Attachment 3

MMS Second Supplementary Proposed Rule

February 6, 1998

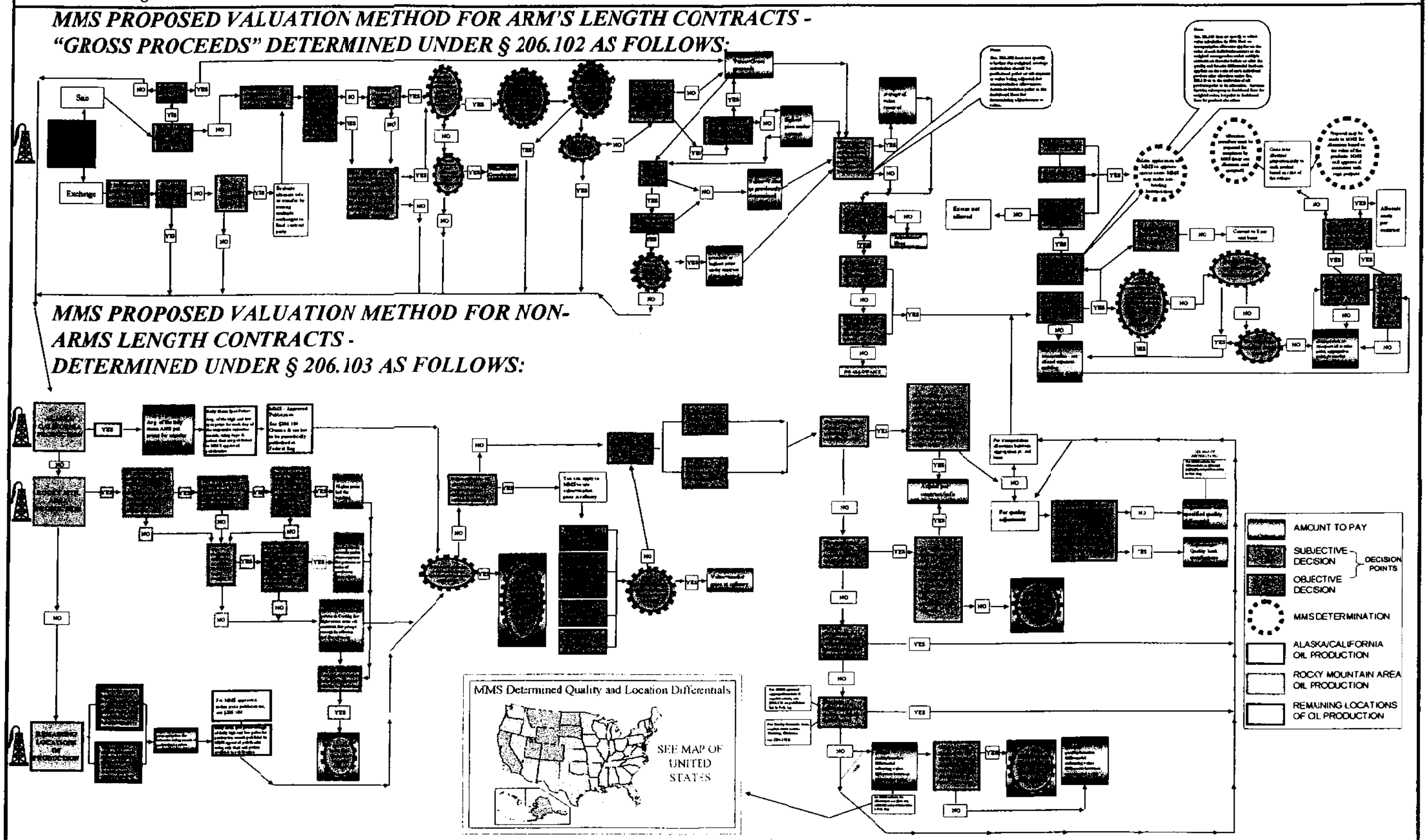
"The proposed rule would result in: Simplification...coupled with certainty, Reduction in...litigation, Reduction in... compliance costs"

\- MMS Economic Analysis of Second Supplementary Proposed Federal Oil Royalty Valuation Rule Under Executive Order 12866

MMS Second
Supplementary Notice
of Proposed
Rulemaking

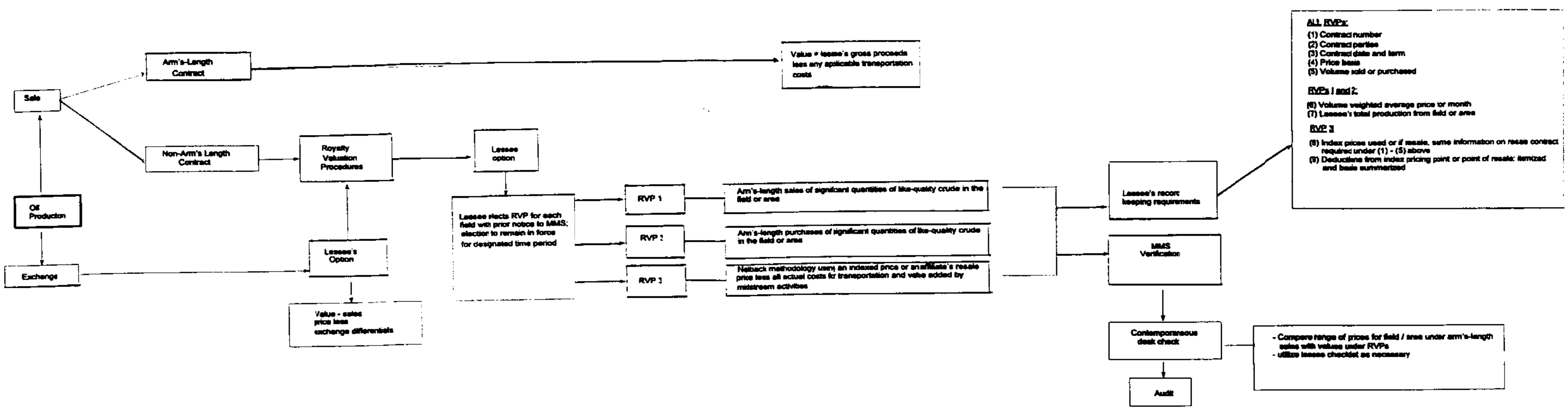
HOW WILL ROYALTY VALUE BE CALCULATED UNDER MMS PROPOSED RULE?

