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Volume Title: Problems of Capital Formation: Concepts, Measurement, and Controlling Factors

Volume Author/Editor: Conference on Research in Income and Wealth

Volume Publisher: NBER

Volume ISBN: 0-870-14175-9

Volume URL: http://www.nber.org/books/unkn57-1

Publication Date: 1957

Chapter Title: A Report on the Calculation of Capital Coefficients for the Petroleum Industry

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Chapter URL: http://www.nber.org/chapters/c5588

Chapter pages in book: (p. 375 - 387)

A REPORT ON THE CALCULATION OF CAPITAL COEFFICIENTS FOR THE PETROLEUM INDUSTRY

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In 1951 the department of economics of the Rice Institute computed capital coefficients for the major branches of the petroleum industry—crude production, pipe lines (crude, refined products, and natural gas), natural gasoline and cycling plants, and refineries—and for the allied industries of oil well drilling by contract and the manufacture of oil field equipment.

The oil industry stands high in capital expenditures in the economy. According to Department of Commerce data, total expenditures for plant and equipment in the United States in 1946–1952 were $149.5 billion. Of this total American Petroleum Institute data for the same period show that the petroleum industry spent $17.3 billion, or approximately 11.6 per cent (Table 1).

TABLE 1

Petroleum Industry Expenditures for Plant and Equipment in the United States, 1946–1952

(*billions of dollars*)

Production	9.67
Refining	2.66
Crude pipe lines	0.97
Other transportation	1.39
Marketing	1.65
Natural gasoline plants	0.45
Miscellaneous	0.51
	17.30

Source: *Petroleum Facts and Figures*, 10th ed., American Petroleum Institute, 1952, p. 235.

The production, refining, and crude pipe line stages of the industry accounted for some $13.3 billion. Consequently these three stages were chosen for most intensive investigation and this paper will be devoted to a few of the problems encountered in computing coefficients for them. Since they cover widely different types of facilities, it is hoped that these studies may help in uncovering problems that may be encountered in future attempts to compute capital coefficients from industry data. Some of these problems are unique to the petroleum industry; others are without doubt universal.

Crude Production

The computation of capital coefficients for the crude-producing industry is a four-step process. To expand the capacity of, say, the steel industry, it means the construction of a new steel plant which is reasonably certain to produce steel—given sufficient demand and reasonably intelligent designing engineers. On the other hand, to increase the nation's capacity to produce crude oil, it means the drilling of an oil well; or more correctly, the drilling of a well *for* oil. In about 40 per cent of the cases no expansion of capacity will result; in 60 per cent, oil, gas, or condensate will be found; but the amount of reserves added, and hence the volume of production, will vary widely.

Consequently in order to determine a capital coefficient for crude production in dollars per barrel per year, one must do the following:

1. Determine an average drilling and completion cost per well (distributed by four-digit SIC industries). This we might designate as C.

2. Determine the amount of new reserves which can be expected from a given number of wells (taking into account any time trend in the probability of hitting oil and the average size of pools discovered). This we might designate as R.

3. Determine the expected average annual productive capacity of the reserves found, say, 9 per cent per year.

4. Compute the total capital coefficients as follows:

$$\text{Capital coefficient} = \frac{C}{0.09R}$$

There are two types of drilling—cable and rotary—each with different cost elements. Total drilling costs per foot for each method vary with the depth of the well and the characteristics of the region in which it is drilled. Costs per foot rise as depth increases. Costs per well for individual items may vary with depth or well location, or with both of these, or they may be constant. Consequently in order to determine an average cost per well for a given item, it may be necessary to (1) determine costs in the principal areas for selected depth ranges and compute a weighted average for each area (using the percentages of drilling in each *depth range* as weights) and (2) determine a national weighted average of area costs (using the percentages of drilling in each *area* as weights). Because current percentage distributions are used for weights, the coefficients carry the implicit assumption that current depth and geographical drilling patterns will be continued. This is obviously not precise, but it would be impossible to anticipate changes in the current depth and regional pattern of drilling.

Since drilling costs are of such importance, it might be wise to examine the computational process for one particular item, viz. rock bits.[1] Rock bits are toothed cutting machines which account for the great majority of rotary drilling. Bit costs are a function of the characteristics of the formation being drilled (the harder the formation, the less footage per bit), the weight on the bit, etc. In general, harder formations are encountered at greater depths than at shallow depths within particular geographical areas; consequently bit costs per foot should increase as the well becomes deeper.

