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6 Measurement of Income and Product in the Oil and Gas Mining Industries

John J. Soladay

6.1 Introduction

We are currently in a period of national concern over the depletion of our stock of natural resources. Unfortunately, however, the "energy crisis" is being debated with little or no reliable evidence available on the value and depreciation of that stock. In view of these problems, this study examines two of the most important minerals, oil and gas, that, at market value, account for approximately half of all natural resource extraction in the United States. It attempts to contribute toward an understanding of the real trade-offs implied by alternative rates of resource utilization by providing economically meaningful measures of both the value and the depreciation of the stock of developed oil and gas resources. Depletion, correctly measured, is treated as capital consumption, with a corresponding negative effect on measured income. I hope the data provided will be a useful input to informed policy decisions concerning these resources.

In this study I define and apply new measures of output, income, capital accumulation, and capital consumption in the oil and gas mining industries. The current Bureau of Economic Analysis (BEA) estimates of income and product in these industries are closely aligned with accounting measures of depreciation and investment that have, at best, a tenuous relationship with economically meaningful measures and pro-

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vide little information on the value of additions to, and consumption of, national wealth in natural resources. For example, at present, additions to national wealth in petroleum are not directly counted as investment. The BEA measures investment as expenditures involved in searching for and developing these minerals. For example, suppose our economy comprised only one firm, producing one product—crude oil. This firm spends \$1 million exploring and developing crude oil and acquires additional crude oil stocks having a present value of \$2 million. The BEA measure of investment would be \$1 million, whereas the revised measure in this study would be \$2 million. The costs of acquisition are used as a measure of investment in BEA accounts. In this study I count the present value of the additional resources as investment. The costs of acquisition are not an appropriate measure of the value of resource additions to wealth because acquisition capital gains (the difference between the value and the acquisition cost of an asset) may be considerable and should be included in a measure of this industry's income and product. As one consequence of the BEA's procedure, reported profits understate industry net revenue.

Current BEA depreciation estimates are also calculated using the acquisition cost base. Regardless of the depreciation formulas used, however, the data to which they are applied are inappropriate. In addition, the accounting formulas bear little resemblance to the utilization or consumption of the resource stock. The major part of BEA depreciation data for this industry is taken directly from tax returns, which report depreciation based on allowable depreciation schedules determined by tax law.[1] These data are unlikely to reflect economic depreciation because firms have an incentive to report tax depreciation charges so as to maximize the present value of expected after-tax returns. Furthermore, the BEA depreciates investment expenditures that are charged to current account by firms for tax purposes at an even rate over a twenty-year period. The rationale for this schedule is nothing more than an estimated average service life of twenty years for drilling equipment. Since the net revenue generated by equipment can change radically over its service life, however, this procedure is clearly not appropriate; it is very unlikely that depreciation would be identical over the period of utilization.

In contrast to the BEA's methods, this study measures investment by estimating directly the value of additions to the developed resource stock. My depreciation estimates are based upon the change in the value of resource capital in the production process rather than the tax depreciation schedules currently used.

The procedure followed in this study is essentially as follows:

1. The BEA measure of investment in this industry is replaced by estimates of the value of additions to the stock of oil and gas reserves.

2. The BEA depreciation measure is replaced by estimating the change in the value of the existing stock of developed oil and gas reserves (net of new additions).

3. In computing the present value of additional oil and gas reserves, it is assumed that the time path of output from any given pool of reserves is technologically given. Separate paths are estimated for each of these minerals. The greater part of the empirical work for this essay consisted in estimating the shape of these paths.

4. The production time path estimates are applied to each barrel of oil in order to attribute a time path of revenue to that oil and thereby calculate the present value.

5. Revised national income accounts are devised for the oil and gas mining industries in order to account properly for investment and disinvestment in these industries. The value of newly discovered and developed resources is included in capital formation, income, and output. Depletion, correctly measured, is treated as capital consumption with a corresponding negative effect on measured income.

6.2 Measurement of Income and Product in the Oil Industry: Theory

6.2.1 Current Accounting Procedures of the National Income Division of the Bureau of Economic Analysis

The major source of BEA national income data is the Internal Revenue Service (IRS) summary data for tax returns. The BEA adjusts reported taxable income in deriving data on business and national income appearing in the national income accounts. These adjustments are especially important in crude oil and natural gas mining because of the tax privileges granted these industries. For example, the depletion allowance permitted all oil and gas firms to deduct 22% of gross revenue from net revenue in reporting taxable income until 1975.[2] This allowance was constrained to be no more than 50% of predepletion allowance net revenue. Although the depletion allowance was deducted from gross income in arriving at taxable income, it was again added to taxable income in arriving at business and national income (U.S. Department of Commerce, OBE 1954, p. 92). The BEA's rationale for not recognizing the depletion of natural resources as an expense or charge against income is that their initial discovery or acquisition is not included in fixed capital or inventories and these are not included in income (Hagen and Budd 1958, p. 264).

Capital outlays for oil and gas well drilling and exploration, which are charged to current expense in the individual firm accounts, are included in the new construction component of gross private domestic investment in the national income accounts. An estimate of the depreciation on such items is included in capital consumption. The difference between such capital outlays and their corresponding capital consumption is entered into income in the national income accounts (*Survey of Current Business* [August 1965], p. 13). These capital outlays are depreciated by the BEA on a straight-line basis over twenty years, that is, at 5% of the initial outlay per year.

The BEA's treatment of investment and depreciation in the oil and gas mining industries is consistent with its treatment of these measures in other industries. Since capital outlays charged to current expense on firm accounts are depreciated in the national income accounts, the acquisition costs on new oil and gas resources are counted as investment. The depletion allowance was not counted as an additional expense, since this would entail double counting depreciation of oil and gas assets. Although firms were permitted such double counting on tax returns, it was corrected in the national income accounts. Furthermore, the depletion allowance in no sense reflected depreciation. Permitting firms to charge 22% of total revenue as an expense for depletion was incorrect, since the costs of acquiring these resources are already depreciated. The BEA's procedure of including the depletion allowance in national income is preferable not because the initial discovery is not included in fixed capital,[3] but because the expenditures associated with natural resource acquisition are already depreciated.

The BEA classifies companies into industries according to their major activity. Since many crude oil and natural gas firms are vertically integrated, with their major activity in manufacturing, they are classified accordingly. The result has been a consistent underreporting of mining gross product. This problem has been discussed by Lerner (1958). The BEA has adjusted for this bias by constructing a series on the gross product in mining which adjusts for the establishment-company industrial reporting bias, Gottsegen (1967).

6.2.2 The Revised Measures of Income and Product

This section presents the structure of my revised gross product statements. In summary of the previous section, my definition of net product is the sum of employee compensation, indirect business taxes, and profits. My profit series includes royalty payments, net interest, monopoly rents, and acquisition capital gains or losses. I do not attempt to measure windfall capital gains;[4] however, I think it useful to present the definitions and calculations in a manner exhibiting their explicit inclusion. My revised statements of the productive contribution of this industry are meant to reflect the effect of additions to national wealth in developed oil and gas resources as well as the depreciation of the existing stock of developed resources. The following equations will aid in the presentation of definitions:

Let

$R^{j,i}_t$ = the expectation in period j, of the net revenue in period t, from a mineral asset acquired in period i;

$V^{j,i}_t$ = the expectation, in period j, of the present value, at the beginning of period t, of mineral assets acquired in period i;

D^i_t = the depreciation, in period t, of mineral assets acquired in period i;

D_t = the depreciation in period t of all existing mineral assets;

C^i_t = the capital gains in period t, from mineral assets acquired in period i;

r_t = the discount rate in period t.

