Oil and Gas Mineral Rights in Land Appraisal

Appraisers should investigate the status of oil and gas mineral rights and evaluate their potential effects on the value of the surface estate. In this article, several definitions and concepts involving mineral rights, royalty rights, and surface damages are discussed, as well as the implications of oil and gas activities in relation to the appraisal of land.

The professional appraiser is challenged enough in attempting to evaluate a property's market value based on comparable sales in a given area. However, major oil and gas discoveries in various parts of the United States have increased the importance of appraisers becoming more knowledgeable on the subject of oil and gas mineral rights. Maine, Vermont, New Hampshire, and Idaho are the only states not having significant oil or gas production.[1]

Some might question the appropriateness of using real estate appraisers to consider subsurface rights and speculate on the income potential of mineral rights in a land appraisal. It is also questionable whether it is appropriate to insert the following phrase in a land appraisal in areas that are known for their mineral production: "This appraisal is for the surface rights and estate only." The closer a subject property is to oil and gas activity, the more important it is that the narrative report include mineral rights and their effect on land value.

It is important that the appraiser include the effect of mineral rights on a property in the narrative report.

The future development of oil and gas has important implications, both positive and negative, for the surface owner, depending on the status of the mineral ownership and the highest and best use of the land. The oil and gas wells that have been discovered in downtown Hollywood and Houston have significant financial implications for the surface and mineral owners who are often not the same party.

Appraisers should investigate and evaluate the status of mineral rights when appropriate and make an effort to consider their effect on the property being appraised.

1. Leslie Haines, "Exploration Highlights." *Oil and Gas Investor* (September 1986).

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LITERATURE REVIEW

Although real estate and appraisal periodicals provide little information on oil and gas mineral valuation, literature in the petroleum engineering field indicates that such standards exist.

The valuation of mineral rights has primarily focused on sand, gravel, clay, rock, and other types of minerals that are mined or quarried from the surface.[2] A recent article by Anthony Rinaldi offers a historical overview and discussion of utilizing the most appropriate method of capitalizing the net income stream and generally concludes that the valuation of mineral properties is similar to that of any other income-producing real estate, "despite historical significance of Hoskold and others that the overwhelming modern and practical consensus is for use of the single-rate annuity premise."[3]

Roland D. Parks states that the essential factors required for calculations utilizing the present value method add important insights to the uniqueness and controversy involving mineral valuations. These factors are:

1. Recoverable reserves and annual production rate from which the life of the operation is determined
2. Plant and equipment needed to attain the estimated production by the mining method to be used and the capital outlay required
3. Cost of production and market value per unit of product, from which the profit spread is estimated
4. Discount rate for the business risks involved; if the Hoskold or other sinking fund premise is used, two rates of interest, speculative and safe, must be selected

Park's claim is made from the lessee or owner-operator's standpoint, not that of the royalty or mineral owner, and calls for the use of two discount rates.

His work also deals primarily with surface-mined minerals and his definition of the term minerals has important implications for appraisers concerning oil and gas deposits.

> Mineral property may be defined as property or sources from which one or more minerals may be produced. While it is desirable that the production be economic, it is not essential to the definition since production could, and often does change from economic to uneconomic, or vice versa with a change in circumstances. The term, mineral property, includes mineral-bearing deposits of all sorts, undeveloped and developed, idle and producing, as well as mineral rights of both owner and lessee.[4]

Real estate and appraisal periodicals are extremely limited in the area of oil and gas mineral valuation. Articles in the petroleum engineering field and references to the Society of Petroleum Evaluation Engineers are more prevalent. A very important article by H. J. Gruy and F. A. Garb, "Determining the

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2. Philip Grossman, "The Valuation of Land with Underlying Natural Resources," *The Appraisal Journal* (April 1935): 236–241; Paul C. Goolsby, "Demonstration Appraisal of a Sand and Gravel Operation," *Proceedings of the Tenth Annual Virginia Tax Assessors Association* (Richmond, Va.: Virginia Tax Assessors Association, 1965), 102–108; W. C. Downing, "Appraisal of a Gravel Pit," *Appraisal Institute Magazine* (January 1959): 16–18; William Wilson and J. J. Edman, "Valuation of Sand and Gravel Which May Be Removed Without Destroying Value of the Land," *The Appraisal Journal* (April 1959): 266–268; William Wilson and Fred C. Ash, "Value of Minerals, Sand, Clay, Etc.," *The Appraisal Journal* (April 1957): 268–269; George L. Schmutz, "The Valuation of Rock, Sand, and Gravel Deposits," *The Appraisal Journal* (April 1948): 174–177; Donald R. Davis, "Income Approach to Value of Quarry Lands," *Assessors Journal* (October 1967): 33–40.
3. Anthony J. Rinaldi, "A Review of Hoskold and the Valuation of Mineral Property," *The Appraisal Journal* (October 1981): 578.
4. Roland D. Parks, "Valuation of Mineral Property," *The Real Estate Appraiser* (May–June 1972): 37.

