleum residual fuels; and tests to date have shown it to be a desirable direct replacement for oil-firing in steam boiler systems. The SRC-II processing cost will naturally make the SRC-II fuel oil more expensive on a \$/Btu basis than the coal from which it can be derived. However, oil-fired boilers require much lower investments and have lower operating costs than comparable coal-fired systems which can more than offset the added fuel costs in a large percentage of new boiler installations. For cases where SRC-II fuel oil would be used to replace present residual oil-firing and eliminate the necessity of installing expensive new coal-firing equipment the savings would be even greater. Other intangible factors such as cleanliness, safety, and ease of handling with liquid systems or limitations of space which make coal use impossible in some situations cannot be quantitatively evaluated on a general economic basis but are definite considerations for industrial situations.

5.2 Steam Costs for Coal-Fired and SRC-II Fuel Oil-Fired Boilers

A study has been made, based on a report by ICF Incorporated,¹ to compare the use of SRC-II fuel oil and bituminous coal in new industrial steam boilers in the New York - Mid Atlantic region. The location was chosen because this region is the largest user of fuel oil in industrial boilers and thus a region of particular interest for the use of alternate fuels. Steam costs were estimated for stoker coal-fired boilers ranging in size from 50,000 lb/hr to 200,000 lb/hr and for pulverized coal-fired boilers from 200,000 lb/hr to 400,000 lb/hr of steam at 650 psig and 750°F. All coal-fired boilers were field-erected, and the systems included flue gas desulfurization (FGD) by limestone scrubbing and removal of particulates by baghouse fabric filters.

It is the experience of both General Motors and Caterpillar Tractor, companies having coal-fired industrial boilers with FGD, that in many locations both FGD and particulates control units are needed to meet sulfur dioxide and particulates emissions requirements. FGD alone is inadequate to meet particulates control requirements.

Costs were calculated for boilers fired by SRC-II fuel oil over the size range of 50,000 lb/hr to 400,000 lb/hr of 650 psig steam at 750°F. All of the SRC-II fuel-fired systems were packaged boilers with single boilers up to 300,000 lb/hr and parallel 200,000 lb/hr boilers for the 400,000 lb/hr system. The costs for SRC-II fuel oil-firing were those developed by ICF for low sulfur fuel oil, but particulate removal included by ICF for low sulfur fuel oil was not considered necessary for the SRC-II fuel oil cases based on the SRC-II fuel oil combustion experience to date (see Volume 2).

¹ "Economic Considerations in Industrial Boiler Fuel Choice," ICF Incorporated, submitted to the Congressional Budget Office, June, 1978.

Costs were calculated for utilization rates ranging from 30% to 80% of nominal capacity. This range covers the utilization capacity factors for steam boilers in industrial use in the size range of interest. The investments, annual costs, and steam costs for boilers ranging in size from 50,000 lb/hr to 400,000 lb/hr at a utilization rate of 60% are summarized in Table 1. More complete investment data as well as fuel and operating costs for various size boilers at 40, 60, and 80% utilization rates are given in Tables 2-6. The investments, capital costs, and operating costs were taken from the ICF report¹ and inflated from 1977 to 1978 dollars. Fuel prices (in 1978 dollars) were taken from a separate report, included in Volume 4, on a study of projected use of SRC-II fuel oil in a Rohm and Haas plant at Philadelphia. The differential between the price of stoker coal and coal for use in the pulverized coal-fired boilers was taken from the ICF report¹. The annual capital costs were developed by ICF on the basis of a 30-year system life.

The steam costs in Table 1 show that for industrial boilers operating at 60% utilization factor it is less expensive to use SRC-II fuel oil at \$3.82/million Btu than stoker coal at \$1.71/million Btu for boilers up to somewhat more than 200,000 lb/hr. The relationships between steam costs and boiler size at other utilization rates are shown in Figures 1 to 4. These curves affirm that steam costs decline with increasing size at any given utilization rate and that steam costs decline with increasing utilization rate for a fixed boiler size. They also show that the curves are steeper for the coal cases which is typical of higher initial investments and lower total operating costs.

Curves for both coal-firing and SRC-II fuel oil-firing are plotted in Figure 5. Because of the different slopes for the two fuels, for each boiler size there is a utilization rate below which the cost of steam is lower for an SRC-II fuel oil-fired boiler and above which the coal-fired system produces cheaper steam. Although this is a general truth, the break-even points will vary with investment, operating costs, and, especially, the cost of fuel. For example, Figure 5 shows that, for a 200,000 lb/hr boiler, the SRC-II fuel oil-fired boiler will produce steam more cheaply than a coal-fired system at utilization rates below about 65%. Assuming an arbitrary \$.50/million Btu additional cost for SRC-II fuel oil, the break-even

Table 1

Steam Costs for Coal-Fired and SRC-II Fuel Oil-Fired Industrial Boilers

Utilization Rate 60%, Costs in 1978 Dollars

New York - Mid Atlantic Location

Delivered Fuel Prices - Stoker Coal, \$1.71/10⁶ Btu; Pulverized Coal, \$1.57/10⁶ Btu; SRC-II Fuel Oil, \$3.82/10⁶ Btu

Boiler Size, 10 ³ lb/hr	50	100	200	300	400
<u>Coal-fired System</u>	<u>Stoker</u>	<u>Stoker</u>	<u>Stoker</u>	<u>Pulverized</u>	<u>Pulverized</u>
Investment, \$10 ³	5,244	8,753	14,825	21,068	26,374
Capital Cost, \$10 ³ /yr ⁽¹⁾	1,045	1,747	2,961	4,208	5,268
Operating & Maintenance Cost, \$10 ³ /yr	450	787	1,391	2,002	2,550
Fuel Cost, \$10 ³ /yr	633	1,267	2,535	3,342	4,445
Total Steam Cost, \$/10 ³ lb	8.10	7.23	6.55	6.06	5.84
<u>SRC-II Fuel Oil-Fired System</u>					
Investment, \$10 ³	1,648	2,624	4,295	5,986	7,514
Capital Cost, \$10 ³ /yr ⁽¹⁾	329	526	861	1,200	1,507
Operating & Maintenance Cost, \$10 ³ /yr	155	254	415	555	682
Fuel Cost, \$10 ³ /yr	1,356	2,711	5,421	8,132	10,842
Total Steam Cost, \$/10 ³ lb	7.00	6.64	6.37	6.27	6.20

(1) Capital Charge rate includes depreciation, return on capital, taxes, and general and administrative expenses

Table 2

COST CALCULATIONS FOR BOILER SYSTEMS
 Coal-Fired and SRC-II Fuel-Fired Systems in New York-Mid Atlantic Region
 Costs in 1978 Dollars, Based on June, 1978, Report by ICF Incorporated on
 "Economic Considerations in Industrial Boiler Fuel Choice"

Boiler Size, lb/hr	50,000	
	Northern Appalachian Coal (Stoker)	SRC-II Fuel Oil
<u>Capital Costs, \$10³</u>		
Boiler Equipment	1,285	448
SO ₂ Control Equipment	983	
Particulate Control Equipment	216	
Other Direct Costs	1,389	654
Indirect Costs	1,371	546
Total Capital Investment	5,244	1,648
Annualized Capital Costs ⁽¹⁾	1,045	329
<u>Operating & Maintenance Costs</u>		
Fixed Costs, \$10 ³ /yr	285	147
Variable Costs at 100% Rate, \$10 ³ /yr	275	13
Total O&M Costs, \$10 ³ /yr		
at 80% utilization rate	505	158
60%	450	155
40%	395	153
<u>Fuel Costs</u>		
Delivered Price, \$/10 ⁶ Btu	1.71	3.82
Fuel Consumption, 10 ⁹ Btu/yr		
at 80% utilization rate	494	473
60%	371	355
40%	247	237
Fuel Costs, \$10 ³ /yr		
at 80% utilization rate	845	1,807
60%	633	1,356
40%	423	904
<u>Steam Costs</u>		
Total Costs, \$10 ³ /yr		
at 80% utilization rate	2,395	2,294
60%	2,128	2,240
40%	1,863	1,386
Steam Output, 10 ⁶ lb/yr		
at 80% utilization rate	350	350
60%	263	263
40%	175	175
Total Steam Costs, \$/10 ³ lb		
at 80% utilization rate	6.84	6.55
60%	8.10	7.00
40%	10.63	7.91

¹ Includes depreciation, return on capital, taxes, and G&A expenses
 Approximately 10-11% return on 100% equity after taxes

Table 3

COST CALCULATIONS FOR BOILER SYSTEMS

Coal-Fired and SRC-II Fuel-Fired Systems in New York-Mid Atlantic Region
 Costs in 1978 Dollars, Based on June, 1978, Report by ICF Incorporated on
 "Economic Considerations in Industrial Boiler Fuel Choice"

Boiler Size, lb/hr	100,000	
Fuel	Northern Appalachian Coal (Stoker)	SRC-II Fuel Oil
<u>Capital Costs, \$10³</u>		
Boiler Equipment	2,235	734
SO ₂ Control Equipment	1,712	
Particulate Control Equipment	400	
Other Direct Costs	2,092	969
Indirect Costs	2,314	921
Total Capital Investment	8,753	2,624
Annualized Capital Costs ⁽¹⁾	1,747	526
<u>Operating & Maintenance Costs</u>		
Fixed Costs, \$10 ³ /yr	468	240
Variable Costs at 100% Rate, \$10 ³ /yr	532	23
Total O&M Costs, \$10 ³ /yr		
at 80% utilization rate	892	259
60%	787	254
40%	680	250
<u>Fuel Costs</u>		
Delivered Price, \$/10 ⁶ Btu	1.71	3.82
Fuel Consumption, 10 ⁹ Btu/yr		
at 80% utilization rate	988	946
60%	741	710
40%	494	473
Fuel Costs, \$10 ³ /yr		
at 80% utilization rate	1,690	3,614
60%	1,267	2,711
40%	844	1,807
<u>Steam Costs</u>		
Total Costs, \$10 ³ /yr		
at 80% utilization rate	4,329	4,399
60%	3,801	3,491
40%	3,271	2,583
Steam Output, 10 ⁶ lb/yr		
at 80% utilization rate	701	701
60%	526	526
40%	350	350
Total Steam Costs, \$/10 ³ lb		
at 80% utilization rate	6.18	6.28
60%	7.23	6.64
40%	9.34	7.37

¹ Includes depreciation, return on capital, taxes, and G&A expenses
 Approximately 10-11% return on 100% equity after taxes

Table 4

COST CALCULATIONS FOR BOILER SYSTEMS
 Coal-Fired and SRC-II Fuel-Fired Systems in New York-Mid Atlantic Region
 Costs in 1978 Dollars, Based on June, 1978, Report by ICF Incorporated on
 "Economic Considerations in Industrial Boiler Fuel Choice"

Boiler Size, lb/hr	200,000		
Fuel	Northern Appalachian Coal (Stoker)	Northern Appalachian Coal (Pulverized)	SRC-II Fuel Oil
<u>Capital Costs, \$10³</u>			
Boiler Equipment	3,888	4,320	1,188
SO ₂ Control Equipment	2,975	2,975	
Particulate Control Equipment	740	740	
Other Direct Costs	3,249	3,270	1,511
Indirect Costs	3,973	4,072	1,596
Total Capital Investment	14,825	15,377	4,295
Annualized Capital Costs ⁽¹⁾	2,961	3,069	861
<u>Operating & Maintenance Costs</u>			
Fixed Costs, \$10 ³ /yr	771	800	390
Variable Costs at 100% Rate, \$10 ³ /yr	1,034	1,053	43
Total O&M Costs, \$10 ³ /yr			
at 80% utilization rate	1,598	1,642	424
60%	1,391	1,432	415
40%	1,185	1,220	407
<u>Fuel Costs</u>			
Delivered Price, \$/10 ⁶ Btu	1.71	1.57	3.82
Fuel Consumption, 10 ⁹ Btu/yr			
at 80% utilization rate	1,976	1,892	1,892
60%	1,482	1,419	1,419
40%	988	946	946
Fuel Costs, \$10 ³ /yr			
at 80% utilization rate	3,379	2,971	7,228
60%	2,535	2,228	5,421
40%	1,690	1,486	3,614
<u>Steam Costs</u>			
Total Costs, \$10 ³ /yr			
at 80% utilization rate	7,938	7,682	8,513
60%	6,887	6,729	6,697
40%	5,836	5,775	4,882
Steam Output, 10 ⁶ lb/yr			
at 80% utilization rate	1,402	1,402	1,402
60%	1,051	1,051	1,051
40%	701	701	701
Total Steam Costs, \$/10 ³ lb			
at 80% utilization rate	5.66	5.48	6.07
60%	6.55	6.40	6.37
40%	8.33	8.24	6.97

¹ Includes depreciation, return on capital, taxes, and G&A expenses
 Approximately 10-11% return on 100% equity after taxes

Table 5

COST CALCULATIONS FOR BOILER SYSTEMS
Coal-Fired and SRC-II Fuel-Fired Systems in New York-Mid Atlantic Region
Costs in 1978 Dollars, Based on June, 1978, report by ICF Incorporated on
"Economic considerations in Industrial Boiler Fuel Choice"

Boiler Size, lb/hr	300,000	
Fuel	Northern Appalachian Coal (Pulverized)	SRC-II Fuel Oil
<u>Capital Costs, \$10³</u>		
Boiler Equipment	5,978	1,712
SO ₂ Control Equipment	4,120	
Particulate Control Equipment	1,069	
Other Direct Costs	4,281	1,999
Indirect Costs	5,620	2,274
Total Capital Investment	21,068	5,985
Annualized Capital Costs ⁽¹⁾	4,208	1,200
<u>Operating & Maintenance Costs</u>		
Fixed Costs, \$10 ³ /yr	1,069	518
Variable Costs at 100% Rate, \$10 ³ /yr	1,555	62
Total O&M Costs, \$10 ³ /yr		
at 80% utilization rate	2,313	567
60%	2,002	555
40%	1,691	542
<u>Fuel Costs</u>		
Delivered Price, \$/10 ⁶ Btu	1.57	3.82
Fuel Consumption, 10 ⁹ Btu/yr		
at 80% utilization rate	2,838	2,838
60%	2,129	2,129
40%	1,419	1,419
Fuel Costs, \$10 ³ /yr		
at 80% utilization rate	4,457	10,842
60%	3,342	8,132
40%	2,228	5,421
<u>Steam Costs</u>		
Total Costs, \$10 ³ /yr		
at 80% utilization rate	10,978	12,609
60%	9,552	9,887
40%	8,127	7,163
Steam Output, 10 ⁶ lb/yr		
at 80% utilization rate	2,102	2,102
60%	1,577	1,577
40%	1,051	1,051
Total Steam Costs, \$/10 ³ lb		
at 80% utilization rate	5.22	6.00
60%	6.06	6.27
40%	7.73	6.81

¹ Includes depreciation, return on capital, taxes, and G&A expenses
Approximately 10-11% return on 100% equity after taxes

Table 6

COST CALCULATIONS FOR BOILER SYSTEMS
 Coal-Fired and SRC-II Fuel-Fired Systems in New York-Mid Atlantic Region
 Costs in 1978 Dollars, Based on June, 1978, Report by ICF Incorporated on
 "Economic Considerations in Industrial Boiler Fuel Choice"

Boiler Size, lb/hr	400,000	
	Northern Appalachian Coal (Pulverized)	SRC-II Fuel Oil
<u>Capital Costs, \$10³</u>		
Boiler Equipment	7,522	2,160
SO ₂ Control Equipment	5,184	
Particulate Control Equipment	1,382	
Other Direct Costs	5,211	2,444
Indirect Costs	7,075	2,910
Total Capital Investment	26,374	7,514
Annualized Capital Costs ⁽¹⁾	5,268	1,507
<u>Operating & Maintenance Costs</u>		
Fixed Costs, \$10 ³ /yr	1,318	633
Variable Costs at 100% Rate, \$10 ³ /yr	2,053	81
Total O&M Costs, \$10 ³ /yr		
at 80% utilization rate	2,960	698
60%	2,550	682
40%	2,139	665
<u>Fuel Costs</u>		
Delivered Price, \$/10 ⁶ Btu	1.57	3.82
Fuel Consumption, 10 ⁹ Btu/yr		
at 80% utilization rate	3,784	3,784
60%	2,838	2,838
40%	1,892	1,892
Fuel Costs, \$10 ³ /yr		
at 80% utilization rate	5,941	14,457
60%	4,455	10,842
40%	2,971	7,228
<u>Steam Costs</u>		
Total Costs, \$10 ³ /yr		
at 80% utilization rate	14,169	16,662
60%	12,273	13,031
40%	10,378	9,400
Steam Output, 10 ⁶ lb/yr		
at 80% utilization rate	2,803	2,803
60%	2,102	2,102
40%	1,402	1,402
Total Steam Costs, \$/10 ³ lb		
at 80% utilization rate	5.05	5.94
60%	5.84	6.20
40%	7.40	6.71

¹ Includes depreciation, return on capital, taxes, and G&A expenses
 Approximately 10-11% return on 100% equity after taxes

Figure 1 COST OF STEAM IN COAL-FIRED BOILERS

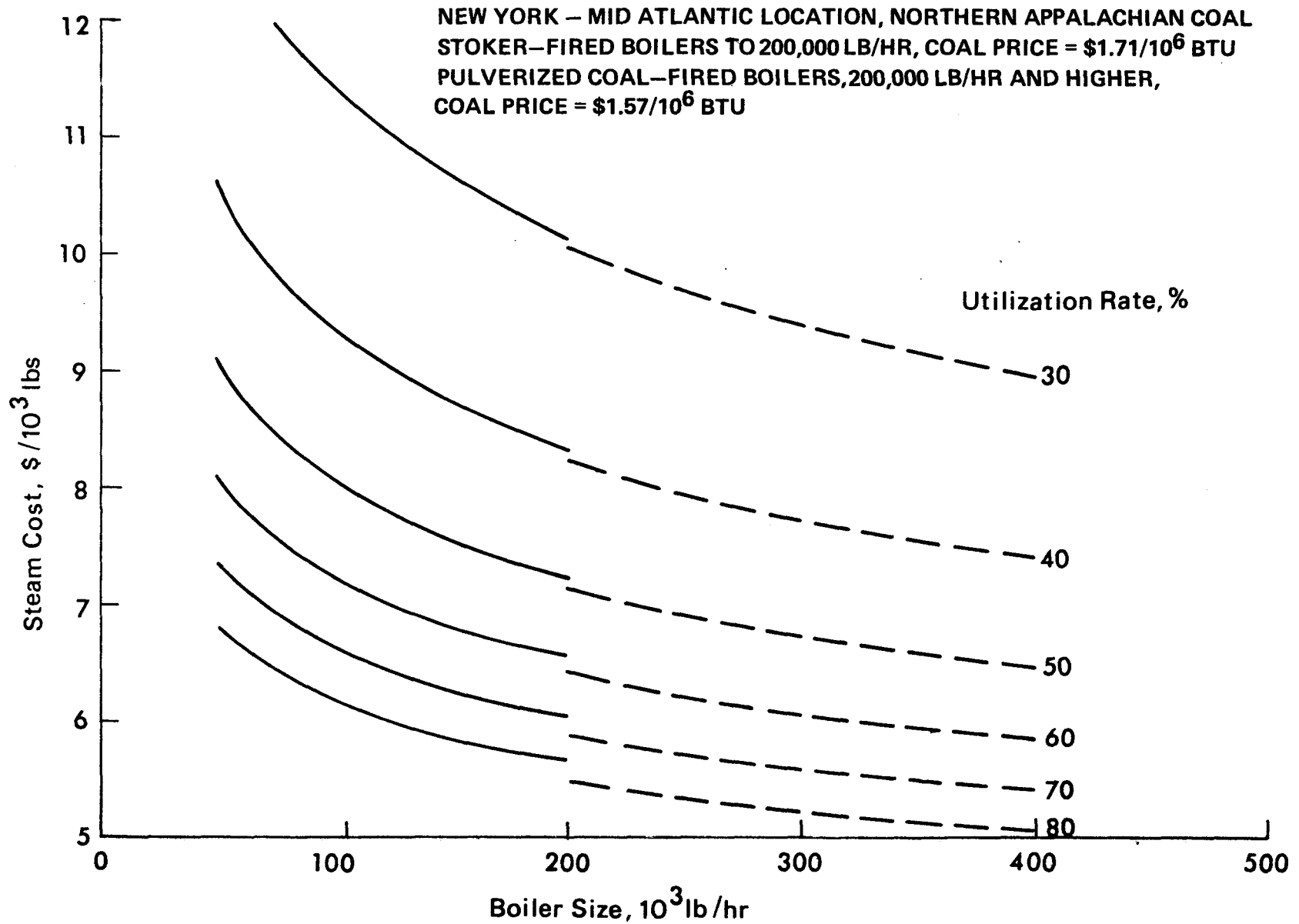


Figure 2 COST OF STEAM IN SRC II FUEL - FIRED BOILERS

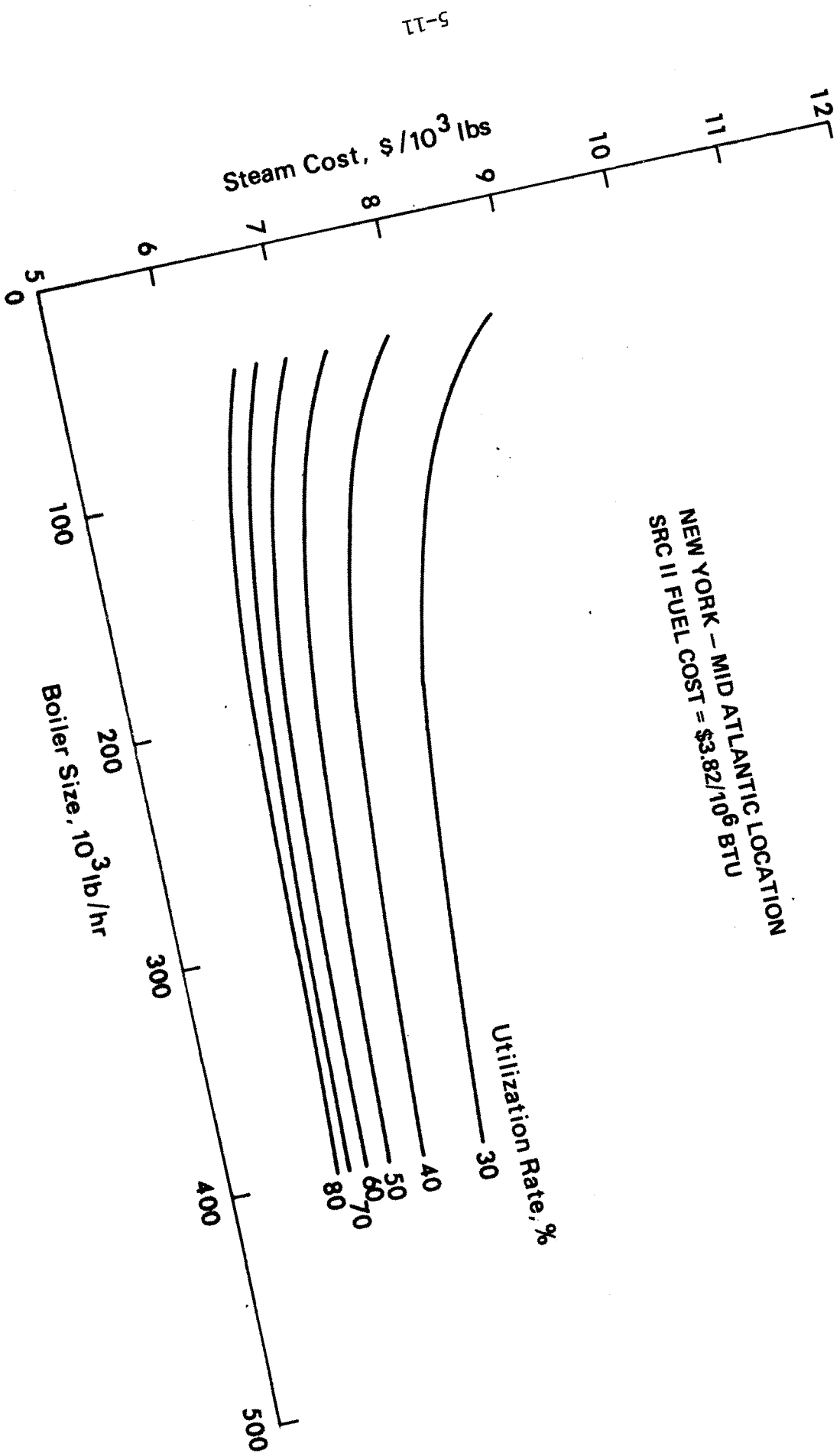


Figure 3 COST OF STEAM IN COAL-FIRED BOILERS

NEW YORK-MID ATLANTIC LOCATION, NORTHERN APPALACHIAN COAL
STOKER-FIRED BOILER COAL PRICE = $\$1.71/10^6$ BTU
PULVERIZED COAL PRICE = $\$1.57/10^6$ BTU

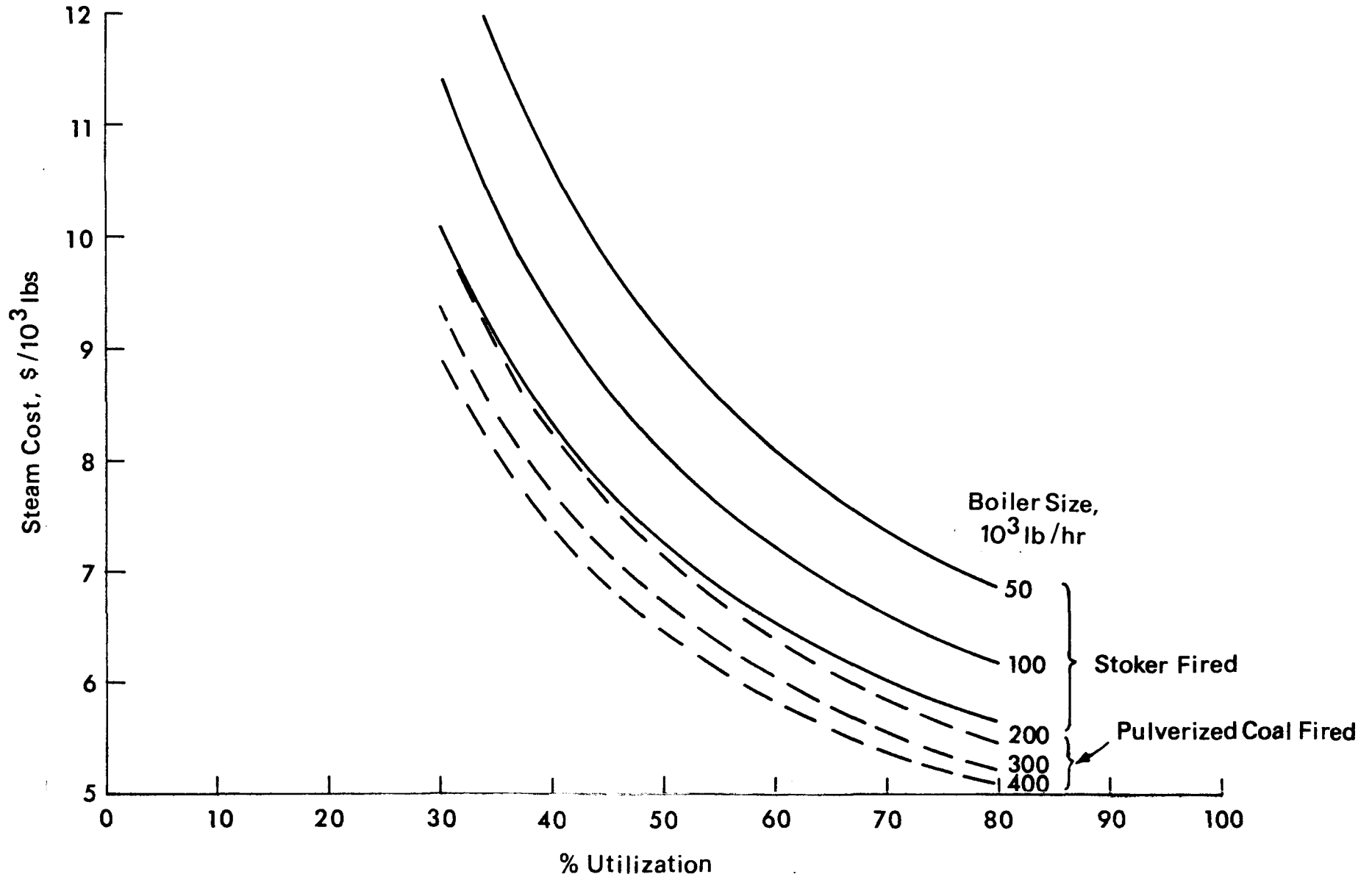


Figure 4 COST OF STEAM IN SRC II FUEL – FIRED BOILERS

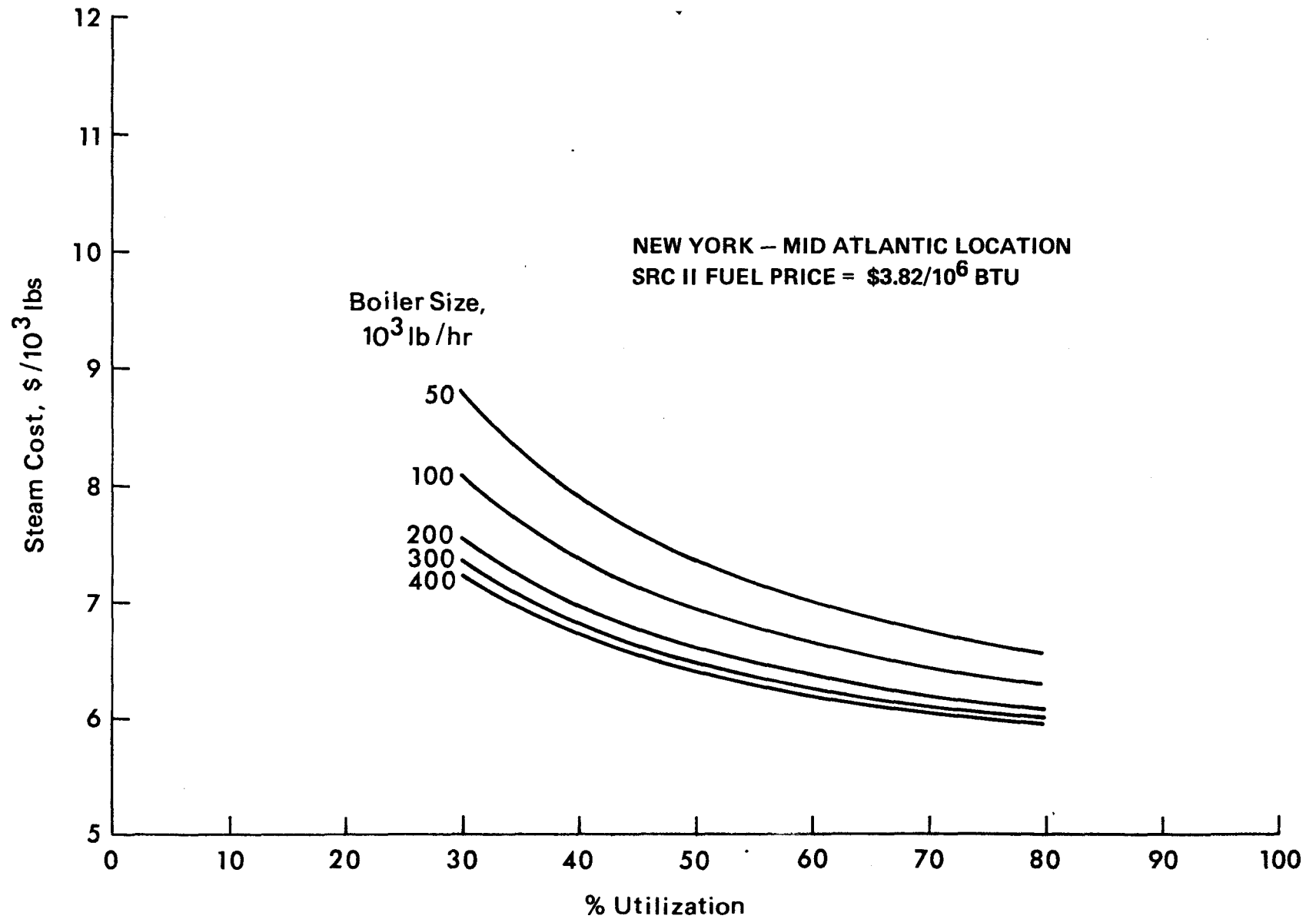


Figure 5 COST OF STEAM IN COAL-FIRED AND SRC II FUEL-FIRED BOILERS

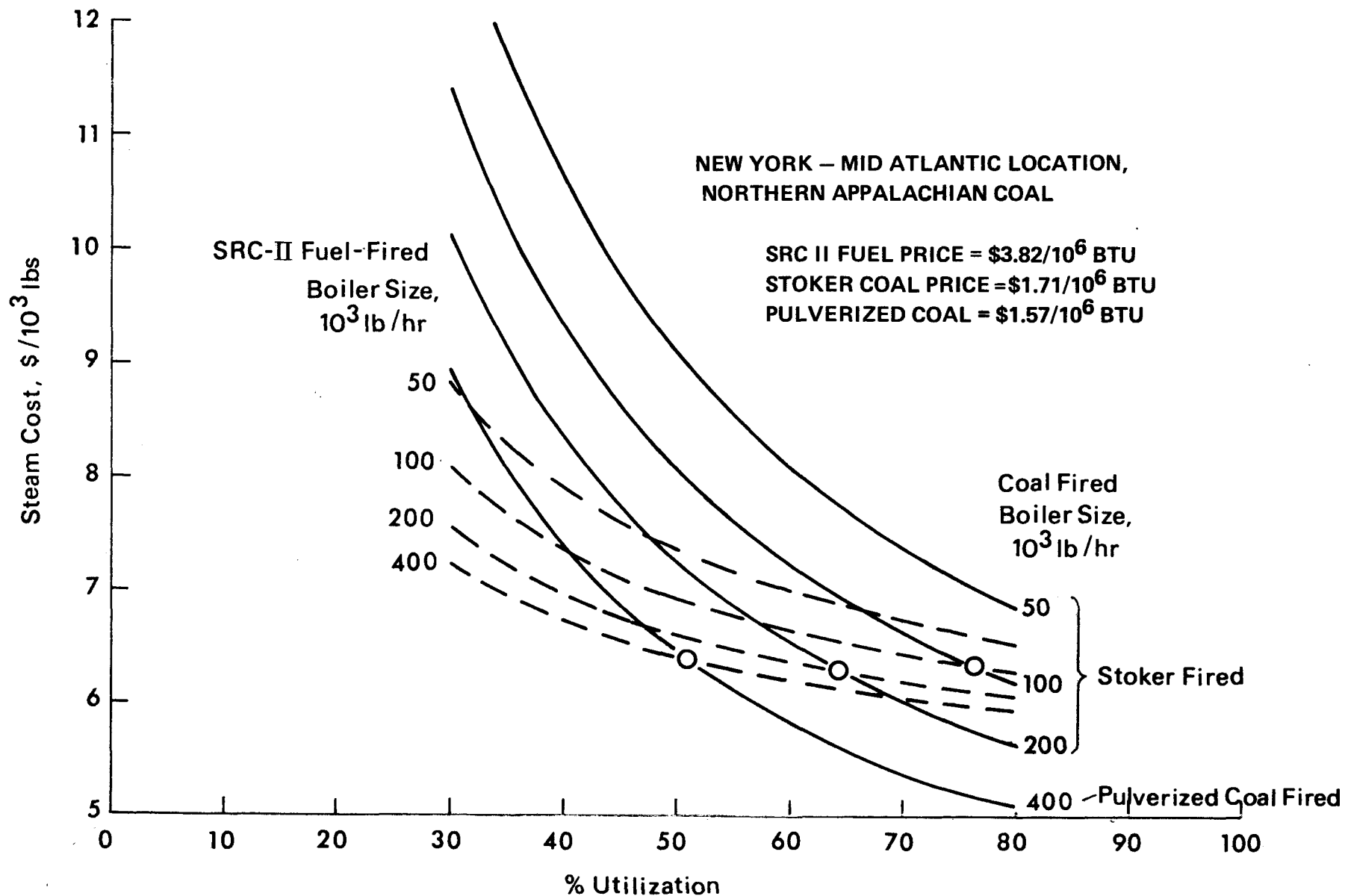
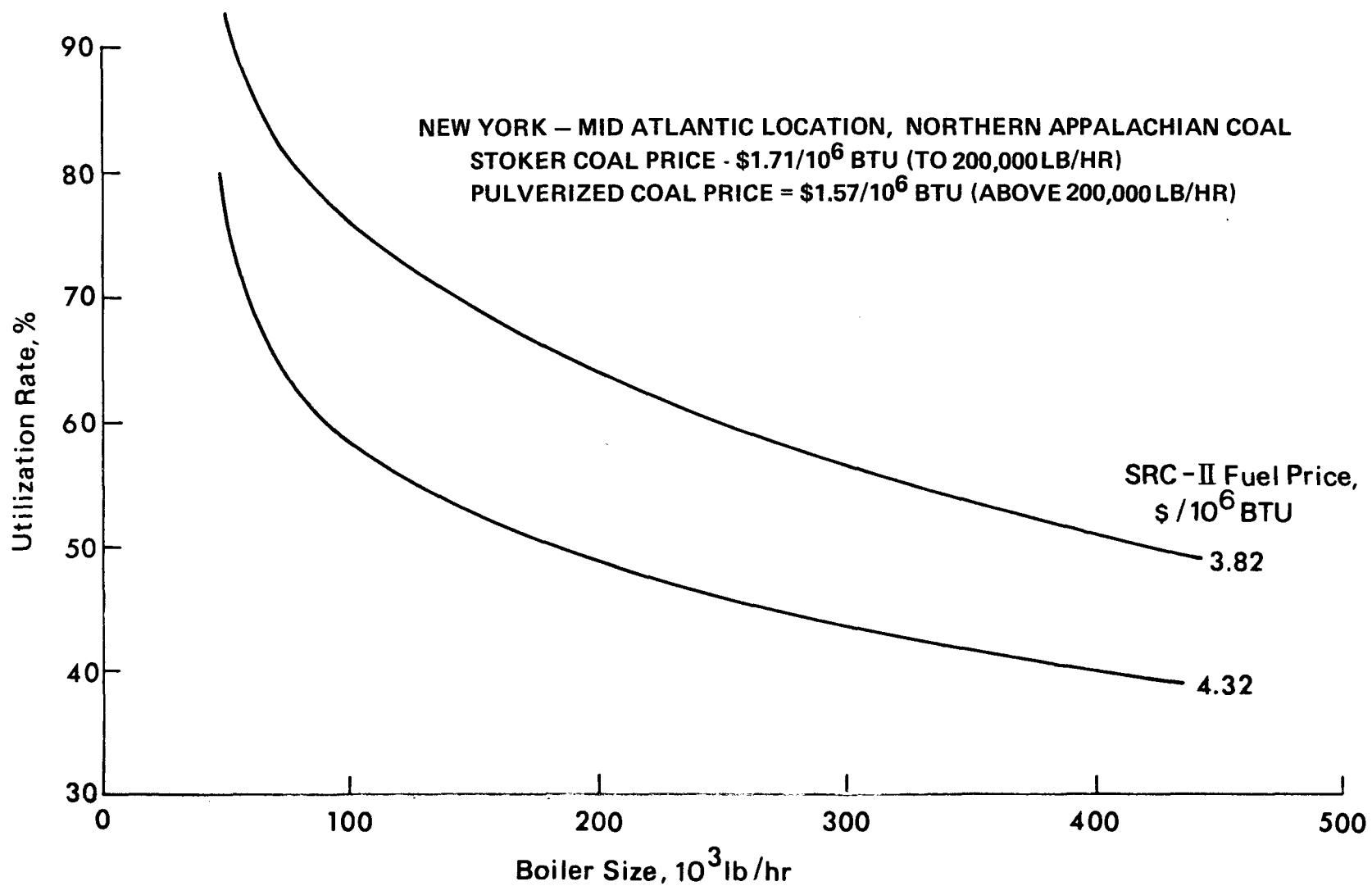


Figure 6 BREAK-EVEN UTILIZATION FACTORS FOR COAL-FIRED AND SRC II FUEL-FIRED BOILERS



utilization rate will drop to about 50%. Figure 6 shows the break-even utilization rates for various size boiler systems at SRC-II fuel oil prices of \$3.82 and \$4.32/10⁶ Btu. It is evident from Figure 6 that the utilization rate at which steam can be produced more cheaply from coal-fired boilers becomes lower as boiler size increases and as the differential between coal price and SRC-II fuel oil price increases.

The steam costs developed in Tables 1-6 and plotted in Figures 1-6 include capital costs taken from the ICF report referred to previously. The annual capital charge was developed by ICF to include depreciation, interest on debt, return on equity, general and administrative expenses, insurance, property taxes, and income taxes. The interest on debt and return on equity used in the ICF capital charge rate calculation are equivalent to a real (not including inflation) after-tax return on equity of about 10-11% with 100% equity financing. This is a rather low capital charge rate not consistent with the cost of capital to industry and tends to favor the coal cases because they require investments about 3 1/2 times greater than the SRC-II fuel oil-fired cases.

5.3 Effect of SRC-II Fuel Oil Price on Steam Generation Economics

Additional calculations were made to show the effect of varying SRC-II fuel oil prices on the DCF rate of return on the incremental investment required for coal-fired steam boilers as compared to SRC-II fuel oil-fired systems. In making these additional calculations the total capital investments, operating and maintenance costs, and coal fuel costs were taken from Tables 2-6. SRC-II fuel oil prices were varied over the range from \$3.32/million Btu to \$6.32/million Btu. Other economic parameters used in the DCF calculations were held constant at the following values:

Federal income tax rate	48%
Investment tax credit	10%
Local property taxes and insurance	2.5%
Investment life	28 years
Depreciation method	sum of years digits

The incremental investments for coal-fired systems and the annual savings in operating plus maintenance plus fuel costs for the 44 cases studied are summarized in Table 7 together with the calculated DCF rate of return. In calculating the cash flow no allowance was made for inflationary changes in operating costs or fuel costs so that the indicated rate of return is a real (not inflated) figure.

The data from Table 7 were used to prepare Figures 7 and 8 which show the SRC-II fuel oil prices which would enable coal-fired systems to provide the indicated DCF rates of return at 60% and 40% utilization rates, respectively. At a utilization rate of 60% it can be seen that coal-fired boilers as large as 400,000 lb/hr will yield less than 15% DCF rate of return when SRC-II fuel oil is priced at its expected value of \$3.82/million Btu. At a utilization rate of 40% the DCF rate of return for the same operation will be less than 10%. Figure 9 shows the price which could be paid for SRC-II fuel oil at various utilization rates if the return on incremental investment for coal-fired systems is fixed at 15% DCF rate of return. If a 20% DCF rate of return is required, which is a common criterion for industrial investments, prices of \$5.00 - 6.00/million Btu for SRC-II fuel oil would still render it the fuel of choice especially in moderate size boilers at utilization rates typical of manufacturing industries.

It is evident from these data that there is a large segment of the industrial steam boiler market which could be satisfied more economically by the use of clean liquid fuels derived from coal than by direct burning of coal with required pollution control. As stated previously, these conclusions are based on calculations for new systems. If direct coal-firing with pollution control were required to replace existing oil-fired systems, the incremental capital cost to be recovered by the lower price of coal would be even greater and the use of SRC-II fuel oil would be even more economically desirable. We have not made general economic calculations for this because it is so dependent on the individual case, but such studies are discussed elsewhere in this volume (Part 4).

Table 7

SUMMARY OF DCF CALCULATIONS FOR VARIOUS SRC-II FUEL OIL PRICES

Plant Size, 10 ³ lb/hr	Incremental Investment, \$10 ³	Utiliza- tion Factor,%	Annual Savings (\$10 ³) and DCF Rate of Return (%) at Various SRC-II Fuel Oil Prices (\$/10 ⁶ Btu)						
			3.32	3.82	4.32	4.82	5.32	5.82	6.32
50	3,596	60		428 (5.7)			960 (16.3)		
		80		615 (9.8)	851 (14.4)	1,088 (18.4)		1,561 (26.1)	
100	6,129	40		533 (2.8)			1,242 (12.2)		1,715 (17.0)
		60		911 (8.1)	1,265 (12.4)	1,620 (16.1)		2,330 (23.0)	
		80		1,291 (12.7)	1,764 (17.5)	2,238 (22.1)		3,184 (31.0)	
200	10,530	40		1,146 (4.7)		2,093 (11.9)		3,039 (17.6)	
		60		1,910 (10.6)	2,620 (15.1)	3,329 (19.1)			
		80		2,675 (15.5)	3,621 (20.9)	4,567 (26.1)			
300	15,082	40		2,044 (7.0)		3,463 (13.9)		4,882 (19.8)	
		60		3,343 (13.4)	4,407 (17.8)	5,472 (22.0)			
		80	3,220 (12.8)	4,639 (18.7)	6,058 (24.2)				
400	18,860	40		2,783 (8.0)		4,675 (15.1)		6,567 (21.1)	
		60		4,519 (14.6)	5,938 (19.2)	7,357 (24.2)			
		80	4,362 (13.9)	6,254 (20.1)	8,146 (26.0)				

Figure 7 SRC II FUEL PRICE JUSTIFIED WHEN COMPARED TO COAL,
 BASED ON 60% UTILIZATION RATE AT VARIOUS DCF RATES
 OF RETURN ON INCREMENTAL INVESTMENT FOR COAL-FIRED BOILERS WITH FGD

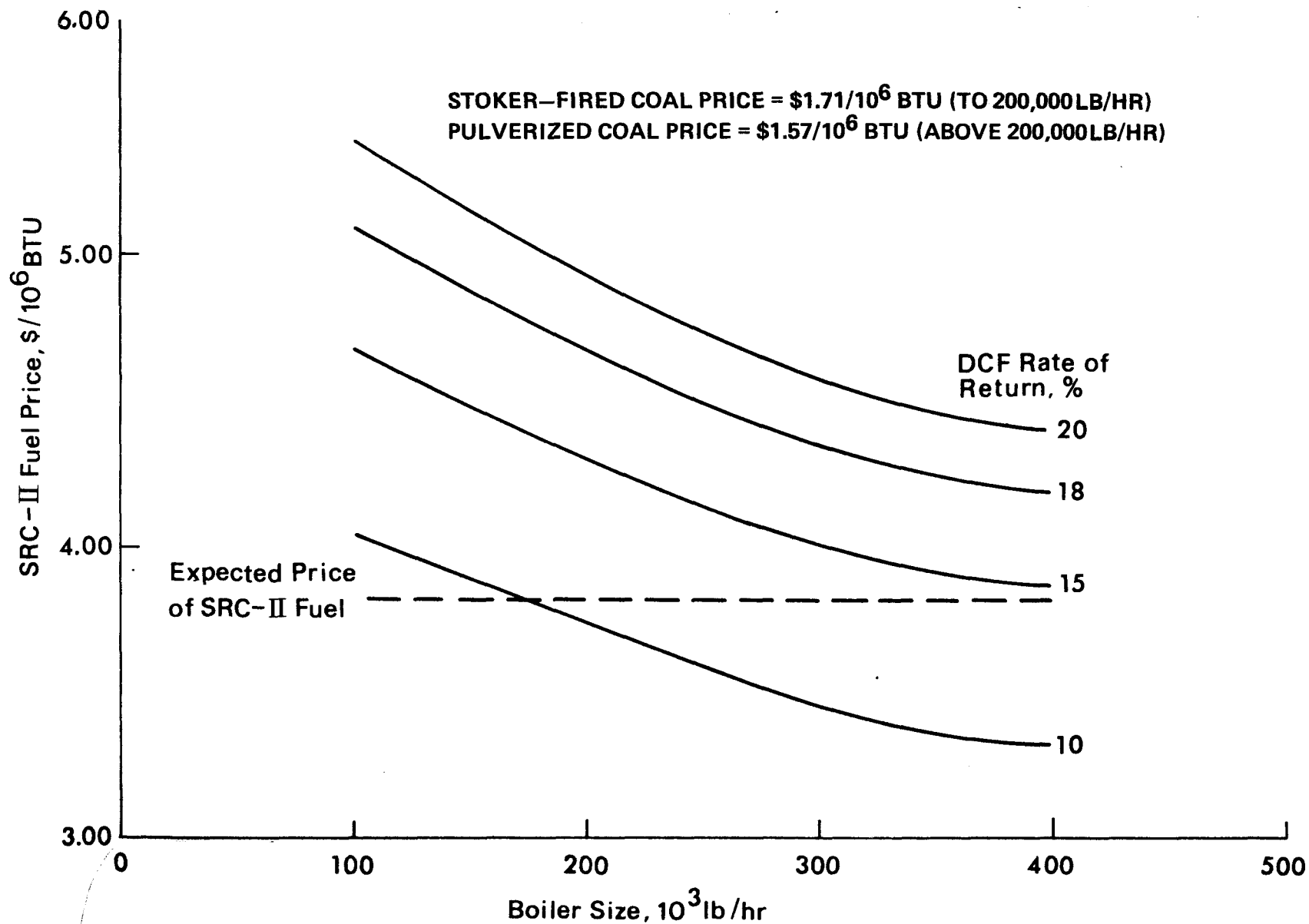


**Figure 8 SRC II FUEL PRICE JUSTIFIED WHEN COMPARED TO COAL,
BASED ON 40% UTILIZATION RATE AT VARIOUS DCF
RATES OF RETURN ON INCREMENTAL INVESTMENT FOR
COAL-FIRED BOILERS WITH FGD**

STOKER-FIRED COAL PRICE = $\$1.71/10^6$ BTU (TO 200,000 LB/HR)
PULVERIZED COAL PRICE = $\$1.57/10^6$ BTU (ABOVE 200,000 LB/HR)

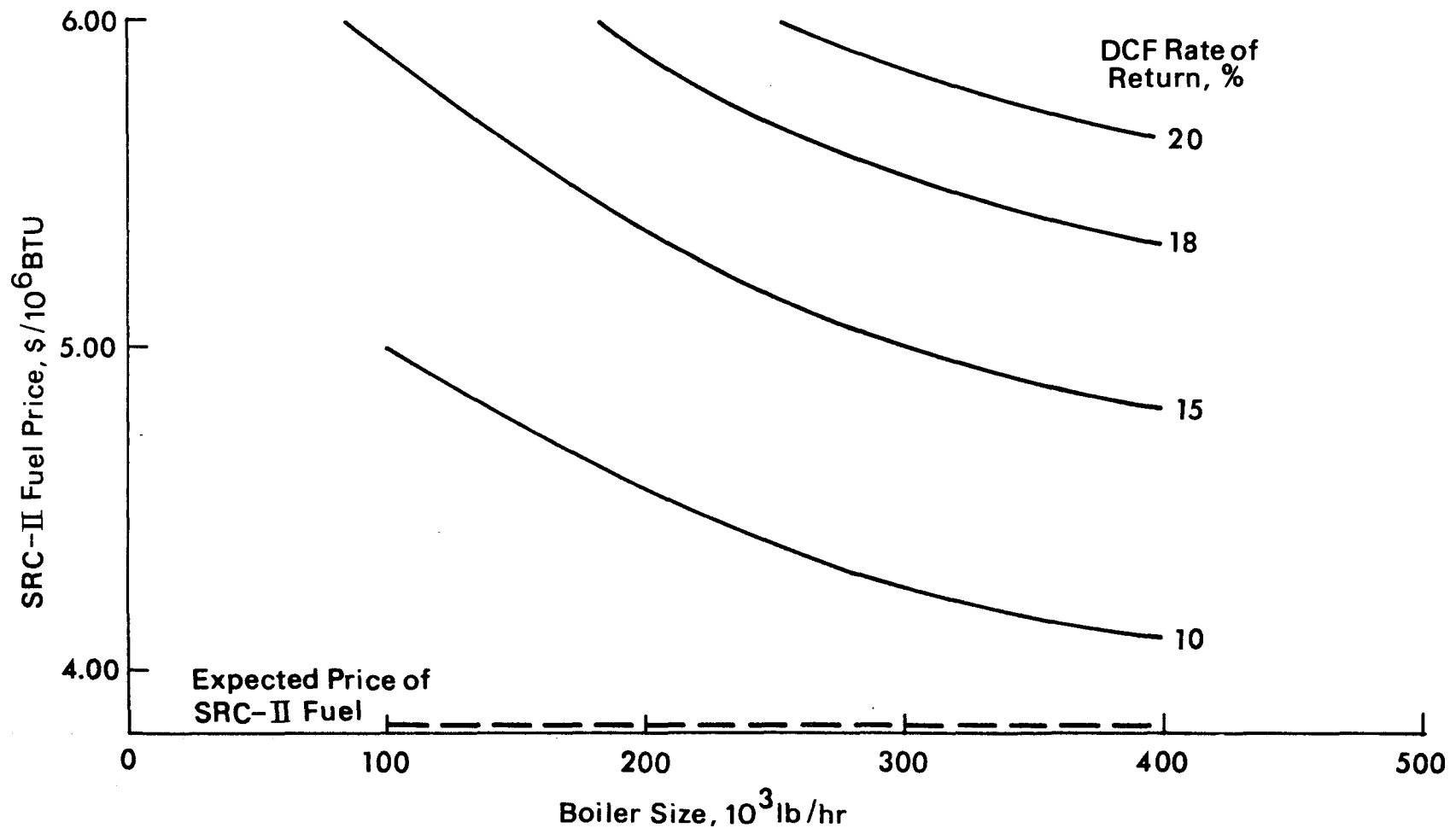
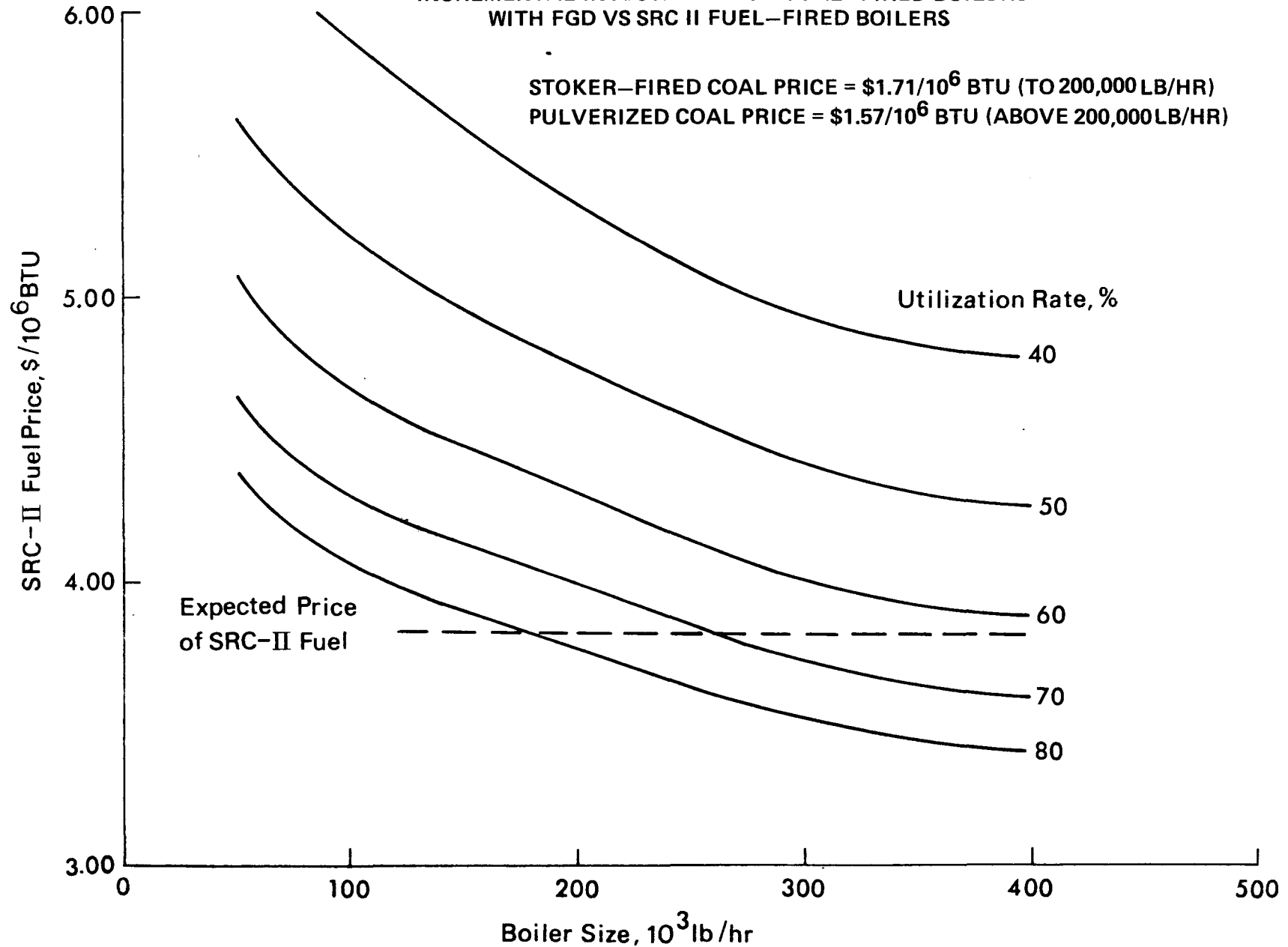


Figure 9 SRC II FUEL PRICE JUSTIFIED WHEN COMPARED
TO COAL, BASED ON 15% DCF RATE OF RETURN ON
INCREMENTAL INVESTMENT FOR COAL-FIRED BOILERS
WITH FGD VS SRC II FUEL-FIRED BOILERS

STOKER-FIRED COAL PRICE = $\$1.71/10^6$ BTU (TO 200,000 LB/HR)
PULVERIZED COAL PRICE = $\$1.57/10^6$ BTU (ABOVE 200,000 LB/HR)



5.4 Economics of Alternative Coal Utilization Systems

In addition to the use of coal-derived SRC-II fuel oil or coal-firing with flue gas desulfurization, other alternative methods for using coal to replace oil or natural gas in industrial fuel use have been suggested. Among these are the use of "compliance" coal in conventional coal-fired equipment, the use of coal in fluidized bed combustion systems, and the gasification of coal by air or oxygen to low or medium Btu industrial fuel gas. As far as we are aware there are no general studies on these alternatives which are as complete as the ICF study used to compare SRC-II fuel oil and coal; however, several specific studies have been made and are discussed below.

5.4.1 Atmospheric Fluidized Bed Combustion

Arthur G. McKee & Company has prepared a report² comparing costs for a 100,000 lb/hr boiler plant addition to an existing gas-fired boiler plant by each of three coal-burning systems: (1) a fluidized bed combustion boiler, (2) a conventional spreader stoker fired boiler with a scrubber for burning high sulfur noncompliance coal, and (3) a conventional spreader stoker fired boiler with an electrostatic precipitator for burning low sulfur compliance coal. A summary of the investments, incremental operating costs, fuel costs, and capital costs from the McKee study is shown in Table 8.

² "100,000 Pound per Hour Boiler Cost Study," Arthur G. McKee & Company, June 23, 1978, DOE Contract EX-76-C-01-2418.

TABLE 8

COMPARISON OF COSTS FOR VARIOUS COAL-FIRING SYSTEMS (McKEE)

	<u>High Sulfur Coal</u>		<u>"Compliance" Coal</u>
	<u>FBC</u>	<u>FGD</u>	<u>Conventional</u>
	<u>Boiler</u>	<u>Boiler</u>	<u>Boiler</u>
	<u>System</u>	<u>System</u>	<u>System</u>
Fuel Price, $\$/10^6$ Btu	1.60	1.60	2.16
Plant Investment, $\$10^3$	6,471	7,362	7,117
Capital Cost, $\$/10^3$ lb steam	2.33	2.65	2.56
Operating Costs, $\$/10^3$ lb steam	1.72	1.95	0.91
Fuel Costs, $\$/10^3$ lb steam	1.93	1.90	2.57
Steam Cost, $\$/10^3$ lb	5.98	6.50	6.04

These data are for a system operating at a utilization rate of about 58%, and the costs from the conventional system with FGD are in reasonable agreement with those from Table 1 for a 100,000 lb/hr stoker fired system at 60% utilization. The McKee data show that, if compliance coal were available at the price shown, the cost of steam would be about 7% less when burning low sulfur coal with electrostatic particulate removal than when burning high sulfur coal with flue gas scrubbing. If the fluidized bed combustion system operates as expected the cost of steam when burning high sulfur coal will be about 8% less than when using FGD. It may be seen from Table 1 that the cost of steam when burning SRC-II fuel oil in a 100,000 lb/hr system at 60% utilization factor is also about 8% less than from a comparable coal-fired system. As pointed out earlier, this comparison is at a conservative capital charge rate and SRC-II fuel oil appears even more favorable at more normal rates of return and lower utilization factors.

If fuel costs are disregarded, the costs of coal-fired FBC are about 12% less than burning coal with FGD and the costs of burning compliance coal are about 25% less than using FGD. The costs of burning SRC-II fuel oil (excluding fuel costs) are about 69% less than when burning coal with FGD. The fuel costs selected for comparison studies are most important.

Exxon has prepared a study³ to compare add-on system investment and operating costs for FBC boiler firing of high sulfur coal with conventional coal-firing plus flue gas scrubbing. Fuel costs were not included in their comparison. The costs have been updated from 1975 to 1978 using a factor of 8%/year and are summarized in Table 9.

TABLE 9
COMPARISON OF COSTS FOR VARIOUS COAL-FIRING SYSTEMS (EXXON)

	FBC Boiler System		Conventional Boiler with FGD	
	100	400	100	400
Steam rate, 10^3 lb/hr				
Plant Investment, \$ 10^3	7,812	17,262	9,198	22,932
Operating Costs, \$/ 10^3 lb steam	2.55	2.04	2.65	2.12
Capital Costs, \$/ 10^3 lb steam	1.98	1.10	2.33	1.45
Total Costs (ex fuel), \$/ 10^3 lb steam	4.53	3.14	4.98	3.57

The Exxon data show that the costs of FBC (ex fuel) are about 9% less than FGD at 100,000 lb/hr of steam and 12% less than FGD at 400,000 lb/hr of steam. Exxon also shows that the costs of burning compliance coal in conventional equipment with electrostatic precipitators are about 28% less than burning coal with FGD. These results are in good agreement with those of McKee. Exxon also shows data that indicate burning of low sulfur fuel oil requires operating and capital costs which are 61% lower than the costs of burning coal with FGD. Again the costs of fuel are the determining factors in selecting industrial steam boiler equipment.

5.4.2 Industrial Fuel Gas from Coal

The production of low- or medium-Btu industrial fuel gas from coal has been widely studied as a means of utilizing coal with minimal environ-

³ "Application of Fluidized-Bed Technology to Industrial Boilers," Exxon Research & Engineering Co., January, 1977. EPA Report No. 600/7-77-011.

mental pollution. Several recent studies^{4,5,6} were reviewed to provide a comparison with other means of utilizing coal for industrial heat in a pollution-free manner. The study by Gilbert Associates⁴ is concerned with producing low and medium Btu gas at rates of 10×10^9 to 100×10^9 Btu/day which is equivalent to about 300,000 to 3,000,000 lb/hr of steam. In this range the price of gas is estimated to be about \$3.00 to \$4.00/million Btu for low Btu gas and \$3.00 to \$5.50/million Btu for medium Btu gas. The economics are presented in a sketchy fashion but include equity capital in the amount of 65% and a DCF return rate of 10%, which makes the costs seem quite optimistic. The cost of coal was not specified.

The study by Dravo Corp.⁵ concerns itself with small gasifiers ranging in size from 1.6×10^9 to 22.7×10^9 Btu/day or the equivalent of about 50,000 to 700,000 lb/hr of steam. Both low and medium Btu gas can be produced. Gas prices estimated by Dravo when using high sulfur coal valued at \$25.00/T (about \$1.00/million Btu) ranged from \$2.30 to \$3.90/million Btu for low Btu gas and from \$3.60 to \$5.20/million Btu for medium Btu gas. These costs are based on utility financing and would be about 15% to 30% higher with equity financing. Also, the use of coal valued at \$1.71/million Btu as was used in the comparison of coal and SRC-II fuel would add about \$0.90-\$1.00/million Btu to the gas price. A more realistic price range for low Btu gas might be \$3.60 to \$5.70/million Btu and for high Btu gas might be \$4.90 to \$7.10/million Btu.

The Consolidated Natural Gas study⁶ is an extensive study of gas production from coal for industrial use. Data are presented for medium Btu gas using several financing methods whereby ultimate gas costs of \$4.65

⁴ "A New Look at Low and Medium BTU Gas for Industrial Applications," Gilbert Associates, AIChE 85th National Meeting, June, 1978.

⁵ "Economic Advantages and Areas of Application of Small Gasifiers," R.W. Culbertson & S. Kasper, Dravo Corp., January, 1978.

⁶ "Low/Medium BTU Coal Gasification: Perspective of the Gas Industry," R.H. McClelland, Consolidated Natural Gas Co.

to \$6.95/million Btu are indicated. These costs are based on a plant making 10×10^9 Btu of gas/d using coal priced at \$1.25/million Btu.

The Dravo and CNG data seem in reasonable agreement for moderate size plants making medium Btu gas which could be fired in natural gas boilers without extensive modification. Using an average value of \$6.00/million Btu for such gas, steam could be produced in a 100,000 lb/hr boiler at 60% utilization factor for a cost of \$9.45/ 10^3 lb as compared to costs of \$6.64/ 10^3 lb and \$7.23/ 10^3 lb using SRC-II fuel oil or coal, respectively. To break even with SRC-II fuel oil the price of gas would need to be about \$4.00/million Btu, and it thus appears that coal gasification is not likely to be a viable alternative means of using coal for normal industrial situations, particularly where coal handling facilities and space are not available or are undesirable from the viewpoint of containment of fugitive dust and water run-off.

SECTION 6

INDUSTRIAL BOILER MARKET DATA BASE AND MARKET OPPORTUNITY

6.1 Gross Fuel Consumption in U.S. Markets

Total fuel usage in the United States for the year 1977 was approximately 76.5×10^{15} Btu (76.5 quads), or the equivalent of 12.8 billion barrels of fuel oil per year (1 barrel of fuel oil = 6×10^6 Btu). This is equivalent to an oil consumption of more than 35 million B/D. The various fuel sources from which our energy was obtained are shown in Table 1, which is based on a previous study¹ on industrial boiler fuel utilization.

TABLE 1

UNITED STATES FUEL USE IN 1977 BY SOURCE

	<u>Quads</u>	<u>% of Total</u>
Coal	14.8	19.4
Petroleum	37.1	48.5
Natural Gas	19.6	25.6
Nuclear	2.7	3.5
Hydropower	<u>2.3</u>	<u>3.0</u>
Total	76.5	100.0

The fuels are consumed in various sectors as shown in Table 2.

TABLE 2

UNITED STATES FUEL USE IN 1977 BY SECTOR

	<u>Quads</u>	<u>% of Total</u>
Residential and Commercial	17.8	23.3
Industrial	22.4	29.3
Utility	16.6	21.6
Transportation	<u>19.7</u>	<u>25.8</u>
Total	76.5	100.0

(1)"Industrial Boiler Fuel Utilization Study," P. D. Twombly, Volume 4, Part 5

It will be seen that industrial fuel uses amounted to more than one-quarter of our total 1977 fuel consumption and about 88% of this was in the form of fossil fuel. Of the total U.S. consumption of 71.5 quads of fossil fuel, industrial uses accounted for 19.8 quads, or about 28%. Industrial fuel is used for steam production, for feedstocks, for furnace (process) heat, and for direct firing of prime movers. A summary of industrial fossil fuel consumption by use and by fuel type is shown in Table 3, which is based on Table XII of the previous study.⁽¹⁾

TABLE 3
UNITED STATES INDUSTRIAL FUEL CONSUMPTION IN 1977

All figures in quads

Fuel Use	<u>Coal</u>	<u>Oil</u>	<u>Gas</u>	<u>Total</u>
Boilers	1.1	1.3	1.8	4.2
Direct Fired Furnaces	2.5	0.7	3.5	6.7
Indirect Fired Furnaces	0.3	0.3	1.4	2.0
Turbines	-	0.1	0.4	0.5
Internal Combustion Engines	-	1.7	1.5	3.2
Feedstocks	<u>0.1</u>	<u>2.6</u>	<u>0.5</u>	<u>3.2</u>
Total	4.0	6.7	9.1	19.8

The data in Table 3 indicate that the use of fossil fuels in industrial boilers amounts to 4.2 quads/yr, or the equivalent of almost 2×10^6 B/D of fuel oil. Of this total usage more than 1.4×10^6 B/D fuel oil equivalent is consumed as oil and gas. As discussed in Reference 1, an exact breakdown of fuel usage in industry is very difficult to make and the total fossil fuel usage in steam boilers may be as much as 6 to 8 quads/yr.

The use of oil and gas for boiler fuel does not represent a high level use of these increasingly expensive and limited resources, and the Fuel Use Act was passed in 1978 to require the replacement of oil and gas by alternate fuels. SRC-II fuel oil has been shown to be an economically and environmentally desirable fuel for use in industrial-sized boilers over a wide

range of size and utilization factors. The size of this market for SRC-II fuel oil can be estimated from an inventory of industrial boilers and the amount of fuel they use together with the steam boiler economics calculations from Section 5.2.

6.2 Development of Industrial Boiler Market Data Base

In recent years, the increased concern with energy and environmental pollution has brought a need for a reasonably accurate assessment of the many facets of energy utilization including a measure of the number, size, and fuel consumption characteristics of the many categories of energy-consuming devices which exist. The category with which this study is concerned is that of industrial boilers. A number of inventories have been made of the industrial boiler population over the past several years, but none which were available when this study was undertaken were appropriate for defining the market for SRC-II fuel oil. To rectify this situation, Battelle-Columbus Laboratories (BCL) were engaged to examine various boiler data bases and prepare an updated base which would provide data on boiler size, capacity, and fuel utilization to meet our needs.

The report⁽²⁾ on the industrial boiler data base developed by BCL is in a separate volume. The data bases which were analyzed were:

NEDS - U.S. Environmental Protection Agency -- National Emissions
Data Summary

MFBI - U.S. Department of Energy -- Major Fuel Burning Installations

ABMA - American Boiler Manufacturers Association

The NEDS data base was compiled by EPA as an inventory of significant emissions sources. Data entries date from 1971 to 1978. Data are more complete for the larger boiler sizes and for the "dirtier" fuels -- coal and residual

(2) "Industrial Boiler Data Base," Battelle-Columbus Laboratories, July 16, 1979, Volume 4, Part 4

oil. The MFBI data base was compiled for DOE in 1973-74 to ascertain fuel usage in industrial combustors. The MFBI base was directed at major fuel users and included boilers of 74,000 lb/hr of steam or greater. The ABMA data base is a record of boiler sales since 1965, and no effort was made to include utilization rates. The NEDS data base was the most complete of the three considered, and by suitable adjustments for estimating smaller size boilers provides the best estimate of the total industrial boiler population.

The new industrial boiler data base system developed by BCL is in computerized form and can be queried to provide answers on boiler number count, age, installed capacity, fossil fuel use, load factor, and fuel use by fuel type. The results can be generated by industrial use (total industry, manufacturing industry, and process industry), by boiler size, by region, by state, or by SIC code. Several interesting observations have been made.

Analysis of fuel usage showed that Region 2, encompassing New York, Pennsylvania, Virginia, West Virginia, Delaware, and New Jersey, had a high fuel usage, balanced between manufacturing industries and process industries, a very high use of residual fuel compared to the nation and other regions of large fuel use, and a high coal use.

A comparison of utilization factors showed a significantly higher factor, more than 20%, for the process industries as compared to the manufacturing industries. For coal-fired boilers in both process and manufacturing industries, utilization factors became higher as size increased. For non-coal-fired boilers, the trend of utilization with size was very slightly upward in the process industries and markedly downward in the manufacturing industries.

In general, the design capacities of the process industry boilers were distributed quite uniformly on a logarithmic basis over the range covered, but the total design capacity in the manufacturing industry was higher in the 50,000 to 100,000 lb/hr steam range. The size distribution of

the boiler population was quite similar between the U.S. as a whole and Region 2 for three of the four categories based on coal-burning and non-coal-burning boilers, and manufacturing and process industries. For the coal-burning boilers in the manufacturing industries, there appeared to be a paucity of boilers at the lower end of the considered design size range.

Although the boiler design capacity is about the same for non-coal-burning boilers in the manufacturing and the process industries, the high load factor in the process industries causes the fuel use in process industry boilers to exceed by a considerable amount that in the manufacturing industries. In the case of coal-burning boilers, the considerably higher population in the manufacturing industries results in about equal fuel usage in the manufacturing and process industries.

The most outstanding result in the study of boiler age data is that the coal-fired boiler population is about 8 years older than the non-coal-fired boiler population.

6.3 Market Opportunities for SRC-II Fuel Oil

Data from the BCL industrial boiler data base may be combined with steam generation economic data from Section 5.2 to provide an indication of the future market for SRC-II fuel oil in industrial boilers. Figure 1 is a plot of the utilization rates for coal- and non-coal-fired boilers in the manufacturing industries as a function of boiler size superimposed on a plot of the break-even utilization factors for coal- vs. SRC-II fuel oil-fired boilers taken from Figure 6 of Section 5.2. The plot shows that it is more economical in new boiler facilities to use SRC-II fuel oil at the estimated price of \$3.82/million Btu than coal at \$1.71/million Btu for boilers of less than 500,000 lb/hr steam capacity.

Figure 2 is a similar plot for process industry boilers. In this case, the higher utilization factors in the process industries result in curves which cross the break-even utilization factor curve. Thus, for non-coal-fired boilers, the use of SRC-II fuel oil is more economical than coal

Figure 1 INDUSTRIAL BOILER UTILIZATION RATES
MANUFACTURING INDUSTRY
ENTIRE UNITED STATES

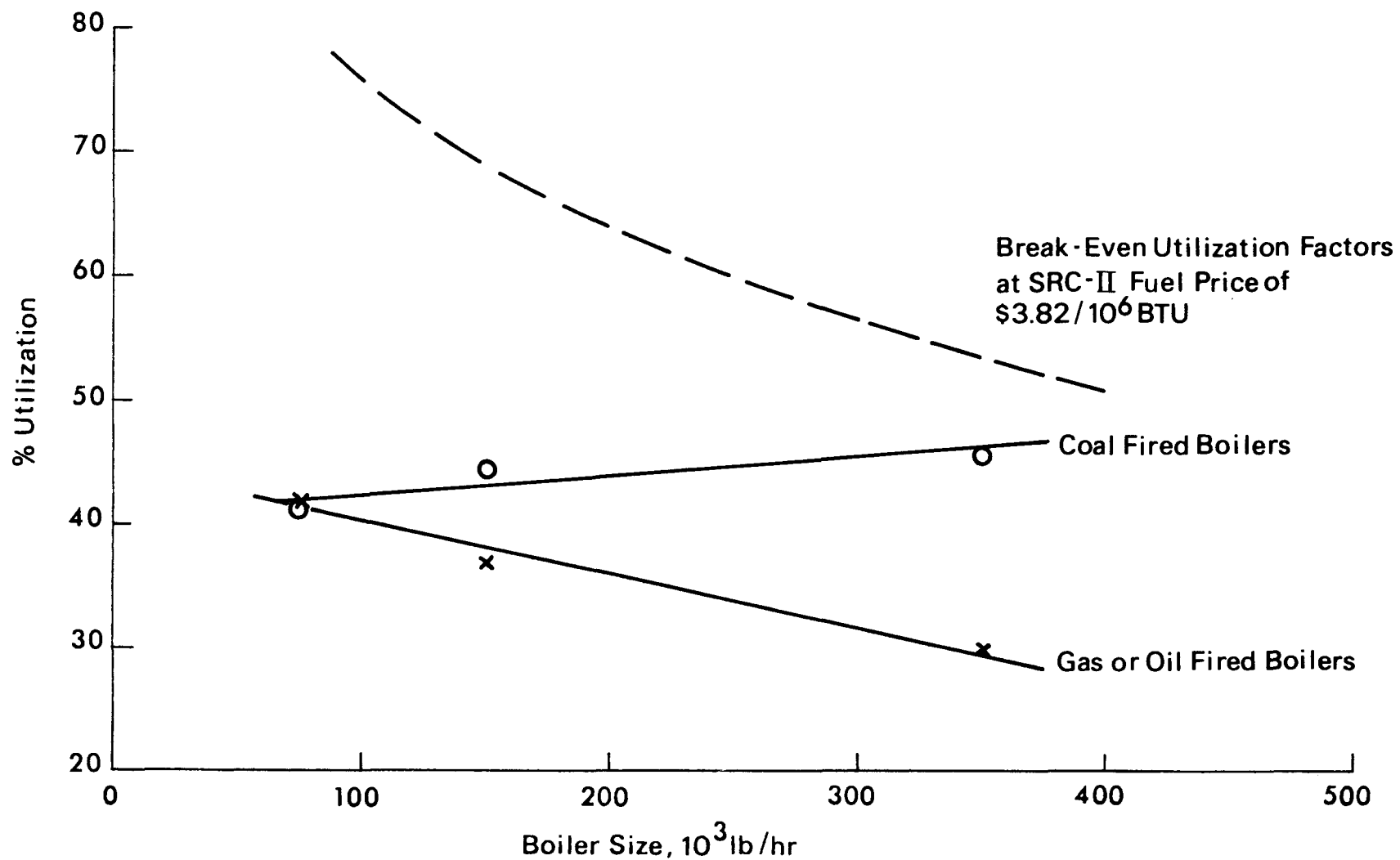
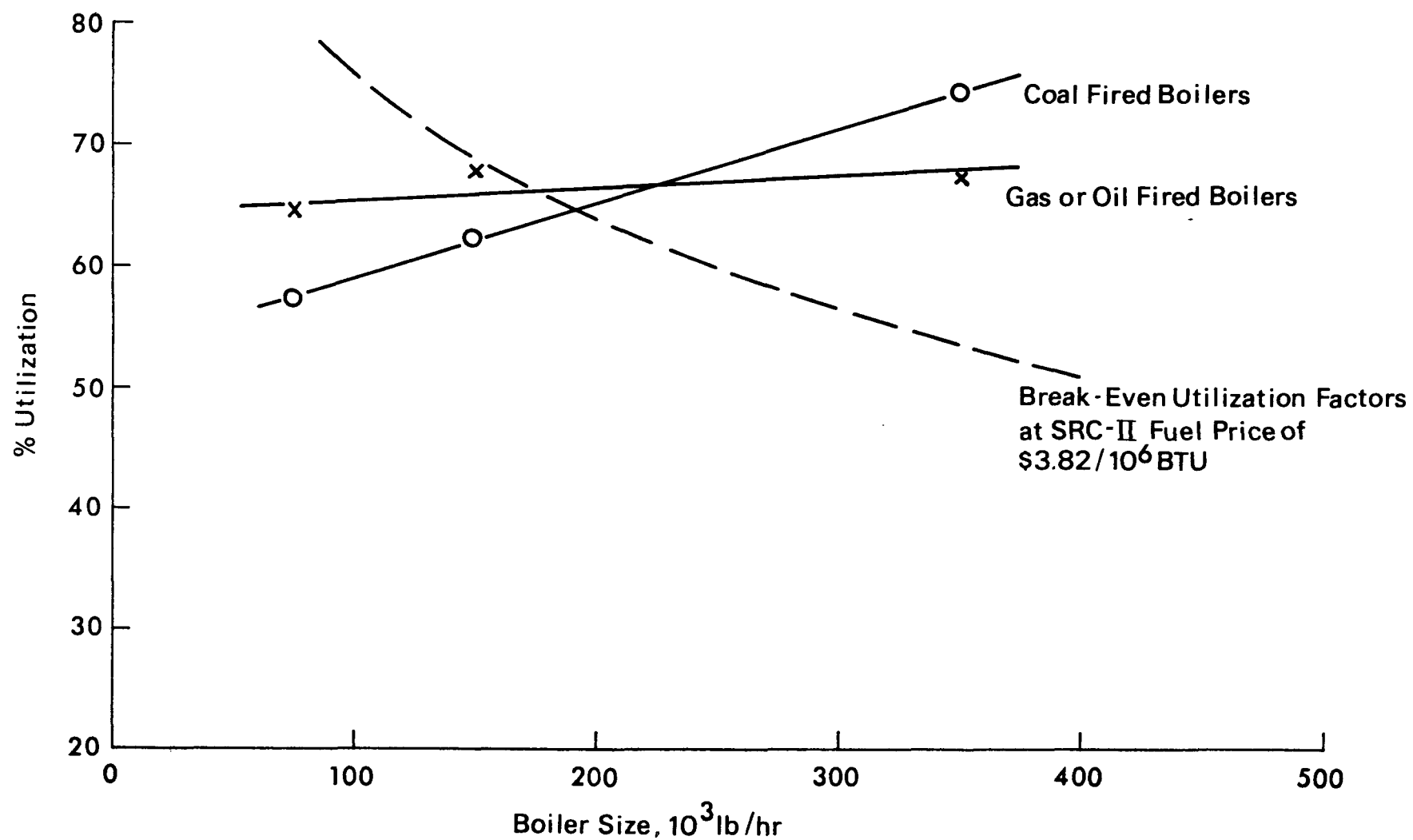


Figure 2 INDUSTRIAL BOILER UTILIZATION RATES
PROCESS INDUSTRY
ENTIRE UNITED STATES



below a boiler size of 175,000 lb/hr of steam and for coal-fired boilers below a size of about 190,000 lb/hr.

In order to convert the information from Figures 1 and 2 to potential market size for SRC-II fuel oil, it is necessary to know the present market size below the cross-over points. For the manufacturing industries, the potential market for SRC-II fuel oil would be the total fuel used. The volumes expressed in 10^3 B/D of fuel oil equivalent are shown in Table 4.

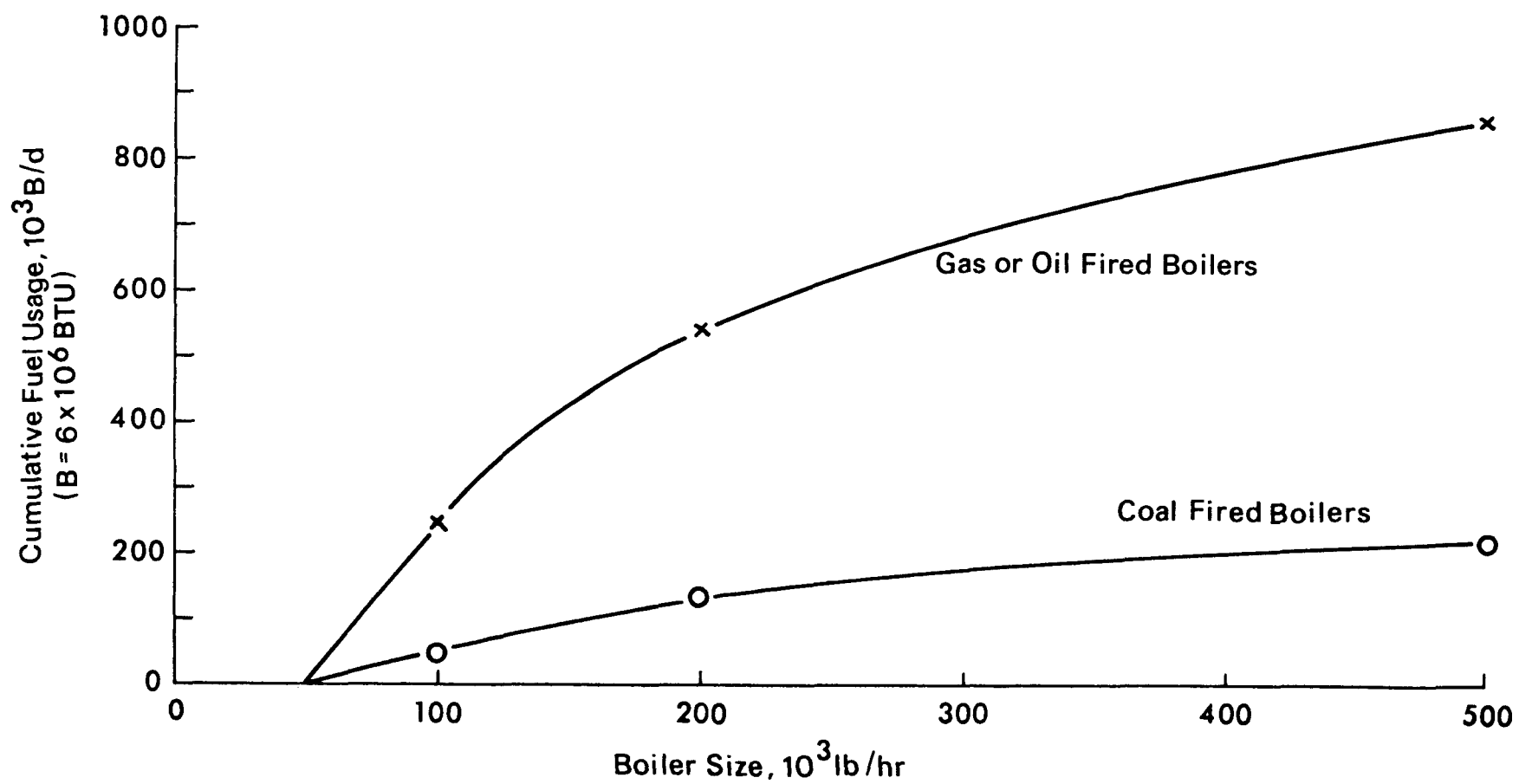
Table 4
POTENTIAL MARKET FOR SRC-II FUEL OIL - 10^3 B/D FOE

	Entire U.S.	East of Miss. River	Region 2
Manufacturing Industry			
Coal-Fired	250	210	40
Non-coal-Fired Boilers	470	280	80
Process Industry			
Coal-Fired Boilers	120	110	60
Non-coal-Fired Boilers	490	370	100

For the process industries, Figure 3 shows the cumulative fuel usage as a function of boiler size. From this curve the potential market for SRC-II fuel oil up to the break-even boiler sizes from Figure 2 have been estimated and are also shown in Table 4. Figures 1, 2, and 3 illustrate the procedure for determining potential markets for SRC-II fuel oil for the entire U.S., and a similar procedure was followed using BCL data to obtain numbers for smaller areas shown in Columns 2 and 3 of Table 4.

The most probable market for SRC-II fuel oil would appear to be those boilers which would be under pressure from DOE to convert from oil- or gas-firing because of the Fuel Use Act. The potential U.S. market for the 48 contiguous states in this case would be 960,000 B/D based on 1977 usage. Because SRC-II fuel oil would initially be expected to be available in the Eastern U.S., the market may be largely in this area where most industries are located. In this area, the potential market by displacing oil and gas would

Figure 3 INDUSTRIAL BOILER FUEL USAGE
PROCESS INDUSTRY
ENTIRE UNITED STATES



be 650,000 B/D. In the more limited Region 2, the market would still be 120,000 B/D.

Because many of the coal-fired boilers used in industry are presently not conforming with environmental laws, it is probable that at least part of this market will find the use of SRC-II fuel oil to be an attractive alternative to flue gas treatment. If 25% of the present usage were converted to SRC-II fuel oil, it would amount to an additional SRC-II fuel oil market of 90,000 B/D for the entire U.S., 80,000 B/D east of the Mississippi River, and 25,000 B/D in Region 2.

The BCL data base computer program can also be used to project future growth in industrial boiler systems and usage. Total fuel requirements are expected to increase by 13.6% by 1985 (about 245,000 B/D) and by 22.9% by 1990 (about 410,000 B/D) and all of this increase would be potential SRC-II fuel oil market. The most likely potential SRC-II fuel oil markets in 1977, 1985, and 1990 are summarized in Table 5.

Table 5

LIKELY SRC-II FUEL OIL MARKET VOLUMES - 10^3 B/D FOE

	<u>1977</u>	<u>1985</u>	<u>1990</u>
Entire U.S.	1,050	1,295	1,460
East of Mississippi River	730	900	1,015
Region 2	205	255	285

The fuel oil market volumes in Table 5 are those which were derived from calculations using the BCL data base. As pointed out earlier, the data base covers the size range from 50,000 to 500,000 lb/hr of steam, and fuel usage in smaller industrial boilers and those not otherwise included in the inventory may be another 50 to 100% of that shown. These numbers may be, therefore, a conservative estimate of the SRC-II fuel oil market.

6.4 Capital Allocation Implications

The average size of all boilers in the BCL data base is 116,000 lb/hr of steam and the average fuel usage is 327 B/D. Based on a DOE requirement to convert oil- and gas-fired boilers to alternate fuels and using the intermediate estimate of new and replacement boilers east of the Mississippi having a fuel requirement of 900,000 B/D in 1985, it can be estimated that about 2,750 boilers of average size would be required. The cost of coal-fired boilers is about \$7 million greater than the cost of SRC-II fuel oil-fired boilers in this size range so that the added capital cost for coal-firing for 2,750 boilers would be about \$19.3 billion in 1978 dollars.

For an SRC-II plant producing 57,000 B/D of SRC-II fuel, the capital cost would be \$1.56 billion. The \$19.3 billion saved by building SRC-II fuel oil-fired boilers would provide sufficient capital to build SRC-II plants with a total capacity of about 700,000 B/D. The total fuel output of the SRC-II plants, however, would be about 1,240,000 B/D. This is provided at the same investment of capital as required incrementally for the coal-fired boilers, which saves only 900,000 B/D of oil or gas. Thus, the SRC-II fuel oil alternative results in a lesser capital formation requirement, or, in other words, capital invested in SRC-II plants is better utilized than capital invested in coal-fired boilers.

SECTION 7

SPECIFIC BOILER FUEL STUDIES

7.1 INTRODUCTION AND SUMMARY

To aid in establishing the market potential for SRC-II fuel oil in industrial boiler applications in the northeast U.S., joint studies have been undertaken with several firms representing typical manufacturing operations. Not all of these studies are complete. This report presents the results of two of these studies, one involving the Philadelphia, Pennsylvania, plant of the Rohm and Haas Company and the other involving the Bridgeport, Connecticut, plant of the General Electric Company. Complete reports of these two studies are given in Volume 4.

The following two sections present brief summaries of these reports. The results of both studies indicate a significant opportunity for SRC-II fuel oil to generate the steam requirements for these plants, based on economics, operating simplicity and environmental considerations compared to the options of firing coal either with added flue gas desulfurization (FGD) or in a fluidized bed combustion system. The General Electric study also included data useful in estimating the extent of the industrial market opportunities for SRC-II fuel oil.

Two other joint studies, initiated but not completed in time for this report, involve the Caterpillar Tractor Company and the General Motors Company. Preliminary information received from these companies indicates that coal firing with FGD will require complete control of particulates as well as gaseous pollutants, and the added cost of particulates control was incorporated in the estimates developed in the Rohm and Haas study.

7.2 ROHM AND HAAS BOILER FUEL ASSESSMENT

SRC-II fuel oil was assessed as a boiler fuel to meet the specific needs of the Rohm and Haas Philadelphia plant and was found to be an attractive fuel candidate to replace, when necessary, the petroleum fuels presently being used. The need for new supplies of clean industrial boiler fuels to replace petroleum fuel oils at the Philadelphia plant is becoming increasingly evident to the Utility Department management as petroleum stocks become less available and more expensive and as pollution control requirements become more stringent. The Philadelphia plant has old boilers and space constraints, which limit the flexibility to modify existing facilities or to install new equipment. Thus, the operating management is increasingly concerned with the options available for continued reliable operation of the boilers.

This joint study was conducted by the staff of Rohm and Haas Delaware Valley Inc. with the aid of Gulf Science and Technology Company and Stearns-Roger, Inc. The purpose of the study was to assist in the identification, consideration, and evaluation of the industrial fuel options available to the Rohm and Haas Philadelphia plant. The Rohm and Haas Philadelphia plant has a need to obtain fuels for generating process steam and steam for the cogeneration of electricity.

In this joint study, the needs of the existing plant of Rohm and Haas in Philadelphia were considered and evaluated in terms of identifying the capabilities of fuels and equipment. This consideration resulted in the incorporation of assumptions and decision criteria that were specific to the needs of an existing plant's requirements without major disruption of the operating status of the plant and within the limitations of the existing facilities and space. Appropriate alternatives to provide the fuel and equipment necessary to generate the Rohm and Haas energy requirement were identified and assessed. Five cases were studied, two involving SRC-II fuel oil, and three involving coal. The alternatives that were evaluated in detail are:

1. Modification of existing facilities to use SRC-II fuel oil.
2. Replacement of existing boilers with new packaged oil-fired boilers using SRC-II fuel oil.
3. Stoker-fed coal-fired boilers with a spray-dry flue gas desulfurization (FGD) system.
4. Stoker-fed coal-fired boilers with a double-alkali FGD system.
5. Direct combustion of high-sulfur coal in atmospheric fluidized bed (AFB) boilers.

The plant studied is a chemicals production plant of Rohm and Haas located in the Bridesburg section of Philadelphia. This plant is an integrated facility with multiple processes and products, primarily batch processes, which includes both development and production facilities. The production level for the plant and the supporting steam generation requirements can be anticipated to remain steady well into the future. The plant is located along the Delaware River and the Frankford estuary and is bounded on all sides by other industrial facilities or communities. Therefore, space for major expansion of operations is not available to the plant. Within the plant site boundaries, the available space is well-utilized and the powerhouse, with its multiple functions, is conveniently located to serve plant needs. Thus, future powerhouse operations will be conducted within the same functional and spatial constraints as today's operations.

The existing powerhouse includes three steam generating boilers which provide process steam and the cogeneration of electricity. These boilers were originally installed in 1946 as coal-fired units and were modified in 1969 to burn No. 6 fuel oil to produce 90,000 lb/hr of steam each. The average boiler production rate is about 150,000 lb/hr of steam. The capacity factor is about 55%. A portion of the steam generated is used to generate electricity, meeting about a third of the plant needs. The remaining

amount of electricity is purchased. The steam demand is low enough to be met by two boilers over the period of April to November, so boilers could be replaced during the limited period. Retrofitting an existing set of equipment and facilities and maintaining reliable operation throughout provided many constraints on design and operations and added to the estimated costs. For the option involving combustion of high sulfur coal coupled with flue gas desulfurization, the FGD system recommended is the spray-dry process because adequate space for sludge handling is not available.

For each of the options considered, plot plans and designs were developed and estimates were made for capital and annual operating costs. Although the use of coal would provide fuel cost savings as compared to SRC-II fuel oil, the options involving combustion of coal require much larger investments. Thus, the return on the additional investment required for direct coal systems was evaluated as part of this study. Rohm and Haas typically requires a 22% rate of return on gross assets. None of the options involving coal combustion would nearly meet this decision objective, so SRC-II fuel oil would be the preferred fuel option. The capital and annual costs for the options are summarized in Tables 1 and 2. The calculated returns are shown in Table 3.

Because of the very high capital investment required, the fuel savings generated by using coal directly rather than SRC-II fuel oil cannot nearly justify the use of coal. This study is included to illustrate some of the effects of space limitations, retrofitting operating characteristics, and transition requirements. It has been shown that these factors tend to favor the use of SRC-II fuel oil instead of the use of direct coal combustion systems.

Table 1

SUMMARY OF CAPITAL COST ESTIMATES
\$1000

	<u>SRC-II Fuel Oil</u>		<u>High-Sulfur Coal</u>		
	<u>Modify Existing</u>	<u>New Boiler</u>	<u>AFB</u>	<u>Stoker and Spray Dry FGD</u>	<u>Stoker and Double Alkali FGD</u>
Equipment and Installation	21	2,310	16,860	15,588	15,395
Engineering, Contingency, Fee	<u>4</u>	<u>462</u>	<u>3,372</u>	<u>3,118</u>	<u>3,079</u>
Total Capital Cost, 1978	25	2,772	20,232	18,706	18,474
Escalated Capital Cost, 1985	43	4,751	34,674	32,059	31,661
Incremental Investment					
- Over Modification					
1978	0	2,747	20,207	18,681	18,449
1985	0	4,708	34,631	32,016	31,618
- Over New Oil Boiler					
1978	(-2747)	0	17,460	15,934	15,702
1985	(-4708)	0	29,923	27,308	26,910

Table 2

SUMMARY OF ANNUAL FUEL AND OPERATING COSTS
\$10⁶ (1978)

			Annual Cost			Incremental Annual Cost*		
			<u>Fuel</u>	<u>Operating</u>	<u>Net</u>	<u>Fuel</u>	<u>Operating</u>	<u>Net</u>
SRC-II Fuel Oil								
-	Modify Existing Boilers		5.04	1.06	6.10	-	-	-
-	Install New Boilers		5.04	1.06	6.10	-	-	-
High-Sulfur Coal								
7-9	-	Stoker-Fired with Spray-Dry FGD	2.39	2.73	5.12	2.65	(-1.67)	0.98
	-	Stoker-Fired with Double-Alkali FGD	2.39	2.67	5.06	2.65	(-1.61)	1.04
	-	AFB	2.39	2.35	4.74	2.65	(-1.29)	1.36

 *(SRC-II Fuel Oil)-(Coal)

Table 3

CALCULATED RETURN-ON-GROSS-ASSETS^a

1985 Values - Escalated Over Plant Life ^b	<u>AFB</u>	<u>Stoker and Spray Dry FGD</u>	<u>Stoker and Double Alkali FGD</u>
- Compared to Modified ^c	5.6	3.1	2.6
- Compared to New ^d	6.7	3.9	3.4
1985 Values - Unescalated Over Plant Life ^e			
- Compared to Modified	1.9	1.1	1.3
- Compared to New	2.5	1.6	1.9

^aInvestment in 1985.

^bPlant life assumed to be only those years when annual cost savings remain positive-1986 is first year of operation.

^cExisting boilers modified to burn SRC-II fuel oil.

^dExisting boilers replaced with packaged oil fired boilers.

^e30 years assumed - 1986 is first year of operation.

7.3 GE BOILER FUEL ASSESSMENT

An assessment of SRC-II fuel oil as an industrial fuel option has been made by the Thermal Power Systems Engineering Section of General Electric's Industrial Products and Components Sector. This fuel is of potential interest to GE for its own manufacturing plants and as a fuel for the equipment supplied by GE. This study provides an evaluation of the available fuel alternatives for typical industrial applications in the 1985 time frame. The alternatives were evaluated with regard to the trade-off between capital investment and fuel cost differences. The results of the study are useful not only for the applications investigated, but also in clarifying the extent of the industrial market opportunities for SRC-II fuel oil.

GE's Bridgeport, Connecticut, plant was selected as a typical northeast urban manufacturing plant to provide a set of authentic site parameters for the evaluation. The plant has 2000 employees engaged in light electrical manufacturing and 1000 employees in corporate executive and administrative functions. Steam generation is required at the plant for both space heating and light manufacturing needs, providing a boiler utilization of about 70%. The present maximum steam demand at Bridgeport is 100,000 lb/hr. The design basis for the boiler plant is to provide three half-size boilers, thus allowing for the maximum steam flow during outages, either scheduled or not. The study also considered increased steam demands of 200,000 and 500,000 lb/hr and capacity factors of 50 and 90%.

The Bridgeport plant is typical of many industrial facilities and the fuels problems to be faced in the late 1980's. Petroleum-derived fuel oils and natural gas, which presently comprise the major fuel supplies, will not be readily available for industrial fuels as a consequence of reduced domestic production, the government's policies to reduce imports, government pressure to use coal and coal-derived fuels, and rapidly rising fuel prices. In order to use coal directly as an industrial fuel, approaches such as low-sulfur coal, flue gas desulfurization, and electrostatic precipitators will have to be used.

It is well known that industrial-size boiler plants designed for firing distillate oil (or SRC-II fuel oil) have substantially lower capital costs than boilers designed for alternate fuels: high sulfur coal which requires flue gas desulfurization (FGD), low sulfur coal, and even low sulfur residual oil which requires electrostatic precipitators. These higher capital costs for the alternate fuels have to be justified by reduced annual operating costs when viewed by a typical industrial firm.

The GE study used the discounted cash flow (DCF) method for analyzing capital budgeting decisions, which is very common among industrial firms. The method determines the rate of return on an incremental capital expenditure which is generated by reduced annual operating costs.

Estimates for capital costs and annual operating costs for a 100,000 lb/hr plant size with a 70% capacity factor for these four fuels are shown in Table 4. These costs are based on 1978 values escalated to 1985 at 6.5%/yr. Coal with an FGD system required almost four times the investment of the SRC-II fuel oil plants. The differences in annual operating costs are small relative to the large incremental investment cost.

Similar data for a 500,000 lb/hr plant size are also shown in Table 4. The low sulfur coal option without FGD has not been considered in this size. Total fuel burning capacity would exceed 250 million Btu/hr, which would require sulfur removal under the proposed federal performance standards. Again, there is a large incremental investment cost for the coal with FGD plant versus the SRC-II fuel oil plant.

The results of the DCF analysis are:

- New Plant Decisions - SRC-II Fuel Oil vs. Coal with FGD

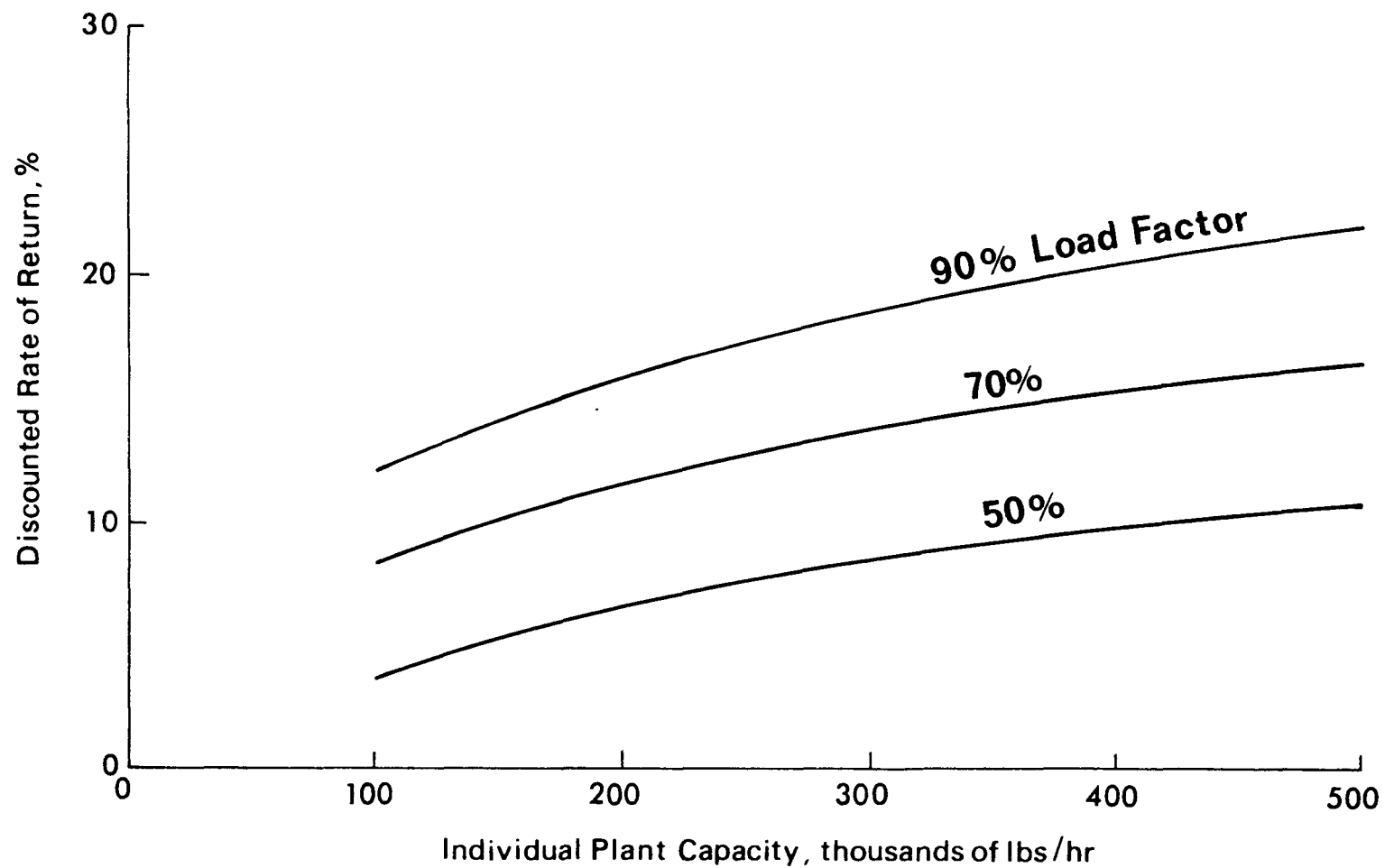
The discounted rate of return (DRR) on the incremental investment for coal with FGD generally could not be justified for typical industrial manufacturing plants. The DRR is shown for plants with

Table 4

SUMMARY OF GENERAL ELECTRIC INVESTMENT AND OPERATING COSTS FOR STEAM PLANTS70% Capacity Factor, 1985 Costs in \$10³

<u>Fuel</u>	<u>SRC-II Fuel Oil</u>	<u>Residual Fuel Oil</u>	<u>High Sulfur Coal</u>	<u>Low Sulfur Coal</u>
100,000 lb/hr steam capacity				
Total Investment	4,580	6,880	16,530	12,060
Annual Operating Costs	5,220	3,940	3,510	3,660
500,000 lb/hr steam capacity				
Total Investment	13,470	17,440	52,770	--
Annual Operating Costs	22,810	16,250	12,520	--

Figure 1 NEW COAL FIRED BOILER WITH FGD VS NEW SRC
FUEL OIL FIRED BOILER DISCOUNTED RATE OF RETURN
ON INCREMENTAL INVESTMENT FOR COAL FIRED BOILER
HIGH SRC COST - \$3.50/10⁶ BTU IN 1977



steam requirements ranging from 100,000 to 500,000 lb/hr in Figure 1. Industrials generally have minimum requirements on DRR of at least 15% and often as high as 25%. The manufacturing industries have cyclic steam demands which lead to lower capacity factors of 50 to 70%. The process industries generally have large continuous steam demands with high capacity factors. It appears that coal with FGD could be justified for large (500,000 lb/hr) continuous steam demands in the process industries. The option of using SRC-II fuel oil is favored at smaller plant sizes and lower capacity factors.

- Existing Oil-Fired Boiler Plants with SRC-II Fuel Oil vs. Coal With FGD

When a new coal with FGD boiler plants is compared with an existing SRC-II fuel oil-fired plant, the entire investment for the coal plant must be justified by the same annual savings, so that the return is not adequate. There is a reduction in DRR of approximately 5% across the board. It is even more unlikely that an industrial manufacturing plant could justify the coal plant with FGD under these circumstances.

- New Plant Decisions - SRC-II Fuel Oil vs. Low Sulfur Coal Without FGD

Coal-fired boiler plants which do not require FGD have a lower incremental investment to justify, but this type of plant would only be a viable alternative in the smaller plant size. For the 100,000 lb/hr plant size, DRR values for the range of SRC fuel costs and capacity factors were found to be:

<u>Capacity Factor</u>	<u>DRR, %</u>	
	<u>Low SRC Cost</u>	<u>High SRC Cost</u>
50%	3.0	7.5
70%	11.1	13.0

Again, the conclusion would be that manufacturing industries would not justify the additional investment required for coal-fired boilers, even in cases where FGD is not required.