Chart 1 shows total bit costs per well plotted against the corresponding depth of well. It is based on actual costs derived from sixty well logs covering wells drilled in West Texas, the Rocky Mountain area, Oklahoma, Kansas, North Texas, Central Texas, and North Louisiana. These logs report the size and type of bits used. Costs per well were determined by pricing the reported sizes with 1951 standard industry prices. These observations were assumed to be representative for the United States as a whole with the exception of the Gulf Coast (83.5 per cent of rotary footage drilled outside of the Gulf Coast is accounted for by these areas). The relationship between bit cost per well and depth of well may be described by the equation

$$y = 0.2237 - 0.3236x + 0.1938x^2$$

where x is in thousands of feet and y in thousands of dollars.

Bit cost per well in the Gulf Coast is lower, chiefly because formations found in this area are relatively soft at all depths in comparison with other areas. Consequently separate costs for the Gulf Coast were determined. A second degree curve was fitted to

[1]The following description of the computation of rock-bit cost is taken from John E. Hodges and L. Cookenboo, Jr., "The Oil Well Drilling Contractor Industry—A Case Study in Pure Competition," *The Rice Institute Pamphlet*, July 1953.

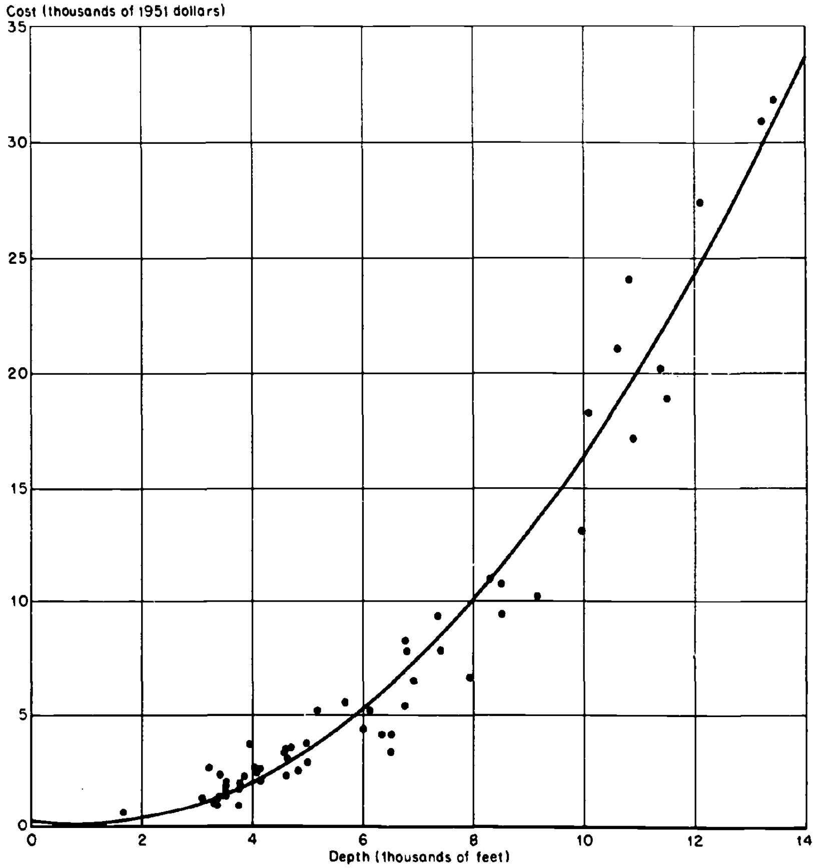

CHART 1
Comparison of Bit Cost and Depth of Wells, United States, Excluding Gulf Coast, Based on 60 Well Logs

the bit cost per well for twenty-five Gulf Coast wells plotted against these wells. This equation is

$$y = 2.0107 - 0.4511x + 0.0702x^2$$

where x is in thousands of feet and y in thousands of dollars.

