III. WORK PLANNED FOR OCTOBER, 1971

The work planned for October will basically be a continuation of the various activities that have been underway for the past few months.

A final summary report on the evaluation of the coals for the in-depth beneficiation program has been written and is now being edited.

The bid package from Koppers for the fluidized-bed gasification PEDU will be reviewed. A list of usable equipment and instrumentation from the Stage 2 PEDU will be developed with the idea of incorporating as many of these items as possible in the new PEDU set-up. Reactivity studies of a new char will be initiated.

Review of the bid package from Koppers for the methanation PEDU is planned. A schedule for the dismantling of the Stage 2 PEDU will be developed to expedite the clearing of the area. Tests in the bench-scale methanator will continue with Catalyst 2684 to determine the critical partial pressure of carbon monoxide that causes carbon deposition. A new batch of catalysts has been received and screening tests will be run to obtain suitable catalysts for detailed evaluation. Planning for the model studies will continue.

Tests in the Stage 2 PEDU (100 lb/hr) have been officially terminated. PEDU Tests 57 and 58 will be evaluated, and work will begin on the preparation of a final summary report. The report will cover the work done since September 20, 1970.

Work on the cold flow model experiments for the 5 ton/hr two-stage gasifier will continue. Material and equipment for the Phase I and Phase III tests will be assembled as they are received.

The computer programs set up for the Stage 2 PEDU will continue to be used. Construction of a room to house the PDP-8/E computer ordered from Digital Equipment Corporation will be started.

Every assistance will be given Koppers to ensure completion of the bid package for the multipurpose research pilot plant facility.

A. Trips and Meetings Planned

October 1, 1971	Koppers Company, Inc. Pittsburgh, Pennsylvania	R. A. Glenn

B. Visitors Expected

October 1, 1971	Office of Coal Research Washington, D. C.	N. P. Cochran
October 5, 1971	Gilbert Associates, Inc. 525 Lancaster Avenue Reading, Pennsylvania	Carl A. Bolez

October 7, 1971	West Virginia University Morgantown, West Virginia	Prof. C. Y. Wen
October 7, 1971	U.S. Bureau of Mines Pittsburgh, Pennsylvania	Dr. P. Yavorsky
October 8, 1971	Hydrocarbon Research, Inc. Trenton, New Jersey	C. A. Johnston

C. Papers to be Presented

April, 1972	Symposium on Quality of Synthetic Fuels ACS Division of Fuel Chemistry Boston, Massachusetts	"Economics of Generating Clean Fuel Gas from Coal Using an Air-blown Two-stage Gasifier" E. K. Diehl J. T. Stewart R. A. Glenn

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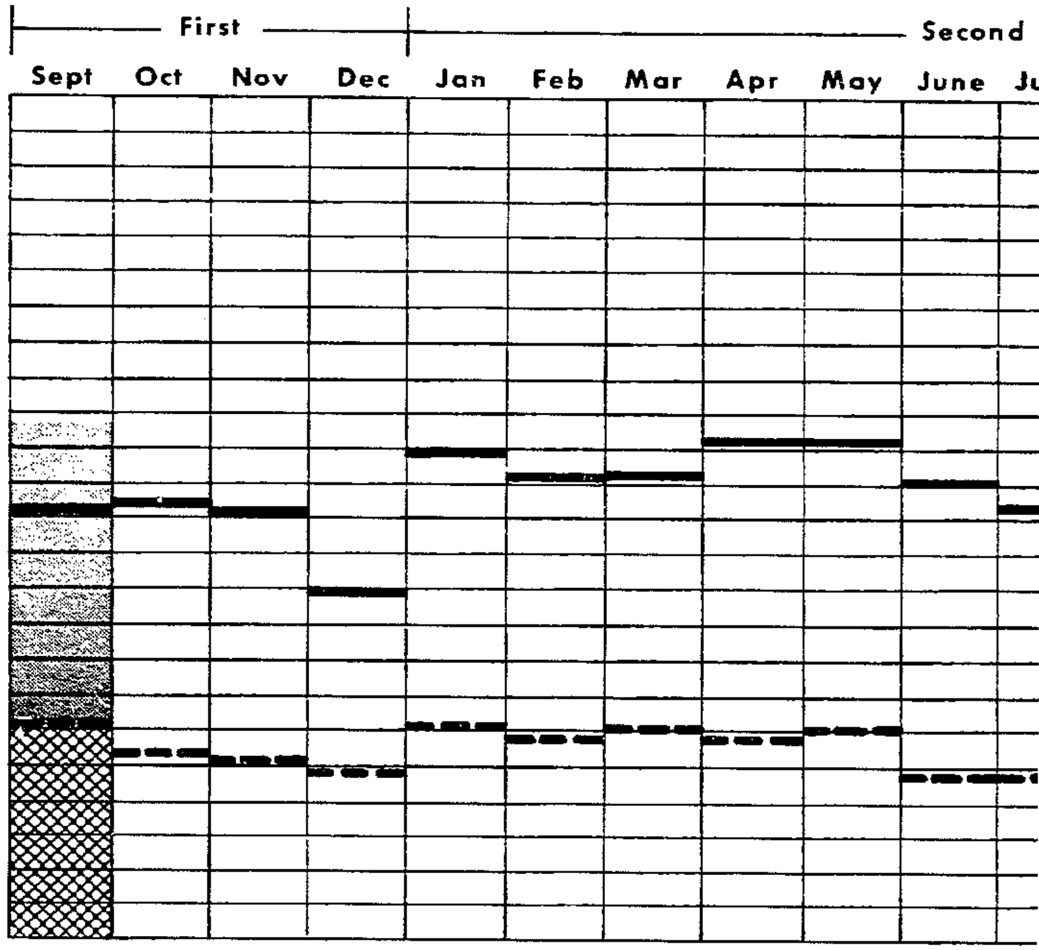
MANHOURS



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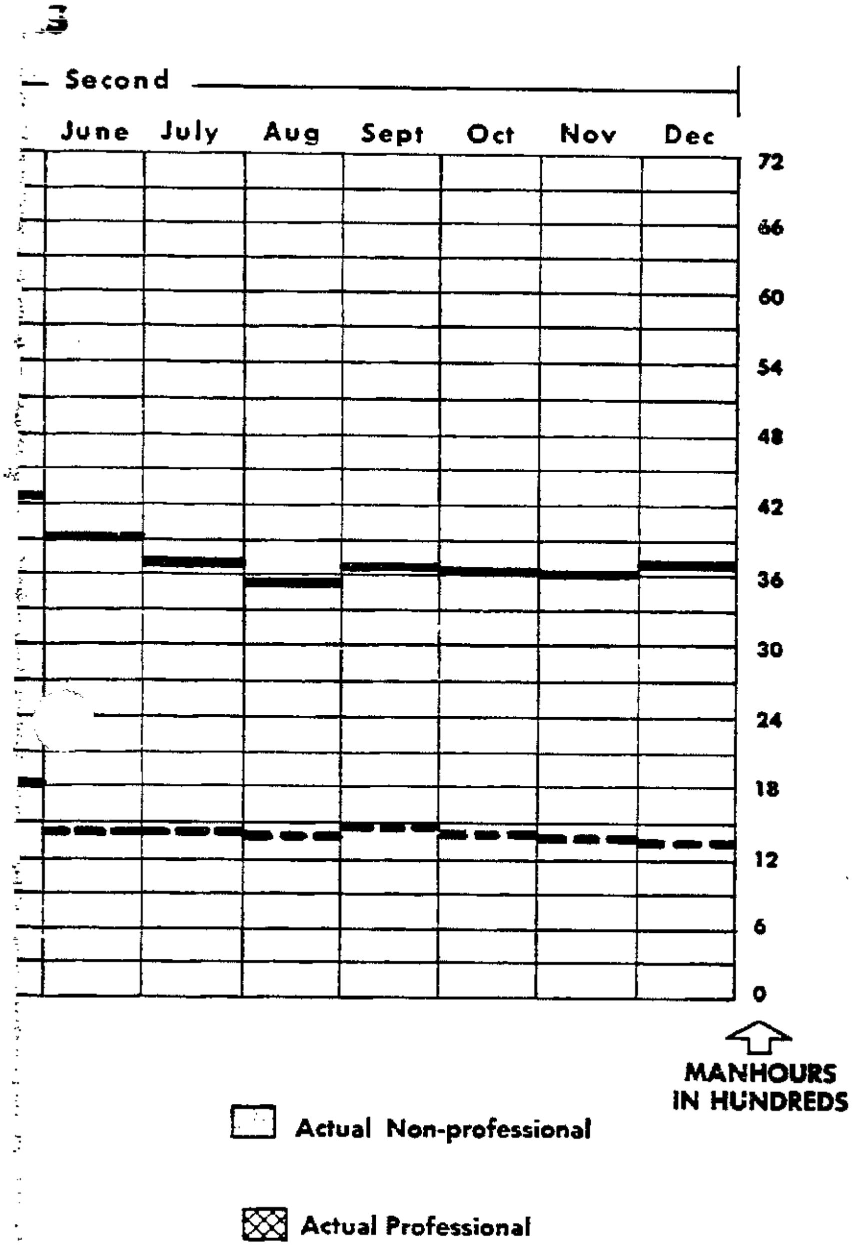
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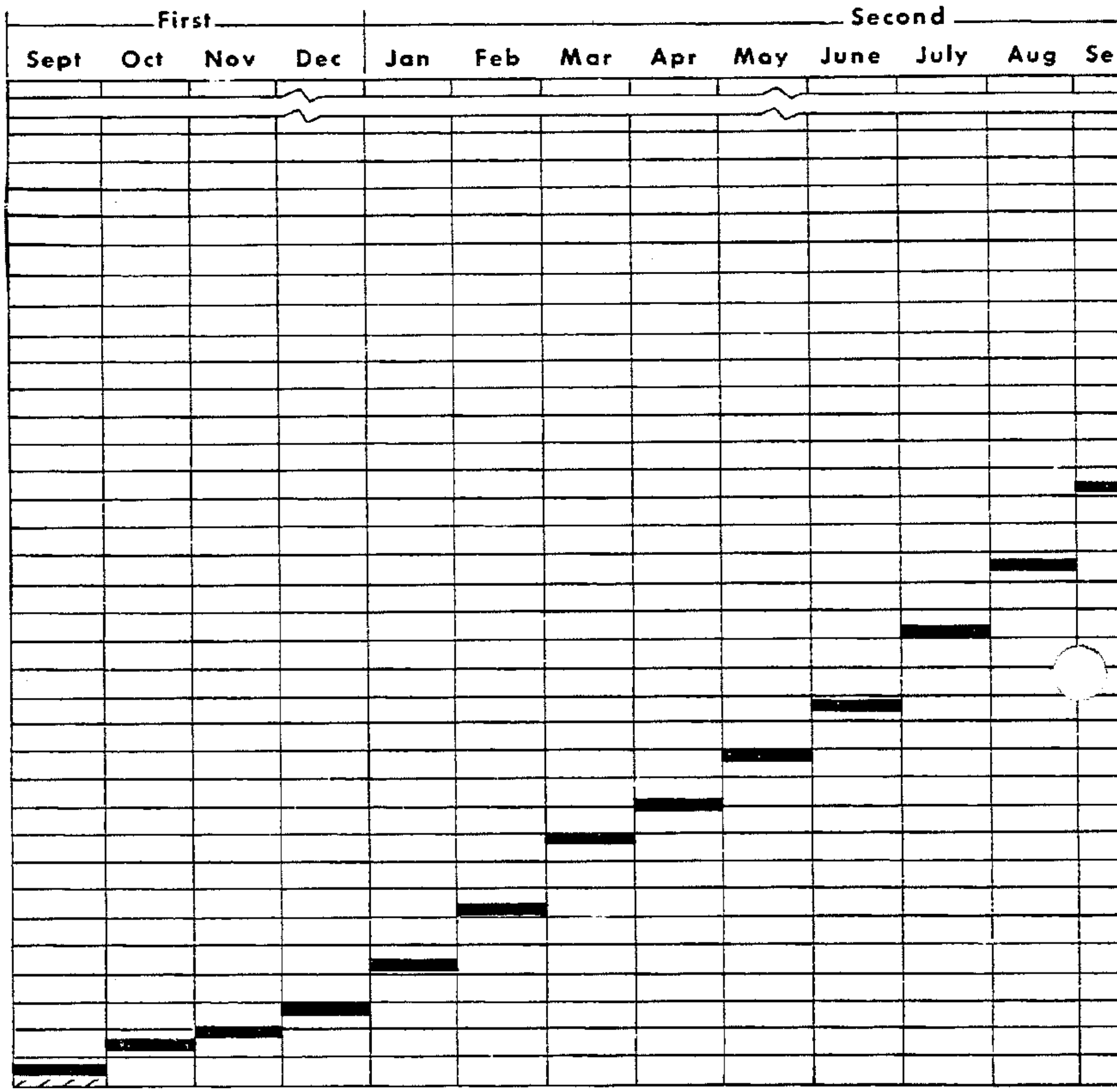

MONTHLY EXPENDITURES (All Costs, in Dollars)

		Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Monroeville	Predicted	129,991	129,991	129,991	129,991	323,486	382,228	558,454	105,058	66,23
	Actual	63,610								
Homer City	Predicted								154,000	215,6
	Actual									
Total	Predicted	129,991	129,991	129,991	129,991	323,486	382,228	558,454	259,058	301,8
	Actual									