Value of Oil and Gas in the Ground," deals primarily with the value of major oil and gas reserves (oil in place) from the producer's perspective and addresses similar concepts and terms used by professional real estate appraisers such as "fair market value," "values from actual sales," and "informal rule-of-thumb valuation measures."[5]

Local tax assessing offices have long considered the value of minerals from the producing and nonproducing standpoint. A petroleum engineer who specializes in mineral resource tax assessment valuation recently concluded that:

> The valuation of oil and gas properties is not an exact science, and exact accuracy is not attainable due to many factors. Nevertheless, standards of reasonable performance do exist, and there are reliable means of measuring and applying these standards.[6]

DEFINITIONS AND CONCEPTS OF MINERAL OWNERSHIP AND VALUE

The fee simple "bundle of rights" theory includes ownership of surface rights, air rights, and 100% of the subsurface rights.[7] The simplest case involves the surface owner having all subsurface or mineral rights. Until the time that mineral activity occurs in the area, that is, leasing negotiations, seismic procedures, exploration, or drilling, the valuation of mineral rights is speculative but may still have important valuation considerations for the professional appraiser.

From the moment a mineral lease is signed by the surface and mineral owner or owners, possible increases or decreases in land value must be considered: decreases from the perspective of long-term surface disruption potential, increases because of potential mineral income from the land. Immediate income from the per-acre bonus received for signing the lease must also be considered.

Let us assume that the surface-mineral owner has 200 acres of farmland in Michigan, 10 miles from a new 500 barrels-of-oil-per day (BOPD) discovery well. The owner has just been offered a $200-per-acre lease bonus to sign a five-year primary term lease paying a 12.5% net revenue royalty interest by a major oil company. The operator will earn an 87.5% working interest in the well by causing the well to be drilled and paying 100% of all the costs associated with drilling, maintenance, and overhead required by oil and gas production. The surface owner is generally further compensated for a one-time payment of surface damages and most often the sale of water used during the drilling of the well. In addition to the lease bonus, the subsurface owner is generally paid an annual delayed rental fee of $1 per acre until such time as a well is drilled or the lease is abandoned during the primary term of the lease. Once oil production is established during the primary term of the lease, the lease remains in effect so long as production is maintained.

From the time a mineral lease is signed, possible increases or decreases in land value must be considered. The lease remains in effect so long as production is maintained.

Additional wells may be dug at any time in the future at the will of the operator unless the lease specifically states that each well "holds" only one drilling location after the expiration of the primary term. These future wells can have

5. H. J. Gruy and F. A. Garb, "Determining the Value of Oil and Gas in the Ground," *World Oil* (March 1982): 105–108; Mohammad Asif Mian, "Customized Forecasting Tool Improves Reserves Estimation," *World Oil* (April 1986): 107–116.
6. Walter Priddy, "Oil Property Evaluation," unpublished paper (Ft. Worth, Tex.: Pritchard and Abbott Inc., 1986).
7. Charles Jacobus, *Texas Real Estate* (New York: Prentice-Hall, 1983), 17.

important value implications to future owners of the land in terms of whether or not the land is purchased with or without mineral rights.

In many states the mineral estate is dominant over the surface estate, which allows mineral owners or their lessee to develop oil and gas wells without ownership of the surface. The surface owner without mineral rights is entitled only to one-time surface damages at the time that the well is drilled and has no interest in the well or future wells whatsoever. Except in the state of Louisiana, the partitioning of mineral rights from the surface is permanent.[8]

A surface owner without mineral rights is entitled only to one-time surface damages and has no interest in the current or future wells.

At any given time, the status of the surface and mineral estate of a given property may be any combination of the following surface-mineral-lease-income matrix:

Surface Estate Status	Mineral Status	Lease Status	Income Status
Undisturbed	100% mineral ownership	No lease	Nonincome-producing
Partially disturbed	Fractional mineral ownership	Partially leased	Income-producing
Totally disturbed	Zero mineral ownership	100% leased	
Potential for disruption (leased)			

A surface owner with a portion of the mineral rights may not be able to keep an oil company from drilling.

