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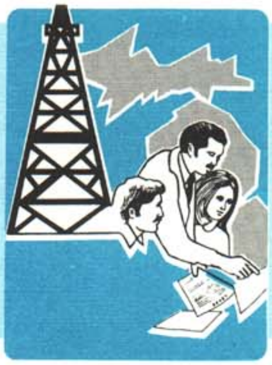
Oil & Gas Royalties: Look Before You Lease



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The New "Royalty Phrase"

In recent years, some oil companies have been adding a small phrase in their leases that has cost landowners money. The phrase appears in the royalty clause and usually goes something like this: the oil company will pay the agreed upon royalty rate, but the landowner will have to "bear the cost of treating the product to render it marketable or pipeline quality."

The landowner signing this type of lease must pay a share of the production costs for the well. The oil company subtracts the landowner's share of the costs to make the product marketable or pipeline quality before paying the royalty. This reduces the actual royalty money a landowner receives. In most cases, such an arrangement is like knocking a percentage point or two off the agreed upon royalty rate; a ⅛ or 12.5% royalty rate may convert to a 10% or 11% actual payment. On a few marginal wells, deducting the portion of production costs has nearly eliminated the royalty payment altogether.

If you look before you lease, however, it's possible to delete this costly phrase from your contract through negotiation. To do so you must know several things: 1) the cost to make the product "marketable or pipeline quality" can be considerable, 2) paying your share of the costs versus having the company pay all costs is **negotiable** (just like every other clause in a lease), 3) you may have to sacrifice something to get the oil company to pay the treatment costs, 4) but if you ask for too much (and get it!), particularly with marginal wells, the company may not be able to make enough money to keep pumping the well as long as they might otherwise have done. If they stop pumping early you may receive less money, as royalty owner, over the life of the well.

Some examples are presented to help clarify the main trade-offs involved in the royalty agreement. First, however, we must establish some facts about how much oil or gas to expect from a typical well in Michigan, even though there really is no "typical" well. Every well is different—unique. Even averages for the state don't do justice to most new wells. But some numbers are necessary to develop case examples, and Michigan's oil and gas records are the best place to start.

Background Data

The Geological Survey Division of Michigan's Department of Natural Resources collects data and keeps records on oil and gas exploration and development in Michigan.

In 1985, there were 5,898 producing oil and gas wells in Michigan located in 51 of our 83 counties. Approximately 800 new wells are drilled each year. Generally, wells have their highest production when first completed, then taper off as underground pressures are released and the quantities of oil and gas diminish. The average life of a Michigan well is between 10 and 12 years, but a few wells in Michigan produced for up to 50 years.

Most of the wells in Michigan (over 60%) are what the Michigan Department of Natural Resources (DNR) calls "hardly-able wells." These are "hardly able" to produce oil or gas any more because they are old wells, drilled 20 or 30 years ago, or they tapped a modest geologic reservoir. Such wells are also called "stripper" wells: they pump just a few barrels of oil per day. They usually don't flow by themselves, the oil has to be pulled, or "stripped" from the rocks by the pump.

If we took Michigan's 1985 total oil production (about 31 million barrels) and total gas production (about 151 billion cubic feet) and divided it by the total number of wells in Michigan that year (5,898), we'd find that the average production per day per well is just 16 barrels of oil and 73 Mcf of gas. At today's well-head prices, the oil would be worth about $320 per day and the gas about $175 per day. That's not much revenue from wells that usually cost over a quarter of a million dollars to drill.

Some wells, of course, produce at above average rates, and a few are truly outstanding. Almost all wells do better at the beginning of their life cycle than in later years. For the largest wells, the DNR sets limits on the amount of oil or gas that a company can pump in order to prevent the waste that rapid extraction can cause. This limitation is called "prorating." The DNR currently prorates about a third of all the wells in the state.

Two "Typical" Michigan Wells

Even though there aren't any typical wells, I've developed some typical well *conditions* so that we can see how much various royalty arrangements might cost landowners. The conditions are for two different geologic targets. The first is the Salina-Niagaran geologic formation, which has been the target of over 50% of the wells drilled in Michigan over the last ten years. Oil is usually the primary product from these wells, but gas is in solution with the oil. The average depth runs between 4,500 feet and 7,000 feet. The cost of drilling a typical well in the Salina-Niagaran is about $350,000 to $500,000 and it takes three to four weeks. The drilling unit—the spacing of wells as regulated by the DNR—is usually 80 acres.

