CBO STAFF MEMORANDUM

ECONOMIC COSTS OF REGULATING OIL AND GAS WASTES: A REVIEW OF THE AMERICAN PETROLEUM INSTITUTE'S STUDY ON RCRA REAUTHORIZATION

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This Congressional Budget Office (CBO) staff memorandum was prepared in response to a request from the House Committee on Energy and Commerce, Subcommittee on Transportation and Hazardous Materials and Subcommittee on Energy and Power, for an evaluation of the analytic methods and findings of a recent report by the American Petroleum Institute, *Estimates of RCRA Reauthorization Economic Impacts on the Petroleum Extraction Industry*.

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INTRODUCTION AND SUMMARY

This memorandum presents a review and critique of a report prepared for the American Petroleum Institute (API) by the Gruy Engineering Corporation, *Estimates of RCRA Reauthorization Economic Impacts on the Petroleum Extraction Industry*. This study, referred to here as the API study, looks at the effects of potential new federal regulations on wastes associated with oil and gas exploration and production. The API study concludes that the regulatory scenario it chose to analyze would dramatically affect the industry--causing 80 percent of oil and gas wells to be closed and reducing reserves of oil by 9 percent and natural gas by 6 percent. The Congressional Budget Office (CBO) agrees that the effects would be significant, but believes that they are overestimated in the API analysis. This memorandum explains how CBO comes to this conclusion.

CBO's review looks at the methods and assumptions of the API study, indicating several areas in which the API's methods would tend to systematically overstate the adverse effects of new waste management regulations. However, the actual significance of these methodological concerns could be minor because the API's findings depend critically on the regulatory scenario it chose to analyze. CBO's review focused on the API's analysis of a specific regulatory scenario, not on the reasonableness of that scenario.

The API assumed businesses would have to correct all past damages within the first year following passage of new waste management legislation, whether wells were abandoned or not. This scenario reflected API's assumptions about the final form of a bill, the Resource Conservation and Recovery Act (RCRA) Amendments of 1991, introduced to the Senate Committee on Environment and Public Work (S. 976). However, language in S. 976 and experience with other hazardous waste sites suggest that some costs of corrective action may be avoided or significantly postponed beyond the first year. CBO did not look at alternative regulatory scenarios that could lead to smaller adverse effects on the oil and gas industry.

The ultimate impact of new regulations is likely to depend on factors that were outside the scope of API's analysis and outside the scope of CBO's review. The API's analytic framework focused on the continued profitability of individual wells. But, given the regulatory scenario it defines, in which businesses would have to correct all past damages within the first year, the impact may depend more on the continued profitability of individual businesses. The API's analytic framework is not appropriate for analyzing business failures.

Background on Hazardous Waste Regulations

The RCRA amendments of 1980 provide for "cradle-to-grave" control of many hazardous wastes by imposing specific requirements for waste management on the generators and transporters of these wastes and on the owners and operators of treatment, storage, and disposal facilities. The RCRA amendments temporarily exempted oil and gas wastes from hazardous waste regulations (contained in Subtitle C), pending study and a regulatory determination by the Environmental Protection Agency (EPA).

Among the exempt oil and gas wastes are high-volume wastes (produced waters and drilling fluids) and other, low-volume wastes associated with exploration, development, and production (including hydrocarbon-contaminated soil and tank-bottom residues). All these wastes may contain hazardous substances, although the concentrations differ greatly. For example, produced waters, which come up to the surface mixed with crude oil or natural gas, generally contain only trace amounts of toxic chemicals; the toxicities of some of the associated wastes, however, are comparable with other hazardous substances already covered by Subtitle C. Collectively these wastes are referred to as exploration and production (E&P) wastes.

Not all wastes associated with the petroleum extraction industry are exempt from regulation under RCRA. Examples of nonexempt wastes are pipeline spills, air emissions from production machinery, and waste solvents left over from equipment maintenance.

In the regulatory determination prepared in response to the 1980 amendments, the EPA concluded that broader regulation of E&P wastes as hazardous substances under Subtitle C of RCRA was not warranted. The EPA did determine that it would be appropriate to improve federal programs under existing authorities (including Subtitle D, which covers nonhazardous wastes) and to work with states to improve their programs. Although recognizing the dangers of E&P wastes, EPA's regulatory determination ultimately reflected its assessment of the low risk to human health (because of the small size and remoteness of the oil and gas sites and the low toxicities of some of the wastes) and the potentially high cost of compliance.

E&P wastes that are exempt from RCRA are not totally unregulated. States regulate these wastes to varying degrees under their own statutes. Additional requirements for the storage and disposal of produced waters exist in the Safe Drinking Water Act and the Clean Water Act. Waste management activities are also restricted by standard industry practice. Finally, the courts have been very active in helping to resolve complaints by communities and individuals about water contamination.

As part of the RCRA reauthorization, the Congress may consider removing the Subtitle C exemption for all or some oil and gas wastes, developing more detailed management guidelines under Subtitle D, or leaving the current exemption in place. New Subtitle D guidelines for all or some oil and gas wastes could include requirements for issuing permits and for remediation (that is, cleaning up existing problems) that would be comparable with current standards for other hazardous substances.

<u>The American Petroleum Institute's Study</u>

The API study analyzes the effects of potential federal action to treat all E&P wastes in a manner similar to other hazardous substances. The report evaluates the impact of regulations that would require the industry to obtain permits for the operation of treatment, storage, and disposal facilities (TSDF) and would set new standards for surface impoundments (or open pits).

In the regulatory scenario defined by the API, the new permitting requirement would apply only to evaporation/blowdown facilities for gas wells and to saltwater disposal facilities. These facilities would be defined as TSDF sites. The API assumes individual permits would have to be issued for every TSDF site, covering requirements for facility design, groundwater monitoring, and financial assurance. Damage assessment and remediation would also be required where needed.

New standards for surface impoundments would require the industry to spend more for facilities to temporarily store and dispose of workover wastes and to use more costly drilling technologies. ("Workover" is an industry term for maintenance activities on oil and gas wells.) In the API regulatory scenario, the industry would also have to clean up existing pits.

The costs of complying with new hazardous waste regulations would cause some existing wells to be abandoned immediately. Other wells may reach their economic limit sooner and stop producing earlier than they otherwise would. And the drilling of some new wells might cease.

The API concluded that the new regulations assumed in its analysis would have very serious consequences for the industry. Eighty percent of all oil and gas wells would be closed. Over 9 percent of oil reserves and 6 percent of natural gas reserves would become uneconomic to produce. And nearly 150,000 jobs in all sectors of the economy (including 40,000 in oil and gas extraction) would be lost. Because the study did not include the offshore producing regions, the total impact may be greater yet.

A Summary of CBO's Conclusions

CBO concurs with the API that changing federal regulations to treat E&P wastes in essentially the same way as Subtitle C hazardous wastes would have serious consequences for the petroleum extraction industry. CBO believes, however, that the API study overstates the effects on the industry because it adopts methods and makes assumptions that systematically overstate the decline in the value of oil and gas wells relative to the costs of RCRA compliance. CBO reached these conclusions after reviewing the methods and assumptions underlying the API analysis, not by conducting an analysis of its own. Although CBO differs with API on several of its assumptions or methods, the general approach of the API study is sound, and the effort involved in accumulating the necessary data and conducting the analysis was considerable.

How much the results of API's analysis would change if CBO's criticisms were taken into account cannot be determined without actually performing the analysis. Several of the criticisms are relatively minor and might not, by themselves, substantially change the results. However, several are very important to the findings.

CBO's principal criticisms of the API study can be divided into those concerning the method of analysis (how the decisions of the industry are modeled) and those concerning the assumptions used in the analysis (particularly the assumed costs of complying with the new regulations and the number of well sites that would have to incur these costs). CBO also differs with the macroeconomic consequences of the new regulations stated by API. Although CBO does not challenge the regulatory scenario the API chose to analyze, a number of CBO's concerns can be traced to specific assumptions in that regulatory scenario. These general criticisms are summarized below and discussed in greater detail in the remainder of this memorandum.

Methodological Issues. The principal issues concerning the methods of the API study are summarized below.

- Unavoidable costs and the decision to abandon a well. Inconsistent with the regulatory scenario it defines, the API study erroneously includes costs of assessing and correcting past environmental damages in the cash flow analysis it uses to determine whether wells would be abandoned. As part of any new RCRA legislation, the API assumes the costs of correcting past problems would have to be paid whether or not the affected wells are abandoned. These "sunk costs" should not be part of the decision to keep a well operating if they cannot be avoided by stopping operations. Excluding these costs would greatly diminish the prospect of massive well closures predicted by the API.

Regardless of their impact on the decision to keep wells operating, sufficiently high remediation costs could cause some firms to become insolvent. This category of costs is a large part of the total costs that API assumes would result from the new regulations. However, the unit of analysis in the API study is the well, not the firm, making it difficult to draw conclusions about how firms might be affected. (This problem is discussed further under the issue of profitability criteria.)

