THE EFFECTS OF THE WINDFALL PROFITS TAX ON AMERICAN CRUDE OIL PRODUCTION

Chet Hammes

TABLE OF CONTENTS

CHAPTER I

THE WINDFALL PROFITS TAX

A BRIEF DESCRIPTION

Public Law 96-223, which embodies the windfall profits tax, is a far-reaching act that is very diverse in its potential economic impact. Besides the provisions related to the tax, the act deals with such things as energy conservation incentives for the business and residential sectors of the economy, incentives for gasohol production, energy assistance to the poor and elderly, and others.

While the above is hardly insignificant and provides a glimpse at a few of the protagonists in the fight for the control of the nation's energy policy, this thesis is concerned basically with the tax imposed on oil producers and, to a much lesser extent, with the provisions related to the use of tertiary techniques for extracting oil. Hence, a brief description of the windfall profits tax is now in order.

The windfall profits tax is in actuality a number of somewhat different taxes imposed on different "tiers" of oil. Tier two oil is any oil that is produced from a "stripper" well (a well with a production rate of ten or fewer barrels of crude oil a day) and oil produced in a National Petroleum Reserve.[1] This oil is generally taxed at a rate of 60 per cent of income net of the $15.20 base price for tier two oil.[2] Tier three oil is made up of newly discovered oil, heavy oil (oil that has a weighted average gravity of 16 degrees API or less), and incremental tertiary oil (oil produced with the aid of an approved tertiary method).[3] The tax percentage for all tier three oil is 30 per cent with $16.55 per barrel of crude oil as the base price for determining taxable net income.[4] Tier one oil is all other oil. It is taxed at the general rate of seventy percent with a base price of $12.81 per barrel.[5]

For independent producers--in other words, producers independent of the major oil companies--engaged in producing tier one and/or two oil, the percentage tax rates are reduced to 50 and 30 per cent, respectively, for the first one thousand barrels of production.[6] The base prices for all producers are also adjusted for severance taxes. The base prices are also adjusted for inflation by each calendar quarter by the GNP price deflator. For tier three oil, the GNP deflator itself is multiplied by $(1.005)^n$ where n equals the number of calendar quarters beginning after September, 1979.[7]

This tax has been designed to be gradually phased out after a certain "target month" which is to be no earlier than January 1987 and no later than December 1990. The target month is later than January 1987 if a total of 227.3 billion dollars in total revenue from the tax is not reached until after January 1987. When the target month is reached, a 33-month phaseout period then begins in which the tax is reduced by three per cent for each consecutive month. The tax must end by September 30, 1993.[8]

Thus, the tax will differ in the percentage of net revenue it absorbs for each tier according to changes in real oil prices and the phaseout period. Consequently, the tax will be symbolized by either $\theta(t)$ or $A(t)$ in the various parts of this thesis.

Although the windfall profits tax seems drastic in nature, it must be remembered that the administration proposal was accompanied by the beginning of President Carter's oil price decontrol. This was in itself a sharp break with the past; Carter had strongly supported price controls in the 1976 campaign. Obviously, when Carter announced his energy plans in early April 1979, he hoped that the windfall tax provision would make the oil price decontrol more acceptable to the American public. In fact, the new energy program brought forth heavy criticism from both conservatives and liberals. The oil industry, not surprisingly, opposed the tax. But, more interestingly, many liberal democrats thought that the tax proposal did not go far enough; they felt that the price decontrol was a bad concession to the industry. Predominantly, they came from oil-consuming states (especially the northeast). Senator Edward Kennedy spoke for many of them when he called the windfall profits tax measure a "fig-leaf" that merely hid the oil industry's profits.[9] Due to these circumstances, most observers felt that the tax would be defeated in Congress.

However, by the fall of that year, the situation had changed in the President's favor, for it was now obvious that at least some sort of windfall tax measure would be passed by Congress. The bill had a rough time in the Senate Finance Committee chaired by Russell Long of Louisiana (an oil state). The committee studied the bill from July to mid-October. Finally, on November first, the bill was recommended favorably to the rest of the Senate.[10] However, there were significant revisions in the bill. Tax rates for most categories of oil were increased, but rates on new discoveries and incremental tertiary oil were reduced to ten and twenty per cent, respectively.[11] Independent producers were also exempted from the tax for their first one thousand barrels per day. This is basically the bill that passed the Senate on December 17, 1979 despite efforts by conservatives to weaken it to the very end.[12]

The tax plan had smoother sailing in the House. Although it was amended somewhat in the Ways and Means Committee (with higher tax rates on most categories of oil), it was more in line with President Carter's original proposals than the Senate version.[13] The bill (H.R. 336) received the required rule from the Rules Committee and was approved by the House on June 28, 1979.[14]

The two versions were, of course, sent to a conference committee on December 19 of the same year. A compromise between the two versions was eventually hammered out. The final bill, according to the experts, would soak up one half of the $442.4 billion that the industry would supposedly make in windfall profits in the coming years. In contrast, the Senate bill would have taken 38 per cent and the original administration proposal 64 per cent.[15] The House accepted the conference report on March 13, 1980.[16] The Senate approved the report on March 27, but not before conservatives made a last ditch effort to have the report referred to the Finance Committee.[17] The President signed the bill (Public Law 96-223) into law on April 2, 1980.[18]

CHAPTER II

OIL INDUSTRY HISTORY

The relationships that have existed between the oil industry and the federal, state, and local governments have been rather complex over the century or so in which the petroleum industry has been in prominence. These relationships have changed considerably from time to time. At times, industry-government relations have been quite cordial, but there have also been eras of indifference or even outright hostility between the two.

It is not surprising that some degree of controversy should surround the American petroleum industry. It is very large and requires vast amounts of capital. Since a stable and adequate supply of relatively cheap energy is of vital concern to any nation, national governments have often come to the aid of the petroleum industry. On the other hand, various governments have viewed the industry with some apprehension. Many a national leader has endeavored to place constraints upon the industry lest (in his view) his nation's sovereignty and power be reduced. National governments have often reacted to these fears by nationalizing oil fields (as in the case of many oil producing nations) or (in the case of many Western nations) forming a national petroleum company in order to ensure a supply of petroleum outside the grasp of the major oil companies.

The modern oil industry was born when Edwin Drake struck oil in Pennsylvania in 1859.[1] American oil production, climbed rapidly throughout the rest of the century. As for government-industry relationships during this time, it should be sufficient to note that this was the heyday of the laissez-faire philosophy of economics. The local, state, and federal governments, for the most part, kept their hands off the domestic oil industry.

However, the growth of large industrial combinations and the tactics many of them employed stirred a public outcry for the federal government to step in and stop certain abusive practices. Hence, the Sherman anti-trust act was approved, and, eventually, "trustbusters" focused their attention upon the domestic oil industry. Their target was the Standard Oil Company headed by John Rockefeller. Standard Oil had been built into a monopoly through a number of predatory tactics--exaction of rebates from various railroads, local price cuts designed to destroy competition, and other such methods. In 1913, the Supreme Court had Standard Oil broken up into several different regional oil companies.[2] Rockefeller, though, had already moved into the world of finance; the regional companies themselves tended to monopolize their regional markets for a number of years.[3] At any rate, the general public has not easily forgotten this era of oil company machinations, as the attitudes to the recent oil crises glaringly reveal.

The actions of the Justice Department, of course, were not really indicative of an adversary relationship between the petroleum industry and the federal government. Cooperation between the two has been quite common over the years. On occasion, however, the government view has been one of indifference or even hostility. For an example of both, one must look at the period immediately after the First World War. At that time, there was great apprehension in the ranks of the Washington bureaucracy over the apparent deterioration of American oil reserves. Fearful that the United States might be left without any direct access to sources of crude oil, the State Department championed the cause of the major American oil companies in their struggle to open up Middle East oil concessions controlled by foreign oil companies.[4] Hence, Exxon and Mobil were able to enter the Iraq Petroleum Company in 1928.[5] Later, other American oil companies won important concessions in the Middle East. In 1936, for instance, Texaco and Standard Oil of California both entered into a joint venture to extract Bahrein oil. SoCal also won oil tracts in Saudia Arabia.[6] However, by this time, the U.S. State Department was no longer interested in securing oil concessions for American oil firms in the Middle East, for new oil reserves had been discovered in Texas; the federal government no longer felt an urgent national security need for assuring foreign supplies of petroleum.[7]

An even more interesting example of cooperation took place between the British government and British oil interests. With the encouragement of the British Foreign Office, the American, British, Dutch, and French members of the Iraq Petroleum Company agreed to obtain oil regions in most of what was once the Ottoman Empire only with the permission of the IPC.[8] This agreement had the effect of strengthening the international positions of British Petroleum and Royal Dutch/ Shell.

As for the European market, the sundry national governments paid little heed--or, perhaps more accurately, practiced a policy of benign neglect--to the activities of the petroleum companies. When a price war broke out in 1927 between Standard Oil of New York (Mobil), Royal Dutch/Shell, and British Petroleum, the companies were eventually able to formulate the Achnacarry Agreement for maintaining their respective market shares for oil products.[9] Whether or not these arrangements were a success is somewhat questionable.[10] But what is interesting is that little was done by the various national governments to impede these arrangements.[11] Indeed, several nations, such as France, actively encouraged such agreements.[12] Again, the activities of the oil companies left a residue of public mistrust that was to haunt the industry at a later date.

In the United States, relations between the oil industry and the state and federal governments also revealed a mix of indifference and cooperation. Two important issues were to become prominent during the years leading up to the Second World War. First, there was an inexcusable amount of waste in the production of American crude oil, especially in terms of premature exhaustion of petroleum reservoirs by operators sharing the same reservoir.[13] This resulted in a concomittant excess of investment into oil reservoirs. Secondly, the discovery of large new oil deposits and the Great Depression depressed the price of crude oil.[14] Not surprisingly, the state governments of the oil producing states began to search for solutions to these problems, especially after President Coolidge's administration balked at getting the federal government involved in the reservoir conservation problem.[15] Oklahoma was the first state to put controls on the production of crude oil, but the discovery of giant new reservoirs made cooperation among the state governments necessary for adequate production control to take place. As a result, a number of meetings were made between oil state governors in 1934 and 1935. Despite difficulties, an agreement (the Interstate Compact to Conserve Oil and Gas) was made to lower the high production rates that were hurting the industry.[16] Rules were also devised concerning well-spacing, pressure maintenance, and so forth. But the objections of Texas governor Alfred seriously weakened plans to give the resulting interstate committee power to assign production quotas to the states.[17] In response to this situation, Congress passed the Connally Hot Oil Act in 1935 which specifically forbade a state to allow more production than allowed under its assigned quota.

With this new law to back up their decisions, state agencies were able to restrain the output levels from oil wells by distributing portions of the estimated demand for oil. These prorationing schemes had a number of important impacts. Although there were undoubtedly beneficial results in terms of more sensible extraction of reservoirs, prorationing probably propped prices up somewhat. Furthermore, since stripper wells (marginal wells with an output of less than ten barrels a day) were exempted under most prorationing rules, these high-cost wells were able to remain in operation. In contrast, the high-volume, low-cost wells were penalized under the prorationing rules.[18]

The prorationing system was not the only example of oil industry-government cooperation before World War Two. The oil industry, for example, was able to obtain special tax provisions. The percentage depletion allowance that was set down by Congress in 1925 established a 27.5 percentage of gross revenue from oil extraction that could be exempt from taxation.[19] On the other hand, the federal government was stringent at times in its enforcement of anti-price fixing statutes.

Important developments were to surface during the aftermath of the Second World War. For one thing, the United States had become a net importer by the late 1940's. Also, many national governments, out of fear of the oil majors and various other reasons, formed public oil companies or encouraged indigenous private oil companies to take a greater role in the international petroleum trade. These governments wanted to bring more of their nation's oil supplies under what they considered to be more sympathetic control.[20] As for the oil exporting countries, many were angry over what they considered to be the reluctance of the oil majors to increase oil production and royalties.[21] Indeed, when the Saudi government demanded more oil revenue in 1950, the U.S. government allowed the oil majors to write off the higher taxes as a tax credit--the U.S. government feared angering the Saudis over this issue.[22]

But there were other trends that were to prove much more ominous to the oil majors. Oil prices were contracted during the late 1950's due to the 1958 recession and Venezuelan and Russian oil.[23] This decline in oil prices led the embattled oil producing nations to form OPEC in 1960 and their subsequent determination to gain control over oil prices and output. The entry of smaller American oil firms, with some assistance of the U.S. government, into the Middle East greatly attentuated the power of the oil majors. This was especially true for Libya, where independents like Occidental, Amerada, and Bunker Hunt gained access to new crude oil reserves. Due to the pressure of the Libyan government, these independents increased their output and cut their prices in order to undercut the oil majors.

By the late 1960's, the world's oil situation was reaching a delicate stage. The oil majors were being buffeted by the oil producing nations over royalties and crude oil prices. The drop in crude oil prices that was instigated by the independents and their cheap Libyan oil fueled the rising world demand for Mideast oil. Few people realized it at the time, but the latent power of OPEC was growing.

Still, there might not have been a 1973 oil crisis had the United States government been more protective towards its oil interests. For instance, when Algeria and Libya moved against the small independents in 1969, the American government did little to back up the helpless companies.[24] Most of them had few other reserves and were in a most vulnerable position. It did not take long for OPEC to press for greater demands that were granted at the April 1971 Teheran agreement. Increasing demand for oil and the Dollar crisis lead to still greater OPEC demands. By early 1972, Saudia Arabia, for example, was able to gain twenty percent of Aramco's Saudi holdings.[25]

As the reader well knows, political considerations in the form of the Arab-Israeli conflict also entered into the picture and led to the 1973 oil embargo. The positon of the American government in the days before the embargo, however, must have emboldened the Arab countries. For instance, the actions of American officials greatly undermined the oil companies' position in the negotiations leading up to the Teheran agreement.[26]

In retrospect, the world was entering a new era in terms of petroleum. The age of "cheap" oil is now well over. This may seem like an incongruous thing to say in light of the fact that world oil prices are cheaper today than at the beginning of the century. Nevertheless, the situation is far removed from that earlier age. Most areas of the world have now been explored; one can predict with some accuracy on the total amount of crude oil still left to be extracted. Furthermore, the new reserves coming on line will cost more to extract than the earlier "choice" reservoirs that have been developed. Assuming that world demand for oil will continue its upward climb, it takes no expert knowledge to realize that oil prices will probably continue their present climb. In such a world, the organization that controls the oil reserves is the master of the situation. This is, of course, the position of OPEC today. Its ownership of more than a third of the world's oil production and more than half of the world's crude oil reserves gives it the power, to a limited extent, to set crude oil prices. To be sure, there are differences between the various member nations that may one day lead to a break up of the cartel: Iran, with its relatively small reserves and large population, is more interested in gaining as much revenue from their limited reserves as possible in the next few years; Saudia Arabia and Kuwait, with their huge reserves and small populations, are more concerned with maximizing the value of their oil wealth over the long term.[27] Still, OPEC probably has enough common interest to keep the price of curde oil stabilized at a high price for quite some time.

Although this new era of oil was perhaps inevitable, stronger support for American oil companies by U.S. government officials might have made the transition longer and less abrupt. It is not readily discernable why the American government, which had initiated import quotas on crude oil in the late 1950's in the name of national security, was not more forthcoming toward its domestic oil industry's problems with OPEC. It is certain that the domestic energy and economic situations, though, were an important influence on American decision-makers. Thus, it is time to take a look at the situation in the United States at this time.

The post-World War Two period was one of enormous change for the American petroleum industry. Not only did new, independent firms enter into the production of Mideast oil for the first time, but there were also new entrants into the domestic market. Many new corporations entered the domestic petroleum market at many different levels--crude oil production, refining, marketing, and so on. The domestic market became much more competitive at every level. Another, much more important development took place in the late 1960's. At this time, the growing exhaustion of American oil reserves was becoming prominent. It has been estimated that, before the start of the petroleum industry, there were around 180 billion barrels of crude oil to be recovered in the United States. By the mid-1970's, over 100 billion barrels of this crude oil had actually been extracted.[28] New oil discoveries can still be made, but only at greater real costs.[29] Hence, the increasingly tight conditions has made it increasingly impossible for the domestic oil industry to satisfy America's thirst for oil with domestic supplies.

To ameliorate such conditions, the nation has basically two options: import more oil or let the price rise to stimulate production and conservation. By 1974, the import option was obviously no longer a viable option, at least for Mideast oil. But complications were to also arise over the second option. Mindful of some of the oil industry's past actions, many consumers and politicians are convinced that the oil majors are manipulating the price of oil and that no real oil crisis exists. These attitudes partly explain the reluctance of policy makers to lift petroleum price controls off the industry. These attitudes have also formed a basis of support for the windfall profits tax.

The new controversy over domestic oil prices is due partly to the asymmetric distribution of crude oil reserves in the United States. Most of the nation's oil wealth is concentrated in Texas, Louisiana, Oklahoma, and California. Other states, especially the northeastern states, have often resented measures that, in their view, increased oil industry profits at the expense of the consumer.

In consequence, many laws and policies beneficial to the American petroleum industry have been repealed or attenuated by these new pressures. For instance, the oil percentage depletion allowance was reduced in 1969 and then again in 1975. This was a particularly strong blow against drilling ventures since drilling funds are often attracted via the prospective profits that are expected from the project.[30] Criticism was also directed at the import quotas that President Eisenhower had established on foreign oil imports. Northeasterners were especially hard hit by the import restrictions. Eventually, President Nixon, also motivated by his fight against inflation, dropped the entire quota system.[31]

This controversy was just a warm-up for the controversies that were to explode with the explosion of oil prices following the Arab oil embargo. When the oil prices shot upward, pressure from the northeast and consumer groups led to the proliferation of price controls that kept American petroleum prices below world levels and subsidized American consumption of increasingly expensive foreign crude oil imports. These controls were only recently completely lifted. They have been a grave hinderance to energy conservation and production in the United States.

When the United States suffered through a second energy crisis in the wake of the Iranian Revolution, it finally became obvious to most policy makers that price controls were having a detrimental effect on the nation's energy security. However, in order to make decontrol politically palatable, President Carter felt that it was necessary to introduce a windfall profits tax measure. It should not be a surprise to anyone that the funds from the tax have been earmarked for tax cuts and programs to help the poor and elderly--issues that have been of great concern to the liberal politicians of the northeastern section of the country. Thus, the windfall profits tax has to be looked upon as a substitute for oil price controls.

CHAPTER III

OIL PRICE OUTLOOK

Although it is not directly related to the issue of the windfall profits tax, it may be profitable to stop for a moment and try to surmise the world crude oil price situation for the next decade or so. Not surprisingly, most experts expect crude oil prices to rise during the next decade. Possible real price rises are of some significance to our study since these possible price rises can affect the revenue for the tax and hence the beginning of the phase-out.

To predict future real price increases, we must be able to predict future demand and supply for oil. Demand for oil is expected to increase during the next decade. Most of this demand, of course, is expected to come from the industrialized nations of North America, Western Europe, and Japan--the OECD countries. However, some studies suggest that the portion of total oil demand belonging to the industrialized West will actually decline. Indeed, a late report from the Exxon Corporation predicts that the total oil demand of the West will decline from 42 million barrels per day in 1979 to 38 million barrels per day in 1990.[1] On the other hand, the least developed countries are expected to greatly increase their demand for oil.[2] Oil demand is also expected to climb in the Communist bloc countries, but at a much lower rate.[3] These projections must be accepted with a grain of salt; greater conservation efforts in the industrial nations may reduce the total oil demand projections by even more within a few years.

Now we turn to projections on oil supplies. Total world oil supply is expected to increase, but not by an amount that is sufficient to forestall real price rises. Oil output by the industrial nations is expected to fall. This will be due mainly to a fall in American crude oil production. It has become increasingly difficult to find new reserves of crude oil in the U.S. Offshore drilling has been most disappointing; domestic reserves have continued to fall.[4] Indeed, it has been estimated that additions to proved reserves would have to exceed the peak years of the 1950's just to stabilize American crude oil production.[5] The cost of discovering and developing new reserves has also been rising.[6] Little relief can be expected from Alaskan oil; it is expected to peak in the 1980's.[7] Western Europe and Japan, of course, will be unable to meet their demands of oil.

Exports from the Soviet Union are also expected to decline in the coming decade. Indeed, many expect the Soviets to become net importers of oil. This decline will be due to declines in the yields from older oil fields and a decline in the rate of newly discovered reserves.[8] In the last few years the Soviet oil industry has been missing its planned targets.[9] Obviously, the Soviet Union cannot be counted upon to relieve an oil shortfall.

