[JOINT COMMITTEE PRINT]

THE DESIGN OF A WINDFALL PROFIT TAX

PREPARED FOR THE USE OF THE

COMMITTEE ON WAYS AND MEANS

BY THE STAFF OF THE

JOINT COMMITTEE ON TAXATION

JUNE 1, 1979

U.S. GOVERNMENT PRINTING OFFICE

46-135 WASHINGTON : 1979 JCS-19-79

CONTENTS

INTRODUCTION

This pamphlet outlines the various issues which must be resolved in designing a windfall profit tax, such as the tax proposed by President Carter or the tax reported by the Ways and Means Committee in 1974. It lists various ways of handling each issue and some of their advantages and disadvantages.

The first part of the pamphlet summarizes the President's plan for phased decontrol of crude oil prices and his proposed windfall profit tax. (A more detailed description is contained in a pamphlet published on May 7 by the staff.) The second part discusses ten basic issues which arise in designing such a tax. These issues are the tax rate, the treatment of State severance taxes, the tax base, the possibility of limiting taxable windfall profits to net income from each property, the determination of the adjusted base price above which producers' revenues are subject to tax, plowback, filing of returns and deposit of tax liabilities, enforcement, the treatment of windfall profits in determining percentage depletion, and the person liable for the tax.

I. SUMMARY OF ADMINISTRATION PROPOSAL

A. Oil Pricing

Old regulations

Under the old crude oil price control regulations, which were superseded on June 1, 1979, there were essentially four categories of crude oil: lower tier oil, upper tier oil, stripper oil, and Alaskan oil. Lower tier oil was controlled at an average price of about $6 per barrel. Upper tier oil was controlled at an average price of about $13 per barrel. Stripper oil was, and continues to be, statutorily exempt from all price controls. North Slope Alaskan oil, while technically in the upper tier, generally sells below its ceiling price, so that it is effectively uncontrolled. In addition, oil produced on the Naval Petroleum Reserve is exempt from controls.

Under both old and new price control regulations, the status of a particular barrel of oil depends on the property from which it is produced. A property is basically either the right to produce oil from a particular geographical area, arising generally from a lease or some other legal interest, or any separate and distinct producing reservoir which the producer elects to treat as a separate property.

To determine the quantities of upper and lower tier oil on a property under the old regulations, a producer first determined his base production control level (BPCL). This BPCL equaled the lesser of (1) 1972 production of all oil on the property or (2) 1975 production of old oil. If production declined between 1972 and 1975 and dropped below the BPCL after 1975, a producer could subsequently adjust his BPCL downward by applying the 1972–1975 decline rate. Also, if production was first above the BPCL and subsequently dropped below it, any shortfalls led to a "cumulative deficiency." On any nonstripper property, all production up to the level of the adjusted BPCL, plus any cumulative deficiency, was defined as lower tier oil; all remaining production was upper tier oil. Stripper oil is any production from a property whose average production was less than 10 barrels per well per day for any consecutive 12-month period since 1972.

New regulations

The new Department of Energy price regulations phase out these controls by September 30, 1981, when legal authority to control oil prices expires; but in the interim several new categories of oil will be established. Upper and lower tier oil will be redefined, and there will be special provisions for newly discovered oil, incremental production from tertiary recovery, marginal properties, and "up front money" for tertiary recovery projects.

Under the new regulations, the lower tier ceiling price will stay approximately where it is now, adjusted only for inflation. The upper tier price, starting January 1, 1980, will be raised on a path designed

to take it to the world price by September 30, 1981, although the details of this path have not been finalized.

Newly discovered oil is deregulated on June 1, 1979. This oil is defined as all production on a property from which no oil was produced in 1978. Incremental production from tertiary recovery is also being deregulated. This incremental production is any production obtained from a property using approved tertiary recovery techniques that is in excess of an estimate of what that property could have produced using nontertiary methods.

Under the new pricing regulations for properties which are neither stripper, newly discovered nor marginal producers will recompute their BPCLs and adjust them in a manner designed to phase out the lower tier by October 1, 1981. The new BPCLs will equal average production in the six months ending March 31, 1979. Further, producers will adjust this BPCL downward by 1½ percent per month in 1979 and 3 percent per month in 1980 and the first 9 months of 1981. Starting on June 1, 1979, lower tier oil is defined as production below this new adjusted BPCL.

Marginal properties, defined according to average well depth and average production per well, will be released to the upper tier more quickly. On June 1, 1979, their BPCL becomes 20 percent of average production in the last six months of 1978; and on January 1, 1980, all oil from marginal properties goes to the upper tier. Also, where approved tertiary recovery projects will be undertaken, additional quantities of lower tier oil may be released to the upper tier to provide "up front money."

All price controls will expire on September 30, 1981.

B. Windfall Profit Tax

The Administration's proposed windfall profit tax is substantially embodied in H.R. 3919, introduced by Chairman Ullman.

Under Chairman Ullman's bill, the windfall profit tax would operate as follows: Crude oil produced in the United States would be taxed in one of three tiers. The tier one tax rate would be 50 percent of the difference between the actual selling price of the oil and the current lower tier, or old oil, ceiling price (now just under $6 per barrel) adjusted for inflation. The tier two tax rate would equal 50 percent of the difference between the actual selling price and the current upper tier, or new oil, ceiling price (now about $13 per barrel) adjusted for inflation. The tier three tax rate would equal 50 percent of the difference between the actual selling price and a base price, adjusted for inflation. A schedule of tier three base prices for various classifications of oil would be issued by the Secretary of the Treasury based on what oil of a particular quality and location would command at the wellhead if the average landed price of crude oil were $16 per barrel, the U.S. price corresponding to the $14.55 price (f.o.b. Saudi Arabia) announced by OPEC just prior to the Iranian revolution. (For the tier three base price, the Administration had proposed a flat $16, regardless of quality or location.)

The tier one rate would apply to oil produced on a property below a statutory decline curve. The quantity of oil subject to the tier one tax rate would equal the average daily amount of oil produced on the property in the period October 1978–March 1979 (the BPCL) reduced by 1.5 percent per month in 1979 and 2 percent per month thereafter. This decline rate would cause the tier one tax rate to be phased out by the end of May 1983. Because the lower tier is being phased out for pricing purposes using a 3-percent monthly decline rate, the oil subject to the tier one tax would be oil above the 2-percent line but below the 3-percent line. (See figure 1 in which the shaded area represents the tier one tax base.)

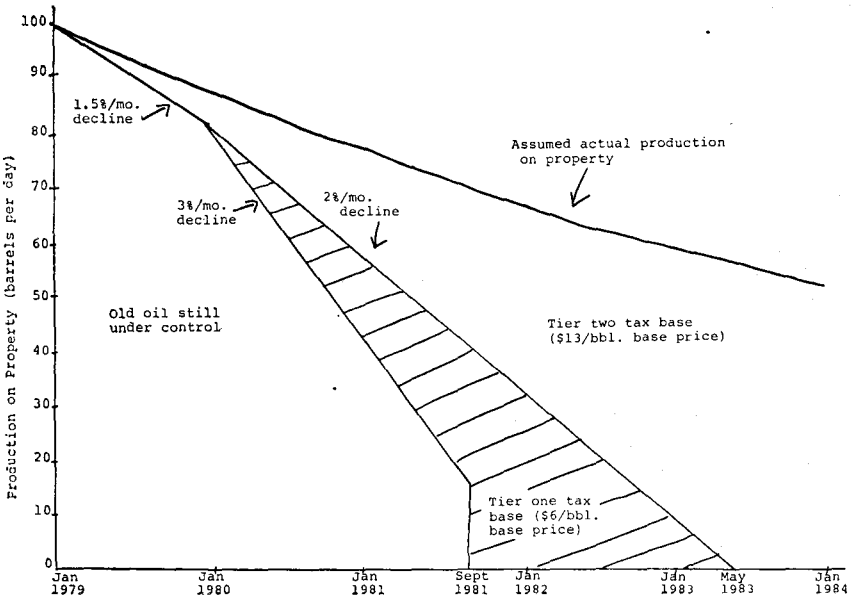
The tier two tax rate would apply to oil from marginal properties (defined according to average well depth and average production per well) and oil produced on a nonmarginal property in excess of the amount indicated by the 2-percent tier one decline curve. This tax rate would phase out between 1986 and the end of 1990 through an upward adjustment of the tier two base price.

The tier three rate would apply to all oil, other than oil produced north of the Arctic Circle, which is not subject to tax under either of the other tiers. This tier would initially include newly discovered oil, stripper oil and oil produced as a result of tertiary recovery. After 1990, tier three would include all oil other than exempt Alaskan oil.

The tax would be a deductible business expense under the income tax. In addition, gross income for purposes of determining percentage depletion would be reduced by the amount of windfall profits subject to the tax. State severance taxes would not be deducted in computing the taxable windfall profit.

46-135 O - 79 - 2

Figure 1.--Determination of Tier One and Tier Two Tax Base on Nonmarginal Property



The revenues from the windfall profit tax would be dedicated to an Energy Trust Fund which also would be established by the legislation. In general, the proposed Energy Trust Fund would be structured in a manner similar to existing trust funds which receive specifically dedicated excise taxes, such as the Highway Trust Fund.

The tax would be effective on January 1, 1980.

II. ISSUES IN DESIGNING A WINDFALL PROFIT TAX

Designing a windfall profit tax similar to the one proposed by the Administration involves making decisions about numerous issues, some relatively technical and others having significant revenue and economic impacts. The following discussion attempts to list the principal issues which the committee will have to decide in marking up a windfall profit tax. It explains how the Ullman bill, H.R. 3919, resolves these issues, the technical ways in which H.R. 3919 differs from the Administration proposal, solutions proposed in other windfall profit tax bills, alternative solutions, and some of the advantages and disadvantages of the various options. The issues discussed are the tax rate, the treatment of State severance taxes, the tax base, the limitation of taxable windfall profits on a property to net income, the determination of the adjusted base prices above which revenues are subject to tax, plowback, the filing of returns and deposit of taxes, enforcement, the treatment of windfall profits in determining percentage depletion, and the persons liable for tax.

A. Tax Rate

The Administration has proposed a tax rate of 50 percent on price increases above the base price applicable to the barrel of oil being taxed. (The base prices average $6 per barrel for tier one, $13 for tier two, and $16 for tier three, and they are adjusted for inflation.) The appropriate tax rate depends, among other things, on the other State and Federal taxes levied on additional producer revenues, the treatment of State severance taxes in calculating taxable windfall profits (discussed in section B below), the base to which the windfall profit tax is to be applied (discussed in section C below), and the impact of the total tax burden on oil production.

The same amount of revenue can be raised from a windfall profit tax either with a broad base and low rate or with a narrower base and a higher rate. (Depending on which year is being considered, the Administration's proposed tax would apply to a base representing between 55 and 70 percent of the overall increase in gross revenue resulting from oil price deregulation and future OPEC price increases.) Whether a high rate, narrow base approach is preferable to a low rate, broad base approach depends on the extent to which the Committee thinks it can isolate particular categories of oil (for example, newly discovered oil) whose production would be especially responsive to a lower windfall tax rate.