Language in S. 976 and experience with Subtitle C sites suggest that some remediation costs may be significantly postponed or, by abandoning the well, avoided altogether. The API findings are consistent with a scenario that enables firms to avoid some costs of assessing and correcting past damages by closing a well. In that event, however, it is incorrect for API to still conclude that the industry pays all those costs. As a consequence, the API overestimates the industry's revenue losses and the impact of those losses on the levels of exploration and employment.

- <u>Methods of estimating future production from existing wells</u>. The method used to estimate reserves from existing wells underestimates actual reserves. (Reserves measure the total volume of oil or gas that producers expect to recover from existing wells.) This underestimation makes it more likely that owners will abandon wells rather than make the additional expenditures to comply with RCRA changes. The API's assumptions about oil and gas prices, which may be too low, may also contribute to the underestimation of reserves.

- <u>Setting an appropriate profitability criterion for investments needed to comply with the new regulations for existing wells</u>. The API study uses too strict a criterion for deciding whether additional expenditures for waste management should be made to keep wells operating. If the prospect of making these expenditures would make the net worth of oil and gas properties negative, the API methods assume the wells are abandoned and associated reserves are lost.

The API assumes that wells must earn a 20 percent rate of return on before-tax income to avoid abandonment. CBO believes that an after-tax rate of return of 10 percent would be more consistent with economic theory and with recent experience in the oil and gas industry. By selecting a discount rate that is too high, the API understates the net worth of wells and makes it more likely that they would be abandoned.

CBO believes that the analysis should explicitly account for income taxes, unless large numbers of affected firms have no positive tax liability. By not accounting for the effects of taxes, the API method overstates the costs of RCRA compliance and exaggerates the number of wells that would be abandoned. Generally, taxes reduce income and the rate of return earned on a given investment. Thus, for example, a property returning 20 percent before taxes would return 12 percent after paying income taxes (assuming a combined rate for federal and state taxes of about 40 percent). In ignoring taxes, the API erroneously assumes that any wells abandoned using a 20 percent before-tax criterion would also be abandoned using a 12 percent after-tax criterion. This is not true. Because any RCRA-related expenditures would be deductible from taxes, expenditures that would push the return on a property below 20 percent before taxes would be less likely to push the return below 12 percent after taxes (and even less likely to push it below 10 percent).

An after-tax rate of return higher than 10 percent might be used for particularly risky investments. However, the expenditures considered in this study apply to existing wells, not to new exploratory wells. In general, the revenue and cost uncertainties facing owners of existing wells do not significantly exceed those faced by other industries.

A higher rate-of-return criterion might be appropriate for some firms that faced particularly high costs of capital, as a result of greater regulatory uncertainty or borrowing from more costly sources. Lenders who were uncertain about the full cleanup liability of oil and gas businesses would require a higher return on their capital before lending. More significant yet, if the costs of complying with the new regulations were very high, operators that typically relied on internal sources of financing for investments might have to use more expensive, external sources. This would almost certainly be the case here, if the

API's regulatory scenario were realized and firms faced massive first-year costs of cleanup.

- o Predicting exploration expenditures as a function of industry revenues. The API study uses a statistical relationship between exploration and development expenditures and current industry revenues to estimate the effects of new regulatory compliance costs on the amount of drilling and added future reserves. CBO believes that the use of this relationship leads to misleading estimates of the implications of the new regulations on drilling activity, principally because the API's model does not include expected profitability, which should be a fundamental determinant of new investment decisions.

  The choice of regulatory scenarios may also affect the API's use of the statistical relationship between revenues and expenditures. If the scenario was revised to allow firms to avoid closure costs by abandoning some wells, the API should not subtract those avoided costs from industry revenues in determining the changes in direct expenditures resulting from changes in RCRA.

- o Overestimating reserve losses from reduced drilling in the future. The API study misspecifies a relationship between the changes in the amount of drilling and changes in reserves, leading to a double counting of some reserves already estimated as lost from existing wells. CBO also believes that the finding rate (the volume of oil and gas discovered per foot drilled) assumed in the analysis is too high, causing the estimate of reserves lost from reduced drilling to be too high.

Assumptions in the Analysis. The principal issues concerning the assumptions used in the analysis are summarized below.

- o Forecasts of oil prices and production costs. The API study assumes constant nominal prices for oil and natural gas--$20 per barrel of oil and $2 per thousand cubic feet of gas--as well as constant nominal unit costs of production. Most forecasters of petroleum prices predict that prices will tend to rise more rapidly than inflation over time. CBO believes that a more realistic long-term forecast would include rising real (that is, after inflation) product prices and constant real unit costs. Using such a forecast would increase the present value of future returns from wells and would reduce the likelihood that the additional costs of complying with new hazardous waste regulations would cause wells to be abandoned because of negative net worth. Forecasts of prices and costs are very uncertain, however. The study would benefit from looking at the effects of using a range of forecasts.

- <u>The number of sites requiring cleanup</u>. The API bases its assumption about the percentage of affected sites needing cleanup on experience with municipal solid waste landfills. CBO believes the API should stress the arbitrariness of this assumption, which is made in the absence of directly relevant information. The study would benefit from looking at a range of assumptions.

- <u>Costs of complying with the new regulations</u>. CBO's review does not present independent estimates of the costs of complying with the new regulations, but does compare cost estimates presented by an environmental group with those of the API. The alternative cost estimates are much lower than those of the API, although the two sets of estimates may not be entirely comparable.

  Lacking expertise in the areas of petroleum engineering and treatment of hazardous materials, CBO has no reason to challenge API's cost estimates for specific activities in oil fields. However, further documentation of the API's cost estimates for pit closures, new tanks, and corrective action, or an independent corroboration of the API numbers, would enhance the value of the study. A scenario approach to costs would also be useful.

  The API's regulatory scenario also affects its assumptions about compliance costs. For example, the API assumes all sites needing permits would be issued costly individual permits. Estimates of permit costs were based on experience with facilities that treat and dispose of hazardous wastes. S. 976, however, indicates permit costs should reflect actual costs to the EPA of administering the hazardous waste program, which should be much lower for oil and gas sites. It would also allow issuance of permits by rule, which would enable producers to avoid some of the damage assessment work that permits for individual sites may require. This should further lower the EPA's administration costs, too.

Macroeconomic Issues. The API study concludes that lost production and drilling activity in the petroleum industry caused by the new regulations results in a loss of about 40,000 jobs in the industry and an additional 109,000 jobs elsewhere in the economy. CBO believes that the study overstates the effect on employment for three reasons.

First, given the regulatory scenario analyzed, CBO believes the study overstates the effects of the new regulations on the industry. A smaller effect would cause fewer lost jobs. If the regulatory scenario was revised to allow firms to avoid the costs of assessing and correcting past damages by abandoning some wells, those avoided costs should not be subtracted, as API did, from industry revenues in determining the direct employment losses from RCRA changes.

Second, the API study ignores the increase in employment that would result from efforts to comply with the regulations. Jobs created by corrective actions and more costly waste management practices might be less permanent than the oil-field service jobs lost and may not require the same skills or be in the same locality. But this increase in employment could at least mitigate, and for a limited period could completely offset, the job losses associated with well closures.

Finally, CBO disagrees with the API's selection or interpretation of multipliers that are used to estimate effects on employment in the entire economy. Changes in employment in the petroleum extraction industry may affect employment in other parts of the economy, but these effects probably would not be permanent.

The Regulatory Scenario. Changes in the regulatory scenario defined by the API could further affect the API's findings. If producers were allowed to avoid paying for correcting past damages by stopping production, one of CBO's main methodological criticisms (concerning the improper treatment of sunk costs) would be removed and, given the API's cost estimates, a dramatic closure of small wells could be expected. However, alternative policy scenarios that exempted certain groups of marginal producers, that called for expedited permitting and damage assessment, or that allowed a phased-in compliance schedule would moderate the API's findings.

REVIEW OF THE STUDY'S ECONOMIC METHODS

The API study assesses the effects of potential environmental regulations by simulating the performance of the domestic oil and gas industry without and with those regulations (Base Case and Subtitle D Case, respectively). The simulations rely on a computer-based model of the industry that was developed for this purpose. The difference between results for the two cases--in terms of such factors as production, reserves, and employment--is attributed to the regulations. Since the representation of production and drilling decisions implicit in this model is critical to the study's findings, this review will start there. A later section reviews that part of the method related to macroeconomic consequences, including effects on employment.

Groups of producing wells are the basic unit of analysis in the API study. In 1989, about 618,000 individual oil wells and 261,000 natural gas wells were producing in the onshore regions of the United States. As a modeling convenience and because of data limitations, the study aggregates these wells into groups--1,004 groups for oil and 643 groups for gas. The groups are organized by geographic region, production rate, and well depth in order to identify wells that operate under comparable cost conditions and that may require comparable treatment under the new waste management regulations. Additional information used to estimate operating costs and RCRA compliance costs includes method of production, water production rate, and the number of wells on a lease.