When a surface owner has only a portion of the mineral rights, it does not necessarily mean that he or she may keep an oil company from drilling.[9] The oil company may still drill, however, after "payout," with the surface-partial mineral owner participating fully as a pro rata partner in the well.[10]

The appraiser can verify the extent of well ownership and mineral income attributable to the landowner by reviewing the original lease, but more importantly by obtaining copies of the original well division order prepared by the abstract and legal department of the oil company and reviewing copies of the landowner's run statements and check stubs, which generally denote the owner's net revenue interest.

Lease bonuses, surface damages, sale of water, delayed rental fees, and royalty income can for all practical purposes be considered net operating income (NOI) attributable to the land without cost to the land-mineral owner.

The income aspects (assuming 100% ownership of mineral rights and land) from a mineral standpoint for a 200-acre Michigan farm would be as follows:

Cost of Drilling	Initial Income to Owner	Cost of Drilling by Oil Company
Lease bonus: 200 acres × $200 per acre =	$40,000	($40,000)
Delayed rental: 200 acres × $1 per year =	$200 (until drilled)	($200)
Surface damages (2 acres per location) =	$3,000	($3,000)
Sale of water (from pond or lake) =	$3,000	($3,000)
Cost of drilling well =	$0	($800,000)

8. In Louisiana, nonproductive minerals revert to the surface owner after 10 years.
9. In Oklahoma, a partial mineral owner may be forced to sign a lease by the courts by what is known as "forced pooling."
10. For example, a surface owner with 50% of the mineral rights would own one-half of the well's NOI after the oil company drilled and received 100% of its investment back.

If the well is a "dry hole" and abandoned, the surface owner's land is generally restored to approximately its original condition. However, the lease remains in effect for the balance of the primary term, which means additional locations could be drilled during the balance of the five years anywhere on the leased premises. This potential for additional surface disruption has implications for the appraiser's land valuation and, at a minimum, the existence of a mineral lease in effect on the property should be noted.

In the case of the 200-acre Michigan farm, let us assume that the oil company has "made a well" (oil jargon for successful) and the well flows 200 BOPD.

Although the first well may be nonproducing, additional wells can be drilled during the balance of the primary lease term. This potential for more surface disruptions affects the appraiser's land valuation.

200 BOPD	Surface-Mineral Owner	Oil Company
Royalty interest (100%)	12.5% *NOI*	–0–
Working interest (100%)	–0–	87.5% gross operating income
Pro rata oil per day production (200 BOPD)	25 BOPD	175 BOPD
Value of oil per day (say $20 per barrel)	$500 per day	$3,500 per day
State taxes (say 8%)	($40 per day)	($280 per day)
Gross operating expenses	NA	($700) (20%)
NOI per day (pretax)	$460 per day	$2,520 per day

value of the 200-acre Michigan farm including 50% of the mineral estate and 50% of the royalty interest in the producing well.

What is the value of the

1. 200-acre surface estate?
2. 50% undivided ownership (100 acres) of the minerals?
3. 50% royalty in the well (12.5% × 50% = 6.25% of all future gross revenue of the well)?

As separate estates, although each may have an effect on the value of the others, these components may be sold separately and therefore could be valued separately or together using various appraisal techniques. As pointed out in an article by Charles P. Everett

The above summary is fairly straightforward but can become complicated quickly when the owner of the surface does not own 100% of the mineral or leasing rights, in which case the lease bonus, delayed rental payments, and income-per-year is reduced accordingly. In contrast, the surface owner without mineral rights (say they had been sold or retained in prior years by former owners) is entitled only to the surface damages and sale of water revenues and has no benefits from the cash flow from the sale of oil and gas.

Let us assume that you have been hired to determine the fair market

in the Congressional committee discussions on the Tax Reform Act of 1976 it was determined that:

> Elements of value which are not related to the farm or business use (such as mineral rights) are not eligible for special use valuation. For example, if there is an oil lease on a farm, the full value of the mineral right is to be taken into account for estate tax purposes.[11]

My opinion is that each component must be valued separately utilizing the three approaches to value and that the resultant cumulative total value would be the fair market value of the property.