There has been considerable dispute over just what fraction of the additional gross revenue to oil producers and royaltyholders resulting from oil price deregulation and future OPEC price increases (i.e., increase above the $16 landed price announced last year for 1979) will be absorbed by higher Federal and State taxes and what fraction will be retained by oil producers and royalty owners. The division of the proceeds from these oil price increases will depend on a number of variables: the rate of any windfall profit tax, the extent of its base, the marginal income tax rate applicable to the producer or royaltyholder, and the rates of applicable State income and severance taxes.

For example, with a 50-percent windfall profit tax applied to a comprehensive base (i.e., all producer and royaltyholder revenues resulting from deregulation and future OPEC price increases) and a Federal income tax rate of 45 percent (approximately the marginal rate paid by producers and royaltyholders), the net income to producers and royaltyholders from a $1.00 windfall profit could be estimated as follows:

Gross income to producers and royaltyholders	$1.00
Less:	
State severance tax (assume 5 percent rate)[1]	−.05
Windfall profit tax	−.50
State income tax (assume 4 percent rate)	−.02
Federal income tax (assume 45 percent tax rate)	−.19
Net income to producers and royaltyholders	.24

[1] This represents an average for the entire country; the actual rate varies from State to State.

However, the result that producers and royaltyholders would keep only 24 cents out of each dollar of windfall profits is very sensitive to the assumptions underlying it.

If, for example, the base of the windfall profit tax is only 60 percent of a comprehensive base, which is approximately the situation under the Administration's proposal in an average year, the net income to producers and royaltyholders would rise from 24 cents to 35 cents:

Gross income to producers and royaltyholders	$1.00
Less:	
State severance tax	−.05
Windfall profit tax	−.30
State income tax	−.03
Federal income tax [2]	−.27
Net income to producers and royaltyholders	.35

[2] This calculation takes into account the fact that percentage depletion would not be allowed on the windfall profit subject to tax but would be allowed on any gross income not subject to windfall profit tax because the tax base is not comprehensive.

Also, if producers and royaltyholders reinvest their entire windfall profit in drilling expenses which are deductible under the income tax in the year incurred, such as dry hole or intangible drilling costs, the State and Federal income taxes would be zero, and their net income, under the less comprehensive windfall tax base, would be 65 cents. Net income would be computed as follows:

Gross income to producers and royaltyholders	$1.00
Less:	
State severance tax	−.05
Windfall profit tax	−.30
Net income to producers and royaltyholders	.65

Thus, depending on what is assumed about reinvestment and the comprehensiveness of the tax base, the net income to producers and royaltyholders under a 50-percent windfall profit tax could range anywhere between 24 and 65 cents out of each dollar of windfall profit.

Table 1 presents a range of estimates of the net income to producers and royaltyholders after State and Federal taxes under various assumptions about the windfall profit tax rate, its tax base and what fraction of income would be reinvested in deductible expenses. For example, assuming 50-percent reinvestment and a base equal to 60 percent of a comprehensive base, an increase in the tax rate from 50 percent to 75 percent would reduce the net income to producers and royaltyholders resulting from a $1.00 windfall profit from 51 cents to 39 cents.

The entries in table 1 closest to the Administration's proposal are probably the 50-percent rate, a base of 60 percent of windfall profits and either 25-percent or 50-percent reinvestment in deductible expenses. Thus, under that proposal, oil producers and royaltyholders would get an average of between 43 cents and 51 cents of net income out of each dollar of profit from oil price-deregulation and future OPEC price increases. Of course, for any particular producer the result could differ, depending on his tax bracket, State tax rates and reinvestment plans.

TABLE 1.—NET INCOME TO PRODUCERS AND ROYALTY OWNERS FROM A $1 WINDFALL PROFIT

Windfall tax rate and base	Assumed reinvestment in deductible expenses (percent)				
	0	25	50	75	100
Comprehensive base:					
0 percent rate	$0.50	$0.61	$0.73	$0.84	$0.95
25 percent rate	.37	.45	.53	.62	.70
50 percent rate	.24	.29	.34	.40	.45
75 percent rate	.11	.13	.15	.18	.20
Base of 60 percent of windfall profit:					
0 percent rate	.51	.62	.74	.85	.95
25 percent rate	.43	.53	.62	.72	.80
50 percent rate	.35	.43	.51	.58	.65
75 percent rate	.27	.33	.39	.45	.50

Note.—Assumes 5-percent severance tax rate, 4-percent State income tax rate, 45-percent Federal income tax rate applied to taxable income. Percentage depletion is denied on windfall profit subject to tax and allowed on any windfall profit not subject to tax. (The various existing limitations on percentage depletion are assumed to reduce its effective rate to 5 percent of gross income.) Reinvestment percentages refer to the percentage of gross income after severance and windfall profit tax which is reinvested in expenses which can be deducted currently under Federal and State income taxes. Severance taxes and income taxes are assumed not to be deductible under the windfall profit tax.

B. Treatment of State Severance Taxes

Various States impose severance or production taxes on the extraction of oil. These taxes may be imposed either on each unit of production as a fixed fee per barrel or as a percentage of the value of each barrel.

Severance taxes generally are imposed on the owners of the various interests in a property (i.e., the operator, other investors, royaltyholders, etc.). However, the taxes normally are paid by the first purchaser of the oil, who withholds the tax from the amount paid to the producer and royaltyholders. For Federal income tax purposes, the amount of severance taxes is included in the producer's or royaltyholder's gross income from the property, and an offsetting deduction for the severance tax is permitted.

In considering the treatment of severance taxes under the windfall profit tax, the Committee has three basic choices. First, the Committee could decide not to provide for a reduction of the taxable windfall profit by the amount of severance taxes paid on oil subject to the windfall tax. This is the position taken by the Administration and followed in H.R. 3919. Proponents of this view argue that at a rate similar to the 50-percent rate of tax imposed by H.R. 3919, no undue burden is placed on the owners of oil by denying them an adjustment for the additional severance taxes paid on the higher price; that is, by having the producer and royaltyholders pay the State severance tax out of the share of the windfall profit remaining after payment of the windfall profit tax.

Further, it is argued that because, under this policy, the owners of oil must absorb any increase in severance taxes themselves, States are encouraged to exercise moderation in their taxing decisions. Denial of any deduction for severance taxes in computing taxable windfall profits may be criticized, however, on the grounds that amounts paid to the States as severance tax are not really windfall profits to the producers and royaltyholders.

Second, the Committee could reduce the windfall profit subject to tax by all increases in severance taxes in excess of the severance taxes that would have been imposed on the oil prior to decontrol (e.g., at rates prevailing in May 1979). This is the approach taken in H.R. 3474 (introduced by Mr. Conable). Advocates of this total exemption of severance tax increases from the windfall profit tax note that amounts collected by State governments do not constitute profits to the owner of the oil. Further, permitting severance taxes to reduce the amount subject to the windfall profit tax is felt to be consistent with the long recognized deductibility of severance taxes under the Federal income tax. Permitting an adjustment for all severance tax increases without limit, however, could cause States to increase their severance taxes, because a significant fraction of such additional tax payments by producers would be offset by lower Federal income and windfall profit

taxes. Such action by the States would transfer the windfall profit tax revenues from the U.S. Treasury to the treasuries of the oil-producing States.

Third, the Committee could reduce the windfall profit subject to tax by the amount of the increase in severance taxes that results from the rising value of oil, but not from an increase in the *rate* of the severance tax above the rate in effect on (say), March 31, 1979. This is the position taken in H.R. 3421 (introduced by Mr. Cotter) and H.R. 4079 (introduced by Mr. Stark). It also was adopted by the Committee in 1974, when it reported a windfall profit tax with an 85-percent top tax rate. Supporters of this approach point out that when the windfall profit tax is imposed at relatively high rates, it is necessary to adjust for some severance tax increases to avoid having the Federal and State taxes on the windfall profit exceed 100 percent in the States with high severance tax rates. (Louisiana's 12½ percent rate is the highest). In addition, limiting the adjustment to one that takes into account only those severance tax increases that reflect the increasing price of decontrolled oil, but not future tax rate increases, eliminates any encouragement to States to increase the rates of their severance taxes.

At very high windfall tax rates (e.g., above 75 percent), a deduction for severance taxes at rates existing on (say) March 31 clearly seems necessary to avoid exceedingly high combined tax rates. At lower windfall tax rates, it is primarily a question of how to distribute a given windfall tax burden among producers and royalty owners in the various producing States. The same amount of tax revenue can be raised either by a 50-percent rate and no severance tax deduction or by a 53-percent tax rate and a deduction for increases in severance taxes. Under the latter alternative, less windfall profit tax would be collected from producers in States with relatively high severance taxes (e.g., Louisiana and Alaska) and more from producers in States with relatively low rates (e.g., California and Wyoming).

C. Tax Base

Decline rate

Overview

The windfall profit tax base is the price received for the oil minus an inflation-adjusted base price, which is different for each of the three tiers of oil. For tier one, the base price is the lower tier ceiling price. For tier two it is the upper tier ceiling price. For tier three the base price averages $16. Under a "comprehensive" windfall profit tax, tier one would include all oil controlled as lower tier oil prior to June 1, 1979; tier two would include all oil controlled as upper tier oil prior to June 1, 1979; and tier three would include all remaining oil. However, the Administration's proposed tax base is narrower than this comprehensive base. This section examines the various deviations between the Administration's tax base and a comprehensive base.

Oil is a depletable resource, which means that production from a well or a property tends to decline over time. Thus, any tax or price control which exempts newly discovered oil will gradually phase itself out over time as the amount of old oil declines and newly discovered oil becomes a larger portion of total supply.

Rather than allowing geological forces to phase out distinctions between old and new oil, it is possible to phase them out through a statutory decline curve. This involves choosing a base period and assuming a statutory decline rate. Production above the resulting decline curve can be given relatively favorable price or tax treatment; production below the amount indicated by the decline curve can be given less favorable treatment. The advantage to this approach of phasing out a tax or price control is that, for producers whose production exceeds the decline curve, increases or small decreases in production command the more favorable price or tax treatment, and incentives to produce are maximized despite the existence of a tax or price control on much of the production. In contrast, phasing out a tax by simply lowering the rate gradually, or phasing out a price control by gradually raising the ceiling price, would provide an incentive to defer production until the phaseout is complete (perhaps by postponing investments which would temporarily increase or maintain production). For this reason, questions have arisen about the method chosen by DOE to phase out the upper tier price control by raising the base price rapidly in 1980 and 1981.

A statutory decline curve is a mechanism for attempting to reflect at a fixed or regular rate the natural, but generally irregular, decrease over time in the level of oil production from a well or a property. A "historic" decline curve is one that is based on the production experience of a particular well or property during a specified time period. Such a curve estimates expected future decreases in production by projecting the historic decline rate forward in time. Generally, once an historic curve is established, no subsequent adjustments are made to the projected rate of decline to reconcile it with the actual production

46-135 O - 79 - 3

level of the well or property. As a result, the actual production of any well or property at any point in time may be above or below the level indicated by its historic decline curve for the same point in time.

Because a property's oil producing capability generally depends upon a number of factors, including its location, the type of equipment and recovery processes employed, and its geological characteristics, the actual (as well as the historic) decline rates of dissimilar properties and projects frequently will vary by a significant amount. Also, decline rates vary not only from field to field but also from year to year for a given oil field.