MONTHLY PROGRESS CHART
Part 2 Expenditures

OFFICE OF COAL RESEARCH
DEPARTMENT OF THE INTERIOR

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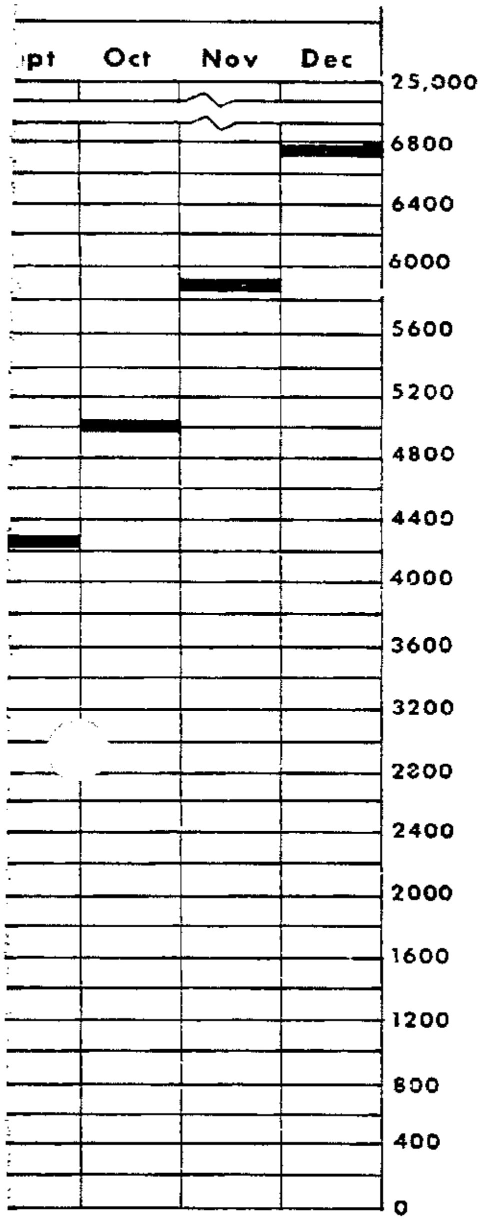
CUMULATIVE EXPENDITURES



Expenditures, Cumulative

Predicted Expenditures, Cumulative

DOLLARS IN THOUSANDS

.	June	July	Aug	Sept	Oct	Nov	Dec
38	86,240	65,813	65,813	74,746	62,273	62,273	62,275
600	280,400	444,300	444,300	444,400	760,600	760,600	760,800
838	366,640	510,113	510,113	519,146	822,873	822,873	823,075

2

APPENDIX B

BI-GAS STAGE 1 TEMPERATURES WITH COMPLETE CHAR RECYCLE

Material and heat balance data for complete gasification using the BI-GAS process were calculated for Illinois No. 6 seam coal. The following coal analysis was used:

Moisture, percent	1.3
Ash, percent	9.1
Heating value, gross, Btu/lb	14,480

Ultimate analysis, daf-basis, percent

Carbon	81.3
Hydrogen	5.4
Nitrogen	1.5
Oxygen	9.6
Sulfur	2.6

As a basis for the calculations, the following data were used:

System Pressure	70 atm
Stage 2 Gas Exit Temperature	1700 F
Coal Preheat Temperature	200 F
Steam Preheat Temperature	980 F
Oxygen Preheat Temperature	800 F
Methane Yield, C basis	20 and 27.5 percent

The steam rate selected was 5 mols/100 lb daf coal which gave a steam decomposition of about 70 percent. A heat loss of 50 Btu/lb daf coal was used. The results obtained for the combined Stage 1 and 2 are shown in Table 15.

Assuming that 15 and 25 percent of the carbon in coal is converted to carbon oxides in Stage 2, the amount of char remaining and recycled to Stage 1 was obtained. Using the amount of oxygen required from Table 15, and assuming that 2.0 and 5.0 mols (40 percent or 100 percent of total) of steam are added in Stage 1, the gas yield, composition, and approximate temperature of Stage 1 gas shown in Table 16 were obtained.

Figure 18 is a plot of the Stage 1 exit temperature versus the mols of steam used in Stage 1. Additional lines are drawn on this graph to delineate somewhat arbitrarily the following temperature regimes:

TABLE 15. MATERIAL AND HEAT BALANCE DATA
(Complete gasification, Illinois No. 6 seam coal)

C of coal as Methane in Stage 2, Percent	20.0	27.5
Basis: 100 lb daf coal (6.77 mols C)		
Feed, mols		
Oxygen	1.64	1.40
Steam	5.0	5.0
Product, mols		
Steam	1.853	1.783
Hydrogen	3.118	2.188
Methane	1.36	1.36
Carbon Monoxide	3.84	3.13
Carbon Dioxide	1.57	1.78
Nitrogen plus Hydrogen Sulfide	0.135	0.135
	11.876	10.876
Steam Decomposition, percent	67	66
(P_{H_2}) at exit, atm (70 atm total pressure)	17.9	14.1
Methane after methanation, mols	3.10	3.19
Basis: 1 MSCF total methane in product		
coal, lb daf	85	82.8
coal, MM Btu daf	1.37	1.33
Oxygen, lb	44.6	37.2
Steam, lb	76.0	74.5

TABLE 16. STAGE 1 DATA FOR COMPLETE GASIFICATION
(Illinois No. 6 seam coal, 1700 F Stage 2 exit temperature)

lb O_2/100 lb daf coal	52.5				44.8			
C as CH_4 in Stage 2, percent	20.0				27.5			
C as ($CO + CO_2$) in Stage 2, percent	15		25		15		25	
lb Steam State 1/100 lb coal	36	90	36	90	36	90	36	90
mols Steam Stage 1/100 lb coal	2	5	2	5	2	5	2	5
lb Steam/lb O_2 Stage 1	0.69	1.71	0.69	1.71	0.80	2.0	0.85	2.0
lb C* in Stage 2 char/100 lb daf coal	52.7	52.7	44.6	44.6	46.7	46.7	38.6	38.6
lb O_2/lb C gasified	1.0	1.0	1.17	1.17	1.15	1.15	1.36	1.36
lb O_2/lb C (70 percent C use)	0.7	0.7	0.82	0.82	0.80	0.80	0.95	0.95
lb O_2/lb C (from Figure 847)	0.6	0.6	0.85	0.85	0.80	0.80	1.25	1.25
mols/100 lb daf coal								
Steam	0.48	2.68	0.86	3.26	0.51	2.81	0.92	3.38
Hydrogen	1.52	2.32	1.14	1.74	1.49	2.19	1.08	1.62
Carbon Monoxide	4.00	3.20	3.02	2.42	3.49	2.79	2.56	2.02
Carbon Dioxide	0.40	1.20	0.70	1.30	0.40	1.10	0.66	1.20
Total	6.40	9.40	5.72	8.72	5.89	8.89	5.22	8.22
Partial pressure of Hydrogen, (P_{H_2}), atm (70 atm total pressure)	16.6	17.2	14.0	14.0	17.3	15.1	14.5	13.8
Stage 1 exit temperature, F	2880	2330	3850	3890	2390	1910	3300	2440
Gas Analysis, percent (wet basis)								
Steam	7.5	28.5	15.0	37.4	8.7	31.6	17.6	41.1
Hydrogen	23.8	24.7	19.9	20.0	25.2	24.6	20.7	19.7
Carbon Monoxide	62.5	34.0	52.9	27.7	59.3	31.4	49.1	24.6
Carbon Dioxide	6.2	12.8	12.2	14.9	6.8	12.4	12.6	14.6

* Unreacted char from Stage 1 not included.

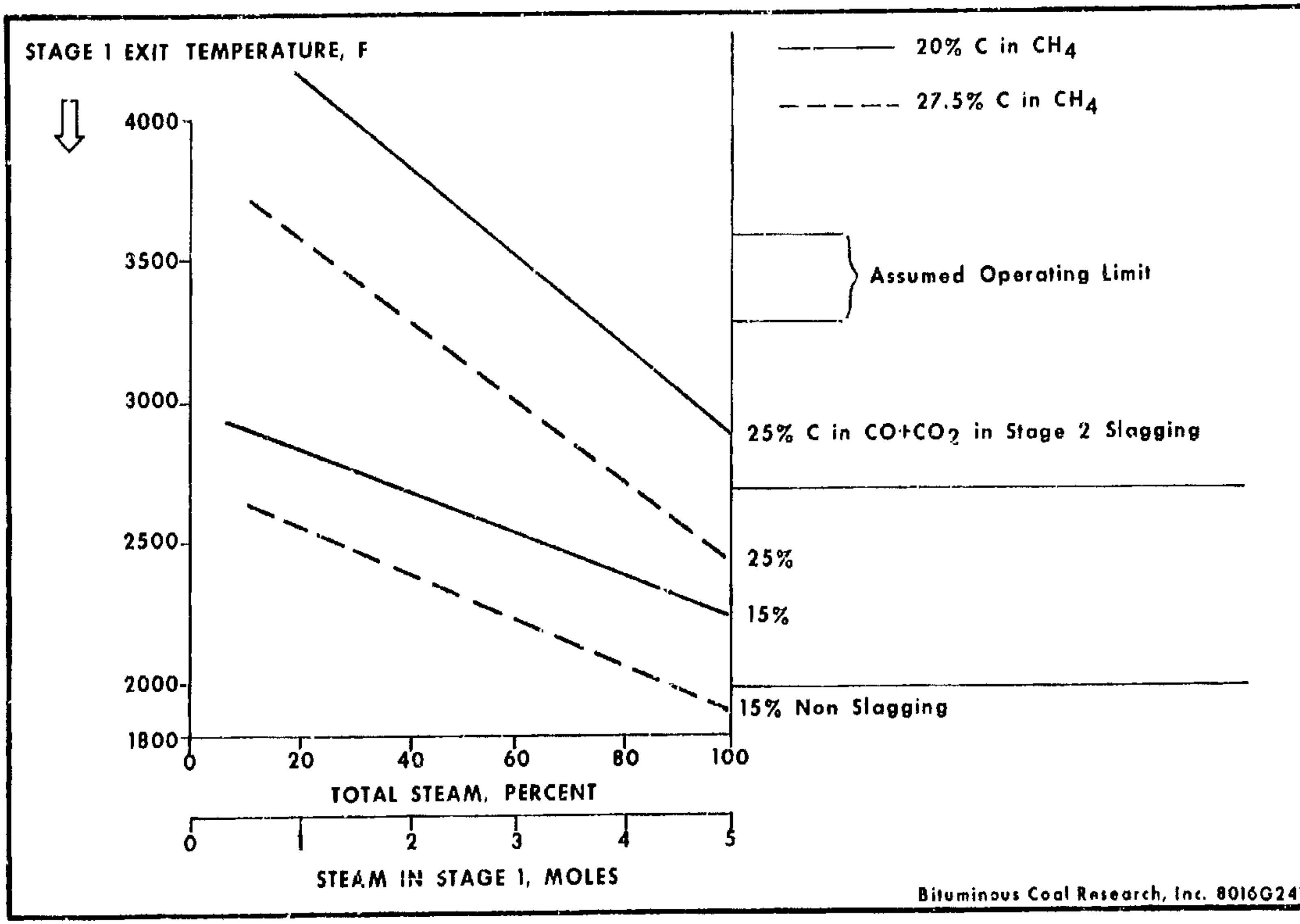


Figure 18. Exit Temperature and Steam Rate in Stage 1
(Varying CH_4, CO, and CO_2 Yield in Stage 2)

Non-slagging operation	Below 2700 F
Slagging operation	Above 2700 F
Limit of operability	3300-3500 F

The data show (1) that for complete gasification the carbon oxide formation in Stage 2 must be kept within definite limits to supply enough char for slagging operation in Stage 1 and (2) that the distribution of the steam between Stage 1 and 2 can be used to control Stage 1 temperature.

In Figure 19 the Stage 1 temperature is plotted versus the ($CO + CO_2$) formation in Stage 2. The data indicate that ($CO + CO_2$) yield above about 30 percent on a carbon basis will lead to excessive Stage 1 temperatures. Thus, in further PEDU experiments, a gas exit temperature and residence time should be selected at which this carbon oxide yield is not exceeded.

It is suggested that the data given here be extended to other coals using methane and carbon oxide yields indicated by the kinetic model for various temperatures, steam rates, and pressures.

Constant values have been assumed for the the heat loss and the recycle carbon rates in the above calculations. A refinement of these assumptions is possible as shown below based on data from the Bureau of Mines, Morgantown.

A. Heat Loss and Oxygen/Carbon Ratio Data

The gasification work at the Bureau of Mines in Morgantown provides data that can be applied to the operation of Stage 1 of the pilot plant.

Bureau of Mines Report of Investigations No. 5573 gives data correlating the oxygen/carbon ratio with the percent carbon gasified. The data, converted to our units, are shown in Figure 20. The line drawn coincides with later data given in Report of Investigations No. 6364. It appears justified to use only the data obtained at the highest pressure used, 300 psi, which gave the highest carbon utilization for a given oxygen/carbon ratio in view of the higher pressure to be used in the BI-GAS pilot plant.

The line of Figure 20 is used in Figure 21 to plot the oxygen/carbon ratio (lb/lb) in the feed coal versus the oxygen/carbon ratio (lb/lb) actually gasified. This correlation is used to obtain the ratio of oxygen to total char recycled into Stage 1 shown in Table 16.

In the Morgantown work, coal was used as feed while the BI-GAS process will use char. There is no information on hand for the relative reactivity of coal and char. It is reasonable to assume that the higher conversion expected at higher pressure and the lower reactivity of the char will be compensating factors. Therefore it is suggested to use, at least at this time, Figure 21 to obtain the ratio of carbon gasified to total carbon feed to Stage 1.

