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Subject: Oil and Gas Problems

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MR. WHITE. First it might be desirable to outline the importance of the oil and gas industry. It is noted that ten of the twenty largest manufacturing companies are oil companies, classed as such because of their refining operations. Five of the ten largest corporations in the United States are oil companies. The financing for the oil and natural gas industry is large, since in one above-average year it was in the neighborhood of $2,000,000,000.

There are several different types of oil companies, the largest ones being known as integrated companies. They are engaged in the production, transportation, refining and marketing of oil products. Very seldom do you find a company that is in perfect balance. Some companies have more production than refining capacity, but most of the larger companies buy crude oil. It is considered advantageous to produce as much as possible of the oil that is refined. Certain companies, such as Sinclair and Atlantic, have been at a disadvantage in the past few years and have been making very large purchases of other producing companies in order to become better balanced. There are a large number of oil-producing company is Amerada, it having no refining or marketing facilities. There are a few pipeline companies which are not owned by refining companies. Years ago a large oil company usually owned outright its own pipelines, but lately they have been going into partnership and five or six companies which are only engaged in refining, some which refine and market, and some--not too large--which engage solely in marketing. Up until the time of the OPA circa 1942, it took a very sharp company to make any money out of marketing, the companies earning profits being mostly limited to the old Standard Oil group.

All of these larger companies produce both oil and natural gas. Many companies have natural gasoline plants or other plants for the recovery of what is known as LPG, being liquified petroleum products such as butane and propane, the common bottled gasses used for heating. We now go into the natural gas companies which, for the most part, are the transportation systems operating pipelines. Also we have the distribution systems. We examine the registration statements for all these companies. The natural gas distribution companies probably give us as little trouble as any we examine. We are mostly interested in the gas supply and the prices paid for gas. Sometimes we have differences in opinion as to the inclusion of the price paid for natural gas--I consider it rather important and feel it should be included in all statements.

The general economics of the oil business are quite important. The average oil company has a tremendous tax advantage in respect of its Federal income tax. It pays very little to the government in proportion to what another type of company earning the same amount of money pays. I noticed that Standard of New Jersey pays approximately 12-1/2% of what is termed their net income in Federal taxes. Some companies pay less than 10%. I was told that the Pure Oil Company paid dividends for 13 years and never paid a cent of Federal income tax. So it is an unusal business. There are two reasons for the low amount of income tax. Companies are permitted to charge off what is known as the intangible drilling cost of a well as an expense, although by any ordinary interpretation it is a capital investment. However, I shall not argue the law. The intangible drilling costs are what would ordinarily be subject to depletion, not being subject to depreciation. Practically everything that is subject to depletion is charged off immediately. The only thing that would be left to be depleted would be the bonus or initial cost of an oil property. Leases bought for off-shore drilling cost a large amount, and the tax advantage on those costs are not great because statutory or percentage depletion cannot be taken at the same time cost depletion is taken. An equally great advantage is the percentage of 27-1/2% of the gross income from the sale of oil and gas production, production, provided it is not greater than 50% of the net income. This tax treatment accounts for those companies paying less income tax.

The market for crude oil and oil products has always been somewhat peculiar in that there never was any futures market for crude oil or its products such as exists for wheat or coffee for example. The price of crude oil has been set by the purchasers and to some extent can be called "controlled." There is not a 100% free market and never has been. Ordinarily the producer had very little trouble selling his oil, though there are exceptions to that. As a matter of fact, most of the oil is "bought" instead of "sold." The market for various grades of oil changes sharply over the years. Ten or so years ago there was a field in California known as San Ardo which had approximately 11 A. P. I. gravity oil. There was no market whatever for it. Today that oil is selling for almost $2 per barrel. This clearly shows oil is not a static industry, but rather that conditions affecting it are subject to change.

Now as to natural gas, before the long pipelines from the natural gas producing areas were built to the Northeast, there was a distinct lack of markets for natural gas, and many wells drilled were either capped or abandoned, although they might have been capable of producing a great deal of natural gas.

I shall not discuss briefly the occurrence of oil. To date no one is sure about the origin of crude oil. It is generally accepted, however, that it comes from decayed animal and vegetable matter.

The formations of the earth are, in general, alternate parallel layers of sandstone, shale, and limestone. Oil is produced almost altogether from sandstone and limestone. The average person would call it solid rock, but actually these rocks which may appear to be solid have porous spaces from as low as 3% in some limestones up to as much as 30 to 35% in unconsolidated sand on the Gulf coast. Sandstone is very much like miniature marbles, and you can get some idea of porosity by stacking a bunch of marbles together. Sand grains are almost spheres, but limestone is entirely different. It has fractures and you cannot determine the porosity in many instances. There are sometimes caverns in limestone which account for very large wells.