For U.S. old oil, the average decline rate was about 0.95 percent per month between 1972 and 1975. However, in recent years the decline appears to have accelerated to about 1.1 percent per month, an increase which some have attributed to price controls on old oil. There is a good deal of variation around those averages, and actual decline rates vary from about one-half percent per month to 1½ percent per month.

Price control regulations

In the case of properties which produced oil during or before 1972, i.e., properties with "lower tier" or "old" oil, price control regulations have used concepts similar to a statutory decline curve since 1973. Initially, the base level of production, below which production was controlled as "old oil," (called the base production control level, or BPCL) was production in the corresponding month in 1972, with no downward adjustment. However, it was recognized that this method did not allow for the natural decline in production, which was causing producers of old oil to sink below their 1972 production. Therefore, in 1976, the regulations were changed to update the BPCL to either 1972 or 1975 production, whichever was more favorable to the producer, and certain properties were permitted to adjust their BPCL downward to project the 1972–75 rate of production decline on the property.

Specifically, under the old DOE regulations, the downward adjustments to the BPCL worked as follows: If production from the property during the five-month period between February and July 1976 was less than the BPCL during that period, the property qualified for a downward BPCL adjustment beginning July 1, 1976. If upper tier oil was produced between February and July 1976, the property could not qualify for a downward adjustment to its BPCL until the first six-month period following the six-month period in which its total production fell below the BPCL.[3] Once the property qualified for a BPCL adjustment, the producer could adjust the BPCL every six months on the basis of the property's historic 1972–75 decline rate. Oil actually produced in excess of the adjusted BPCL generally was classified as "upper tier," "second tier," or "new" oil, and was entitled to receive the upper-tier price.[4]

---

[3] 10 C.F.R. sec. 212.76(a)(2).

[4] Once a property produced an amount of oil above its adjusted BPCL, if it subsequently produced an amount of oil below the level of its adjusted BPCL, the difference between the reduced amount and the adjusted BPCL resulted in a "cumulative deficiency." Before a property's production in excess of its adjusted BPCL could be classified as upper tier oil, any amount of oil by which the property fell below its BPCL for all prior months, i.e., its cumulative deficiency, had to be eliminated or "paid back."

Recent regulatory changes

Pursuant to a rule published by the Economic Regulatory Administration of DOE on April 12, 1979, a producer may elect to have the BPCL for any property be the average monthly production of lower tier oil from the property for the six-month period ending March 31, 1979. For properties for which the producer elects to use this BPCL, the BPCL is reduced by 1.5 percent per month for 1979. The first such adjustment is effective as of June 1, 1979, but will be calculated as if the adjustments had become effective January 1, 1979. Thus, if an election is made for a property, its BPCL is reduced by 9 percent, effective June 1, 1979 (six months x 1.5 percent).

Effective June 1, 1979, the rule eliminates all cumulative deficiencies.

On January 1, 1980, the BPCL decline rate generally would be increased from 1.5 percent per month to 3 percent. The 3-percent decline factor applicable to 1980 and 1981 is available for all properties, including those electing not to use the updated BPCL in 1979.

The effect of this decline curve is to phase out the lower tier of price controls so that relatively little lower tier oil (19 percent of the BPCL) will remain just before price controls expire on September 30, 1981.

As discussed below, this rule also would remove all oil produced from "marginal properties" from the lower tier by January 1, 1980. This action alone would affect an estimated 616,000 barrels of daily production from about 39,300 wells on 7,150 properties.[5]

Windfall profit tax

Under the Administration's proposal the amount of production of lower tier oil released to the upper-tier, and represented by the difference between the 3-percent price control decline curve and a less accelerated 2-percent tax decline curve, would be subject to the windfall profit tax on the difference between the inflation-adjusted May 1979 lower tier ceiling price (averaging about $6 per barrel) and the wellhead price. Lower tier oil released to the upper tier in excess of the 2-percent decline curve would be subject to the tax only on the difference between the inflation-adjusted May 1979 upper tier ceiling price (averaging about $13 per barrel) and its wellhead price. Under the April 12, 1979, DOE rule, lower tier oil produced from marginal properties also would be removed from the tier one tax base. Figure 1, above, shows the determination of tier one and tier two oil on a nonmarginal property.

Considerations

The windfall profit tax base could be expanded by modifying the decline curve used for computing the tier one tax base. Tier one taxable oil, for example, could be defined to include the entire gap between the production estimated by projecting the property's historic decline rate and the 3-percent DOE decline curve, rather than only the difference between the 3-percent price decline curve and a 2-percent curve. This approach is used in H.R. 3421 (Mr. Cotter) and H.R. 4079 (Mr. Stark). Such a change could be administered without a sizable

---

[5] Dept. of Energy, Econ. Reg. Admin., *Final Regulatory Analysis of Final Rule Adopting Production Incentives for Marginal Properties (April 1979).*

increase in paperwork or complexity since many producers currently must maintain records which verify the adjusted BPCL's and historic decline rates for their properties. (Overlapping recordkeeping, attributable to the difference between the tax and price control decline curves, would exist regardless of whether the proposed 2-percent tax decline rate is modified.)

Use of a historical decline rate for each property, rather than one statutory 2-percent rate for all properties, would take some account of the variation in natural decline rates among properties. However, natural decline rates vary not only across properties but also for a particular property from one year to the next. Those properies which had an unusually rapid decline between 1972 and 1975 have already benefited from the choice of that particular period under price controls, and its continued use in a tax could compound inequities which already exist under price controls. Thus, in view of the yearly variation in natural decline rates for particular properties, use of a uniform statutory decline rate is probably more appropriate. Also, use of a historical rate penalizes those companies who made investments to try to maintain production during the 1972–75 period of oil shortage.

The 2-percent rate chosen by the Administration is faster than the natural decline rate of virtually all oil fields. It results in a narrow tier one tax base, which consists only of the gap between the 3-percent price control decline curve and the 2-percent tax decline curve. A slower statutory decline rate could increase the tax base significantly; however, if the statutory decline rate were reduced below about 1½ percent, there would be properties producing below their decline curves, and some producers would no longer be in a situation in which increments to production affect only the amount of oil subject to the more favorable tier two tax rate. As the decline rate is lowered below 1½ percent, this would be the situation with more and more properties. Thus, the tradeoff is between revenue and production incentives.

Lower linear decline rates also would postpone the phaseout of the tier one tax rate which would occur in May 1983 under a 2-percent decline curve, in July 1984 with a 1½ percent decline curve and in April 1987 with a 1-percent decline curve. Use of a "declining balance" concept, in which the decline rate is applied, not to the original BPCL, but to the prior month's adjusted BPCL, as is done under the old price control regulations and under H.R. 3421 and 4079, would mean that the tier one tax rate would not phase out fully until all lower tier oil were depleted or declined into stripper or marginal status.

An alternative to broadening the tier one tax base through a lower decline rate would be raising the tax rate on a narrower base. The narrow-base, high rate approach would have the advantage of keeping more properties above their BPCL's. However, it could lead to quite high combined rates of windfall, income and severance taxes. (See Table 1, above.)

Marginal properties

Under a DOE rule published on April 12, 1979, oil produced from "marginal properties" would be categorized as a new classification of

oil generally eligible to receive upper tier prices. Specific properties,[6] rather than individual wells, could qualify as "marginal," depending upon the production level at different well depths. A property would qualify as marginal if, for calendar year 1978, the average completion depth of all the property's producing wells and the average daily per well production from the property meet the following limits:[7]

Average depth (in feet)	*Average daily production (in barrels)*
2,000, but less than 4,000	20 or less.
4,000, but less than 6,000	25 or less.
6,000, but less than 8,000	30 or less.
8,000 or more	35 or less.

To determine the average completion depth of all wells that produce crude oil on the property during the qualifying period, the producer must divide the sum of the completion depths for all wells by the number of those wells. For this purpose, injection wells and other wells that did not produce crude oil during the period may not be taken into account. Similarly, if a well produced crude oil during the qualifying period from two or more completion depths at the same time, the well may not be counted as two or more wells, and the various completion depths may not be averaged, unless the well consisted of two or more separate tubing strings running inside the casing, and the production capability of each formation that is tapped is unaffected by any change in the production level of any other formation producing through the same well. In addition, adjustments to the average daily production would have to be made to account for any well which was not operated at the maximum efficient rate of produc-

[6] Under DOE regulations, a "property" is the right to produce domestic crude oil which arises from a lease or a fee interest. Alternatively, a producer may treat as a separate property each separate and distince producing reservoir subject to the same rights to produce crude oil provided that the reservoir is recognized by the appropriate government regulatory authority as a producing formation that is separate and distinct from, and not in communication with, any other producing formation. Thus, the price control definition of "property" may include smaller subdivisions than the income tax definition of that term contained in section 614 of the Code. The price control definition of "property" also may result in some administrative problems where a single well has different completion depths and produces crude oil from separate reservoirs located at each of those depths. Under the DOE regulations, such a well could constitute more than one property.

[7] This definition essentially is the same as that used in the Texas conservation statute; however, the Texas law applies on a well-by-well basis, not property-by-property.

During its consideration of H.R. 5263 in the 95th Congress, the Senate rejected a motion to table an amendment which would have exempted marginal well production from price controls. The amendment was withdrawn, however, to expedite the passage of the bill.

During its consideration of H.R. 7014 in the 94th Congress, the House adopted an amendment which would have exempted from price controls production from marginal wells. Under the amendment, "marginal wells" would have been defined similarly to the definition of "marginal properties" contained in the recently published DOE regulations, although on a well-by-well basis. Under the House amendment only wells incapable of producing at their maximum capacity except by pumping, gas lift, or other artificial means could have qualified as "marginal." The House finally substituted a Senate bill for its version of the bill.

tion in accordance with recognized conservation practices, or was curtailed significantly by reason of mechanical failure or other disruption in production. The regulations are unclear about how the various wells are to be weighted in computing the average in cases where some wells failed to produce at the maximum efficient rate for the whole year.

Marginal properties are estimated to be about one-fourth of lower tier oil; however, some analysts have suggested that this estimate is too low.

On June 1, 1979, for pricing purposes the BPCL for a marginal property will be 20 percent of the average monthly production of lower tier oil from that property for the last six months of 1978, and the BPLC for marginal properties will be reduced to zero as of January 1, 1980. Hence, after June 1, 1979, all production on a marginal property in excess of 20 percent of 1978 production from the property may be sold at the upper tier price. On January 1, 1980, all oil from marginal properties is eligible for the upper tier price. Meanwhile this upper tier price will be moved up to the world price between January 1, 1980, and September 30, 1981.

DOE's establishment of a marginal property category, the oil production from which is entitled to receive upper tier prices, effectively would allow 25 percent, and possibly more, of all lower tier oil to be eligible for upper tier prices as of January 1, 1980. Under H.R. 3919, and the Administration's proposal, a windfall profit tax would be imposed upon oil production from marginal properties only on the difference between the wellhead sale price and the inflation-adjusted upper tier price, rather than upon the difference between the wellhead price and the inflation-adjusted lower tier price to which that production would have been entitled in the absence of the DOE reclassification of this production. Thus, the special treatment of marginal properties results in a significant decrease in the amount of oil taxed at the tier one tax rate.