Assume $r_t = r_{t+j}$ for all j.

Then we may define $V^{t,t}_t$, D^i_t, and C^i_{t+1} as

(1) $$V^{t,t}_t = \sum_{\tau=0}^{\infty} = \frac{R^{t,t}_{t+\tau}}{(1+r)^{\tau}};$$

(2) $$D^i_t = V^{t,i}_t - V^{t,i}_{t+1};$$

(3) $$D_t = \sum_{i=0}^{t} D^i_t = \sum_{i=0}^{t} (V^{t,i}_t - V^{t,i}_{t+1});$$

(4) $$C^i_{t+1} = V^{t+1,i}_{t+1} - V^{t,i}_{t+1}.$$

The object is to create a time series on depreciation (D_t) and present value ($V^{t,t}_t$) of oil and gas resources. Equations (1) and (3) are used to accomplish this task. These equations are connected to other variables by the following agebraic relationships. Let

V^i_t = the present value at the beginning of period t of the mineral asset acquired in period i;

E^i_t = the revenue in period t generated by a mineral asset acquired in period i;

E_t = the revenue in period t generated by crude oil production from all vintages;

Q^i_t = production in year t from new oil acquired in year i;

Q^P_t = predicted output in year t from all vintages;

Q^R_t = reported aggregate production in year t;

D^i_t = the depreciation in year t from a mineral asset acquired in period i;

D_t = aggregate oil depreciation in year t;

$r =$ the discount rate;
$w_i =$ the production time path coefficient representing the ratio of current production from new oil reported i years previously to the quantity of new oil reported i years ago;
$b_t =$ average revenue per barrel of predicted oil production in year t;
$N_t =$ the quantity of new oil reported in year t.

Our calculations as based on two main assumptions. The first is that the discovery of one barrel of reserves in year t will result in extra output of oil of w_i in the year $t + i$, where the series of w_i represents technical coefficients and where $\sum_{i=0}^{\infty} w^i \leq 1$ because production from reported reserves cannot exceed the amount of the reserves available. If follows immediately that

$$Q_t = w_o N_t + w_1 N_{t-1} + \ldots + w_n N_{t-n}. \tag{5}$$

This equation is used to estimate the w_i from time series cross-sectional data on output ($Q^R{}_t$) and new oil (N_t). Identical procedures are followed for gas.

The present value of new oil additions is calculated as the stream of new revenues originating from production. A new oil addition reported in year t is evaluated in year t as

$$V^t{}_t = \sum_{\tau=0}^{T} \frac{E^t{}_{t+\tau}}{(1+r)^\tau}.$$

Similarly, we can express the present value of new oil reported in year i and evaluated n years later in year t as

$$V^i{}_t = \sum_{\tau=0}^{T-n} \frac{E^i{}_{t+\tau}}{(1+r)^\tau},$$

where i also denotes vintage.

We calculate the amount of net revenue in year t attributable to oil initially reported in year i as:

$$E^i{}_t = \frac{E_t}{Q^P{}_t} \times Q^i{}_t,$$

where $\frac{E_t}{Q^P{}_t}$ represents average revenue per unit of predicted output

and $$Q^P{}_t = \sum_{i=0}^{15} w_i N_{t-i};$$

$$Q^i{}_t = w_i N_{t-i}.$$

Observations on net revenue include the years 1948 to 1974. Since the estimated service life of new oil is sixteen years (twenty-six years for natural gas) and we are attempting to calculate the present value of new oil from 1948 to 1974, it was necessary to project average revenue for the years 1975 to 1989 (1999 for natural gas). The observed relationship between current and lagged ratios of revenue to predicted output is assumed to generate forecasts of future revenue.

We assume average revenue per barrel of oil expected in 1975 is a weighted average of past ratios; that is,

$$b_{75} = c_o + \sum_{i=1}^{n} d_i \, b_{t-i}$$

$$b^{*}_{75} = b_{75}$$

and that expectations are met, so that 1976 average revenue is

$$b^{*}_{1976} = c_o + d_1 \, b^{*}_{75} + \sum_{i=2}^{n} d_i \, b_{t-i}.$$

Iteration is continued until 1985 (1999 for natural gas).

6.3 Description of the Data

6.3.1 Introduction

This section represents an attempt to analyze a number of problems arising from the data used in this study. Certain problems are solved in my estimates; others remain. My task was to acquire data permitting me to estimate a relationship between expenditures on acquisitions of developed crude oil and the eventual revenue generated by these additions. To some extent, the data sources defined my method of approaching the problem of acquiring estimates of present value and depreciation. Since sufficient data are not available to allow a direct estimate of the relationship between acquisition costs and net revenue, I proceed stepwise. I first estimate a relationship between additions to the mineral stock and production. Yearly net revenue is then attributed to these current and past additions to the developed oil stock, thus enabling me to derive estimates of the net revenue stream resulting from additions to the stock of developed oil. I then discount this stream and acquire estimates of present value and depreciation. Differences between the value of new oil and the cost of acquiring it provide information on acquisition capital gains (or losses).

In section 6.3.2 I examine the natural of crude oil reserves data and consider some of the consequences for my estimates of using these data. Section 6.3.3 treats the BEA acquisition cost data, and section 6.3.4

examines the net revenue data used in this study. Section 6.3.5 considers some of the problems raised by the joint-product nature of oil and gas acquisition and production.

6.3.2 The Nature of Crude Oil Reserves Data

The American Petroleum Institute (API) publishes annual estimates of proved crude oil reserves. Reserves are defined by the API as volumes of crude oil that geological and engineering information indicates are recoverable "beyond reasonable doubt, under existing economic and operating conditions" (Lovejoy and Homan 1965, pp. 17–19).

The API breaks down the new oil added each year into three categories: new pools discovered during the year, extensions of old pools, and revisions of previous estimates. Estimates in these categories may be described as follows.

New pools or discoveries. These are previously undeveloped and possibly unknown oil pools that are brought to the producing stage during the year.

Extensions of existing reservoirs. New reserves sometimes result from the drilling of additional development wells after the year of initial discovery.

Revisions. Revised estimates frequently arise from additional information concerning the performance of a reservoir or from new processes that increase recovery. The reserves figures published by the API are not used as an indication of the recoverable oil at any time but correspond more closely to oil that can eventually be produced under current operating conditions—that is, a working inventory.

The typical relationship between the eventual recovery from a pool and the amount of oil initially reported by the API as oil contained in a new pool discovery is not known. Extensions and revisions are credited by the API to additions to reserves of the year in which the extensions and revisions are noted, not to reserves of the year of initial discovery. If we could attribute all extensions and revisions during 1946 to 1974 to new pools discovered over the period (excluding the large Alaskan reserve, reported in 1970 and not producing in 1974), the data indicate that, on average, 7.06 times the amount of oil initially reported in new pools is eventually reported as producible.