- SRC-II Fuel Oil vs. Low Sulfur Residual Oil

Fuel oil cost projections provided by Gulf for this study indicate that residual oil will become more expensive than SRC-II fuel oil in the early to mid-1990's. For this study, it was assumed that any incremental investment to handle residual oil in boiler plants installed in 1985 would have a useful life of only six years. The DRR analysis was made for this foreshortened investment life. It appears that using residual oil, if allowed by regulations, would be preferred over SRC-II fuel oil in most instances. When the cross-over in price occurs, the industrial boilers will probably be switched to the lower priced SRC-II fuel oil.

The cogeneration of electric power and process steam was evaluated by GE for several cases having steam demands of 500,000 lb/hr. All of the fuels considered can be used in a steam turbine cogeneration system with equal economic attractiveness. However, SRC-II fuel oil offers a potential significant advantage as a fuel for cogeneration with a combined steam and gas turbine cycle, since the other fuels cannot be used in the gas turbine. The combined cycle provides a very attractive industrial energy option, providing substantial energy savings (over 920,000 bbl/yr of oil equivalent) and economic advantage (a DRR well over 25% compared to all other options).

Atmospheric fluidized bed (AFB) technology was also considered as an alternative for direct coal combustion to coal-fired boilers with FGD equipment. This technology offers a potential reduction in investment costs of about 20%, but is in the development stage. At this time, the ability of AFB to meet cyclic steam demands appears questionable. Because of the investment savings, AFB might be a preferred option to the coal with FGD case for high capacity factor plants (90%). However, the potential market application for SRC-II at lower capacity factors and smaller sizes remains basically unchanged by the consideration of AFB technology.

**GULF SCIENCE AND TECHNOLOGY COMPANY
PITTSBURGH, PENNSYLVANIA**

**SRC-II FUEL OIL: COMBUSTION TECHNOLOGY
FOR UTILIZATION IN BOILERS**

J. E. HAEBIG

**CHEMICALS AND MINERALS DIVISION
REPORT NO. 633RK111
JULY, 1979**

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SUMMARY/CONCLUSIONS

Most of the properties of SRC-II fuel oil are those of a high-quality oil such as No. 2 fuel oil; these properties include distillation range, viscosity, and sulfur and ash contents. The only potential problems in the combustion of SRC-II fuel oil would arise from its high content of nitrogen, tending to form NO_x (nitric oxides) emissions, and its high aromatics content, which could increase smoke formation.

Since some petroleum fuel oils also contain appreciable amounts of fuel-bound nitrogen, a method has already been developed to prevent the conversion of that nitrogen into excessive NO_x emissions. In this method, termed staged combustion, admixture of the combustion air into the fuel sprays is slowed down, and more of the fuel-bound nitrogen is then converted to harmless nitrogen (N_2) instead of NO_x . Using staged combustion, utility boiler operators now routinely burn No. 6 fuel oil containing nearly 1% nitrogen while keeping NO_x emissions below the EPA New Source Performance Standard of 225 ppm. This standard is 225 ppm of NO_x for petroleum fuels, and a standard of 375 ppm is proposed for coal-derived fuels, although some local regulations might retain a lower limit for coal-derived fuels.

The use of staged combustion with SRC-II fuel oil was first tested by KVB, Inc. in a laboratory boiler firing 20 gallons/hr. NO_x emissions were reduced to 225 ppm by staged combustion in contrast to uncontrolled emissions two or three times higher. However, under staging conditions, SRC-II fuel oil tended to form excessive smoke, because of its high aromatics content.

A very successful full-scale field demonstration was then conducted in a 44 MW utility boiler of the Consolidated Edison Co. By staged combustion techniques, boiler operating conditions were optimized for minimum NO_x emissions of only 175 ppm from firing SRC-II fuel oil at full load. The burners used were the conventional units on hand for use with No. 6 oil. There was no visible smoke, and particulates levels were below the proposed EPA standard of $0.03 \text{ lb}/10^6 \text{ Btu}$. This test demonstrated that SRC-II fuel oil can be cleanly burned in this type of boiler (tangential-fired), which

constitutes a major fraction of the present utility boiler population of the United States.

The other types of utility boiler designs (wall-fired boilers) tend to produce more NO_x , but clean combustion of SRC-II fuel oil in such units should also be successful, especially with the use of new staging burner designs. These designs are now receiving full-scale optimization and inherently minimize NO_x from fuel-bound nitrogen.

These staging burners should also permit the clean use of SRC-II fuel oil in retrofitted industrial boilers. The high quality of SRC-II fuel oil could be used to better advantage in industrial boilers, many of which require distillate fuels, as opposed to utility boilers which generally can utilize more residual-type fuels. In this way, conversion from petroleum to coal-derived fuels would be facilitated in the industrial fuel market as well as in the utility boiler fuel market.

Further work which would greatly facilitate the use of SRC-II fuel oil in utility boilers, and especially in industrial boilers, would include an emissions compliant demonstration in a wall-fired utility boiler and the further development and demonstration of staging burners.

A.1 PROCESS STEPS AND PROPERTIES: FILTERED AND DISTILLED PRODUCTS AND HYDROTREATING

The SRC-II process results in a low-viscosity middle distillate fuel oil containing minimal sulfur (<0.2%), ash (<10 ppm) and non-volatile matter. See Table A.1-1. A heavy distillate product, though containing more impurities, is still a non-residual oil resembling heavy gas turbine fuels which have at times been used. Two properties of SRC-II middle distillate differ greatly from those of petroleum oils: the content of nitrogen (0.9-1.1%) and aromatics (62-65%), reflecting the coal source. The 9.1% hydrogen content is associated with its aromatics content. These impurities could tend to produce excessive NO_x and soot emissions in combustion, and they could be removed by current hydrotreating technology in a separate high-pressure hydrogenation reactor containing appropriate fixed-bed catalyst. Studies by GS&T in-house have shown that to hydrotreat such a coal liquid to the quality of No. 2 fuel oil (vis-a-vis nitrogen and aromatics) would consume 2000-3000 SCF of hydrogen per bbl of oil, costing \$2.50 to \$5.00 for a total price of \$24-29/bbl⁽¹⁾ in contrast to the estimated price of SRC-II fuel oil of \$21-24/bbl. Such a catalytic hydrotreating reactor is indeed incorporated into the Exxon EDS process,⁽²⁾ and all product in the boiling range is hydro-treated and has a commensurate predicted price and process thermal efficiency.

One goal of the SRC-II process development program has been the most economical process possible, in terms of cost and energy efficiency. Our expectation has been that NO_x and soot emissions could be prevented by in-combustion or post-combustion technology (to be explored extensively in this report) with lower total costs than hydrotreating SRC-II fuel oil. On the other hand, this approach still retains the option of performing some hydro-treating, should a certain amount of it be required for some combustion applications.

Many still expect a coal liquid to resemble the processes under development in 1970-75, e.g., H-coal boiler fuel; these process and products differed importantly from SRC-II and EDS distillate products. Typically, the reactor effluent, a slurry of liquid, ash and unreacted coal, was filtered. In contrast to the distillation approach in SRC-II, filtration carried through

**TABLE A.1-1 ASTM TEST PROPERTIES OF
SRC-II FUEL OILS AND CONVENTIONAL FUEL OILS^a**

<u>Product</u>	<u>ASTM D2880 No. 2-GT Specs</u>	<u>Middle Distillate</u>	<u>Heavy Distillate</u>	<u>No. 2 Grade</u>	<u>No. 5 Grade^b</u>
<u>Inspections:</u>					
Gravity: °API	>30	13.8	0.4>30	19	
Density (15°C): kg/dm ³		0.974	1.072	<0.876	0.940
Color		dark	dark	light	dark
Viscosity: cSt					
100°F	2.0-4.3	3.1-3.4	49.6-90.2	2.0-3.6	26-194
210°F		-	4.0-5.1	-	2.9-48
Viscosity: SUS					
100°F		36.3-37.3	342-418	32.6-37.9	124-900
210°F		-	39.8-42.7	-	36-224
Flash Point, P-W: °F	>100	>160	>180	>130	>150
Pour Point: °F	>-6	<-45	<+45	<+5	-15 - +80
Carbon Residue, Con: %W					
10% Bottoms		<1.2	-	<0.35	-
Total Sample		-	<1.5	-	2-10
Nitrogen: %W		0.9-1.1	1.2-1.4	<0.02	<0.3
Oxygen: %W		3.6-4.3	1.4-1.8	<0.09	<0.4
Sulfur: %W		<0.2	0.37-0.47	0.04-0.48	0.07-1.9
Carbon: %W		86.0	89.1	87.0	88.3
Hydrogen: %W		9.1	7.5	12.8	10.7
Hydrocarbon Groups (HPLC): %V					
Saturates		35-38	-	>65	-
Aromatics & Polar Compounds		<62-65	-	<32	<-
Asphaltenes, IP143: %W		<0.1	0.9-2.7	<0.1	<5.0
Phenolics: %W		3-20	-	0	-
Naphthalenes: %W		14-19	-	<6	-
Smoke Point: mm		5-8	-	>14	-
Ash, D482: %W	<0.01	<0.001	0.03-0.1	<0.003	<0.05
Neut. No. (Tan), D664		0.27-0.42	0.25-0.57	<0.30	<0.45
Copper Strip Corrosion, D130		1-3	1	1	1
Heat of Combustion, Gross, D240					
Btu/Lb		16 900	17 000	19 300	18 700
Btu/Gal		137 100	151 800	136 700	146 600
Cetane No., D613		<20	-	40-55	-
Autoignition Temperature: °F		925	895	594	600-700
Thermal Stability, NBTL (D1661)					
Thimble Rating					
Unwashed		1	1	1	1
Washed		1	1	1	1
Washed and Wiped		1	1	1	1
Rating of Tube		1	1	1	1
Accelerated Stability, D2274					
Deposit Weight: mg/100 ml		<0.8	<3.5	<1.0	-
Stability Test, 64 hr @ 210°F					
Insolubles: mg/100 g		<0.3	<3.5	<1.0	-
Distillation: °F		<u>D86</u>	<u>D1160; 760mm</u>	<u>D86</u>	
Over point		338-396	538-554	369-389	-
10%		386-406	568-584	422-445	-
50%		425-444	640-656	498-516	-
90%	540-640	483-500	785-820	580-593	-
End Point		538-553	928-939	630-640	-

Notes:

a - Preliminary values based on pilot plant production. Values of commercial product may vary. Reprocessing is also capable of altering product properties.

b - Product is a blend of distillate and residual fuels.

c - Metals content subject to considerable variation depending on crude source.

a large amount of ash with the filtrate product, as well as non-volatile liquid, which increased the product viscosity. H-coal typically had 0.20% ash, a viscosity in the high No. 6 range, and 0.5% sulfur.⁽³⁾ This may have helped to establish the idea that there was a spectrum of fuel qualities, increasing in viscosity and content of nitrogen, aromatics, sulfur, ash, and non-volatile material, proceeding from No. 2 fuel, through No. 6 fuel oil, and on to coal liquids at the "poor" end of the quality spectrum. Although SRC-II, EDS, and H-coal "syncrude" mode distillate products are still at the poor end of the quality spectrum with regard to nitrogen and aromatics content, their other properties are in the No. 2 oil region of the quality spectrum, proving this idea to be an oversimplification.

A.1 REFERENCES

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2. W. R. Epperly, J. W. Taunton, "Exxon Donor Solvent Coal Liquefaction Process Development," Presented at Coal Dilemma II, sponsored by ACS, Colorado Springs, Colorado, February 12-13, 1979.
3. D. T. Beecher, et al., Energy Conversion Alternatives Study, Westinghouse, Phase II - Final Report, NASA CR-134942, Vol. II (1976), p. 5-174.

A.2 COMPOSITION AND PROPERTIES OF SRC-II; COMPARISON WITH OTHER FUELS

Some further properties of SRC-II fuel oil and other fuels have been determined which further clarify the properties and relation to other fuels. Figure A.2-1 shows the close correlation⁽¹⁾ between hydrogen content and aromaticity (as determined by C^{13} NMR). SRC-II is mid-way in the spectrum of quality from No. 2 oil to SRC-I recycle solvent (not a product). Hydrogen content (and thus aromaticity) also correlates with the density (or specific gravity) of oils,⁽²⁾ as shown in Figure A.2-2 and Table A.2-1. This is the origin of the term "heavy" distillate referring originally to the petroleum fractions having higher densities, which also usually had the highest distillation ranges (or were non-volatile distillation residues) and lowest hydrogen contents. Thus, "heavy" or high density petroleum oils were associated with poor quality, in contrast to coal liquids and their properties. It is interesting that in the above table and figure, the cycle oil, which is a product from catalytic processing of petroleum, fits the same density-hydrogen content correlation as the coal-derived materials.

Figure A.2.3a from ASTM D86 distillation at atmospheric pressure, clarifies that SRC-II (here, a blend of 5.75 middle distillate to one heavy distillate) was completely vaporized as the sample reached 300-350°C, in contrast to the much smaller amount of No. 5 fuel oil vaporized at such temperatures. Furthermore, in the "burning profiles" of these two fuels in a furnace, the SRC-II combustion was completed at 240°C furnace temperature, and the No. 5 oil, at 550°C (Figures A.2-6 and 3c). The wide variations in properties that commercial residual fuel oils have always displayed is of interest here and regarding the DOE-NASA-Lewis combustor development program discussed elsewhere in this report series. Table A.2-2 lists eight such fuels,⁽⁴⁾ varying in viscosity (SUV at 100°F) from 186 to 8606. Other properties listed which are of special interest to this discussion are sulfur, ash and nitrogen contents, and the carbon-hydrogen ratio, all varying widely. The nitrogen content of SRC-II fuel oil is fairly evenly distributed over its distillation range, as shown in Table A.2-3, the lowest and highest boiling fraction both containing nearly 1% nitrogen. In contrast, the nitrogen

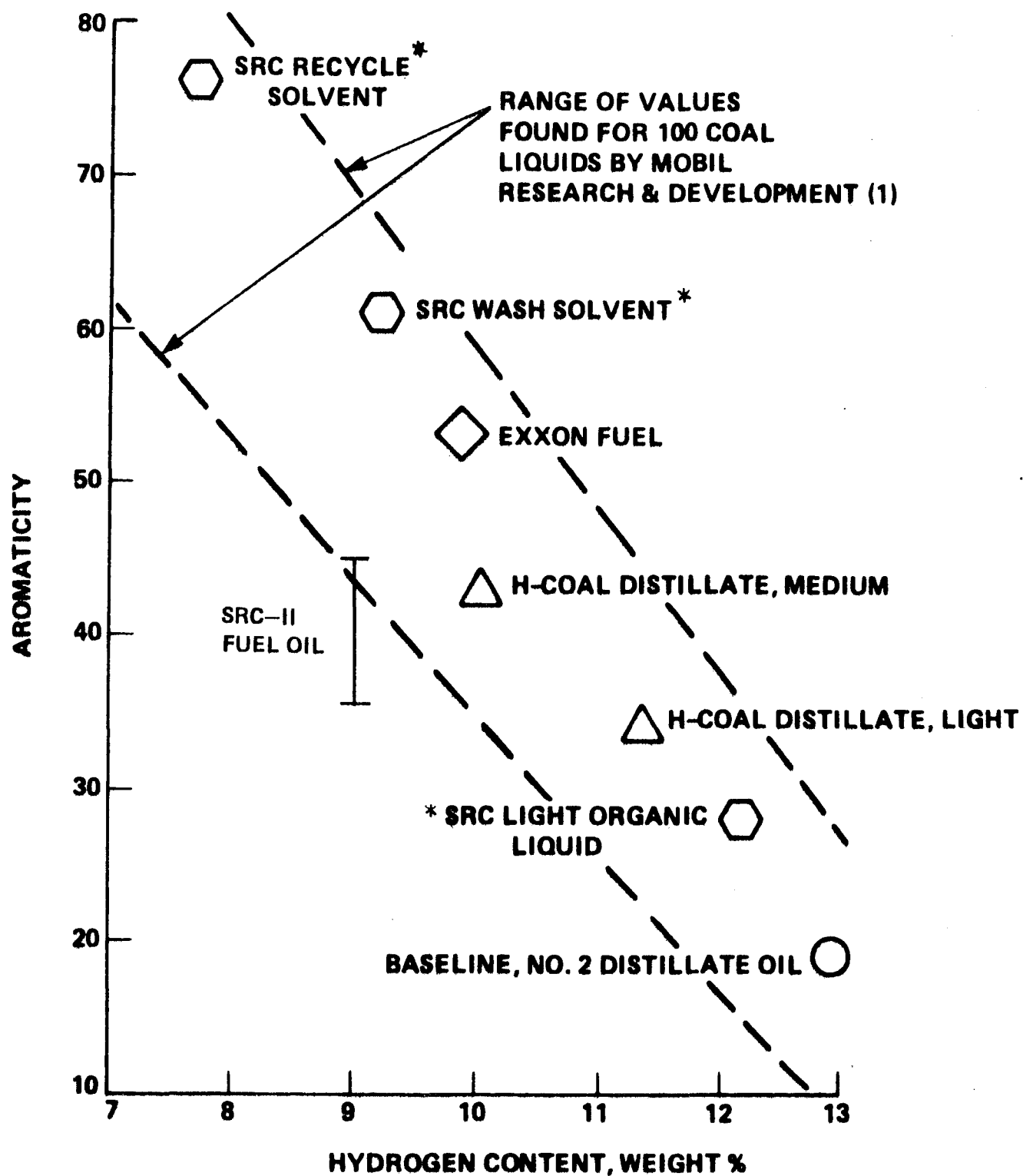


Figure A.2-1 RELATION OF AROMATICITY TO HYDROGEN CONTENT (FROM REF. A.2-1)
* FROM SRC-I PROCESS

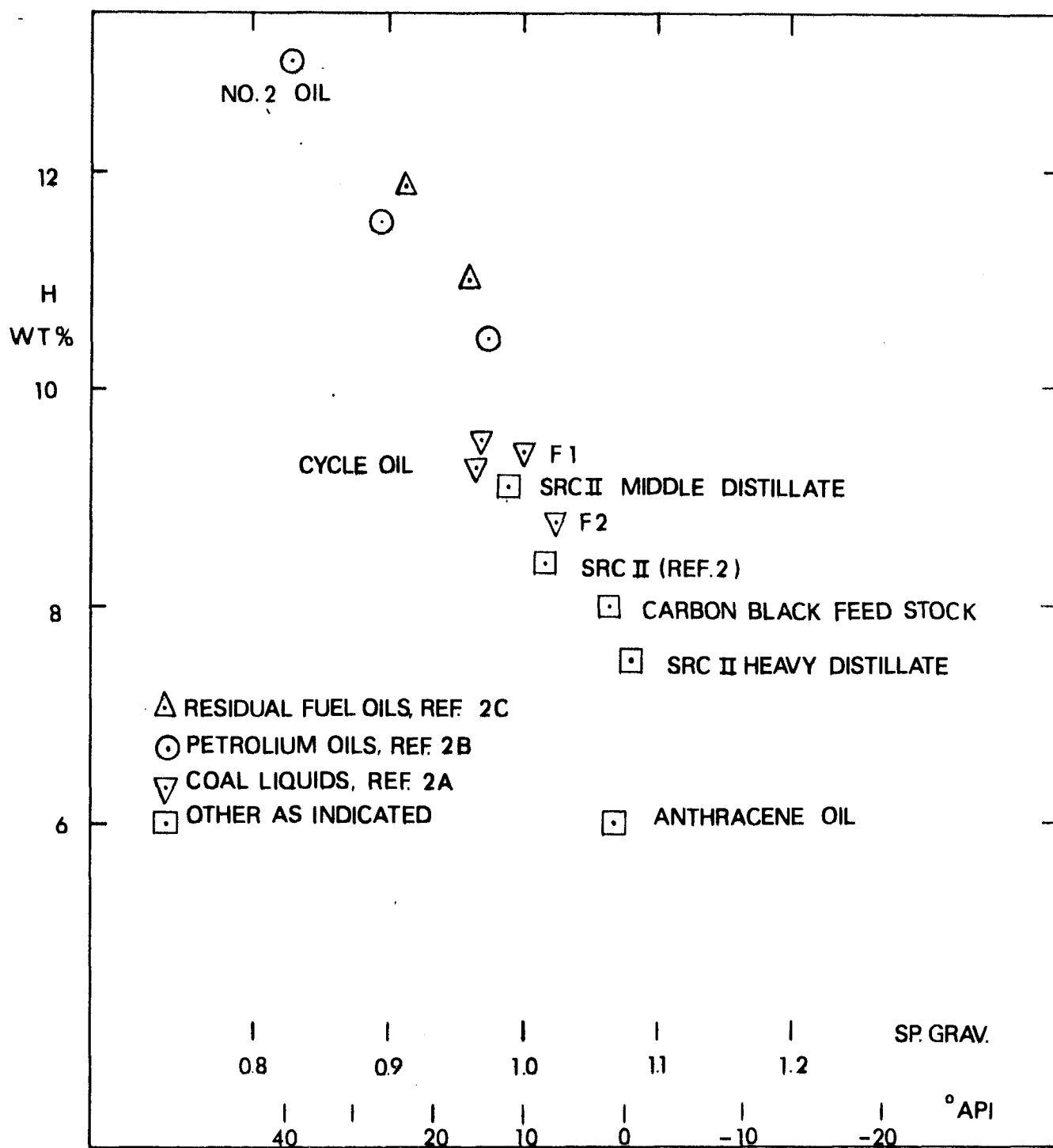


Figure A.2-2 RELATION OF SPECIFIC GRAVITY TO HYDROGEN CONTENT

Table A.2-1

PROPERTIES OF VARIOUS TYPES OF LIQUID FUELS

	D86 Distillation Range B pt, °F (% Distilled)	% H	% C	% N	% S	Viscosity, cs 100°F	API Gravity
No. 2 Fuel Oil ^(2A)	360 (10%) 640 (90%)	13.1	86.9	0.01	<0.2	2.5	34.5
No. 6 Fuel Oil ^(2A)							
High Sulfur	--	11.0	86.25	0.41	2.2	680	17.3
Low Sulfur	--	11.85	87.94	0.16	0.5	48	24.7
Light Cat. Gas Oil	465 (10%) 610 (90%)	est. 9-11%		<0.1		3	15.3
Decant Oil	720 (10%) 880 (90%)	est. 8-9.5%		<0.1		40	5.5
Carbon Black Feedstock (F.S. 120)	--	est. 8%		<0.1		No. 5 H Range	<2
Shale Oil by In Situ Retorting	400-900	11-13		1.5- 2.0	0.3- 0.8	10-40	20-30
SRC-II Fuel Oil							
Middle Distillate (MD)	350 (0%) 550 (100%)	9.1	86	0.9-1.1	<0.2	3.1-3.4	13.8
Heavy Distillate (HD)	550 (0%) 930 (100%)	7.5	89	1.2-1.4	.37- .47	50-90	1
Anthracene Oil Reilly Tar & Chem. Co.	est. heavy distillate range	6		1.0		30	1

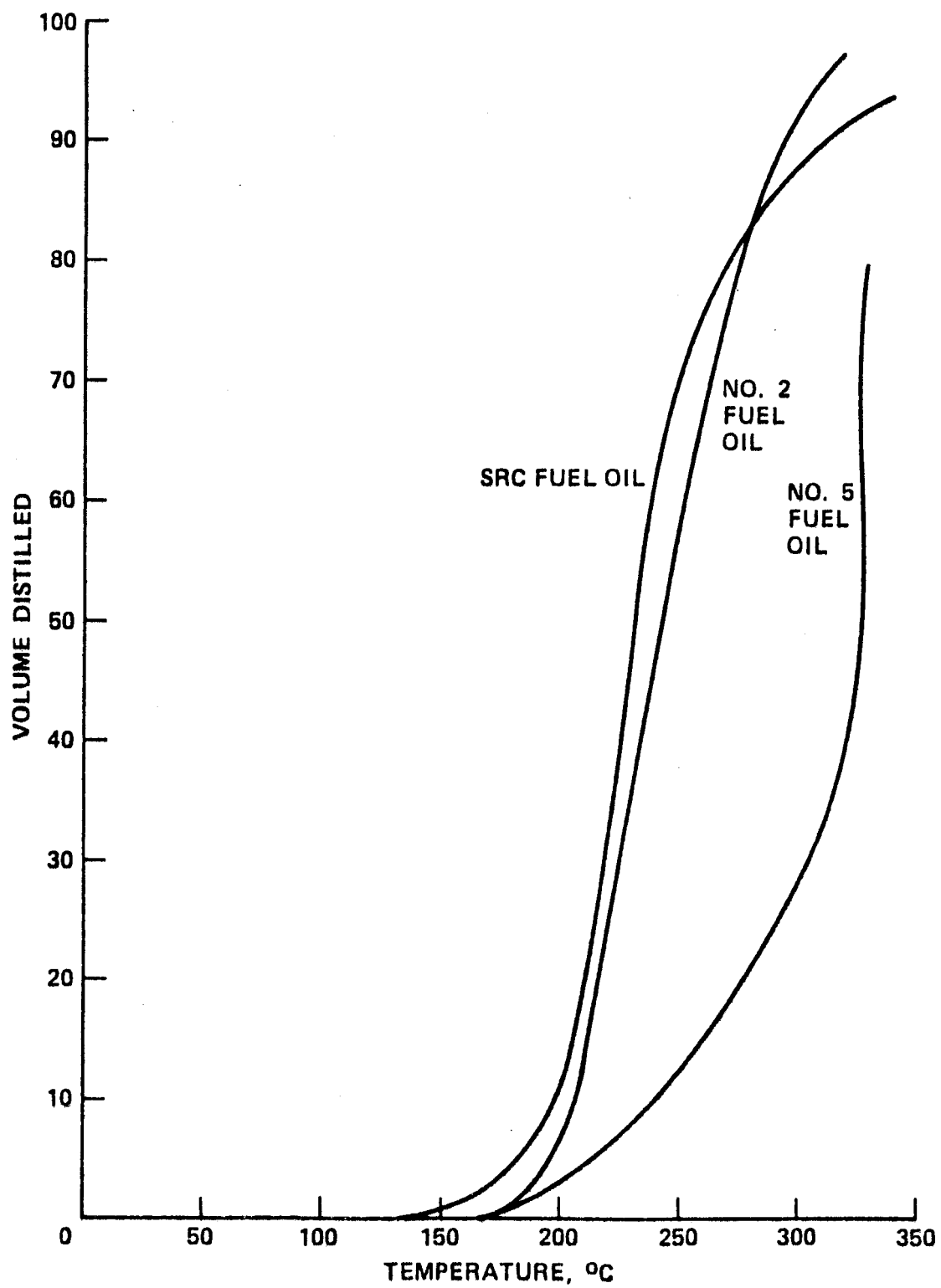


Figure A.3-3a. ATMOSPHERIC DISTILLATION CURVES
OF SRC-II FUEL OIL AND PETROLEUM OILS (FROM REF. A.2-8)

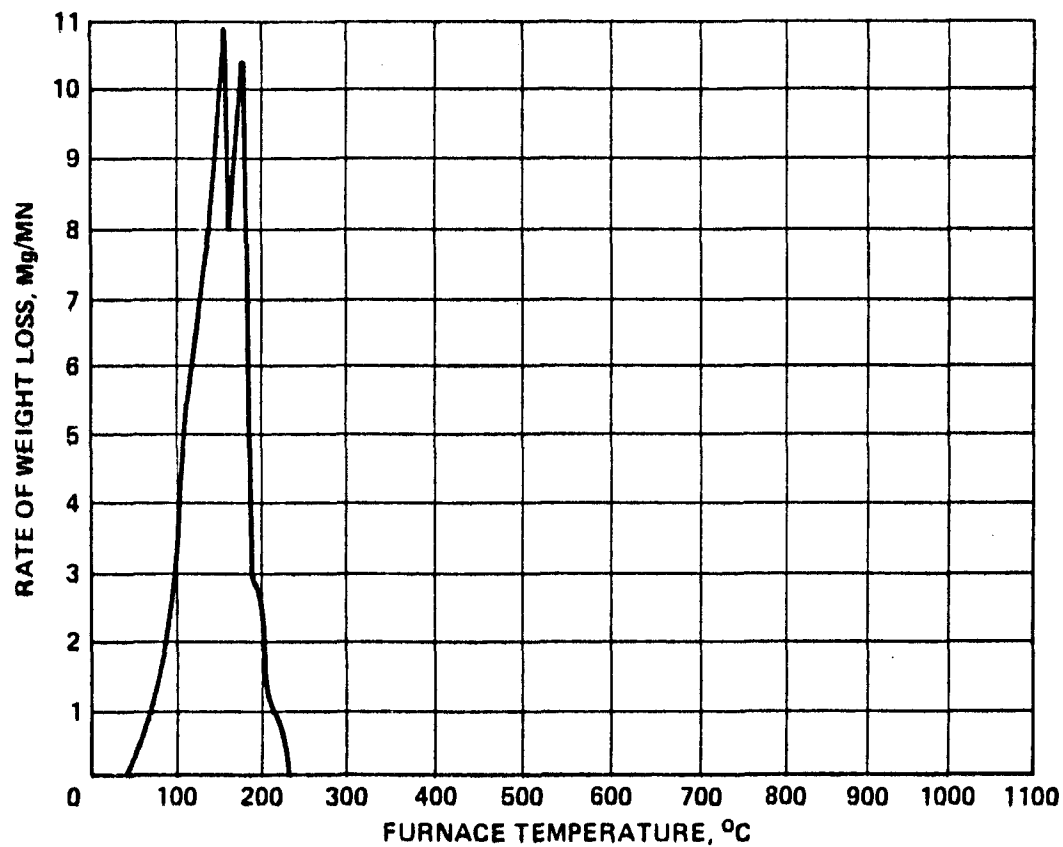


Figure A 2-3b BURNING PROFILE FOR SRC II FUEL OIL (FROM REF. A.2-2)

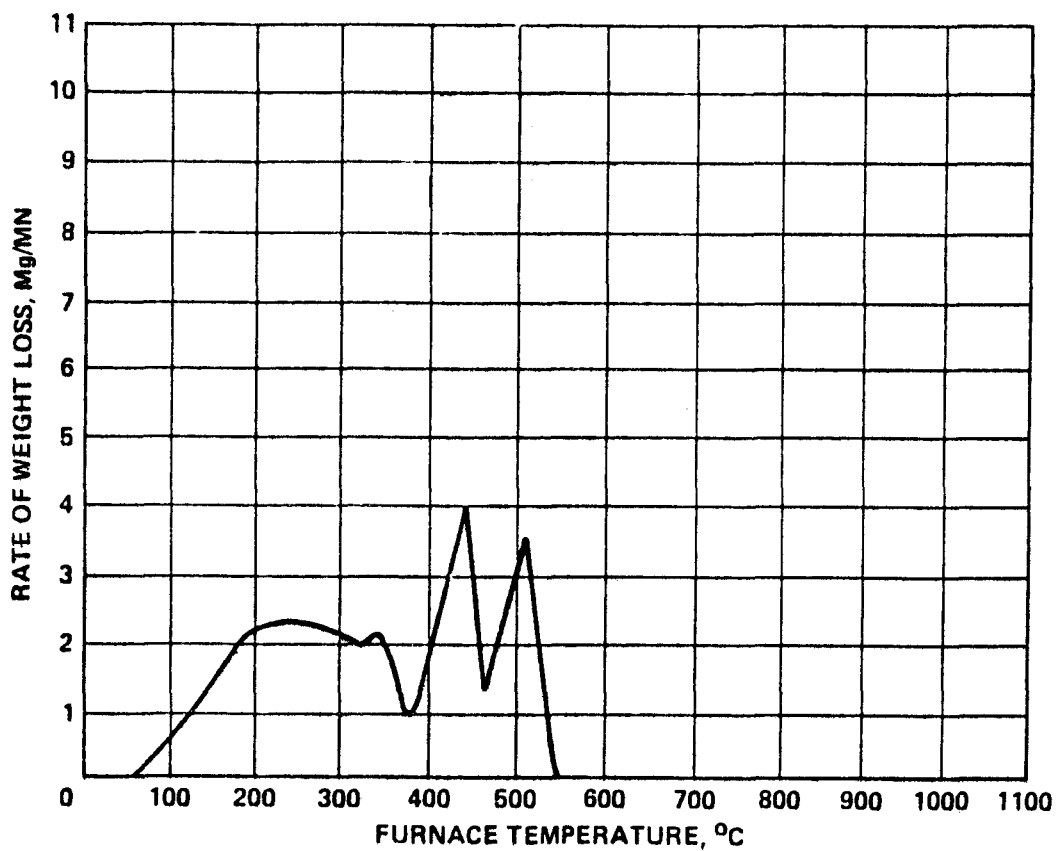


Figure A.2 -3C BURNING PROFILE FOR NO. 5 FUEL OIL (FROM REF. A2-8)

TABLE A.2-2 PROPERTY RANGES OF RESIDUAL FUEL OILS (FROM REF. A.2-4)

	Midwest No. 6	East Coast		Gulf Coast		West Coast No. 6	Caribbean No. 6	African No. 6
		No. 5	No. 6	No. 6	No. 6-1% S			
Gravity: °API	3.6	9.1	15.1	13.7	16.4	12.4	14.7	21.3
Density: lb./U.S. Gal. at 60°F.	8.723	8.382	8.038	8.116	7.967	8.189	8.060	7.712
Viscosity, SUV: Sec.								
100°F.	186.3	200	2505	4794	8606	5558	4517	1570
130	86.2	97.1	818	1462	1406	1462	1261	-
210	40.5	43.5	122.0	193.3	166.5	175.2	161.0	-
Viscosity, Furol: Sec.								
122°F.	-	-	109.4	198.7	200	200	169.9	72.9
Flash, P-M: °F.	225	205	220	210	190	154	220	240
Flash, OC: °F.	335	295	300	320	320	290	305	-
Fire, OC: °F.	400	335	360	395	345	335	340	-
Pour Point: °F.								
Maximum	+40	+10	+45	+25	+65	+45	+20	+55
Minimum	+35	+5	+40	+20	+40	+35	+15	-
Sulfur: % by Wt.	1.46	0.81	0.78	2.05	0.85	1.73	2.18	0.48
Water by Dist'n., ASTM D95	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	0.1	-
Water and Sediment: % by Vol.	< 0.05	< 0.05	< 0.05	0.10	0.10	0.10	0.05	0.10
Sediment, ASTM D473: % by Wt.	0.04	0.02	0.02	0.01	0.02	0.01	0.01	0.02
Carbon Residue, Con.: % by Wt.	3.29	4.24	8.05	11.4	7.50	11.2	10.9	7.2
Carbon-Hydrogen Ratio	11.0	9.6	7.8	8.0	7.6	8.1	7.6	-
Nitrogen: % by Wt.	-	-	0.33	-	-	0.92	0.44	0.31
Ash, ASTM D482: % by Wt.	0.04	0.01	0.02	0.03	0.01	0.03	0.05	0.01
Fusion Point, 1000°F., Ash: °F.	> 1500	> 1500	> 1500	> 1500	> 1500	> 1500	1196	-
Spectrographic Analysis: PPM								
Aluminum	80	15	15	5	6	2	8	7
Barium	-	0.6	-	8	1	0.4	-	-
Boron	-	-	-	-	0.02	-	-	-
Calcium	2	2	10	40	4	0.8	6	10
Chromium	0.06	0.2	0.5	0.8	0.09	0.2	0.2	0.4
Cobalt	-	1	3	1	2	3	-	-
Copper	0.06	0.03	0.07	0.1	0.04	0.07	0.01	0.1
Iron	10	4	7	20	10	40	3	3
Lead	-	0.5	-	50	1	-	-	2
Magnesium	4	2	10	15	1	0.2	2	20
Manganese	0.5	0.3	0.7	0.5	0.2	0.5	-	0.5
Molybdenum	-	-	0.2	0.3	-	0.2	0.7	0.6
Nickel	1.3	5.7	25	18	9.3	102	58	42
Potassium	0.7	0.3	0.4	0.4	0.03	0.2	0.3	3
Silicon	100	10	10	5	6	3	2	3
Silver	-	-	0.01	-	-	0.01	0.04	0.01
Sodium	7	4	6	6	8	0.9	15	50
Strontium	0.5	0.2	0.6	0.7	0.4	0.2	0.9	0.9
Tin	-	0.6	4	-	-	-	-	5
Titanium	3	0.4	0.8	0.3	0.2	0.7	2	0.5
Vanadium, GRM 803	1.0	2.4	20	20	5.2	60	179	16
Zinc	-	-	-	10	-	-	-	-
Heat of Combustion, Calculated								
BTU/Lb. Gross	17,944	18,358	18,858	18,400	18,713	18,243	18,406	19,006
BTU/Gal. Gross	156,526	153,877	151,580	149,334	149,016	149,392	148,352	146,571

TABLE A.2-3
NITROGEN CONTENTS OF VARIOUS DISTILLATION
FRACTIONS OF SRC-II FUEL OIL* AND PETROLEUM OILS

<u>SRC-II FUEL OIL</u>		
<u>%w over</u>	<u>Dist. temp. °F</u>	<u>%w N</u>
Initial B.P.	212	----
10 %	424	0.88
20 %	436	----
30 %	448	0.91
40 %	458	----
50 %	474	0.96
60 %	492	----
70 %	530	1.06
80 %	590	----
90 %	722	1.11
 <u>CRUDE OIL FRACTIONS</u>		
	<u>Boiling Range °F</u>	<u>%w N</u>
Heavy Naphtha	310-375	0.0007
Light No. 2 Fuel Oil	375-520	0.00080
Heavy No. 2 Fuel Oil	520-680	0.0193
Gas Oil	680-870	0.13
Vacuum Residue	860+	0.73
Vacuum Residue	1000+	0.94

*From Reference A.2-7.

compounds in petroleum are concentrated in the highest boiling range; see the data in Table A.2-3, taken from an assay of a commercially important crude oil.

The detailed compound-type compositional analysis of coal liquids has been carried out very extensively by Gulf, other fuel producers, and universities. This information is valuable in process development work, but also offers interpretations about the fuels' combustion behavior. Although it is outside the scope of this report to review⁽⁵⁾ this work or to explore the detailed composition-combustion behavior relation, a few examples of its importance follow.

Because of the similarity between some of the properties of coal liquids and those of cycle oils or decant oils, the latter have been studied as potential surrogates for coal liquids whose supplies have been scarce. Blends of petroleum components were prepared to give the same elemental and physical properties as various coal liquids, and comparative tests in gas turbine combustors were run.⁽¹⁾ The results were initially promising, and the fuel-derived NO_x and smoke from the surrogates resembled those from the respective coal liquids. However, further work has revealed occasional but unpredictable anomalies.⁽⁶⁾ Thus, two oils having the same elemental and physical properties (distillation range, viscosity, etc.) will not necessarily exhibit the same combustion behavior if they were derived from different materials, e.g., coal and petroleum, and thus had possibly different detailed molecular compositions.⁽⁷⁾ Nevertheless, if two coal liquids from different processes, e.g., SRC-II and EDS, have the same elemental and physical properties, they will have very similar molecular composition and thus similar combustion behavior.

In a DOE-NASA-Lewis combustor development project, to be described in another report, it was suggested that coal liquids, if unavailable, be simulated by nitrogen-doping a residual oil with pyridine. Depending on the combustor concept to be tested, such a blend could exhibit combustion behavior much different from a coal liquid, because the pyridine would vaporize more quickly than the somewhat higher molecular weight nitrogen compounds in coal liquids. The nitrogen compounds in a high-nitrogen residual oil would, of

course, provide even less resemblance to those in coal liquids. Finally, the non-volatile or residual components in a residual oil resemble the non-volatile components in older type, filtered coal liquid but would not simulate a totally distillate product such as SRC-II fuel oil.

A.2 REFERENCES

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- 2a. J. E. Haebig, B. E. Davis, E. R. Dzuma, "Preliminary Small-Scale Combustion Tests of Coal Liquids," *Envir. Sci. and Technol.* 10 (3), 243 (1976).
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7. L. J. Muzio and J. K. Arand, "Combustion and Emission Evaluation of SRC-II Fuel Oil," KVB Report No. 19900-733 to Gulf Mineral Resources Co., 12/77.
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A.3 CURRENT FUEL QUALITY REQUIREMENTS AND SRC-II FUEL OIL

Having described the SRC-II process and the general characteristics of SRC-II fuel oil in comparison with other fuels, we turn to current boilers and the detailed fuel property requirements which have been developed through years of field experience. SRC-II fuel oil has been tested and examined according to these specifications, and it complied with these requirements as reported in this section, with the exceptions of its tendency to form NO_x and soot, which are analyzed later in this report. The ASTM D396 fuel oil specifications are listed in Table A.3-1.

In the SRC-II process, a fraction, the "middle distillate" (MD), is currently being separated with an upper distillation cut-point of 550°F, approximately 100° below that of typical No. 2 fuel oil. This comprises approximately 75%v of the fuel oil product from the process as currently operated. The viscosity of SRC-II middle distillate is in the No. 2 oil range. The remainder of the fuel oil range product, heavy distillate (HD), has a distillation range between 550 and 930°F, and its viscosity is in the No. 5 oil range. However, SRC-II heavy distillate is superior to No. 5 or No. 6 fuel oils (see Table A.2-2) because the latter usually contain 10-40% non-volatile residual material (hence, the absence of distillation data for No. 5 oils in Table A.2-2).

The following items are some more detailed comments about certain of the specifications under ASTM D396.

(1) Pour points of SRC-II middle distillate and heavy distillate do not exceed those of No. 2 and No. 5 fuel oils, respectively.

(2) Flash Point: The flash points of SRC-II middle distillate and heavy distillate are within the safe range for handling, but are not so great as to indicate any problem with igniting a spray of these fuels with an electric spark in boiler burner.

TABLE A.3-1 ASTM D396 SPECIFICATIONS FOR FUEL OILS (FROM REF. A.3-1)

Detailed Requirements for Fuel Oils ^a																			
Grade of Fuel Oil	Flash Point, °C (°F)	Pour Point, °C (°F)	Water and Sediment, vol %	Carbon Residue on 10 % Bottoms, %	Ash, weight %	Distillation Temperatures, °C (°F)			Saybolt Viscosity, s ^b				Kinematic Viscosity, cSt ^c				Specific Gravity 60/60°F (deg API)	Copper Strip Corrosion	Sulfur, %
						10% Point	90% Point		Universal at 38°C (100°F)		Furol at 50°C (122°F)		At 38°C (100°F)		At 50°C (122°F)				
	Min	Max	Max	Max	Max	Max	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Max	Max
No. 1 A distillate oil intended for vaporizing pot-type burners and other burners requiring this grade of fuel	38 (100)	-18 ^c (0)	0.05	0.15	...	215 (420)	...	288 (550)	...	...	...	...	1.4	2.2	...	...	0.8499 (35 min)	No. 3	0.5
No. 2 A distillate oil for general purpose heating for use in burners not requiring No. 1 fuel oil	38 (100)	-6 ^c (20)	0.05	0.35	...	...	282 ^c (540)	338 (640)	(32.6)	(37.9)	...	...	2.0 ^c	3.6	...	...	0.8762 (30 min)	No. 3	0.5 ^d
No. 4 Preheating not usually required for handling or burning	55 (130)	-6 ^c (20)	0.50	...	0.10	...	...	...	(45)	(125)	...	...	5.8	26.4 ^e	...	...	...	...	...
No. 5 (Light) Preheating may be required depending on climate and equipment	55 (130)	...	1.00	...	0.10	...	...	...	(>125)	(300)	...	...	>26.4	65 ^e	...	...	...	...	...
No. 5 (Heavy) Preheating may be required for burning and, in cold climates, may be required for handling	55 (130)	...	1.00	...	0.10	...	...	...	(>300)	(900)	(23)	(40)	>65	194 ^e	(42)	(81)	...	...	...
No. 6 Preheating required for burning and handling	60 (140)	^a	2.00 ^f	...	...	...	...	...	(>900)	(9000)	(>45)	(300)	...	...	>92	638 ^e	...	...	...

^a It is the intent of these classifications that failure to meet any requirement of a given grade does not automatically place an oil in the next lower grade unless in fact it meets all requirements of the lower grade.

^b In countries outside the United States other sulfur limits may apply.

^c Lower or higher pour points may be specified whenever required by conditions of storage or use. When pour point less than -18°C (0°F) is specified, the minimum viscosity for Grade No. 2 shall be 1.8 cSt (32.0 SUS) and the minimum 90 % point shall be waived.

^d Viscosity values in parentheses are for information only and not necessarily limiting.

^e The amount of water by distillation plus the sediment by extraction shall not exceed 2.00 %. The amount of sediment by extraction shall not exceed 0.50 %. A deduction in quantity shall be made for all water and sediment in excess of 1.0 %.

^f Where low sulfur fuel oil is required, fuel oil falling in the viscosity range of a lower numbered grade down to and including No. 4 may be supplied by agreement between purchaser and supplier. The viscosity range of the initial shipment shall be identified and advance notice shall be required when changing from one viscosity range to another. This notice shall be in sufficient time to permit the user to make the necessary adjustments.

^g Where low sulfur fuel oil is required, Grade 6 fuel oil will be classified as low pour +15°C (60°F) max or high pour (no max). Low pour fuel oil should be used unless all tanks and lines are heated.

(3) Heat of Combustion, Gross: Although the heating value of SRC-II fuel oil per pound is 200 Btu's less than typical No. 2 oil because of its lower hydrogen content, its higher density makes its heating value per unit volume the same as that of No. 2 oil.

(4) Fuels Compatibility: SRC-II middle distillate is more aromatic than No. 2 oil, but is a better solvent than No. 2 oil for the high molecular weight components of residual oils which sometimes are precipitated by the addition of No. 2 oil to a tank previously containing the residual oil. SRC-II heavy distillate contains some less-soluble high molecular weight compounds ("asphaltenes" in Table A.2-2) which might precipitate upon admixture of heavy distillate with a low-aromatics petroleum fuel oil. ASTM spot tests should be used to identify this possibility.

(5) Compatibility with Materials of Construction: There are materials presently in use (some elastomers, for example) which might be attacked by the aromatic nature of SRC-II fuel oil, but resistant alternative materials are available. Data on the subject are currently being obtained.

(6) Carbon Residue: Good nozzle design and spray patterns, which prevent recirculation and spray impingement, normally prevent carbon deposition. Nozzle purging on shutdown may also be recommended.

(7) Gravity, Aromatics and Hydrogen Content: The specific gravities of SRC-II middle distillate and heavy distillate are much higher than the maximum typical for No. 2 or No. 5 oils. (A maximum specific gravity specification for No. 2 oil assures a minimum hydrogen content.) We have described the unusually low hydrogen content and high aromatics content of SRC-II fuel oil and the implied problem of soot emissions and radiative heat transfer, and will analyze these problems later in this report; several potential solutions are identified.

(8) Nitrogen: The high nitrogen content of SRC-II fuel oil, described in Section A.1, implies excessive NO_x emissions. The analysis in the rest of this report describes solutions to this problem. Some solutions

involve the SRC-II process, but the most economical and effective solutions appear to be in combustion modification or possibly flue gas NO_x removal.

(9) Ash and Trace Metal Contaminants: The ash level in SRC-II middle distillate is well below the No. 2 limit, but the heavy distillate ash was excessive in the sample analyzed. Gulf has realized the importance of the trace metals content of SRC-II, and has recently been closely monitoring this property. The heavy distillate fraction was found to be susceptible to metal contamination through occasional physical carryover of solid or liquids particles in the distillation equipment at the Ft. Lewis pilot plant. Continually improved operations have now brought the ash content of the heavy distillate well below 100 ppm. Even lower levels of ash and trace metals have been achieved in the pilot plant at the GS&T laboratories. There is no evidence for distillable organometallic compounds, and further reduction in metals contents of SRC-II middle distillate and heavy distillate are anticipated.

A.3 REFERENCES

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B. TYPES OF BOILER DESIGNS

Here we provide examples of some of the main types of boiler designs, sufficient to clarify how designs affect SRC-II fuel oil combustion results. Figure B-1 is a side view of a wall-fired utility boiler, showing the flames from the lower and upper rows of six burners, and the gas flow directions through the water-tube lined furnace and heat exchanger sections.⁽¹⁾ A tangential or corner-fired utility boiler has the same rectangular furnace shape, but the eight burners are mounted in the corners of the furnace and are aimed at an angle, tangential to an imaginary circle at the center of the boiler, so as to give the flame angular momentum about the vertical axis, resulting in the circular gas path shown in Figure B-2.

Industrial-size boilers, smaller than 25 MW or 250×10^6 Btu/hr heat input, have a wider variety of designs. Figure B-3 shows a 45 000 lb steam/hr (45×10^6 Btu/hr) FM watertube boiler, having one burner, and a diagram of the flame direction and flow path.⁽³⁾ Finally, Figure B-4 shows a smaller firetube boiler; the flame from the burner, in the lower portion of the boiler, is surrounded by a water-wall creating a long narrow combustion chamber.⁽⁴⁾

B. REFERENCES

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2. Electric Power Research Institute Final Report FP-1029, Projects 1235-5 and 1412-2, May 1979, "Combustion Demonstration of SRC-II Fuel Oil in a Tangentially Fired Boiler," prepared by KVB Incorporated.
3. B&W, "Characterization and Combustion of SRC-II Fuel Oil," Babcock & Wilcox Company, March 1979, Report No. FP-1028 to EPRI.
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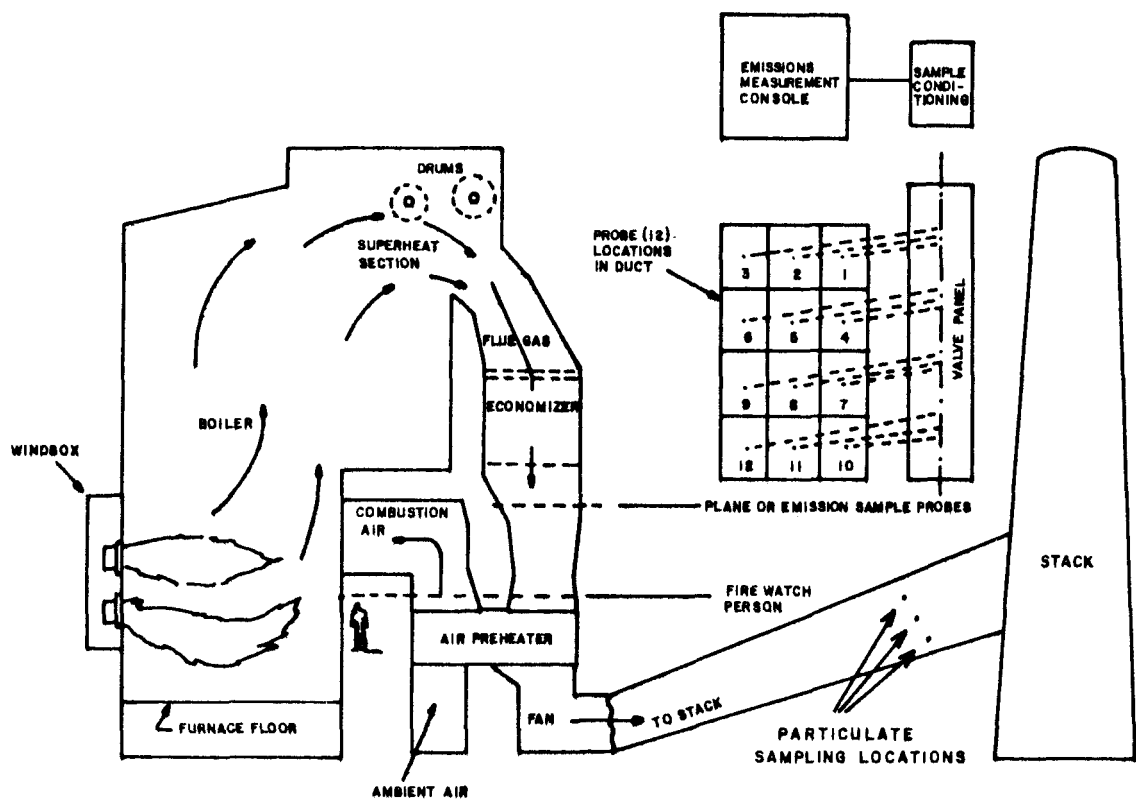


Figure B-1 WALL-FIRED UTILITY BOILER, SIDE VIEW (FROM REF. B-1)

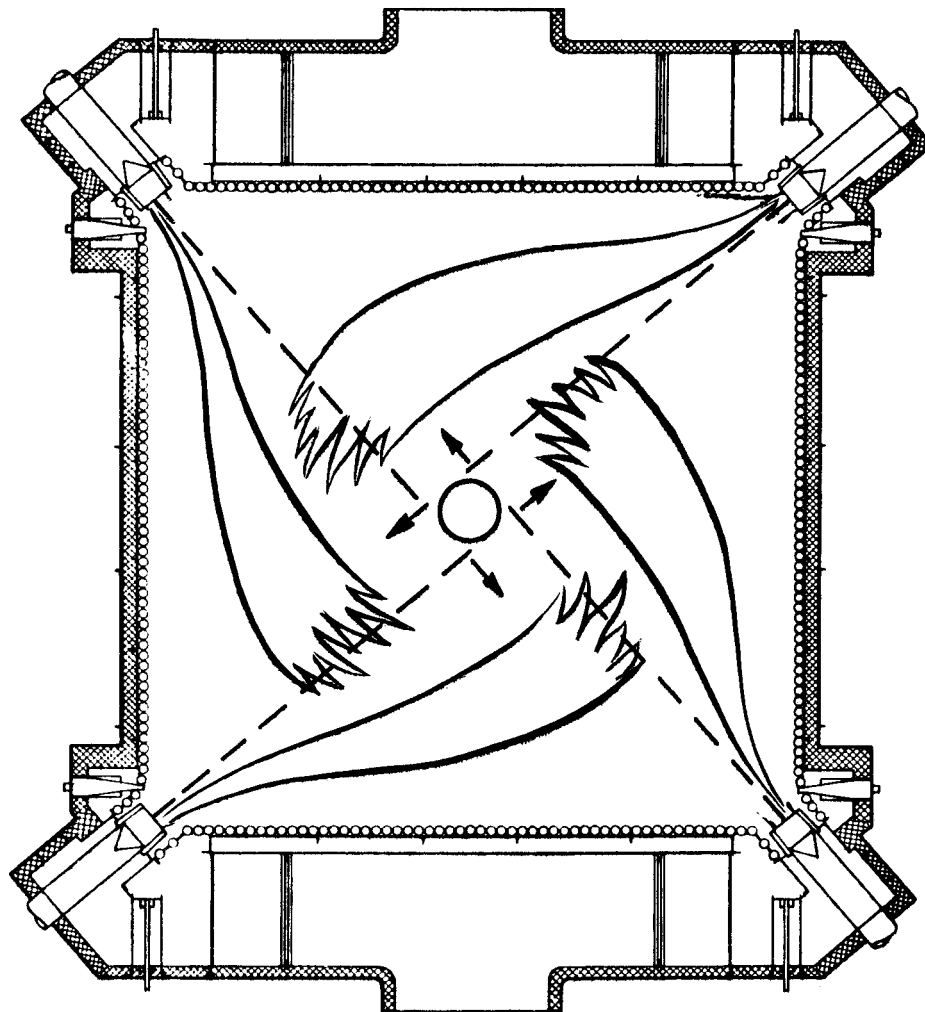


**Figure B-2 CORNER-FIRED UTILITY BOILER (TOP VIEW)
AND CIRCULAR FLAME PATHS (FROM REF. B-2)**

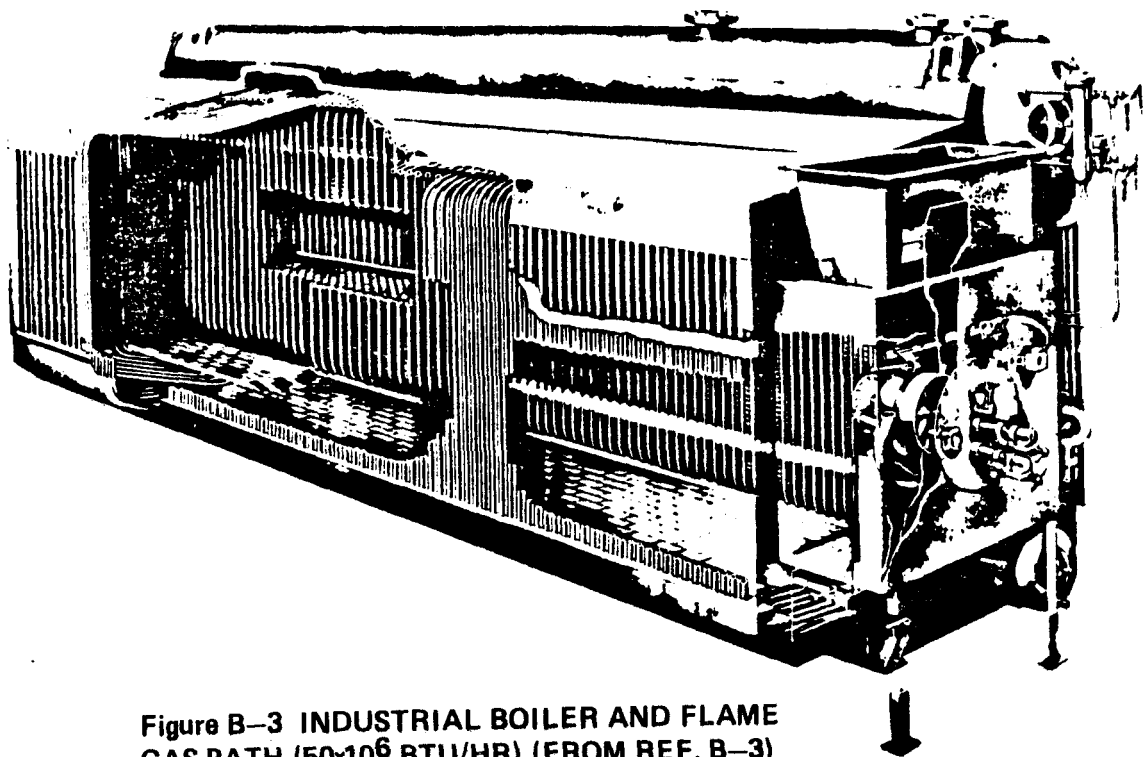
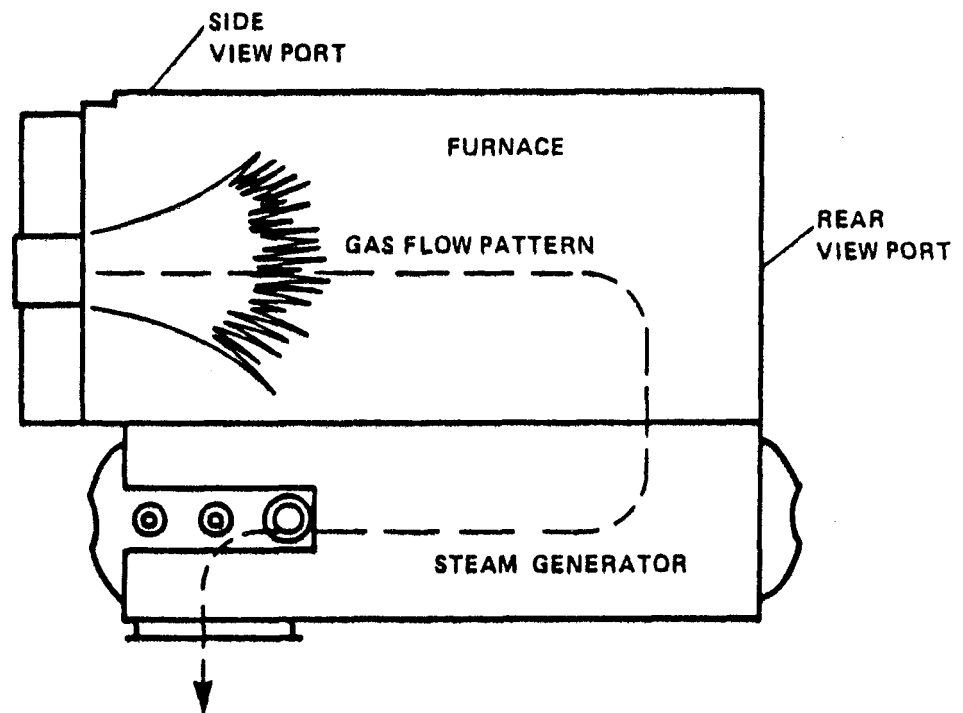


Figure B-3 INDUSTRIAL BOILER AND FLAME
GAS PATH (50×10^6 BTU/HR) (FROM REF. B-3)

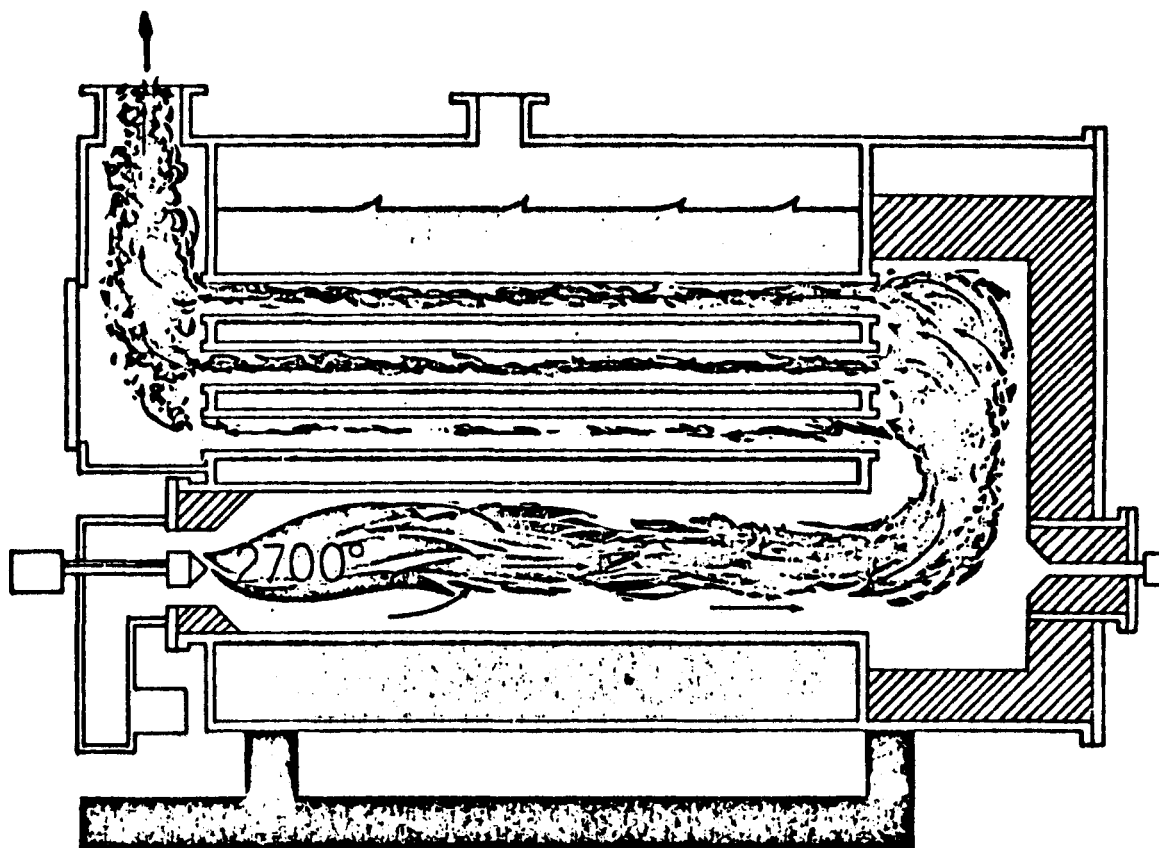


Figure B-4 FIRETUBE BOILER COMBUSTION CHAMBER (FROM REF. B-4)

C. EMISSIONS SUPPRESSION FROM CONVENTIONAL FUEL OILS

Having found that the only problems in burning SRC-II fuel oil in boilers were fuel-derived NO_x and soot emissions, we reviewed the experience acquired by boiler operators in cleanly burning nitrogenous residual oils. In empirically testing boiler operating conditions, a number of combustion modifications have been developed; however, most of these combustion modifications address the suppression of air-derived NO_x formed from oxidation of nitrogen in the combustion air. These are the methods listed in Table C-1 which decrease the flame temperature;⁽¹⁾ the chemistry behind this is described in Appendix A, as is the chemical interpretation of the fuel- NO_x suppression methods and of soot formation and burnout. The combustion modifications which suppress NO_x from oxidation of fuel nitrogen do so by excluding excessive oxygen from the early part of the flame. These methods are delayed mixing of fuel and air and primary fuel-rich flame zone, listed in Table C-1, generally termed "staged combustion."

Figure C-1 contains a good demonstration of the effectiveness of staged combustion.⁽²⁾ This experiment was conducted early in the development of this technique, in a 50-hp boiler firing 20 gph of fuel oil containing 0.25% nitrogen. Figure C-2 shows the boiler combustion chamber, in which the first stage was made fuel rich by feeding sub-stoichiometric air to the burner at its end. The rest of the combustion air was delivered through the long tube entering the rear of the boiler and was injected as the flame gases entered the second stage. In Figure C-1, 1.15 actual/stoichiometric air entering the burner ($\phi_a=1.15$) produces 410 ppm NO_x ; reducing the excess air suppresses the NO_x to some degree, but sub-stoichiometric air (ϕ_a less than one) is even more effective. This experiment also showed that cooling between stages reduced the NO_x . Other effects of operating conditions found by various workers were the following: (1) the fraction of the fuel nitrogen which was converted to NO_x (the fuel- NO_x yield) decreased from 80 to 100% at low fuel nitrogen levels to 20-40% at high nitrogen levels (e.g., 1%N), and (2) the fuel- NO_x yield decreased with increasing residence time and higher temperature in the first stage.

TABLE C-1 COMBUSTION MODIFICATION METHODS TO SUPPRESS NO_x (FROM REF. C-1)

Combustion Conditions	Control Concept	Applicable Equipment	Effect on Thermal NO _x	Effect on Fuel NO _x	Primary Applicable Controls		
					Operational Adjustments	Hardware Modification	Major Redesign
Decrease primary flame zone O ₂ level	Decrease overall O ₂ level	Boilers, furnaces	Reduces O ₂ -rich, high-NO _x pockets in the flame	Reduces exposure of fuel nitrogen intermediaries to O ₂	Low excess air firing	Flue gas recirculation (FGR)	
	Delayed mixing of fuel and air	Boiler, furnaces	Flame cooling and dilution during delayed mix reduces peak temp.	Volatile fuel N reduces to N ₂ in the absence of oxygen	Burner adjustments	Low NO _x burners	Optimum burner/firebox design
	Increased fuel/air mixing	Gas turbines	Reduces local hot stoichiometric regions in overall fuel lean combustion	Increases			New can design; premix, prevap.
	Primary fuel-rich flame zone	Boilers, furnaces, IC	Flame cooling in low-O ₂ , low-temp. primary zone reduces peak temp.	Volatile fuel N reduces to N ₂ in the absence of oxygen	Burners out of service; biased burner firing	Overfire air ports, stratified charge	Burner/firebox design for two-stage combustion
Decrease peak flame temperature	Decrease adiabatic flame temperature	Boilers, furnaces, IC, gas turbines	Direct suppression of thermal NO _x mechanism	Ineffective	Reduced air preheat	Water injection, FGR	
	Decrease combustion intensity	Boilers, furnaces	Increased flame zone cooling yields lower peak temp.	Minor direct effect; indirect effect on mixing	Load reduction		Enlarged firebox increased burner spacing
	Increased flame zone cooling/reduce residence time	Boilers, furnaces	Increased flame zone cooling yields lower peak temp.	Ineffective			Redesign heat transfer surfaces, firebox aerodynamics
Chemically reduce NO _x in post-flame region	Inject reducing agent	Boilers, furnaces				Ammonia injection possible on some units	Redesign convective section for NH ₃ injection

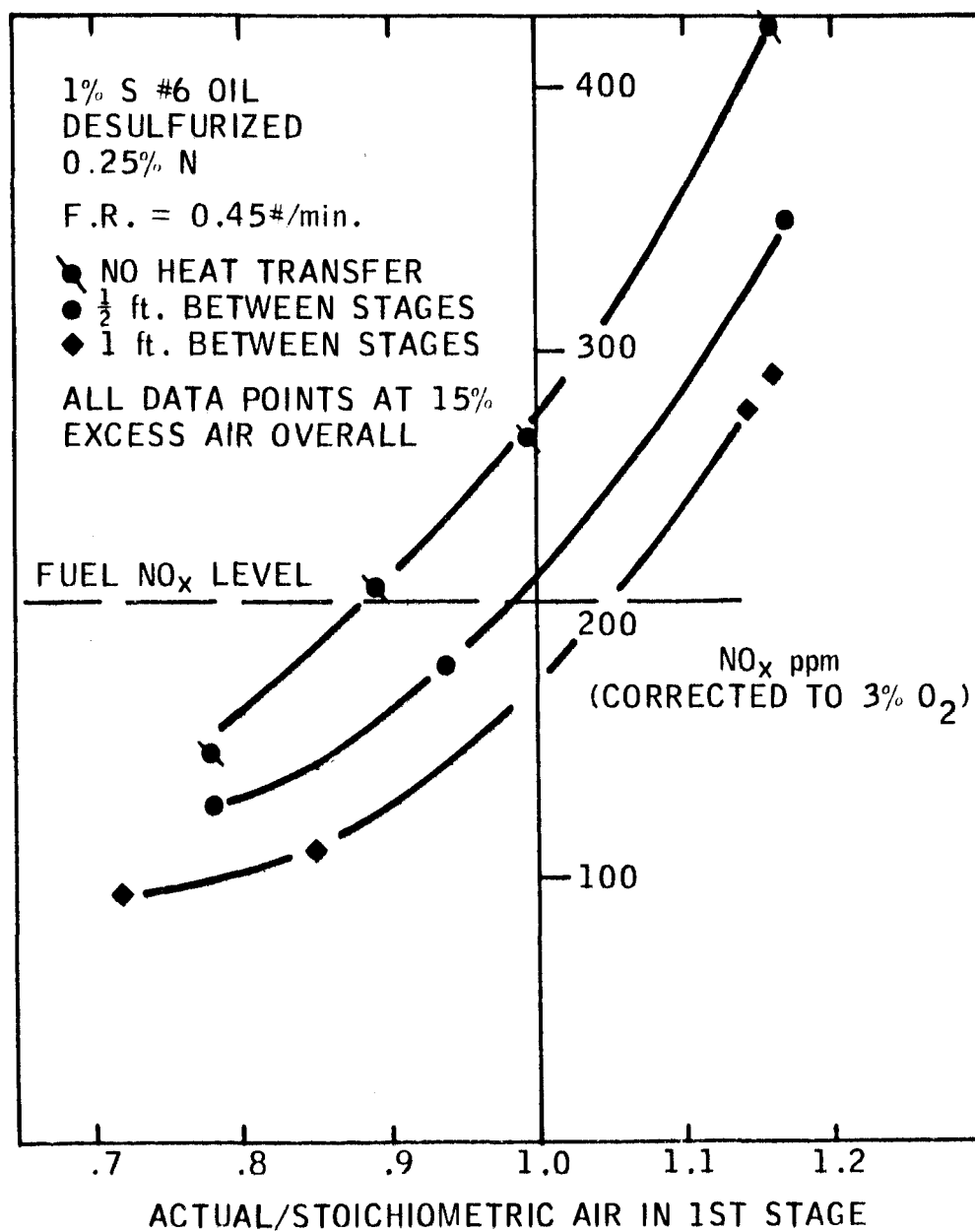


Figure C-1 STAGED COMBUSTION IN SMALL BOILER:
FUEL - NO_x SUPPRESSION (FROM REF. C-2)

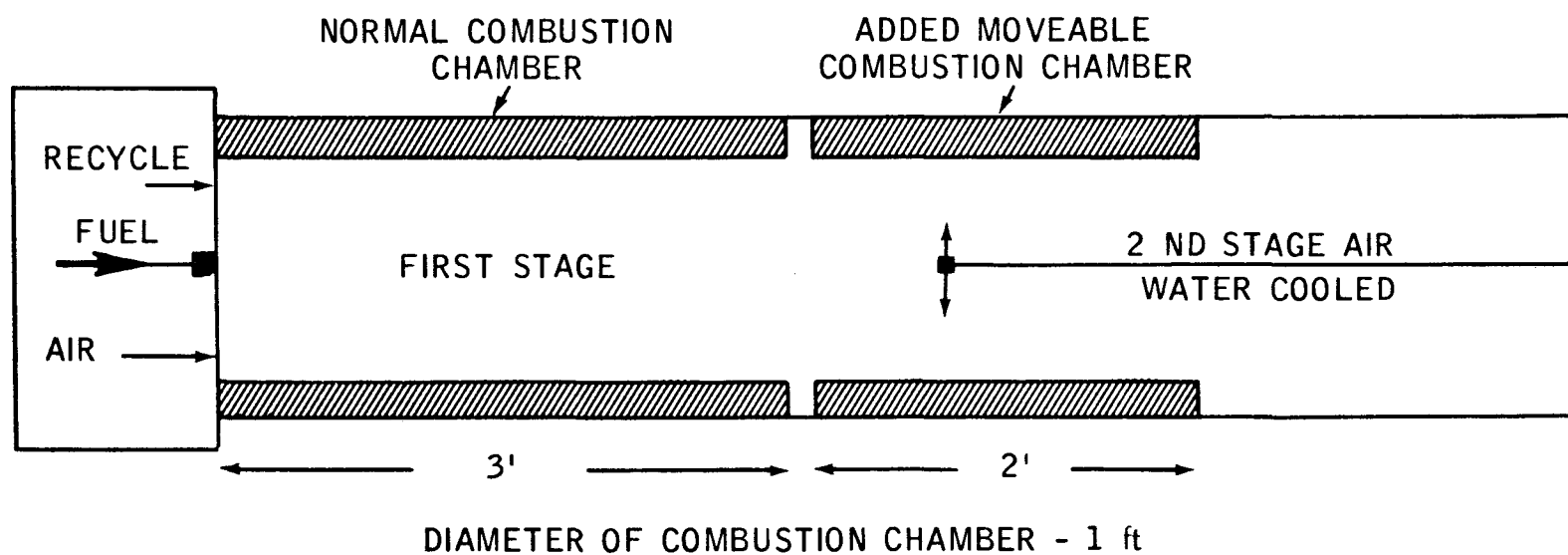


Figure C-2 COMBUSTION CHAMBER DESIGN FOR TWO STAGE OPERATION (FROM REF. 2)

The implementation of staged combustion in commercial utility boilers has proceeded quite far. EPA has sponsored field tests, many by Exxon Government Laboratories, of combustion modifications in at least 20 utility boilers representing various designs, reported in the EPA Stationary Source Combustion Symposia. An example of these efforts is the following, a test of a boiler built for firing coal, but converted to oil firing. Such boilers have longer furnace residence times than boilers designed for oil firing, and may burn out more of the copious smoke formed in the fuel-rich first stage of staged combustion, a problem which will be accentuated in coal liquids firing. These trials used six units of the Atlantic City Electric Company, which are listed in Table C-2 from Reference C-3. The summary of the results in Table C-3 shows that boilers No. 8 and 9 at the Deepwater Station gave the greatest NO_x reduction under "low-NO_x" (staged) firing conditions. Furthermore, Boiler No. 9 (Figure C-3) responds better than Boiler No. 8 (Figure C-4), judging from the figures.

Exxon's reports are an example of the details which affect such field implementations. Each boiler has many individual characteristics which could strongly affect the outcome of a "clean" combustion installation. For example, Boiler No. 8 had low fan capacity which limited the extent of the staging. Another interesting detail is the observation of decreased superheat temperature during staged combustion. This was probably due to increased radiative heat transfer from the first stage soot to the furnace water-walls, a process which may be even more dominant in coal liquid combustion. This process did not reduce the boiler operability, but did reduce its efficiency, which would require a permanent remedy of the installation of additional superheater surface. Staging caused a slight but not excessive increase in smoke.

The application of combustion modification techniques, including staged combustion, has been adopted by many utilities; approximately one hundred of them have received engineering services for this purpose from KVB, Inc. and similar firms. Further information about operations in various types of boiler designs is found in References C-1 and C-4.

TABLE C-2 BOILERS USED IN SOME NO_x-REDUCTION
TESTS AT ATLANTIC CITY ELECTRIC (FROM REF. C-3)

ATLANTIC CITY ELECTRIC COMPANY
SUMMARY OF COAL-TO-OIL CONVERTED BOILERS TESTED

<u>Station</u>	<u>Blr No.</u>	<u>Blr Mfr.</u>	<u>Type of Firing</u>	<u>MCR (MW)</u>	<u>No. of Burners</u>	<u>Test Variables</u>	<u>No. of Test Runs</u>
Deepwater	3	B&W	FW	57	6	5	8
Deepwater	5	B&W	FW	56	6	4	4
Deepwater	8	B&W	FW	83	16	14	25
Deepwater	9	CE	FW	22.8	6	6	7
B. L. England	1	B&W	Cyc.	133	3	4	7
B. L. England	2	B&W	Cyc.	168	4	2	2

TABLE C-3 NO_x-REDUCTION ACHIEVED IN FIELD BOILER FIELD TESTS (REF. C-3)

ATLANTIC CITY ELECTRIC COMPANY

SUMMARY OF NO_x EMISSIONS
FOR COAL-TO-OIL CONVERTED BOILERS

Boiler	Operating Mode (Gross Load-MW)	% O ₂	NO _x Emissions			CO
			ppm (3% O ₂)	lb 10 ⁶ Btu	Gr/10 ⁶ Cal	ppm (3% O ₂)
Depwater No. 3	Baseline (57)	6.1	142	--	--	67
	"Low NO _x " (57)	5.0	118	--	--	81
Deepwater No. 5	Baseline (56)	4.2	221	0.29	0.52	55
	"Low NO _x " (56)	2.8	209	0.28	0.50	84
Deepwater No. 8	Baseline (83)	4.5	246	0.33	0.59	49
	"Low NO _x " (81)	4.4	123	0.16	0.29	64
Deepwater No. 9	Baseline (23)	1.8	286	0.38	0.68	44
	"Low NO _x " (21)	2.6	101	0.13	0.23	64
B. L. England No. 1	Baseline (133)	1.5	441	0.59	1.06	57
	"Low NO _x " (132)	0.5	313	0.42	0.76	1523
B. L. England No. 2	Baseline (167)	2.2	361	0.48	0.86	85
	"Low NO _x " (167)	1.6	303	0.42	0.76	231

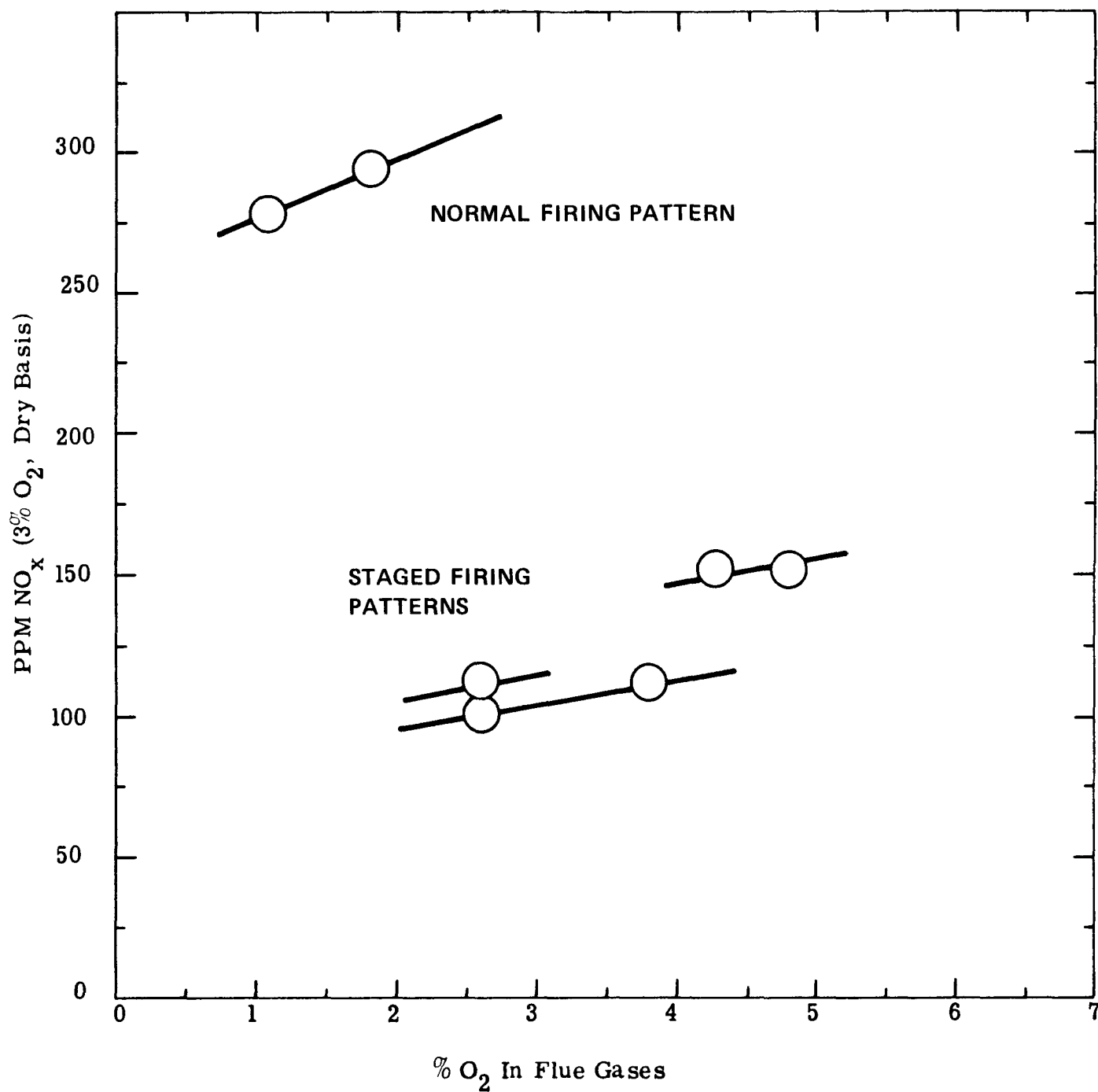


Figure C-3 BOILER NO. 9 – NO_x RESPONSE TO STAGING (FROM REF. 3)

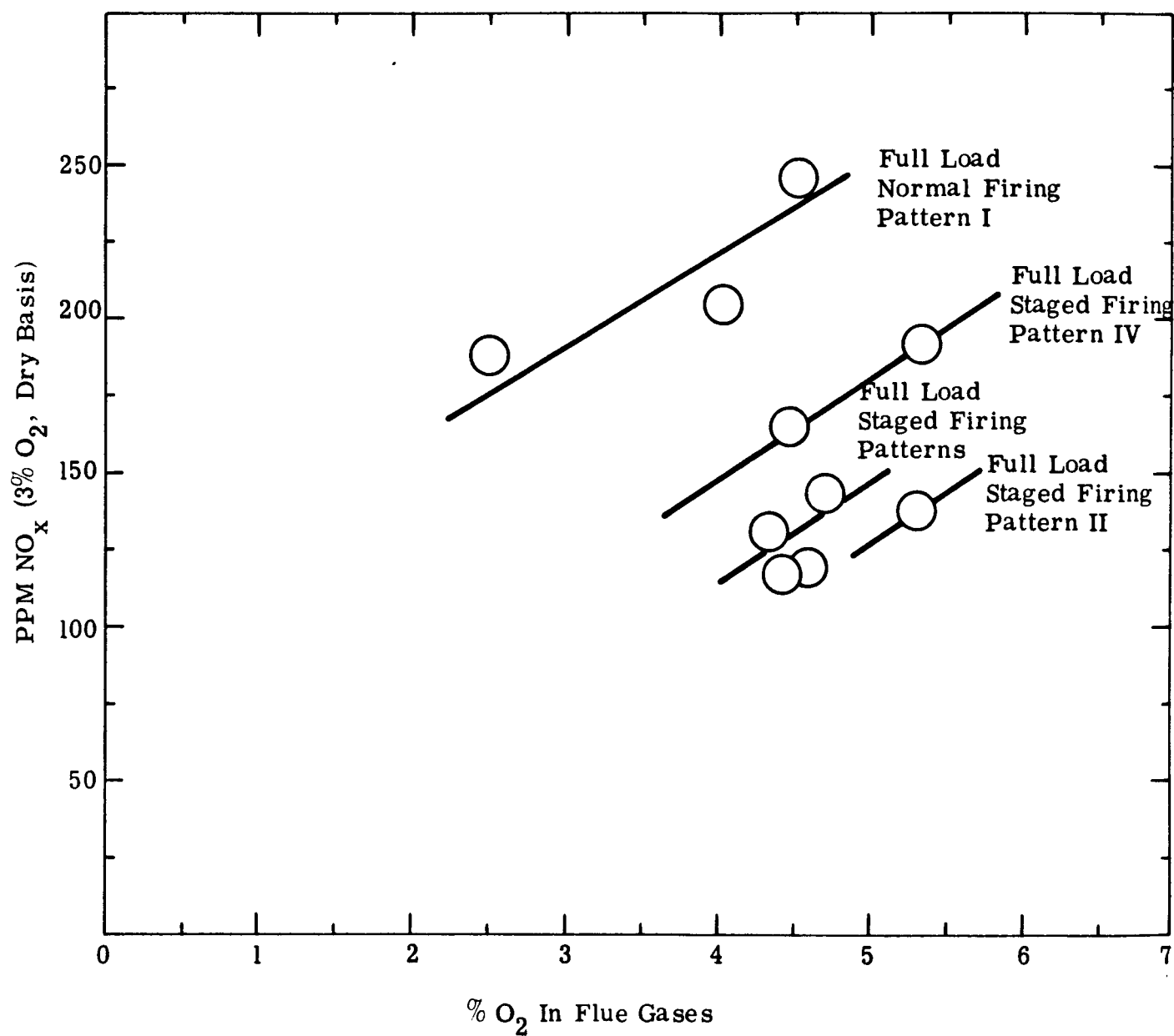


Figure C-4 BOILER NO. 8 — NO_x RESPONSE TO STAGING (FROM REF. C-3)

Another significant advance in staged combustion was made in a test of blends of shale oil (2.0% N) and low nitrogen No. 6 oil (0.2% N) in a 44 MW wall-fired boiler already shown in Figure B-1. The resulting fuel-NO_x yields are shown in Figure C-5, plotted against the ratio of increasing shale oil content along the x-axis of the figure⁽⁵⁾. In the top curve, shale oil and No. 6 oil were blended in a tank and delivered to all six burners, without staged (or off stoichiometric, O/S) combustion. The fuel-NO_x yield reached 20% at the highest shale oil content. Staged or O/S burning with tank blending reduced the fuel-NO_x yield to 17%, but "dual-fuel" firing reduces it to nearly 10%, very low for utility boilers. In "dual-fuel" firing, the shale oil was fired to the lower row of burners, and the low-nitrogen oil was fired to the upper row of burners. The high fuel nitrogen concentration in the lower burner flames accounts for this low fuel-NO_x yield.

C. REFERENCES

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2. "Staged Combustion and Flue Gas Recycle: Potential for Minimizing NO_x from Fuel Oil Combustion," prepared for presentation at the American Flame Research Committee Flame Days, Chicago, IL, September 6-7, 1972.
3. A. R. Crawford, E. H. Manny, and W. Bartok, "Field Testing: Application of Combustion Modifications to Control NO_x Emissions from Utility Boilers," EPA-650/2-74-066, June 1974.
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5. ASME Publication, Paper No. 77-WA/FU-1, "Low NO_x Combustion of Paraho Shale Oil in a 45 MW Utility Boiler," by D. G. Jones and M. N. Mansour.

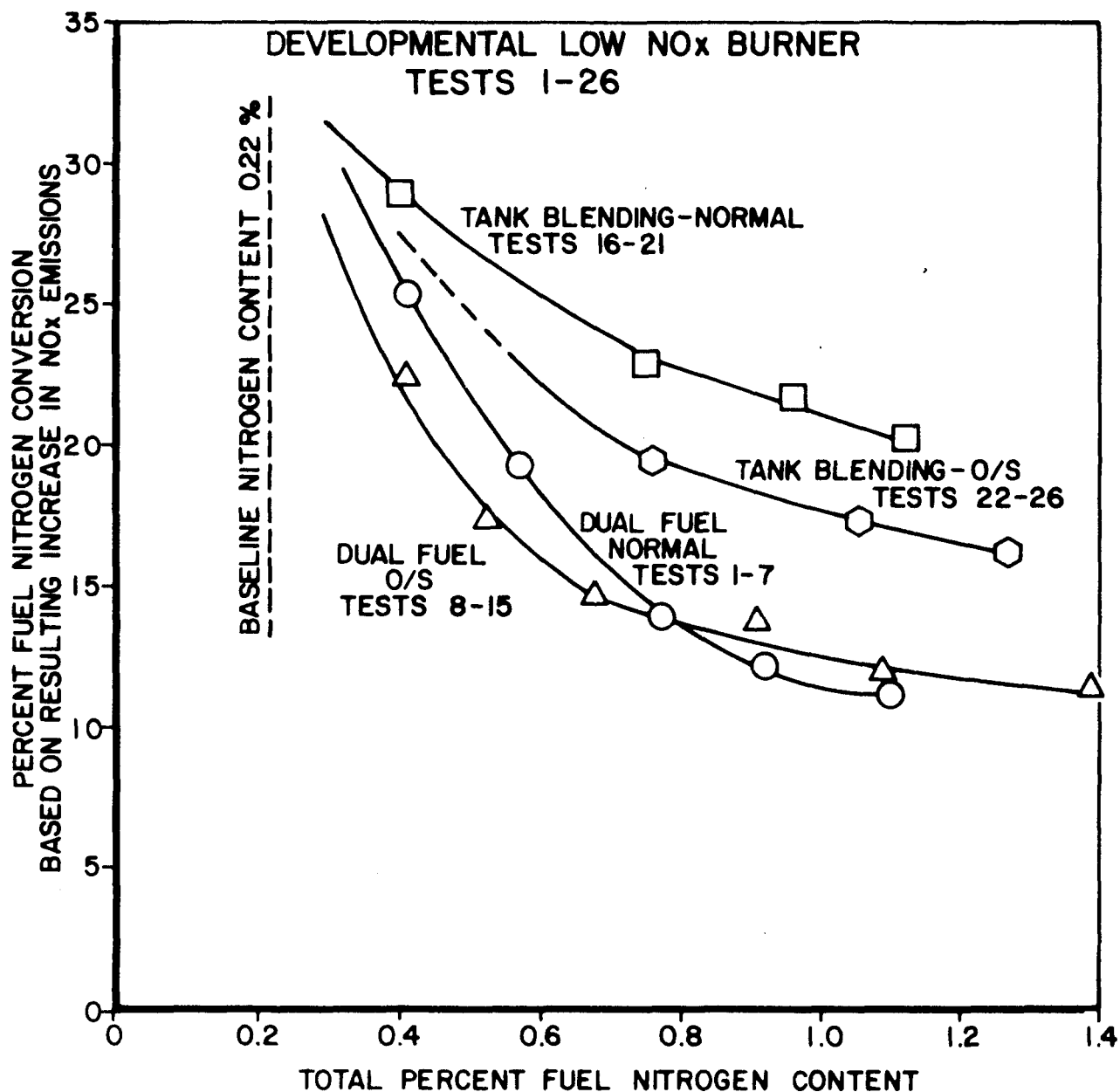


Figure C-5 FUEL — NO YIELD IN UTILITY BOILER
REDUCED BY "DUAL FUEL" FIRING WITH STAGING (FROM REF. C-5)

D. COAL LIQUIDS COMBUSTION TESTS IN BOILERS

One of the first good indications of the effectiveness of staged combustion with coal liquids was obtained in a combustion test by KVB, Inc., in a 20 gph boiler.⁽¹⁾ The introduction of air into the second stage of boiler resembled that in Figure C-2. The SRC-II fuel oil sample used contained 67% middle distillate and 33% heavy distillate; No. 6 oil and No. 2 oil were also used for reference. Figure D-1 shows the NO_x emissions from SRC-II fuel oil which decreased from 800 ppm at $\phi_a=1.4$ (40% excess air, unstaged) to 225 ppm at $\phi_a=0.80$ (staged). However, as one expects from rich conditions, soot emissions increased as ϕ_a decreased below 1.0 (see Figure D-2), and the SRC-II fuel oil made a smoke number 2 to 3 times greater than that of the No. 6 oil. There is a trade-off, for example, at $\phi_a=0.8$, where the NO_x has just decreased to 225 ppm, the NSPS standard for oil fuel, but the particulates emissions have risen to $0.2 \text{ lb}/10^6 \text{ Btu}$, twice the EPA NSPS level. Metallic anti-smoke additives were then tried, and succeeded in reducing the smoke to acceptable levels. The expectation is that in a larger boiler, the soot downstream from the flame will have a sufficient residence time to burn out, in contrast to the small KVB boiler.

A full-scale boiler test was conducted in September, 1978, in a $450 \times 10^6 \text{ Btu/hr}$ boiler at the 74th Street Station of Consolidated Edison in New York City. Figure D-3 is a side view of this boiler; Figure B-2 represents its cross section gas path. 45,000 bbl of SRC-II fuel oil (5.75:1 MD:HD ratio) were brought to the site in a barge from which delivery was made to the burners. No. 6 oil (0.2-0.3% N) was burned for reference, chosen because it would be Consolidated Edison's alternative fuel. Figure D-4 is an end-on view of one of the four corner burner arrays, showing the two oil guns, spaced approximately 4 feet apart, the air registers in which the oil guns are located (the "oil registers"), and the adjacent auxiliary registers.

KVB operated the boiler during the test and determined the firing configurations (the set of fuel and air flow rates to the various burners and registers) based on their extensive success with numerous private utility

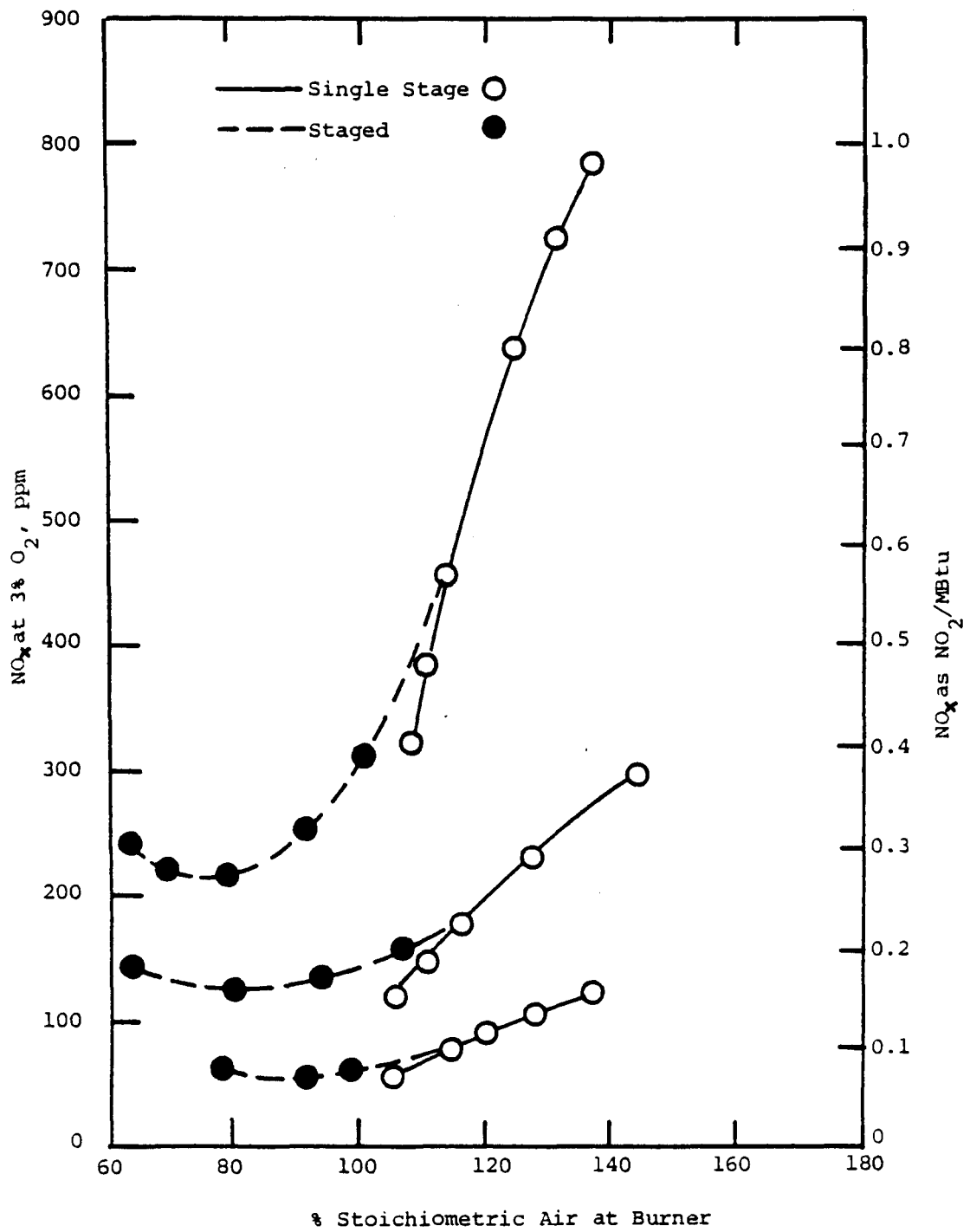


**Figure D-1 STAGED COMBUSTION IN BOILER
SUPPRESSES FUEL-NO_x(FROM REF. D-1)**

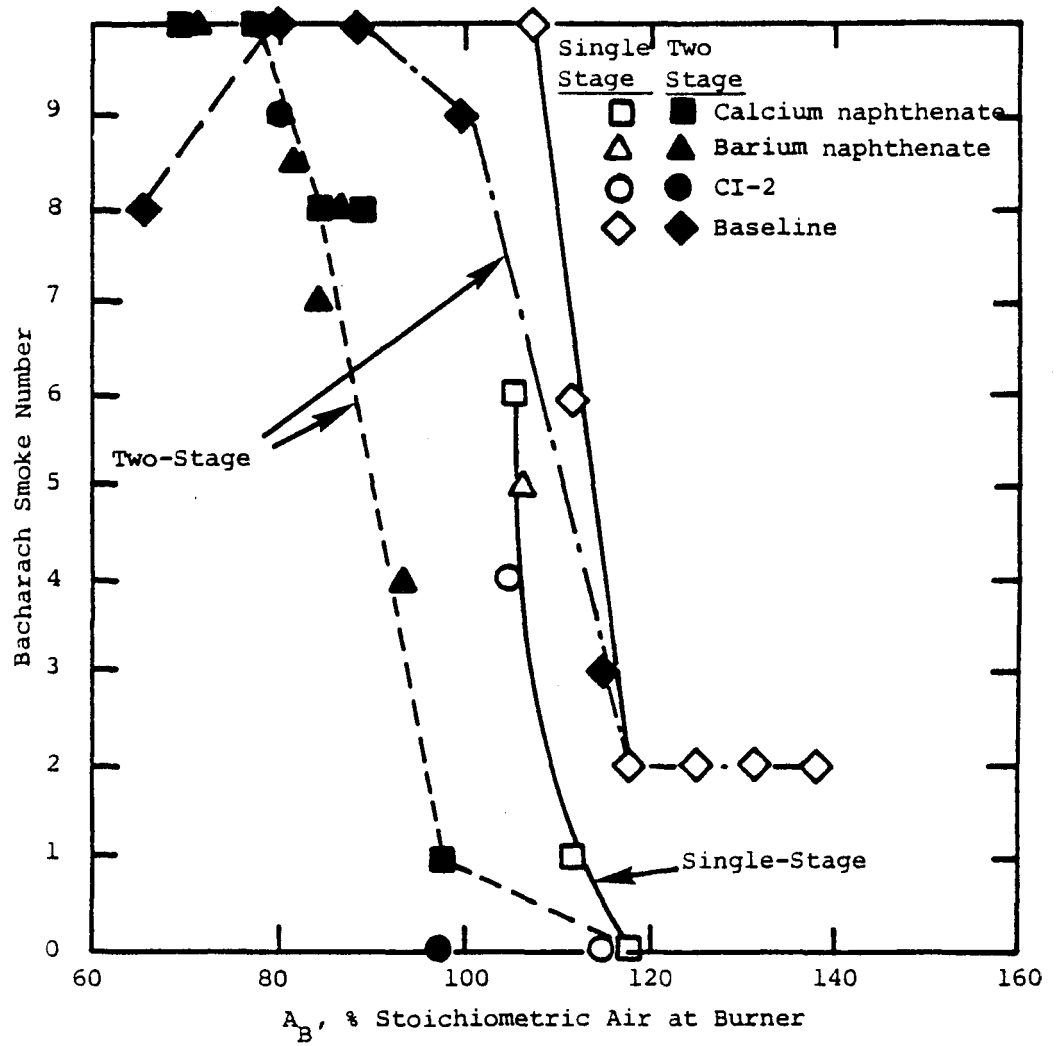
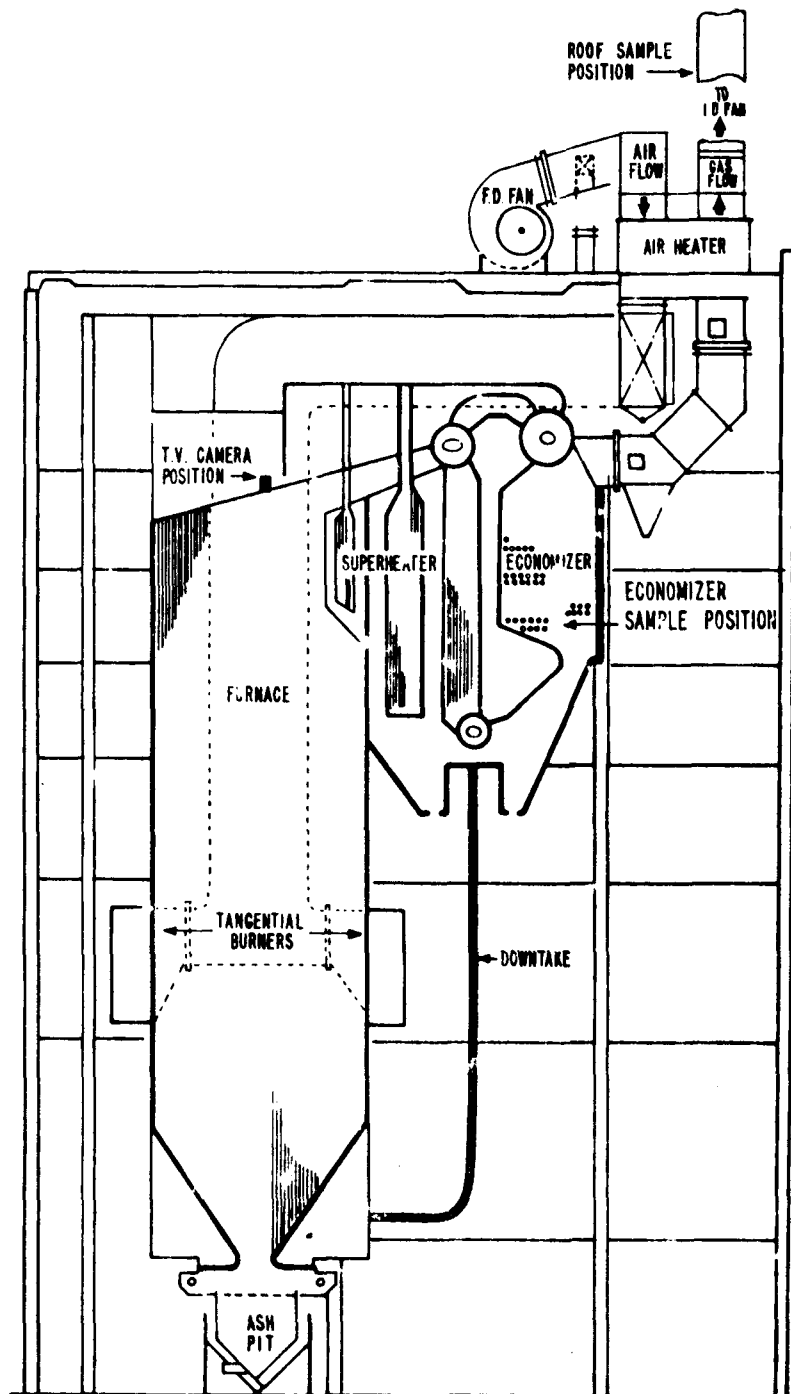


Figure D-2 SMOKE LEVELS UNDER STAGING CONDITIONS (FROM REF. D-1)



BOILER N^o 122
74th STREET STATION

**Figure D-3 44 MW BOILER IN CONSOLIDATED EDISON TEST
 OF SRC-II FUEL OIL (FROM REF. D-2)**

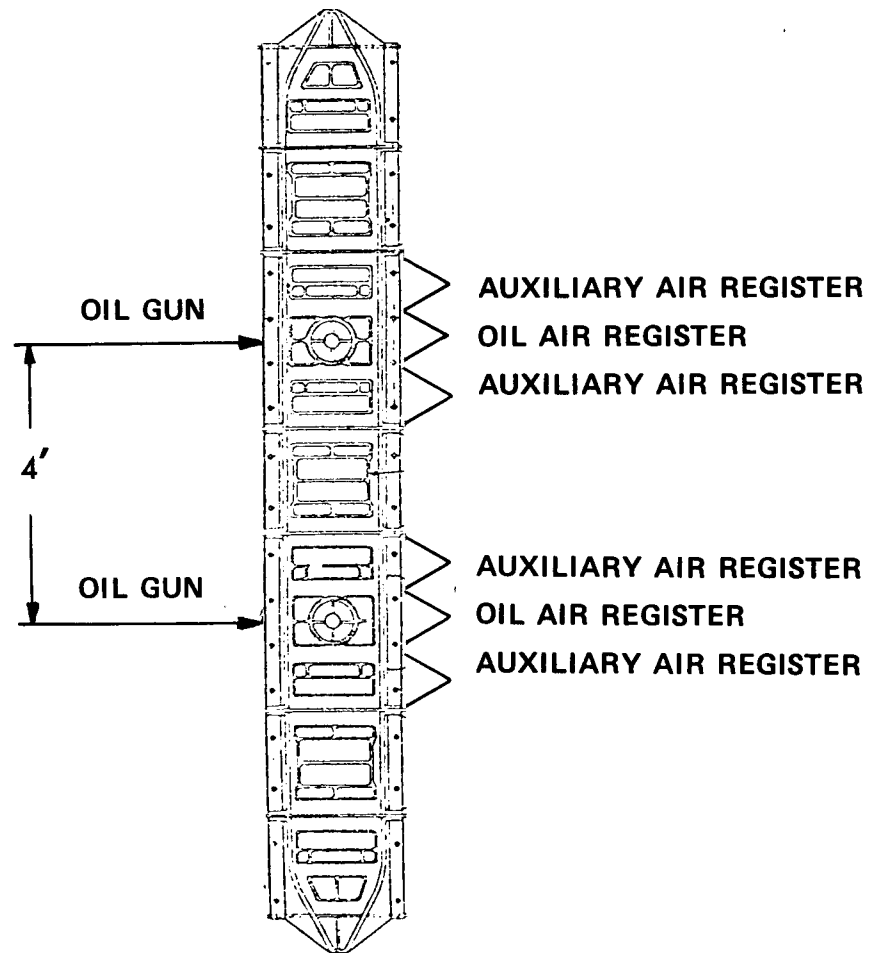


**Figure D-4 END-ON VIEW OF ONE CORNER ARRAY OF
BURNERS IN CON-ED BOILER (FROM REF. D-2)**

clients in emission and efficiency problems. The following excerpt from the report of this test identifies the baseline configuration and the ways in which staged combustion was achieved via air or fuel redistribution. "Low- NO_x " refers to these staged configurations, and "baseline" refers to the equivalent boiler operation without any air or fuel redistribution.