The Report of Investigations No. 5573 data show that the heat loss per sq ft of internal gasifier surface increases with the oxygen/carbon ratio and the coal thruput, as shown in Figure 22. The heat loss depends very little upon the pressure in the range from 75 to 300 psig, as shown in Figure 23. An increased

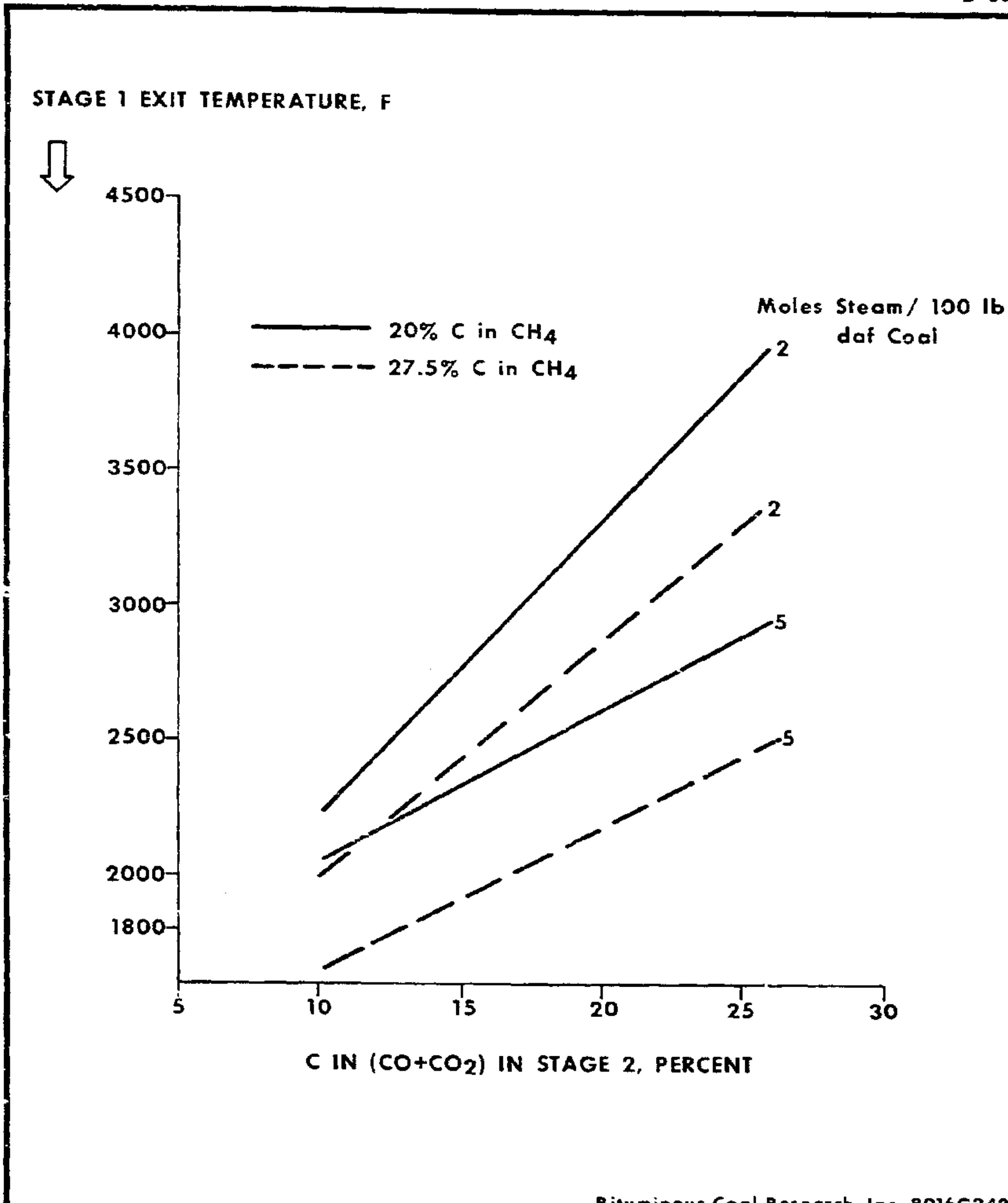


Figure 19. Exit Temperature Stage 1 and Carbon Oxides Yield Stage 2 (Varying CH_4 Yield and Steam Rate in Stage 1)

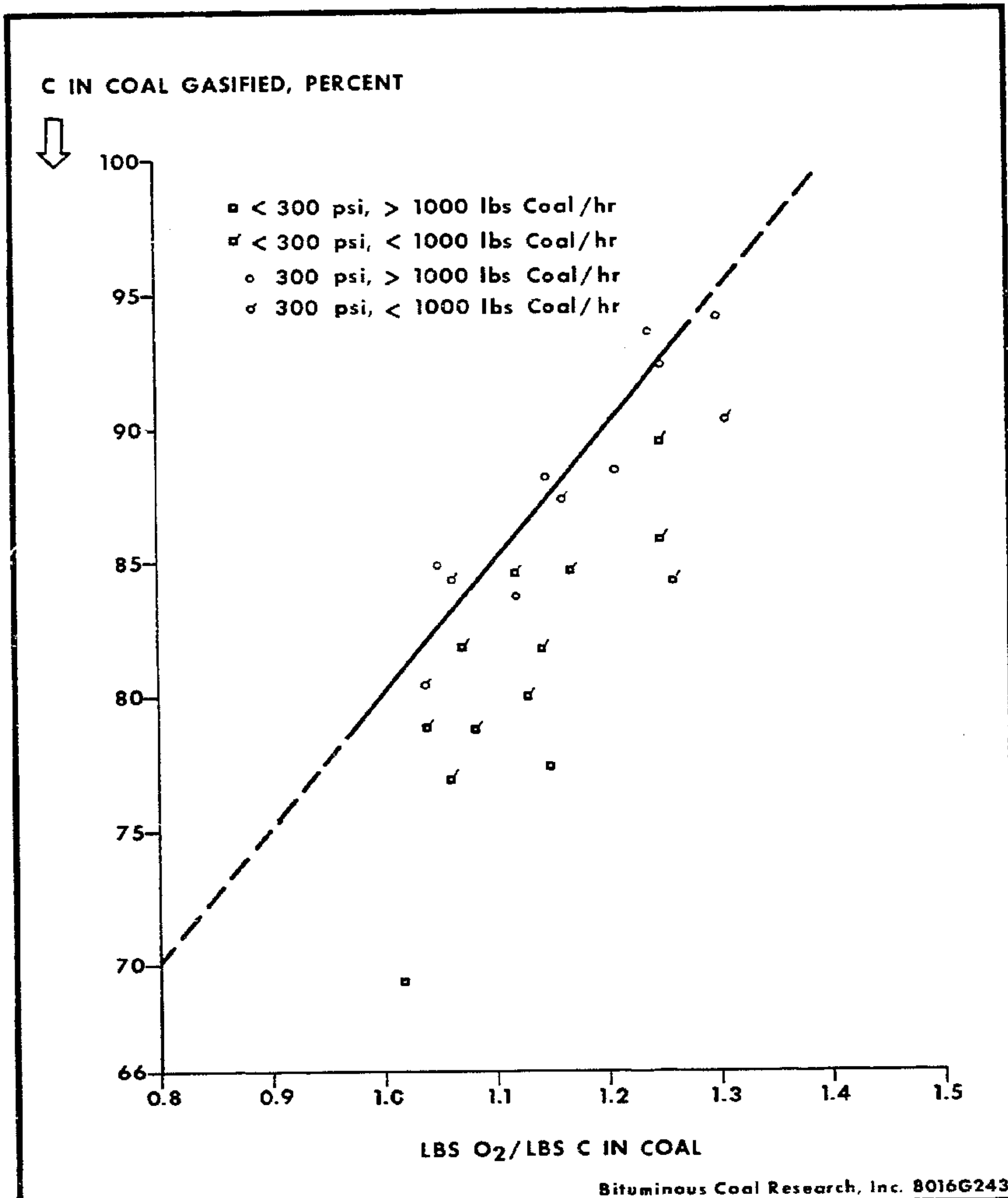


Figure 20. Ratio of Oxygen to Carbon and Carbon Gasified (R. I. 5573, Page 45.)

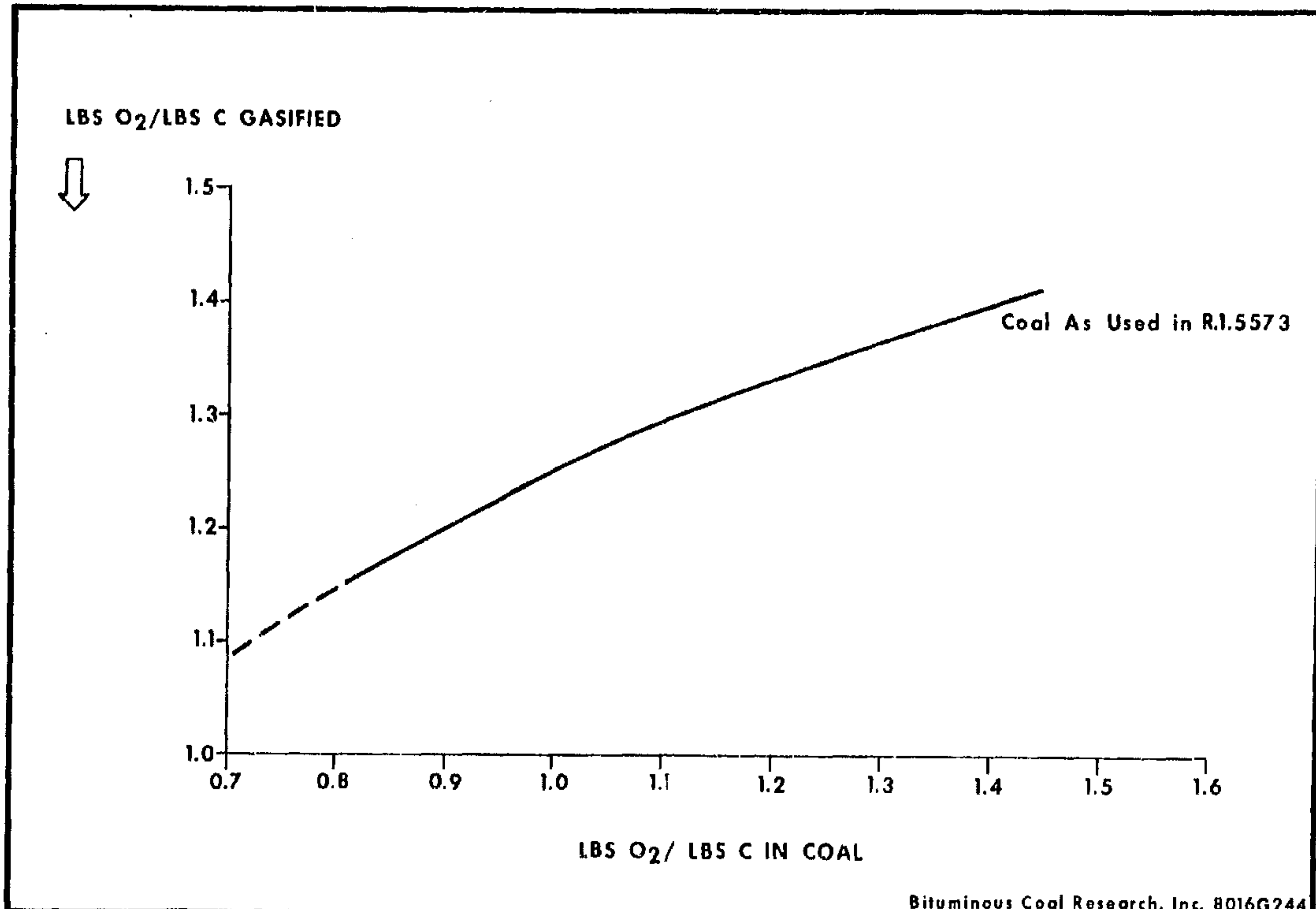


Figure 21. Ratio of Oxygen to Carbon in Coal and Carbon Gasified
(R. I. 5573, Page 45.)

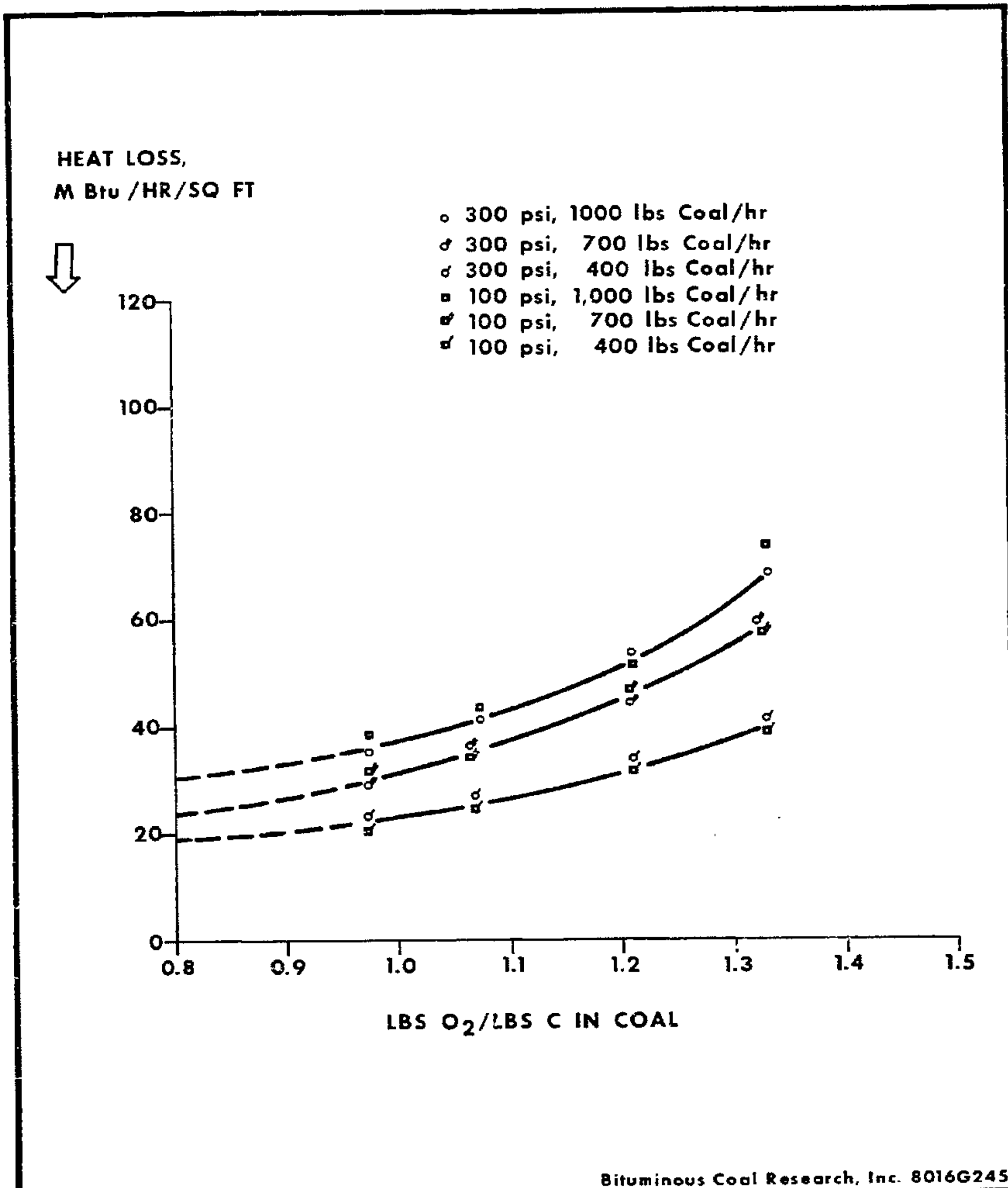


Figure 22. Oxygen/Carbon Ratio and Heat Loss
(R. I. 5573, Page 44 Figure 33., 13 ft^2 Gasifier Surface)