Each of the components of a property with mineral rights—surface estate, mineral estate, and royalty estate—should be valued separately.

11. Charles D. Everett, "Estate Tax Special Use Valuation: Preparing the Farmland Appraisal for the Estate and IRS." *The Appraisal Journal* (April 1984): 173.

VALUATION OF THE SURFACE ESTATE

To value the surface rights, the appraiser must find comparable sales without mineral rights, or discount each comparable sale by an appropriate amount.

Let us assume that the 200-acre Michigan farm is fairly typical in the area and after considering all the data, that the most appropriate appraisal technique to employ is the sales comparison approach.

While this may appear to be a fairly straightforward appraisal assignment, the problem becomes one of finding and confirming comparable sales that occurred without mineral rights, or discounting each comparable sale used by an appropriate amount thereby stripping it of its mineral value. The latter method is fairly subjective because of the uniqueness of each comparable's geological location and differing mineral potential. Land values without mineral rights are difficult to document in new oil and gas areas as the result of mineral estates generally still being intact with the surface. Mineral rights are often retained by sellers only after mineral activities occur and production is established.

The appraiser should consider the immediate and long-term effects that the drilling and production locations and oil and gas facilities have on the balance of the property when valuing the surface estate.

Nevertheless, the appraiser must consider what percentage of the mineral rights passed with the sale of each comparable. This can be established during confirmation of each sale, or quite frequently by the field deed, which often contains language such as, "The subject property is being sold together with all rights, save and except fifty percent (50%) of the minerals are reserved by the grantor."

If it is assumed that all else is comparable, the confirmed cash sales that took place within a six-month period listed in Table 1 should be considered, each of which is located in the immediate area of the subject property.

The initial resultant value of the surface of the Michigan farm appears to be $1,000 per acre for the land and $200 per acre for the mineral rights; however, there are other considerations that the appraiser needs to address. For example, the subject property already has a well that disrupts some portion of the surface. Therefore, the present market value of the surface estate should be adjusted downward accordingly. A description of the types of surface disruptions follows with a rationale for the five-acre adjustment presented.

Types of surface disruptions and effects on surface value

The drilling and production of oil and gas wells affect the present and future values of the surface estate. While owners having both the surface and mineral estates are partially compensated with royalty from the wells, the surface owner without mineral rights can be severely affected on a long-term basis by the presence of drilling and production activities.

The professional appraiser should consider the immediate and long-term effects that the drilling location, production location, and associated oil and gas facilities have on the balance of the property.

Drilling location preparation

Prior to drilling operations, the site is prepared by excavation and leveling. This usually entails removal of all vegetation including grasses, undergrowth, trees, and the digging of two or more pits in which drilling fluids (drilling mud, water, and displaced drilling strata) are circulated and recycled. The size of the drilling location and pits varies directly with the depth of the planned well. Shallow wells of 2,000 feet generally require approximately one acre and deeper wells of 10,000 feet or more require two or more acres. The location may be graveled to aid in the ease of moving the drilling rig, pipe trailers, and trucks that facil-

TABLE 1 Comparable Land Sales with Mineral Rights Considered

Comparable	Size	Mineral conveyed	Leased [a]	Production [a]	Sales price per acre	Adjusted price per acre	Mineral rights value per acre
A	200 acres	100%	Yes	No	$1,200 per acre	$1,000 per acre	$200 per acre
B	180 acres	50%	Yes	No	$1,100 per acre	$1,000 per acre	$200 per acre
C	220 acres	25%	No	No	$1,050 per acre	$1,000 per acre	$200 per acre
D	200 acres	0	Yes	No	$1,000 per acre	$1,000 per acre	NA

Estimate of value of the 200-acre Michigan farm surface estate:

200 acres
× $1,000 per acre (from comparable sales)
$200,000
− $5,000 (5 acres affected by oil operations)
$195,000 adjusted value of surface

itate logging, cementing, and fracturing the well.

After several years, abandoned locations may show few signs that there was ever a well drilled. However, the destabilized soil conditions on or near pits can require special foundation engineering for building purposes. For this reason, appraisers should note these old locations (when possible) on land being appraised. That the surface owner at the time was compensated for surface damages will do future owners of the land little good when development is contemplated and a problem arises.

Production location and facilities

If a well is successfully completed, the associated surface equipment generally includes a wellhead (the point of production on the ground), a pumping unit or "pump-jack," a tank battery for oil storage, and a natural gas metering station if gas is found. Other associated land uses that can have long-term effects on surface values are access roads to individual wells, electrical lines, and oil and gas pipelines.