The API's aggregation of data on wells is a very useful exercise, since new RCRA regulations could affect individual oil and gas operations in significantly different ways. Developing a data base and economic model for individual well groups is a good way to estimate what the total cost impact of those regulations may be, how many properties may be affected, and where those properties may be located.

The API model evaluates the aggregate profitability, or net worth, of each group of oil and gas wells by analyzing its present and future cash flow (sales revenues minus costs). Product prices are assumed to remain constant in nominal terms (that is, not accounting for the impact of inflation) at $20 per barrel for oil and $2 per thousand cubic feet for gas. By assuming new RCRA requirements for waste management and imputing the costs of those requirements to individual wells, the model can calculate the impact of new regulations on the cash flow and net worth of individual well groups. Estimated changes in the aggregate level of production from existing wells (including immediate abandonment) is based on changes in cash flow and profitability of continued production for individual well groups.

The API model also evaluates decisions on exploration and development drilling. Changes in the level of new exploration and development drilling, which would add new production in the future, are modeled on the basis of changes in industry revenues and finding costs, using aggregate historical relationships.

The following sections review issues related to how the API model determines the profitability of existing wells and how costs associated with the new regulations would affect that profitability. They also examine the effects of increased costs for hazardous waste activities on spending for exploration and development.

Unavoidable Costs and the Decision to Abandon Existing Wells

Added RCRA costs may not affect the net worth of individual producing wells in the same way that they affect the net worth of the parent companies, depending on whether the costs may be avoided by abandoning the wells.

Abandonment and the Profitability of Wells. In the API analysis, the calculation of the present value of expected cash flow from a property would include higher RCRA costs in the future (such as more costly water disposal practices or well and reservoir maintenance), as well as the costs of any initial expenditures required by the new regulations (including corrective actions and spending on new tanks or pit linings). However, the API's regulatory scenario assumes that a significant part of those initial costs--spending for pit closures and remediation of existing problems--would have to be paid even if the well closes. (Pits are surface impoundments built to hold wastewaters produced from wells or other fluid wastes generated when drilling and maintaining wells.)

CBO believes any costs that must be paid immediately, even if a well is abandoned, should not affect the decision to abandon the property or continue operations. In the API's regulatory scenario, all corrective action must take place in the first year, and these costs add equally to the expense of shutting down and of staying open. Accordingly, they should be deemed "sunk costs" and omitted from the cash flow analysis. This point is very significant, since over $46 billion of API's estimated initial RCRA costs of $56 billion fall into the "sunk" category. Because of this treatment of costs, the study systematically overestimates the number of wells closed and, thus, overstates present and future losses of reserves and production.

The API's treatment of RCRA compliance costs in its cash flow analysis is not consistent with its regulatory scenario. Table 1 reviews specific categories of compliance costs and compares API's treatment of those costs with the treatment CBO suggests is consistent with the regulatory scenario. The basic distinction is between costs that may be avoided by abandoning wells and costs that are incurred anyway. Costs that cannot be avoided are referred to as sunk costs. Costs that can be avoided are referred to for tax

TABLE 1. TREATMENT OF NEW RCRA-RELATED COSTS IN API'S CASH FLOW ANALYSIS AND CBO'S ALTERNATIVE TREATMENT

Facility or Waste Management Activity	American Petroleum Institute	Congressional Budget Office
Workover Pits		
Closure of existing pits	Fixed Cost	Sunk Cost
Retrofitting workover rigs with tanks	Fixed Cost	Fixed Cost
Disposal of workover wastes (other than nonexempt wastes)	Variable Cost	Variable Cost
Emergency Pits at Oil Well Tank Batteries		
Closure of existing pits	Fixed Cost	Sunk Cost
New tanks	Fixed Cost	Fixed Cost
Emergency Pits at Enhanced Recovery Facilities and Gas Plant Facilities		
Closure of existing pits	Fixed Cost	Sunk Cost
New tanks	Fixed Cost	Fixed Cost
Treatment, Storage, and Disposal Facilities (Saltwater Disposal Facilities and Evaporation/ Blowdown Pits)		
Operational costs for startup		
Closure of emergency pits	Fixed Cost	Sunk Cost
New emergency tanks, saltwater tanks, and scrubbers	Fixed Cost	Fixed Cost

(Continued)

TABLE 1. Continued

Facility and Waste Management Activity	American Petroleum Institute	Congressional Budget Office
Treatment, Storage, and Disposal Facilities (Saltwater Disposal Facilities and Evaporation/ Blowdown Pits) (continued)		
Annual operational costs		
Permitting fee	Variable Cost	Variable Cost
Operations, maintenance, and reports	Variable Cost	Variable Cost
Demonstration of financial assurance	Variable Cost	Variable Cost
Groundwater monitoring	Variable Cost	Variable Cost
Remediation costs		
RCRA facility investigation and corrective measures study	Fixed Cost	Sunk Cost
Corrective action (pumping and treating contaminated groundwater; bioremediation; excavation, disposal, and containment)	Fixed Cost for Past Damages Variable Cost for Future Contamination	Sunk Cost for Past Damages Variable Cost for Future Contamination
Disposal of Associated Wastes, All Sites (Other than workover wastes and nonexempt wastes)	Variable Cost	Variable Cost

SOURCE: Congressional Budget Office.

NOTE: RCRA = Resource Conservation and Recovery Act.

purposes as either fixed costs or variable costs. Fixed costs are capital expenses that should be amortized for purposes of calculating tax benefits, and variable costs are normal business expenses that are deductible in the year incurred.[1] Tax treatment is discussed in a later section.

If, under a different regulatory scenario, the costs of pit closure and corrective action could be avoided by closing the well, those costs should be subtracted from the well's net worth, as the API has done. In that case, shutting down could cost less than staying open, and the massive closure of wells predicted by the API would be more likely. Alternatively, if RCRA compliance was extended beyond the first year, either through an explicitly phased-in compliance schedule or through delays in the permitting process, the present value of postponed closure costs would decline. As a result, the net worth of a well would increase, and the well would be less likely to be abandoned.

CBO has no comment on the regulatory scenario selected by the API, only on whether its methods are appropriate to that scenario. The choice of scenarios, however, can have a significant impact on the results. Language in S. 976, on which the API regulatory scenario was modeled, suggests that some remediation costs may be avoided by abandoning a well, which could lead to a large regulatory impact if compliance was required in the first year.[2] But experience with Subtitle C sites indicates that corrective actions may be significantly delayed, which would result in a smaller impact.

<u>Abandonment and the Profitability of Businesses</u>. Imposing assessment and remediation costs of the magnitude assumed by API on the petroleum extraction industry would profoundly affect the industry. Some firms might not have the resources available to pay these costs and would go out of business. Some of the properties of these firms might be purchased by firms that could cover the costs. Assessment and remediation costs on other properties could be so high relative to the revenues from the oil or gas that no firm would want to take on the liability. Bankruptcies and abandonments of these types could cause production and reserves to fall. The API model

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1. Some costs that are similar to capital expenses to providers of well services or drilling services may actually represent normal business expenses to the well owner who pays for those services. Such costs would include those for the retrofitting of workover rigs and the acquiring of new closed-loop mud systems for drilling. For the purposes of the API study, however, there would be no substantive difference between deducting the full cost in year one and deducting the present value of all future amortized costs.

2. Language in the Resource Conservation and Recovery Act Amendments of 1991 (S. 976), amendments to RCRA Subtitle D, section 4011, paragraph (f)(2) suggests that only facilities seeking a permit would require corrective action; that is, with immediate abandonment, corrective action could be avoided.

and data base, which were built up from individual wells rather than individual firms, cannot be used to examine directly the extent of this effect.

Within the API's analytic framework, however, large assessment and remediation costs that do not directly affect the profitability of individual wells could indirectly affect the oil and gas industry in another way. The need to pay large sums for corrective actions would force the industry to seek more costly sources of financing, thus raising the cost of capital for all industry investments, both old and new. This secondary effect is discussed in the section on regulatory uncertainty and external financing.

Setting an Appropriate Criterion for Abandoning Existing Wells

Economic theory suggests that the most important criterion for determining whether an existing well should continue to operate is its net worth: wells with a positive net worth should continue production; those with a negative net worth should shut down. Net worth is measured as the present value of future cash flows expected from that well, after taxes and adjusted for uncertainty. (Present value reflects the time value of money; earnings far in the future have less value than the same earnings today. Uncertain future earnings have less value than certain earnings.)

To express future cash flows in present value terms, they are divided by a discount rate. The discount rate is represented by the highest rate of return a company can obtain on its money. For a company that needs to borrow funds, the discount rate can be measured by its after-tax cost of capital (or cost of funds). The discount rate would be raised to compensate for any added uncertainty (vis à vis other industries) about future product prices, production potential, and production costs. If the present value of the well's cash flow is positive, the well has positive net worth and should keep operating. Otherwise, it should shut down.