Although oil demand is expected to rise greatly among the least developed countries, it is also expected that these countries, overall, will be able to supply this increased demand with their own increased production of oil.[10] Hence, only the OPEC countries can meet the higher oil demand of the future. But it is not clear if they will do so. Saudia Arabia, the main OPEC producer, is not expected to produce above its present levels of around 8.5 million barrels per day. The Saudis will not produce above this level for a number of reasons: fears of affecting ultimate recovery, the socially disruptive effects of high domestic spending, and so forth.[11] After all, it has been estimated that the Saudis could satisfy their minimum revenue demands with an output of only 2.3 - 5.0 million barrels of oil per day.[12] Of the rest of OPEC, only Iraq is expected to boost production in the coming decade.[13] It is apparent that real oil prices will be rising in the future.

How high will a barrel of crude oil go? No one can know for certain. But one government forecast has predicted a possible price of $44.00 (in 1979 dollars) per barrel of crude oil by 1990.[14]

CHAPTER IV

THE NATURE OF PETROLEUM RESERVOIRS AND SOME IMPLICATIONS

It is of considerable importance in understanding the economic models in this paper that one understand how extraction rates can affect the total recoverable crude oil stock of a petroleum reservoir. Thus, the reader will now be given a short geology lesson on the nature of a typical crude oil reservoir.

Actually, there is no such thing as a "typical" petroleum reservoir. All petroleum reservoirs differ in their geological characteristics. In general, crude oil reserves are found as pockets in geological "traps." The crude oil was created by heat and pressure forces acting upon the remnants of pre-historic vegetation.[1] Over time, these liquids and gases flowed into the geological traps where it could no longer flow to areas of low potential energy.[2]

Hence, the crude oil is itself extracted by the use of pressure differentials. Imagine that a wildcatter punches through the trap boundary with an oil bit. If the pressure within the oil pipe is lower than the pressure within the newly found oil reservoir, then the liquid crude will be forced through the steel pipe to the surface.[3] The hydrostatic pressure (the pressure on the pool of crude oil) on the reservoir, then, is normally the force that enables the oil producer to bring his crude to the surface for marketing to the refiner.

There are three broad types of "natural drives" through which the hydrostatic forces can push the crude oil to the surface. (Actually, it can be said that there are four more types of drives, for there can exist any combination of the three types to be explained.) The crude oil, since it can be compressed only slightly, offers little in the way of a pressure drive; the low-pressure bore would soon exhaust the crude oil pressure.[4] Thus, the requisite pressure within the reservoir is maintained by certain gases and/or liquids.

The first drive we shall study is the "dissolved-gas drive" which is probably the most common drive to be encountered by an oilman. Practically all crude liquid reservoirs have at least some dissolved natural gas. This dissolved gas is the medium that absorbs the hydrostatic forces that are imposed upon the reservoir--the gases are dissolved into the liquid crude by the hydrostatic pressure.[5] When a unit of crude oil is extracted from the reservoir, a corresponding amount of natural gas comes out of solution to fill the pore spaces emptied by the extracted crude.[6] Accordingly, as production continues, the reservoir gradually becomes primarily a natural gas reservoir. The natural drive provided by the once-dissolved gas loses its potency as the transition to natural gas production commences.[7] This type of drive is quite inefficient in comparison to other drive-types. Indeed, crude oil yields from these reservoirs usually amount to only ten to thirty per cent of the amount of crude oil that is actually located within the reservoir.[8] However, it is sometimes possible to convert a dissolved gas reservoir to a different type of drive.[9]

The second type of drive is known as the gas-cap drive. This occurs when there is a pocket or bubble of gas at the top of the oil reservoir. It is sometimes also possible to create a man-made pocket of gas in the reservoir.[10] As the oil pipe drains the crude oil, the gas bubble expands to fill the vacuum left in the pore spaces by the extracted oil. This type of drive is fairly efficient if the pressure in the gas cap can be sustained through injection. Otherwise, the gas-cap drive is no more efficient than a dissolved gas drive, for the gas is a poor displacing agent.[11]

A third type is the water drive. In this case, the water is at the bottom of the reservoir. This water must be under a greater pressure than the oil portions of the reservoir in order to drive the crude into the operator's bore. It is also possible that the water will be at the reservoir boundaries, pressuring the crude oil inward instead of upward.[12] Obviously, there must be a large water reservoir contiguous to the petroleum reservoir if the water drive is to remain at an adequate level.[13] Of course, it is possible to pump water into the water-saturated portions in order to maintain the drive. Due to the fact that water does a better job of displacing the crude oil than natural gas, water-drive reservoirs tend to be much more efficient than gas-drives; percentages of the reservoir oil recovered can be as high as ninety per cent.[14]

There are many other geological characteristics of an oil reservoir that can have a bearing on oil production. For one thing, the hydrostatic pressure on the oil reservoir normally varies directly with the depth of the oil trap in question, although there are exceptions to this maxim.[15] There are numerous other reservoir variables that are of importance. The porosity of the reservoir rock--that is, the total amount of pore space per cube unit of formation rock--is significant in considering the displacement potential of gas and water. The degree of ease by which liquids can flow through the reservoir rock (permeability) is again of significance when considering the use of natural or artificial drives. The temperature of the reservoir oil and its specific gravity (whether or not it is "heavy" oil) must also be taken into account by the reservoir operator when he maps out his extraction strategy. And, of course, there is the pressure within the oil reservoir itself.[16]

Furthermore, it should also be mentioned that the surrounding rock formations and the type of trap that the reservoir is located in may influence drilling decisions.

For example, many reservoirs are associated with geological faults.[17] The oil producer will probably avoid drilling through such a fault, lest a shift in the rock along the fault snap his bore in two.

Naturally, the reader is probably asking himself why we have sidetracked ourselves on this geology information. The reason is quite simple but very cogent. The amount of crude oil that can be extracted in a period of time (let us say one year) may very well be dependent upon the quantity of oil recovered in a previous year. Indeed, the total stock of crude oil that can be recovered is often somewhat dependent upon the production rates attained in the early years of reservoir production. These possibilities arise due to the possible interactions between the drives of the reservoir, the reservoir rock, and the crude oil, gases, and water inside the reservoir. For instance, suppose for a moment that we are producing early in the production life of a water drive reservoir. If the crude oil is extracted at a very high rate, then some of the reservoir oil may be lost if the water moves around pockets of some of the oil. This problem might arise due to the capability of water to move through most types of reservoir rock more easily than crude oil.[18] Similar extraction rate problems may present themselves with a gas-cap reservoir. If the crude oil is extracted too quickly, then the gas may furrow its way through the liquid oil portion of the reservoir to the oil well bit when the gas flows through the more permeable sections of the reservoir rock. The ultimate oil recovery will eventually be less; more oil could be recovered in the long-run if the oil had been drained at a rate consistent with the potential of the gas-cap to expand and replace the vacated crude.[19] Of course, it is possible that injected gas or steam could be used to rebuild the gas-pressure drive in this example, but the surrounded oil reserves in the example are lost forever.[20] Besides, it only makes sense to make as much use as possible of the natural drives one has handy.

Nevertheless, the discriminating reader may not be impressed by these facts. After all, it is often true that for some reservoirs almost any level of present production will lessen the ultimate recoverable stock of crude oil. In such cases, it is preferable to arrange the rates of extraction in every production period in such a manner as to equate the marginal net revenue (discounted for time) acquired in each production year, all other things being equal during the reservoir life.[21] Such an arrangement maximizes the present value of all future cash flows from production.

Unfortunately, though, American legal views and the patterns of reservoir ownership in the United States have often precluded the achievement of such maximizing relationships for individual reservoirs. The "rule of capture" for petroleum recovery has been the major obstacle. For an example of this, let us imagine that there are two oil producers extracting from the reservoir independently of each other. According to the courts, if some of the oil captured by one of the operators has actually been drained from under the other producer's property, that quantity of oil is nevertheless in the possession of the operator who extracted it. Such a legal view may be logical to a lawyer, but there have been highly detrimental economic consequences of this view. Lest he lose some of his oil stock to his neighboring producer, a reservoir operator in this situation will extract oil at the highest rate possible. Hence, the reservoir will be extracted at a rate that is greater than the rate consistent with the greatest ultimate recovery. Valuable oil will be lost over the life of the reservoir due to such competitive production. Moreover, this situation occurs frequently due to the small size of American land-holdings relative to reservoir sizes.[22]

Thus, "unitization" agreements on oil production are needed if shared petroleum reservoirs are to be utilized in the most economical manner possible. However, state governments have not always been supportive of reservoir unitization. Although there has been considerable progress over the years, less than one-half of all American crude oil came from unitized reservoirs during the mid-1970's.[23] Also, state agencies have not always been known to be overly stringent in their enforcement of petroleum conservation laws.[24] It should also be noted that the purchase and leasing of potential oil-bearing land owned by the federal government is still accomplished in a manner that fosters fragmented ownership of oil reservoirs.[25] Despite these barriers, one should not overlook the progress that has been made. Many oil states now have unitization laws and other oil conservation measures, and there is now less wastage of oil stock.

Before we completely leave the subject of petroleum reservoirs, a note should be made of the various "advanced tertiary" techniques that have been developed in recent years. A tertiary technique consists of the injection of detergents into a crude oil reservoir. The detergents aid oil extraction by reducing the ability of the crude oil to adhere to the reservoir rock.[26] The detergents enable the crude oil to flow together and is hence easier to recover from the reservoir.[27] Other chemicals can be added that lower the viscosity of the crude oil. Obviously, such tertiary techniques could be used in conjunction with other natural and artificial recovery procedures. These new techniques have tremendous potential, but they are at this stage exorbitantly expensive and research into these methods has yet to be finished. Unfortunately, the joint ownership of many American oil reservoirs may also be an obstacle to the diffusion of such future techniques in the American oil industry.[28] The windfall profits tax provisions on tertiary oil are not very helpful, either.

CHAPTER V

THE EFFECTS ON INDIVIDUAL PRODUCERS AND WILDCATTERS

If we are to discern how the windfall profits tax will affect American crude oil production, we must understand how the tax will affect the independent operator of a petroleum reservoir and the individual wildcatter who desires to find new sources of petroleum. We shall first take up the situation of the operator of an oil reservoir.

However, there is a need for a short digression before we take up the subject. The astute reader may find the above emphasis questionable. After all, the major oil corporations, which own a large proportion of American crude oil reserves, are considered to be oligopolistic in nature. Is it possible that these huge corporations are using their market power to induce crude oil prices and production rates that deviate from what one would find under fully competitive extraction of oil? Such a situation is certainly plausible, but it is unlikely that such market power has any real effect on crude oil prices or production rates at the present time. There are several reasons for such a conclusion. First, and most importantly, we must remember that the OPEC cartel sets the world price for crude oil, at least for long-term contracts. Thus, all domestic producers--large and small--tend to be pricetakers. Another important consideration lies with the vertical structure of the larger domestic oil companies. Some of these companies are relatively more involved in production activities than in refining or marketing activities; on the other hand, other companies base their operations in refining or marketing. Consequently, the oil majors often sell and buy crude oil between themselves; the market power of these large corporations tends to be counterbalanced.[1]

Now, it is time to delve into McDonald's model of oil production. Let us suppose that we have a fairly well developed petroleum reservoir operated by a single operator. This operator, quite naturally, wants to maximize the total profits that can be gained from the total stock of oil that is to be extracted from the reservoir during the reservoir's production life. As McDonald points out, there are many factors for him to take into account: the reservoir's "natural drive," possible alternative artificial drives that may be employed, the possible rates of production under different drives and different numbers of wells, the costs of drilling new wells (if the operator wishes to speed up depletion), the costs endured under different drives and rates of production, the loss of possible reserves under different drives and rates of production, and, perhaps most importantly, expected prices, taxes, and tax deductions over the life of the reservoir.[2]

The operator must find, in order to maximize his return from the reservoir, the most profitable production rate at each point of time in the reservoir's production life; he desires to maximize the present value of the potentially recoverable reservoir oil under a minimum rate of return. Borrowing from McDonald, we can show the operator's present-value-maximizing condition through the following model:[3]

(1) $$MNR_0 = (1+b_t)\ (MNR_t)/(1+r)^t$$

where MNR_0 = the marginal net revenue, or the increment to net revenue from a unit shift in production to the present period (t=0).

MNR_t = the marginal net revenue from a unit shift in production to a future time period t.

b_t = the fraction of a unit of production lost from ultimate recovery in the indicated period as a result of producing the last unit at the present time period.

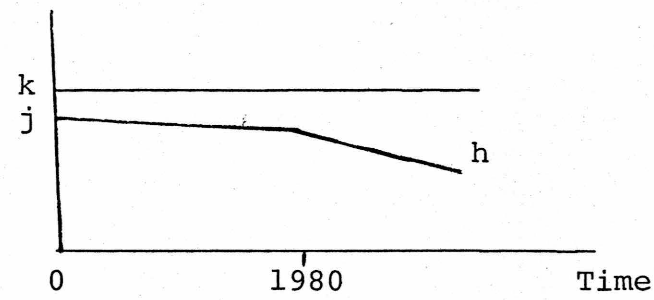
r = the rate of discount; the rate of interest that has been adjusted for risk, uncertainty, and inflation.

When the condition (1) holds for an oil producer, the oil producer will be indifferent toward shifting a unit of crude oil production between the present and future production periods. However, if $MNR_0 > (1+b_t)(MNR_t)/(1+r)^t$, then it would be profitable for the operator to shift some production to the present period. Likewise, if $MNR_0 < (1+b_t)(MNR_t/(1+r)^t$, then it pays to shift some production to period t.[4] It should be noted that b_t may very well have a value of zero. This might be possible very early in the reservoir's production life. Artificial recovery techniques might also result in $b_t = 0$.

Now, if the operator expects the future real price of crude oil to be greater at the future period t, then the operator will obviously gain by shifting some production to time t, all other things being equal. Since it seems likely that the future will hold such price increases, this is basically the position we are in today. Oil producers hold back their present production a bit because they feel that future oil prices will be somewhat higher.

It should be noted, however, that the recent decontrol of crude oil prices has probably led to a shift in production to the present. Under President Carter's decontrol program newly discovered oil was exempt from price regulations. On the other hand, the lower tier of price controls--"old" oil that was equal to the amount of oil produced from the well in question in 1972 minus "released" oil that was produced unit for unit with the amounts of "new" oil produced above the 1972 production boundary--was priced at \$5.86 in May 1979.[5] A "decline curve" was used to deregulate this old oil. The decline curve was fixed by adjusting the "base production control level" downward by one and a half percent per month till the beginning of 1980 and by three per cent per month afterwards.[6] In May, 1979, the ceiling price for such oil was $13.06 per barrel.[7] The following diagram of production from an imaginary well may be helpful in explaining this decline curve:

Oil Production per year in barrels



Here, the x and y axes refer to the time periods involved and the level of oil production per year, respectively. The production level j is the 1972 production level that was used as the production boundary between oil and new oil; k denotes the production rate of the well during this period. For our purposes, it is assumed to be higher than the 1972 production rate. The h curve is the decline curve that was used for oil decontrol. Please note the steeper (three per cent per month) slope after the first of January, 1980. Oil production above this line was priced at world prices; the production below the line was priced at $5.86. While this scheme was in effect, it is plainly obvious that many operators who were producing near their 1972 production levels probably elected to shift a unit of oil production to the present despite possible increases in costs in order to gain a greater net revenue under the recent oil price decontrol.

The windfall profits tax, predictably enough, will also cause similar shifts in production over time, for the system of taxes is designed to be phased out after a still-to-be-determined date--perhaps as early as January, 1988. For example, let us multiple the MNR_0 of an operator by the windfall profit tax of some percentage $\theta (0<\theta<1)$ of net revenue, where the MNR_0 is equal to a $(1+b_t)(MNR_t)/(1+r)^t$ of a time t later than the October 1990 deadline for the initiation of the phaseout period of the windfall tax. When θ is applied, we naturally find the following inequality:

(2) $$\theta(MNR_0) < (1+b_t)(MNR_t)/(1+r)^t.$$

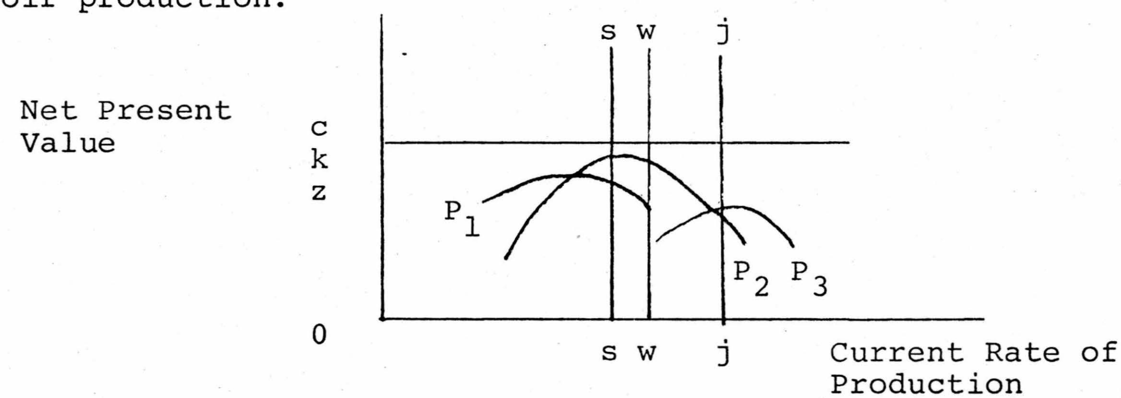
Hence a unit of production will be shifted to the future time point t. Thus, due to the windfall profits tax, we would expect all those reservoir operators who still expect to be producing oil from the reservoir during and after the phase-out period, and whose reservoirs have a $b<0$, to shift some of their production to future time periods in order to gain greater profits over the life of the reservoir.

Such a windfall profits tax cannot be considered to be beneficial to society, at least not under the assumptions upon which the above model is based. For example, since McDonald assumes that the operator will produce along a time path that maximizes the present value of his expected income, he will increase his addition to the existing number of oil wells to the point where the increment to maximum present value is just equal to the increment to cost in order to maximize the present value of his expected income. This activity is assumed also to maximize society's net benefits over time due to the assumption that the costs and income from the reservoir are the same for both the operator and society.[8] However, as we have just seen, the windfall profits tax impedes this optimal time-path of reservoir extraction and thus decreases the optimal number oil wells.

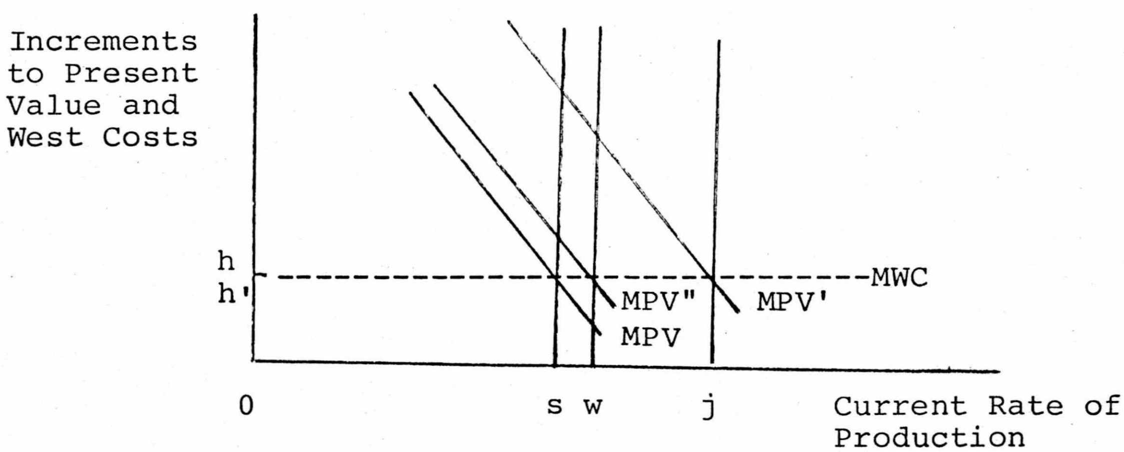
Of course, nothing is as neat and perfect as the situation depicted above. There are always externalities in every economic activity or market that distort the true benefits and costs to society. For instance, since the use of refined oil as a fuel creates dangerous air pollutants, the above assumptions are somewhat illusory. An excise tax on crude oil would help to "internalize" such external costs, although an excise tax on the refined oil products in question (gasoline and so forth) would be even better. Another external cost would be the threat of a Persian Gulf oil cut-off. In order to meet such a contingency, it would be wise for the federal government to create incentives for excess production and storage capacity.[9]

But the externality we are most concerned with is related to the ownership patterns that exist in American oil reservoirs. Individual landholdings in the United States are usually much smaller than the underlying petroleum reservoirs.[10] Coupled with the "rule of capture" that has been expounded by the courts, this situation has created severe external costs in the extraction of crude oil. The various operators of a reservoir will extract oil at the greatest rate possible for a time period t--they literally compete to produce the greatest amount of oil possible. If an individual operator produces at a less-than-maximum rate for a particular time period, then he risks losing the foregoing production to one of the other operators.[11] Needless to say, such a situation can be costly in terms of the ultimate extractable oil stock and will also reduce the amount of benefits to society from the extraction of oil.[12] The following diagrams describe such effects of competition style reservoir production:[13]

A.