The theory behind reducing the windfall profit tax on "marginal properties" is that lifting costs increase with well depth, and that a higher after-tax price is needed to keep these properties in production. The question appears to be "how much higher?" At a world price of $18, compared to a current lower tier price of $6, oil taxed in the first tier will pay a $6 tax and will experience a price increase from $6 to $12 ($18 price minus $6 tax). If the property is profitable, which the truly marginal ones are not, there are also State and Federal income taxes. Also, there is a State severance tax on the $18 price. If such a property were taxed in tier two on a $13 base, the tax would be $2.50 and the net after-tax price would be $15.50 ($18 minus $2.50) minus the severance tax.

Under the Administration's proposal, there is no requirement that a producer establish that production on a property would be uneconomic in order to have it certified as "marginal." Also, the provision in H.R. 3919 limiting the taxable windfall profit to net income from a property provides some relief for truly marginal properties where costs exceed price. (See section I below.)

If the Committee believes that putting all marginal oil in tier two of the tax is too generous, it could put that oil in tier one under the generally applicable decline curve or give marginal oil an especially rapid decline rate.

If there is to be a special category for marginal oil, a second issue is whether any definition of marginal oil should be property-by-property, as proposed by the Administration, or well-by-well, as in Texas. (Similarly, Louisiana has a severance tax abatement determined on a well-by-well basis.)

Some of the high costs of these properties clearly are related to specific wells (e.g., direct lifting costs), but others are related to the entire property (e.g., secondary recovery costs).

The DOE test for establishing whether a "property" is marginal may be difficult to administer and enforce in some cases due to the DOE definition of the term "property." For example, under DOE rulings and regulations, a "property" may be a separate producing reservoir which is distinct from, and not in communication with, any other producing formation. Under this definition, a particular well could be tapping several different "properties" if the well had various different completion depths and locations. (Multiple completion locations are relatively common.) In the absence of individual production stringers and metering equipment installed in the well for each completion location, which function to register the flow of production from that level, it is virtually impossible for a producer to determine the amount or level of production from each single producing reservoir. Producers would generally have had little reason to install such an elaborate system of metering equipment in previously drilled wells. As a result, if a well has several completion locations which tap into distinct reservoirs, producers may not be able to determine with any degree of certainty the effect of a particular wells' production level on each property's potential classification as marginal. Thus, such a multiple completion well could not be properly taken into account for purposes of qualifying a property as being marginal.

However, there are also administrative problems with the well-by-well approach. Except in States, like Texas, which have laws based on production of a particular well, there is no reason why producers would have kept records of their well-by-well production for 1978 (the base period for determining whether a property is marginal).

The marginal property definition may create an incentive for producers to transfer a portion of their property to qualify the transferred portion as marginal. If, for calendar year 1978, the average completion depth and the average daily per well production of all the property's producing wells did not meet the DOE standard pertaining to marginal properties, but the depth and per well production of part of the property did meet it, then it might be possible to transfer the qualifying portion to someone else and establish a new property which apparently might qualify as being marginal. To prevent such gerrymandering of existing properties, property lines could be frozen as of a specific date in 1979; that is, whether a particular well belongs to a property which is marginal would be determined irrevocably by its status in 1978, regardless of future transfers.

If the category of marginal "properties" is retained, rather than substituting a marginal "well" definition, then it would be necessary to define more precisely what is meant by "producing wells" for purposes of determining the average daily per well production from the property. The price control regulations count wells in production for only part of the year, but use their average daily production over the days

they were in production. Also, the regulations measure a well's production at its maximum efficient rate. An alternative would be to include only those wells on the property whose production has been maintained for the entire year in question at the maximum efficient rate of production which is consistent with recognized conservation practices, and which have not been curtailed significantly by reason of mechanical failure or other disruption in production. This alternative definition would exclude wells which produced for a minor number of days during calendar year 1978, and would exclude, of course, nonproductive input and injection wells. However, it would not resolve the question of whether, or how, to take into account wells which produced for a substantial part of the year, but not for all of it. Some method of computing a weighted average is needed.

Alaskan Oil

Overview

Oil produced from wells located north of the Arctic Circle, like most other domestic production from a property which commenced production after 1972, is permitted to be priced at the upper tier ceiling price under existing DOE price regulations applicable to the first sale of domestic crude oil. Although technically it is controlled as upper tier oil, oil produced from wells located north of the Arctic Circle sells at a market price below its ceiling price. In 1978, when the price of uncontrolled stripper oil was $14 per barrel and Alaska's upper tier price was about $12 per barrel, Alaskan oil sold for approximately $5.25 per barrel at the wellhead.

Essentially, the wellhead price for Alaskan oil will equal the price at which the oil can be sold to a refiner in the lower 48 States (or abroad, if the law is changed to permit export of Alaskan oil), minus the transportation costs from the wellhead to the refinery, principally the tariff imposed by the Trans-Alaskan Pipeline System (TAPS) and various marine and tanker charges. The TAPS tariff is determined by the appropriate regulatory commissions, the Alaskan Pipeline Commission, the Interstate Commerce Commission, and the Federal Energy Regulatory Commission (FERC). Presently, the TAPS tariff ranges from $6.04 to $6.44 per barrel.[8] Shipping costs to West Coast and Gulf refineries currently range up to $2.00 or $3.00 per barrel. (Apparently, a small amount of Alaskan oil is even being shipped all the way to Exxon's New Jersey refinery.)

---

[8] These rates are imposed only on an interim basis, and are subject to potential refund with interest, pending the outcome of rate-of-return proceedings. In this proceeding, the FERC is contending that the TAPS tariff should be based on the cost of the pipeline plus a reasonable rate-of-return, estimated to be approximately $4.25 per barrel. The pipeline owners contend, however, that the tariff should be based on a higher figure. Under the FERC's theory of the proceeding, items such as the investment tax credit and accelerated depreciation would be treated as a cost-of-service item to the pipeline company. As such, these items would be credited to the cost-of-service, and thereby reduce the tariff imposed. Under a cost-of-service theory, the tariff would decrease over time as the pipeline company's investment is recouped. Similarly, if the capacity of the TAPS line were to be increased to its maximum of 2 million barrels per day, the various costs of augmenting its capacity would be included in its rate base and thereby increase the total tariff, although the per-barrel tariff could decline because these costs would be spread over a larger volume of oil. It is estimated that the rate-of-return proceeding will not be concluded for about 1½ years.

Thus, Alaskan oil sells at the wellhead for about $8–$9 less than the price of uncontrolled oil in the lower 48 States. So far, this price differential resulting from transportation costs has kept Alaskan oil's wellhead price well below its upper tier ceiling price. However, several forces could raise the wellhead price up to the current ceiling price. If the world oil price rises to about $22 per barrel, Alaskan oil would go up to its ceiling price. Also, if the pipeline tariff were reduced, the wellhead price to the producer would rise correspondingly.

The wellhead price obtained for oil produced north of the Arctic Circle has been subject to inclusion in the determination of the legal composite price for oil which, until June 1, 1979, restricted the extent to which DOE could raise wellhead prices. For purposes of the entitlements program, oil produced from north of the Arctic Circle is considered to be imported oil.

The Prudhoe Bay area of Alaska's North Slope has three known oil formations, Lisburne, Sadlerochit, and Kuparuk.[9] To some extent, the first and last of these formations lie about and below Sadlerochit, which is by far the largest of the formations. The Kuparuk zone has an average depth of about 8,000 feet, the Sadlerochit has an average depth of about 9,500 feet, and the Lisburne zone averages 11–12,000 feet. Although some multiple completion wells have been drilled into more than one of these formations, only the Sadlerochit zone currently is producing oil. Approximately 1.2 million barrels per day are produced by the 150 wells which tap this zone. (It is estimated that by about 1984 approximately 500 wells will be producing this same daily amount from Sadlerochit.) Much of this production is stimulated by reinjecting the gas which is produced in conjunction with the oil,[10] and it is anticipated that waterflooding will be undertaken to sustain production. Normal production decline from Sadlerochit is expected to begin between 1985 and 1987.

The commercial feasibility of producing oil from either the Lisburne or Kuparuk formations currently is being evaluated. Industry estimates indicate that a maximum daily production of 120,000 barrels could be expected from the shallower Kuparuk, and that the maximum Lisburne output might be between 10,000 and 50,000 barrels per day. Such production from these formations is not anticipated prior to 1982.

Considerations

Under the Administration's proposal, and H.R. 3919, oil produced from a well located north of the Arctic Circle would be exempted en-

[9] Various tracts of the Beaufort Sea, of which Prudhoe Bay is an inlet, may be offered for lease bids. Although these tracts may be attractive exploratory areas, especially in view of their relative proximity to TAPS, there is no assurance that oil will be located or, if located, will be commercially feasible to develop at a given per barrel price.

As of February 1979, Atlantic Richfield and Sohio-BP Alaska shared the operating responsibility for the Prudhoe Bay Unit owners. The latter company is responsible for about 55 percent, and the former for about 45 percent, of the field's production. The economic interest in the North Slope oil is owned largely by Sohio, Arco, Exxon, and the State of Alaska.

[10] Much of the associated gas production which now is being reinjected into Sadlerochit might be sold if a gas pipeline from the North Slope existed. The gas-oil ratio, *i.e.*, the number of cubic feet of gas produced per barrel of oil produced, is about 800:1. This is a low gas-oil ratio, and indicates an efficient use of reservoir energy.

tirely from the windfall profit tax, including the third, or OPEC, tier of that tax. This exemption is intended, in part, to eliminate the possibility of creating a disincentive for the production of Alaskan oil, and in apparent recognition of the large disparity between the wellhead price of oil produced north of the Arctic Circle and its actual refinery selling price.

Oil production from the Sadlerochit reservoir was highly profitable at 1978 Alaskan prices (about $5.25 per barrel), and there appears to be relatively little risk that a tax on oil from this reservoir using a base price of $7 to $8 would discourage production. Production costs will, however, be higher for the other two, much smaller. Prudhoe Bay reservoirs, Kuparuk and Lisburne, and a much higher base price is justified for these reservoirs. (Because it is possible that a single well can tap more than one of the reservoirs, it may be appropriate to have a rule that all production from a well producing from Sadlerochit will be deemed to be from that reservoir even if that well also produces from one of the other reservoirs.) Of course, costs are unknown for any other Alaskan oil remaining to be discovered, and any tax on newly discovered Alaskan oil risks having an adverse impact on production.

H.R. 4079 (Mr. Stark) would impose a windfall profit tax on all oil produced from wells located north of the Arctic Circle. This oil would be subject to the tier three tax, and the windfall profit would be the difference between actual selling price of the oil and the adjusted base price, prescribed by Treasury regulations to be the price at which uncontrolled crude oil of the same grade, quality, and location would have sold in December 1979 if the average landed price for imported crude were $16.00 a barrel. (For Alaskan oil, this base price would work out to between $7 and $8 per barrel.) The windfall profit tax imposed under the bill would be 85 percent of the difference between these two figures (after a deduction for additional severance taxes on the higher price).