Using the API's methods, new regulatory costs would cause some existing well groups to be abandoned immediately. Others would fail a separate criterion for profitability (positive annual cash flow) for continued operation in later years and have a curtailed production life, or economic limit. To determine whether a well should be abandoned immediately, the API applies some rules of thumb that individual companies use to screen potential investments. (The API's criterion for the economic limit of existing wells is critiqued in a later section.)

The three profitability criteria for existing wells are payout time (three years to recoup expenses, before tax), undiscounted profit-to-investment ratio

(1.0, before tax), and internal rate of return (20 percent, before tax). That is, a well should be abandoned if it cannot pay off its new RCRA costs in three years, cannot achieve a ratio of undiscounted cash flow to RCRA costs of at least 1.0, or cannot maintain a positive net worth when future cash flow is discounted using a 20 percent rate of return. At 20 percent, the rate-of-return criterion is generally the most restrictive of the three.

Only the API's rate-of-return criterion is consistent with the criterion of net worth suggested by economic theory. CBO believes the payout and profit-to-investment (PI) criteria should not be the sole basis for the final investment decision. They may be useful for making quick comparisons in the field or ranking projects for the corporate planners, but only if they are routinely calibrated to the business's rate-of-return requirements. In practice, it is the corporate decision on how much to budget for maintaining and developing existing wells that determines how far down the payout or PI priority list projects get funded. That corporate plan should take into account the future path of prices and costs and some minimum required rate of return on corporate spending.

The API's rate-of-return criterion is the correct general approach, but it must, at a minimum, be applied to cash flow net of income taxes and must not include costs that are unrelated to the abandonment decision at hand. To accomplish this within the model's framework, the API should lower its estimates of additional waste management costs to reflect their deductibility from federal and state income taxes, and use an after-tax rate of return that is more in line with the recent experience of large oil and gas producers. The API may further assume that the high costs of RCRA compliance will force oil and gas businesses to resort to more costly sources of financing, in which case the required rate of return may be higher than recent experience. The following sections on taxes, historical returns, and uncertainty address these issues as they bear on the decision to abandon a well.

Accounting for Income Taxes on Existing Wells

The API method ignores the effect of income taxes on cash flow for existing wells. Taking income taxes into account would allow businesses to write off part of the costs of meeting new waste management regulations and would both reduce their accounting losses and enhance their property's net worth. Because all of the added costs would be deductible, cash flow net of taxes would not drop as much as the API study indicates, regardless of the specific assumptions about the nature of changes in waste management practices or their direct costs.

It is not sufficient to simply note, as the API study correctly does, that the payment of income taxes lowers the rate of return on any past investment. For example, assuming a combined federal and state income tax rate of 40 percent, cash flow that yields a 20 percent rate of return on investment before taxes would yield only a 12 percent return after taxes.[3] However, the important question for the API study is whether taxes alter the effect of new expenditures on net worth, not whether taxes alter the return on past expenditures; that is, will an expenditure that pushes a well's before-tax profitability below 20 percent also reduce the after-tax profitability below 12 percent?[4] Depending on the type of new waste management costs--normal business expenses, capital expenses, or some combination--the failure to account for income taxes could make some well groups more likely to appear unprofitable.

If an expenditure was fully deductible in the first year as a normal business expense, after-tax profitability would not drop as much as before-tax profitability. The property therefore would be much less likely to be abandoned using an after-tax rate-of-return criterion. However, if an expenditure was a capital expense, with the writeoff significantly deferred, the before- and after-tax criteria give similar results. The fact that the tax writeoffs for a present cost occur in the future means the present value of the writeoff is lower. The longer the depreciation schedule, the greater the real cost of the capital expense, and the lower the after-tax rate of return.

Properly accounting for income taxes would represent a major complication in the API method, especially because the tax structures of different companies in the industry vary greatly. The U.S. tax code offers the oil and gas industry many ways to defer taxes, and the tax liability of individual companies can be very low at times. The effective tax rate for new wells in particular is much lower than the nominal corporate tax rate.

For the purposes of its study, however, the API need not replicate the correct tax treatment of all oil and gas costs for existing wells--only the new waste management costs. Some costs, such as disposal costs for workover wastes, should be identified as normal business expenses to be deducted in the first year of the new law. Others, such as costs for new storage tanks or

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3. The Energy Information Administration (EIA) reports the effective tax rate on oil and gas production for large energy companies. That rate was 39 percent in 1988 and 42.1 percent in 1989. See EIA, *Performance Profiles of Major Energy Producers 1989*, DOE/EIA-0206(89) (January 1991).

4. Or, equivalently, whether an expenditure that makes the before-tax net worth of a well negative using a 20 percent discount rate would also make the after-tax net worth negative using a 12 percent discount rate.

injection wells, should be identified as capital expenses, to be written off in future years.

The Historical Rate of Return for Existing Wells

The required rate of return for any project should reflect the opportunity cost of a company's capital, or the next highest rate of return that could be earned by investing in other economic activities. As a practical matter, the appropriate risk-weighted, after-tax rate of return should be in line with recent experience in the oil and gas industry.

As a before-tax rate of return, the API's assumption of 20 percent may be higher than the actual return on oil and gas properties. The API justifies its choice of 20 percent on the basis of the high uncertainty surrounding petroleum prices, ultimate recovery, regulations, and so forth. Although oil and gas prices may be uncertain, the overall level of uncertainty for revenues from existing wells (as opposed to new exploratory wells) does not significantly exceed that for other industries.

CBO believes the profitability criterion for existing wells should be established using historical after-tax returns to the oil and gas extraction industry, as discussed above. For the period 1981 to 1989, the after-tax rate of return from oil and gas production (measured as net income divided by stockholder equity for all publicly traded firms) was about 10 percent for large companies.[5] (Small, publicly traded oil and gas producers earned significantly less during the 1980s--only about 4 percent after tax. During the 1970s, however, earnings of small firms tracked more closely with those of large firms.) This historical return is lower than the 12 percent that would be consistent with a before-tax return on 20 percent.

As a first approximation, a requirement of 10 percent for the after-tax return should be consistent with the concept of profitability of existing wells in the study's Base Case. However, there may be other circumstances related to regulatory uncertainty and the cost of funds that would argue for a higher rate of return in the Subtitle D Case.

5. Energy Information Administration, *Performance Profiles of Major Energy Producers 1989*, figures 12 and 13.

Regulatory Uncertainty and Higher Costs of External Financing

In the API's Subtitle D Case, added regulatory uncertainty and significant new regulatory costs could further raise the required rate of return for existing wells above the historical average.

New waste regulations could increase the level of uncertainty for future lenders (or investors). A potential lender to a company could not know whether some property owned by that company needed costly damage remediation. To compensate lenders for the prospect of unknown costs, oil and gas businesses would have to pay more for the funds they borrow. And, as a result of this higher cost of capital, existing oil and gas wells (and all other economic activities these businesses engage in) would have to earn a greater return to justify their continued operation.

Significant new expenditures for waste management could raise the cost of borrowing to the industry in another way: by depleting its internal cash flow and forcing companies to resort to more expensive sources of external financing. To the extent that a firm's internal cash flow is the cheapest source of funds, some level of additional spending on maintenance and development projects may become uneconomic when those funds are no longer abundant.

Whether the limits of internal cash flow should raise the rate-of-return criteria for the Subtitle D Case above the industry's historical average depends on several factors:

- The annual level of spending required by the new regulations relative to the available flow of internal funds. This level is determined by the total costs of RCRA compliance, the timing of compliance, and the industry's current financial health.
- The resulting level of external financing required relative to the collateral worth of oil and gas businesses. Collateral worth can limit the industry's ability to raise capital from outside sources.
- The incremental cost of the next cheapest source of capital, which determines how much the rate-of-return criterion must rise as businesses move from internal to external financing.

Under the regulatory scenario the API chose to analyze, the industry would incur RCRA compliance costs of $56.4 billion in the first year. Because this amount would be greater than the current cash flow to the industry, oil and gas businesses would have to seek more costly sources of outside financing.[6] However, if the initial requirement for complying with RCRA changes was phased in over a number of years or if some compliance could be avoided by abandoning wells, the added financing costs for the industry each year would be much lower. Initial financing requirements would also be lower if the costs of services and equipment needed to comply with RCRA changes were significantly lower. (The possibility that the compliance costs could be lower is investigated in the section on API's cost assumptions.) In any case, the API's estimates of costs in subsequent years of around $3.3 billion would be more affordable with internal funds.