B.

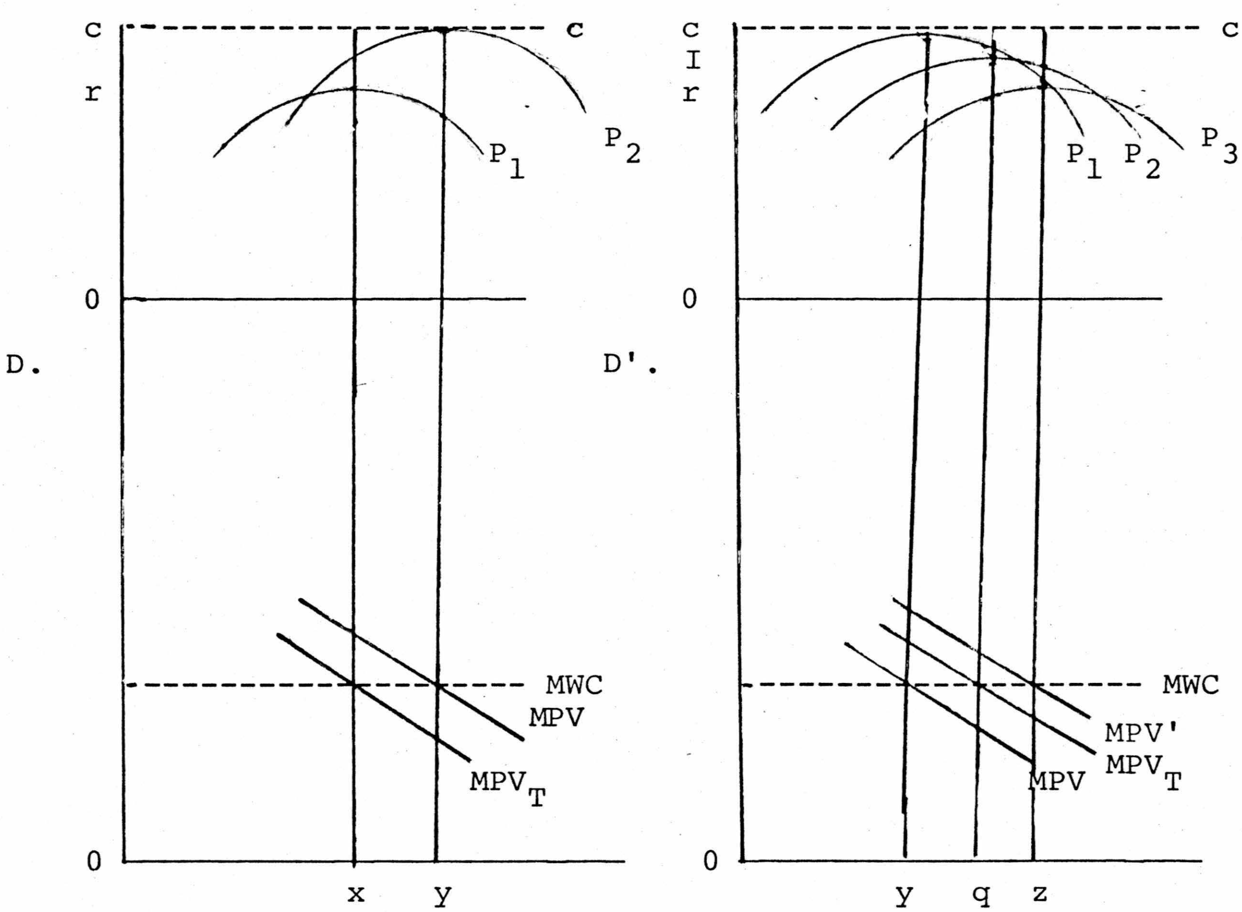


where the current rate of production is considered to be a proxy for the time-path production--the higher the current rate of production, the more concentrated is production in the early time periods. The point c on the y-axis of diagram A indicates the maximum present value of production in the reservoir when the reservoir is operated as a single unit at an exogeneous rate of interest which is equal to the producer's rate of return.[14] The curves P_1, P_2, and P_3 represent the net present value that can be gained from a given number of oil wells with the number of wells increasing with a greater subscript. The MWC line in diagram B shows the incremental well cost which is assumed to be constant, while MPV is the curve that plots the incremental maximum present value.[15]

Now, if each operator competes for the reservoir oil against the other operators, he will increase his production rate from the maximizing current rate of production at s to the new rate j. Since an extra number of wells will enable the operator to take oil from his neighbors, there is a bonus increment to the maximum present value as the number of wells is increased.[16] Thus, the operator has a MPV' curve that is to the right of the MPV curve for production when the reservoir is operated as a single unit. As the A diagram reveals, the operator has increased the number of oil wells in order to extract more oil. It is also self-evident that the producer has lost gains from production.[17] Indeed, if we assume that the gains to society over time of oil extraction is equal to c, then such pell-mell extraction is creating unnecessary costs to society.[18] Not only have the gains to society (represented by the c net present value line) been reduced to k, but some of society's resources in the form of extra oil well capacity has been wasted since society can have greater benefits from the reservoir with a smaller number of oil wells.

It is now time to consider the effects of the windfall profits tax upon this situation, and, for comparison's sake, the "normal" case of an oil reservoir operated as a single unit:

C. C'.



where the axes are the same as in the earlier diagrams. A windfall profits tax applied to a unitized reservoir operator induces a shift in his MPV to MPV_t, which is at a lower current rate of production x. He also moves to a lower number of operational wells--if that is indeed possible. It is quite clear that the operator is not achieving his possible maximum net present value. Furthermore, under our present assumptions, society is not realizing the highest gains that are possible. However, for the case of the independent producers given by diagrams D and D', the results are somewhat different. Under operator competition, the individual operator's MPV shifts to MPV' with the undesirable results that have already been mentioned. But when a windfall profits tax is applied, the operator's MPV is shifted to MPV_T at a lower rate of current production, a smaller number of oil wells, and a net present value that is closer to the net present value obtained under normal conditions. Assuming c to be the net present value that is optimum to society as a whole, a windfall profits tax can help in cutting the costs to society resulting from uncontrolled extraction of oil reservoirs.

We can also show how the independent operator will allocate production with a given number of oil wells--that is, how the current rate of production is shifted along one of the P curves in the above diagrams. To do so, we shall have to modify the MNR equation in order to take account of the unrestrained production activities of the other producers in the field:

(3) $$MNR_0 = (1-X_t)(1+b_t)\ (MNR_t)/(1+r)^t$$

where X is, according to McDonald, the "fraction of a unit of production drained by neighbors in the period indicated as the result of the last unit of production postponed."[19] The value of X is inversely related to the operator's efforts to raise the production of his section of the reservoir--the faster he develops his part of the reservoir, the smaller the value of X.

It is clear that if the values of MNR_0, MNR_t, and b_t that gave an equality in the earlier restrained production MNR equation are plugged into the new MNR equation for a given X $(0<X_t<1)$, an inequality will result with the right-hand of the equation being smaller than the left-hand side. Hence, a unit of production will be shifted from period t to the present.[20] If we were to apply a windfall profits tax to the present time period, this production-shift effect could be considerably ameliorated. Indeed, the production shifts could, with a sufficient tax rate, be cancelled. Consequently, for some reservoirs operating under unrestrained operation, a windfall profits tax can be a partial substitute for the lack of a unitization agreement among the various reservoir operators. In order to completely negate the effects of unrestrained oil extraction, the percentage windfall profits tax θ would have to be equal to the multiplier $(1-X_t)$. The tax can perhaps be thought of as a "second-best solution" to the problem of unrestrained petroleum production. An unitization agreement among the various reservoir operators would, of course, be the best solution. It should be noted, however, that some careful thought will have to be given to the design of these agreements if the major oil companies are not to utilize them in price-fixing attempts.

Since, under the given assumptions, the effects of a windfall profits tax upon a unitized reservoir and an unrestrained reservoir have differing effects upon the benefits society receives from oil production, it is now prudent to ask ourselves what the overall effect will be. Obviously, the proportion of the nation's oil reservoirs that are unitized and the total reserves of those reservoirs relative to the total reserves of unrestrained resrvoirs are the deciding factors. In this context, it is important to point out that most oil producing statutes do have some sort of a compulsory unitization law.[21] However, Texas, the most important oil producer among the lower forty-eight states, still does not have a unitization law. True, the Texas Railroad Commission has the ability to legally limit production from Texas oil wells, but, since the 1973 Arab oil crisis, wells of Texas and other oil-producing states have usually been allowed to produce at the full amount possible under the respective reservoirs' natural drives.[22] When considering the low prospects for increasing the nation's oil reserves, such a situation can only have a deleterious impact on the nation's energy future. A windfall profits tax, by slightly lowering oil production in these reservoirs for the next ten or so years, ameliorates the situation somewhat. However, a national unitization law would be better, for it would allow the cognizance of the individual characteristics of every petroleum reservoir.

Now, a word about McDonald's model. Although it is helpful in identifying the effects of price increases and windfall profits taxes upon present and future rates of production and the choice number of oil wells, it does have certain limitations. For one thing, it does not measure the effects of price and tax increases upon investment (other than oil well investment) in proven reserves. Also, McDonald's model is, in a sense, rather unsophisticated; it does not include all of the factors that affect production rates. Moreover, it says nothing about the effects of the tax when it is levied upon a reservoir for that reservoir's entire production life (for instance, a reservoir that runs dry before the end of the phase-out of the tax in the late 1980's or early 1990's). Hence, it is now time to turn our gaze toward a more sophisticated reservoir production model.

THE KULLER AND CUMMINGS MODEL

The following model for petroleum reservoir management has been formulated by Robert G. Kuller and Ronald G. Cummings. It seems appropriate to utilize this model because it gives a better picture of the factors that influence the levels of production and investment in an oil reservoir. McDonald, in contrast, does not directly incorporate these factors into his MNR model.

Suppose that we have an oil reservoir and we also have the adequate knowledge--the pressure drive of the reservoir, the fluid properties of the reservoir, geological properties of the reservoir rock, and production rates--for our petroleum engineers to calculate different reservoir performance curves under different annual rates of production.[23]

We now have a "planning horizon" of T times periods with t=1, 2, ..., T, with the following variables:[24]

u_t = total volume of petroleum extracted during the present time period t.

U_t = $(u_1, u_2, \ldots, u_t)$, the total set of oil volumes extracted during the production periods 1 to t.

v_t = gross investment for all capital components for the reservoir for period t.

V_t = $(v_1, v_2, \ldots, v_t)$, the total set of the gross investments for all periods up to t.

X = total recoverable quantity of petroleum in the reservoir.

K_t = capital stocks at the beginning of period t.

F_t = upper (physical) bound on the capacity to extract petroleum at t.

C_t = the "generalized" cost function for production of oil at t.

Kuller and Cummings submit the following relationships for our typical petroleum reservoir:[25]

(1) $\sum_{r=1}^{T} u_r \leq X(U_T, V_T), \partial X/\partial u_r \lesseqgtr 0, \partial X/\partial v_r \geqq 0.$

This merely states that the total petroleum production over T periods cannot be greater than the total recoverable stock X, which is in turn a function of the time-paths of production and investment over the same period. Note that an increase in production during a single production period may lower X, while an increase in gross investment for a period may increase X.[26] This is what we would expect from what we know of the nature of petroleum reservoirs.

(2) $u_t \leqq F_t(U_t, V_t, K_t), \partial F_t/\partial u_t \leqq 0, \partial F_t/\partial v_t \geqq 0, \partial F_t/\partial K_t \geqq 0.$

This equation shows the limit on annual production of a reservoir during period t. As we well know, F_t may be lowered by increases in past and present annual production rates, while F_t may be increased by past and present increases in investment as well as increases in capital stock.[27]

(3) $C_t(U_t, V_t, K_t), \partial C_t/\partial u_r \geqq 0, \partial C_t/\partial v_t \geqq 0, \partial C_t/\partial v_r \leqq 0,$

$\partial C_t/\partial K_t \leqq 0 \quad (r \neq t).$

This is, of course, the generalized cost function and its determinants. Increases in production in the previous period r may increase unit costs due to some lost natural drive, while increases in gross investment v_r in a previous period r may lower present unit costs. An increase in capital stock, K_t, at the beginning of the production period may also lower unit costs. On the other hand, an increase in present gross investment may increase unit costs.[28] Much depends on the state of the natural drive in all of the above partial derivatives. For instance, if u_t and v_t are at such levels that pumping or tertiary recovery is needed to increase u_t, then obviously $\partial C_t/\partial u_t > 0$.[29]

At this point, Kuller and Cummings proceed to outline a model for petroleum production and investment for the reservoir. Accordingly, some new notation is formed in order to account for the n number of operators that use the reservoir:[30]

u_{jt} = the total volume of petroleum produced by a firm j, j = 1,2,..., n during the time period t.

U_t = annual production rates by all firms during all periods, 1,2,..., t; in other words, $(u_{11}, u_{21}, \ldots, u_{n1}, \ldots, u_{1,t-1}, \ldots, u_{n,t-1}, u_{1,t}, \ldots, u_{n,t})$.

$v_{jt} = (v_{j,1,t}, \ldots, v_{j,q,t})$, the gross investment in all capital components of j during t.

V_t = gross investment for all capital components by all firms during the periods 1,..., t.

K_{jkt} = firm j's stock of capital component k at the beginning of period t.

K_{jt} = $(K_{j,1,t}, \ldots, K_{j,q,t})$, the total stock of all capital stocks at the beginning of period t.

D_{jkt} = net depreciation of firm j's stock of capital component k at the beginning of period t.

F_{jt} = an upper (physical) bound on firm j's capacity to extract oil during the period t.

B_t = a discount factor, $(1+z)^{-t}$, where z is the appropriate discount rate.

p_t = unit price of crude oil during the time period t.

In this petroleum reservoir model, it is assumed (as in the other reservoir models) that the operators are price takers. It is also assumed by Kuller and Cummings that all prices are known for the time horizon. Now, each operator desires to maximize the stream of discounted profits from the sale of oil over the planning horizon.[31] Hence, we have the following relation:

(4) $$\sum_{t=1}^{T} p_t U_{jt} - C_{jt}(U_t, V_t, K_{jt})\ Bt$$

where $p_t u_{jt}$ is the gross revenue to the firm and C_{jt} is the firm's cost function.[32] Of course, for our our purposes, the relation can be restated as

(4') $$\sum_{t=1}^{T} \theta p_t u_{jt} - \theta C_{jt}(U_t, V_t, K_{jt})\ B_t,$$

where θ is the percentage of profits taxed by the windfall profits tax at time t. However, we will continue to use (4) in order to fully protray Kuller and Cummings' reservoir management model.

The production process is restricted by the following relations:[33]

(5) $K_{jk,t+1} = K_{jkt} - D_{jkt}(u_{jt}, V_{jkt}, K_{jkt})$, or, alternatively,

$K_{jkt} = K_{jk,t-1} - D_{jk,t-1}(u_{j,t-1}, v_{jk,t-1}, K_{jk,t-1})$;

(6) $u_{jt} \leqq F_{jt}(U_t, V_t, K_{jt})$, for all j, k, and t; and

(7) $\partial D_{jkt}/\partial v_{jkt} \leqq 0$, $\partial D_{jkt}/\partial u_{jt} \geqq 0$, $\partial D_{jkt}/\partial K_{jkt} \geqq 0$.

Equation (5) merely states that the stock of capital component k at the end of period t (or t-1) is equal to the initial capital stock minus <u>net</u> depreciation. As shown through the partial derivatives, net depreciation is thought to decrease with gross investment and increase with u and K.[34] As for (6), a ceiling is placed on the t (current) production rates. It is significant to note that this production ceiling is determined by the past and current production and investment rates of all the firms producing from the reservoir. This is due to the fact that reservoir pressure and investment for pressure maintenance is determined by the production and investment activities of all the reservoir's firms.[35]

Hence,

(8) $\partial F_{jt}/\partial u_{ir} \leqq 0$, $\partial F_{jt}/\partial v_{ir} \geqq 0$, $\partial F_{jt}/\partial K_{jt} \geqq 0$

for all i, j, k, and t; r=1,..., t; i refers to all other reservoir firms except j.

To round out their model of reservoir production, Kuller and Cummings give an adaption of (1) that enables one to determine the entire recoverable stock of the reservoir:[36]

(9) $$\sum_{r=1}^{T} \sum_{j=1}^{n} u_{jr} \leqq X(U_T, V_T).$$

We can recognize from equation one that the total recoverable stock varies inversely with the rate of extraction for any firm in any period of time. On the other hand, the total recoverable stock varies in a positive manner with the gross investment of any firm in any time period on the planning horizon.

Now that we have learned of these various characteristics of a typical petroleum reservoir, it is now time to find the optimum rate of production from such a reservoir, or at least the optimum rate condition. Only by finding such an optimum rate can we isolate the effects of a windfall profits tax.

First, it is necessary to have the profit maximizing relationship of the n firms in the reservoir:[37]

(10) $$\sum_{t=1}^{T} \sum_{j=1}^{n} p_t u_{jt} - C_{jt}(U_t, V_t, K_{jt})\ B_t.$$

This relation is subject to a number of constraints,

(a) $$K_{jk,t+1} = K_{jkt} - D_{jkt}(u_{jt}, v_{jkt}, K_{jkt}),$$

(b) $$u_{jt} \leqq F_{jt}(U_t, V_t, K_{jt}),$$

(c) $$\sum_{r=1}^{T} \sum_{j=1}^{n} u_{jr} \leqq X(U_T, V_T)$$

(d) $$u_{jt} \geqq 0,\ v_{jkt} \geqq 0, \text{ for all } j, k, \text{ and } t.$$

Such constraints, of course, give rise to a set of necessary conditions for the profit maximizing relationship. Kuller and Cummings' findings concerning these necessary conditions have been reproduced in the appendix for the curious and adventuresome reader. What is more important is the equation that Kuller and Cummings have found that characterizes the optimal path of production for a single firm in the reservoir:

(11) $$(p_t - \partial C_{jt}/\partial u_{jt}) B_t = @B_T(1 - \partial X/\partial u_{jt})) + \psi_{jt} B_t$$

$$-\sum_{n=t}^{T} \sum_{i=1}^{n} {}_{ir}(\partial F_{ir})/(\partial u_{jt})\ B_r + \sum_{k=1}^{q} \Delta_{jk,t+1} B_{t+1} (\partial D_{jkt})/(\partial u_{jt})$$

$$+ \sum_{r=t+1}^{T} (\partial C_{jr}/\partial u_{jt}) B_r + \sum_{r=t}^{T} \sum_{i=1}^{n} (\partial C_{ir}/\partial u_{jt}) B_r$$

where $i,j=1,\ldots, n;\ 1 = t = T$.[38]

According to Kuller and Cummings, a firm j will produce at the rate characterized by the above relation for any t ($1 \leqq t \leqq T$).[39] It is assumed here that $u_{jt} > 0$. The left side of the equation is the present value of marginal net income to the firm during the time period t.[40] The six terms on the right side of the equation are the "user costs" created from an increase by the firm of oil extraction during the time period in question. That is, the terms reveal the present value of future profits lost due to an increase in the present rate of production.[41]

In order to clarify the above equation, let us quickly study the user costs in the right-hand side of the equation. Of the many user cost we find, the first term $(@B_T(1-\partial X/\partial u_{jt}))$ on the right-hand side is considered to be the "stock user cost" during t. The Lagrangian multiplier @ measures the change in net income from a change in u_{jt} which creates a change in X.[42] Thus, $@B_T$ is the "marginal scarcity value" of oil for the entire reservoir during the planning horizon--it measures the change in present value of net income due to a change in u_{jt}.[43] $(1-(\partial X/\partial u_{jt}))$ reveals the change in total recoverable stock due to a change in u_{jt}. It is always greater than one since $X/\partial u_{jt}<1$.[44] The second and third terms are known as the "boundary user costs." U_{ir} is another Lagrangian multiplier that indicates the change in net income for any firm i for any period r from t to T that produces at the rate F_{ir} (the limit) for the time period r.[45] $\partial F_{ir}/\partial u_{jt}$ measures the change in F_{ir} that results from a change in u_{jt}.[46] Such a change is negative, of course, which explains why the third term is negative. The second term, $\psi_{jt}B_t$, registers the change in net present value from an incremental change in u_{jt} if the operator j has been producing at the rate $u_{jt} = F_{jt}$.[47] The fourth term is the "user cost of capital consumption by the firm j."[48] The multiplier $\Delta_{jk,t+1}$ indicates the change in future net incomes from the additions to all kinds of capital stock in the future. The future additions to capital stock that are actually made is naturally dependent upon the present rates of capital depreciation which, in turn, are dependent upon u_t. The last two terms show the effects of a change in the extraction rate of the produer at t upon the future cost functions of all firms producing from the reservoir. This is what one would expect if current extraction rates debilitate the natural drive of the reservoir and thus possibly requiring increased use of artificial pumping at later time periods and so forth.[49]

As we have already observed, a firm, according to the above equation, should produce at the rate where the firm's marginal net income is equal to the user costs created by the firm's production.[50] According to Kuller and Cummings, if inequality occurs for (1), the operator will not produce at all during the time period j.[51]

If we apply a windfall profits tax to the entire time horizon of the reservoir, the present value of marginal net income is reduced. Consequently, the user costs on the right hand side of the equation must decrease if the equality is to be maintained. Since @ measures the change in net income created by a change of X through u, this multiplier will be less due to the net income reducing nature of the windfall profits tax. The multiplier $\Delta_{jk,t+1}$ should also be smaller now that the windfall profits tax will absorb some of the increase in net income induced from additions to all forms of future capital stock. Hence, the first and fourth terms of the right-hand side of (11) are now smaller. Since all firms in the reservoir have to pay the tax, we can also expect ψ to decrease. Since the third term on the right-hand is negative, the decline in ψ implies that the third term increases and hence somewhat offsets the decreases in the first and fourth terms. More importantly, the windfall profits tax also induces a decrease in the equilibrium u_{jt}. This decrease is implied by the fact that both @ and ψ are lower than they would be in the absence of the tax. Now, @, as has been shown, indicates the increase in net income created by a change in X through u_{jt}. If the present value of the net income of the petroleum in the reservoir with a current rate of extraction of u_{jk} has been reduced by the windfall profit tax, then, all other things being equal, the operator of the firm will attempt to increase the present value of his net income by lowering the current production rate u_{jk}. The lower u_{jk} may very well increase the total recoverable oil stock X of the reservoir. Hence, by lowering the current extraction rate, the producer can restore the total net income over the life of the reservoir that is consistent with the desired rate of return of his capital investments. Of course, this means that there is now a lower equilibrium current rate of production.