Establishing Oil Value for
Royalty Due on Federal Leases.
63 FED. REG. 6113
FEBRUARY 6, 1998



Attachment 4

PROPOSED ROYALTY VALUATION PROCEDURES



Attachment 5

Comments on
Discrimination Against Affiliates in the Midstream Market

dc8125

Comments on
Discrimination Against Affiliates in the Midstream Market

Overview

The proposed oil valuation regulations exceed the authority of the Minerals Management Service to establish a reasonable value of production for the purpose of computing royalty because:

(1) The proposed regulations establish an irrebuttable presumption of control by one entity of another based upon ownership of as little as 10 percent of the voting securities of an entity, interest in a partnership or joint venture, or other forms of ownership, with the consequence that contracts between the two entities cannot be arms-length. (definition of "Affiliate" and "Arm's length contract").

(2) For oil sold by a lessee to an affiliate (as newly defined in the proposed regulations), the proposed regulations establish an irrebuttable presumption that the price received by the lessee does not establish the reasonable value of production.

(3) For oil sold by a lessee to an affiliate (as newly defined in the proposed regulations), the proposed regulations in section 206.102 establish an irrebuttable presumption that the price received by the affiliate in an arm's-length downstream resale establishes the reasonable value of production at the lease. They thus establish the netback valuation methodology as the exclusive methodology for valuing production in such situation.

(4) The proposed regulations in section 206.102 establish an irrebuttable presumption that the affiliate does not add any value to the commodity other than the cost of transportation. This presumption will result in the government receiving royalties on the gross proceeds (less only transportation costs) of a business entirely separate and distinct from the exploration for and production of oil.

(5) The proposed regulations in section 206.103 establish value based upon regional market center spot prices (with certain exceptions for production from leases in the Rocky Mountain Area) and do not allow adequate deductions to calculate value at the lease. They will therefore result in the government receiving royalties on more than the value of production at the lease.

(6) The proposed regulations in section 206.103(b)(2) establish value based upon affiliate arm's-length contracts and therefore have the same infirmities as the proposed regulations in section 206.102.

(7) The proposed regulations, if adopted, would be discriminatory because they would impose a penalty on lessees who sell to affiliates by establishing a royalty value which is higher than the royalty value for lessees who make arm's-length sales of their oil. Shell Western E&P, Inc., 112 IBLA 394, 399, GFS(O&G) 5 (1990).

Comments

I. Extent of the Government's Entitlement to Royalties (the Duty to Market Where?)

The Mineral Leasing Act of 1920, 30 U.S.C. sec. 181 et seq. provides that a lease shall be conditioned upon the payment of royalties "in amount or value of the production removed or sold from the lease." § 226(c). Similarly, the Outer Continental Shelf Lands Act, 43 U.S.C. § 1331 et seq., provides that leases require the payment of royalties " in amount or value of the production saved, removed, or sold." § 1335(a)(8); § 1337(a)(1)(A). Under such leases, the government is entitled to take its production in kind (royalty in amount of production) or to be paid on the value of the royalty share of production. The question then is, what is production?

The term production has since the inception of these leasing laws been understood to mean the production at the wellhead conditioned only to the extent necessary to be acceptable to a first purchaser. This is evident from an examination of the original valuation regulations, case law, and IBLA and MMS decisions.

The valuation regulations in existence prior to the current regulations made it clear that royalties were to be based on the value of the product at the lease. The onshore regulation provided:

> The value of production, for the purpose of computing royalty, shall be the estimated reasonable value of the product as determined by the Associate Director due consideration being given to the highest price paid for a part or for a majority of production of like quality in the same field, to the price received by the lessee, to posted prices, and to other relevant matters. Under no circumstance shall the value of production of any of said substances for the purposes of computing royalty be deemed to be less than the gross proceeds accruing to the lessee from the sale thereof or less than the value computed on such reasonable unit value as shall have been determined by the Secretary. In the absence of good reason to the contrary, value computed on the basis of the highest price per barrel, thousand cubic feet, or gallon paid or offered at the time of production in a fair an open market for the major portion of like-quality oil, gas, or other products produced and sold from the field or area where the leased lands are situated will be considered to be a reasonable value.

30 C.F.R. §206.103 (1987) (emphasis added).

Similarly, the offshore regulation provided:

> The value of production shall never be less than the fair market value. The value used in the computation of royalty shall be determined by the Director. In establishing the value, the Director shall consider: (a) The highest price paid for a part or for a majority of like-quality products produced from the field or area; the price received by the lessee; (c) posted prices; (d) regulated prices; and (e) other relevant matters. Under no circumstances shall the value

of production be less than the gross proceeds accruing to the lessee from the disposition of the produced substances or less than the value computed on the reasonable unit value established by the Secretary.

30 C.F.R. §206.150 (emphasis added).

The valuation regulations for onshore and offshore federal leases were consolidated when the existing valuation regulations were adopted effective March 1, 1988. The current oil valuation regulations also clearly recognize that the production on which royalties are owed is the product at the lease. Thus, for example, for oil not sold pursuant to an arm's-length contract, the value of oil production is to be determined in accordance with the first applicable of five benchmarks. In three of these benchmarks, reference is made to purchases or sales "in the same field (or, if necessary to obtain a reasonable sample, from the same area)." 30 C.F.R. §206.102(c)(1), (2) and (4). A fourth benchmark references purchases or sales "in the same area or nearby areas." 30 C.F.R. §102(c)(3).

