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PROCESS FOR THE ECONOMICAL UTILIZATION OF IDLE STANDBY OILGAS PLANTS TO PRODUCE LOW-COST PETROCHEMICALS

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Natural gas covering over 97% of the requirements of the U.S. gas industry(1) has almost completely replaced manufactured gas produced from coal, coke or oil, which still represents over 99% of the gas distributed in Europe (9).

In most cases, in the U.S.A., gas plants have been converted to produce oil-gas and are being maintained as standby facilities to cover peakloads, sometimes so required by State Utility Commissions. However, in general, such plants (appr. 150 gas generators), are operated for less than 15 days per year.

This situation is economically unsound, when considering the important capital investment in such plants, the required maintenance, and the necessity of having skilled labor available all year round for only a few days' operation per year.

On the other hand, natural gas contracts generally limit the quantity of natural gas available for peakloads, which may be as high as 4 times the lowest sendout volume. Price for extra peakload gas may be up to 6 times the average cost of natural gas. With the increase in space heating load, the dynamic competition of other fuels and the upward trend in the cost of natural gas, the peakload problem is becoming increasingly acute.

A solution is proposed which is believed to solve the peakload problem of the gas industry. Its application will permit continuous year round operation of presently idle gas plants.

This solution provides to produce oilgas with a higher than conventional heat value and which may contain up to 50% higher hydrocarbons (C_2 to C_8). Recovery, fractionation and further processing of such hydrocarbons would then make available basic petrochemicals. Due to the high value of petrochemicals recovered from the oilgas, the residual gas can be made available at a lower cost than that of natural gas. The residual gas is more readily interchangeable with natural gas than oilgas. During most of the year, residual gas may be used to cover heat and power requirements; during peakload periods, it can be made available for gas distribution and liquid fuels are used for the plant.

The process can make available to the chemical industry basic petrochemicals such as ethylene, propylene, butylene-butadiene, cyclopentadiene, benzene, toluene, cumene and styrene. Production would be nearer to large consumption areas, as for instance on the East Coast of the U.S.A., and possibly at lower cost than that prevailing on the Gulf Coast.

Taking ethylene as an example: 62.6% of the total U.S.production originates from the Gulf Coast at a price of appr. 5cents/lb. and only 15.4% from the East Coast at appr. 6 cents/lb. such prices being based on plants of 200 to 300 million pounds per year capacity (8).

With this solution, it would be possible to produce ethylene at a price of appr. 2.5 cents/lb., in New England in a plant having a capacity of only 43 million pounds per year (oilgas plant of 10,000 MCFD). In this case, the residual gas is valued at 30% below the average cost of natural gas, and the other products at their market value in this area.

A plant with an annual capacity of 26 million pounds of ethylene (6,000 MCFD gas plant) would still be economically feasible with this solution, whereas such relatively small plants are not competitive when using other processes. By application of the proposed solution at a single converted gas plant in the N.Y. metropolitan area, 150 million pounds of ethylene could be obtained and this right near major markets for the products.

The growth of the petrochemical industry has been dynamic and continues at an unprecedented rate. During the last two decades, production in the U.S.A. had doubled about every five years. In 1958, it amounted to appr. 5 billion dollars annually, and is expected to grow to 20 billion dollars by 1967(6).

In papers presented at the World Petroleum Congress held recently in New York, as well as in several publications (6, 7) production of petrochmicals over a decade has been forecast as per following Table.

Anticipated Increase in Production of some Basic Petrochemicals in the United States in a Decade in Billion Pounds

	1955	1965
Ethylene	3.05	6.50
Propylene	1.60	2.70
Butylene-Butadiene	2.15	3.60
Aromatics	3.00	8.00
Styrene	1.01	1.75
All Petrochemicals	31.50	85.00

Natural gas is the principal source (50%) from which ethylene is produced in the U.S. (8). Natural gas contains relatively small percentages of ethane from which ethylene is produced by thermocracking, after recovery of ethane from natural gas. In our case, the ethylene is already present as such in the oilgas (over 20% by volume) in addition to other hydrocarbons the total content of which may be as high as 50% by volume. This allows lower capital investment and permits the economical recovery of hydrocarbons in smaller plants.