A similar analysis can be performed concerning the multiplier ψ. ψ_{ir} can be interpreted as being the addition to net income from an increase in the maximum production rate F for any operator at any future time who is at that time period producing at F. If a windfall profits tax results in a decrease in values of ψ and present value of future net income, then the operator j will lower his current extraction rate in order to induce greater net future income for the other firms that will produce at some F rate in the future due to the fact that a drop in u_{jt} will increase F_{ir}. Hence, the current equilibrium u_{jt} will be smaller than in the absence of the windfall profits tax, all other things being equal. Remember, that we are assuming that the reservoir is being exploited according to an agreed plan; there is no unrestrained production here.

Although we have taken an important step in our endeavor to discover the effects of a windfall profits tax upon crude oil production, it is important to note that the above analysis is flawed in that it does not take into account the effects on investment. One only needs to casually observe that the constraints a, b, and c contain functions that are determined by both u and v in order to understand the need for a further enlargement of our undertakings. More specifically, we must understand the correct (optimum) level of investment for a producer in a unitized reservoir. Kuller and Cummings provide such a relationship that gives the present value of the marginal costs of investment by a single operator. The equation is as follows:

$$(12)\qquad (\partial C_{jt}/\partial v_{jkt})B_t = -(\Delta_{jk,t+1}B_{t+1})\ (\partial D_{jkt}/\partial v_{jkt}) + @B_T(\partial X/\partial v_{jkt}) + \sum_{r=1}^{T}\ \sum_{i=1}^{n} \psi_{ir}B_r(\partial F_{ir}/\partial v_{jkt}) - \sum_{i=1}^{n}(\partial C_{it}/\partial v_{jkt})B_t - \sum_{r=t+1}^{T}\ \sum_{i=1}^{n}(\partial C_{ir}/\partial v_{jkt})B_r$$

where i, j=1,..., n; $i \neq j$; k=1,..., q; $1 \leqq t \leqq T$.[52]

The left-hand side of the equation is the present value of the marginal costs of investment of the firm in question. The right-hand side of the equation shows the total benefits that accrue to the reservoir as a result of investment by the firm (remember, there is no unrestrained production in this model).[53]

The benefits to the reservoir, as revealed by the various elements in the right-hand side, manifest themselves in several forms. The first term can be interpreted as the present value of the future stream of benefits from an incremental change in investment during the present time period ($\Delta_{jk,t+1}B_{t+1}$) multiplied by the partial derivative ($\partial D/\partial v$) which is negative (Kuller and Cummings state that it is -1).[54] The first term denotes the present value of the aggregate increase in future productivity created by new investment at the present. Since @B_T is the marginal scarcity value of recoverable oil stocks and $\partial X/\partial v \geq 1$, the second term indicates the increase in the present value of X created by an increase in v_{jkt}.[55] The third term shows the impact by an increase in v_{jkt} upon any operator producing at the upper bound at any future time period.[56] Since we are assuming that increases in current investment aid in preserving the pressure in the oil reservoir or otherwise aid in increasing possible production rates in the future, an increase in investment today will increase the prospective bound F for a producer in the future.[57] The last two terms reveal the effects of present investment on the future cost functions of all operators. Once again, we are assuming that current investment conserves the pressure in the reservoir and hence leads to lower variable operating costs for every producer in the future.[58]

The above equation thus indicates that a firm chooses a rate of investment (the optimum rate of investment) in the reservoir for which the marinal costs to the firm of investment in k-type capital is equal to the present values of the benefits that accrue to all firms in the reservoir.[59] If it can be shown that the windfall profits tax influences current investment, then it can also be shown that the potential benefits to the entire reservoir will also be affected. We have already found in discussing McDonald's model that a windfall profits tax will lessen investment by an operator for the development of a reservoir, at least in terms of investment for new oil rigs. A windfall profits tax, by forcing the potential investor to lose a portion of the return on his capital that he would obtain in the absence of such a tax, makes prospective investment in oil reservoir development less attractive in comparison to other possible opportunities in the American economy. Moreover, an operator may try to recoup his loss of present net revenue to the windfall profits tax by lowering his current costs by reducing present investment. This analysis, however, has assumed that there are not any other tax provisions that can be used by the investor to increase his return on capital investment. Although the "expensing" of intangible drilling costs and the (now attenuated) percentage depletion allowance remain in effect, these tax provisions have not been made more generous. Indeed, percentage depletion is not allowed on the part of a firm's windfall profit that is taxed.[60] Thus, we can safely conclude that the tax will reduce investment in a petroleum reservoir.

At any rate, such a decrease in present investment will have considerable effects on oil production during the life of the reservoir. For one thing, as the first term of (12) clearly shows, operator j's oil wells will in the future be less productive due to the drop in the present investment rate. According to the second term, the total stock of crude oil that will be recovered from the reservoir will be smaller with the loss of present investment. Also, due to the third term, firms that produce at the upper limit F sometime in the future will be extracting less oil as a result in the drop in present investment by the firm. The variable costs of all firms will also be higher in the future due to the loss of current investment.

Can the two equations that have been discussed (11) and (12)--be combined in some way in order to study the effects of the tax on both u and v at the same time? Kuller and Cummings combine (11) and (12) in such a way as to show the effects of a change in marginal net income on both u_{jt} and v_{jkt}. First, Z is used to denote all of the terms on the right-hand side of (11) except those terms involving $@B_T$, while Y is used in place of all the terms on the right-hand side of (12) with the exception, once again, of all $@B_T$ terms.[61] Then, Kuller and Cummings solve the equation (12) for $@B_T$ and plug this value of $@B_T$ into equation (11).[62] Thus, Kuller and Cummings come up with a new equation that will be used to study the impact on both u and v simultaneously. The new equation is given as follows:

$$(13) \qquad ((p_t - \partial C_{jt}/\partial u_{jt})B_t - Z)/(1 - \partial X/\partial u_{jt})$$
$$= ((\partial C_{jt}/\partial v_{jkt})B_t - Y)/(\partial X/\partial v_{jkt}).$$ [63]

For some level of marginal profits $(p_t - \partial C_{jt}/\partial u_{jt})$, we, of course, have the equilibrium values of u_{jt} and v_{jkt}. Now, if a windfall profits tax is applied, we have inequality in the above equation. As in the case of the preceding examples, the lower marginal profits imply a lower equilibrium u_{jt}. Since the equilibrium u_{jt} is smaller, some of the terms in Y may also be smaller.[64] Thus, the equation (12) is also characterized by inequality due to changes in the multipliers. This implies, according to Kuller and Cummings, that the equilibrium v_{jkt} is now lower than before the tax.[65] Hence, we now have the effects of the tax upon both u_{jt} and v_{jkt} simultaneously. Notice that the equilibrium v_{jkt} is changed through changes in u_{jt} due to the fact that the various Lagrangian multipliers measure the impact of a shift in marginal profits by a change in u_{jt}.

Through the discussion of Kuller and Cummings' petroleum reservoir production model, we have been assuming that the reservoir in question is to be exploited under some sort of unitization agreement. That is, every firm in the reservoir takes into account the potential impacts of his production and investment activities on the other producers in the reservoir. However, not all of the producing reservoirs in the United States operate under such agreements. It is important then to seek a modification of the model that takes into account such a contingency.

If an operator extracts oil in an unrestrained fashion, he will ignore the user costs of such production that apply to the other operators in the reservoir. Likewise, he will invest in his portion of the reservoir in complete disregard of the benefits that will accrue to other operators in the future. In consequence, the operator, as revealed in McDonald's model, will produce at the greatest rate possible in order that the other producers in the reservoir do not receive any of the oil production that our operator may forego. Kuller and Cummings have formulated the following optimal relationships which describe this new set of conditions:

$$(p_t - \partial C_{jt}/\partial u_{jt}) - \sum_{k=1}^{q} \Delta_{jk,t+1}(\partial D_{jkt}/\partial u_{jt})B_{t+1} = \psi_{jt} \tag{14}$$

$$-(\partial C_{jt}/\partial v_{jkt}) = \Delta_{jk,t+1}(\partial D_{jkt}/\partial v_{jkt})B_{t+1} \tag{15}$$

for some $j = 1,\ldots, n;\ 1 \leqq t \leqq T$;

where (14) and (15) correspond to the earlier equations (11) and (12), respectively.[66]

The new equations merely conform to the revised reservoir production characteristics. Since the operator produces at the rate of $u = F$ for every time period, the marginal profit to the firm minus the capital consumption costs equals the incremental cost of the upper production limit (ψ_{jt}) which is dependent only on the stock of capital existing at the beginning of the time period (K_{jt}), or, alternatively, the marginal profit equals the marginal imputed cost of the upper bound plus the capital consumption costs.[67] The second equation, which is concerned with the optimal rate of investment for an unrestrained operator, is a bit more subtle. Since the multiplier $\Delta_{jk,t+1}$ indicates the increase in future value resulting from future increases in capital stock, the right-hand term reveals that the marginal future value of such additions in future stock which is also influenced by the effects on current capital consumption by current investment rates. Thus, (15) states that current production facilities (oil wells, and so forth) will be increased to the point that the marginal costs of increasing these facilities are equal to the marginal future benefits of increasing future production facilities.[68]

A number of aspects of the modified model need to be pointed out. As we have already mentioned, the u_{jt} of the operator will be much higher than under unitization agreements since the operator is no longer taking into account the external costs to his current production. Most importantly, the external costs in terms of the total recoverable stock (the first term on the right-hand side of (11)) are completely ignored; in consequence, the current production rate of j decreases the total volume of crude oil that will eventually be extracted from the reservoir. Thus, a loss is created for society as a whole, all other things being equal. This loss in total recoverable stock will not be made up by investment designed to increase this stock (such as water pumping to increase pressure maintenance). This situation can be easily shown by equation (15), where the external benefits of an increase in current investment is not taken into account. It may seem somewhat paradoxical that the operator would reduce his investment when he is trying to produce as much oil as he possibly can during every time period. However, it should be pointed out that, due to the unrestrained production, new investment will bring lower rates of return to the individual operator than under unitized operations. Also, thanks to unrestrained operations, there are fewer benefits accruing to the individual operator that engages in water-pumping or tertiary recovery activities since the other firms will "steal" some of the increase in the total recoverable oil stock. On the other hand, there will probably be an increase in investment into oil rigs, for an increased number of oil wells will enable the firm to increase its current production rates and surrender less total recoverable stock to the other reservoir producers (McDonald has already pointed this out). However, for other kinds of investment, especially those that enhance the total recoverable oil stock, unrestrained oil extraction by independent oil firms leads to underinvestment in the oil reservoir. Note that Kuller and Cummings appear to view investment basically in terms of stock enhancing investment; hence, the apparent conflict with McDonald over oil rig investment (such investment can easily be incorporated into the Kuller and Cummings model as a particular k-type of capital stock).

As in the case of the first set of optimization equations, we can study the effects of a windfall profits tax with equations (14) and (15). A percentage of the current marginal profit $(p_t - \partial C_{jt}/\partial u_{jt})$ is taken away by the tax. If the tax is in place during the entire life of the reservoir, then we would expect the multipliers $\Delta_{jk,t+1}$ and ψ_{jt} to be lower. B_{t+1} might also be higher to reflect the now greater opportunity cost of future investment in the reservoir. The smaller multipliers imply a new but smaller equilibrium u_{jt} since the operator can gain by lowering his production due to a greater decrease in capital consumption costs associated with the decline in production. The decrease in production continues until the two sides of the equation are once again equal. Likewise, the tax will reduce the equilibrium v_{jkt}. Since $\Delta_{jk,t+1}$ is now smaller, the marginal costs of current investment must decline or there will be no investment in t due to the fact that the marginal costs of investment will be greater than the marginal benefits. Of course, this can happen only if the new optimum v_{jkt} is smaller. Incidently, the decline in present investment rates should force the rate of return on the investor's capital investment back to its former levels.

We shall now turn to a model of crude oil production that has been developed by Cox and Wright. This model will be analyzed for a number of reasons. For one thing, this model was developed independently of Kuller and Cummings. Thus, it will be interesting to see if an analysis of this model will turn up results similar to those found with the Kuller and Cummings model. More importantly, the emphasis of each model is rather different. Whereas Kuller and Cummings were concerned with revealing the effects of reservoir pressure on reservoir production, Cox and Wright focus upon the effects of certain federal tax provisions (such as the intangible drilling costs provisions, and so forth) upon a firm's production and drilling investment. Hence, the incorporation of the windfall profits tax will seem less artificial with this new model.

And now we turn to the model itself. For any point in time t the after-tax flow for an oil extractor is

(16) $$N(t) = N_1(t) - IC(t) - NC(t)$$

where $N_1(t)$ is revenue at t, $IC(t)$ the investment cost term, and $NC(t)$ the non-investment cost term. Hence, $N(t)$ is the net revenue at time t. Note that we are in continuous time.[69]

Each of the terms in (6) will now be examined for their determinants. $N_1(t)$ is characterized by the following function:

(17) $$N_1(t)=(1-y(t)-f(t)[1-y(t)-d(t)])\$(t)p(t)Q(t)$$

where $p(t)$ is the price of crude oil at t, $Q(t)$ is the quantity of marketed output at t, and \$ is the proportion of gross revenue that belongs to the oil producers. It should be noted here that (1-$) gives the proportion of gross revenue that accrues to the land-owner of the oilfield (assumed not to be the oil producer himself) as royalties.[70]

The rest of the terms designate certain types of taxes. The term y(t) is the average production and severence tax rate imposed upon the oil operator by local and state governments at t. The term f(t) is the federal income tax that is imposed by the federal government at time t. For the moment, the windfall profits tax is not considered to be a part of f(t). Since the local and state production and severence taxes are deductible from the federal income tax, the f(t) term is reduced by the amount (1-y(t)).[71] The term d(t) refers to the percentage of the gross revenue that is deductible by the percentage depletion allowance. Hence, f(t) is also lowered by the amount (1-d(t)).[72] Note, however, that the percentage depletion allowance (percentage of gross income that is free from federal income tax) no longer exists for the large vertically integrated firms and is being reduced to fifteen per cent of gross income for other producers by 1984.[73] Considering the large holdings of crude oil reserves held by the major companies, it is obvious that the d(t) term is going to be zero for most reservoirs and quite low in the others. Thus, the after-tax revenue portion of cash-flow at any point of time is determined by royalties and the tax provisions of the various governments in question.[74]

The investment cost term is as follows:[75]

$$(18) \qquad IC(t) = [(1-f(t))(q_1(I(t),t) = q_2(I(t),t)) + (1-f(t)\ D(t))q_3\ (I(t),t)]I(t).$$

There are several forms of investment cost that are incurred in petroleum investment activities, and these are recognized in the above cost function. The term $I(t)$ is defined as the "total reserve acquisition cost at time t."[76] The expression $q_1(I(t),t)$ is that proportion of investment cost that has been spent on drilling dry holes; $q_2(I(t),t)$ is the proportion of $I(t)$ used for the so-called "intangible" costs of successful wells.[77] On the other hand, $q_3(I(t),t)$ is the proportion of investment cost that is expended upon the "tangible" costs of successful wells.[78] Sensibly enough, q_1, q_2, and q_3 add up to one at any point of time t. $D(t)$ is the discounted present value at t of the stream of tax deductions made from one dollar of depreciable expenditure at time t.[79]

Obviously, there is a need for an explanation of just what "tangible" and "intangible" drilling costs are. Intangible drilling costs are considered to be those expenses which purchase goods and services that are needed for oil drilling and which have no salvage value--such things as rental for machinery, wages, fuel and electricity, and so forth.[80] These expenses are deducted in the year in which they are incurred. Since such costs may consume as much as ninety percent of the typical outlay on an oil-producing property, one can easily see that this is a most generous tax deduction.[81] Due to the fact that this provision applies only to the oil industry, it has become politically controversial and in 1975 was repealed for intangible expenses in foreign nations.[82] Dry hole costs are also deducted from gross income in the year the costs are incurred. Thus, both q_1 and q_2 are multiplied by $(1-f(t))$ which in turn is the percentage of gross revenue left after federal income taxes.

"Tangible" drilling costs, in contrast, refer to the capital that is invested in the property and may have some salvage value at the end of its productive life.[83] Obviously, this refers to the oil rig itself and related items. Such investments are depreciated over a certain number of years. Hence, q_3 is multiplied by $D(t)$ in order to indicate the present value of the tax deductions that result from this depreciation. Also, q_3 is multiplied by $(1-f(t))$ in order to show the percentage of after-federal income tax that the deductions represent. The terms of (18) are multiplied by $I(t)$ to find the total investment costs.[84]

Federal income taxes also play an important role in the determination of other costs. For instance, the non-investment cost function $NC(t)$ is

$$(19) \qquad NC(t) = \{(1 - f(t))w_1(t) + (1 - f(t)D(t))w_2(t) + w_3(t)\}L(t)$$

where L is considered to be the "index of the quantities of non-reserve inputs into the production of crude petroleum."[85] Here, w_1 is the tax deductible percentage of L (input costs incurred for goods and services that do not add to the total amount of oil reserves); w_2 refers to the percentage of nonreserve inputs that are deductible through depreciation.[86] On the other hand, w_3 refers to those costs which are not deductible due to the decision of the producer to use percentage depletion instead of cost depletion.[87] Percentage depletion differs from cost depletion in that cost depletion is based on the actual costs of developing a property. Percentage depletion, in contrast, is based upon the gross income of a producer.[88] Since the percentage depletion allowance no longer applies to the largest oil producers, cost depletion has become much more significant. The w_3 measures the nondeductible cost per unit of L under the percentage depletion allowance; this term is now of less importance.[89] The term $w_1(t)$ is multiplied by $(1-f(t))$ in order to indicate the total amount fo costs created by the "nonreserve inputs" L; w_2 is multiplied by $(1-f(t))D(t)$ to reveal the present value of the costs of L that are not deductible through depreciation.[90] Naturally, all of the w terms are multiplied by $L(t)$ to describe the noninvestment costs of production at time t.