An average bit cost was determined for each of several depth ranges in both the Gulf Coast and the rest of the United States (Table 2). The average cost within each depth range from 2,500

TABLE 2

Computation of Average Bit Cost per Well

Depth Range (feet)	*Depth at Which Cost Is Calculated (feet)*	*Per Cent of Rotary Wells*	*Bit Cost per Well*[a] *(1951 dollars)*
Areas Other than Gulf Coast[b] *(83.73 per cent of Rotary Wells)*			
0–2,500	2,000	26.11	$ 351.70
2,500–5,000	3,750	49.55	1,735.50
5,000–7,500	6,250	18.17	5,771.50
7,500–10,000	8,750	4.22	12,230.00
10,000 and over	11,250	1.96	22,111.00
		100.00	
Weighted average			2,949.93
Gulf Coast (16.27 per cent of Rotary Wells)			
0– 2,500	2,000	14.90	351.70
2,500– 5,000	3,750	25.07	1,735.50
5,000– 7,500	6,250	25.79	1,934.60
7,500–10,000	8,750	22.24	3,440.50
10,000 and over	11,500	12.00	6,110.90
		100.00	
Weighted average			2,484.90
Weighted average—entire United States			2,874.26

[a]Weighted by the depth distribution in 1951.
[b]Based on weighted average of West Texas, Ark-La-Tex, Rocky Mountains, Oklahoma, and Kansas.
Source: Computed from *Oil and Gas Journal* surveys and industry data.

feet to 10,000 feet was determined by solving the appropriate equation for the midpoint of the depth range. The average depth for the category "0 to 2,500" feet was assumed to be 2,000 feet since very few rotary wells are drilled in the 0 to 1,250 foot range. The average depth for the depth range of "10,000 and over" for the United States excluding the Gulf Coast was estimated to be 11,250 feet. For the Gulf Coast this average was estimated to be 11,500 feet since the Gulf Coast has a large number of very deep wells.

These average costs for each depth range were then weighted by the corresponding percentages of rotary wells drilled in each range to give a weighted average cost for the Gulf Coast and for the rest of the United States. These two weighted average costs were then averaged once more and weighted by the proportion of drilling in the Gulf Coast and the rest of the United States, giving an average bit cost for the United States of $2,874 per well drilled (1951 dollars).

TABLE 3

Contract Fees per Foot by Regions, 1951

Depth Range (feet)	*Per cent of Rotary Wells*	*Contract Fee (1951 dollars)*
United States Other Than Gulf Coast and California (77.52 per cent of Rotary Wells)		
0– 2,500	25.64	$ 3.08
2,500– 5,000	50.23	3.90
5,000– 7,500	18.35	5.37
7,500–10,000	4.01	7.20
10,000 and over	1.77	9.39
	100.00	
Weighted average		4.19
Gulf Coast (16.27 per cent of Rotary Wells)		
0– 2,500	14.90	1.80
2,500– 5,000	25.07	2.50
5,000– 7,500	25.79	3.50
7,500–10,000	22.24	4.49
10,000 and over	12.00	5.69
	100.00	
Weighted average		3.48
California (6.21 per cent of Rotary Wells)		
0– 2,500	31.93	3.67
2,500– 5,000	41.02	5.49
5,000– 7,500	15.97	8.09
7,500–10,000	6.71	10.68
10,000 and over	4.37	13.28
	100.00	
Weighted average		6.01
United States weighted average		4.19

Source: Computed from *Oil and Gas Journal* surveys and industry data.

A more complex computation was the determination of casing costs, the most important single cost item for a producing well.[3] In casing an oil well, anywhere from one to six strings of concentric pipe of varying sizes may be used. Consequently it was necessary to determine average programs and sizes in each depth range in each area and then compute a weighted national average casing cost per well. Fortunately we had over 5,000 observations which could be used for this computation.

[3]Most wells must be cased even though they may turn out to be dry holes. Casing is therefore classified as a drilling cost.