The biggest negative impact on oil and gas businesses would occur in the event that the new RCRA costs not only exceeded their internal cash flow, but also exceeded the collateral worth of all their assets. In that scenario, the uncertainty for lenders and investors would rise significantly, as would the cost of financing. Those businesses that could not afford or could not obtain outside financing to cover their new RCRA costs would have to shut down without performing remediation. However, the properties of businesses unable to obtain financing would find buyers and continue in operation, so long as their net worth was still positive and the financial positions of potential buyers were still sound. But oil and gas properties that had negative net worth, even including sunk costs, would shut down permanently, since those remediation costs would be incremental costs to potential buyers.

The specter of widespread business failures would apply more to smaller companies. Because there is no direct correspondence between the size of a well group and the size of a parent company, there is no way to tell, using the API model, how many existing wells could be lost because of this constraint on financing. If the API modified its regulatory scenario to allow for the possibility of exempting smaller companies from some RCRA requirements or of allowing a delayed compliance schedule, the predicted losses of wells and reserves could be moderated.

Raising the profitability criterion for the Subtitle D Case would increase the negative impact on wells and reserves for any given level of new regulatory costs. The ultimate impact would depend on the current financial health of the industry, the costs of RCRA compliance, the prospects for avoiding compliance by abandoning wells, the compliance schedule, and whether any groups of small producers (small businesses, small wells, or small waste generators) would be exempted.

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6. The Energy Information Administration reports after-tax cash flow from all operations for large energy companies in 1989 as $48.3 billion. Before-tax cash flow from oil and gas production alone was $36.1 billion in that year. See EIA, *Performance Profiles of Major Energy Producers 1989*.

Changing the Economic Limit of Existing Wells and Counting Reserve Losses

Operators of oil leases can control the rate of production from existing wells through the current recovery system--be it pumping, water injection, or some form of enhanced recovery. The rate of production from gas wells is determined mainly by the natural pressure of the reservoir. Expenditures for maintaining wells and reservoirs give operators added control over the oil and gas production, as do development expenditures for increasing ultimate recovery (for example, spacing wells more closely or fracturing the oil-bearing rock). When it is no longer economical to produce from a well, tubing in the well and all surface equipment are removed and the well is plugged.

Operators have only limited discretion on maximum flow rates, within the bounds of state conservation laws and standard industry practice. State laws and the terms of oil and gas leases also dictate procedures for closing wells. However, the outlook for profitability can have a significant effect on maintenance and development activities and on the decision of when to abandon a lease.

The API model includes a simple representation of production and abandonment activities. Annual production levels from existing wells are not represented as changing as a result of direct expenditures for maintenance or development (other than development drilling).[7] Rather, the levels of maintenance and development are implicit in the reserve estimates and production profiles for the individual well categories in API's Base Case. Added regulatory costs would lead currently producing wells to reach their economic limit sooner, and diminished net worth may lead some wells to be abandoned immediately.

The API assumes a well group reaches its economic limit when its annual cash flow goes negative and it is no longer profitable to operate. As a result, each well may continue to produce the same pattern of output, but, with added operating costs, it would cease operations at some higher level of production than otherwise. Using this new economic limit and a discount rate, the API model calculates a new present value of future cash flow, or net worth, for the well group. If the net worth is negative, the well is abandoned immediately. The model calculates first-year reserve losses as a consequence of immediate abandonment and, for those wells that keep producing, curtailed production lives.

7. Changes in industry revenues affect development drilling and ultimate production potential through the model's exploration and development equation, described in the section on reserve losses from new wells.

As with the decision to abandon a well, CBO believes the economic limit should be based on the present value of future cash flow at each point in time, not on the current cash flow at that time. Given the API's assumption of constant prices, these two approaches would not lead to significantly different results: the economic limit would occur one or two years earlier if negative present value was the criterion for abandonment. If prices were expected to rise significantly, however, the two approaches could yield different results. A business would endure a period of negative cash flow if an outlook for rising prices meant the present value of future cash flow was still positive.

Aside from the methodological concern of how to identify the economic limit, the API also errs in its accounting of reserve losses from changes in the economic limit. When the model first runs its Base Case with the study's assumptions about price and unit costs, it identifies economic limits for every well group and tallies a total estimate of reserves for oil and gas. To the extent those assumptions are not realistic, the model can yield reserve estimates for the Base Case that are not consistent with actual data on reserves. That is the case here.

The API's estimates of onshore oil and gas reserves in the Base Case are lower than the historical data on which they are based. For example, onshore oil reserves in the Base Case total 19.1 billion barrels, compared with 23.2 billion barrels reported by oil companies for the end of 1989.[8] The significance of this difference is that when the Subtitle D Case is run, the pool of future earnings that must pay for the RCRA changes is too small. If the Base Case reserve estimates were initialized to a higher historical level, fewer properties would be found uneconomic.

Predicting Reserve Losses from New Wells

Economic theory suggests that an individual firm will spend on exploration and development drilling for new prospects so long as the expected present value of future revenues attributable to that activity exceeds its cost. The API does not use this activity-specific analysis of expected cash flow to evaluate new discoveries. Instead, the API method related to new discoveries proceeds in three steps:

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8. The source for reported reserves is the Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1989 Annual Report*, DOE/EIA-0216(89) (October 1990). The API estimate was calculated by dividing API's estimate of oil reserves lost in the Subtitle D Case (2.48 billion) by the reported percentage change from the Base Case (13.02 percent).

1. The model uses the aggregate cash flow from existing properties (net of added waste management costs for those properties) and a historical relationship between industry revenues and drilling expenditures to determine future expenditures for exploration and development drilling.

2. The model calculates a finding cost for oil and gas discoveries (cost per barrel of oil and gas discovered) by dividing an assumed finding rate (barrels per foot drilled) into an assumed unit cost of drilling (cost per foot), including an added cost to cover new waste management requirements.

3. The model divides drilling expenditures from step 1 by the estimate of the finding cost from step 2 to calculate the level of reserve additions.

In general, the use of aggregate historical relationships to predict future activity is an acceptable econometric technique. However, three problems with the specific relationships identified by the API could cast doubt on the study's findings: conceptual weaknesses in the model linking revenues and drilling expenditures; a potential double-counting of a part of future reserve additions; and a possible exaggeration of the finding rate.

<u>Conceptual Weaknesses in the Revenues/Expenditures Model</u>. The first problem is related to API's assumption that industry cash flow constrains exploration and development expenditures (or, equivalently, that industry always spends a fixed share of its revenues on drilling). CBO believes this assumption causes the API to overstate the drop in drilling and future reserve additions attributable to RCRA changes.

Current revenues may be rationalized as a leading indicator of drilling activity because of their close correlation with current net cash flow and profitability. Net cash flow, when sufficiently constrained, can raise the cost of capital to a firm, as discussed in the preceding section on uncertainty and external financing. Statistically, however, this cost-of-funds effect should be limited, since it would only show up when the total cost of potential oil and gas investments with above-market profitability exceeds available internal cash flow. Current profitability, in turn, can be related to the more relevant future profitability, but only to the extent that current price trends are expected to continue.

Current revenues are only loosely correlated with the cost of capital and expected profitability and, hence, remain a poor proxy for the expected profitability of future investments. Regardless of the level of current revenues, the firm should not invest those funds in new drilling unless the new projects offer a good return. If several new projects look like winners, the firm should not be constrained by low earnings from other projects; it should be able to borrow on the strength of expected earnings. Conversely, if the projects look like losers, the firm should not invest in them just because its current revenues are high. The relationship between revenues and drilling expenditures should be based primarily on the increased cost of capital for investing, not on the loss of investment capital.

The earlier discussion of cash flow and the cost of funds not withstanding, current revenues on their own should be a poor predictor of exploration and development drilling. However, the API identifies a statistical link between revenues and drilling expenditures that looks quite strong. The reason for this strong link is that oil and gas prices are reflected in both sides of the equation. Price influences revenues, and oil and gas prices influence the demand for drilling services and, hence, both the unit costs of drilling and total drilling expenditures.

In econometrics, a misspecified equation can sometimes still yield acceptable predictions. The API model could do so if other relationships underlying the revenues/expenditures equation make economic sense and do not change, but that is not the case here. Underlying the API equation linking revenues and drilling expenditures are two relationships: one between current production and drilling levels, and one between price and unit drilling costs. Any statistical relationship observed between current production and current drilling levels would result from the stability of lead times between current drilling and future additions to production capacity. This is the wrong direction of causality, since the API wants revenues (production) to affect expenditures (drilling). In any case, new waste management practices could lengthen those lead times.

The other component of the revenues/expenditures equation, unit drilling costs, is determined not only by the demand for drilling (as influenced by oil and gas prices and production costs), but also by the supply of drilling services. New waste management practices would increase the cost of supplying any given level of drilling services, as the API assumes. But the prospect of higher production costs with the RCRA changes also means that oil and gas companies will value those drilling services less. As a result, the actual increase in unit drilling costs from the Base Case to the Subtitle D Case would probably be less than the API assumes.