The relationship between reserves eventually reported as producible from a pool and those initially reported has interesting implications for our accounting of capital acquisitions. We note that 50% of the additional reserves attributed to previously reported new oil are due to revisions. As mentioned above, these reserves are not all directly associated with additional development in existing pools. The revisions (if unexpected) represent increases in the evaluation of existing oil assets that can be considered windfall capital gains. Firms must generally expect the eventual recovery from new pools to exceed the conservative estimates of the API. Ideally, then, we should count the expected future revenues and expenditures (associated with the extensions category) in the year in which these expectations were formed. Unfortunately, data are not available that would permit us to attribute extensions and revisions back to the initial year in which the pools were reported, and even if these data were available, there would be no way of testing whether these quantities of additional oil were expected at the initial acquisition date of the new pool.

Because of data restrictions, I am forced to treat the quantity of new oil (new pools + extensions + revisions) reported by the API as resulting solely from current investment; and any capital gains on acquisition (difference between cost and value of new oil) are attributed not to date of the initial expectation but to the current period. Unexpected additional reserves that are reported in the current period and may be considered windfall capital gains will be included in the value of new oil and will show up in the income accounts as acquisition capital gains rather than as windfall gains.

6.3.3 An Analysis of Acquisition Cost Data

My acquisition cost data on new oil and gas basically comprise the weighted sums of two entries in the National Income Accounts. The first, "Petroleum and Natural Gas Well Drilling and Exploration," includes: (1) all capital outlays for new oil and gas that are expensed on firm account (for tax purposes), and (2) those acquisition costs that are depreciated on firm account and result in the construction of fixed structures on new oil and gas property. The second entry is "Mining and Oil Field Machinery." Costs included under this item represent durable equipment other than that in fixed structures. Some of these reported costs represent purchases of equipment for mining other than oil and gas. Fortunately, such costs are relatively small. To correct for them, I have multiplied the data for mining and oil field machinery by the ratio of the BEA Gross Product in Oil and Gas to the BEA Gross Product in Mining in the corresponding year. This item was added to Petroleum and Natural Gas Well Drilling and Exploration to obtain acquisition costs for oil and gas. Some of the implications of treating investment outlays as acquisition costs of currently reported new oil and gas are treated in Soladay (1974, pp. 24–25).

6.3.4 Net Revenue Data

Net revenue data for the years 1948 to 1974 for oil and gas mining were derived mainly from the BEA gross product statements. Data on net interest, capital consumption allowances, and profits are available for the two industries combined. After-tax profits are not reported. We approximated joint after-tax profits by multiplying yearly reported profits by one minus the ratio of yearly corporate profits tax liability to corporate profits (both of which are reported in the national income accounts as totals for crude petroleum and natural gas).

Royalty payments are also considered a component of net revenue and were derived from industry survey data (Joint Association Survey). These payments are usually a fixed percentage of gross sales paid to landowners whose property is used for oil or gas extraction. They are treated as payments to the real estate industry by the BEA (Ruggles 1949, p. 53). Although they represent a flow of funds from oil mining firms and, as such, cannot be considered as revenue available to the firms, these payments are generated by the oil industry and may be considered payments for the oil contained in the landowner's property rather than for his real estate. Thus, royalty payments represent part of the surplus generated by the mining activity and are considered here as part of net revenue originating in mining regardless of whether the firm owns the land in which the natural resources are contained. Because they are payments from mining operators to resource owners, royalty payments are included in the gross product and net revenue generated in mining.

Net interest is treated as a cost of current production by the BEA. Since net interest represents a net payment for the use of borrowed capital, it constitutes a claim on net revenue, originating in the oil industry, that is transferred to bondholders. As part of income distributed to owners of the firm's capital, net interest should be treated not as a current cost but again as a component of net income generated in mining.

Since I also estimate depreciation, the original net revenue data include BEA capital consumption allowances. In reporting profits in my revised gross product statements, capital consumption allowances are reported separately.

6.3.5 Conceptual and Data Problems related to the Joint-Product Nature of Crude Petroleum and Natural Gas

The BEA data on acquisition expenditures and gross product are reported only for the combination of the crude oil and natural gas mining activities. Because no data are available for either mineral separately, we are faced with a number of difficulties in attempting to acquire separate estimates of the present value and depreciation of oil and of gas. Because of the joint-product nature of oil and gas, a problem arises when we attempt to acquire separate cost and revenue estimates for these minerals. I believe that the additional information gained from the individual estimates reflects a great deal more than these arbitrary allocations, however, and hence it seems worthwhile to me. A more complete discussion of the joint-product nature of these resources is provided in Soladay (1974, pp. 26–27).

Acquisition costs. Fortunately, no aggregative bias is introduced into my results by the somewhat arbitrary apportionment of the acquisition-cost data. With total acquisition costs given, the segregation I perform merely allocates capital gains among minerals. Acquisition capital gains for the combination do not change. I attribute the BEA acquisition costs to oil and gas by using weighted ratios of new reserves. For example, the ratio for oil was calculated as the product of the current oil price and new oil reserves divided by the sum of the product of the current oil price and new reserves and the product of the current gas price and new gas reserves. This ratio was multiplied by acquisition costs for oil and gas in order to determine oil acquisition costs. Acquisition costs for gas were calculated in a similar manner.

Net revenue data. Revenue was allocated between minerals in the same fashion as acquisition costs. In this case the product of the current price and production for each mineral was divided by the sum of the price and output products for both minerals. This ratio, when multiplied by joint revenue, yielded the revenue attributable to each mineral separately.

6.4 The Empirical Evidence

6.4.1 Introduction

This section presents my estimates of the value of new oil, the capital gains associated with the acquisition of that oil, and the depreciation and value of the entire oil stock for the period 1948 to 1974. To reiterate, my approach to the problems of acquiring economically meaningful magnitudes for the variables mentioned above is to estimate first the relationship between additions to the oil stock and production. This relationship, which is referred to as the production time path, indicates current and future output from new oil assets acquired during the estimation period. Knowledge of the production time path permits us to attribute yearly net revenue to these current and past additions to the developed oil stock, thus enabling us to acquire estimates of present value and depreciation.

Section 6.4.2 presents my estimates of the production time path for oil; in section 6.4.3 the production time path for natural gas is presented; in section 6.4.4 I explore the problem of allocating net revenue among the production from current and past additions to the developed oil and gas stock. Finally, section 6.4.5 presents my numerical solutions.

6.4.2 The Production Time Path Estimates for Oil

Data on crude oil reserves and production were acquired for the years 1948 to 1974 for the eighteen states that accounted for approximately 98% of United States production and reserves during the period.[5] The source of data on reserves and production was the American Gas Institute and the American Petroleum Institute (1975).

All the state data on production, reserves, and new oil are expressed as ratios to the reserves at the end of 1960 in each state. This procedure permits us to adjust for size differences among states. Current oil output (Q_t) can be expressed as the sum of contributions to current output of current and past additions to the resource stock (N_t):

$$Q_t = w_0 N_t + w_1 N_{t-1} + w_2 N_{t-2} + \dots + w_n N_{t-n}. \tag{6}$$

This section presents the results of a number of attempts to estimate the parameters of the production time path. The rational lag estimator is used to derive these estimates, which utilize several groupings of data on eighteen states for the years 1948 to 1974. The different groupings of state data were used in hope of ascertaining the degree to which estimation results were sensitive to the types of regressions run on the same basic data.