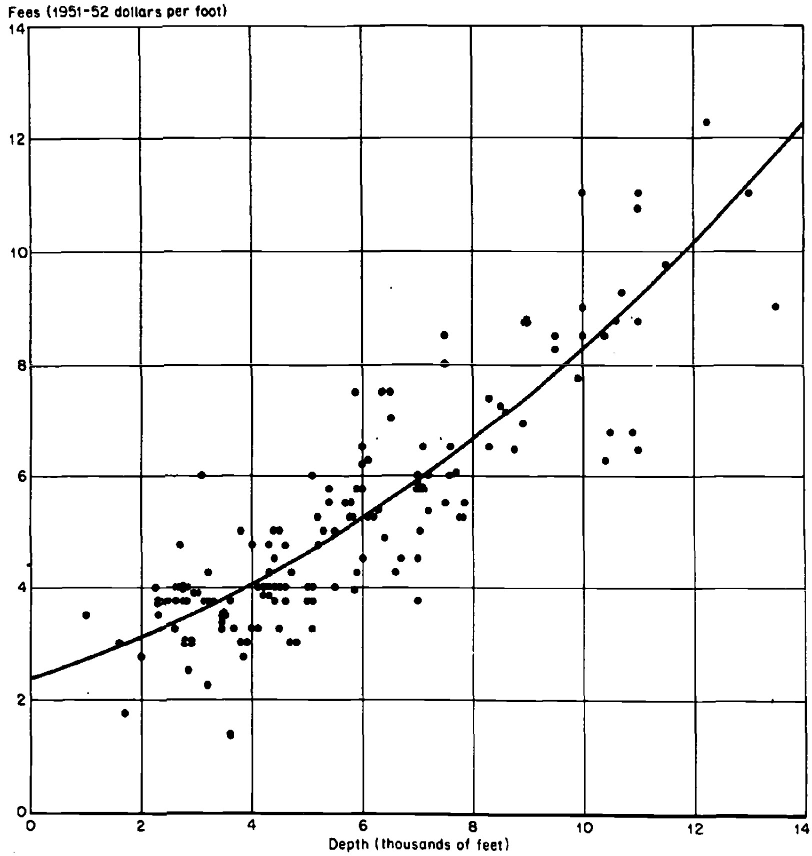

CHART 2
Comparison of Rotary Drilling Contract Fees per Foot with Depth of Wells, United States, Excluding Gulf Coast and California, Based on Data for 158 Wells

The total drilling cost per well is determined by competitive bidding. Consequently in order to get a total capital coefficient per well, it was necessary to average actual drilling contract prices per foot for wells of varying depths. Over 200 observations were used to establish the relationship between contract prices and depth for the principal part of the United States and for the two regions having divergent costs—California and the Gulf Coast (Table 3 and Chart 2).

Completion costs, as distinguished from drilling costs, were also computed. These are costs incurred when a well turns out to be a producer. They are not incurred on dry holes. These costs vary from well to well depending upon whether it produces oil, gas, or condensate. Weighted averages for various classes of completion equipment per well drilled were therefore computed, using as weights the percentages of wells which turn out to be dry, oil, gas, or condensate. Finally cable and rotary drilling costs and completion costs were combined to form a composite cost per well drilled.[3]

The accuracy of capital coefficients computed in step 4 obviously depends upon the reliability of the estimates of new reserves which can be expected from a given number of wells and the annual productive capacity of these reserves determined in steps 2 and 3. A primary study of reserves and productive capacity (the maximum efficient rate of production) was beyond the scope of our project. Therefore we were forced to rely upon information published by the American Petroleum Institute, the Petroleum Administration for Defense, the Texas Railroad Commission, and certain technical articles.

Refineries

It was our original intention to utilize, insofar as possible, the engineering method of computing capital coefficients for refineries instead of relying on averages of actual costs for specific plants. However, we did not have the time or financial means to use the engineering approach and were forced to rely on such data as were available for complete plants, balanced additions, and subunits. Unfortunately only one complete refinery of any size has been built in the United States from the ground up in the last dozen years or so. Since this was built during the war, we were able to obtain the application for the critical materials used to build it. However, this plant had two extra units that would not be expected in normal refinery construction. Since costs for these units could not be segregated, we had to omit the entire plant.

There were, however, six usable applications for critical materials: one a smaller complete plant, four balanced additions, and one complete plant that was not built. Since major balanced additions to refineries are very nearly like complete refineries (the basic difference being a lesser need for auxiliary facilities), we

[3]Detailed description of types of equipment and services used in drilling wells, sources of data, and methods of computation are contained in John E. Hodges, L. Cookenboo, Jr., and W. F. Lovejoy, "Capital Requirements Arising from the Drilling of Wells for Oil, Gas, and Condensate," Bureau of Mines, unpublished.

classified and averaged the cost data for these six plants to determine a set of preliminary coefficients.

The lack of agreement among individual four-digit SIC coefficients and among total coefficients for the six plants was somewhat discouraging. In an attempt to improve the coefficients, we investigated the possibility of computing coefficients for each important unit of a typical refinery from actual cost data on individual subplant units. After subplant unit coefficients had been computed, we planned to combine them in the proper proportions for several types of refineries. It was hoped that the various sets of data on particular units, e.g. catalytic crackers, fractionating facilities, etc., would show more agreement among particular SIC coefficients for the various projects than the six balanced additions and complete plants. It was felt that six sets of data on new fluid catalytic crackers, for example, should have more nearly equal costs per barrel of capacity than six sets of data on additions that might include facilities for removing bottlenecks peculiar to only one plant—even though the additions were composed for the most part of the same types of facilities.