"The low NO_x operation represents a condition (or conditions) in which the combustion controls are deliberately adjusted to achieve low NO_x emissions. The technique used to achieve this condition is to operate the near flame zones fuel rich thereby decreasing the peak flame temperature and the available oxygen. Complete combustion is then achieved by mixing in sufficient air to complete combustion after the initial combustion products have lost heat to the furnace walls. This technique, sometimes called staged combustion or off-stoichiometric operation, has been used successfully on many boilers and is currently the most widely employed technique used to control NO_x throughout the country.

Near flame fuel rich operation is established by redistributing the fuel and/or the air flowrates. Fuel redistribution is achieved by taking selected burners out of service while maintaining the same air to those burners. This results in an increased fuel flow rate to the burners in service since the total fuel flow rate remains constant to maintain load. The degree of local fuel richness depends on the number of air-only burners in service since the total fuel flow rate remains constant to maintain load. The degree of local fuel richness depends on the number of air-only burners in service and the amount of local excess air.

Air redistribution is achieved by varying the relative primary and auxiliary air admittance so that less air is available in the immediate vicinity of the burners while the remaining air needed for total combustion is admitted at some distance from the burners. Corner fired boilers are relatively flexible in this respect in that the relative damper positions between the auxiliary air and the primary compartments can be used to achieve the desired air to fuel ratios."

The NO_x results of these low- NO_x and baseline runs are given in Table D-1 from the report of this test. For example, in the right-hand column of Table D-1, while burning SRC-II fuel oil the NO_x was 270 ppm in the baseline configuration, but was reduced to 175 ppm by the low- NO_x configuration. This same configuration was then used with No. 6 oil, and was also effective with it, reducing the NO_x from 155 to 100 ppm.

In interpreting these results, KVB calculated the fraction of the total air flow to the boiler which entered near the oil guns and was immediately available (analogous to the air entering the first or lower stage of a wall-fired boiler in staged combustion), and they plotted NO_x concentrations and fuel- NO_x yields (Figures D-5 and D-6, respectively) against this parameter in analogy to plots of results for first-stage stoichiometry in wall-fired boilers. Figure D-5 and D-6 show that the NO_x and fuel- NO_x yields do correlate with this parameter, and indicate that under low- NO_x configurations the fuel- NO_x configurations the fuel- NO_x yield was only 10%.

Particulate emissions were always less than the proposed NSPS of $0.03 \text{ lb}/10^6 \text{ Btu}$, and particulates from SRC-II fuel oil were half these from No. 6 oil. No electrostatic precipitator or other particulate removal device was used, in contrast to the field test of SRC-I fuel. Ninety percent of the particles were smaller than 0.1 micron, and the emissions of polynuclear aromatic hydrocarbons were less than $6 \times 10^{-6} \text{ lb}/10^6 \text{ Btu}$, although measurement of this low level was nearly outside the capability of the analytical method. The SRC-II fuel oil presented no operational problems with fuel handling, nozzle coking, etc.

The tangential design of the ConEd boiler used in this test favors low NO_x emissions, (in contrast to wall-fired boilers) for two reasons: (1) its lower flame temperature reduces thermal NO_x and (2) the burner orientation permits the long slow-mixing flames which were especially prominent in the "air redistribution" runs. To facilitate the wide use of SRC-II fuel oil, a field test in a wall-fired boiler should also be conducted, provided that it would inform utility companies how to use SRC-II fuel oil acceptably. For a field test with acceptable emissions and no operating

TABLE D-1 LOW NO_x EMISSIONS RESULTS IN CON-ED TEST (FROM REF. D-2)

LOAD	CONDITION	NITRIC OXIDE EMISSIONS					
		NO. 6 FUEL OIL				SRC II FUEL OIL	
		MINIMUM ACHIEVED		DUPLICATE OF SRC II			
		ppm, Dry @ 3% O ₂	$\frac{\text{lbs/NO}_2}{10^6 \text{ Btu}}$	ppm, Dry @ 3% O ₂	$\frac{\text{lbs NO}_2}{10^6 \text{ Btu}}$	ppm, Dry @ 3% O ₂	$\frac{\text{lbs NO}_2}{10^6 \text{ Btu}}$
Full (450,000 lbs/hr Stm)	Baseline (Range)	--	--	155 (140-162)	.202 (.182-.211)	270 (258-298)	.351 (.335-.387)
	Low NOx	100	.130	100	.130	175	.228
Half (225,000 lbs/hr Stm)	Baseline (Range)	--	--	165	.215	280 (261-301)	.364 (.339-.391)
	Low NOx	96	.125	117	.152	188	.244
3/4 Load (340,000 lbs/hr Stm)	Baseline	--	--	--	--	--	--
	Low NOx	93	.121	98	.127	159	.207

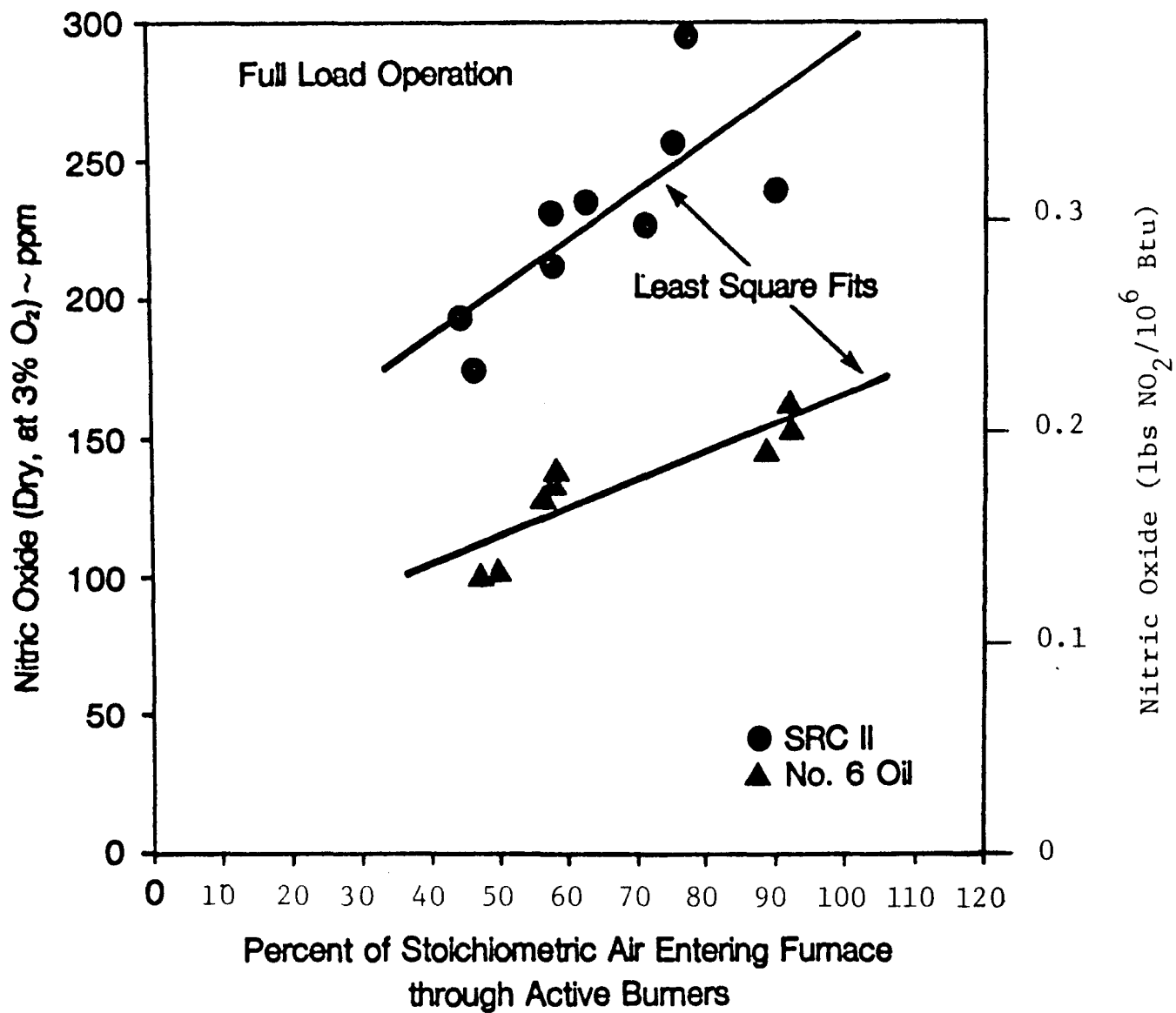


Figure D-5 NO_x EMISSIONS FROM CON-ED TANGENTIAL BOILER
CORRELATE WITH STAGING PARAMETER (FROM REF. D-2)

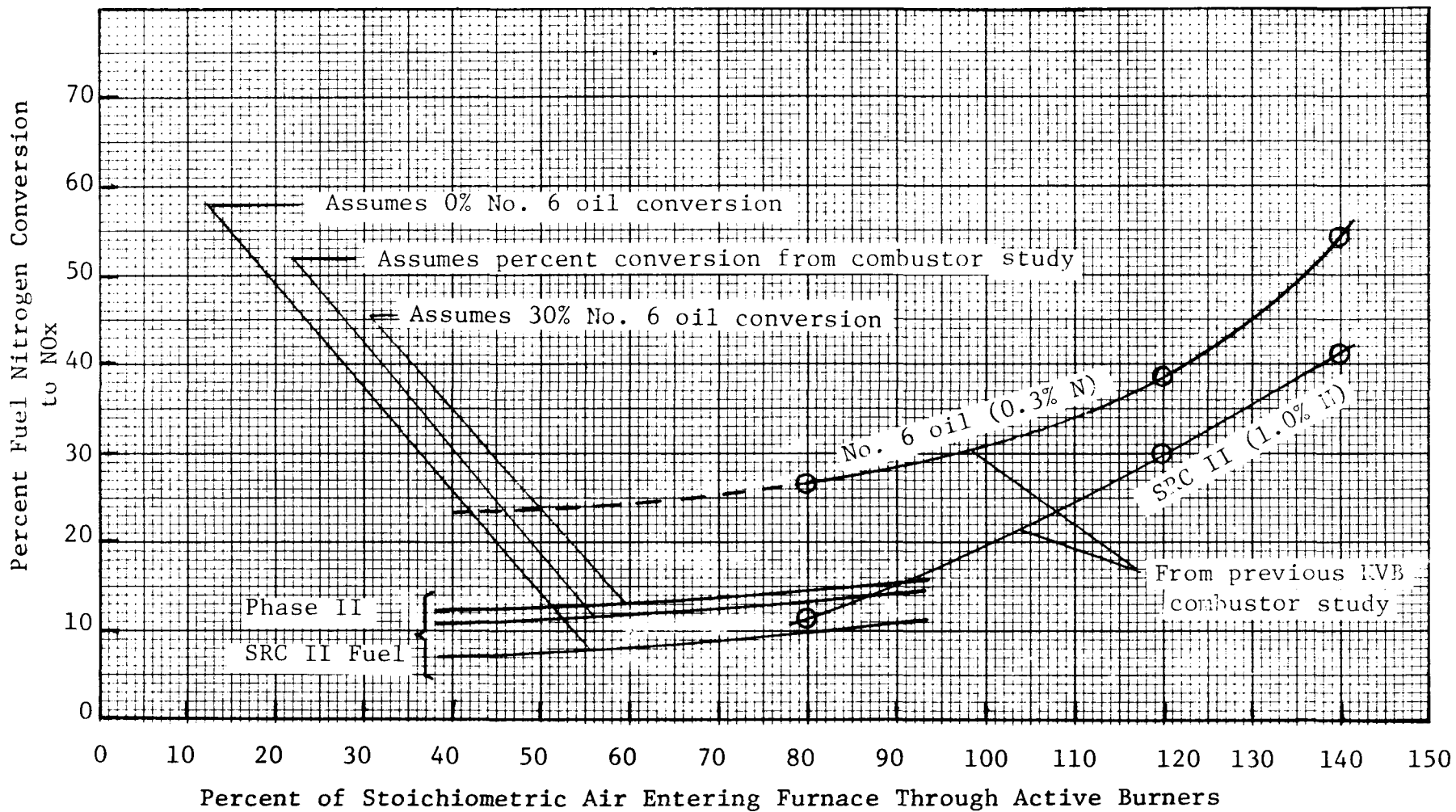


Figure D-6 ESTIMATED FUEL-NO_x YIELD IN CON-ED TEST (FROM REF. D-2)

problems, staged combustion as commonly conducted with nitrogenous residual oils should be tested, but low-NO_x burners (i.e., low fuel-NO_x) such as those of EER, Inc., would demonstrate a more satisfactory mode of operating to the utilities, with greater safety and operating margins. The first such test would address only the emissions and operating characteristics of SRC-II fuel oil in such a burner-boiler system. Long-term problems such as corrosion would have to await the availability of fuel from the demonstration plant. Even the emissions-only field boiler test would consume excessive amounts of SRC-II fuel oil samples; such a test should await the certitude that the needs of higher-priority uses of the fuel were met, including industrial boiler and burner tests and tests in the MIT experimental furnace.

D. REFERENCES

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2. Electric Power Research Institute Final Report FP-1029, Projects 1235-5 and 1412-2, May 1979, "Combustion Demonstration of SRC-II Fuel Oil in a Tangentially Fired Boiler," prepared by KVB Incorporated.

E. INDUSTRIAL BOILERS; LOW-EMISSION BURNER DESIGNS

The first SRC-II fuel combustion utilization tests have addressed utility boilers for a number of reasons. Clean combustion was most likely to be achieved in a utility-size boiler, where staged combustion techniques have been developed. Furthermore, utilities and related organizations were organized and supportive, due to their long-range awareness and concern about fuel supplies. However, industrial boiler fuel supplies are also uncertain; since industrial boilers have fewer fuel options technically open to them than do utility boilers, industrial boiler operators' interest in SRC-II fuel oil is growing and the use of it in the industrial boiler market would fill an area of possibly greater need than the utility boiler market over the long term. Furthermore, because of the viscosity, distillation range, and other properties of SRC-II fuel oil (excepting its nitrogen and aromatics contents) its quality would satisfy the requirements of all industrial boilers but would not be used to maximum advantage in utility boilers. Since the clean utilization of SRC-II fuel oil in industrial boilers is more difficult than in utility boilers, we have monitored technical developments in this area which appear to have potential to solve such problems; these are reported in the following.

Staged combustion in utility boilers has been achieved by varying or redistributing different burners' relative air or fuel flow rates. In contrast, industrial boilers such as those in Figures B-3 or B-4 have only one (or at most, four) burners preventing staging by this means. Moreover, industrial boilers have smaller furnaces with shorter residence times for completion of the reactions in the rich stage which convert fuel-nitrogen into N_2 and burn out soot in the second stage.

However, there are other ways to delay the air-fuel mixture process than two-staging; one of these was indeed used in the Consolidated Edison test, and accounted for over half of the reduction in the fuel- NO_x yield. This technique was air redistribution, in which the air flowrate through the "oil registers" (referring to Figure D-4) was decreased while increasing the

flow rate through the adjacent auxiliary registers. This kept the oil jet in an air-lean area until air from the auxiliary registers could become entrained further downstream in the oil jet. In a similar manner, a single burner in an industrial boiler can be designed to delay the air mixture into the fuel jet.

Extensive studies by the International Flame Research Foundation of the aerodynamics of flames including pressure and air-assist sprays and combustion air swirl also revealed the advantages of the delayed mixing approach. This work is being continued by Energy and Environmental Research, Inc., in an EPA program described below, and is also being adopted by some boiler and burner manufacturers. We describe the EER results to date in the following because it is the most promising development to facilitate clean SRC-II fuel oil utilization in industrial boilers. Figure E-1 illustrates EER's embodiment of staged combustion, created aerodynamically by the burner.⁽¹⁾ As the fuel first emerges from the fuel nozzle, it enters the "rich hot recirculation zone" where the recirculation traps it until it progressively mixes with the surrounding secondary and tertiary air streams. EER has termed this embodiment of staged combustion "the distributed mixing" burner. Figure E-2 shows the burner parts which control the flow rate and swirl of the various air streams, and thus the fuel/air ratio and residence time of the recirculation zone.

EER is continuing to scale up this design toward commercial sizes, and has two test enclosures for this purpose, of 12×10^6 Btu/hr and 120×10^6 Btu/hr capacities, simulating watertube boilers. Figure E-3 shows the results of a test of a large version of the distributed mixing burner fired at 2.7 MW in the 12×10^6 Btu/hr enclosure; residual oil containing 0.77% nitrogen was used. When operated in a non-staged fashion, the NO emissions decreased with decreasing air, as expected. With staged firing, with a fuel-rich fuel/air ratio in the inner zone and the remaining combustion air entering the furnace through the outermost annulus, the NO_x decreased much more, going from 520 ppm to 250 ppm as the air entering the inner annuli of the burner became substoichiometric.

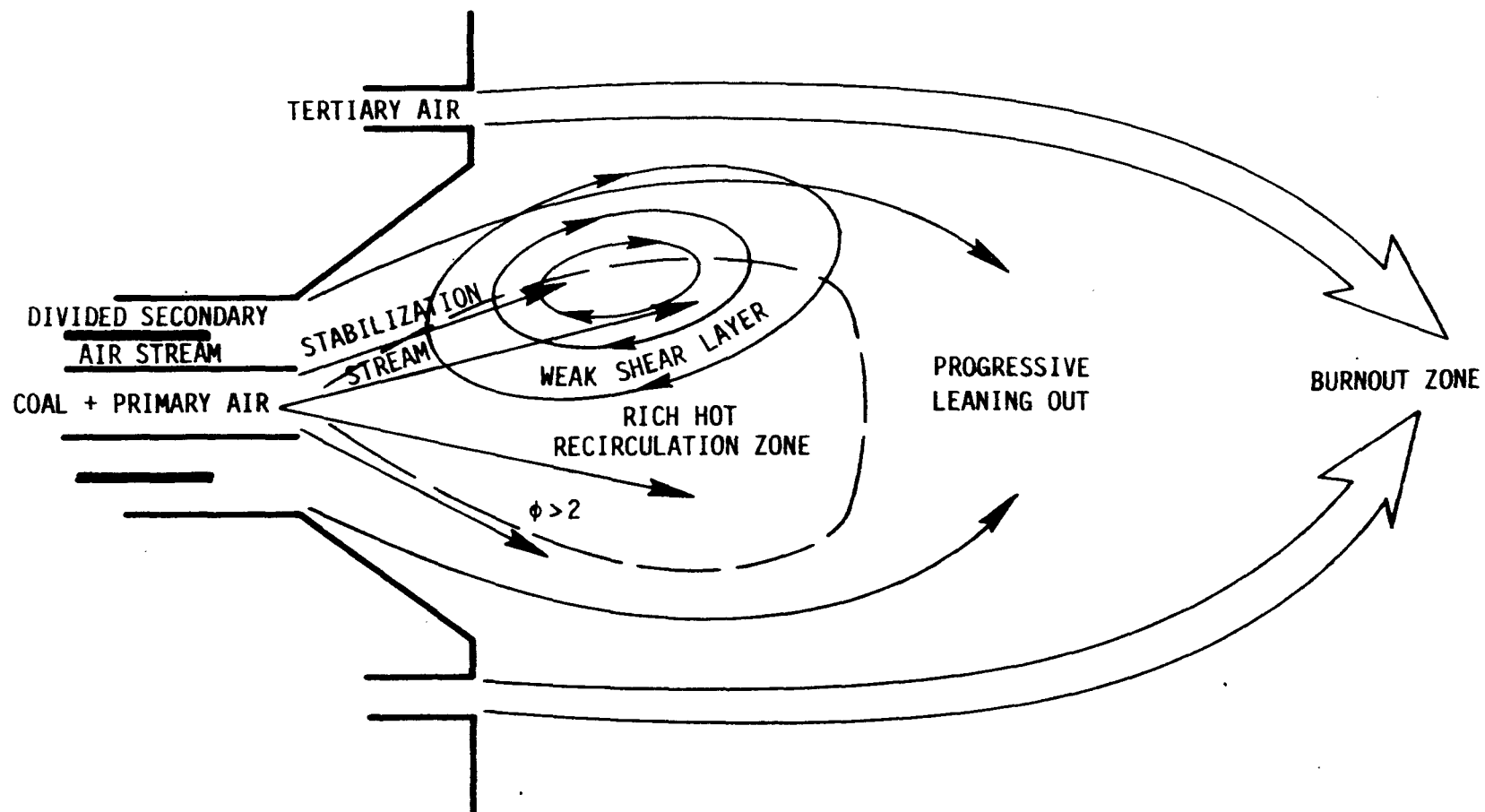


Figure E-1 EER'S DISTRIBUTED MIXING BURNER CONCEPT:
FLAME ZONES AND REACTIONS (FROM REF. E-1)

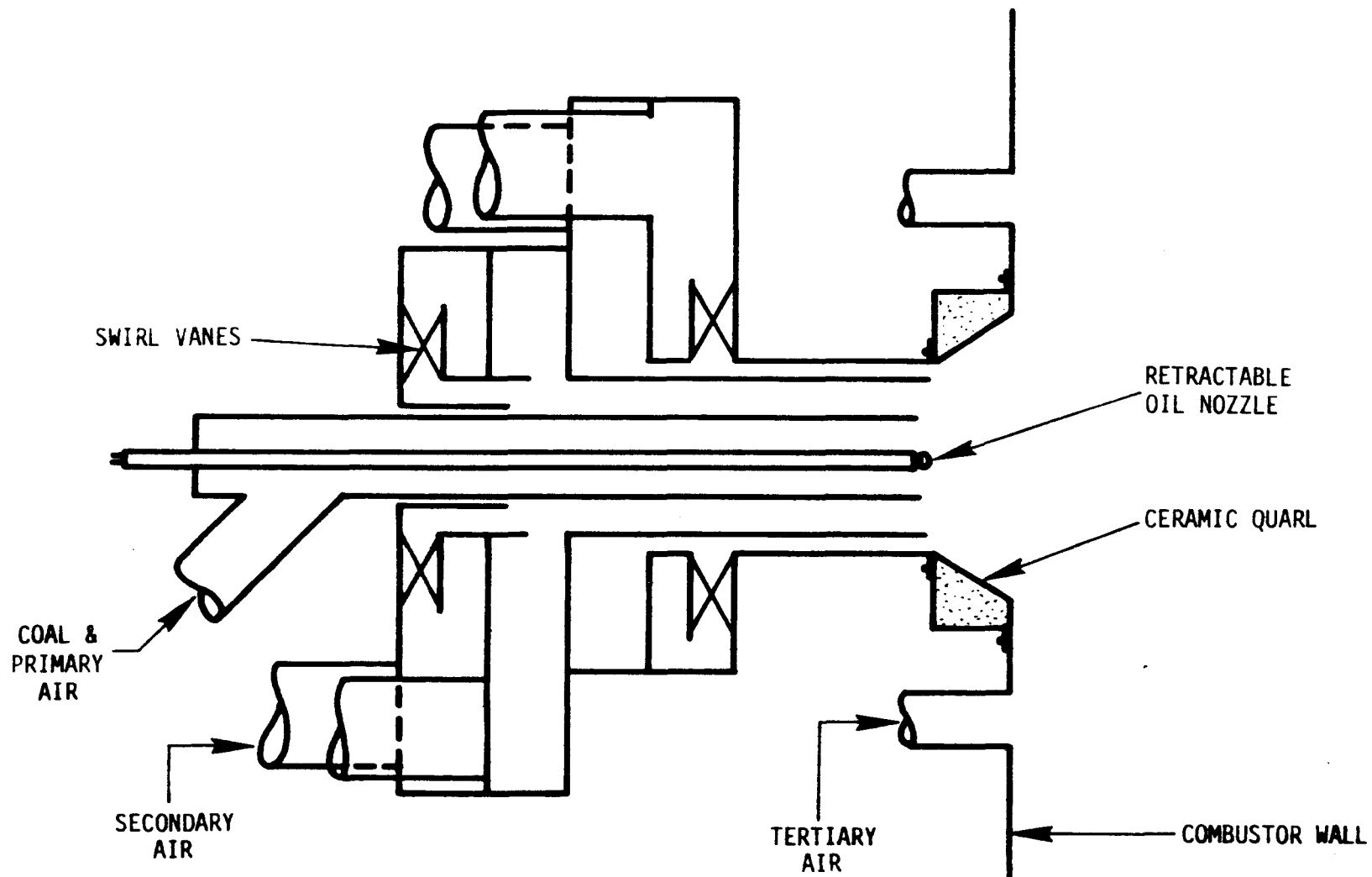


Figure E-2 EER BURNER DESIGN
TO ACCOMPLISH DISTRIBUTED MIXING CONCEPT (FROM REF. E-2)

E-5

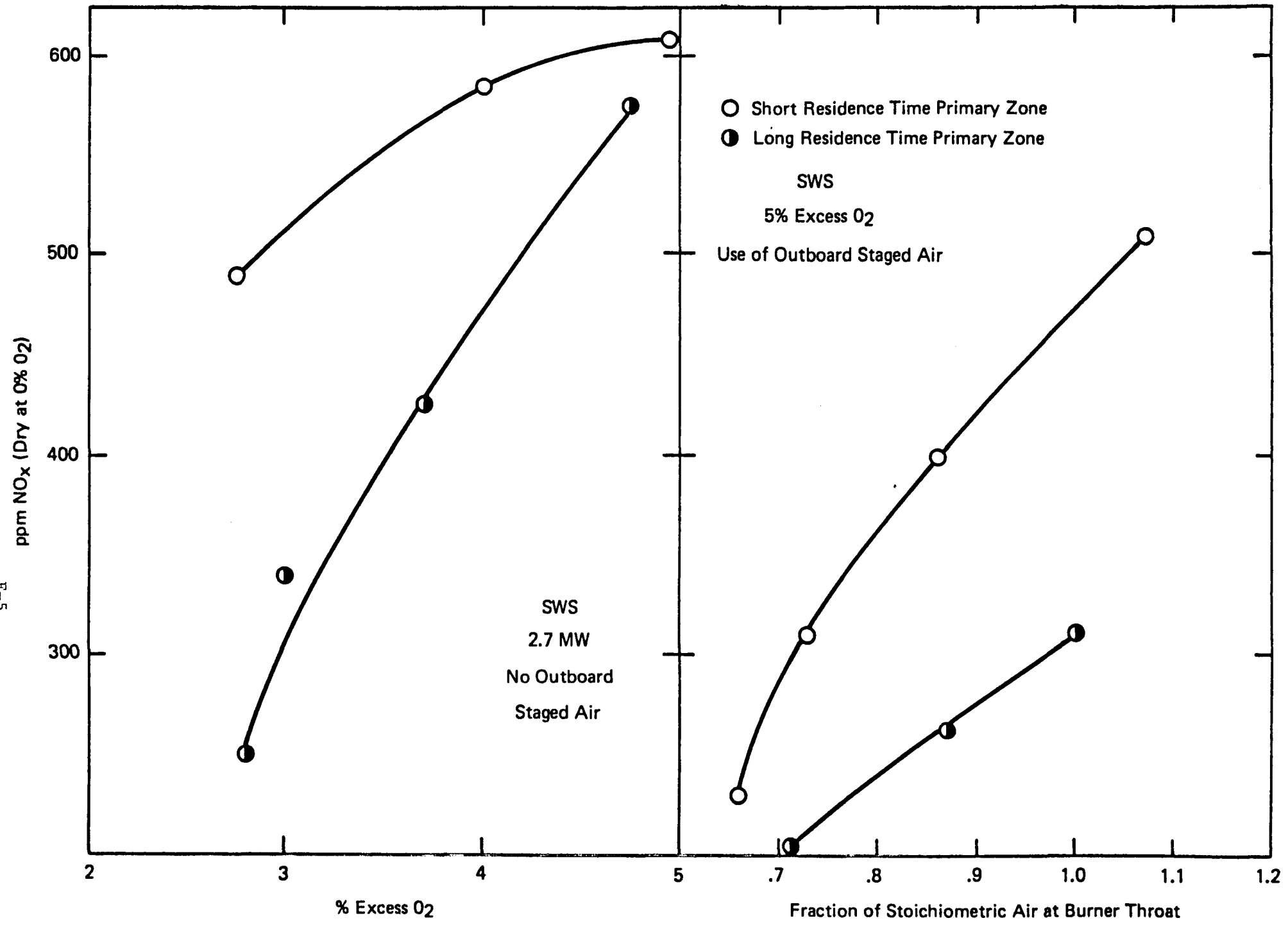


Figure E-3 NO_x REDUCTION BY EER BURNER (FROM REF. E-2)

Other burner designs are being developed by other organizations, including Babcock & Wilcox (the Dual Register Burner and the Primary Combustion Furnace), Gulf Oil Canada (the Vortometric burner), Southern California Edison and TRW, Inc., and National Air Oil, among others. Several of these designs include approaches and principles other than rich flame staging, and although testing to date has not revealed any intrinsic advantages over rich flame staging, such new approaches should be monitored carefully. Report Volume 3.1.2, Combustion Test Programs - Supporting Reports, contains reports of tests of some of these burners, and some interpretive comments on them.

A program which complements the EER burner work and is of equal importance is being conducted in the Combustion Research Facility in the MIT Energy Laboratory. This unit is sufficiently large to represent conditions in utility boilers, and it has a very complete instrumentation and control system. Its simple geometry permits gas sampling within the furnace, and determination of the spatial distribution of flame gas temperature, velocity, and composition. In this way, soot can be watched as it forms and subsequently burns out; the radiative heat transport as promoted or obscured by the soot can also be determined. In a similar unit in Holland, measurements and modeling of some of these processes was begun very successfully, and this approach will be continued at MIT. Tests including SRC-II fuel oil are scheduled, under EPRI funding. The models for soot and heat transport can be used in the planning of tests in field boilers and interpretation of results, and such field data can also be input to the model for its improvement.

E. REFERENCES

1. "Design and Scale-up of Low-Emission Burners for Industrial and Utility Boilers," by R. Gershman, M. P. Heap, and T. J. Tyson, in Proceedings of the Second Stationary Source Combustion Symposium, Volume V Addendum, EPA-600/7-77-073, July 1977.
2. "Combustion Modification Pollutant Control Techniques for Industrial Boilers - The Influence of Fuel Oil Properties and Atomization Parameters," M. P. Heap, G. C. England, and J. W. Lee, Energy and Environmental Research Corporation, Irvine, CA.

APPENDIX A. FUNDAMENTAL COMBUSTION RESEARCH PROGRAM OF EPA

The EPA Fundamental Combustion Research Program of the Environmental Protection Agency is conducting basic research on the chemistry aerodynamics of oil spray flames and emissions. Its results will greatly benefit SRC-II fuel oil utilization in boilers and design of burners therefore (by EER and others, mentioned in section E), and the following excerpts, from the Third Stationary Source Combustion Symposium, March 5-15, 1979, describe some of the research plans. The reader is referred to the Proceedings (EPA-600/7-79-050a-e) for details. There are three main parts to the FCR program:

1. The chemical kinetics in the gas phase (Appendix A.1)
2. Droplet and particle vaporization and combustion (Appendix A.2)
3. Numerical modeling of real flames, including chemical reactions, transport processes and large-scale aerodynamics (Appendix A.3)

APPENDIX A.1

NO_x ABATEMENT IN FOSSIL FUEL COMBUSTION.

Chemical Kinetic Considerations

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SECTION 1

INTRODUCTION

The Fundamental Combustion Research (FCR) Program of the Environmental Protection Agency is aimed at the establishment of strategies for reducing NO_x production through combustion process modification. Complete characterization of the factors affecting NO_x production must, by nature of the combustion process itself, include consideration of such diverse processes as homogeneous gas phase reactions, heterogeneous gas-solid reactions, heat transfer, and aerodynamics. We report here on current progress under the FCR program in the elucidation of the homogeneous gas-phase chemical kinetic mechanism of NO_x formation in fossil-fuel combustion.

The strategy adopted in the FCR program is discussed in this manuscript. Illustrations of selected results will be presented and updated at the "Third Symposium on Stationary Source Combustion".

With the depletion of natural gas and petroleum reserves (which are lacking or low in nitrogen content - and, hence, relatively low in the emission of NO_x formed from the nitrogen bound in the fuel), and the increasing substitution of coal, coal-derived liquids, residual fuel-oils, and shale oils (which are high in nitrogen content), NO_x emissions, which are already unacceptably high in several urban areas, are bound to increase unless an abatement strategy is developed and implemented. Insofar as the mechanism by which fuel-bound nitrogen is converted to NO_x is complex, and insofar as early attempts^{1,2} to reduce NO_x emissions by empirical adjustment of combustion parameters (e.g., temperature, fuel/air ratio, degree of mixedness, etc.) utilizing conventional combustors have achieved only a fraction of their full potential, a more fundamental elucidation of the NO_x formation mechanism has become essential in order to achieve the desired engineering goal of modifying the combustion process in such a way as to favor the conversion of fuel-bound nitrogen to the desired (combustion) end

product, N_2 , rather than to the undesired product, NO .

As such, the organization of the FCR program has defined the following approach to achieving this end:

- a) Identification of chemical reaction sets with an emphasis on fuel nitrogen conversion,
- b) Validation of these reaction sets by modeling a wide range of pertinent experimental results, and concomitant computational screening to identify the minimum reaction subsets adequate for prediction of NO_x emission levels,
- c) Through these processes, identification of critical gaps in the existing data base necessary for prediction of NO_x levels,
- and d) Application of the fuel-N reaction set to the computation of NO_x emission levels from systems of practical interest, and utilization of predictive capabilities for development of NO_x abatement strategies.

In order to clarify the results, initial chemical kinetic studies have concentrated on aerodynamically clean systems in which interpretation of results are not complicated by mixing effects. A parallel effort under the FCR program is the characterization of the aerodynamics and development of methodologies for coupling the kinetics with the flow field in real, aerodynamically complex combustors.

SECTION III

ESTABLISHMENT OF A KINETIC MECHANISM FOR NO_x FORMATION AND DESTRUCTION FROM FUEL-BOUND NITROGEN.

As indicated above, development of an NO_x control strategy rests heavily upon optimizing the conversion of volatile fuel-nitrogen species to N₂. Insofar as the residence times in typical combustors are far too short to achieve chemical equilibrium in the burnt gases, it is necessary to consider the time dependent flow of nitrogenous species through the many sequential and competing reaction pathways leading to NO_x and N₂ formation, in order to develop a methodology for maximizing or minimizing certain product yields - i.e., both the elementary reaction pathways and reaction rates must be considered.

Although at this time, many details of the NO_x formation and destruction mechanism are not fully understood, a considerable literature^{8,12} has appeared in recent years, in which the predominant nitrogenous species appearing as intermediates or products of fuel-nitrogen conversion have been identified, and from which a rough reaction mechanism^{13,14,15} may be deduced.

Having identified an adequate species set, a "complete" reaction mechanism has been constructed¹⁵ by permitting all species to inter-react via elementary reactions. Rate constants were selected from a search of the experimental literature where available, or from tabulated estimates (made, generally, by the method of Johnston¹⁶). The fuel-nitrogen reaction set is shown in Table 1. Conspicuously absent are several reactions, for example, $\text{NH}(\text{NH}_2) + \text{NO} \rightarrow \text{N}_2 + \text{OH}(\text{H}_2\text{O})$, often invoked in NO mechanisms. Although of

questionable "elementary" nature, for completeness, they have been included in modelling efforts.

Current efforts under the FCR program are directed to extending the kinetic mechanisms to higher hydrocarbons. Unfortunately, there is a dearth of elementary mechanistic and rate data for hydrocarbons representative of petroleum, coal, or shale derived fuels. Global modelling²⁷ of hydrocarbon combustion (by either finite or infinite rate formation of CO and H₂), has proven to be useful for purposes of estimation of heat release rates, but may seriously mis-predict intermediate free radical levels²⁸ which are crucial to the proper computation of NO_x emissions, particularly under fuel rich conditions. Current semi-global developments²⁹ are more promising in that they include some higher intermediates between the initial hydrocarbon and CO. The approach under development is the extension of the semi-global method based upon the observation³⁰ that several relatively small hydrocarbon species appear as (pyrolysis) intermediates in the combustion of higher hydrocarbons. The initial species set under consideration includes C₂H₂ (a major intermediate of aromatic systems), C₂H₄, CH₄, and CO/H₂. The combustion mechanisms of C₂H₂ and C₂H₄ have been recently studied³¹ and are under continuing investigation.

APPENDIX A.2

HETEROGENEOUS PROCESSES INVOLVED IN THE CONTROL OF NITROGEN OXIDE FORMATION IN FOSSIL FUEL FLAMES

By:

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SECTION 1

INTRODUCTION

The general philosophy and overall objectives of the FCR* program have been described elsewhere (1). This program involves the planning and direction of several projects whose overall goal is to provide the EPA/CRB with the necessary understanding of the fundamental behavior of combustion systems to develop control technology which will minimize the emission of both NO_x and associated pollutants from stationary sources. The program is focused on well-defined priority target areas, and the research effort is directed towards providing engineering solutions to specific problems within a time frame consistent with the technology development programs. Neither the time nor resources are limitless, and the program has been planned to provide products which can be realized in both the near and far-term. Information is being generated now which can either be directly transferred to "technology development" programs, or used in the development of empirical engineering models to aid the designer of low NO_x combustion systems. Projects with a long-term payoff, which are in the minority, are associated with the development of numerical models capable of describing pollutant formation in complex combustors.

The FCR program is primarily concerned with the basic mechanisms associated with the formation and destruction of nitrogen oxides in fossil fuel flames. However, some effort has been initiated relating to the formation of soot and fine particulate matter, as well as the mechanisms of sorbent extraction of SO_2 in flames. Reviewing the sources of anthropogenic NO_x emissions, it can be seen that approximately 50 percent can be attributed to stationary combustion; and of this, 50 percent greater than 55 percent is associated with the combustion of nitrogen-containing fuels which are mainly

* Fundamental Combustion Research Applied to Pollution Control

coal or oil. Thus, the primary initial objective was to focus upon pollutant production in one-atmosphere turbulent diffusion flames burning pulverized coal or residual oil and radiating to cold walls. Since the increased use of coal is one of the nation's methods of achieving energy independence, this initial objective has considerable relevance because any increase in the use of coal or coal-derived fuels without the application of necessary control technology will probably result in an increase in NO_x emissions.

A key element of the FCR program is the establishment of the lower bounds set on NO_x emissions under various limiting situations and constraints. It is important when assessing control strategies to know that for a particular set of process requirements that there exists a limit on the level of control achievable by combustion modifications and set by these requirements. Thus, the value of studies leading to the establishment of lower bounds is not only that they provide a yardstick by which to measure the effectiveness of other control schemes, but they also provide strong guidance in the development of advanced control techniques.

The generation of nitrogen oxides during the combustion of pulverized coal and residual oil in turbulent diffusion flames involves the complex interaction of several physical and chemical phenomena. Transport processes involving heat or mass, gas phase kinetics, and heterogeneous processes are all involved in the formation and destruction of NO in these flames. This paper describes projects included in the FCR program, both ongoing and planned for the future, which can be classified as heterogeneous processes. Projects associated with mass transfer phenomena and homogeneous gas phase kinetics are discussed in two other papers.

SECTION 3

HETEROGENEOUS PROCESSES — AN FCR PROGRAM ELEMENT

Figure 3 presents a schematic showing the relationship between the heterogeneous processes program element and the other FCR program elements:

- Homogeneous Kinetics
- Transport Processes
- Measurement System Assessment/Development
- Numerical Model Development

The various projects under this program element can be classified under three major headings which are:

- Thermal Decomposition
- Gas Solid Reactions
- Reactor Studies

Figure 3 shows the Principle Investigators associated with the projects in each of the areas.

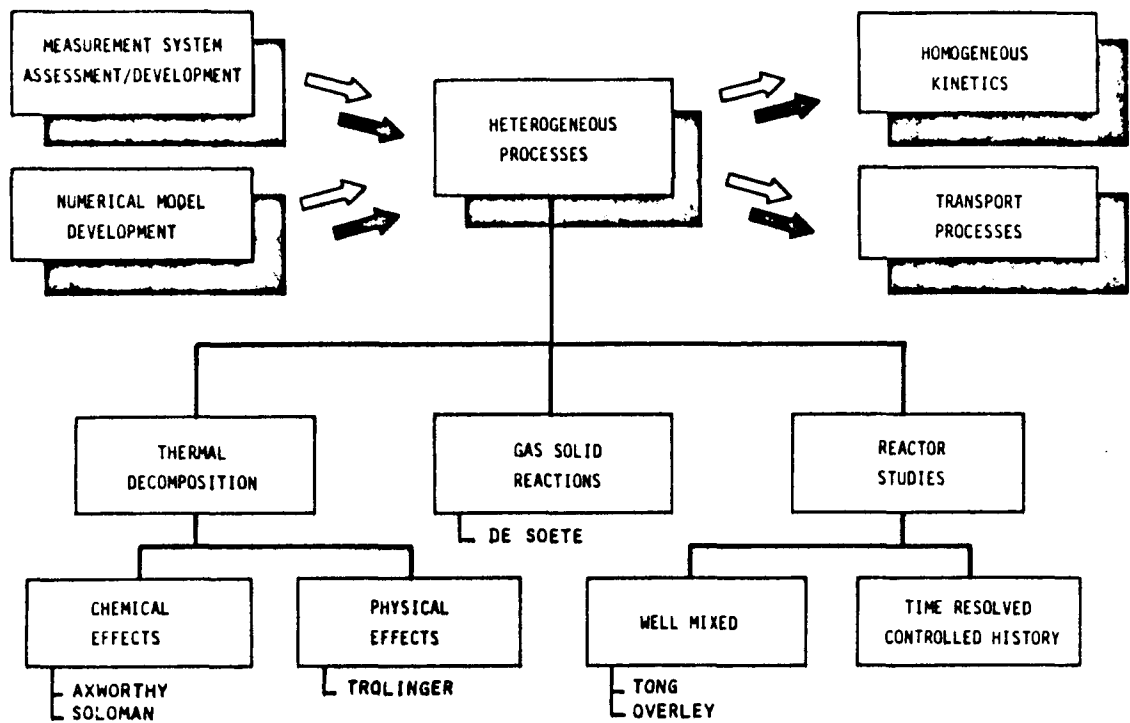


Figure 3. Heterogeneous Processes — Project Organization

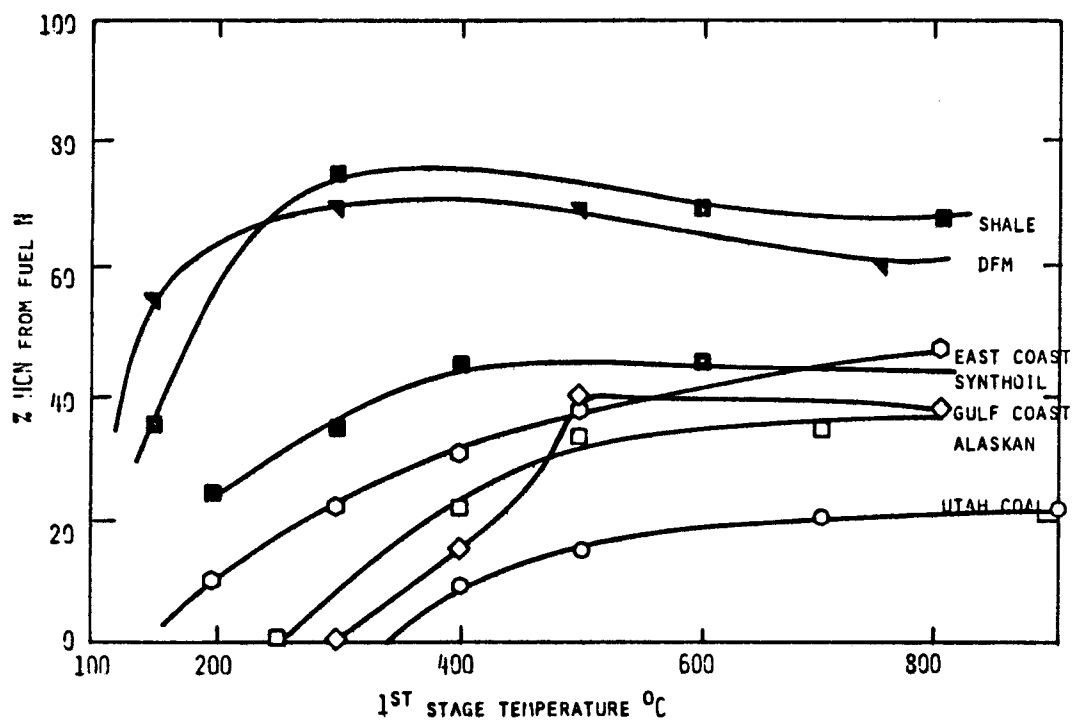


Figure 4. Composite Plot Showing the Volatility of Convertible Fuel Nitrogen for Several Fuels as Measured by Axworthy

APPENDIX A.3

TRANSPORT PROCESSES AND NUMERICAL MODEL DEVELOPMENT
— FCR PROGRAM ELEMENTS

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SECTION 1

INTRODUCTION

The FCR program has two major objectives. These are:

- To provide guidance to development programs concerned with the application of low NO_x combustion systems to stationary sources.
- To gain insight into the fundamental phenomena controlling the production of NO_x in these devices in order to define potential advanced control techniques.

One major aspect of the program involves the presentation of basic information in such a way as to be of the most benefit to the development engineer. This information may be transferred directly or in the form of a model which can be used as a design tool, thereby cutting the cost and delay time associated with empirical development programs.

Two fuels, coal and residual oils, when burned in large turbulent diffusion flames confined by relatively cold walls produce the major fraction of NO_x emissions from stationary combustion sources. Two previous papers have discussed the dominant homogeneous and heterogeneous kinetic processes associated with the production of nitric oxide in these combustion systems. However, these papers did not consider the detailed physics involved in the turbulent mixing process associated with fuel/air contacting in real combustors. This paper discusses two other elements of the FCR program; those concerned with numerical model development, and transport processes which serve the key function of synthesizing information generated in the other program elements in order to provide an understanding of the basic mechanisms limiting NO_x formation in practical combustion devices.

In the FCR program elements concerned with homogeneous kinetics and heterogeneous processes the dominant physical and chemical mechanisms pertinent to NO_x production during the combustion of clouds of oil droplets or

coal particles will be defined. Several experiments have been planned which, in conjunction with the development of numerical models, will provide a predictive capability capable of describing NO_x production in simple reactor systems. Two of these programs are concerned with solid and liquid fuels, and were described in an earlier paper. Two other experimental programs, one being carried out by Myerson at Exxon and the other by Clark at EER, are directed towards the generation of data which will allow the verification of an adequate kinetic mechanism capable of describing NO_x production from simple fuel nitrogen compounds during the combustion of hydrocarbon fuels. This predictive capability will be refined and verified by comparison with measurements made in these simple combustion reactors. Once confidence has been established in the predictive capability, it can be used to analyze the behavior of staged combustion reactors in a rational and comprehensive search for those reactor combinations which yield the lower limit of NO_x emission set by the basic physics and chemistry of fossil fuel combustion.

Simple zero- and one-dimensional reactors do not completely reflect the detailed physics and chemistry associated with turbulent diffusion flames burning in real furnaces. Consequently, an additional effort has been planned which will parallel the reactor studies and thoroughly characterize turbulent diffusion flame phenomena pertinent to NO_x formation and destruction. Two general classes of turbulent diffusion flames can be recognized; those which involve rapid fuel/air mixing and are dominated by near-field behavior. The second group of turbulent diffusion flames are far-field dominated and can be described as long coaxial jet flames. Several tasks have been initiated in the CR program which are directed towards understanding the basic turbulent diffusion layer structure in these general flame types. These investigations are concerned with particle transport, both ballistic and turbulent, macroscale turbulent transport of energy and matter, the persistence of coherent structures in large-scale flames, and the detailed processes occurring within these coherent structures.

Once the capability has been developed to model the microscale behavior of oil droplets and coal particles, and after verifying the model by comparison of prediction and observations, it is appropriate to use this model in a

search for lower bounds on NO_x emissions dictated by the basic physics of turbulent transport. The model will aid the understanding of NO_x production and destruction in basic flame elements such as turbulent shear layers, well-backmixed zones, and plug flow zones. This understanding can then be transferred to a modular model capable of describing all the complexities of the fuel/air contacting processes in turbulent diffusion flames. The generation of experimental data to allow this modular model to be developed represents a major subtask of the transport processes program element, and focuses on the macroscale flame behavior in an attempt to establish how burner combustion chamber designs and operating parameters affect the manner in which diffusion zones and well-mixed zones are established and interact. Once the gross features of the flow field have been defined the production and destruction of pollutants on a microscale can be analyzed in an overlay fashion. Having synthesized the physical and chemical processes associated with NO_x production and destruction with the capability to describe the mass transfer in combustion systems, this model can be used to establish the scaling characteristics of low NO_x devices. The definition of scaling criteria represents one of the most important goals of the FCR program, and provides the major driving force towards the description of NO_x production in two-phase turbulent diffusion flames by a hierarchy of models. It should be recognized that in the near-term these models will contain many empirical subelements. However, their modular nature will allow for a more complete mathematical description as the relevant physical and chemical phenomena are defined and quantified.

It is readily apparent that both the development of an understanding of transport processes and the development of numerical models play an important role in the achievement of the FCR program goals. Not only do they provide a predictive capability, they also establish a rationale whereby the effectiveness of NO_x control techniques can be compared against that expected from the lower bounds set by the various physical and chemical constraints. In addition, the development of numerical models provides a tool with which to extract the maximum amount of information from the various experimental programs associated with homogeneous kinetics and heterogeneous processes program elements of the FCR program.

SECTION 3

FLUID MECHANICS AND MODELING OF DIFFUSION FLAMES

Pulverized coal and residual fuel oil are burned in turbulent diffusion flames (i.e., the fuel and oxidant are injected into the combustion chamber separately) and the rate of heat release is normally controlled by the rate of fuel oxidant mixing. Combustion and pollutant formation is complicated by the turbulent mixing process, and currently there does not exist an adequate model for gaseous systems let alone one involving solid or liquid fuels. One aspect of the approach being taken in the FCR program is to examine the influence of various types of molecular diffusion controlled reaction zones on pollutant formation since these could represent the full range of reaction zones likely to be embedded within real turbulent diffusion flames. In addition, the understanding gained from studying simple flame systems provides validation of the kinetic mechanism under conditions that are very different from those used in its development.

MOLECULAR DIFFUSION FLAMES

A generalized diffusion kinetics analysis code has been developed which allows several flame systems to be modeled which involved molecular diffusion. The utility of such models is associated with the computational time required to carry out meaningful calculations. The current code utilizes operator splitting techniques for those situations which are path dependent, and fully implicit techniques involving the inversion of block tridiagonal matrices for conditions which have an asymptotic solution. The generalized code includes the following options:

- strained flames
- steady state particle/droplet flames
- transient confined particle/droplet diffusion flames
- transient spherical gas pockets
- free shear layer flames

- coaxial jet flames
- flat premixed flames

The code has been used to date to examine flat premixed flames, coaxial jet flames, and strained opposed jet diffusion flames. The strained flame provides one link between the modeling being carried out on molecular diffusion flames and turbulent diffusion flames, since the coherent flame structure model assumes that reaction takes place in diffusion layers separating the fuel and the oxidant. Computations have been carried out on the effect of strain rate on flame thickness, flame temperature, thermal NO production and fuel NO production from ammonia. These computations are currently being used by Broadwell and Marble in a model of NO production in a simple turbulent diffusion flame.

DIFFUSION EFFECTS IN PARTICLE/DROPLET COMBUSTION

The conversion of fuel nitrogen to NO in coal and oil flames may depend upon diffusion controlled processes which occur during thermal decomposition, and are associated with the physical effects of particle droplet heating. Experimental data on fuel nitrogen conversion in premixed fuel-lean coal flames suggests that approximately 30 percent of the total fuel nitrogen is converted to NO. Taking account of the division of fuel nitrogen between gas and char components, conversion on the order of 60 percent of the volatile component can be expected. These are similar to conversions measured with liquid fuels of similar nitrogen contents. However, in a fuel-lean premixed gaseous system, fuel nitrogen conversions on the order of 90 percent would be expected. Therefore, any model which assumes that nitrogenous species released from the particle/droplet are immediately completely mixed with the surrounding bulk gases will provide conversion rates which are higher than those encountered in practice. Thus, reaction in a diffusion-controlled layer might well be a necessary submodel for heterogeneous systems.

Nitrogen species may be driven from a coal particle as a jet, or feed some zone around the particle which then reacts in a layer surrounding the particle rather than in the bulk gas phase. Numerical experiments are planned to compare fuel nitrogen conversion in diffusion layers of these types (i.e., mantle, wake or envelope) to that which would occur in the bulk

gas phase. Reaction in the diffusion layer will also control particle temperatures which may yield particle temperatures well in excess of the mean bulk flow and thus have a strong influence on devolatilization rates.

FLUID MECHANICS AND MODELING OF TURBULENT DIFFUSION FLAMES

Broadwell and Marble are developing a coherent flame structure model for gaseous turbulent diffusion flames. In addition there are several experimental studies either planned or in progress. They will provide information which will later be fed into a model of turbulent diffusion flames. The tasks currently underway are:

- Wendt and Hahn at the University of Arizona are measuring the conversion of ammonia to NO in a methane/air opposed jet diffusion flame representative of strained flamelets which may dominate the internal behavior of turbulent flames.
- Vranos at UTRC is currently investigating the combustion of heavy oil droplets in a free shear layer separating oxidant from high temperature combustion products.
- A study will be initiated shortly with IBM to use high-speed cinematography to ascertain whether coherent structures play a significant role in large-scale turbulent diffusion flames.

A subcontract effort is planned to characterize in detail long turbulent diffusion flames of both pulverized coal and heavy fuel oil at various scales.

SECTION 5

SUMMARY

This paper has reviewed the effort which is currently underway or planned in the FCR program elements concerned with numerical model development and transport processes. One key feature of the overall approach is the use of limit-case models to evaluate the lower bounds on NO_x production which are set by practical constraints. Examples of such limit-case studies are provided by the use of simple gas phase reactors with a suitable reaction set in order to evaluate the optimum time/temperature stoichiometry history of staged combustion systems. Figure 1 provides an example of one such study. The decay of XN specie in a fuel-rich combustor is kinetically-limited and the optimum combustor will be a compromise between volume and pollutant emissions. Thus it is necessary to maximize the rate of XN decay in a fuel-rich zone. The example shown in Figure 1 illustrates how distributed air addition to a fuel-rich region can maximize this decay rate. Further calculations of this type are planned involving heterogeneous as well as gaseous systems.

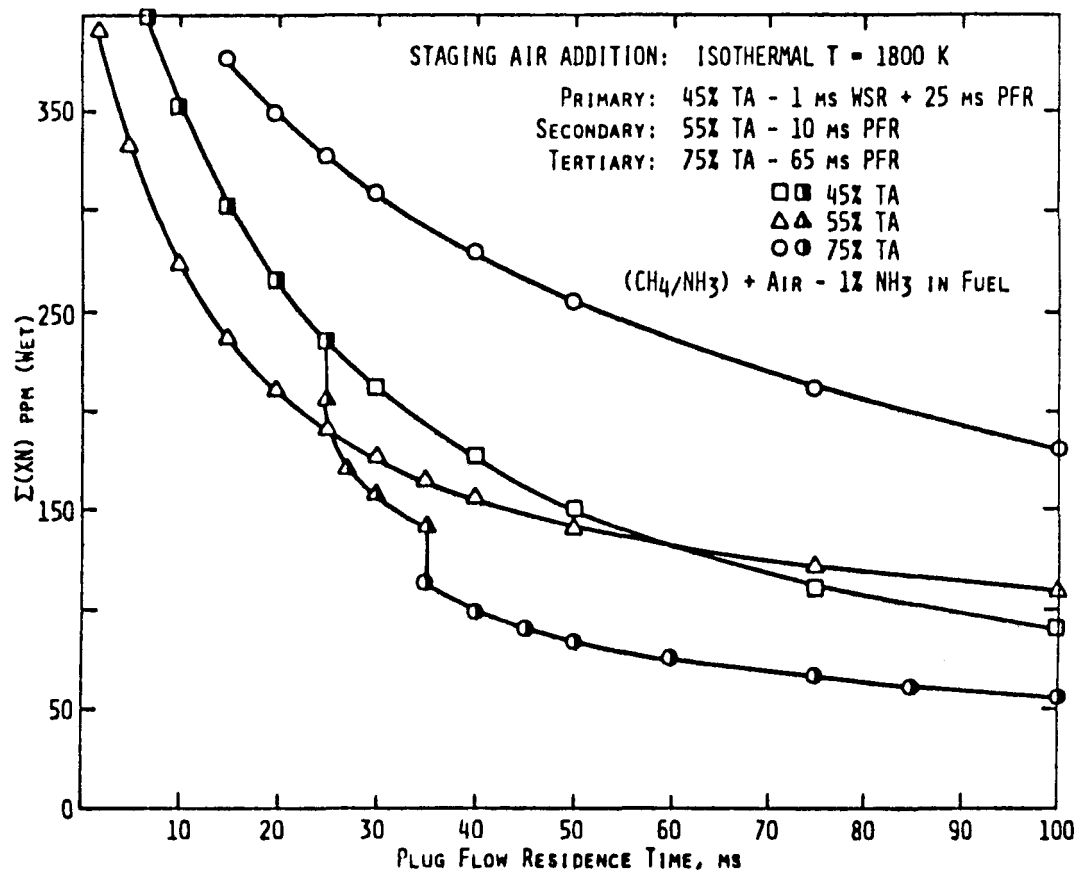


Figure 1. Decay Rate of Total XN Species in Isothermal Plug Flow Reactor as a Function of Stoichiometry and Temperature Showing that Distributed Addition Maximizes Decay Rate

APPENDIX B. BASICS OF NO_x AND SOOT FORMATION OF FLAMES

The following sections describe some of the intermediate reactions involved in the formation of thermal and fuel-derived NO_x in flames, and in the formation and burnout of soot. These sections were prepared for Report 3.1.1 on gas turbines, in this report series, from which their numbering derives. The chemistry described applies equally well to the understanding of the boiler flames discussed in this report.

C. AIR-DERIVED NO_x

C.1 MECHANISMS FOR AIR-DERIVED NO_x

The formation of NO_x from atmospheric nitrogen in a flame is well understood. The maximum temperature of a hydrocarbon flame in air at one atmosphere pressure is approximately 2200°K, or 3500°F, with a stoichiometric fuel-air ratio. If the conversion of N₂ to NO_x were sufficiently rapid, the NO_x concentration would reach its thermal equilibrium value at 4000 ppm. The actual NO_x concentration reached is only 50-200 ppm, because NO is formed slowly via the well-known Zeldovitch free radical chain reactor.



In addition, 2-5% of the NO is usually further converted to NO₂, the total concentration of NO and NO₂ being denoted "NO_x."

Most commercial burners operate with large turbulent diffusion flames, and many of these are of sprays of liquid fuels. It is impossible to observe details of the chemistry of the gas phase flame fronts in such flames, because they are obscured by the droplet vaporization, turbulent eddies of changing concentration, temperature and position, etc. Rather, bench-scale laboratory burners have been used, which produce stationary flat flame fronts or other stable simplified geometries whose zones can be sampled.

A brief description of the structure of a flame is needed to exemplify this process; a premixed flame is used as the simplest case for discussion. The fuel/air ratio is designated by the fuel equivalence ratio ϕ_f , actual fuel/stoichiometric fuel; ϕ_f is less than one for a flame receiving more than enough air to consume all the fuel, the usual mode of operation of combustion equipment. Typically, an industrial furnace would receive 110% of the stoichiometric air, or 10% excess air, and $\phi_f = 0.91$.

In a non-turbulent (laminar) flame of a mixture of fuel vapor and air (a "premixed" flame), the primary flame zone is only a few mm thick, and

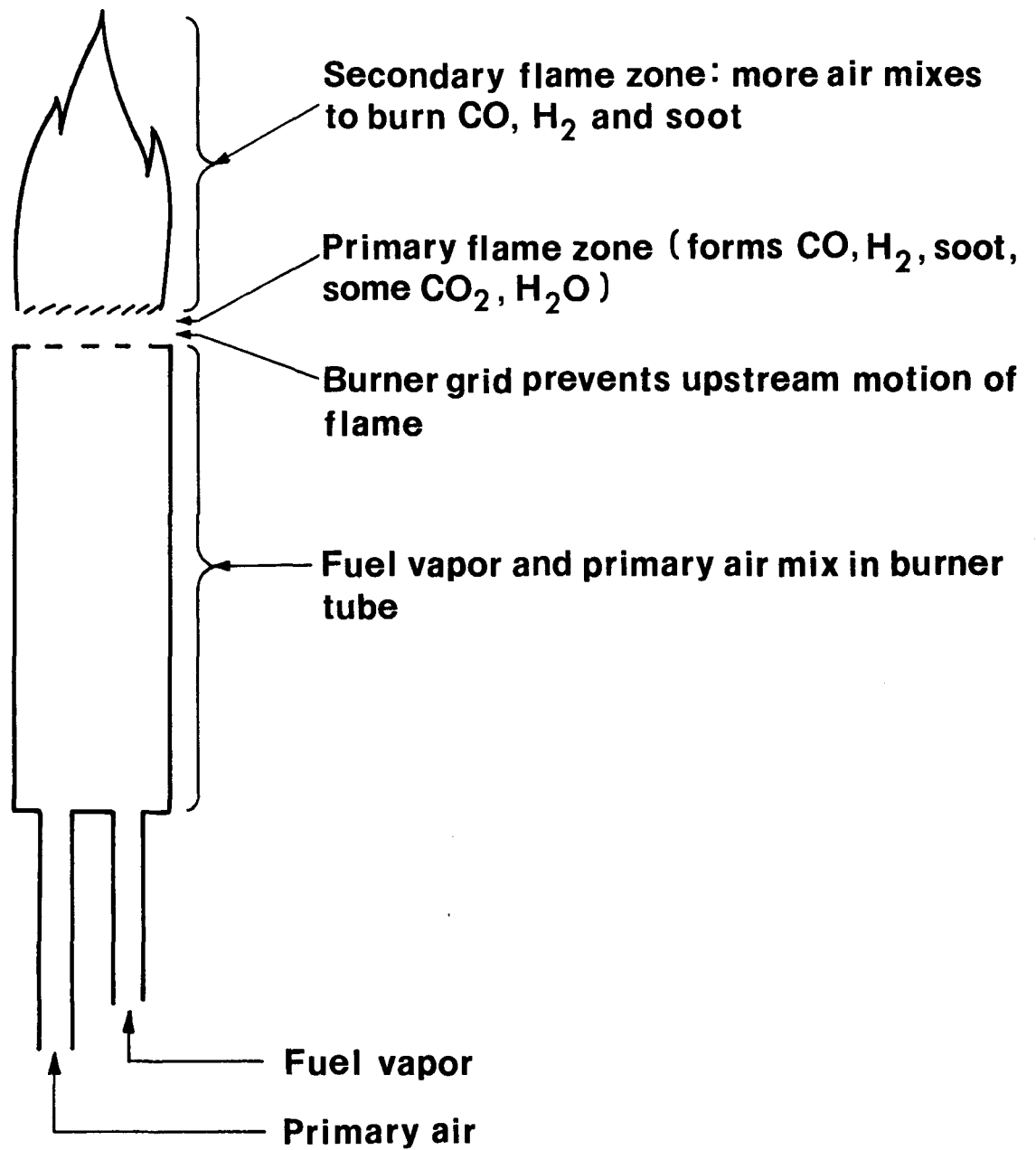


Figure C.1-1 ZONES IN A LAMINAR PREMIXED FLAME

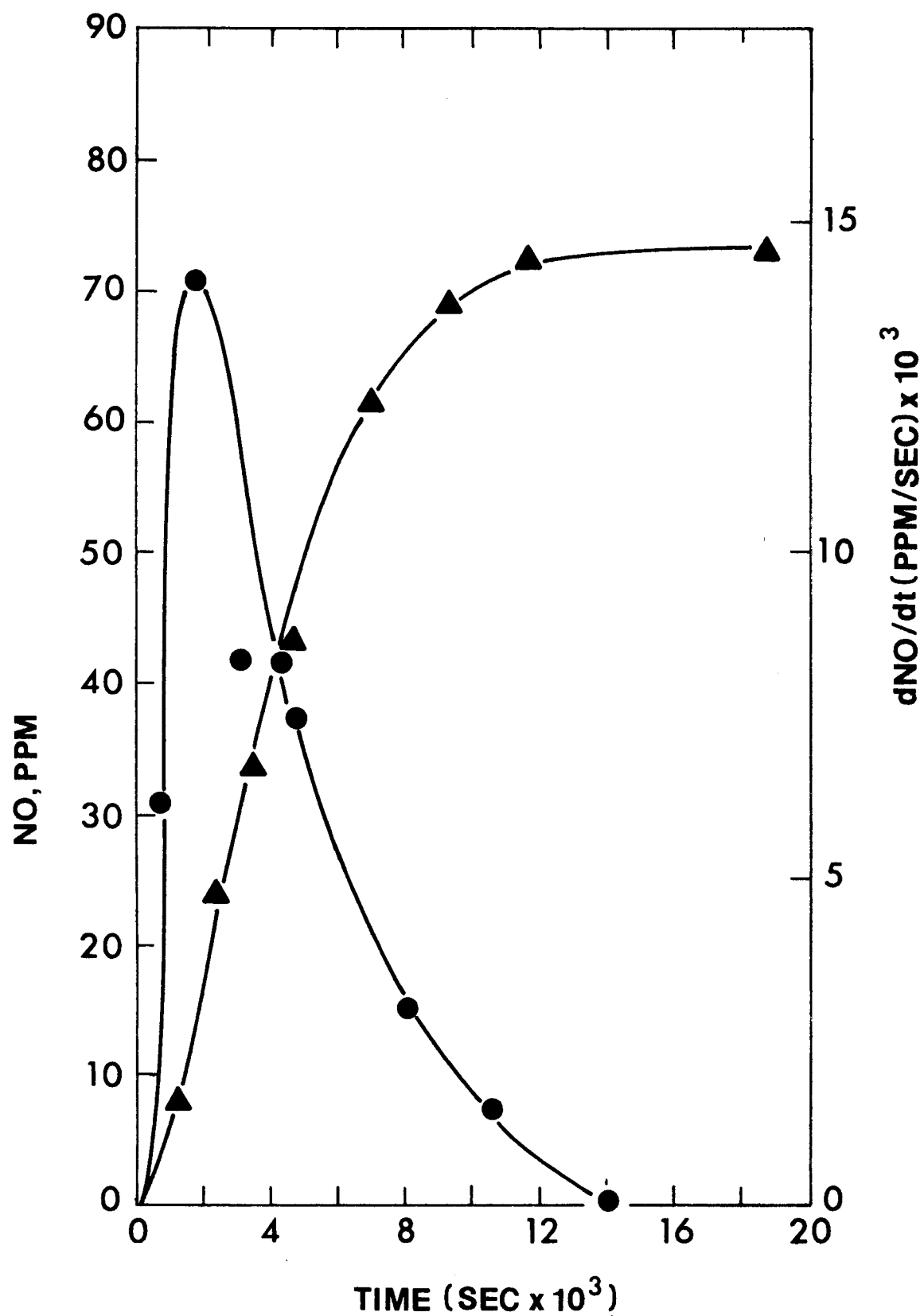


Figure C.1-2 RATES OF FORMATION AND CONCENTRATIONS OF NO AS A FUNCTION OF RESIDENCE TIME [15 PERCENT EXCESS AIR] (FROM REF. C.1-2)

within this zone NO_x is rapidly formed and the fuel is partially oxidized to CO and H_2 within a few msec. (See Figures C.1-1 and C.1-2). The secondary flame zone is downstream from the primary zone; and here, within 10-100 msec, the CO and H_2 are consumed and the gas cools rapidly below the temperature where NO_x formation rate is appreciable^(1,2). Although downstream from this point the thermal equilibrium NO_x concentration becomes less than the actual NO_x concentration, the latter does not decrease further because the path for NO_x destruction, the Zeldovitch mechanism, has become too slow.⁽³⁾ (NO_x refers to the usual existence of 1-5% of nitric oxides as NO_2 .) The NO_x concentration is "frozen in" at that concentration. The NO_x formed by this process is termed "thermal NO_x ." Amounts of NO_x in excess of this have been observed under conditions representing gas turbine combustors, being rapidly formed in the primary flame zone and termed "prompt NO_x ."⁽²⁾ It is observed only in hydrocarbon flames. Thermal NO_x emissions from a wide variety of aircraft engines have been found to correlate with the flame temperatures; see the data in the curve in Figure C.1-3. This empirical correlation agrees with the Zeldovitch expression based on elementary reaction rate data.

This great suppression of thermal NO_x emissions by decreasing the flame temperature by a few hundred degrees has been utilized for pollution control. Several combustion modification methods have been used to achieve this, all by increasing the gas (air or water) flow rate to the flame, increasing the gas mass/combustion enthalpy release ratio, and lowering the flame gas temperature. This approach has also been used with boilers, using water injection or flue gas recirculation for the added mass.

C.1 REFERENCES

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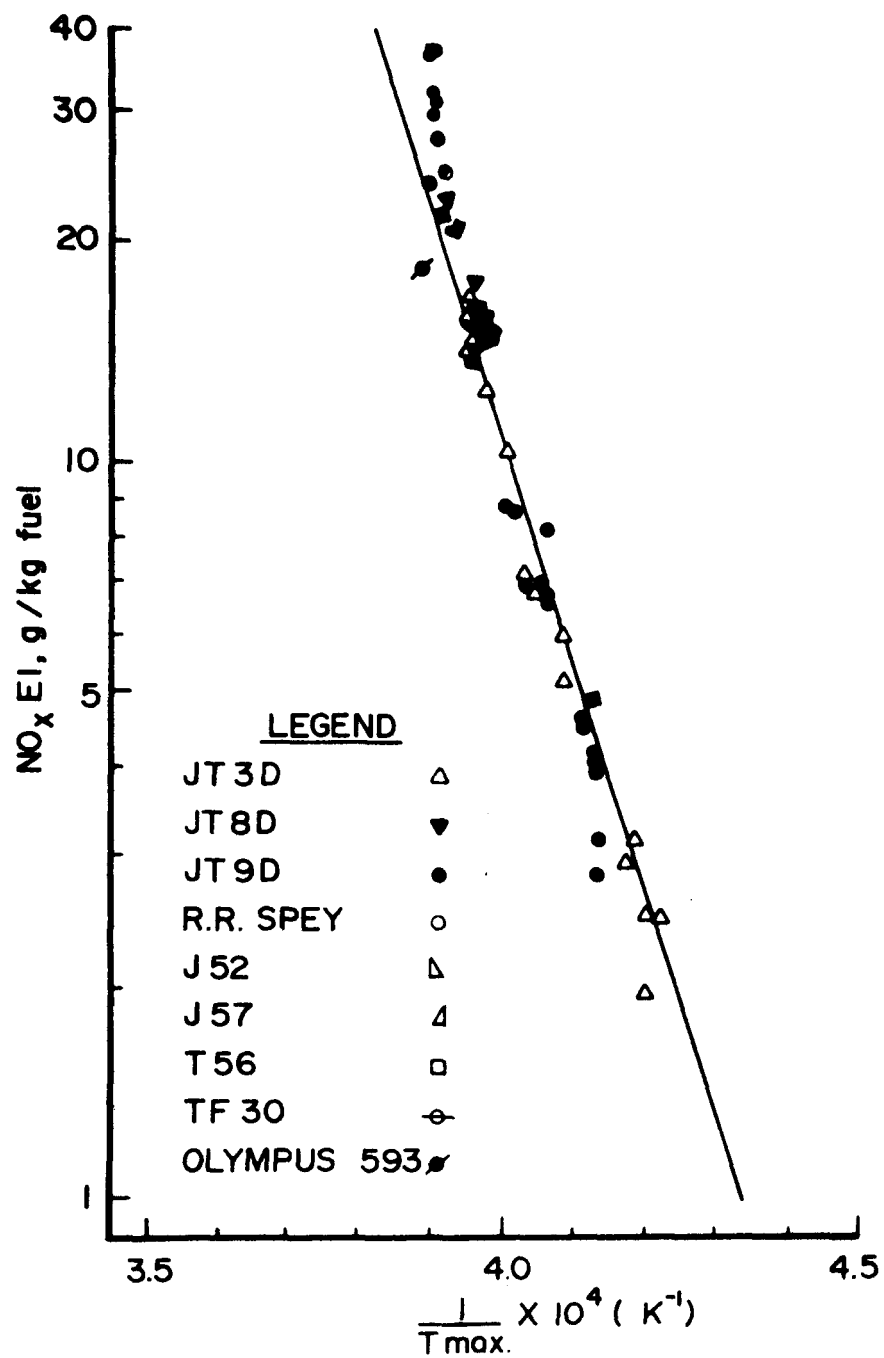


Figure C.1-3 RELATION OF THERMAL NO_x TO FLAME TEMPERATURE (FROM REF. C.1-4)

C.2 THERMAL NO_x REDUCTION IN FRAME-TYPE GAS TURBINES

In the following some examples of reduction in NO_x emissions from frame-type heavy duty gas turbines (in contrast to aircraft engines) are presented. The drawbacks or trade-offs resulting (e.g., smoke increase) will be mentioned here, but a systematic discussion of smoke will be presented later, in section E.

Single shaft gas turbines have the compressor vanes and depressurizing turbine blades on a single shaft, which is also connected to an electric generator, and these components all rotate at constant speed. Increases in load on the generator cause increases in fuel firing rate and the temperature of the combustor outlet (turbine inlet) gases. Since the temperature of the gases in the combustor increases greatly, but their residence time at this temperature changes less, more thermal NO_x is produced. Figure C.2-1 is an example of this increased NO_x production. Curve I is for an unmodified combustor; at the lowest load, only 20 ppm NO_x were produced, and the gas flowing through the combustor was heated by 350°F, from the 300°F combustor inlet temperature (typical) to the 650°F turbine inlet temperature.⁽¹⁾ At the highest load, the combustor temperature rise was 1100°F, the turbine inlet temperature was 1450°F, and 180 ppm NO were produced. At full load, the overall fuel-air ratio was 0.018 lb fuel/lb air, or 390% of stoichiometric air.

This test was conducted on a Westinghouse Electric W-251 gas turbine rated at 25 MW. In unmodified operation, each combustor (it has eight combustors) received 110% stoichiometric air at the primary zone, 29% of the total air flow. Reduction of NO_x emission was first attempted by reducing the residence time of the gases in the primary flame zone, by moving the dilution holes in the combustor liner closer to the primary zone for quicker dilution or cooling of the gas. This reduced the NO_x emissions by 60 ppm (Curve II). Secondly, cooling of the primary zone flame itself was done by increasing the air flow rate to the primary zone to 45% and 100% of the total air flow (Curves III and IV, resp.), via changes in the liner holes. This achieved a further reduction by 40 ppm of NO_x. General Electric achieved a similar NO_x reduction by primary zone leaning of this sort.⁽²⁾

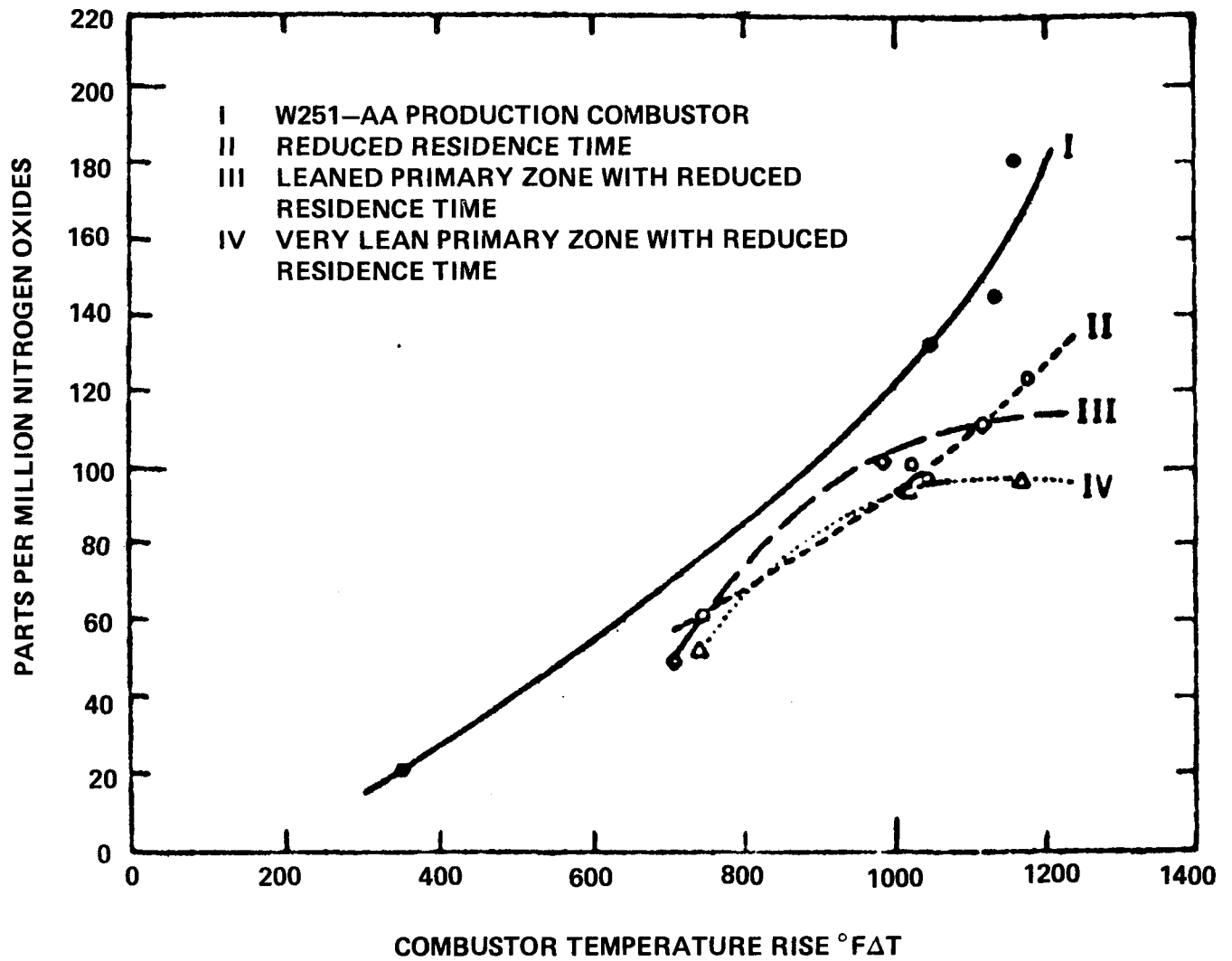


Figure C.2-1 SUPPRESSING THERMAL NO_x BY FLAME COOLING (FROM REF. C.2-1)

This approach of reducing NO_x by cooling the flame tends to have several drawbacks, including increased emissions of CO, hydrocarbons and soot where complete consumption is retarded in a cooler flame and narrowed operational limits for flame stability. Figures C.2-2 and C.2-3 show that as the combustor gas temperature decreases with lower load (lower fuel-air ratio in Figure C.2-3 and lower firing temperature in Figure C.2-2), CO and hydrocarbon emission suddenly increase; this principle applies to reducing the fuel-air ratio in the primary zone.⁽³⁾

Injection of water into the primary zone has also been tested for the past 5-10 years for thermal NO_x suppression, with considerable success. From a number of studies, correlations of the effects water injection been uncovered for frame-type and aircraft-type combustors. These correlations show the exponential-like rise in NO_x with flame temperature, characteristic of the Zeldovitch mechanism for thermal NO_x .

The example shown in Figure C.2-4 is taken from a recent test on a GE 75MW ten-combustor machine, equipped with a film-cooled liner permitting higher temperature operation, and instrumented for flow and temperature measurements.⁽⁴⁾ It is first to be noted (top curve) that at full load, the combustor exit temperature is 2200°F, (1500°K) considerably higher than the 1800°F discussed above, and the NO_x is 280 ppm. At part load, with a combustor exit temperature of 1800°F (1230°K) the NO_x is 100 ppm, consistent with earlier low-temperature turbine operation.

On these tests, firing No. 2 fuel oil, the NO_x was, for example, reduced by 50% when the water mass injection rate was 1.0% of the combustor air flow rate; this water mass flow rate is approximately 50% of the fuel mass flow rate. The other curves show the further NO_x reduction from still greater water injection rates. Field studies have verified the approximately 50% reduction in NO_x by water injection at this rate. Smoke was unaltered by water injection, but CO emission increased, the same drawback as occurred in the other flame-cooling NO_x suppression approach, i.e., leaner primary zones. The other disadvantage in commercial use of water injection is the need for a

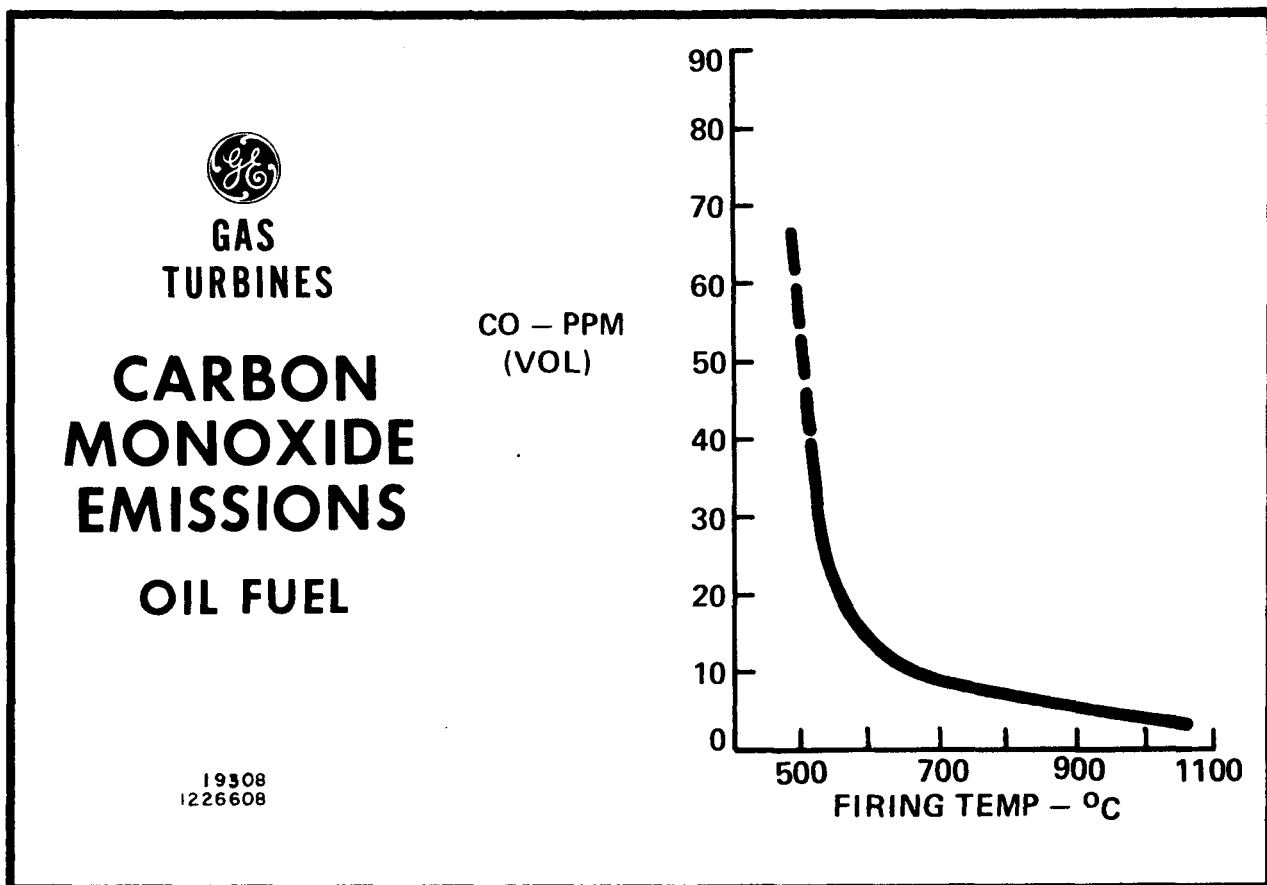


Figure C.2-2 COOLING FLAME INCREASES CO EMISSIONS (FROM REF. C.2-2)

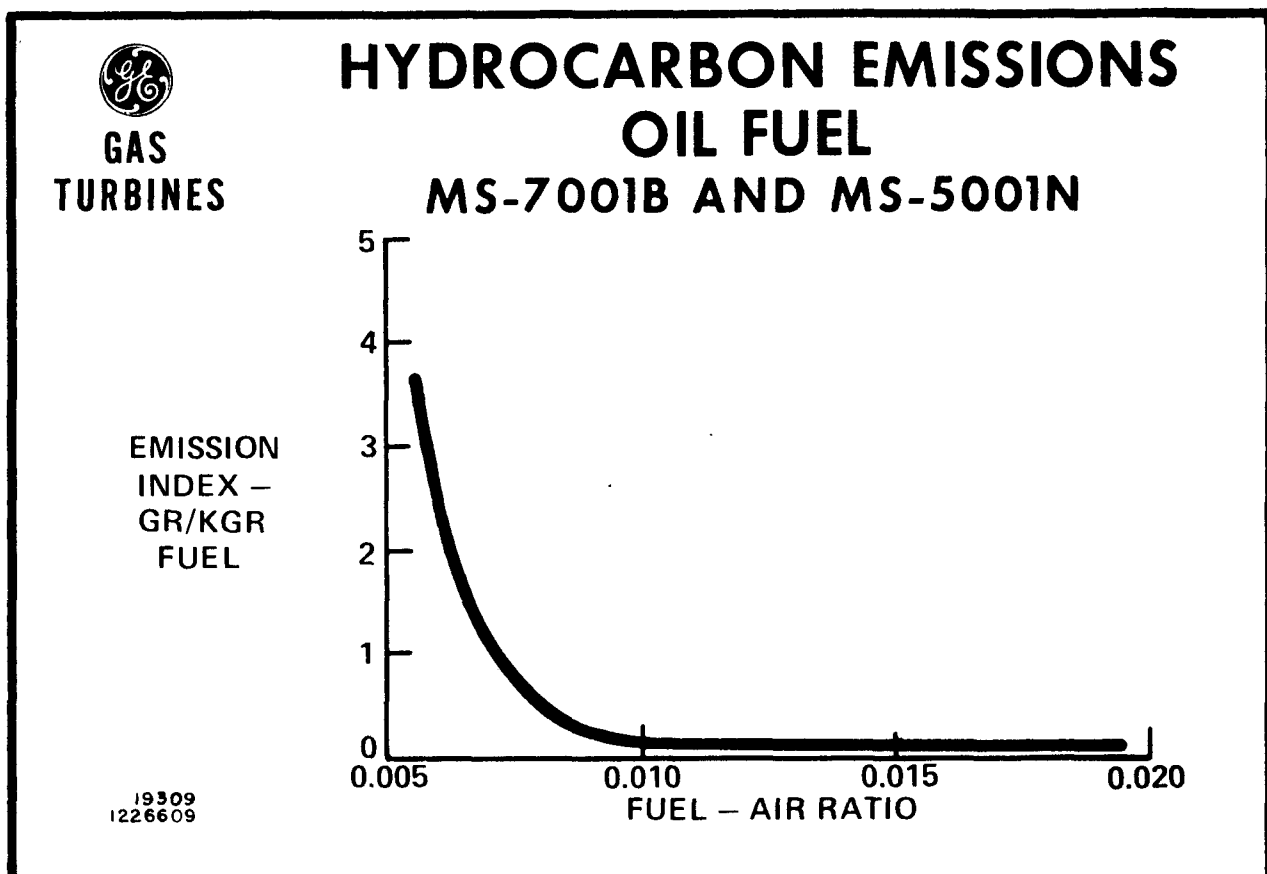


Figure C.2-3 LEANING INCREASES HYDRO CARBON EMISSIONS (FROM REF. C.3-2)

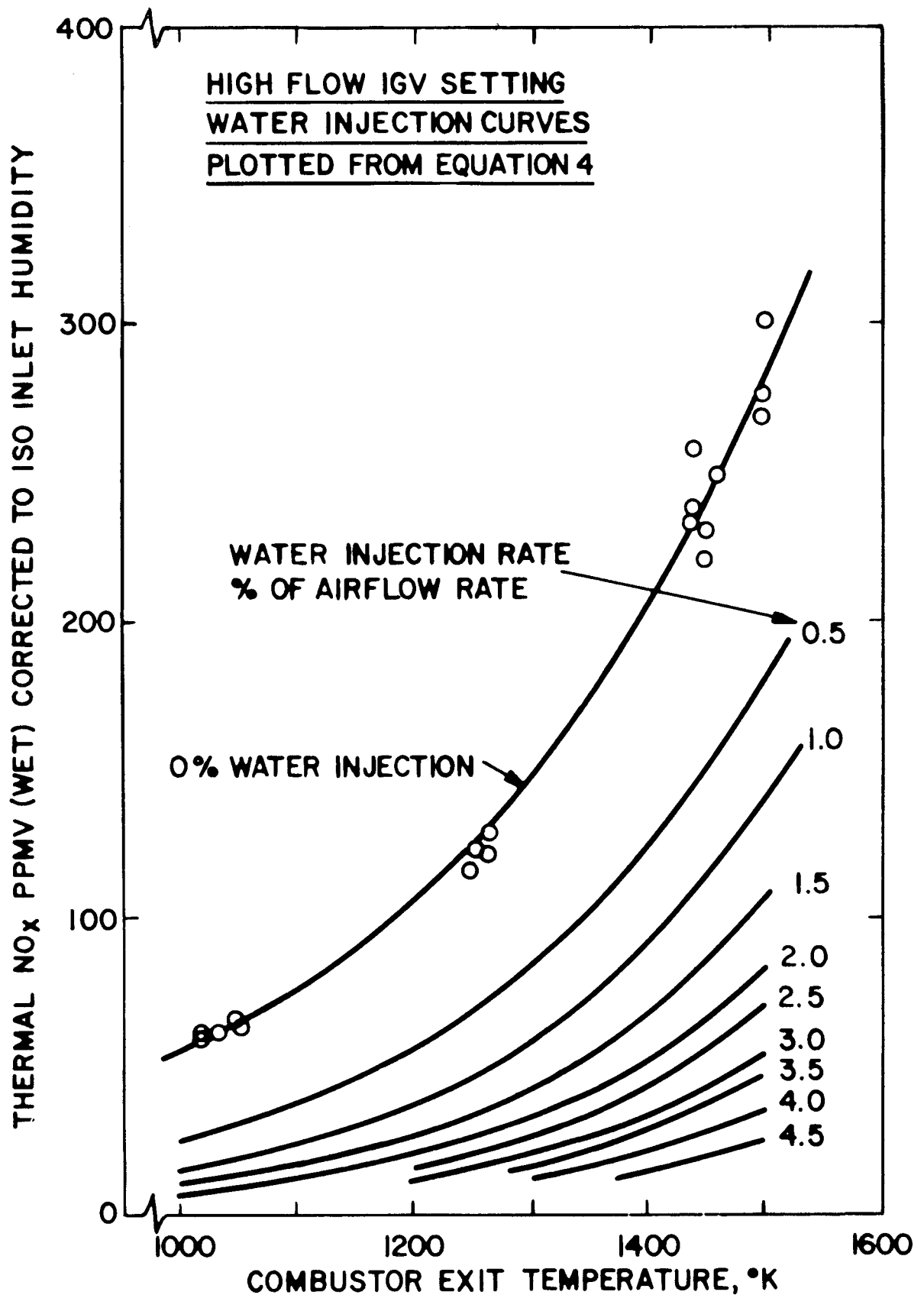


Figure C.2-4 THERMAL NO_x — EFFECT OF
COMBUSTOR EXIT TEMPERATURE AND WATER

water supply and a demineralizing facility having appreciable capital costs and requiring operator attendance. All of these technical and commercial limits to water injection for NO_x reduction have been analyzed in Reference 5. Although it is advantageous in some localities, there has been a general need for "dry" NO_x control techniques.

C.2 REFERENCES

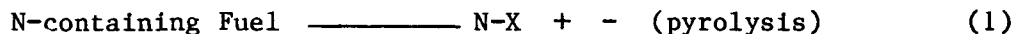
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D.2 Basic Mechanisms of Fuel Nitrogen Conversion to NO or N₂

The empirical observations of fuel-NO_x suppression in boilers (Section D-3) were studied in bench-scale burners and reactors in flames of greatly simplified geometry, such as described in Section C-1. These experimental studies uncovered numerous steps in the sequence of the conversion of fuel-nitrogen, which strongly interacted with the geometry-dependent mass transport processes, in contrast to thermal-NO_x formation process. In spite of this complexity, the analysis of these complex fuel-NO formation processes is now complete enough for qualitative interpretation of the major effects observed in boilers. Furthermore, thermal and aerodynamic mass transport models have been developed to successfully model some simple boiler and gas turbine flames and their fuel nitrogen chemistry. Here, items relevant to SRC-II fuel oil combustion will be selected in order to provide some qualitative insights.

D.2.1 The Nitrogen Intermediate and Competing Reaction Paths

One of the first demonstrations in a simple laboratory flame of the reduction of fuel-NO_x by decreased excess air or increased fuel equivalence ratio (ϕ_f) was by Fenimore,⁽¹⁾ who burned N-doped ethylene in a flat-topped burner, and measured the yield of fuel-NO, the fraction of fuel-nitrogen converted to NO.⁽¹⁾ Four additives were used: pyridine, methacrylonitrile, methylamine, or ammonia. The fuel-NO_x yield was nearly 100% when the flame was fuel-lean ($\phi_f = 0.9$), and when the added nitrogen dopant was dilute (630 ppm). At the other extreme, the fuel-NO_x yield was less than 10% in very fuel-rich flames ($\phi_f = 1.5$) with high nitrogen-dopant concentrations (25 000 ppm). From those data Fenimore hypothesized a mechanism involving the conversion of fuel-nitrogen into a nitrogen-containing intermediate molecule, NX, (reaction [1]) which could then either be oxidized to NO_x in a fuel-lean nitrogen-dilute flame (reaction [2]), or could react bimolecularly to form N₂ instead of NO_x (reaction [3]), in a fuel-rich high-nitrogen flame.



This competing-pathway mechanism quantitatively fit the data over the ranges of fuel equivalence ratio and fuel-nitrogen concentration used, and this mechanism also provides a useful qualitative visualization of how the rich-lean combustor design is effective in suppressing fuel- NO_x . However, this mechanism did not describe other more complex flames, for which purpose a great amount of subsequent investigation has been required.

Another demonstration of the reduced fuel- NO_x yields in fuel-rich or high-nitrogen flames is the following experiment by Sarofim, et al.⁽²⁾ A flat flame burner was used, burning methane doped with ammonia. For example, (Figure D.2.1-1), in the set of dilute ammonia (0.5%) runs the fuel- NO_x yield is 100% until ϕ_f exceeds 1.0, whence the yield decreases rapidly.

An example of the detailed understanding of flame NO_x chemistry which has been developed since the above work is the analysis by Haynes⁽³⁾ of a premixed laminar flame on a flat flame burner, not only of the NO_x from the flame, but of the gas composition within the flame. (See Figure D.2.1-2). This experiment identified Fenimore's postulated intermediate as HCN, and demonstrated that its oxidation to NO quantitatively agreed with the competing path mechanism. Under Haynes' conditions, the oxidative path predominated, but other studies (Figure D.2.1-1), under other conditions, have demonstrated that the conversion of NX to N_2 by reaction (3) is fast enough to be effective in most flames⁽⁴⁾.

D.2.2. Initial Reaction Step of the Fuel and Effect of Fuel Type

Continuing the discussion of successively earlier steps in the sequence of reactions of fuel-nitrogen, the source of the HCN (or NH_x , also

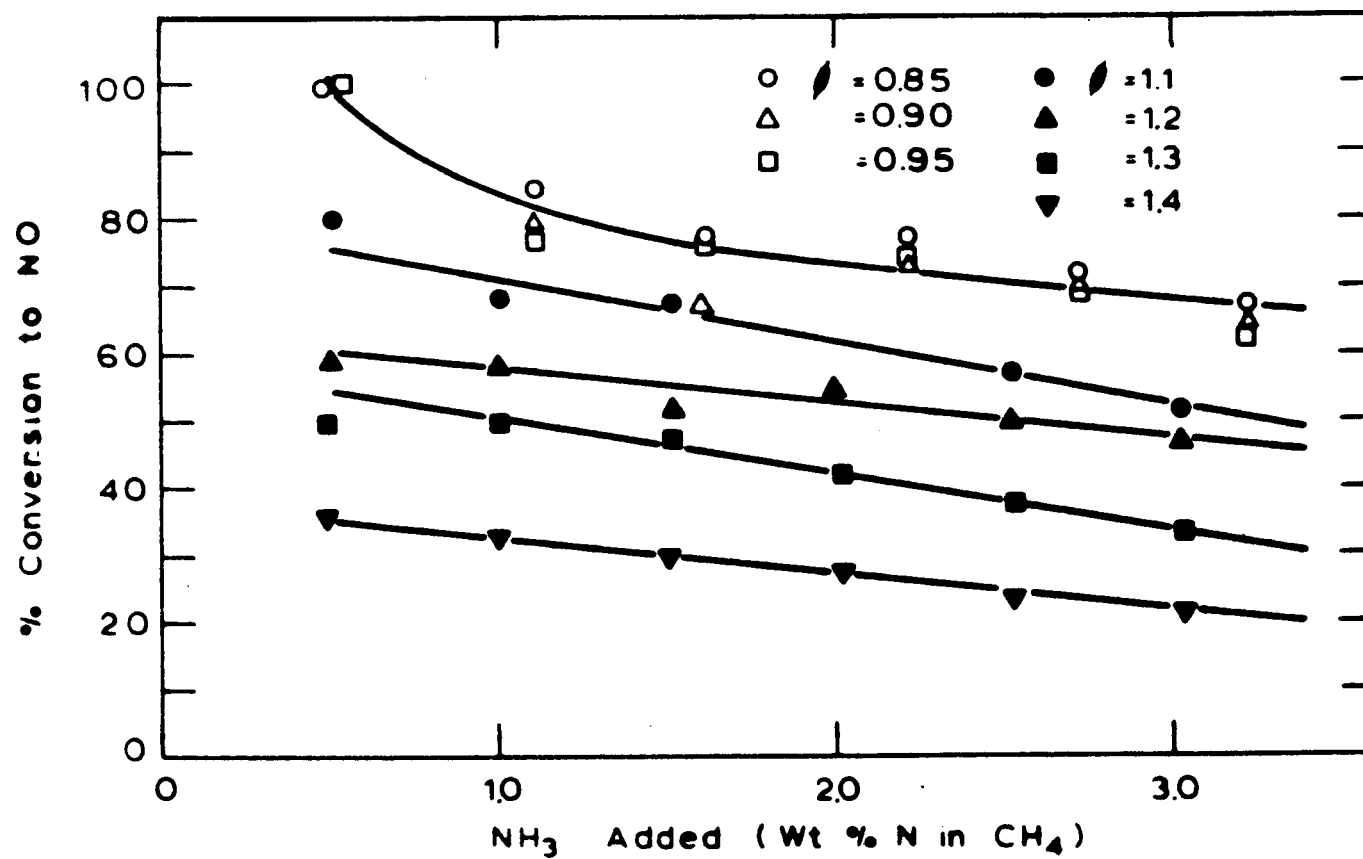


Figure D.2.1-1 FUEL-NO YIELD-EFFECT OF Φ_F
AND FUEL NITROGEN CONTENT (FROM REF. D. 2-2)

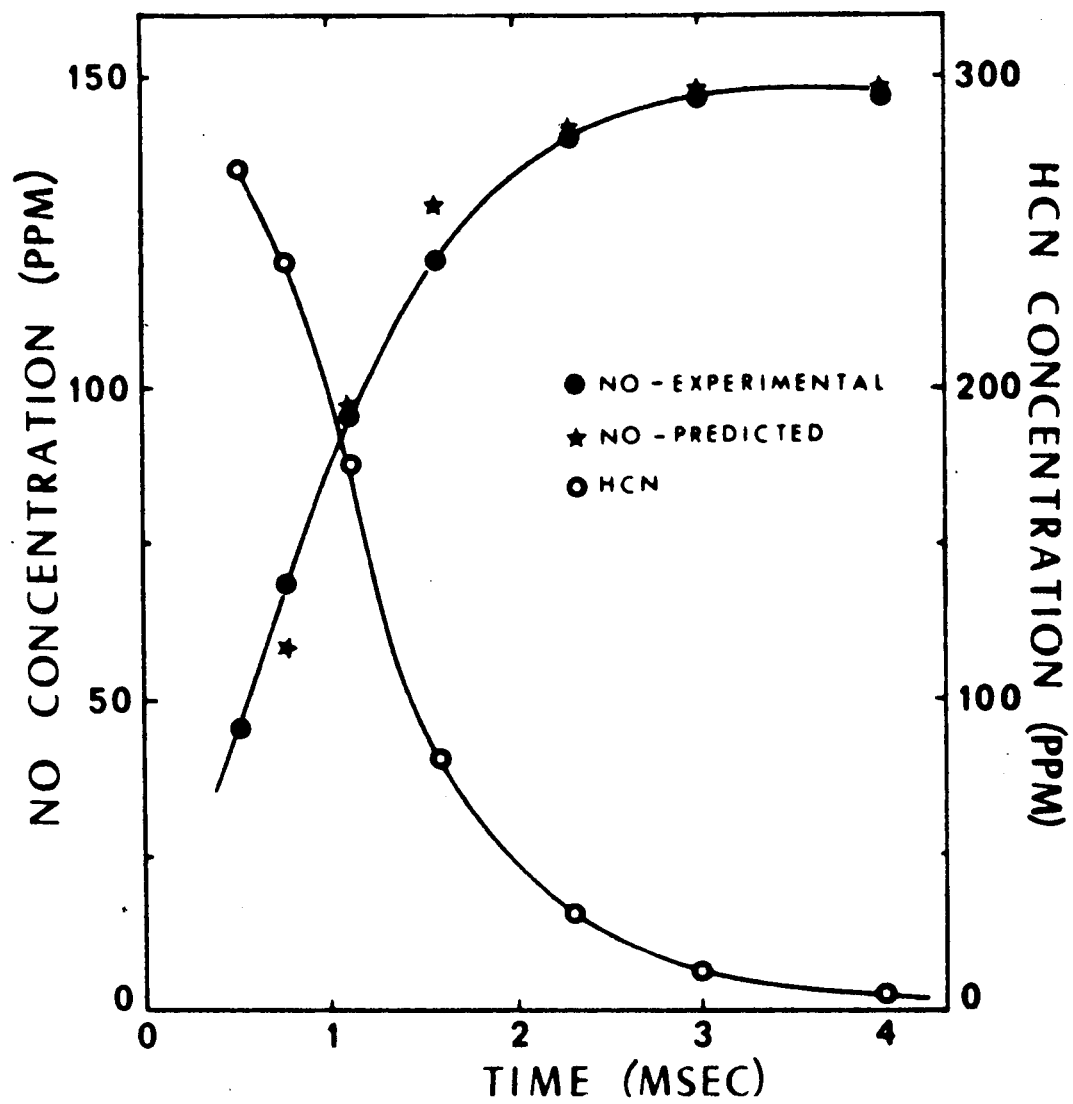


Figure D.2.1-2 INTERMEDIATE HCN FORMS NO (FROM REF. D.2-3)

identified as a possible precursor of NO, having a role similar to that of HCN) was shown to be pyrolysis of the fuel. In Figure D.2.2-1 the fuel (ammonia) is present at 50 ppm at the top of the burner plate where the combustion reactions begin; at increasing distances above the burner, downstream in the reacting gases, the ammonia quickly disappears between 0 and 6 mm, while HCN undergoes a corresponding increase in the same region of the flame, apparently being a product of the ammonia consumption.

Nitrogen present in other chemical forms in other fuels may react differently, and this question has been addressed by Axworthy⁽⁵⁾. In this study, the fuels used ranged from pure compounds (e.g., pyridine) to distillate and residual fuel oils and coal and shale-derived oils. When pyrolyzed in inert gas in a 2-cc sub-second residence time reactor at temperatures between 750 and 1100°C, HCN formed, its yield increasing sharply with temperature, but ammonia and N₂ were not formed. High HCN yields would increase the effectiveness of staged combustion, since nitrogen in this form would easily be converted to N₂, not NO. The HCN yields also varied with fuel type, as follows: No. 6 oil, 44%; coal liquid (from a catalytic hydrocracking process, 350-900°F distillate) 51%; shale oils, 60-70% and pyridine, 100%. The HCN yield apparently increases with fuel volatility, but may not imply that a non-petroleum fuel would yield more HCN than otherwise similar petroleum-derived fuel.

Furthermore, Figure D.2.2-2 shows that the more volatile fuels (shale oil or shale-derived diesel fuel [DFM], which resemble SRC-II fuel oil in their volatility) were easily converted to HCN at low reactor temperatures, in contrast to the residual petroleum oils and Synthoil, a coal-derived liquid with a residual-like distillation curve. Axworthy also added a second pyrolysis reactor immediately downstream from the first reactor, for some experiments with No. 6 oil. With the first reactor at a lower temperature than the second reactor, runs with increasing temperatures of the second reactor produced more HCN. This implies that the products from the first stage were some precursor to HCN, being converted to HCN only in the second hotter reactor.