There are numerous ways to impose a third tier tax on Alaska oil which would provide some recognition of the special characteristics of it. For example, there could be an upward adjustment to the base price for any decline in the real value of the TAPS tariff, so that wellhead price increases resulting solely from reductions in the pipeline tariff would be excluded from tax. Also, newly discovered Alaskan oil, or all Alaskan oil other than oil from the Sadlerochit reservoir, could be given a base price higher than the $7 to $8 implied by the tier three formula. Another alternative would be a flat per barrel tax on Alaskan oil equal to one-half of the difference between the world price and $16, adjusted for inflation, with a lower rate, or exemption, for new fields or new reservoirs. This flat tax would prevent any changes in transportation costs or quality differentials from affecting the tax rate on Alaskan oil.

In considering what, if any, type of a third tier tax might be imposed on Alaskan oil, the Committee may want to examine the possibility of producers avoiding the tax by shifting production from oil to natural gas. Currently oil production from Sadlerochit is stimulated by the reinjection of associated gas production, a practice which is encouraged by the present lack of inexpensive facilities needed for the sale of the gas. If a heavy tax were imposed on the sale of Sadlerochit oil, producers might market, rather than reinject, the gas. This could

lead to a decrease in oil production in the late 1980's if a pipeline is built to transport the gas.

Stripper properties

The Trans-Alaska Pipeline Authorization Act provided a statutory exemption from price controls for the first sale of crude oil produced from stripper well leases. For this provision, a stripper well lease was defined to mean a property whose average daily production during the preceding calendar month did not exceed the qualifying limits set by the statute. This test for stripper well lease qualification was modified by the Emergency Petroleum Allocation Act of 1973 from one based on production levels during the preceding calendar month to one based on production levels during the preceding calendar year. The Energy Conservation and Production Act continued the stripper well property exemption. However, it provided that to qualify for this exemption a property's average daily per well production of crude oil (excluding a condensate recovered in non-associated production) could not exceed 10 barrels per day during any preceding consecutive 12-month period beginning after December 31, 1972.

The reason for the stripper property exemption was to prevent the early shutting-in or abandonment of properties which might be uneconomic under existing price controls in light of their level of production and operating costs.

To qualify under the stripper exemption a property must be operated at the maximum feasible rate of production and in accordance was recognized conservation practices.[11] However, once a property has qualified as being within the exemption, it retains that status regardless of any future increase in the level of its production. As a result, the exemption may have given producers an incentive to curtail production artificially for 12 months in order to qualify properties as stripper and obtain the market price for their oil.

Production from stripper property currently represents about 15 percent of domestic production. Oil produced from these properties is entitled to the world price. Under the various bills introduced to impose a windfall profit tax, oil produced from stripper well properties either would not be subject to tax, or would be subject only to the tier three tax rate.[12] None of the bills would limit the stripper well

---

[11] Injection wells are not considered to be wells for purposes of determining whether the average daily production of a property was 10 barrels or less per well. Rul. 74–29, 39 Fed. Reg. 44414 (Dec. 24, 1974).

[12] H.R. 3919 would impose the windfall profit tax on all domestic production, and would classify stripper well properties within the tier three tax. H.R. 3421 (Mr. Cotter) H.R. 3474 (Mr. Conable) would apply the windfall profit tax only to that oil which is subject to price controls, and therefore would not apply to stripper well properties H.R. 4079 (Mr. Stark) would apply windfall profits tax to all domestc production, and would tax stripper well production at the tier three level.

In conjunction with its consideration of H.R. 5263 in the 95th Congress (the Energy Tax Act of 1978), the Senate approved an amendment which would have allowed producers to include water and other injection wells in determining qualification as a stripper property. The effect of this amendment would have been to increase the amount of production, by increasing the number of qualifying properties, exempted from price controls. The conference commttee on the Energy Tax Act did not adopt this amendment.

property category for tax purposes to those which qualified as stripper properties as of some fixed date. As a result, some producers may continue to have an incentive to reduce production below 10 barrels per well per day for 12 months to qualify properties as stripper, and thus be entitled to both a stripper well price (which will be advantageous prior to full decontrol in October 1981) and be subject to the least onerous tier three tax. Such an incentive may be particularly attractive in the case of wells or properties which could not qualify as marginal under either the DOE regulation or under a revised definition of marginal wells. The Committee may want to consider limiting stripper properties for tax purposes to properties which qualified as stripper as of (say) January 1, 1980.

Definition of "newly discovered oil"

Under regulations published on May 2, 1979, "newly discovered oil" is defined as crude oil which is sold after May 31, 1979, and which is produced from (1) an outer continental shelf area for which the lease was entered into on or after January 1, 1979, and from which there was no production in calendar year 1978 or (2) an onshore property from which no crude oil was produced in calendar year 1978. Oil produced from a property, as defined by DOE regulations, which previously had been developed but from which there was no production in calendar year 1978 is treated as newly discovered oil. The determination of whether crude oil production from a particular property may be sold as newly discovered crude oil on or after June 1, 1979, is to be made by the producer, subject to DOE's possible review. Under H.R. 3919, newly discovered oil is subject to the tier three tax rate.

It is generally believed that production of newly discovered oil is more sensitive to price changes than other kinds of oil, and the question appears to be whether to tax it in tier three or exempt it entirely. However, some questions have arisen about the specific way the Administration proposes to define newly discovered oil.

Producers would have an incentive to get their production classified as newly discovered oil so as to avoid the tier one or tier two taxes. It is possible that this could be accomplished by a producer's transfer of a portion of a proven producing property with production in calendar year 1978. If there was no production in that portion of the property which was transferred, it is possible that any future production from the transferred portion of the property could be misclassified as newly discovered oil. Although various DOE rulings have recognized the possibility of a producer transferring or "gerrymandering" property so as to obtain a higher price for future production, there appears to be no explicit DOE prohibition on a producer transferring part of a producing property to obtain a higher price for the production from the transferred portion. In enforcing price controls, DOE has denied new property classification in cases of transfers effected solely for the purpose of avoiding price regulations. Such an evaluation procedure, of course, would have to be undertaken on a case-by-case basis, could be subject to a substantial degree of circumvention, and in any case does not deal with the problem of transfers where other motives are present.

To prevent an avoidance of the windfall profit tax through a transfer of a portion of a proven producing property, an amendment could

be included to prevent the classification of production from the transferred property as "newly discovered oil," and thus subject only to the tier three tax, if the property from which the oil was produced had been severed previously from a property which otherwise would not qualify as producing newly discovered oil under the DOE regulations. Similar problems exist with marginal and stripper definitions.

The Administration's definition of newly discovered oil includes both actual new discoveries and also production from old properties which did not produce in 1978. The Committee may want to examine whether this treatment of previously shut-in or abandoned properties is appropriate, or whether this oil should be subject to the tier two tax.

Qualified tertiary enhanced recovery projects

Under a DOE rule, first sales of incremental crude oil resulting from the implementation or expansion of a "qualified tertiary enhanced recovery project" are exempted from the otherwise applicable ceiling price limitations. A qualified tertiary enhanced recovery project is one which is certified by DOE as being uneconomic at the otherwise applicable ceiling prices and which involves one or more of several specified chemical, fluid, gaseous, or miscible recovery techniques.[13]

Generally, incremental tertiary production is the amount of production on a property, where a qualifying project is being undertaken, in excess of an estimate of what production would have been without the tertiary project.

Specifically incremental crude oil, the price of which may exceed the ceiling price, is that amount (1) in the case of a new project, which is or will be produced in excess of the amount which could have been produced from the property or project through maximum feasible production from those ordinary recovery methods used prior to DOE certification, or (2) in the case of an expansion of an existing project, which is or will be produced as a result of the expansion over the amount which could have been produced through maximum feasible production from the pre-expansion recovery methods, or (3) in the case of a project which antedated the rule, which is or will be produced by continuing either the project or a high-cost phase of the project in excess of the amount which could have been produced through maximum feasible production from methods other than the tertiary method, or any phase thereof, which would be discontinued in the absence of a price incentive.

The first DOE certification for tertiary enhanced recovery of crude oil pursuant to these regulations was issued on April 16, 1979, to the Shell Oil Company. The average price of the oil that Shell recovered using a steam injection process was $8.62 per barrel, and its production cost was $9.03 per barrel. The DOE certification exempts incremental production in excess of a declining "Non-incremental Crude" schedule from the otherwise applicable ceiling price limitations.

---

[13] These methods include: (1) miscible fluid displacement, i.e., the pressurized injection of alcohol or gas so that the reservoir oil is displaced by the resulting mixture, (2) steam drive injection, (3) microemulsion, i.e., an augmented waterflooding technique, (4) in situ combusion, (5) polymer augmented waterflooding, (6) cyclic steam injection, (7) alkaline flooding, (8) carbonated waterflooding, (9) immiscible carbon dioxide displacement, and (10) any specific variation of any of these techniques.

Incremental production from a qualified tertiary enhanced recovery project is not subject to the otherwise applicable ceiling price limitations. Under the Administration's tax proposal, as embodied in H.R. 3919, the incremental production from a qualified tertiary enhanced recovery project would be subject only to the tier three tax. This tax rate would apply regardless of whether the incremental production otherwise would have been entitled to the lower or upper tier price, or whether production from the property would have been economic at some price in excess of the otherwise applicable ceiling price but below the uncontrolled price for similar crude oil.

There are administrative problems in determining how much of the production from a property is the incremental production resulting from the tertiary recovery project, and hence eligible for the tier three tax rate, and how much is nonincremental and subject to higher taxes. No one knows what production would have been in the absence of the tertiary project. An alternative to the Administration's approach would be to exempt all production from any property on which a qualifying tertiary project was being undertaken. Another alternative would be to exempt production in excess of a relatively high statutory decline rate (e.g., 2 percent).

Each of these alternatives would expand the amount of oil qualifying for the tier three tax. If this is considered too generous, the base price for the tertiary oil, above which revenues are subject to the windfall tax, could be set not at $16 but rather at the price at which the incremental production was determined by DOE to be economic. While this sort of determination presents administrative difficulties, it now must be done in order to obtain DOE certification for the project pursuant to existing regulations, so it would create no additional complexity.

It should be noted that the problem of determining how much incremental production results from tertiary recovery exists under present law during the years 1981 to 1983. In those years the rate of percentage depletion on oil and gas is scheduled to phase down from 22 percent to 15 percent; however, incremental production resulting from secondary and tertiary recovery retains a 22-percent rate until 1984, when its rate drops to 15 percent.

"Up front money" for tertiary recovery projects

In its energy message of April 26, 1979, the Administration proposed that for pricing purposes, beginning on January 1, 1980, producers who invest in enhanced recovery projects after June 1, 1979, be allowed to release specified volumes of lower tier oil to the upper tier price to finance that investment. H.R. 3919 makes no special provision for this oil for tax purposes on the theory that DOE would provide enough "up front" money through the pricing structure and would take into account the fact that additional price increase would be subject to tax. In the absence of final DOE regulations, this was the only feasible way to draft H.R. 3919.