The implicit production function for oil produced at time t is

$$(20) \qquad M(Q(t), R(t), L(t), t) = 0$$

where R is the stock of proved reserves in the reservoir.[91] Cox and Wright, in their original model, had a somewhat more complex statement for the production function in which $R(t)$ was replaced by $\emptyset(t)$ where $\emptyset(t) = S(t)^k R(t)$, $0 \leq S(t) \leq 1$, and $0 < k$. $\emptyset(t)$ was the "full time equivalent stock of proved reserves," S was the "market demand factor" that was set by a state agency in a market-demand prorationing scheme, k was the "elasticity of the full-time equivalent stock of reserves with respect to the market-demand factor S."[92] Simply put, the model was originally designed to discern the effects of state prorationing schemes upon reservoir investment and production. Since state prorationing schemes were allowed a quiet death after the 1973 oil crisis, this modification to the model is not included here. Note also with (2) that the quantity of output at t is constrained by the nonreserve inputs and the stock of proved reserves.

This implicit function becomes somewhat more comprehensible with reference to the function of the stock of proved reserves. Gross additions to the proved reservoir reserves is given by the function g(I(t), t). Using this new function and equation (20), the stock of proved reserves at any time t is as follows:

$$r(t) = g(I(t), t) - Q(t) \tag{12}$$

where r(t) should be interpreted as the rate of change in proved oil stocks which is of course equal to the rate of change in reserve additions less the rate of change for output.[93] Since it is assumed that the marginal addition to recoverable reserves per amount of investment decreases other time, then r(t) declines, assuming that I(t) and Q(t) have constant rates of change over time.[94]

Now, as we have earlier seen with the Kuller and Cummings model, the reservoir operator wants to maximize the present value of after-tax cash flow.[95] This reasonable assumption is given by the following equation:

$$(22) \qquad V = {}_{0}\, N(t)e^{-\int_0^t i(s)\,ds}\, dt$$

where the term i(s) is the rate of interest after all taxes.[96]

In order to maximize (22), one must first realize that it is subject to the restraints given by the equations (20) and (21), plus R(t) (in Cox and Wright's original model, Ø(t) = $S(t)^k$ R(t) for prorationing conductions is also a constraint).[97] Hence, the problem at hand is to maximize the following Lagrangian function where u(t) refers to the optimal net cash flow:

$$(23) \qquad \int_0^\infty u(t)d(t) = \int_0^\infty \{N(t) + \&(t)M(Q(t),\ R(t),\ L(t),\ t)$$

$$+ ¢(t)\ [g(I(t),\ t) - Q(t) - r(t)]\}\ e^{-\int_0^\infty i(s)ds\,\frac{}{dt}}\ dt$$

where &(t) and ¢(t) are Lagrangian multipliers.[98]

Cox and Wright then plug in the accounting identities (16) through (19) into (23). Consequently, they find equations (20) and (21) to be two of the Euler necessary conditions.[99] Furthermore, the following mathematical statements are also included as being necessary conditions for the above maximization problem:

(24) $0 = \partial u(t)/\partial Q(t) = \&(t)(\partial M/\partial Q(t)) + \{1-y(t) - f(t)$
$\cdot[1 - y(t) - d(t)]\} \ \$(t)p(t) - ¢(t),$

(25) $0 = \partial u(t)/\partial L(t) = \&(t)(\partial M/\partial L(t)) - \{[1 - f(t)] w_1(t)$
$+ [1 - f(t)D(t)]w_2(t) + w_3(t)\},$

(26) $0 = \partial u(t)/\partial I(t) = ¢(t)(\partial g/\partial I(t)) - \{[1 - f(t)](q_1(I(t), t)$
$+ q_2(I(t), t)] + [1 - f(t) D(t)] q_3(I(t), t)\}$
$- \{[1 - f(t)] [(\partial q_1/\partial I(t)) + (\partial q_2/\partial I(t))]$
$= [1 - f(t) D(t)] (\partial q_3/\partial I(t))\} \ I(t)$, and

(27) $0 = \partial u(t)/\partial R(t) - (d/dt)(\partial p(t)/\partial r(t))$
$= \&(t)(\partial M/\partial R(t)) + d¢(t)/dt - i(t)¢(t).$[100]

It should be noted here that equation (27) is somewhat different in Cox and Wright's original model due to the fact that state prorationing rules are no longer considered to be a factor.

Our purpose here is similar to the objective obtained with the Kuller and Cummings model. That is, the intention is to show the effect on production of a windfall profits tax. The Lagrangian multipliers, of course, measure the change on the maximum present flow of net value that is created by a change in a certain constraint at time t--M and r(t) for the Lagrangian multipliers &(t) and ¢(t), respectively.[101]

What is of greater importance for our purposes is the tax portion that is a part of all of the necessary conditions save condition (27). Obviously, a change in y(t), f(t), or d(t) can have far-reaching effects. For example, suppose that the percentage of the federal income tax that is deductible by the percentage depletion allowance (d(t)) is lowered. Consequently, the percentage of federal income tax (f(t)) is larger and the after-tax profits per unit of crude oil production for the oil reservoir operator and the tax term of the necessary condition (24) are now smaller. Thus, we have an inequality for equation (24). Now, if we had assumed that there had existed an equilibrium situation for the model--the maximization problem had been solved--with corresponding equilibrium values for the multipliers &(t) and ¢(t), one or more of the other elements in equation (24) must now change in order to maintain the maximizing situation. For the moment, $(t) and p(t) are assumed to be unchanged. The partial derivative $\partial M/\partial Q(t)$ is, of course, assumed to be unchanged. On the other hand, we would expect one or both of the equilibrium multiplier values to change since they each measure the effect of a change in one of the constraints.

To show this fact more clearly, it may be helpful to explore more fully the meaning of the multipliers &(t) and ¢(t). For instance, &(t) can be thought of as measuring the gain (loss) at time t to the present value of after-tax cash flow that results from an increase (decrease) in crude oil production at time t (or, more precisely, a change in one of the time-variables of the implicit production function M at time t). Likewise, ¢(t) measures the change in present value of cash flow that is induced by a change in the rate of the stock of reserves at t. One can readily see that we can now use changes in the Lagrangian multiplier to explain the results that arise from changes in local, state, and federal tax policies. Indeed, we conducted a highly similar process with regard to the Kuller and Cummings model. Thus, an increase in the federal income tax that is originated by a decrease in the percentage depletion allowance induces a corresponding decrease in &(t) due to the stipulation that an increase in the federal income tax will reduce in percentage terms the gains that can be made from a unit incrase of crude oil production, ceteris paribus. One can further assume that ¢(t) will also be smaller when the federal income tax rate increases at time t; the gains to be made to present value of cash flow from an increase in the rate of change in the stock of proved crude oil reserves are also reduced by a decrease in the percentage depletion allowance. This situation has actually taken place, for Congress has reduced the gains to the oil industry from the percentage depletion allowance. It should be noted that it is assumed here that the reduction in percentage depletion remains in effect during the rest of the reservoir life after the tax increase at time t.

Naturally, we can, just as we did for the Kuller and Cummings model, use the above observations to indicate the effects of a windfall profits tax. Suppose that we subtract the percentage of revenue that is taxed by the windfall profits tax (A(t)) from the revenue equation (17):

$$(17') \quad N_1(t) = \{1 - y(t) - A(t) - f(t)[1-y(t) - d(t)]\} \$(t)p(t)Q(t).$$

Obviously, if this was imposed for the maximization problem for time t, then the middle term of the right-hand side of equation (24) would once again have a smaller value than is needed for the maximization to hold. Consequently, the optimal values of &(t) and ¢(t) must be lower if we are to have a maximization situation.

Furthermore, as we have earlier found with the Kuller and Cummings model, these changes in the Lagrangian multipliers are also indicative of other changes in one or more of the other endogeneous time-variables in the model. Since $\bar{\&}(t)$ and $\bar{\text{¢}}(t)$ each measure the impact of a change in a certain constraint upon the optimal present value of the after-tax cash flow, then a change in $\bar{\&}(t)$ and/or $\bar{\text{¢}}(t)$ indicate a change in the optimal values of Q(t), R(t), L(t), and/or I(t).

Ignoring for a moment the fact that Kuller and Cummings state that the production function is of the CES type, we shall now find the explicit function Q(t) = M(R(t), L(t)) that exists under certain circumstances. According to the "implicit function theorem," if the implicit function has continuous partial derivatives and if the variable Q is non-zero at a set of points Q_0, L_0, and R_0; then there is a "neighborhood" of those solution values at which the explicit function is defined.[102] Now, it is already known that the implicit function M is differentiable.[103] Surely, there are a large number of solution sets in which Q is non-zero. Indeed, it is difficult to foresee a zero value for Q unless either R or L or both have zero values, too. Hence, it can safely be assumed that there is an explicit function for Q that is applicable to the present model.

It has already been submitted that lower values of &(t) and ¢(t) are indicative of different optimal values of the endogeneous variables in the model. Will the new equilibrium value of one of these variables, say Q(t), be lower or higher with the windfall profits tax? The necessary condition (24) implies that the new $\bar{Q}(t)$ will be lower. This can easily be seen by the fact that the &(t)($\partial M/\partial Q(t)$ + ... + ¢(t) of (24) is the $\partial p(t)/\partial Q(t)$ partial derivative. If one supposes for a moment that &(t) and ¢(t) have not yet changed with the imposition of the tax, then the &(t)($\partial M/\partial Q(t)$ + ... + ¢(t) polynomial is negative. Hence, equilibrium $\partial p(t)/\partial Q(t)$ is also negative. ($\partial p(t)/\partial Q(t)$) changes with changes in Q(t) due to the existence of constraints on the net revenue function). Hence, $\bar{Q}(t)$ must be smaller in order for $\partial\bar{p}(t)/\partial\bar{Q}(t)$ to be equal to zero.

Since the implicit production function is not likely to be linear, $\partial M/\partial Q(t)$ will also change with the imposition of the tax. For the moment, the CES nature of the production function will again be ignored. Consequently, because of the paucity of knowledge of the implicit production function, it cannot be said with any certainty what is the sign of the new $\partial M/\partial Q(t)$ or whether the new value differs from the $\partial M/\partial Q(t)$ that we had before the introduction of the windfall profits tax.

Nevertheless, either R or L or both will change in value with the imposition of the tax as the necessary condition (20) readily attests.

We can also use the change in $\phi(t)$ to show the change in r(t) that is experienced with the introduction of the windfall profits tax. Now, it has been stated that $\phi(t)$ will now be lower since the benefits that would come from an addition of the stock of proved reserves will now be smaller since the tax will soak up some of the prospective revenue that can be gained from an addition to the proven reserve stock of crude oil. However, the direction of the change in r(t) must be found. It is already known that Q(t) in (21) is smaller with the imposition of the tax. Hence, the tax A(t) can be entered into the necessary condition (26) to find the directional change of r(t); this is quite feasible since the windfall profits tax will reduce the amount of gross income against which the various drilling costs are deductible. Unfortunately, there is not enough knowledge of the sundry values of $q_1(I(t), t)$, $q_2(I(t), t)$, $q_3(I(t), t)$, $\partial q_1/\partial I(t)$, $\partial q_2/\partial I(t)$, $\partial q_3/\partial I(t)$, and I(t) to make a conclusion. Unlike the case with (24), there is more than one term A(t) induces a percentage change of after-tax gross income. Hence, one cannot easily find the new $\partial p(t)/\partial I(t)$, and, consequently, cannot discern whether I(t) must decrease or increase in order for $\partial p(t)/\partial I(t)$ to once again be equal to zero. The same problem is encountered with the necessary condition (25); A(t) can be entered into two

(1- f(t)) terms. As a result, it is impossible to say whether the new $\partial p(t)/\partial L(t)$ is greater or less than (or even equal to) zero. The directional change is therefore not observable through this technique. In the same wein, it should be noted that (27) is also not amenable to the same type of analysis.

However, not all is lost, for the production function that is being used in this model is given as a CES (Constant Elasticity of Substitution) production function. Such production functions are usually homogeneous to the first degree. In simpler words, we are assuming that if the two actions of production (in this case R(t) and L(t)) are both increased by a certain amount, then Q(t) in turn will be increased by the same amount. For instance, if both R(t) and L(t) are doubled, then Q(t) is also doubled for the point in time t.[104]

This CES production function is given by

$$(28) \qquad Q(t) - Ye^{ht}\{aR(t)^{-v} + (1-a)L(t)^{-v}\}^{-b/v}$$

where Y>0 is the "scale parameter," h=0 is the rate of technological change that is consistent with oil drilling and reservoir extraction, and a is the distribution parameter.[105] The parameter a gives the relative factor shares of R(t) and L(t). Its value is between one and zero with the various shares differing with each individual reservoir.[106] The parameter v (v>-1) is the substitution parameter. It measures the elasticity of substitution between the two factors.[107] The parameter b is the degree of homogeneity of the production function. According to Cox and Wright, $0 < b \leqq 1$. It is assumed here that b will be equal to one (according to Chiang), but the most important consideration is that the production function be concave when one factor is increased while the other is held constant.[108] The term e^{ht} is part of the function in order to show that the technology relevant to the reservoir changes continuously over time at a rate of h.

Of course, one would want to find $\partial Q(t)/\partial R(t)$ and $\partial Q(t)/\partial L(t)$. For both, let us assume that $h = 0$ and $(\ldots)$ refers to the expression in the brackets for (28):

$$\partial Q(t)/\partial R(t) = (-bY/v)(\ldots)^{(-b/v)-1}(a)(-v)R(t)^{-v-1}$$

$$=abY(\ldots)^{(-b/v)-1}R(t)^{-v-1}$$

$$Q(t)/\partial L(t) = ((-bY)/v)(\ldots)^{(-b/v)-1}(1-a)(-v)L(t)^{-v-1}$$

$$= b(1-a)Y(\ldots)^{(-b/v)-1}L(t)^{-v-1}.$$

Now, if b is assumed to be equal to one (the production function is linearly homogeneous to the first degree with constant returns to scale), then $\partial Q(t)/\partial R(t) = ab(Y^{1+v}/Y^{v})(\ldots)^{-(1+v)/v}R(t)^{-(1+v)}$

$$= (ab)/(Y^{v})(Q(t)/R(t))^{(1+v)}$$

and $$\partial Q(t)/\partial L(t) = (b(1-a)/Y^{v})\ (Q(t)/L(t))^{(1+v)}$$

are the partial derivatives.[109]

Since $\partial p(t)/\partial R(t) = (\partial p(t)/\partial Q(t))(\partial Q(t)/\partial R(t))$ and $\partial p(t)/\partial L(t) = (\partial p(t)/\partial Q(t))(\partial Q(t)/\partial L(t))$, it is now easy to observe how the drop in production rate created by the windfall profits tax will induce declines in R(t) and L(t). Now, at the optimum extraction rate $\bar{Q}(t)$, $\partial\bar{p}(t)/\partial\bar{Q}(t)$ is, as we have previously seen, equal to zero. Hence, $\partial\bar{p}(t)/\partial\bar{R}(t)$ and $\partial\bar{p}(t)/\partial\bar{L}(t)$ of the before-tax optimal Q(t) is now negative (as one can easily see from (24)). The negative partial derivative indicates that $\bar{Q}(t)$ is greater than the new after-tax Q(t) (remember, $\partial p(t)/\partial R(t)$ and $\partial p(t)/\partial L(t)$ are also no longer at their optimal values--both are now less than zero). Hence, Q(t) is reduced in order to reach a new optimal rate, and L(t) and R(t) are accordingly also reduced.

How much will that reduction be? If b = 1, then R(t) and L(t) will both be reduced by the same fraction as Q(t). For example, if Q(t) is reduced by 1/k, then R(t) and L(t) will be reduced by 1/k ((1/k) Q(t) = (1/k)R(t), (1/k)L(t)).[110] If b is less than one, then R(t) and L(t) will be reduced by a greater amount. If one assumes that b = ½ and if Q(t) is reduced by 1/k, then R(t) and L(t) are each reduced by the fraction $1/k^2$ ($(1/k)Q(t) = (1/k^2)R(t), (1/k^2)L(t)$).[111]

How can one be sure that both R(t) and L(t) will both be reduced with the introduction of the tax? Since there is a least-cost combination of R(t) and Lt) for every level of Q(t), it is only logical that both factors will be decreased, lest there be too much of one of the factors than what is consistent for a least cost combination of the two factors.

There is also another subsidiary matter to be dealt with; namely, condition (21) and I(t) (reserve acquisition cost at time t). If we take the integral of (21), we will find the following equation:

(21') $\quad R(t) = G(I(t), t) - (SQ).$

G(I(t)) is the gross additions to proven reserves at t and

(SQ) is the quantity (stock) of proven reserves extracted at t. With the imposition of the windfall profits tax, we already know that both R(t) and (SQ) will be smaller with the new optimum situation. Hence, G(t) will decline by a greater amount than (SQ) has. Since an increase in the rate of gross acquisitions of proven reserves increases reserve acquisitions costs (I(t)), the rate of those additions can be expected to be smaller since the rate of benefits from the additions will now be smaller due to the tax. If we assume I(t) to be a function of capital investment (drilling rigs and so forth), then the lower G implies less capital investment towards acquiring new reserves at t. This is what one would expect from the study of McDonald's model.

Finally, it would be of some interest if we took a look at a new version of the partial derivative $Q(t)/\partial R(t)$. Now, the partial derivative can be rewritten as $(\partial p(t)/\partial R(t))/(\partial p(t)/\partial Q(t))$ which is equal to the following fraction:

$$\frac{i(t)¢(t) - d¢(t)/dt}{[\{1 - y(t) - f(t)[1 - y(t) - d(t)]\} \$(t)p(t) - ¢(t)]},$$

which is derived from the necessary conditions (24) and (27).[112] This can be rewritten as $[\{i(t) - (1/¢(t))\ (d¢(t)/dt\}\ ¢(t)] \div [\{1 - y\ (t) - f(t)[1 - y(t) - d(t)]\}\ \$(t)p(t) - ¢(t)]$. The numerator is interpreted to be the "marginal after-tax net cost of holding reserves."[113] Since we are at the optimal situation, $¢(t)$ can be viewed as the "marginal after-tax cost of a unit of proved reserves" (marginal revenue equals marginal costs at the optimal situation).[114] $[1/¢(t)][d¢(t)/dt]$ is the interest on reserves that accrues to the owner.[115] Since i(t) is the after-tax interest rate, the optimal situation is reached where i(t) = (1/¢(t)) (d¢(t)/dt); that is, where the rate of interest consistent with the entire economy is equal to the owner's rate of interest. The denominator is the "marginal after-tax net return from producing a unit of reserves," where [{1 - y(t) - f(t)[1 - y(t) - d(t)]}. $(t)p(5)] is the "marginal after-tax revenue from selling a unit of output."[116] Obviously, as the reservoir is extracted over the years, the denominator takes on a negative value, assuming that y(t), f(t), d(t), $(t), and p(t) do not change dramatically. At that point, drilling for new reserves will be abandoned; the revenue from an increment of crude oil extracted will not be able to cover the marginal cost of acquiring new reserves to replace the oil extracted.

When the windfall profits tax -A(t) is added to (1 - y(t) - f(t)), the denominator is smaller, and both ¢(t) and d¢(t) are also smaller. Hence, there is now a positive fraction. This is symptomatic of a wasteful policy, for Q(t) is not at an optimal level with reference to R(t). Moreover, the rate of return to society is now greater than the rate of return to the operator. Thus, under-investment, from society's point of view, will now result.

CHAPTER VI

A NOTE ON EXPLORATION MODELS

The effects of the windfall profits tax upon oil exploration is perhaps of even greater importance than the effects of oil production from existing oil fields. Not surprisingly, the effects on investment once again looms as the important factor through which the tax induces its effects.

A note needs to be made here about models of oil exploration. Most of these models make use of certain probability functions and "stochastic production functions."[1] The object in such models is to estimate the probability of finding a given number of oil pools of a given size with a certain amount of wildcat drilling (which is a form of capital investment) in an area that has been suspected of harboring sizable quantities of crude oil. Often, after working out a suitable function for finding new reserves, wildcatting statistics and geological information of a particular oil producing region are plugged into the function. The results are then compared with the actual wildcatting results of the region in question.

Such models can be extremely complex. Studing them in depth would undoubtedly be most interesting and rewarding. However, the probability aspects of the models will not be studied intensively in this paper for two particular reasons. First, the probability functions are in themselves not intrinsically important to understanding the effects of the windfall profits tax upon the level of exploration. The standard procedure to be used with such models is to simply hold the given probability terms constant over time. Only in this manner can we find how the tax itself induces changes in exploration efforts. After all, the probability functions themselves are determined by geological, not economic, factors.