Transmission or "sale" pipelines are generally buried and carry with them a written and long-term easement across the land. In contrast, easement pipelines that may connect numerous wells with the oil lease storage tank battery may run along the surface or be buried below "plow depth" as called for in the original oil and gas lease.

Future sites and locations of wells

The appraiser should be aware that while a property may have only one well located on the tract of land, the lease may often allow for the drilling of multiple wells based on a drilling and spacing grid regulated, in most cases, by the state's oil and gas agency. In Texas and Oklahoma, for example, wells less than 1,000 feet (depending on the field rules) may be drilled every 330 feet, while 10,000-foot wells may require 640 acres per well. In many parts of the United States there are geological areas that have multiple pay zones requiring a separate well drilled and separate production facilities for each.

While the appraiser estimates the value of a property on a specific date in an "as is condition," the implication of failure to consider and mention the possible ramifications of an existing oil lease in the appraisal report could be disastrous to a potential buyer or lender.

Failure to consider the implications of an oil lease in an appraisal report could have disastrous consequences for a potential buyer or lender.

While the production site may use substantially less land than the original drilling site, the long-term effect on future land use and, therefore, on the value of the property is significant.

Many states and municipalities restrict the construction of schools, homes, and commercial buildings to within 300 feet of a producing well for safety considerations. Conversely, many states have laws prohibiting drilling of oil and gas wells within 300 feet of a single-family residence without permission of the surface estate owner. Any rerouting of electrical lines, pipelines, or access roads to wells to utilize the surface for a higher and better use or a higher coexistent use of the land with mineral production is at the expense of the developer. While roads to production and well locations may appear to be an asset to the surface for future development, they are generally owned and maintained by the oil company and as such are private and should not be considered as contributing any positive value to the property surface estate being appraised. On the contrary, these private roads, easements, and associated oil production equipment can have a serious negative financial impact on the value of the surface estate.

VALUATION OF THE MINERAL ESTATE (WITHOUT ROYALTY IN THE EXISTING WELL)

In valuing the mineral estate, there are three approaches the appraiser can use. Two assume that the royalty estate is not being conveyed while the mineral estate is being appraised. The third assumes that it is being conveyed simultaneously.

There are really three approaches to valuing the mineral estate. The first two assume that while the mineral estate is being appraised, the royalty estate or interest in the productive well is not being conveyed.

The first technique involves utilizing the residual values of the mineral rights from the comparable sales in valuing the surface estate (see Table 1). A second but more data-restrictive method is to research area mineral deeds and determine the fair market value of undivided mineral rights being sold.

Mineral deeds are quite common, particularly when a major new well is completed in a "wildcat" area. However, unlike the common practice of confirming land sales through cooperative buyers, sellers, and real estate brokers, the buying and selling of mineral rights often takes place on a strictly confidential basis.

Estimated value of the mineral estate:

	200	acres
×	$200	per acre (from comparable sales)
	$40,000	gross value of mineral estate
×	50%	of the mineral estate
Present value =	$20,000	utilizing comparable sales

It is important to understand that no rights to the cash flow of the existing well are included in the $20,000 value. The $20,000 in this case represent the present value of future leasing rights and the speculative income of future wells drilled on the property.

The third method of valuing mineral estates involves the use of cash flow analysis of only the existing well's income and assumes that the royalty interest in the existing well is also conveyed simultaneously. This method results in zero or no valuation of the mineral estate and assigns no value to future leasing rights or wells being drilled.

VALUATION OF THE ROYALTY ESTATE

A geologist or petroleum engineer needs to be consulted in projecting the future performance of a well. In projecting the cash flow of the well, several factors need to be considered that are beyond the area of expertise and capability of most land appraisers.

1. Price of oil—The future price of oil can only be speculated by future contract quotes for relatively short time periods. Unlike rent from real estate that may change slowly over a long period of time, oil prices fluctuate daily and an appraisal report must make some broad assumptions.

2. Size of the reservoir—The type and thickness of the oil-bearing formation rock is directly related to the amount of oil in place that is economically feasible to produce.
3. Pressure of the reservoir—This is determined by depth and the type of "drive," water or gas, that moves the oil and gas through the formation rock or sand. Downhole pressure will determine whether the well will flow naturally or need to be pumped, how long the well will most likely produce, and at what rates.
4. The projected decline curve of the well—Other factors unknown to the appraiser that affect the production of the well and therefore the value of the royalty estate involve the cost of oil production by the working interest owner. While there still may be substantial oil reserves in place that cost the royalty owner nothing to produce, if the well becomes economically inefficient, the working interest owner (the oil company) may abandon the well.