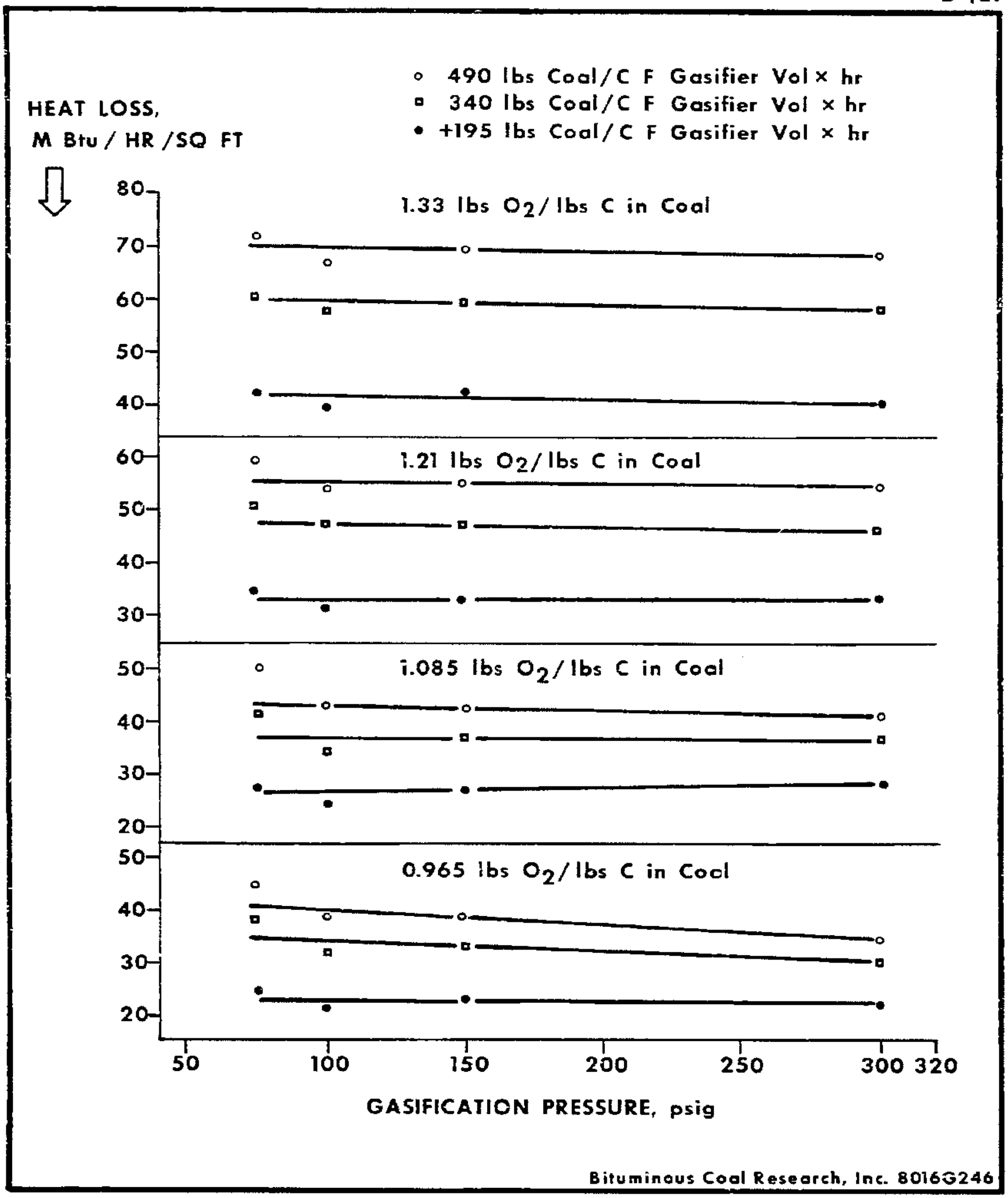


Figure 23. Heat Loss and Pressure

oxygen/carbon ratio leads to higher reaction temperature and logically to a higher heat loss. A possible explanation for the increase of the heat loss with the coal throughput is that less heat is abstracted per pound of coal, and thus a higher average reaction temperature prevails. This leads to the higher heat loss per unit gasifier surface. Then the higher average temperature and the higher reaction rate connected with it would compensate for the shorter residence time in comparison with that obtained with smaller throughputs and longer residence times and lower temperatures. In all these tests, about 0.3 lb of steam per pound of coal were used.

For use in the heat and material balance calculations for the pilot plant, the heat loss data are replotted in Figure 24 using the coal or carbon throughput per cu ft of gasifier volume as the other variable.

In Figure 25 the calculated exit temperatures are plotted versus the residence time. The curves, together with Figure 20, seem to indicate that the reaction, after the first exothermic combustion step, is essentially completed in about one second, and that from there on only cooling through heat radiation reduces the temperature. This indicates that too large a Stage 1 volume can be harmful as well as one that is too small.

Koppers drawing 2415-2A50 provides for a Stage 1 vessel of 2 ft ID and 4 ft long with two 45° cones at either end. This gives the following volume:

4 ft cylinder	11.5 cu ft
2 cones	1.5 cu ft
Total	13.0 cu ft

The internal surface is about 33 sq ft.

Assuming a pilot plant coal throughput of 10,000 lb/hr (8,960 lb/hr daf coal), Table 2 from the Bureau of Mines report leads to the data shown in Table 17 for the above configuration. An alternate to the above configuration of 9.5 cu ft volume and 24 sq ft internal surface[1] leads to the data given in the lower part of Table 17. The throughput in Stage 1 thus varies between 290 and 820 lb C/cu ft/hr.

Report of Investigations No. 4971 indicates (Figures 23 and 20 and p.1) that for the same carbon gasification, the coal throughput can be increased in direct proportion to pressure. At 300 psi a coal throughput of 485 lb/cu ft/hr (-340 lb C/cu ft/hr) is indicated. This would extrapolate at 1,000 psi to 1,140 lb C/cu ft/hr, considerably above the throughput indicated in Table 17 for Stage 1 volume of 13 or 9.5 cu ft. Another way of looking at this throughput figure is that at 2 seconds residence time about 0.6 lb carbon enter the gasifier per second for each cubic foot of its volume. This is a density that is far below that of a fluidized bed.

On this basis, it appears justified to place emphasis in the cold, full-size model experiments on rapid mixing, avoidance of flame impingement on walls, (see Figure 25) and of slag carry over to Stage 2 in a gasifier of 2 to 3 ft ID and a volume of about 8 to 13 cu ft.

[1] A 0.5 inch thickness of refractory or slag reduces the effective diameter to 23 in.

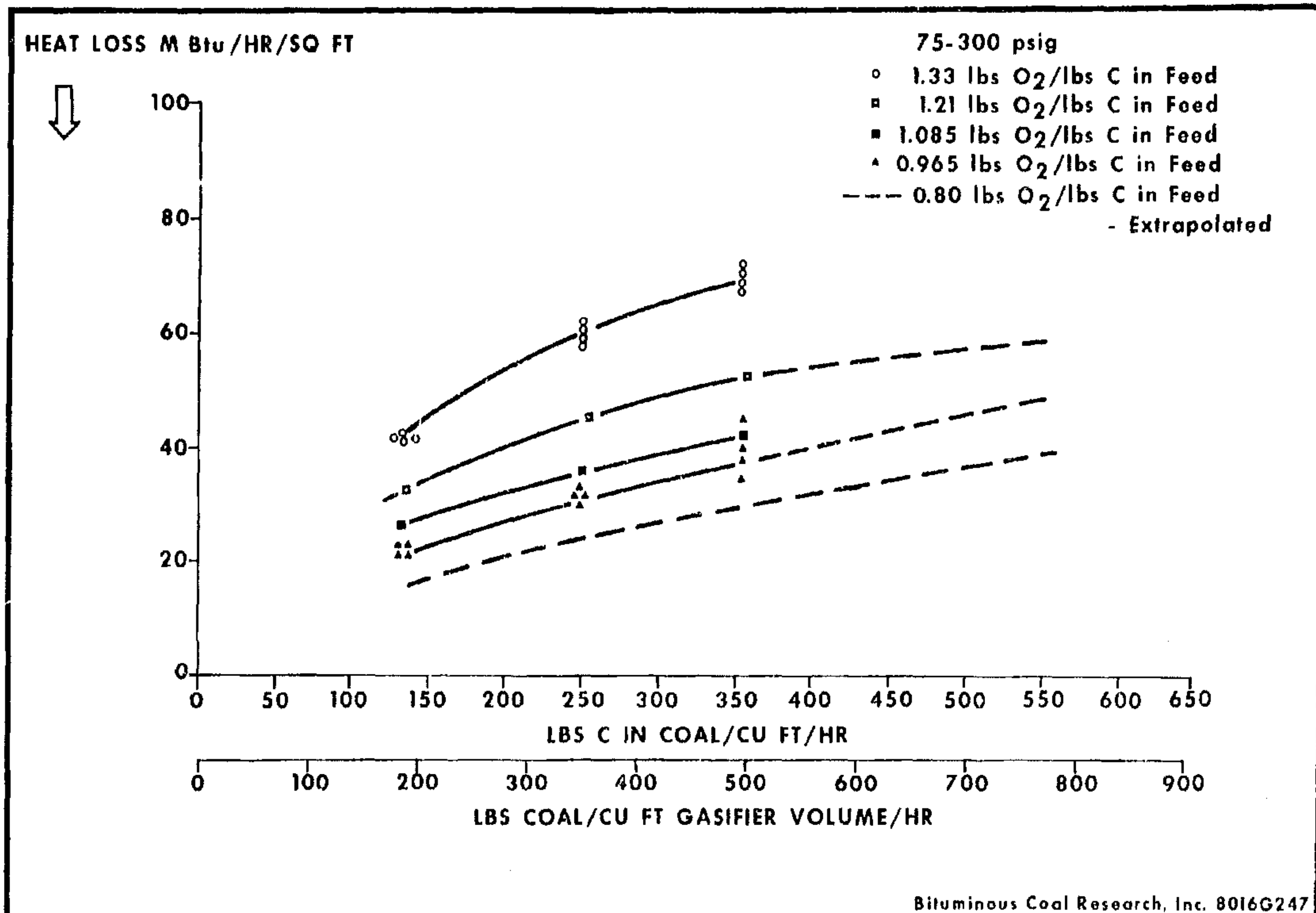


Figure 24. Heat Loss and Coal Throughput (R. I. 5573, Figure 33.)

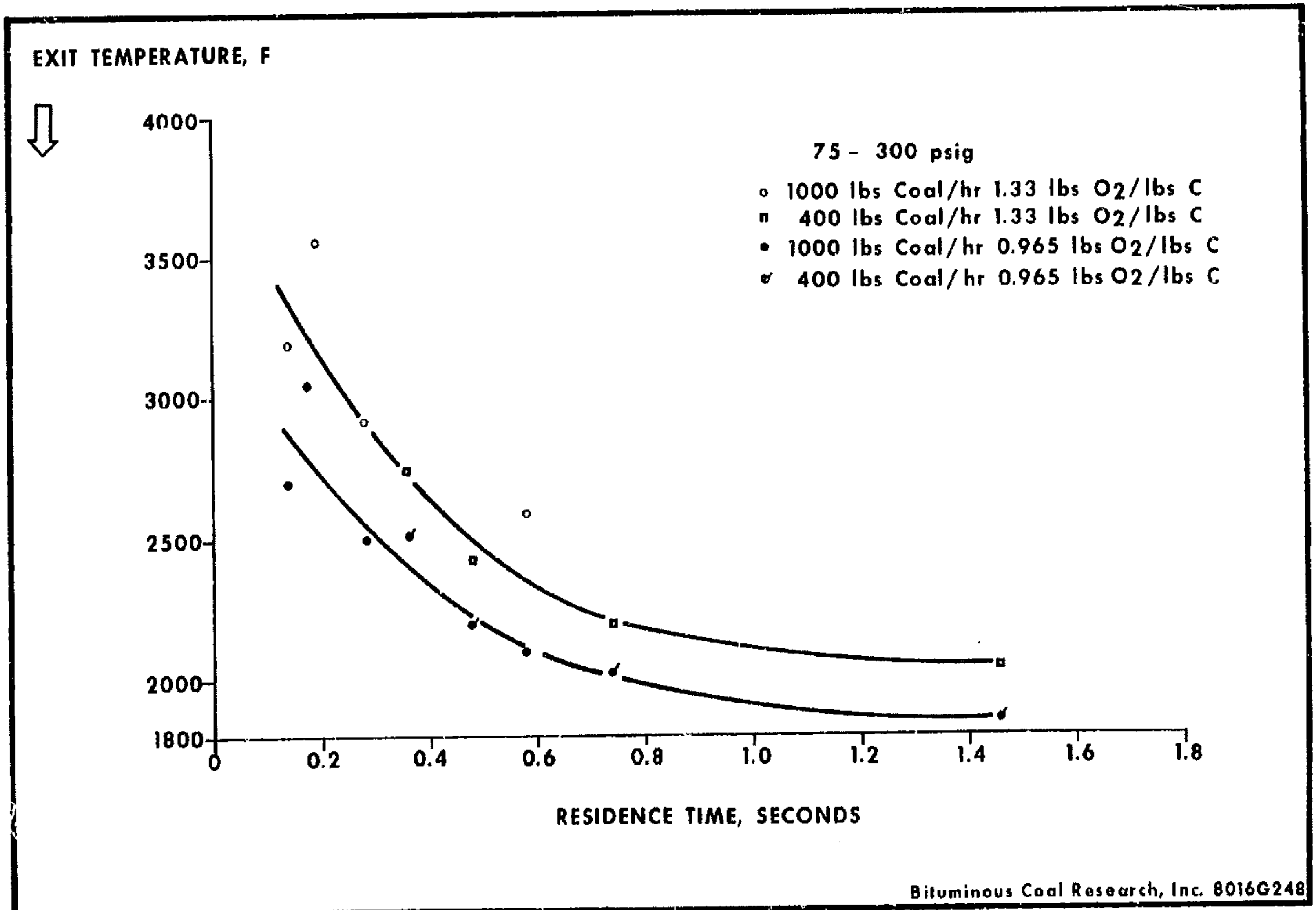


Figure 25. Residence Time and Gas Exit Temperature
(R. I. 5573, Figure 32.)