Case law also supports the conclusion that the production to which the government is entitled in amount or value is the product at the lease. In United States v. General Petroleum Corporation, 73 F.Supp. 225 (S.D. Calif. Central Division 1946), a case involving federal leases covering wells in the Kettlemen Hills Field of California, the Court recognized that under the Mineral Leasing Act of 1920, the lessees were only "obligated to return to the government the specified value at Kettlemen Hills of the oil produced." [Emphasis added.] Id. at 235.

If the product cannot be sold at the lease because there is no market at the well or on the lease, case law and decisions still support the conclusion that the production to which the government is entitled in amount or value is the product at the lease. Therefore, the reasonable costs incurred in transporting lease production to the nearest available market place or sales outlet were one of the "relevant matters" to be considered under the pre-1988 regulations. In other words, in order to arrive at a wellhead value for production when there was not a market at the lease, the Secretary could allow transportation costs to be deducted from the value of the product at the nearest available market. United States v. General Petroleum Corp., supra at 263, aff'd Continental Oil Co. V. United States, 184 F.2d 802 (9th Cir. 1950); Conservation Division Manual, 647.5.3; Shell Oil Co., MMS-92-0039-O&G (Mar. 1, 1994). Similarly, under the current valuation regulations, lessees are entitled to a transportation allowance for the reasonable, actual costs incurred by the lessee to transport oil to a sales point or point of value determination off the lease. 30 C.F.R. § 206.104(a).

Similar allowances have historically been allowed for other activities which also add value to the product on which the government is entitled to royalties. For example, gas producers have historically be entitled to an allowance for the cost of processing natural gas into liquid hydrocarbon products and residue gas. The purpose of this allowance is to determine the value at the well of gas which is processed by the lessee prior to sale. As stated in United States v. General Petroleum Corporation, 73 F.Supp. 225, 254 (S.D. Calif. 1946):

Natural-gas royalties are payable on the gas as it is produced at the well. It is the value of that gas which must be determined. Ordinarily the gas as produced contains a certain amount of "casing-head" gasoline. If the gas is processed in an extraction plant, two products result, the natural gasoline and dry residual gas. Since part of the value of the gasoline and dry gas *so manufactured is attributable to the extraction process, allowance must be made for the* manufacturing costs in order to arrive at the value of the gas as originally produced.

[Emphasis added.] See also, 30 C.F.R. §206.106 (1987); Section 647.7, Conservation Division Manual (Manufacturing or Processing Allowances); discussion in Wexpro, 106 IBLA 57. That allowance was retained in the 1988 gas valuation regulations. See 30 C.F.R. §§206.158 & 159 (1988).

The purpose of the allowances is to arrive at the value of production at the wellhead or lease when there is no market at the lease. The value added to the product by transportation or processing is subtracted from the value of the product at the nearest available market off the lease in order to determine the value at the lease. This is known as a netback valuation method. Prior decisions have established, consistent with the conclusion that the production on which royalties are owed is the product at the lease, that the government is not entitled to any profits from transporting production off the lease to market, processing production, or otherwise adding value to production.

The value of production at the lease, determined by the netback method, should be the same as the value the government would have realized had its taken its share of production in kind. That there should be no difference in royalties between taking in kind or being paid in value is illustrated by Sun Oil Company, et al., GS-60-O&G(OCS) (Oct. 11, 1974) in which it was held:

> When royalty payments are taken in kind under the Outer Continental Shelf Lands Act, the Supervisor would treat the transportation costs from the lease to the processing facility as a "reasonable cost of transporting" royalty substances to the point of delivery which must be paid by the purchaser of royalty substances. It would therefore appear reasonable to require that, when royalties are paid in value, that same cost should be considered one of the "other relevant matters" considered in determining reasonable value of the product.

See also, Kerr McGee Corp., 22 IBLA 124, 128 (1975) in which the Board stated that logic compels the conclusion that there should be a transportation allowance when royalties are taken in value. The Board stated, "[i]t would be an anomalous result if the Government royalty interest was, in effect, chargeable with transportation when taken in kind, but not when taken in value."

Not only should any determination of value result in the same value to the government as if the government had taken its royalty in kind, but any such determination should also result in the same value as if the lessee had sold its production at the wellhead or lease in an arm's-length transaction. This is illustrated by the case of United States v. General Petroleum Corporation, 73 F.Supp. 225 (S.D. Calif. 1946). One of the issues in that case was how to calculate an allowance for actual extraction costs. The government allowed the actual costs of operating a wet gas gathering system which collected gas from wells scattered over an area 16 miles long and 3 miles wide and brought the gas to two or three absorption plants located in the field. The government also allowed depreciation on the capital investment in the gathering line as "actual extraction costs." However, the government refused to allow a return on the capital investment. The Court held that a return on the lessee's depreciated investment in the wet gas gathering system should have been allowed. The Court stated:

> If the lessees had had no gathering system of their own they would have been compelled to have that service performed by someone else. In such event the contract for that service would necessarily have included as elements of cost to the lessees not only the labor and other costs for operating the lines and depreciation on the capital investment therein, but as well a reasonable return on the capital investment in the facilities so used. When, instead of paying for the service to be done by someone else, the lessees performed that service for themselves and for the government, they were entitled to have the government royalty gas bear its proportionate share of these costs which daily accrued against them.

Id. at 257.