The results of this attempt to improve the coefficients were discouraging. Agreement among total initial costs per unit of capacity for individual plant units was apparently neither better nor worse than for the totals of balanced additions and complete plants. Similarly there was no improvement for individual four-digit SIC coefficients. However, it is still our opinion that this is basically the proper way to compute capital coefficients for a chemical processing industry such as oil—or indeed for any industry where a plant is made up of several distinct operations located on the same piece of property. It would be even more desirable to use engineering cost estimates rather than historical cost data since the latter are subject to reporting errors, individual plant pecularities, etc. After costs of various sizes and types of unit had been established, units could be combined to get total costs for the particular types of expansions needed for a given program.

Since we were unable to make an engineering study of unit costs and since the actual subplant unit costs did not give satisfactory results, we relied on coefficients determined from the original data on balanced additions and complete plants. However, one important modification of the original coefficients had to be made. We were working with cost and capacity data that were ten years old. We felt no real apprehension about the danger of technological change in the intervening period since the basic processes introduced during World War II are still in use. This was confirmed by our engineering consultants. There have been some improvements, but fluid catalytic crackers are still fluid catalytic crackers.[4]

We originally computed and averaged the plant coefficients in 1942 dollars. Then each individual four-digit SIC coefficient was adjusted for price change with such indexes as were available. After aggregating the adjusted coefficients, the total capital coefficient per barrel of crude input capacity was found to be $1,343 in 1951 dollars compared with $781 in 1942 dollars. We were able to compare this result with the total capital cost per barrel of input capacity for nineteen small complete refineries and balanced additions built in 1951–1952. The mean of these nineteen observations was $845 per barrel, a considerably smaller value than that indicated by adjusting the prices of the individual items. After further inquiry, our consultants stated that there was considerable difference between 1952 and 1942 in barrels of capacity per pound of equipment. This is due in part to improvements in equipment and in part to changes in the product mix from high octane aviation gasoline to the middle distillates, but for the most part it is attributable to "learning" on the part of refinery engineers. The example which we like to cite is a unit in a large refinery which was installed with a rated capacity of 14,000 barrels per day. After some months of experimenting and acquainting themselves with the unit, the engineers were able to spend a very small amount (relative to initial cost) and increase its capacity to 42,000 barrels per day—an increase of 200 per cent. Even though there may not have been a technological change in the type of capital facilities used in an industry between the time cost data are collected and capital coefficients are computed and used, the coefficients may be worthless simply because the industry has learned to use its facilities more efficiently.

Since we did not have details of various classes of materials and equipment used in the nineteen current projects, these observations could not be used to compute capital coefficients for individual SIC categories. However, we used the average total capital cost per barrel of input capacity for these nineteen plants ($845) as the total capital coefficient and distributed this total by individual SIC numbers on the basis of percentages of total cost derived from the six plants and balanced additions for which complete data were available (Table 4).

[4]If we had been forced to work with data fifteen years old, they would have been almost worthless since there was a major technological change beginning about 1940.

TABLE 4

Capital Coefficients for Balanced Additions and Complete Plants

SIC Number (materials)	*Cost per Barrel per Day (1951 dollars)*	*SIC Number (materials)*	*Cost per Barrel per Day (1951 dollars)*	*SIC Number (materials)*	*Cost per Barrel per Day (1951 dollars)*
142	$ 0.04	3323	$ 4.69	3567	$ 0.15
1441	0.05	3332	0.25	3569	1.62
2231	0.01	3351	0.13	357	0.45
2232	0.06	3352	0.09	3576	0.10
2294	0.03	3359	1.65	3585	1.56
2411	3.56	3361	0.14	3589	0.56
2421	7.99	3391	6.33	3591	58.89
2431	0.11	3399	0.13	3592	0.73
2432	0.25	3423	3.15	3611	2.54
2491	0.43	3429	0.27	3614	13.80
2613	0.05	3431	0.01	3615	0.76
2851	0.87	3432	0.04	3616	4.72
2911	0.02	3439	0.89	3617	2.77
2951	0.27	3441	27.54	3619	0.03
2952	0.48	3442	1.07	3631	1.34
3099	0.13	3443	100.79	3664	0.05
3211	0.34	3444	0.12	3691	0.02
3241	6.58	3466	0.05	3711	0.87
3251	1.29	3471	0.78	3811	1.19
3253	0.11	3481	0.21	3821	13.46
3254	0.83	3489	0.79	3982	0.26
3255	3.54	3494	3.76	3999	0.02
3259	0.04	3511	6.79	252	0.06
3261	0.21	3519	1.89		
3269	0.10	3541	3.69		
3271	0.08	3542	2.13	Total materials	$506.99
3272	0.01	3553	0.62		
3274	0.02	3559	56.50	Construction	143.66
3275	0.55	3561	29.98		
3292	3.16	3562	0.39	Labor	194.35
3293	10.29	3563	1.21		
3297	0.10	3564	6.15	Total	$845.00
3312	74.50	3565	7.58		
3321	14.46	3566	0.67		