TABLE 17. HEAT LOSS IN THE STAGE 1 OF THE PILOT PLANT

C as CH_4 in Stage 2, percent	20		27.5	
lb Oxygen/100 lb daf coal	52.5		27.5	
C as $(CO + CO_2)$ in Stage 2, percent	15	25	15	25
Basis: 10,000 lb/hr coal				
lb C in gasified char	4700	4000	4190	3470
lb O_2/lb C gasified	1.0	1.17	1.15	1.36
lb O_2/lb total C feed	0.6	0.85	0.80	1.25
lb total C/hr to Stage 1	7800	5500	6000	3800
lb total C/cu ft/hr (Stage 1 = 13 cu ft)	600	420	460	290
Heat loss, MBtu/hr/sq ft	(25)*	33	33	54
Heat loss, MBtu/hr (33 sq ft)	(790)*	1090	1090	1780
Heat loss, Btu/lb coal	(79)*	109	109	178
Heat loss, percent Btu in coal	(0.6)*	0.8	0.8	1.4
Alternative Stage 1				
(Assume 3 ft ID, 1 ft height, flat top, bottom cone 1 ft high) 9.5 cu ft, 24 sq ft				
lb total C/cu ft/hr (9.5 cu ft)	820	580	630	400
Heat loss, MBtu/hr/sq ft	(27)*	40	40	62
Heat loss, MBtu/hr (24 sq ft)	(650)*	960	960	1480
Heat loss, Btu/lb coal	(65)*	96	96	148
Heat loss, percent Btu in coal	(0.5)	0.75	0.75	1.1

*Estimate, O_2/C ratio outside of experimental range.

APPENDIX C

OXYGEN COST FROM APCI REPORT

Figure 2 of the APCI report shows the following figures for steam production and consumption:

Auxiliary boiler	1,329,400 lb/hr
From this to O_2 plant	82,200 lb/hr
Waste heat steam to O_2 plant drives	1,056,000 lb/hr
Total O_2 plant drives	1,138,200 lb/hr (= 85.5%)

This leads to the following two cases for the cost of 1,000 psi oxygen in the 6,000 ton/day plant:

	Case 1	Case 2
Steam from auxiliary boiler to O_2 plant	0%	85.5%
	Investment Cost, MM Dollars	
Oxygen plants (Table X)	26.3	26.3
Auxiliary boiler plant (Table IX $8,592,000)	0.5	7.3
Methanation boilers and superheaters (Table VIII)	0.8	--
Off sites, utilities 23.3%	6.4	--
16.9%**	--	5.7
	34.0	39.3
Contractor's Fee 5%	1.7	2.0
	35.7	41.3
Interest during construction, 5%	1.8	2.1
Total Fixed Investment	37.5	43.4

** Reduced by auxiliary boiler plant cost.

(347 Operating Days)	Operating Cost, M $/Year Case 1	Case 2
Steam 1,138,000 lb/hr at 12.1 cents/MM Btu	1,680	--
Table IV 85.5% of 2,215 x 10^6 Btu/hr at 12.1 cents/MM Btu	--	1,900
Other material (6.2%)	100	114
Direct Labor, 3 man/shift	106	106
Maintenance Labor	1,020	1,180
Maintenance Supplies	153	177
Supervision	11	11
Payroll O.H.	12	12
General O.H.	645	737
	3,727	4,237
Depreciation 5%	1,875	2,170
Taxes, insurance 3%	1,125	1,300
	5,727	7,707
Contingency 2%	114	154
Total Operating Expense	5,841	7,861
($/T O_2, 6,000 T/d at 1,000 psi)	(2.80)	(3.78)
Return on investment 8%	3,000	3,470
Total including Return	8,841	11,331
($/T O_2, 6,000 T/d at 1,000 psi)	(4.24)	(5.45)

Figure 26 then shows the cost of oxygen for a 250MMscf/d BI-GAS plant in relation to the cost of coal.

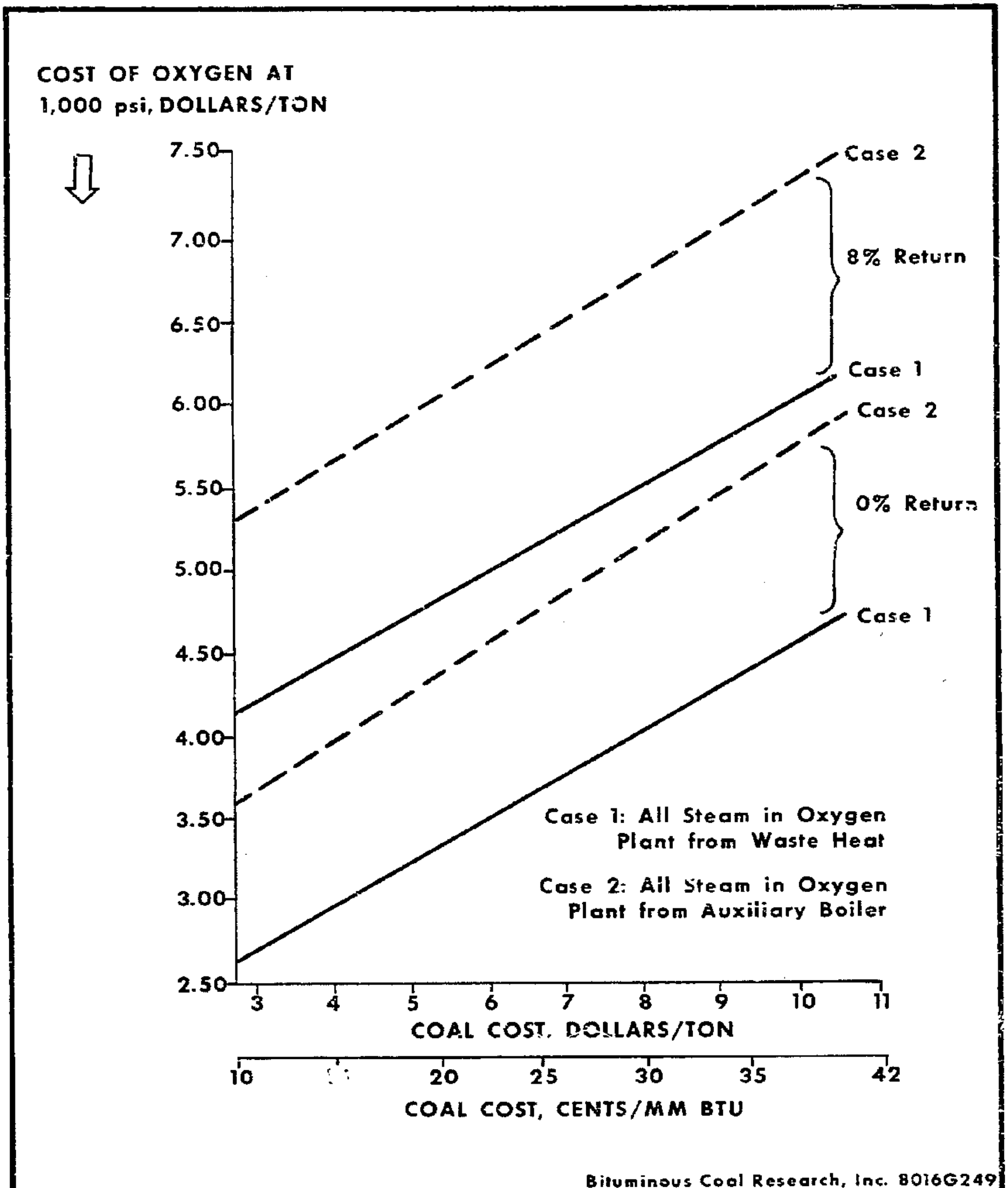


Figure 26. Cost of Oxygen for 250 MM scf per Day BI-GAS Plant

APPENDIX D

COST OF FUEL GAS BY THE BI-GAS PROCESS
(oxygen-blown, without shift, carbon dioxide removal, and methanation)

Basis: Air Products Report 1970

	Fixed Investment Millions of Dollars	
	Pipeline Gas	Fuel Gas
Coal Preparation and Feeding	25.3	26.0*
Gasification	7.4	7.4
Shift Conversion	12.5	--
Acid Gas Removal and Sulfur Recovery	30.0	6.5+
Methanation	11.7	--
Drying	0.1	--
Oxygen Plants	26.3	26.3
Off-sites, Utilities	26.4	22.0
	139.7	88.2
Contractors Fee, 5 percent	7.0	4.4
	146.7	92.6
Interest during Construction, 5 percent	7.3	4.7
Total Fixed Investment	154.0	97.3

* Includes additional waste heat boiler and decreased quench.

\+ 95 percent hydrogen sulfide and 35 percent carbon dioxide removal from gas before shift.

Gas Composition, Quantity and Heating Value

	Volume, Percent	Mscf/hr
Carbon Dioxide	9.6	2,680
Carbon Monoxide	46.7	13,080
Methane	16.56	4,620
Hydrogen	25.8	7,240
Nitrogen	0.7	195
Hydrogen Sulfide	0.08	21
Steam	0.56	64
	100.00	27,900

Hydrogen sulfide - 356 Mols/hr, H.V. - 402 Btu/scf, 11,250 x 10^6 Btu/hr, 270 x 10^9 Btu/day; Sulfur: 34,200 lb/hr, 368 lt/d.

OPERATING EXPENSE
Annual Cost (347 Op. Days)

	Thousands of Dollars	
	Pipeline Gas	Fuel Gas
Coal, run-of-mine $2.00/t = $3.21/t washed = 12.1 cents/MM Btu	15,600	15,600
Other Materials	963	620*
Direct Operating Labor	1,485	1,345+
Maintenance Labor	4,193	2,650*
Maintenance Supplies	629	400*
Supervision	148	134+
Payroll Overhead	163	147
General Overhead	3,228	2,265
	26,409	23,161
Depreciation, 5 percent	7,705	4,865
Taxes, Insurance	4,623	2,919
	38,737	30,945
Contingency, 2 percent	775	619
Total	39,512	30,564
Cents/MM Btu, 237 x 10^9/d**	45.0	--
Cents/MM Btu, 270 x 10^9/d**	--	29.9
Return, 8 percent	12,300	7,780
Total Including Return	51,812	38,344
Cents/MM Btu, 237 x 10^9/d**	59.9	--
Cents/MM Btu, 270 x 10^9/d**	--	38.3

* In proportion to investment
\+ 42 men/shift reduced to 38
** Sulfur Credit 368 lt/d at $20 = $73 60/d = 3.1/2.7 cents/MM Btu

Figure 27 then shows the cost of fuel gas, using the BI-GAS process, in relation to the cost of washed coal.

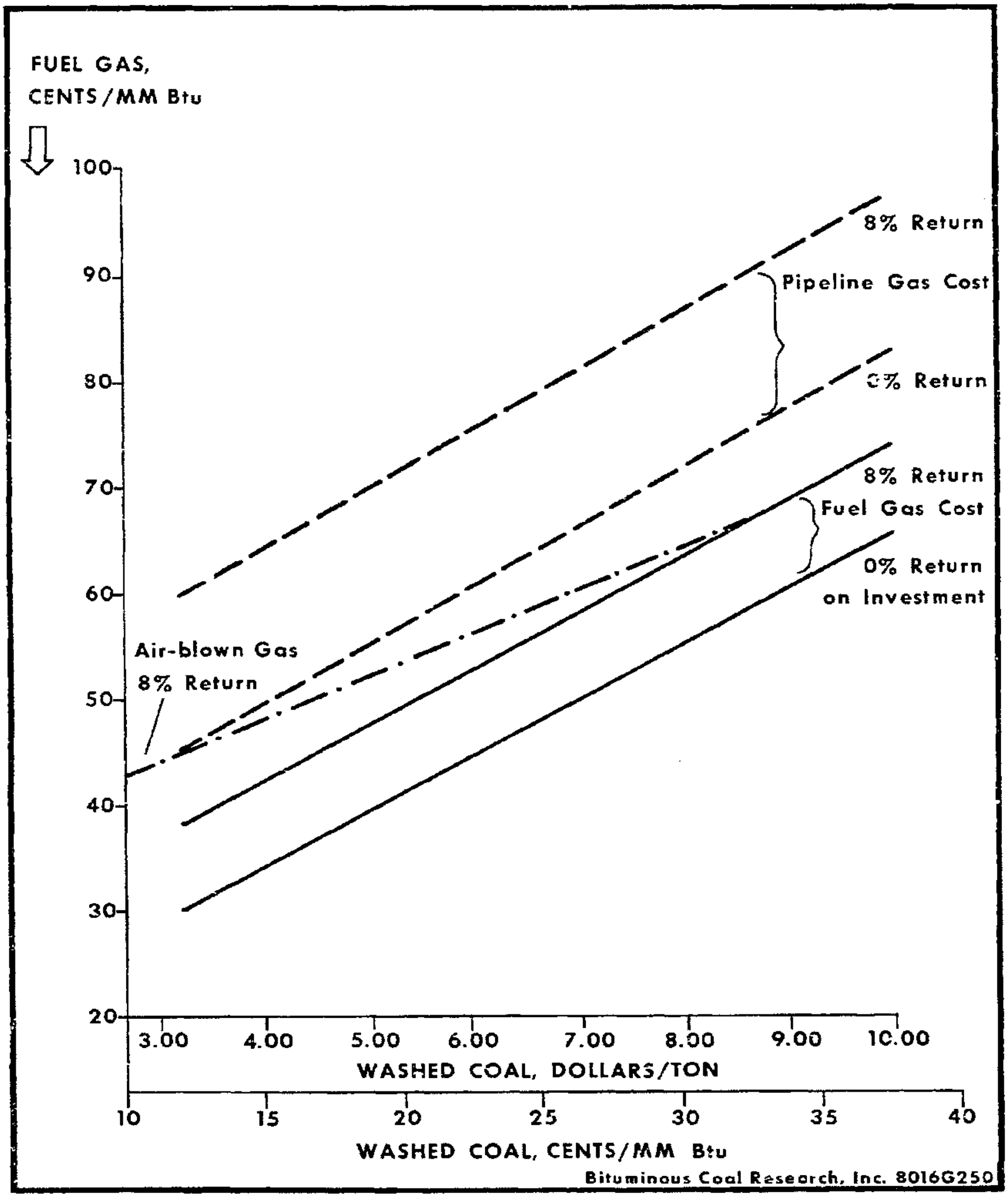


Figure 27. Fuel Gas and Coal Cost Oxygen-blown BI-GAS Process
(270×10^9 Btu Gas per Day of 402 Btu per scf)