That proper application of the netback method requires exclusion of profits derived from activities which add value to the production is further supported by the decision in Marathon Oil Co. v. United States, 604 F.Supp. 1375 (D. Alaska 1985), aff'd, 807 F.2d 759 (9th Cir. 1986) in which the MMS allowed a reasonable rate of return on an LNG plant to be deducted from the lessee's gross proceeds. That this must be done is further supported by the discussion in Petro-Lewis Corp, 108 IBLA 20, 39 (March 20, 1989) of whether the MMS could use the netback method to calculate royalties on oil production converted into electricity prior to sale. In discussing the Marathon case, the Board stated:

> In effect, by allowing a reasonable rate of return to be deducted from the gross proceeds, MMS was eschewing a royalty assessment on the profits derived from the manufacture of the LNG. [footnote omitted]

Turning to the case before it, the Board stated;

> This is the precise point made by Petro-Lewis in the instant appeal, viz., MMS should not be permitted to assess royalty on profits derived from the processing of the crude oil into electricity, yet, by its computation method, MMS was essentially seeking a royalty upon the profits attributable to the cogeneration facility. We believe appellant's point is well taken. Even if the netback approach were applicable in the instant case, the decision of the Director, MMS would have to be set aside since a review of the costs allowed appellant fails to disclose that any deduction was permitted for a reasonable rate of profit from the cogeneration facility.

The Board went on to hold that computation of royalty based on the netback method was incorrect inasmuch is royalty is due on the value of crude oil, not on the gross proceeds (even properly adjusted pursuant to the netback methodology) from the sale of the electricity into which it was converted. In reaching this conclusion, the Board noted in footnote 8:

> In this regard, it is useful to keep in mind the fact that the United States always reserves the right to take its royalty in-kind. Had the United States elected to do so in the instant case, it would have received one-eighth of the crude oil attributable to the production of electricity. The cogeneration process Petro-Lewis used was not performed to upgrade the crude oil so as to make it marketable. Rather, the crude oil which the United States would receive would be in the exact same condition as that which Petro-Lewis was using to fire its steam generations and, indeed, the United States would be able to so use the crude without further alteration of the oil. A royalty based on the value of the crude oil at the lease is the economic equivalent of the value of the royalty oil. By valuing the oil appellant consumed in the generation of energy in the form of steam which was then used to produce electricity, the United States is receiving all to which it is fairly entitled.

[Emphasis added.]

From all of the foregoing, it is an inescapable conclusion that ***the government is only entitled to a royalty in amount or value of the product at the lease. It is not entitled to a royalty on any value added to production by downstream activities***. As stated by the United States District Court for the District of Montana in the case of Beartooth Oil & Gas Company v. Manual Lujan, Jr.,[1] "the IBLA should be concerned with the value of the gas at the lease, and not the value of the gas at some point located off the leasehold." Id., Slip Op. at pgs. 5-6. The Court went on to state:

> [T]he case law does not support the contention that the market of concern is 50 miles away from the leasehold. Rather, case law and the regulations indicate that the market of concern is the market at the leasehold.

Id. at pgs. 6-7, citing 30 C.F.R. §206.151 (definition of marketable condition adopted in 1988); Marathon Oil, 604 F.Supp. at 1386 (value at the wellhead), California Co., 296 F.2d at 387 (market within short distance of the wells).

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1 Case No. CV 92-99-BLG-RWA (D. Mont. Sept. 22, 1993). The Court remanded the case for further proceedings. On remand, the parties filed a joint motion to dismiss the case on the ground they had reached an agreement to compromise and settle all issues raised in the case. The motion was granted by order of the Board. Beartooth Oil & Gas Co. (On Judicial Remand), IBLA 94-461 (May 9, 1995). Accordingly, the Court decision is not published.

Once oil is produced, the only services the lessee is required to provide at no cost to the government are to put the product in marketable condition. However, consistent with the conclusion that the market of concern is the market at the leasehold, it has been held that the obligation to put production in marketable condition only requires that the product be in a condition satisfactory to the nearest available market. See, Beartooth and cases cited therein.

As all of the foregoing also conclusively establishes, ***there is no duty on the part of a federal lessee to value production based upon any market beyond the nearest available market.***

These conclusion are consistent with the law with regard to fee lessees. When production is not taken in kind, lessees under fee leases, although subject to an implied covenant to market, have not been required to do more than arrange for the sale of the product at the lease, if there is a market there. Merrill, "Covenants Implied in Oil and Gas Leases," 221 (2d ed. 1940). If there is no market at the lease, there is a split of authority as to whether the lessee is even obligated to construct facilities to use the production or transport it to market. Compare, Kretni Development Co. V. Consolidated Oil Corp., 74 F.2d 497, 500 (10th Cir. 1934) (the duty to make reasonable effort to market gas does not extend to the point of providing pipeline facilities ninety miles in length at a large outlay of money with an attending financial hazard due to possible exhaustion of the supply and other frequently encountered factors) with Union Oil Co. Of Cal. V. Ogden, 278 S.W.2d 246 (Tex. Civ. App. 1955) (lessee required to construct a pipeline to deliver gas to a market one-half mile distant). However, if the lessee does transport production to a distant market, the lessee is entitled to deduct its reasonable transportation costs in order to determine the value of the production at the wellhead where royalty value is to be calculated.

There is no dispute that fee lessees are not required to go into a separate business. As stated by Professor Merrill, "[o]f course there is no duty to go into a completely different business, such as the retail distribution of gas in a municipality." Merrill at 222. ***Similarly, as will be discussed in later portions of these comments, the purchasers at the nearest available market are engaged in a business entirely separate from the business in which oil and gas producers are engaged and there is no basis in the law for ever requiring oil and gas producers to engage in that business or for penalizing those who elect to do so.***

II. Two Separate Businesses

A. The Business of Exploration, Development and Production

The business of exploring for, developing and producing oil and gas (the "E&P Business") has always been recognized as an enterprise distinct from the business in which oil and gas purchasers are involved. The following summary of the exploration, development and production process was prepared from Williams and Meyers, Oil and Gas Law, Chapter 1 (Scientific and Engineering Background) (Matthew Bender 1997):

Exploration is the process of searching for underground formations favorable to the accumulation of oil and gas. Since there is no way to find oil and gas without drilling wells, the exploration process involves identifying prospects from generally available geological data such as regional surveys, surface geology reports, etc. From this data, geologists reduce the area of interest to a size that can be accommodated in a company's exploration budget. They use geophysical surveys or other methods to do this. With the geological and geophysical information available, land is leased and a decision made as to where to locate the first exploratory well. Title to the test area is examined and title defects cured before a well is drilled. If the well is a dry hole, data from the well is nevertheless obtained to add to the geologists' knowledge of the subsurface. Core tests and electrical well logs are obtained. With the new information supplementing the old, a second test well is located and drilled. The process of drilling, coring, and electrical logging goes on until a company's exploration budget is exhausted or petroleum is found. If a discovery is made, the remaining exploration problem is to establish the boundaries of the field.