The Stark Process (U.S.Patent No. 2,714,060) proposed in this paper has been described previously in several publications (2, 3, 4, 5, 11) This process offers a great deal of flexibility regarding the degree of hydrocarbon recovery, purity and type of products which can be obtained.

A number of schemes, A to E, mostly new, have been worked out to show various possibilities in recovery and production of petrochemicals and their economics are outlined hereafter.

In all of the following schemes, oilgas is the basic charge stock for the proposed recovery and petrochemical plants. The oilgas is produced in existing converted, reactivated or new gasplant facilities.

The conventional oilgas generator permits vapor phase cracking with steam but without catalyst. A variety of fuels such as Bunker C oil, residuum crude oils, and crude oil may be used for oilgas making. The oilgas generator can be heated by heavy oil, tar or gas. By suitable adjustment of the operating conditions, particularly of the cracking temperature, an oilgas of desired analysis and heat value (700 Btu/cf to 1600 Btu/cf) can be produced. As the hydrocarbon content of the gas (C_2 to C_8) increases, the heating value of the oilgas increases accordingly. It may range between 5 mol percent for a 700 Btu/cf gas to 50 mol percent for a 1600 Btu/cf gas(10).

The present study is based on a typical oilgas of 1250 Btu/cf having the following analysis expressed in mol percent, based on operating data available from various plants.

CH_4	33.0%	
C_2	24.0%	
C_3	6.6%	
C_4	3.8%	
C_5	1.2%	
C_6-C_8	3.4%	
H_2	16.0%	
CO, CO_2, O_2, N_2	12.0%	Heat value 1250 Btu/cf
	100.0%	Gravity 0.86

The combined percentage of unsaturated hydrocarbons and aromatics in above analysis represents appr. 33%. The residual gas after recovery of higher hydrocarbons will have a heat value and gravity nearer to the natural gas and may be used as a substitute thereof, with better interchangeability and characteristics than the conventional oilgas of 1000 Btu/cf. The residual gas may, however, also be used within the plant itself to provide for heat and power requirements. Depending on local market conditions, by crediting the market value of the recovered petrochemicals, this may result in a lower cost for residual gas than for the price of natural gas in the specific area.

The H_2S is removed from the oil and the tar is separated and dehydrated at the gas plant by conventional procedures. The oilgas accumulated in the holder is compressed and sent to the recovery plant.

As the organic sulphur compounds generally contained in the oilgas (appr. 30 grains/100 cf) are removed from the gas during the recovery processing, the residual gas will be practically free of organic sulphur and can, if so desired, be used in a catalytic generator for the production of hydrogen, which cannot be obtained from the oil/gas directly because of this sulphur (12). This allows also to build ammonia plants starting from heavy oil as the only charge stock. In such case, hydrogen could be produced from the residual gas and any balance of the residual gas could be used to cover the important heat and power requirements of the ammonia plant. This possibility is not covered in this paper.

Schemes A to E are outlined below:

Scheme A (Fig. 1)

This plant proposes the recovery of appr. 70% of C_3, and more than 98% of C_4 to C_8 cuts (2). The residual gas will have the following appr. analysis in mol percent:

CH_4	38.0%
C_2	27.0%
C_3+	2.6%
H_2	18.4%
CO, O_2, CO_2, N_2	14.0%
	100.0%
Heat value	970 Btu/cf
Gravity	0.68

Scheme B (Fig.2)

Recovery of 88% of the C_2 fraction and appr. 98% of the higher hydrocarbons(C_3-C_8) is proposed. The residual gas will have the followinf appr. analysis in mol percent:

CH_4	49.2%
C_2+	9.1%
H_2	24.7%
CO, CO_2, O_2,N_2	17.0%
	100.0%
Heat value	750 Btu/cf
Gravity	0.58

The residual gas can be enriched to a gas of 1000 Btu/cf and appr. 0.70 gravity using appr. 4% of the annual output of the recovered C_3 cut.

Scheme C (Fig.3)

Provides for the addition to the recovery plant as per Scheme A of another Plant (P1) to handle 50% of the residual gas.