APPENDIX E

COMPARISON OF THE COST OF USING OXYGEN OR ELECTRIC HEATING IN STAGE 1 OF THE BI-GAS PROCESS

The successful use of electric energy for the gasification of char in a fluidized bed indicated the need for a comparison of this method of supplying heat to Stage 1 of the BI-GAS process with the use of oxygen. Table 18 gives the results of material and heat balance calculations for the complete gasification of Illinois No. 6 seam coal with the following analysis:

Coal as used:

Moisture	1.3 percent
Ash	9.1 percent
Heating value, gross	14,480 Btu/lb
Heating value, net	13,980 Btu/lb

Ultimate analysis, daf basis, percent:

Carbon	81.3
Hydrogen	5.4
Nitrogen	1.5
Oxygen	9.6
Sulfur	2.6

To obtain the gas composition given in Table 18, establishment of the shift reaction equilibrium was assumed and the following temperatures used:

Gas exit temperature, F	1700
Coal temperature, F	200
Steam temperature, F	980
Oxygen temperature, F	800

In addition, a steam/coal ratio was selected that gave 67 to 69 percent overall steam decomposition, and a heat loss of 50 Btu/lb of coal was used.

The gas obtained was further converted by shift reaction, acid gas removal, and methanation into methane. The throughput of these units per M scf of final methane is given in the last part of Table 18.

The APCI report gives a battery limit investment cost (excluding off-sites, utilities, contractor's fee, and interest during construction) of $113.2 million. The annual operating cost, excluding coal cost, is $23.9 million, or 21.1 percent of the investment. Using this percentage to obtain the operating cost of the shift reaction and gas removal and methanation, the data in Table 19 are obtained.

TABLE 18. SUMMARY DATA FOR TWO-STAGE GASIFICATION USING OXYGEN AND ELECTROTHERMAL HEATING

C in CH_4, percent	20	27.5		35		42.5
Heat Source*	O_2	El.	O_2	El.	O_2	El.
Basis: 100 lb daf coal, mols						
Methane	1.36	1.86	1.86	2.37	2.37	2.88
Hydrogen	3.118	4.648	2.188	3.268	1.508	2.058
Carbon Monoxide	3.84	3.47	3.13	2.81	2.31	1.98
Carbon Dioxide	1.57	1.44	1.78	1.59	2.09	1.91
Steam	1.853	2.823	1.783	2.683	1.943	2.873
Nitrogen plus Hydrogen Sulfide	0.135	0.135	0.135	0.135	0.135	0.135
Total	11.876	14.376	10.876	12.856	10.356	11.836
$\left(P_{H_2}\right)$ at exit, atm (70 atm total pressure)	17.9	22.6	14.1	17.8	10.2	12.2
Preformed CH_4, percent	43.7	47.8	59.3	61.0	71.4	74.0
Total CH_4, mols	3.1	3.89	3.19	3.89	3.32	3.89
Total CH_4, scf	1178	1472	1208	1472	1260	1472
lb steam/Mscf total CH_4	76	104	74.5	98	78.5	98
Steam decomposition, percent	67	69	68	68	69	67
Amount to heat 1 Mscf total CH_4						
Oxygen, lb	44.6	--	37.2	--	28.7	--
Electricity, kwh	--	63.8	--	51.6	--	40.7
Basis: 100 lb daf coal						
CO shifted, mols	2.1	1.42	1.80	1.29	1.36	0.97
CO_2 removed, mols	3.67	2.88	3.58	2.88	3.45	2.88
CH_4 synthesized, mols	1.74	2.03	1.33	1.52	0.95	1.01
For 1 Mscf total CH_4						
CO shifted, mols	1.78	0.97	1.49	0.88	1.08	0.66
CO_2 removed, mols	3.12	1.96	2.96	1.96	2.73	1.96
CH_4 synthesized, mols	1.48	1.38	1.10	1.03	0.75	0.74

* O_2 = Oxygen, El. = Electrothermal

TABLE 19. PROCESSING UNIT COSTS

Unit	Battery limit investment cost, Dollars, MM	Annual operating cost‡ Dollars, MM	Operating cost per Mscf total methane, ¢	Reacted or Removed		
				Compound	Mols per Mscf total CH_4	Operating cost, cents/mol
Shift Reaction	12.46	2.63	3.24	CO	2.14	1.52
Acid Gas Removal	29.96	6.31	7.78	CO_2	3.34	2.33
Methanation	11.73	2.48	3.06	CH_4	1.37	2.23
Lower Cost Acid Gas Removal*	19.96	4.21	5.20	CO_2	3.34	1.55

‡ 21.1 percent of Battery limit used as average from the APCI report.

* The APCI report states that use of the Rectisol process would reduce acid gas removal cost by $10 million.

The APCI report provides a production of 250,000 M scf gas/d with a heating value of 947 Btu/scf. This corresponds to 234,000 M scf/d of methane on a Btu basis. The report also shows the amount of CO shifted, CO_2 removed, and CH_4 synthesized. Thus, the operating costs of these units per mol of conversion are also shown in Table 19.

Using the following raw material and utility costs:

Coal	15 cents/MM Btu = $3.90/T as used
Oxygen	$5/T
Electricity	0.4 cents/kwh
Steam	30 cents/M lb

and the conversion quantities from Table 18 and conversion cost from Table 19 the differential operating costs in Table 20 are obtained. The differential pipeline gas costs (cents/M scf CH_4) are plotted versus the percent carbon converted to methane for the use of oxygen and electric heat in Figure 28.

PEDU correlations* show that the methane yield, MY, in percent carbon converted depends on the hydrogen partial pressure, as expressed in Equation (1).

$$MY = \frac{0.08 + (0.012)\ (P_{H_2})}{1 + (0.012)\ (P_{H_2})}$$

This correlation is used in Figure 29 to intersect with the lines for oxygen and electrothermal gasification and gives, at 1,000 psi gasifier pressure, 23 percent and 27.6 percent carbon conversion to methane, respectively. This yield and the differential operating cost from Figure 28, and the sulfur credit from Figure 30 at $20/lt = 0.89 cents/lb give the following net differential operating cost:

	Cents/M scf CH_4	
Gasification in Stage 1	Oxygen	Electrothermal
Differential operating cost	6.5	15.9
Sulfur credit	-1.9	-1.6
Net differential operating cost	4.6	14.3
Or	0	9.9

* Gas Generator Research and Development, Progress Report No. 85, OCR Contract 14-01-0001-324. p. 3381.

TABLE 20. OPERATING COST DIFFERENTIALS

C in CH_4, percent	20	27.5		35		42.5
Heat source	O_2	El.	O_2	El.	O_2	El.
Preformed CH_4, percent	43.7	47.8	59.3	61.0	71.4	74.0
For 1 Mscf CH_4						
Coal at 15 cents/MM Btu ($3.90/t, 9.1% ash, 1.3% H_2O)	18.5	14.8	18.0	14.8	17.3	14.8
Oxygen, $5.00/t	11.2	--	9.3	--	7.2	--
Electricity, 0.4 cents/Kwh	--	25.5	--	20.7	--	16.3
Steam, 30 cents/M lb	2.3	3.1	2.2	2.9	2.3	2.9
Shift Reaction, 1.52 cents/mol CO	2.7	1.5	2.3	1.3	1.6	1.0
CO_2 Removal, 2.33 cents/mol CO_2	7.3	4.6	6.9	4.6	6.4	4.6
CH_4 Synthesis, 2.23 cents/mol CH_4	3.3	3.1	2.4	2.3	1.7	1.7
Total	45.3	52.6	41.1	46.6	36.5	41.3
Differential from lowest cost	8.8	16.1	4.6	10.1	0	4.8