Moreover, the role of the probability functions are downgraded partly because the general expectations of present and future petroleum exploration can already be fairly well discerned. Several studies have revealed that expected future oil finds in the United States are expected, on the average, to be smaller in terms of the number and size of discoveries, at least for the lower forty-eight states.[2] There may be some significant discoveries still to be found in Alaska, but weather and transportation problems limit the potential for significant new discoveries in this area.[3] Furthermore, the chances for any new discoveries off the West, East, or Gulf of Mexico coasts seem rather remote at the present time.[4] At any rate, even if there were some new finds in these areas, it would in all likelihood not be able to offset the expected future paucity of new oil finds in the lower forty-eight states and thereby alleviate the steady decline in proven oil reserves. Since it is painfully clear that new discoveries of crude oil will be declining with or without the windfall profits tax, there is much less urgency to studying the probability functions themselves, at least in terms of possible American independence of foreign sources of oil. We shall therefore simply assume that the probability portions of the following models will be constant.

Another important question needs to be dealt with here. When considering the complexity of some of the following models, how can one be certain that a wildcatter actually makes his drilling decisions in such a manner? Quite frankly, I doubt that a wildcatter actually thinks in the manner that is portrayed in these models, unless we are considering one of the larger oil companies. However, it is really not a sticky problem, for, as long as the results of a wildcatter's decision making conforms reasonably well with the results of our models, then the use of these models is acceptable.

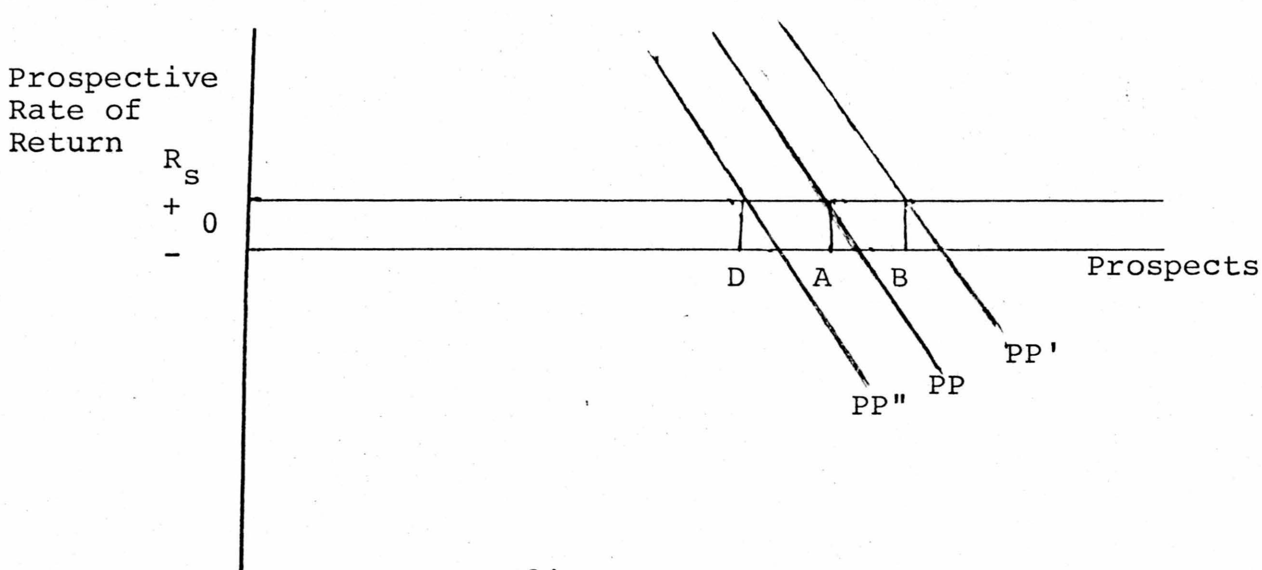
First, McDonald's framework will be used to study the effects of the tax. The models developed by Uhler and Bradley and Arps and Roberts will be utilized. Finally, a model by Kuller and Cummings will also be studied. As before, the main emphasis is to recognize the direction (positive or negative) in which exploration efforts are affected by the tax.

CHAPTER VII

THE EFFECTS ON INDIVIDUAL
OIL EXPLORATION

The windfall profits tax will also greatly affect the exploration for brude petroleum in the United States. Once again, McDonald provides us with a relatively simple model for studying such impacts.

If we view the typical oil explorer as being confronted with a broad number of prospects, the prospects will differ from each other due to their differing probabilities of containing viable prospects of a given quality, the differing costs of exploration for each, and the dissimilar costs of development and extraction in the case of a productive discovery.[1] Since much dissimilar prospects will yield different degrees of expected profits, we can form a downsloping curve matching each prospective rate of return with a number of prospects:[2]



We can use this diagram to show the effects of price and tax changes on oil exploration. If future real prices of crude oil are suddenly expected to be higher than previously thought, oil exploration now becomes (all other things held equal) more profitable. For a given rate of return, more prospects will be explored. If R_s is assumed to be the rate of return optimal to society, then (also assuming that the wildcatter's rate of return matches that of society's) the number of oil prospects to be explored increases from A to B.[3]

A windfall profits tax will create an opposite effect. If a wildcatter expects his future net revenue to be taxed at a much higher rate than previously expected, then the PP curve for the operator is shifted to the left to PP". The tax on windfall profits makes each prospect less profitable at every prospective rate of return. Indeed, those prospects that give only a slight prospective rate of return will probably not be explored at all. With a socially optimum rate of return of R_s, the number of prospects explored drops from A to D. The windfall profits tax will thus reduce the number of prospects explored at any given rate of return irrespective of whether there are expected future real price increases or not.

A number of other points also need to be explored here. For one thing, the costs of oil exploration have been rising dramatically since the early 1970's.[4] Increases in exploration costs will, of course, shift a wildcatter's PP curve to the left. The number of wildcat wells did indeed decline in the early years of the decade.[5] However, the cost of new oil wells was not the only factor that apparently induced this decline in crude oil exploration. It is important to realize that most oil exploration in the United States is financed through equity capital. These "drilling funds" were, during the 1960's, supported by huge tax shelters that often gave virtually a dollar-for-dollar tax credit for investments in exploration and production.[6] However, changes in the depletion allowance and in the federal government's individual income tax policy reduced the scope of such investments. With a smaller pie from which to draw equity money, it now takes higher given rates of return to attract the necessary capital. Hence, the PP curves for wildcatters shifted even more to the left. This was basically the situation that wildcatters faced in the early part of the decade. The dramatic price hikes that followed the 1973 oil embargo, though, resulted in a shift of the PP curves back to the right. The greater prospective profit for each exploration prospect made exploratory drilling much more attractive. Accordingly, the number of exploratory wells have climbed sharply since the oil crisis.[7]

Some discussion is also needed in terms of the time frame we are using. Since the windfall profits tax, bar political tinkering, will be phased out at the very least by the early 1990's, the point in time at which the wildcatter contemplates the various exploration choices before him may be of considerable importance. As the expected date signaling the beginning of the phase out period looms closer, the expected profit from a given exploration prospect at a given rate of return (all other things equal) will be higher. This is due to the fact that, if a reservoir is discovered, part of its production life will coincide with the phase out period and the windfall tax-free period afterwards. Hence, the closer the discovery date is to the phase out date, the more of the reservoir's production life will coincide with the phase out and the more valuable the prospective stock of recoverable oil will be. If the wildcatter intends to be a producer of the prospective reservoir, then the various prospects facing him will become more valuable the closer the point of time in question is to the beginning of the phase-out. However, even if the wildcatter plans to sell his finds after he discovers them, they will still be more valuable as they are discovered nearer the phase out date since the finds to be sold will bring a higher price. Thus, all other things being equal, we can expect oil exploration activity to increase as we come closer to the phase out date.

In order to understand how the windfall profits tax will influence exploration investment for a given region that is being explored, one must use more sophisticated models. Such analysis can benefit from an adaption of the model by Kuller and Cummings that has already been studies. But first, it would be profitable to take a look at the following probability function that has been developed by Uhler and Bradley:

(1) $$\underline{R} = \sum_{i=1}^{\underline{N}} F_i \underline{S}_i$$

where $\underline{R}$, $\underline{S}_i$, and $\underline{N}$ are all considered to be random variables.[8] $\underline{S}_i$ refers to the sizes (volumes) of the individual reservoirs that have been discovered. The size of each reservoir is assumed to be in accordance with a lognormal distribution.[9] The most important aspect of such a lognormal distribution of reservoir size is that relatively smaller volume reservoirs occur with much greater relative frequency than larger volume reservoirs.[10] A diagram of such a lognormal distribution is given in the appendix to this paper for the reader's convenience. $\underline{N}$ is the number of reservoirs found in the area explored.[11] Like $\underline{S}_i$, $\underline{N}$ is a random variable which has, in contrast, a negative binomial distribution. In a negative binominal distribution the frequency of finding a small number of reservoirs is much greater than finding a large number. $\underline{R}$ is another random variable, but in this case it is simply the summation of the various discovered recoverable reservoir volumes. It is a random variable for the simple reason that $\underline{N}$ and $\underline{S}_i$ are also random variables.[12] F_i refers to the "recovery factors" that determine just how much of the oil in place is recoverable from the producing reservoir.[13] This variable will shortly be explored in greater detail. It is helpful in this analysis to think of the exploration that has been accomplished as being achieved by a single entity, such as one of the major oil companies. Consequently, all of the reservoir that will be developed will be operated in an unitized fashion.

The $\underline{N}$ and $\underline{S}_i$ variables are determined, of course, by the land area being explored for new crude oil and by the exploration drilling and information on the area explored. Actually, the model is not particularly good for predicting the results of exploratory drilling and increasing information on the amount of proved reserves over time for a single exploratory area. It can be helpful, however, if the new area to be explored is similar to other petroleum-bearing areas that have already been developed.[14] Otherwise, the model is rather useless since it is not known for an idiosyncratic area just how the probability parameters change over increasing increments of wildcat drilling, at least not initially.[15]

It is the F_i variable that is of the most concern. Let us assume that the region to be explored is similar geologically to other petroleum producing areas. Then there are a large number of factors related to the possible potential of the discovered oil in place to be converted into proven reserves. The type of "natural drive" involved is obviously an important variable. Other reservoir characteristics, such as the depths of the reservoirs, viscosity of the oil involved, the porosity of the reservoir's rock, and so forth are also of great importance in determining proved reserves. The geological knowledge held by the wildcatters and owners is a most important factor. Furthermore, the extent of exploration (wildcat drills) is perhaps the most important factor to be considered. Drilling is also a determinant of the geological information owned. The state of technology, as present and possible developments in tertiary recovery readily attest, can also be a determining factor.

Of these factors, we are concerned basically with exploratory drilling. Hence, the other factors will be assumed to be constant over time and with changes in drilling investment. Our problem now is to show how the windfall profits tax will affect drilling investments for exploratory drilling.

Investment in wildcatting is a function of the net benefits that can be obtained from an increment of wildcat investment--a sort of crude return on the exploration investment. The benefits that can be obtained from wildcat drilling are given by

(2) $U = U(q_0, V, T)$

where U is the total amount of benefits created by the drilling investment, q is the production capacity benefit created by wildcat investment, V refers to the benefits of new proved reserves that are discovered, and T refers to the benefits of knowledge of the reservoir that is created by the drilling investment.[16] Since the wildcat well will become a part of productive capacity if oil is struck, the q term is actually a fraction of the wildcat wells drilled (not all wildcat wells will make a find).

One might ask which of the variables in (2) are more important in the determination of U. It is difficult to say with complete certainty; it would probably vary a little with each different region to be explored. The relative magnitudes of the additions to q, V, and T created by an increment of I (investment) are fairly well known, however. The percentage additions to U of V are greater than the additions by q or T for the typical exploratory well.[17]

Now, we naturally want to know the addition to benefits from an increment in investment. Thus, one merely takes the total differential of (2):

$$(3) \qquad dU = (\partial U/\partial q_0)dq_0 + (\partial U/\partial V)dV + (\partial U/\partial T)dt,$$

$$q_0 = \emptyset(I),\ V = \theta(q_0),\ T = F(q_0).^{18}$$

To understand the impact of the windfall profits tax, there must be an understanding of the q, V, and T benefits. The total benefits from the increment of proven reserves discovered is, naturally, the expected present value of the addition to proven reserves that has been induced by the increment of exploration investment. This is multiplied by a percentage that is indicative of the changes in recoverable stock that are induced by different extraction rates in the future. Hence the second term in (3) can be referred to as $(1 - x_t)(\Delta V_t)(1/1+c)^t$, which is similar to one of the equation terms in the McDonald MNR model. Here, V refers to the increase in the value of proved reserves, t refers to the future time periods involved, $(1-x_t)$ is the expected reduction of the present value of revenue at time period t due to the expected production rates at time periods before t--greater production rates before time t may reduce oil production rates during t if reservoir pressure is lost.

For q_0, the benefits concerned are the expected future net revenues obtained from the new productive capacity. This is due to the fact that the q_0 benefits accrue to the oil operator; hence, the benefits are in the form of net incomes. As an interesting sidelight, it needs to be explained just what kind of costs are incurred in obtaining the new proved reserves. For this model and other exploration models, it is reasonable to assume that the region to be explored was obtained via an auction system. In such a system, a perspective wildcatter bids for an area to be explored along with other potential wildcatters. The land naturally goes to the highest bidder. It is hoped that under such a system most of the economic rent of the area bought will be captured by the seller.[19] By economic rent, one means the net of the present value of future receipts from the stock of crude oil over the prevent value of all future expenditures made for the development of that oil. The bidders will bid up the price of the land in question until the price has reached a point where the expected economic rent that has not been captured is consistent with the opportunity cost of capital that may be invested in the prospective oil bearing region, or, in other words, the return on capital that is needed to attract the requisite amounts and kinds of capital.[20] This is the type of system that is generally used by the Federal government when it decides to open up certain public lands or parts of the offshore continental shelf to oil exploration. In the United States, which is the only nation in the world that uses such a system, auction bidding for potential oil areas is known as "bonus" bidding. The lands that are sold are known as a "lease sale."[21] Consequently, the prospective wildcatter and oil operator will have to include such an auction price with the cost of his capital investments and his labor in the total cost of exploring and producing from a prospective region. Hence, the benefits from an increase of q_0 due to an increment of exploratory investment can be written as $\sum_{t=1}^{k} (1-x_t)(\Delta NI_t)(1/1+i)^t$. Here we simply have the sum of the present values of the increases in all future values of net income arising from the increase in exploration investment.

Before we go to the T term, one might ask how the requisite amount of economic rent will always be absorbed by the selling agency under the auction system. Actually, there is no guarantee that the system works for every individual lease. The bid by the winning wildcatter may be higher or lower than the actual value of the oil in the ground. If the bid is higher, then the lease will not be developed lest the wildcatter/operator suffer a grievous economic loss. If the winning bid is far below that which is dictated by the return on capital consistent with society's demand for oil, then the wildcatter will earn an unjustified windfall. However, it is reasonable to assume that for a large number of individual leases, there two possibilities will average themselves out.[22] It is assumed, of course, that a firm will never willingly bid below or above a price consistent with the optimal rate of return; to attempt such tactics will lead to a loss of the bid or a prospective rate of return on capital that is lower than what can be obtained elsehwere, respectively.[23]

The T term in (3) involves benefits of a different kind. The knowledge of the reservoir that is gained by an increment of investment will be used with the existing store of reservoir knowledge in making future decisions on where and how much to drill. Thus, T can be considered as a proxy of the benefits that can be gained with the next increment of exploratory drilling. In other words, increases in T reduce the risk and uncertainty that is attached to the next increment of drilling investment and concomitantly increase the marginal proven reserves that will be found with the new drilling investment.

The benefits that accrue to the wildcatter from an increase in T can be viewed in another manner. If an increase in T leads to better drilling decisions in the future, then the increase in T can lead to lower or greater requisite returns on investment for future drilling investments. Early in the development of a newly acquired oil region, the needed rates of return will be relatively high due to the risk and uncertainty surrounding the initial drilling investments. Increases in T reduce the needed rate of return by reducing the risk and uncertainty. In the later stages of a region's exploration, it is expected that new wildcat wells have less of a chance of finding new reservoirs of oil.[24] The amount of knowledge owned at the time can help to determine the higher rates of return that will then be needed to attract new drilling investment (the rates of return will be higher because the store of knowledge indicates that there is less probability of striking oil with a new wildcat rig).

However, if knowledge does not increase with more drilling investment, then an entirely new situation arises. Suppose that only an initial amount of information and technological knowledge exists when the exploration of the leased area is implemented. In a situation like this, the best prospects are drilled first, with the less attractive prospects being explored next, and so on. In contrast to the situation of knowledge increasing with more investment (in which the incremental returns from increments in drilling investment increase till a certain point is reached and then begin to decrease), the incremental returns under fixed knowledge start to fall immediately after the initial exploration investments.[25] In this situation, one would expect the needed rates of return to increase with more drilling investment and subsequent utilization of the more attractive reservoir prospects.

The question of what mathematical term to use in place of the T term in (3) still remains. The term ${}_{r}P_{s+1} \sum_{s+1}^{k} (\Delta V)$ $(1/1+i)^{t}(1-x_{t})$ will now be used. ${}_{r}P_{s+1}$ is simply the probability of finding a certain amount of oil reserves with the next increment of wildcat drilling investment. We are using T here as a proxy for possible future finds of crude petroleum where s+1 refers to the next exploration period in which exploration investment is made. $\sum_{s+1}^{k} (\Delta V)(1/1+i)^{t}(1-x_t)$ is the present value of all additions to proven reserves resulting from the next exploration period. Note that ${}_{r}P_{s+1}$ will change with further increments of exploration investment since the returns from increments of investment will eventually begin to decline. Hence, we can replace equation (3) with

$$(4) \qquad dU = \sum_{t=1}^{k} (\Delta NI)(1-x_t)(1/1+i)^{t} + (\Delta V)(1-x_t)(1/1+i)^{t} + {}_{r}P_{s+1} \sum_{t=1}^{k} (\Delta V)(1/1+i)^{t}(1-x_t).$$

Now, let us impose a windfall profit tax on this equation where the tax is a certain portion of the revenue obtained in production during a period t:

$$(5) \qquad dU = \sum_{t=1}^{k} (\theta_t)(\Delta NI)(1-x_t)(1/1+i)^{t} + (\Delta V)(1-x_t)(1/1+i)^{t} + {}_{r}P_{s+1} \sum_{s+1}^{k} (\Delta V)(1/1+i)^{t}(1-x_t).$$

Only the first term is affected by the tax since proven reserves cannot be taxed unless they are extracted. Also, θ_t may change with time. This is due to the phase out period of the tax which will be completed at the latest in the early 1990's. Furthermore, changes in prices may also change θ_t due to changes in the wellhead price of oil and the base price that is used to compute the tax amount.

It is apparent from comparing (4) and (5) that the tax reduces the benefits that are accrued from an increment in exploration investment. Hence, the wildcatter in question will make fewer investments in exploring the region; he can probably obtain higher returns on his capital investment in some other investment. This is what we would expect from studying McDonald's model. Thus, holding the other recovery factors constant, there would be less total exploratory investment for (1) and hence R will be smaller, ceteris paribus.

Arps and Roberts give another model for measuring the returns from an increment of exploration investment that is used with an oil-bearing region that has to some extent already been explored. For an increment in the number of wildcat wells, the number of new reservoirs of a certain size is

(6) $$d/dw(N(w)f(a;w))da = \underline{a}a(N(\infty)f(a;\infty) - N(w)f(a;w))da.$$

Here N(w) is the number of wells drilled in the time period, f(a;w)da is the probability function showing the probability that a successful wildcat will discover a reservoir of size a. Taking d/dw of that exprsession gives the increase in the number of new reservoirs of size a discovered by an increment in w. f(a;w) itself refers to the probable density of reservoirs which is dependent upon a and w (which is exogeneous). Differentiating by a gives the probable density for any given reservoir size a.[26]

This increase in new reservoirs by an increment of w is determined by the right side of (6) where a is the constant level of knowledge and technology, $N(\infty)f(a;\infty)da$ equals the number of reservoirs of a volume to be found initially (or by an infinite number of w), and N(w) f(a;w)da is the number of reservoirs of a given size that have been found by the first w wildcat wells.[27] The fact that a is constant indicates that the number of discoveries of a given size that are discovered with an increment of w declines after the initial number of wells dug. The N(w)f(a;w)da confirms this situation; as w becomes larger, the smaller the probability of finding new reservoirs of the given size.