In a notice of proposed rulemaking published on March 29, 1979, the Economic Regulatory Administration of DOE revealed some details of an incentive program to provide producers with "front-end" money to initiate or expand certain types of tertiary recovery projects. Under this proposed rule, a producer could charge market prices

for some amount of current production which otherwise would be subject to a price ceiling, provided that revenue from the sale in excess of the amount which otherwise would be permitted under the pricing regulations in the absence of any action (the "tertiary incentive revenue") could not exceed 75 percent of certain specified expenses actually incurred for enhanced oil recovery. These expenses would have to be reported to DOE. Recoupable expenses would be dependent upon the type of enhanced oil recovery technique which the project employed. No more than $20,000,000 of expenses could be recouped with respect to a particular project. However, no limitation would be placed on the number of projects for which a producer could recoup expenses through the release of oil to the market price. The proposal would permit producers to charge market prices for oil produced from properties other than the one on which the enhanced recovery project was located. In addition, no repayment obligation would be required. Moreover, the ability to release oil to the market price to provide "front-end" money would not be based on the financial resources of the producer engaged in the project, rather it would be based on the investment risk presented by a particular project. Under the rules, a producer could receive market prices for released crude pursuant to a self-certification procedure whereby a producer and a professional engineer certify to Economic Regulatory Administration that a qualified tertiary project had been undertaken, and the production would be uneconomic without the project.

Phaseout of tier two tax

Under the Administration's decontrol proposal, the price of upper tier oil would be increased to the world price between January 1980 and October 1981. The tier two tax would be phased out by the end of 1990. This would be accomplished by increasing the base price for tier two oil in 50 ratable monthly increments, between November 1986 and January 1991, so as to eliminate the differential between the tier two and tier three base prices. The tier two tax would be phased out to simplify the tax at a time when tier two tax revenues are expected to be decreasing due to the diminished volume of upper tier oil.

This method of phasing out the tier two tax by raising the base price provides incentives to withhold production until the phaseout is complete, perhaps by delaying investments which would be required to maintain or increase production. Fortunately, this adverse incentive is minimized by the fact that the gap between the tier two and tier three base prices is relatively small. One alternative to H.R. 3919 would be not to phase out the tier two tax at all, but instead to allow it to phase itself out as more and more of the nation's oil becomes newly discovered oil in tier three. Alternatively, the tier two phaseout could be based on a decline curve based on production in the first half of 1979 with a very low statutory decline rate. (For example, a decline rate of 0.75 percent per month, starting July 1, 1979, would phase out the tier two tax by September 1990.)

Property unitization

To facilitate the economic production of oil from a single pool or reservoir which is subject to more than one separately owned producing lease, producers frequently enter into an agreement for the joint, or "unitized," operation of their interests. Such an agreement may

make it economically feasible to undertake various pressure maintenance and secondary recovery programs. These agreements have been recognized by DOE and have been taken into account for price control purposes, both under the old and the new regulations.

In the absence of some ameliorative price control action, producers of price-preferred oil could be hesitant to join with other producers in a unitization plan that might result in a loss of some of their price-preferred oil, even though total production might be increased through enhanced recovery techniques. For this reason DOE has adopted special pricing rules with respect to production pursuant to a unitization agreement. Generally, producers who enter into unitization agreements are guaranteed the continued classification of their production as price-preferred oil in an amount equal to the pre-agreement level of that production. If total post-unitization production exceeds the combined pre-unitization production, the excess is categorized in proportion to each type of oil which had been produced immediately prior to the unitization. Thus, for example, production from stripper well leases retains its exempt status when unitized with other leases with respect to the average daily production for the 12-month period immediately preceding unitization. Alternatively, if it is more favorable to the producer, the unitized property can be guaranteed the same percentage of stripper production that existed prior to unitization.

Generally, similar "hold harmless" treatment is provided for production from marginal properties which are subject to a unitization agreement and for newly discovered oil. Therefore, as is the case with production from stripper well properties subject to a unitization agreement, producers of newly discovered oil, or oil from a marginal property, would be guaranteed the continued classification of prior price-preferred production after entry into a unitization agreement, either the absolute amount of such production or the same percentage, whichever is greater. The balance of any increased production from the unitized property would be eligible for the upper tier price.

The windfall profit tax could contain similar rules to make sure there is no disincentive to unitize properties.

D. Limit of Windfall Profit to Taxable Income

H.R. 3919 includes a provision limiting the windfall profit subject to tax on a particular property to the net income from that property. For this purpose, net income equals taxable income allocable to the property computed without regard to the depletion deduction, the deduction for intangible drilling costs on productive wells and the deduction for the windfall profit tax itself. The effect of this limitation is that for any property the windfall profit tax, at a 50-percent rate, cannot exceed 50 percent of the net income from that property. The rules for computing the net income from a property should not cause any significant technical problems, because a similar calculation has been required for many years in connection with the determination of percentage depletion, which is limited to 50 percent of taxable income from each property.

The 100-percent-of-net-income limit on the windfall profit subject to tax is intended to relieve the tax burden on high cost properties. It could, in that sense, be considered as an alternative to establishing a special category under the tax for marginal properties.

A similar provision was included in the windfall profit tax reported by the Committee in 1974. That tax would have limited the taxable windfall profit to 75 percent of net income from a property. Because the 1974 tax had an 85-percent rate on most windfall profits, the 75-percent limit implied that the windfall profit tax itself generally could not exceed 63.75 percent of net income from a property. (85 percent of 75 percent is 63.75 percent.) In contrast, H.R. 3919 would limit the tax to only 50 percent of the net income from a property.

Under H.R. 3919, in cases where the windfall profit tax is reduced because of this limitation, producers and royaltyholders would claim a refund of the tax paid on the oil after the close of the year when they file income tax returns.

E. Determination of Base Prices and Inflation Adjustments

Under H.R. 3919, the windfall profit tax on a barrel of taxable crude oil would equal one-half of the difference between the actual selling price of the oil and the inflation-adjusted base price applicable to that oil. For oil in tiers one or two of the tax, the base prices would be the lower or upper tier ceiling prices, respectively, under price controls for oil sold from that property in May 1979. For tier three oil, the base price would be determined under Treasury regulations which would establish various classifications of oil, according to gravity, quality and location, and estimate for each classification the price for which that oil would have sold in December 1979 if the average landed price for imported crude oil had been $16 in that month. The $16 tier three base price is an estimate of what imported oil would cost (f.o.b. the United States) if the price of imported oil were $14.55 (f.o.b. Saudi Arabia). The $14.55 price represents the price increase announced by OPEC late last year, prior to the Iranian revolution, to be phased in by October 1979.

These base prices would be adjusted upward for inflation as measured by the GNP deflator. The adjustment would occur every quarter and would be lagged by six months to take account of delays in publishing the deflator. (The first revision of the GNP deflator for a particular quarter becomes available in the third week of the second month following the close of the quarter.) Thus, the first inflation adjustments to the tier one and two base prices, which are initially based on May 1979 prices, would occur for the third quarter of 1979 (July–September) and would be based on the inflation which occurred between the last quarter of 1978 and the first quarter of 1979, the data for which would be published in May 1979. The next inflation adjustment would be for the fourth quarter of 1979 and would be based on inflation between the first and second quarters of 1979, the data for which would be published in August 1979. For tier three, whose base price initially is related to a December 1979 price, the first inflation adjustment would be for the first quarter of 1980 and would be based on inflation between the second and third quarters of 1979. This method of lagged inflation adjustments is similar to the one which has been used by the Department of Energy to adjust the lower and upper tier ceiling prices. The DOE adjustments are also lagged by several months for the same reason.

It has been suggested that use of the GNP deflator, which measures inflation in domestically produced goods and services, is not an appropriate measure of inflation, that instead some measure of the costs of oil production should be used. Such a measure could be more appropriate, but it would be a formidable task to construct such a price index. The costs involved in extracting old oil, for example, are of a quite different character and magnitude than the costs of discovering new oil; and significant parts of the cost, like royalty payments and severance taxes, tend to rise whenever the price of oil goes

up, lending an element of circular reasoning to any excise tax rate based solely on production costs.

If the Committee believes that the inflation adjustment based on the GNP deflator is not sufficiently generous, it simply could add a "kicker" of one or two percent annually to the GNP deflator. This would preserve the simplicity of the use of a general price index, while taking account of the likelihood that oil production costs will rise faster than the overall price level.

The tier three base price in H.R. 3919 differs from the Administration proposal, which would have applied a $16 base to all tier three oil, regardless of quality or location or any other factors which cause actual oil prices to vary from the national average. Under that method, the tier three tax would have applied to the higher quality oil even if the average price for all oil remained at or below $16. However, the array of base prices used in H.R. 3919 could lead to disputes about what oil belongs in what category, although such dispute could be reduced if Treasury classifications of oil are exempt from judicial review except on the grounds that they are arbitrary or capricious.

Another way to set the tier three tax rate would be to set a uniform rate each quarter for all oil equal to one-half the difference between the national average selling price and $16 (adjusted for inflation). A single tier three tax rate for all oil in that tier would be considerably simpler and would eliminate any possible disputes about an individual property's base price. Also, it would eliminate the possibility of a producer's charging a fraudulent lower price to avoid the tax. However, this approach would fail to adjust the windfall tax rate for price changes resulting from changing quality or location differentials, in effect excluding the resulting price changes from tax. As explained above, however, this method may be appropriate for Alaskan oil, where changes in quality and location differentials are especially significant and production costs are uncertain.

The national average approach is employed in H.R. 4222, introduced by Mr. Dingell. That bill employs a tax rate base on national averages for the tier one and two taxes as well. The problems that can arise from this approach can be seen by considering a world with two types of oil with lower tier ceiling prices of $5 and $7 and upper tier prices of $11 and $15 (i.e., a widened quality differential during the period between May 1973, the date to which lower tier ceiling prices refer, and September 1975, the corresponding reference point for upper tier price ceilings). The Dingell bill would set a tier one tax rate equal to 100 percent of the gap between the national average lower tier price and the national average upper tier price, in this case $7 ($13 minus $6). However, a $7 tax on the $11 oil would reduce the net proceeds to its producer to $4, a dollar below its already low ceiling price. Similar problems exist today under price controls because the entitlements program is also based on national averages and also arose under the original crude oil equalization tax proposal in 1977.

F. Plowback

Overview

The windfall profit tax reported by the Ways and Means Committee in 1974 contained a plowback credit which producers and royalty-holders could claim against the windfall profit tax for qualified investments in excess of a threshold level of investment. A plowback credit would reduce the revenue raised by a windfall profit tax. It also would significantly alter the incentives provided by the tax and pricing structure.

With no plowback credit, a windfall profit tax would affect producer incentive in the same manner as a reduction in the price of crude oil. To the extent oil production is sensitive to price changes, a question on which there is no consensus among economists and the answer to which undoubtedly varies for different kinds of oil, a windfall profit tax would discourage production, although this adverse impact can be reduced by lowering the tax rate on categories of oil—likely newly discovered oil—where production is likely to be relatively sensitive to price changes.