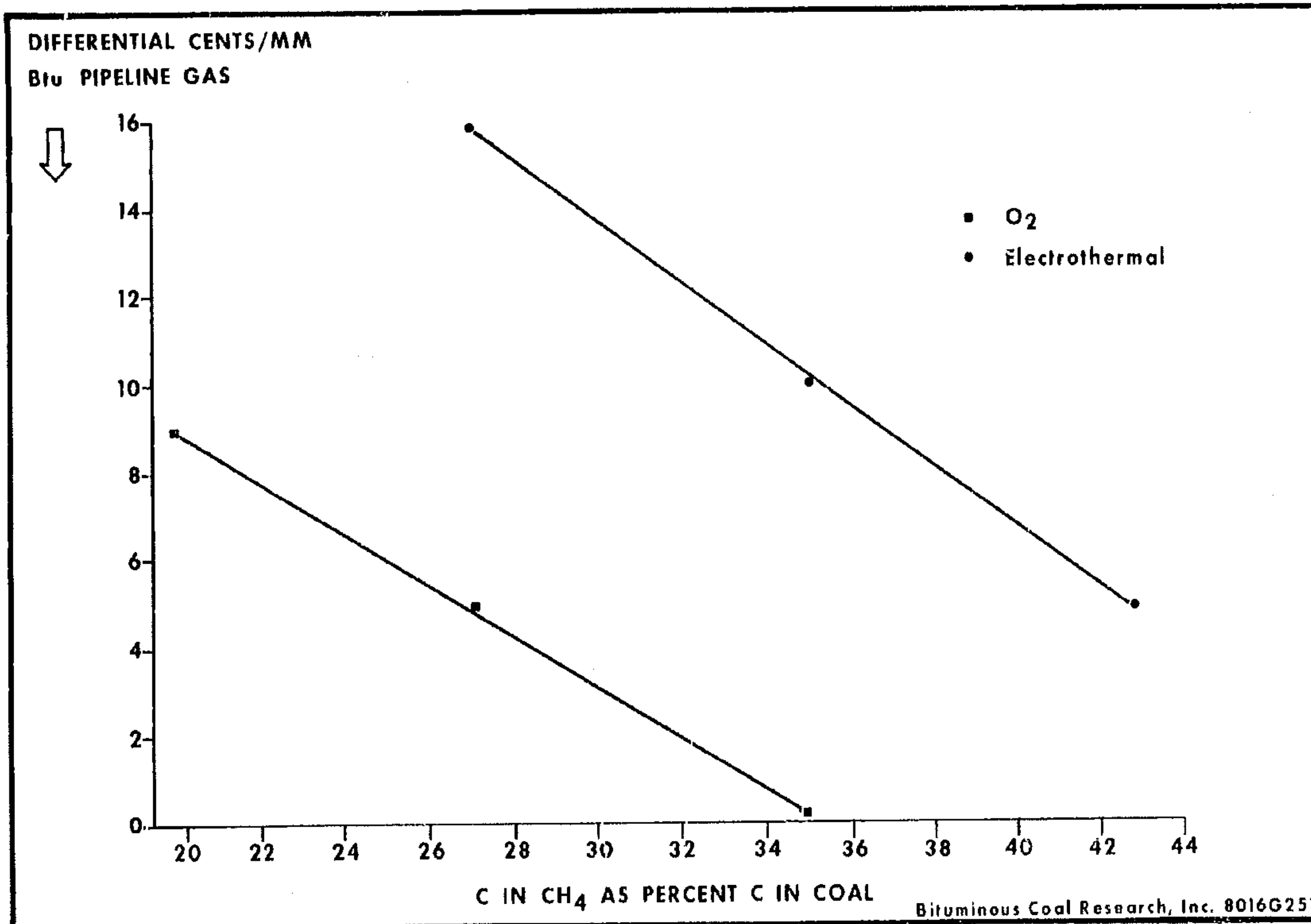


Figure 28. Pipeline Gas Cost Differential for Complete Gasification of Coal

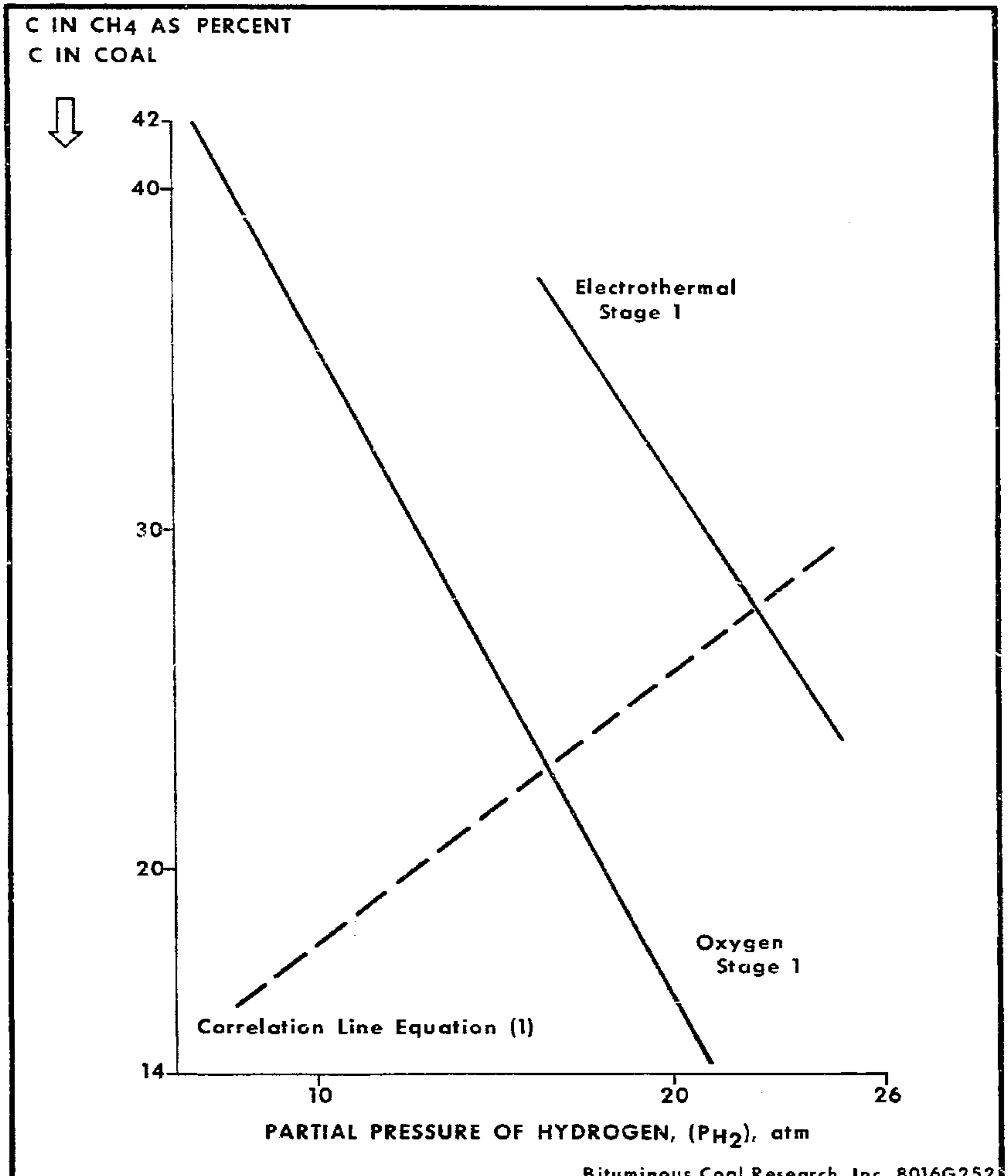


Figure 29. Relation Between Methane Yield and Hydrogen Partial Pressure for Complete Gasification of Coal

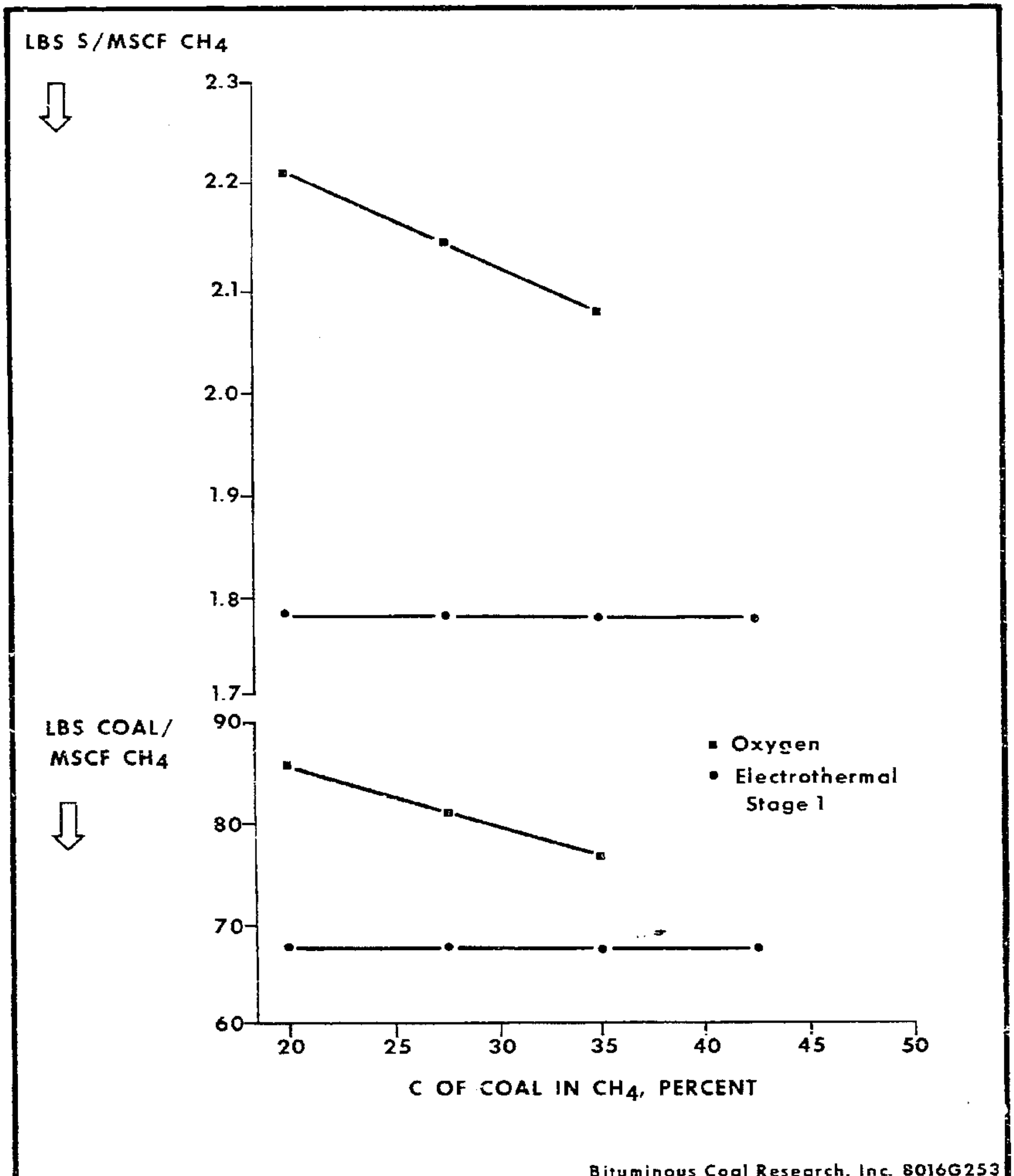


Figure 30. Relation Between Sulfur Credit and Conversion to Methane for Complete Gasification of Coal

This shows a clear advantage of the use of oxygen in Stage 1 over electric heating for the complete gasification of coal using the BI-GAS process.

The calculations were extended to a case with char withdrawal: 20 percent of the carbon in the coal is withdrawn as char. Otherwise the same conditions were used. A summary of the data for 20 and 27.5 percent carbon converted to methane is given as Table 21. Using the previously obtained cost data from the APCI report, and quantities from Table 21, the operating cost differentials in Table 22 were obtained.

In Figure 31, the pipeline gas cost differentials are plotted versus the percent carbon converted into methane in Stage 2. The methane yield in Stage 2 is plotted versus the hydrogen partial pressure in Figure 32. The dotted line is the PEDU correlation line, Equation 1, that connects hydrogen partial pressure with methane yield. The intersection of this line gives the expected methane yield. At 1,000 psi total pressure it is 22.3 percent for oxygen and 26.1 percent for electrothermal gasification.

It is assumed that 95 percent of the sulfur in the coal will be converted to hydrogen sulfide and recovered as elemental sulfur. Figure 33 shows, then, the sulfur recovered per M scf of methane. The sulfur will be credited at \$20/lt = 0.89 cents/lb. This gives the following operating cost differentials:

Stage 1 Gasification:	Oxygen	Electrothermal
Percent C in coal as CH_4	22.3	26.1
Percent C in coal as char	20.0	20.0
	Cents/M scf CH_4	
Operating cost differential	4.9	12.4
Sulfur credit	-2.2	-1.8
Net operating cost differential	2.7	10.6
Or	0	7.9

This shows, for the gasification case with char withdrawal, an advantage of 7.9 cents/M scf methane for the oxygen gasification; a result very similar to that obtained for the complete gasification of coal

TABLE 21. SUMMARY DATA, TWO-STAGE GASIFICATION USING OXYGEN AND ELECTROTHERMAL HEATING, 20% C AS CHAR

C in CH_4, percent	20		27.5	
Heat Source*	El.	O_2	El.	O_2
Basis: 100 lb daf Illinois No. 6 coal, mols				
Methane	1.36	1.36	1.86	1.86
Hydrogen	4.258	2.068	2.958	1.311
Carbon Monoxide	3.16	2.76	2.46	2.21
Carbon Dioxide	0.90	1.30	1.10	1.35
Steam	1.713	1.403	2.013	1.16
Nitrogen plus Hydrogen Sulfide	0.135	0.135	0.135	0.135
Total	11.526	9.026	10.526	8.026
Char, lb daf (H.V. 14,400 Btu)	16.2	16.2	16.2	16.2
Char, MMBtu/100 lb daf coal	0.233	0.233	0.233	0.233
(P_{H_2}) at exit, atm (70 atm total pressure)	25.9	18.0	19.6	11.5
Preformed CH_4, percent	42.4	53.1	58.0	68.0
Total CH_4, mols	3.21	2.566	3.21	2.74
Total CH_4, scf	1215	973	1215	1039
Steam, lb/Mscf Total CH_4	89	65	89	61
Steam Decomposition, percent	74	66	70	72
For 1 Mscf total CH_4				
lb O_2	--	42.6	--	29.3
Kwh	68.6	--	55.5	--
Basis: 100 lb daf coal				
CO Shift, mols	1.31	1.554	1.11	1.33
CO_2 Removal, mols	2.21	2.854	2.21	2.68
CH_4 Synthesis, mols	1.85	1.206	1.35	0.88
For 1 Mscf Total CH_4				
CO Shift, mols	1.08	1.60	0.91	1.29
CO_2 Removal, mols	1.82	2.93	1.82	2.58
CH_4 Synthesis, mols	1.52	1.24	1.11	0.85

* El. = Electrothermal; O_2 = Oxygen

TABLE 22. OPERATING COST DIFFERENTIALS
(20 percent C as char)

C in CH_4, percent	20		27.5	
Heat Source*	El.	O_2	El.	O_2
Basis: 1 Mscf methane				
Coal at 15 cents/MM Btu ($3.90/t, 9.1% ash, 1.3% H_2O)	17.9	22.3	17.9	20.9
Char credit at 15 cents/MM Btu	2.9	3.5	2.9	3.4
Net gasifier fuel, cents	15.0	18.8	15.0	17.5
Oxygen, $5.00/t	--	10.7	--	7.3
Electricity, 0.4 cents/kwh	27.5	--	22.2	--
Steam, 30 cents/M lb	2.7	2.0	2.7	1.8
Shift reaction, 1.5 cents/mol CO	1.6	2.4	1.4	1.9
CO_2 removal, 2.33 cents/mol CO_2	4.3	6.8	4.3	6.0
CH_4 synthesis, 2.23 cents/mol CH_4	3.4	2.8	2.5	1.9
Total	54.5	43.5	48.1	36.4
Differential from lowest cost	18.1	7.1	11.7	0

* El. = Electrothermal; O_2 = Oxygen

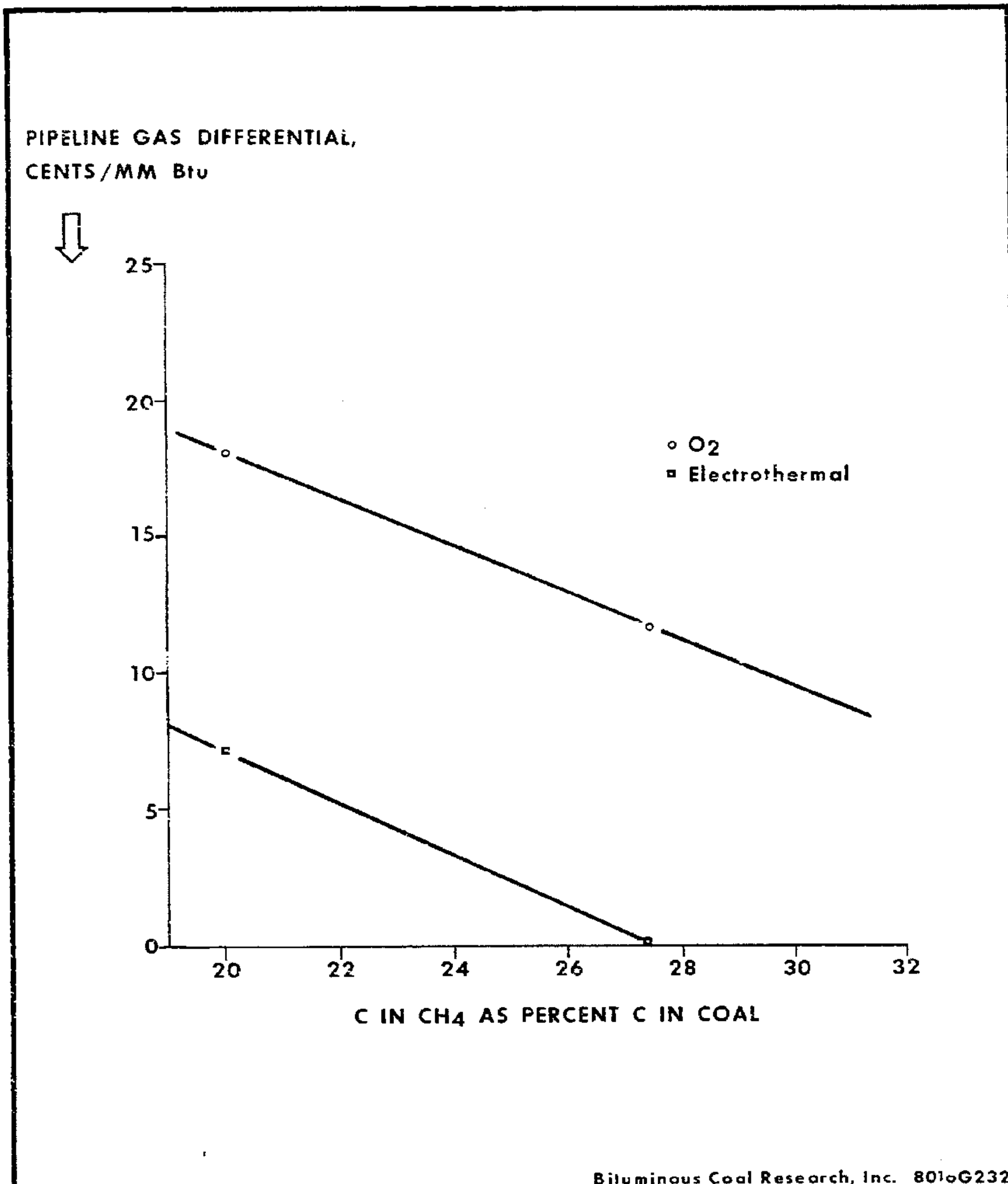


Figure 31. Pipeline Gas Cost Differential for Gasification with 20 Percent Char Withdrawal