Part of the residual gas, with addition of benzene, is sent to Plant P1, where all of the propylene in the gas with the benzene is catalytically converted to cumene (C_9H_{12}), and the ethylene with the benzene is converted to ethylbenzene (C_8H_{10}) an aromatic solvent remaining as byproduct. The ethylbenzene can then be dehydrogenated into styrene (C_8H_8) in an additional plant P2.

The quantity of cumene and styrene produced may be varied by changing the percentage of volume of residual gas processed in plants P1 and P2.

Scheme D (Fig. 3)

Shows conditions when all of the residual gas is processed in plants P1 and P2,otherwise at the same conditions as Scheme C.

Scheme E (Fig. 4)

Refers to an alternate in which the first plant is limited to the extraction of 95% of C_4 and heavier fractions. Plants similar to D are provided, however, all of the C_3 will be used in Plant P1 resulting in greater cumene production than provided for in the preceding scheme, but no propylene cut is recovered.

A typical example is given for a plant with a daily capacity of 6,000 MCFD of oilgas corresponding to the operation of only one large size conventional oilgas generator unit.

An oilgas of 1250 Btu/cf, typical analysis as above, based on 345 days of operation per year, has been assumed; this amounts to an input in the extraction plant of 7,500 MM Btu/day or 2,587,700 MM Btu/year. Consumption of heavy oil for gas making and heating of the oilgas generator based on 13.5 gal/MCF is 764,000 bbl/year.

The following tables illustrate the economics of such typical plant for each of above schemes, based on present market conditions prevailing in the New England area.

Table I, indicates quantities produced, as well as charge stocks, on an annual basis.

Table II, shows the upgrading, i.e. market value of the product obtained less the cost of charge stocks (heavy oil and benzene) with corresponding unit prices for each product.

Residual gas has been estimated at the cost of heavy fuel in equivalent Btu, i.e. 35¢/MMBtu, plus 10% for difference in efficiency and cost of preheating of the heavy oil making a total of 38.5¢/MMBtu. This is 30% lower than the average cost of natural gas in the New England region (appr. 55¢/MMBtu). It makes possible to use residual gas as fuel, either partially or totally, for petrochemical or power plants or gas distribution. Above calculations do not reflect credit for the much higher value of residual gas when used for peakload requirements (other substitutes being up to 6 times higher)

An economic evaluation for each scheme is summarized in Table III.

The required capital investments should be established separately for each project, however, an indication has been given in Tabulation III.

Equity has been assumed at 50% of the capital requirements, interest rate at 6 percent per annum on balance of required capital with amortization over 10 years resulting in an average annuity of 3.59%

Cost of utilities and labor on which these studies are based:

Steam	70¢/1000 lbs.
Electricty	1.1¢/KWH
Fuel oil	$2.20/Bbl
Fuel gas	38.5¢/MCF
Water	0.5¢/1000 gals
Skilled labor	$2.40/hour

A conservative figure of 20¢ per MCF has been used for the cost of oil-gas at holder including tar dehydration.

The return on total capital is defined as income plus interest dividedby the total capital.

The payout is defined as number of years resulting from the capital investment divided by net income ater taxes plus depreciation.

Tabulation III shows that the net return on capital equity after taxes is 21% to 72% and payout 4.7% to 2.1 years based on above conditions.

Figs. 5 and 6 illustrate payout and percentage of net income after taxes on the equity(**50% of capital**) for Schemes A thru E above, for plants of capacities from 3,000 MCFD to 10,000 MCFD based on present market con ditions in the New England area.

A specific study should be made for each case as the economics will depend on the local and market conditions.

If payout of 5 years is taken as a basis for Scheme B and for a plant of 10,000 MCFD capacity, the cost of ethylene for a production of 43 million pounds per year (instead of 26 million pounds/year in a 6,000 MCFD plant) may be as low as 2.5¢/lb in the New England area.

The cost of styrene under above conditions for a plant of 10,000 MCFD, using this process will be only appr. 8¢/lb. and of cumene 5.3¢/lb. i.e. appr. 30% lower than market prices in the New England area.

It is to be emphasized that, depending on market conditions, plants of smaller capacity become economically feasible by application of this process. This may be of special importance for plants outside the United States where smaller quantities of petrochemicals are marketable and can be produced at much lower cost than they can be imported.