My "typical" production figure for a new well in the Salina-Niagaran is 100 barrels of oil per day for 330 days per year (i.e., 10% downtime for maintenance). At $20 per barrel, which is about the current selling price, this well would yield $660,000 for the first year.

The second geological formation that has drawn a lot of attention in Michigan recently is the Prairie du Chien horizon. It is deeper than the Salina-Niagaran. Only about 5% of the wells being drilled in Michigan are into the Prairie du Chien, but this new target zone has been a source of excitement ever since 1980 when it yielded Michigan's first deep well discovery (the Dart-Edwards well in Missaukee County). Most of the Prairie du Chien wells are 10,000 to 13,000 feet deep. Generally, the drilling units are 640 acres, but the Michigan DNR has allowed a few wells to be drilled on 320 acre drilling units. The deep Prairie du Chien wells usually take six months to drill and cost anywhere from $1.5 million to $2.5 million dollars each.

The Prairie du Chien formation has produced only gas to date. When this gas is drawn up to the ground surface, however, some of it condenses into a light hydrocarbon liquid, like propane. This "condensate" is a valuable product too, and some deep wells have produced a considerable amount.

My "typical" new well production figure for a Prairie du Chien well is 1,000 Mcf of gas per day for 350 days of production per year (gas wells require less maintenance time per year than oil wells). The current price is about $2.40 per Mcf, so this typical new well would yield $840,000 in the first year.

Now that we have some basics for wells in Michigan, let's reconsider the royalty-clause again. Remember, different factors are important to different people.

Neighbors Negotiate Differently

Meet Mr. Acceptable. He is a gentle person who does not like to disturb other people. He is busy with his farming and doesn't want to take time away from his work right now to investigate something new. He'd much rather accept what the person at the door is saying about the lease he has just been handed than challenge or confront him with hearsay from neighbors. He owns the surface and mineral rights to 40 acres that the landperson wants to lease for $50/acre bonus payment and a 1/8th (or 12.5%) royalty. The phrase "lessor's interest to bear one-eighth of the cost of treating the oil or gas to render it marketable or of pipeline quality" is included.

After discussing the offer with his wife and thinking it over for a few days, he accepts the offer. That afternoon Mr. Acceptable signs the lease and is pleased to receive a 45-day site draft for his $2,000 bonus check (40 acres (x) $50/acre). He takes the site draft to his bank that afternoon. His bank sends it to the other bank that it was drawn on and, if funds are available 45 days later, they follow through and deposit the money.

Mrs. Zealous is a neighbor of Mr. Acceptable. She owns 40 acres adjacent to Mr. Acceptable's land. She was approached the same day by the same landperson who wanted to lease her land, too. Mrs. Zealous was very skeptical immediately as she often is. She had already talked to several people in her senior citizens group about their leases and knew that companies were trying to change the clause that would deduct the cost of treating the oil and gas from the royalty payments. She also knew that

Table 1: Summary of Well
(for 10 years of life)

Revenue		$3,300,000
Cost to Company		
Drilling	$1,750,000	
Treatment	$154,688 ($165,000 – $10,312)	
Operating	$600,000	
Payment to Royalty Owners:		
Mr. A:		
Bonus	$2,000	
Royalty	$195,938	
Mrs. Z:		
Bonus	$4,000	
Royalty	$275,000	
Total Costs		$2,981,626

Therefore, Net to Oil Company:
= $3,300,000 Revenue - $2,981,626 costs
= **$318,374** Net revenue to company over 10 years

Continued from other side...

Revenue Mrs. Z:
= Royalty rate, *times* share of drilling unit, *times* total life-time revenue of well.
= 1/6th (x) 1/2 (x) $3,300,000
= $275,000

Costs to Mrs. Z:
NO costs were charged to Mrs. Z.

Net to Mrs. Z over 10 yr.:
= Revenue – Cost
= $275,000 – 0
= $275,000

The sum of the revenues and costs over the life-history of this "typical" well shows that the oil company would make a net total profit of $318,374 over the ten years (see Table 1).

If the oil company's drilling success rate was not as good as we've assumed (i.e., if 1-in-6 wells were successful instead of 1-in-5), another dry well at $350,000 would cause the company to lose money. Or if the operating costs averaged $85,000 per year, and **both** royalty owners had aggressively negotiated the same lease agreement that Mrs. Zealous obtained, the company would again lose money. In reality, such factors would cause the company to stop producing from this well before the ten year period ended. The well would have become "uneconomic" earlier. Of course, the payments to the royalty owners would likewise stop as soon as production ceased. The figures for a marginal well, one that produces only 20 to 30 barrels per day initially, would look much worse.