Several estimating equations were used in an attempt to acquire information on the production profile. A direct estimate of the beginning of the production profile provided information on the initial buildup in production. A modified Koyck equation was also used that allowed for the production buildup. I also made use of the instrumental variables technique in an attempt to remove difficulties associated with using a lagged dependent variable. Results were not much different from OLS.[6]

The rational lag estimator was used in more general form in equation (7) (see table 6.1). This equation permitted the buildup in production during the first few years but did not constrain remaining production to lie on a geometrically declining path, as did the Koyck equations. I found that this estimating equation performed better than others used in deriving the production time path weights. The coefficients on more than two lagged values of new oil or production tended to become insignificantly different from zero. Of course, the significance test on individual coefficients whose variables are to some degree multicollinear is an insufficient test of the significance of individual coefficients, but in

Table 6.1 **Output as a Function of Current and Lagged New Oil and Lagged Output**

(Eq. 7) $q_t = \sum_{i=0}^{4} b_{5i} n_{t-i} + \sum_{i=1}^{2} c_{5i} q_{t-i} + u_t$

Variable or Statistic	Regression Coefficients and Standard Errors: Overall	State Cross-sectional	State Time-Series
n_t	.0570	.0579	.0550
	(.0066)	(.0068)	(.0067)
n_{t-1}	.0260	.0281	.0255
	(.0072)	(.0074)	(.0072)
n_{t-2}	.0046	.0093	.0046
	(.0069)	(.0072)	(.0070)
q_{t-1}	.0686	.9649	.9517
	(.0485)	(.0485)	(.0485)
q_{t-2}	−.0960	−.1084	−.0950
	(.0450)	(.0449)	(.0456)
Σn	.0876	.0953	.0851
	(.0101)	(.0112)	(.0108)
Σq	.8726	.8565	.8567
	(.0164)	(.0182)	(.0197)
r.d.f.[a]	426	403	409
DW	2.0178	2.0223	2.0196
R^2	.9151	.9128	.8663
F	918.490	1117.25	691.903
SE	.0110392	.0107873	.0109356
α	.6876	.6641	.5939
	(.1435)	(.1429)	(.1292)

[a]Residual variance degrees of freedom. Of the original sample of twenty-seven years for eighteen states, or 486 observations for each variable, two years of observations were lost in generating the lagged values of new oil and an additional year was lost in calculating the new oil variable as current output plus the difference between reserves at the end of this year and the end of last year (see definition of page 00). With twenty-four remaining years of observations (432) we lost one degree of freedom for each mean calculated and one for each variable on the right-hand side. Since there is only one mean in the overall, we have 426 degrees of freedom, the eighteen means in the state time series (one for each state) give us 409 degrees of freedom and finally the twenty-two means (one for each year) in the cross section give us 403 degrees of freedom.

many instances the sums of coefficients changed very little, yielding no or generally insignificant changes in recovery rates or in the shape of derived production time paths. Additional coefficients also approached zero or became negative.

Turning to the new oil coefficients of equation (7) we note that their sums were 0.0876 in the overall, 0.0851 in the time series, and 0.0953 in the cross section. The time-series and cross-sectional sums of new oil coefficients are not statistically different, since the difference between coefficient sums is less than the standard error of the difference.[7] There is, however, a possibility that these sums of coefficients are biased downward because of an error-in-variables problem. Approximately 75% of United States oil is produced in states that regulate production by prorating market demand; five of the eighteen states in our sample were regulated by this system. Each of these states limits production to forecasts of quantities demanded. These forecasted quantities (net of predicted unregulated production) are then allocated among regulated wells by permitting regulated wells to produce state-determined percentages of an assigned maximum allowable production level. These maximums are not directly related to capacity or reported revenues.[8] The divergence between observable new oil and other units of production capacity (among market-demand states and between market-demand states and the remaining states with other types of production restrictions) contributes to a problem of errors in variables.

Turning to the sum of lagged production coefficients, we note no appreciable difference between the estimates, the overall, time-series, and cross-section sums of coefficients being 0.8726, 0.8567 and 0.8567 respectively. To test for autocorrelation, the error term u_t was regressed on u_{t-1}. The coefficient of u_{t-1} was not significantly different from zero, indicating no serial correlation. This test was used instead of the Durbin h test because the Durbin h was not calculable.[9]

My estimate of the recovery rate was 0.6876 in the overall, 0.5939 in the time series, and 0.6641 in the cross section. The differences among the overall, time-series, and cross-sectional recovery rates are not statistically significant.

The production time path derived from the cross-section regression of equation (7) reported in the Appendix was selected for use in my estimates of the value of new oil and depreciation. The criteria used were the higher R^2 and lower standard error of estimate of the equation. In addition, the cross-sectional results appeared less affected by the errors-in-variables problem present in the time series results.

My estimate of the amount of oil recovered per barrel reported apparently contradicts the description of new oil data as reported by the API. Results indicate that 66% of reported new oil is produced, while the API indicates that 100% is producible.

To determine how well my production time path estimate performed when applied to aggregate United States data on new oil, I constructed a predicted output series to be used in comparisons with United States reported output over the period 1948 to 1974. The predicted output series was constructed by applying the structural coefficients of equation (7)[10] for the overall regression to data on United States new oil over the period 1933 to 1974.[11] Note that the data used to construct the predicted series differ from the state data sample for the period 1948 to 1974 used in the estimation of equation (7).[12]

Since the predicted output series summed to 69% of reported output over the sample period, the estimate of the recovery rate is biased downward. As a rough check on the recovery rate estimate, I note, for illustrative purposes only, that if we blow up the production time path weights so that they sum to unity (by dividing each of the weights by their sum), the sum of predicted output over the entire period would amount to 103.7% of reported output. It appears that difficulties associated with errors in variables for new oil data outweigh the distributed lag bias associated with using lagged dependent variables. Since the amount of net revenue attributed to oil production is allocated evenly over predicted output, the fact that the recovery rate is less than unity does not necessarily produce any bias in our results. To the extent that predicted output is lower than actual output, average revenue per barrel will be higher than actual average revenue.

6.4.3 The Production Time Path Estimates for Natural Gas

Reserves, production, and new gas data are compiled by the American Gas Association (AGA). The concepts used by the AGA in defining natural gas reserves are quite similar to those used by the API concerning crude oil reserves.

Data on natural gas reserves and production were acquired for seventeen states over the period 1948 to 1974.[13] These states accounted for approximately 98% of United States gas production and reserves over the period. The state data on reserves were compiled by the AGA. The same econometric techniques that were used for oil were also applied to natural gas. To adjust for size differences among the states in our sample, all variables are divided by the 1960 value of state reserves.

In an attempt to determine the production time path for new gas, we estimated the modified Koyck equation (8). The number of new gas lags used was extended to four, since the sum of new gas coefficients continued to increase up to that point. The sum of new gas coefficients was 0.0428, 0.0584, and 0.0430 in the overall, time-series, and cross-sectional regressions. The lower cross-sectional sum of new gas coefficients may be due to a more severe errors-in-variables problem in the cross section. To the extent that institutional differences between reported and producible new gas are more important across states than are differences between reported and producible new gas over time, the cross-sectional sums of new gas coefficients will be lower.

The lagged production coefficients were 0.9168 in the overall, 0.9319 in the time-series, and 0.9140 in the cross-sectional regressions. The Durbin h statistic indicates autocorrelation in the overall and cross-sectional regressions; no autocorrelation is indicated in the time-series regression. The presence of autocorrelation in the overall and cross-sectional regressions will produce biased estimates of coefficients and therefore make the overall and cross-sectional results less reliable.