The API may find it necessary to replace its revenues/expenditures equation with a new relationship that avoids these specification problems and incorporates a role for expected profitability. Such an equation would rely on the statistical relationship between drilling levels (as the dependent variable) and product prices, finding and lifting costs (net of new waste management costs), and current cash flow (as a proxy for the cost of financing). Finding and lifting costs should not include costs identified with correcting past environmental damages. The API may ignore the contribution of income taxes to costs (as is the case in its current revenues/expenditures equation) if those taxes have not changed significantly in the historical period of estimation.

A further problem the API may encounter in using its model to estimate changes in drilling for new wells concerns the accounting of RCRA compliance costs. The API model deducts all RCRA compliance costs from industry revenues. In a different regulatory scenario, in which compliance could be avoided by abandoning wells, the drop in industry revenues would not be as great as the API now assumes.

Double-Counting Reserve Losses from Existing Wells and New Wells. The second problem with API's treatment of new discoveries derives from the way the study defines the finding rate, or volume of oil and gas reserves added per foot of drilling. To estimate future reserve losses from reduced drilling, the study relies on a relationship between the national drilling level and total reserve additions--from data revisions, extensions of existing reservoirs, and discoveries from exploration (see Box 1 for a definition of reserves and a discussion of the different sources of reserves). More correctly, only reserve additions from extensions and discoveries should be attributable to that drilling. Reserves from revisions should only be attributable to existing wells. But reserve losses from revisions were separately estimated in the section of the API model dealing with abandoning and changing the economic limits of existing wells. Thus, the study potentially double-counts some reserve losses.

Net revisions to oil and gas reserves result from changes in the economics of producing from old fields and from a learning experience with old fields. API's study counts economic-based and learning-based reserve revisions in its treatment of new wells through its definition of the finding rate. Lower drilling levels lead to lower total additions from revisions, extensions,

Box 1
THE RELATIONSHIP BETWEEN RESERVES AND PRODUCTION

The production capacity of oil and gas reservoirs is indicated by "proved reserves"--oil or gas resources that have been discovered and developed and can be economically producible in the current business environment. Implicit in any estimate of reserves is a sustained level of effort over time to provide maintenance for both the production equipment and the reservoir. Reserves are used up through production. Reserves are added through net revisions to reserves data, extensions of existing reservoirs, and discoveries of new reservoirs and fields.

Most crude oil reserves are added through positive net revisions of existing reserve estimates, as more is learned about existing reservoirs, or as the economics of producing from existing reservoirs improves. Falling prices or rising taxes would lead to negative revisions.

Historically, reserve revisions for natural gas were not as significant as those for crude oil--partly because the geology of gas reservoirs is less complicated, and partly because gas was sold almost exclusively under long-term contract and the business environment changed little. In the past, year-to-year changes in revisions of gas reserves mainly reflected economic factors related to oil. (About a quarter of all natural gas is produced in association with crude oil wells.) Today, however, most natural gas is sold under short-term contracts, and the size of gas reserve revisions has increased severalfold.

A smaller amount of oil reserves and the biggest part of gas reserves are added through the extension of existing reservoirs and the discovery and development of new reservoirs and new fields as a result of exploratory and development drilling. Exploration and development drilling helps to extend the boundaries of existing reservoirs (through infill drilling or step-out wells) and to bring new discoveries into production. On average, only about 40 percent of crude oil reserves are added through extensions and new discoveries combined. (Up to the mid-1980s, almost 90 percent of natural gas reserves came from extensions and new discoveries, but by 1990, that number was down to only 60 percent.) The rest comes through net revisions.

Any increases in waste management costs would result in negative revisions for both oil and gas, as some reservoirs are prematurely abandoned or as the economics of sustaining production from the still-profitable reservoirs is diminished.

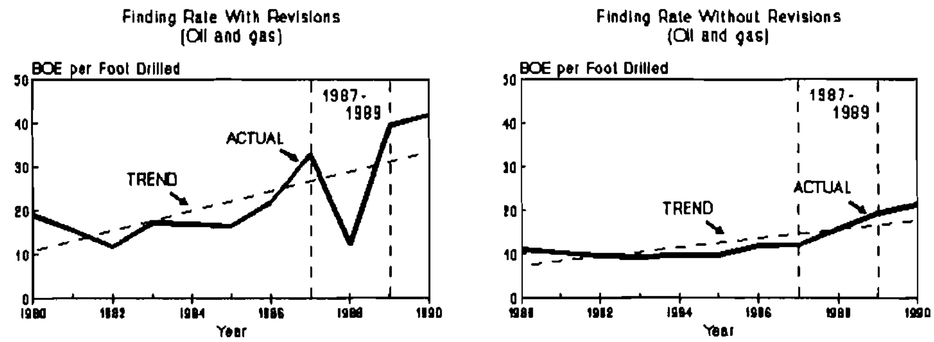
and discoveries. However, the study also calculates revisions from changes in economics in its treatment of existing wells. Abandonments and changes in the economic limit of existing wells result in reserve losses that oil and gas companies would report as economic-based revisions. Hence, the double count--and a resulting exaggeration of reserve losses attributable to RCRA changes.

In a potentially offsetting error, however, API's treatment of existing wells does not account for any future drops in learning-based revisions as a consequence of RCRA-induced abandonments. The learning process and future revisions end when a well is abandoned. But the loss of learning-based revisions from old wells is accounted for in API's treatment of new wells, albeit mistakenly. CBO did not determine to what extent API's mistaken estimate of revision losses from lower drilling for new wells could offset its underestimate of reserve losses from abandoning existing wells.

Estimating the Finding Rate for New Wells. The third problem arises from the period of estimation for the finding rate and the aggregation of oil and gas activity in that rate. The problem with revisions not withstanding, CBO believes the API estimate of reserves discovered per foot of drilling may be too high. The years selected by the API for estimating the finding rate, 1987 through 1989, correspond to an unusually high level of total reserve additions relative to the level of drilling (see Figure 1).[9]

9. The API finding rate is calculated for the onshore regions only. The estimates of the finding rate presented in Figures 1 and 2 are based on reserve additions and drilling levels for the total United States, onshore and offshore. However, the trends depicted for the total United States are representative of those for the onshore regions.

FIGURE 1. TOTAL FINDING RATES WITH AND WITHOUT RESERVE REVISIONS



SOURCE: Congressional Budget Office using data from the Energy Information Administration.

NOTE: BOE = barrel-of-oil equivalent.

There are several reasons why the period that the API selected is atypical. Individual finding rates for both oil and gas increased in the late 1980s, but, more significantly, oil drilling declined dramatically relative to gas drilling (see Figure 2). Because finding rates for gas are historically much higher than those for oil, the shift in drilling pushed the aggregate finding rate up sharply.

One would expect that individual finding rates for oil or gas would decline over time, as resources become increasingly difficult to locate. However, technological innovations and transient economic factors can result in short-term changes that are counter to the long-term trend. One such development was the drop in oil prices in 1986, with the subsequent industry shakeout of less efficient drillers and a new focus on less risky drilling ventures. Another important development was the deregulation of new natural gas wells in 1985, which effectively decoupled drilling for natural gas from that for crude oil. CBO believes that finding rates now will resume their long-term downward trend (not shown in the figures) and that, as oil prices increase in the mid-1990s, the level of oil drilling will increase relative to that for gas, further reinforcing the fall in the aggregate finding rate.

Other Consequences of New Waste Management Regulations

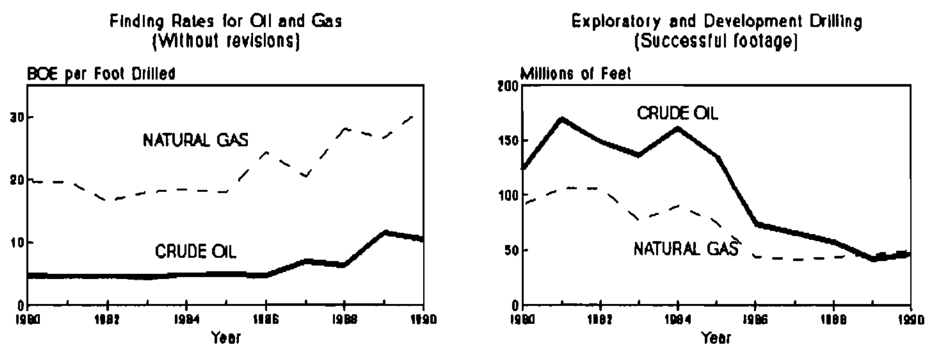
CBO's review of API's economic methods also raises concerns about macroeconomic findings reported in the study (including effects on employment and local tax revenues) and other economic effects of RCRA changes that the study omitted.

Effects on Employment. The API study finds that, as a further consequence of new waste management costs, employment in exploration and production activities and in the economy at large would drop. This finding is based on two relationships. The first identifies a statistical link between oil and gas revenues and employment in oil and gas extraction activities. On the basis of that relationship, a drop in industry revenues resulting from new RCRA compliance costs would cause the industry to lay off employees. Using a second relationship--between employment in the oil and gas industry and employment in the economy at large--the API is able to attribute additional job losses, outside the oil and gas industry, to the RCRA changes.