Petroleum engineers primarily appraise mineral properties for oil companies and utilize the following methods and rules of thumb.

1. Dollars per barrel of reserves—There is a direct relationship between posted wellhead prices and the value of reserves in the ground and the old rule of thumb that oil in the ground is worth about one-third of the posted price.[12]
2. Dollars per daily barrel of productions—In 1980, 87.5% net revenue leases (after royalties were taken out but before expenses) to the working interest owner were selling on the basis of $15,000 to $25,000 per-barrel-per-day production. The variance was related to a) amount of reserves in place, b) cost of production, c) life expectancy of the wells, and d) availability of other proven drilling locations on the leases.
3. Gross income multipliers (per month)—In 1980, working interests were selling for 24 to 36 times monthly income, while royalty interests were selling for 36 to 60 times monthly income with variances occurring as described above.
4. Comparable sales of royalty interest—In many areas these can be verified and used to determine market value. As with the sale of mineral rights, however, data are generally very hard to find and confirm. Most often value is tied more to the cash flows of the well or is speculative in the case of nonproductive rights.
5. Present value of discounted annual cash flows—This is determined by utilizing an appropriate single rate of risk for working interest and royalty interest. This is by far the preferred method of valuation; however, it is still quite subjective because of substantial oil price fluctuations and different decline curves for each well.

The projected decline curve for

In valuing the royalty estate, the appraiser should consult a geologist or petroleum engineer in projecting the future performance of a well.

12. Mian, Gruy and Garb. This informal discounting to present value is for working interest owners who must pay overhead and operational expenses. Royalty interest is worth considerably more due to being primarily NOI or a percentage of gross profits without expenses, save and except state severance taxes and income taxes.

wells in many areas can be predicted based on the projected performances of the subject well as determined by geologists and historical data on wells in the same field.[13] Monthly production figures and trends for each lease can be obtained from state agencies, taxing authorities, or from the royalty owner's production reports.

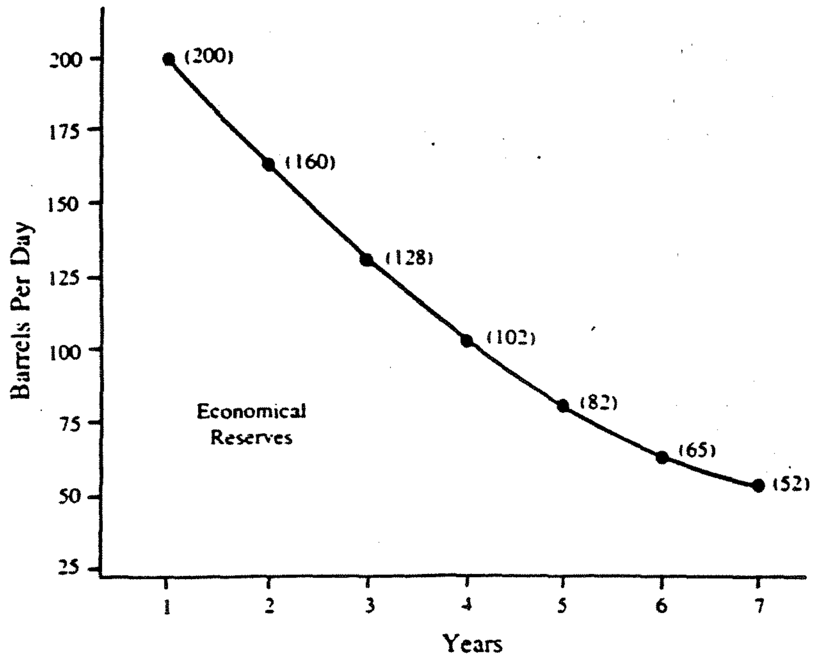
Appraisers should consider whether wells are producing naturally or requiring pumping units before drawing conclusions on the present value of the primary production.

With the help of a plotted trend line of nearby wells, it is projected that the Michigan farm's well will have a 20% drop in production each year until the seventh year when the working interest owner will consider the well uneconomical to operate and it will be plugged and abandoned. The production decline curve is illustrated in Figure 1.