The exploration process is an expensive one with wells costing between $100,000 and several million dollars and with only one wildcat out of nine a producer.

If a discovery is made, a new string of pipe, called casing, is run into the wellbore. The casing is then set by forcing oil well cement between it and the wall of the hole. After the cement hardens, the well is perforated by a special device that blows holes through the casing and cement, allowing the oil and gas to enter the well bore. Sometimes it is necessary to increase the flow of petroleum into the hole by acidizing or hydraulic fracturing the formation. The surface activities for completing an oil well consist of installing the Christmas tree (a complex set of gauges and valves controlling the flow of oil and gas from a well-head) and stock tanks and connecting the well with a pipeline, if one exists in the area. A variety of special equipment may also be installed to treat the oil prior to its delivery to the pipeline (such as heater-treaters and lease separators). If there is no pipeline the oil is shipped by truck or railroad to its destination, usually a refinery.

The primary assets of an E&P Company consist of its producing leases and its portfolio of undeveloped leases. The activities of an E&P Company are capital intensive since bonuses must be paid to acquire leases, rentals must usually be paid to hold undeveloped leases,
the cost of drilling an oil well runs from $100,000 to several million dollars with a success rate for wildcat wells of one out of nine, and there are on-going operating costs associated with a producing well. The revenue of an E&P Company comes from the sale of the production from its producing leases. An E&P Company, whether or not affiliated with a midstream marketer (described below) has no incentive to sell its production for less than its fair market value since the revenues from such sale are necessary for continued operations.

In addition to the dry hole risk, oil producers are subject to price risk based upon factors ranging from the quality of their production to the level of world production of oil. All of these risks affect wellhead oil prices and thus the income of the E&P Company.

B. The Business of the Oil Purchasers at the Nearest Available Market

In an article published in 1971 in the Twenty-Second Annual Institute on Oil and Gas Law and Taxation, Frank C. Bolton, Jr., General Counsel for the North American Division of Mobil Oil Corporation, described crude oil markets in the United States. He explained that there were essentially two crude oil markets, the primary market at the wellhead or lease stock tanks, and the secondary market in gathered crude oil.

With regard to the primary market, the sellers are the producers and royalty owners and the buyers are predominantly refiners and occasionally brokers or a combination of gatherers and brokers who purchase for resale. The point of sale (where a pipeline connection exists) is at the outlet side of the flange connecting the tank battery to the pipeline. Transportation from the stock tank is for the account of the purchaser and the purchaser takes the risk of loss after delivery. If there is no pipeline connection available, initial transportation from the stock tanks will be by truck. Some or all of these costs are usually reflected in the price which the seller realizes.

Selling oil at the tank battery if a pipeline connection exists or transporting oil from the stock tank to the nearest available market is the last stage of the E&P Business. What happens to the oil after that point is the business of participants in what Mr. Bolton called the secondary market. As described by him:

> The primary participants in this market in gathered crude are refiners with the broker-gatherer playing an important but relatively small part in the market. The refiners are each seeking the raw material for their refinery operations. The motivation of the integrated and non-integrated refiner is identical in that each is seeking the raw material supply best suited for the type of plant he has and at the lowest possible acquisition cost. Each refiner has a problem slightly different from any other refiner and thus, with reference to any particular volume of crude there may be motivation for a transaction. Why is this so? Because each plant is an individual problem, not only because of the hardware which is in the plant but because of its location and because of the product mix which that plant is at that time expected to make. Not only do refiners change their product by seasons - maximizing heating oil in the winter and gasoline in the summer - some refineries operate with a special product market; for example, jet fuel rather than gasoline may be the desired product. Add to these variables the facts that the refineries are not located at the same geographical sites and are not served by the same truck or pipeline systems, and you can begin to see the opportunities for saving cost in transportation or acquiring crude more suitable for the specific use of the individual refiner which motivates trades in the secondary market. The transactions which result may be categorized as exchanges, term transactions (usually between a non-refiner and a refiner), or spot sales.

Id. at 155-56.

Mr. Bolton also explains in detail that because above-ground storage at the lease is only sufficient for a few days' production and off-lease above-ground storage is expensive to erect and is only adequate for operation of the distribution systems and not for storage, buyers in the primary market must have a knowledge of transportation alternatives and crude requirements for each refinery, not just their own, in order to keep the product moving. Thus, the exchanges and other types of transactions which the MMS has observed are an operational necessity, not a royalty avoidance mechanism.

The foregoing discussion illustrates the fact that the purchasers of oil at the nearest available market are in an entirely separate business from the E&P Business. One of those purchasers, Scurlock Permian Corporation, filed comments on November 3, 1997, in response to the January 24, 1997, and September 22, 1997, notices of proposed rulemaking in this docket. In those comments, Scurlock Permian Corporation described its business as follows:

> SPC has its headquarters in Houston, Texas. SPC is a gatherer and marketer of crude oil in the United States. SPC employs over 900 people with operations in 15 states. SPC operates more than 2,400 miles of active crude oil gathering lines and pipelines. SPC also operates a fleet of more than 300 tractor-trailers to gather crude oil. SPC also has crude oil tankage at 154 onshore terminal locations plus 12 marine terminals.
>
> Neither SPC nor any of its affiliates, including its parent Ashland Inc., owns or leases significant crude oil producing properties. SPC holds no federal lease interests and no operating interest in any crude oil producing field. SPC is a third-party purchaser of crude oil utilizing outright purchase contracts (and division orders) and buy/sell exchanges.
>
> ...
>
> SPC, as an active lease oil purchaser, provides a market for oil produced by independent crude oil producers. SPC also conducts a portion of its business by offering buy/sell exchange contracts to creditworthy independent producers and major oil companies. These exchange contracts provide a service and efficiency to the domestic crude oil business by repositioning oil inventories to locations where buyers and sellers need volumes and wish to locate inventory at lower cost than, and in lieu of, straight transportation service.
>
> ...
>
> ... Exchanges offered by SPC provide a valuable service to crude oil buyers and sellers. The components of this service include purchasing and receipt of crude at the lease, in-field gathering by pipelines or trucks owned by SPC (or by others in some cases), scheduling movements on other pipelines, owning, carrying and maintaining a large crude oil inventory, and arranging sales at delivery points. SPC provides this service by taking title to the crude oil **and placing its assets at risk for price movements, potential loss or spill of pipeline crude oil and motor vehicle maintenance, potential breakdown, injury and spillage.**

SPC employs over 600 truck drivers, gaugers and other field personnel and about 200 office personnel. As mentioned above **SPC maintains a large capital investment in pipelines, trucks, equipment, tankage and real estate** and, in addition, **SPC must carry at considerable cost a very large investment in crude oil inventory** to provide for and facilitate these exchanges. Generally these exchanges are effectuated by SPC's transferring oil in and out of its inventory at appropriate locations, saving on actual physical transportation costs which are passed on to customers in the form of lower gathering and handling rates, and avoiding transportation delays and risks attendant thereto.

[Emphasis added.]

From the foregoing articles and comments, it is evident that the secondary or midstream market - between the wellhead on the one end and the market center or refinery on the other - adds value to the product above and beyond the cost of transportation from the wellhead to the refinery. Value is also added by the following services (each with its own risks):

Transportation
- Contracting for or providing transportation
- Scheduling of volumes
- Providing pipeline fill
- Tracking volumes delivered
- Providing credit services

Storage
- Constructing or leasing storage facilities
- Scheduling storage volumes
- Maintaining inventory

Risk Management
- Dealing with price fluctuations at or upstream of market centers
- Risk of loss of pipeline volumes
- Environmental liabilities for spills
- Risk of purchasers' default

Marketing
- Aggregating volumes
- Satisfying specialized customer quality preferences

C. The Duty to Market (Again)

It has never been previously suggested that producers have an obligation to be in the midstream marketing business in which SPC and others are engaged. Nor has it ever been previously suggested that royalty owners are entitled to royalties on the value of production at the *point of resale by a midstream marketer such as SPC. Finally, as SPC's comments illustrate, the value which SPC adds to the commodity extends far beyond the cost of transporting oil from the lease to SPC's resale points. SPC incurs costs in the operation of its business which extend far beyond the cost of such transportation. Nevertheless, the proposed oil valuation regulations in §102(a)(2) would require federal lessees selling to affiliates who are in the same business as SPC to pay royalties on their affiliate's arms-length resale prices with only a transportation allowance adjustment. It should be obvious that such regulations would unjustly discriminate against lessees who sell to affiliates since lessees who sell to unaffiliated midstream marketers, such as SPC, do not have to pay royalties on their purchasers' resale prices less only a transportation allowance. This point is discussed in more detail below.*

D. Why Affiliates Are Created

Implicit in the proposed oil valuation regulations is the assumption that affiliates are created to avoid royalty obligations. This is not the case. Every competent business lawyer knows to advise his or her client to consider creating affiliates when engaging in separate lines of business. Through the use of affiliates, a company can protect the assets of one enterprise from the business risks of another. This ability has been recognized by the Courts. As stated by the Tenth Circuit in the case of Cascade Energy and Metals Corp. v. Banks, 896 F.2d 1557, 1576 (10th Cir. 1990), "[t]he law permits the incorporation of businesses for the very purpose of isolating liabilities among separate entities." This ability has fostered progress by enabling companies to take risks which they might otherwise not be willing to take.

So strong is this right in the law to isolate liabilities through the use of affiliates, that the courts have held that only under extraordinary circumstances should the "separateness" of affiliated entities be disregarded. Franks v. U.S. West, Inc., 3 F.3d 1357, 1362 (10th Cir. 1993).

In the oil and gas context, the use of affiliates allows an E&P Company to separate the risks and liabilities of a midstream marketing business, including, for example, environmental liabilities for spills from the assets of the E&P Business so that the assets of the E&P Business are not at risk for those liabilities. Similarly, the use of affiliates allows a midstream marketing company to separate the risks and liabilities of an E&P Business, including, for example, the dry hole risk, from the assets of the midstream marketing business so that the assets of the midstream marketing business are not at risk for those liabilities. The ability to isolate liabilities benefits not only vertically integrated companies but also other forms of affiliation such as a company formed by a group of producers to participate in the midstream marketing business.

From the previous descriptions of the midstream marketing business, it should be obvious that that is a business very different from the E&P business. The midstream marketing business in which SPC and others are engaged clearly has its own risks, capital requirements, costs and rewards. **Business lawyers prudently advise their E&P clients who are considering going into the midstream marketing business to create an affiliate to engage in that business so as to protect the assets of the E&P business from the claims of creditors of the midstream marketing**

business. Isolating liabilities among separate entities is the motivating factor, not royalty avoidance, as the MMS apparently assumes from its proposed oil valuation regulations.

There are, thus, legitimate and, in fact, compelling business reasons for creating affiliates when engaging in the two separate businesses of E&P and midstream marketing. The government's presumption that the formation of affiliates is motivated by the desire to avoid royalty obligations is simply not the reason why affiliates are formed. In fact, in many transactions which will be irrebuttably presumed to be affiliate transactions under the proposed new definition of affiliate (irrebuttable presumption at only 10% ownership), there is not even an economic incentive to price production below market value. This was recognized by the Interior Board of Land Appeals in Shell Western E&P Inc., 112 IBLA 394 (1990) in which the Board stated that while:

> economic incentives exist which might impel producers to shift profits to wholly owned subsidiaries as a means of decreasing royalty obligations ... the economic viability of such a strategy declines where, as here, outside interests in the subsidiary are substantial. Thus, while a parent corporation might well desire to have profits transferred from one corporation to another in an attempt to lessen royalty payments of 12.5 percent on the value of production, the incentive to do so when the parent corporation owns only 50 percent of the second corporation evaporates, since such a procedure results in the net loss of 37.5 percent.