Ratios of eventual recovery to the quantity of new gas reported are 0.5144, 0.8576, and 0.5000 in the overall, time-series, and cross-sectional regressions. Apparently, the lower estimates of recovery rates in the overall and cross-sectional regressions originated because both new gas and lagged output coefficients were lower than the time-series coefficients; for example, 0.0430 and 0.9140 in the cross-sectional as opposed to 0.0584 and 0.9319 in the time-series. Since the Durbin-Watson statistic is biased, it is not used to indicate whether positive or negative autocorrelation exists. However, the lower lagged output coefficients in the cross-sectional regressions would be consistent with negative autocorrelation, while the lower cross-sectional new gas coefficients might be considered as due to a more severe errors-in-variables problem. The time-series results appear more reasonable than the cross-sectional or overall results because no autocorrelation is indicated in the time series and the time series standard error of estimate is lower.

In an attempt to determine whether additional lagged values of production would alter my results, I ran additional regressions. No significant difference in recovery rates occurred in any of the regressions. I take this as indicating that the modified Koyck equation discussed above is a reasonable specification of the production time path. The table in the Appendix presents the estimates of the structural coefficients derived from table 6.2. The better performance of the time-series estimating equation leads to its selection in generating the structural coefficients. Since the sum of the first sixteen structural coefficients is only 62% of the sum to infinity, the length of the structural equation is extended to twenty-six periods. The sum of coefficients thereby expanding to 81% of the sum to infinity. During this period the coefficients sum to 0.6977, or 81% of their sum to infinity.

6.4.4 Numerical Solutions

Oil. As described in sections 6.2 and 6.3, industry net revenue and acquisition cost was first allocated among oil and gas by using weighted ratios of production and new reserves. Then the net revenue for each mineral in each time period was distributed evenly over the contributions to current output of current and lagged values of new reserves. To calculate the present value of new oil and new gas I had to project average revenue for the years 1975 to 1989 for oil and from 1975 to 1999 for natural gas. This task was performed by testing a number of equations relating current and lagged ratios of revenue to predicted output for each mineral. I selected one equation for each mineral on

Table 6.2 **Gas Output as a Function of Current and Lagged New Gas and Lagged Output**

(Eq. 8) $q_t = \sum_{i=0}^{4} c_{4i} n_{t-i} + c_{51} q_{t-1}$

Variable or Statistic	Regression Coefficients and Standard Errors: Overall	State Time-Series	State Cross-sectional
n_t	.0171	.0188	.0170
	(.0041)	(.0039)	(.0040)
n_{t-1}	.0043	.0042	.0035
	(.0044)	(.0042)	(.0043)
n_{t-2}	.0076	.0125	.0089
	(.0057)	(.0054)	(.0056)
n_{t-3}	−.0056	−.0007	−.0093
	(.0059)	(.0056)	(.0058)
n_{t-4}	.0194	.0236	.0229
	(.0061)	(.0058)	(.0060)
q_{t-1}	.9168	.9319	.9140
	(.0151)	(.0163)	(.0150)
Σn	.0428	.0584	.0430
	(.0076)	(.0083)	(.0072)
$r.d.f.$	367	351	346
R^2	.9201	.9059	.9206
F	847.008	708.840	853.263
SEE	.00805809	.00750854	.00764782
DW	1.7460	2.0180	1.7270
Dh	2.5685	.1833	2.7578
α	.5144	.8576	.5000
	(.1466)	(.2511)	(.1350)

the basis of minimum standard error of estimate and used it to generate the expected average revenue series for each mineral. These expected net revenue paths were then discounted in order to acquire the present value and depreciation variables described in section 6.2.

A number of discount rates were used in the present value and depreciation calculations. Since the net revenue variables were presented in terms of constant 1972 dollars, the effect of inflation was netted out. It follows that the appropriate rate of interest to use in discounting net revenue should not be the market rate of interest facing petroleum firms, since that rate includes a component for the expected rate of inflation. Nominal interest rates would be appropriate only if current-dollar estimates of net revenue were being discounted.

The nominal Aaa corporate bond rate ranged from 2.82 in 1948 to 8.57 in 1974. These rates present an upper limit on the discount factor because they include an inflation premium.

No attempt will be made in this study to estimate expected rates of inflation. Knowledge of the geometric mean rate of inflation and the various long-term corporate bond rates will be used to present a range of estimates of depreciation and the present value of new oil. The mean rate of inflation over the period 1953 to 1974 was 4.6%.[14] Yohe and Karnosky (1969) of the Saint Louis Federal Reserve Bank estimate long-term real rates of interest from 1960 to 1969 that range from (in three series) 2 to 4%. These estimates offer added information concerning a lower limit on interest rates to be applied. The geometric mean Aaa corporate bond rate was 5.8% from 1955 to 1974. Depreciation and present value were therefore computed using interest rates of 3%, 5%, and 7%.

I calculated depreciation and present value of the stock of oil resources as well as the present value of additions to the stock, using interest rates of 3%, 5%, and 7%. At 3% interest, the mean value of depreciation was \$4.3 billion, while the mean value of the stock was \$31.1 billion and the mean value of new oil was \$5.4 billion. The 1970 entry for the value of new oil, \$23.8 billion, reflects the large quantity of new oil reported in Alaska. These Alaskan reserves were assumed not to produce until 1978 and to continue production until 1993. The average revenue predictions are extended over this period. The drop in the depreciation series from \$5.0 billion in 1969 to from \$4.1 billion in 1970 to \$4.2 billion in 1974 is due to the negative depreciation of new oil in Alaska. Since all revenues from Alaskan oil are discounted fewer periods from 1970 to 1977, the present value of these reserves must increase and thereby depreciate negatively. Mean depreciation, value of the oil stock, and value of new oil were \$3.6, \$26.7, and \$4.5 billion respectively, calculated at a 7% interest rate.

Table 6.3 gives estimates of (1) the present value of new oil (calculated using 5% interest); (2) the cost of new oil; and (3) the resulting acquisition capital gains. I have also reported the results of my calculations of (4) the value of the capital stock in oil, and (5) depreciation.

An examination of table 6.3 indicates substantial acquisition capital gains averaging \$3.0 billion per year or 61% of the value of new oil acquired each year. Mean depreciation (\$3.9 billion) was 13% of the mean value of the oil stock over the period. The \$19.4 billion value of new oil in 1970 reflects mainly the acquisition of Alaskan reserves, which are assumed, as before, not to produce until 1978.