The application of this process will result in the following advantages:

1) Utilization of idle investment in gas plants by operating them all year round, instead on only less than two weeks a year.

2) Possibility of making available to the gas industry a better substitute gas at much lower cost than other substitutes for peakloads and appr. 30% lower than the average yearly cost of natural gas in the area.

3) Possibility of making available to the chemical industry basic petrochemicals closer to the consuming markets (for instance the East of the U.S.) at a price possibly lower than prevailing on the Gulf Coast of U.S.A.

4) To obtain a high net income on equity capital after taxes (21% to 72%) and payout of the investment in 2 - 5 years.

5) Possibility to install plants of small capacity which is, in general, not economically possible with other processes.

6) Economic utilization of heavy oils, either Bunker C oil or crude oil, which may be either in oversupply or too far from market areas.

This process may show even better economics when applied in other countries even if installation of gas plant equipment may be required, because chemicals are generally imported and their cost is higher than in U.S.A whereas labor is less expensive.

Application of this process may benefit both the gas and chemical industries and may contribute to better standards of living in many countries.

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TABLE I

PRODUCTS AND REQUIRED CHARGE STOCKS

FOR DIFFERENT SCHEMES FOR A TYPICAL 6000 MCF/D PLANT

		A	B	C	D	E
PRODUCTS						
Residual Gas	MM BTU /yr	1,675,000	1,020,000	1,280,000	950,000	970,000
Tar	MM gals/yr	14.10	14.10	14.10	14.10	14.10
Ethylene	MM lbs /yr		26.30			
Propylene Cut	MM gals/yr	2.83	3.85	2.83	2.83	
Butadiene-Butylenes Cut	MM gals/yr	2.23	2.23	2.23	2.23	2.23
Cyclopentadiene-Pentene Cut	MM gals/yr	.67	.67	.67	.67	.67
BTX (Benzene-Toluene-Xylene)	MM gals/yr	2.16	2.16	2.16	2.16	2.16
Styrene	MM lbs /yr			41.90	83.80	84.50
Cumene	MM lbs /yr			5.04	10.04	38.20
Aromatic Solvent	MM gals/yr			.82		
CHARGE STOCKS						
Heavy oil for oil-gas making and heating oil-gas generator	MM bbl /yr	.764	.764	.764	.764	.764
Benzene	MM gals/yr			5.750	11.500	14.100
Alternate Benzene required, if Benzene from BTX is used	MM gals/yr			4.320	10.070	12.670

TABLE II

UPGRADING VALUES IN MILLION DOLLARS/YEAR FOR DIFFERENT SCHEMES FOR A TYPICAL 6000 MCF/D PLANT WITH UNIT PRICES OF PRODUCTS

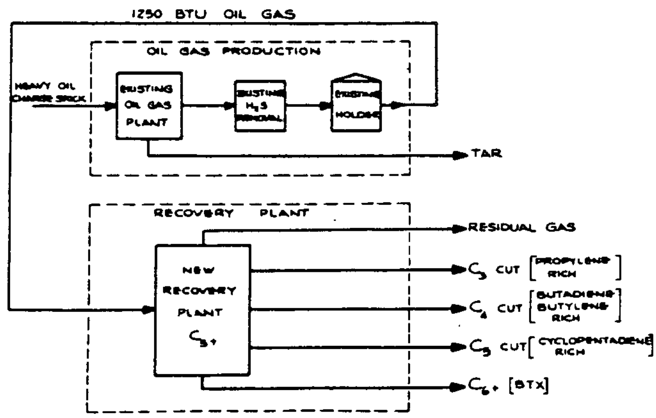
	Unit Prices	A	B	C	D	E
VALUE OF PRODUCTS						
Residual Gas	$ .385/MMBTU	.645	.392	.492	.366	.373
Tar	$ .10 /gal	1.410	1.410	1.410	1.410	1.410
Ethylene	$ .05 /lb		1.313			
Propylene	$ .14 /gal	.396	.539	.396	.396	
Butadiene-Butylenes	$ .09 /gal	.200	.200	.200	.200	.200
Cyclopentadiene-Pentenes	$ .09 /gal	.060	.060	.060	.060	.060
BTX	$ .18 /gal	.389	.389	.389	.389	.389
Styrene	$ .12 /lb			5.020	10.040	10.120
Cumene	$ .08 /lb			.403	.806	3.060
Aromatic Solvent	$ .15 /gal			.123	.246	.308
TOTAL		3.100	4.303	8.493	13.913	15.920
COST OF CHARGE STOCKS						
Heavy oil for oil-gas making and heating oil-gas generator	$2.20 /bbl	1.680	1.680	1.680	1.680	1.680
Benzene	$ .31 /gal			1.780	3.560	4.360
TOTAL		1.680	1.680	3.460	5.240	6.040
UPGRADING VALUES (Equal to Value of Products less Cost of Charge Stocks)		1.420	2.623	5.033	8.673	9.880