Id. at 400 n. 4.

Furthermore, even in those situations where there could technically be an economic incentive to shift profits, there are ***other more compelling checks in the law*** which discourage any such abuse of the relationship between affiliates. For example, the objective of isolating liabilities among separate entities is entirely defeated if the two entities are judicially declared to be alter egos of each other. Further, the doctrine of piercing the corporate veil allows a court to disregard the separate corporate entities where, for example, a subsidiary is a mere agency, instrumentality, or a adjunct of the parent corporation. 18A Am.Jur.2d Corporations §856 at 732. Further, where there exists minority shareholders, applicable law requires that their interests be protected. Therefore, where the separate existence of the affiliated entities in a marketing transaction has been suitably maintained, there should be less of a concern that the transaction is a sham transaction from a royalty perspective. In fact, because of fear of creating grounds for piercing the corporate veil or giving rise to minority stockholder claims, negotiations between affiliated companies can often be more adversarial than negotiation with third parties.

III. Who is an Affiliate (A New Irrebuttable Presumption)

There are numerous statutory, regulatory and case law definitions of affiliate, all involving the concept of control by one person or entity of another person or entity. Black's Law Dictionary defines affiliate as a company effectively controlled by another company. [Emphasis added.] Note that this definition is not limited to corporations and is broad enough to include other types of business entities. The concept of control is often defined in contracts to mean possession, directly or indirectly, of sufficient power to direct or cause the direction of management or policies of another person or entity.

Under the oil valuation regulations which have been in effect since 1998 (the "1988 Valuation Regulations"), affiliate is defined as follows:

> Two persons are affiliated if one person controls, is controlled by, or is under common control with another person. For purposes of this subpart, based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership: (a) ownership in excess of 50% constitutes control, (b) ownership of 10 through 50% creates a presumption of control, and ownership of less than 10% creates a presumption of noncontrol which MMS may rebut if it demonstrates actual or legal control, including the existence of interlocking directorates.

30 C.F.R. §206.101.

In the proposed oil valuation regulations, the MMS proposes to change its definition of affiliate to provide that an affiliate is a "person who owns, is owned by, or is under common ownership with another person to the extent of 10 percent or more of the voting securities of an entity, interest in a partnership or joint venture, or other forms of ownership." This proposed regulation creates an irrebuttable presumption that ownership in excess of 10 percent constitutes affiliation and would literally mean that a 10% minority shareholder in a closely held corporation would be deemed to be dealing with an affiliate when it sold its own oil production to such corporation.

This proposed definition ignores the concept of what constitutes "effective control" used elsewhere in the law. The proposed definition is then used in the definition of "arms'-length contract" to exclude from the definition of "arm's-length contract" agreements between persons who are affiliates. The irrebuttable presumption created by the proposed definition of "affiliate," coupled with the proposals for valuation of oil sold to an affiliate, will penalize producers who sell to affiliates whether or not they have any effective control of their affiliates. This result is unreasonable.

IV. Selling to an Affiliate (More Irrebuttable Presumptions)

As explained by the MMS in the preamble to the proposed oil valuation regulations, the conceptual framework of the proposed rule is that if oil is ultimately sold at arm's length before refining regardless of the distance from the lease and without regard to risks undertaken or value added by the seller, it will generally be valued on the gross proceeds accruing to the *seller* (not the *lessee*) under the seller's arm's-length resale. 63 Fed. Reg. 6115. This means that if a lessee sells its oil to an affiliate and the affiliate resells the oil in an arm's length transaction before refining, the value of the oil sold by the lessee will be based upon the gross proceeds from the affiliate's resale. The effect of this proposal is to create an irrebuttable presumption that the lessee's selling price does not represent the value of the product. Even if the proposed definition of affiliate were reasonable, this presumption is not.

A. Existing Law (Netback Only As a Last Resort)

Even if two entities are affiliates in fact (i.e., one entity effectively controls the other), the law has never presumed that ordinary commercial transactions between the two are not arm's-length. As stated in 18A Am.Jur.2d Corporations Section 798:

> In transactions between a parent or controlling corporation and a subsidiary or affiliated corporation involving the purchase or sale of products or services by the former from the latter, the critical factor is the fairness of the challenged transaction, and to determine fairness, courts consider the market price of the goods sold if one is ascertainable, whether the corporation received full value in all the commodities purchased, the extent of dominance by the controlling corporation, who initiated the complained of transactions, and more generally whether reasonable and disinterested directors would have assented to the transactions.

Thus, for example, in Gootesman v. General Motors Corp., 279 F.Supp. 361, remanded on other grounds, 414 F.2d 956 (2nd Cir. 1969), on remand, 310 F.Supp. 1257 (S.D. N.Y. 1970), aff'd 436 F.2d 1205 (2nd Cir. 1971), cert. den. 403 U.S. 911, 29 L.Ed. 2d 689, 91 S.Ct. 2208 (1971), reh. den. 404 U.S. 876, 30 L.Ed.2d 125, 92 S.Ct. 29 (1971), a derivative action by minority stockholders of General Motors Corporation against E. I. du Pont de Nemours & Company, the claim was made that by reason of du Pont's 23% stock interest in GM, du Pont dominated and controlled GM in the purchase of du Pont products. The issues in the case were whether du Pont controlled GM to the extent that it (i) entrenched itself as the primary supplier to GM of automotive fabrics and finishes, (ii) insulated the GM market from free competition in these products, and (iii) as the result of such activity, caused injury to GM. Id. at 363. The Court found that du Pont's ownership of 23% of GM's stock gave it the power to control GM because of the unrelated ownership of the balance of the shares (i.e., ownership of the remaining shares were widely scattered). Id. at 368. **Note, in contrast to MMS' proposed irrebuttable presumption of ownership at as little as 10%, that the Court made a specific finding of fact on the question of control rather than basing its holding on any presumption of control above a certain percentage of ownership.**