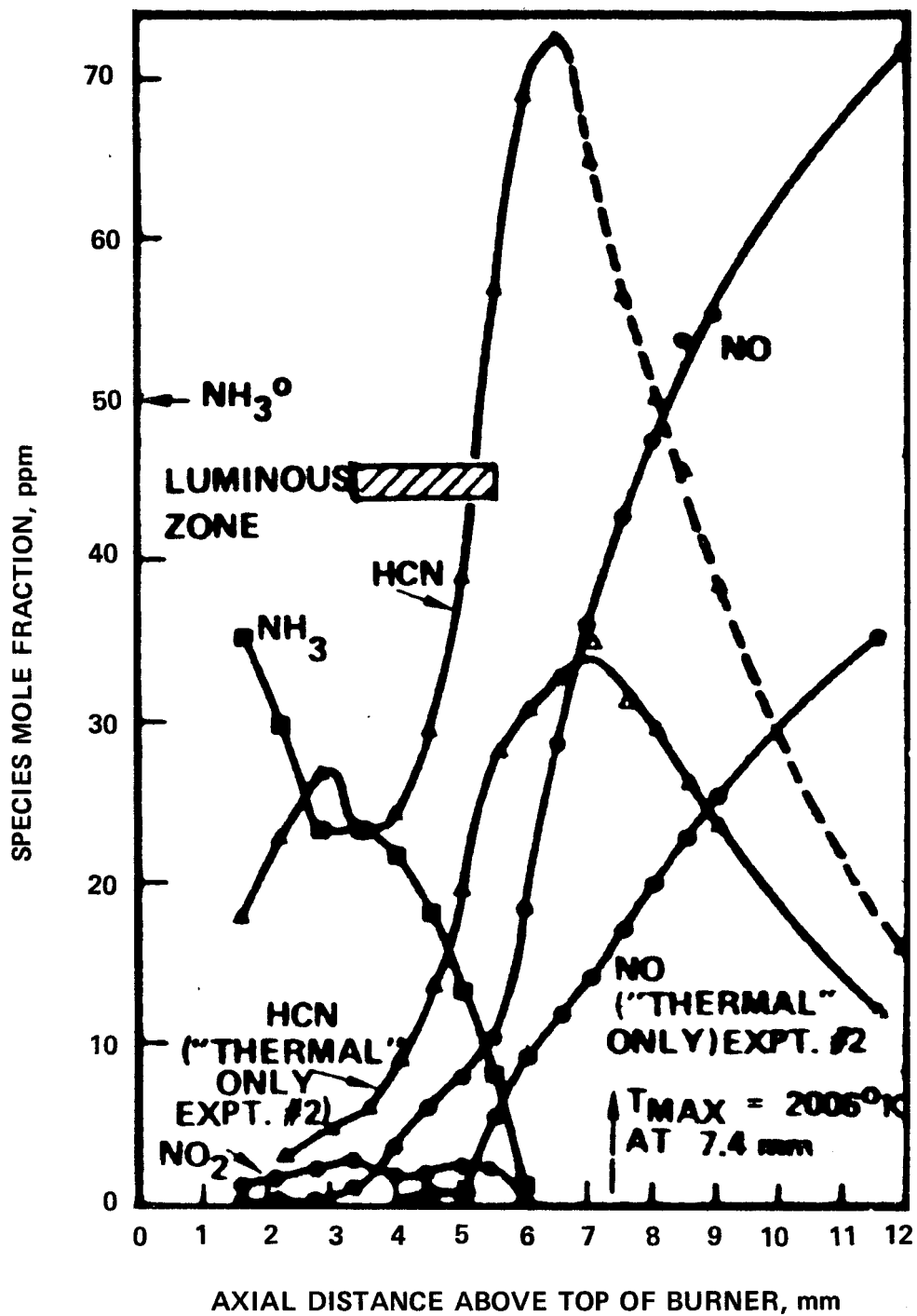


Figure D.2.2-1 FUEL-NITROGEN (NH₃) CONVERSION TO HCN
(FROM REF. D.2-5) PRESSURE = 76 TORR,
 $\phi_F = 1.5$, 50 PPM NH₃ IN FUEL

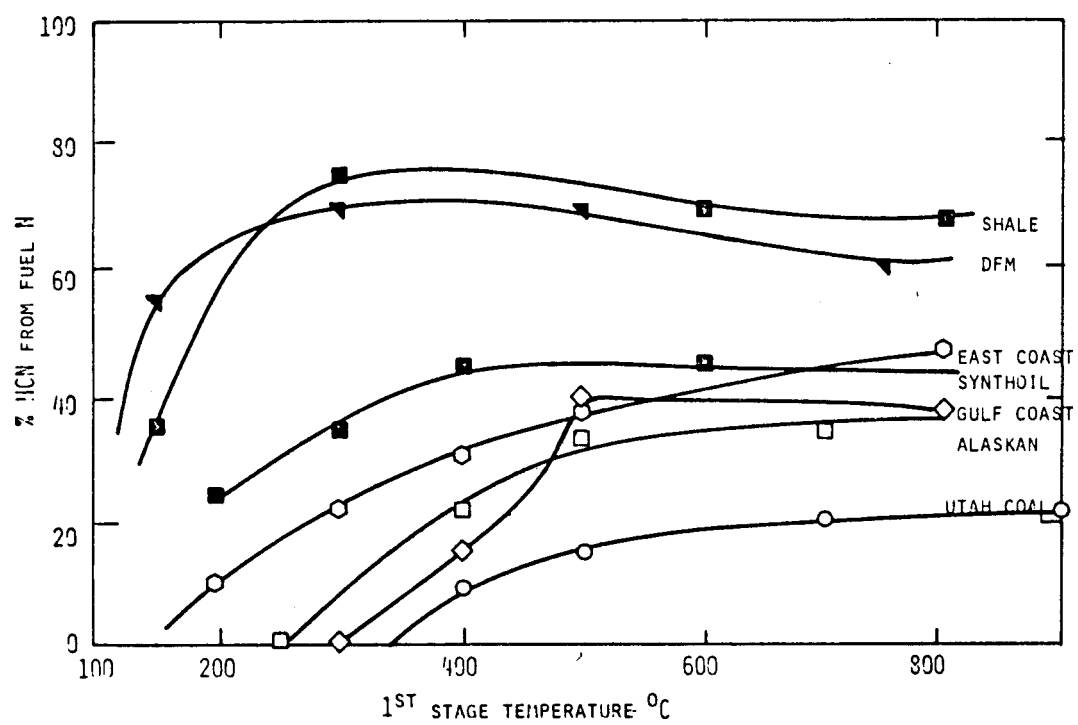


**Figure D.2.2-2 HCN YIELDS – PYROLYSIS OF FUELS
OF VARYING VOLATILITY (FROM REF. D.2-5)**

D.2.3. Other Flame Geometries and Fuel-Nitrogen Conversion

Fuel-nitrogen conversion to NO_x has also been studied in laboratory burners having air-fuel mixing geometries differing from premixed laminar axisymmetric flames discussed above, and large effects were observed, which are critical in applying the basics discussed here to commercial burner design with complex mixing geometries. Sarofim, et al.,⁽²⁾ studied an axisymmetric diffusion flame of methane (inner 2.5 cm dia cylinder) surrounded by an outer cylinder (7.5 cm outer diameter) of air flowing with the same direction and velocity as the fuel. The fuel- NO_x yields were much less than those observed in premixed flames; for example, in the run with 0.5% ammonia, the fuel- NO_x yield from this diffusion flame was 30%, in contrast to 100% in the premixed flame discussed above. Furthermore, when the ammonia was added to the air stream rather than the fuel stream in the diffusion flame, the fuel- NO_x yield decreased to 20%.⁽⁷⁾

This result is consistent with the competing-path mechanism as follows: Ammonia is pictured in the inner cylindrical stream of fuel, diffusing towards the boundary between the fuel and air zones, where the sheet-like diffusion flame is located. As ammonia approaches the flame, it is pyrolyzed to "XN" fragments, but there is no air to oxidize them to NO_x , and they take the other path instead, to N_2 . This is an oversimplified picture, of course, and diffusion flames of nitrogeneous fuels are undergoing sophisticated spatially-resolved experimental and interpretive analysis which continues to increase our detailed understanding of these reactions.

Important fuel- NO_x yield measurements have also been made on a jet-stirred reactor which is at the other extreme of the scale of fuel-air mixing rates, and which resembles a well-stirred reactor model used to model the first stage of a staged combustor. In the experiment represented in Fig. D.2.3-1 in which ammonia-doped methane was used, the fuel- NO yield was 65% at stoichiometric (100% theoretical air), but decreased rapidly, to only 15% at 65% stoichiometric air. The predicted points in this figure will be discussed later.

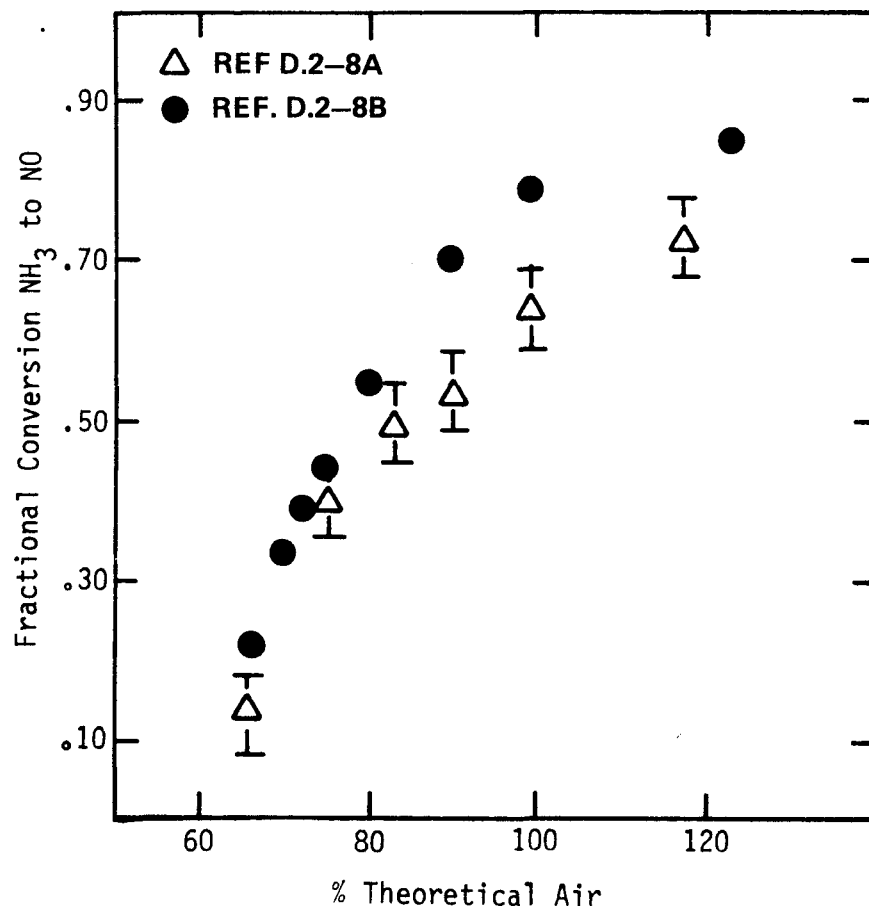


Figure D.2.3-1 LOW NO_x FROM RICH WELL-STIRRED REACTOR FLAME
(FROM REF. D.2-8A)

D.2.4 A Strategy for Fuel-NO_x Suppression; Thermodynamic Limits

After the empirical discovery of fuel-NO_x suppression by staged combustion, the study of the chemical and fuel-air mixing substeps of this process began, and as the foregoing examples have shown, revealed a strategy (Figure D.2.4-1) of substeps which needed to be enhanced (reaction [3]) or suppressed (reaction [2]) in efforts to design low-emissions equipment. The first need was to determine what the fuel-NO_x yield would be if the reaction (1-3) were fast enough for the gases in the first stage to reach thermodynamic equilibrium. Sarofim⁽⁹⁾ calculated the equilibrium concentrations of "fixed nitrogen species" (NO, HCN and NH₃, which would all become NO emissions upon entering the second stage) as a function of fuel equivalence ratio ϕ_f and gas temperature in the first stage. Figure D.2.4-2 shows the results for a fuel having a H/C atomic ratio of 1.3, typical of a coal liquid. (These equilibrium calculations are independent of the fuel nitrogen content, the nitrogen atom level in the system being set by the nitrogen content of air.) For example, for 2000°K, the fixed nitrogen species have a minimum concentration of 200 ppm (the EPA limit for oil fuel) when the fuel equivalence ratio is 2.6. Figure D.2.4-3 replots these results in a way that clarifies air preheat as well as high ϕ_f as an optimum strategy for fuel-NO suppression; the derivation of this conclusion is described by Sarofim in the following excerpt from Reference 9.

. . . most experimental measurements of bound nitrogen species for equivalence ratios greater than 1.2 greatly exceed the equilibrium values, suggesting that kinetic constraints prevail. This is not surprising since the adiabatic flame temperatures at high fuel equivalence ratios are low. The plots show, however, that at the high equivalence ratios the temperature could be raised considerably above the adiabatic temperature without exceeding the equilibrium NO_x constraint. For example, for H/C = 1.3 and $\phi_f = 1.6$ the temperature could be raised to above 2400°K. These arguments suggest that fuel-rich operation (to overcome the thermodynamic constraint) with high air preheats (to overcome the kinetic constraint) is desirable for minimizing the conversion of fuel nitrogen to nitric oxide.

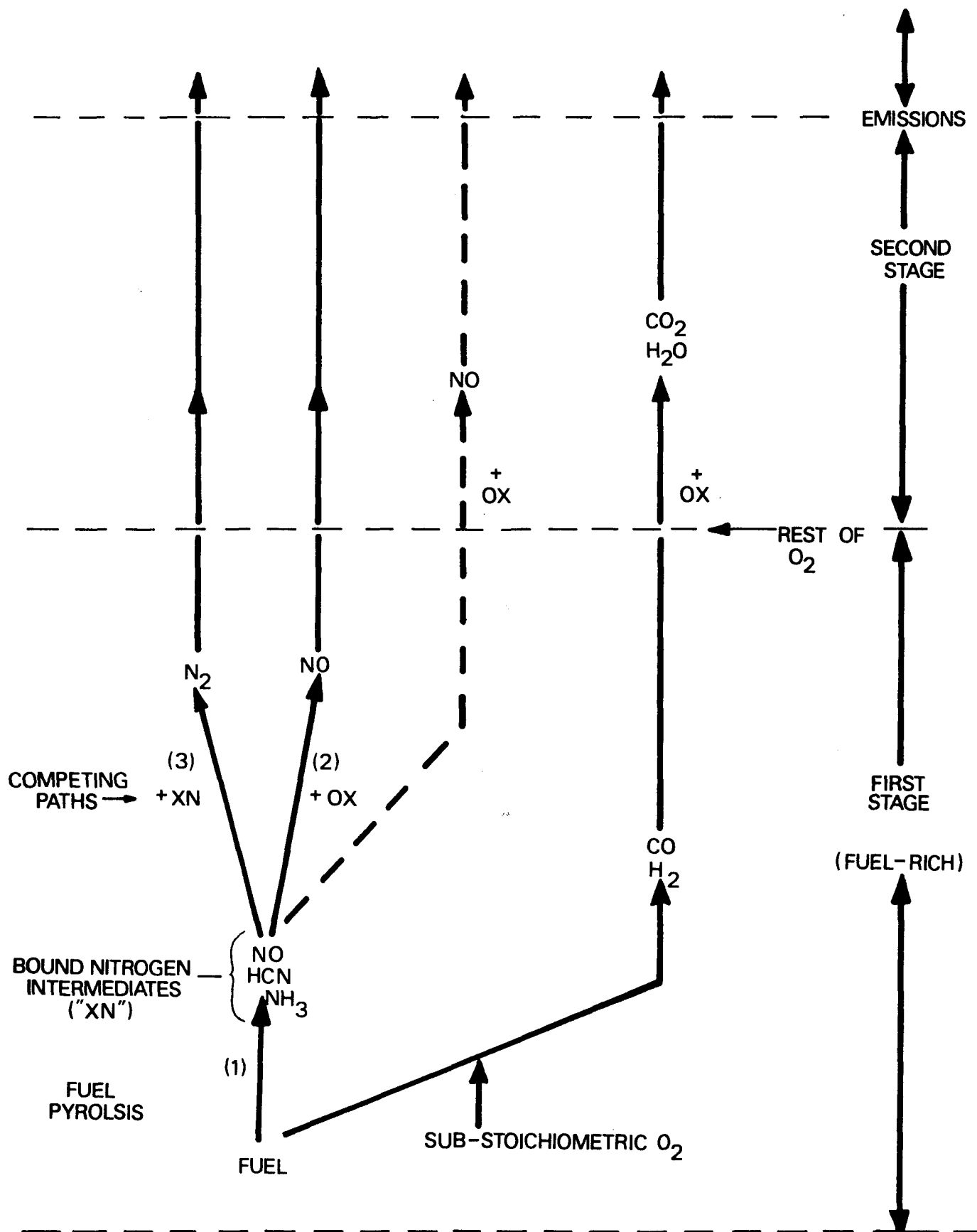


Figure D.2.4-1 CHEMICAL PATHWAYS IN TWO-STAGE FLAME

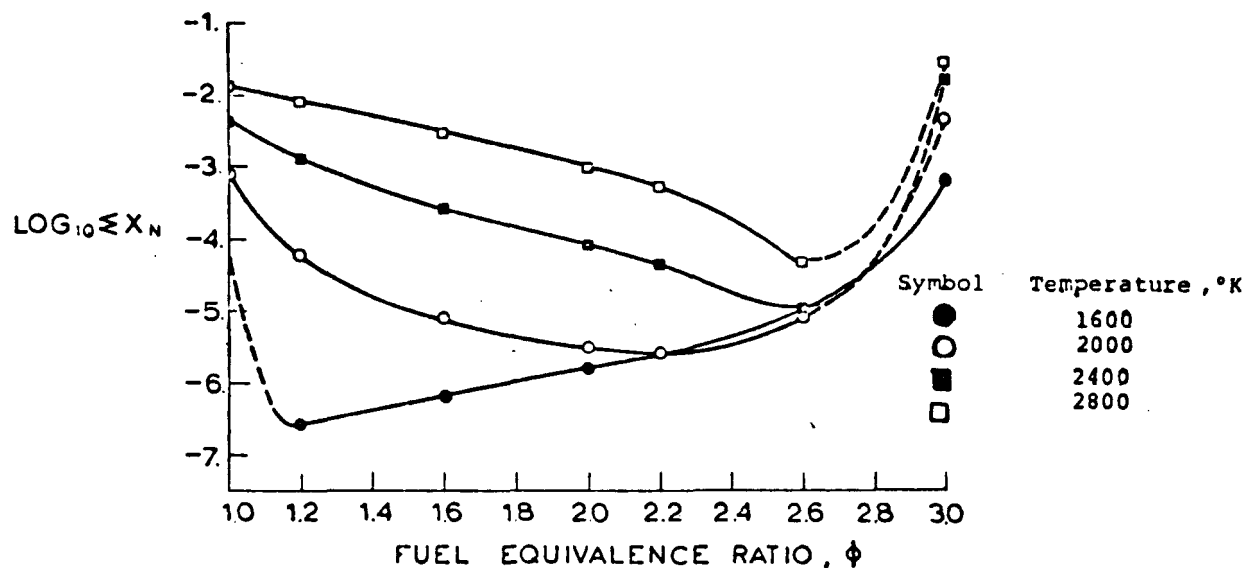


Figure D.2.4-2 (FROM REF. D.2-9)

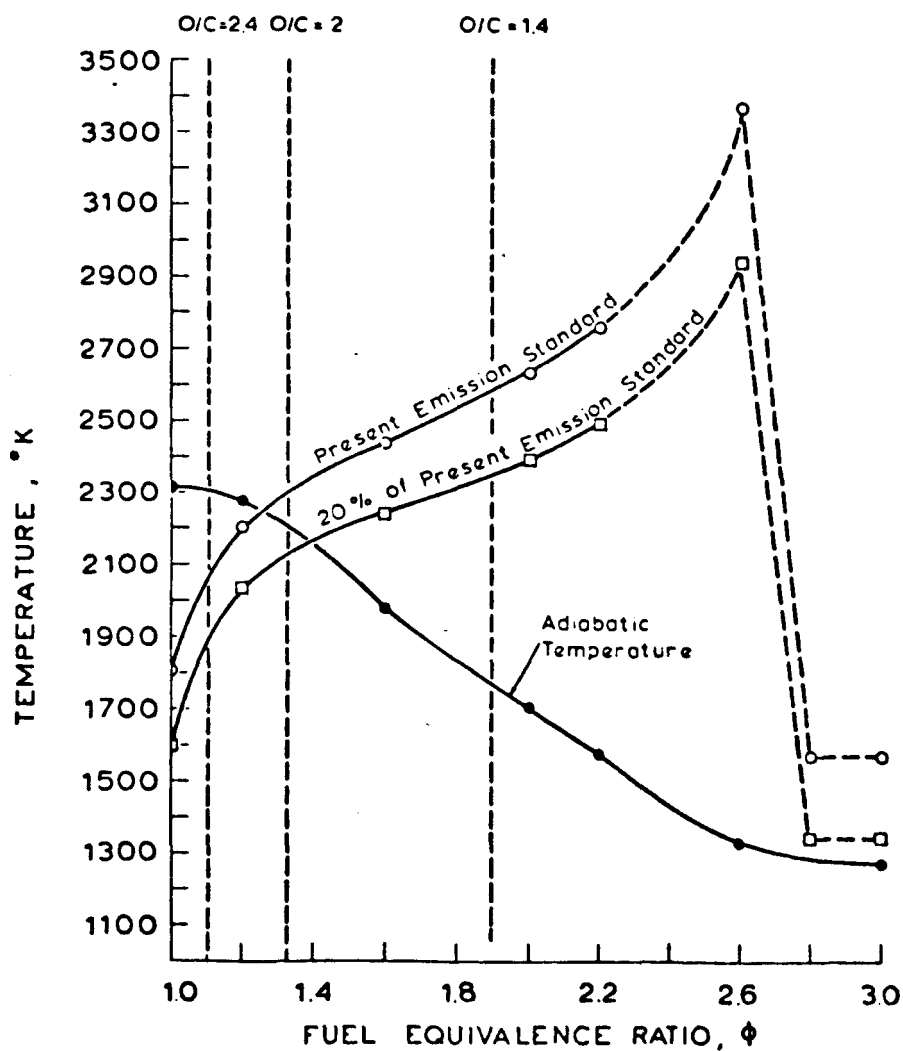


Figure D.2.4-3 (FROM REF D.2-9)

It is interesting to note that this recommendation for high air preheat is beneficial from a standpoint of energy conservation and can be contrasted with the recommendation to reduce air preheat in order to reduce thermal sources of NO_x under conventional fuel-lean operation. Information is needed on mechanism and kinetics in order to determine the minimum air preheat needed under fuel-rich conditions to increase the flame temperature sufficiently to overcome kinetic constraints. Another practical constraint is the sooting tendency of flames under fuel-rich conditions. The O/C ratios on the plots are included to indicate the range of equivalence ratios under which Street and Thomas and Wright observed sooting from preheated, premixed reactants in Bunsen flames and a well-stirred reactor, respectively. It is probable that strategies for high-temperature fuel-rich operation will require that the second stage be sized large enough to burn out the soot formed in the first stage. Such practical considerations will obviously influence the operating conditions of a combustor.

D.2.5 Current Detailed Chemical and Aerodynamic Studies

Since thermodynamic calculations have shown that there are combustion conditions in which the concentration of "fixed nitrogen species" from fuel-nitrogen could be reduced below emissions standards, the present thrust of research sponsored by EPA and the other organizations is to discover through kinetic and aerodynamic studies how to accelerate the reactions approaching such equilibrium concentrations. EPA's program "Fundamental Combustion Research Applied to Pollution Control" was initiated in 1977, and its projects fall into three main categories: gas phase chemical kinetics, heterogeneous combustion of fuel particles and droplets, and fluid mechanics or aerodynamics of mixing of fuel and air. EPA hopes that within 4 years the program will produce basic results implementable in technology development efforts. It will focus on large boiler flames, which account for 60% of present stationary NO_x emissions. However, the secondary objectives of the program include gas turbines (including combined cycle) fired with coal liquids and residual oils, and catalytic combustors for high-nitrogen fuels. The EPA Stationary Source Combustion Symposia contain yearly updates of

progress in these programs. Excerpts therefrom summarizing the status of some projects relevant to gas turbine combustion are contained in Appendix A.

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E. SOOT EMISSIONS

E.1 Soot Formation and Burnout Mechanisms

We will start with a few examples of soot emissions from simple flames in which the effects of flame conditions are more easily distinguished; this will also serve to define some terms. Soot is observed in the primary and secondary zones of flames even at fuel-air ratios at which the absence of solid carbon is predicted by equilibrium considerations.⁽¹⁾ The reasons for the persistence of soot involve the rates of its formation and burnout, examples of which follow. Figure E.1-1 represents an experiment done with a flat flame burner, positioned for upward flow of premixed fuel and oxidant, as described in Section C.⁽²⁾ As the sampling probe was moved upward from the burner (along the x-axis in Figure E.1-1), at about 2 cm above the burner the amount of soot ("soot volume" in the figure) rose suddenly from zero as the heavy hydrocarbons decreased, being the precursors to the soot. The soot was also then agglomerated into smaller numbers of larger molecules. This demonstrates the formation of soot in the primary flame zone, which in this example was very extended by operating the burner in a low pressure enclosure. This soot formation process is strongly affected by numerous variables, such as the fuel equivalence ratio, flame temperature, pressure, state of admixture of fuel and air, and fuel composition, the latter by virtue of the very composition-dependent pyrolysis of the fuel preceding soot appearance in the flame.

Although soot may be formed in a flame, in many cases it is burned out in the secondary flame zone as shown by common experience with a luminous but cleanly burning candle. Soot burnout is exemplified in Figure E.1-2 by the decrease in soot concentration with increasing distance from the burner (x-axis) in this C₃-hydrocarbon flame at atmospheric pressure.⁽³⁾ Furthermore, the burnout was faster in Run 5, in which the temperature was 1550-1680°K, than in Run 1, in which the temperature was 1400-1750°K, and the oxygen was half that in Run 5. Unburned soot emerged from the flame in Run 5.

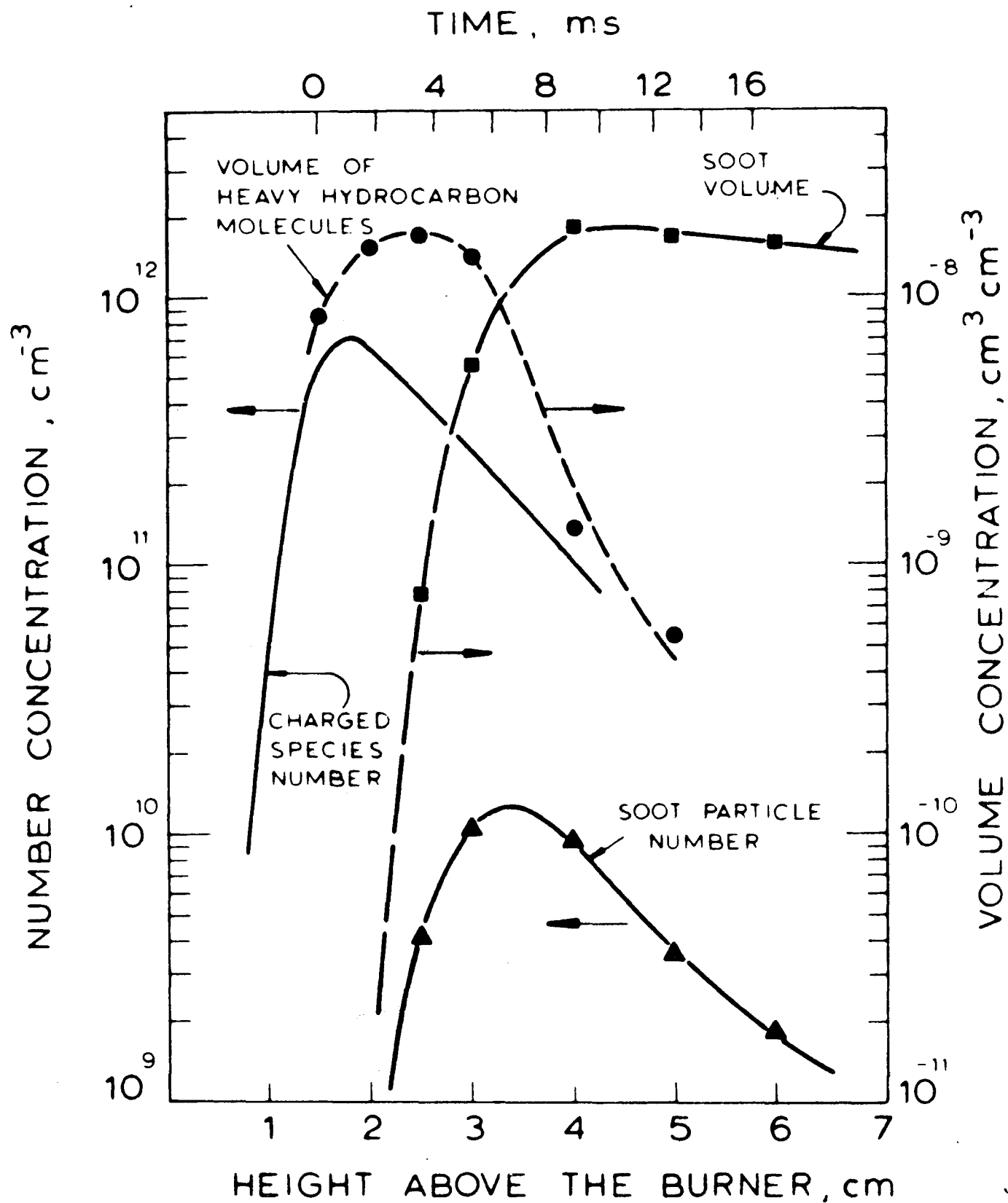


Figure E.1-1 SOOT FORMATION IN FLAME (LOW PRESSURE BURNER) (FROM REF. E.1-2)

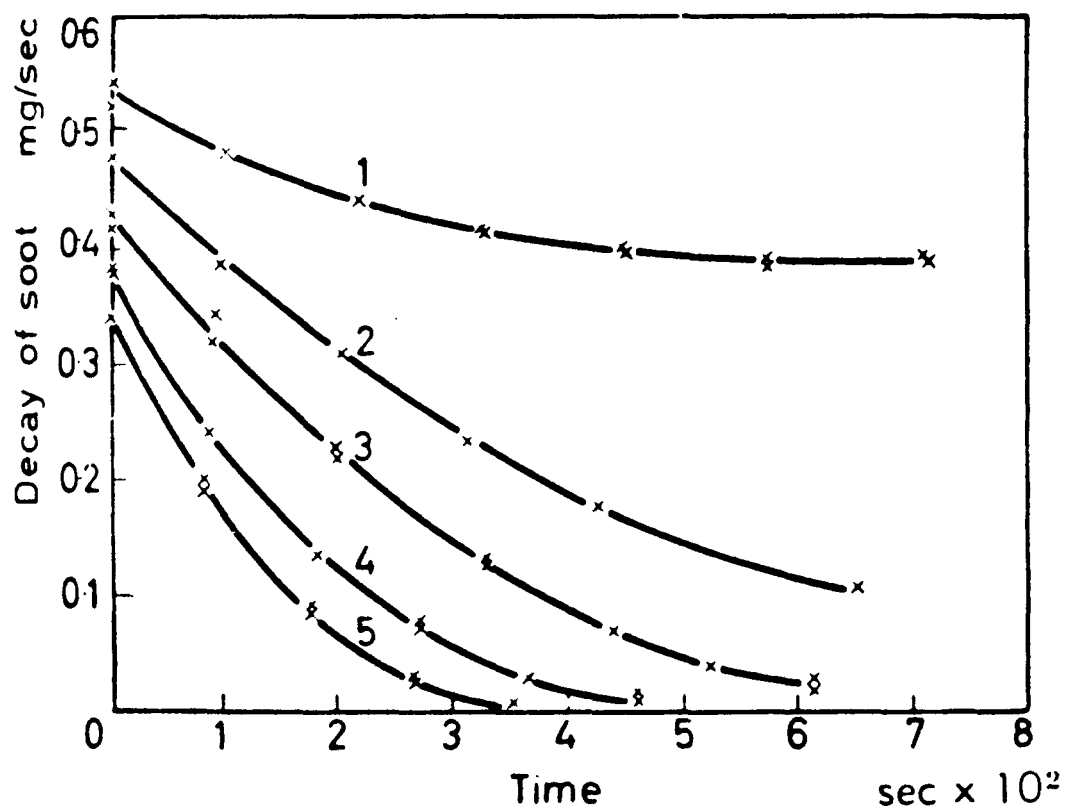


Figure E.1-2 SOOT BURNOUT IN FLAME (FROM REF. E.1-3)

Some observations of soot from premixed flames at high pressure are interesting because they relate to gas turbine combustor conditions as well as providing illustrations of the effects of fuel equivalence ratio, flame temperature, and fuel composition⁽⁴⁾ (Figure E.1-3). In Figure E.1-3a, for n-hexane, at 10 atm. pressure, soot first appears (at threshold "T") as the fuel equivalence ratio increases to 1.4, but with further increases in pressure, the soot never exceeds 0.5 wt% of the total fuel carbon. In the case of benzene (Figure E.1-3b), a somewhat lower fuel equivalence ratio (1.2) is needed for soot appearance at 10 atm., and the yield of soot rises to 5% at $\phi_f = 2.0$. Soot yields also increased with flame temperature, as shown in Figure E.1-4. When the radiative loss of heat from the flame was prevented by surrounding the flame with a reflective insulated cylinder (Curve B), the flame temperature was several hundred degrees C hotter than in the unshielded case (Curve A), and substitution of argon for nitrogen further increased the temperature by 150°C (Curve C). The soot yield increased manyfold with temperature and occurred over a wider range of ϕ values.

These increases in soot with fuel concentration, temperature, and fuel aromaticity are consistent with known mechanisms of soot formation which include fuel pyrolysis (accelerated by temperature), and agglomeration of soot precursors (enhanced by fuel concentration) which are aromatic. The great variation in the rate of pyrolysis of various compounds has a large role in explaining their various soot formation tendencies. There are presently important advances being made in the understanding of these mechanisms, which should be a qualitative guide to new combustor concepts for aromatic fuels such as SRC-II fuel oil, and in time may be incorporated into engineering models for their optimization. To review this work is outside the scope of this report (see Ref. 5).

We have described the strong response of fuel-nitrogen conversion to flame geometry and the fuel-oxidant admixture process; these also strongly affect the soot formation process. The extreme example of this was the well-stirred reactor, of interest because it resembles the primary zone of a gas turbine combustor, which usually has strong recirculation of flame gases for

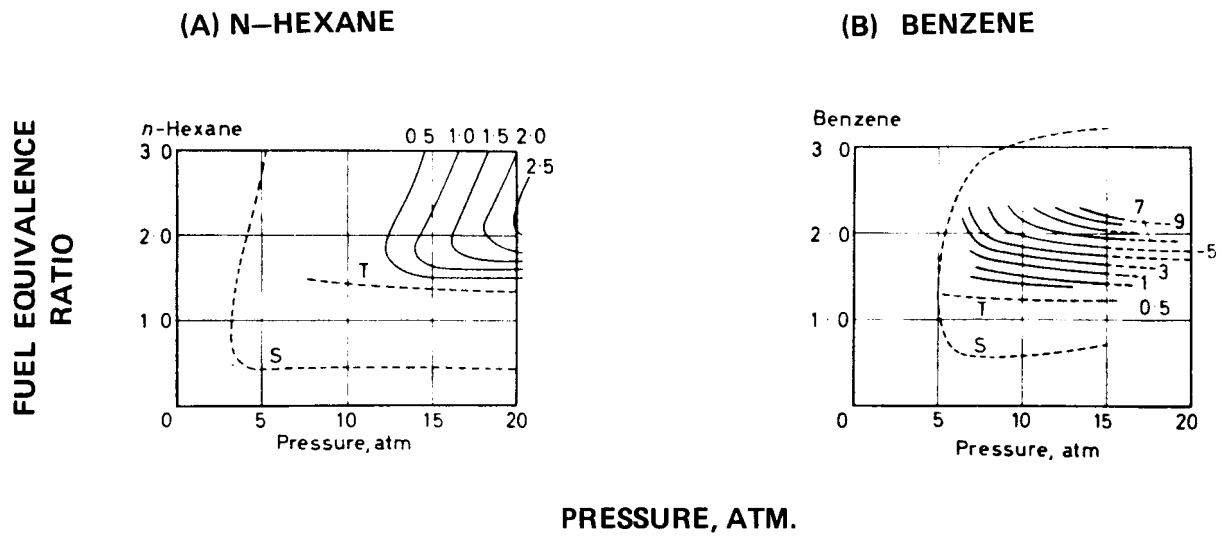


Figure E.1-3 EFFECT OF PRESSURE AND MIXTURE STRENGTH ON SOOT FORMATION. HIGH INJECTION VELOCITY BURNER. SHOWING CONTOURS OF SOOT FORMATION RATIO PER CENT. S DENOTES FLAME STABILITY LIMIT, AND T SOOT FORMATION THRESHOLD (FROM REF. E.1-4)

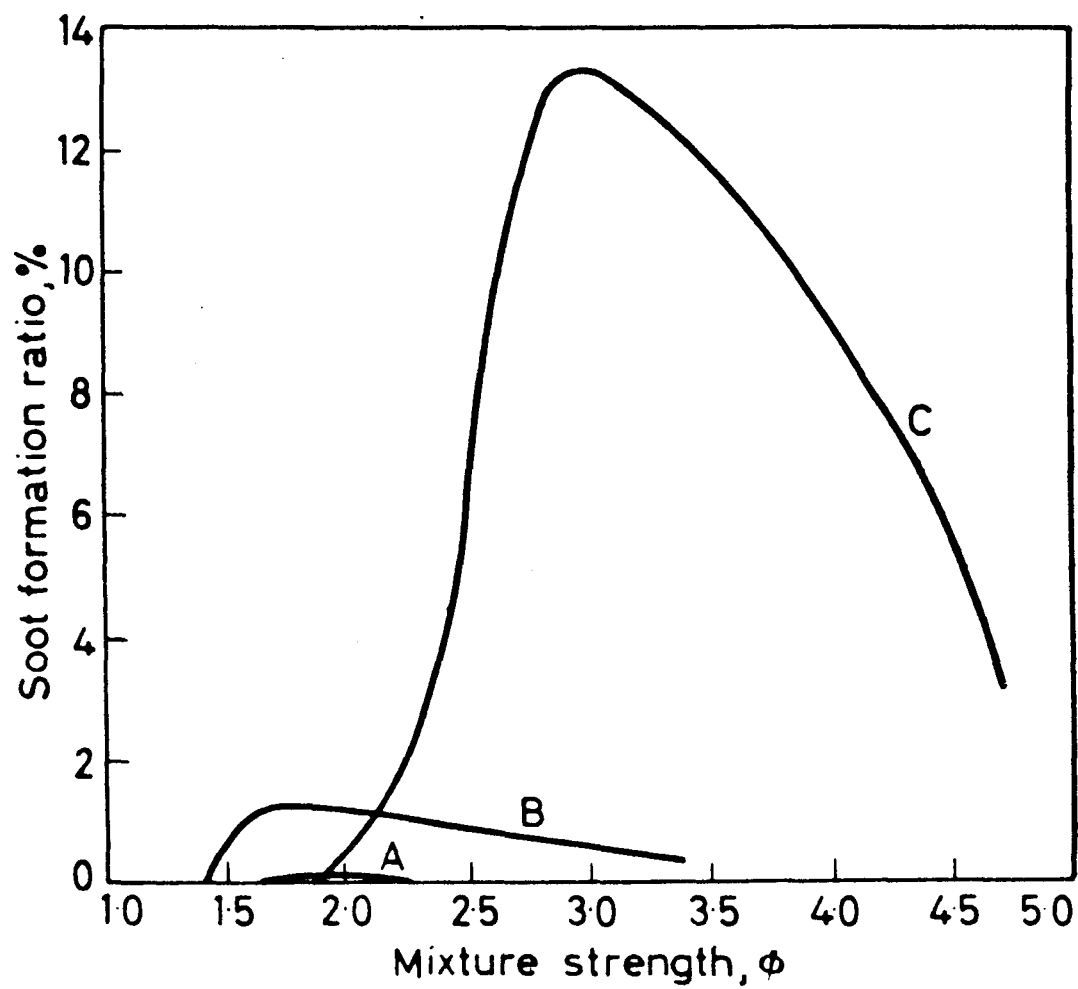


Figure E.1-4 SOOT INCREASE WITH FLAME TEMPERATURE
N-HEXANE 15 ATM (FROM REF. E.1-4)

flame stabilization. The soot yields in Figure E.1-5 show that less soot formed in a well-stirred reactor than in a premixed flat flame burner, the fuel being toluene.

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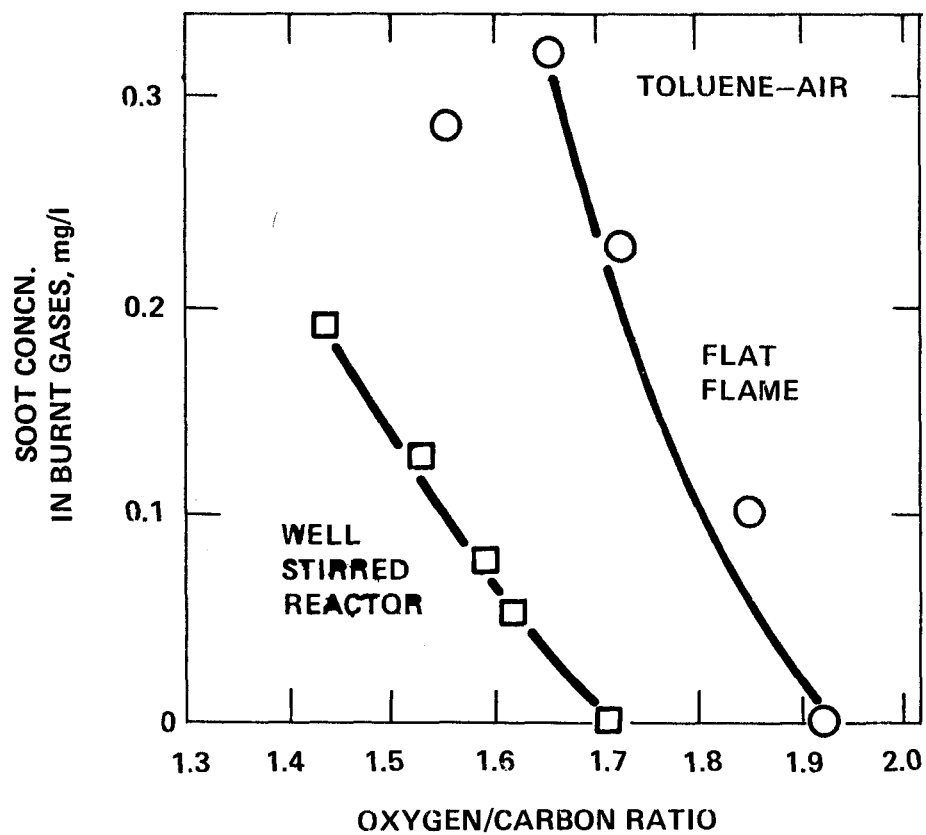


Figure E.1-5 WELL-STIRRED BURNER
MAKES LESS SOOT (FROM REF. E.1-1)

**GULF SCIENCE AND TECHNOLOGY COMPANY
PITTSBURGH, PENNSYLVANIA**

**SRC-II FUEL OIL: COMBUSTION TECHNOLOGY FOR
UTILIZATION IN STATIONARY GAS TURBINES**

J. E. HAEBIG

**CHEMICALS AND MINERALS DIVISION
REPORT NO. 633RK110
JULY, 1979**

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SUMMARY

This section summarizes the information obtained and the conclusions drawn about the combustion of SRC-II fuel oil in stationary gas turbines. Also included are recommendations about research and development, and issues to be considered by the gas turbine industry, government agencies and other institutions.

The SRC-II coal liquefaction process is based on the discovery that recycled mineral matter from the coal catalyzes the liquefaction of coal. The fuel oil fraction is removed from the ash-laden reactor effluent stream by distillation instead of filtration as in earlier processes and the result is fuel oil containing very little ash, metals, or non-volatile fractions. (See Table A.1-1) SRC-II fuel oil resembles No. 2-5 fuel oils in its distillation range, viscosity, ash and sulfur content. Therefore, gas turbines or small boilers seemed to be an appropriate utilization of this fuel, instead of utility boilers where in a number of instances coal could just as well be used.

SRC-II fuel oil is more aromatic (lower hydrogen content) and contains more nitrogen than comparable petroleum distillate fuels. Although the nitrogen could be removed with a hydrotreater added to an SRC-II plant, Gulf expects that such emissions resulting from fuel bound nitrogen will be more economically suppressed by new gas turbine combustor designs or post-combustion NO_x removal. This report examines the probable success of these alternatives.

ASTM specification D2880 for stationary gas turbine fuels was examined for potential problems with SRC-II fuel oil use in turbines. The following fuel oil properties were found satisfactory: viscosity, flash point, heat of combustion, fuels compatibility, compatibility with materials of construction, and carbon residue. Although the low hydrogen content of SRC-II fuel oil leads to the expectation of the overheating of conventional combustor liners, the new low-emissions combustor designs described in this report are also solutions to this potential problem. The Ft. Lewis 150-bbl/

day pilot plant has been steadily improved in its running conditions, and the metals content of SRC-II fuel oil has decreased to its present level of less than 100 ppm ash and less than 1 ppm of Na+K, near the present specification. Further improvements are expected with installation of a new vacuum tower specifically designed for the SRC-II process. Corrosion and deposition should be no more problematic than with conventional fuels. Long-term corrosion tests on turbine blade materials should be conducted since the trace metal composition of SRC-II fuel oil differs from that of conventional fuels; however, these tests should wait until the pilot plant product metals content is thoroughly lined out and reproducible. If tests of new combustor designs indicate excessive emissions and liner heating, the SRC-II process parameters should possibly be altered to provide sufficiently clean fuel for the combustors matching the process and combustion equipment for optimized economics of the total system.

Through these preliminary considerations of SRC-II fuel oil properties, gas turbine fuel specifications and emissions regulations, NO_x and soot emissions and combustor liner overheating were identified as the greatest potential technical barriers to SRC-II fuel oil use in stationary gas turbines. In order to understand whether solutions to these problems would best come from advances in combustion equipment or from more intensive processing of SRC-II fuel oil, a review of the combustion chemistry behind pollutant emissions was conducted, of gas turbine combustor designs and their potential for emissions reduction, high temperature and advanced cycle turbines, post-combustion NO_x removal, and alternative fuels to coal liquids. The following summarizes the background information obtained on these topics, with the conclusions derived.

The suppression of NO_x formed by oxidation of molecular nitrogen (N_2) in the combustion air ("thermal NO_x ") in gas turbines has received extensive chemical and engineering study. The elementary chemical reactions involved are relatively simple and can be suppressed by reducing the peak flame temperatures occurring in the combustor. This has been successfully engineered and widely applied, being achieved by increasing the air/fuel ratio in the primary flame zone of the combustors, or by water injecting at a one-

to-one water/fuel weight ratio. However, this approach suffers a trade of increased emissions of CO and unburned hydrocarbons. NASA has supported a large emissions-reduction combustor development program for each of the classes of aircraft engines. In contrast, emissions-reduction work on stationary heavy-duty gas turbine has been conducted largely in-house by the turbine manufacturers.

The nitrogen chemically bound in fuel oil is converted to NO_x ("fuel- NO_x ") when oxygen is readily available in the flame; otherwise it converts to molecular nitrogen, N_2 . Fuel- NO_x formation in fuel oil flames in boilers has been suppressed successfully by excluding excess oxygen from the primary flame zone or first stage of the boiler, termed "staged combustion"; this also results in the formation of large amounts of CO, hydrogen and soot, since the flame is fuel-rich. Downstream admission of the rest of the combustion air readily consumes the CO and hydrogen, but care must be taken to assure oxidation of all the soot. The N_2 formation process in the first stage (rich) and the soot oxidation process in the second stage (lean) both require the long residence times which exist in boilers, but which tend to be too short in gas turbine combustors. Nevertheless, detailed studies of the chemistry of these very complex reactions are revealing possible approaches to sufficiently accelerating them to make staged combustion in gas turbines effective (being termed "rich-lean" combustion in gas turbines). In efforts by the major turbine manufacturers, universities and especially in an EPA-supported program, this chemistry is being modelled and incorporated into aerodynamic descriptions of the air-fuel flow to permit computer modelling of new concepts for combustor configurations. This work has shown that the suppression of fuel- NO_x is not very dependent on the types of nitrogen molecules in the fuel, but is facilitated by rapid fuel vaporization and high temperatures in the fuel-rich zone, suggesting that SRC-II fuel oil is a favorable candidate for the rich-lean approach, especially because of its high volatility compared to, the nitrogenous compounds in No. 6 residual petroleum fuel oil.

Soot emissions are the combined result of soot formation in the primary flame zone and subsequent soot burnout in the secondary zone. Many

sub-steps have been found to be involved in the formation of soot particles. These include pyrolysis of the fuel molecules to precursors, most importantly aromatic molecules, which explains why aromatic (and thus low-hydrogen) fuels tend to produce more smoke, and also why hotter flames smoke more. Another soot-forming substep is the agglomeration of precursor molecules into soot particles, which explains why soot formation increases supra-linearly with combustor pressure. Although SRC-II fuel oil has the disadvantage of being highly aromatic, as are other coal-derived liquids, flame chemistry studies have suggested that the very highest boiling fractions of SRC-II fuel oil contribute to soot formation far out of proportion to their concentration; a collaborative study of this effect of fuel composition on emissions by fuel producer and turbine manufacturer is highly recommended. A similar study is recommended of the opportunity for the fuel producer to provide soot-burnout-enhancing additives in the fuel with appropriate combustor burnout zone design and testing by the manufacturer based on promising laboratory studies of such additives.

Aircraft engine smoke emissions (most severe at low power) and high-power combustor liner overheating have been found to correlate very well with the hydrogen contents of the jet fuels, and jet fuel specifications have become based on hydrogen content, requiring at least 13.0% hydrogen. Aircraft-derived stationary power gas turbines, having smaller combustors than heavy-duty machines, may have a higher smoking tendency with aromatic fuels. They might, for example, require a lower distillation fraction of SRC-II fuel oil. Heavy-duty stationary gas turbines have been fired successfully with fuels having low-quality viscosities and hydrogen contents (11% unofficially required) extensively during the last twenty years; however, in these cases suppression of fuel-NO was not attempted.

Some interesting observations of fuel-NO formation at gas turbine conditions had been obtained before coal liquids became available. The fraction of fuel-nitrogen converted to NO_x (the "fuel- NO_x yield") decreased to only 20-40% for the most nitrogenous (0.8%N) fuels, and in a very large single-combustor power turbine with an apparently fuel-rich primary zone, the fuel- NO_x yield was 5-10%. Faster fuel-air mixing, sometimes done in some

designs in order to reduce smoke, and water injection, which reduces thermal- NO_x formation, both greatly increased the fuel- NO_x emissions. This empirical information from conventional combustors has been useful in seeking new design approaches.

A set of coal-derived liquid (CDL's) has been tested in conventional half-scale and full-scale single combustors by Westinghouse in an EPRI-sponsored program. The CDL's had hydrogen contents between 7.7% and 12.25%, and the smoke and liner heating followed a correlation which aligned well with a correlation involving a more conventional hydrogen range in another combustor. Fuel- NO_x yields paralleled other fuel- NO_x results mentioned above. Although the NO_x and soot emissions from these coal liquids appeared to be an approximate extension of experience with conventional fuels, attempts to find petroleum-derived aromatic refinery streams ("surrogates") to closely mimic the soot and NO_x emissions of the CDL's were unsuccessful, suggesting that the surrogate approach should be used with caution.

All new combustor design concepts to suppress fuel- NO_x incorporate a fuel-rich zone. Rich-lean concepts have been proposed since 1976, for example (among others), in the Westinghouse ECAS Phase II work and in a chemical kinetic modeling study of advanced cycle combustor concepts for ammonia-contaminated low-Btu gas for EPA by Energy and Environmental Research, Inc. (EER). This concept is embodied in a combustor configuration now widely known, which contains a rich primary reactor (fuel equivalence ratio $\phi = 1.3$, or 30% excess of fuel over air), a quick-quench section rapidly admixing the rest of the gas turbine dilution air and a CO burnout section. Substantial experimental success in implementing this configuration has been reported in an EPA project by Pratt & Whitney Aircraft Group; whose work utilized engineering methodology developed in their aircraft combustor design work. With No. 2 oil doped to 0.5% nitrogen as pyridine, the bench-scale combustor produced 75 ppm NO_x and acceptable CO using a variable-geometry air inlet vane to the primary reactor to keep the fuel/air ratio at $\phi = 1.3$ while the load was varied. The critical physical and chemical sub-processes occurring in this configuration have been modelled for the full-scale unit, which has been fabricated, and full-scale testing is now commencing.

Although in conventional combustors SRC-II fuel oil will produce higher liner temperatures than conventional fuels, particularly at the primary zone where most of the combustion is completed, these rich-lean designs distribute the heat-releasing combustion more evenly over the entire length of the combustor, and should prevent liner overheating when SRC-II fuel oil is used. This should obviate an otherwise important barrier to SRC-II fuel oil utilization in gas turbines.

Work by four or five gas turbines manufacturers as contractors in the DOE-NASA-Lewis "Low NO_x Heavy Fuel Combustor" program will begin in mid-1979. Since the rich flame principle will be widely utilized in this program, and since SRC-II fuel oil will be used in the testing, this program appears likely to successfully generate a low-emissions retrofittable combustor for CDL. The program goal is for the combustor to also be capable of burning No. 6 oil cleanly and without operating problems. Such a design would then also be capable of burning SRC-II fuel oil cleanly. The timing for verification testing of the combustor in a complete gas turbine, for completion in late 1984, will hopefully coincide with the availability of SRC-II fuel oil from the proposed 20,000 bbl/day demonstration plant. The program also has interest in testing the effects of variations in fuel properties, which will be coordinated with the SRC-II process development activities, discussed previously.

In addition to the rich-lean concept, there have recently appeared other promising concepts for clean CDL combustion, which are described briefly in the following. Some of these approaches involve recirculation of some of the flame gas to the fuel injection area, an approach which would also benefit No. 6 oil burning. Heat removal by an external steam generator between the rich reactor and the quick quench zone is also proposed (by EER, Inc.) for suppressing thermal NO generation in the CO burnout reactor. Finally, honeycomb catalysts in the combustion chambers are being widely explored and could have certain benefits in rich flame reactor sections. The basic chemistry of soot formation, burnout and nitrogenous fuel combustion is receiving vigorous research, which should lead to further improvements in combustor design approaches. Discussions of the needed technology have been held with four

major gas turbine manufacturers, who all expect success in these efforts; see Appendix B for accounts of these discussions.

Post-combustion NO_x removal appears to be a very viable and important alternative to low- NO_x combustors for solving the fuel- NO_x problem of SRC-II fuel oils, although the latter would be less expensive. In this process, ammonia is injected into the turbine effluent as it passes through a honeycomb catalyst. This approach would be especially opportune in a combined cycle plant, where the catalyst would be installed in the heat recovery boiler. The operating and capital costs have been evaluated by a turbine manufacturer to be modest increments and EPRI is supporting some pilot-scale verifications of this approach.

Advanced cycles with increased thermal efficiency are expected to financially permit the consumption of more costly fuels which will be the case for SRC-II fuel oil and conventional fuels in the mid-1980's. Advanced cycle plants also present some unique opportunities for clean CDL combustion. One of these is ammonia injection NO_x removal. Another approach is the inter-stage heat removal outside the combustor, both mentioned above. Another possibility involves an auxiliary firing of the heat recovery boiler in a staged fashion to suppress NO_x from the nitrogen in both the gas turbine and boiler fuels. This has also been shown to be possible in repowering an existing boiler. Finally, combustors suppressing fuel- NO_x from CDL's can be compatible with the firing of ammonia-contaminated low-Btu gas.

CONCLUSIONS

In conclusion, this review has found that SRC-II fuel oil is very likely to make a good technical and economic fit into the future stationary gas turbine market. This conclusion is based on the following facts:

- (1) The low viscosity and distillation range of SRC-II fuel oil meets the requirements of all stationary gas turbines.

- (2) Its content of corrosive trace metals is below present requirements.
- (3) The NO_x and soot emissions expected because of its nitrogen and aromatics content can be prevented. Basic combustion chemistry shows the potential effectiveness of fuel-rich combustion conditions in achieving low emissions.
- (4) On this basis, Pratt & Whitney has engineered and built a successful low-emissions combustor in an EPA-sponsored project.

Implementation of retrofittable and new rich combustor designs in the gas turbine industry has a good technical beginning and adequate support through the new DOE/NASA-Lewis combustor design program. Its plans include concept screening, design scale-up and optimization, component durability tests and full-scale engine testing in 1984. The latter will hopefully verify reliability to prospective utility purchasers, who have pressing needs for expanding their capacity.

- (5) Alternatively, NO_x removal from the flue gas by selective catalytic reduction will be feasible in most systems, if needed, but may have slightly higher costs.
- (6) High efficiency systems (high turbine inlet temperatures and advanced combined cycles) will offset the price of SRC-II fuel oil and, in addition, will provide unique opportunities for further emissions-suppression combustor technology.
- (7) The price of SRC-II fuel oil will be competitive with petroleum-derived fuels in the utility gas turbine market in the mid- to late 1980s, and the characteristics of that market are very favorable, as indicated in a previous volume of this report.

RECOMMENDATIONS

In order to accelerate and optimize the above favorable developments, we especially recommend the following:

- (1) Pursuit of the DOE/NASA combustor program as rapidly as possible. Its acceleration may be possible through incorporation of the Pratt & Whitney combustor technology. Utilization of the interpretive and modeling capabilities developed in the EPA boiler combustion chemistry studies, possibly through the consultants for each contractor.
- (2) Test post-combustion NO_x removal and staged auxiliary-fired combined cycle boilers and explore other advanced cycle opportunities for low-emissions combustor configurations.
- (3) Coordinate variations in SRC-II fuel oil process parameters (distillation range and possibly mild hydrotreating) for an optimum match with the capabilities of developing low-NO_x combustor designs.
- (4) A full-scale engine test should demonstrate to the utilities how to economically burn SRC-II fuel oil without problems of emissions or equipment damage. This would require the combustor verification test in the DOE program, or conventional combustors with post-combustion NO_x removal or some kind of combined cycle NO_x suppression system.
- (5) Information should be continually supplied to prospective gas turbine purchasers about the progress of these low-NO_x developments toward a commercial engine and about the options for increasing their capacity with components which retain system flexibility to retrofit low-NO_x options, e.g., combustors, especially in combined cycle systems.

- (6) Because of the low metals contamination of SRC-II fuel oil, there is a need for extensive corrosion and deposits testing only for purposes of warranty data preparatory to a long-duration test of a new low-NO_x engine. In particular, regarding use of the relatively limited volumes of SRC-II fuel oil available until Demonstration Plant operation, low-NO_x combustor development work should take precedence over most corrosion testing.
- (7) Blends of SRC-II fuel oil with petroleum fuel oils would reduce NO_x emissions, but such blending should be done on-site by the fuel user, if it is done at all. Wide distribution of such blends in the existing fuel oil marketing system would be impracticable. Furthermore, such blending is inherently a less effective means to minimize fuel-NO emissions than is staged or rich-lean combustion of undiluted SRC-II fuel oil.
- (8) For utilities' planning purposes, there is a need for information about the future availability of residual petroleum-derived fuel oil and about the legality of its use in utility gas turbines; however, the factors involved may be too unpredictable.
- (9) Gulf intends to cooperate with each gas turbine manufacturer's contract and in-house efforts to design the needed equipment for SRC-II fuel oil utilization, and Gulf also intends to keep actively involved in offering its viewpoint as a fuel processor.

ACKNOWLEDGMENT

The preparation of this report included very helpful discussions with Curtiss-Wright, General Electric, United Technologies and Westinghouse, all of which are gratefully acknowledged.

A. SRC-II PROCESS AND PRODUCT PROPERTIES

A.1. THE SRC-II PROCESS

The SRC-II coal liquefaction process is based on the discovery that the ash in coal can serve as the catalyst for the liquefaction of coal under moderately high temperatures and hydrogen pressures. The development of the process, equipment and conditions have been conducted in a 3 bbl/day pilot plant at Gulf laboratories and at the 150 bbl/day pilot plant at Ft. Lewis, WA; this is the subject of other reports, but the processing parameters are discussed here as they affect the properties of the products. Figure A.1-1 is a diagram of the process units and streams, which are described in the following.⁽¹⁾

"Figure A.1-1 presents a schematic flow diagram of the process in a full-scale plant. The feed coal is initially dried to about 5 percent moisture, pulverized, and mixed with recycle slurry from the process. The resulting coal-slurry mixture is pumped, together with hydrogen, through a fired preheater to a reactor at elevated temperature and pressure. In the reaction system the coal is not only dissolved, but is also largely hydrocracked to distillate fuel oil, naphtha, and light hydrocarbons.

The reactor effluent flows through a series of vapor-liquid separators, where it is separated into process gas, light hydrocarbon liquid, and product slurry. H_2S and CO_2 are removed from the gas, consisting primarily of hydrogen and gaseous hydrocarbons. Hydrocarbons are removed in a cryogenic separation step. The purified hydrogen is recycled to the process, while the recovered hydrocarbons become by-products of the process. The C_1 fraction is sent to a methanator to convert the remaining CO to methane. The other light hydrocarbons are fractionated to produce ethane, propane, and a

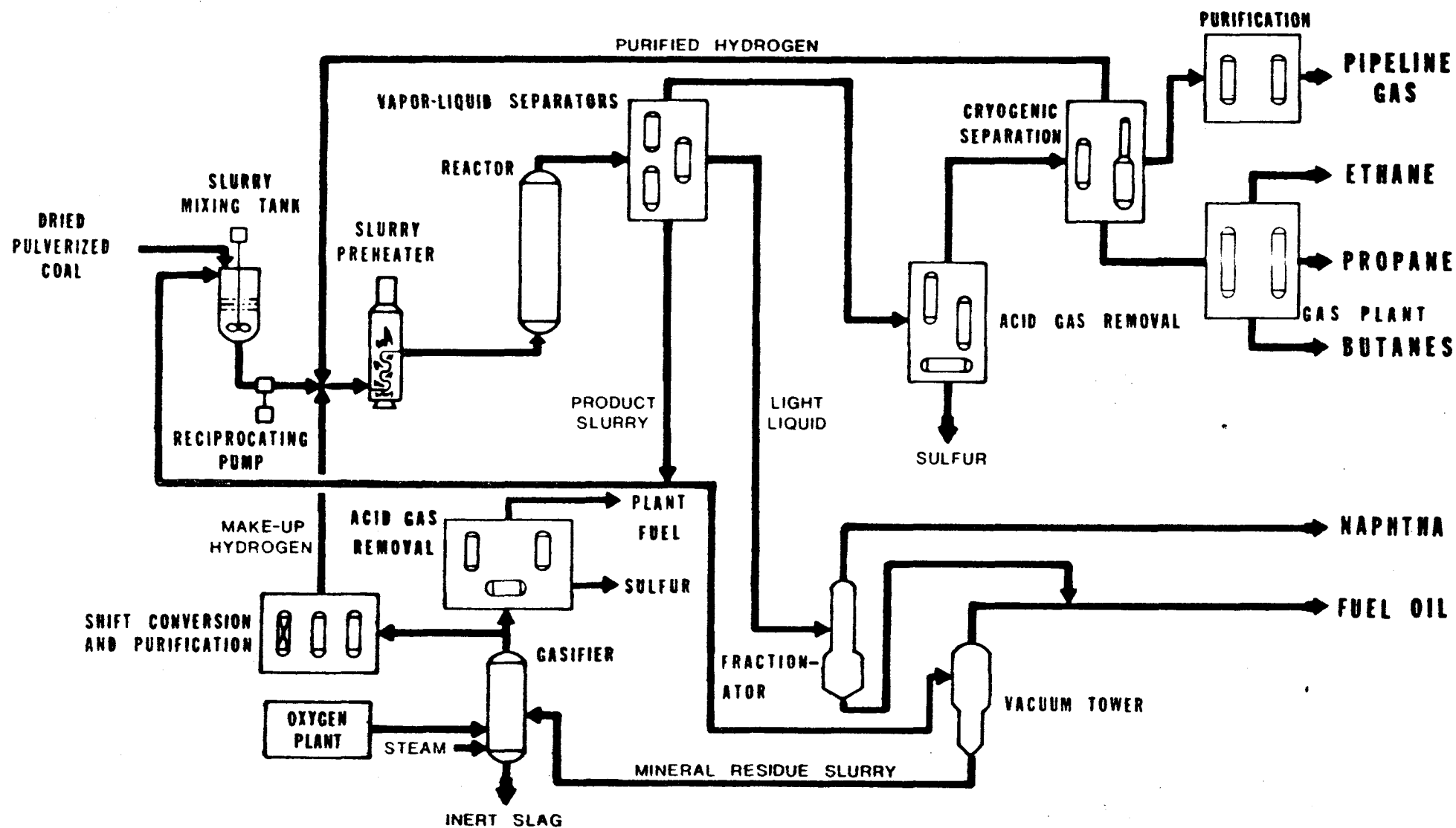


Figure A.1-1 SRC-II PROCESS DIAGRAM¹

mixed butane stream. The light hydrocarbon liquid goes to a fractionator where it is separated into naphtha (C_5 -350°F nominal boiling range) and a middle distillate (350°-600°F boiling range).

The product slurry is split, with one portion being recycled to the reaction part of the process for slurring the feed coal. The other portion of the product slurry goes to a vacuum tower from which a heavy fuel oil is distilled overhead. The heavy distillate, together with middle distillate from the atmospheric pressure fractionation step, makes up the total fuel oil product of the process.

The residue slurry from the vacuum tower is pumped to a high-pressure slagging gasifier for production of synthesis gas. A portion of the synthesis gas is converted by the shift reaction to form additional hydrogen. The synthesis gas in excess of that required for hydrogen production is processed in a separate acid gas removal step for removal of CO_2 and H_2S and expanded through a power recovery turbine for ultimate use as plant fuel."

In summary, a Demonstration Plant is in the design stage, in which commercial-size confirmation of the operability and reliability of certain new process steps would be achieved. The fuel oil products, of interest for gas turbine and boiler use, originate from the light liquid and product slurry streams from the vapor-liquid separators. The product slurry is delivered to the vacuum tower, where the fuel oil is thoroughly freed from ash, unreacted coal, and non-volatile high-molecular weight liquid by vacuum distillation. Currently, two streams are being obtained from the distillation: a middle distillate fuel oil product having the distillation range in the area of No. 2 fuel oil, 350-550°F, and a heavy distillate boiling between 550°F and 930°F. Table A.1-1 presents the inspection properties of middle and heavy distillate SRC-II fuel oil fraction, and also those of No. 2 and No. 5 petroleum fuel

oils. Since desulfurization reactions occur somewhat more easily than the fragmenting and liquefaction of the coal, the volatile fuel oil products also have been 95% desulfurized. Ft. Lewis pilot plant runs with a specific coal have established that the yield of middle distillate is 2.9 times greater than that of the heavy distillate.

A.1 REFERENCE

1. D. M. Jackson and B. K. Schmid, "Production of Distillate Fuels by SRC-II," presented at "New Fuels and Advances in Combustion Technology," New Orleans, LA, March 26-30, 1979.

**TABLE A.1-1 ASTM TEST PROPERTIES OF
SRC-II FUEL OILS AND CONVENTIONAL FUEL OILS^a**

<u>Product</u>	<u>ASTM D2880 No. 2-GT Specs</u>	<u>Middle Distillate</u>	<u>Heavy Distillate</u>	<u>No. 2 Grade</u>	<u>No. 5 Grade^b</u>
<u>Inspections:</u>					
Gravity: °API	>30	13.8	0.4>30	19	
Density (15°C): kg/dm ³		0.974	1.072	<0.876	0.940
Color		dark	dark	light	dark
Viscosity: cSt					
100°F	2.0-4.3	3.1-3.4	49.6-90.2	2.0-3.6	26-194
210°F		-	4.0-5.1	-	2.9-48
Viscosity: SUS					
100°F		36.3-37.3	342-418	32.6-37.9	124-900
210°F		-	39.8-42.7	-	36-224
Flash Point, P-W: °F	>100	>160	>180	>130	>150
Pour Point: °F	>-6	<-45	<+45	<+5	-15 - +80
Carbon Residue, Con: %W					
10% Bottoms		<1.2	-	<0.35	-
Total Sample		-	<1.5	-	2-10
Nitrogen: %W		0.9-1.1	1.2-1.4	<0.02	<0.3
Oxygen: %W		3.6-4.3	1.4-1.8	<0.09	<0.4
Sulfur: %W		<0.2	0.37-0.47	0.04-0.48	0.07-1.9
Carbon: %W		86.0	89.1	87.0	88.3
Hydrogen: %W		9.1	7.5	12.8	10.7
Hydrocarbon Groups (HPLC): %V					
Saturates		35-38	-	>65	-
Aromatics & Polar Compounds		<62-65	-	<32	<-
Asphaltenes, IP143: %W		<0.1	0.9-2.7	<0.1	<5.0
Phenolics: %W		3-20	-	0	-
Naphthalenes: %W		14-19	-	<6	-
Smoke Point: mm		5-8	-	>14	-
Ash, D482: %W	<0.01	<0.001	0.03-0.1	<0.003	<0.05
Neut. No. (Tan), D664		0.27-0.42	0.25-0.57	<0.30	<0.45
Copper Strip Corrosion, D130		1-3	1	1	1
Heat of Combustion, Gross, D240					
Btu/Lb		16 900	17 000	19 300	18 700
Btu/Gal		137 100	151 800	136 700	146 600
Cetane No., D613		<20	-	40-55	-
Autoignition Temperature: °F		925	895	594	600-700
Thermal Stability, NBTL (D1661)					
Thimble Rating					
Unwashed		1	1	1	1
Washed		1	1	1	1
Washed and Wiped		1	1	1	1
Rating of Tube		1	1	1	1
Accelerated Stability, D2274					
Deposit Weight: mg/100 ml		<0.8	<3.5	<1.0	-
Stability Test, 64 hr @ 210°F					
Insolubles: mg/100 g		<0.3	<3.5	<1.0	-
Distillation: °F		<u>D86</u>	<u>D1160; 760mm</u>	<u>D86</u>	
Over point		338-396	538-554	369-389	-
10%		386-406	568-584	422-445	-
50%		425-444	640-656	498-516	-
90%	540-640	483-500	785-820	580-593	-
End Point		538-553	928-939	630-640	-

Notes:

- a - Preliminary values based on pilot plant production. Values of commercial product may vary. Reprocessing is also capable of altering product properties.
- b - Product is a blend of distillate and residual fuels.
- c - Metals content subject to considerable variation depending on crude source.

A.2 PROCESS STEPS AND PROPERTIES: FILTERED AND DISTILLED PRODUCTS AND HYDROTREATING

The process characteristics result in a (No. 2 range) middle distillate low-viscosity fuel oil containing minimal sulfur ($<0.2\%$), ash (<10 ppm) and non-volatile matter. The heavy distillate product, though containing more impurities, is still a non-residual oil resembling heavy gas turbine fuels which have at times been used. Two properties of SRC-II middle distillate differ greatly from those of petroleum oils: the content of nitrogen ($0.9-1.1\%$) and aromatics ($62-65\%$), reflecting the coal source. The 9.1% hydrogen content is associated with its aromatics content. These impurities could tend to produce excessive NO_x and soot emissions in combustion, and they could be removed by current hydrotreating technology in a separate high-pressure hydrogenation reactor containing appropriate fixed-bed catalyst. Studies by GS&T in-house have shown that to hydrotreat such a coal liquid to the quality of No. 2 fuel oil (vis-a-vis nitrogen and aromatics) would consume 2000-3000 SCF of hydrogen per bbl of oil, costing \$2.50 to \$5.00 for a total price of \$24-29/bbl⁽¹⁾ in contrast to the estimated price of SRC-II fuel oil of \$21-24/bbl. Such a catalytic hydrotreating reactor is indeed incorporated into the Exxon EDS process,⁽²⁾ and all product in the boiling range is hydrotreated and has a commensurate predicted price and process thermal efficiency.

One goal of the SRC-II process development program has been the most economical process possible, in terms of cost and energy efficiency. Our expectation has been that NO_x and soot emissions could be prevented by in-combustion or post-combustion technology (to be explored extensively in this report) with lower total costs than hydrotreating SRC-II fuel oil. On the other hand, this approach still retains the option of performing some hydrotreating, should a certain amount of it be required for some combustion applications.

Many still expect a coal liquid to resemble the processes under development in 1970-75, e.g., H-coal boiler fuel; these process and products differed importantly from SRC-II and EDS distillate products. Typically, the reactor effluent, a slurry of liquid, ash and unreacted coal, was filtered.

In contrast to the distillation approach in SRC-II, filtration carried through a large amount of ash with the filtrate product, as well as non-volatile liquid, which increased the product viscosity. H-coal typically had 0.20% ash, a viscosity in the high No. 6 range, and 0.5% sulfur.⁽³⁾ This may have helped to establish the idea that there was a spectrum of fuel qualities, increasing in viscosity and content of nitrogen, aromatics, sulfur, ash, and non-volatile material, proceeding from No. 2 fuel, through No. 6 fuel oil, and on to coal liquids at the "poor" end of the quality spectrum. Although SRC-II, EDS, and H-coal "syncrude" mode distillate products are still at the poor end of the quality spectrum with regard to nitrogen and aromatics content, their other properties are in the No. 2 oil region of the quality spectrum, proving this idea to be an oversimplification.

A.2 References

- 1 Internal GS&T Report, March 1978.
- 2 W. R. Epperly, J. W. Taunton, "Exxon Donor Solvent Coal Liquefaction Process Development," Presented at Coal Dilemma II, sponsored by ACS, Colorado Springs, Colorado, February 12-13, 1979.
- 3 D. T. Beecher, et.al., Energy Conversion Alternatives Study, Westinghouse, Phase II - Final Report, NASA CR-134942, Vol. II (1976), p. 5-174.

A.3 Composition and Properties of SRC-II: Comparison with Other Fuels

Some further properties of SRC-II fuel oil and other fuels have been determined which further clarify the properties and relation to other fuels. Figure A.3-1 shows the close correlation⁽¹⁾ between hydrogen content and aromaticity (as determined by C^{13} NMR). SRC-II is mid-way in the spectrum of quality from No. 2 oil to SRC recycle solvent (not a product). Hydrogen content (and thus aromaticity) also correlates with the density (or specific gravity) of oils,⁽²⁾ as shown in Figure A.3-2 and Table A.3-1. This is the origin of the term "heavy" distillate referring originally to the petroleum fractions having higher densities, which also usually had the highest distillation ranges (or were non-volatile distillation residues) and lowest hydrogen contents. Thus, "heavy" or high density petroleum oils were associated with poor quality, in contrast to coal liquids and their properties. It is interesting that in the above table and figure, the cycle oil, which is a product from catalytic processing of petroleum, fits the same density-hydrogen content correlation as the coal-derived materials.

Figure A.3.3a from ASTM D86 distillation at atmospheric pressure, clarifies that SRC-II (here, a blend of 5.75 middle distillate to one heavy distillate) was completely vaporized as the sample reached 300-350°C, in contrast to the much smaller amount of No. 5 fuel oil vaporized at such temperatures. Furthermore, in the "burning profiles" of these two fuels in a furnace, the SRC-II combustion was completed at 240°C furnace temperature, and the No. 5 oil, at 550°C (Figures A.3-3c and 3d). The wide variations in properties that commercial residual fuel oils have always displayed is of interest here and regarding the DOE-NASA-Lewis combustor development program discussed elsewhere in this report series. Table A.3-2 lists eight such fuels,⁽⁴⁾ varying in viscosity (SUV at 100°F) from 186 to 8606. Other properties listed which are of special interest to this discussion are sulfur, ash and nitrogen contents, and the carbon-hydrogen ratio, all varying widely. The nitrogen content of SRC-II fuel oil is fairly evenly distributed over its distillation range, as shown in Table A.3-3, the lowest and highest boiling fraction both containing nearly 1% nitrogen. In contrast, the nitrogen

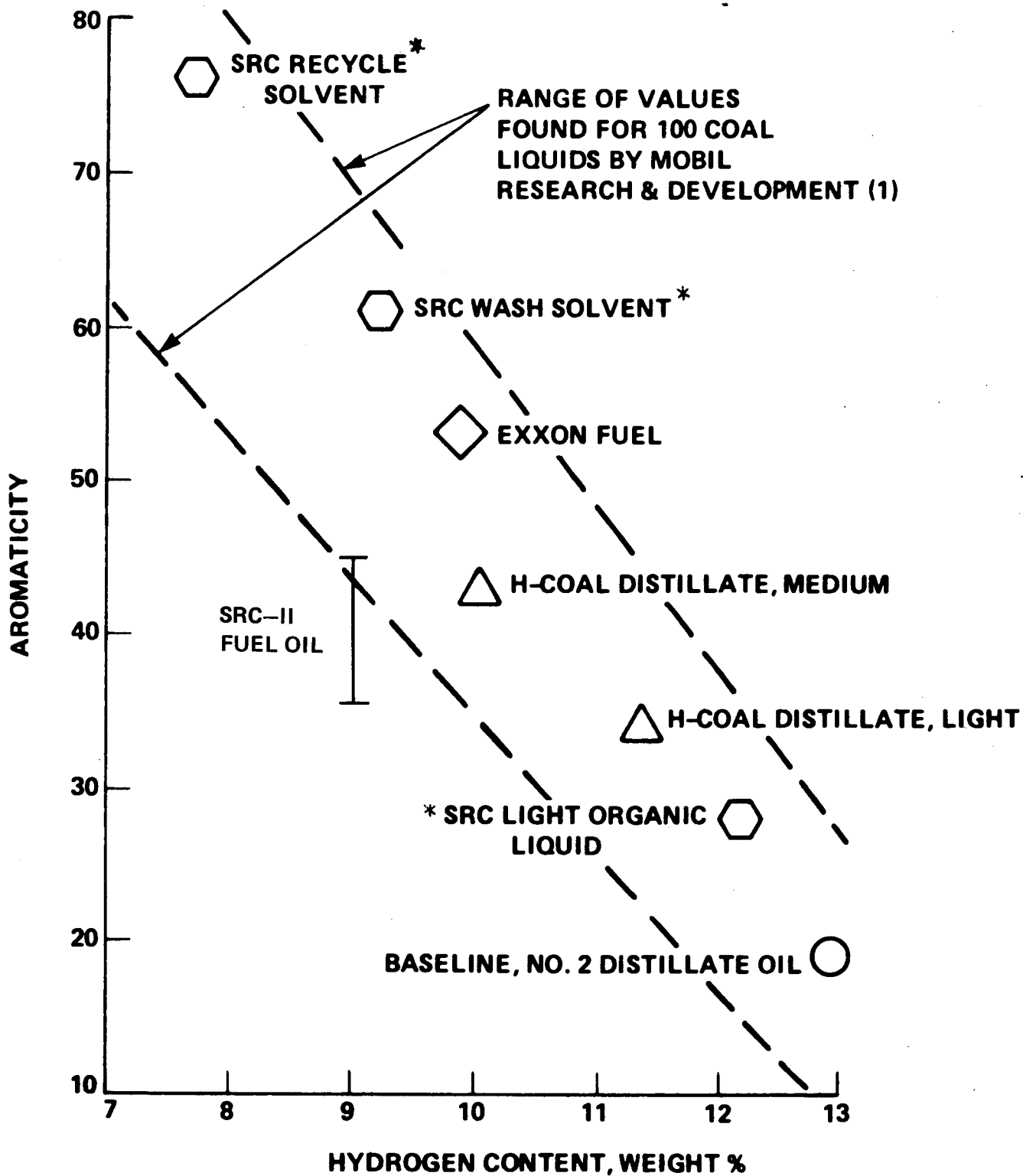


Figure A.3-1 RELATION OF AROMATICITY TO HYDROGEN CONTENT (FROM REF. A.3-1)
* FROM SRC-I PROCESS

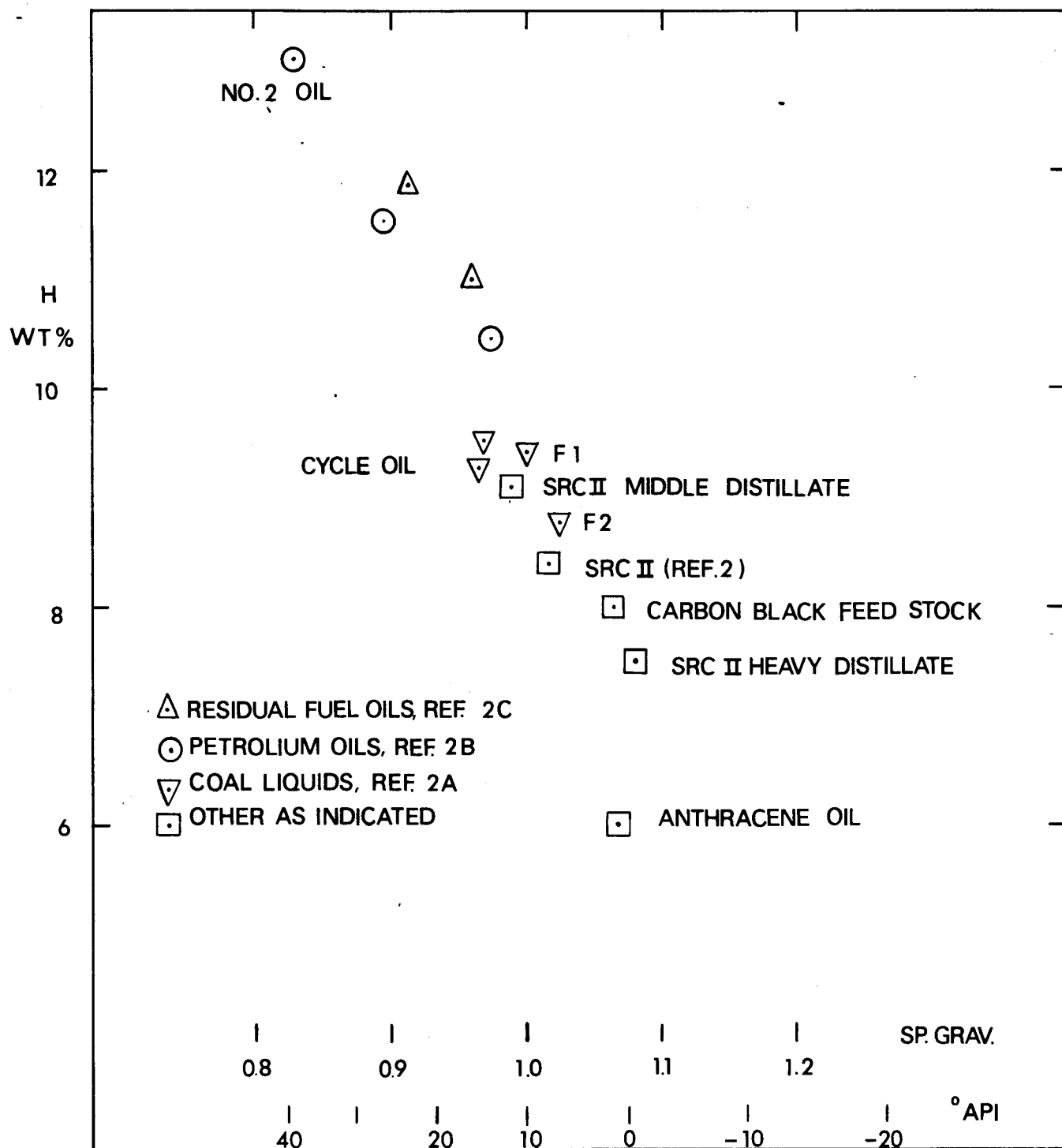


Figure A.3-2 RELATION OF SPECIFIC GRAVITY TO HYDROGEN CONTENT

Table A.3-1

PROPERTIES OF VARIOUS TYPES OF LIQUID FUELS

	D86 Distillation Range B pt, °F (% Distilled)	% H	% C	% N	% S	Viscosity, cs 100°F	API Gravity
No. 2 Fuel Oil ^(2A)	360 (10%) 640 (90%)	13.1	86.9	0.01	<0.2	2.5	34.5
No. 6 Fuel Oil ^(2A)							
High Sulfur	--	11.0	86.25	0.41	2.2	680	17.3
Low Sulfur	--	11.85	87.94	0.16	0.5	48	24.7
Light Cat. Gas Oil	465 (10%) 610 (90%)	est. 9-11%		<0.1		3	15.3
Decant Oil	720 (10%) 880 (90%)	est. 8-9.5%		<0.1		40	5.5
Carbon Black Feedstock (F.S. 120)	--	est. 8%		<0.1		No. 5 H Range	<2
Shale Oil by In Situ Retorting	400-900	11-13		1.5- 2.0	0.3- 0.8	10-40	20-30
SRC-II Fuel Oil							
Middle Distillate (MD)	350 (0%) 550 (100%)	9.1	86	0.9-1.1	<0.2	3.1-3.4	13.8
Heavy Distillate (HD)	550 (0%) 930 (100%)	7.5	89	1.2-1.4	.37- .47	50-90	1
Anthracene Oil Reilly Tar & Chem. Co.	est. heavy distillate range	6		1.0		30	1

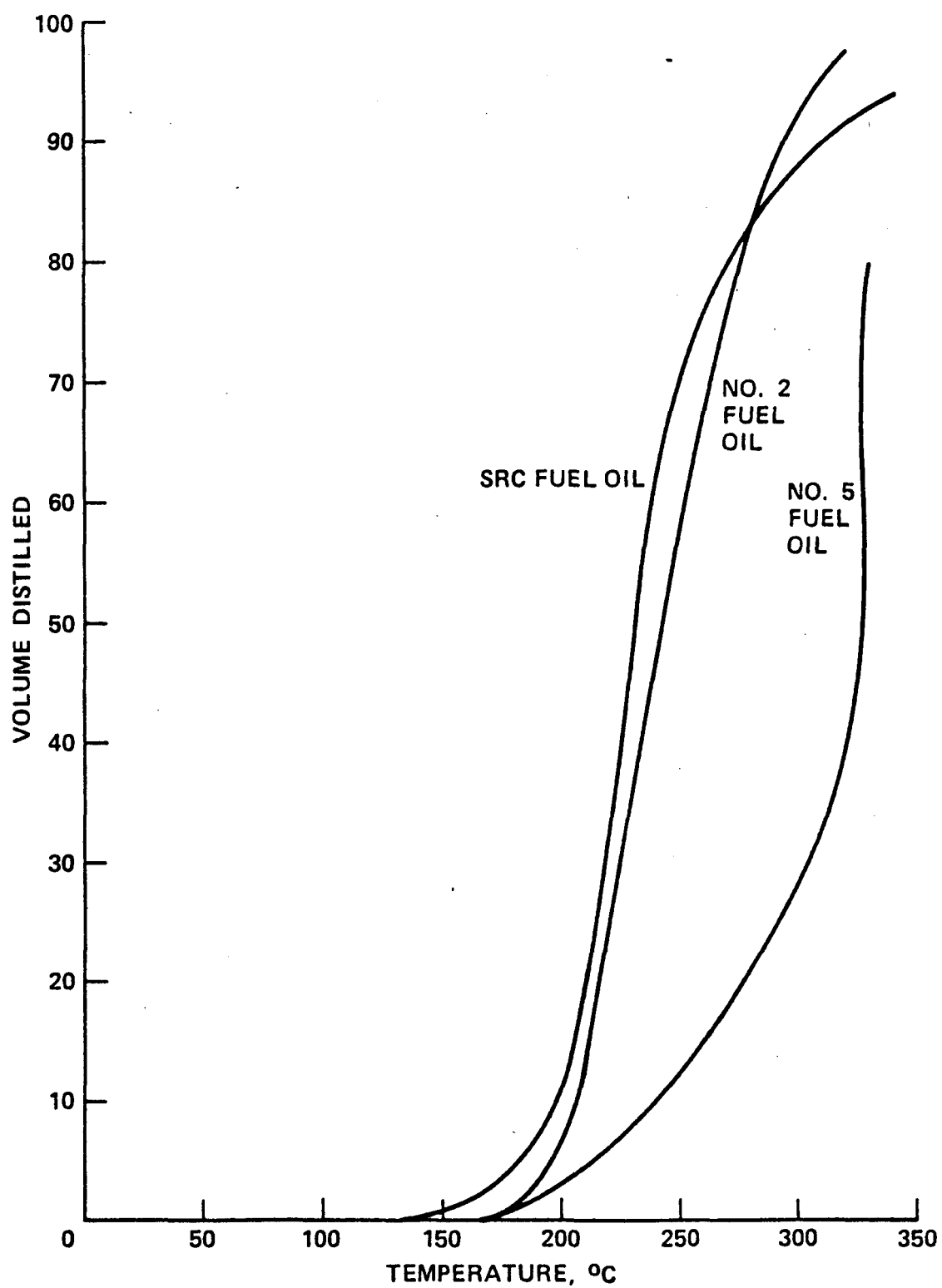


Figure A.3-3a. ATMOSPHERIC DISTILLATION CURVES
OF SRC-II FUEL OIL AND PETROLEUM OILS (FROM REF. A.3-8)

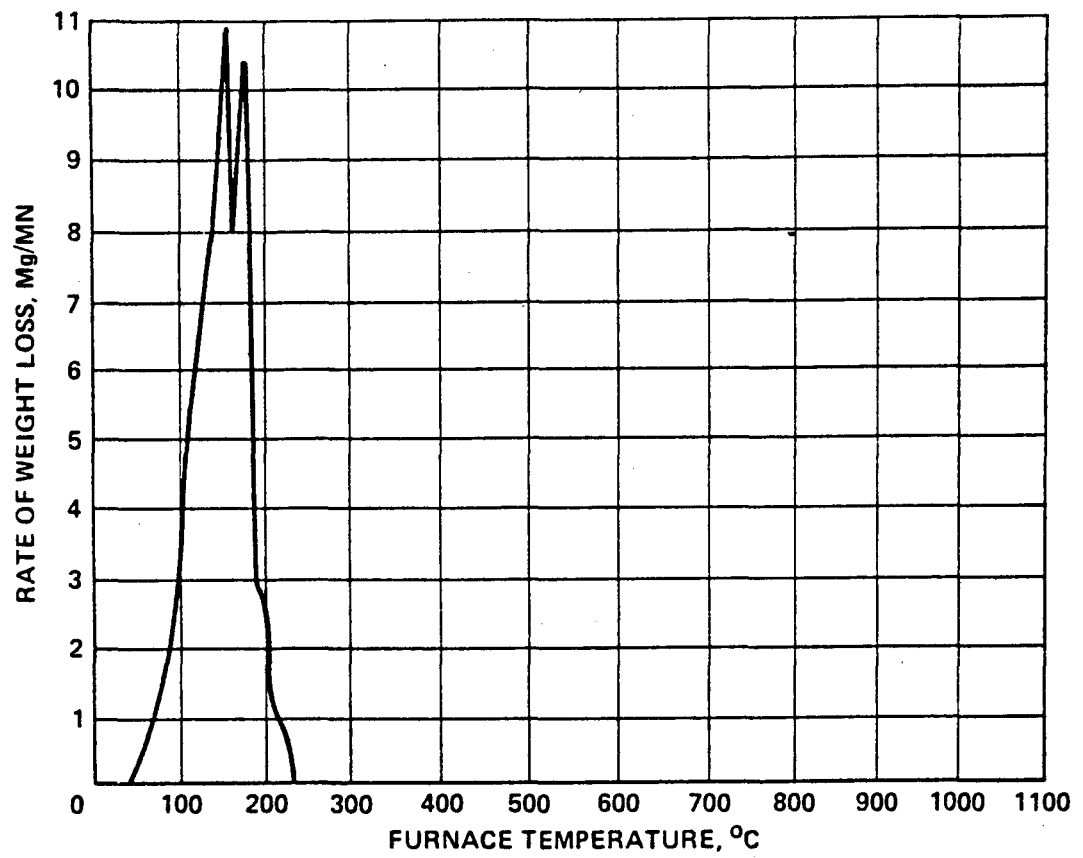


Figure A.3-3b BURNING PROFILE FOR SRC II FUEL OIL (FROM REF. A.3-2)

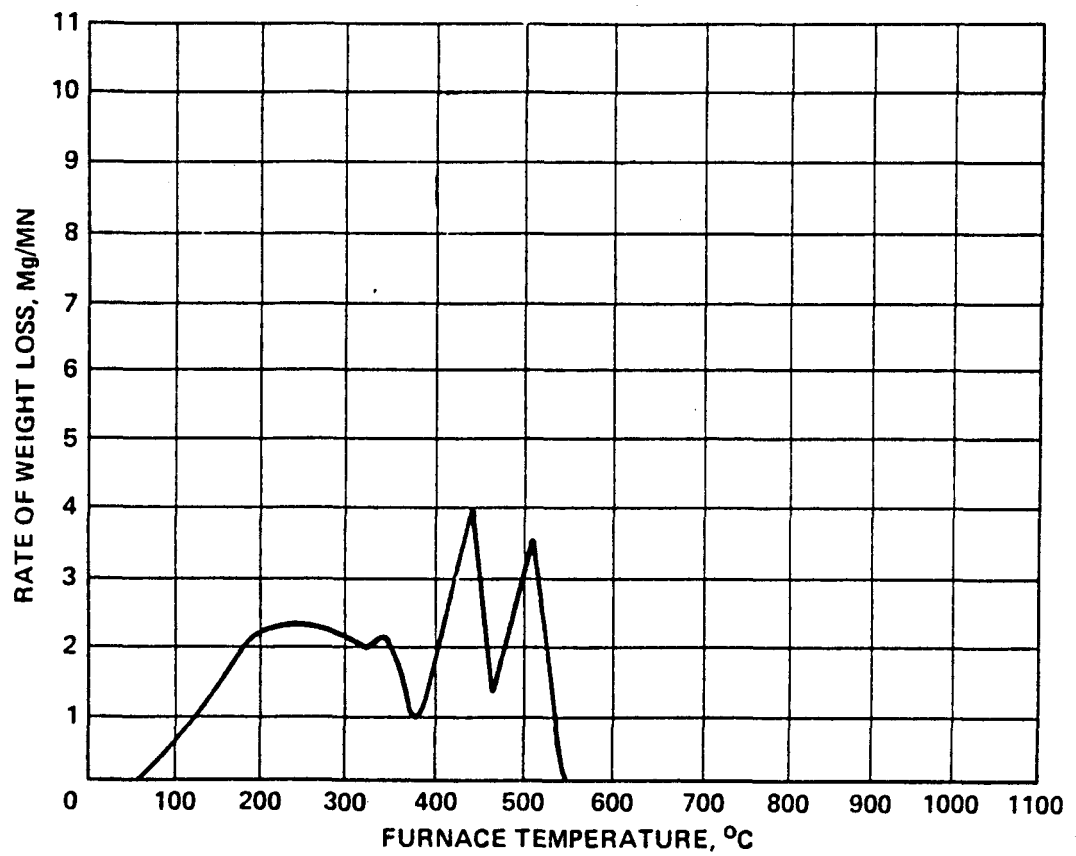


Figure A.3-3C BURNING PROFILE FOR NO. 5 FUEL OIL (FROM REF. A3-8)

TABLE A.3-2 PROPERTY RANGES OF RESIDUAL FUEL OILS (FROM REF. A.3-4)

	Midwest No. 6	East Coast		Gulf Coast		West Coast No. 6	Caribbean No. 6	African No. 6
		No. 5	No. 6	No. 6	No. 6-1½ S			
Gravity: °API	3.6	9.1	15.1	13.7	16.4	12.4	14.7	21.3
Density: lb./U.S. Gal. at 60°F.	8.723	8.382	8.038	8.116	7.967	8.189	8.060	7.712
Viscosity, SUV: Sec.								
100°F.	186.3	200	2505	4794	8606	5558	4517	1570
130	86.2	97.1	818	1462	1406	1462	1261	-
210	40.5	43.5	122.0	193.3	166.5	175.2	161.0	-
Viscosity, Furol: Sec.								
122°F.	-	-	109.4	198.7	200	200	169.9	72.9
Flash, P-M: °F.	225	205	220	210	190	154	220	240
Flash, OC: °F.	335	295	300	320	320	290	305	-
Fire, OC: °F.	400	335	360	395	345	335	340	-
Pour Point: °F.								
Maximum	+40	+10	+45	+25	+65	+45	+20	+55
Minimum	+35	+5	+40	+20	+40	+35	+15	-
Sulfur: % by Wt.	1.46	0.81	0.78	2.05	0.85	1.73	2.18	0.48
Water by Dist'n., ASTM D95	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	0.1	-
Water and Sediment: % by Vol.	< 0.05	< 0.05	< 0.05	0.10	0.10	0.10	0.05	0.10
Sediment, ASTM D473: % by Wt.	0.04	0.02	0.02	0.01	0.02	0.01	0.01	0.02
Carbon Residue, Con.: % by Wt.	3.29	4.24	8.05	11.4	7.50	11.2	10.9	7.2
Carbon-Hydrogen Ratio	11.0	9.6	7.8	8.0	7.6	8.1	7.6	-
Nitrogen: % by Wt.	-	-	0.33	-	-	0.92	0.44	0.31
Ash, ASTM D482: % by Wt.	0.04	0.01	0.02	0.03	0.01	0.03	0.05	0.01
Fusion Point, 1000°F., Ash: °F.	> 1500	> 1500	> 1500	> 1500	> 1500	> 1500	1196	-
Spectrographic Analysis: PPM								
Aluminum	80	15	15	5	6	2	8	7
Barium	-	0.6	-	8	1	0.4	-	-
Boron	-	-	-	-	0.02	-	-	-
Calcium	2	2	10	40	4	0.8	6	10
Chromium	0.06	0.2	0.5	0.8	0.09	0.2	0.2	0.4
Cobalt	-	1	3	1	2	3	-	-
Copper	0.06	0.03	0.07	0.1	0.04	0.07	0.01	0.1
Iron	10	4	7	20	10	40	3	3
Lead	-	0.5	-	50	1	-	-	2
Magnesium	4	2	10	15	1	0.2	2	20
Manganese	0.5	0.3	0.7	0.5	0.2	0.5	-	0.5
Molybdenum	-	-	0.2	0.3	-	0.2	0.7	0.6
Nickel	1.3	5.7	25	18	9.3	102	58	42
Potassium	0.7	0.3	0.4	0.4	0.03	0.2	0.3	3
Silicon	100	10	10	5	6	3	2	3
Silver	-	-	0.01	-	-	0.01	0.04	0.01
Sodium	7	4	6	6	8	0.9	15	50
Strontium	0.5	0.2	0.6	0.7	0.4	0.2	0.9	0.9
Tin	-	0.6	4	-	-	-	-	5
Titanium	3	0.4	0.8	0.3	0.2	0.7	2	0.5
Vanadium, GRM 803	1.0	2.4	20	20	5.2	60	179	16
Zinc	-	-	-	10	-	-	-	-
Heat of Combustion, Calculated								
BTU/lb. Gross	17,944	18,358	18,858	18,400	18,713	18,243	18,406	19,006
BTU/Gal. Gross	156,526	153,877	151,580	149,334	149,016	149,392	148,352	146,571

compounds in petroleum are concentrated in the highest boiling range; see the data in Table A.3-3, taken from an assay of a commercially important crude oil.

The detailed compound-type compositional analysis of coal liquids has been carried out very extensively by Gulf, other fuel producers, and universities. This information is valuable in process development work, but also offers interpretations about the fuels' combustion behavior. Although it is outside the scope of this report to review⁽⁵⁾ this work or to explore the detailed composition-combustion behavior relation, a few examples of its importance follow.

Because of the similarity between some of the properties of coal liquids and those of cycle oils or decant oils, the latter have been studied as potential surrogates for coal liquids whose supplies have been scarce. Blends of petroleum components were prepared to give the same elemental and physical properties as various coal liquids, and comparative tests in gas turbine combustors were run.⁽¹⁾ The results were initially promising, and the fuel-derived NO and smoke from the surrogates resembled those from the respective coal liquids. However, further work has revealed occasional but unpredictable anomalies.⁽⁶⁾ Thus, two oils having the same elemental and physical properties (distillation range, viscosity, etc.) will not necessarily exhibit the same combustion behavior if they were derived from different materials, e.g., coal and petroleum, and thus had possibly different detailed molecular compositions.⁽⁷⁾ Nevertheless, if two coal liquids from different processes, e.g., SRC-II and EDS, have the same elemental and physical properties, they will have very similar molecular composition and thus similar combustion behavior.

In a DOE-NASA-Lewis combustor development project, to be described in Section F.4, it was suggested that coal liquids, if unavailable, be simulated by nitrogen-doping a residual oil with pyridine. Depending on the combustor concept to be tested, such a blend could exhibit combustion behavior much different from a coal liquid, because the pyridine would vaporize more quickly than the somewhat higher molecular weight nitrogen compounds in coal

TABLE A.3-3

NITROGEN CONTENTS OF VARIOUS DISTILLATION
FRACTIONS OF SRC-II FUEL OIL* AND PETROLEUM OILS

<u>SRC-II FUEL OIL</u>		
<u>%w over</u>	<u>Dist. temp. °F</u>	<u>%w N</u>
Initial B.P.	212	----
10 %	424	0.88
20 %	436	----
30 %	448	0.91
40 %	458	----
50 %	474	0.96
60 %	492	----
70 %	530	1.06
80 %	590	----
90 %	722	1.11

CRUDE OIL FRACTIONS

	<u>Boiling Range °F</u>	<u>%w N</u>
Heavy Naphtha	310-375	0.0007
Light No. 2 Fuel Oil	375-520	0.00080
Heavy No. 2 Fuel Oil	520-680	0.0193
Gas Oil	680-870	0.13
Vacuum Residue	860+	0.73
Vacuum Residue	1000+	0.94

*From Reference A.3-7.

liquids. The nitrogen compounds in a high-nitrogen residual oil would, of course, provide even less resemblance to those in coal liquids. Finally, the non-volatile or residual components in a residual oil resemble the non-volatile components in older type, filtered coal liquid but would not simulate a totally distillate product such as SRC-II fuel oil.

A.3 References

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- 2a. J. E. Haebig, B. E. Davis, E. R. Dzuna, "Preliminary Small-Scale Combustion Tests of Coal Liquids," *Envir. Sci. and Technol.* 10 (3), 243 (1976).
- 2b. P. F. Schmidt, *The Fuel Oil Manual*, 3rd Ed., 1969, Industrial Press Inc., NY.
- 2c. H. L. Goldstein, C. W. Siegmund, "Influenced Heavy Fuel Oil Composition and Boiler Combustion Conditions on Particulate Emissions," *Envir. Sci. Technol.*, 10 (12), 1109 (1976).
3. D. T. Beecher, et.al., *Energy Conversion Alternatives Study*, Westinghouse, Phase II - Final Report, NASA CR-134942, Vol. II (1976), p. 5-174.
4. Internal communication, Gulf Oil Corporation.
5. K. S. Seshadri, et al., "Carbon-13 Nuclear Magnetic Resonance Spectra of Model Hydroaromatics and Solvents," *Fuel* 57, 111 (1978), and previous publications.
6. Private communication, EPRI.
7. L. J. Muzio and J. K. Arand, "Combustion and Emission Evaluation of SRC-II Fuel Oil," KVB Report No. 19900-733 to Gulf Mineral Resources Co., 12/77.
8. W. Downs, A. J. Kubasco, "Characterization and Combustion of SRC-II Fuel Oil," EPRI Report FP-1028, March 1979.

A.4 CURRENT GAS TURBINE FUEL SPECIFICATIONS AND SRC-II

Having described the SRC-II process and the general characteristics of SRC-II fuel oil in comparison with other fuels, we turn to current gas turbines and the detailed fuel property requirements which have been developed through years of field experience. SRC-II fuel oil has been tested and examined according to these specifications and complies with these requirements, as reported in this section, with the exceptions we have mentioned (NO_x , soot, and liner overheating) which are analyzed later in this report. Visits to discuss SRC-II fuel oil with four major stationary gas turbine manufacturers have verified these conclusions about SRC-II fuel oil application. Reports of these discussions and ideas about gas turbine technology needs occur in this and other volumes of this report series.

The ASTM D2880 Requirements for Gas Turbine Fuels are listed in Table A.4-1. These fuels decrease in quality from No. 0-GT to 4-GT. The No. 2-GT fuel specifies an upper (90%) distillation point of 540-640°F; in the SRC-II process the middle distillate fraction ("MD") is currently being separated with an upper distillation cut-point near that range. In the table (A.1-1) of SRC-II fuel oil properties, the No. 2-GT specifications are listed for comparison with SRC-II middle distillate, which meets the specifications for viscosity, flash point, pour point, and ash. Specific comments about some of these properties and others follow:

(1) Viscosity and pour point. SRC-II middle distillate meets the specifications.

(2) Flash point: The flash point of SRC-II middle distillate is within the safe range of handling, but is not so great as to indicate any problem with igniting a spray of this fuel with an electric spark in a gas turbine combustor.

(3) Heat of combustion, gross. Although the heating value of SRC-II fuel oil per pound is 200 Btu less than typical No. 2 oil, because of its lower hydrogen content, its higher density makes its heating value per unit volume the same as that of No. 2 oil.

TABLE A.4-1A (FROM REF. A.4-1)

Detailed Requirements for Gas Turbine Fuel Oils at Time and Place of Custody Transfer to User															
Designation ^a	Grade of Gas Turbine Fuel Oil	Flash Point, °C (°F) ^b	Pour Point, °C (°F) ^b	Water and Sediment, vol %	Carbon Residue on 10 % Residuum, wt %	Ash, wt %	Distillation Temperature, 90 % Point ^b		Kinematic Viscosity, cSt ^c			Saybolt Viscosity, s ^d			Specific Gravity 60/60°F (°API) ^e
									at 40°C (104°F)		at 50°C (122°F)	Universal at 38°C (100°F)		Furol at 50°C (122°F)	
		min	max	max	max	max	min	max	min	max	max	min	max	max	max
No. 0-GT	A naphtha or other low-flash hydrocarbon liquid.	^d	...	0.05	0.15	0.01	...	...	^d	...	...	...	...	...	...
No. 1-GT	A distillate for gas turbines requiring a fuel that burns cleaner than No. 2-GT.	38 (100)	-18 ^f (0)	0.05	0.15	0.01	...	288 (550)	1.3	2.4	...	...	(34.4)	...	0.850 (35 min)
No. 2-GT	A distillate fuel of low ash suitable for gas turbines not requiring No. 1-GT.	38 (100)	-6 ^f (20)	0.05	0.35	0.01	282 (540)	338 (640)	1.9	4.1	...	(32.6)	(40.2)	...	0.876 (30 min)
No. 3-GT	A low-ash fuel that may contain residual components.	55 (130)	...	1.0	...	0.03	...	...	5.5	...	638	(45)	...	(300)	...
No. 4-GT	A fuel containing residual components and having higher vanadium content than No. 3-GT.	66 (150)	...	1.0	...	...	...	...	5.5	...	638	(45)	...	(300)	...

^a No. 0-GT includes naphtha, Jet B fuel, and other volatile hydrocarbon liquids. No. 1-GT corresponds in general to Specification D 396 Grade No. 1 fuel and Classification D 975 Grade No. 1-D diesel fuel in physical properties. No. 2-GT corresponds in general to Specification D 396 Grade No. 2 fuel and Classification D 975 Grade No. 2-D diesel fuel in physical properties. No. 3-GT and No. 4-GT viscosity range brackets Specification D 396 Grade No. 4, No. 5 (light), No. 5 (heavy) and No. 6 and Classification D 975 Grade No. 4-D diesel fuel in physical properties.

^b Values in parentheses are for information only and may be approximate.

^c 1 cSt = 1 mm²/s.

^d When flash point is below 38°C, or when kinematic viscosity is below 7.3 cSt at 40°C, or when both conditions exist, the turbine manufacturer should be consulted with respect to safe handling and fuel system design.

^e For cold weather operation, the pour point should be specified 6°C below the ambient temperature at which the turbine is to be operated except where fuel heating facilities are provided. When a pour point less than -18°C is specified for Grade No. 2-GT, the minimum viscosity shall be 1.7 cSt, and the minimum 90 % point shall be waived.