The model given by (6) is best suited for regions that have already been partly explored. It is designed to make decisions upon past trends of exploration in the region as shown by the right-hand side of (6). Inicently, one could find the total number of reservoirs and their size distribution by first integrating over a range of wildcat wells drilled and then once again integrating over a for every volume class.[28]

Since the number of wells that will be drilled is dependent upon investment into oil exploration, we should be able to use the model to show the effects of a windfall profits tax. Now, we multiply the right-hand side of (6) by $(\emptyset_t) \sum_{t=1}^{k} (MR)$ $(1/1+i)^t$, where $(\emptyset_t)$ is the fraction of the reservoir crude oil that is recoverable. Here it is assumed that the new reserves will be developed and thus create marginal revenues. Hence,

$$(7) \qquad RE = a\underline{a}(\emptyset t) \sum_{t=1}^{k} (MR)(1/1+i)^t \, (N(\infty)f(a;\infty) - n(w)f(a;w))da.$$

RE is the present value of the fraction of new discoveries found by an increment of W. Accordingly, a windfall profits tax will reduce future marginal revenues of the discoveries made with an increment of exploration investment (a wildcat well is, after all, a capital investment into exploration). Hence, the investor may very well search for other investment prospects in lieu of the decrease of the return on his wildcat investment; exploration investment will be reduced.

It is now appropriate to consider a model in which the expected crude oil discoveries of the entire nation can be incorporated. Kuller and Cummings, besides the model of reservoir management given earlier, have also presented a model of the estimate of the total optimal petroleum stock X_t for a given time period t:

$$(8) \qquad X_t = \sum_{n+1}^{N} X_n(U_n, V_n)$$

where the total recoverable stock of crude oil is determined by the present and past production and gross investment rates for all of the nation's crude oil reservoirs.[29] N refers to the number of reservoirs in the entire nation; U and V have the same meanings in the earlier Kuller and Cummings petroleum reservoir management model. Now, if Γ is the increase in known reserves during t, then (8) can be rewritten as

$$(9) \qquad X_t = \sum_{n=1}^{N} X_n(U_n, V_n) + \Gamma(E_t)$$

where Γ is determined by E_t--the level of exploration expenditures during t (productivity factors are assumed to be constant during t).[30]

Thus, we must find the effect of the windfall profits tax on exploration expenditures. To do that, we need the optimal relationship between marginal expenditures on oil exploration and the marginal benefits of oil exploration. For this, Kuller and Cummings give the following equation:

(10) $$B_t = AB_t\ (\partial\Gamma/\partial E_t).$$

B_t is the present value of one dollar of incremental exploration expenditure; the reader will also recognize it as the discount factor.[31] A is the "marginal scarcity value of the nation's known petroleum reserves;" in simpler words, A indicates the marginal increase in net benefits that is created by an incremental increase in known reserves.[32] It is multiplied by B_t to give the present value of A for future time periods. A is optimally determined, just as @ was determined in the reservoir management model.[33] $\partial\Gamma/\partial E_t$ is, of course, the expected increase in proved reserves resulting from an incremental increase in E_t.[34]

With the advent of a windfall profits tax, one would expect A to be smaller at the optimal level of expenditures; the increase in net income over time that is created by an increment in known reserves will be decreased by the tax. With marginal expenditures now greater than the marginal benefits of an increase in exploration expenditures, there can be no exploration expenditures at the level with which the before tax optimal A was associated. Since $A(\partial\Gamma/\partial E_t)$ must always be equal to one, the partial derivative must be larger to offset the decrease in A. This will occur at lower levels of E_t since exploration expenditures are first made on the most promising prospects. Consequently, the partial derivative has

has a greater value at low levels of exploration expenditures. The optimal level of exploration expenditures must then be smaller with the imposition of the tax. If we use exploration expenditures as a proxy for exploration investment, then we have once again found that the level of exploratory investment is lower with the introduction of the windfall profits tax.

CHAPTER VIII

THE PROBLEMS OF CERTAIN LAND OWNERSHIP PATTERNS

Before the subject of petroleum exploration is left for good, the externalities that surround exploratory drilling and oil extraction in the United States should be briefly examined. Of special importance is the effect of typical American landholding patterns, for crude oil exploration and extraction in the United States is often complicated by the land ownership conditions that exist in the area to be explored.

There is fairly good evidence that leases of most wildcatters usually do not cover the entire size of the reservoir that is eventually discovered.[1] There are a number of reasons for this situation. For one thing, most landholdings encountered by a wildcatter in his exploration efforts are relatively small in comparison to the size of the oil reservoir that can usually be found.[2] But that is not the entire problem. After all, there is nothing to stop the prospective wildcatter from buying up the landholdings and consolidating them into an area to be drilled--aside from obtaining the necessary credit, of course. If this leasing campaign falls short, however, then problems begin to surface.

Why would the landholders be unwilling to lease their properties to the wildcatter? The reasons can be numerous. Often, the landowner attaches a value to his land that is greater than the amount the wildcatter is willing to pay for the land. This view may arise for many different reasons. The landowner may be using the land in such a manner (cattle grazing, for instance) that results in the divergence in valuations. Or the two may disagree over the chances of oil being struck on the property or the quantity of crude lying under the property.[3]

Yet, the landholders may not lease his property even if none of the above disagreements exist. The difficulties may arise since the landowner, unlike the wildcatter, does not have to take into account exploration costs in his valuation of the oil lease.[4]

The size of the landholdings is also of considerable importance. A landholder whose land comprises only a very small portion of the potential reservoir will be much more willing to withhold his land for a higher offer than a landholder with a tract that is relatively large in comparison to the prospective reservoir. The small land tract does not greatly affect the amount of profit to be gained from the reservoir if the tract stays in the hands of the original owner.[5] In contrast, a large landowner must take into account the effects of his decision upon the wildcatter's expectations. If the withholding of the lease greatly reduces the expected profitability of drilling for new oil reserves, then the prospective wildcatter may not bother to explore for oil at all.[6] Hence, large landholdings will in all likelihood leased at a price that is more consistent with the wildcatter's demands. On the other hand, if the area to be explored is comprised of many small holdings of land, then the wildcatter may have grave problems with his leasing campaign.

Moreover, there is often an element of speculation involved in the leasing of land for oil exploration. It is not unusual to find speculators entering a prospective oil-bearing region in hopes of gaining a profit on his speculative activities. This may also damage the profit expectations of the wildcatter if the speculation is conducted after the wildcatter has attempted to obtain leases.[7]

Incidently, it is not certain that the extra costs propagated by these ownership patterns are absorbed completely by the wildcatter. For one thing, the obstacles found in leasing properties may induce the wildcatter to bid less intensively since he cannot obtain the full benefits to be gained from exploration when he cannot gain all of the leases he desires. Furthermore, the ownership costs may be partly borne by future producers. If the wildcatter is forced to bid higher than he wants for the leases in question and the value of the oil discovery does not match this lease price (allowing for a desired rate of return on investment), then the wildcatter will reduce his exploration efforts since he is now receiving a less than favorable profit from his undertaking. Due to the reduced exploration, oil production firms may bid up the price of the now less numerous oil-bearing lands, assuming that the demand for new oil properties does not change with changes in the quantity of new proven reserves being offered. Thus, producing firms may end up shouldering some of the costs.[8]

There are also external benefits that result from exploratory drilling on these lands. First, there are the benefits that accrue to other lease holders when a wildcatter makes an oil discovery. If the newly discovered reservoir extends beyond the boundaries of the wildcatter's lease, then the holders of some of the neighboring leases (who may be wildcatters in their own right) benefit from the find at the wildcatter's expense.[9]

Also, each exploration well, even if it does not strike oil, increases the geological knowledge of the surrounding areas and consequently aids future exploration efforts. This externality would probably exist even in the absence of highly fragmented landholdings. However, the situation usually encountered makes the problem more severe.[10]

Of course, the fragmented nature of American land ownership can also have undesirable effects on crude oil production. Obviously, it tends to foster the type of wasteful extraction that is associated with the lack of a unitization agreement among the producers of a reservoir.

There are a number of other issues that plague oil exploration and production in the United States. One of these is concerned with the size of oil leases that the federal government creates out of its public lands. These leases tend to be too small in size to avoid the aforementioned problems.[11] Also, the Federal leasing system encourages speculation.[12]

Another problem arises with the use of royalties by landowners when they lease their holdings to oil firms. Since a royalty will take a percentage of the revenue from a producing property without regard to cost, royalties may make marginal properties (like stripper wells) unprofitable.[13] Furthermore, royalties may force an early shutdown of an oil well. If an oil field reaches a point late in its producing life where its revenues just barely cover its costs, then it will be shutdown even though continued production from the field would be socially beneficial.[14]

CHAPTER IX

CONCLUSIONS

Important policy implications can be derived from the analyses of the preceding models. For one thing, the rate of current production for an unrestrained operator is not optimal for society as a whole. It has been pointed out that unrestrained extraction by several firms occupying the same reservoir, all other things being equal, will create a loss in the total amount of crude oil stock that will be extracted over the life of the reservoir. Thus, a loss is made for society since the oil operators are not using their resources in the most efficient manner possible. There is also a loss to society through a higher than necessary rate of capital consumption for certain types of capital such as oil well equipment. Furthermore, there is still a further loss to society through a decrease in certain types of investment that aid in maintaining the pressure in a reservoir and thus increase the recoverable stock of oil. Some kind of centralized control or a production agreement among the firms in such a reservoir would be most helpful in eliminating such waste.[1] Such an agreement would include a set of production guidelines consistent with the optimal rates of production and investment that are given by equations (11) and (12) of Kuller and Cummings.[2]

Another alternative would be an excise tax on crude oil production and investment.[3] However, precise knowledge of the nature of the problem is necessary if an optimum excise tax rate structure is to be found. For that matter, if central control of reservoir production is to be socially beneficial, then adequate geological information of a form that is easily obtainable by oil reservoir owners is a must. A means must also be devised to bar large oil companies from using unitization agreements as a means to fix crude oil prices.

Unitization of oil reservoirs has become increasingly popular. Most oil states now have compulsory unitization laws, although some of these laws are probably not strict enough in their content and enforcement.[4] Many states still rely mainly on such clumsy methods as compulsory spacing of oil wells for petroleum conservation. It would be most beneficial to the entire nation if these stragglers would follow the lead set by others.

An excise tax on oil production could also be of considerable benefit. Such a tax, which has been submitted by Kuller and Cummings, would enter the external costs of unrestrained reservoir extraction into the price of crude oil. The formerly external costs are hence internalized in the price system. The higher price of crude oil, of course, leads to a drop in consumption and production of crude oil. Accordingly, pressure maintenance is preserved. Such an excise tax has some major drawbacks, though. It does nothing to assauge the loss of profits by an oil operator producing in an uncontrolled oil reservoir. Moreover, since such an operator is still in competition with the other firms using the reservoir, the oil operator still has little incentive to invest in pressure-maintenance capital. To be sure, certain investment incentives can be formulated along with the exicse tax. Still, a national unitization law seems to be the optimal policy choice.

Stepping back from the purely theoretical considerations of these proposals for a moment, it is also possible that an excise tax may also be inferior from an enforcement point of view. The excise tax would be imposed only upon unrestrained reservoir producers. If the tax is also imposed on unitized reservoir producers, society will lose the optimal oil production rates of these firms. Indeed, if an excise tax is to be truly successful in ameliorating petroleum production waste, it would have to differ with each reservoir due to the dissimilar geological characteristics of each reservoir. Thus, a large and cumbersome bureaucracy might be needed for such an effort. Besides, the geological information needed for the reservoirs could be put to even better use with unitization agreements. In terms of public policy, it is probably best to rely upon unitization laws in order to halt oil production waste. Of course, it might be possible to combine the two approaches. For instances, the unitization of petroleum reservoirs could be made compulsory nation-wide, with a stiff excise tax to be applied to those crude oil producers that fail to obey the law of signed unitization agreements. Such an operator would have to submit, lest he be priced out of the crude oil market. But this would still involve a large bureaucracy.

The windfall profits tax itself is of some value in the fight against wasteful petroleum production, but it must be considered a third-line choice at best. It is of no use in encouraging investment in unrestrained petroleum reservoirs that lack investment. True, the tax will reduce the extraction rate of such reservoirs to a more optimal rate, but it must be pointed out that the smaller future extraction rates may be partly reduced by a lack of pressure maintenance investment resulting from the windfall profits tax. Furthermore, the tax would also lower the production and investment rates for centrally controlled reservoirs below what would be the optimum for both the reservoir operators and society. Hence, the tax can hardly be considered a beneficial part of a national energy strategy, at least not in the traditional sense of such a program. It does nothing to boost energy supplies or to lower the demand for energy.

To be sure, one might argue that, since crude oil producers are now, thanks to the OPEC price hikes, making a return on their capital that is well above average, there is a real need for such a windfall profits tax. The rather low price elasticity of supply of crude oil production makes the need for the tax, in the view of the tax's proponents, rather urgent. These proponents, mainly composed of politicians from the oil-consuming states, do not feel that it is proper for oil producers to be gaining a windfall when the producers have gained such profits through a cartel price and not through greater investment, greater efficiency, and so forth. Since consumers of refined oil products have been hard hit by the OPEC price boosts, these proponents also feel that the tax revenue is needed in order to assuage the income effects of the huge oil price hikes of the last decade.[5]

In response, it must be pointed out that such a policy may not be the correct one for society over the long-run. This analysis indicates that taxing the windfall profits of crude oil producers will make the supply of crude oil even less elastic due to lowered production and investment. Hence, the tax will impede proper resource allocation in the future, for some of the spur to new outside investment that has been created by the higher profits will be at least partially lost.[6]

On the other hand, there is perhaps an alternative and far more cogent argument for a windfall profits tax. It has already been pointed out that American crude oil reserves are beginning to dwindle. For example, yearly proven reserves have fallen from a total of over thirty-one billion barrels per year for most of the 1960's to only 27.8 billion in 1978.[7] More ominously, oil drillers are finding, on the average, much less oil per drilling pipeline foot than they used to.[8] One could argue that, due to the increasing costs that will be needed to find smaller amounts of crude oil reserves, it would be far wiser to use the windfall profits of the crude oil producers in conservation and alternative energy efforts. It does appear that energy conservation provides a relatively cheap manner in which to reduce dependence upon foreign energy sources.[9] Yet, a relatively small proportion of the revenue created from the windfall profits tax is earmarked for energy conservation. The efficacy of using the new tax revenues to fund alternative sources of energy is more questionable. Some of these sources, such as shale oil and synthetic fuels, will actually require considerable amounts of energy in order to transform the raw mineral inputs into a form (oil) convenient for energy use.[10] Other forms of alternative energy, like fusion reactors and certain highly sophisticated forms of solar energy, are still being developed in the laboratory. However, such questions are rather moot, for relatively little of the windfall revenue is set aside for these exotic forms of energy.

Another possible defense of the windfall profits tax concerns the problem of pollution. The use of refined oil products as energy creates external costs via the waste fumes that are vented into the air. One might contend that the tax helps to "internalize" for the crude oil producers the external pollution costs of petroleum fuel use. However, in this case, only crude oil producers will have to pay for the external costs. Oil refiners and motorists will not be forced to pay for their part in creating the external pollution costs. An excise tax on crude oil or refined petroleum fuels, carefully calibrated in order to capture all of the external costs in question, would be a much more effective and fairer means by which the costs of pollution can be registered in the economy's price mechanism--especially since much of the windfall profits revenue will be returned to refined oil consumers in the form of income tax reductions.

Another note needs to be made on tertiary oil. If an oil producer arranges his investments between tertiary projects and other productive petroleum investments so that the rates of return on all investment projects are equal, then the oil producer will invest more heavily into tertiary projects with the imposition of the tax (amount of investment money available held constant); the profits of a tertiary project are taxed less heavily under the windfall profits tax than other productive projects. Considering the potential of tertiary methods, this is a possible benefit of the tax. However, since the tax will reduce investment in the oil industry, it is not clear if there will actually be more investment into tertiary oil with the imposition of the tax.

As I have argued, the windfall profits tax should reduce domestic crude oil production. How great will this reduction be? The government has yet to come out with the predicted declines resulting from the legislation that was eventually approved. However, there are estimates for the original House and Senate Finance Committee bills. The Senate Finance Committee bill was expected to reduce domestic oil production by 190,000 barrels per day in 1985 and 290,000 barrels per day in 1990. For the original House bill, the figures are 455,000 and 840,000 respectively.[11] For crude oil production from new reserve discoveries, the Senate Finance Committee bill registers declines of 80,000 for 1985 and 185,000 for 1990. The figures for the House bill are 310,000 and 305,000 respectively.[12]

Are such reductions wise? It depends a great deal on the situation in other energy sources. If other energy sources expand at a greater rate than expected in the 1980's, then the impact upon the total domestic energy supplies will be marginal. If these other energy supplies do not take up the slack, however, then the windfall profits tax will be judged a mistake.

APPENDIX

The necessary conditions for the Kuller and Cummings model are as follows:

$$\text{Maximize} \quad L = \sum_{t=1}^{T} \sum_{j=1}^{n} p_t u_t - C_{jt}(U_t, V_t, K_{jt})B_t$$

$$- \sum_{j=1}^{n} \sum_{k=1}^{q} \Delta_{jk,t+1} B_{t+1} \{K_{jk,t+1} - K_{jkt} + D_{jkt}(u_{jt}, v_{jkt}, K_{jkt})\}$$

$$\sum_{j=1}^{n} \psi_{jt} B_t \{u_{jt} - F_{jt}(U_t, V_t, K_{jt})\} - @B_T \{\sum_{r=1}^{T} \sum_{j=1}^{n} u_{jr} - X(U_T, V_T)\}$$

$$+ \sum_{j=1}^{n} E_{jt} B_t u_{jt} + \sum_{j=1}^{n} \sum_{k=1}^{q} \theta_{jkt} B_t v_{jkt}.$$

Necessary and sufficient conditions for the above are:

$$\text{(A1)} \quad \partial L/\partial u_{jt} = (p_t B_t - \sum_{r=1}^{T} \sum_{i=1}^{n} (\partial C_{ir}/\partial u_{jt}) B_r)$$

$$- \sum_{k=1}^{q} \Delta_{jk,t+1} B_{t+1} (\partial D_{jkt}/\partial u_{jt})$$

$$-\psi_{jt} B_t + \sum_{r=t}^{T} \sum_{i=1}^{n} \psi_{ir} B_r (\partial F_{ir}/\partial u_{jt}) - @B_t (1 - \partial X/\partial u_{jt})$$

$$E_{jt} B_t \leqq 0;$$

$$\text{(A1')} \quad (\partial L/\partial u_{jt}) u_{jt} = 0, \; j = 1, \ldots, n; \; t = 1, \ldots, T;$$

$$\text{(A2)} \quad \partial L/\partial v_{jkt} = (-(\partial C_{jt}/\partial v_{jkt}) B_t - \sum_{i=1}^{n} (\partial C_{it}/\partial v_{jkt}) B_t$$

$$- \sum_{r=t+1}^{T} \sum_{i=1}^{n} (\partial C_{ir}/\partial v_{jkt}) B_r) - \Delta_{jk,t+1} B_{t+1} (\partial D_{jkt}/\partial v_{jkt})$$

$$+ \sum_{r=t}^{T} \sum_{i-1}^{n} \psi_{ir} B_r (\partial F_{ir}/\partial v_{jkt}) + @B_T (\partial X/\partial v_{jkt}) +$$

$$\theta_{jkt} B_t \leqq 0;$$

(A2') $(\partial L/\partial v_{jkt})v_{jkt} = 0;\ j = 1,\ldots, n;\ k = 1,111, q;$

$g = 1,\ldots, T;$

(A3) $\partial L/\partial K_{jkt} = (-\partial C_{jt}/\partial K_{jkt})B_t - \Delta_{jkt}B_t$

$+ \Delta_{jk,t+1}B_{t+1}(1-\partial D_{jkt}/\partial K_{jkt}) + \psi_{jt}B_t(\partial F_{jt}/\partial K_{jkt}) \leqq 0;$

(A3') $(\partial L/\partial K_{jkt})K_{jkt} = 0,\ j = 1,\ldots, n;\ k = 1,\ldots, q;\ t = 1,\ldots, T;$

(A4) $(\partial L/\partial \Delta_{jk,t+1} = -\{K_{jk,t+1} - K_{jkt} + D_{jkt}(u_{jt}, v_{jkt}, K_{jkt})\} \geqq 0;$

(A4') $(\partial L/\partial \Delta_{jk,t+1})\ \Delta_{jk,t+1} = 0,\ \Delta_{jk,t+1} \gtreqless 0,$

$j = 1,\ldots, n;\ k = 1,\ldots, q;\ t = 1,\ldots, T;$

(A5) $\partial L/\partial \psi_{jt} = -\{u_{jt} - F_{jt}(U_t, V_t, K_{jt})\} \geqq 0;$

(A5') $(\partial L/\partial \psi_{jt})\ \psi_{jt} = 0, \psi_{jt} \geqq 0,\ j = 1,\ldots, n;\ t = 1,\ldots, T;$

(A6) $\partial L/\partial @ = - \{\sum_{r=1}^{T} \sum_{j=1}^{n} u_{jr} - X(U_T, V_T)\} \geqq 0;$

(A6') $(\partial L/\partial @)@ = 0,\ @ \geqq 0;$

(A7) $v_{jkt} \geqq 0,\ v_{jkt}\theta'_{jkt} = 0,\ \theta'_{jkt} \geqq 0,\ j = 1,\ldots, n,\ k = 1,\ldots, q;$

$t = 1,\ldots, T;$ also,

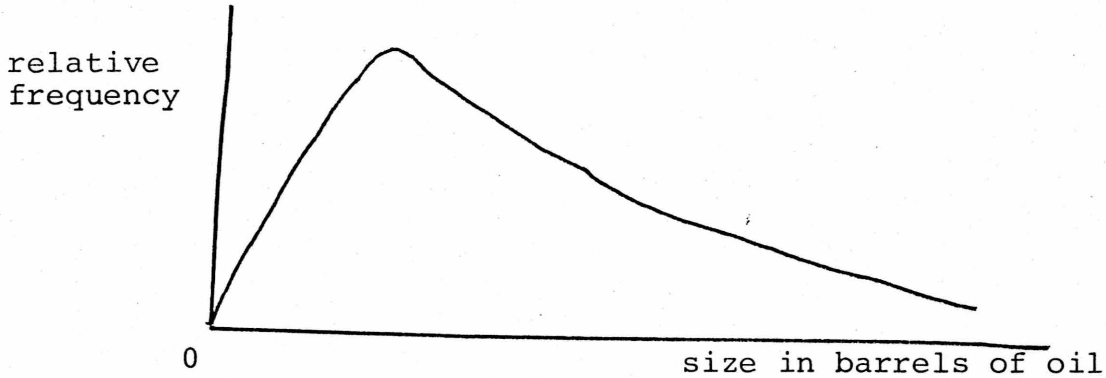
(A8) $\Delta_{jkt}B_t = -(\partial C_{jt}/\partial K_{jkt})B_t + \psi_{jt}B_t(\partial F_{jt}/\partial K_{jkt})$

$+ (1 - \partial D_{jkt}/\partial K_{jkt})\ \Delta_{jk,t+1}B_{t+1}$ for all t, $1 \leqq t \leqq t^*;$

(A9) $u_{jt} \geqq 0,\ u_{jt}E_{jt} = 0,\ E_{jt} \geqq 0,\ j = 1,\ldots, n;\ t = 1,\ldots, T.$

(from Kuller and Cummings, pages 77-78)

An example of a lognormal distribution of pool size. From Adelman, Alaskan Oil, page 106.