Based on the production decline curve found in Figure 1, fixed operating expenses, and a 15% discount rate, the valuation of the 7/8 working interest and the 1/16 royalty interest (50% of 1/8 full royalty interest) from the 200-acre Michigan farm could be estimated as seen in Tables 2 and 3.

Not all wells have such an even decline curve. The decline curves (see points A) in Figure 2 are for a well drilled in January 1985 in north central Texas.[14] The well produces both oil and gas and would be evaluated separately based on their respective prices. The well flowed naturally until reservoir pressures were depleted, at which time a mechanical pumping unit was put in service to increase production (see points B). Appraisers should consider whether wells are producing naturally or requiring pumping units before drawing conclusions on the present value of the primary production. Secondary re-

FIGURE 1 Production Decline Curve Based on Production of Barrels of Oil Per Day (BOPD)



13. Gruy and Garb.
14. Interview with owner-operator, June 28, 1987.

TABLE 2 Appraisal of 7/8 Working Interest (WI)

1 Projected annual 8/8 production	×	2 .875 WI	×	3 WI net oil price	=	4 WI gross revenue (in 1000s)	−	5 Operating expense (in 1000s)	=	6 WI net revenue (in 1000s)	×	7 (15%)[a] discount rate	=	8 Payout WI net revenue (in 1000s)
73,000 Bbls.	×	.875 WI	×	$18.40	=	$1,175.3	−	268.6	=	$906.7	×	.932505	=	$845.5
58,400 Bbls.	×	.875 WI	×	18.40	=	940.2	−	268.6	=	671.6	×	.810874	=	544.6
46,720 Bbls.	×	.875 WI	×	18.40	=	752.2	−	268.6	=	403.6	×	.705108	=	341.0
37,376 Bbls.	×	.875 WI	×	18.40	=	601.7	−	268.6	=	333.1	×	.613137	=	396.5
29,900 Bbls.	×	.875 WI	×	18.40	=	481.4	−	268.6	=	212.8	×	.533163	=	177.6
23,920 Bbls.	×	.875 WI	×	18.40	=	385.1	−	268.6	=	116.5	×	.463620	=	54.0
19,136 Bbls.	×	.875 WI	×	18.40	=	308.1	−	268.6	=	39.5	×	.403148	=	15.9

288,452 = 8/8 Reserves (recoverable barrels of oil)

Present value of discounted cash flows = $2,275.10
Fair market value factor .80[b]
Fair market value = $1,820,080.00 (or 24 months of initial production)

[a]The use of different discount rates for working interest and royalty owners has not been observed in practice. Due to risk factors and expenses involved in oil operations by the working interest owner, it would seem the "nonrisk," passive status of royalty owners would require the use of a lower discount rate.

[b]Discount valuation factor associated with the sale of oil and gas properties.

TABLE 3 Appraisal of 1/8 Royalty Interest (RI)

Projected annual 8/8 production	×	.125 RI	×	RI net oil price	=	RI net revenue (in 1000s)	×	(15%)[a] discount rate	=	Payout RI net revenue (in 1000s)
73,000	×	.125 RI	×	$18.40	=	$167.9	×	.932505	=	$156.6
58,400	×	.125 RI	×	18.40	=	134.3	×	.810874	=	108.9
46,720	×	.125 RI	×	18.40	=	107.4	×	.705108	=	75.7
37,316	×	.125 RI	×	18.40	=	85.9	×	.613137	=	52.7
29,900	×	.125 RI	×	18.40	=	68.8	×	.533163	=	36.7
23,920	×	.125 RI	×	18.40	=	55.0	×	.463620	=	25.5
19,136	×	.125 RI	×	18.40	=	44.0	×	.403148	=	17[illegible]

288,452 = 8/8 Reserves (recoverable barrels of oil)

Present value of discounted cash flows = $473.8[illegible]
Fair market value factor
Fair market value of 100% royalty = $379,040.00 (or 27 months of initial production)
Fair market value of 50% of full 1/8th royalty interest = $189,520.00

[a]The use of different discount rates for working interest and royalty owners has not been observed in practice. Due to risk factors and expenses involved in oil operations by the working interest owner, it would seem the "nonrisk," passive status of royalty owners would require the use of a lower discount rate.