CBO believes that the API study overstates the employment losses attributable to RCRA changes for three reasons. First, CBO believes the study overstates the production losses from new waste management regulations. With fewer wells being abandoned, direct employment losses in oil and gas production would be lower.

Second, CBO believes that new waste management regulations could add jobs at the outset, both locally and nationally. The API findings ignore

FIGURE 2. FINDING RATES AND DRILLING LEVELS FOR OIL AND NATURAL GAS



SOURCE: Congressional Budget Office using data from the Energy Information Administration.

NOTE: BOE = barrel-of-oil equivalent.

the short-term employment stimulus that new regulations would provide. The new regulations would actually require the industry to spend more on the basic activities it now engages in. Drilling and production operations would be more expensive, and some of the additional spending would be for labor employed in the oil and gas extraction industry. Much of the remainder would be spent in the same local communities.

The real issues here are how temporary is the employment added by the increased spending for waste management and whether it compensates for the permanent employment losses as a result of lower production and drilling levels. The answer to these questions depends largely on the regulatory scenario. The RCRA requirements probably would be phased in over a number of years, by legislative design, administrative delays, or court actions. The possibility of such a phase-in could lessen the direct negative impact of new regulations on oil and gas employment. In the current slack economy, any net increase in industry spending could be a plus for economic growth and employment at the national level--at least in the early years of the RCRA program.

The third way that CBO differs with the API study is in the use or the interpretation of multipliers that are used to estimate effects on employment in the entire economy. Changes in employment in the petroleum extraction industry may affect employment in other parts of the economy, but the effects on total employment would not be permanent, as the API has assumed.

A further problem the API may encounter in applying its model for oil and gas employment concerns the accounting of RCRA compliance costs. Currently, the API deducts all RCRA compliance costs from industry revenues. In a different regulatory scenario, in which compliance could be avoided by abandoning wells, the drop in industry revenues would not be as great as the API now assumes, so employment losses would be smaller. (As long as additional wells are abandoned, however, some oil and gas employment losses would result.)

Local Tax Revenues. The API study also concluded that tax revenues of local governments would suffer as a consequence of reduced oil and gas production and lower employment. Oil and gas production would probably be lower, although not by the large amounts initially predicted in the API study. However, economic growth and employment could both benefit as a result of increased industry spending, as discussed above, and that increased economic activity could in turn boost tax revenues. Further quantitative analysis would be needed to determine whether the tax revenues lost through lower oil and gas production would be more or less than the tax revenues added through economic expansion.

Other Economic Effects. The API study did not address any of the benefits of new waste management regulations. Many of those benefits were understandably outside the scope of the study, including the value of wildlife harmed by open waste pits and contaminated wetlands. However, there may be other, more quantifiable economic benefits. For example, contamination of local groundwater can raise the cost of supplying fresh water to oil and gas production sites. Such contamination has also opened oil and gas companies to lawsuits by local communities and individuals. Avoiding these costs would be a direct economic benefit to the industry. At a minimum, the API study should acknowledge some of these benefits.

ASSUMPTIONS UNDERLYING THE ANALYSIS

The results of any economic model of production and investment may be traced to the analytic method and the assumptions made for the study. The method represents the decisionmaking process, dictating what types of costs to consider and what profitability criteria to apply. The assumptions, which may be tailored to the analysis of a particular policy issue, also ultimately determine the outcome of the analysis. Among the important assumptions of the API study are the outlook for oil and gas prices and normal operating costs, the number of wells that the RCRA changes may affect, and the costs of complying with the new regulations.

Forecasts of Petroleum Prices and Unit Production Costs

The API study bases its evaluation of the profitability of existing wells and the decision of whether to keep producing on the net present value of future cash flow, or net worth, of each group of oil and gas wells. However, specific assumptions of the study contribute to estimates of net worth that may be too low. In particular, the prices and unit costs used by the API for estimating future cash flows may not be consistent with the more relevant market view held by businesses.

The API assumes constant nominal values for future prices and costs, consistent with government reporting requirements for financial disclosure purposes and with common banking practice for evaluating the collateral worth of oil and gas properties. These price and cost assumptions, however, need not match the market's outlook, and it is that market outlook that should be the basis for the industry's investment decisions.

The API may support its assumption of declining real prices and costs as a reasonable industry forecast. At $20 per barrel, the API's assumption for oil prices is consistent with other forecasts for the next two to five years. At $2 per thousand cubic feet, the API's assumption for natural gas is higher than current prices, although it should be higher because the API model ignores the value of natural gas liquids (petroleum liquids extracted from natural gas) in its net worth calculations. In the longer term, however, both oil and gas prices should be expected to increase. CBO believes a more realistic long-term forecast for the analysis would include rising real prices and constant unit costs.[10] At a minimum, an outlook for some price increase would be consistent with the production losses that the API model predicts.

With API's assumption of constant nominal prices, cash flow to existing wells will decline in future years in real terms, both as a result of declining production and of inflation. Compared with any assumption of higher prices, this assumption results in a lower pool of earnings from which companies could pay new costs. The relative profitability of the different well groups is not affected by the assumptions about prices--as the API observes. However, to the extent that the resulting present value of cash flow is too low, any given increase in current year costs--resulting, for example, from new waste management regulations--would make a well group more likely to show a negative present value, or net worth, and stop production too soon. Because of the API's treatment of new wells, lower prices and revenues result in lower drilling levels and lower future reserve additions.

Costs of Compliance and Number of Facilities

The API study concludes that new waste management regulations could have a large negative impact on the oil and gas industry. Several elements of the study's methods contribute to this finding. Probably more important, however, are the study's assumptions concerning the costs of complying with the new regulations and the number of wells that the regulations would affect. With the high compliance costs the API has assumed and its severe regulatory scenario (with all compliance accomplished in the first year), modifying the API model to address CBO's methodological concerns would do little to alter the API's findings.

CBO is not in a position to offer its own opinion on what the correct cost and technical assumptions for the API study should have been. Rather, in this section, specific assumptions about coverage and costs made by the API are compared with estimates presented in a critical review of the API study

10. For example, see Energy Information Administration, *Annual Energy Outlook 1991*, DOE/EIA-0383(91) (March 1991).

by an environmental group, the Southwest Research and Information Center.[11] Some of the Southwest Research estimates may not be comparable, and CBO presents these estimates here without any judgment as to their merit. CBO made no effort to validate the cost assumptions of Southwest Research or API.

Estimates of Unit Costs. Comparing the two sets of estimates of unit costs indicates a basis for believing that the costs of complying with RCRA changes could be much lower than the API assumes (see Table 2). Figures compiled for Southwest Research were based on discussions with state energy offices and private oil and gas service companies, but represent their own assessment.

Among the basic API assumptions that Southwest Research challenges is the characterization of the new law as requiring all individual treatment, storage, and disposal facilities to go through a permitting process, including damage assessment and remediation planning. The great number of sites involved would place a tremendous administrative burden on the Environmental Protection Agency. CBO also believes that a simpler procedure for issuing permits would probably be applied to the oil and gas industry.

Southwest Research also challenges API's estimates of permit fees and the costs of preparing RCRA facility investigations and corrective measures studies. The API's estimates are based on treatment, storage, and disposal facilities currently regulated under Subtitle C. In general these Subtitle C facilities are bigger, handle many more types of wastes, and are much more complex to assess than gas with saltwater disposal (SWD) facilities and gas wells with evaporation/blowdown (EVB) pits. Language in S. 976 would permit the Environmental Protection Agency to establish permit fees commensurate with the government's cost of overseeing the proper management of treatment, disposal, and storage facilities. CBO believes the oversight required for affected SWD and EVB facilities and, hence, the permit fee would be much lower than for facilities that regularly handle large volumes of dangerous substances.

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11. Acacia Environmental Services, Inc., *Review of API-Gruy Study*, prepared for Southwest Research and Information Center (October 3, 1991).

TABLE 2. RCRA COMPLIANCE COSTS FOR SELECTED ITEMS AS ESTIMATED BY THE AMERICAN PETROLEUM INSTITUTE AND SOUTHWEST RESEARCH AND INFORMATION CENTER

Facility or Waste Management Activity	American Petroleum Institute	Southwest Research
Workover Pits		
Closure of existing pits	$25,000	$4,000
Retrofitting workover rigs with tanks	$25,000	$11,000
Disposal of workover wastes (other than nonexempt wastes)	$65 per ton	n.a.
Emergency Pits at Oil Well Tank Batteries		
Closure of existing pits	$25,000	$4,000
New tanks	$25,000 per 500-barrel tank	$11,000 per 500-barrel tank
Emergency Pits at Enhanced Recovery Facilities and Gas Plant Facilities		
Closure of existing pits	$25,000	$12,500
New tanks	$35,000 per 1,000-barrel tank	$20,000 per 1,000-barrel tank
Treatment, Storage, and Disposal Facilities (Saltwater Disposal (SWD) Facilities and Evaporation/Blowdown (EVB) Pits)		
Operational costs for startup		
Closure of emergency pits	$25,000 (SWD and EVB)	$7,500 (SWD); $4,000 (EVB)
New emergency tanks, saltwater tanks, and scrubbers	$35,000 per 1,000-barrel tank; $10,000 per scrubber	$20,000 per 1,000-barrel tank; scrubber cost n.a.
Operational costs	$16,000 (SWD); $11,100 (EVB)	n.a.