With a plowback credit, this pattern of incentives changes, but the changes for any particular producer depend on the amount of his qualified investments in relation to whatever threshold level of investment is established. There are three principal cases:

For a producer whose investments are well below his threshold, so that large investments would be needed to get into a position at which further investments qualify for credit, provision of a plowback credit would not change the incentive structure provided by the windfall profit tax. Such a producer would pay the full windfall profit tax, and there would be no incentive to make additional investments, except perhaps for a very large investment program, one sufficient to carry the producer above his threshold.

For a producer whose qualified investments are so large that they exceed not only his plowback threshold but also his entire windfall profit tax liability, the plowback credit would eliminate the entire windfall profit tax liability. It would increase the producer's incentive to produce more oil because the windfall profit tax on any additional production could be offset by the producer's excess plowback credits. However, because this producer has excess plowback investments, the existence of the plowback credit itself would not provide a direct incentive to make additional investments except to the extent that investments are needed to achieve whatever additional production stimulated by the low windfall tax. Thus, for a producer with enough investments to have excess plowback credits, a windfall profit tax with a plowback credit is equivalent, in both its revenue and incentive effects, to no tax at all.

The third case is a producer whose investments are close to his threshold. For him, additional investments would qualify for plowback credit, and a dollar-for-dollar plowback credit would provide a very

powerful incentive to make additional expenditures for qualified investments, at least up to the point where the windfall profit tax would be offset completely by the plowback credit. If one dollar of investment qualifies for one dollar of plowback credit, then the investment incentive provided to this producer by the plowback credit can be as high as would be the case if the government simply paid for his drilling costs.[14] If a dollar of qualified investment led to (say) 50 cents of plowback credit, the effect on investment incentives could be as high as a government subsidy equal to one-half the drilling costs.

Thus, it is hard to predict the exact economic effects of a windfall profit tax with a plowback credit. They would be different for each producer, depending on the level of his plowback threshold in relation to the amount of qualified investment which the producer would have done without any plowback credit, a relationship which would vary greatly among producers and royaltyholders.

If the Committee decides to include a plowback credit against the windfall profit tax, there are several specific issues which must be addressed. These include the eligible investments, the plowback threshold, carrybacks and carryovers of excess credits, the treatment of producers and royaltyholders who are prevented by law from making qualified investments, and the treatment of the plowback credit under the Federal income tax.

Eligible investments

The Committee's 1974 windfall profit tax made the following expenditures eligible for plowback credit: (1) intangible drilling costs; (2) expenditures for depreciable property used in oil exploration, development and production (including oil shale); (3) property used to convert oil shale into oil and for coal liquefaction and gasification; (4) refineries; (5) pipelines; (6) secondary and tertiary recovery costs; and (7) expenditures for acquisition of onshore leases. This list was intended by the Committee to be broad, and it was recognized at the time that most producers, although not necessarily most royaltyholders, would have enough qualified investments to offset their entire windfall profit tax liability.

Any list of qualified investments raises certain questions. For those producers whose investments, in the absence of a plowback credit, would be close to or above their threshold but not large enough to offset their entire tax liability, the plowback credit represents a large government subsidy for the purchase of qualified equipment, as explained above. Such a subsidy can be expected to cause major changes in investment behavior for these companies. Too narrow a list of qualified investments would mean that the government was, in effect, regulating fairly specifically what investments are to be made by at least part of the industry. Too broad a list of investments, however, would mean that the Treasury, in effect, would be subsidizing the expansion of oil producers into other industries, such as refining, oil transportation

[14] This is the result whenever the qualified investments can be expensed immediately under the income tax. However, the effective investment subsidy is smaller for qualifying investments which must be capitalized under the income tax. In this case, the fact that the plowback credit reduces a deductible windfall tax, while the qualifying investments are not immediately deductible, means that the implicit subsidy provided by plowback is less than 100 percent.

and production of alternative sources. Such a policy might be inconsistent with national antitrust policies which, while not banning such concentration, does not normally subsidize it.

Some problems arise with some of the specific items on the 1974 list. Making lease asquisition costs eligible for the plowback credit could encourage producers to bid more for leases, which would not increase production at all. Also, it may be difficult to define secondary and tertiary recovery costs precisely enough to include them as a qualifying expenditure. Further, some legal issues about precisely what constitute intangible drilling costs remain unsettled.

Plowback threshold

Most producers and many royaltyholders are already making large enough expenditures on qualified investments to offset even very large windfall profit tax liabilities. Thus, the plowback credit provide an incentive for additional investment for more than a small number of producers, there must be some threshold level of investment before expenditures can begin to qualify for plowback credit. A threshold was adopted in the Committee's 1974 bill.

Designing a threshold, however, is difficult because companies vary widely in the extent to which they reinvest their earnings. A threshold, for example, could equal a percentage of gross income based on the industry-wide average level of investment in qualified expenditures in relation to industry-wide gross income. However, most individual companies investments are significantly different from the industry-wide average. Alternatively, each producer and royaltyholder could be given a separate threshold based on his own past level of investment. This would penalize those companies who have contributed to the energy program with a high rate of investment during whatever base period is chosen. Also, such a threshold would require rules to establish base periods for new companies and for reorganized companies. None of these approaches is entirely satisfactory.

Carrybacks and carryovers

It is desirable to have liberal carrybacks and carryovers of excess plowback credits to discourage postponement of investments which would generate excess credits out of fear that, otherwise, insufficient credits would be available in future years. However, the interaction between these carrybacks and carryovers, a changing plowback threshold and any other limits on the plowback credit (e.g., to a percentage of tax liability) would result in an extremely complicated tax.

In the Committee's 1974 bill these complexities were reduced somewhat by use of a "recomputation method" for computing the plowback credit. Under the recomputation method, taxpayers would compute their tax and credit for each year with no carrybacks and carryforwards of excess credits. Then, after year one, they would also recompute their tax liability and credit for the current year and all subsequent years as if that multiyear period were simply one taxable year. If this recomputed liability were less than the sum of the individual years' liabilities, the difference would be allowed as a tax credit against the current year's liability. While this procedure would solve the drafting problems posed by carrybacks and carryovers, it may be difficult for taxpayers to understand.

Producers prevented by law from making qualified investments

Some producers and royaltyholders are prevented by State or local law from making plowback investments. In 1974, the Committee's bill exempted from the windfall profit tax State and local governments and tax-exempt educational, charitable and religious organizations if they were prohibited by pre-existing State or local law from making any of the investments eligible for the plowback credit. This exemption was provided because the Committee recognized that it was establishing a windfall profit tax rate far higher than would have been justified in the absence of a generous plowback credit, and it believed that it was appropriate to relieve the tax burden on organizations which could not take advantage of the plowback.

Furthermore, the 1974 tax would have been a temporary, 5-year tax, and it was not reasonable to expect State and local governments to change their laws in response to the tax. If the Committee agrees to a permanent windfall tax with a high threshold level of investments for any plowback credit, however, the case for an exemption for persons prevented by law from making plowback investments is weaker than in 1974.

Interaction between plowback credit and income tax

Many oil company investments are immediately deductible for income tax purposes, notably dry hole and intangible drilling costs and many costs associated with secondary and tertiary recovery. For these investments, a dollar of investment can be made with a dollar of gross income. However, other investments must be capitalized and deducted over the life of the asset. For these investments, the gross income plowed back into the investment must exceed the actual amount of the investment because that income is subject to income tax. With a 46-percent top corporate income tax rate, it takes $1.85 of pre-tax income to yield $1.00 of after-tax income available for reinvestment in depreciable property.

To deal with the problem of capitalized investments, the Committee's 1974 bill provided that, in the case of qualified investments which could not be expensed immediately under the income tax, $1 of plowback credit was to be allowed for each $0.50 of qualified investment. This two-for-one rule, of course, made it easier for companies to meet the plowback requirement. However, because the capitalized investments can eventually be written off through depreciation or depletion deductions, the two-for-one rule biased the plowback credit towards providing a somewhat stronger incentive for depreciable or depletable investments than for investments expensed in the year they were made.

G. Return Filing and Deposits

Administration proposal

As proposed by the Administration, and contained in H.R. 3919, the windfall profit tax would require that only a few hundred persons file returns and make deposits of tax. Generally, the purchaser of any taxable crude would be required to make bimonthly tax deposits, provide producers with monthly information statements with respect to their oil production, and file quarterly returns with respect to the tax. The purchaser would deduct the tax from the amount he would otherwise pay to the producer. Other parties normally would not be subject to the various return filing, reporting, or depository requirements. If the net income limitation reduces the tax, the producer or royaltyholder concerned could claim an annual refund at the time his or her income tax return is filed.

This exchange of information between purchasers and producers is consistent with existing business practices in the industry. Generally, under existing business practices, records are maintained, called run statements, of the price per barrel and the quantity sold or removed from the premises at a given time. Prior to the purchaser's payment for the oil, "division orders" generally are circulated by the purchaser among the various owners of interests in the property for their signatures. These records show the fractional interest in the oil sold or removed. They also are used for determining the amount of sales proceeds due to each party, and for purposes of determining each party's respective depletion deduction. However, it is on the basis of the division orders that the purchaser generally makes the payment directly to the owner of each interest for the applicable share of the proceeds, after reduction for severance or production taxes.

Plowback provision

Plowback would require that each person with an economic interest in taxable production be required to file the applicable tax returns and make the tax deposits generally required under the tax. Only the individual producer and royaltyholder would know just how large his own plowback credit would be and exactly how much tax would be owed. This switch in the depository and return filing obligation away from the purchaser would increase the number of persons involved from several hundred purchasers to hundreds of thousands of producers, investors and royaltyholders.

Conceivably, the purchaser could continue to pay the tax and file returns, and producers and royalty holders claiming a plowback credit could file for a refund on their income tax returns. However, this procedure could reduce the effectiveness of plowback because the Treasury would have the money deposited by the purchaser and the producers and royalty holders would have to borrow against their plowback refund to obtain funds for investment.

H. Windfall Profit Tax Enforcement

Overview

Because of allegations about inadequate enforcement of DOE price controls, questions have arisen about enforcement of the windfall profit tax.

Noncompliance with the obligations imposed by the windfall profit tax could subject the producer both to the generally applicable civil and criminal Internal Revenue Code penalties, as well as those specifically set forth in H.R. 3919. Proposed Code section 6050C would require the purchaser to furnish monthly statements to the producer. These statements would be required to show the following items: (1) the amount of oil purchased, (2) the purchase price, (3) the base price and adjusted base prices, (4) the amount of tax withheld, and (5) any other information that is required by regulations. In addition, the operator of the well would be required to furnish the purchaser with such certified information as may be specified by regulation. It is anticipated that such information would include the type and classification of the oil purchased. Proposed Code section 7241 would make it a misdemeanor to fail wilfully to comply with these obligations, and section 6652(b) would require additions to tax for failure to comply. In addition, the obligations imposed upon the various parties by the windfall profit tax also would be subject to generally applicable tax penalties for civil or criminal fraud, as well as those for negligence.

Unlike the situation with respect to the DOE regulations, only one event would determine the windfall profit tax liability—the first sale. In contrast, price controls must be applied at several stages of production and distribution, each of which presents an opportunity for noncompliance. Because the tax is imposed on the producer and collected at the first sale by the purchaser, there would only be one opportunity for a party to falsify "well data," such as meter readings or oil classifications. Because each item of information required to be reported or certified under proposed Code section 6050C would be an operative element as to the determination of any party's tax liability, the misrepresentation of any item could give rise to the imposition of the appropriate tax sanction. Each item of information also would have to be categorized as a "material fact" necessary for the filing of a valid return or the furnishing of accurate information statements. As a result, supporting records would have to be maintained, and misrepresentation of any of these items could render a party subject to the applicable civil or criminal sanction.