Gas. The arithmetic manipulations are identical to those used for oil. Numerical solutions for depreciation and present value of the entire gas stock as well as new gas additions for interest rates of 3% and 7% were obtained. Using the 3% rate, we note that mean depreciation was \$1.4 billion, or 6.46% of the mean value of the gas stock (\$21.5 bil-

Table 6.3 **Value of New Oil, Acquisition Costs, Acquisition Capital Gains, Value of the Oil Stock, and Depreciation over the Period 1948–74 (Millions of 1972 Dollars)**

Year	V^t_t	C_t	$V^t_t - C_t = ACG_t$	V_t	D_t
1948	5,314	1,377	3,937	19,715	3,420
1949	4,423	1,329	3,094	20,718	3,010
1950	3,596	1,402	2,194	21,304	3,364
1951	6,251	1,884	4,367	24,191	3,644
1952	3,944	1,947	1,997	24,491	3,500
1953	4,814	1,963	2,851	25,805	4,057
1954	4,238	2,396	1,842	25,986	3,857
1955	4,275	2,159	2,116	26,404	4,412
1956	4,419	2,050	2,369	26,411	4,445
1957	3,589	2,255	1,334	25,555	4,343
1958	3,855	1,681	2,174	25,067	4,196
1959	5,473	2,098	3,375	26,344	4,106
1960	3,596	1,758	1,838	25,834	3,906
1961	4,143	1,722	2,421	26,071	3,925
1962	3,477	1,648	1,829	25,623	4,124
1963	3,527	1,602	1,925	25,026	4,236
1964	4,403	1,914	2,489	25,193	3,777
1965	5,168	1,958	3,210	26,584	4,035
1966	5,135	1,995	3,140	27,684	4,229
1967	5,236	1,773	3,463	28,691	4,451
1968	4,422	2,002	2,420	28,662	4,381
1969	3,899	2,467	1,432	28,180	4,623
1970	19,416	2,920	16,496	42,973	3,614
1971	4,453	1,884	2,569	43,812	3,846
1972	3,068	1,543	1,525	43,034	3,407
1973	4,353	1,766	2,587	43,980	3,422
1974	4,146	1,835	2,311	44,704	3,604
Sum	132,633	51,328	81,305	778,042	105,934
Mean	4,912	1,901	3,011	28,816	3,923

Note: Interest rate = 5%; the price deflator used was the implicit price deflator of oil and gas mining gross product (S1C13).

lion). The mean value of new gas was \$1.9 billion. At 7% interest, mean depreciation (\$9.2 billion) was 5.44% of the mean value of the gas stock (\$17 billion). The average value of new gas was \$1.35 billion.[15]

Table 6.4 presents the numerical solutions for (1) the present value of new gas reported in the current period; (2) the acquisition cost of currently acquired new gas; (3) capital gains or losses associated with acquisition; (4) the value of the entire capital stock in natural gas; and (5) depreciation. The interest rate used is 5%.

Table 6.4 **Present Value of New Gas, Acquisition Capital Gains, Value of the Gas Stock, and Depreciation over the Period 1948–74 (Millions of 1972 Dollars)**

Year	V^t_t	C_t	$V^t_t - C_t = ACG_t$	V_t	D_t
1948	1,009	331	678	9,269	352
1949	951	293	658	9,868	294
1950	931	556	375	10,505	356
1951	1,277	500	777	11,426	504
1952	1,167	684	483	12,089	514
1953	1,698	831	867	13,273	722
1954	814	364	450	13,365	681
1955	1,909	918	991	14,593	769
1956	2,201	1,135	1,066	16,025	815
1957	1,814	775	1,039	17,024	698
1958	1,751	912	839	18,077	740
1959	1,949	853	1,096	19,286	918
1960	1,334	948	386	19,702	1,092
1961	1,679	917	762	20,289	1,155
1962	1,932	1,199	733	21,066	1,223
1963	1,826	1,178	648	21,669	1,348
1964	2,054	1,077	977	22,375	1,139
1965	2,189	1,132	1,057	23,425	1,393
1966	2,090	1,213	877	24,122	1,563
1967	2,272	1,155	1,117	24,831	1,693
1968	1,431	1,011	420	24,569	1,684
1969	882	719	163	23,767	1,776
1970	3,919	385	3,534	25,910	1,607
1971	1,046	1,364	−318	25,349	1,839
1972	1,026	1,726	−700	24,536	1,723
1973	734	1,493	−759	23,547	2,016
1974	931	1,359	−428	22,462	1,703
Sum	42,816	25,028	17,788	512,419	30,317
Mean	1,586	927	659	18,978	1,123

Note: Interest rate = 5%.

We note in table 6.4 substantial capital gains in new gas acquisition. While the mean value of new gas was \$1.6 billion, the mean cost of acquiring it was \$0.93 billion, indicating average acquisition capital gains of 0.66, or 41% of the value of new gas on average. The value of the gas stock was rising substantially from \$9.3 billion in 1948 to \$25.9 billion in 1970. From 1971 to 1974 the value of the gas stock declined from \$25.3 billion in 1971 to \$22.5 billion in 1974 because of the smaller additions of new gas reserves over the period 1971–74. The mean value of the gas stock was \$19.0 billion over the entire period.

The average value of the new gas reserves from 1971 to 1974 was \$0.9 billion, compared with the \$1.6 billion mean value of new gas over the entire period. Depreciation also increased fairly steadily over the period, from \$0.3 billion in 1948 to \$1.7 billion in 1974, with a mean value of \$1.1 billion. Over the period, depreciation was approximately 5.9% of the value of of total gas reserves.

6.5 Integration of Results into the National Income Accounts

6.5.1 The BEA and the Revised Accounts

This section presents my estimates of income and production in the crude oil and natural gas mining industries. These estimates are meant to reflect the economic definitions underlying the gross product statement of the oil and gas mining activities. The results provide us with measures of additions to national wealth in oil and gas minerals as well as the depreciation and value of the current stock of developed oil and gas resources.

The concept of income I apply in constructing gross product statements in the crude oil and natural gas mining industries is that income equals consumption plus change in wealth. The value of newly discovered and developed resources is included in capital formation, and in output. The value of new oil and gas, net of investment expenditures responsible for their acquisition however, are, also included as income (acquisition capital gain), to be recorded in the year in which the new acquisitions are made. The diminution over time of the value of existing oil and gas assets is considered depreciation.

Table 6.5 exhibits the present value (measured at the beginning of the period) of currently acquired new oil and gas as well as the cost associated with the acquisition of those minerals. The difference between the value and costs of new oil indicates acquisition capital gains. As noted previously, acquisition capital gains refer not only to gains on physical capital but also to the surplus the firm realizes on all capital expenditures, whether or not they result directly in tangible capital. Column 4 lists the present value, also measured at the beginning of the period of the entire oil and gas stock, and, finally, depreciation is listed in column 5. Over the period 1948 to 1974, the mean value of newly acquired oil and gas (\$6.5 billion) was 2.3 times the mean cost of acquiring those minerals, resulting in average acquisition capital gains of \$3.7 billion. We also note that the average value of the capital stock in developed oil and gas resources was \$47.8 billion. The value of the oil and gas stock increased steadily from a low of \$28.9 billion to \$69.2 billion in 1971, one year after the reporting of oil in Prudhoe Bay, Alaska (assumed to begin production in 1978). Relatively low

Table 6.5 **Present Value of New Oil and Gas, Acquisition Costs, Acquisition Capital Gains, Value of Oil and Gas Reserves and Depreciation over the Period 1948–74 (Millions of 1972 Dollars)**