Mrs. Z's share of Treatment Costs:
No treatment costs were charged to Mrs. Z.

Net to Mrs. Z:
Net = Revenue – Cost
= $55,000 – 0
= *$55,000*/yr

Mr. Acceptable received $39,188 in the first year, and Mrs. Zealous received $55,000 that year. Same well; same amount of land leased. Mrs. Zealous' aggressive negotiation netted her $15,812 more that year than Mr. Acceptable.

Excessive Negotiation is Possible

But, can this aggressive negotiation go "too far?" The answer is "Yes!" It won't break the bank, but it can break the company's economics and cause them to look elsewhere or possibly to stop production early. Let's take a look at the company's side of this well.

First, let's assume that production from this well continues for ten years, but tapers off after the first year so that its average for the ten years is only half of the first year's production, or 50 bbl/day for 330 days per year. To keep things simple, I'll use a constant price of $20/bbl. The well's life-time revenue therefore would be:
50 bbl/d (x) 330 d/y (x) $20/bbl
= $3,300,000/10 yr.

Let's lump the company's costs into four main categories: drilling costs, treatment costs, other operating costs, and payments to royalty owners.

I'll assume drilling costs were $350,000/well. Even though this well was successful, the company's success rate in this region was only 20%. That means the company must account for four other wells, all dry holes, that were drilled along with this successful one. Therefore, total attributable drilling costs would be:

Drilling Costs:
$350,000/well (x) 5 wells =
$1,750,000

Costs to treat this oil to bring it to pipeline quality averaged $16,500/yr over the ten year production life of the well. Therefore, total treatment costs would be:

Treatment Costs:
$16,500/yr (x) 10 yr = $165,000

The other operating costs averaged $60,000/yr to pump the oil and maintain this well. Therefore, over 10 years, the total for the other operating costs would be:

Operating Costs:
$60,000/yr (x) 10 yr = $600,000

Payments to the two royalty owners are pretty clear. Mr. Acceptable received a $2,000 bonus payment and 1/8th of the revenue minus 1/8th of the operating costs on his half of the drilling unit.

Revenue Mr. A:
= Royalty rate, *times* share of drilling unit, *times* total life-time revenue from well.
= 1/8th (x) 1/2 (x) $3,300,000
= $206,250

Cost Mr. A:
= Royalty rate, *times* share of drilling unit, *times* total treatment costs of life of well.
= 1/8th (x) 1/2 (x) $165,000
= $10,312

Net to Mr. A over 10 yr.:
= Revenue – Cost
= $206,250 – $10,312
= $195,938

Mrs. Zealous received her $4,000 bonus payment plus a clear 1/6 royalty on her half of the drilling unit.

Continued on other side...

she wanted to get at least $100/acre bonus, just like her friend Agnes. More importantly, she was going to fight hard to get a 1/6th royalty rate with no deductions for costs. She knew that the State of Michigan receives a clear 1/6th royalty rate, without deductions for treatment costs, on the public lands it has leased recently. Mrs. Zealous discussed her requirements with the landperson at the door, and they made arrangements to meet again in several days to discuss specifics.

Mrs. Zealous immediately called her friend Agnes to get the name of the company that leased her land. Mrs. Zealous contacted that company and was soon able to get a competing offer. She talked with a number of friends and was reassured that each of her demands was justified (at least in isolation). When the landperson came back, Mrs. Zealous persuaded him to meet most of her demands, especially the $100/acre bonus and 1/6th clear royalty without deductions. However, she had to agree to a ten year lease. Since the lease length was not a concern to her, she signed the lease. She went directly to the bank to cash her $4,000 bonus "check" (40 acres (x) $100/acre). As it turns out, she also was given a site draft because the leasing company wanted time (30 days in this case) to check the records, especially to see that her deed was clear. Eventually, the money was deposited in her account.

Achieving a "Typical" Well

To keep things simple, let's assume both of these properties became part of the same drilling unit, each contributing half of an 80 acre unit that was issued a permit to drill into the Salina-Niagaran formation. Delays occurred, as usual. First, a different company bought the leases from the landperson. Then further surface exploration was conducted. This seismic work was allowed by both leases. Then there was a year long wait for no apparent reason. Finally drilling began.

Let's further assume that the "landowner's dream" came true—the well was a success. It's important to remember, however, how rare this success story really is. First, most parcels that are leased are never drilled. Second, the odds are truly against any well actually being successful. In amply explored areas, the success rate is still only about one-in-five (meaning about 20% are successful). It's just hard to see through 6,000 feet of rock.