(Continued)

TABLE 2. Continued

Facility or Waste Management Activity	American Petroleum Institute	Southwest Research
Treatment, Storage, and Disposal Facilities (Saltwater Disposal (SWD) Facilities and Evaporation/Blowdown (EVB) Pits) (continued)		
Annual operational costs		
Permitting fee	$100,000 (SWD); $2,500 (average EVB)	Issuance of "permits by rule" would lower cost.
Operations, maintenance, and reports	$5,300 per year (SWD); $4,300 per year (EVB)	n.a.
Demonstration of financial assurance	$3,500 per year	n.a.
Initial remediation costs		
RCRA facility investigation (RFI) and corrective measures study (CMS)	$300,000 per RFI; $100,000 per CMS	Costs for Subtitle C treatment facilities, extrapolated by API, are not relevant for SWD and EVB sites.
Corrective action (pumping and treating contaminated groundwater; bioremediation; excavation, disposal, and containment)	Pumping and treating ($5 million per facility); bioremediation ($50 per cubic yard); excavation ($165 per cubic yard)	Soil washing and reinjecting contaminated waters would lower costs.
Groundwater monitoring	$5,100 per facility	n.a.
Continuing remediation costs	$4,900 per year (SWD); $1,900 per year (EVB)	n.a.

(Continued)

TABLE 2. Continued

Facility or Waste Management Activity	American Petroleum Institute	Southwest Research
Disposal of Associated Wastes, All Sites (Other than workover wastes and nonexempt wastes)	\$12 to \$13 per barrel	n.a.
Increased Drilling Costs	Equipment (\$3.61 per foot); waste disposal (\$3.11 per foot)	Drilling with new "closed-loop mud" systems may not be more expensive.

SOURCES: Gruy Engineering Corporation, *Estimates of RCRA Reauthorization Economic Impacts on the Petroleum Extraction Industry*, prepared for the American Petroleum Institute (July 20, 1991); Acacia Environmental Services, Inc., *Review of API-Gruy Study*, prepared for Southwest Research and Information Center (October 3, 1991).

NOTES: n.a. = not available; RCRA = Resource Conservation and Recovery Act.

Number of Facilities Incurring Costs. The assumptions the API makes about how many wells will incur those costs are as important as the estimates of unit costs. The major assumptions affecting coverage are summarized in Box 2.

Several of the API's major assumptions concern how many of the oil and gas facilities that would require permits to continue operating would actually have problems to correct. The API bases the numbers of affected SWD and EVB facilities on the EPA's experience with municipal solid waste landfills. For example, the API assumes that 67 percent of SWD and EVB facilities would need study and corrective action. CBO recognizes the need to make some assumption about the incidence of environmental damage, but the problems of SWD and EVB facilities should bear little resemblance to those of municipal landfills. In the absence of solid information, the API study should stress the arbitrariness of these important assumptions.

Box 2
API ASSUMPTIONS ABOUT THE NUMBER OF WELLS AFFECTED BY RCRA CHANGES

60 percent of all workover rigs need to be retrofitted with tanks (3,200 rigs).

10 percent of oil and gas wells have workover pits to be closed (88,000 wells).

100 percent of oil well tank batteries with emergency pits need to be closed (232,000 tank batteries).

100 percent of all enhanced oil recovery (ER) facilities and gas plants have one emergency pit to be closed (13,600 ER facilities and 870 gas plants).

15 percent of gas wells have evaporation or blowdown pits to be closed (39,000 wells).

50 percent of gas wells with evaporation/blowdown facilities will require scrubbers (20,000 wells).

67 percent of SWD and EVB facilities need RFI and CMS (15,000 SWD and 26,000 EVB).

50 percent of SWD and EVB facilities needing RFI/CMS need excavation, disposal, and containment for saltwater contamination (7,500 SWD and 13,000 EVB).

50 percent of SWD and EVB facilities needing RFI/CMS need bioremediation for hydrocarbon contamination (7,500 SWD and 13,000 EVB).

9 percent of SWD and EVB facilities need pumping and treatment of groundwater (2,000 SWD and 4,000 EVB).

58 percent of SWD and EVB facilities need continuing groundwater monitoring (13,000 SWD and 22,000 EVB).

0.5 percent of SWD and EVB facilities need continuing remediation each year.

SOURCES: Gruy Engineering Corporation, *Estimates of RCRA Reauthorization Economic Impacts on the Petroleum Extraction Industry*, prepared for the American Petroleum Institute (July 20, 1991).

NOTES: RCRA = Resource Conservation and Recovery Act; SWD = saltwater disposal; EVB = evaporation/blowdown; RFI = RCRA facility investigation; CMS = corrective measures study.

TABLE 3. TOTAL FIRST-YEAR COSTS AS ESTIMATED BY THE AMERICAN PETROLEUM INSTITUTE AND SOUTHWEST RESEARCH AND INFORMATION CENTER
(In billions of dollars)

Facility or Waste Management Activity	American Petroleum Institute	Southwest Research
Workover Pits		
Closure of existing pits	2.2	0.4
Retrofitting workover rigs with tanks	0.1	0.04
Emergency Pits at Oil Well Tank Batteries		
Closure of existing pits	5.8	0.9
New tanks	5.8	2.6
Emergency Pits at Enhanced Recovery Facilities and Gas Plant Facilities		
Closure of existing pits	0.4	0.2
New tanks	0.5	0.3
Treatment, Storage, and Disposal Facilities (Saltwater Disposal (SWD) Facilities and Evaporation/Blowdown (EVB) Pits)		
Closure of emergency pits	0.5 (SWD); 1.0 (EVB)	0.3 (SWD); 0.1 (EVB)
New emergency tanks, saltwater tanks, and scrubbers	1.5 (SWD); 1.2 (EVB)	0.8 (SWD); 0.8 (EVB)
Startup operational costs	0.4 (SWD); 0.4 (EVB)	n.a.

(Continued)

TABLE 3. Continued

Facility or Waste Management Activity	American Petroleum Institute	Southwest Research
Treatment, Storage, and Disposal Facilities (Saltwater Disposal (SWD) Facilities and Evaporation/Blowdown (EVB) Pits) (continued)		
RCRA facility investigation and corrective measures study	8.9 (SWD); 5.4 (EVB)	n.a.
Corrective action (pumping and treating contaminated groundwater; bioremediation; excavation, disposal, and containment)	13.0 (SWD); 9.7 (EVB)	n.a.
Total First-Year Costs	56.4	n.a.

SOURCES: Gruy Engineering Corporation, *Estimates of RCRA Reauthorization Economic Impacts on the Petroleum Extraction Industry*, prepared for the American Petroleum Institute (July 20, 1991); Congressional Budget Office based on unit cost estimates presented in Acacia Environmental Services, Inc., *Review of API-Gruy Study*, prepared for Southwest Research and Information Center (October 3, 1991).

NOTE: Items do not add to API total because of rounding.

A few, not unreasonable changes in the API's assumptions can have a major impact on the study's findings. Table 3 (on pages 38 and 39) compares the API's estimates of the initial costs of complying with RCRA changes with estimates based on unit costs reported by Southwest Research. Using these alternative assumptions, costs of closing existing workover pits and emergency pits (at tank batteries, enhanced recovery facilities, and treatment, storage, and disposal facilities) would be $1.9 billion, not $9.9 billion. Total costs for installing new tanks (on workover rigs and at tank batteries, enhanced recovery facilities, and treatment, storage, and disposal facilities) would be only $4.5 billion, not $9.1 billion.[12]

The biggest cost categories, as estimated by the API, are for RCRA facility investigations and corrective measures studies ($14.3 billion) and corrective action ($22.7 billion). If the incidence of environmental contamination at oil and gas sites is lower than that observed for municipal landfills, these estimates would be reduced accordingly. Lower costs of conducting damage assessments or correcting damages would lower these estimates still further.

The API study also estimates that the industry will incur $3.3 billion in annual operating costs. Since $2.2 billion of that sum is for permitting fees, any assumptions that would significantly lower the cost of permits would also significantly lower annual costs.

12. The API cost for new tanks at treatment, storage, and disposal facilities includes emergency tanks, saltwater tanks, and scrubbers.