World Oil Prices 1973-1980
per barrel of crude oil in American dollars

	1973	1974	1975	1976	1977	1978	1979	1980
Saudia Arabia	2.41	10.84	10.46	11.51	12.09	12.70	13.34	26.00
Iran	2.40	11.04	10.67	11.62	12.81	12.81	13.45	30.37
Kuwait	2.31	10.74	10.37	11.30	12.37	12.27	12.83	27.50
Libya	2.87	11.98	11.10	12.21	13.74	13.80	14.52	34.50

Reproduced from 1979 International Energy Annual, page 50.

FOOTNOTES

Chapter 1 -- Description of the Tax

[1] 96th Congress, 96-233, pp. 7-8.

[2] Ibid., pp. 3, 6.

[3] Ibid., p. 6.

[4] Ibid., pp. 5-6, 8.

[5] Bernard A. Gelb and Richard A. Nelson, Oil Windfall Profits Tax: Issue Brief Number IB80010, (Washington, D. C., Library of Congress), p. 21.

[6] Ibid., p. 21.

[7] 96th Congress, 96-223, p. 5.

[8] Ibid., pp. 6-7.

[9] New York Times, May 1, 1979, p. 1.

[10] Gelb and Nelson, p. 27.

[11] Ibid., p. 8.

[12] Ibid., p. 26.

[13] Ibid.

[14] Ibid.

[15] Washington Post, February 27, 1980, pp. A1, A4.

[16] Gelb and Nelson, p. 26.

[17]Ibid., p. 27.

[18]Ibid.

Chapter 2 -- Pre-tax History of the Industry

[1]Robert Stobaugh, Energy Future, Robert Stobaugh and Daniel Yergin, eds. (New York: Random House, 1979), p. 17.

[2]Standard Oil Company of New Jersey v. United States, 221 U. S. 1 (1911).

[3]William G. Shepherd and Clair Wilcox, Public Policies toward Business (Homewood, Ill.: Richard D. Irwin, 1979), p. 139.

[4]John M. Blair, The Control of Oil (New York: Pantheon Books, 1976), p. 32.

[5]Ibid., p. 33.

[6]Ibid., p. 36.

[7]Ibid., p. 34.

[8]Ibid.

[9]Ibid., p. 55.

[10]Mira Wilkins, The Oil Crisis, Raymond Vernon, ed., (New York: W. W. Norton, 1976), pp. 160-161.

[11]Blair, The Control of Oil, p. 64.

[12]Ibid.

[13]Wallace F. Lovejoy and Paul T. Homan, Economic Aspects of Oil Conservation Regulation (Baltimore: John Hopkins University Press, 1967), p. 34.

[14]Ibid.

[15]Stephen L. McDonald, Petroleum Conservation in the United States: An Economic Analysis (Baltimore: John Hopkins University Press, 1971), pp. 35-36.

[16]Lovejoy and Homan, Economic Aspects of Oil Conservation Regulation, pp. 41-44.

[17]Ibid.

[18]Blair, The Control of Oil, p. 365.

[19]Ibid., p. 191.

[20]Neil H. Jacoby, Multinational Oil: A Study in Industrial Dynamics (New York: MacMillan Publishing, 1974), p. 95.

[21]Blair, Control of Oil, pp. 81, 211-213.

[22]Stobaugh, Energy Future, Stobaugh and Yergin, eds., pp. 21-22.

[23]Blair, The Control of Oil, p. 213.

[24]Miran Wilkins, The Oil Crisis, Vernon, ed., pp. 166-167.

[25]Edith Penrose, Ibid., p. 45.

[26]Mira Wilkins, Ibid., pp. 167-168.

[27]Central Intelligence Agency, The World Oil Market in Years Ahead (1979), p. 6.

[28]Blair, The Control of Oil, pp. 12-13.

[29]Kent P. Anderson and James C. DeHaven, The Long-Run Marginal Costs of Energy (Santa Monica: The Rand Corp., 1975), pp. 17-18.

[30]Norman A. White, ed., Financing the International Petroleum Industry (New York: AMACOM, 1978), pp. 30-33.

[31]Stobaugh, Energy Future, p. 18; and Blair, The Control of Oil, pp. 181-183.

Chapter 3 -- Future Price Outlook

[1]Exxon Corporation, World Energy Outlook (1980), p. 21.

[2]Ibid.

[3]Ibid.

[4]CIA, The World Oil Market in the Years Ahead, pp. 2-3, 18.

[5]Ibid., p. 3.

[6]Anderson and DeHaven, Long-Run Marginal Costs of Energy, p. 18.

[7]CIA, The World Oil Market in the Years Ahead, pp. 2-3.

[8]Ibid., p. 4.

[9]V. V. Strishkov, "Soviet Union" (from Mining Annual Review (1980)), p. 3.

[10]CIA, The World Oil Market, p. 32.

[11]Ibid., p. 6.

[12]U. S. International Trade Commission, Factors Affecting World Petroleum Prices to 1985 (Washington, D. C.: U. S. Government Printing Office, 1977), p. A-39.

[13]CIA, The World Oil Market in the Years Ahead, p. 6.

[14]Energy Information Administration, Annual Report to Congress, 1979 (Volume Three: Synopsis) (Washington, D. C.: Government Printing Office, 1980), p. 14.

Chapter 4 -- The Nature of Petroleum Reservoirs

[1]Encyclopedia Britannica: Macropaedia (Volume 14) (Chicago: H. H. Benton, 1979), pp. 167-170.

[2]Ibid.

[3]Lovejoy and Homan, Oil Conservation Regulation, p. 60.

[4]Ibid.

[5]Ibid., pp. 59-61.

[6]Ibid., p. 61.

[7]Ibid.

[8]Ibid.

[9]Ibid.

[10]Ibid., pp. 61-62.

[11]Ibid.

[12]Ibid., p. 62.

[13]Ibid.

[14]Ibid.

[15]Ibid., p. 60.

[16]Ibid.

[17]McDonald, Petroleum Conservation, pp. 11-13.

[18]Robert G. Kuller and Ronald G. Cummings, "An Economic Model of Production and Investment for Petroleum Reservoirs," American Economic Review 64 (March 1974), p. 68.

[19]McDonald, Petroleum Conservation, p. 19.

[20]Kuller and Cummings, "Petroleum Reservoirs," p. 68.

[21]McDonald, Petroleum Conservation, pp. 75-76.

[22]Edward Miller, "Some Implications of Land Ownership Patterns for Petroleum Policy," Land Economics 49 (November 1973), pp. 415-416.

[23]Harry W. Richardson, Economic Aspects of the Energy Crisis (Lexington, Mass.: Lexington Books, 1975), p. 60.

[24]Blair, Control of Oil, p. 186.

[25]Miller, "Land Ownership Patterns," p. 423.

[26]Blair, Control of Oil, pp. 328-329.

[27]Ibid.

[28]Ibid., p. 329.

Chapter 5 -- The Effects on Crude Oil Production

[1]Walter S. Measday, The Structure of American Industry, Walter Adams, ed. (New York: MacMillan, 1977), p. 152.

[2]McDonald, Petroleum Conservation, p. 76.

[3]Ibid., p. 77.

[4]Ibid., p. 78-79.

[5]H. R. 3919, 96th Congress, first session, p. 18.

[6]Ibid.

[7]Ibid., p. 20.

[8]McDonald, Petroleum Conservation, pp. 81-83.

[9]Stogaugh and Yergin, Energy Future, p. 47.

[10]Miller, "Land Ownership Patterns," p. 423.

[11]McDonald, Petroleum Conservation, p. 84.

[12] Ibid., pp. 84-85.

[13] Ibid., p. 82.

[14] Ibid., pp. 80-82.

[15] Ibid., p. 81.

[16] Ibid., p. 86.

[17] Ibid.

[18] Ibid.

[19] Ibid., p. 85.

[20] Ibid.

[21] Ibid., pp. 224-225.

[22] Miller, "Land Ownership Patterns," pp. 414-415.

[23] Kuller and Cummings, "Production and Investment for Petroleum Reservoirs," p. 68.

[24] Ibid., pp. 68-69.

[25] Ibid., pp. 69-70.

[26] Ibid., p. 69.

[27] Ibid.

[28] Ibid.

[29] Ibid., p. 70.

[30] Ibid.

[31] Ibid.

[32] Ibid.

[33]Ibid.

[34]Ibid.

[35]Ibid., pp. 70-71.

[36]Ibid., p. 71.

[37]Ibid.

[38]Ibid.

[39]Ibid., p. 72.

[40]Ibid.

[41]Ibid.

[42]Ibid.

[43]Ibid.

[44]Ibid.

[45]Ibid.

[46]Ibid.

[47]Ibid.

[48]Ibid.

[49]Ibid., pp. 72-73.

[50]Ibid.

[51]Ibid., p. 73.

[52]Ibid., pp. 71-72.

[53]Ibid., p. 73.

[54] Ibid.

[55] Ibid.

[56] Ibid.

[57] Ibid.

[58] Ibid.

[59] Ibid.

[60] Gelb and Nelson, <u>Oil Windfall Profits Tax</u>, p. 14.

[61] McDonald, <u>Petroleum Conservation</u>, p. 75.

[62] Ibid.

[63] Ibid.

[64] Ibid.

[65] Ibid.

[66] Ibid., p. 74.

[67] Ibid.

[68] Ibid.

[69] J. C. Cox and A. W. Wright, "The Determinants of Investment in Petroleum Reserves and their Implications for Public Policy," <u>American Economic Review</u> 66 (March 1976), p. 154.

[70] Ibid.

[71] Ibid.

[72] Ibid.

[73] Blair, <u>Control of Oil</u>, p. 203.

[74] Cox and Wright, p. 155.

[75] Ibid.

[76] Ibid., p. 154.

[77] Ibid.

[78] Ibid.

[79] Ibid.

[80] Blair, Control of Oil, p. 192.

[81] Ibid.

[82] Ibid., p. 203.

[83] Harry W. Richardson, Economic Aspects of the Energy Crisis, p. 61.

[84] Cox and Wright, p. 155.

[85] Ibid.

[86] Ibid.

[87] Ibid.

[88] Gerard M. Brannon, Energy Taxes and Subsidies (Cambridge: Mass.: Ballinger, 1974), pp. 25-26, 32. Also, Blair, p. 192.

[89] Cox and Wright, p. 155.

[90] Ibid.

[91] Ibid.

[92] Ibid.

[93] Ibid.

[94] Ibid., p. 156.

[95]Ibid.

[96]Ibid.

[97]Ibid.

[98]Ibid.

[99]Ibid.

[100]Ibid.

[101]Alpha C. Chiang, Fundamental Methods of Mathematical Economics (New York: McGraw-Hill, 1974), p. 381.

[102]Ibid., p. 218.

[103]Cox and Wright, p. 101.

[104]Chiang, p. 102.

[105]Ibid., p. 417-418, and Cow and Wright, p. 157.

[106]Ibid.

[107]Chiang, p. 418.

[108]Cox and Wright, p. 157.

[109]Chiang, p. 418.

[110]Ibid., pp. 403-404, 418.

[111]Ibid.

[112]Cox and Wright, pp. 156-157.

[113]Ibid., p. 157.

[114]Ibid.

[115]Ibid.

[116]Ibid.

Chapter 6 -- Note on Exploration Models

[1]See R. S. Uhler, "Costs and Supply in Petroleum Exploration: The Case of Alberta," in the Canadian Journal of Economics (February, 1976), pp. 72-90, for a good example.

[2]Richard Nehring, The Outlook for Conventional Petroleum Resources (Santa Monica: The Rand Corp., 1979), p. 18, and CIA, The World Oil Market, pp. 2-3.

[3]Stobaugh and Yergin, Energy Future, pp. 42-43.

[4]Ibid.

Chapter 6 -- The Effects of the Tax on Oil Exploration

[1]McDonald, Petroleum Conservation, p. 87.

[2]Ibid.

[3]Ibid., pp. 89-90.

[4]American Petroleum Institute, The American Petroleum Institute Seminar on Reserves (Washington, D. C.: API, 1976), pp. 10-11.

[5]Ibid.

[6]White, Financing the International Petroleum Industry, pp. 30-33.

[7]API, Seminar on Reserves, pp. 10-11.

[8]Paul G. Bradley, Alaskan Oil: Costs and Supply, M. A. Adelman, ed., (New York: Praeger Publishers, 1971), p. 108.

[9]Ibid.

[10]Ibid., p. 106.

[11]Ibid., p. 108.

[12]Ibid.

[13]Ibid.

[14]Ibid., pp. 112-113.

[15]Ibid., pp. 109-111.

[16]Ibid., p. 98.

[17]Ibid., p. 97.

[18]Ibid., p. 98.

[19]Kenneth W. Dam, Oil Resources: Who gets What How? (Chicago: University of Chicago Press, 1976), p. 5.

[20]Ibid.

[21]Ibid., p. 7.

[22]Ibid., p. 6.

[23]Ibid.

[24]Bradley, Alaskan Oil, p. 106.

[25]Ibid., p. 104.

[26]Ibid., pp. 114-115.

[27]Ibid.

[28]Ibid., p. 115.

[29]Kuller and Cummings, "Production and Investment for Petroleum Reservoirs," p. 76.

[30] Ibid.

[31] Ibid.

[32] Ibid.

[33] Ibid.

[34] Ibid.

Chapter 7 -- The Effects of Landownership Patterns

[1] Miller, "Land Ownership Patterns," pp. 415-416.

[2] Ibid., p. 418.

[3] Ibid., p. 419.

[4] Ibid.

[5] Ibid., p. 420.

[6] Ibid.

[7] Ibid., p. 419.

[8] Ibid.

[9] Ibid., p. 416.

[10] Ibid.

[11] Ibid., p. 423.

[12] Ibid., p. 422.

[13] Dam, Oil Resources, p. 149.

[14] Ibid.

Chapter 8 -- Conclusions

[1]Kuller and Cummings, Production and Investment for Petroleum Reservoirs, pp. 74-75.

[2]Ibid.

[3]Ibid.

[4]McDonald, Petroleum Conservation, pp. 225-226.

[5]G. M. Brannon, "U. S. Taxes on Energy Resources," American Economic Review 65 (May 1975), p. 401.

[6]Arthur W. Wright, "Discussion" on Brannon's "U. S. Taxes on Energy Resources," American Economic Review 65 (May 1975), p. 405.

[7]CIA, World Oil Market, pp. 18-19.

[8]Ibid.

[9]Yergin, Energy Future, pp. 179-182.

[10]Blair, Control of Oil, p. 330.

[11]Congressional Budget Office, The Windfall Profits Tax: A Comparative Analysis of Two Bills (Washington, D. C.: U. S. Government Printing Office, 1979), pp. 72-73; and Gelb and Nelson, Oil Windfall Profits Tax, p. 12.

[12]Ibid.

BIBLIOGRAPHY

Adams, Walter, ed. The Structure of American Industry. New York: MacMillan, 1977.

Adelman, M. A., ed. Alaskan Oil: Costs and Supply. New York: Praeger Publishers, 1971.

American Petroleum Institute. The American Petroleum Institute Seminar on Reserves. Washington, D. C.: American Petroleum Institute, 1976.

Anderson, Kent P. and DeHaven, James C. The Long-run Marginal Costs of Energy. Santa Monica: The Rand Corp., 1975. Pages 1-37.

Blair, John M. The Control of Oil. New York: Pantheon Books, 1976.

Brannon, Gerard M. Energy Taxes and Subsidies. Cambridge, Mass.: Ballinger, 1974. Pages 1-45.

Central Intelligence Agency. The World Oil Market in the Years Ahead. Washington, D. C.: U. S. Government Printing Office, 1979.

Chiang, Alpha C. Fundamental Methods of Mathematical Economics. New York: McGraw-Hill, 1974.

Congressional Budget Office. The Windfall Profits Tax: A Comparative Analysis of Two Bills. Washington, D. C.: U. S. Government Printing Office, 1979.

Cox, J. C. and Wright, A. W. "The Determinants of Investment in Petroleum Reserves and their Implications for Public Policy." American Economic Review 66 (March 1976): 153-67.

Dam, Kenneth W. Oil Resources: Who gets What How? Chicago, University of Chicago Press, 1976.

Energy Information Administration. Annual Report to Congress, 1979: Volumes Two and Three (Synopses). Washington, D.C. U. S. Government Printing Office, 1980.

Exxon Corporation. World Energy Outlook. New York: Exxon Corporation, 1980.

Gelb, Bernard A. and Nelson, Richard A. Oil Windfall Profits Tax: Issue Brief Number IB80010. Washington, D. C.: Library of Congress, 1980.

Jacoby, Neil H. Multinational Oil: A Study in Industrial Dynamics. New York: MacMillan Publishing Company, 1974.

Kuller, Robert G. and Cummings, Ronald G. "An Economic Model of Production and Investment for Petroleum Reservoirs." American Economic Review 64 (March 1974): 66-79.

Lovejoy, Wallace F. and Homan, Paul T. Economic Aspects of Oil Conservation Regulation. Baltimore: The John Hopkins University Press, 1967.

McDonald, Stephen L. Petroleum Conservation in the United States: An Economic Analysis. Baltimore: The John Hopkins University Press, 1971.

Miller, Edward. "Some Implications of Land Ownership Patterns for Petroleum Policy." Land Economics 49 (November 1973): 414-423.

Nehring, Richard. The Outlook for Conventional Petroleum Resources. Santa Monica: The Rand Corp., 1979.

96th Congress. Public Law 96-223.

Richardson, Harry W. Economic Aspects of the Energy Crisis. Lexington, Mass.: Lexington Books, 1975.

Shepherd, William G. and Wilcox, Clair. Public Policies toward Business. Homewood, Ill.: Richard D. Irwin, 1979.

Stobaugh, Robert and Yergin, Daniel, eds. Energy Future: Report of the Energy Project at the Harvard Business School. New York: Random House, 1979.

Strishkov, V. V. "Soviet Union." Mining Annual Review, 1980.

U. S. International Trade Commission. Factors Affecting World Petroleum Prices to 1985. Washington, D. C.: U. S. Government Printing Office, 1977.

Vernon, Raymond, ed. The Oil Crisis. New York: W. W. Norton, 1976.

White, Norman A., ed. Financing the International Petroleum Industry. New York: AMACOM, 1978.