All of the oil produced comes from these porous spaces. The porous spaces also contain water called "connate water" because it does not move. The oil itself usually contains gas in solution, so there are three fluids that fill the porous spaces, which is under some amount of pressure. In the reservoir the pressure, in most instances, is equal to the weight of a column of water as high as the depth of the oil. If it is 1,000 feet deep, you get a 430 pound pressure. There are areas of abnormally low pressure and some of abnormally high pressure. The pressure has a lot to do with how much oil and gas is recovered. The huge Hugoton-Panhandle Gas Field is a low pressure area with about 1/3 or even less of the pressure it should have based on its depth. In the Gulf Coast area we have some areas where pressures are twice normal. The pressure is what causes an oil well to flow. When a reservoir is tapped and the pressure in the rock is released, this fluid mixture of oil and gas starts to rise because the gas in solution tends to expand. A cubic foot of gas at the surface from a well having 3,000 pounds of pressure would only occupy about 1/200 of a cubic foot when in the ground. When the pressure is dissipated or depleted, a well will no longer flow and the oil has to be pumped. The oil will rise just so high in the well, but it won't rise high enough to flow without artificial means. When wells are completed, such methods as the acidizing of limestones, and the shooting of sandstones with nitroglycerin are used to open up more rock face to the bore hole which is ordinarily only six inches in diameter. The theory being that if you can get cracks out from the bore hole, there would be more space opened from which oil may run out.

In the past, the techniques used in the oil industry have not been static. Within the past five years there has been developed a fracturing process which has caused a lot of additional oil to be produced. It has also caused a lot of holes to be drilled and completed which will never pay out because the formation was so tight or there was so little oil there, that no matter what was done it would not produce enough to pay. That is one of the penalties for improvement. Ordinarily, every oil field, unless the quality was a little off, is profitable since as you go deeper you have more pressure. The deeper the hole, the more it costs; but you have more pressure, and therefore you get more oil. The deepest oil wells now approach four miles in depth, while dry holes have been drilled to depths greater than four miles.

Crude oil is not a simple chemical compound. The oil that comes out of the ground is a mixture of numerous chemical compounds, and you don't get the same combination in every area. The so-called hydrocarbon paraffin series have the constituents--carbon and hydrogen--in different mixtures. The lowest one is CH_4, which is methane, the ordinary natural gas. Then you go on up until you come to very heavy crude oil.

When a field becomes almost depleted, secondary recovery methods are often used to recover additional oil. Secondary recovery, as opened to shooting, acidizing or pumping, is where an energizing force is used in order to recover part of the oil which still remains in the formation. There are several different kinds of primary producing mechanisms. One is strictly gas expansion, others are water drive, gas cap pressure, and combinations thereof. All of these aid in causing the fluids to come out. Under a strictly gas expansion field you may recover 20% or less of the oil in place. Under efficient water drive it runs 50, 60%, and even higher in some instances. With an efficient water drive there is usually nothing else that ever needs to be done, except returning the water to the reservoir, and you get all of the oil that you can reasonably expect.

Secondary recovery methods are ordinarily used for the gas expansion fields, and either water, gas, or air are put back into the reservoir at high pressure, which moves more oil to the bore hole. Pressure maintenance is also used which, applied early in the life of the field when it is only partially depleted, will tend not only to produce the oil faster, but by keeping the pressure up will actually get more oil from the formation.

A geologist does not locate oil. He locates a likely place to drill for oil, and he does that, for the most part, by determining the geologic structure. Years ago when I started doing this type of work, there were large areas in the United States where one could go out and actually map the surface outcrops and determine the geologic structure. The importance of favorable geologic structures is that most of the oil is found in them. In addition to mapping the surface geologic structure, one can always use the logs of wells which had been drilled and determine structure by using the elevation on top of the ground and platting the elevation above or below sea level of certain datum or stratigraphic levels which have always been identifiable. Subsurface geology is one method that will always be used. In the past 25 years or so the use of geophysics to determine structure has been introduced, the most successful method being the reflection seismograph. All of the country could not be mapped from the surface, since you had to have fairly hard beds of rock, and that is what caused the use of geophysics. Down on the Gulf Coast of Texas one would be almost helpless with surface work alone. The reflection seismograph involves the setting off of charges of some type of explosive in shallow holes of perhaps 100 feet in depth, and recording the return vibrations by seismograph. The vibrations caused by the blast of this explosion goes downward until it hits a rock of consequent hardness to reflect the wave, and then it comes back. The time involved can be measured, and by using the velocity through the formations it is possible to plat up points of elevation. All structure is based on contouring datum points. Contours are simply lines of equal elevation.