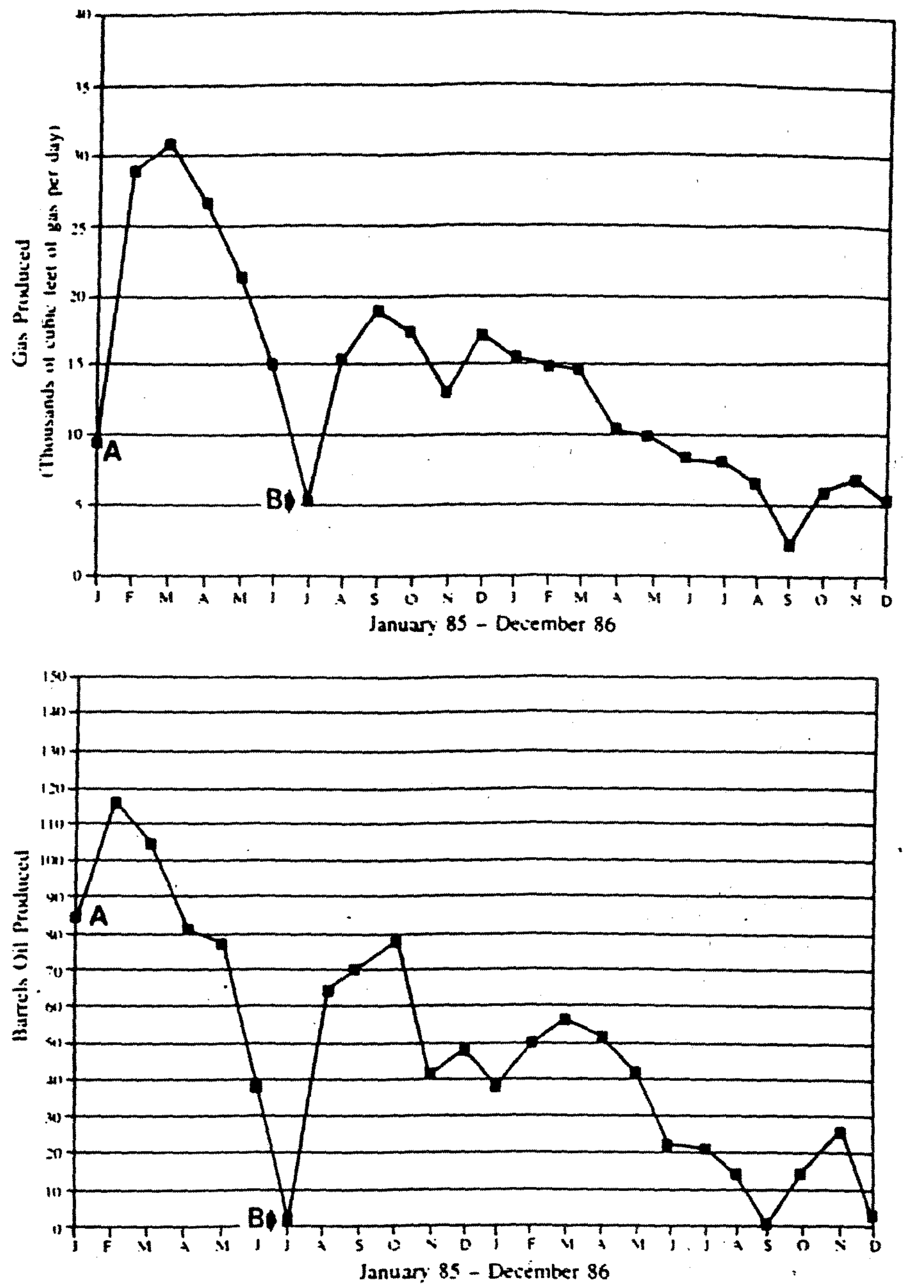
[b]Discount valuation factor associated with the sale of oil and gas properties.

covery methods involving the injection of gas, water, steam, polimers, and so forth in nearby wells can also have a significant effect on the future cash flow of an oil and gas property.

CONCLUSION

Oil and gas mineral rights can have important implications for the valuation of the surface rights being appraised.

FIGURE 2 Gas and Oil Decline Curves for a Well in North Central Texas



Given adequate comparable sale data, reliable production histories and projections, the professional appraiser can render an opinion of value of the surface, mineral, and royalty estates of a given property.

The value of the three separate estates for the 200-acre Michigan farm are as follows:

Adjusted value of the surface	$195,000
Value of 50% of minerals	$20,000
Value of 50% of the royalty	$189,520
Total estimate of value	$404,520