Year	Vt_t	C_t	ACG_t	V_t	D_t
1948	6,323	1,708	4,615	28,984	3,772
1949	5,374	1,622	3,752	30,586	3,304
1950	4,527	1,958	2,569	31,809	3,720
1951	7,528	2,384	5,144	35,617	4,148
1952	5,111	2,631	2,480	36,580	4,014
1953	6,512	2,794	3,718	39,078	4,779
1954	5,052	2,760	2,292	39,351	4,538
1955	6,184	3,077	3,107	40,997	5,181
1956	6,620	3,185	3,435	42,436	5,260
1957	5,403	3,030	2,373	42,579	5,041
1958	5,606	2,593	3,013	43,144	4,936
1959	7,422	2,951	4,471	45,630	5,024
1960	4,930	2,706	2,224	45,536	4,998
1961	5,822	2,639	3,183	46,360	5,080
1962	5,409	2,847	2,562	46,689	5,347
1963	5,353	2,780	2,573	46,695	5,584
1964	6,457	2,991	3,466	47,568	4,916
1965	7,357	3,090	4,267	50,009	5,428
1966	7,225	3,208	4,017	51,806	5,792
1967	7,508	2,928	4,580	53,522	6,144
1968	5,853	3,013	2,840	53,231	6,065
1969	4,781	3,186	1,595	51.947	6,399
1970	23,335	3,305	20,030	68,883	5,221
1971	5,499	3,248	2,251	69,161	5,685
1972	4,094	3,269	825	67,570	5,130
1973	5,087	3,259	1,828	67,527	5,438
1974	5,077	3,194	1,883	67,166	5,307
Sum	175,449	76,356	99,093	1,290,461	136,251
Mean	6,498	2,828	3,670	47,795	5,046

additions to reserves from 1971 to 1974, on average \$4.4 billion, account for the minor decline in the value of the oil and gas stock to \$67.2 billion in 1974. Depreciation increased from \$3.7 billion in 1948 to \$6.4 billion in 1969. The decline in the series to from \$5.2 billion in 1970 to \$5.3 billion in 1974 is due predominantly to the negative depreciation associated with the Alaskan oil over this period. Mean depreciation (\$5.0 billion) was 10% of the average value of the stock of developed resources over the period 1948 to 1974.

Table 6.6 presents the BEA gross product series; my revised series is presented in table 6.7. Employee compensation and indirect business taxes are the same in both series. In the revised series, net interest and royalty payments are included in profits. In addition, and far more important quantitatively, acquisition capital gains are included in profits. Furthermore, instead of using the tax formulas for depreciation, depreciation in the revised accounts was calculated in accord with the definitions in section 6.2, as the change in the value of existing assets.

Average employee compensation was $2.3 billion and average indirect business taxes were $0.7 billion. Revised gross product had a mean value of $14.7 billion, while average BEA gross product was only $9.6 billion. On average, over the period 1948 to 1974, the revised series was

Table 6.6 **BEA Gross Product Crude Petroleum and Natural Gas Mining (Millions of 1972 Dollars)**

Year	Gross Product	Employee Compensation	Net Interest	CCA	IBT	Profits
1948	6,335	1,266	22	1,063	310	3,674
1949	5,993	1,252	18	1,119	369	3,235
1950	6,582	1,344	33	1,318	412	3,475
1951	7,432	1,582	34	1,551	462	3,803
1952	7,684	1,752	26	1,654	515	3,737
1953	8,035	1,827	24	1,820	526	3,838
1954	8,098	1,762	24	1,778	485	4,049
1955	8,846	1,889	25	2,157	529	4,246
1956	9,244	2,050	25	2,169	571	4,429
1957	9,208	2,058	25	2,065	560	4,500
1958	8,653	1,924	27	2,159	570	3,973
1959	9,192	2,127	28	2,295	666	4,076
1960	9,094	2,081	29	2,510	713	3,761
1961	9,316	2,125	20	2,548	770	3,853
1962	9,577	2,214	35	2,653	760	3,915
1963	9,950	2,310	49	2,802	788	4,001
1964	10,003	2,377	47	2,820	815	3,944
1965	10,229	2,446	32	2,893	787	4,071
1966	10,707	2,634	33	3,040	880	4,120
1967	11,193	2,626	39	3,036	877	4,615
1968	11,624	2,803	38	3,121	962	4,700
1969	11,958	3,018	77	3,210	1,006	4,647
1970	12,264	3,133	97	3,394	1,065	4,575
1971	12,185	3,280	91	3,400	1,162	4,252
1972	12,308	3,229	115	3,556	1,153	4,255
1973	12,186	3,296	211	3,144	1,166	4,369
1974	12,048	2,889	252	2,275	1,265	5,367
Sum	259,944	61,294	1,476	65,550	20,144	111,480
Mean	9,628	2,270	55	2,428	746	4,129

Table 6.7 **Revised Gross Product Crude Petroleum and Natural Gas Mining (Millions of 1972 Dollars)**

Year	Gross Product	Employee Compensation	CCA	IBT	Profits
1948	11,837	1,266	3,772	310	6,489
1949	10,514	1,252	3,304	369	5,589
1950	9,987	1,344	3,720	412	4,511
1951	13,556	1,582	4,148	462	7,364
1952	11,144	1,752	4,014	515	4,863
1953	12,814	1,827	4,779	526	5,682
1954	11,380	1,762	4,538	485	4,595
1955	13,022	1,889	5,181	529	5,423
1956	13,781	2,050	5,260	571	5,900
1957	12,750	2,058	5,041	560	5,091
1958	12,735	1,924	4,936	570	5,305
1959	14,840	2,127	5,024	666	7,023
1960	12,515	2,081	4,998	713	4,723
1961	13,722	2,125	5,080	770	5,747
1962	13,431	2,214	5,347	760	5,110
1963	13,901	2,310	5,584	788	5,219
1964	14,866	2,377	4,916	815	6,758
1965	15,950	2,446	5,428	787	7,289
1966	16,329	2,634	5,792	880	7,023
1967	17,401	2,626	6,144	877	7,754
1968	16,178	2,803	6,065	962	6,348
1969	15,356	3,018	6,399	1,006	4,933
1970	34,314	3,133	5,221	1,065	24,895
1971	16,584	3,280	5,685	1,162	6,457
1972	15,143	3,229	5,130	1,153	5,631
1973	16,122	3,296	5,438	1,166	6,222
1974	16,228	2,889	5,307	1,265	6,767
Sum	396,400	61,294	136,251	20,144	178,711
Mean	14,681	2,270	5,046	746	6,619

53% higher than the BEA series. The relatively high value of new oil and gas acquired in 1970 ($23.3 billion) is due to the reporting of Alaskan reserves. As evidenced in 1970, our estimates are more sensitive to changes in wealth in natural resources. I believe this property is consistent with what we are attempting to measure when constructing gross product statements. Changes in natural resource wealth enter the BEA national income accounts only as acquisition costs, and future depreciation of those costs ignores often significant differences between the cost and the present value of newly acquired mineral assets. The mean value of acquisition capital gains ($3.6 billion) accounts for 73% of the difference between the two series.

Turning to the depreciation series, we note that mean BEA depreciation was $2.4 billion over the entire period, while mean depreciation in my series was $5.1 billion, an average of 2.12 times the BEA series. One reason for the higher revised series is that my base for depreciation is the value of new oil and gas (mean value 1948 to 1974 of $6.5 billion) rather than acquisition costs (mean = $2.8 billion). The difference between these two bases ($3.7 billion), which represents acquisition capital gains, accounts for a substantial portion of the $2.6 billion average discrepancy between the BEA and revised depreciation series. In addition to the difference in the bases, I calculate depreciation as reductions in present value; the BEA uses accounting rules that I believe are not well related to economic depreciation.

6.5.2 Summary

In this study I have attempted to measure income and product in the crude oil and natural gas mining industries in a manner consistent with generally accepted definitions of income and value. The results are in no sense final but rather are interpreted as preliminary estimates of income and product in the oil and gas industries.