The oil down in these deep formations, as far as is known, was originally distributed everywhere. But it accumulates in traps or structures. It settles out strictly on an inverse gravity basis. Oil floats on water. These fluids or mixtures of fluids below the surface are under equal pressure in a general area, but gradually oil came to the top of the water. and then gas, in turn, if in sufficient amounts, comes to the top of the oil. As stated before, the geologist's primary purpose is to locate favorable structures. Over the years the geologist had a difficult time making himself acceptable to the industry. They had to overcome a lack of confidence. Most all oil is found in basins between uplifts. One does not go to the top of a mountain to look for oil. Possible oil bearing formations dip away from the uplift, and the deformations appear down in the basin. 80% of all the oil that has been found in the free world has been located on defined domes or anticlines. That is a tremendous percentage. Those structures may have been located either from the surface, by subsurface geology, or some form of geophysics. But still these are structures based on contouring. About 8% of the oil which has been found has come from stratigraphic traps which are not reflected structurally. An example of such would be a sandstone underlying Montgomery County, but the shales came in and it wedged out, and the sandstone never actually was present in the District. The place where the sand stops or edged out is a good place to find oil, but this condition is not reflected on the surface. Stratigraphic traps are often located by studying the logs of other wells. In area A you may have a sand that carries water, and over in are B the sand is not present. In between these areas is a very likely place for a stratigraphic trap, but these are not found very easily, often requiring the drilling of a sizeable number of dry holes.

The other 12% of the oil comes from faulted structures and combinations. So by and large the geologic anticlinal structure is the place where most oil has been found and does accumulate.

There is no accepted direct method of locating the presence of oil and gas. We have our glorified doodle-bugs which attempt the use of electric current, radioactivity, etc., that have a little glamor and might mislead people. Geologists do not locate oil. They locate the place to drill. At the present rate, they are locating about one producing structure out of eight or nine tested. The ratio varies in different sections of this country and from year to year, but it has been some time since they have found more than one productive well in seven tries. The record, of course, in the Near East has been much better than that.

In our work here in the Commission the most important phase is the checking of the crude oil and natural gas reserves set forth in prospectuses that come to our attention. There is a tremendous amount of controversy about this subject. Reserve estimations are no better than the judgment and experience of the man who makes them, and no better than the amount of data which he has available.

Proved oil reserves are the only ones that we accept. They fall into three categories: (1) from horizons presently producing from specific wells; (2) from wells which have penetrated horizons that are behind the pipe and not connected to the bore-hole; and (3) from proved undeveloped reserves. The latter may approach the probable category, to some extent, as used in mining. But we accept no probable reserves and no possible reserves. Proved reserves have to be capable of being produced at a profit.

Commercial production comes from an oil well which is more profitable to produce than to abandon after allowing for reasonable depreciation of equipment. Your actual cash intake is greater than your cash outlay, plus depreciation. This definition applies to a well already drilled. There are productive oil wells drilled which never pay out. They just don't make quite enough oil. If you spend $100,000 to drill a well, you don't plug it because it is only going to make $80,000. You get the $80,000. Commercial production as applied to an undrilled location means you have to recover the cost of drilling in addition to all other expenses plus something extra. Thus you have almost a double definition of commercial production, but in either case there must be a profit over and above future expenditures.

For wells which have already been drilled, the reserves which we figure are reasonable are those which can be expected to be produced from that well by the production methods now being used. Proved undeveloped reserves are reserves which based upon all production and development data available and upon the geologic structural information are reasonably sure to be produced--reasonably certain--but not sure or certain--because actually offset wells don't always produce. Otherwise, you would have oil all over the country. There would be no limit.

When there are differences of opinion, it is not our position that under no circumstances might the reserves estimated by registrant be produced eventually from the lease, but that the claimed amount cannot be considered proved at this time.

Reserves are never characterized as "accurate" since they are based entirely on several estimates of pertinent factors. They are referred to as reasonable or reliable. We do not like the characterization of estimations as "conservative," since it implies an assurance or guarantee that the estimations amounts set forth will be recovered, which is beyond the province of an estimation.

A specific example is the Great Sweet Grass - Kroy Case with which some of you are probably familiar. There the engineer included in his report 93-1/2 million barrels of "probable" reserves which were to be produced from "reservoirs not yet discovered." He was claiming 1.2 millions of barrels of developed reserves and 8.2 million barrels of proved undeveloped reserves for Great Sweet Grass. There were five fields involved, three of which we did not argue about, but as to the other two we took particular exception. There was some oil production in one field, that was not very good, for which he estimated 510,000 barrels of developed reserves, but we thought 170,000 was all that was justified. When he came to the undeveloped with some 5,000,000 barrels, that was considered much too high. We ended up with about 1/3 of what he had claimed originally. This engineer never gave any consideration to the production decline method of estimating reserves.