Note: For description of content of SIC classifications, see *Standard Industrial Classification Manual*, Bureau of the Budget, 1945.

Source: Rice Institute Department of Economics Petroleum Research Project. Total cost is average of nineteen current actual projects distributed to individual SIC categories on the basis of percentages of total cost determined from six balanced additions and complete plants.

Crude Pipe Lines

In the case of crude pipe lines we were able to follow largely an engineering approach. Certain items do not lend themselves too well to armchair computation, e.g. building costs, station site improvements, etc. (We were able to secure actual costs for these items from company accounting records.) The most important items, however, lend themselves to engineering estimation. For example

TABLE 5

Total Capital Coefficients for Crude Oil Pipe Lines

Throughput (barrels)	*Outside Diameter (inches)*	*Total Capital Cost[a] (thous. $)*	*Total Capital Coefficients (dollars per barrel per day per thous. miles)*
25,000	8	$28,119	$1,125
	10	28,528	1,181
	12	33,151	1,326
75,000	8	66,177	882
	10	44,847	598
	12	41,402	552
	14	41,286	550
	16	44,504	593
	18	49,948	666
	20	55,549	741
	22	59,587	794
100,000	10	59,748	597
	12	48,365	484
	14	46,494	465
	16	47,711	477
	18	52,111	521
	20	57,121	571
	22	60,830	608
	24	64,663	647
	26	69,433	694
150,000	14	59,852	399
	16	56,108	374
	18	57,574	384
	20	61,074	407
	22	63,788	425
	24	67,054	447
	26	71,412	476
	30	79,204	528
	32	84,801	565
200,000	16	67,127	336
	18	64,771	324
	20	66,269	331
	22	67,502	337
	24	69,908	349
	26	73,796	369
	30	80,950	405
	32	86,303	431
300,000	20	80,860	269
	22	77,957	260
	24	77,948	260
	26	80,021	267
	30	85,330	284
	32	90,025	300
400,000	24	87,504	219
	26	87,789	219
	30	90,380	226
	32	94,483	236

[a]Excluding land.

the amount of steel required for any size of line pipe can be computed (given certain assumptions), as can the total horsepower required to create any throughput in a given size of line. The required horsepower is, in turn, the basis for computing pump requirements, motor requirements, switchgear, valves and fittings, and other auxiliary equipment. Such a study was carried out for all expected sizes of pipe and selected throughputs from 25,000 to 400,000 barrels per day (encompassing the largest crude line yet built). Capital costs and coefficients for selected line sizes and throughputs are shown in Table 5. A member of our staff has subsequently combined these capital costs with other pipe line costs into a pipe line cost curve for use in a separate project.[5]

From these studies it is clear that there are (1) capital economies of scale for any given line size (that is, initial costs per barrel per day for a given line size decrease as throughput increases); and (2) economies of scale in the operation of lines. There are also variable proportions of the factors of production for any given throughput. A given throughput might be had by using a 12-inch line with many stations, i.e. with a large total horsepower developed throughout the line, or by using a 20-inch line with a few stations. Indeed we can derive engineering production functions relating horsepower and line size for any given throughput.

To recapitulate, pipe line capital coefficients were computed for all relevant sizes of line and throughputs. There are increasing returns to scale in pipe line operation, and there are variable proportions. Which coefficients should be used? (We have a total of something like one hundred sets.) There is, of course, no answer in a case like this unless the particular expansion program is known. In industries where either of these is an important problem, it is impossible to compute general-purpose coefficients. Rather, sets of coefficients covering the expected sizes and types of plants must be available so that the set which best describes a given expansion program may be selected.

[5]See L. Cookenboo, Jr., "Costs of Operating Crude Oil Pipe Lines," The Rice Institute Pamphlet, April 1954, pp. 35–113, and *Crude Oil Pipe Lines and Competition in the Oil Industry,* Harvard University Press, 1955.