To reiterate, the basis of this project has been the definition of income as consumption plus the increase in wealth. The concept of wealth or value in natural resources relates to the stream of net revenue expected to result from their utilization. Gross capital accumulation or investment in any year hence consists of the present value of the current and future revenue from new oil and gas reported in that year. Purchases of physical plant and equipment are treated as embodied in the new oil and gas and are therefore not depreciated separately. The diminution over time of the value of the originally anticipated revenue stream, at its originally anticipated discount rates and expected prices, represents what I consider depreciation.

The current BEA estimates of income and product are closely aligned with accounting measures of depreciation and investment and have an often tenuous relationship with economically meaningful magnitudes. Currently, investment is measured not as the addition to national wealth in minerals over time but as expenditures involved in the search for, and development of, these minerals. Consequently, current measures of investment are accurate only when there is no divergence between the value of newly acquired oil and gas assets and the acquisition costs currently used as measures of investment. Since acquisition capital gains may be considerable, however, they should not be excluded from the income of this industry. Thus, BEA reported profits will understate the net revenue of the industry when these acquisition capital gains are positive.

Current BEA depreciation estimates are also calculated using the acquisition cost base. Regardless of the depreciation formulas used, the data to which they are applied is inappropriate. In addition, the accounting formulas bear little resemblance to the utilization or changes in the value of the resource stock.

In contrast to the BEA's methods, my estimates of investment were derived by estimating directly the value of additions to the developed resource stock. Depreciation estimates were obtained by ascertaining the change in the present value of the existing stock (net of new additions) of developed oil and gas resources. One shortcoming of my study is that this measure of depreciation is consistent with the concepts of income and value only in the absence of windfall capital gains and losses. (Windfall capital gains are assumed to be zero while acquisition capital gains are captured in the valuation of resources.) The revised estimate of output, investment, and depreciation were based upon my estimates of the utilization and revenue generated by current and past additions to the developed stock of these minerals.

Appendix

Table 6.A.1 **Oil and Gas Production Time Path Coefficients**

$Q_t = w_o N_t + w_1 N_{t-1} + \dots + w_t N_{t-t}$

Oil		Gas	
Structural Coefficient	State Cross-Sectional	Structural Coefficient	State Time-Series
w_0	.0579	w_0	.0188
w_1	.0840	w_1	.0217
w_2	.0840	w_2	.0327
w_3	.0720	w_3	.0298
w_4	.0604	w_4	.0514
w_5	.0504	w_5	.0479
w_6	.0421	w_6	.0446
w_7	.0352	w_7	.0416
w_8	.0294	w_8	.0388
w_9	.0245	w_9	.0361
w_{10}	.0205	w_{10}	.0337
w_{11}	.0171	w_{11}	.0314
w_{12}	.0143	w_{12}	.0292
w_{13}	.0119	w_{13}	.0272
w_{14}	.0100	w_{14}	.0254
w_{15}	.0083	w_{15}	.0237
		w_{16}	.0220
		w_{17}	.0205
		w_{18}	.0191
		w_{19}	.0178
		w_{20}	.0166
		w_{21}	.0155
		w_{22}	.0144
		w_{23}	.0135
		w_{24}	.0125
		w_{25}	.0117
$\sum_{i=o}^{15} w_i$	.6220	$\sum_{i=o}^{25} w_i$	.6977
$\sum_{i=o}^{\infty} w_i$	.6641	$\sum_{i=o}^{\infty} w_i$	.8576
$\dfrac{\sum_{i=o}^{15} w_i}{\sum_{i=o}^{\infty} w_i}$	.9366	$\dfrac{\sum_{i=o}^{25} w_i}{\sum_{i=o}^{\infty} w_i}$	.8136

Notes

1. The BEA currently calculates aggregate depreciation on the basis of 85% of the service lives specified in the 1942 edition of Bulletin F issued by the IRS. The difference between the old depreciation (taken directly from tax returns) and the current series is reported as a capital consumption adjustment that is included in income (Young 1975). However, this revision is not currently reported on an industry basis and therefore does not apply to the BEA depreciation data included in this study.

2. The 1975 Tax Reduction Act eliminated percentage depletion for oil, for taxpayers owning production per day in the calendar year in excess of 2,000 barrels per day in 1975; in 1976 it would drop to 1,800; and it was to decline thereafter until 1981, when it would level off at 1,000 barrels per day. The depletion allowance for major intrastate gas producers was abolished as of 1 January 1975, and for major interstate producers this was effective 1 July 1976. The 22% depletion allowance for small independent producers was continued until 1980, after which it will decrease annually to a final level of 15% in 1984.

3. The initial rationale cited in Hagen and Budd (1958, p. 5) was published when capital outlays charged to current expense for tax purposes were not included in new construction in the national income accounts.

4. Although the definitions of value and depreciation are couched in terms of expected values of variables, the present estimation procedure uses ex post measurements of these variables. Since data on the output and cost expectations of firms involved in oil and gas exploration do not exist, to my knowledge, expectations are assumed to be perfect; that is, the values of expected variables are assumed to be identical to the values of observed current variables. Firms involved in oil production have a wealth of information upon which to base expectations. This information, which is not available to me, certainly goes beyond the lagged observed variables used in most expectations models. I believe that the assumption of perfect expectations introduces less error to my results than an attempt to bring in estimates of expectations. Furthermore, it should be noted that the assumption of perfect expectations does not preclude the existence of acquisition capital gains (defined as the difference between the value and cost of new oil and gas), which are attributed here to the presence of monopoly elements or other imperfections in these industries.

5. The states included in the sample were Kansas, Louisiana, New Mexico, Texas, Oklahoma, Arkansas, California, Colorado, Mississippi, Montana, Nebraska, Wyoming, Illinois, Indiana, Ohio, Pennsylvania, Kentucky, and Virginia.

6. Full information on these results and my interpretation of them will be provided upon request.

7. Standard error of the difference equals $(.0108^2 + .0112^2)^{1/2} = .0156$.

8. A fuller discussion is provided in Lovejoy and Homan (1967) and MacDonald (1971).

9. $Dh = r\sqrt{\dfrac{n}{1 - nV(c_{51})}}$; since $nV(c_{51}) > 1$, the test was inapplicable.

10. Since the initial sixteen production time path weights sum to 93.7% of their sum to infinity, the predicted output series was blown up by the ratio $1/0.937 = 1.0677$.

11. Before 1945, new oil included a number of elements that were reclassified after 1945 and not included in post-1945 data on new oil. I made a rough adjustment for this classification change by deflating pre-1945 new oil by the ratio of

new oil as reported under the later classification in 1945 to new oil as reported under the old classification.

12. The data sample on which the structural estimates were based was different. To generate the predicted series aggregate, new oil data for the period 1933 to 1974 were acquired. As noted previously, pre-1946 new oil data were not comparable in definition to post-1946 data, and my adjustment of the early series was only a rough approximation. It may also be plausible to believe that these early quantities of new oil also differed in reporting characteristics concerning the quantities of new oil that were reported as producible.

13. The states included in the sample were Arkansas, California, Colorado, Illinois, Kansas, Kentucky, Louisiana, Michigan, Mississippi, Montana, New Mexico, Ohio, Oklahoma, Pennsylvania, Texas, West Virginia, and Wyoming.

14. The implicit price deflator of GNP was used.

15. Full data are available from the author.

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