There are three generally accepted methods of estimating crude oil reserves. The best method, when applicable, is the platting of the production by months against time. If that is platted on straight coordinate paper and the well is producing unrestrictedly, you will get a curve, not a straight line. Production, when platted on semilog paper, that is, production on the logarithmic scale and time on simple coordinate scale, yields a straight line in many instances. Sometimes the curve will be above a straight line, sometimes it will be lower. You should take whatever the line shows, not what you hoped it would show. The theory of platting on the semilog is that the production declines a certain percentage each time period. In order to have a straight line on coordinate paper, the production would have to decline a certain amount each time period. Production is also platted in certain instances on log-log paper, which is on logarithmic scale both ways. If you get a straight line on log-log paper, you have an excellent property. Most of the curves for good properties will fall somewhere between straight lines on the log-log and on the semi-log. Great Sweet Grass's engineer didn't use any curves. The production history didn't mean anything to him. He claimed the oil was down there, in fact, he knew it was there because he saw an electric log, and that was all that was necessary. We take performance first. We are always interested in their hopes and expectations, but we don't figure you can include them in proved reserves. On this point we have a lot of our arguments.

Natural gas reserves are usually estimated by platting pressure drop versus withdrawal on simple co-ordinate paper of by the volumetric method used similarly as for oil reserves.

Engineers can really go wild on their claims for undeveloped reserves. In one instance the basis for undeveloped reserves was a well which the engineer in his report said was making 25 barrels of oil per day. Actually it was making eight, plus water. We had enough information here to show that what he said was not right. We cannot pull these figures out of our hat, we have to have data. We were able to take available figures and show that his claim as to the accumulative production from that well stated to be 260,000 barrels was actually 75,000 barrels. We would have had no way of checking their claim of 260,000 barrels if we had not had some data. He then estimated 2,200,000 barrels of undeveloped reserves for undrilled acreage to the northeast of this well, despite the fact the well was making water and there had been several dry holes completed around it. He drew a conjectural contour map and I also drew a conjectural contour map, and until additional wells are drilled, no one can say which is right. When it gets to that stage, where there are no proved reserves--there must be more than conjecture.

In my opinion all that was justified was one proved location with reserves equal to the expected recovery from the present well.

If and when we get more information, we may have a different situation. We work on what we know today, we don't add anything to it. And when we estimate the proved reserves under a lease to be so many barrels at a given time, it doesn't mean that they might not find another horizon on that lease which would increase the reserves. But they don't know about it, and we don't know about it. So they can't put down barrel figures for that.

In the Great Sweet Grass-Kroy case, there had been two wells on one lease, one of which had made some 25,000 barrels, and another 20,000. The two wells had been abandoned, but the engineer said this was premature. We have enough information in our office that we can look up a specific lease in the State of Oklahoma, for example, and determine the current and accumulated production. That takes quite a few files. With such data we were able to say immediately, without going anywhere or doing anything else, that there were no commercially proved reserves on that lease. It didn't make any difference what they said, unless they were supported by facts. We didn't take their story on blind faith. It so happened that they had drilled a well right between two abandoned wells, and it proved dry. We wouldn't have said it was certain to be dry. We only said that as of the date that the report was made there were no proved reserves on that lease. The engineer had another lease almost as bad, and we threw that out, too. On the secondary recovery project, which was actually in operation, our opinion was that they had overestimated the reserves materially.

Another engineer included secondary recovery reserves for certain Sweet Grass properties to be recovered from leases where the operation had not even started. We feel that there must have been some results from secondary operations before any reserves can be considered proved by that method. We permit discussion of many matters qualitatively--where they have possibilities--that is considered full and fair disclosure. Some leases, as far as anybody knows, offer no chance of getting additional oil from any other formation or by any other method. Such a lease, if it has 100,000 barrels of proved reserves is not as valuable a lease as one that has 100,000 barrels of proved reserves with additional possibilities though not proved. I think it is only fair for a person owning this second type of lease to tell something about it. He has a better lease.