The Internal Revenue Service, of course, would need to have complete access to DOE records with respect to each producer's property so as to facilitate the enforcement of the tax.

For these reasons, "voluntary" compliance with the tax can be expected to be greater than compliance with price controls. To some ex-

tent, compliance with the tax will depend on how complicated it is—how many different categories of properties there are and how many variables determine the status of oil on a property. A single-rate tax, for example, would probably lead to greater compliance than a multi-rate tax.

Another significant difference between enforcing a windfall profit tax and establishing compliance with DOE regulations involves the placement of the burden of proof. As generally is the situation under the Internal Revenue Code, the burden of establishing the entitlement to preferential tax treatment under the windfall profit tax would be upon the taxpayer asserting that right. In other words, each producer would have to be prepared to establish that the tax reported is fairly mandated by the applicable windfall profit tax provision. Thus, each producer would have to be prepared to establish the various items upon which windfall profit tax liability is predicated, including the classification and base price of oil sold and the category to which the producing property belong. (In contrast to the enforcement situation under the DOE regulations, where the burden of proof is on DOE, the IRS generally does not have to establish that a taxpayer is not entitled to a particular tax treatment.)

Enforcement personnel

For fraud and negligence penalties to be meaningful, however, there would still have to be considerable auditing of producers. Because the proposed windfall profit tax would incorporate existing DOE regulations, the administration of the windfall profit tax would have to be carried out by either the Internal Revenue Service, DOE, or both. However, it is not clear that either of these agencies have the necessary personnel to enforce the tax adequately.

According to testimony by Secretary Schlesinger before the Ways and Means Committee on May 10, 1979, DOE's appropriation for personnel in its enforcement section was reduced, thereby significantly decreasing the number of its agents. Moreover, Secretary Schlesinger testified that some enforcement agents are being reassigned from production compliance responsibilities ot audits of retail outlets. (During 1978, staff persons in DOE's Inspector General's Office alone decreased from 120 to 100.) Similarly, the Commissioner of Internal Revenue recently told the Senate Appropriations Treasury Subcommittee that the Service's final fiscal year 1980 budget is a "bare maintenance request—not an expansion budget, and not one that will permit [the IRS] to maintain 1979 planned levels of service. . . ." and added that, as a result, the percentage of tax returns audited by the IRS in 1980 would decrease.

The proposed imposition of a windfall profit tax in conjunction with the decontrol program would require various parties to certify the accuracy of a number of items. There would be four categories of properties: (a) marginal properties, (b) stripper properties, (c) newly discovered oil, and (d) tertiary recovery. In addition, lower and upper tier oil still would have to be segregated and certified, at least until 1983 under H.R. 3919, as would upper tier oil eligible for tier three until 1991. As a result, in the absence of a strict auditing program, producers could evade the windfall profit tax by misclassifying their oil

production. Yet, it is not clear that any Federal agency will have adequate personnel to police the accuracy of the various obligations imposed by the windfall profit tax unless the budget of the IRS or DOE is expanded to accommodate the additional auditing needed to enforce the tax.

Delegation to States

One method of attempting to minimize false oil classifications or property certifications might be to adopt a review procedure similar to that employed under the Natural Gas Policy Act of 1978. Section 503 of that Act provides that the appropriate State or Federal agency generally must make an advance determination that a party's gas production qualifies as being within a classification that is entitled to a high price. Such a determination includes the subsidiary findings which necessarily are preliminary to a decision as to the category for which natural gas production qualifies, and it is reviewable. In the absence of a favorable advance determination, a seller generally may not charge the high price requested.

Some of the producer self-certifications which would be needed to qualify for various kinds of special treatment under either DOE's new pricing rules or the windfall profit tax are similar to analogous natural gas determinations which ordinarily must precede a seller's right to collect a higher price under the Natural Gas Policy Act of 1978 and, under that Act, are overseen by State agencies. In addition, many of the State agencies which could be charged with certifying the validity of the classification of an oil-producing property for windfall profit tax purposes currently perform similar tasks for local law purposes.

There are several serious objections, however, to adopting the method of enforcement used in the 1978 Natural Gas Policy Act. It would amount to delegation of Federal tax enforcement to the States, who could not necessarily be counted on to make the Federal Government's interest paramount. Also, some States now appear to be overburdened by their responsibilities under the natural gas law. (Some States objected to the DOE proposed that they certify properties as marginal, which caused DOE to abandon that idea.) Thus, using the normal procedure of IRS audits appears to be a better way of enforcing the tax than advance determinations by State agencies.

Another alternative, advance certification of the status of properties by a Federal agency, such as DOE or the IRS, seems unduly cumbersome in the absence of any evidence that self-certification with IRS audits will not lead to a high degree of compliance.

I. Effect of Windfall Profits on Percentage Depletion

Generally, percentage depletion is not available in the case of oil and gas production. However, independent producers and royalty owners, those not involved in the "down-stream" activities of the oil business, are entitled to percentage depletion to the extent that their average daily production does not exceed a specified exemption. For 1979, the examption is 1,200 barrels per day or the equivalent amount of natural gas. The exemption will be established permanently at 1,000 barrels per day in 1980. Oil production eligible for percentage depletion represents approximately 23 percent of domestic production, which is split about evenly between royaltyholders and independent producers. The rate of percentage depletion is 22 percent of gross income, but this is scheduled to phase down to 15 percent between 1980 and 1984 except for oil produced from secondary and teritary recovery, which remain at 22 percent depletion until 1984.

The percentage depletion allowance is calculated by multiplying the taxpayer's gross income from the property by the applicable percentage specified in the Code. Thus, the amount of the taxpayer's gross income from the property directly affects the amount of the percentage depletion deduction. Absent enactment of some provision to the contrary, the increase in the sales price of oil occasioned by decontrol would result in a proportionate increase in the percentage depletion allowance.

The Committee may wish to consider limiting the increase in percentage depletion resulting from decontrol by excluding some or all of the windfall element from gross income from the property for the purpose of calculating depletion. H.R. 3919 and H.R. 4079 (Mr. Stark) would exclude the entire amount of the taxable windfall profit from gross income for the purpose of calculating percentage depletion. Thus, in the future, the percentage depletion allowance would be increased only through price increases not subject to the windfall tax owing to the phaseout of the first and second tiers of the windfall tax and inflation adjustments to the base prices. Immediate increases in price resulting from decontrol and OPEC price increases generally would not increase the percentage depletion allowance.

Two arguments have been advanced to support a complete exclusion of the taxable windfall from the depletion calculation. First, proponents believe it would be inconsistent to impose a windfall profits tax on a price increase and at the same time allow that increase to result in greater income tax deductions and, therefor, increased after-tax profits. Second, it may be argued that the percentage depletion allowance is intended to provide for tax-free recovery of investments in the oil and that the adequacy of the percentage depletion rates as applied to oil sold at controlled prices to recover the cost thereof was implicitly considered by the Congress as recently as 1975 when it restricted the

depletion allowance. In addition, as to the oil the cost of which is not adequately recovered through percentage depletion, cost depletion will be available.

Opponents of a complete exclusion of the windfall profit from the depletion calculation argue that percentage depletion was intended to provide for recovery of the discovery value or replacement cost of oil. They believe that to deny a depletion allowance based upon decontrolled prices will fail to provide a recovery of the replacement cost of the oil since that replacement cost should properly reflect the decontrolled price of oil.

H.R. 3421 (Mr. Cotter) and H.R. 3474 (Mr. Conable) would provide for the calculation of depletion on the selling price of oil reduced by the amount of tax imposed thereon. This position was also taken in the Committee's 1974 windfall profit tax, although with the high rate of that tax, there was not a significant difference between reducing gross income by the amount of the windfall profit and reducing it by the amount of the tax. This position may be supported by the theory that the windfall tax represents the public's rightful share of income attributable to decontrol and thus ought not be subject to depletion by the owner of the oil.

J. Person Liable for Tax

Generally, the bills introduced to tax windfall profits would impose the tax on the first sale of taxable crude oil and require payment of the tax by the "producer" of the oil. (Generally, the tax is to be withheld by the first purchaser of the oil and deposited with the Treasury by him.) The bills generally define the producer as the owner of the economic interest in the oil and thus place the burden of the windfall tax on the persons who will receive the increased income resulting from decontrol. Thus, each investor and royaltyholder who owns an economic interest in the oil would be liable for tax on his share of the gross revenues. The Committee, however, may wish to consider narrowing the definition of producer.

The primary issues that have arisen in determining the person liable to pay the windfall profit tax are whether exemptions should be provided for public or charitable entities and for small producers.

H.R. 3919 and H.R. 4079 (Mr. Stark) would impose a windfall profit tax on all owners of crude oil, including State and local governments and tax-exempt organizations. H.R. 3474 (Mr. Conable) would provide an exemption for independent producers and small royaltyowners whose average daily production does not exceed 1,200 barrels.

Supporters of an exemption from the windfall tax for governmental units and exempt organizations argue that governmental units and exempt organizations generally are exempt from income taxes and should also be exempt from the windfall profit tax because the tax is, in effect, imposed on increased income resulting from decontrol. Proponents of this view also argue that the increased profits received by these entities will be directed to public purposes and, therefore, do not need to be diverted to the public sector by imposition of the windfall profit tax.

Those who favor taxing all windfalls regardless of recipient argue that the nation's energy needs are so great that funds should not be diverted from the Energy Trust Fund to other public purposes and that the notion of a windfall profit does not relate to the identity of the recipient. Further, they note the windfall tax is an excise tax and that governmental units and exempt organizations have been subjected to other excise taxes. (They are not exempt, for example, from the gas guzzler tax, the most recent excise tax imposed by Congress.)

A third possibility which the Committee may wish to consider is providing a limited exemption from the windfall profit tax for only some types of public or charitable entities.

H.R. 3474 would provide an exemption from the windfall tax for independent producers and small royaltyholders. Proponents of this view argue that such an exemption would continue to encourage investment in oil development by these persons and thus dis-

courage further vertical integration of the oil industry. Opponents, on the other hand, argue that independent producers and small royalty-holders realize a windfall upon decontrol, just as will the major companies, and should not be permitted to reap all this windfall at the expense of the Energy Trust Fund. Furthermore, about one-half of the benefits of such an exemption based on a fixed number of barrels per day generally would go to royaltyholders, and to that extent this exemption would not provide any additional production incentive.

The only case in which H.R. 3919 imposes the tax on a person other than the holder of the economic interest in the oil is that of a production payment which involves payment of oil to someone until such time as the total cumulative payment has added up to a fixed number of dollars (as opposed to a fixed number of barrels). In these cases, the windfall from higher prices is really received by the owner of the residual interest in the oil, not the holder of the production payment, because the payment can be worked off with fewer barrels of oil owing to the higher price. H.R. 3919 would shift the tax burden to the producer in this case.

○