^f Gas turbines with waste heat recovery equipment may require sulfur limits in the fuel to prevent cold-end corrosion (see Appendix X2.4.1.11).

API D 2880

TABLE A.4-1B (FROM REF. A.4-1)

TRACE METAL LIMITS OF FUEL ENTERING TURBINE COMBUSTOR(S)

X1.1 *Scope*—For improved turbine life, the turbine user must make arrangements to assure that the fuel entering the combustor(s) meets the requirements shown in Table X1. This might include transportation arrangements with the fuel supplier, particular care to on-site fuel storage and quality control procedures, and on-site clean-up procedures. The significance of trace metals with respect to hot corrosion of turbine components is discussed in Appendix X2.

X1.2 *Description of Term:*

X1.2.1 *Fuel Entering the Combustor(s)*—The term used to designate the fuel that is actually burned in the gas turbine. For the purposes of control of trace metals, fuel may be sampled at a point upstream from the point of entry to the combustor(s), provided the sample is representative of fuel entering the combustor(s).

X1.3 *Analytical Methods*—Methods for analysis

of these metals are to be agreed upon by the interested parties. Suitable methods are under development for the analysis of concentrations of vanadium, sodium, potassium, calcium, and lead.

X1.4 *Modification to Table X1*—Lower trace metal contaminant levels will promote longer parts lives from a corrosion standpoint. However, lower levels may limit the availability of the fuel. The user may elect to adopt different levels from those of Table X1 if, after discussion with the turbine manufacturer and the fuel supplier, he determines that his overall operation can thereby be optimized.

X1.5 *Fuel Handling Procedures*—For discussions of fuel handling, reference should be made to ASTM STP 531.⁶

⁶ *Manual on Requirements, Handling, and Quality Control of Gas Turbine Fuel, ASTM STP 531*, Am. Soc. Testing Mats., 1973.

TABLE X1 Trace Metal Limits of Fuel Entering Turbine Combustor(s)

Designation	Trace Metal Limits (max), ppm by wt.			
	Vanadium (V)	Sodium plus Potassium (Na + K)	Calcium (Ca)	Lead (Pb)
No. 0-GT	0.5	0.5	0.5	0.5
No. 1-GT	0.5	0.5	0.5	0.5
No. 2-GT	0.5	0.5	0.5	0.5
No. 3-GT	0.5	0.5	0.5	0.5
No. 4-GT	(Consult turbine manufacturers)			

(4) Fuels compatibility. SRC-II middle distillate is more aromatic than No. 2 oil, and is a better solvent for the high molecular weight components of residual oils, which sometimes are precipitated by the addition of No. 2 oil to a tank previously containing the residual oil. SRC-II heavy distillate contains some less-soluble high molecular weight compounds ("asphaltenes" in Table A.4-2) which might precipitate upon admixture of heavy distillate with a low-aromatics petroleum fuel oil. ASTM spot tests should be used to identify this possibility.

(5) Compatibility with materials of construction. There are materials presently in use (some elastomers, for example) which might be attacked by the aromatic nature of SRC-II fuel oil, but resistant alternative materials are available. Data on the subject are currently being obtained.

(6) Carbon Residue. Good nozzle design and spray patterns normally prevent carbon deposition. Nozzle purging at shutdown may also be recommended.

(7) Gravity. The gravity of SRC-II fuel oil is much lower than the minimum specified for No. 2-GT. The No. 2-GT gravity value is the means by which ASTM insures a minimum hydrogen content. We have referred to the unusually low hydrogen content of SRC-II fuel oil and the implied problem of soot emissions and radiative liner overheating are referred to, and will be analyzed later in this report; several potential solutions are identified.

(8) Nitrogen, aromatics, and hydrogen content: These facets of SRC-II fuel oil composition have been described in section A.2; they imply excessive emissions of NO_x and soot, and liner overheating. The analysis in the rest of this report describes solutions to these problems. Some solutions involve the SRC-II process, but the most economical and effective solutions appear to be in combustor modification or possibly flue gas NO_x removal.

(9) Ash and trace metal contaminants: The ASTM limits are 100 ppm ash (for No. 2-GT) and 0.5 ppm of Na+K, V, Ca, or Pb for any GT fuel except No. 4-GT. The ash level in SRC-II middle distillate is less than 10% of the No. 2-GT limit. Gulf has realized the importance of the trace metals content

of SRC-II fuel oil as a potential gas turbine fuel, and has been closely monitoring this property. The heavy distillate ("HD") fraction was found to be susceptible to metal contamination through occasional physical carryover of solid or liquid particles in the distillation equipment at the Ft. Lewis pilot plant. Continually improved operations have now brought the ash content of the heavy distillate within the No. 2-GT limits, and have limited the Na+K in the middle distillate to less than one ppm.

Even lower levels of ash and trace metals have been achieved in the pilot plant at the Gulf Science and Technology laboratories; a middle distillate-heavy distillate blend contained only 36 ppm ash, with 0.13 ppm N+K, as determined in the central laboratories of a major gas turbine manufacturer. There is no evidence for distillate organometallic compounds, and further reduction in metals contents of middle distillate and heavy distillate is anticipated. Since the metals content from pilot plant runs will be decreasing in late 1979 and 1980, a long-term single-blade corrosion test using early 1979 product would not indicate potential corrosion in a subsequent complete turbine test with the cleaner 1980 product.

With fuels like clean natural gas, hot corrosion of the turbine blades proceeds at a modest rate, equivalent to normal oxidation. With liquid fuels, blade deterioration might proceed much more rapidly. This is ascribed primarily to the ash formed by five trace metals which are occasional contaminants in distillate fuels, but may reach appreciable concentrations in residual fuels:

1. Sodium, potassium, and calcium, primarily from traces of sea water picked up in ocean transport.
2. Lead, primarily from transportation equipment used for gasoline.
3. Vanadium, a normal component of residual fuel oils but rarely a contaminant in lighter fuels.

SRC-II middle distillate, like petroleum distillates, can be expected to be free of metallic elements as manufactured but might pick up trace contaminants in the common carriers and storage tanks of a bulk distribution system. The coal liquids might be even more prone to retain contaminants because of their higher density and content of natural polar compounds.

Some of the effects of temperature, sodium, and vanadium are shown in Figure A.4-1. In industrial and marine environments, scrubbers may be required on the air inlet to the turbine since these same trace metals are sometimes found in the air as well as in the fuel.

As peak operating temperatures in industrial turbines advanced from 1200-1250°F around 1950 to 1450-1650°F in the 1960's, to 1950°F and higher at present, the tolerance for trace metals in the fuel has decreased. ASTM started to write a specification for gas turbine fuel oils in 1964. Four fuel grades were established, having the same handling and combustion characteristics as common burner and diesel fuels, but with added limitations on trace metal contaminants. When the specification was completed in 1970, the trace metals limits (e.g., 2 ppm vanadium; 5 ppm sodium plus potassium; 5 or 10 ppm calcium, depending on the fuel grade; and 5 ppm lead) were obsolete and unacceptable to turbine manufacturers and users.

ASTM writes consensus standards, in this case representing unanimous agreement among fuel suppliers, gas turbine manufacturers, and users. However, fuel suppliers have refused to agree to limits of 1 or 2 ppm on the trace metals, as desired by the turbine manufacturers and users. Kerosene, home heating oil, and diesel fuel normally meet the desired limits at the refinery and usually meet the limits as delivered. Yet with the uncertainties of minor contamination in pipelines, tankers, trucks, etc., fuel suppliers are reluctant to guarantee the desired purity. The guarantee could imply heavy liability for damaged turbines. A further stumbling block is the lack of ASTM-approved analytical tests for low concentrations of trace metals. The whole problem of turbine corrosion, fuel handling and purity, and analytical methods for trace metals was covered in an ASTM symposium in Los Angeles, June 1972. The papers have been printed in ASTM Special Technical Publication 531, "Manual on Requirements, Handling, and Quality Control of Gas Turbine Fuel."

Figure A.4-1

EFFECTS OF TEMPERATURE, SODIUM, AND VANADIUM
CORROSION ON GAS TURBINE BLADE MATERIALS*

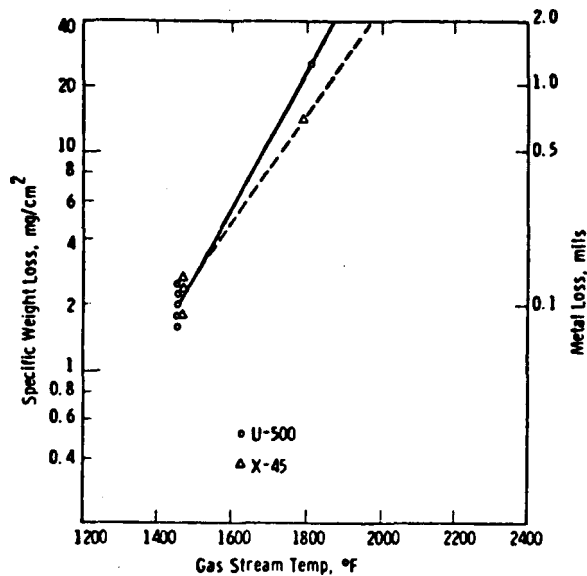


Fig. 12 Effect of gas temperature on hot corrosion characteristics of X-45 and U-500—specimens tested for 50 hr at 3 atm pressure

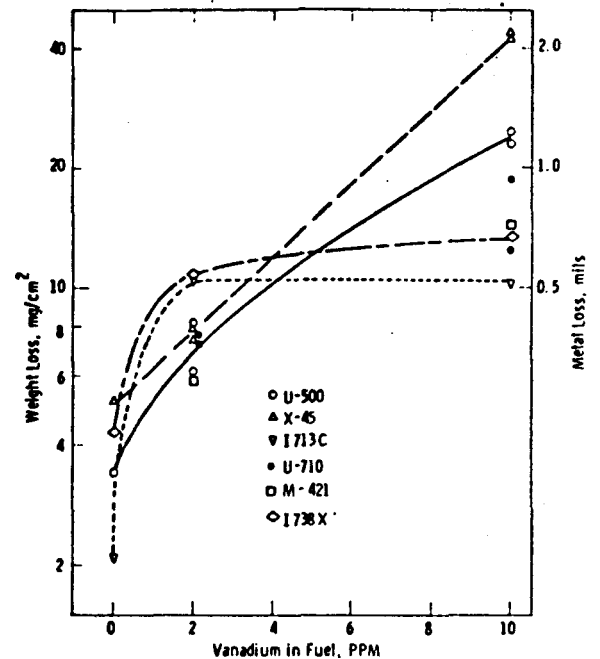


Fig. 13 Effect of vanadium (with no sodium) on various alloys tested in the pressurized passage at 1500 deg F metal temperature and 3 atm pressure for 150 hr

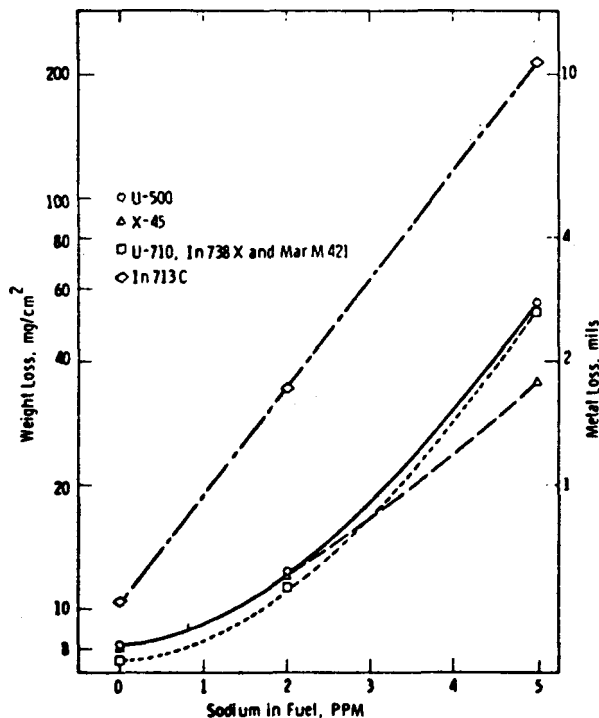


Fig. 15 Effect of sodium (with 2 ppm vanadium) on various alloys tested in the pressurized passage at 1500 deg F metal temperature and 3 atm pressure for 150 hr

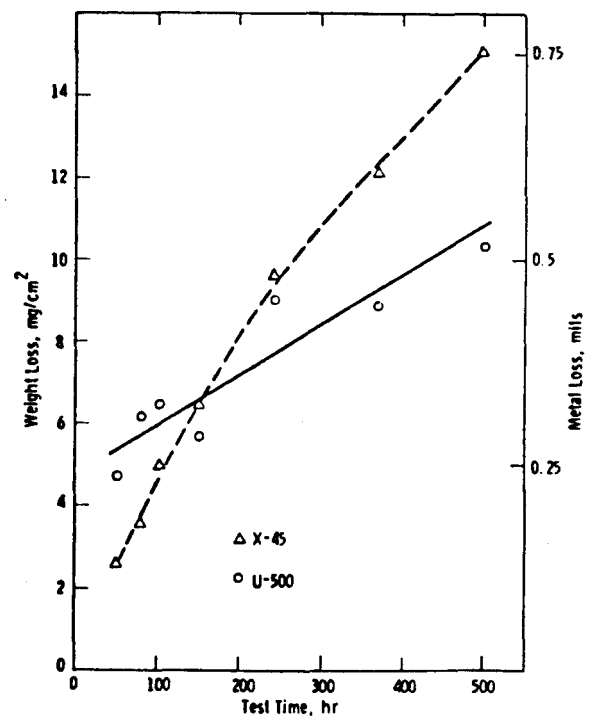


Fig. 14 Corrosion rates of X-45 and U-500 tested in the passage with 2 ppm vanadium and no sodium at 1500 deg F and 3 atm pressure

* From Lee, S. Y., DeCorso, S. M., and Young, W. E., "Laboratory Procedures for Evaluating High-Temperature Corrosion Resistance of Gas Turbine Alloys", ASME Winter Annual Meeting, New York, 1970, Paper No. 70-WA/CD-2.

The present thinking on the ASTM Gas Turbine Fuel Oil specification is to include the trace metal limits in the appendix where they serve as information but not a requirement. These leave room for negotiation between fuel supplier and purchaser and also leaves room for on-site purification when needed.

In contrast with the persistent effort to get clean fuels, some gas turbines operate on No. 6 Fuel Oil containing appreciable sodium and vanadium. They require a water-washing scheme to remove salts from the fuel, and addition of magnesia, Epsom Salts, or some other magnesium compound to inhibit the corrosive action of vanadium. Obviously, treatment of this kind is only suited to larger, base-loaded power plants and not to small, unattended or intermittent peaking units. Another factor is the attitude of power plant operators that this is a refinery operation and foreign to power plant routine.

Washing and inhibition are important features of fuel preparation for the use of blended residuals in industrial gas turbines and also in various utility gas turbines. Washing requires a density difference between water and the fuel and, in addition, is influenced by surface active agents that are inherent in-or added to-the system. The electrostatic characteristics of the fuel are important in those systems that rely on electrostatic forces for water removal. Companies that specialize in chemicals and equipment for fuel preparation have indicated their willingness to investigate the cleaning of coal liquids and, indeed, have been involved to some extent in coal-liquids treatments related to processing problems within the liquefaction plants.

A.4 REFERENCES

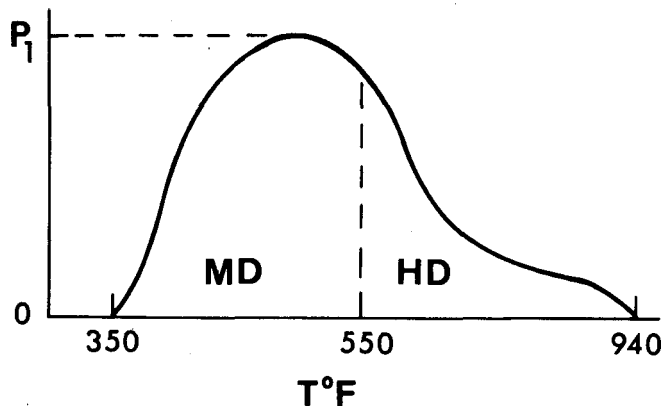
1. 1978 Annual Book of ASTM Standards, Part 24, ASTM, Philadelphia (1978).
2. S. Y. Lee, et al., Laboratory Procedures for Evaluating High-Temperature Corrosion Resistance of Gas Turbine Alloys, ASME Winter Annual Meeting, New York, 1970, Paper 70-WA/CD-2.

A.5. ADAPTING PROCESSING AND COMBUSTION CAPABILITIES TO EACH OTHER

The gas turbine combustor design efforts for coal-derived liquids ("CDL") could reveal that new designs can clearly burn CDL only up to a certain limiting nitrogen or aromatics content. This is more likely to be the case for aircraft-derived turbines than for heavy-duty units, which may even be capable of burning full-range SRC-II fuel oil (middle distillate and heavy distillate, having 8.5%H). The CDL product quality must then be adapted to the turbine's capabilities through modification of the process. In addition to some degree of hydrotreating, referred to in Section A.2, higher boiling material may require exclusion from the product by distillation at a certain cutpoint (now 550°F for middle distillate). To establish the values of these processing parameters required by the combustor design, combustor tests would be needed with a series of fuel samples covering the likely range of the parameter.

For example, if excessive smoke occurred with full-range SRC-II, tests of a series of samples having successively lower cutpoints and higher hydrogen contents (8.5 to 9.1%) would establish the cutpoint needed for smoke-free combustion. One might also choose to cover this range of hydrogen contents with a set of fuels obtained by blending low-hydrogen and high-hydrogen stocks in different ratios, instead of obtaining samples ("process-varied samples," for reference) directly from the process with varied parameters. The blending approach could misrepresent the process-varied fuel, as illustrated qualitatively in Figure A.5-1.

In Figure A.5-1, each curve represents the amount of material in the sample at the boiling point indicated by the x-axis. Sample B is one of the series distilled to a certain upper boiling point, being 700°F in this case. Assuming for argument that the hydrogen content of Sample B were found in small-scale work to be 8.8%, one might choose to simulate Sample B by a blend of middle distillate and heavy distillate having the same hydrogen content, as in Sample C in the figure. However, Sample C contains some material boiling between 700° and 940°F which Sample B does not, indicated by the shading in Sample C, and Sample C could easily produce emissions differing from those of



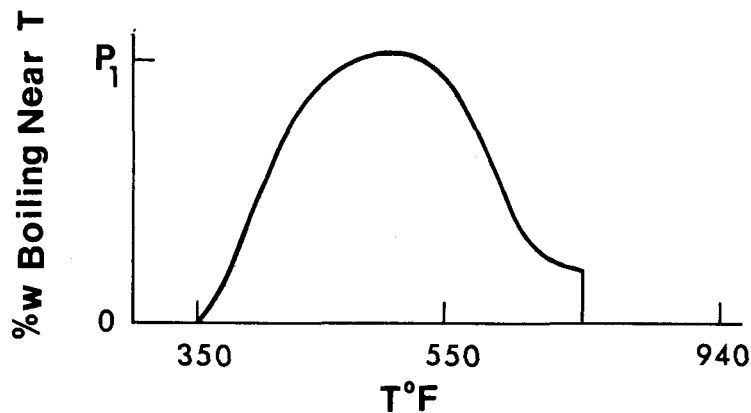
Sample A

Full range SRC-II F.O., 8.5% H

70% wMD, 30% wHD

MD has 9.1% H

HD has 7.5% H

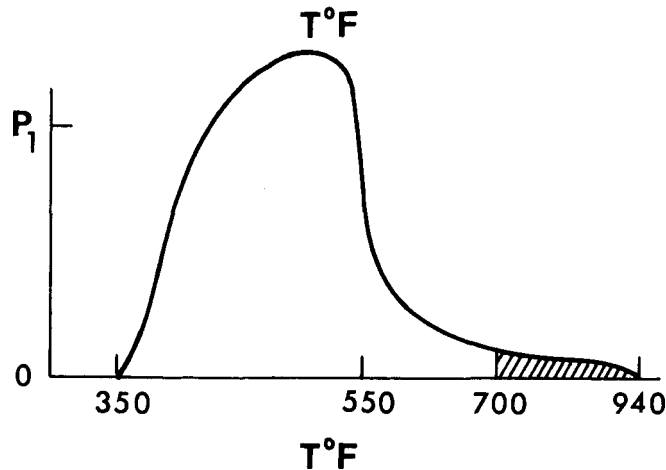


Sample B

Process variation used,

cutpoint at 700° F,

giving 8.8% H



Sample C

MD-HD blend to represent

Sample B; 85% MD-15% HD

gives 8.8% H, but contains

700- 940° F fraction (shaded)

which Sample B does not have.

Figure A.5-1 BLENDING COULD MISREPRESENT
PROCESS VARIATIONS. (PLOT IS SCHEMATIC ONLY)

an authentic Sample B. The smoke would be especially susceptible to a non-representative increase by the unwanted 700-940° material; the literature suggests that such compounds catalyze sooting.

The same sort of differences between authentic process-varied samples and blends could occur in work involving nitrogen compounds, NO_x, hydrotreating, and possibly surrogate CDL's. Gulf, as the process developer, would prefer to collaborate in providing authentic samples where appropriate, in order to avoid the creation of misleading information about the CDL properties required for problem-free combustion. Such information about varied process parameters and combustor designs should then be implemented in a study of economics optimization.

A.6 Emissions Limits

The most recent statement from EPA about gas turbine emissions is the proposed Standards of Performance for New Stationary Sources (NSPS) proposed in October 3, 1977 in the Federal Register.⁽¹⁾ The proposed NO_x limit is 75 ppm in the dried exhaust gas containing 15% oxygen. Particulates are not mentioned, and sulfur limit is 150 ppm, equivalent to 0.8% sulfur in the fuel. A two-month comment period was announced, but this regulation still has not yet been promulgated, possibly because of the high number of comments received. The allowable NO_x level is increased in cases of nitrogenous fuels, described in the following excerpt:

"For a fuel containing more than 0.25% N, the allowable NO_x is increased by 50 ppm.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere, except as provided in paragraphs (b), (c), and (d) of this section:

(1) From any gas turbine with a heat rate at peak load of more than or equal to 14.4 kilojoules per watt hour, based on the lower heating value of the fuel fired, any gases which contain nitrogen oxides in excess of:

$$\text{STD} = 0.0075 + F$$

where:

STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

F = NO_x emission allowance for fuelbound nitrogen as defined in part (3) of this paragraph.

(2) From any gas turbine with a heat rate at peak load of less than or equal to 14.4 kilojoules per watt hour, based on the lower heating value of the fuel fired, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075 \left(\frac{14.4}{Y} \right) + F$$

where:

STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at peak load (kilojoules per watt hour).

F = NO_x emission allowance for fuel-bound nitrogen as defined in part (3) of this paragraph.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-bound nitrogen (percent by weight)	F (NO _x percent by volume)
N ≤ 0.015	0
0.015 < N ≤ 0.1	0.04(N)
0.1 < N ≤ 0.25	0.004 + 0.0067(N - 0.1)
N > 0.25	0.005

where:

N = the nitrogen content of the fuel (percent by weight).

(b) Stationary gas turbines with a heat input at peak load of 107.2 gigajoules per hour (100 million Btu/hour) or less, based on the lower heating value of the fuel fired, are exempt from paragraph (a) of this section for a period not to exceed five years from (date of proposal)."

EPA stated the rationale for this allowance as follows:

"(This regulation) would include an adjustment to the NO_x emission limit as a function of the fuelbound nitrogen level in the fuel fired. This approach would require NO_x controls on all new stationary gas turbines, but would not restrict new, modified or reconstructed gas turbines to firing premium gaseous and distillate fuels. Thus, stationary gas turbines would not be penalized for firing heavy fuel oils, nor would there be any added impetus toward the firing of heavy or residual fuel oils in order to evade standards of performance."

Although it acknowledges that gas turbines burning coal liquids now would exceed this limit, the EPA announcement also expects gas turbine technology to become able to meet this regulation in ten years, the time when EPA expects coal liquids to be available in commercial quantities.

There have been few experimental demonstrations of innovative combustor concepts for coal liquids, and none has yet used an actual coal liquid, although there has been notable success with nitrogen-doped No. 2 oil. It would be premature to make a strong statement about the eventual success of technology in meeting the regulation. However, the Combustion Branch of EPA is sponsoring some of the most advanced combustor development projects and it seems likely that there would be adjustment of regulations due to possible feasibility problems, as well as EPA analyses of the impact upon the economy, etc., such as presented in Reference A.6-2.

A.6 References

1. Federal Register 42 (191) p. 53782 October 3, 1977.
2. "Standards Support and Environmental Impact Statement, Vol. 1: Proposed Standards of Performance for Stationary Gas Turbines" September, 1977, EPA - 450/2 - 77 - 0/72.

B. STATIONARY GAS TURBINE STRUCTURE AND TYPES OF COMBUSTORS

Some manufacturers' drawings with captions are provided here, for any introduction or definitions of turbine components which may be needed. Figure B-1 is a typical heavy-duty stationary gas turbine, with rather large combustors (No. 15-17 in Figure B-1). The functions of the combustor are depicted in Figure B-2 by the gas flow path arrows. Figure B-3 illustrates a gas turbine derived from an aircraft engine; the combustors are smaller than in the heavy-duty machines. Finally, Figure B-4 depicts the Brown-Boveri (Turbodyne) design, having only one very large combustor.

B. REFERENCES

- ¹ General Electric Product Bulletin GEA-8501.
- ² C. Wilkes, R. C. Russel, ASME Paper 78-GT-89 (1978).
- ³ Product Bulletin, General Electric Corporation, Evendale, IL.
- ⁴ Brown-Boveri Product Bulletin.

Series 5000 Simple-cycle, Single-shaft Gas Turbine

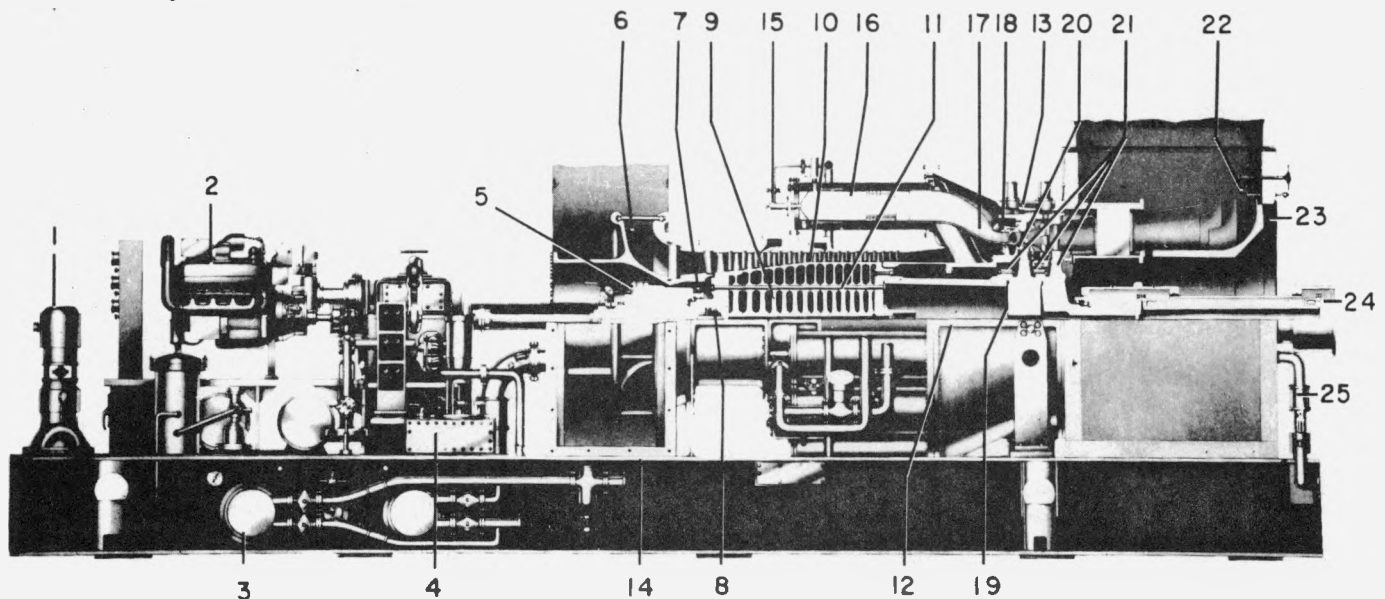
DESIGN FEATURES

ACCESSORY EQUIPMENT 1. **Lubrication Oil Pump Drives** — Variety of oil-pump drive systems are available to meet individual requirements — Shaft, a-c motor, d-c motor, expansion or steam turbine driven in various multiple combinations. 2. **Starting Device** — Choice of diesel engine, motor, steam turbine, or expansion turbine. 3. **Twin Oil Coolers** (optional) — Shown with three-way transfer valve. Each cooler handles full system capacity providing maximum reliability on continuous duty applications. 4. **Base-mounted Auxiliaries** — All turbine auxiliaries base-mounted for savings in installation costs and assurance of reliability through factory test as a complete power plant system.

COMPRESSOR 5. **Thrust and Journal Bearings** — Main thrust bearing is pivoted-shoe type. All bearings are steel-backed, tin-babbitted, pressure-lubricated and use conventional turbine oil. 6. **Radial Inlet Casing** — Provides uniform circumferential inlet flow to compressor. 7. **Compressor Blading** — Large chord, sub-sonic compressor blading of stainless steel material provides rugged air path design with wide operating limits. 8. **Compressor Design** — Proven high-efficiency, axial-flow compressor design with demonstrated long-life in varied types of service and environments. 9. **Wheel Construction** — Wheels of individual pancake forgings for maximum material homogeneity machined to constant stress cross-section. 10. **Rim Clearance** — Wheel rim clearance protects rotor from distortion during starting or any abnormal operating conditions. 11. **Through-bolt Construction** — Produces rigid, high-torque rotor design, without shrink fits, that is least sensitive to thermal bowing.

STATOR CASINGS 12. **Horizontally Split** — All casings split on horizontal centerline to facilitate inspection and maintenance. 13. **Shell Cooling** — Turbine shell cooling provides dimensional stability to maintain close rotor clearances for optimum long-time high efficiency performance. 14. **Inlet Orientation** — Available at each 90° quadrant for necessary adaptability to station design.

COMBUSTION 15. **Fuel Distribution and Flexibility** — Balanced fuel flow and equalized air distribution through precision cast first-stage turbine nozzle provides uniform combustion in all chambers. Gas, oil or dual fuel nozzles are available for flexibility in fuel selection. 16. **Reverse Flow Combustion Chambers** — Increased length of combustion path mini-



mizes temperature variations, prolongs life of parts. 17. **Temperature Distribution** — Combustion chamber and transition section design provides a slanted radial hot gas temperature profile which is matched to the turbine bucket stress profile, thereby increasing bucket life.

TURBINE 18. **Nozzle Cooling Design** — Trailing edge cooling increases nozzle life and reduces metal temperature by directing air through the body of the individual nozzle partitions and out small openings in the thin trailing edge. Segmented construction results in reduced stress during expansion and contraction of the nozzle. 19. **Two-stage Impulse Turbine** — High efficiency, two-stage heavy-duty turbine utilizes a high energy stage design with large temperature drops across stationary nozzles to produce conservative temperatures in rotating components. 20. **Long-shank Buckets** — Design isolates wheel rim from hot gas path reducing rim temperature and thermal gradient on wheel, thereby producing uniform dovetail load distribution and decreasing bucket sensitivity to vibration. 21. **Wheel Cooling** — Turbine wheels are maintained at design temperature by control of wheel space cooling air temperature and by built-in mechanical design features including bucket shank seals and cooling circuit design.

EXHAUST 22. **Temperature Measurement** — Two separate exhaust temperature control and monitoring systems provide complete protection. The primary electronic system using thermocouple measurement has rapid response and high accuracy necessary for dependable operation during transient operating conditions. A separate, secondary system provides two-stop automatic alarm and trip should malfunction occur. 23. **Exhaust Orientation** — Exhaust can be directed in each of the four major axes.

OTHER 24. **Load Coupling** — Continuously lubricated flexible coupling assures smooth operation, compensates for minor variations in shaft alignment. 25. **Guarded Oil Piping** — For maximum safety, all high-pressure oil piping in the vicinity of hot parts is either inside oil return lines or oil tank.

Figure B-1 PARTS OF HEAVY-DUTY GAS TURBINE, GE MS5000

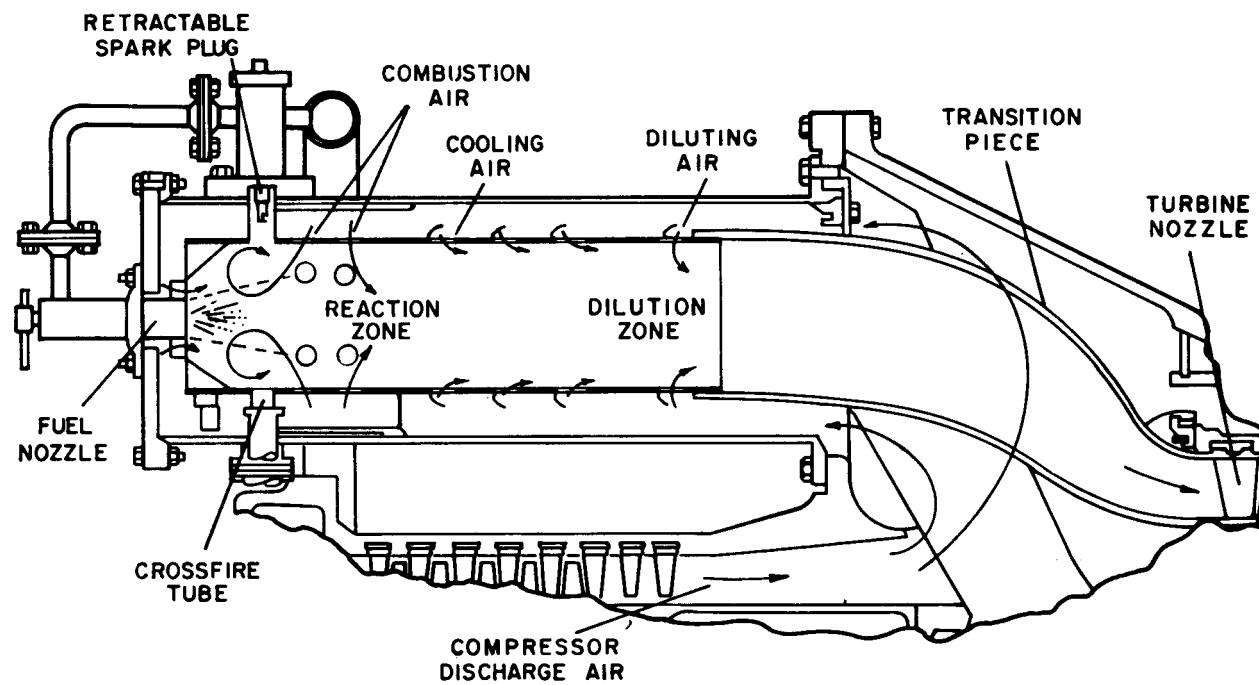
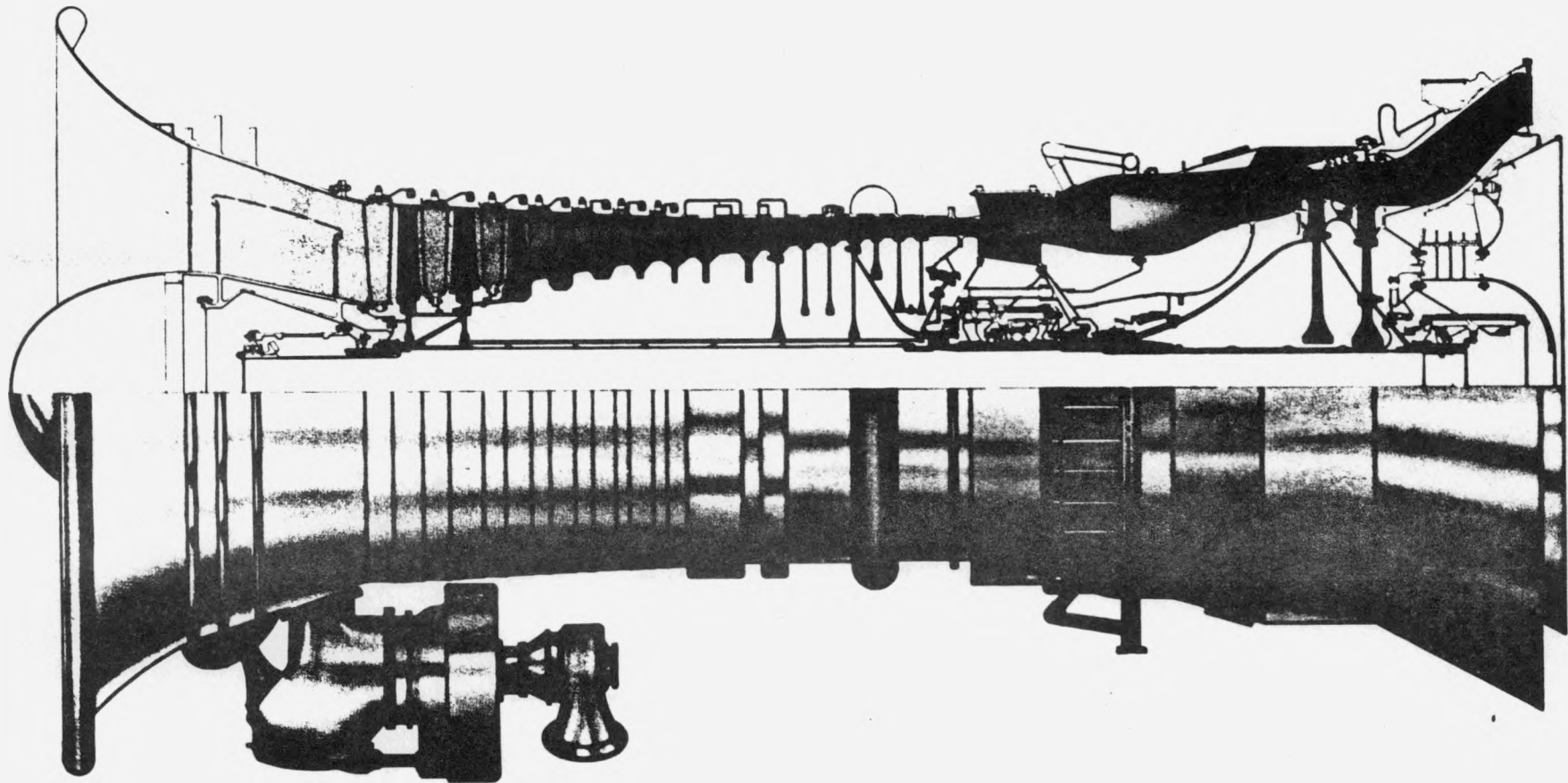


Figure B-2 COMBUSTOR PARTS, HEAVY-DUTY GAS TURBINE (FROM REF. B-2)



GENERAL ELECTRIC LM2500 GAS GENERATOR

Figure B-3 AIRCRAFT – D TYPE GAS TURBINE, GE LM 2500 (FROM REF. 4)

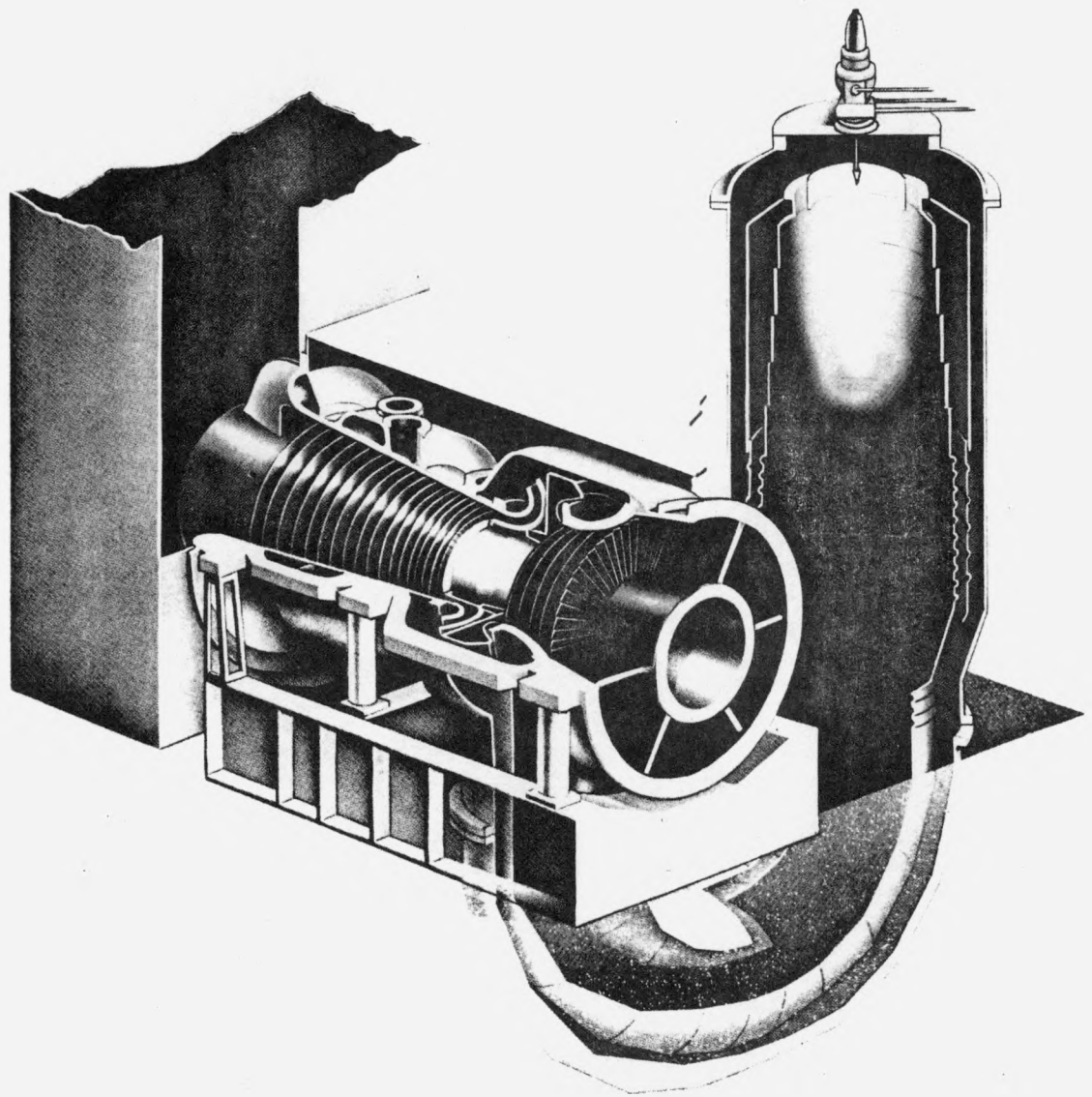
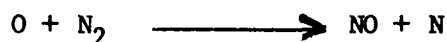


**Figure B-4 SINGLE-COMBUSTOR, HEAVY-DUTY GAS TURBINE
BROWN-BOVERI 55 MW, (FROM REF. 4)**

C. AIR-DERIVED NO_x

C.1 MECHANISMS FOR AIR-DERIVED NO_x

The formation of NO_x from atmospheric nitrogen in a flame is well understood. The maximum temperature of a hydrocarbon flame in air at one atmosphere pressure is approximately 2200°K, or 3500°F, with a stoichiometric fuel-air ratio. If the conversion of N₂ to NO_x were sufficiently rapid, the NO_x concentration would reach its thermal equilibrium value at 4000 ppm. The actual NO_x concentration reached is only 50-200 ppm, because NO is formed slowly via the well-known Zeldovitch free radical chain reactor.



In addition, 2-5% of the NO is usually further converted to NO₂, the total concentration of NO and NO₂ being denoted "NO_x."

Most commercial burners operate with large turbulent diffusion flames, and many of these are of sprays of liquid fuels. It is impossible to observe details of the chemistry of the gas phase flame fronts in such flames, because they are obscured by the droplet vaporization, turbulent eddies of changing concentration, temperature and position, etc. Rather, bench-scale laboratory burners have been used, which produce stationary flat flame fronts or other stable simplified geometries whose zones can be sampled.

A brief description of the structure of a flame is needed to exemplify this process; a premixed flame is used as the simplest case for discussion. The fuel/air ratio is designated by the fuel equivalence ratio ϕ_f , actual fuel/stoichiometric fuel; ϕ_f is less than one for a flame receiving more than enough air to consume all the fuel, the usual mode of operation of combustion equipment. Typically, an industrial furnace would receive 110% of the stoichiometric air, or 10% excess air, and $\phi_f = 0.91$.

In a non-turbulent (laminar) flame of a mixture of fuel vapor and air (a "premixed" flame), the primary flame zone is only a few mm thick, and

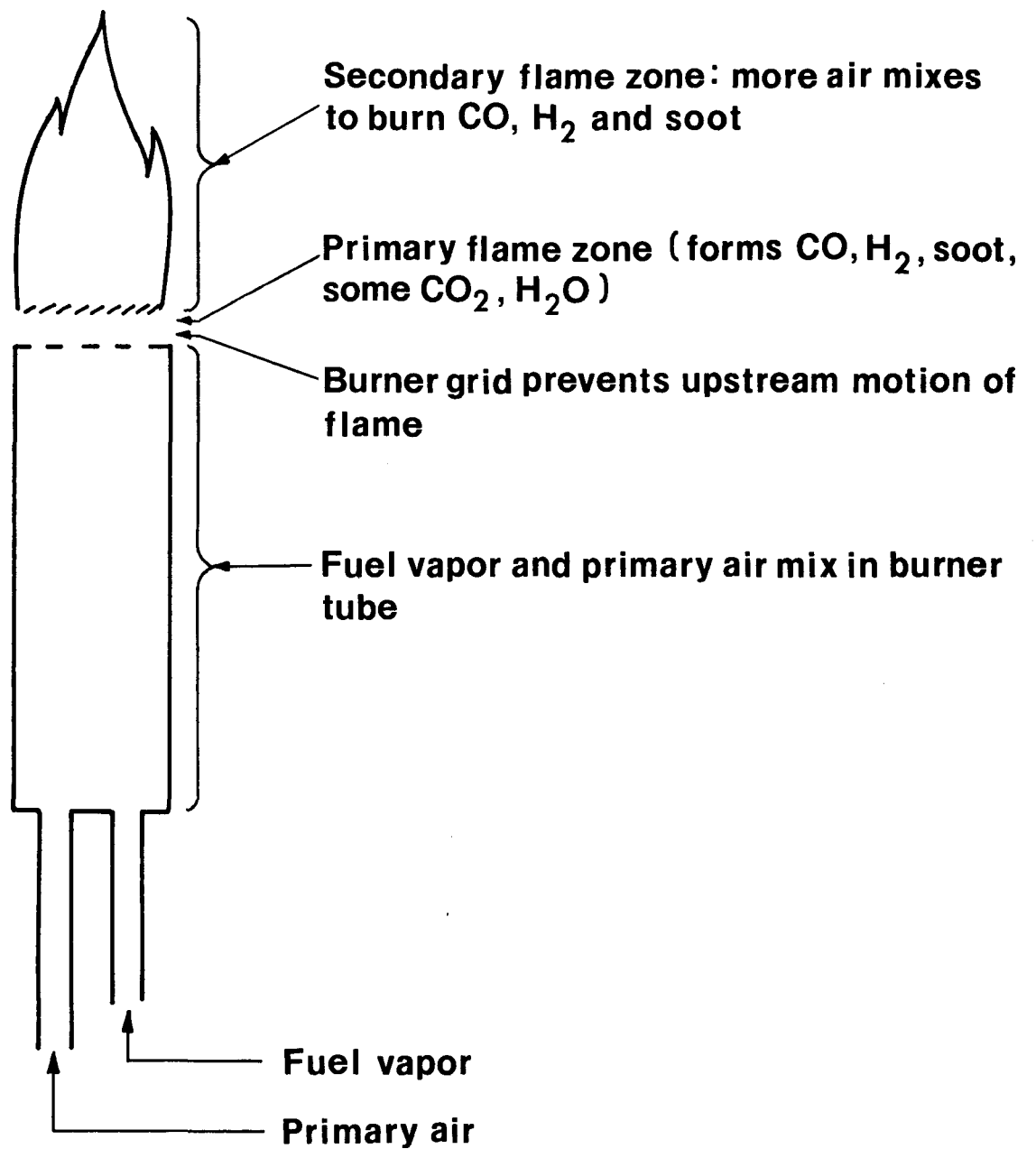


Figure C.1-1 ZONES IN A LAMINAR PREMIXED FLAME

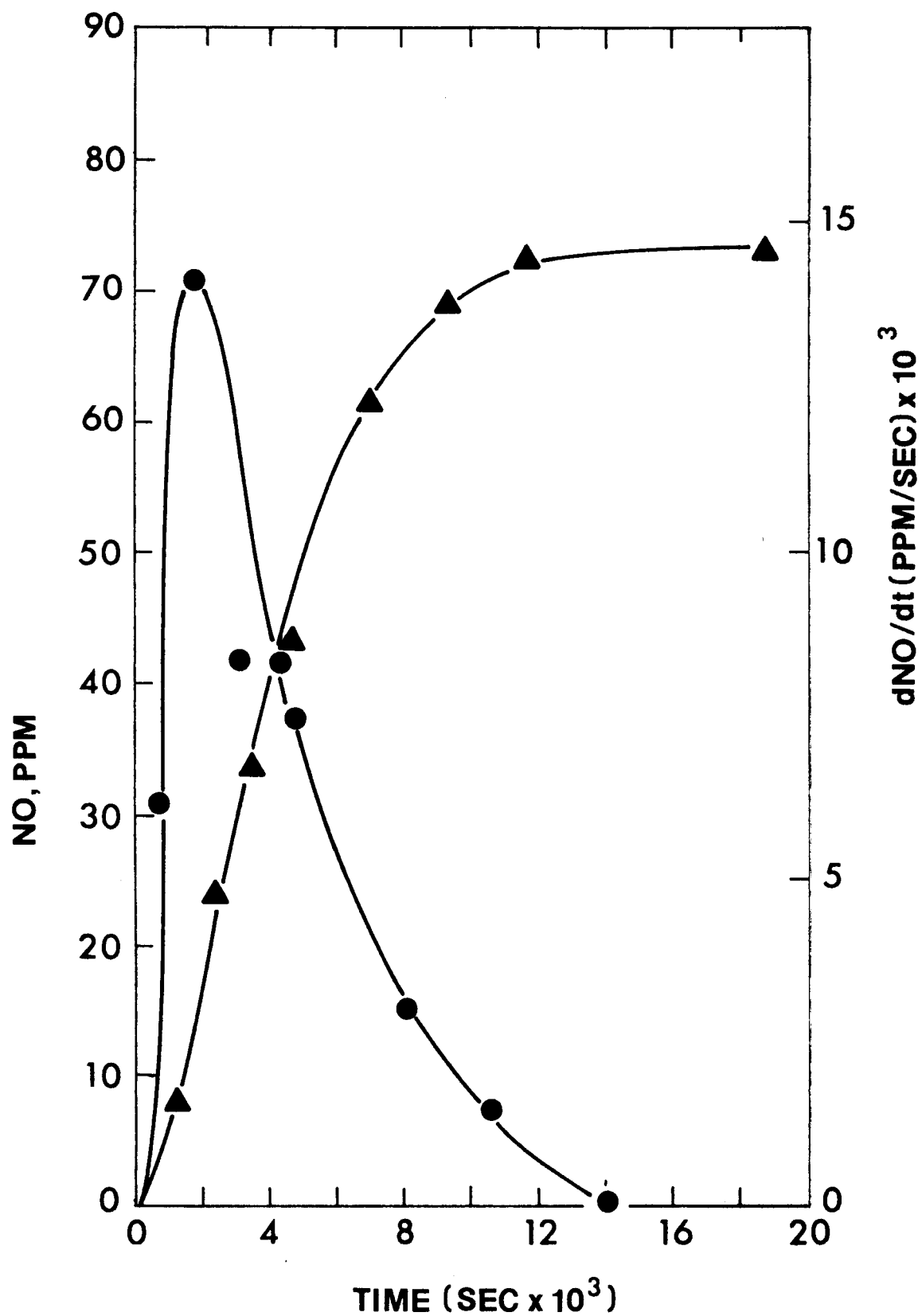


Figure C.1-2 RATES OF FORMATION AND CONCENTRATIONS OF NO AS A FUNCTION OF RESIDENCE TIME [15 PERCENT EXCESS AIR] (FROM REF. C.1-2)

within this zone NO_x is rapidly formed and the fuel is partially oxidized to CO and H_2 within a few msec. (See Figures C.1-1 and C.1-2). The secondary flame zone is downstream from the primary zone; and here, within 10-100 msec, the CO and H_2 are consumed and the gas cools rapidly below the temperature where NO_x formation rate is appreciable^(1,2). Although downstream from this point the thermal equilibrium NO_x concentration becomes less than the actual NO_x concentration, the latter does not decrease further because the path for NO_x destruction, the Zeldovitch mechanism, has become too slow.⁽³⁾ (NO_x refers to the usual existence of 1-5% of nitric oxides as NO_2 .) The NO_x concentration is "frozen in" at that concentration. The NO_x formed by this process is termed "thermal NO_x ." Amounts of NO_x in excess of this have been observed under conditions representing gas turbine combustors, being rapidly formed in the primary flame zone and termed "prompt NO_x ."⁽²⁾ It is observed only in hydrocarbon flames. Thermal NO_x emissions from a wide variety of aircraft engines have been found to correlate with the flame temperatures; see the data in the curve in Figure C.1-3. This empirical correlation agrees with the Zeldovitch expression based on elementary reaction rate data.

This great suppression of thermal NO_x emissions by decreasing the flame temperature by a few hundred degrees has been utilized for pollution control. Several combustion modification methods have been used to achieve this, all by increasing the gas (air or water) flow rate to the flame, increasing the gas mass/combustion enthalpy release ratio, and lowering the flame gas temperature. This approach has also been used with boilers, using water injection or flue gas recirculation for the added mass.

C.1 REFERENCES

1. Glassman, I., Combustion, Acad. Press, New York, 1977.
2. Bowman, C. T., Progress in Energy & Combustion Science, Vol. 1, p. 33 (1975).
3. Kahn, D. R., Axworthy, A.E., "Chemical Reaction in the Conversion of Fuel Nitrogen to NO_x : Low-Pressure Flat Flame Burner Studies," in Proc. Second Stationary Source Combustion Sympos. Vol. IV, p. 139 (1977) EPA-600/7-77-073.

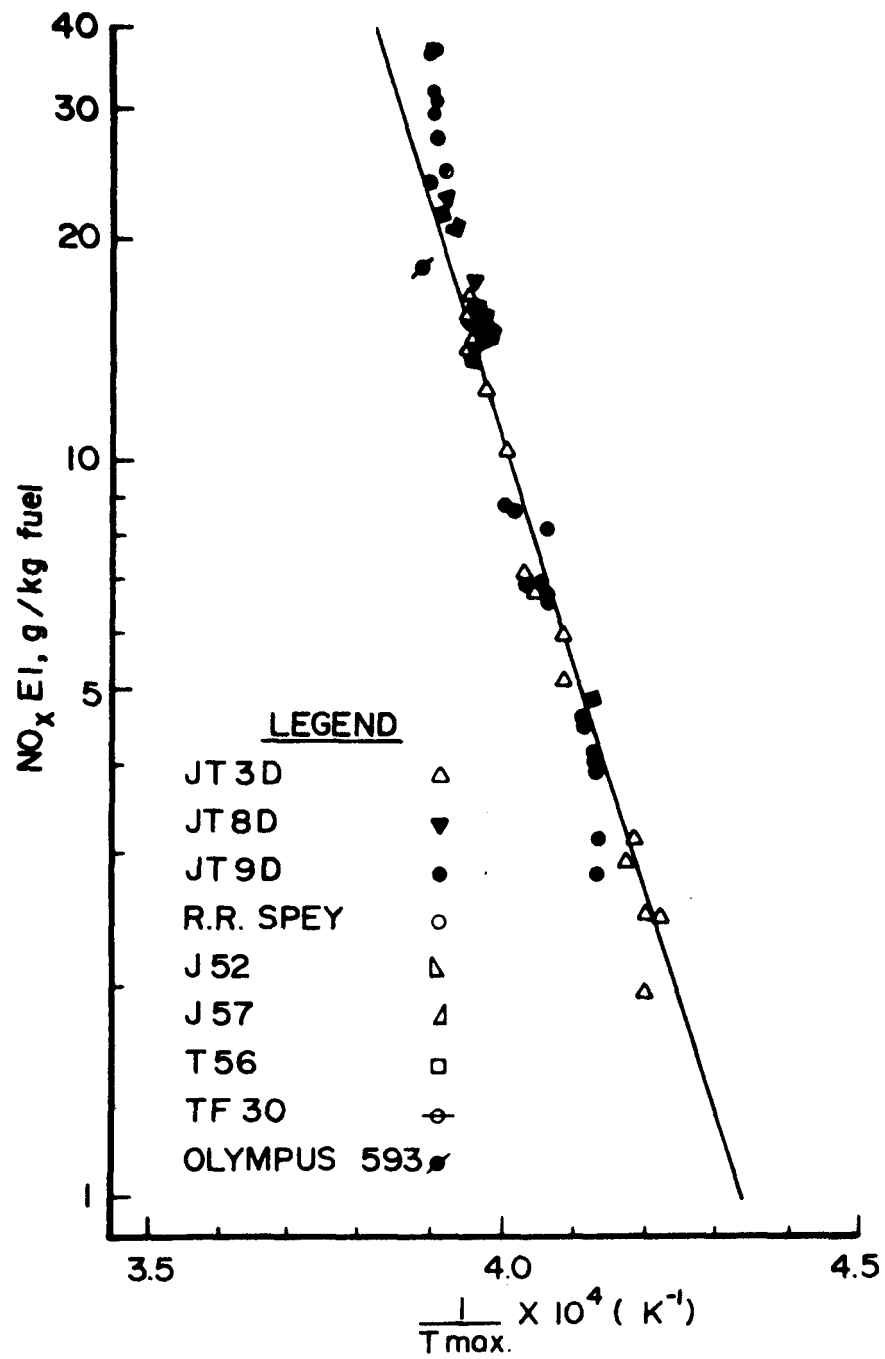


Figure C.1-3 RELATION OF THERMAL NO_x TO FLAME TEMPERATURE (FROM REF. C.1-4)

C.2 THERMAL NO_x REDUCTION IN FRAME-TYPE GAS TURBINES

In the following some examples of reduction in NO_x emissions from frame-type heavy duty gas turbines (in contrast to aircraft engines) are presented. The drawbacks or trade-offs resulting (e.g., smoke increase) will be mentioned here, but a systematic discussion of smoke will be presented later, in section E.

Single shaft gas turbines have the compressor vanes and depressurizing turbine blades on a single shaft, which is also connected to an electric generator, and these components all rotate at constant speed. Increases in load on the generator cause increases in fuel firing rate and the temperature of the combustor outlet (turbine inlet) gases. Since the temperature of the gases in the combustor increases greatly, but their residence time at this temperature changes less, more thermal NO_x is produced. Figure C.2-1 is an example of this increased NO_x production. Curve I is for an unmodified combustor; at the lowest load, only 20 ppm NO_x were produced, and the gas flowing through the combustor was heated by 350°F, from the 300°F combustor inlet temperature (typical) to the 650°F turbine inlet temperature.⁽¹⁾ At the highest load, the combustor temperature rise was 1100°F, the turbine inlet temperature was 1450°F, and 180 ppm NO were produced. At full load, the overall fuel-air ratio was 0.018 lb fuel/lb air, or 390% of stoichiometric air.

This test was conducted on a Westinghouse Electric W-251 gas turbine rated at 25 MW. In unmodified operation, each combustor (it has eight combustors) received 110% stoichiometric air at the primary zone, 29% of the total air flow. Reduction of NO_x emission was first attempted by reducing the residence time of the gases in the primary flame zone, by moving the dilution holes in the combustor liner closer to the primary zone for quicker dilution or cooling of the gas. This reduced the NO_x emissions by 60 ppm (Curve II). Secondly, cooling of the primary zone flame itself was done by increasing the air flow rate to the primary zone to 45% and 100% of the total air flow (Curves III and IV, resp.), via changes in the liner holes. This achieved a further reduction by 40 ppm of NO_x. General Electric achieved a similar NO_x reduction by primary zone leaning of this sort.⁽²⁾

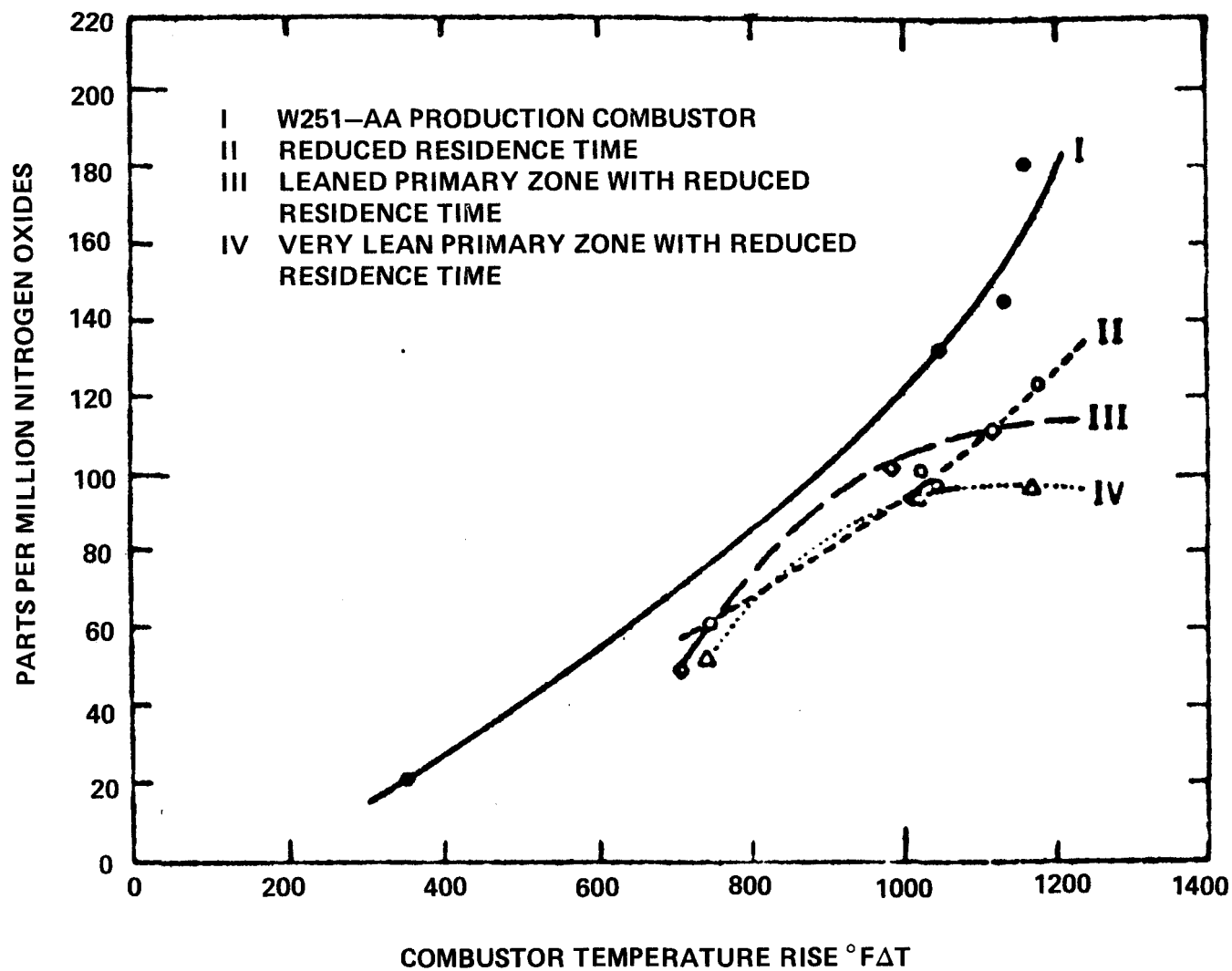


Figure C.2-1 SUPPRESSING THERMAL NO_x BY FLAME COOLING (FROM REF. C.2-1)

This approach of reducing NO_x by cooling the flame tends to have several drawbacks, including increased emissions of CO, hydrocarbons and soot where complete consumption is retarded in a cooler flame and narrowed operational limits for flame stability. Figures C.2-2 and C.2-3 show that as the combustor gas temperature decreases with lower load (lower fuel-air ratio in Figure C.2-3 and lower firing temperature in Figure C.2-2), CO and hydrocarbon emission suddenly increase; this principle applies to reducing the fuel-air ratio in the primary zone.⁽³⁾

Injection of water into the primary zone has also been tested for the past 5-10 years for thermal NO_x suppression, with considerable success. From a number of studies, correlations of the effects water injection been uncovered for frame-type and aircraft-type combustors. These correlations show the exponential-like rise in NO_x with flame temperature, characteristic of the Zeldovitch mechanism for thermal NO_x .

The example shown in Figure C.2-4 is taken from a recent test on a GE 75MW ten-combustor machine, equipped with a film-cooled liner permitting higher temperature operation, and instrumented for flow and temperature measurements.⁽⁴⁾ It is first to be noted (top curve) that at full load, the combustor exit temperature is 2200°F, (1500°K) considerably higher than the 1800°F discussed above, and the NO_x is 280 ppm. At part load, with a combustor exit temperature of 1800°F (1230°K) the NO_x is 100 ppm, consistent with earlier low-temperature turbine operation.

On these tests, firing No. 2 fuel oil, the NO_x was, for example, reduced by 50% when the water mass injection rate was 1.0% of the combustor air flow rate; this water mass flow rate is approximately 50% of the fuel mass flow rate. The other curves show the further NO_x reduction from still greater water injection rates. Field studies have verified the approximately 50% reduction in NO_x by water injection at this rate. Smoke was unaltered by water injection, but CO emission increased, the same drawback as occurred in the other flame-cooling NO_x suppression approach, i.e., leaner primary zones. The other disadvantage in commercial use of water injection is the need for a

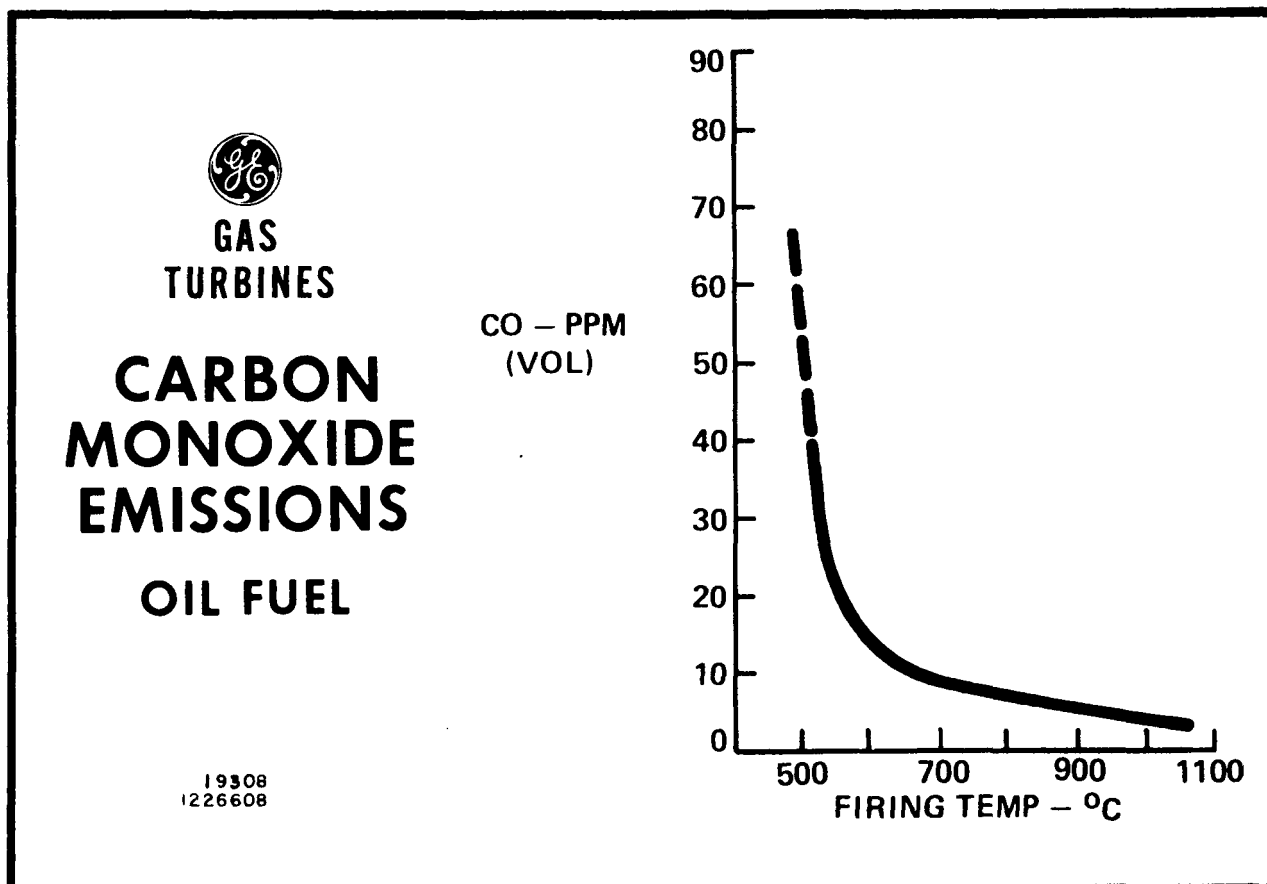


Figure C.2-2 COOLING FLAME INCREASES CO EMISSIONS (FROM REF. C.2-2)

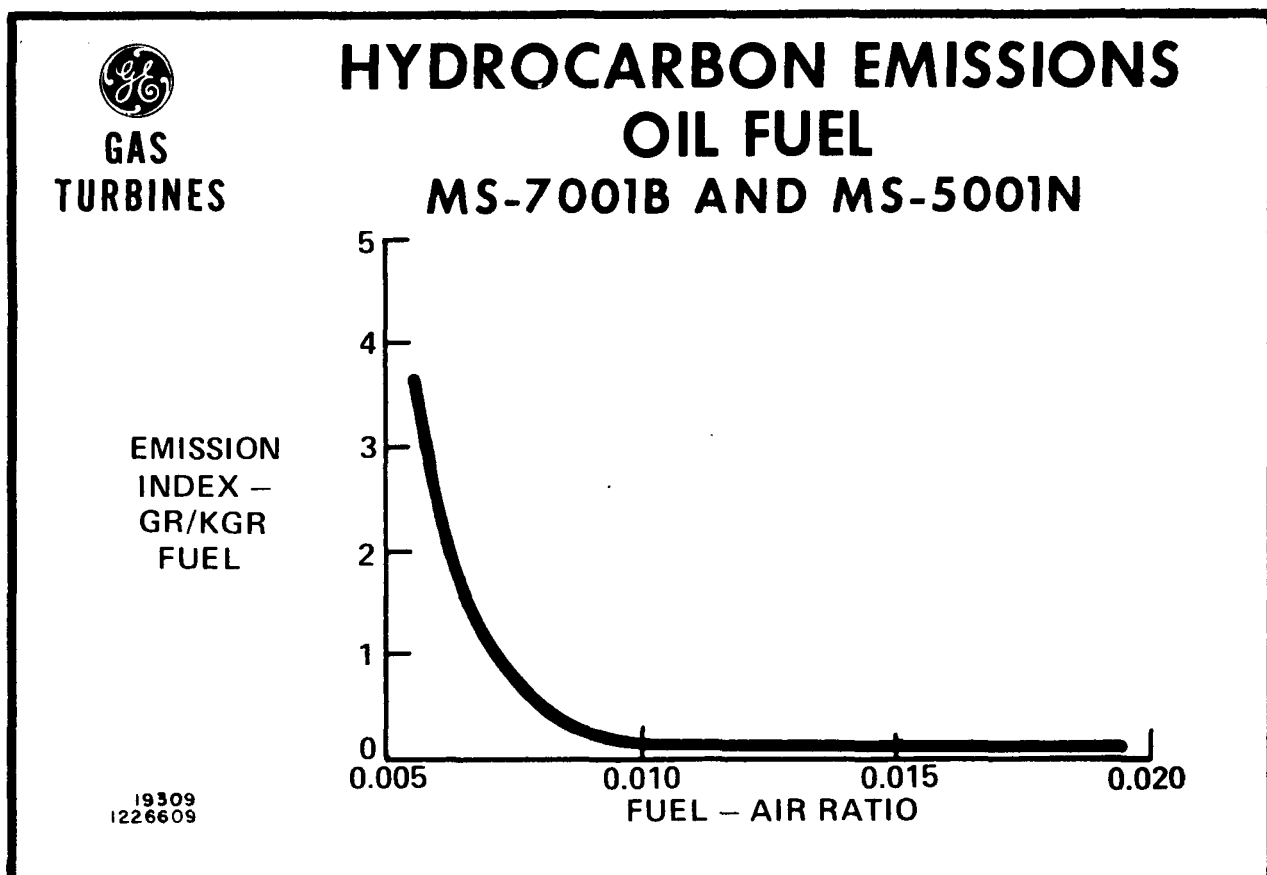


Figure C.2-3 LEANING INCREASES HYDRO CARBON EMISSIONS (FROM REF. C.3-2)

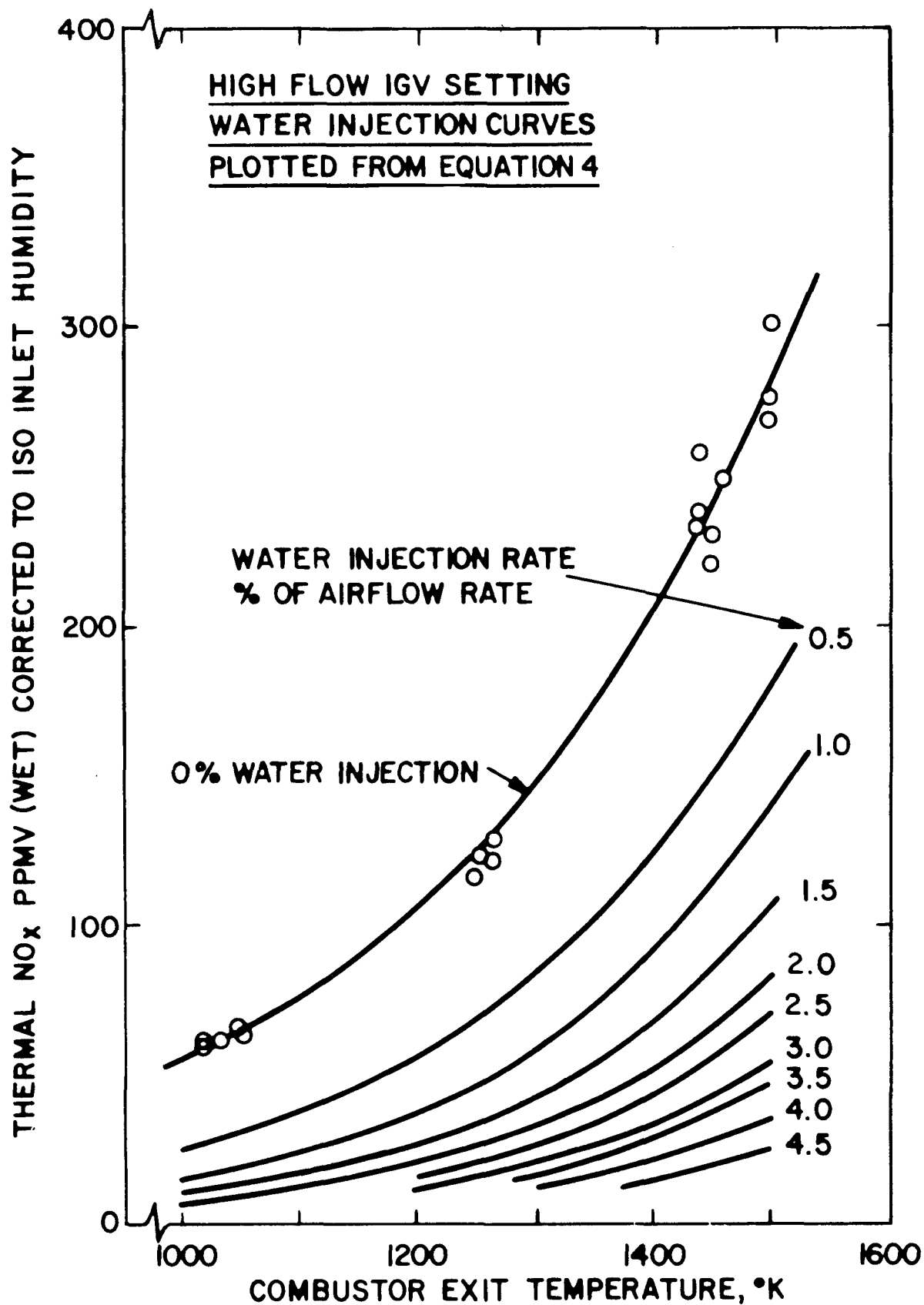


Figure C.2-4 THERMAL NO_x — EFFECT OF
COMBUSTOR EXIT TEMPERATURE AND WATER

water supply and a demineralizing facility having appreciable capital costs and requiring operator attendance. All of these technical and commercial limits to water injection for NO_x reduction have been analyzed in Reference 5. Although it is advantageous in some localities, there has been a general need for "dry" NO_x control techniques.

C.2 REFERENCES

1. Singh, P. P., Young, W. E. and Ambrose, M. J., "Formation and Control of Oxides of Nitrogen Emissions from Gas Turbine Combustion Systems," J. Eng. Power, Oct 1972, p. 271.
2. Hilt, M. B. and Johnson, R. H., "Thermal NO_x Suppression by Water Injection and Aerodynamic Changes," ASME Paper No. 72-GT-53.
3. Johnson, R. H. and Wilhelm, C. F., "Control of Gas Turbine Emissions in the World Environment," General Electric publication ESOA-7401 (1974).
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5. Day, W. H., Kydd, P. H., "Maximum Steam Injection in Gas Turbines," presented at 1972 Joint Power Generation Conference, Boston, Sept. 10-14, 1972.

C.3 AIRCRAFT COMBUSTOR MODIFICATION FOR LOW THERMAL NO_x

Considerable effort has been devoted to modifying aircraft combustor emissions, including thermal-NO_x. Several large programs have been conducted by NASA-Lewis, in which gas turbine manufacturers tested combustor concepts. Although future aircraft fuels will probably not contain sufficient nitrogen to be a cause for fuel-NO_x reduction combustor design, information about these programs may be useful in fuel-NO_x reduction from stationary gas turbines. Aircraft combustors are being incorporated into stationary turbines; furthermore, the success (or lack thereof) of aircraft combustor programs should be used in directing the programs on stationary turbines which are being started. Descriptions of these programs, their approach and achievements are found in References 1 and 2. The stationary gas turbine programs include a five-contractor program "Low-NO_x Heavy Fuel Combustor Concept," part of the advanced cogeneration technology (ACT) program in DOE.

The goals for these emissions reduction programs have been the EPA standards which were promulgated in 1978, indicated in Table C.3-1 for several classes of engines. The associated aircraft are also indicated. The quantity of pollutant (EPA parameter, EPAP) per EPA cycle is shown in Table C.3-1, normalized by the engine size. The EPA landing-takeoff cycle specifies the length in minutes of taxi, take-off, climb, etc. The variations in exhaust pollutant concentrations during the cycle are indicated in Figure C.3-1. NO_x is highest during takeoff at 100% power; CO and hydrocarbons are maximum during the lowest power operation, idle, and taxiing. This is partly traceable to the same combustion tradeoff principle exhibited by stationary turbines (Figures C.2-2,3) which involved the effects of flame temperature on these pollutants.

Table C.3-1 shows that all three pollutant EPAP's of some engines in these classes now exceed the EPA standards, meaning that anti-pollutant measures must reduce the peaks in Figure C.3-1 in NO_x at high power (e.g., 30-40 g/kg of fuel, the "emissions index", EI) and also the pollutants peaking at low power, CO (40-70 g/kg) and THC (10-30 g/kg). The relevance of the low-power emissions of these aircraft-type combustors to stationary turbines

TABLE C.3-1 EPA AIRCRAFT EMISSION STANDARDS (FROM REF. C.3-1)

1979 Standards

ENGINE CLASS	THC ^a		CO ^a		NO _x ^a		SMOKE	
	PRES	STD	PRES	STD	PRES	STD	PRES	STD
T1	4-16	1.6	15-60	9.4	2.5-4.5	3.7	40	32
T2,T3,T4	2-21	0.8	7-20	5.3	3-10	3.0	15-30	25
P2	6-12	4.9	20-30	26.8	5-10	12.9	55	50

1981 Standards

T2,T3,T4	2-21	0.4	7-20	3.0	3-10	3.0		25

1980 Standards

T5	16.2	3.9	66.5	30.1	8.8	9.0	30	20

^a Pounds of pollutant/1000 pounds thrust-hours/cycle or pounds of pollutant/1000 horsepower-hours/cycle.

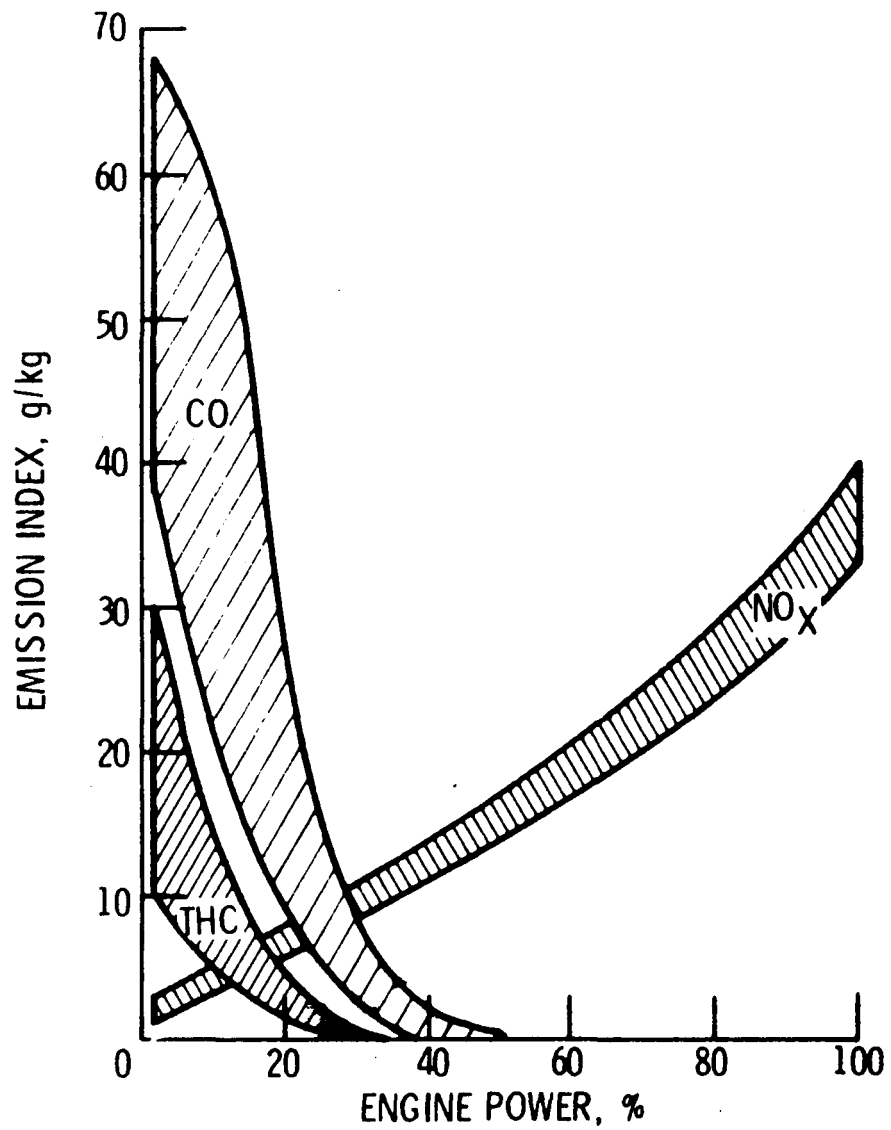


Figure C.3-1 EFFECT OF ENGINE POWER ON EMISSIONS OF CO, HYDROCARBONS AND NO_x (FROM REF. C.3-1)

depends on the low-power fraction in the duty cycle of the latter, which varies from peaking to intermediate and a small but growing fraction of baseload cases.

Figure C.3-2 clarifies that the "cures" for low-power emissions (CO and THC) are in the opposite direction from the cures for high-power NO_x . An EPA feasibility study classified pollution reduction approaches into two groups, one requiring only minor modifications and, the second, major modifications (Table C.3-3). The primary zone leaning and water injection methods described in Section C.2 for stationary turbines resemble the "minor modifications" for aircraft combustors, both having achieved only a two-fold reduction in NO_x .

C.3 REFERENCES

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2. Mellor, A. M., "Gas Turbine Engine Pollution," *ibid*, 1, 111 (1975).

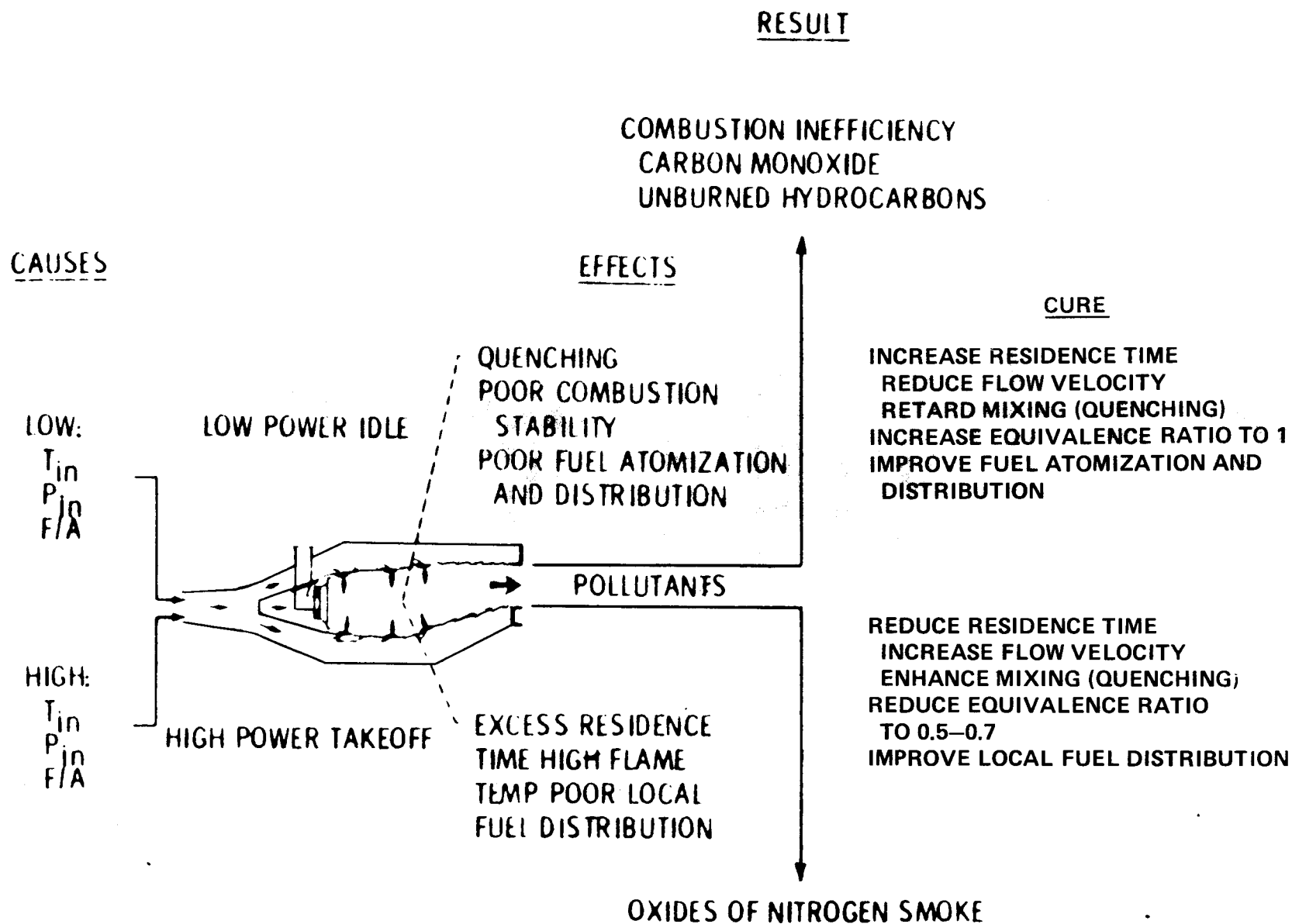


Figure C.3-2 "CURES" FOR NO_x AND CO EMISSIONS (FROM REF. C.3-1)

TABLE C.3-3A

Emissions Control Techniques Requiring Minor
Combustor/Injector Modifications

EPA Designation	Modification
t1 - minor combustion chamber redesign	Minor modification of combustion chamber and fuel nozzle to achieve best state-of-art emission performance.
t4 - divided fuel supply system	Provide independent fuel supplies to subsets of fuel nozzles to allow shutdown of one or more subsets during low-power operation.
t5 - water injection	Install water injection system for short duration use during maximum power (takeoff and climb-out) operation.
t6 - modify compressor air bleed rate	Increase air bleed rate from compressor at low-power operation to increase combustor fuel-air ratio.

From reference C.3-2

TABLE C.3-3B

Emissions Control Techniques Requiring Major
Combustor/Injector Modifications

EPA Designation	Modification
t2 - major combustion chamber redesign	Major modification of combustion chamber and fuel nozzle incorporating advanced fuel injection concepts (carburetion or prevaporization).
t7 - variable geometry combustion chamber	Use of variable airflow distribution to provide independent control of combustion zone fuel/air ratio.
t8 - staged injection combustor	Use of advanced combustor design concept involving a series of combustion zones with independently controlled fuel injection in each.

From reference C.3-2

D. FUEL-DERIVED NO_x

D.1 Introduction

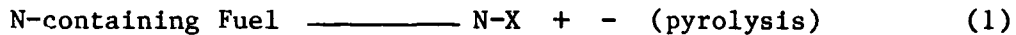
NO_x from nitrogen compounds in the fuel, and its suppression, was first studied in boilers in the 1960's, where nitrogenous residual oils and coal were burned, but was not tested in gas turbines, burning clean fuels, until the post-embargo interest in alternative fuels. Through empirical methods, the staged combustion conditions which suppressed fuel NO_x in boilers were readily formed, of which some key examples are given in Section D-2. Basic studies of nitrogenous fuel combustion also began to produce understanding of the chemical reaction steps involved, as well as the physical fuel-air mixing processes (Section D-3). The first tests of nitrogenous fuels in gas turbines were relatively recent, and were under normal (non-staged) combustion conditions which produced extremely high NO_x levels (Section D-4), but were interpretable by basics, which predicted that staged or rich-lean would suppress fuel NO_x. This work (Section D-4) has produced some promising results, but since gas turbine combustors as presently designed are ill-suited to rich-lean operation, an extensive program will be required to design new combustors. Judging from basic information and preliminary combustor types, there is a very high probability that this work will produce designs burning SRC-II fuel oil cleanly, especially because SRC-II fuel oil is a volatile distillate with low viscosity.

D.2 Basic Mechanisms of Fuel Nitrogen Conversion to NO or N₂

The empirical observations of fuel-NO_x suppression in boilers (Section D-3) were studied in bench-scale burners and reactors in flames of greatly simplified geometry, such as described in Section C-1. These experimental studies uncovered numerous steps in the sequence of the conversion of fuel-nitrogen, which strongly interacted with the geometry-dependent mass transport processes, in contrast to thermal-NO_x formation process. In spite of this complexity, the analysis of these complex fuel-NO formation processes is now complete enough for qualitative interpretation of the major effects observed in boilers. Furthermore, thermal and aerodynamic mass transport models have been developed to successfully model some simple boiler and gas turbine flames and their fuel nitrogen chemistry. Here, items relevant to SRC-II fuel oil combustion will be selected in order to provide some qualitative insights.

D.2.1 The Nitrogen Intermediate and Competing Reaction Paths

One of the first demonstrations in a simple laboratory flame of the reduction of fuel-NO_x by decreased excess air or increased fuel equivalence ratio (ϕ_f) was by Fenimore,⁽¹⁾ who burned N-doped ethylene in a flat-topped burner, and measured the yield of fuel-NO, the fraction of fuel-nitrogen converted to NO.⁽¹⁾ Four additives were used: pyridine, methacrylonitrile, methylamine, or ammonia. The fuel-NO_x yield was nearly 100% when the flame was fuel-lean ($\phi_f = 0.9$), and when the added nitrogen dopant was dilute (630 ppm). At the other extreme, the fuel-NO_x yield was less than 10% in very fuel-rich flames ($\phi_f = 1.5$) with high nitrogen-dopant concentrations (25 000 ppm). From those data Fenimore hypothesized a mechanism involving the conversion of fuel-nitrogen into a nitrogen-containing intermediate molecule, NX, (reaction [1]) which could then either be oxidized to NO_x in a fuel-lean nitrogen-dilute flame (reaction [2]), or could react bimolecularly to form N₂ instead of NO_x (reaction [3]), in a fuel-rich high-nitrogen flame.



This competing-pathway mechanism quantitatively fit the data over the ranges of fuel equivalence ratio and fuel-nitrogen concentration used, and this mechanism also provides a useful qualitative visualization of how the rich-lean combustor design is effective in suppressing fuel- NO_x . However, this mechanism did not describe other more complex flames, for which purpose a great amount of subsequent investigation has been required.

Another demonstration of the reduced fuel- NO_x yields in fuel-rich or high-nitrogen flames is the following experiment by Sarofim, et al.⁽²⁾ A flat flame burner was used, burning methane doped with ammonia. For example, (Figure D.2.1-1), in the set of dilute ammonia (0.5%) runs the fuel- NO_x yield is 100% until ϕ_f exceeds 1.0, whence the yield decreases rapidly.

An example of the detailed understanding of flame NO_x chemistry which has been developed since the above work is the analysis by Haynes⁽³⁾ of a premixed laminar flame on a flat flame burner, not only of the NO_x from the flame, but of the gas composition within the flame. (See Figure D.2.1-2). This experiment identified Fenimore's postulated intermediate as HCN, and demonstrated that its oxidation to NO quantitatively agreed with the competing path mechanism. Under Haynes' conditions, the oxidative path predominated, but other studies (Figure D.2.1-1), under other conditions, have demonstrated that the conversion of NX to N_2 by reaction (3) is fast enough to be effective in most flames⁽⁴⁾.

D.2.2. Initial Reaction Step of the Fuel and Effect of Fuel Type

Continuing the discussion of successively earlier steps in the sequence of reactions of fuel-nitrogen, the source of the HCN (or NH_x , also

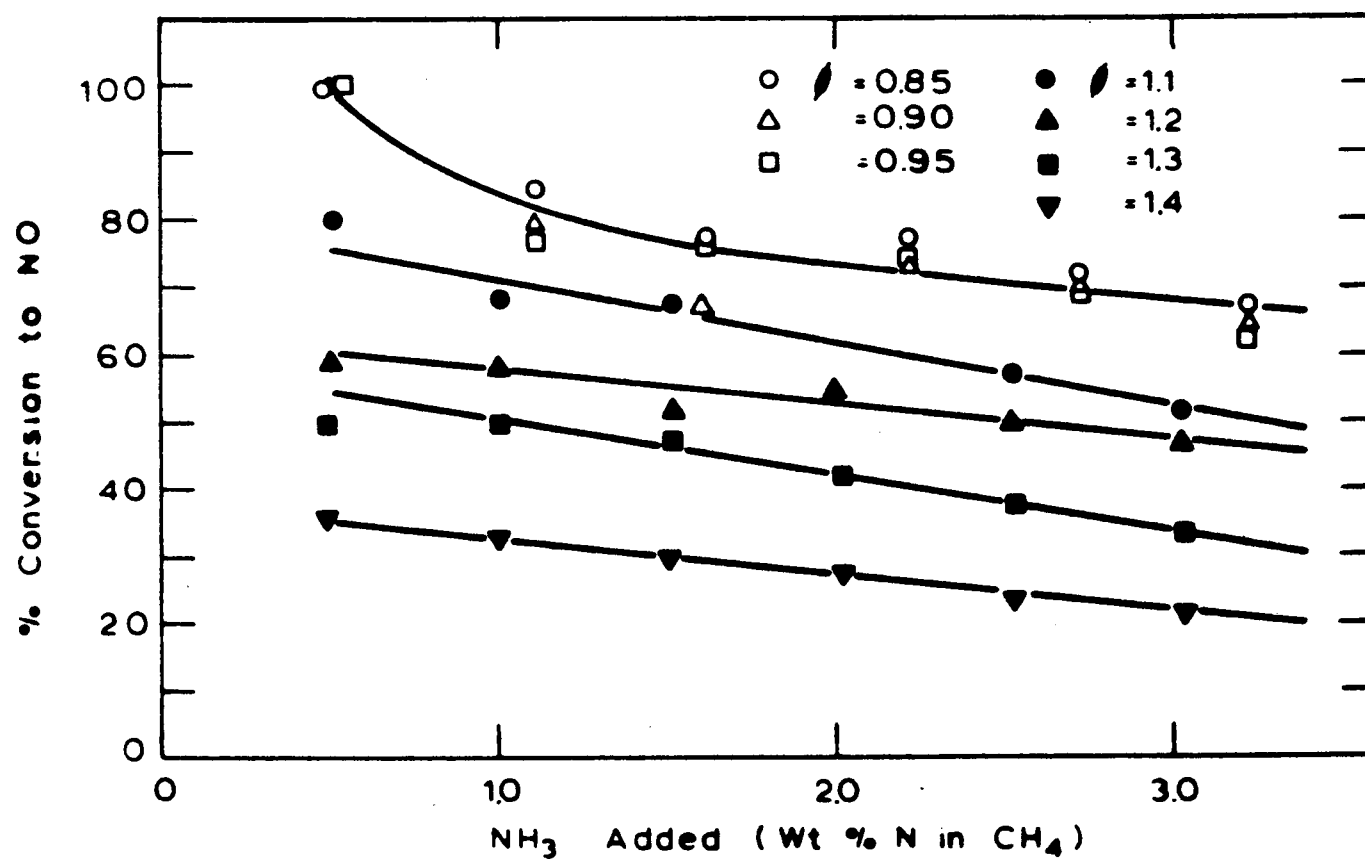


Figure D.2.1-1 FUEL-NO YIELD-EFFECT OF ϕ F
AND FUEL NITROGEN CONTENT (FROM REF. D. 2-2)

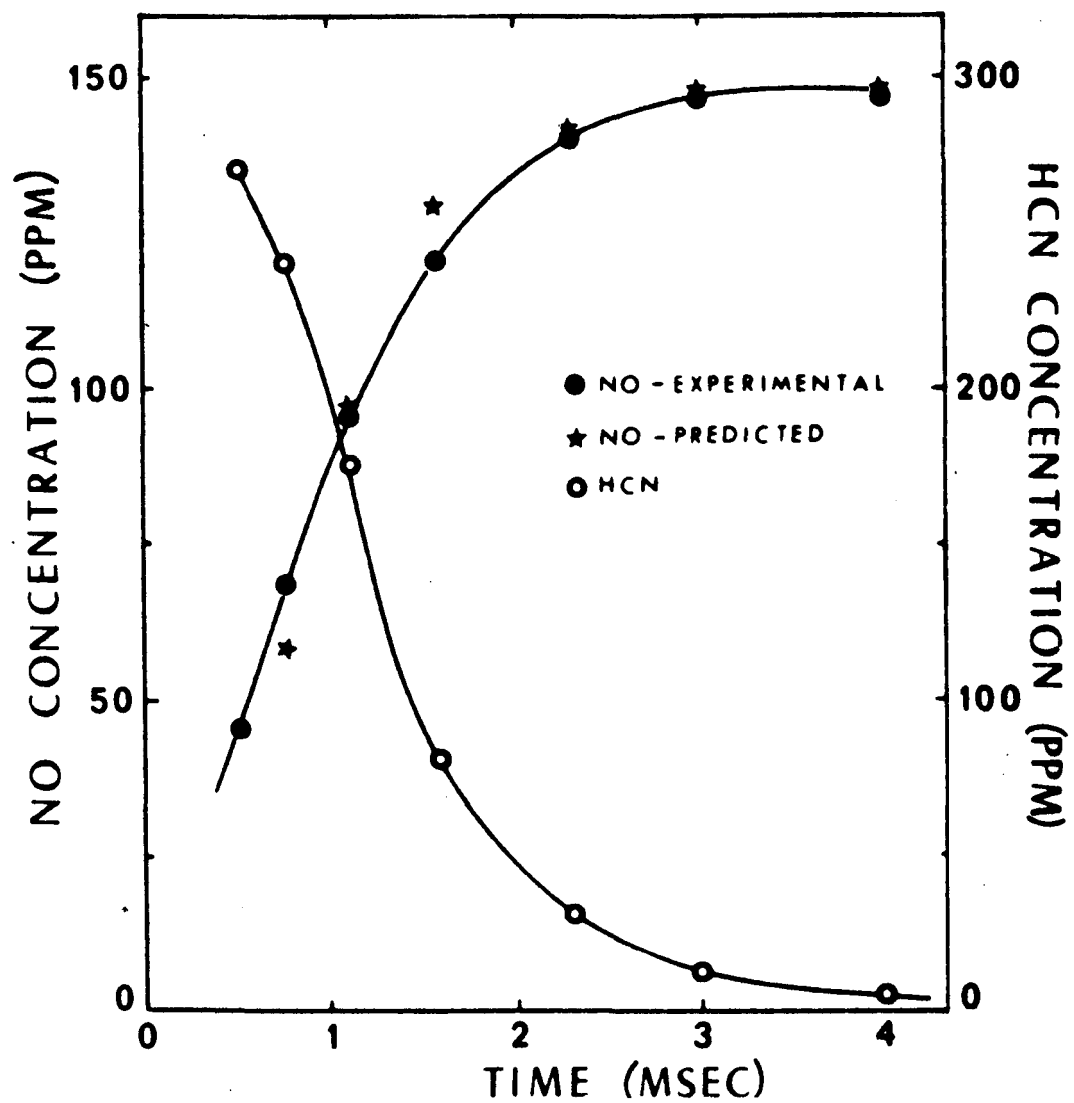


Figure D.2.1-2 INTERMEDIATE HCN FORMS NO (FROM REF. D.2-3)

identified as a possible precursor of NO, having a role similar to that of HCN) was shown to be pyrolysis of the fuel. In Figure D.2.2-1 the fuel (ammonia) is present at 50 ppm at the top of the burner plate where the combustion reactions begin; at increasing distances above the burner, downstream in the reacting gases, the ammonia quickly disappears between 0 and 6 mm, while HCN undergoes a corresponding increase in the same region of the flame, apparently being a product of the ammonia consumption.

Nitrogen present in other chemical forms in other fuels may react differently, and this question has been addressed by Axworthy⁽⁵⁾. In this study, the fuels used ranged from pure compounds (e.g., pyridine) to distillate and residual fuel oils and coal and shale-derived oils. When pyrolyzed in inert gas in a 2-cc sub-second residence time reactor at temperatures between 750 and 1100°C, HCN formed, its yield increasing sharply with temperature, but ammonia and N₂ were not formed. High HCN yields would increase the effectiveness of staged combustion, since nitrogen in this form would easily be converted to N₂, not NO. The HCN yields also varied with fuel type, as follows: No. 6 oil, 44%; coal liquid (from a catalytic hydrocracking process, 350-900°F distillate) 51%; shale oils, 60-70% and pyridine, 100%. The HCN yield apparently increases with fuel volatility, but may not imply that a non-petroleum fuel would yield more HCN than otherwise similar petroleum-derived fuel.

Furthermore, Figure D.2.2-2 shows that the more volatile fuels (shale oil or shale-derived diesel fuel [DFM], which resemble SRC-II fuel oil in their volatility) were easily converted to HCN at low reactor temperatures, in contrast to the residual petroleum oils and Synthoil, a coal-derived liquid with a residual-like distillation curve. Axworthy also added a second pyrolysis reactor immediately downstream from the first reactor, for some experiments with No. 6 oil. With the first reactor at a lower temperature than the second reactor, runs with increasing temperatures of the second reactor produced more HCN. This implies that the products from the first stage were some precursor to HCN, being converted to HCN only in the second hotter reactor.