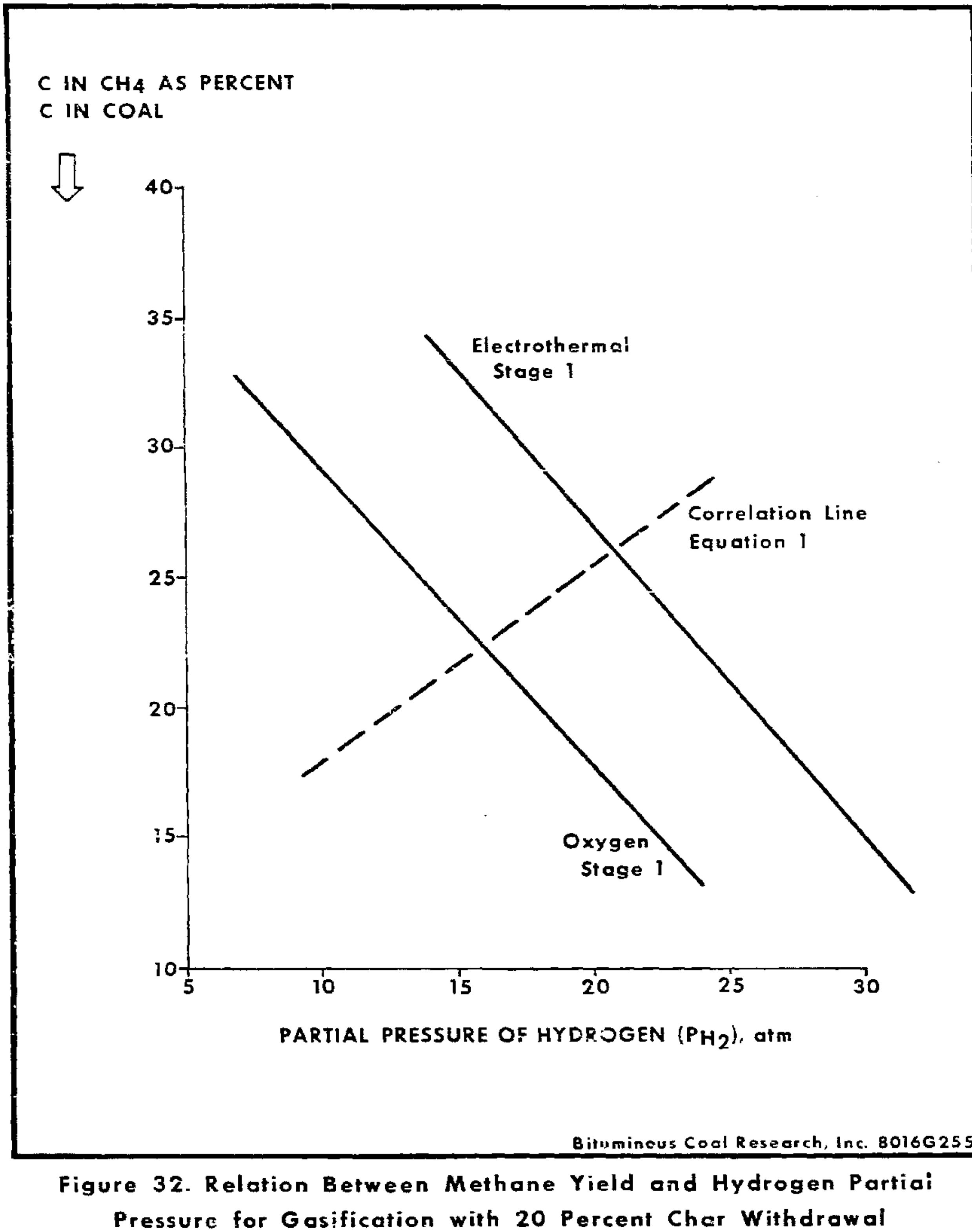


Figure 32. Relation Between Methane Yield and Hydrogen Partial Pressure for Gasification with 20 Percent Char Withdrawal

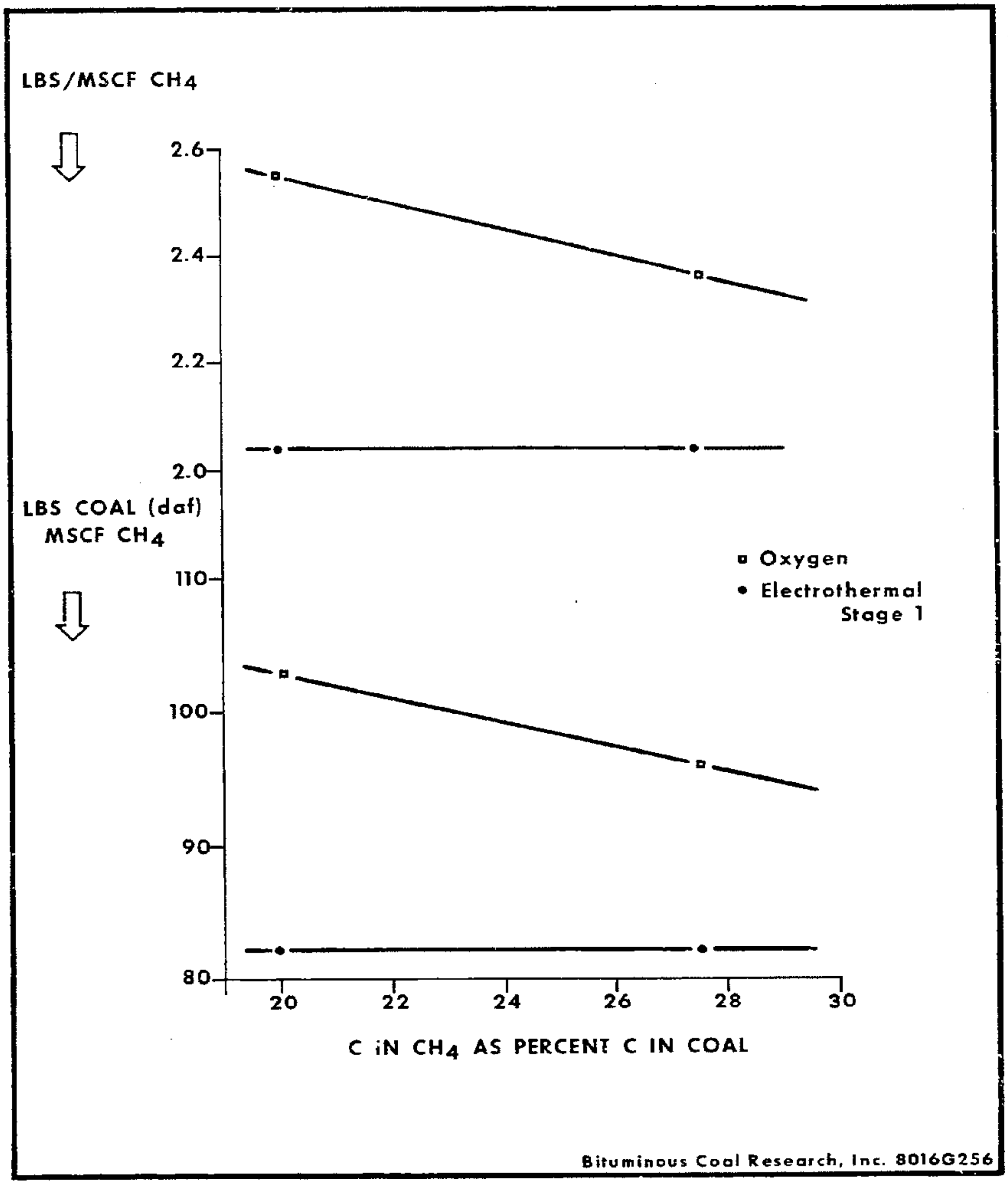


Figure 33. Relation Between Sulfur Credit and Methane Yield for Gasification with 20 Percent Char Withdrawal

PROGRESS REPORT #26

BITUMINOUS COAL RESEARCH, INC.
COAL GASIFICATION

SEPTEMBER 1971

KOPPERS CONTRACT 2415

I. STATUS OF CONTRACT

A. PILOT PLANT ENGINEERING BID PACKAGE

(1) Work is proceeding on schedule. Engineering drawings and specifications are scheduled for completion and submittal to BCR for approval on December 3, 1971. Cost estimate, cash flow projection, construction schedule and models are scheduled for completion on December 31, 1971.

(2) At BCR's request, Koppers submitted on September 8, 1971 letter 2415-C135 covering additional information and detailed cost breakdown for the proposed services by Koppers in connection with the advance procurement of the long lead and critical items recommended in Koppers letter 2415-C114 dated August 12, 1971.

(3) Initial site work (to be performed by others at the Homer City Pilot Plant) was recommended by Koppers to start immediately and concurrently with the engineering for the bid package in the letter 2415-C139 dated September 9, 1971.

(4) Capital cost estimate for the BI-GAS Pilot Plant at Homer City for the scope of work specified by Amendment #7 to Subcontract No. 2 was submitted to BCR on September 15, 1971 (2415-C144).

(5) On September 17, 1971 (letter 2415-C150) Koppers provided clarification and additional information to justify the changes in design of the gasifier.

(6) On September 24, 1971 Koppers submitted to BCR a summary of the anticipated electrical power load for the proposed power plant (2415-C156).

(7) An inspection of the Homer City Pilot Plant was made on September 10, 1971 jointly with representatives of BCR, Penn Electric and Indiana Development Corporation. For additional information please refer to Conference Report No. 196.

(8) By letter dated September 23, 1971, BCR requested Koppers to proceed with inquiries and to obtain responsible quotations from outside engineering firms, qualified to conduct soils investigation and make additional site survey of the Homer City pilot plant site.

B. ENGINEERING ASSISTANCE AND RECOMMENDATIONS FOR PEDU PROGRAM

(1) Preliminary capital cost estimates (1972 expenditure) for Methanation PEDU and Fluidized Bed Gasification PEDU were transmitted to BCR on September 9, 1971 (letter 2415-C136).

(2) Process description and P&I flow diagrams for Char Fluidized Bed Gasification PEDU and Methanation PEDU were submitted for BCR's approval on September 13, 1971, letter 2415-C141.

(3) Report on insurance requirements for both PEDU units was transmitted to BCR on September 13, 1971 (2415-C142).

(4) Koppers Research Department submitted experimental program philosophy and comments on char reactivity in connection with Fluid Bed Char Gasification.

(5) A review of the electrical power requirements for PEDU program was made jointly by BCR and Koppers personnel and reported in Conference Report No. 195 (meeting dated September 2, 1971).

(6) Koppers transmitted to BCR for approval on September 30, 1971 specifications for the Methanation PEDU (2415-C165).

(7) Koppers transmitted to BCR for approval on October 1, 1971 (2415-C168) specifications for Char Fluidized Bed Gasification PEDU.

Issuance of the specifications for these two PEDU's completes on schedule Parts B-1 and B-2a of Appendix A of Amendment #6 to our contract. Execution of the detailed engineering is pending customer's approval and authorization to proceed.

II. CONTRACT EVALUATION

By letter dated September 29, 1971, BCR transmitted to Koppers "Execution Copy" of the proposed Amendment #7 to Koppers Subcontract #2 with BCR which reflects the revised scope of work presently used in the preparation of the bid package for the BI-GAS pilot plant. In addition, this amendment transfers the activities originated under OCR contract 14-01-0001-324 to OCR contract 14-32-0001-1207.

APPENDIX G

ADDITIONS TO ABSTRACT FILE, SEPTEMBER 1971

"Development of a process for producing an ashless, low-sulfur fuel from coal. COG refinery economic evaluation - Phase I," Vol. I, Pt. 2, Chem Systems, Inc., Interim Rept. No. 3 to U.S. Office Coal Res., R&D Rept. 53 (undated). 61 pp. 540.000 OCR-C

> Six alternate processes were evaluated in choosing the most economical combination for the COG refinery. The multipurpose plant is basically a combination of the SRC (solvent refined coal) Process, BI-GAS Process, H-oil Process, and hydrotreating processes integrated with the necessary gas separation and purification steps. The flow sheet of the process is given along with the material balance based on a total coal feed of 58,600 tons per day. (Adapted from text)

Janka, J. C. and Malhotra, R., "Estimation of coal and gas properties for gasification design calculations," Inst. Gas Technol., Interim Rept. No. 7 to U.S. Office Coal Res., R&D Rept. 22 (1971). 76 pp. 540.000 OCR-I

> Data on gas properties and characteristics of coal and char compiled from many sources are included in this manual with examples of their use in calculations for design of coal gasification systems. Original references are listed.

Schora, F. C., Jr., Lee, B. S., and Matthews, C. W., "The IGT HYGAS Process," Inst. Gas Technol., 162nd Natl. ACS Meet., Washington, D.C., 1971. 13 pp. 540.000 71-6

> Three methods of hydrogen production from char are being considered for the HYGAS Process: electrothermal gasification, oxygen gasification, and the steam-iron process. A schematic diagram shows how each method fits into the system. Char discharge and coal preparation, pretreatment, and feed are also discussed.