TABLE III

ECONOMIC EVALUATION OF DIFFERENT SCHEMES

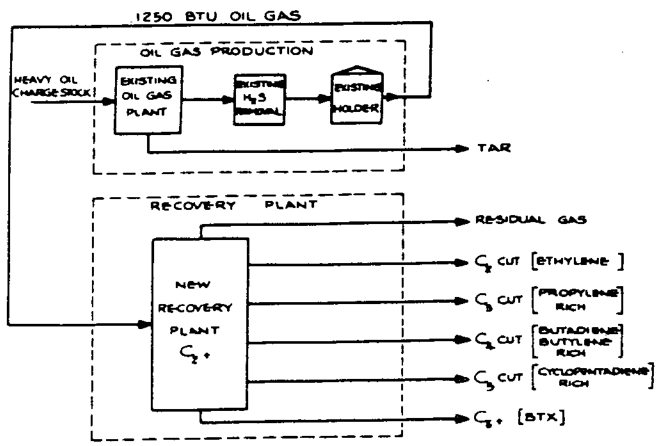
IN MILLION DOLLARS/YEAR FOR A TYPICAL 6000 MCF/D PLANT

	A	B	C	D	E
Estimated Capital Investment	2.10	3.90	6.10	8.20	7.90
Financing, Equity (50%)	1.05	1.95	3.05	4.10	3.85
Loan	1.05	1.95	3.05	4.10	3.85
COSTS, MM $/yr					
Gas Manufacturing Plant incl. tar processing, but excl. charge stock	.416	.416	.416	.416	.416
Petrochemical Plant					
Utilities and Chemicals	.097	.234	.878	1.659	1.720
Labor	.080	.193	.216	.216	.193
Miscellaneous incl. maint., insur., gen. man., sales, royalties etc.	.135	.263	.568	.870	.914
Depreciation (10 yrs)	.193	.375	.571	.764	.727
Interest, 6% amort. 10 yrs. (average 3.59% per year)	.038	.070	.110	.147	.138
TOTAL.	.959	1.551	2.759	4.072	4.108
Upgrading (Value of Products, less Costs of Charge Stock)	1.420	2.623	5.033	8.673	9.880
Income	.461	1.072	2.274	4.601	5.772
Income Taxes (52%)	.240	.556	1.182	2.395	3.000
Net Income	.221	.516	1.092	2.206	2.772
% Return on Equity after Taxes	21.0	26.5	35.8	53.8	72.0
% Return on Capital Investment after Taxes	12.3	15.0	19.7	28.7	36.9
Payout after Taxes	4.7	4.2	3.4	2.6	2.1