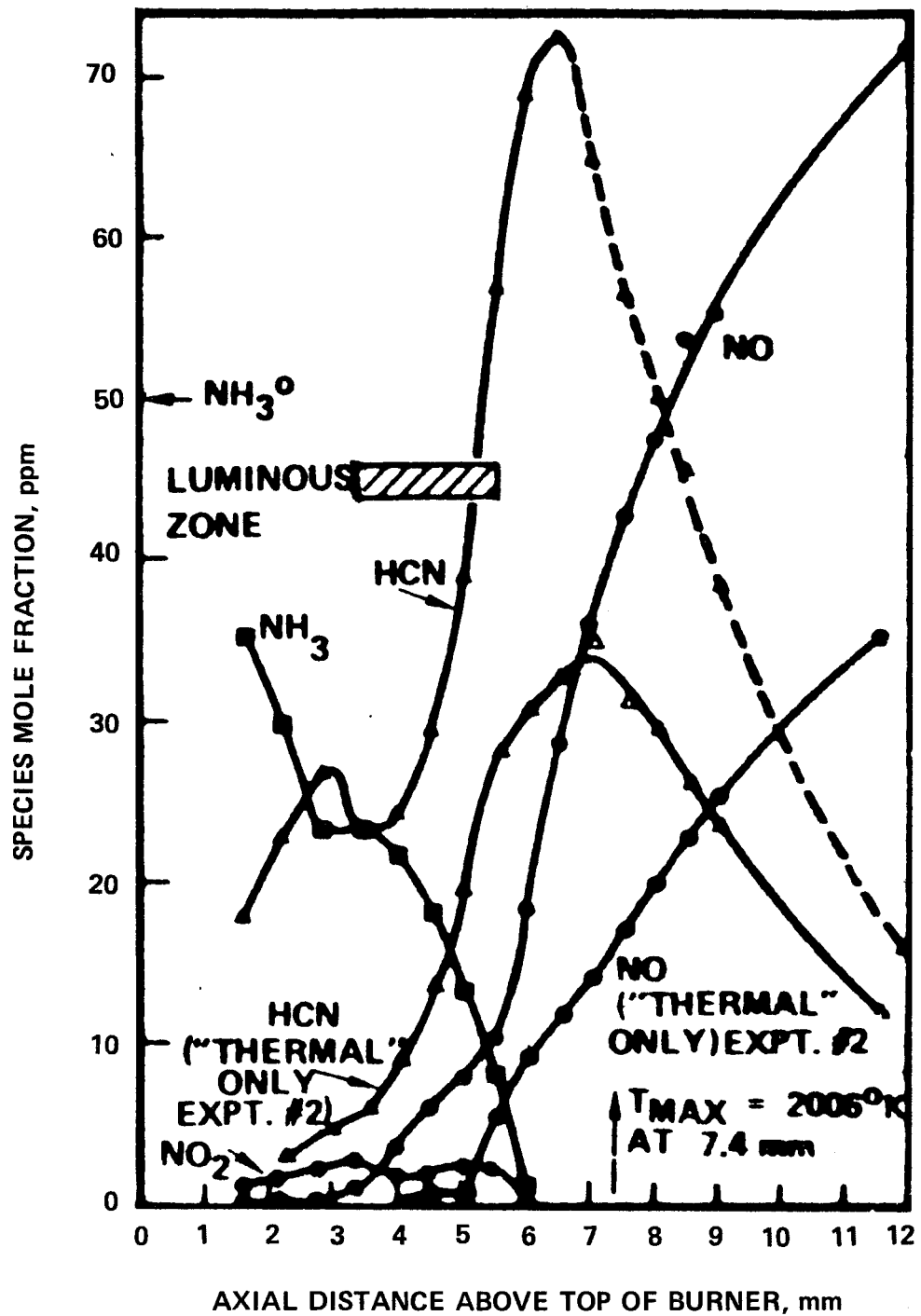


Figure D.2.2-1 FUEL-NITROGEN (NH_3) CONVERSION TO HCN
(FROM REF. D.2-5) PRESSURE = 76 TORR,
 $\phi_F = 1.5$, 50 PPM NH_3 IN FUEL

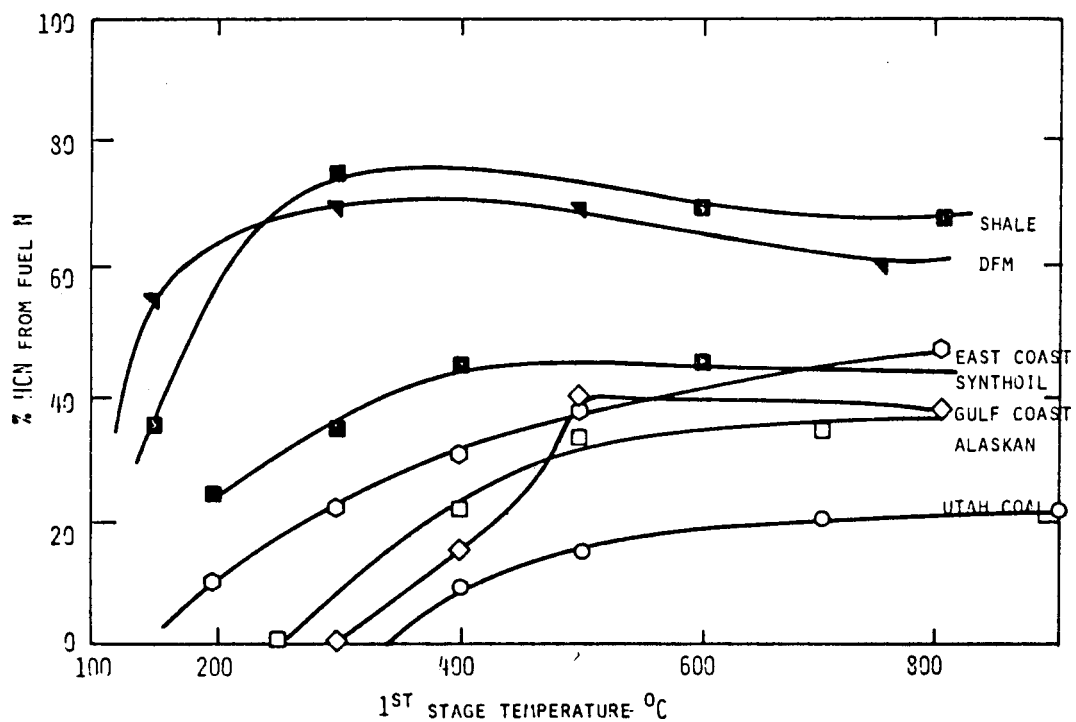


**Figure D.2.2-2 HCN YIELDS – PYROLYSIS OF FUELS
OF VARYING VOLATILITY (FROM REF. D.2-5)**

D.2.3. Other Flame Geometries and Fuel-Nitrogen Conversion

Fuel-nitrogen conversion to NO_x has also been studied in laboratory burners having air-fuel mixing geometries differing from premixed laminar axisymmetric flames discussed above, and large effects were observed, which are critical in applying the basics discussed here to commercial burner design with complex mixing geometries. Sarofim, et al.,⁽²⁾ studied an axisymmetric diffusion flame of methane (inner 2.5 cm dia cylinder) surrounded by an outer cylinder (7.5 cm outer diameter) of air flowing with the same direction and velocity as the fuel. The fuel- NO_x yields were much less than those observed in premixed flames; for example, in the run with 0.5% ammonia, the fuel- NO_x yield from this diffusion flame was 30%, in contrast to 100% in the premixed flame discussed above. Furthermore, when the ammonia was added to the air stream rather than the fuel stream in the diffusion flame, the fuel- NO_x yield decreased to 20%.⁽⁷⁾

This result is consistent with the competing-path mechanism as follows: Ammonia is pictured in the inner cylindrical stream of fuel, diffusing towards the boundary between the fuel and air zones, where the sheet-like diffusion flame is located. As ammonia approaches the flame, it is pyrolyzed to "XN" fragments, but there is no air to oxidize them to NO_x , and they take the other path instead, to N_2 . This is an oversimplified picture, of course, and diffusion flames of nitrogeous fuels are undergoing sophisticated spatially-resolved experimental and interpretive analysis which continues to increase our detailed understanding of these reactions.

Important fuel- NO_x yield measurements have also been made on a jet-stirred reactor which is at the other extreme of the scale of fuel-air mixing rates, and which resembles a well-stirred reactor model used to model the first stage of a staged combustor. In the experiment represented in Fig. D.2.3-1 in which ammonia-doped methane was used, the fuel- NO yield was 65% at stoichiometric (100% theoretical air), but decreased rapidly, to only 15% at 65% stoichiometric air. The predicted points in this figure will be discussed later.

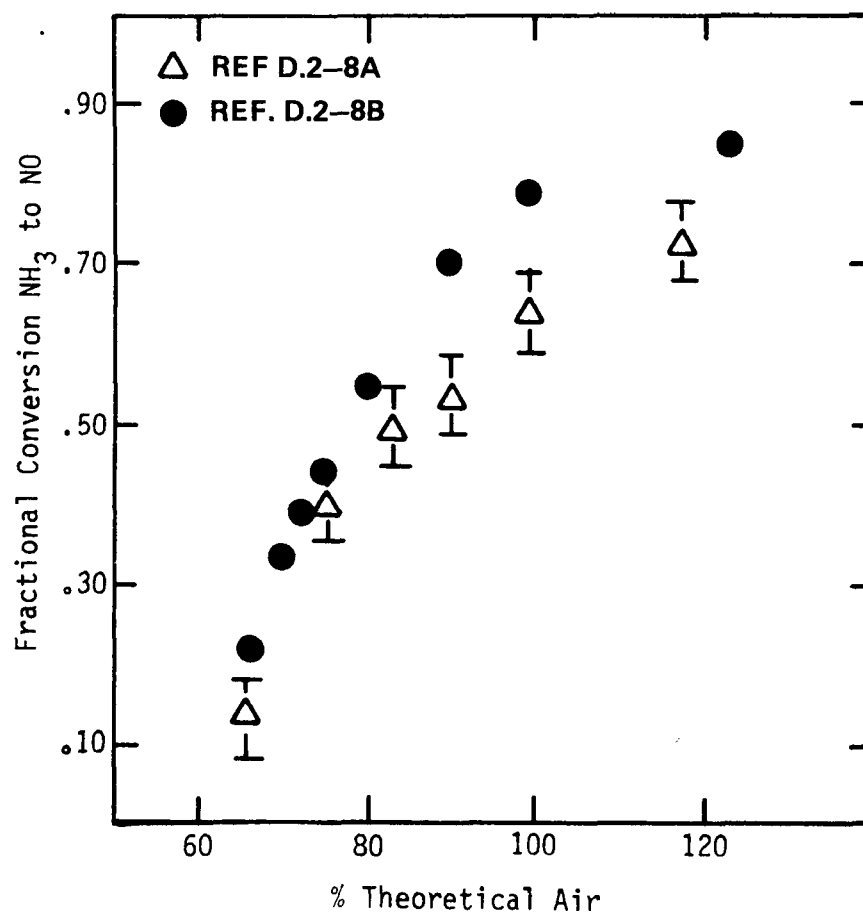


**Figure D.2.3-1 LOW NO_x FROM RICH WELL-STIRRED REACTOR FLAME
(FROM REF. D.2-8A)**

D.2.4 A Strategy for Fuel-NO_x Suppression; Thermodynamic Limits

After the empirical discovery of fuel-NO_x suppression by staged combustion, the study of the chemical and fuel-air mixing substeps of this process began, and as the foregoing examples have shown, revealed a strategy (Figure D.2.4-1) of substeps which needed to be enhanced (reaction [3]) or suppressed (reaction [2]) in efforts to design low-emissions equipment. The first need was to determine what the fuel-NO_x yield would be if the reaction (1-3) were fast enough for the gases in the first stage to reach thermodynamic equilibrium. Sarofim⁽⁹⁾ calculated the equilibrium concentrations of "fixed nitrogen species"(NO, HCN and NH₃, which would all become NO emissions upon entering the second stage) as a function of fuel equivalence ratio ϕ_f and gas temperature in the first stage. Figure D.2.4-2 shows the results for a fuel having a H/C atomic ratio of 1.3, typical of a coal liquid. (These equilibrium calculations are independent of the fuel nitrogen content, the nitrogen atom level in the system being set by the nitrogen content of air.) For example, for 2000°K, the fixed nitrogen species have a minimum concentration of 200 ppm (the EPA limit for oil fuel) when the fuel equivalence ratio is 2.6. Figure D.2.4-3 replots these results in a way that clarifies air preheat as well as high ϕ_f as an optimum strategy for fuel-NO suppression; the derivation of this conclusion is described by Sarofim in the following excerpt from Reference 9.

. . . most experimental measurements of bound nitrogen species for equivalence ratios greater than 1.2 greatly exceed the equilibrium values, suggesting that kinetic constraints prevail. This is not surprising since the adiabatic flame temperatures at high fuel equivalence ratios are low. The plots show, however, that at the high equivalence ratios the temperature could be raised considerably above the adiabatic temperature without exceeding the equilibrium NO_x constraint. For example, for H/C = 1.3 and $\phi_f = 1.6$ the temperature could be raised to above 2400°K. These arguments suggest that fuel-rich operation (to overcome the thermodynamic constraint) with high air preheats (to overcome the kinetic constraint) is desirable for minimizing the conversion of fuel nitrogen to nitric oxide.

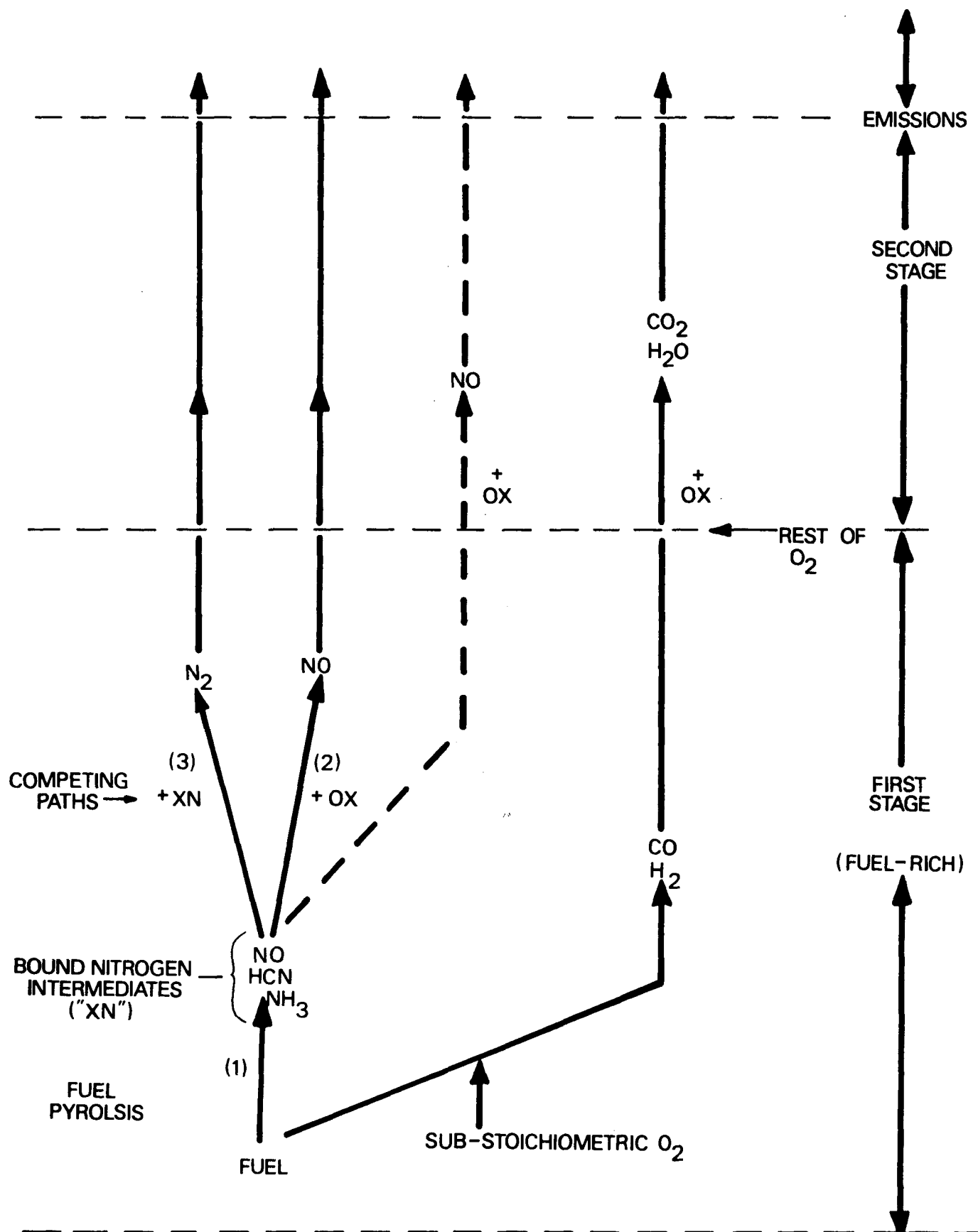


Figure D.2.4-1 CHEMICAL PATHWAYS IN TWO-STAGE FLAME

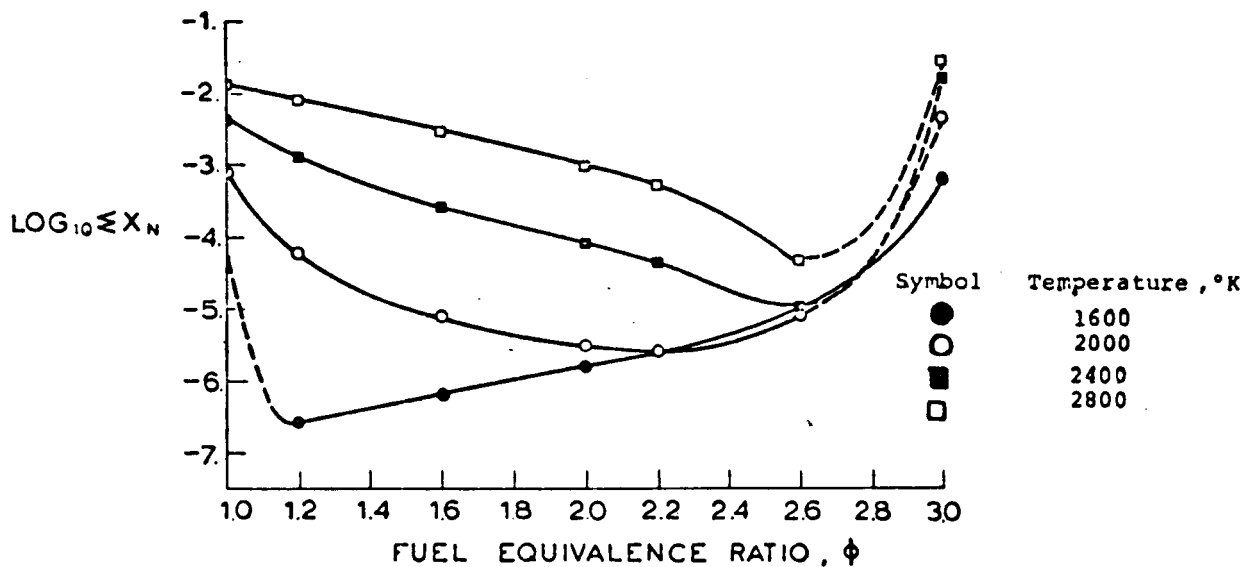


Figure D.2.4-2 (FROM REF. D.2-9)

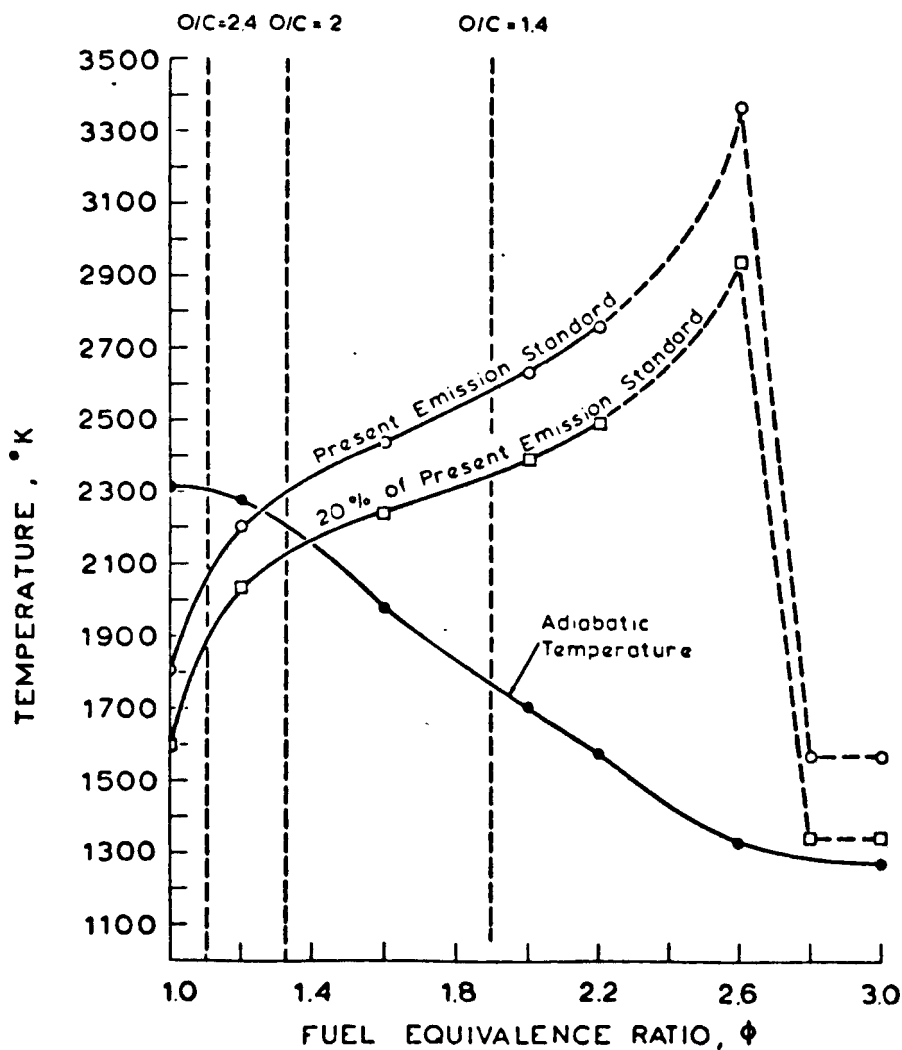


Figure D.2.4-3 (FROM REF D.2-9)

It is interesting to note that this recommendation for high air preheat is beneficial from a standpoint of energy conservation and can be contrasted with the recommendation to reduce air preheat in order to reduce thermal sources of NO_x under conventional fuel-lean operation. Information is needed on mechanism and kinetics in order to determine the minimum air preheat needed under fuel-rich conditions to increase the flame temperature sufficiently to overcome kinetic constraints. Another practical constraint is the sooting tendency of flames under fuel-rich conditions. The O/C ratios on the plots are included to indicate the range of equivalence ratios under which Street and Thomas and Wright observed sooting from preheated, premixed reactants in Bunsen flames and a well-stirred reactor, respectively. It is probable that strategies for high-temperature fuel-rich operation will require that the second stage be sized large enough to burn out the soot formed in the first stage. Such practical considerations will obviously influence the operating conditions of a combustor.

D.2.5 Current Detailed Chemical and Aerodynamic Studies

Since thermodynamic calculations have shown that there are combustion conditions in which the concentration of "fixed nitrogen species" from fuel-nitrogen could be reduced below emissions standards, the present thrust of research sponsored by EPA and the other organizations is to discover through kinetic and aerodynamic studies how to accelerate the reactions approaching such equilibrium concentrations. EPA's program "Fundamental Combustion Research Applied to Pollution Control" was initiated in 1977, and its projects fall into three main categories: gas phase chemical kinetics, heterogeneous combustion of fuel particles and droplets, and fluid mechanics or aerodynamics of mixing of fuel and air. EPA hopes that within 4 years the program will produce basic results implementable in technology development efforts. It will focus on large boiler flames, which account for 60% of present stationary NO_x emissions. However, the secondary objectives of the program include gas turbines (including combined cycle) fired with coal liquids and residual oils, and catalytic combustors for high-nitrogen fuels. The EPA Stationary Source Combustion Symposia contain yearly updates of

progress in these programs. Excerpts therefrom summarizing the status of some projects relevant to gas turbine combustion are contained in Appendix A.

D.2 REFERENCES

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D.3 Empirical Development of Fuel-NO_x Suppression in Boilers

Staged combustion for fuel-NO_x suppression was first discovered and developed empirically with considerable success. For optimization and full use of the potential of this method, investigation of the principles behind fuel-NO_x formation was begun. We have described these principles in the preceding section (D.2) for reference in this brief description of successful boiler fuel-NO_x suppression in this section. Boiler fuel NO suppression to facilitate SRC-II fuel oil use in various designs of utility and industrial boilers will be reported in detail elsewhere in Report 3.1.1.4 of this series; here only certain aspects of boiler combustion which apply also to fuel NO suppression in gas turbines are described to show that these empirical observations of spray flames in laboratory and field boilers are consistent with the principles outlined in Section D.2.

To cause reaction (3) ($2\text{XN} \longrightarrow \text{N}_2$) of the competing path mechanism to dominate the alternative NO-forming reaction (2), a fuel-rich condition is needed. This is shown by the relatively small reductions in fuel-NO_x observed in tests of low excess air or flue gas recycle, in which all combustion air enters the furnace via the burner, all parts of the furnace having some excess oxygen.

In contrast, the fuel-rich zone in staged combustion successfully minimizes the available oxidant (e.g., O or OH) in reaction (2). A test by KVB, Inc. of SRC-II fuel oil was done in a small boiler (3×10^6 Btu/hr) in which the zones of staged combustion are clearly identifiable.⁽¹⁾ Figure D.3-1 shows the horizontal gas path. The first zone begins at the burner, which is fired fuel rich. This boiler was extensively modified with an air injection device inserted into the rear of the boiler furnace, supporting a perforated torus injecting air at the beginning of the second stage. A similar configuration was used in the first boiler demonstrations of staged combustion of residual oils by Siegmund.⁽²⁾ Figure D.3-2 shows the effectiveness of staged combustion in suppressing fuel-NO from SRC-II fuel oil combustion. At a constant total 16% excess (over stoichiometric) air level, firing

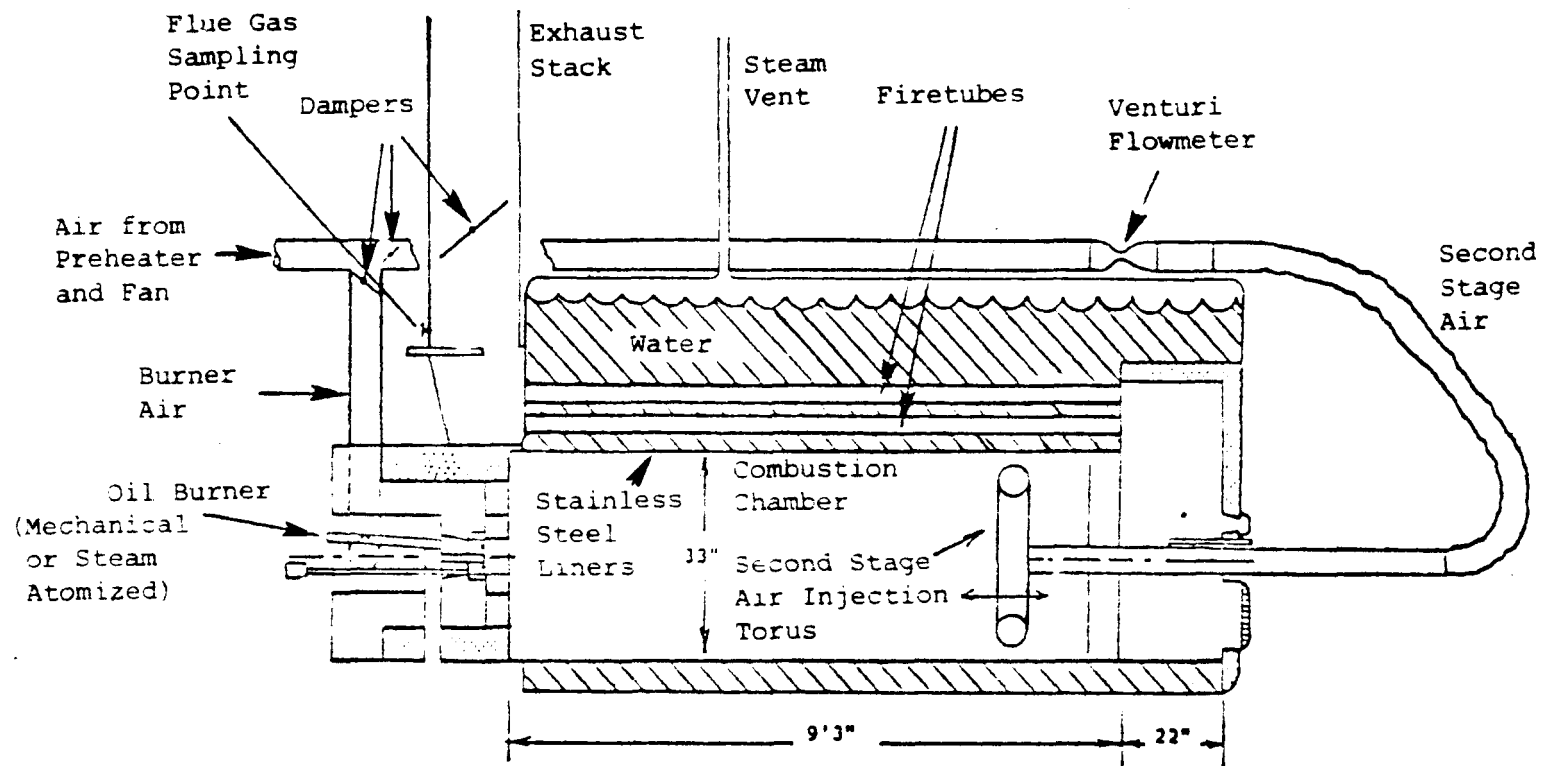


Figure D.3-1 BOILER GAS PATH AND STAGES (FROM REF. D.3-1)

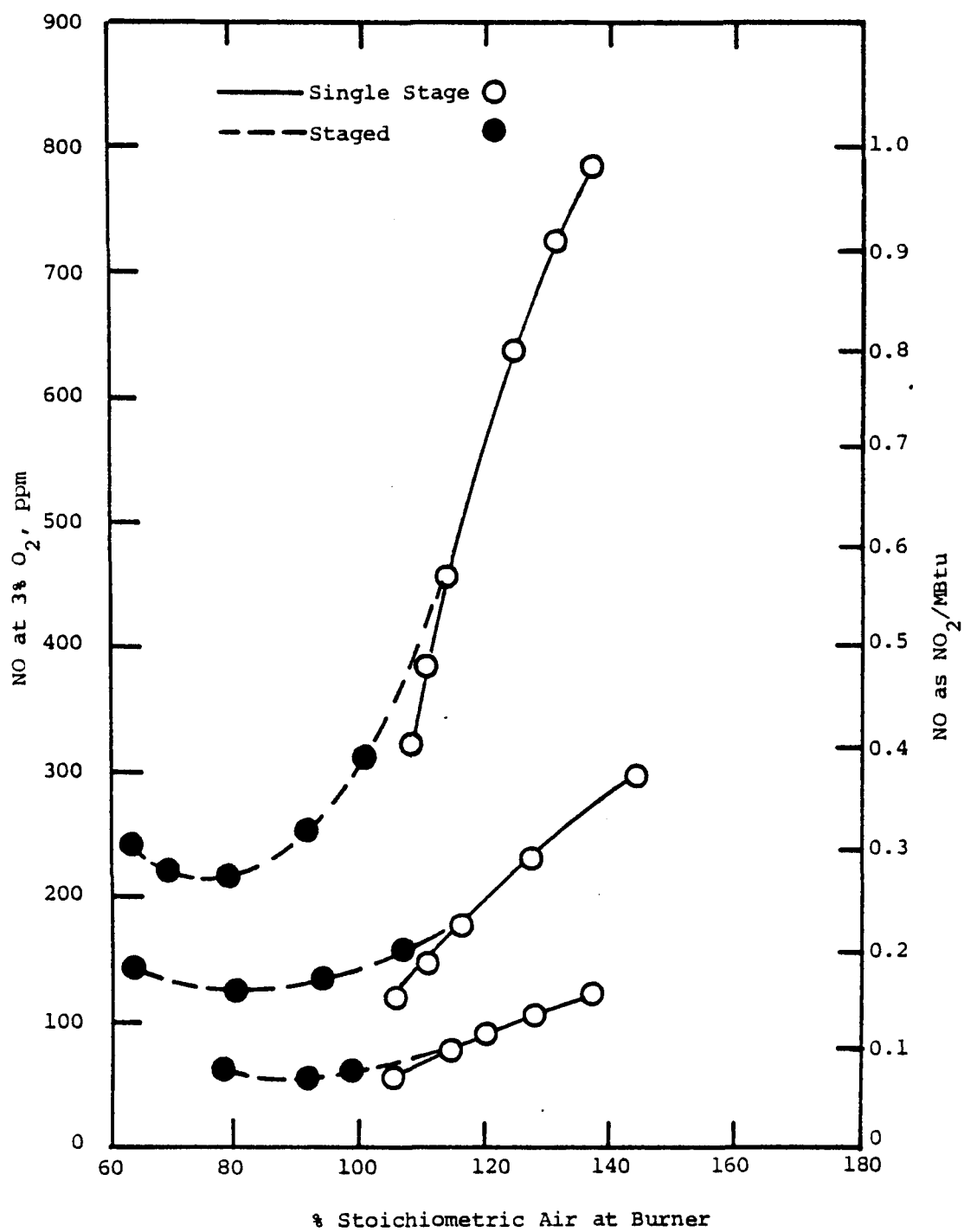


Figure D.3-2 STAGED COMBUSTION IN BOILER
SUPPRESSES FUEL-NO (FROM REF. D.3-1)

the burner increasingly fuel-rich reduced the NO emissions from 780 ppm to 225 ppm when the first stage received only 80% of the stoichiometric amount of air.

Tests in boilers have also shown that increasing fuel-nitrogen concentrations increase the dominance of reaction (3). In the combustion of nitrogen-rich fuels, the fraction of that nitrogen converted to NO_x is consistently lower than that for low-nitrogen fuels. This principle was also apparent in a test of shale oil (containing 2% nitrogen) in a 44 MW utility boiler.⁽³⁾ The shale oil was burned in two firing modes, both staged: (1) blended in equal portions with low-nitrogen No. 6 oil, the blend being delivered to all burners; (2) a "dual-fuel" firing mode, in which the shale oil was delivered to burners in the upstream fuel-rich section of the furnace, and an equal flowrate of the No. 6 oil was fed to the second stage of the furnace. The NO_x emitted in the blended and dual-fuel firing modes were, respectively, 426 and 271 ppm. The much lower NO_x emissions during dual-fuel firing need to be partly ascribed to the high fuel-nitrogen concentration in the dual-fuel first stage flame, although certain other factors contributed. Furthermore, the competing path scheme suggests that reduced fuel-NO_x emission occurs with increased residence time in the fuel-rich first stage; this has been observed by Siegmund.⁽²⁾ Thus, the competing path mechanism, measured in certain bench-scale flames, is also qualitatively consistent with boiler flames; it may also serve as a guide for gas turbine combustors, at least until mathematical models have been further developed.

A large barrier to suppressing fuel-NO_x emissions by promoting N₂ formation via the competing path mechanism is the long furnace residence time required for this process. Long residence times are available in utility boiler furnaces but not in industrial boilers, being much smaller, and even less so in gas turbines. Nevertheless, the handicap of the small volume of industrial boilers is being overcome by modifications of the aerodynamics and gas flow patterns of burners and boiler furnaces. These gas flow patterns are already rather complex in design, for purposes of maintaining flame stability and reducing soot emissions. They were then modified to eliminate local

excessive temperature zones in order to suppress the thermal-NO formed there. More recently, EER, Inc. is designing a gas flow pattern in a burner which will itself create fuel-rich and fuel-lean zones for staged combustion, permitting staged combustion in small one-burner boilers as well as utility boilers.⁽⁴⁾ Furthermore, such efforts are employing sophisticated chemical kinetic and fluid dynamic models with great success. In the design of gas turbine combustors, there have been parallels to these activities, to be described. The success of the boiler burner design efforts clarifies the appropriateness of the rich-lean concept for gas turbine combustors, and suggests that it will succeed in making possible the clean use of alternative fuels, including SRC-II fuel oil.

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D.4 Fuel-Nitrogen Conversion Under Gas Turbine Conditions

We have described some principles underlying the flame chemistry of fuel-nitrogen, found in simple flames, and have shown that the empirical development of staged combustion in boilers for fuel-NO_x suppression has been validated and facilitated by these principles. Observations of fuel-NO_x at gas turbine conditions (examples to be described in this section) also follow these principles, which must be used in engineering modeling to develop fuel-NO_x suppression in gas turbines. The starting point for the industry's effort is the combustor concepts for thermal-NO_x, described in Section C, as well as some approaches to soot suppression to be described in Section E.

A considerable amount of data has been obtained about fuel-nitrogen conversion at gas turbine conditions, but very little of it yet involves coal liquids. From this work we will select items exemplifying the principles involved, as well as the variety of work done, which includes fuel-lean and fuel-rich conditions, laboratory burners, pilot rigs, and complete field turbines. In addition to the chemical factors (fuel/air ratio, nitrogen concentration in the fuel, temperature) in the laboratory burner studies which have been emphasized so far, the aerodynamics of fuel-air mixing will be an important new factor involved in interpreting results from real combustors involving sprays of fuel oils.

D.4.1 Chemical Factors in Fuel-Nitrogen Conversion

In a single-stage laboratory combustor experiment, fired at gas turbine intensities⁽¹⁾ showed a decrease in fuel-NO yields occurred as the fuel equivalence ratio decreased below one (see Figure D.4-1). The reactor resembled a gas turbine combustor; it was a 4 in. I.D. cylinder, firing No. 2 fuel oil axially with an air-atomizing spray nozzle. The combustion air entered colinearly with the fuel spray and was given enough swirl to provide rapid turbulent fuel-air mixing and some backmixing of flame gases toward the nozzle.

Several tests have also been done in single combustors. Tests in a

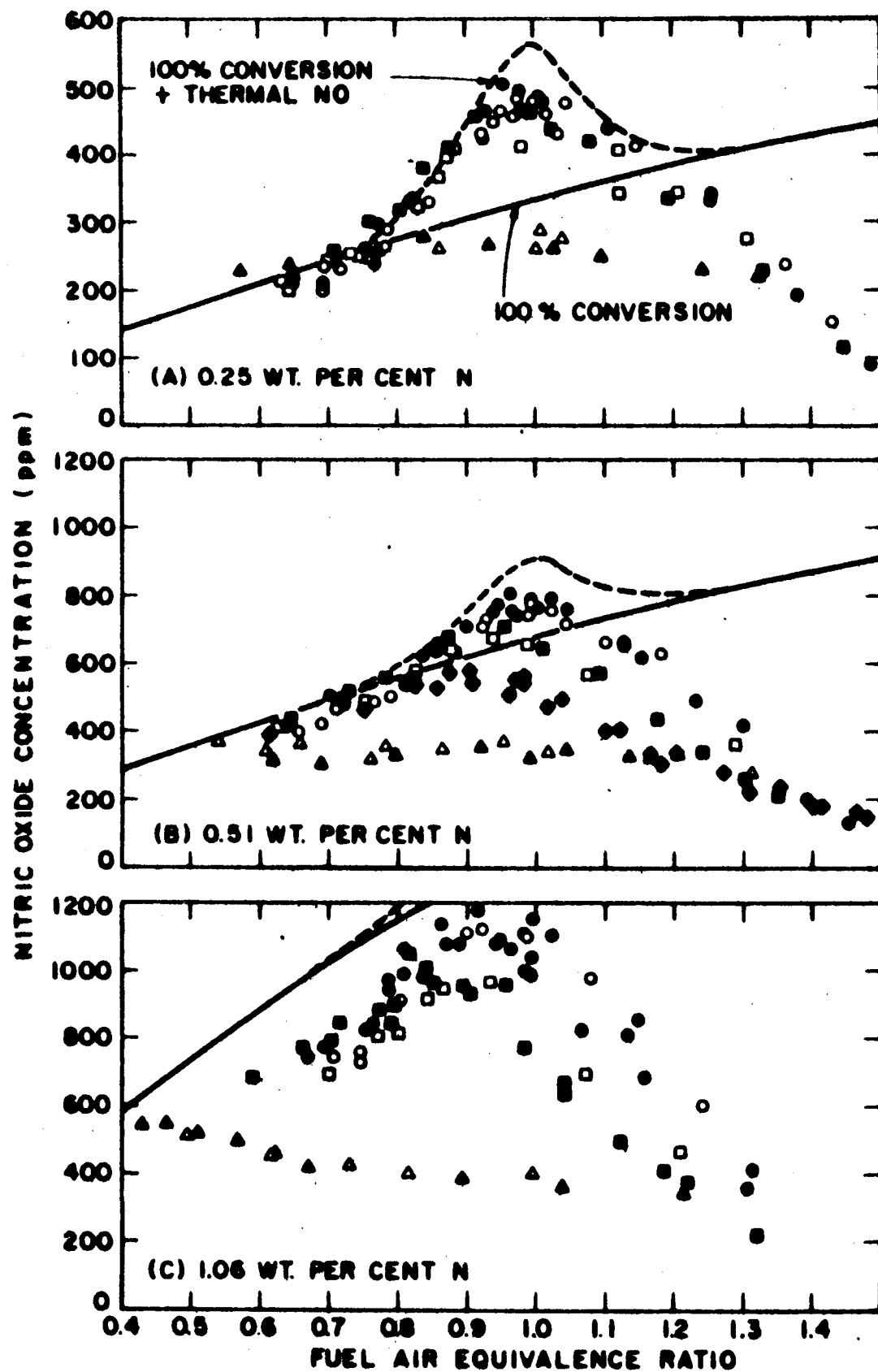


Figure D.4-1 (FROM REF. D.4-1)

Several tests have also been done in single combustors. Tests in a T56 single combustor of pyridine-doped jet fuel (0.3 and 1.0%N) and of shale oil-derived jet fuel containing 0.025-0.8%N showed that over this range of fuel-nitrogen contents, with increasing fuel-nitrogen content, the fuel-NO_x yield decreased from 80-100% to 20-46% (Figure D.4-2).⁽²⁾ The other interesting result from this test was the decrease in fuel-NO_x yield with increasing temperature of the air entering the combustor. These results are consistent with several other combustor tests of nitrogen-containing fuels.

Full-scale gas turbines have also been used in nitrogenous fuel tests. In the tests on a 75 MW GE stationary gas turbine, referred to in Section C,⁽³⁾ No. 2 fuel oil was doped with pyridine to a maximum of 0.5%N. Water injection was also used during these runs (Figure D.4-3), and caused the fuel-NO_x yield (at a 0.18%N doping level) to increase from 30% to 75% at the maximum water injection rate, 3% of the air flow rate. This effect also fit the predictions of a model. In this model,⁽⁴⁾ all the fuel-nitrogen is assumed to be instantly oxidized to NO_x, some of which is destroyed downstream in the flame as the NO_x reaches a concentration predicted by the thermodynamic equilibrium of the gases, this being altered by the presence of the water. However, note the kinetic aspects shown to also be important under some conditions (Section D.2). The counter-effectiveness of water injection with nitrogenous fuels when trying to meet emissions regulations is clearly expressed in the following excerpt from Ref. 3, referring to Figure D.4-4:

It may be seen that for a nominal FBN concentration of 0.18%, there is a substantial difference between the thermal NO_x as determined from the distillate fuel data and the total NO_x found from the doped distillate data. Further, this difference increased with water injection rate due to: (a) the increase in fuel flow rate required to maintain a nearly constant combustor exit temperature and (b) the increase in FBN yield, as shown in Figure [D.4-4]. The dotted line in Figure [D.4-4] is representative of one of the NO_x codes now under consideration in the United States at the time of writing. It may be seen that when burning a light distillate fuel of insignificant nitrogen content to comply with the NO_x code would require a water-injection rate of little less than 1.5%. When burning a fuel with

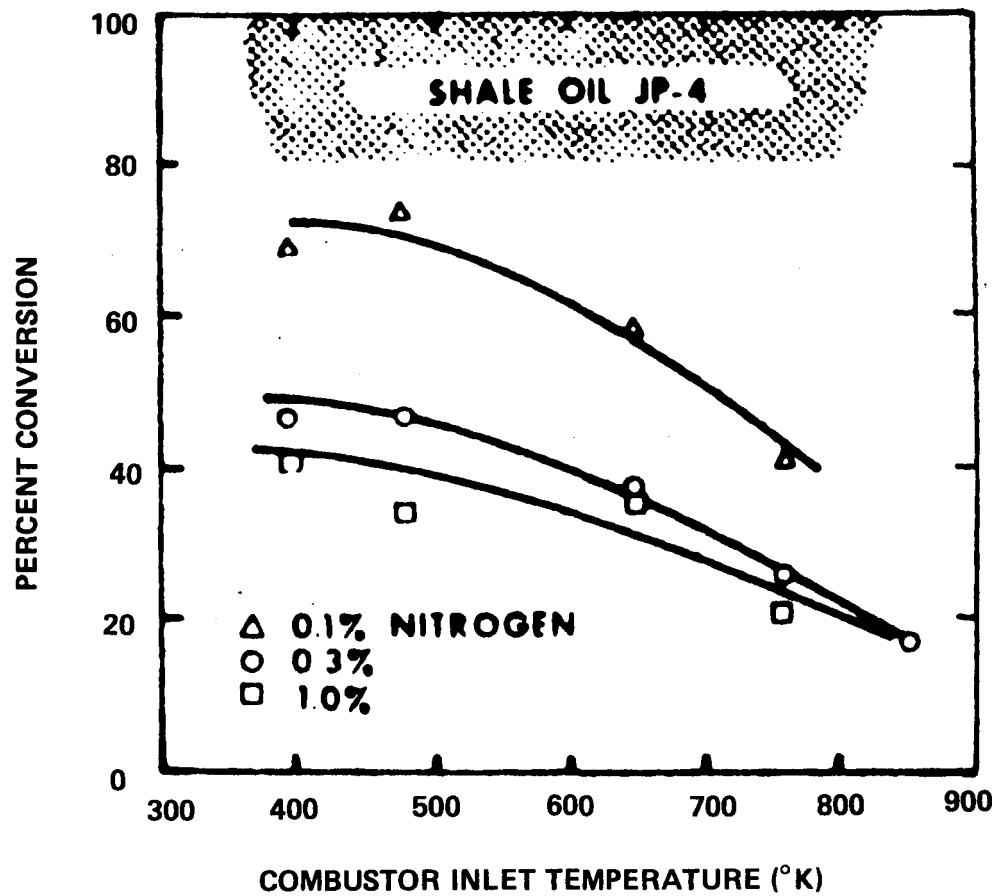


Figure D.4-2 FUEL BOUND NITROGEN CONVERSION TO NO_x IN AN AIRCRAFT GAS TURBINE COMBUSTOR (FROM REF. D.4-2)

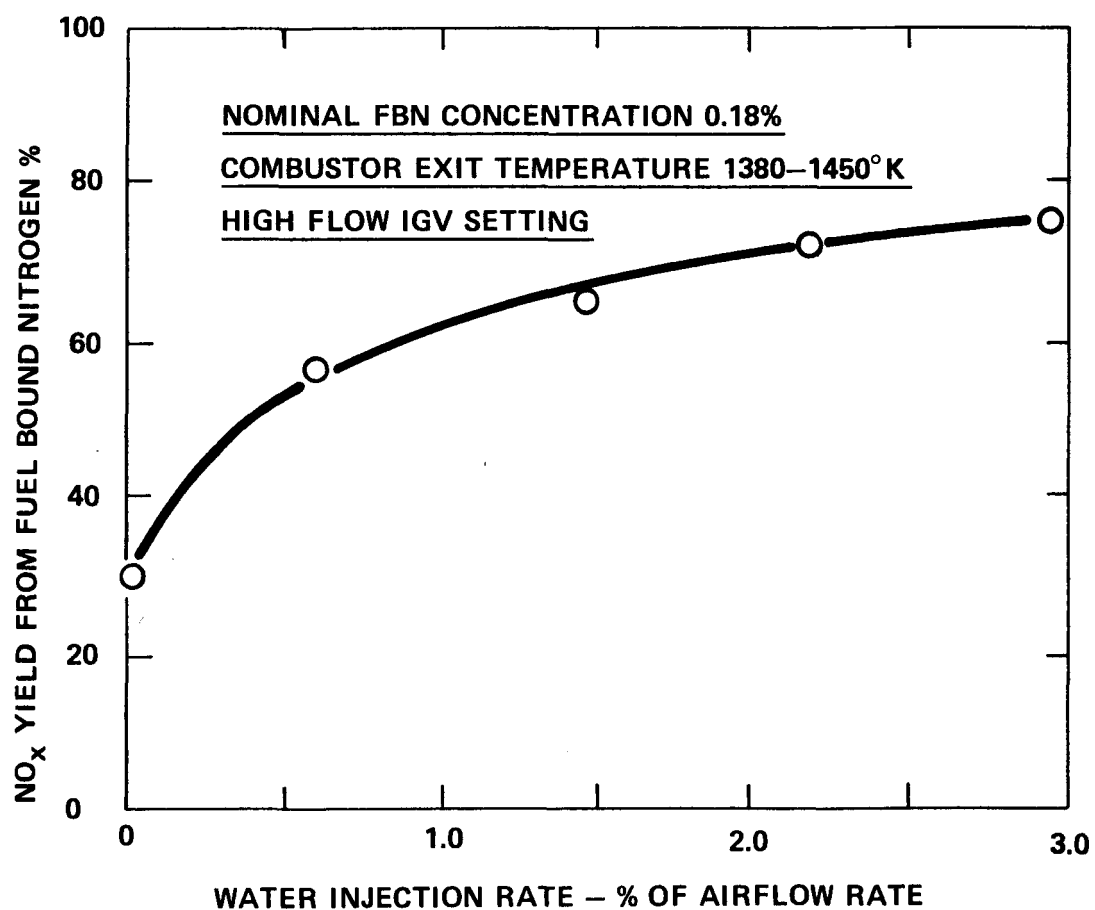


Figure D.4–3 FUEL – NO YIELD INCREASED BY WATER INJECTION (FROM REF. D.4–3)

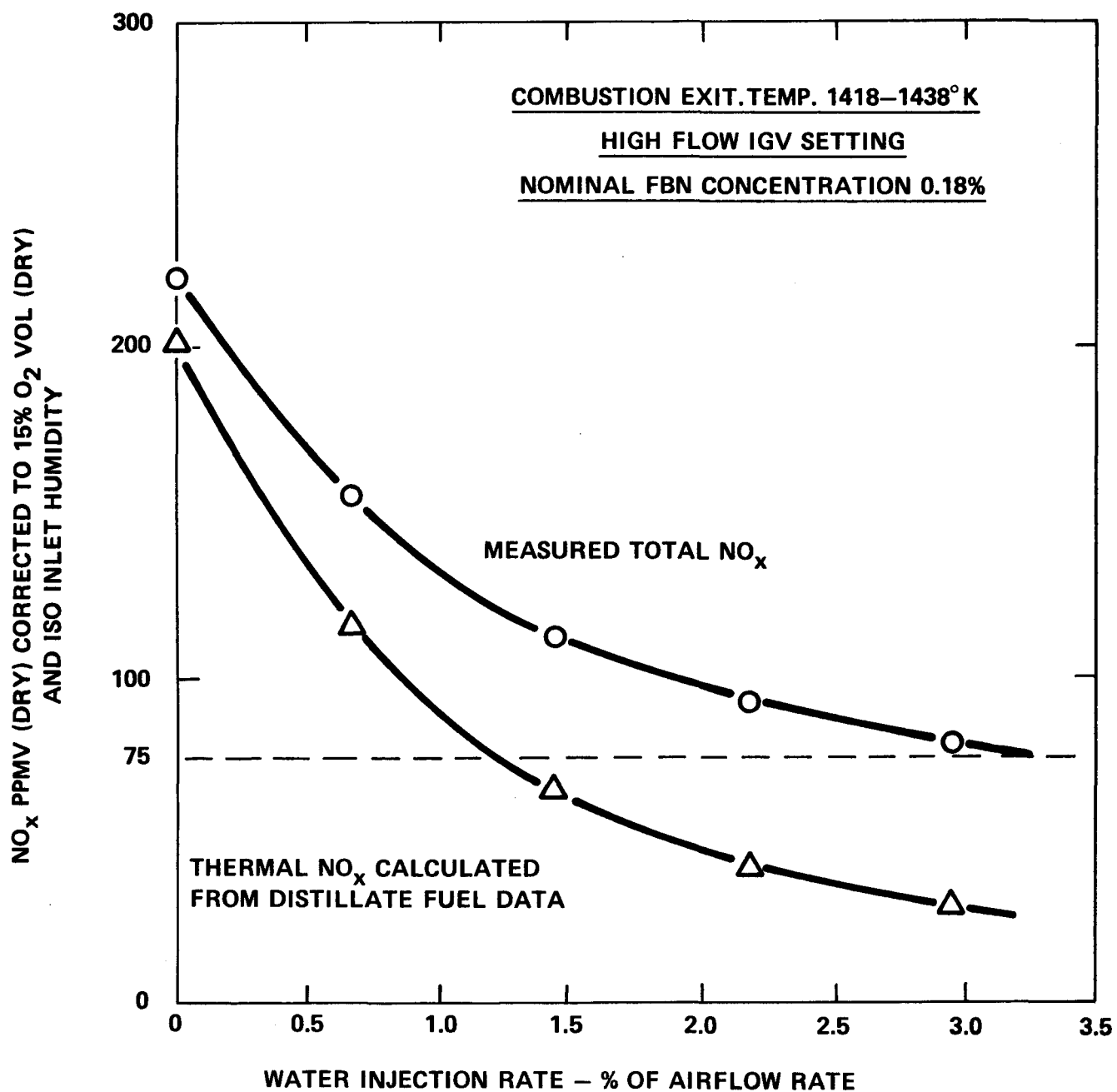


Figure D.4–4 FUEL–NO, WATER INJECTION AND EMISSION LIMITS (FROM REF. D.4–4)

a nominal 0.18% FBN, however, a water-injection rate of just over 3.5% is required, or more than the normal water-injection limit.

A test of nitrogenous fuels in a 50 MW Brown-Boveri gas turbine is interesting because rich-lean conditions existed.⁽⁵⁾ The authors chose to use methylpyridines boiling at 290°F to increase the nitrogen content of No. 2 fuel oil to 0.5% maximum, since the lower boiling point of pyridine (240°F) makes it less representative of the nitrogen compounds actually present in turbine fuels. At base load, the fuel-NO_x yield was 5-10% for fuel-nitrogen contents between 0.15 and 0.55%. This low conversion is attributed to the unique design of the Brown-Boveri combustor, which differs from other stationary gas turbines. This turbine has only one combustor (Figure D.4-5) of much larger diameter and residence time than each of the many combustors in other turbine designs. Making the assumption that the 25 msec residence time in the primary zone is sufficient for equilibrium, the authors conclude from equilibrium composition calculations that the primary zone must be operating slightly fuel-rich with a fuel equivalence ratio of 1.1. The potential of the single-combustor design to suppress fuel-NO_x by accommodating a long residence time fuel-rich primary zone should be explored further. Such a combustor may also promote soot burnout very well, an advantage in burning a low-hydrogen fuel such as SRC-II fuel oil in a fuel-rich primary zone. However, thermal NO_x emissions tend to be higher than those from other smaller combustors.

D.4.2 Aerodynamic Factors in Fuel-Nitrogen Conversion

In addition to the chemical factors (fuel-air ratio, temperature, fuel-nitrogen content) discussed above which affect fuel-nitrogen conversion, we want to mention a few examples of another equally important parameter, the rate of fuel-air admixture, and the gas and fuel spray flow pattern in general.

In the laboratory combustor experiment reported in Reference D.4.2-1, increasing the atomizing air pressure in the burner increased the fuel-NO_x yield. The probable interpretation is that the increased atomizing

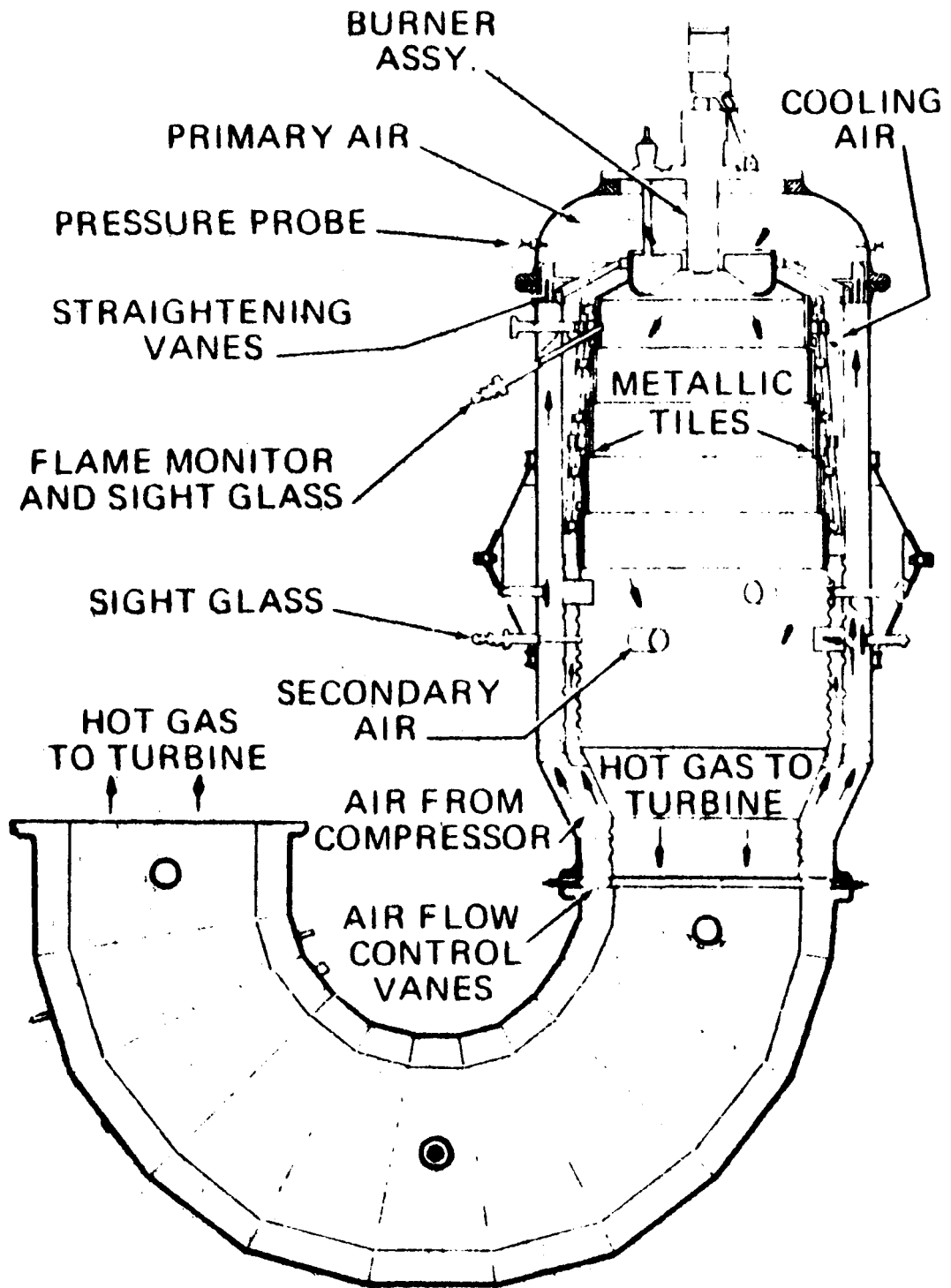


Figure D.4-5 THE SINGLE COMBUSTOR IN BROWN-DOVERI GAS TURBINES (FROM REF. D.4-5)

air flow reduced the droplet sizes, increased their evaporation rate, and increased the turbulent entrainment of combustion air into the fuel spray. This decreased the size and lifetime of fuel-rich eddies favoring the formation of N_2 , and accelerated fuel-air contact and fuel- NO_x formation. The authors later quantitatively substantiated this interpretation with an aerodynamic analysis. Modification of the combustion air flow is done in numerous ways, one of which is to impart axial angular momentum or swirl to the combustion air by vanes tilted with respect to the burner axis. This causes part of flame gases to flow back towards the burner, recirculating of combustion reaction products back into the reactant stream, which is frequently modeled as a well-stirred reactor. This technique has been introduced into designs for gas turbine combustors and also furnace burners in order to provide flame stability and to reduce smoke. These effects of secondary air swirl were observed in tests in a residential-size furnace, in which four burners having successively increasing swirl (burners Nos. 125, 75, 40, and 10, respectively in Figure D.4-6) produced increasing fuel- NO yields.⁽⁶⁾

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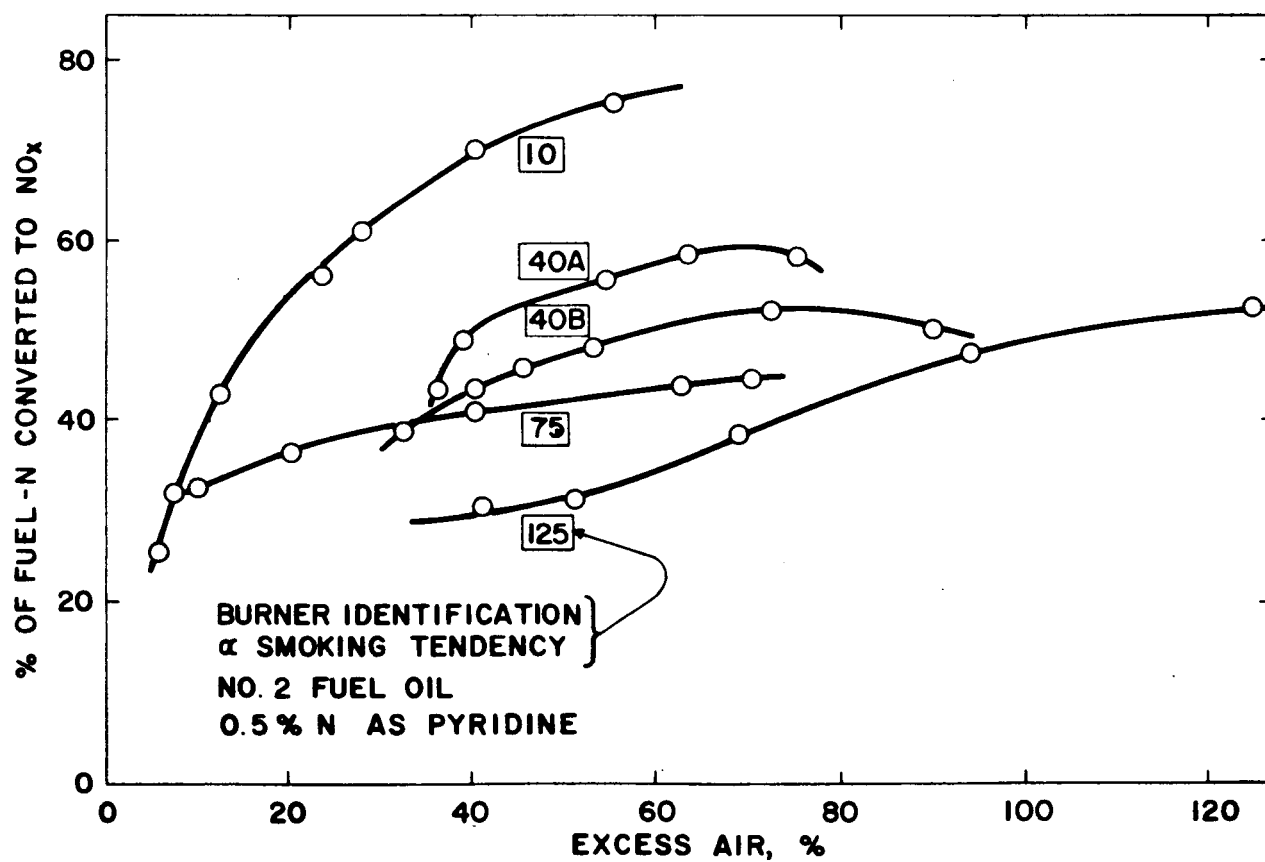


Figure D.4-6 LOW SMOKE, FAST MIXING BURNERS
MAKE MORE FUEL-NO (FROM REF. D.4-6)

E. SOOT EMISSIONS

E.1 Soot Formation and Burnout Mechanisms

We will start with a few examples of soot emissions from simple flames in which the effects of flame conditions are more easily distinguished; this will also serve to define some terms. Soot is observed in the primary and secondary zones of flames even at fuel-air ratios at which the absence of solid carbon is predicted by equilibrium considerations.⁽¹⁾ The reasons for the persistence of soot involve the rates of its formation and burnout, examples of which follow. Figure E.1-1 represents an experiment done with a flat flame burner, positioned for upward flow of premixed fuel and oxidant, as described in Section C.⁽²⁾ As the sampling probe was moved upward from the burner (along the x-axis in Figure E.1-1), at about 2 cm above the burner the amount of soot ("soot volume" in the figure) rose suddenly from zero as the heavy hydrocarbons decreased, being the precursors to the soot. The soot was also then agglomerated into smaller numbers of larger molecules. This demonstrates the formation of soot in the primary flame zone, which in this example was very extended by operating the burner in a low pressure enclosure. This soot formation process is strongly affected by numerous variables, such as the fuel equivalence ratio, flame temperature, pressure, state of admixture of fuel and air, and fuel composition, the latter by virtue of the very composition-dependent pyrolysis of the fuel preceding soot appearance in the flame.

Although soot may be formed in a flame, in many cases it is burned out in the secondary flame zone as shown by common experience with a luminous but cleanly burning candle. Soot burnout is exemplified in Figure E.1-2 by the decrease in soot concentration with increasing distance from the burner (x-axis) in this C₃-hydrocarbon flame at atmospheric pressure.⁽³⁾ Furthermore, the burnout was faster in Run 5, in which the temperature was 1550-1680°K, than in Run 1, in which the temperature was 1400-1750°K, and the oxygen was half that in Run 5. Unburned soot emerged from the flame in Run 5.

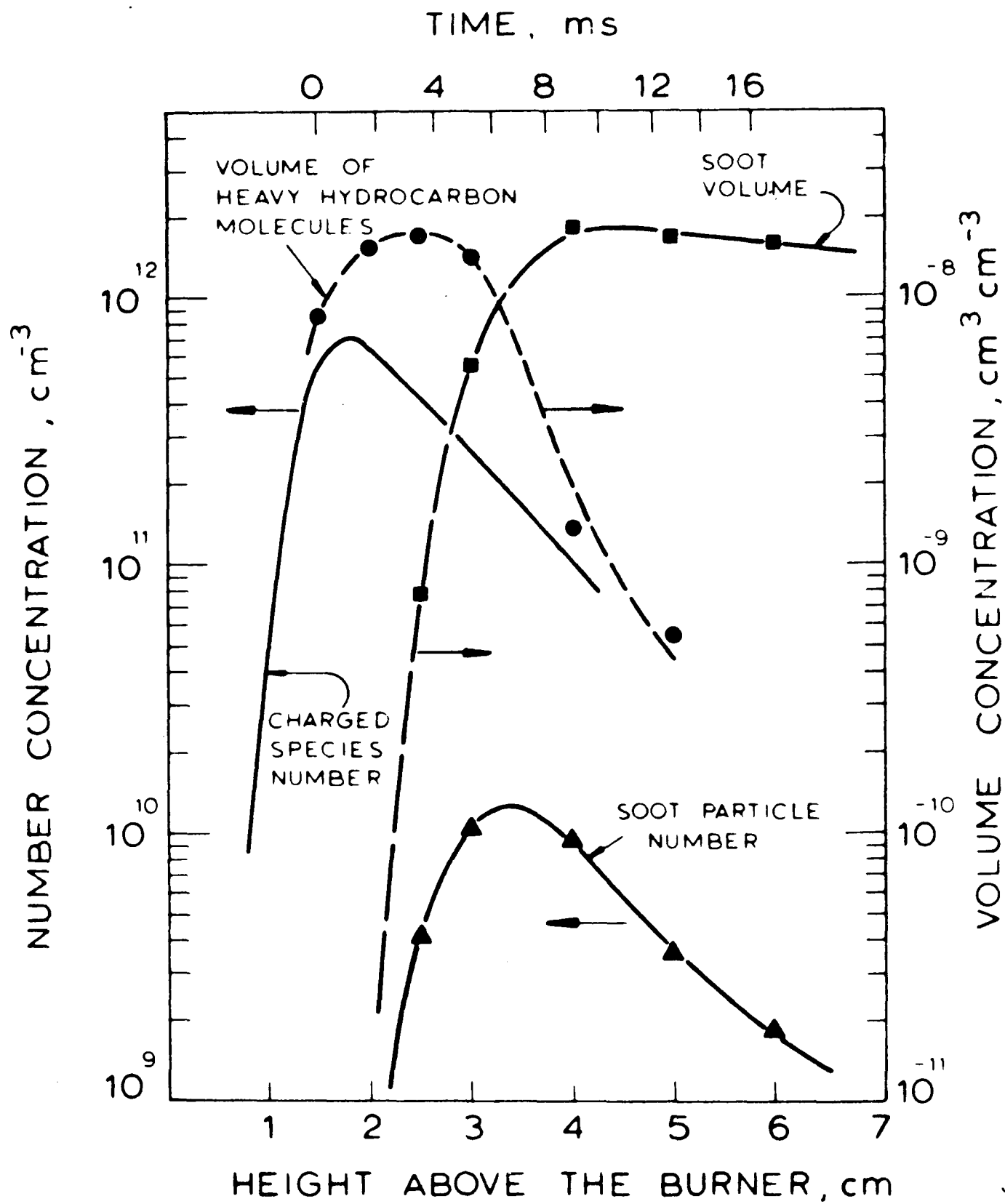


Figure E.1-1 SOOT FORMATION IN FLAME (LOW PRESSURE BURNER) (FROM REF. E.1-2)

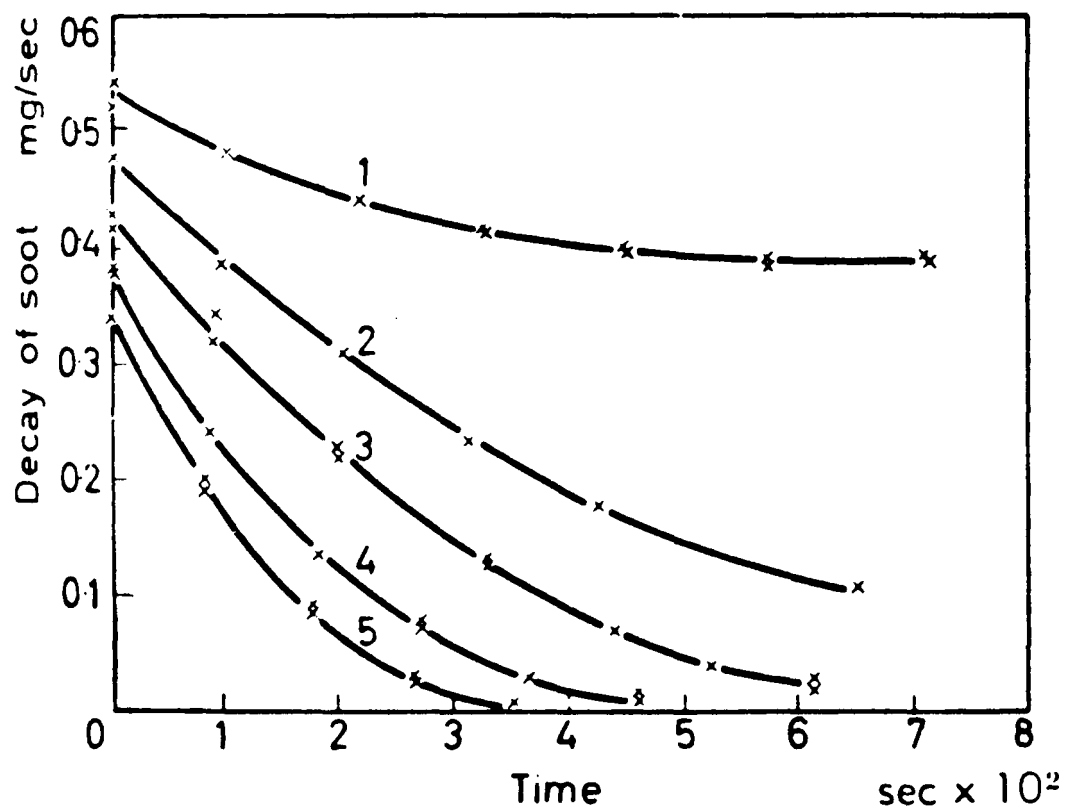


Figure E.1-2 SOOT BURNOUT IN FLAME (FROM REF. E.1-3)

Some observations of soot from premixed flames at high pressure are interesting because they relate to gas turbine combustor conditions as well as providing illustrations of the effects of fuel equivalence ratio, flame temperature, and fuel composition⁽⁴⁾ (Figure E.1-3). In Figure E.1-3a, for n-hexane, at 10 atm. pressure, soot first appears (at threshold "T") as the fuel equivalence ratio increases to 1.4, but with further increases in pressure, the soot never exceeds 0.5 wt% of the total fuel carbon. In the case of benzene (Figure E.1-3b), a somewhat lower fuel equivalence ratio (1.2) is needed for soot appearance at 10 atm., and the yield of soot rises to 5% at $\phi_f = 2.0$. Soot yields also increased with flame temperature, as shown in Figure E.1-4. When the radiative loss of heat from the flame was prevented by surrounding the flame with a reflective insulated cylinder (Curve B), the flame temperature was several hundred degrees C hotter than in the unshielded case (Curve A), and substitution of argon for nitrogen further increased the temperature by 150°C (Curve C). The soot yield increased manyfold with temperature and occurred over a wider range of ϕ values.

These increases in soot with fuel concentration, temperature, and fuel aromaticity are consistent with known mechanisms of soot formation which include fuel pyrolysis (accelerated by temperature), and agglomeration of soot precursors (enhanced by fuel concentration) which are aromatic. The great variation in the rate of pyrolysis of various compounds has a large role in explaining their various soot formation tendencies. There are presently important advances being made in the understanding of these mechanisms, which should be a qualitative guide to new combustor concepts for aromatic fuels such as SRC-II fuel oil, and in time may be incorporated into engineering models for their optimization. To review this work is outside the scope of this report (see Ref. 5).

We have described the strong response of fuel-nitrogen conversion to flame geometry and the fuel-oxidant admixture process; these also strongly affect the soot formation process. The extreme example of this was the well-stirred reactor, of interest because it resembles the primary zone of a gas turbine combustor, which usually has strong recirculation of flame gases for

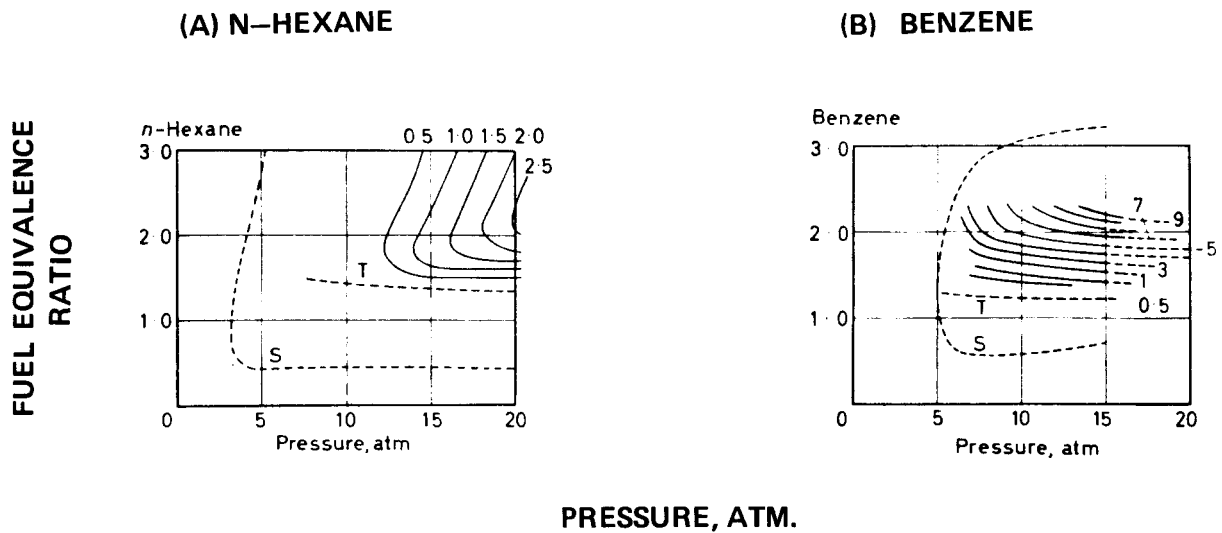


Figure E.1-3 EFFECT OF PRESSURE AND MIXTURE STRENGTH ON SOOT FORMATION. HIGH INJECTION VELOCITY BURNER. SHOWING CONTOURS OF SOOT FORMATION RATIO PER CENT. S DENOTES FLAME STABILITY LIMIT, AND T SOOT FORMATION THRESHOLD (FROM REF. E.1-4)

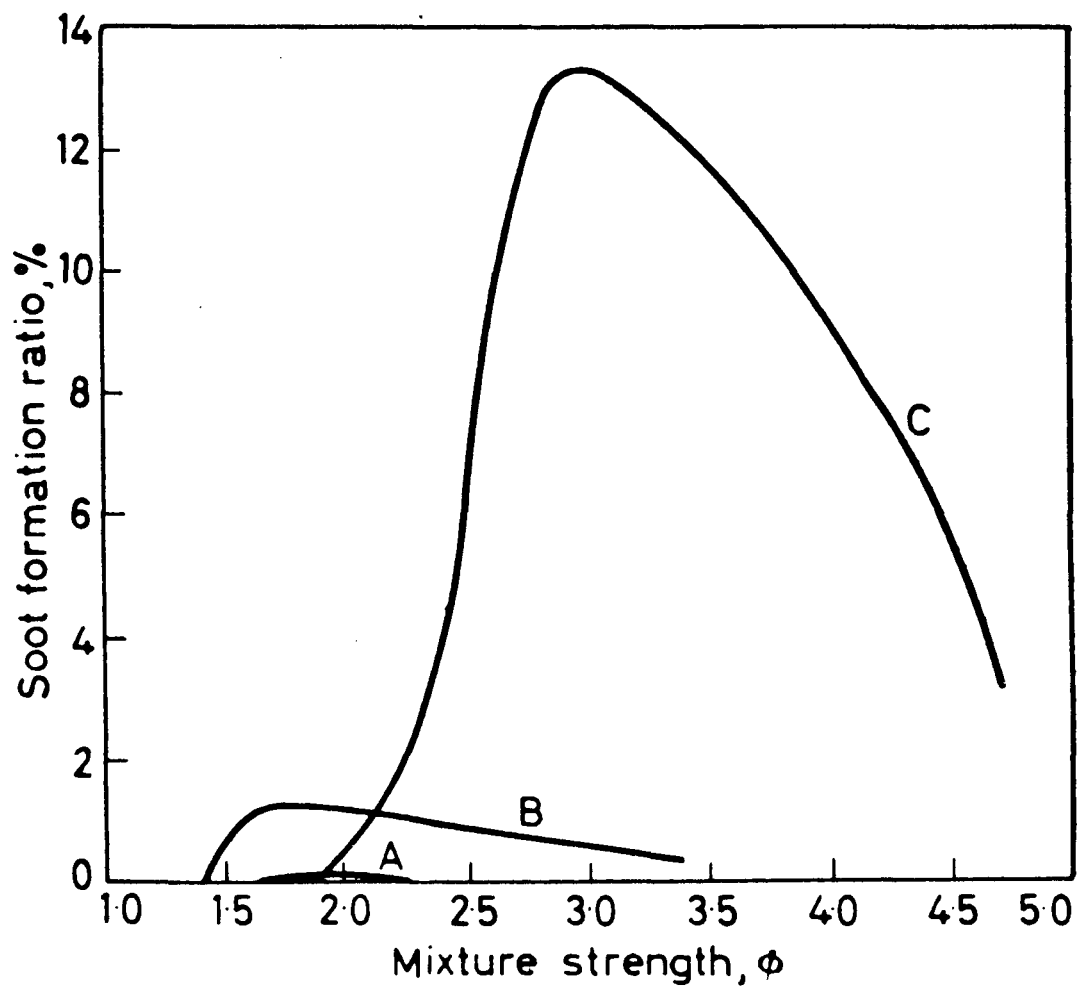


Figure E.1-4 SOOT INCREASE WITH FLAME TEMPERATURE
N-HEXANE 15 ATM (FROM REF. E.1-4)

flame stabilization. The soot yields in Figure E.1-5 show that less soot formed in a well-stirred reactor than in a premixed flat flame burner, the fuel being toluene.

E.1 References

1. W.S. Blazowski, "Future Jet Fuel Combustion Problems and Requirements," Prog. Energy Combust. Sci 4 177 (1978). (Same as ref. D.4-2).
2. B.L. Wersborg et.al., "Concentration and Mass Distribution of Charged Species in Sooting Flames," Fifteenth Symposium (International) on Combustion, p. 1439, (1974).
3. K.B. Lee, M.W. Thring, J.M. Beer, "On the Rate of Combustion of Soot in a Laminar Soot Flame," Combust. and Flame 6, 137 (1962).
4. J.J. McFarlane, F.H. Holderness and F.S.E. Whitcher, "Soot Formation Rates in Premixed C₅ and C₆ Hydrocarbon - Air Flames at Pressures up to 20 Atmospheres," Combust. and Flame 8, 215 (1964).

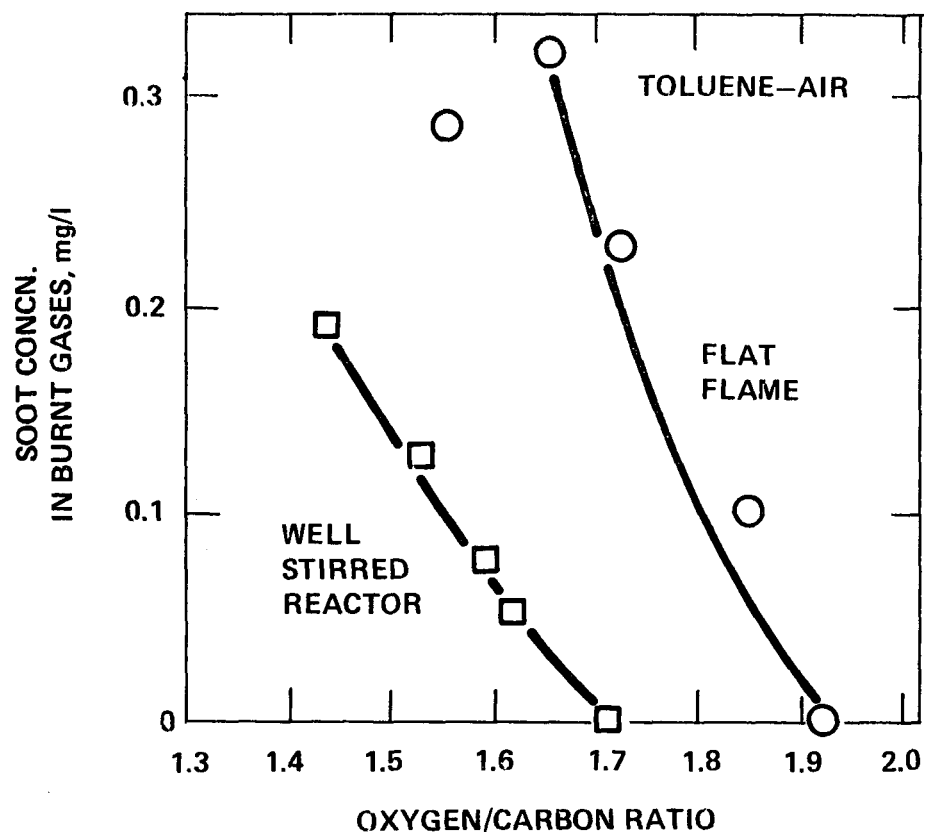


Figure E.1-5 WELL-STIRRED BURNER
MAKES LESS SOOT (FROM REF. E.1-1)

E.2 Soot Emissions, Combustor Overheating and Fuel Property Requirements of Equipment

The sooting tendencies of various compounds and fuels has been studied for many years; typically, a large number of fuels and mixtures of compounds covering a wide range of properties is burned in a burner and the smoke point (maximum height of the flame which does not produce smoke from its tip) or the amount of soot is measured. However, the burners used have covered a wide range of conditions, ranging from wick lamps in the ASTM tests to high-pressure gas turbine spray combustors. The relevance of the ASTM wick lamp tests in trying to establish the tendency of a fuel sample to smoke in a jet engine has been questioned. Many more tests have been conducted in jet engine combustors than in heavy duty stationary gas turbine combustors, because the former tend much more to emit soot. The soot from the fuels in the series in these tests increased with decreasing hydrogen content of the fuel, as shown in the example in Figure E.2-1, conducted in a JT8D single combustor can.⁽¹⁾ The hydrogen content has given a better correlation to soot than other fuel properties such as aromatic content, although some anomalies may have appeared in some recent tests of a set of coal-derived liquid probably because the composition of these fuels has varied more widely than the typical jet fuel blends used in previous studies (See Section F.1).

The efforts described in Section C.3 to improve the designs of jet engines for lower NO_x emissions also sought to reduce smoke emissions, and to enable the use of off-specification fuel. For example, Jet A specification includes 20% maximum aromatics. These design efforts are making progress, which is significant to the use of SRC-II fuel oil in those stationary gas turbines which are derived from aircraft combustors, for example, Pratt & Whitney's FT4 engine and the GE Aircraft Group (Evendale, IL) engines. Stationary power systems using these engines usually require fuel close to jet fuel in quality, for example, No. 2 furnace oil, although there have been some recent successes in the use of higher-boiling distillates which, however, still had hydrogen contents near that of No. 2 oil. New rich-lean combustor designs to suppress fuel- NO_x and soot from high-aromatics fuels (see

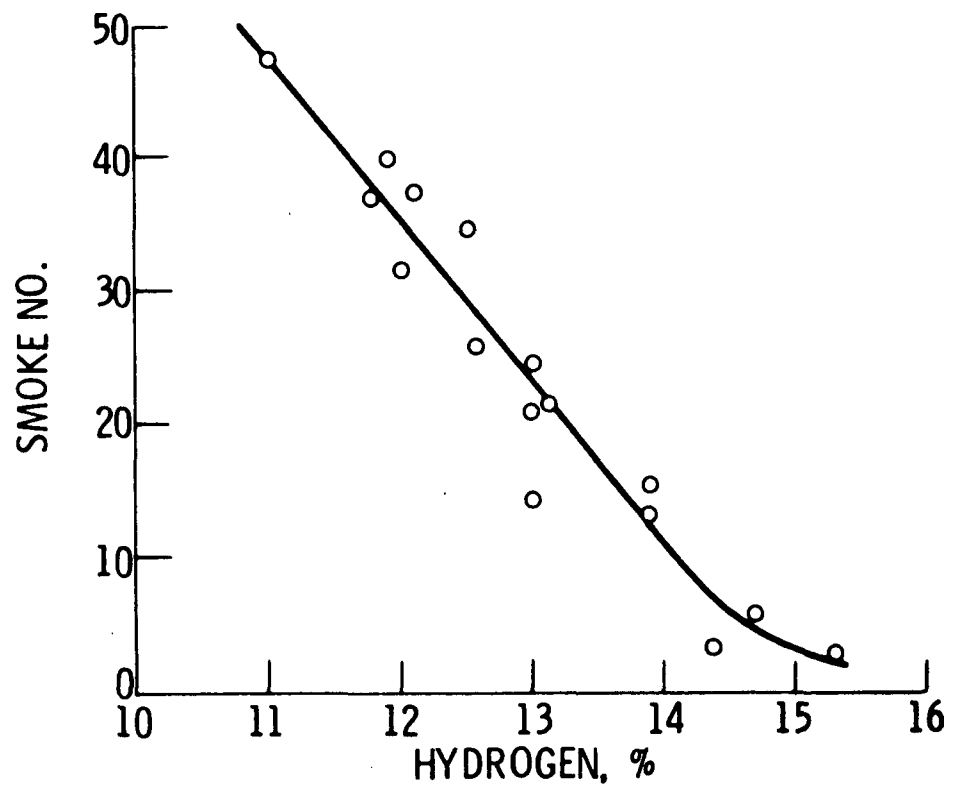


**Figure E.2-1 INCREASING SOOT WITH DECREASING
HYDROGEN CONTENT (FROM REF. E.2-1)**

Section F.2 regarding the Pratt & Whitney and DOE-NASA projects) tend to be longer than the combustor enclosures in aircraft-type engines; if they can be shortened in subsequent projects, these designs will greatly facilitate the use of SRC-II fuel oil in those engines. The measurement of particulate emissions from gas turbines has been a very uncertain art for a long time, but reliable methods are now being developed. Reference 2 describes a test of a FT4 power system firing No. 2 oil in which reliable particulates measurements established the effect of an anti-smoke additive on the amount of particulates and their composition.

In contrast to the aircraft-related combustors described above, the older stationary gas turbine designs described in Section C.2 have employed larger combustors, in which there is sufficient residence time in the secondary flame zone for the soot to burn out. This class of stationary gas turbines has been fired with fuel oils having much lower quality than those for the aircraft-derived turbines. During the 1960's residual oils were commonly burned, having hydrogen contents as low as 11%, without excessive emissions, liner overheating or corrosion, the fuels being treated for metal contaminants.

A problem associated with soot formation in gas turbine combustors is the radiative transfer by soot of heat to the combustor liner, overheating it to damaging temperatures. The measurement of this effect was made independent of the particular combustor chosen to test fuels series by Blazowski, who devised a temperature parameter (T.P.) which is $(T_L - T_{L0}) / (T_{L0} - T_3)$. The liner temperatures T are: T_{L0} , of the liner with a standard fuel, T_L , the test fuel, and T_3 , the combustor inlet temperature. Figure E.2-2 shows that T.P. is independent of combustor, and furthermore, that it increases (higher liner temperatures) with decreasing hydrogen content, correlating well with fuel hydrogen contents between 10% and 14.5%. T.P. also appeared to be fairly constant for fuels of different composition (relative amounts of mono- and diaromatics) if they all had the same hydrogen content.

New aircraft combustor designs are preventing liner overheating as well as soot emissions resulting from low-hydrogen jet fuels, as shown by an example being the bottom line in Figure E.2-2, for the double-annular CF6-50 design. Furthermore, stationary gas turbine combustors suffer the greatest overheating near the primary flame zone. New rich-lean designs will prevent such temperature extremes and will more evenly distribute the heat to the liner, because the rich flame zone will be cooler than the adiabatic temperature of a flame supplied with an excess of combustion air, as in present designs. In this way, the rich-lean design will prevent liner overheating despite the low hydrogen content of SRC-II fuel oil as well as suppressing fuel-NO_x emissions.

References

1. R. E. Jones, "Gas Turbine Emissions - Problems, Progress, and Future," in Progress in Energy and Combustion Science, Vol. 4, No. 2, pp. 73-113 (1978).
2. S. Hersch et al., "The Effects of Smoke Suppressant and Corrosion Inhibiting Additives on the Particulate and Gaseous Emissions from a Utility Gas Turbine," ASME Meeting, December 1977, Paper 78-GT-64 (1978).
3. "Future Jet Fuel Combustion Problems and Requirements," Progr. Energy and Combust. Sci., Vol. 4, 177 (1978).

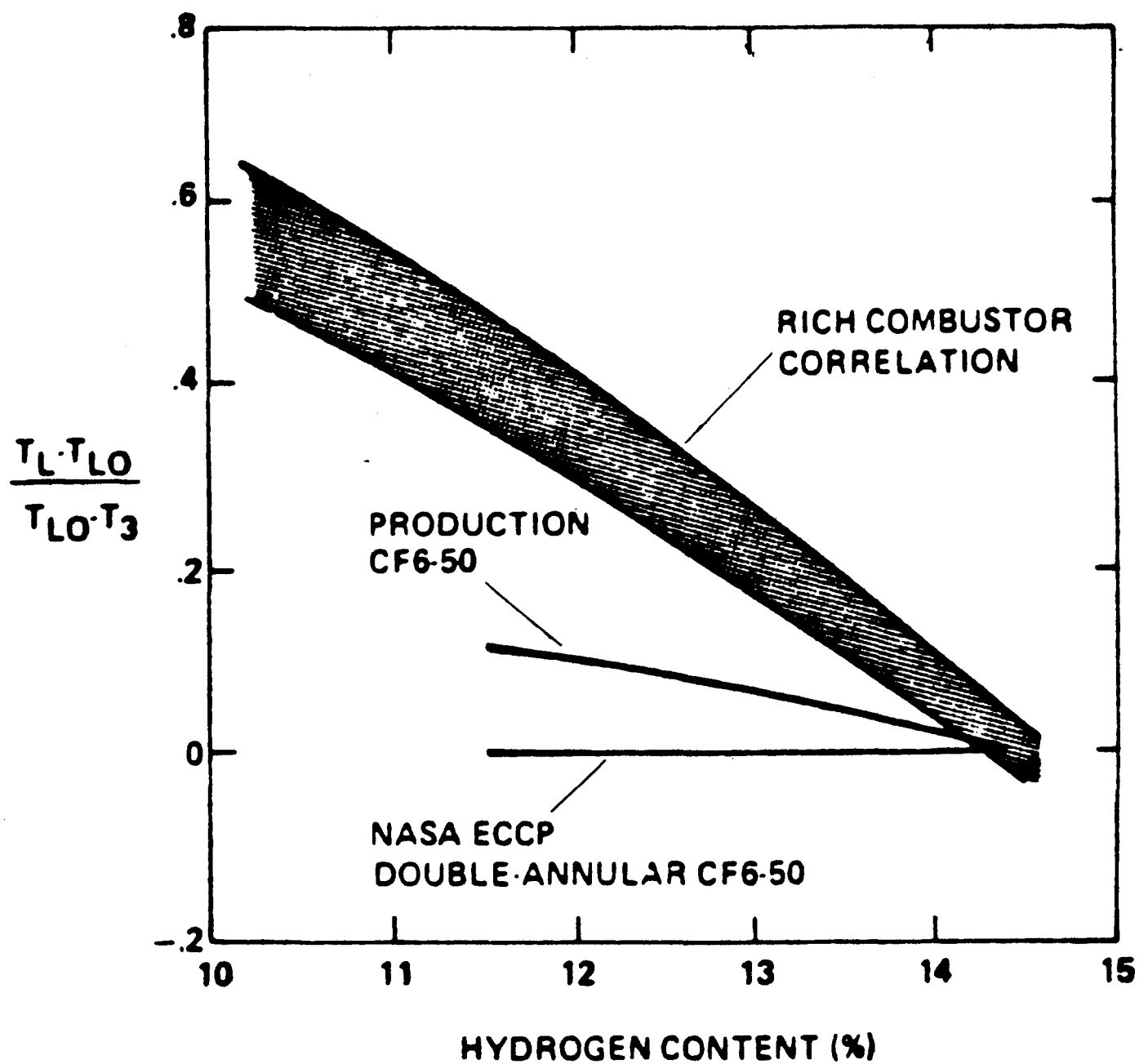


Figure E.2-2 LINER TEMPERATURE PARAMETER INCREASES WITH DECREASING HYDROGEN CONTENT (FROM REF. E.2-3)

F. COAL LIQUIDS COMBUSTION EMISSIONS AND THEIR PREVENTION

In Sections C-E, NO_x and soot emissions basics, typical turbine behavior, emissions suppression methods, including some synfuels data, and equipment problems were discussed. In this section, it is convenient to describe together all these aspects of combustor development for new fuels, and work in the most recent projects.

F.1 CDL Tests in Conventional Combustors

In 1977, EPRI initiated a program with the Combustion Turbine Systems Division of Westinghouse and Mobil Research and Development Corporation to prepare coal-derived liquids (CDL) covering a range of properties and to test them in single combustor rigs. The general objective of the program was to outline what combustor developments, or, on the other hand, what minimal CDL qualities would be necessary for problem-free utilization of CDL in gas turbines. A further objective was the combustor testing of petroleum-derived liquids as possible surrogates for scarce CDL's. Conventional combustors were used for baseline information; new designs were not involved.

The test results reported to date have involved six coal-derived liquids, whose properties are described in Table F.1-1. They covered hydrogen contents between 7.74 and 12.18% (excluding the No. 2 oil used as a reference), 0.08-0.69% nitrogen, and 28-76% aromaticity.⁽¹⁾ These included three liquids from the SRC-I process (not the SRC-II process), two H-coal liquids and an Exxon Donor solvent liquid (EDS). SRC-II fuel has been tested in work subsequent to the publications in Reference 1.

In the first tests, a mini-scale combustor was used, 4 inches in diameter and 4.5 inches long. During the test of the SRC recycle solvent, the most viscous and aromatic of the samples, the combustor suffered coke deposition and wall damage; nozzle coking was also observed, and it seems possible that there occurred spray diversion and wall impingement.⁽²⁾ No such events occurred in the next phase of this project, done with a half-scale combustor (Figure F.1-1, 5.5 inches in diameter and approximately 27 inches long) and a

**TABLE F.1-1 COAL LIQUIDS PROPERTIES
IN WE-EPRI TESTS (FROM REF. F.1-1A)**

COAL LIQUID	VISCOSITY @ 313K (100°F) * $10^{-6} \frac{m^2}{sec}$	PERCENT H (wt.)	PERCENT N (wt.)	PERCENT O (wt.)	PERCENT S (wt.)	AROMA- TICITY % Ca	BOILING RANGE K (°F)
SRC WASH SOLVENT	1.75	9.23	.35	5.7	.26	61	423-510 (302-458)
SRC LT. ORGANIC LIQUID	1.03**	12.18	.29	3.3	.57	28	325-474 (125-394)
SRC RECYCLE SOLVENT	6.04	7.74	.69	2.2	.30	76	484-661 (411-730)
H-COAL (LIGHT)	1.12	11.38	.16	1.4	.13	34	371-515 (208-467)
H-COAL (MEDIUM)	2.56	10.03	.33	1.2	.09	43	459-581 (367-586)
EXXON FUEL	2.67	9.95	.08	0.3	.03	53	428-637 (311-686)
NO. 2 OIL BASELINE	2.61	12.93	.008	< 0.1	.093	19	454-629 (358-672)
*ONE CENTISTOKE EQUALS $10^{-6} m^2/sec$. **THIS VISCOSITY ONLY WAS RECORDED AT 283K (50°F); ALL OTHERS AS SHOWN.							

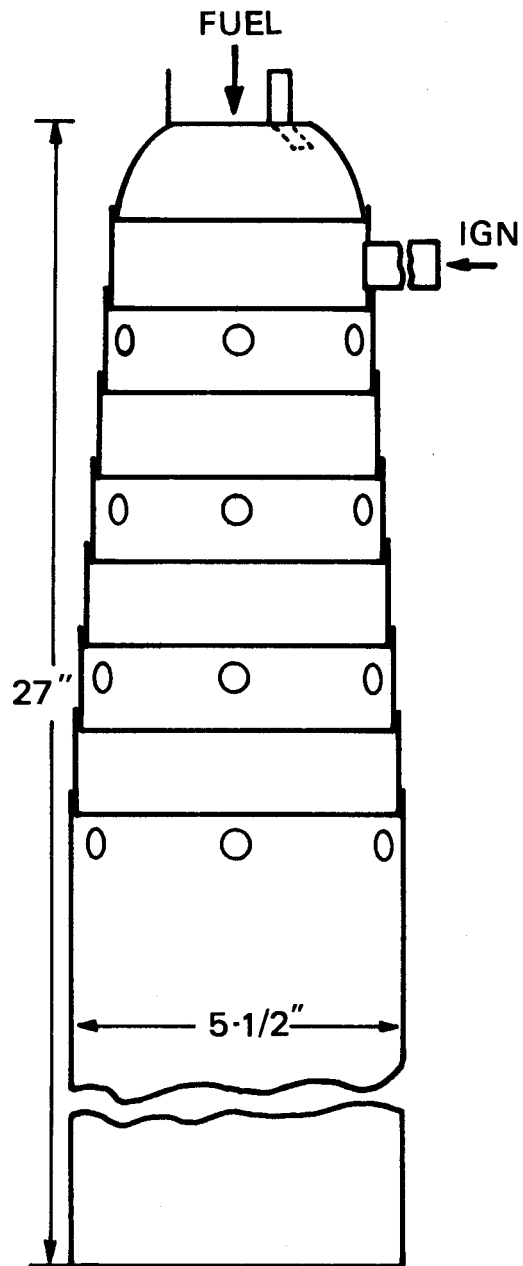


Figure F.1-1, SUB-SCALE COMBUSTOR IN
WE-EPRI TESTS (FROM REF F.1-3)

full-scale combustor (12 inches in diameter and 39 inches long, the type used in the W 251 gas turbine). In runs in the subscale combustor, a 1.5 lb/sec flowrate of 600°F air at 4 atm was maintained while the fuel flowrate was increased, accompanied by increased combustor exit temperatures (1000-2100°F) and increased fuel equivalence ratio in the primary zone. This corresponds to the operating mode of many power systems turbines. The measured NO_x emissions are in Figure F.1-2. The thermal- NO_x rise from No. 2 oil resembles that in Figure C.3-1 in a complete machine. The apparent fuel- NO_x from the coal liquids is the increment over the thermal- NO_x , increasing with fuel-nitrogen content. The fractional conversion of fuel-nitrogen to NO_x is shown in Figure F.1-3 to decrease from nearly 100% with low-nitrogen fuels to 30-50% with high-nitrogen fuels, consistent with earlier observations of doped oils or shale oils; thus, these coal-derived liquids generally resemble other nitrogeneous oils in this respect. The conversion was also less at higher loads, when the higher firing rate would increase the fuel equivalence ratio in the primary zone, reduced conversion being consistent with previous discussions.

Soot emissions from stationary heavy duty turbines increase with fuel flowrate (a problem differing operationally from low-power smoke from jet engines [Section C]). The full-scale combustor used in the WE-EPRI project (Figure F.1-4) produced increasing smoke with increasing No. 2 fuel oil flow rate. An interpretation of this should consider the effect of increased fuel flow on the soot formation rate, possibly increased by the higher fuel concentration and temperature in the primary zone, as well as soot burnout, possibly enhanced by the increased secondary zone temperature. The coal liquid most tested in the full-scale combustor was the light H-coal; the soot from it paralleled but slightly exceeded that from No. 2 oil.