Despite these odds, however, "our" well was not only successful, it was better than average. It matched our "typical new well" performance in the Salina-Niagaran formation. Here are its numbers.

"Typical" New Michigan Well Performance

Production:
100 barrels of oil pumped per production-day

Days of Operation:
330 days of production per year (*Note:* The other time [35 days/yr.] are needed for maintenance of the well and for transport logistics).

Price (well-head):
$20/bbl current price at the well-head (1987)

Given these figures, this well could produce:
100 bbl/d (x) 330 days = 33,000 bbl/year.

This would provide a revenue of:
33,000 bbl/yr (x) $20/bbl
= $660,000/yr.

What Difference Did Negotiating Make?

How did our two lessors share in the first year's production? Remember that each leased one-half of the total drilling unit. Mr. Acceptable's 1/8th royalty on half the acreage of the drilling unit works out to be:

Mr. A's Revenue:
= Royalty rate, *times* share of drilling unit, *times* total revenue from well.
= 1/8th (x) 1/2 (x) $660,000 revenue/yr, or
12.5% (x) 50.0% (x) $660,000
= 6.25% (x) $660,000
= $41,250/yr

Mr. A's Share of Treatment Costs:
= Proportion of treatment costs, *times* share of drilling unit, *times* total treatment costs for well.
= 1/8th (x) 1/2 (x) $33,000* costs/yr, or
12.5% (x) 50.0% (x) $33,000
= 6.25% (x) $33,000
= $2,062/yr

Net to Mr. A:
Net = Revenue – Cost
= $41,250 – $2,062
= *$39,188*/yr

For Mrs. Zealous, the finances are a little different even though her half came from the same well. Her receipts would be:

Mrs. Z's Revenue:
= 1/6th (x) 1/2 (x) $660,000 revenue/yr, or
16.7% (x) 50.0% (x) $660,000
= 8.33% (x) $660,000
= $55,000/yr

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*NOTE: The amount of treatment costs would be provided to the lessors by the oil company; I've estimated them at 5% of revenue.

Conclusion: Be Reasonable, It's To Your Advantage

The economics get complicated quickly, but it's a sure thing that once the oil company stops making a profit on a well, they will stop trying to produce oil from it. And the royalty owners will stop receiving their checks. So, it's very important to examine your royalty clause, and all other parts of the lease very carefully, negotiate for what's important to you, but realize that the oil drilling company has some big risks and substantial costs to balance, too.

References

- Current prices from *Michigan Oil & Gas News* (October 1987) and The Michigan Public Service Commission (personal contact: October 1987).
- Michigan oil & gas drilling statistics came from the Geological Survey Division, Michigan Department of Natural Resources, *Michigan's Oil & Gas Fields; Annual Statistical Summary* (Lansing: Michigan Department of Natural Resources) and Ray Ellison, (personal communications July-August 1987) Michigan Department of Natural Resources, Lansing.
- Several oil company executives, suppliers, and oil and gas processing people were contacted to develop the estimated costs for the "typical" well conditions

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Many other Cooperative Extension Service bulletins are available on the topic of oil and gas. For more information, call, write or visit the Cooperative Extension Service office in your county for a catalog of available publications. Below is a list of some related bulletins available there or by writing to: MSU Bulletin Office, P.O. Box 6640, East Lansing, MI 48826-6640.

E-1512 Oil/Gas Leasing—Basic Considerations for Landowners, 8 pp., 30¢

E-1513 Hints on Negotiating an Oil and Gas Lease, 8 pp., 30¢

E-1514 A Review of Oil and Gas Production in Michigan, 8 pp., 30¢

E-1515 Rights and Obligations under an Oil and Gas Lease, 12 pp., 35¢

E-1612 Compulsory Pooling, 2pp. (free)

E-1613 Oil and Gas Drainage, 2 pp. (free)

E-1614 The Dormant Minerals Act, 2 pp. (free)

E-1615 Oil/Gas Leasing in Michigan—Essential Considerations, 4 pp. (free)

E-1647 Michigan's Oil and Gas Industry: Past, Present, Future, 4 pp. (free)

E-1648 Michigan's Oil and Gas Regulations, 4 pp. (free)

E-2124 Seismic Testing on Your Property, 4 pp. (available soon)

New-7:88-5M-TCM-RP. Price 45 cents. File 28.531 (Oil and Gas).