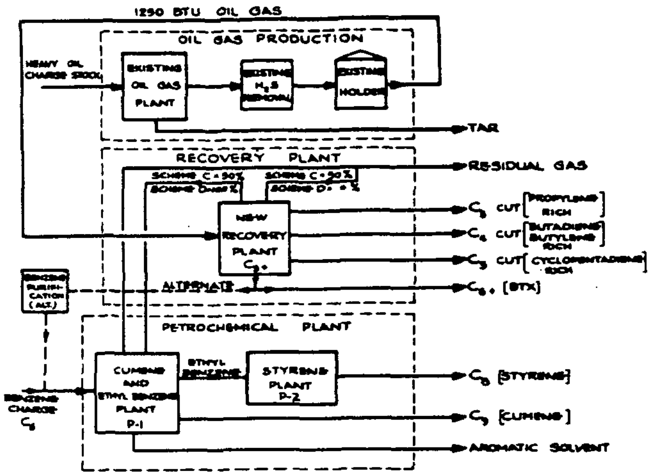
SCHEME A

FIG. I



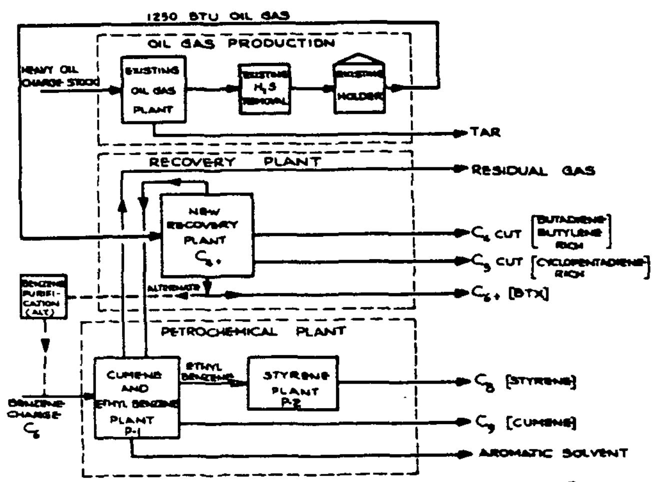
SCHEME B

FIG. II



SCHEMES C AND D

FIG III



SCHEME E

FIG IV

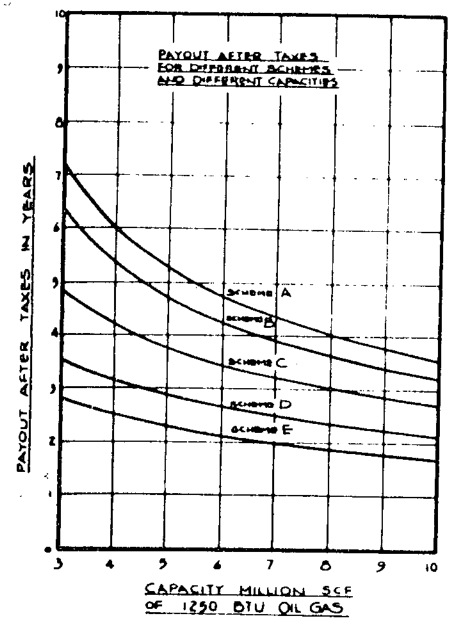

PAYOUT AFTER TAXES FOR DIFFERENT SCHEMES AND DIFFERENT CAPACITIES
PAYOUT AFTER TAXES IN YEARS
SCHEME A
SCHEME B
SCHEME C
SCHEME D
SCHEME E
0
1
2
3
4
5
6
7
8
9
10
3
4
5
6
7
8
9
10
CAPACITY MILLION SCF OF 1250 BTU OIL GAS

FIG. V

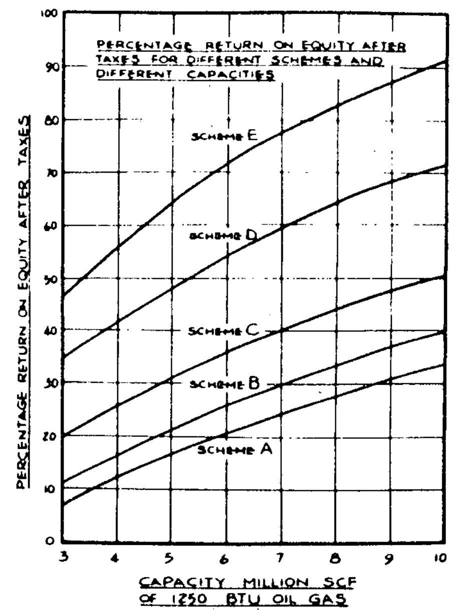

PERCENTAGE RETURN ON EQUITY AFTER TAXES FOR DIFFERENT SCHEMES AND DIFFERENT CAPACITIES
PERCENTAGE RETURN ON EQUITY AFTER TAXES
SCHEME E
SCHEME D
SCHEME C
SCHEME B
SCHEME A
0
10
20
30
40
50
60
70
80
90
100
3
4
5
6
7
8
9
10
CAPACITY MILLION SCF OF 1250 BTU OIL GAS

FIG. VI