The sooting tendencies of the other coal liquids in the WE-EPRI study paralleled their hydrogen contents, as shown in Figure F.1-5, taken in the subscale combustor fired at mid-load conditions. The smoke number at each hydrogen percent value is normalized with that at 12.5% hydrogen, which permits plotting of data from a completely different combustor, with different

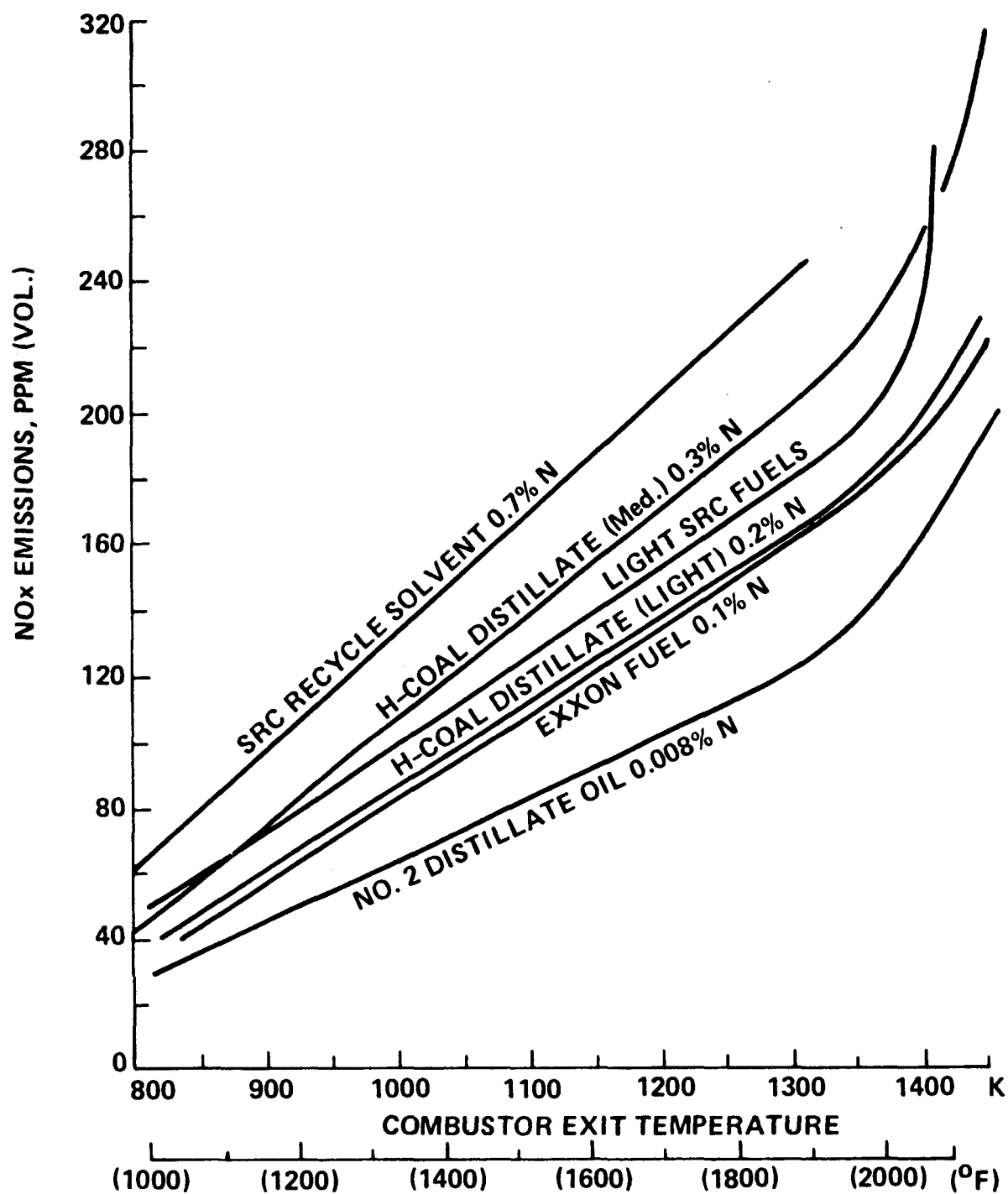


Figure F.1-2 NO EMISSIONS FROM COAL LIQUIDS – INCREASE WITH FUEL FEED RATE AND FUEL NITROGEN (FROM REF. F.1-1A)

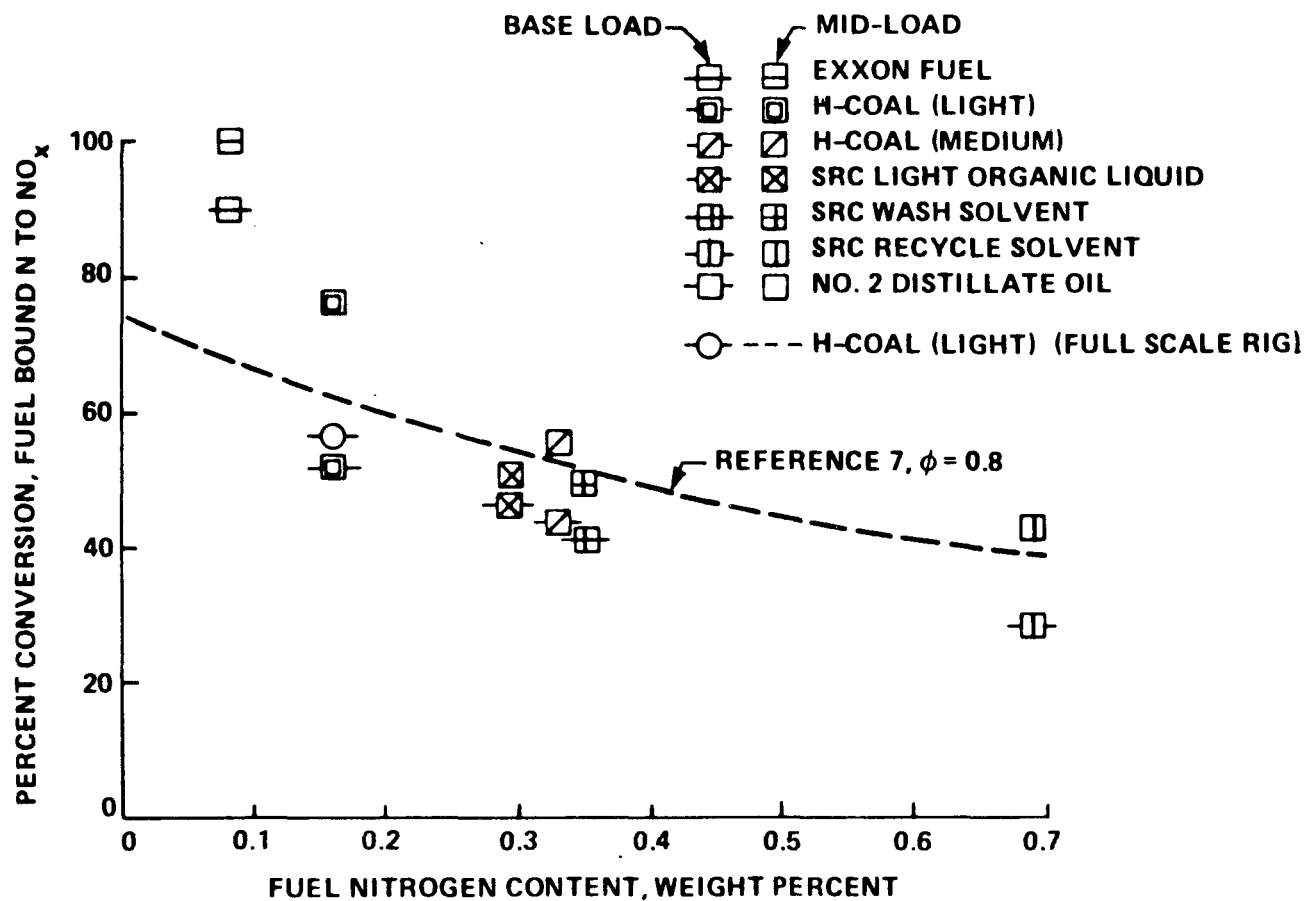


Figure F.1-3 FUEL-NO YIELD FROM CDL'S DECREASES WITH %N (FROM REF. F.1-1)

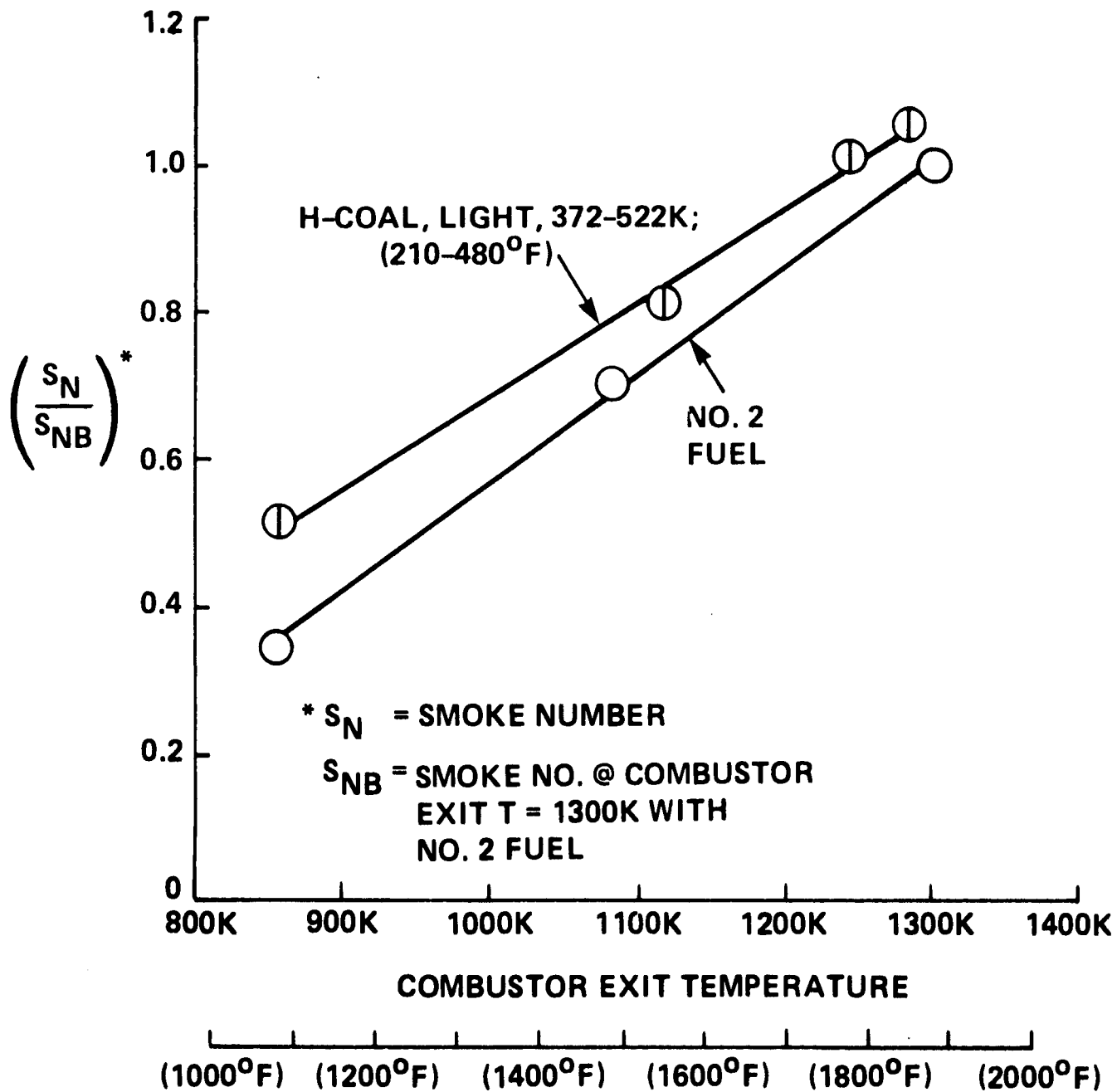


Figure F.1-4 SMOKE NUMBER (NORMALIZED)
 INCREASED WITH LOAD (FROM REF. F.1-1A)

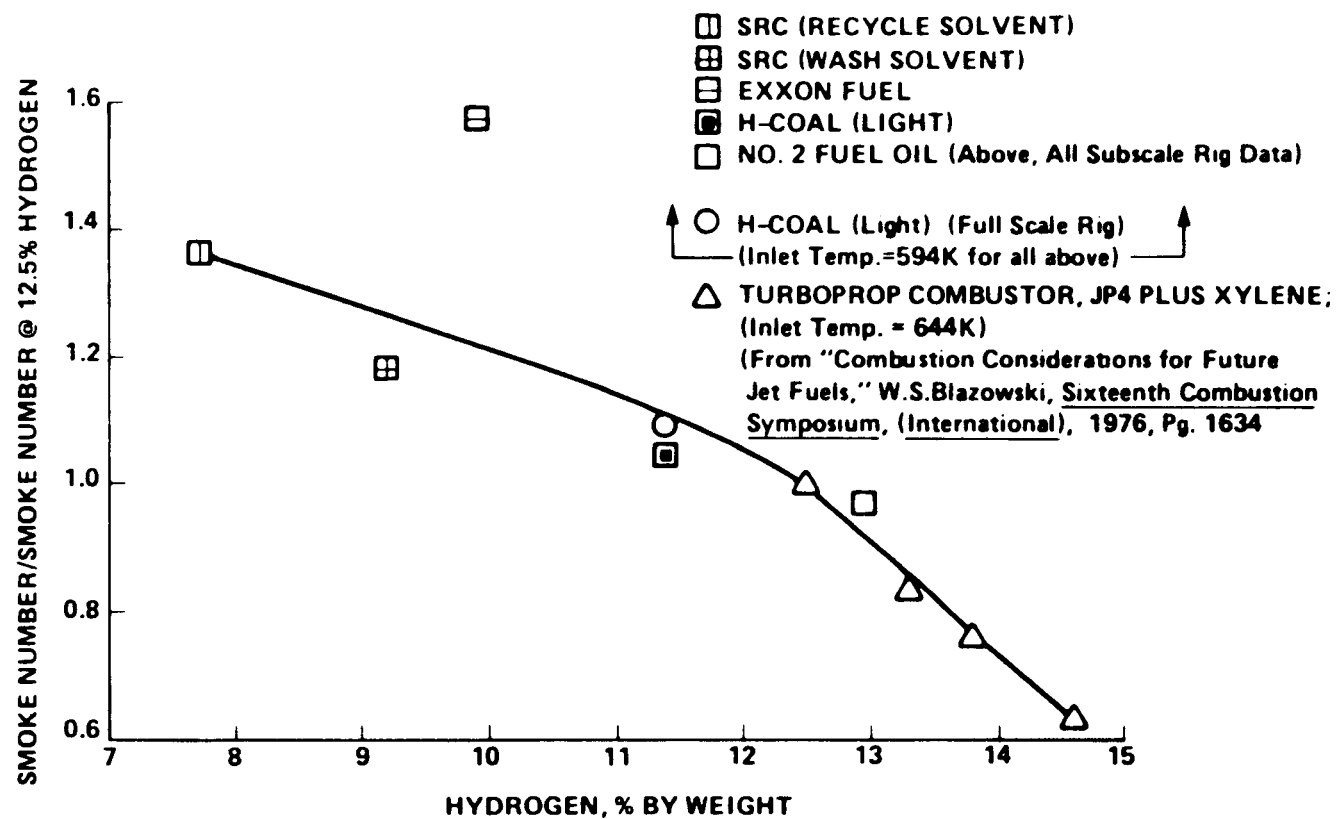


Figure F.1-5 SMOKE FROM COAL LIQUIDS: INVERSE CORRELATION WITH HYDROGEN CONTENT (FROM REF. F.1-1A)

smoking characteristics, in a manner which cancels out the combustor differences and permits comparison of their responses to fuel hydrogen content. With fuel hydrogen content decreasing from 13% (No. 2 oil) to 7.7% (SRC-I recycle solvent), the smoke number increased 50%. The Exxon fuel appears to give a 30% higher smoke number than indicated by the trend of the other coal liquids; its other soot-related properties (aromaticity, distillation range) fit the trends of the other coal liquids, and offer no explanation for this anomalously high smoke number (unless fuel-nitrogen or oxygen could have an anti-soot effect). The 50% increase in smoke number, a reflectance method, implies a several-fold greater increase in soot mass emissions.

The close agreement of the normalized smoke numbers for light H-coal in the subscale and full-scale combustors in Figures F.1-4 and 5 somewhat validates the use of this normalized treatment, but would be better tested by use of a lower-hydrogen fuel. The other data in Figure F.1-5 were obtained from a turboprop combustor fired at cruise operating conditions with jet fuel doped with xylene to vary its hydrogen content. The normalized smoke numbers increase with decreasing hydrogen, and align with the other combustor data.

During the tests of these coal liquids the combustor liner temperatures were monitored by numerous contact thermocouples. With all fuels (coal liquids and No. 2 oil) the maximum in liner temperature occurred about 1/4 combustor length from the nozzle end of the combustor, indicating that the flame had a normal shape in all cases. The average liner temperature in Blazowski's temperature parameter (Section E.2) correlated fairly well with the fuel's hydrogen content as shown in Figure F.1-6, and aligned with the turboprop data. The concurrent increase in soot and liner temperature with decreasing hydrogen content are consistent with the known role of soot in radiative heat transfer. A heat flux sensor in the full-scale combustor verified that the coal liquid used there (light H-coal) raised the heat flux by 12-15% over that from No. 2 oil.

Some other problems, which are common with low-quality fuels, did not occur during these tests. There was no carbon deposition on the nozzle or

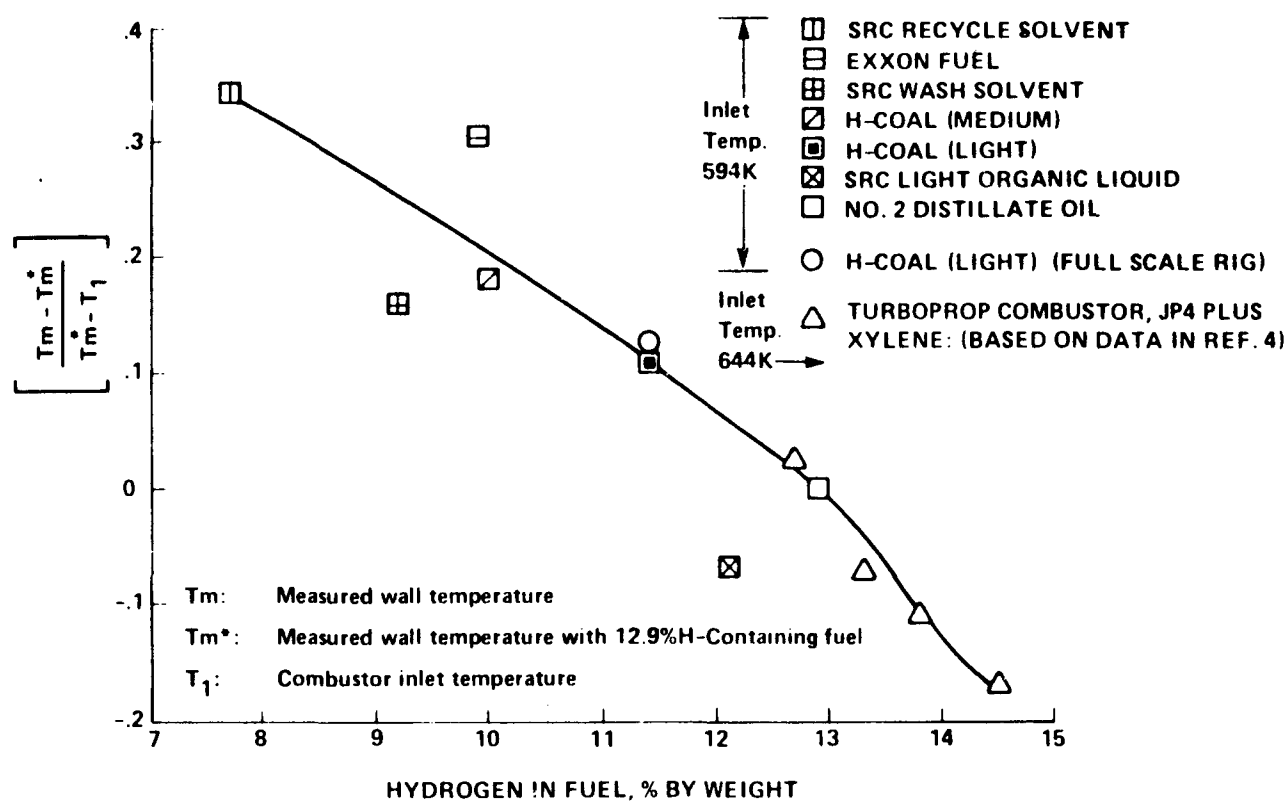


Figure F.1-6 LINER HEATING INCREASES WITH LOWER %H (FROM REF. F.1-1a)

liner. Furthermore, start-up ignition with coal-liquids and hot conditions were normal, as well as flame stability.

The nozzles and combustors used in these tests were unmodified commercial items for No. 2 oil firing. Current progress in new technology indicates that prevention of excessive soot and liner overheating will be possible with new liner cooling air flow designs, materials, and fuel-NO_x suppression combustor designs.

F.1 References

- 1a. P. W. Pillsbury, P. P. Singh, A. Cohn, T. R. Stein, "Fuel Effects in Recent Combustion Turbine Burner Tests of Six Coal Liquids," presented at ASME Meeting, March 1979, paper number 79-GT-137.
- 1b. P. W. Pillsbury, et al., "Investigating Combustion Turbine Burner Performance with Coal-Derived Liquids Having High Fuel Bound Nitrogen," ASME Meeting, April 1978, Paper 78-GT-126.
2. A. V. Cabal, et al., "Utilization of Coal-Derived Liquid Fuels in a Combustion Turbine Engine," ACS Div. of Fuel Chem. Preprints 23 (1) 119 (1978).
3. EPRI, private communication.

F.2 New Combustor Designs for Clean CDL Burning

The aircraft engine combustor modification projects described in Section C.3 did not have as a major objective the clean burning of nitrogenous fuels, and do not include the rich flame principle which suppresses fuel- NO_x formation, although these projects succeeded in suppressing smoke and thermal- NO_x . The tests by WE and others of low-hydrogen high-nitrogen fuels in conventional combustors have established the need for designs suppressing fuel- NO_x and soot. Some prominent examples of the progress made to date in this direction will be described here in order to indicate the high probability that such further work will produce equipment cleanly burning SRC-II fuel oil. Furthermore, advanced cycles present even more opportunities for low-emissions concepts, which are described in another section of this report.

F.2.1 ECAS Study

The use of the rich flame principle in combustor design was proposed in several studies, including the Westinghouse Electric (WE) ECAS study, and an EPA kinetic modeling study by Energy and Environmental research, Inc. (EER). In the WE ECAS study of a combined cycle plant burning a "semi-clean" coal liquid (H-coal,⁽¹⁾ containing 1.3%N and 7.4%H) a combustor was proposed which included a rich section for converting fuel-nitrogen to N_2 . A simple kinetic model was used to estimate that this concept would produce only 0.6 lb $\text{NO}_2/10^6$ Btu, instead of 3.3 lb predicted from a conventional combustor.

F.2.2 EER LBG Kinetics Study

Since low-Btu gas from a co-sited coal gasifier and power gas turbine could contain ammonia, EPA initiated a study at EER of the resulting fuel- NO_x emissions. In the absence of hydrocarbons, the gas fuel combustion chemistry was easily modeled and verified in simple burners, and various stages of partial combustion and heat removal were found to suppress fuel- NO_x formation.^(2,3)

F.2.3 Pratt & Whitney Experimental Rich-Lean Combustor

Several gas turbines manufacturers are currently doing in-house studies of combustor designs to actualize the rich flame concept; one of these efforts, by Pratt & Whitney in an EPA contract, has been published and will be described here because it has combustors experimentally demonstrating the effectiveness of this concept.^(4,5)

The goals of this program included 100 ppm NO_x with 0.5% nitrogen in the fuel, and less than 100 ppm of CO. Its plan contained four phases: (1) analysis of concepts for their potential; (2) bench testing of the most promising concepts; (3) design and fabrication of a full-scale combustor; and (4) testing and optimization of the full-scale combustor.

In Phase I, the twenty-nine concepts listed in Figure F.2.3-1 were analyzed by a computer model; 18 were selected for experimental bench-scale testing. Half of the twenty-nine concepts involve in some way a rich flame, and other concepts showing no value for nitrogen-containing fuels. One of the concepts, rich burn/quick quench, was superior among the former; Figure F.2.3-2 shows the concept and the bench-scale combustor, the critical features being listed in the following excerpt from Reference F.2.3-4.

Critical Features - Three key requirements for low exhaust emissions have been identified, using distillate and low Btu gaseous fuels:

- all air entering the fuel-rich primary zone must be premixed with fuel to prevent diffusion burning (in particular, liner cooling airflow cannot be discharged into the primary combustion region);
- minimum NO_x concentration levels are obtained at primary zone equivalence ratios near 1.3;

<i>Concept No.</i>	<i>Title</i>
1	Low-Intensity Flame
2	Premixing Catalytic Burner
3	Superlean with Heat Recirculation
4	Superlean with Preburner
5	Heat Removal
6	Quench Reheat
7	Staged-Centertube Burner
8	Exhaust-Gas Recirculation
9	Hydrogen Enrichment
10	Surface Combustion
11	Distributed Flame
12	Ceramic Liner
13	External Combustion
14	Boost-Air Dilution
15	Artificial Excitation
16	Extended Injector
17	Pebble Bed
18	Coanda Flame
19	Electric Assist Nozzles
20	Virtual Staging
21	Engine Inlet Fuel Injection
22	Flameless Combustion
23	Air Staging
24	Fuel Staging
25	Vorbix (Vortex Burning and Mixing)
26	Fuel/Air Premixing

27	Refractory Block Flame Stabilizer
28	Rich Burning
29	Rich Burner/Quick Quench

Figure F.2.3—1 COMBUSTOR CONCEPTS ANALYZED BY P&W (FROM REF. F.2—4)

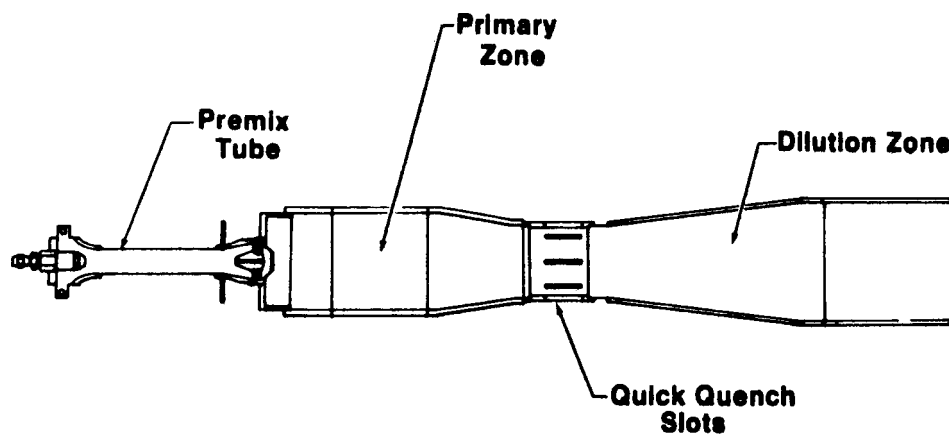
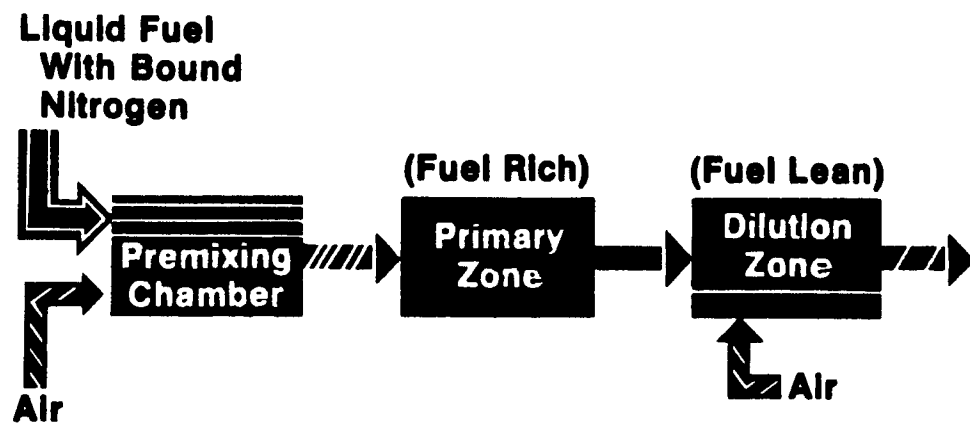


Figure F.2.3-2 RICH BURNER CONCEPT DIAGRAM AND SKETCH OF BURNER COMPONENTS (FROM REF. F.2-5)

- quick-quench air is added at a single site, and must be introduced in a manner that produces vigorous admixing, approximately a step change in composition and temperature.

The resulting emissions (Figure F.2.3-3) reached the goals over the fuel flowrate range. For example, at low power (overall ϕ 0.15) only 7% of the total air flow entered the primary zone to keep it rich enough (primary zone $\phi = 1.3$); but, at high fuel flow, the primary air flow was increased to 14% by a variable-geometry concept, a movable vaned entry port to the primary zone.

It is noteworthy that this combustor also met the emissions goals with low-Btu gas containing 0.3% ammonia, since such fuel-switching could occur in the future utilities scenario.

The result of the Phase III engineering design of the full-scale combustor is shown in Figure F.2.3-4; its basic features are described in the following excerpt:

- a. A single centrally mounted premixing tube is provided having a velocity versus length schedule similar to that of the smaller tubes employed successfully throughout the bench-scale test program. Variable vanes (not shown) are provided at the premixing tube inlet to regulate the primary zone airflow. The premixing tube is offset slightly with respect to the centerline of the combustor in order to be in-line with an engine diffuser passage.
- b. An extended length primary zone is provided for increased residence time.
- c. A primary liner cooling scheme is provided that does not call for discharging spent cooling air into the combustion region of the primary zone. Airflow from the primary-liner convective cooling passage is discharged into the combustor through the quick-quench slots.
- d. The quick-quench section is designed to provide strong mixing, so that an abrupt termination of the primary-zone rich burning process can be achieved. An area ratio of 2.8 to 1 was adopted

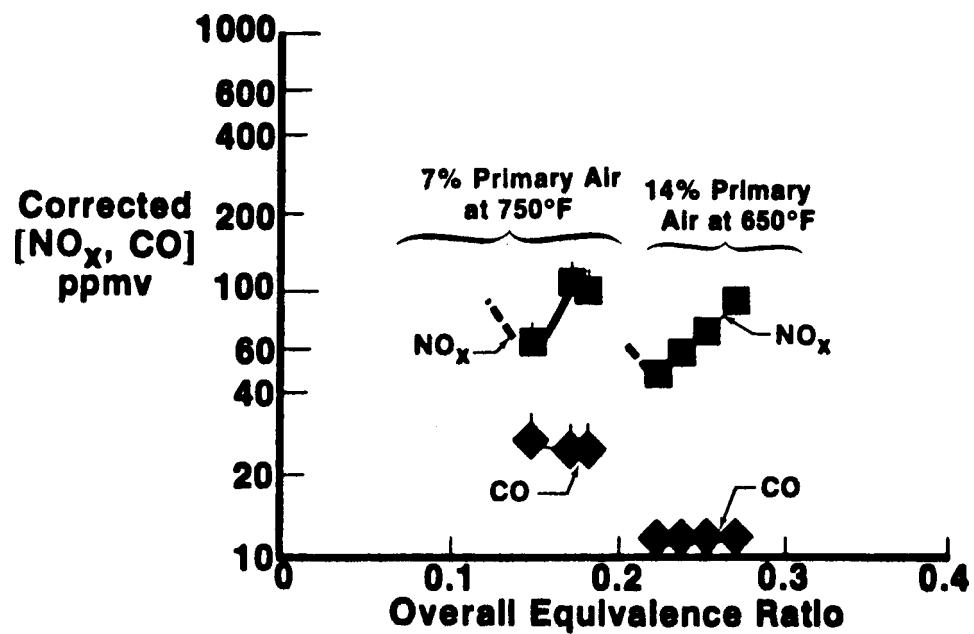


Figure F.2.3-3 EMISSIONS FROM RICH BURNER. FUEL IS PYRIDINE-DOPED (0.5% N) NO. 2 OIL (FROM REF. F.2-5)

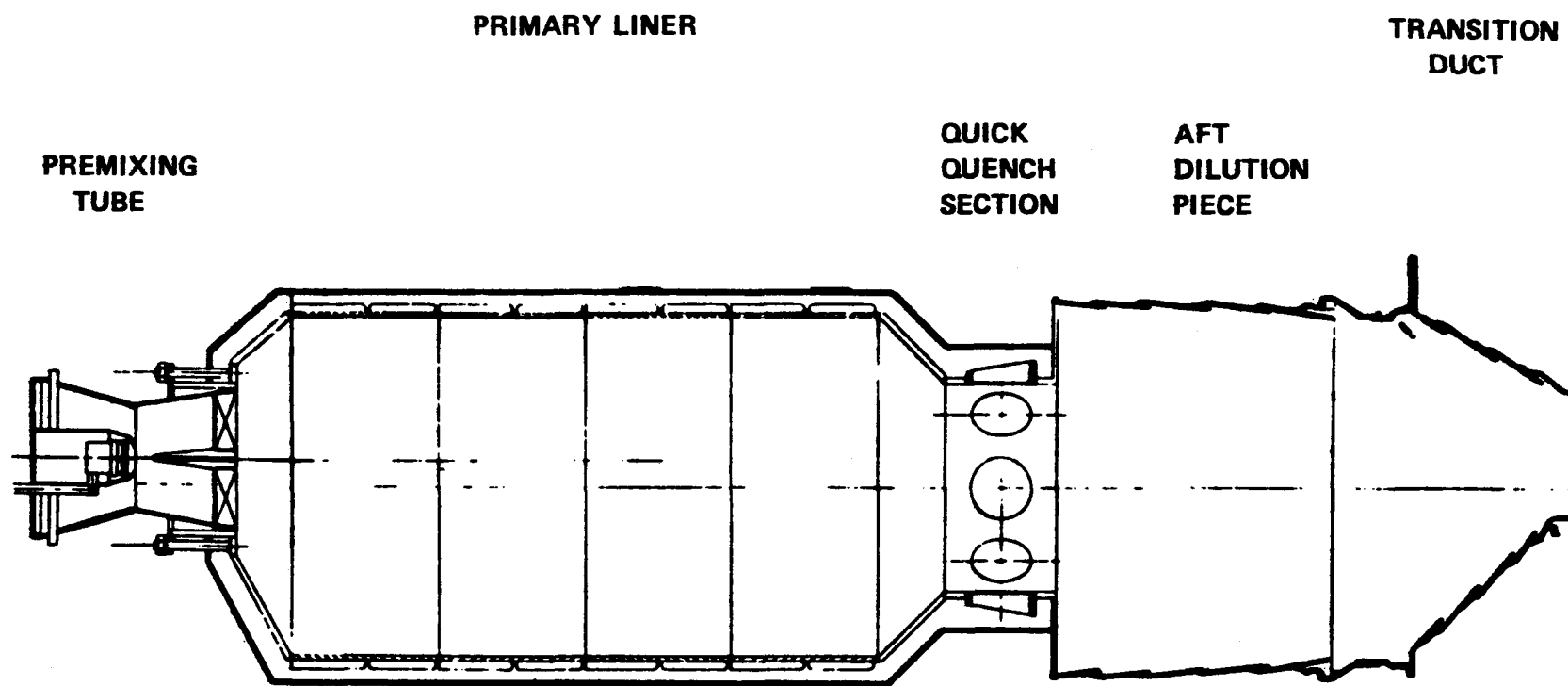


Figure F.2.3-4 FULL-SCALE COMBUSTOR DESIGN (FROM REF. F.2-5)

in the "necked-down" section of the combustor, matching the optimum value determined in the bench-scale tests.

- e. The aft dilution zone of the combustor is combined with the engine transition duct to provide a maximum allocation of the available combustor length for the oxidation of CO while still maintaining an extended-length primary zone in the interest of achieving low NO_x .

Critical to the success of the full-scale combustor was the valid modeling of the processes in each component, since simple scaling was inapplicable. The modelled processes included the following: primary inlet vanes; aerodynamics in the primary combustor, and dilution section for rapid mixing; overall pressure drop loss, convective cooling of the primary section; atomization and vaporization and mixing in the premix section. Currently, the emission performance of the full-scale combustor is being optimized. This includes establishing the compromise necessary between long primary zone residence time (for the N_2 -forming reactions discussed in Figure D.2-5) and low NO_x emissions on the one hand, and the other hand, a combustor short enough to fit into present aircraft-derived (and possibly heavy-duty) gas turbines.

Coal liquids have not yet been tested in this program, but such tests are being planned. The volatility of SRC-II fuel oil will allow the premix section to function normally, but the approximately 0.8% to 1% nitrogen content of SRC-II fuel oil may produce excessive NO_x emissions. Soot emissions data are not reported and apparently were negligible with No. 2 fuel oil, but may appear in CDL tests. However, numerous measures would be available for soot elimination, including modifying the secondary zone for soot burnout, water injection, anti-soot additives, and possible modification of the burner mixing characteristics at the primary zone entry port.

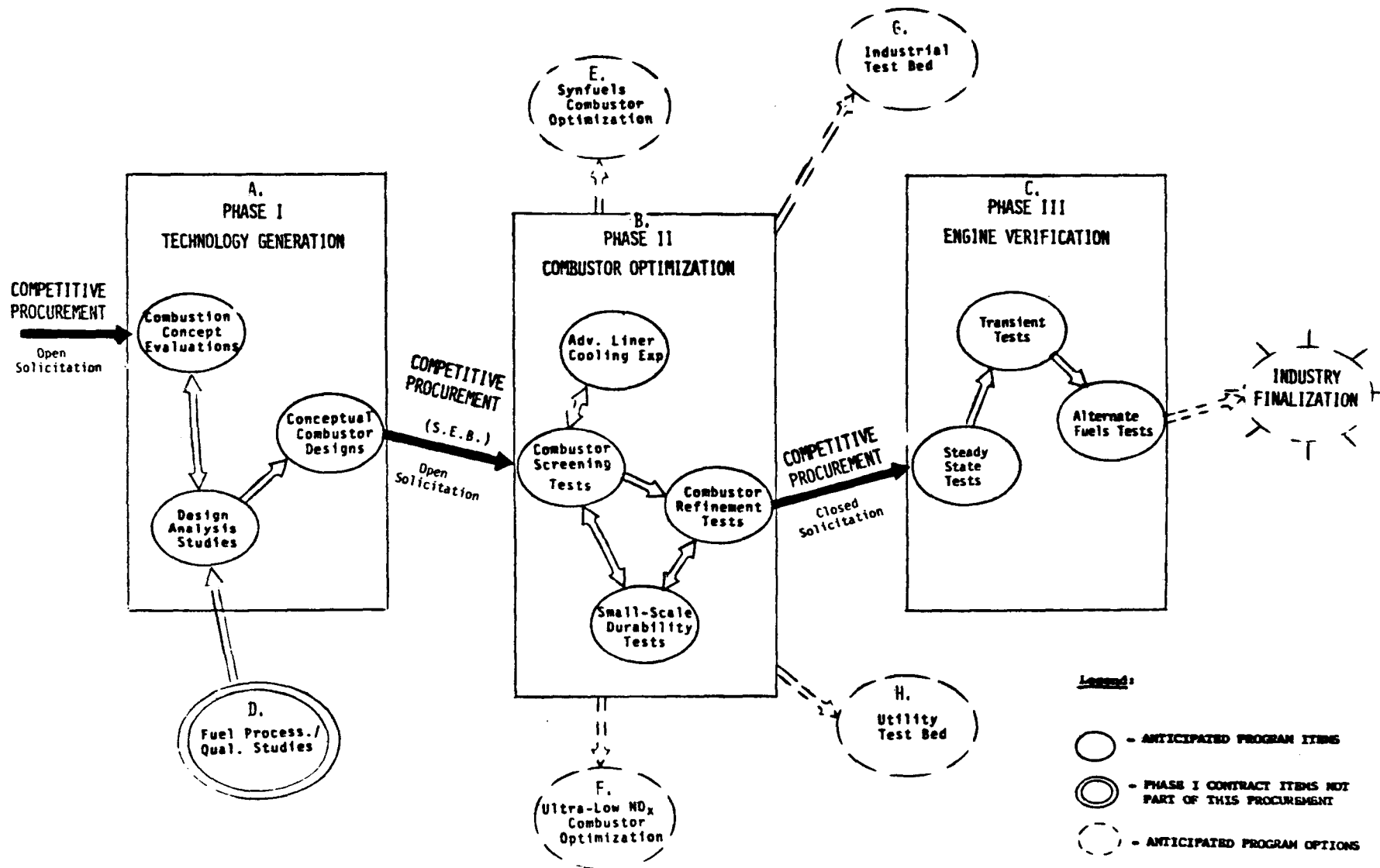
F.2.4 DOE Low NO_x Heavy Fuel Combustor Program

In November 1978, NASA-Lewis, technical manager of this program, published a Request for Proposals for development of a retrofittable combustor

to enable industrial and utility gas turbines to utilize "heavy" fuels, i.e., residual fuel oils and coal liquids.⁽⁶⁾ In the fuels scenario behind this RFP, stationary gas turbines would increasingly burn residual oil during the next few decades, but as this fuel became unavailable, there would be fuel-switching to coal liquids, whose production would be increasing. The design goals include no degradation of performance or efficiency; fuel flexibility; and emissions limits of 75 ppm NO_x and SAE Smoke number 20. The program is intended to respond to environmental needs as well as shifting petroleum utilization to reduce its importation. The three phases of the program are illustrated in Figure F.2.4-1 and resemble the structure of the aircraft combustor development programs referred to in Section C.3. Phase I is the only phase covered in this procurement; it contains bench-scale screening and testing of numerous concepts. Phase II contains detailed design and testing of component functions and durability in the best concepts from Phase I. Phase III is for verification, in a complete engine, of the performance of the combustor resulting from Phase II.

Three fuels are to be tested in the program: Fuel A, essentially No. 2 fuel oil; Fuel B, a "minimally processed" petroleum residual; and Fuel C, a synfuel or surrogate for it. The original plans were for a petroleum-derived surrogate for a synfuel, lacking supplies of the latter. Fortunately, SRC-II fuel oil became available in sufficient quantity to fill the contractors' needs, and it will be Fuel C, avoiding the uncertainties of testing with a surrogate. NASA-Lewis and Gulf plan for SRC-II middle distillate to be used in all initial work, followed by tests of full distillation range (or possibly heavy distillate) SRC-II fuel oil in selected concepts. The specifications in the RFP for Fuel C derived from those of oil and from products from coal liquefaction processes of several years ago, which had the viscosity and boiling range of residual fuel oils, and even higher nitrogen and aromatic contents. (An example is the H-coal "semi-clean" coal liquid discussed in the ECAS studies.) (See Section A for discussion of SRC-II fuel oil properties.) The lower viscosity and distillation range of SRC-II fuel oil, similar to those of No. 2 fuel oil, will make it easier to burn in gas turbines than the first-generation coal liquids. The residual

LOW NO_x HEAVY FUEL COMBUSTOR PROGRAM



F.2-10

Figure F.2.4-1 THREE PHASES OF DOE PROGRAM "LOW-NO_x HEAVY FUEL COMBUSTOR DEVELOPMENT" (FROM REF. F.2-6)

fuel oil (Fuel B) to be used in the program will also differ somewhat in its properties from those listed for Fuel B in the RFP; the former will be more typical of the residual oil market, of interest for gas turbine use.

The work breakdown structure of Phase I (this procurement) is shown in Figure F.2.4-2 from the RFP. Tasks IV, V, and VI, concerning the three fuels, each specify the following details of test performance in order to give proposals a common basis for evaluation: sets of combustor operating conditions; variables to be measured; blends of Fuel B or C with Fuel A ("Fuel Property Variation" subtasks), and nitrogen-doping with pyridine to specified levels. During the negotiation of contracts with each of the winning proposers, such test details would be expected to be modified to be appropriate to the respective combustor concepts and fuels, although a common denominator among contractors would have to be maintained for purposes of identification of superior concepts.

Fuel Quality. With the availability of a bona fide coal liquid, pyridine doping will probably not be needed; furthermore, pyridine doping is regarded by many to be a poor simulation of a CDL, the latter's nitrogen compounds being less volatile than pyridine. Furthermore, there would have been other deficiencies in the scheme suggested in the RFP for simulating a synfuel (by which we now mean a second-generation synfuel) by pyridine-doping a residual oil, the latter being too viscous and high-boiling, and containing less aromatics and more hydrogen than SRC-II fuel oil. The adequacy of using surrogates also depends strongly on the type of combustor concept being tested.

The "Fuel Property Variation Tests" appear to be a valuable component of the program, and could contribute greatly to Gulf's desires to match the liquefaction process and the resulting product properties to the needs of the combustion equipment, or, to optimize the entire fuel processing and utilization system. The latter is indeed the objective of the NASA-Lewis RFP "Fuel Quality/Processing Study."⁽⁷⁾

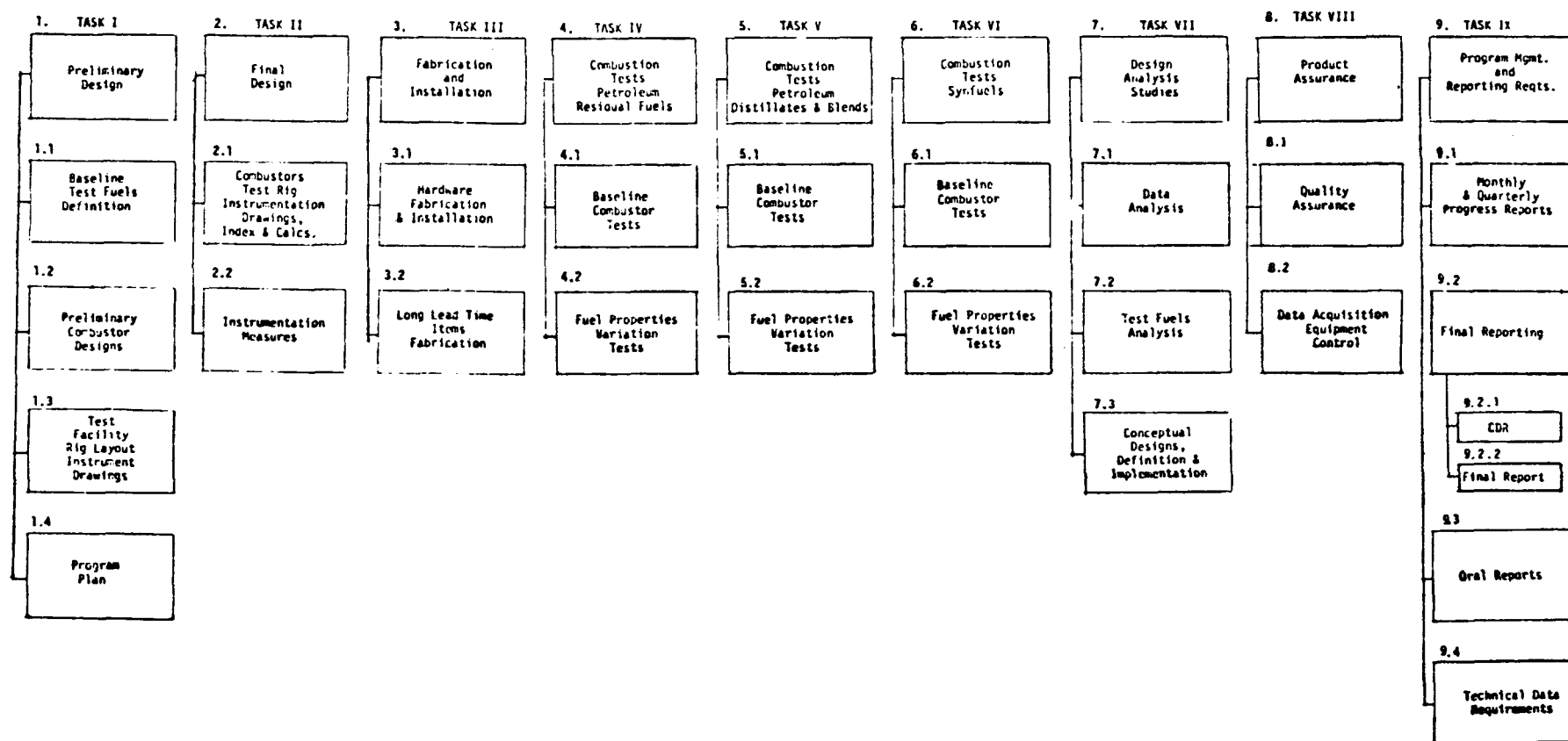


Figure F.2.4-2 PHASE I WORK BREAKDOWN STRUCTURE, DOE PROGRAM (FROM REF. F.2-6)

F.2.5 Other Combustor Innovations

In addition to the rich-lean concept, there have recently appeared other promising concepts for clean CDL combustion, which are described briefly in the following. Some of these approaches involve recirculation of some of the flame gas to the fuel injection area, an approach which would also benefit No. 6 oil burning. Heat removal by an external steam generator between the rich reactor and the quick quench zone is also proposed by several organizations for suppressing thermal-NO_x generation in the CO burnout reactor. Finally, honeycomb catalysts in the combustion chambers are being widely explored, and could have certain benefits in rich flame reactor sections. The basic chemistry of soot formation, burnout, and nitrogeneous fuel combustion is receiving vigorous research, which should lead to further improvements in combustor design approaches.

F.2 References

1. D. T. Beecher, et.al., Energy Conversion Alternatives Study, Westinghouse, Phase II - Final Report, NASA CR-134942, Vol. II (1976), p. 5-174.
2. B. A. Folsom, et al., "Advanced Combustion Concepts for Low Btu Gas Combustion," Third Stationary Source Combustion Symposium, Vol. II, p. 163 (1979).
3. B. A. Folsom, et al., "Evaluation of Combustor Design Concepts for Advanced Energy Conversion Systems," Second Stationary Source Symposium Vol. V, P. 145 (1977).
4. R. M. Pierce and S. W. Mosier, "Advanced Combustion Systems for Stationary Gas Turbine Engines," Second Stationary Source Combustion Symposium, New Orleans, August 29-September 1, 1977.
5. R. M. Pierce, et al., "Low NO_x Combustor Development for Stationary Gas Turbine Engines," Third Stationary Source Combustion Symposium, Vol. III, p. 137 (1979).
6. Request for Proposal No. 3-870802, "Low NO_x Heavy Fuel Combustor Concept Program," issued September 1, 1978.
7. Request for Proposal No. 3-150914Q, "Fuel Processing/Quality Study.

F.3 Post Combustion NO_x Removal

Post-combustion NO_x removal appears to be a very important and viable alternative to solving the fuel-NO_x problem of SRC-II, although low NO_x combustors would be less expensive. In this process, ammonia is injected into the turbine effluent as it passes through a honeycomb catalyst. This approach would be especially opportune in a combined cycle plant, where the catalyst would be installed in the heat recovery boiler. The operating and capital costs have been evaluated by a turbine manufacturer to be modest increments, and EPRI is supporting some pilot-scale verification of this approach.

G. HIGH TEMPERATURE TURBINE TECHNOLOGY AND ADVANCED CYCLES

G.1 EFFICIENCY*

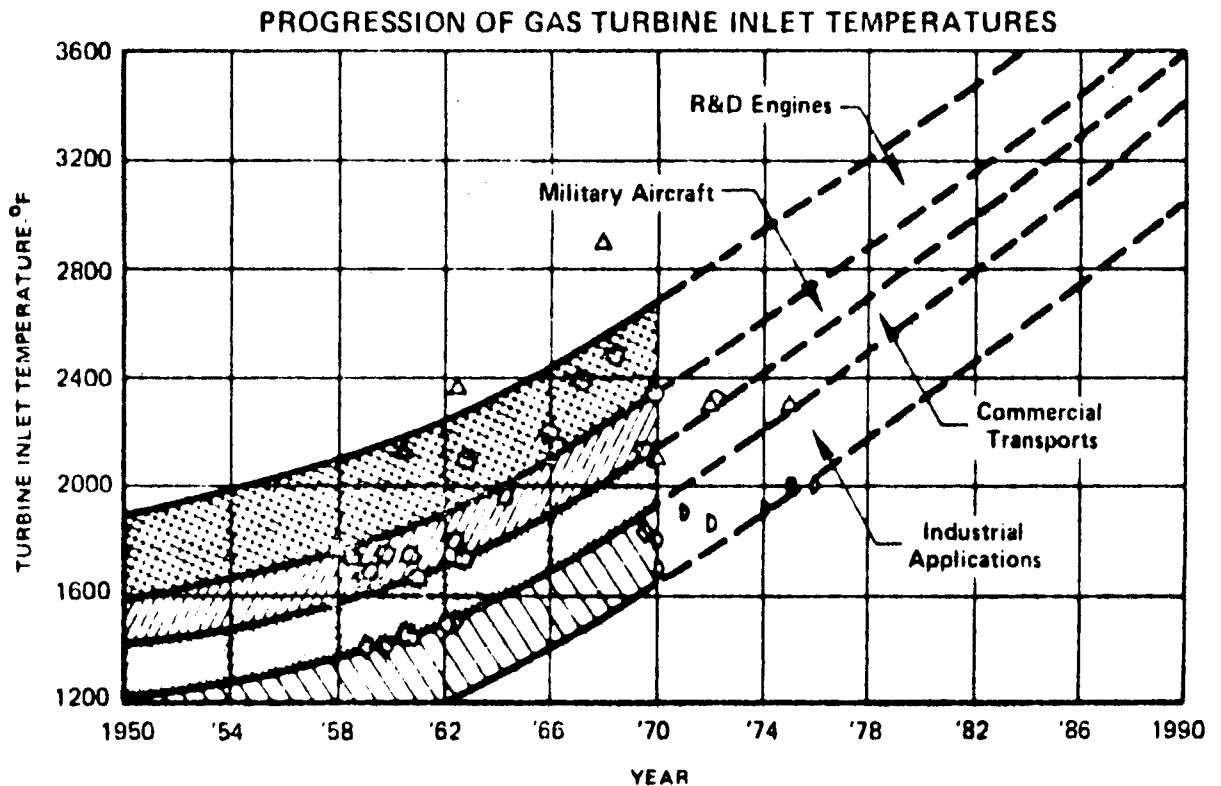
In many energy conversion schemes, gas turbines are included as the prime mover, the unit which converts heat into shaft horsepower. For the success of these plans, it is important to recognize that maintenance costs and performance of gas turbines are greatly influenced by the quality of the fuel used.

Like any heat engine, the gas turbine shows improved efficiency when the working fluid (combustion gas) enters the turbine at the highest possible temperature. Gas turbine output may increase 20% with an increase of 100°F in combustion temperature.

Figure G.1-1 shows the trend in gas turbine inlet temperatures, in the effort to improve thermal efficiency. At these indicated industrial operating temperatures, the simple cycle gas turbine rises to about 35-40% thermal efficiency, or equivalent to the best fossil steam units of today. Moreover, combined cycle gas turbine units have been predicted to reach efficiency levels of 50-55% and thereby surpass all other known commercial modes of power.

Other factors increase with temperature also, notably the corrosion of turbine blades and "nozzles" (stationary guide vanes). Turbine efficiency is related to gas temperature, but corrosion is related to metal temperature. Therefore, new designs include hollow or porous blades with arrangements for air or water to circulate or "transpire" through the blades and cool them by 150°F for example. Otherwise, gas turbine blades operate in the working fluid with no protective cooling comparable to the steam in boiler tubes or the jacket water in diesel engines.

* (Contributed to R. C. Amero and P. G. Cooper, GS&T, Chemicals and Minerals Division, Harnmarville.)



Source: "Utility Applications For Advanced Gas Turbines to Eliminate Thermal Pollution", F.N. Biancardi, G.T. Peters ASME 70-WA/GT-9

**EFFECT OF FUEL ON GAS TURBINE
OPERATION & OUTAGE**

Maintenance Requirement	Outage Hours	INTERVAL (HRS.)		
		Natural Gas	#2 Dist.	#6 Residual
Fuel nozzle cleaning and Ash removal by water wash	8	Not Required	4,000 to 8,000	750
Combustion inspection	24	30,000	10,000 to 14,000	2,000 to 4,000
Hot gas path inspection	80	30,000	10,000 to 14,000	2,000 to 4,000
Major inspection	160	30,000 to 40,000	20,000 to 24,000	16,000 to 24,000

BASIS: 1) All values typical for a MS-5001 gas turbine
 2) No repair time for components - replacement only
 3) Necessary parts and tools at site
 4) Ash removal is not required with operation on #2 Dist. fuel.

AVERAGE TOTAL MAINTENANCE COST* MS-5001 GAS TURBINE	
Fuel	Maintenance Cost Mils/KW-HR
Natural Gas	0.30
#2 Distillate Oil	0.43
Typical crude oil	0.67
#6 Residual oil	1.08

*Maintenance costs are total costs including parts and repairs. Assumes base load operation 8,400 hrs./year at ISO rating.

* Wilson, W. B. and Hefner, W. J., "The Role of Gas and Steam Turbines to Reduce Industrial Plant Energy Costs", ASME Industrial Power Conference, Louisville, Ky., May 21-23, 1973.

**Figure G.1-1 TURBINE INLET TEMPERATURES,
AND FUEL-RELATED CORROSION COST EFFECTS**

Gas turbines have been designed to operate on various fuels, but the operating and maintenance costs vary with the fuel quality. No. 6 fuel oil, having a higher carbon-hydrogen ratio than No. 2 fuel oil, burns with a more radiant flame and causes more heat damage and soot formation in the combustor. This damage is separate from the high temperature ash corrosion discussed below. It is also separate from the erosive action of abrasive dust, which has defeated all attempts to burn powdered coal in a practical gas turbine. Figures G.1-1 indicates that outages and maintenance costs may be two or three times greater with viscous, black, No. 6 fuel oil than with No. 2 fuel oil of diesel fuel or home heating oil quality.

An important objective of test work on coal-derived fuels is to find their proper position in the above tables. SRC-II middle distillate, for example, has viscosity and volatility equivalent to No. 2 fuel oil, but a higher carbon-hydrogen ratio than No. 6 fuel oil. Therefore, fuel nozzle cleaning and ash removal experience might parallel that of No. 2 fuel, but combustion and hot gas path inspections might be more similar to that for No. 2 fuel.

By way of explanation, the simple or open cycle gas turbine can be visualized as two fans (or rotors) on the same shaft. Fuel is burned in the air stream blowing out of the first rotor. The heat of combustion expands each unit volume of air to 4 or 5 volumes of combustion gas to drive the second rotor or power turbine.

The volume of fuel burned must be limited to avoid overheating the power turbine. Four or five volumes of air might be moved through the machine for every volume required for combustion. A 20,000 HP gas turbine might typically have a power section (second rotor) that generates 100,000 HP and a compressor section (first rotor) that consumes 80,000 HP. Gas turbines that tolerate extremely high temperatures will provide greater output as well as higher efficiency from a given size of machine.

These large volumes of gas and air are exhausted from the power turbine at temperatures on the order of 1000°F. They can be used to generate

steam in a waste heat boiler, either with or without the combustion of additional fuel in this air-rich exhaust stream. This, of course, can be a combined cycle operation, with the gas turbine generating power in its own right, and providing by-product heat which is captured in a steam boiler-steam turbine installation to generate additional power.

An alternate way to utilize gas turbine exhaust heat is for warming up the air stream from the turbine compressor, thus reducing the amount of fuel required for this task. The required heat exchangers introduce a penalty of pressure drop and power loss as well as increased complexity, weight, and first cost. Sometimes when more power output is required from a simple, open-cycle gas turbine, additional fuel is injected and water is injected at the same time. The water flashes to steam, lowering the temperature and providing additional gas or vapor volume to drive the turbine. Water injection requires pure--and therefore costly--water to avoid high temperature deposits and corrosion problems discussed later in the text. Water injection also compromises the advantage of gas turbines over steam turbines in deserts and other water-scarce locations.

Closed-cycle gas turbines have also been used, in which air (or a selected gas such as helium) from the turbine compressor is heated indirectly in a boiler-like device. Air or gas exhausted from the power turbine is cooled and reintroduced to the compressor. These turbines permit the use of cleaner, more thermodynamically efficient gases in the turbine but they impose many of the complications of operating a steam plant on top of a gas turbine cycle.

In the case of a recuperative air preheating, thermal- NO_x reduction was proposed via flame temperature reduction through water injection or catalysts. Rich-lean combustors would also achieve this, while also permitting the use of CDL in such a plant.

In a report prepared by Bechtel Power Corporation for the Electric Power Research Institute,⁽²⁾ it is stated that "the present generation industrial utility turbines operate at a 10:1 compression ratio and a 2000°F

turbine inlet temperature." The heat rate corresponding to these conditions is about 8200 Btu/kWh. In a discussion of projected future technology, Bechtel points out the desirability of going to a higher inlet turbine temperature and higher compression ratio. Increasing the turbine inlet temperature to about 2400°F lowers the turbine heat rate. Further increases in temperature have little effect on heat rate but increase the capacity of the machine, thereby, lowering capital costs. Increasing the turbine compression ratio also lowers the heat rate and, for temperatures at 2400°F or above, improvements are still being obtained up to and beyond the 25:1 compression ratio point. These effects are illustrated in Figures G.2-2 and G.2-3 taken from the Bechtel study. Studies of advanced combustion turbine technology assume a turbine inlet temperature of 3000° and a compression ratio of 16:1.⁽³⁾ The Bechtel study projected a heat rate of 6400 Btu/kWh for 1990, assuming a 3000°F inlet temperature (Figure G.1-4).

It is hoped that evaporative water cooling of the turbine components will allow this high inlet temperature to be achieved.⁽³⁾ Such cooling could keep the surface temperature of the components as low as 1000°F, substantially lessening the rate of hot corrosion and possibly eliminating it.⁴ This will allow the use of a low-cost alloy for the core of the turbine buckets with only a cladding of IN-671 alloy required. Therefore, going to the higher capacity achieved by the higher temperature and compression ratio tends to lower the capital cost of these machines according to projections given (Figure G.1-4, and Reference 3).

The projected improvements in heat rate and the relatively low, possibly decreasing projected capital cost for gas combustion turbines in combined cycle units will make this type of unit very attractive economically. While a relatively expensive liquid fuel will be required, the low heat rate offsets this to a large degree and the low capital cost provides another substantial offset.

G.1 REFERENCES

- 1a. F. N. Biancardi, G. T. Peters, "Utility Applications for Advanced Gas Turbines to Eliminate Thermal Pollution," ASME Paper No. 70-WA/GT-9.

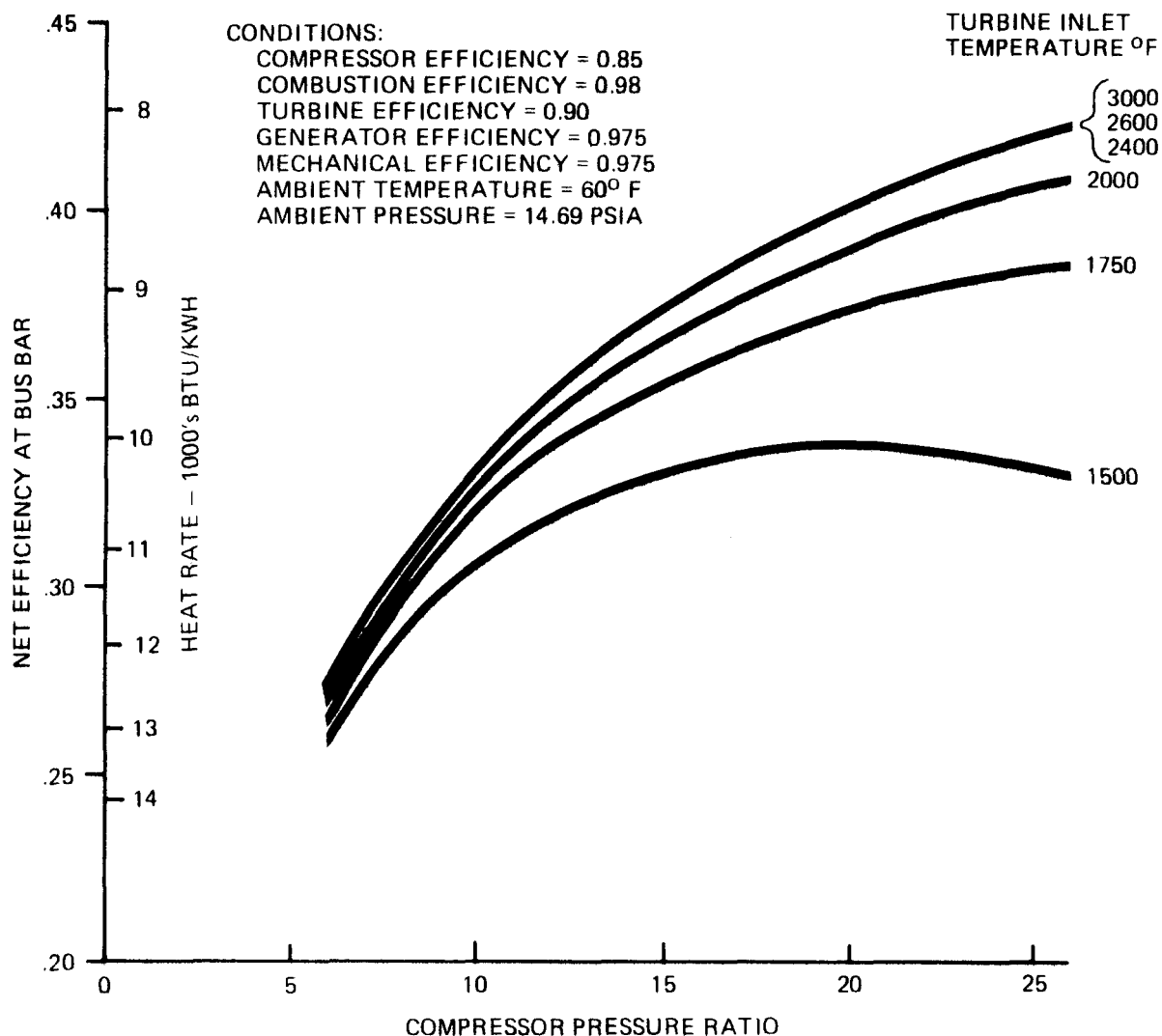


Figure G.1-2 SIMPLE OPEN-CYCLE GAS TURBINE NET EFFICIENCY VARIATION WITH COMPRESSOR PRESSURE RATIO FOR VARIOUS TURBINE INLET TEMPERATURES (FROM REF. G-3)

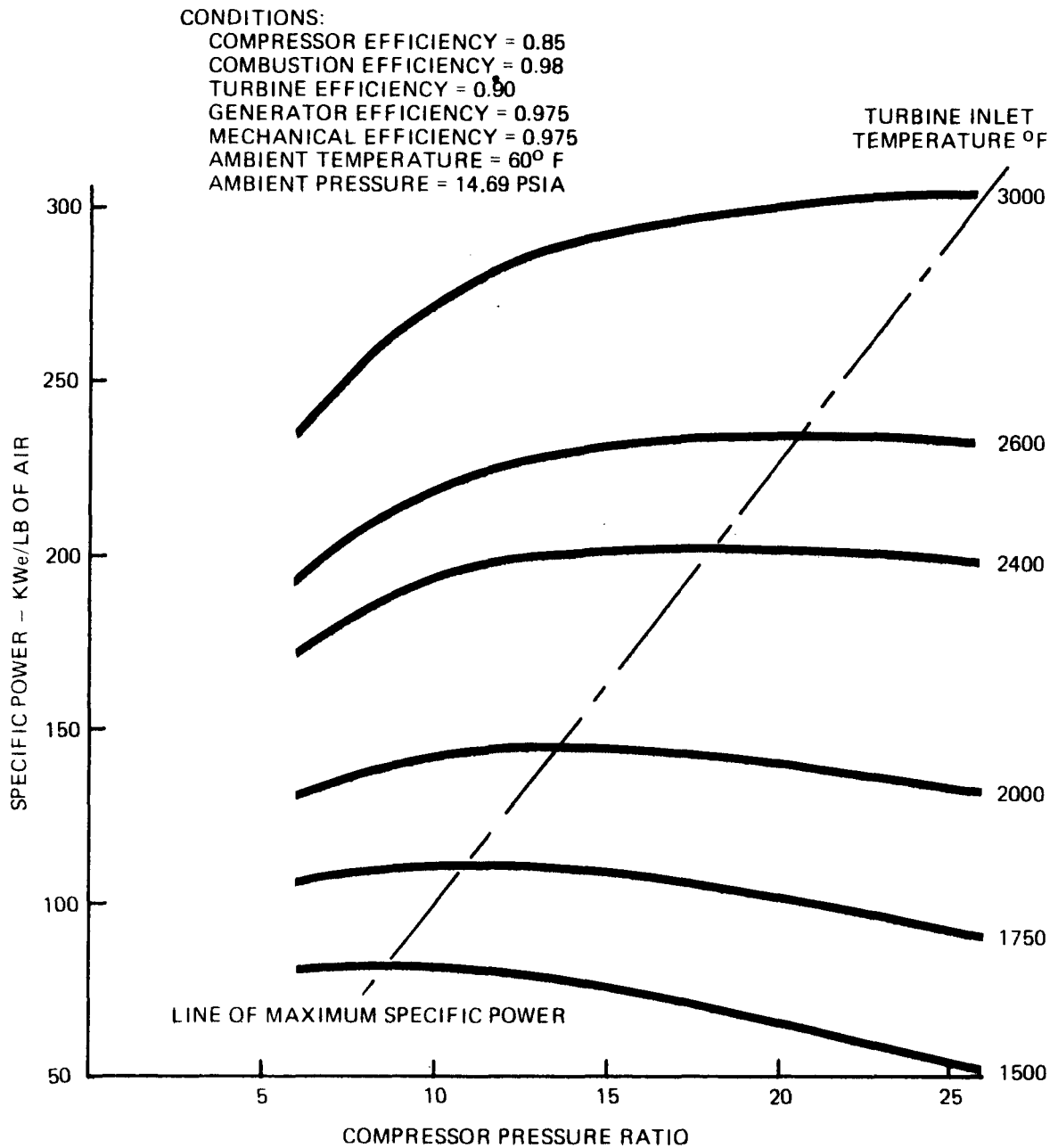


**Figure G.1-3 SIMPLE OPEN-CYCLE GAS TURBINE
 SPECIFIC POWER VARIATION WITH COMPRESSOR PRESSURE
 RATIO FOR VARIOUS TURBINE INLET TEMPERATURES (FROM REF. G-3)**

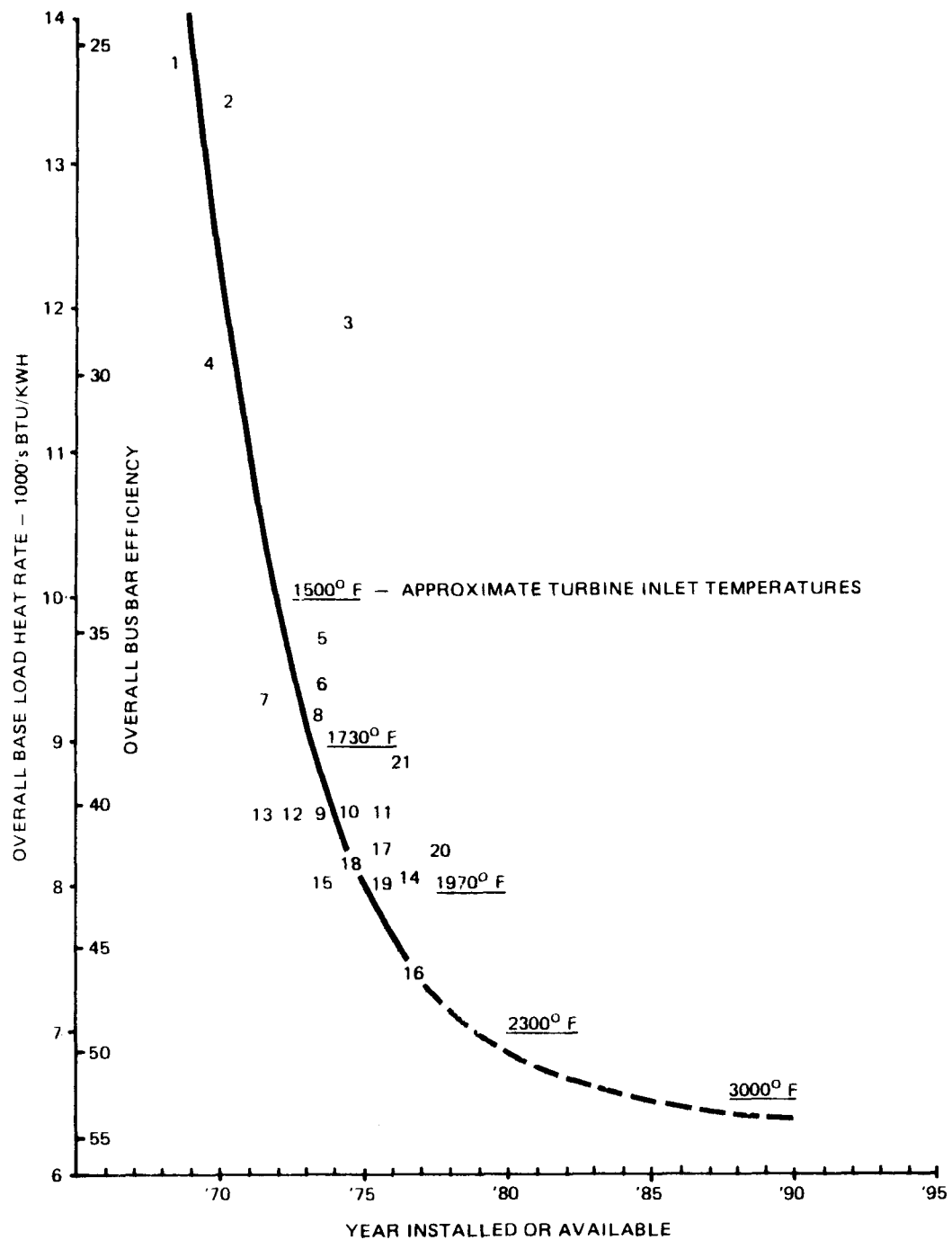


Figure G.1-4 TREND OF COMBINED-CYCLE HEAT RATES (FROM REF. G-3)

- 1b. W. B. Wilson and W. J. Hefner, "The Role of Gas and Steam Turbines to Reduce Industrial Plant Energy Costs," ASME Industrial Power Conf., Louisville, KY, May 21-23, 1973.
- 2 Bechtel Power Corporation, "Combined Cycle Power Plant Capital Cost Estimates," EPRI Report AF-620, December 1977.
- 3 General Electric Company, "Comparative Study and Evaluation of Advanced Cycle System," EPRI Report AF-664, Volume 2, Part 1, February 1978.
- 4 "Overall Plant Design Description of Coal-Derived Liquid Electric Power Plant," Dept. of Energy Report No. FE-1806-24, July 1977 (General Electric Company).

G.2 EMISSIONS AND FUELS

Advanced cycles with increased thermal efficiency are expected to permit the use of more costly fuels which will be the case for SRC-II fuel oil and conventional fuel in the mid-1980's.⁽¹⁾ Advanced cycle plants also present some unique opportunities to achieve CDL combustion cleanly. When the combustion process is separated in two or three stages, there is more flexibility the choice of the conditions in each state (residence time, heat removal by external steam cycle, fuel composition, etc) when the system is combined cycle rather than simple cycle. In an EPA project, EER has used a chemical kinetics computer model for the 100 reactions in an ammonia-contaminated low-Btu gas flame to predict the fuel-NO_x emissions from various cycle component conditions. Figure G.2-1 is an example of the fuel-NO_x reductions achieved in going to case (b) rich-lean, and then to case (c), rich-lean with heat removal from the rich stage, made possible by a steam cycle.⁽²⁾ The following excerpt from Reference G.2-2, reporting a combustion analysis of coal gasifier-combined cycle system, summarizes other NO_x-reducing conditions made possible by the combined cycle units.

A simplified cycle analysis program has been used to assess the tolerance of COGAS cycle performance to variations in combustor design. The types of combustor considered in the analysis were:

- an adiabatic gas generator,
- a reheat combustor
- a nonadiabatic gas generator raising steam, and
- a duct heater for supplementary firing the waste heat boiler.

The study indicates that COGAS cycle performance is not strongly dependent upon such design parameters as:

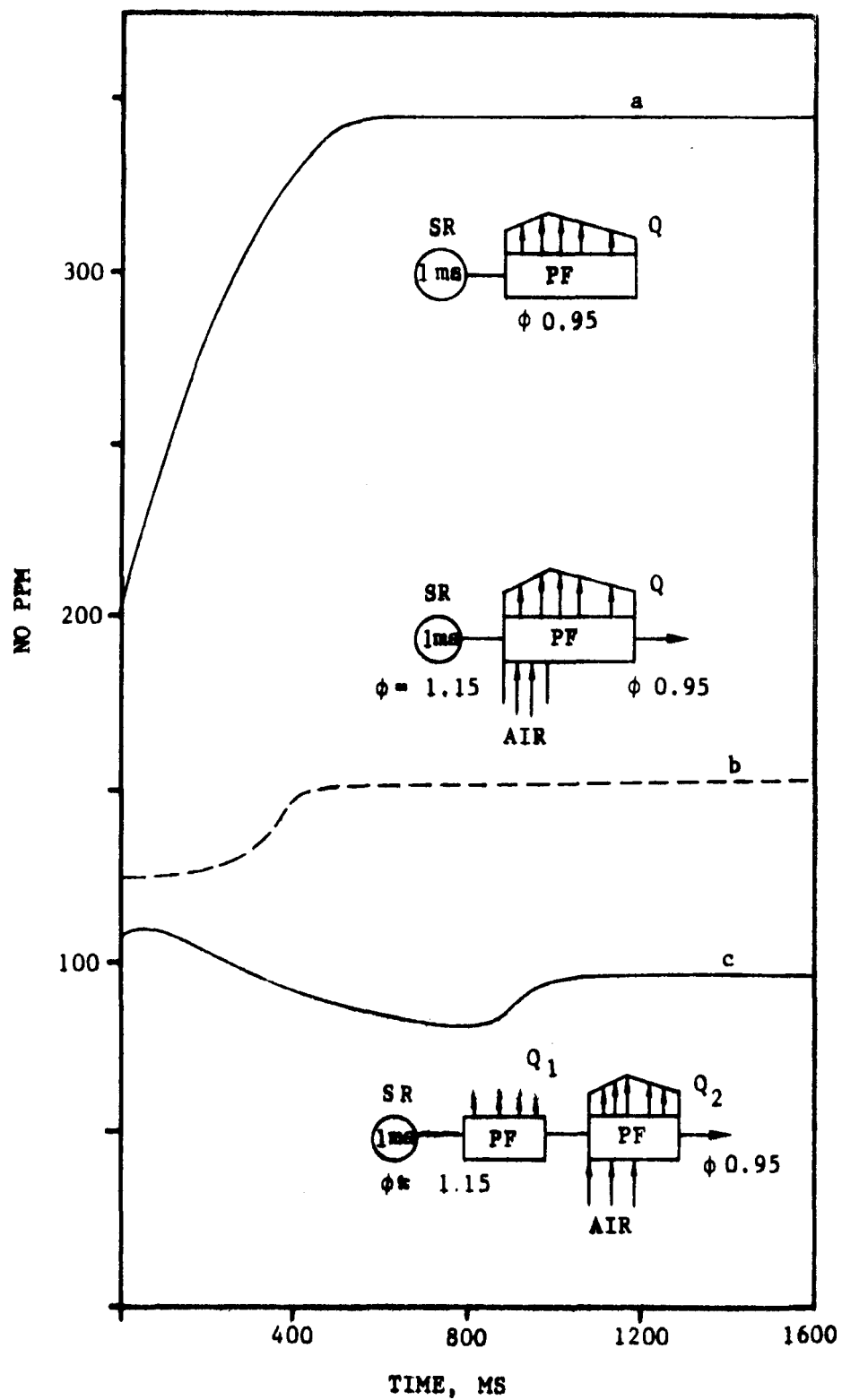


Figure G.2-1 ADVANCED LOW-EMISSION CYCLES (FROM REF. B-2)

- combustor pressure drop,
- combustor pressure,
- combustor stoichiometry (corresponds to the amount of steam raised in the supercharged boiler, the degree of reheat, or the fraction of total heat released in the duct heater).

Indeed, cycle performance can be enhanced by the use of a reheat combustor or a nonadiabatic gas generator which raises steam. The combined cycle performance is tolerant of these combustor parameters because heat lost from the gas turbine is not completely lost to the overall cycle since it can be used to raise steam in the bottoming cycle which is one of the inherent advantages of the COGAS cycle.

Low Btu coal gas will probably contain ammonia, some of which will be converted to NO_x during combustion. The tolerance of the overall cycle performance to variation in combustor design parameters allows several combustion modification techniques to be explored to limit NO_x emissions from advanced COGAS power plants to minimal levels. These techniques include:

- staged main gas generator with temperature control via steam generation;
- staged reheat combustor for minimum fuel nitrogen conversion and incineration of NO_x formed in the main combustor; and
- staged or diffusion flame duct burners for minimization of fuel nitrogen combustion and incineration of NO_x formed in the main combustor.

Such an approach may also be applicable to SRC-II fuel oil fuel- NO_x research, although EER has shown that when hydrocarbon fuel reactions are involved, instead of low-Btu gas, the chemistry modeling problem exceeded their capabilities.

The simpler but related question has also arisen about possible increases in thermal- NO_x when turbine inlet temperatures are increased. Increased turbine inlet temperature would be achieved by increased fuel firing

rates while maintaining the same air flow rate. Although the primary flame zone fuel-air ratio and temperature might be unchanged, its size and residence time would increase, increasing thermal- NO_x emissions. However, this thermal NO_x problem, caused by high turbine temperatures, could be eliminated by the same combustor/cycle modifications adapted to reduce fuel- NO_x , namely, a rich-lean combustor, interstage cooling, etc., in which the primary flame zone would be too cool to form thermal- NO_x .

G.2 REFERENCES

1. R. P. Shah and J. C. Corman, "Open-Cycle Gas Turbine/Steam Turbine Combined Cycle With Synthetic Fuels from Coal," ASME Meeting, December 1977, Paper 77-WA/Ener-9.
2. B. A. Folsom, et al., "Evaluation of Combustor Design Concepts for Advanced Energy Conversion Systems," Second Stationary Source Symposium Vol. V, p. 145 (1977).

APPENDIX A

A more complete outline of the EPA Fundamental Combustion Research Program, mentioned in Section D.2.5, is given in the following excerpts from papers presented by researchers in that program at the Third Stationary Source Combustion Symposium, March 5-8, 1979. The reader is referred to the Proceedings (EPA-600/7-79-050a-e). There are three main parts of the FCR program:

1. the chemical kinetics in the gas phase (Appendix A.1),
2. droplet and particle vaporization and combustion (Appendix A.2),
3. numerical modeling of real flames, including chemical reactions, transport processes and large-scale aerodynamics (Appendix A.3).

Although this work is restricted, concerns only atmospheric-pressure flames, and some of it involves coal combustion, it also contains much work of potential use in gas turbine combustor design efforts.

APPENDIX A.1

NO_x ABATEMENT IN FOSSIL FUEL COMBUSTION.

Chemical Kinetic Considerations

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SECTION 1

INTRODUCTION

The Fundamental Combustion Research (FCR) Program of the Environmental Protection Agency is aimed at the establishment of strategies for reducing NO_x production through combustion process modification. Complete characterization of the factors affecting NO_x production must, by nature of the combustion process itself, include consideration of such diverse processes as homogeneous gas phase reactions, heterogeneous gas-solid reactions, heat transfer, and aerodynamics. We report here on current progress under the FCR program in the elucidation of the homogeneous gas-phase chemical kinetic mechanism of NO_x formation in fossil-fuel combustion.

The strategy adopted in the FCR program is discussed in this manuscript. Illustrations of selected results will be presented and updated at the "Third Symposium on Stationary Source Combustion".

With the depletion of natural gas and petroleum reserves (which are lacking or low in nitrogen content - and, hence, relatively low in the emission of NO_x formed from the nitrogen bound in the fuel), and the increasing substitution of coal, coal-derived liquids, residual fuel-oils, and shale oils (which are high in nitrogen content), NO_x emissions, which are already unacceptably high in several urban areas, are bound to increase unless an abatement strategy is developed and implemented. Insofar as the mechanism by which fuel-bound nitrogen is converted to NO_x is complex, and insofar as early attempts^{1,2} to reduce NO_x emissions by empirical adjustment of combustion parameters (e.g., temperature, fuel/air ratio, degree of mixedness, etc.) utilizing conventional combustors have achieved only a fraction of their full potential, a more fundamental elucidation of the NO_x formation mechanism has become essential in order to achieve the desired engineering goal of modifying the combustion process in such a way as to favor the conversion of fuel-bound nitrogen to the desired (combustion) end

product, N_2 , rather than to the undesired product, NO.

As such, the organization of the FCR program has defined the following approach to achieving this end:

- a) Identification of chemical reaction sets with an emphasis on fuel nitrogen conversion,
- b) Validation of these reaction sets by modeling a wide range of pertinent experimental results, and concomitant computational screening to identify the minimum reaction subsets adequate for prediction of NO_x emission levels,
- c) Through these processes, identification of critical gaps in the existing data base necessary for prediction of NO_x levels,
- and d) Application of the fuel-N reaction set to the computation of NO_x emission levels from systems of practical interest, and utilization of predictive capabilities for development of NO_x abatement strategies.

In order to clarify the results, initial chemical kinetic studies have concentrated on aerodynamically clean systems in which interpretation of results are not complicated by mixing effects. A parallel effort under the FCR program is the characterization of the aerodynamics and development of methodologies for coupling the kinetics with the flow field in real, aerodynamically complex combustors.

SECTION III

ESTABLISHMENT OF A KINETIC MECHANISM FOR NO_x FORMATION AND DESTRUCTION FROM FUEL-BOUND NITROGEN.

As indicated above, development of an NO_x control strategy rests heavily upon optimizing the conversion of volatile fuel-nitrogen species to N₂. Insofar as the residence times in typical combustors are far too short to achieve chemical equilibrium in the burnt gases, it is necessary to consider the time dependent flow of nitrogenous species through the many sequential and competing reaction pathways leading to NO_x and N₂ formation, in order to develop a methodology for maximizing or minimizing certain product yields - i.e., both the elementary reaction pathways and reaction rates must be considered.

Although at this time, many details of the NO_x formation and destruction mechanism are not fully understood, a considerable literature^{8,12} has appeared in recent years, in which the predominant nitrogenous species appearing as intermediates or products of fuel-nitrogen conversion have been identified, and from which a rough reaction mechanism^{13,14,15} may be deduced.

Having identified an adequate species set, a "complete" reaction mechanism has been constructed¹⁵ by permitting all species to inter-react via elementary reactions. Rate constants were selected from a search of the experimental literature where available, or from tabulated estimates (made, generally, by the method of Johnston¹⁶). The fuel-nitrogen reaction set is shown in Table 1. Conspicuously absent are several reactions, for example, $\text{NH}(\text{NH}_2) + \text{NO} \rightarrow \text{N}_2 + \text{OH}(\text{H}_2\text{O})$, often invoked in NO mechanisms. Although of

questionable "elementary" nature, for completeness, they have been included in modelling efforts.

Current efforts under the FCR program are directed to extending the kinetic mechanisms to higher hydrocarbons. Unfortunately, there is a dearth of elementary mechanistic and rate data for hydrocarbons representative of petroleum, coal, or shale derived fuels. Global modelling²⁷ of hydrocarbon combustion (by either finite or infinite rate formation of CO and H₂), has proven to be useful for purposes of estimation of heat release rates, but may seriously mis-predict intermediate free radical levels²⁸ which are crucial to the proper computation of NO_x emissions, particularly under fuel rich conditions. Current semi-global developments²⁹ are more promising in that they include some higher intermediates between the initial hydrocarbon and CO. The approach under development is the extension of the semi-global method based upon the observation³⁰ that several relatively small hydrocarbon species appear as (pyrolysis) intermediates in the combustion of higher hydrocarbons. The initial species set under consideration includes C₂H₂ (a major intermediate of aromatic systems), C₂H₄, CH₄, and CO/H₂. The combustion mechanisms of C₂H₂ and C₂H₄ have been recently studied³¹ and are under continuing investigation.

APPENDIX A.2

HETEROGENEOUS PROCESSES INVOLVED IN
THE CONTROL OF NITROGEN OXIDE FORMATION
IN FOSSIL FUEL FLAMES

By:

M. P. Heap and T. J. Tyson
Energy and Environmental Research Corporation

Professor A. F. Sarofim
Massachusetts Institute of Technology

Professor J. O. L. Wendt
University of Arizona

SECTION 1

INTRODUCTION

The general philosophy and overall objectives of the FCR* program have been described elsewhere (1). This program involves the planning and direction of several projects whose overall goal is to provide the EPA/CRB with the necessary understanding of the fundamental behavior of combustion systems to develop control technology which will minimize the emission of both NO_x and associated pollutants from stationary sources. The program is focused on well-defined priority target areas, and the research effort is directed towards providing engineering solutions to specific problems within a time frame consistent with the technology development programs. Neither the time nor resources are limitless, and the program has been planned to provide products which can be realized in both the near and far-term. Information is being generated now which can either be directly transferred to "technology development" programs, or used in the development of empirical engineering models to aid the designer of low NO_x combustion systems. Projects with a long-term payoff, which are in the minority, are associated with the development of numerical models capable of describing pollutant formation in complex combustors.

The FCR program is primarily concerned with the basic mechanisms associated with the formation and destruction of nitrogen oxides in fossil fuel flames. However, some effort has been initiated relating to the formation of soot and fine particulate matter, as well as the mechanisms of sorbent extraction of SO_2 in flames. Reviewing the sources of anthropogenic NO_x emissions, it can be seen that approximately 50 percent can be attributed to stationary combustion; and of this, 50 percent greater than 55 percent is associated with the combustion of nitrogen-containing fuels which are mainly

*Fundamental Combustion Research Applied to Pollution Control

coal or oil. Thus, the primary initial objective was to focus upon pollutant production in one-atmosphere turbulent diffusion flames burning pulverized coal or residual oil and radiating to cold walls. Since the increased use of coal is one of the nation's methods of achieving energy independence, this initial objective has considerable relevance because any increase in the use of coal or coal-derived fuels without the application of necessary control technology will probably result in an increase in NO_x emissions.

A key element of the FCR program is the establishment of the lower bounds set on NO_x emissions under various limiting situations and constraints. It is important when assessing control strategies to know that for a particular set of process requirements that there exists a limit on the level of control achievable by combustion modifications and set by these requirements. Thus, the value of studies leading to the establishment of lower bounds is not only that they provide a yardstick by which to measure the effectiveness of other control schemes, but they also provide strong guidance in the development of advanced control techniques.

The generation of nitrogen oxides during the combustion of pulverized coal and residual oil in turbulent diffusion flames involves the complex interaction of several physical and chemical phenomena. Transport processes involving heat or mass, gas phase kinetics, and heterogeneous processes are all involved in the formation and destruction of NO in these flames. This paper describes projects included in the FCR program, both ongoing and planned for the future, which can be classified as heterogeneous processes. Projects associated with mass transfer phenomena and homogeneous gas phase kinetics are discussed in two other papers.

SECTION 3

HETEROGENEOUS PROCESSES — AN FCR PROGRAM ELEMENT

Figure 3 presents a schematic showing the relationship between the heterogeneous processes program element and the other FCR program elements:

- Homogeneous Kinetics
- Transport Processes
- Measurement System Assessment/Development
- Numerical Model Development

The various projects under this program element can be classified under three major headings which are:

- Thermal Decomposition
- Gas Solid Reactions
- Reactor Studies

Figure 3 shows the Principle Investigators associated with the projects in each of the areas.

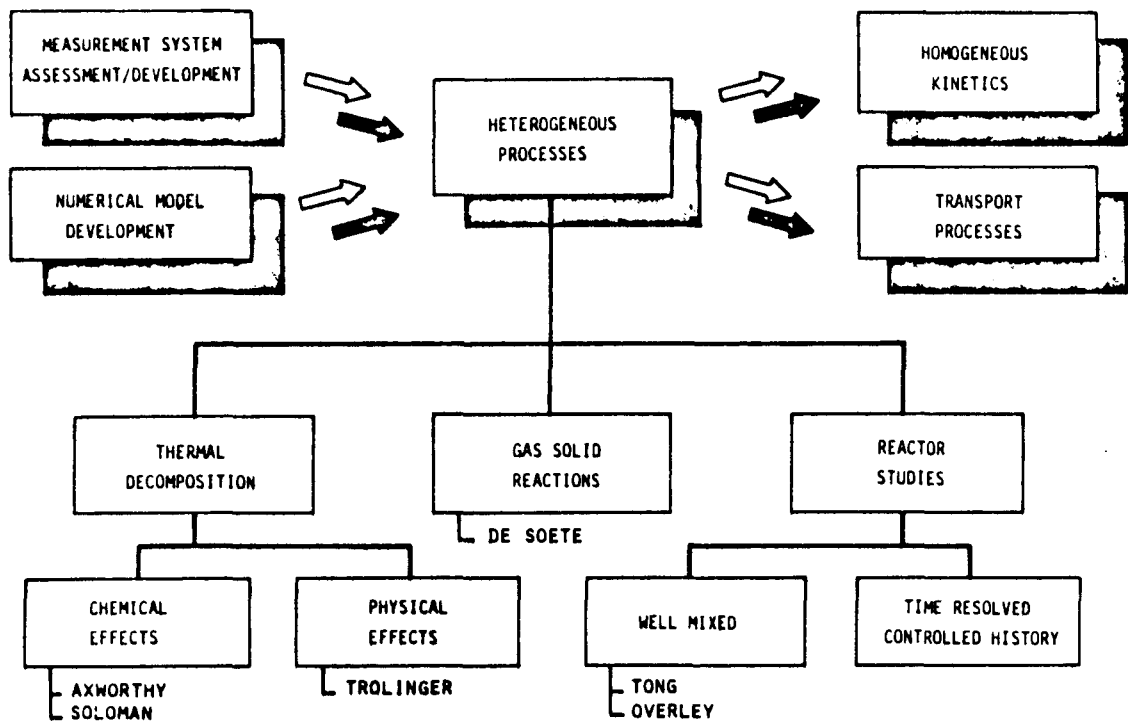


Figure 3. Heterogeneous Processes — Project Organization

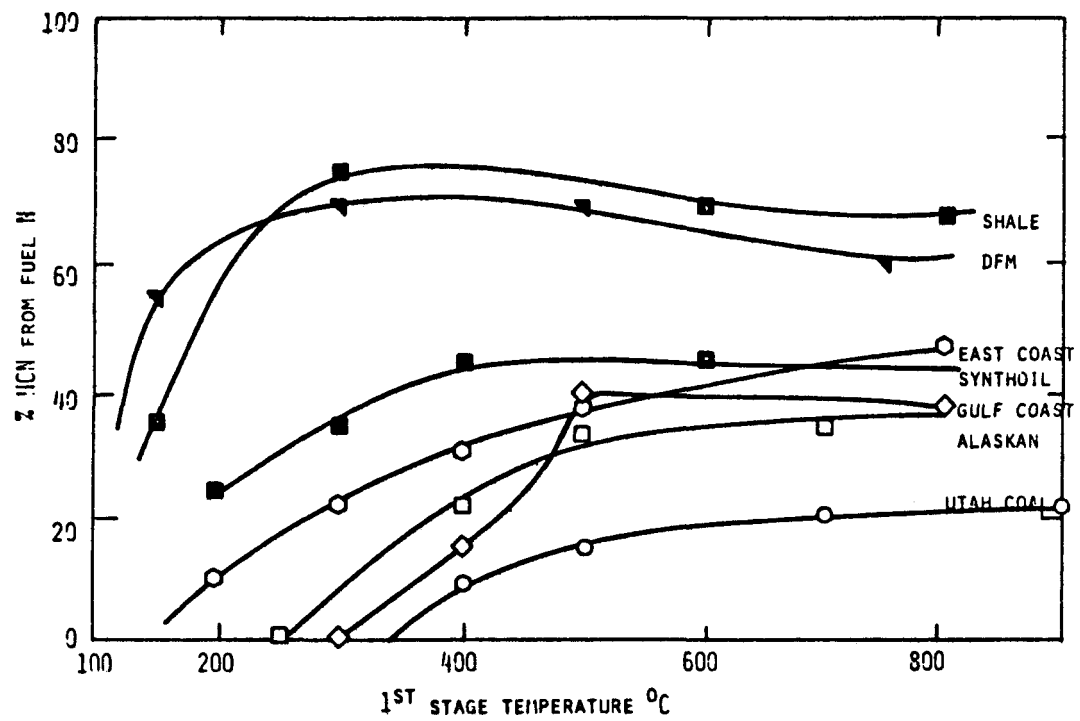


Figure 4. Composite Plot Showing the Volatility of Convertible Fuel Nitrogen for Several Fuels as Measured by Axworthy

APPENDIX A.3

TRANSPORT PROCESSES AND NUMERICAL MODEL DEVELOPMENT — FCR PROGRAM ELEMENTS

By:

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SECTION 1

INTRODUCTION

The FCR program has two major objectives. These are:

- To provide guidance to development programs concerned with the application of low NO_x combustion systems to stationary sources.
- To gain insight into the fundamental phenomena controlling the production of NO_x in these devices in order to define potential advanced control techniques.

One major aspect of the program involves the presentation of basic information in such a way as to be of the most benefit to the development engineer. This information may be transferred directly or in the form of a model which can be used as a design tool, thereby cutting the cost and delay time associated with empirical development programs.

Two fuels, coal and residual oils, when burned in large turbulent diffusion flames confined by relatively cold walls produce the major fraction of NO_x emissions from stationary combustion sources. Two previous papers have discussed the dominant homogeneous and heterogeneous kinetic processes associated with the production of nitric oxide in these combustion systems. However, these papers did not consider the detailed physics involved in the turbulent mixing process associated with fuel/air contacting in real combustors. This paper discusses two other elements of the FCR program; those concerned with numerical model development, and transport processes which serve the key function of synthesizing information generated in the other program elements in order to provide an understanding of the basic mechanisms limiting NO_x formation in practical combustion devices.

In the FCR program elements concerned with homogeneous kinetics and heterogeneous processes the dominant physical and chemical mechanisms pertinent to NO_x production during the combustion of clouds of oil droplets or

coal particles will be defined. Several experiments have been planned which, in conjunction with the development of numerical models, will provide a predictive capability capable of describing NO_x production in simple reactor systems. Two of these programs are concerned with solid and liquid fuels, and were described in an earlier paper. Two other experimental programs, one being carried out by Myerson at Exxon and the other by Clark at EER, are directed towards the generation of data which will allow the verification of an adequate kinetic mechanism capable of describing NO_x production from simple fuel nitrogen compounds during the combustion of hydrocarbon fuels. This predictive capability will be refined and verified by comparison with measurements made in these simple combustion reactors. Once confidence has been established in the predictive capability, it can be used to analyze the behavior of staged combustion reactors in a rational and comprehensive search for those reactor combinations which yield the lower limit of NO_x emission set by the basic physics and chemistry of fossil fuel combustion.

Simple zero- and one-dimensional reactors do not completely reflect the detailed physics and chemistry associated with turbulent diffusion flames burning in real furnaces. Consequently, an additional effort has been planned which will parallel the reactor studies and thoroughly characterize turbulent diffusion flame phenomena pertinent to NO_x formation and destruction. Two general classes of turbulent diffusion flames can be recognized; those which involve rapid fuel/air mixing and are dominated by near-field behavior. The second group of turbulent diffusion flames are far-field dominated and can be described as long coaxial jet flames. Several tasks have been initiated in the VCR program which are directed towards understanding the basic turbulent diffusion layer structure in these general flame types. These investigations are concerned with particle transport, both ballistic and turbulent, macroscale turbulent transport of energy and matter, the persistence of coherent structures in large-scale flames, and the detailed processes occurring within these coherent structures.

Once the capability has been developed to model the microscale behavior of oil droplets and coal particles, and after verifying the model by comparison of prediction and observations, it is appropriate to use this model in a

search for lower bounds on NO_x emissions dictated by the basic physics of turbulent transport. The model will aid the understanding of NO_x production and destruction in basic flame elements such as turbulent shear layers, well-backmixed zones, and plug flow zones. This understanding can then be transferred to a modular model capable of describing all the complexities of the fuel/air contacting processes in turbulent diffusion flames. The generation of experimental data to allow this modular model to be developed represents a major subtask of the transport processes program element, and focuses on the macroscale flame behavior in an attempt to establish how burner combustion chamber designs and operating parameters affect the manner in which diffusion zones and well-mixed zones are established and interact. Once the gross features of the flow field have been defined the production and destruction of pollutants on a microscale can be analyzed in an overlay fashion. Having synthesized the physical and chemical processes associated with NO_x production and destruction with the capability to describe the mass transfer in combustion systems, this model can be used to establish the scaling characteristics of low NO_x devices. The definition of scaling criteria represents one of the most important goals of the FCR program, and provides the major driving force towards the description of NO_x production in two-phase turbulent diffusion flames by a hierarchy of models. It should be recognized that in the near-term these models will contain many empirical subelements. However, their modular nature will allow for a more complete mathematical description as the relevant physical and chemical phenomena are defined and quantified.

It is readily apparent that both the development of an understanding of transport processes and the development of numerical models play an important role in the achievement of the FCR program goals. Not only do they provide a predictive capability, they also establish a rationale whereby the effectiveness of NO_x control techniques can be compared against that expected from the lower bounds set by the various physical and chemical constraints. In addition, the development of numerical models provides a tool with which to extract the maximum amount of information from the various experimental programs associated with homogeneous kinetics and heterogeneous processes program elements of the FCR program.

SECTION 3

FLUID MECHANICS AND MODELING OF DIFFUSION FLAMES

Pulverized coal and residual fuel oil are burned in turbulent diffusion flames (i.e., the fuel and oxidant are injected into the combustion chamber separately) and the rate of heat release is normally controlled by the rate of fuel oxidant mixing. Combustion and pollutant formation is complicated by the turbulent mixing process, and currently there does not exist an adequate model for gaseous systems let alone one involving solid or liquid fuels. One aspect of the approach being taken in the FCR program is to examine the influence of various types of molecular diffusion controlled reaction zones on pollutant formation since these could represent the full range of reaction zones likely to be embedded within real turbulent diffusion flames. In addition, the understanding gained from studying simple flame systems provides validation of the kinetic mechanism under conditions that are very different from those used in its development.

MOLECULAR DIFFUSION FLAMES

A generalized diffusion kinetics analysis code has been developed which allows several flame systems to be modeled which involved molecular diffusion. The utility of such models is associated with the computational time required to carry out meaningful calculations. The current code utilizes operator splitting techniques for those situations which are path dependent, and fully implicit techniques involving the inversion of block tridiagonal matrices for conditions which have an asymptotic solution. The generalized code includes the following options:

- strained flames
- steady state particle/droplet flames
- transient confined particle/droplet diffusion flames
- transient spherical gas pockets
- free shear layer flames

- coaxial jet flames
- flat premixed flames

The code has been used to date to examine flat premixed flames, coaxial jet flames, and strained opposed jet diffusion flames. The strained flame provides one link between the modeling being carried out on molecular diffusion flames and turbulent diffusion flames, since the coherent flame structure model assumes that reaction takes place in diffusion layers separating the fuel and the oxidant. Computations have been carried out on the effect of strain rate on flame thickness, flame temperature, thermal NO production and fuel NO production from ammonia. These computations are currently being used by Broadwell and Marble in a model of NO production in a simple turbulent diffusion flame.

DIFFUSION EFFECTS IN PARTICLE/DROPLET COMBUSTION

The conversion of fuel nitrogen to NO in coal and oil flames may depend upon diffusion controlled processes which occur during thermal decomposition, and are associated with the physical effects of particle droplet heating. Experimental data on fuel nitrogen conversion in premixed fuel-lean coal flames suggests that approximately 30 percent of the total fuel nitrogen is converted to NO. Taking account of the division of fuel nitrogen between gas and char components, conversion on the order of 60 percent of the volatile component can be expected. These are similar to conversions measured with liquid fuels of similar nitrogen contents. However, in a fuel-lean premixed gaseous system, fuel nitrogen conversions on the order of 90 percent would be expected. Therefore, any model which assumes that nitrogenous species released from the particle/droplet are immediately completely mixed with the surrounding bulk gases will provide conversion rates which are higher than those encountered in practice. Thus, reaction in a diffusion-controlled layer might well be a necessary submodel for heterogeneous systems.

Nitrogen species may be driven from a coal particle as a jet, or feed some zone around the particle which then reacts in a layer surrounding the particle rather than in the bulk gas phase. Numerical experiments are planned to compare fuel nitrogen conversion in diffusion layers of these types (i.e., mantle, wake or envelope) to that which would occur in the bulk

gas phase. Reaction in the diffusion layer will also control particle temperatures which may yield particle temperatures well in excess of the mean bulk flow and thus have a strong influence on devolatilization rates.

FLUID MECHANICS AND MODELING OF TURBULENT DIFFUSION FLAMES

Broadwell and Marble are developing a coherent flame structure model for gaseous turbulent diffusion flames. In addition there are several experimental studies either planned or in progress. They will provide information which will later be fed into a model of turbulent diffusion flames. The tasks currently underway are:

- Wendt and Hahn at the University of Arizona are measuring the conversion of ammonia to NO in a methane/air opposed jet diffusion flame representative of strained flamelets which may dominate the internal behavior of turbulent flames.
- Vranos at UTRC is currently investigating the combustion of heavy oil droplets in a free shear layer separating oxidant from high temperature combustion products.
- A study will be initiated shortly with IBM to use high-speed cinematography to ascertain whether coherent structures play a significant role in large-scale turbulent diffusion flames.

A subcontract effort is planned to characterize in detail long turbulent diffusion flames of both pulverized coal and heavy fuel oil at various scales.

SECTION 5

SUMMARY

This paper has reviewed the effort which is currently underway or planned in the FCR program elements concerned with numerical model development and transport processes. One key feature of the overall approach is the use of limit-case models to evaluate the lower bounds on NO_x production which are set by practical constraints. Examples of such limit-case studies are provided by the use of simple gas phase reactors with a suitable reaction set in order to evaluate the optimum time/temperature stoichiometry history of staged combustion systems. Figure 1 provides an example of one such study. The decay of XN specie in a fuel-rich combustor is kinetically-limited and the optimum combustor will be a compromise between volume and pollutant emissions. Thus it is necessary to maximize the rate of XN decay in a fuel-rich zone. The example shown in Figure 1 illustrates how distributed air addition to a fuel-rich region can maximize this decay rate. Further calculations of this type are planned involving heterogeneous as well as gaseous systems.

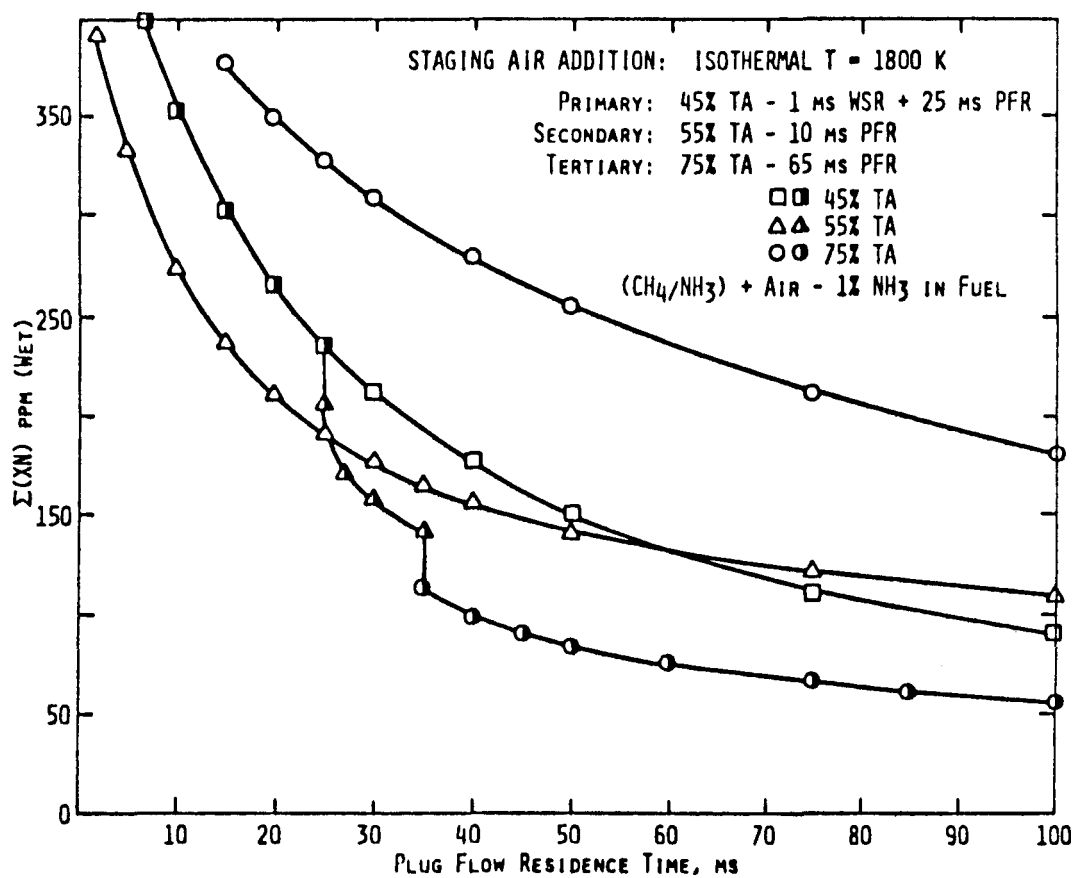


Figure 1. Decay Rate of Total XN Species in Isothermal Plug Flow Reactor as a Function of Stoichiometry and Temperature Showing that Distributed Addition Maximizes Decay Rate

APPENDIX B

SRC-II MARKET SURVEY - STATIONARY GAS TURBINES

SUMMARY

Technical discussions were held with members of the stationary gas turbine engineering staffs of the Curtiss Wright, General Electric, United Technologies, and Westinghouse Companies. All have a vital interest in synthetic fuels. They foresee combined-cycle turbines in base-load applications only if synthetic fuels are available for their use. Their early focus tended to be on low-BTU gas from coal, which was viewed as being nearer term. The rapid advances in coal liquefaction technology over the past few years have caused them to rethink that position and all have given coal liquids considerable thought.

They seem agreed that SRC-II fuel oil will be a suitable turbine fuel if NO_x regulations can be met. The DOE/NASA Lewis "Low NO_x Combustor Development Program" is viewed as the vehicle for determining how far this can be accomplished in retrofit combustors. NO_x removal from the turbine exhaust is also of interest to them. In general, there seemed to be a fair degree of optimism that the fuel and engine would eventually prove compatible despite the fuel nitrogen content.

INTRODUCTION

Existing markets for stationary gas turbine fuels are largely in intermediate- and peaking-load applications in electrical utilities, although there are also some industrial applications. Future gas turbine markets could conceivably be much larger if combined cycle units find acceptance in base-load power generation. Recent literature suggests that such cycles are more efficient and economical than coal fired steam with flue gas desulfurization; but the Fuel Use Act requires new base-load capacity to use coal or coal-derived fuels. Thus, the future of turbines in base-load applications remains unsure, sharing basically the same uncertainties as the synthetic fuels industry itself.

The technical discussions reported here were undertaken to share with the turbine manufacturers Gulf's latest information on SRC-II fuel oil properties and to elicit their thoughts on developing turbine combustors which will allow SRC-II use in their engines. Market size and growth were not considered. Rather, the emphasis was on fuel and engine compatibility, and the technical issues which remain to be resolved.

SRC II MARKET ANALYSIS - STATIONARY GAS TURBINES

TECHNICAL DISCUSSIONS WITH PERSONNEL OF THE GAS TURBINE
DIVISION, GENERAL ELECTRIC COMPANY - JUNE 5, 1979

SRC-II - Status and Plans

J. C. Koenig of Gulf Mineral Resources Company (GMRC) described the status of Gulf's SRC-II process. This included the history of the process concept, its high thermal efficiency and advanced state of development, expected product slate from the planned demonstration plant, and also from future commercial operations. He also discussed the properties of SRC-II fuel oil in general, as well as of the various distillate fractions produced. It was pointed out that, unlike comparable petroleum products, the high specific gravity of aromatic fuels such as SRC-II fuel oil does not correspond to heavy viscous materials; and that, in fact, SRC-II products are relatively light, and non-viscous with very low contained metals. The major differences between SRC II fuel oil and petroleum fuels are the aromaticity and nitrogen content (about 1%) of the former. Detailed economics of the SRC-II process and the high costs of upgrading the fuel oil products were discussed, together with Gulf's view of logical markets. The case for considering combustion turbines as a suitable market for SRC-II middle distillate was presented in detail.

Approximately 20 General Electric personnel attended this presentation. Thereafter, a round table discussion was held with a smaller number of key General Electric personnel. The following participated in this discussion:

J. C. Koenig (GMRC)	-	Dick Johnson, Advanced Product Planner and Proposal Manager (GE)
J. Freel (GS&T)		Marty Cutrone, Manager, Proposal and Advanced Projects (GE)

J. E. Haebig (GS&T)

Chris Coccio, Manager, Advanced
Product Planning (GE)

R. C. Amero (GS&T)

Doug Todd, Manager, STAG Market
Development (GE)

Howard Gerlaugh, Energy Systems
Technology (GE)

Jeet Gil, Environmental Planning
(GE)

Ben Sheih, Energy Technology
Operations (GE)

COAL DERIVED FUELS AND COMBUSTION TURBINES -
GENERAL ELECTRIC VIEWPOINT

General Electric discussed their present strategy on coal derived fuels and the series of studies which have directed their thinking along particular lines. In the ECAS study for DOE, they examined the efficiency, economics and environmental impact of several advanced power generation systems. Almost all had some merit, and each of the advanced cycles was more efficient than proposed steam cycles. Combustion turbine combined-cycle concepts utilizing coal gas and coal derived liquids were amongst the most economical.