The volumetric method of estimating reserves causes the most trouble for us. Since they started the proration of oil, the decline curve cannot be used where the production is held back arbitrarily by state regulatory bodies. This has caused the volumetric method to be used extensively, since it is the only method that can be used unless a reliable comparison can be made with some other field which is considered to be similar. Theoretically, a well or a field with 20 feet of sand will produce twice as much as one with 10 feet, everything else being equal. This is one phase of the comparative method. The difficulty with the volumetric method is that after you obtain all the pertinent factors, which I shall mention later, it is necessary to apply a recovery factor, which involves the judgment (or lack of judgment) of the engineer. He is concluding what the reserves will be before a barrel of oil is produced. He often ends up with a ceiling figure. Of course, he may use too small a recovery factor, but we aren't usually troubled with too small a reserve. The volumetric method is dependent either on log data or core data. The thickness of the sand is determined by log and/or core data, the porosity of the formation and the amount of connate water by core analysis, and the amount of natural gas which is in solution with the oil by another method involving bottom hole sampling of fluid. Incidentally, some natural gas commingled with the crude oil is usually produced along with the oil, but some natural gas fields don't produce any oil at all. All natural gas has some liquid content, some being richer than others. With these factors it is a matter of mathematical calculation. If all the factors are accurate, you can certainly determine the amount of oil in place in the ground. Then you apply the recovery factor to see how much you will produce. There are surely some wide variations in estimations by this method from those determined by a decline curve. One of the worst examples of that was a case of a lease owned by Gulf Coast Leasehold. Their engineer estimated 499,000 barrels of reserves for their interest in a given field. Again we had just enough information to determine something was wrong, so we suggested that they try the decline curve method on these wells which were making large amounts of water. Their revised estimation was 18,000 barrels, to which would have been added the six or eight months interim production, not a material amount. This shows the falaciousness of paying no attention to the actual production history.

We are always using the comparative method more or less automatically. This is where experience becomes important. There is no manual on any of this material. Every job is tailor-made.

We also examine geological reports involving structure rather than reserves.

Just a few words about Regulation B. This is an exemption from formal registration of amounts up to $100,000 covering fractional undivided interests in oil and gas properties. For instance, a man owns 160 acres of land which he leases to John Jones, retaining a 1/8 landowners royalty. The landowner's royalty can be subdivided and sold by means of an offering sheet under Schedule A, if it is producing, and Schedule B if it is nonproducing. As to the leasehold interest, John Jones can sell it to Bill Smith and retain an overriding royalty. The overriding royalty can be under Schedules C and D of Regulation B--C if it is producing, and D if it is nonproducing. The remaining portion is now the working interest. Smith can take the working interest, fractionate it, and offer it to the public. He uses Schedule D for a wildcat well. We process all of these offering sheets. We now have very few producing landowners royalties offered, and the ones that we have are considered quite fair. When I came here twenty years ago we processed 145 offerings under Regulation B each month. Over the years, the increasing availability of capital in the oil country plus a couple of criminal cases tended to dry up the landowners royalty sales, which were the bulk of the offerings at the time.

There is also an oil payment schedule under Regulation B, but we have never had any offerings.

Schedule D is a question and answer prospectus. It has been criticized as being too long, but I don't think so. There are questions and cross-questions in this which finally gives us the story. There is enough tie-in in there to allow us to check back and find the facts.

Schedule D which covers most of the filings we are now processing has some 32 questions. The first part states exactly what is being offered for sale, the extent of the participation of the property being sold, that is whether it covers the whole lease, just one well, or just one horizon, etc. Next comes a group of questions relating to the title--what kind of title does the man have. There are a group of items covering oil development nearby and the possibilities of finding oil. The latter part of the schedule shows how much it is going to cost to drill a well, how much the offeror is going to put in himself, and whether he had any additional interest nearby the operation. There are also two exhibits: one is a map and one is a specimen copy of the conveyance. A lot of people complain about the conveyance, but that is the best guarantee we have that a purchaser has a chance to see what he is supposed to get.

There is a registraion form, Form S-10, which is used to sell fractional interests in oil and gas properties where the exemption under Regulation B is not available. Regulation B can be unavailable for several different reasons: one is that the offering is over $100,000; another is that the amount being sold falls between $30,000 and $100,000, without the offeror retaining a prescribed percentage of the production; and a third is the offering of noncontiguous tracts. We feel that the operator in order to get the exemption should keep enough of the well to give him a real interest in it. We don't want any orphan wells.

I think the groups pay entirely too much attention to what I call the disclosure or inner portions of S-10. It is nothing more than a glorified offering sheet. When I examine one I give it about the same treatment I do an offering sheet, with a little extra touch because of the extra amount involved.

Some groups have actually made research problems out of Form S-10 examinations. I think they should cover the front and back portions--and check same as to what should be filed, etc., and to check items not involved in the business phase of the offering. If you receive one of these for examination, you don't have to try to understand every phase of it because that is difficult in one attempt.