In a subsequent study for EPRI/Fluor, GE examined the cost of electricity for a combined-cycle plant based on the combustion turbine and fueled by gas produced from various coal gasifiers. The slagging Lurgi and Texaco slurry feed gasifiers gave lowest costs. In later, internally-funded studies, General Electric concluded that, even with present turbine firing temperatures, a combustion turbine combined-cycle with dedicated coal gasifier gave 20% lower electricity costs than steam generation with flue gas desulfurization. At a 2600°F firing temperature, the economics look even better.

Based on studies of this type, General Electric believes that the gasifier/combined-cycle turbine makes good sense for base load generation; and in December of last year they put a STAG turbine on the market designed for future use of coal derived fuels. If ordered today, such plants will be on line by 1985, burn petroleum distillate during the 5 year exemption allowed by ERA and be retrofitted to burn either coal derived liquids or gases in 1990. However, the ERA has stated that it will issue no exemptions to burn oil in such units since they believe that synthetic fuels will not be available commercially in the time frame mentioned.

The relative merits of coal derived liquids and gas were discussed in detail. General Electric's calculations show that liquids look much better for intermediate and peak load generation, where the use-factor precludes the costs of a dedicated gasifier. Their present data suggest a modest advantage for gas in base-load power generation; but the economics are very sensitive to projected gas and liquid prices, which in their view are still somewhat soft.

THE USE OF COAL DERIVED LIQUIDS IN COMBUSTION TURBINES - TECHNICAL ISSUES

The technical problems of burning nitrogen containing, aromatic fuels in combustion turbines were discussed at length. General Electric made it clear that these fuels cannot be burned in present machines without creating problems. Their on-going R&D work therefore includes (a) studying rich/lean combustion with which they have had success in the laboratory using distillate fuel spiked with nitrogen, (b) working on claddings to help keep turbine parts operating in the gas path despite the presence of impurity metals in the fuel and (c) considering water cooling (as opposed to air cooling) to keep the flame temperature high and reduce blade temperature (cooler blades equate with less corrosion).

They anticipate severe high temperature corrosion problems with coal gas, and also anticipated such problems with coal derived liquids. They were surprised at Gulf's data on SRC-II fuel oils, showing a very pristine fuel in terms of ash and contained metals.

Except for the rich-lean combustion study described above, GE has done relatively little with coal liquids. But, they are a contractor on DOE's "Low NO_x Combustor Development" program, so that such work is beginning to be emphasized. They indicated that they would be extremely interested in testing SRC-II at their Lynn Plant where post combustion de-NO_x control will be available. It was agreed that the Gulf personnel would try to follow this up.

In general terms, the GE personnel seemed to feel that corrosion should not be a problem at today's blade temperatures, given Gulf's data on ash and contaminant metals. Their technical people would not make predictions about the fuel nitrogen content which may eventually prove tolerable in future combustors designed to minimize NO_x. They quoted the Pratt & Whitney experiment as showing feasibility, but believe quantification must await more detailed studies, which they expect to come from the "Low NO_x Combustor Development" program.

Further discussion of the "Low NO_x Combustor Development Program" centered on the use of petroleum residual fuel as a model for SRC II fuel oil. The GE personnel agreed that residual oils are not an adequate surrogate for coal liquids. They feel it is unlikely that a combustor design optimized for residual fuels will also be optimal for coal liquids.

General Electric is extremely interested in post turbine NO_x removal, and has a small combined cycle unit in Japan in which a catalyst was placed in the heat recovery boiler and ammonia injected for NO_x removal. The test was successful, but they experienced some corrosion problems in the heat recovery boiler. They are currently building a unit in the U.S. to try to solve these corrosion problems. They are also prepared to sell combined cycle units which can be retrofitted for catalytic de-noxing in the future.

Conclusion

The general conclusion of these technical discussions was that combustion turbines form a logical market for SRC-II, but that some tricky technical problems with respect to NO_x control remain to be resolved. DOE's low NO_x combustor program is viewed optimistically as the vehicle for defining how successful the turbine manufacturers will be.

The General Electric personnel were encouraged by our reports on the extremely low levels of metal contaminants attainable with SRC-II, and believe corrosion may not be a problem.

A clear concern was the timing of coal liquids availability. The turbine manufacturers are in the position of offering the most efficient technology for power generation, but must have liquid or gaseous fuels. If these arrive too late, the less economical route of coal fired steam cycles with flue gas desulfurization may win by default.

While GE would not predict the eventual degree of success of low-NO_x combustor designs, it seemed clear that they believe SRC II-fuel oils can eventually be burned in an efficient and environmentally acceptable way. The uncertainties are whether fuel oil upgrading, low-NO_x combustor designs or catalytic exhaust treatment will be the most economic route. Their intuitions seemed to coincide with our own, i.e., severe fuel oil upgrading processes will probably not be the most advantageous way to go.

SRC-II MARKET ANALYSIS - STATIONARY GAS TURBINES -
DISCUSSIONS WITH WESTINGHOUSE PERSONNEL, JUNE 22, 1979

In attendance were:

Gulf

R. C. Amero, GS&T
J. Freel, GS&T
J. E. Haebig, GS&T
J. C. Koenig, GMRC

Westinghouse

Dennis Seipp, Mgr., Energy Program
Development
Cliff Seglem, Mgr., Technical Liaison
Mario Decorso, Project Manager
Richard Mulik, Principal Engineer
George Bauserman, Senior Engineer
Paul Pillsbury, Senior Engineer

SRC-II - STATUS AND PLANS

J. C. Koenig gave an introductory talk on SRC-II as outlined in the report of our General Electric discussions.

COAL-DERIVED FUELS AND COMBUSTION
TURBINES - WESTINGHOUSE VIEWPOINT

The power generation group of Westinghouse Power Systems Company manufactures steam turbines, generators, and combustion turbines (primarily single-shaft turbines of large size for generator drives). This group conducts all work on combustion turbine research relating to coal-derived fuels, including combined cycle applications.

Westinghouse pointed out that the diffusion flame combustor, used in current turbine designs, leads to high temperatures at the flame front, and hence high NO_x . Thus, new combustors with new design features are clearly necessary to burn nitrogen-containing fuels in an emissions compliant manner. They have, in fact, burned H-coal, EDS products, SRC-II fuel oil and shale oil in conventional combustors, and are writing a report for EPRI on

these tests (which should be available in about 6 months). Basically, they found that very high fuel aromaticity produced sufficiently high combustor wall temperatures to shorten combustor life; however, the more moderate aromatics content and distillation range of SRC-II is less likely to overheat combustors. They also encountered problems with smoke and NO_x emissions for all fuels with substantial fuel nitrogen content. (These effects are all predictable for conventional petroleum distillate combustor designs.)

These early tests revealed no corrosion problems due to the use of coal liquids. However, the tests were run at 1650°F. At higher turbine temperatures, they are concerned by the possibility of deposition on the turbine blades.

The Westinghouse personnel agreed that combustion turbines appear to form a natural market for SRC-II fuel oil. Like their colleagues at General Electric, they believe that the combined-cycle turbine is the most efficient way of generating base-load power, but recognize the need to utilize coal or coal-derived fuels for base-load applications. They believe their technology will prove economically superior to advanced steam cycles with flue gas desulfurization; but are acutely aware that solid coal is available today, while synthetic fuels are not.

They see their potential customers faced with two major uncertainties; the uncertainty of timing of synthetic fuel availability, and the uncertainty that the combustion turbine will be able to use the fuels without excessive emissions or component damage, once they become available. Therefore, Westinghouse believe a field demonstration of the problem-free use of SRC-II in a commercial turbine should be carried out as soon as possible. They suggested that an existing turbine of conventional design could be used, since durability and not NO_x emissions would be the issue. Gulf personnel basically agreed with the desirability of a durability test, but pointed out the importance of the NO_x issue. We suggested that the utilities would be dissatisfied with such a test and that it would be in everyone's best interests to await low- NO_x combustor designs before carrying out the test. It

was agreed that representatives of the two companies should follow up on the discussion to design a mutually satisfactory program leading up to a field demonstration.

In Westinghouse's view, the fuel contaminant levels allowable should be specified as soon as possible, by operating turbine tests run with coal liquids. Federal regulatory policy should then be established for their use, burning them as mixtures with petroleum distillates, if necessary.

An interesting concept not mentioned in our talks with GE was that of "repowering." Such concepts refer to upgrading the base-load capacity of existing steam boiler plants by installing a combustion turbine to drive one generator, feeding the turbine exhaust to the existing boiler, where the turbine exhaust heat is recovered and its oxygen is used for boiler fuel combustion. Westinghouse has studied several variants. In the best case, base-load wattage can be increased by 40% with an accompanying 10% decrease in heat rate for roughly \$200 per installed kW. Clearly, this is much less costly than a new grass-roots plant. It also offers the potential for utilizing coal liquids in the added combustion turbine while meeting fuel requirements of the existing plant from oil.

The role of coal-derived liquids versus coal gasification in base-load applications was also discussed. Westinghouse felt that gas will have an economic advantage. Like GE, they feel that liquids are preferable for intermediate and peak load generation. However, they pointed out that someone must pull together all the components to ensure development of the coal-gas based system (i.e., gasifier, gas clean-up, combined cycle turbine), and that this does not seem to be progressing very well.

COAL-DERIVED FUELS AND COMBUSTION TURBINES - TECHNICAL ISSUES

Westinghouse has four test rigs of various sizes and pressure ratio/temperature capabilities.

<u>Location</u>	<u>Fuel Use (lb/sec)</u>	<u>Pressure Ratio</u>	<u>Preheat (°F)</u>
R&D Pittsburgh	5	5/1	800
Waltz Mill, PA	12	20/1	1100
Lester, PA	40	9/1	800
Concordville, PA	85	20/1	1100

In the area of synthetic fuel use in gas turbines, most of their R&D activity has been with coal gas, including coal gasification R&D at Waltz Mill. However, they believe they have conducted enough studies on the various synfuels to specify the best combustor approach for each. In the case of low Btu gas, a conventional diffusion-flame combustor seems best. For medium Btu gas, or low-nitrogen coal liquids, they favor either premixed, lean-burning, or possibly lean catalytic combustion; both have the potential for essentially zero NO_x emissions. For high fuel nitrogen synthetic fuels, they feel rich-lean staged combustion is the only answer. Westinghouse will be a participating contractor in the DOE/NASA Lewis combustor development program, and their work will include rich-lean combustor concepts. Further discussion of that program elicited their view that the same combustor design is unlikely to be suitable for both coal liquids and petroleum residual fuel.

Westinghouse has also assessed catalytic processes for NO_x removal from turbine exhausts. They carried out an analysis of such systems on behalf of the Sacramento Municipal Utility District. It focused mainly on the Hitachi-Zosan process, which Chemico has licensed. The turbine exhaust is too hot for optimal catalyst performance, the correct temperature occurring in the heat recovery boiler of combined cycle systems. For the Chemico process, the ideal temperature (about 390°C) gave about 70% NO_x abatement. Costs for a 160 MW combined cycle plant were roughly \$14 million capital investment (\$8 million for the hardware and \$6 million for catalyst). But the catalyst must be replaced routinely every year, and can be ruined prematurely if the exhaust gas temperature drops significantly.

CONCLUSIONS

A general conclusion is that Westinghouse are vitally interested in using SRC-II fuel oil in combustion turbines. Clearly, they have given the matter a great deal of thought, and as with GE, are comfortable with its eventual use in their engines. They are concerned that SRC-II fuel oil will not be available sooner. They feel that their customers must be convinced that the fuel will work and will definitely be available for purchase. Otherwise, they fear the utilities will have little choice but to specify direct coal firing for any new base-load capacity.

A partial solution is to conduct durability tests in a real engine as soon as possible, and Westinghouse believe that a sufficiently convincing test could be carried out in an existing turbine. They agree that it would be more logical to await the development of new coal liquid combustors, but feel pressed to resolve some of their customers' uncertainties with minimum delay. All agree that such a test would yield high NO_x emissions. It seems crucial, therefore, that Gulf and Westinghouse cooperate to design a program which will help the turbine manufacturers demonstrate the compatibility of SRC-II fuel oil and combustion turbines, without, at the same time, creating the mistaken impression that SRC-II fuel oil will give high NO_x emissions in the turbines of the future.

SRC-II MARKET ANALYSIS - STATIONARY GAS TURBINES -
TECHNICAL DISCUSSIONS WITH PERSONNEL OF THE UNITED
TECHNOLOGIES CORPORATION - JUNE 26, 1979

In attendance were:

<u>Name</u>	<u>Position</u>
Fred Kemp (UTC-PSD)	Program Management
Tom Gilmartin (UTC-PSD)	Asst. Project Engineer
Larry Preston (UTC-PSD)	Asst. Proj. Eng.- Fuel Proc.
Gene Szetela (UTC-UTRC)	Senior Engineer
Dick Sederquist (UTC-PSD)	Project Engineer - Fuel Processing and Combustion
Jeff Arnold (UTC-PSD)	Project Engineer - Fuel Processing
Tom Rosjord (UTC-UTRC)	Res. Engr. - Comb., Fuel Inj.
John Freel (GS&TC)	Res. Associate
John Koenig (Gulf Min. Res. Co.)	Dir., Commercial Development
Jon E. Haebig (GS&TC-Pgh)	Sen. Res. Chemist
Dan Seery (UTRC)	Prin. Scien. - Comb. Sciences
Bob Pierce (UTC-GDP)	Senior Engineer
Bob Amero (GS&TC-Pgh)	Staff Engineer
Stan Mosier (UTC-P&WA Fla)	Tech. Mgr. - Fuel and Emissions
John Horgan (PSD-SWEF)	Proj. Engineer
Paul Grevstad (UTC-PSD)	Mgr.-Indust. Gas Turb. Programs

SRC-II STATUS AND PLANS

J. C. Koenig (GMRC) gave the same introductory talk on this subject as in the visits with GE and Westinghouse.

COAL-DERIVED FUELS AND COMBUSTION TURBINES - UNITED TECHNOLOGIES VIEWPOINT

United Technologies (UTC) personnel, like the other turbine manufacturers, were extremely interested in the properties and future availability of SRC-II fuel oil, since they view it as a viable future fuel for combustion turbines. They believe that the fuel cost does not seem problematic, and that turbine designs for its use seem realizable. Their major concern is at what time coal-derived liquids will be available in commercial quantities. If synthetic fuels are not available in quantity by the late 1980's-early 1990's, there is likely to be a liquid fuel gap which will keep combustion turbines out of base-load power generation. UTC is concerned that utilities will be forced to opt for less efficient steam boilers with flue gas desulfurization.

UTC personnel also expressed concern that the oil companies would use coal-derived liquids in their refineries to make conventional products, or at least blend them with petroleum fuels. In that case, today's concerns about burning pure coal liquids would become meaningless. J. C. Koenig expressed the view that such would not be the case; but that the coal-derived liquids, because of their properties, would be segregated from petroleum in an essentially total manner. The only exception might be those light components best utilized in gasoline.

COAL DERIVED LIQUIDS AND COMBUSTION TURBINES - TECHNICAL ISSUES

UTC believes that there is nothing to be gained by attempting to burn coal liquids in existing gas turbine designs. Their studies show clearly that the turbine will not behave properly. The two problem areas are damage to hot parts due to flame radiation (related to high fuel aromaticity), and high NO_x emissions. Rather, they feel that the turbine companies should be working towards a new combustor designed specifically for coal liquids, and that a full-scale durability test on turbines fitted with this combustor should be carried out as soon as possible.

They stressed the importance of environmental regulations in regard to such a development program. They believe that coal liquids could be burned efficiently in only slightly modified combustors, but not in an environmentally acceptable way. Thus, if today's environmental regulations remain in force, this low-cost development option is not open. On the other hand, they foresaw very high development costs in learning to burn coal liquids to meet today's environmental regulations, but seemed optimistic that it can eventually be done. UTC's optimism stems largely from the work of their Bob Pierce, which still represents the only meaningful experiment in rich-lean combustion in a gas turbine combustor. (About 20 bbl of SRC-II fuel oil is being blended at Ft. Lewis for such ongoing studies.)

They now have research going on at all levels from the bench to full-size engines looking at the NO_x problem. In the laboratory they are studying the kinetics of processes in both the fuel rich and fuel-lean zones. In subsize combustors they are investigating new concepts, including both rich-lean and catalytic burning. In their development laboratories they are running full-scale combustors on coal-derived gas, while they are investigating dry NO_x removal processes in full-size engines. Much of this ongoing R&D work is being done for EPA and EPRI. They have achieved NO_x levels below 100 ppm with fuel of 0.5% nitrogen content in combustion tests at 2650°F, and Stan Mosier expressed the view that 1% fuel nitrogen will probably be controllable. Their primary R&D thrust is in rich-lean thermal combustion and rich catalytic combustion. If they could obtain funding, they believe a parametric program should be conducted in their lab-scale combustors to examine the effects of various operational parameters on both efficiency and emissions. Such a program could be carried out for approximately \$200,000.

The UTC personnel were extremely interested in Gulf data which show that the contaminant metals in SRC-II fuel oil will be extremely low. They believe, nonetheless, that turbine corrosion must be investigated with coal liquids, since no one knows what presently unidentified problems might be unearthed.

DISCUSSIONS WITH W. J. LUECKEL, MANAGER
PROGRAMS AND MARKETING, POWER SYSTEMS DIVISION

J. C. Koenig and J. Freel met with Bill Lueckel to discuss UTC's views on the timing of SRC-II commercialization around 1990, and the fuel gap which is concerning the turbine manufacturers if the Fuel Use Act is rigidly applied.

Bill agreed that this is an area of real concern and considerable business uncertainty, both to UTC and the utilities. However, he pointed out that the Fuel Use Act gives the administration wide discretionary power in terms of granting exemptions. The trouble is that no test case is in the offing, because the utilities are not ordering new base-load capacity. Projections of electricity demand are much lower than those of a few years ago, and the utilities are very wary of placing new orders. When they do, one will begin to see whether government intends to penalize the more efficient combined-cycle based on combustion turbines because the coal-derived fuels they need are not yet available. Bill seemed to feel a general optimism that such would not be the case, with DOE, EPRI, EPA and the turbine manufacturers working so hard to realize combined-cycle systems using coal liquids and gas.

J. C. Koenig also took the opportunity to discuss UTC's fuel requirements for fuel cells. He pointed out that if SRC-II naphtha is utilized for BTX production, the raffinate left after aromatics extraction should be very similar to a straight-run petroleum naphtha. Bill Lueckel felt that such a fraction should be eminently suitable for UTC's fuel cell system. In fact, he would like Gulf to provide such a fuel for testing in the UTC/Consolidated Edison fuel cell demonstration unit, presently nearing completion. J. C. Koenig agreed to pursue this further.

CONCLUSIONS

It seemed clear that the UTC personnel shared our perception that combustion turbines form a logical market for light SRC-II fuel oil. They

seemed more optimistic than either GE or Westinghouse that low-NO_x combustors will be developed to allow 1% fuel nitrogen to be burned successfully. This is encouraging since UTC seems to be a little further ahead in that area of R&D, due to past EPA and EPRI funded projects.

SRC-II MARKET ANALYSIS - STATIONARY GAS TURBINES

**Technical Discussions with Personnel of the
Curtiss Wright Corporation - March 22nd, 1979**

In attendance were:

Gulf

Curtiss Wright

R. C. Amero

J. C. Wolf

HTTT Program Mgr.

J. E. Haebig

T. Kobush

Combustor Design

J. C. Koenig

A. Leto

Design Mgr., Power
Systems

L. Nucci

Combustor Design

S. M. Woldsin

Metallurgist

E. Harrison

Test Unit Operation

SRC-II Status and Plans:

J. C. Koenig gave an introductory talk on the status of SRC II and plans for its demonstration and commercialization.

Coal Derived Fuels and Combustion Turbines -
Curtiss Wright Viewpoint

Curtiss Wright's main activity in advanced turbine R&D is their participation in the DOE High Temperature Turbine Technology (HTTT) program with the objective of demonstrating technology readiness for a turbine operating at 2600°-3000°F. As a consequence, their main focus has been on corrosion prevention and they have developed a unique approach to blade cooling (transpirational cooling) with air bled from the turbine compressor. The program rationale has been that a high temperature combustion turbine would have sufficiently high efficiency (40-45%) as a prime-mover to offset the costs of producing liquid or gaseous fuels from coal, thus making the

overall system (coal mine to bus bar) competitive with direct coal firing in steam cycles with flue gas desulfurization.

The program thus far has been tied to low BTU coal gasification, and much of their recent work has been concerned with the effects of coal gas dust on turbine blades by erosion and deposition. Recently, however, they have begun to sense that coal liquefaction is moving more rapidly than gasification, and have a desire to switch emphasis to coal derived liquid fuels such as SRC-II.

If DOE approves this change, Curtiss Wright plan to work towards a full scale HTT test in early 1982. A 100 hr test at 16 000 lb of fuel per hour would require about 4800 bbl of SRC-II at that time. They requested a drum of SRC-II fairly soon for preliminary evaluations and were advised on how to proceed in that regard.

Coal Derived Fuels and Combustion Turbines - Technical Issues

Due to their heavy emphasis on coal gas, Curtiss Wright have confined their interest in coal liquids to monitoring the technology. Their major expertise is in erosion/deposition prevention for the same reason. They were encouraged by the extremely low metals and ash which Gulf believe is obtainable with SRC II fuel oil, and requested further data on this topic.

They are not involved in the DOE/NASA Lewis programs on low NO_x combustor designs. Their strategy is to focus on R&D to increase turbine operating temperature and use the low NO_x combustors when they become available. DOE has discouraged them from including rich-lean combustion concepts in the HTTT program because it would duplicate efforts on the low NO_x contracts. For these reasons, the Curtiss Wright personnel felt unable to comment on the likelihood that 1% fuel nitrogen can be burned with tolerable NO_x emissions. They did allow that thermal NO_x may be a more significant problem in the high temperature turbine, but have not really come to grips with this issue as yet.

Conclusions

Curtiss Wright's emphasis has been on high turbine temperatures and coal gas. This experience did not allow them to comment on the compatibility of stationary combustion turbines and SRC-II fuel oil. Clearly though, they are becoming concerned about the progress of coal gasification technology, and are beginning to switch their attention to coal derived liquids.

GULF SCIENCE AND TECHNOLOGY COMPANY
Pittsburgh, Pennsylvania

RECOMMENDED SRC-II COMBUSTION TESTING PROGRAM

By

R. C. Amero
J. E. Haebig

Chemicals & Minerals Division
Report No. 633RK103
July 1979

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RECOMMENDED SRC-II COMBUSTION TESTING
PROGRAM AND SAMPLE NEEDS FOR 1979

1. SUMMARY AND CONCLUSIONS

As an aid to planning the optimum disposition of the Ft. Lewis SRC-II product for 1979 this report considers the suitability of various types of combustion equipment for SRC-II fuel oil use. From a wide variety of potential uses (Table 1) five areas were selected: utility and industrial boilers, stationary gas turbines, medium-speed diesels, transportation gas turbines and fired industrial processes. The Naval Ships Research and Development Center has also requested samples recently, which adds the category of marine use in boilers, diesel engines and gas turbines. Recommended tests in these areas are listed in Table 2. In this table, comments have been included on tests now supported or proposed by EPRI, DOE, and EPA. Additional tests have also been suggested in order to include the most promising advanced combustion concepts, which may greatly facilitate SRC-II utilization.

Most of the major organizations involved in these equipment areas have been contacted, as shown in Tables 3 and 4. These contacts have served to update our information and to assure that industry is accurately informed about SRC-II fuel oil properties. The attachments show that several organizations have requested small samples for preliminary tests, and we recommend that these requests be honored as soon as possible. The samples will provide orientation for possible users and will provide valuable feedback to the SRC-II program on diverse applications.

The total sample requirements listed for 1979 are less than 3000 bbl of SRC-II products, and will decrease due to slippage in some programs. Therefore, it seems reasonable to satisfy all sample requests in Table 2 without assigning priorities. As some of the programs progress from laboratory and pilot plant to full-scale demonstration runs, the demand for samples might exceed availability. For example, Table 2 indicates 500 bbl of SRC-II fuel oil in 1980 for a boiler test by Energy and Environmental Research Com-

pany, and 800 bbl for a field test in a stationary gas turbine. Other demonstration tests in gas turbines, boilers, kilns, and process heaters could easily be arranged because of the general interest in alternate fuels.

When priorities on sample distribution are required, preference should be given to those tests with the greatest likelihood of outstanding performance, both from the viewpoint of equipment operation and the viewpoint of combustion emissions. The significance and real likelihood of eventually using SRC-II products in the potential application must also be considered. Within that general framework, priority should be given to tests representing the highest value application. For example, SRC-II fuel oil can be handled readily in utility boilers, but progressively greater development work might be required for test results in industrial boilers and direct-fired heaters, in stationary gas turbines, in medium speed diesel engines, and in transportation gas turbines. On the other hand, the economic value of fuels for transportation is higher than fuels for large boilers, but such fuels can perhaps be produced most economically from the petroleum displaced from boiler and other SRC-II product applications.

Based on the above parameters, the programs on low NO_x combustors for stationary gas turbines and for industrial burners warrant high priority, along with corollary tests on equipment durability. Then suitable demonstration tests can be arranged. Demonstration tests in medium speed diesels and transportation gas turbines need not be considered until small scale testing has been accomplished.

2. INTRODUCTION: OVERALL MARKET AREAS

This report reviews combustion tests of SRC-II fuel oil needed in various types of equipment, and sample needs for such tests in 1979. An overview of the possible types of combustion equipment representing markets for SRC-II fuel oil is provided in Table 1. During the last several months, contacts have been made with certain sectors selected from Table 1, including manufacturers and users of boilers, stationary gas turbines, medium-speed

Table 1
Potential Uses for SRC-II Liquids (Not Upgraded)

<u>Market</u>	<u>Use</u>
Utility	Boiler Start-up and pilot fuel Main fuel Gas turbine fuel Diesel Fuel Intermediate Speed Low Speed Co-generation fuel
Industrial	Boilers and Process Heaters Kilns (copper, glass, ceramics, bricks, clay, refractories, cement) Furnaces (blast, heat treating, cupolas) Dryers (rotary, tunnel, spray , flash) Gas turbine fuel for transportation equipment Process Oils and Solvents (rubber compounding, wood preservative, printing ink, electrode manufacture, etc.)
Marine	Boiler fuel Gas Turbine fuel Diesel fuel Main propulsion Maneuvering Blending
Commercial	Boilers, Institutional (schools, prisons, colleges, hospitals, government buildings)

Table 2. SRC-II Sample Requirements for Equipment Tests

Application					
Item	Organization	Quantity (55-gal drums)	Fuel Type ^a	Delivery by	Comments
1. <u>BOILERS AND BURNERS</u>					
1.	KVB	85	various	1/79	Small-scale boiler tests, effects of fuel composition (Item C in EPRI list).
2.	MIT Energy Lab	30	HD	3/79	Fundamental studies of emissions and heat transfer. (Item D in EPRI list).
		130	MD		
3a.		--	--	--	Burner Development (Item F in EPRI list). We suggest EER for contractor; see ff item.
3b.	EER (Energy & Environmental Research Co.)	60	U	5/79	In EPA project has developed a very successful low-NO _x burner design for high-N fuels. EPA funding a possibility. Include SRC-II in industrial boiler field test in EPA program.
		40	U	8/79	
		500	U	1980	
4.	National Air Oil	20	U	1979	Potential low-NO _x burner design. One-day test in Air Oil's lab furnace.
5.	Tests in Large Utility or Industrial Boilers	--	U	1980	Tests should await the availability of low NO _x burners.
Subtotal, 1979		365			
3. <u>Stationary Gas Turbines</u>					
1.	Westinghouse	30	HD	1/4/79	Std. and Catalytic Turbine (Item A in EPRI list.)
		40	MD	1/4/79	
2.	Accurex	20	MD	1/4/79	Std. and Catalytic Turbine (Item B in EPRI list.)
3.	Five contractors, to be specified	600	U	9/79 12/79	DOE RFP 3-870802 "Low NO _x Heavy Fuel Combustor," SRC-II is to be "Fuel C" in the RFP. Contractors to be announced soon. Initial design tests in RFP outline are oriented toward residual petroleum oil, thence intended for coal liquids. However, coal liquids viscosity and dist. range are lower, suggesting that residual fuel burners may not be optimized for coal liquids.
4.	Pratt & Whitney W. Palm Beach	30 400	U U	4/79 8/79	Tests in combustor designs in EPA project; a promising rich-lean concept for high-N fuels. EPA funding a possibility. DOE program (Item 3) might contain this work; to be ascertained from DOE.
5.	(Several possible companies)	20 (est.)	FR	1979	Tests of water-washability for corrosive trace element removal.
6.	Brown-Boveri:	1 800	U U	Soon 1980	Large combustor may be uniquely suited for low NO _x and smoke from coal liquids. One drum to BB Switzerland labs; field turbine available in U.S.
7.	Unspecified	--	--	--	Complete (multi-combustor) field turbine test. (Item E in EPRI list). We suggest such a field demonstration after low-NO _x combustors are developed and incorporated in it.
Subtotal, 1979		1140			(Subtract 430 if Item 4 is include in Item 3.)
2. <u>Diesel Engines</u>					
1.	General Electric, Erie, PA	4-10	MD	Indefinite	Two-cylinder test in full-scale engine.
2.	Cooper Energy Services, Mt. Vernon, Ohio	10 gal 4 drums	MD MD	Soon 4/79	Fuel pump test stand evaluation. Single cylinder combustion test in full-scale engine.
3.	GM-EMD, LeGrange, IL	2 gal 20 drums	MD MD	Soon --	Laboratory inspection. Initial engine test.
4.	Various manufacturers	600	MD	1979	For DOE program in medium and high speed diesels under a forthcoming RFP mentioned by Mr. E. Lister. This could overlap testing mentioned above.
Subtotal		640			

Table 2 (Continued)

Application					
Item	Organization	Quantity (55-gal drums)	Fuel Type ^a	Delivery by	Comments
D. Gas Turbines, Transportation					
1.	Detroit Diesel Allison, Indianapolis, IN	1 10-11	MD MD	Soon Soon	General screening Combustion Test
2.	AiResearch, Phoenix, AZ	1	MD	Soon	Screening Test
3.	Solar, San Diego, CA	1	MD	Soon	General Screening (larger quantities might be requested later.
4.	GM Technical Center Warren, MI	3 <u>5 tons</u>	MD SRC-I	Soon Soon	For engine tests of NO _x emissions. For continuous engine combustion tests.
Subtotal		20			
E. Industrial Processes					
1.	Inland Steel Company	3 285	SRC-I MD	Soon Mid-1979	To be tested as binder for briquets. Test to be arranged; probably a reheat furnace. Note that no NO _x control is planned.
2.	Oak Ridge National Laboratory	300	U	1980	To be evaluated in combustion tests at 1350°C for effects on industrial refractories (spelling and deterioration).
3.	John Zink Company		U	Soon	Preliminary combustion and emissions tests in a 10 million BTU/hr low-NO _x burner of a type used in process heaters in refineries and chemical plants.
Subtotal, 1979		<u>590</u>			
F. Marine					
1.	Naval Ships Research and Development Center		U	Soon	To be subjected to extensive laboratory analysis plus inspection tests vs military specifications for jet fuel and diesel fuel, which is also used in boilers and propulsion gas turbines.
(a) MD: middle distillate FR: full range					
HD: heavy distillate U: undetermined					

Table 3. Organizations Contacted Re SRC-II Utilization: Boilers, Utility & Industrial, and Burners

<u>Company</u>	<u>Contact & Position; Items Discussed With Gulf Contact</u>	<u>Activities & Interests</u>
I. Boilers, utility: Users		
A. Consolidated Edison, NY City	G. Stegman, Sr. Engr; Interpretation of SRC-II test, future needs. D. Mormile	4500 bbl SRC-II test Sept. 1978, EPRI
B. Southern California Edison (SCE)	M. Mansour; Sr. Engr.	Testing TRW burner design with SRC-II. Interim report in February
C. A group of New England utilities sponsoring work by Dr. Beer at MIT	Dr. Beer; Discussion of test program	Mechanism of combustion and NO _x formation
D. New England Power Service Co., Salem, MA	Mr. Batra; Combustion of Coal-Oil-Mixtures	A DOE project on using Coal-Oil-Mixture in an 80-MW boiler designed for coal; may be interested in coal liquids
E. Florida Power Company		COM project with Dravo. private funding
F. EPRI	Dr. W. C. Rovesti	Sponsoring projects - See Table II
II. Boilers, Industrial: Users		
A. GM	Mr. R. Teno, Manager and fuel planner in GM's Coal-Oil-Mixture project; Discussed the COM project and possible interest in SRC-II	GM is testing Coal-Oil-Mixtures as a means to extend fuel oil supplies
B. American Boiler Manufacturers' Assoc.	Mr. W. Axtman, Executive Secretary, ABMA; Discussed sales, population, and use patterns, and fuel requirements for various types of industrial boilers	Trade association of boiler manufacturers
C. Council of Industrial Boiler Owners	Mr. W. Marx, Executive Director; Discussed SRC-II program and potential application in industrial boilers	Trade association of boiler owners
D. Manufacturing Chemists Association	Mr. H. J. Sauer; Discussed SRC-II program and potential application to industrial boilers	Trade association of manufacturers of chemicals

Table 3 (Continued)

<u>Company</u>	<u>Contact & Position; Items Discussed With Gulf Contact</u>	<u>Activities & Interests</u>
III. Boilers Manufacturers		
A. Combustion Engineering	Mr. R. W. Borio, heads a research group working with a large burner test tunnel at the Windsor, Connecticut laboratory	
B. Babcock & Wilcox	Mr. S. Johnson, Engineer, New Designs, Barberton, Ohio; Mr. W. Downs, Engineer, Burner Test, Barberton, Ohio	Tested SRC-II in new dual-register burner for EPRI
IV. Burner Mftrs for Utility/Industrial Boilers		
A. Babcock and Wilcox	Mr. W. Downs, Engineer, Burner Tests, Barberton, Ohio; Discussed uncertainties in EPRI test at Barberton; burner may still have potential but future work is unplanned yet	Dual-register burner
B. National AirOil	Mr. G. Bitterlich, V. P. for Engineering; Discussed new burner design which yields reduced fuel-derived NO _x with No. 6 Oil	
C. TRW	Mr. D. B. Sheppard, Manager, burner program design principles; Discussed test of TRW burner by Southern California Edison, also data on No. 6 Fuel Oil in all burner types	
D. John Zink, Tulsa	Drs. R. R. Martin and R. Reed; Discussed arrangements for combustion tests on SRC-II in the John Zink test facility	Burners for industrial boilers and process furnaces
E. See V, B.(EER); D.(Acurex)		

Table 3 (Continued)

<u>Company</u>	<u>Contact & Position; Items Discussed With Gulf Contact</u>	<u>Activities & Interests</u>
V. Research Labs/Universities		
A. KVB	Messrs. S. Hersh (NY), L. Muzio (CA), others; Sr. Engrs. many lab and field tests	SRC-II test in 20 gpm boiler for EPRI; 5 more tests planned. Operated boiler at Consolidated Edison to produce low NO _x
B. Energy & Environmental Research (EER)	Mr. D. Zallen	Burner design for EPA are testing 20 gal of SRC-II
C. Gulf Oil Canada/Ontario Research Foundation	Mr. L. McKinley	Testing staged operation of Vortometric burner w. SRC-II
D. Aerotherm Acurex	Mr. R. A. Brown	Has good test furnaces
E. Battelle Columbus	Messrs. R. Giammar, R. Barrett and A. Putnam; Discussed combustion and industrial boiler population	
F. MIT	J. M. Beer, Prof., M. Jacques, Project Leader Detailed discussion on principles	MIT-GS&T collaboration on EPRI contract, SRC-II testing in 1 MW furnace & drop- tube
G. Princeton	Prof. Fred Dryer	
H. Penn State U.	Prof. H. B. Palmer	
I. Ohio State U.	Prof. R. H. Essenhigh	
J. Pittsburgh Energy Tech Center of DOE (Bruceton)	Mr. D. Bienstock, head, Combustion Section	

Table 4
Product Application Activities on SRC-II
Gas Turbine, Diesel, Process and Technical

	Contact		Market	Samples Desired	When Desired	Comments
I. Gas Turbine, Industrial & Marine						
A. General Electric, Schenectady, NY	R. Johnson					
	C. C. Coccio					
	H. V. Doering	Phone	Utility	15 bbl	late 1979	Have analyzed SRC-II from H. McIlvried, GS&T
	J. W. Hickey	& visit	& Industry			
B. General Electric, Evendale, OH	N. R. Dibelius					
	M. W. Shayeson	Phone	Utility, In- dustry, Marine, Aircraft	--	--	
C. Westinghouse, Concord- ville & Lester, PA	S. M. DeCorso	Phone	Utility,	6000 bbl full- scale 2-3 wk test	Not imminent	Combusted coal-derived and "surrogate" fuels for EPRI and Mobil
	C. Seglem	& visit	Industry			
D. Westinghouse, Churchill (Pgh), PA	P. R. Mulik	Phone	(Gas Turbine	--	--	Received and combustor-tested SRC-II MD & HD
	P. O. Singh	& visit	Research)			
E. Brown-Boveri Turbo- machinery, Inc. St. Cloud, MN	F. Berg	Phone	Utility,	1. Small sample, possibly	To be developed	Should promote sending small sample to Switzerland lab followed by full-scale U.S. test
	K. Hanson		Industry	2. 40 000 gal full-scale test	To be developed	
F. Solar San Diego, CA	R. T. LeCren	Phone	Utility, Industry,	300 gal	Soon	Screening test
		& visit	shallow-draft marine	100 000 gal	--	Full-scale test
G. Curtiss-Wright	S. Lombardo	Phone	Utility, Industry	--	--	Interested to learn properties of SRC-II. Considering inclusion of SRC-II in High Temperature Turbine Program
	T. Koblish	& visit				
H. United Technologies West Palm Beach, FL & E. Hartford, CN	J. Herron	Phone	Utility, Industry,	--	--	Will be testing SRC-II in development of low-NO _x
	S. Mosier	& visit	Marine, Aircraft			
I. Pratt & Whitney, E. Hartford, CN	A. Marsh	Phone	Aircraft, Utility, Industry, Marine	--	--	Not involved in testing alternate fuels, which is a function of United Technologies
J. Seaworthy Marine	M. F. Winkler	Phone	Marine Consultants	--	--	Experienced in burning residual fuel emulsions in marinized airframe turbines

Table 4 (Continued)

	Contact		Market	Samples Desired	When Desired	Comments
K. EPA Triangle Park	S. Lanier	(JEH Contact)	(Government)			
L. U.S. Navy Annapolis, MD	E. White	Meeting (Naval Rsrch)				Monitoring synthetic fuel developments for U.S. Navy Requesting samples for comparison with MIL fuel specifications
M. U.S. Navy Philadelphia, PA	E. Weinert	Meeting	shallow & deep- draft marine			Gas Turbine engineer for U.S. Navy
N. American Society of Mechanical Engineers 1. Gas Turbine Div. Combustion & Fuels Committee	W. Blazowski, Chairman	Meetings	Technical Information	--	--	Committed to promoting exchange of technical informa- tion and providing a forum for related publications
2. ANSI Subcommittee B133.7	S. M. DeCorso, Chairman	Meetings	Technical Information	--	--	Organized to gather information on alternate fuels and alternate fuels requirements and ultimately write a Gas Turbine Fuels procurement standard equivalent to the ANSI B133.7 document on petroleum fuels.
P. Tretolite Div., Groves, MD	R. W. Greenlee	Phone	Water separators, desulfifiers	1 gal each liquid grade	Soon	For test on fouling of tubular heaters
II. Gas Turbine, Transportation						
A. Detroit Diesel Allison Indianapolis, IN	J. Vaught F. Salb et al.	Phone & visit	Industrial & Transportation	40 gal middle dis- tillate 60 gal middle distillate	Soon Soon	Screening Test Combustion Test
B. Greyhound Lines Inc.	J. G. Stieber	Visit	Bus Transportation	--	--	Would rely on Allison regarding suitability of SRC-II in Allison-powered buses
C. AiResearch Phoenix, AZ	J. F. Laird, et al.	Visit	Industrial, Marine, Aviation	80 gal middle distillate	Soon	Screening test
D. GM Technical Center Warren, MI	Alex Sapre	(GMRC Contact)		5 tons SRC-I	Soon	SRC-I for continuous combustion engine tests; SRC-II for engine NO _x emission tests
E. Continental Controls Corporation	C. Ross Fisher, et al.	Visit	Fuel controls, Gas Turbine	3 bbl SRC-II	Soon	

Table 4 (Continued)

	Contact		Market	Samples Desired	When Desired	Comments
III. Medium Speed Diesel						
A. General Electric Erie, PA	J. G. Hoffman S. Vargyai P. K. Danyluk	Visit	Railroad	2100-500 gal mid- dle distillate	Indefinite	2-cylinder engine test
B. Colt Fairbanks, Beloit, WI	C. L. Newton	Visit	Marine, Industrial nuclear standby	--	--	Cooperating with DOE and DEMA in alternate fuels considerations.
C. Cooper Energy Svcs., Mt. Vernon, OH	D. L. Siekkinen M. J. Helmich	Visit	Utility & Industry	10 gal middle distillate	Soon	Sample for fuel pump test stand
D. GM-EMD, LeGrange, IL	T. N. Pratt H. A. Williams	Visit	Railroad, Indus- trial, Marine, Off-highway truck	2 gal middle distillate 1000 gal middle distillate	--	The 1000 gal would be for initial engine test
E. Burlington Northern St. Paul, MN	D. H. Propp	Visit	(Railroad operator)	--	--	Suggests initial use of SRC-II in railroad boiler houses rather than in diesel locomotives
F. Electrical Components Div. Bendix	c. V. Brack et al.	Visit	Fuel injectors for non-automotive diesels	--	--	Intereste in effects of SRC-II on elastomers and corrosion of metals
G. Diesel Engine Manu- facturers Assn.	G. Wherry E. Ustruck	Phone & visit	Trade Association, large diesels	--	--	

Table 4 (Continued)

	Contact		Market	Samples Desired	When Desired	Comments
IV. Industrial						
A. Inland Steel Company	M. Holowaty A. Hoagland	Meeting	Blast furnace, open hearth, reheat, boilers, etc.	3 drums SRC-I 350 bbl SRC-II	SRC-I now; SRC-II indefin. probably 1979	SRC-I to be tested as binder for coke briquets, SRC-II as fuel for reheat furnace
B. United Technologies (Fuel Cell Dept.)		Visit	Potential utility market	--	--	
C. North American Mfg. Cleveland, OH	R. Reed	Phone	Process burners	--	--	Just starting to study low-NO _x burners
D. John Zink Co.	R. Reed	Phone	Refy. heater	--	--	Already mfctg. low NO _x burners; has test facility
E. Oak Ridge National Laboratory	V. J. Tennery	Phone	Refractories Testing	300 bbl SRC-II	1980	For combustion tests to determine effects of ash on refractories in comparison with No. 6 Fuel Oil
V. General: Technical Societies, Academia, Government						
A. American Society for Testing & Materials			Writes industrial consensus standards			Established "Surveillance Panel on Alternate Fuels" 12/5/78. GS&TC is represented.
B. Engine Manufacturers Association			Writes procurement standards for gas turbine fuels) Trade Assn., high speed diesels			Has prepared document on energy situation and prospects for future fuels which they kindly sub- mitted to GS&TC for comments

diesel engines, and process equipment. These contacts had several purposes: to obtain updates on what was happening in the field, to survey the market (in the cases of medium-speed diesels and transportation gas turbines), and to acquaint the industries with the properties of SRC-II fuel oil. Tables 3 and 4 list these contacts with organizations involved with these types of equipment, with comments on their interests and sample needs.

3. LARGE SAMPLES FOR EQUIPMENT DEVELOPMENT PROJECTS

In the above contacts, information was obtained about the suitability of conventional equipment for SRC-II fuel oil usage. In some cases, excessive emissions would result and optimized equipment operating conditions must be identified, or new equipment designs or combustion techniques must be developed. The technical problems involved in such efforts have been considered. On-going and proposed projects and also the large amounts of SRC-II fuel oil sample required for such equipment development projects have been discussed with contractors and sponsors.

Table 2 presents our recommendations for a slate of projects to address those needs. This list of projects derives partly from the list prepared by EPRI, as noted in Table 2, but includes alternatives to several items, and additional projects. The list of sample needs is as complete as possible at this time. Table 2 indicates timing, funding source for the work, follow-up work needed in 1980, etc. More detailed comments on each item are presented below, with numbering arranged to correspond with Table 2.

3.1 BOILERS AND BURNERS

3.1.1. Small-Scale Boiler, KVB.

The first of the five proposed blends for KVB has the same composition as the blend used in the ConEd test, in order to see if the KVB boiler simulates the ConEd boiler. If differences are initially observed, KVB will seek operating conditions where their boiler does simulate the ConEd

unit. Tests of the other four blends will provide information about compositional effects, provided that simulating conditions can be found in the KVB boiler.

3.1.2. Fundamental Boiler, MIT.

GMRC will collaborate with MIT in planning runs and analyzing collected particulates and facilitate the use of the results in designing burners and low-emission boiler tests.

3.1.3. Burner Development/EER Corp.

The EPRI project list suggested burner development, and we suggest that SRC-II fuel oil be incorporated into EER's project for EPA. In this program, the "distributed mixing" burner concept which aerodynamically delays the admixture of combustion air into the fuel spray jet, producing a staged combustion effect is being developed. For example, by burning 0.8%-nitrogen residual oil. Recently, less than 200 ppm NO_x was produced. EER is testing SRC-II fuel oil along with 20 other fuel types in an 0.8×10^6 Btu/hr furnace, to obtain parameters for guiding the operation of the distributed mixing burners for each fuel oil. Regarding SRC-II fuel oil, the next task would be 60 hours of parameter-optimizing runs in a 5×10^6 Btu/hr burner, (approx. one drum/hr) and an eight-hour confirming run in their 50×10^6 Btu/hr burner. This work would require 100 drums of SRC-II fuel oil (middle/heavy ratio yet to be decided), and could be done in 1979. This could then be followed by a field demonstration in 1980. EPA has contracted EER to equip a 250×10^6 Btu/hr four-burner industrial boiler with distributed mixing burners for some long-term coal combustion tests, but could possible work in a week's test of SRC-II fuel oil in that unit, one to 1-1/2 years from now. Our February 12 telephone discussion of this test with the EPA project officer, Mr. G. Blair Martin, seems sufficiently definite to include 100 drums of SRC-II fuel oil in the list of needed samples. We will continue to develop details re-timing, etc. EER's capabilities are documented in several reports of their project for EPA's third stationary source symposium in March 1979.

3.1.4. National Airoil Company (Philadelphia).

This company has a new burner design which might suppress fuel-derived NO_x . They have a 20×10^6 Btu/hr (maximum) test tunnel furnace with gas analysis and could do an initial 2-4 hour test of SRC-II fuel oil for approximately \$2000, using 20 bbl (maximum) of sample.

3.1.5. Tests in Large Utility or Industrial Boilers.

Further tests in industrial boilers following the ConEd test should await the availability of low- NO_x burners, results from MIT and KVB, etc. Other variables related to economics and location need to be factored into the selection of the next field test, from the study conducted by Gulf Science and Technology on the "SRC-II Fuel Oil Industrial Boiler Market Opportunity" which is part of the Phase Zero report for DOE.

3.2. STATIONARY GAS TURBINES

In order to get a baseline, EPRI representatives have proposed a full-scale complete turbine test in a conventional machine. In a recent telecon, however, they seemed to appreciate our point that a preferable field test might be one using new combustor designs and producing low NO_x and smoke emissions. Mr. S. M. DeCorso of Westinghouse has expressed a similar attitude; he would like to see a full-scale test as soon as possible, but would first want to do the necessary ground work to assure that such a visible test would produce acceptable emissions. (Post-combustion de- NO_x with a conventional turbine would be an alternative solution which EPRI representatives plan to explore.) On the other hand, a field test in a conventional turbine might be reasonable if it provided needed "systems" data about the use of SRC-II fuel oil in complete turbines (e.g., cross-fire ignition), and if expendable SRC-II fuel oil samples were available. However, if the choices were the allocation of a quantity of SRC-II fuel oil to either such a conventional field test or to the development of new combustor designs, priority would be given to the latter. The following comments reflect these ideas:

3.2.1. Westinghouse (Standard and Catalytic Gas Turbines).

A letter from Dr. W. Rovesti of EPRI to Mr. J. C. Koenig, December 11, 1978, says that in this project, conventional standard full-scale combustors will be tested to prepare for a field test in a complete turbine, and that catalytic sub-scale tests will also be run. A catalytic combustor per se does not suppress fuel-derived NO_x , but it might aid this if it facilitated rich-lean staged combustion, which does suppress fuel-derived NO_x . In spite of our reservations about conventional and catalytic combustors, this item should not be withdrawn from the sample list, since this work may already be underway, judging from the timing (January 4) expressed in Dr. Rovesti's letter.

3.2.2. Accurex (Standard and Catalytic Turbine).

Information received on February 13 indicates that this work emphasizes catalyst poisoning by SRC-II fuel oil, rather than rich-lean fuel- NO_x suppression and that the work is apparently already underway. However, regarding future work, one should first determine whether catalysts are effective under fuel-rich conditions, and if so, then test their susceptibility to long-term poisoning effects. Results probably would differ from the poisoning effects under fuel-lean conditions, which are not of interest (unless post-combustion NO_x -removal is used).

3.2.3. DOE Program "Low NO_x Heavy Fuel Combustor".

(Part of ACT, Advanced Cogeneration Technology Program); RFP 870802 is for Phase I, "Combustion Technology Generation." There will be five contractors, and the total coal liquids ("Fuel C") needed for this Phase is 25,000 gallons or 600 drums to be delivered in portions to contractors between 9/1/79 and 1/1/80.

Allocation of 600 bbl of SRC-II fuel oil for Phase I of the gas turbine low NO_x program (RFP 870802) is highly desirable. Although the tasks

have been negotiated and nearly signed, much technical detail is still to be selected and the DOE program is not yet committed to a specific combustor design (recalling our past concerns that this program would build a combustor optimized for residual oil). Appendix A reviews some of the items in the RFP which suggest that much detailing remains and can still be done consistent with the actual properties of SRC-II fuel oil.

The properties of the fuels C and B are still unspecified, as well as (possibly) the combustor concepts which are to be listed during the contractors' Task I. By supplying information about fuels through meetings, correspondence, and telephone conversations with NASA and with turbine manufacturers, representatives of Gulf Mineral Resources Company and Gulf Science and Technology Company have attempted to help optimize the choices yet to be made. In particular, there are two issues:

(a) If each combustor concept is tested with Fuel B (Task IV) before Fuel C (Task VI), some concepts may be rejected which would have worked well with Fuel C, in the case that Fuel B is poorly chosen. For example, there is a final boiling point at 1000° F and a residual fuel, and the RFP is ambiguous on this point in its description of Fuel B.

(b) Should SRC-II middle distillate (MD) or full-range (FR) fractions be used? The RFP suggests that one synfuel will be chosen, but perhaps the "Fuel Property Variation Tests" could be re-defined (see Task VII) to try both MD and FR SRC-II fuel oil. The middle distillate might be cleaner burning and lower in trace ash elements. The Fuel Quality/Processing Study which is the subject of a separate RFP might illuminate these alternatives.

3.2.4. Several Possible Companies (Water Washing Tests).

To protect gas turbines against high temperature corrosion by hot fuel-oil ash, a two-step treatment has become fairly routine with heavy fuel oils:

(a). The fuel is mixed with water and a demulsifier; then the water is separated out by gravity, centrifuging, or electrostatic treaters. Sodium compounds and other water-soluble components are removed with the water.

(b). A powder, solution, or slurry of magnesium compounds is added to the fuel to counteract the corrosive action of oil-soluble vanadium compounds. Manganese compounds are more expensive but are also good deposit modifiers and may be used if the smoke-reducing action of manganese is needed. Other deposit-modifying compounds may be used, notably those of silicon or aluminum.

The difference in density between water and fuel is important to the separation step in the washing procedure. For this reason, an effort to measure density of SRC-II middle distillate, heavy distillate, and full-range distillate at temperatures from 60 to 300°F is being planned at Harmarville, PA as suggested by Mr. Roy Greenlee of Tretolite. Whenever we have a drum of any SRC-II liquid available, and a stated need to know its performance in a fuel-washing treatment, Tretolite (desalting chemicals) and its sister company Petreco (desalting equipment) will be anxious to work with us. This is a desirable investigation to promote. We also recommend complying with Mr. Greenlee's request for one gallon of each SRC-II fluid for Tretolite's evaluation in an on-going test program to simulate fouling tendencies in a fuel heater (heat exchanger).

3.2.5. Brown Boveri Turbomachinery, Inc. (Single Combustor Design).

Before being acquired by Brown Boveri, Turbodyne had conducted and reported on full-scale combustion tests on No. 2 Fuel doped with pyridine. Interestingly, all of the analytical data on fuels for this program were performed at Harmarville through the program for Sales and Analytical Services. Like other gas turbine manufacturers, Brown Boveri has a program to produce low NO_x emissions with "dry" combustion (no water injection); they

believe that their single-combustor machine will achieve this goal more readily than their competitors' machinery. With water injection, they "can handle" fuels with nitrogen contents up to 0.75% in their present machines, but would not feel comfortable about meeting NO_x emission standards with fuels exceeding 0.9% nitrogen content.

Brown Boveri has no rig-testing machinery in the United States, but very adequate facilities in Baden, Switzerland. Currently we are acquainting domestic Brown Boveri engineers with the properties of SRC-II fuel oil, with the remote objective of working towards a full-scale combustion test in an existing Brown Boveri turbine installation in the United States (400-425 bbl test fuel, minimum). In the interim, it may develop that a small sample, perhaps five gallons, will be requested for rig testing in Switzerland.

3.2.6. Unspecified (Full-Scale Test of SRC-II Liquid as Gas Turbine Fuel).

Utility companies are reluctant at present to buy a gas turbine fueled with natural gas or petroleum, because they are not sure that these fuels will be available to them for the life of the turbine (perhaps 20 years). Consequently, turbine sales are in the doldrums and there is some commercial interest in demonstrating that present turbines will operate satisfactorily on the fuels of the future. This creates some pressure for a full-scale demonstration test of SRC-II fuel oil as soon as possible. However, an unsatisfactory performance could be more damaging than no test at all, so the need for proper background testing is recognized.

Westinghouse and EPRI are burning SRC-II middle and heavy distillates in conventional combustor rig tests by way of preparation. Blends of middle and heavy are also under consideration, and are being tested at the Westinghouse laboratory (Pittsburgh area).

As other manufacturers work towards a full-scale demonstration, we hope to cooperate fully with them. However, each demonstration should be predicated on unique features that promise to keep emissions within acceptable limits; e.g., a low-NO_x control built into the boiler part of the cycle.

3.3. MEDIUM SPEED DIESEL ENGINES

Attachment II shows that General Motors-Electromotive Division and Cooper Energy Services requested a 2-gallon and a 10-gallon sample of SRC-II middle distillate, respectively, and it is recommended that these samples be supplied as soon as possible. The following larger samples would also provide useful combustion information in engines of different designs. It is recommended that they be supplied in 1979 if possible:

3.3.1. General Electric, Erie, PA

GE manufactures a 4-stroke cycle engine which powers 20% of the locomotives in the United States.

3.3.2. Cooper Energy Services

Cooper manufactures both two-stroke and four-stroke cycle engines, many with dual-fuel capability, that are used in stationary service. They also manufacture stationary engines fueled with natural gas, and have developed a modification for burning diesel fuel in existing units, using spark plugs and a pilot flow of natural gas for ignition.

3.3.3. GM-EMD

EMD provides 80% of the locomotive engines in the United States; a two-stroke cycle design.

3.3.4. Various Manufacturers

Other manufacturers of medium and slow speed piston engines, such as Colt Fairbanks in Beloit, Wisconsin, and Clark Dresser in Olean, New York, are associated with the above companies through Diesel Engine Manufacturers Association and may be involved in providing information and possibly test work for DOE through DEMA. Fuel oil samples should be made available as

required, with emphasis on the medium speed railroad locomotive and domestic marine diesel applications.

3.4. GAS TURBINES, TRANSPORTATION

AiResearch, Detroit Diesel Allison, and Solar (which is not strictly in the transportation area) all indicated an interest in samples. We suggest they each be offered a drum of SRC-II middle distillate, on which they would perform exploratory testing. Further sample requests would probably result from this work. We also suggest sending the three drums (SRC-II middle distillate) requested by the GM Technical Center.

3.5. INDUSTRIAL PROCESSES

Industrial processes include direct-fired heaters where the combustion gases are in direct contact with the products being manufactured, such as rotary kilns, blast furnaces, glass melting furnaces, open hearths, and tunnel dryers. This category also includes furnaces in which oil or liquid chemicals are heated in tubes, much as water and steam are heated in boiler tubes. These furnaces and heaters often require multiple burners for precise control of heating profiles and use liquid or gaseous fuel to better achieve this control. Satisfactory performance with SRC-II fuel oil as a replacement for present fuels will, in most cases, require a low-NO_x burner with means to assure complete combustion of aromatic fuels.

3.5.1. Inland Steel Company

As an integrated steel company, Inland has large fuel requirements in diverse applications. A test of three drums of SRC-I as a binder for coke sounds very desirable. Their proposed test of 350 bbl of SRC-II middle distillate as fuel for a reheat furnace is also desirable as a new and different application. However, the letter of February 1 from Mr. Holowaty of Inland to Mr. J. C. Koenig indicates that the selection of a test furnace is still under consideration. Consideration should be given to NO_x emissions and whether they can be expected to be in an acceptable range in the application selected for test.

3.5.2. Oak Ridge National Laboratory

In a program sponsored by DOE, samples of selected industrial refractories are being exposed to combustion gases from No. 6 fuel oil at 1350°C, then studied for deterioration and mineralogical changes caused by heat and fuel ash components. The project manager is interested in including SRC-II fuel oil in this study of alternate fuels for industrial use and is exploring various avenues for funding a test run.

This appears to be a very desirable test to promote. With the low or nil ash content of SRC-II fuel oil, a favorable result is practically assured, and the usual distribution of their published results will bring favorable attention to SRC-II fuel oil in a diverse cross-section of fuel-using industries.

3.5.3. John Zink Company

As a leading manufacturer of burners used in process heaters for the refining and chemical industries, this company maintains a burner demonstration laboratory in Tulsa, Oklahoma, under the supervision of recognized authorities on combustion. Waste materials, often liquids of high viscosity or unusual composition, are evaluated here for customers. Development work on burner design is also conducted. An article reporting some of their work on NO_x reduction appeared in Chemical Engineering Progress, December, 1978. For a fee, they will burn SRC-II fuel oil in a 10 million BTU/hr burner at various fuel-air ratios, measure the emissions, and report the results achieved. From the properties of SRC-II fuel oil, they anticipate combustion results that will be approximately borderline acceptable in NO_x emissions, and it is recommended they be contracted to conduct a test.

3.6. MARINE

Marine power plants are much the same as land-based power plants; involving boilers, medium or low speed diesels, or large gas turbines for deep draft marine, and medium or high speed diesels or transportation gas turbines

for smaller vessels and boats. Emissions limitations would be non-existent on the high seas, but low cost would be important, as well as interchangeability with bunker fuels picked up at other ports.

3.6.1. Naval Ships Research and Development Center

A special situation exists with respect to the U.S. military which has the responsibility of keeping track of developments in synthetic fuels and their potential for the fleet and other military uses.

In supplying samples requested by NSRDC, it will be important to explain that conformance to existing fuel specifications cannot be the criterion of value although it may well be the criterion of suitability for fleet use.

Appendix A

Abstract of DOE Program "Low NO_x Heavy Fuel Combustor"

RFP 870802

Task 1. Preliminary Design (due 30 days after contract starts). Prepare preliminary designs of test rigs, a list of combustor configurations for Phase I, and testing plans and procedures. Be consistent with Fuel B properties. (Fuel B is "Petroleum residual," 10.8% hydrogen, initial boiling point 600°F, final boiling point 1000°F, max. sulfur 0.8%, max. nitrogen 0.2%, max. pour point 50°F). The combustor should also be designed to accept Fuels A and C if its ability to handle Fuel B will not be compromised. (Fuel A is a distillate like No. 2 oil; Fuel C was originally intended to be a petroleum-derived equivalent of coal-derived fuel but now will be SRC-II.)

Task 2. Final Design. (due 60 days after Task I.)

Task 3. Fabrication and Installation (due 180 days after contract starts.)

Task 4. Combustion Tests. Petroleum Residual Fuels (Fuel B). Each combustor concept shall undergo tests, modifications and retests to define the potential of each concept for low emissions, fuel flexibility (Fuels A, B, and C) and performance. Test conditions will be selected by the contractor based on his prior experience.

Subtask 4.1. Baseline tests: (120 days span) Fuel B only, pyridine doped, twelve combustor configurations, three hours run time on each.

Sub-task 4.2. Fuel Property Variation Tests (180 days span, following sub-task 4.1) Blends of Fuels A and B, with pyridine doping; twenty-eight 3-hr tests.

Task 5. Combustion Tests, Petroleum Distillate Fuels (Fuel A) (concurrent with Task IV, scope one-half of Task IV). The goal is ultra-low NO_x, 37 ppm.

Sub-task 5.1. Baseline tests, Fuel A. Six 3-hr tests.

Sub-task 5.2. Fuel Property Variation Tests. Fourteen 3-hr tests, blends of Fuels A and B, no pyridine doping.

Task 6. Combustion Tests, Synfuels (Fuel C). Same scope and format as Task 5, but with Fuel C. The goal is 75 ppm NO_x with fuel-nitrogen 1.2% max.

Sub-task 6.1. Baseline tests Fuel C. Selected combustor configurations with Fuel C as received and nitrogen-doped between 0.6 and 1.2%.

Sub-task 6.2. Fuel Property Variation Tests. Blends of Fuels C and A nitrogen-doped between 0.6 and 1.2%.

Task 7. Design Analysis Studies. Data analysis, defining and redefining the test fuels and combustor approaches concurrently with the test program, and providing input to applications (to the subsequent phases of this program).

**GULF SCIENCE AND TECHNOLOGY COMPANY
PITTSBURGH, PENNSYLVANIA**

SRC-II PRODUCT CHARACTERISTICS

D. L. STAHLFELD

**CHEMICALS AND MINERALS DIVISION
REPORT NO. 627RK008
JULY, 1979**

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1.0 SUMMARY

SRC-II product distillates (400°F+) represent potential boiler or gas turbine fuels for utility and industrial applications. The exact boiling range products which a commercial SRC-II installation would produce depends upon the demands of the market and requirements of specific applications. No significant handling, storage, distribution or utilization problems are indicated for their use alone or in blends with petroleum-derived fuels in installations currently using No. 4, No. 5, or No. 6 fuels derived from petroleum sources if reasonable attention is given to specific, but easily accommodated, differences between coal-derived and petroleum-derived fuels. For example, SRC-II distillate fractions with a given boiling range have a higher specific gravity than corresponding petroleum-derived fuels with the same boiling range. Similar considerations would also be addressed with regard to relating the desired viscosity for a given installation with the boiling range selected or the amount of SRC-II material blended with a petroleum stock.

Blending data for SRC-II distillates and various petroleum-based fuels indicate that no compatibility problems should be expected as long as the SRC-II distillate comprises at least 25 volume percent of the final blend. Thermal stability is excellent. Current work is being conducted to obtain corrosion data on iron and non-ferrous metals, to determine effects on elastomer deterioration, and to evaluate potential water separability problems. It is already known that mild hydrotreating of the middle distillate essentially eliminates its tendency to form emulsions with water, as indicated by the water reaction test.

Laboratory and field tests demonstrate that the total SRC-II distillate burns cleanly and well. No handling or burning problems were encountered in a large-scale utility field test sponsored by EPRI and ConEd.

SRC-II distillates have aromatic contents which preclude their direct substitution for their petroleum-derived counterparts used in most diesel engines, jet aircraft, and gas turbine applications. Nitrogen levels

constitute a possible problem with regard to allowable NO_x emissions in these applications. However, SRC-II distillates may be used directly in low-speed marine diesels and certain gas turbines modified to accommodate the higher radiant heat release and the NO_x emission potential of SRC-II distillates.

DOE-sponsored work at Chevron and UOP indicates that existing technology can upgrade coal-derived distillates to produce premium quality diesel, jet, and gas turbine fuels, providing their economic value justifies the processing costs. The various diesel fuel specifications, jet fuel requirements, and gas turbine fuel specifications soon to be adopted illustrate the complicated nature of the various fuel requirements. The degree of upgrading required for various boiling fraction SRC-II distillates is a complex optimization issue, but it can be predicted that such upgraded SRC-II distillates could produce transportation fuels without problems in the existing modes of handling, storage, and distribution.

2.0 PROPERTIES OF MIDDLE AND HEAVY SRC-II DISTILLATES NEAT AND IN BLENDS WITH PETROLEUM-DERIVED FUELS

Laboratory inspections of SRC-II liquids produced by liquefying Western Kentucky, Pitt Seam, and Illinois No. 6 coals are displayed on Table 1 (naphthas from all three coals), Table 2 (distillates from Western Kentucky), Table 3 (distillates from Pitt Seam), and Table 4 (distillates from Illinois No. 6). While the major thrust of this section concerns the handling, storage, distribution and utilization of the distillates, the naphtha data are displayed only to document the different fractionation cut points of the naphthas from the contiguous middle distillate materials. In a properly designed and operated commercial fractionating system, it would be possible to make a rather sharp cut between these two fractions. The experimental nature of the equipment on which these materials were produced precluded making as sharp a separation as would normally be expected. While there is some naphtha material in the distillate and some distillate material in the naphtha, the relative quantities are such that no significant changes would be expected from the analytical results reported compared to what would be obtained on well-fractionated naphtha and middle distillate.

Table 1

INSPECTIONS ON SRC-II NAPHTHAS PRODUCED FROM DIFFERENT COALS

<u>Coal Source</u>	<u>Western Kentucky</u>	<u>Pitt Seam</u>	<u>Illinois No. 6</u>
Absolute Density, 15°C(59°F): kg/dm ³	0.8359	0.8276	0.8087
Gravity: °API	37.7	39.4	43.4
Nitrogen, Total: Wt %	0.88	0.62	0.53
Nitrogen, Basic: Wt %	0.51	0.33	0.24
Carbon: Wt %	84.54	85.09	84.80
Hydrogen: Wt %	11.93	11.82	12.35
Sulfur: Wt %	0.24	0.52	0.52
Oxygen, Total: Wt %	3.28	2.47	2.14
Arsenic, PPB	< 5	< 25	< 25
Bromine Number	45	40	46
Maleic Anhydride Value	6.9	10.9	5.2
Hydrocarbon Group (HPLC): Vol %			
Saturates	64.9	63.1	69.3
Aromatics	26.7	32.2	24.3
Olefins	8.4	4.7	6.4
Hydrocarbon Analysis, ASTM D-1319(FIA): Vol %			
Saturates	62.0	68.0	71.0
Aromatics	30.5	27.0	19.5
Olefins	7.5	5.0	9.5
Hydrocarbon Analysis(Mass Spec.)			
ASTM D-2789: Vol %			
Paraffins	21.4	28.0	30.1
Monocycloparaffins	33.1	39.3	43.7
Dicycloparaffins	11.7	5.1	6.4
Aromatics(Total)	33.8	27.6	19.8
Benzene	1.7	1.8	1.3
Toluene	5.4	7.9	5.9
C ₈ Alkylbenzenes	9.5	10.8	8.0
C ₉ Alkylbenzenes	7.1	3.8	2.9
C ₁₀ Alkylbenzenes	3.3	1.0	0.8
C ₁₁ Alkylbenzenes	1.0	0.5	0.0
C ₁₂ Alkylbenzenes	0.0	0.0	0.0
Indans/Tetralines	5.2	1.7	0.9
Naphthalenes	0.6	0.1	0.0
Mass Spec. Analysis for Liquid Coal			
Group Type - G 5374: Vol %			
Benzenes	12.1	17.8	12.7
Tetralins	6.0	5.7	3.8
Naphthalenes	0.3	0.9	0.7
Dihydroxybenzenes	0.4	0.0	0.1
Phenols	11.7	1.8	0.6
Biphenyls	0.0	0.1	0.1
Distillation, ASTM D-86			
Over Point: °C(°F)	62.8(145)	50.0(122)	45.6(114)
End Point: °C(°F)	216.1(421)	226.7(440)	211.7(413)
5% Condensed at: °C(°F)	73.9(165)	65.6(150)	58.9(138)
10	97.2(207)	77.8(172)	75.0(167)
20	115.0(239)	96.7(206)	91.1(196)
30	122.2(252)	106.7(224)	102.2(216)
40	140.0(284)	116.7(242)	111.7(233)
50	150.0(302)	126.7(260)	122.2(252)
60	161.1(322)	141.1(286)	133.3(272)
70	168.9(336)	153.3(308)	143.3(290)
80	173.9(345)	165.6(330)	153.9(309)
90	187.8(370)	183.3(362)	170.0(338)
95	207.2(405)	210.0(410)	200.6(393)
Recovery: %	96.0	98.0	96.5
Residue: %	1.0	1.0	1.4
Loss: %	3.0	1.0	2.1

Table 2

INSPECTIONS ON SRC-II DISTILLATES PRODUCED
FROM WESTERN KENTUCKY COAL

Inspection	Middle Distillate	Heavy Distillate	Additional Inspections	Middle Distillate	Heavy Distillate
Absolute Density, 15°C(59°F); kg/dm ³	0.9739	1.087	Total Halides as NaCl		
Gravity, ASTM D 287; °API	13.7		Gulf 528: Lb/1000 Bbl	5	18
Viscosity, SUS(cs), ASTM D 161			Iodine Number, Gulf 18	25.9	-
37.8°C (100°F)	37.3(3.18)	418(90.15)	Smoke Point, D 1322: mm	8	-
98.9°C (210°F)	-(1.07)	43(5.11)	Naphthalene, ASTM D1840: Vol %	19.8	-
			Luminometer No., ASTM D 1740	2b.	-
Flash Point, ASTM D 90, °C(°F)	85.0(125)	168.3(335)	Water Reaction, ASTM D1094		
Pour Point, ASTM D97: °C(°F)	-42.8(-45)	47.2 (+45)	Change in Volume: cm ³ (ml)	7	20
			Interface Rating	4	4
Nitrogen, Total, Wt %	1.10	1.43	Separation Appearance Rating	3	3
Nitrogen, Basic, Wt. %	0.913	0.790	Aromatics by Mass Spec.		
Carbon, Micro Method, Wt %	86.34	88.89	G-5374T: Wt %		
Hydrogen, Micro Method, Wt %	9.29	7.50	Benzopyrene	0.0	-
Carbon Residue, ASTM D189: Wt %	1.15 ^a	1.49	Chrysene	0.0	-
Aniline Point, ASTM D 611: °C(°F)	<-3.0(<26.6)	20.0(68)	Fluorenes	0.2	-
Ash Content, ASTM 482: Wt %	0.002	0.028	Tetrahydrofluoranthrenes	0.0	-
Sulfur, ASTM D 1552: Wt %	0.20	0.37	Pyrenes/Fluoranthrenes	0.0	-
Neutralization No. (TAN), ASTM D 664	0.42	0.35	Dihydroxybenzenes/Tetrahydrochrysene	0.6	-
Nickel, PPM	<0.1	0.3	Octahydrophenanthrenes	1.4	-
Vanadium, PPM	<0.1	<0.1	Hexahydrophenanthrenes	0.5	-
Copper Strip Corrosion, ASTM D 130			Tetrahydrophenanthrenes	1.7	-
100°C(212°F) 8 Hrs	1	1	Phenanthrenes	0.2	-
Asphaltenes, IP 143: Wt %	0.04	2.69	Fluorenes/Dihydrophenanthrene	0.8	-
Heat of Combustion, ASTM D 240			Acenaphthenes/Biphenyls	2.8	-
MJ/kg(BTU/Lb) Gross	39.02(16,776)	39.64(16,042)	Tetralins	16.8	-
Oxygen, Total, Wt %	4.20	1.76	Tetrahydroacenaphthenes	1.4	-
Oxygen, Combined, Wt %	4.19	1.45	Naphthalenes	13.6	-
Mercaptan Sulfur, Wt %	0.007	0.003	Benzenes	5.0	-
Existent Gum, ASTM D 381: Mg/100g	12+	-	Naphthols	0.9	-
Potential Gum, ASTM D 873: Mg/100g	1,602	-	Dihydroxybenzenes	1.4	-
Spot Test - Compatibility Rating			Phenols	17.5	-
Proc. A - Hot, Gulf 856			Total	65.0	-
Straight Run No. 2 F.O.	1	2			
No. 2 Heating Oil	1	2			
FCC No. 2 F.O.	1	2			
Proc. B - Cold, Gulf 856					
Straight Run No. 2 F.O.	1	3			
No. 2 Heating Oil	1	3			
FCC No. 2 F.O.	1	3			
Thermal Stability, ASTM D 1661 (NBTL)					
Unwashed, Thimble Rating	1	1			
Washed, Thimble Rating	1	1			
Wiped, Washed Thimble Rating	1	1			
Rating of Tube	1	1			
Stability Test, Gulf 562 - 16 Hrs					
Existent Insolubles: Mg/600G	10.7	not applicable ^c			
Potential Insolubles: Mg/600G	0.8	not applicable ^c			
Filtrate Color, ASTM D 1500	L 5.0 dil.	not applicable ^c			
Stability Test, Gulf 462 - 64 Hrs					
Existent Insolubles: Mg/600G	10.7	not applicable ^c			
Potential Insolubles: Mg/600G	1.0	not applicable ^c			
Filtrate Color, ASTM D 1500	D 8.0 dil.	not applicable ^c			
Absolute Stability, ASTM D 2274					
Total Insolubles: Mg/100 ml.	0.8	-			
Stability Test, AT-SR-148.9°C(300°F), G902	borderline	-			
Hydrocarbon Type (HPLC): Gulf 1558: Vol %					
Saturates	35	-			
Aromatics	65	-			
Rust Preventive Test, NACE T3P					
(ASTM D 605 Mod.):	A(None)	-			

- a. Carbon Residue on 10% bottoms
b. Beyond scope of method
c. Sample will not filter as prescribed by the method to determine existent and potential insolubles.

Table 3

Inspections on SRC-II Distillates Produced from Pitt Seam Coal

Inspection	Middle Distillate	Heavy Distillate	Additional Inspections	Middle Distillate	Heavy Distillate
Absolute Density, 15°C (59°F): kg/dm ³	0.9733	1.0681	Aromatics, Mass Spec., Gulf 5374T: Wt %		
Gravity, ASTM D 287: °API	13.8	0.9	Benzopyrenes	0.0	-
Viscosity, SUS (cs), ASTM D 2161			Chrysenes	0.0	-
25.0°C (77°F)	40.7 (456)	- (-)	Decahdropyrenes	0.0	-
37.8°C (100°F)	36.3 (3.10)	249 (53.5)	Hexahdropyrenes	0.2	-
54.4°C (130°F)	- (1)	96.8 (19.72)	Tetrahydrofluoranthenes	0.0	-
98.9°C (210°F)	- (1.02)	39.9 (4.21)	Pyrenes/Fluoranthenes	0.1	-
Flash Point, P-M, ASTM D 93: °C (°F)	75.6 (168)	82.2 (180)	Dithdropyrenes/Tetrahydrochrysenes	0.3	-
Pour Point, ASTM D 97: °C (°F)	-45.6 (-50)	9.4 (+15)	Octahdropyrenes	1.4	-
Nitrogen, Total: Wt %	1.04	1.31	Hexahdropyrenes	0.5	-
Nitrogen, Basic: Wt %	0.84	0.72	Tetrahydrophenanthrenes	2.2	-
Carbon: Wt %	86.17	89.04	Phenanthrenes	0.2	-
Hydrogen: Wt %	8.94	7.28	Fluorenes/Dihydrophenanthrenes	1.0	-
Carbon Residue, Con., ASTM D 189: Wt %	0.95 ^a	0.87	Acenaphthenes/Biphenyls	2.6	-
Sulfur, ASTM D 1552: Wt %	0.17	0.39	Tetralins	27.4	-
Color, ASTM D 1500	L 3.5	D 8.0 (D11)	Tetrahydroacenaphthenes	1.3	-
Aniline Point, ASTM D 611: °C (°F)	<0 (<32)	40.5 (104.9)	Naphthalenes	18.6	-
Neutralization No. (TAN), ASTM D 130	0.27	0.25	Benzenes	4.3	-
Nickel: PPM	<0.1	0.8	Naphthols	1.0	-
Vanadium: PPM	<0.1	0.8	Dihydroxybenzenes	0.9	-
Copper Strip Corrosion, ASTM D 130			Phenols	1.3	-
100°C (212°F), 3 Hr.	3	1	Total	63.3	-
Asphaltenes, IP 143: Wt %	0.10	1.62			
Heat of Combustion, ASTM D 240:					
MJ/kg (BTU/LB), Gross	39.79 (17,106)	39.58 (17,017)			
Oxygen, Total: St %	3.64	1.38			
Mercaptan Sulfur: Wt %	0.022	0.021			
Compatibility Rating, Gulf 856					
Procedure A: Hot					
Straight Run No. 2 F. O.	1	3			
No. 2 Heating Oil	1	3			
FCC No. 2 F. O.	1	3			
Procedure B: Cold					
Straight Run No. 2 F. O.	1	3			
No. 2 Heating Oil	1	3			
FCC No. 2 F. O.	1	3			
Thermal Stability, ASTM D 1661 (NBTL)					
Unwashed: Thimble Rating	1	1			
Washed: Thimble Rating	1	1			
Wiped: Thimble Rating	1	1			
Rating of Tube	1	1			
Stability Test, Gulf 562, 16 Hr.					
Existent Insolubles: Mg/600C	0.5	-			
Potential Insolubles: Mg/600C	0.9	-			
Filtrate Color, ASTM D 1500	L 5.0	-			
Stability Test, Gulf 562, 64 Hr					
Existent Insolubles: Mg/600C	6.5	-			
Potential Insolubles: Mg/600C	1.6	-			
Filtrate Color, ASTM D 1500	D 8.0 Dil.	-			
Accelerated Stability, ASTM D 2274					
Total Insolubles: Mg/100ml	0.4	-			
Stability Test, ATSF,					
Gulf 902, 148.9°C (300°F)	borderline	-			
Hydrocarbon Group (HPLC), Gulf 1558: Vol %					
Saturates	36.7	-			
Aromatics	63.3	-			
Ash, Gulf 599: Wt %	0.0005	0.04			
Smoke Point, ASTM D 1322: Mm	5	-			
Naphthalenes, ASTM D 1840: Vol %*	24.3	-			
Cetane Number, ASTM D 613	<20	-			
Water Reaction, ASTM D 1094					
Change in Volume: cm ³ (ml)	4	NA			
Interface Rating	1	NA			
Separation Rating	3	NA			

^a Carbon Residue on 10% Btms.

* Method designated for aviation turbine fuels.

Naphthalene value shown is outside scope of the method.

NA Not applicable for this material.

Table 4

INSPECTIONS ON SRC-II DISTILLATES PRODUCED
FROM ILLINOIS NO. 6 COAL

Inspection	Middle Distillate	Heavy Distillate	Additional Inspections	Middle Distillate	Heavy Distillate
Absolute Density, 15°C(59°F): Kg/dm ³	0.9726	1.0729	Aromatics, Mass Spec., Gulf 5374T: Wt %		
Gravity, ASTM D 286: °API	13.9	0.3	Benzopyrenes	0.0	-
Viscosity, SUS (cs), ASTM D 2161			Chrysenes	0.0	-
25.0°C(77°F)	41.6(4.74)	- (-)	Decahydrophenes	0.0	-
37.8°C(100°F)	36.8(3.25)	231(49.60)	Hexahydrophenes	0.2	-
54.4°C(130°F)	- (-)	92.6(18.72)	Tetrahydrofluoranthenes	0.0	-
98.9°C(210°F)	- (1.07)	39.6(4.03)	Pyrenes/Fluoranthenes	0.1	-
Flash Point, P-M, ASTM D 93: °C(°F)	71.1(160)	160(320)	Dihydrophenes/Tetrahydrochrysenes	0.4	-
Pour Point, ASTM D 97: °C(°F)	bel -53.9(bel -65)	-9.4(+15)	Octahydrophenanthrenes	1.5	-
Nitrogen, Total, Wt. %	0.85	1.18	Hexahydrophenanthrenes	0.5	-
Nitrogen, Basic, Wt. %	0.72	0.66	Tetrahydrophenanthrenes	1.9	-
Carbon, Wt. %	85.58	89.21	Phenanthrenes	0.2	-
Hydrogen, Wt. %	9.12	7.66	Fluorenes/Dihydrophenanthrenes	0.8	-
Carbon Residue, Con., ASTM D 189: Wt. %	0.85 ^a	1.02	Acenaphthenes/Biphenyls	2.5	-
Sulfur, ASTM D 1552: Wt. %	0.19	0.47	Tetralins	25.9	-
Color, ASTM D 1500	L 2.0 Dil.	D 8.0 Dil.	Tetrahydroacenaphthenes	1.5	-
Aniline Point, ASTM D 611: °C(°F)	< 0 (< 32)	< 10 (< 50)	Naphthalenes	17.2	-
			Benzenes	5.2	-
Neutralization No. (TAN)	0.42	0.57	Naphthols	1.2	-
Nickel, PPM	≤ 0.1	0.9	Dihydroxybenzenes	1.0	-
Vanadium, PPM	≤ 0.1	1.1	Phenols	1.5	-
Copper Strip Corrosion, ASTM D 130			Total	61.6	-
100°C(212°F), 3 Hr	3	1			
Asphaltenes, IP 143: Wt. %	0.17	0.93			
Heat of Combustion, ASTM D-240					
MJ/kg(Btu/Lb), Gross	39.59(17,020)	39.69(17,064)			
Oxygen, Total, Wt. %	4.29	1.64			
Mercaptan Sulfur, Wt. %	0.015	0.008			
Compatibility Rating, Gulf 856					
Procedure A: Hot					
Straight Run No. 2 F.O.	1	3			
No. 2 Heating Oil	1	3			
FCC No. 2 F.O.	1	3			
Procedure B: Cold					
Straight Run No. 2 F.O.	1	3			
No. 2 Heating Oil	1	3			
FCC No. 2 F.O.	1	3			
Thermal Stability, ASTM D 1161 (NBTL)			Distillation, ASTM	D 86	D 1160
Unwashed: Thimble Rating	1	1	Over Point: °C(°F)	170.0(338)	-
Washed: Thimble Rating	1	1	End Point: °C(°F)	281.1(538)	502.8(937)
Wiped: Thimble Rating	1	1	5% Condensed at: °C(°F)	191.1(376)	290.6(555)
Rating of Tube	1	1	10	196.7(386)	297.8(568)
Stability Test, Gulf 562, 16 Hr.			20	203.3(398)	308.3(587)
Existent Insolubles: Mg/600G	6.7	-	30	208.9(408)	317.2(603)
Potential Insolubles: Mg/600G	0.5	-	40	211.7(413)	327.2(621)
Filtrate Color, ASTM D 1500	L 5.5	-	50	218.3(425)	337.8(640)
Stability Test, Gulf 562, 64 Hr.			60	223.9(435)	351.1(664)
Existent Insolubles: Mg/600G	6.7	-	70	231.7(449)	367.2(693)
Potential Insolubles: Mg/600G	1.2	-	80	239.4(463)	389.5(733)
Filtrate Color, ASTM D 1500	D 8.0 Dil.	-	90	250.6(483)	418.2(785)
Accelerated Stability, ASTM D 2274			95	258.9(498)	450.0(842)
Total Insolubles: Mg/100ml	0.6	-	Recovery, %	98.8	-
Stability Test, ATSF,			Residue: %	1.0	-
Gulf 902, 148.9°C(300°F)	Borderline	-	Loss: %	0.2	-
Hydrocarbon Group (HPLC) Gulf 1558: Vol. %					
Saturates	38.4				
Aromatics	61.6				
Ash, Gulf 599: Wt. %	0.0003	0.10			
Smoke Point, ASTM D 1322: Mm	5	-			
Naphthalenes, ASTM D 1840: Vol. %*	21.0	-			
Cetane Number, ASTM D 613	< 20	-			
Water Reaction, ASTM D 1094					
Change in Volume: CM ³ (ML)	4	NA			
Interface Rating	1	NA			
Separation Rating	3	NA			

a. Carbon Residue on 10% Btms.

* Method designed for aviation turbine fuels. Naphthalene value shown is outside scope of method.

NA Not applicable for this material.

Evaluation of the SRC-II distillate inspection data indicates that:

1. SRC-II distillates have much higher density and are somewhat more viscous than typical petroleum-derived fuels of similar boiling range.
2. The SRC-II middle distillate (MD) boiling range is similar to that of kerosene or No. 1 fuel oil. This is simply representative of the manner in which the distillates were fractionated and imposes no restriction on how a commercial fractionation system would be designed and operated. Such a commercial installation would have the flexibility to produce various boiling range SRC-II distillates to accommodate various markets and specific applications.
3. Viscosity of the MD product is slightly higher than typical No. 2 fuel oil, while the heavy distillate (HD) has a viscosity in the range of a light No. 5 fuel oil.
4. In general, MD and HD contain more nitrogen, oxygen, and aromatics and less hydrogen than petroleum fuels. While these factors suggest that SRC-II distillates are likely to yield higher smoke and NO_x emissions than petroleum fuels, laboratory and field tests indicate that excessive smoking is not a problem with these fuels and appropriate combustion techniques can produce NO_x emissions within acceptable limits.
5. Sulfur contents of MD and HD are within the current maximum 0.5% level required for No. 2 fuel oil as stated in ASTM D396, Standard Specifications for Fuel Oils. This standard permits whatever local sulfur specification is legally required for No. 4, No. 5, and No. 6 fuels; it is expected that SRC-II distillates would meet most, if not all, local sulfur specifications.

6. MD and HD appear to be reasonably compatible with petroleum stocks with no undue precipitation occurring at concentrations greater than 25% v.
7. Due to a much higher aromatic content than petroleum fuels and the presence of significant phenolic compounds, some attack on some elastomeric fuel system components could be expected from SRC-II distillates. This issue is being addressed by current studies.
8. MD and HD have good thermal stability (NBTL Test) indicating no undue preheater deposits should be formed in combustion equipment.
9. MD and HD appear to be fairly stable in accelerated stability tests. That is, low levels of potential insolubles or precipitated solids indicate no undue formation of solids would be expected during extended storage. Results of similar tests of blends with petroleum stocks (especially for SRC-II MD) indicate that as the amount of MD is lowered to about 25% v, the blends become increasingly unstable. This is believed to be a manifestation of solvent activity of the highly aromatic SRC-II liquid, which at higher concentrations prevents precipitation of oxidized products. It should be noted that freshly distilled SRC liquids rapidly darken, indicating some oxidation occurs.
10. Metals and ash content of these products are quite acceptable indicating no substantial ash would be formed during combustion, and corrosiveness by metals would be low.
11. MD and HD can form hard-to-separate emulsions with water, which could present problems in storage and handling. Ongoing work is evaluating this potential problem and is discussed later.

Very mild hydrotreating of the middle distillate dramatically improves its water reaction test (an indication of emulsion-forming tendencies).

12. The low cetane number of the MD, due to high aromatics content and presence of phenols, indicates limited potential for use as a diesel engine fuel.

Based on this study, the SRC-II derived distillates and blends with petroleum stocks would be suitable as fuels for industrial applications.

3.0 FUEL OILS

Table 5 shows the viscosity range which normally classifies various fuel oils. According to this classification, the SRC-II middle distillates are in the No. 2 fuel range and the SRC-II heavy distillates are in the No. 5 fuel range. Table 6 extends this classification concept to include discussions of when a specific type atomization is needed, pumping and handling limitations, etc. No problems are indicated for SRC-II distillates. ASTM D396 lists the standard specifications for various fuel oils and the significance of the various tests.

In principle, SRC-II distillates could be used as high quality fuel in applications requiring currently specified No. 4, No. 5 and No. 6 fuel oils. High aromaticity and low °API gravity prevent SRC-II middle distillate from being used in No. 1 or No. 2 fuel oil applications. However, as discussed later, the SRC-II distillate can be upgraded for these applications.

Preliminary studies have been conducted to evaluate how the SRC-II distillate stores, responds to inhibitors, nitrogen blanketing, etc., by itself and when in admixture with petroleum derived materials. While there is no industry-wide accepted method to measure storage stability,* the following comments are offered.

* This is the basis of concern leading to a new section being formed under ASTM Committee D-2, Technical Division E.

TABLE 5

PETROLEUM FUELS

VISCOSITY-BOILING RANGE - GRAVITY RELATION

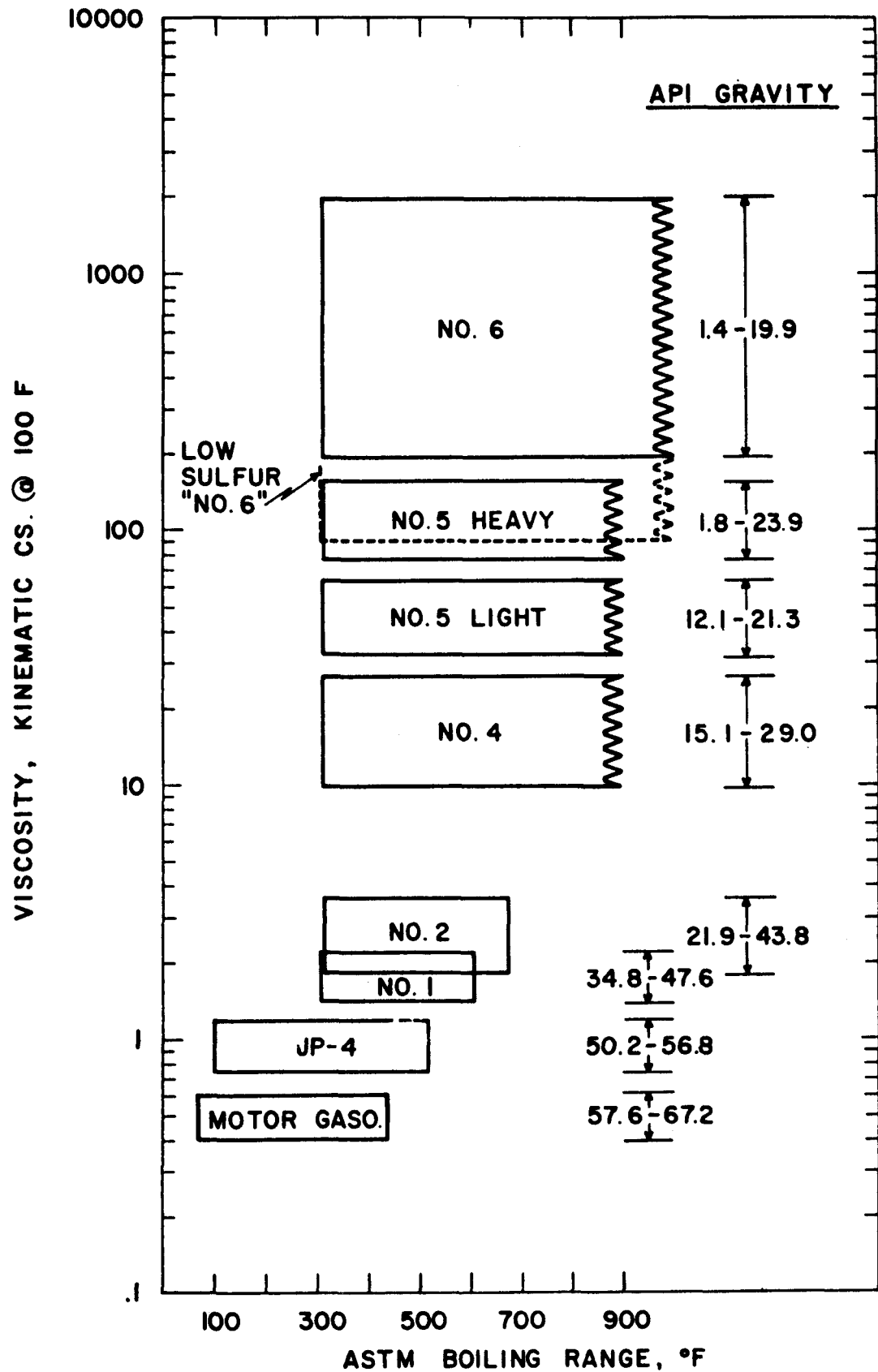
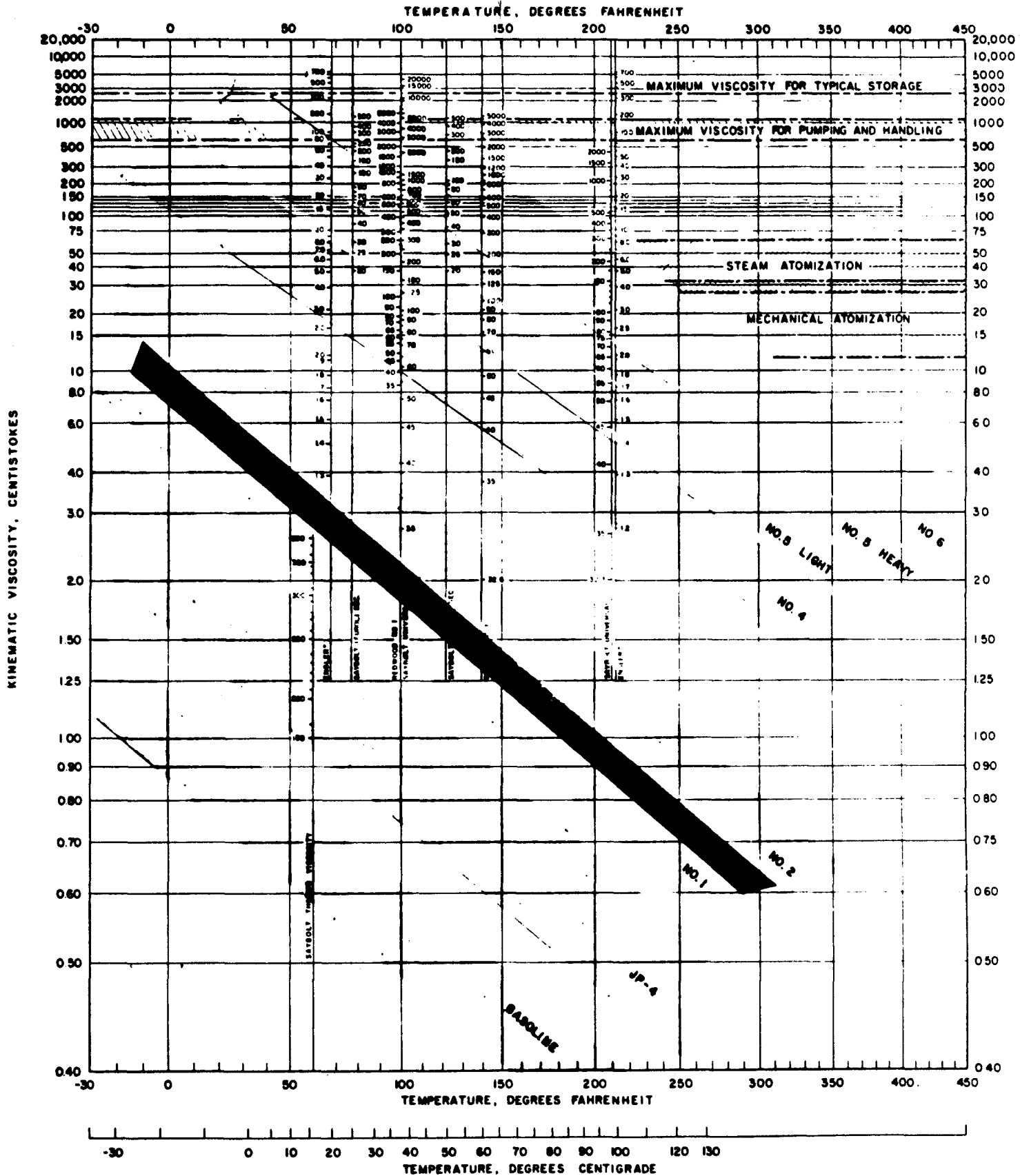


TABLE 6



The results of these stability tests are somewhat scattered and not always consistent. In fact, even some of the aged-uninhibited samples contain fewer insolubles than found initially in inhibited samples, which might indicate this test method may not be applicable to all types of fuels; 6% of the samples tested show a decrease in the existent insolubles and 53% show a decrease in potential insolubles during the first four weeks. Agent Amergy 5200 appears to be most effective and Agent GA 1173 the least.

Test results indicate that the asphaltene content of the SRC-II heavy distillate can be reduced somewhat with the addition of any of the six agents. The greatest reduction was with the addition of Agent Tolad 340, which shows a 67% reduction after aging four weeks and 43% reduction after eight weeks.

The results of the Gulf 499 centrifuge test are quite low (<0.05) both before and after inhibiting the heavy distillate. As a result, all values could be classified as trace.

Effectively, the net result of these preliminary investigations suggests that, providing reasonable handling, storage and blending considerations are understood and employed, there should be no insurmountable obstacles involved with using SRC-II distillates neat or in blends with petroleum stocks for those industrial fuel applications operating with current fuels identified as No. 4, No. 5 or No. 6. Outside combustion studies confirm this conclusion. A large-scale New York City combustion test with SRC-II distillate presented no handling problems and burned cleanly and well according to its sponsors, EPRI and ConEd. The results of a study to evaluate the applicability of SRC-II distillates for premium boiler fuels at a Rohm and Haas industrial facility in Philadelphia, Pennsylvania, are located in Volume 4. Additional studies are being conducted at Gulf to obtain data on the impact of SRC-II distillates on iron and non-ferrous metal corrosion, elastomer deterioration, water separability problems, sludge formation due to oxidation, and solids precipitation.

Mild hydrotreating of the middle distillate produced from Western Kentucky coal effected a marked improvement in water reaction (a measure of emulsion forming tendency) but no such benefit was observed with the mildly hydrotreated heavy distillate. The degree of desired hydrotreating is a complex optimization issue. Even very mild hydrotreating of the middle distillate results in desirable benefits. Whether the associated costs are justified depends upon many factors.

3.1 Jet Fuels

In addition to ASTM D1655 (the standard specification for jet fuels) Table 7 lists the primary commercial Jet A-1 Specifications. MIL-T-5624K is a list of test methods and specifications for military jet fuels.

SRC-II distillates simply do not meet jet fuel specifications for aromatic content, smoke point, luminometer number, naphthalene content, and stability. However, if the objective of a coal liquefaction installation is to maximize transportation fuels, one of which is a specification jet fuel, the SRC-II distillate can be hydrotreated. In a DOE sponsored study conducted by Chevron, a high quality jet fuel was produced by this procedure. No compatibility, transportation, storage, handling, or distribution problems would be anticipated with such a high quality SRC-II product; this could be checked rather quickly and inexpensively.

3.2 Gas Turbine Fuels

The proposed revised ASTM D2880-78 standard specification for gas turbine fuel oils is expected to become effective in 1980. Of particular concern here are stringent trace metal limits (viz., vanadium, sodium plus potassium, calcium, and lead). It would be expected that a wide range SRC-II middle distillate produced in properly designed and operated commercial fractionating facilities would have no particular difficulty in producing a product whose trace elements would meet the most stringent specifications. However, the °API gravity and the nitrogen level of the SRC-II distillate

TABLE 7

PRIMARY COMMERCIAL JET A-1 SPECIFICATIONS

	D. Eng. R. D. 2494 Issue 8 (10-78)	IATA GUIDANCE Kerosene (11-78)	ASTM D-1655 Jet A-1 (11-78)
Appearance	Clear & Brt	-	Clear & Brt
Total Acidity, mgKOH/gm	0.015 Max	0.1 Max (A)	0.1 Max (A)
Aromatics, % v	22.0 Max	22.0 Max	22.0 Max
			25.0 Max (Jet A)
Olefins, % v	5.0 Max	-	-
Sulfur, % w	0.3 Max	0.3 Max	0.3 Max
Mercaptan Sulfur, % w	0.001 Max	0.003 Max	0.003 Max
or			
Doctor Test	Sweet	Sweet	Sweet
Distillation, F (C)			
IBP	Report	-	-
10 % Rec.	401 Max (205)	400 Max (204)	400 Max (204)
20 % Rec.	Report	-	-
50 % Rec.	Report	Report	Report
90 % Rec.	Report	Report	Report
EP	572 Max (300)	550 Max (288)	572 Max (300)
Residue, %	1.5 Max	1.5 Max	1.5 Max
Loss, %	1.5 Max	1.5 Max	1.5 Max
Flash Point, F	100 Min	100 Min	100 Min
Gravity, API	39-51 (B)	37-51	37-51
Freeze Point, F	-58 Max	-58 Max	-58 Max
Viscosity, cSt @ -20 C	8 Max	8 Max	8 Max
Hydrogen, % w	13.8 Min (C)	-	-
Heat Value, BTU/LB, Net	18,400 Min	18,400 Min	18,400 Min
or			
Aniline Gravity Product	5,250 Min	-	-
Smoke Point, mm	19 Min	19 Min	19 Min
			18 Min (Jet A)
Naphthalenes, %	3 Max	3 Max	3 Max
Copper Strip Corrosion,			
2 Hr @ 212 F, Rating	1 Max	1 Max	1 Max
Silver Corrosion, Rating	1 Max	-	-
Thermal Stability, (D)			
Filter Pressure Drop, mm Hg	25 Max	25 Max	25 Max
Tube Rating, Visual	L.T. 3	L.T. 3	L.T. 3
or			
Tube Rating, TDR	17 Max	-	-
Copper Content, µg/kg	150 Max (E)	-	-
Existent Gum, mg/100 ml	7 Max	7 Max	7 Max
Water Reaction,			
Interface Rating	1b Max	1b Max	1b Max
Separation Rating	2 Max	2 Max	2 Max
Water Separation Index Modified			
Without Static Additive	85 Min	-	-
With Static Additive	70 Min	-	-
Electrical Conductivity, pS/m (F)	50-450	50-300	50-300

- (A) IATA and ASTM require a Total Acid No. of 0.1 Max by either the D-974 or D-3242 methods in lieu of the DEngRD Total Acidity Test.
- (B) The actual specification limit is 0.775-0.830 kg/l at 15 C by the D-1298/IP 160 method.
- (C) If the fuel meets the 13.8 % Hydrogen content limit by the IP 338 method five other specification tests are eliminated. These are the olefins, heat value, aniline gravity product, smoke point and naphthalenes tests.
- (D) IATA and ASTM allow the use of either the old D-1660 Coker or the new D-3241 JFTOT methods for determining the fuel's thermal stability. DEngRD accepts the new D-3241 JFTOT method only.
- (E) This requirement applies only to fuels which contain copper sweetened components.
- (F) This requirement applies only to fuels which contain a static dissipator additive.

would present problems meeting the gravity specification and the most likely maximum NO_x emissions level. High aromaticity tends to generate more radiant heat in the combustors and would probably require their redesign. More specific information on the potential of SRC-II distillates for gas turbine fuels is presented in Volume 1.

Again, upgrading of the SRC-II distillate by hydrotreating becomes an optimization question with regard to processing optimization (the degree of hydrotreating to be done on a specific part of the SRC-II distillate with a particular catalytic system) and the optimization of the combustor design and operation in the gas turbine application to achieve satisfactory emissions from a given fuel. Chevron and UOP data indicate that various processing options are available to conduct the necessary hydrotreating to sufficiently upgrade the SRC-II distillates to produce premium gas turbine fuels. The optimum degree of upgrading necessary or desirable remains to be determined.

3.3 Diesel Fuels

Diesel applications mainly fall into three main categories which can be conveniently classified as low speed (e.g., marine diesels), medium (e.g., railroads and power generation), and high speed (trucks and automotive). Some of the fuel characteristics for these different applications are listed on Tables 8 and 9.

While ASTM D975 is the main specification in defining different grades of Diesel fuel oils (e.g., No. 1-D, No. 2-D, No. 4-D), each diesel engine manufacturer has its "own little book" relating specific fuel requirements to its engines in conjunction with the controlling ASTM D975 specifications. These reflect years of time and considerable cooperation between the manufacturer and supplier of the fuel, the engine designer and builder, and the actual field experience of the user. They are rather involved and diversified, and it is expected that Gulf would continue as a major contributor and participant in the cooperation necessary between the various parties involved to enable acceptance of SRC-II products into the diesel fuel market. Examples of such joint cooperation are reflected in the diesel fuel specifications for such companies as White Industrial Power (Alco Engines

TABLE 8

FUEL REQUIREMENTS OF DIESEL ENGINES

ENGINE	SLOW SPEED	MEDIUM SPEED	MEDIUM/HIGH SPEED	HIGH SPEED
FUEL	HIGH SULFUR HEAVY RESIDUAL, 3500 REDWOOD #1	HIGH SULFUR RESIDUAL & INTERMEDIATE 1500 REDWOOD #1 DISTILLATE (.4% - 1.0%S) DISTILLATE (.4 - 3.0%S)		

TABLE 9

**CETANE NUMBER REQUIREMENT
VS ENGINE SPEED**

<u>RPM RANGE</u>	<u>CETANE NUMBER (PREFERRED)</u>
0-100	15-30
100-200	15-40
200-400	30-45
400-800	35-50
800-1500	45-55
1500-3000	50-60

GRDC/PTD/GLK
MAR 74

Division), Caterpillar Tractor, Chicago Pneumatic Tool, Cooper-Bessemer, Superior, General Motors (Detroit Diesel Allison Division), Deutz, Electromotive Division of GM, Colt Industries (Fairbanks Morse Engine Division), Fulton Iron Works, Ingersoll-Rand, International Harvester, Waukesha, and White Engines.

SRC-II distillates have too high an aromatic content to have the required cetane number for any but the most restricted, extremely large, slow-speed marine diesel market. However, the aforementioned Chevron data which reported on upgrading SRC-II distillate to specification grade jet fuel indicates this same material would most likely constitute an acceptable diesel fuel, even though no cetane numbers were given. The degree of upgrading required is directly related to the speed of the diesel engine in which the fuel is to be used; very little, if any upgrading being necessary for slow-speed engines and considerable upgrading being necessary for high-speed engines. There seems to be no obstacle to upgrading SRC-II liquids to whatever products the market demands, whether it be home heating oil, jet fuel, gas turbines, diesel fuel, or whatever. With the SRC-II products available, all kinds of processing and marketing options become available; the particular disposition route chosen by one location could well be extremely different from the route chosen by another installation in another location. SRC-II distillates constitute potentially viable premium boiler fuels; as markets and prices dictate, the degree of upgrading necessary to optimize all the factors involved in the operation of the synfuels industry will surely follow.

While there are some relatively minor constraints with regard to using SRC-II distillates in the existing mode of handling, distributing, storing and utilizing boiler fuels, it is expected that these can easily be accommodated; more importantly, as upgrading is implemented and maximum transportation fuels are sought from SRC-II liquids, there will be no problems with their compatibility to existing modes of handling, distributing, storing and utilizing the various transportation fuels.

4.0 REFERENCES

1. Standard Specification for Gas Turbine Fuel Oils, ANSI/ASTM D2880-78.
2. IATA Guidance Material for Aviation Fuels, November, 1978.
3. Fuel Oil, Burner, MIL-F-859E, September, 1965.