However, the Court did not jump from the fact that du Pont had the power to control GM to the conclusion that this power had been improperly exercised. Instead, the Court examined the evidence to determine whether du Pont directed the purchasing practices of GM and concluded from an examination of the operational structure of GM that such direction would have been difficult and in fact did not exist. Id. at 370. This was because of the decentralization of authority at GM in the field of operations. General managers of each independent operating division had the authority and responsibility of a chief executive of an independent corporation and were judged by the results achieved. **It is submitted that affiliates are even more likely to be judged by results achieved than divisions of a single entity.**

In response to a claim that du Pont had a fiduciary duty to GM by virtue of the membership of its designees on the Executive Committee and Policy Committee of GM, the Court concluded that it did not need to decide whether that was enough to impose a fiduciary duty on du Pont because, in any event, any such duty had not been breached. The Court found:

> The business relationships growing out of the sale of automotive fabrics and finishes by du Pont to General Motors were completely unrelated to the stock interest that du Pont held in General Motors. These sales and purchases resulted from arm's length transactions under competitive conditions. The prices paid by General Motors were market place prices. The quality of the products and the service that was furnished with the products were equal to if not better than what was available in the market place.

Id. at 384-5. Nowhere in this decision did the Court presume an improper exercise of control. It examined the facts of the case to reach its conclusions.

A similar methodology has been used by the courts to evaluate other types of transactions between affiliated entities. See, Spach v. Brant, 309 F.2d 886 (C.a. Fla. 1962) (test of validity of transaction between stockholder and corporation, giving proper consideration to all surrounding circumstances, is whether transaction has earmarks of arm's length bargain); Stearns Magnetic Mfg. Co. v. Commissioner of Int. Rev., 208 F.2d 849 (7th Cir. 1954) (an agreement between a corporation and its sole stockholder is valid if the arrangement is fair and reasonable judged by standards of a transaction entered into by parties dealing at arm's length); Holahan v. Henderson, 277 F.Supp. 890 (D.C. La. 1967) (essence of test for determining validity of transaction between corporation and its sole owner is whether or not, under circumstances, the transaction carries the earmarks of an arm's length bargain); In re Kentucky Truck Sales, Inc., 52 B.R. 797 (Bkrtcy. Ky. 1985) (transaction between controlling shareholder and corporation is always subject to close scrutiny, but it is not per se invalid; if terms are basically fair, then the effects of that transaction are the same as if they occurred between any two unrelated parties)

Similarly, in the context of sales of production by a fee lessee to an affiliate, the case law shows that there is no presumption of unfairness in the selling price. No case has been found in which the mere existence of a sale to an affiliate constituted a per se breach of the express or implied marketing covenants in a fee lease.[2] Nor should there be any such case. As so clearly explained in

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[2] One court has made a statement *in dicta* which suggests otherwise. In Tara Petroleum Corp. v. Hughey, 630 P.2d 1269 (Okla. 1981), in response to a claim that the lessee and the gas purchaser were related entities, the Court stated, "Courts should take care not to allow lessors to be deprived or defrauded of their royalties by their lessees entering into illusory or collusive assignments or gas purchase contracts. Whenever a lessee or

one of the earliest implied covenant cases, Brewster v. Lanyon Zinc Co., 140 F. 801 (8th Cir. 1905), what is required by the implied covenant to market must be determined from all of the factual circumstances and pertinent business practices. Similarly, whether market value (under a market value type of gas royalty clause) or a fair and reasonable price (under a proceeds type of gas royalty clause) has been obtained, is also a question of fact. Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225 (5th Cir. 1984).

Thus, for example, in Parker vs. TXO, 716 S.W.2d 644 (Tex. App. 1986), a case involving the sale of gas produced by Texas Oil & Gas Corporation ("TXO") to its subsidiary, the Court did not presume that the selling price was unfair even though, eventually, Delhi installed compressors to better deliver the gas from the wells into Delhi's pipeline system and began to charge TXO 5% of the gross proceeds resulting from the sale of the gas as a compression fee. Although the evidence was that the Delhi contract price was the maximum legal rate for the gas, less the 5% compression charge, whereas other purchasers in the area were paying the maximum legal rate without any deductions, the trial court ruled in favor of TXO. This ruling was sustained on appeal under the reasonably prudent operator standard. The Appellate Court reviewed the testimony regarding the reasons for the sale to Delhi. The testimony established that the sale to Delhi was arranged in haste because of drainage of the field by the other operator's well, that other potential markets were considered but Delhi was chosen partly because of its reputation for being capable of handling large amounts of gas, that TXO did not concern itself with Delhi's possible profit or loss on a well, that other unaffiliated sellers were accepting terms similar to those which Delhi offered, that Delhi bought more gas from others than from TXO **(a fact also true in many sales of federal lease production to affiliates)** under similar contract terms, that the compression term was viewed by TXO as a means to increase production, and that the compression term was a standard contract term offered by Delhi to all producers. The Appellate Court of Appeals concluded that there was sufficient evidence in the record to support the finding of the trial court that TXO acted in good faith, and as a reasonably prudent operator.

The royalty owners also argued that the trial court should have pierced the corporate veils of TXO and Delhi and concluded that the sale of gas to Delhi was a sham transaction. The Court of Appeals disagreed, stating that while there was evidence that the corporations involved had some

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assignee is paying royalty on one price, but on resale a related entity is obtaining a higher price, the lessors are entitled to their royalty share of the higher price. The key is common control of the two entities." Id. at 1275. Although the use of the word "whenever" suggests an absolute rule, the statement as a whole shows a concern for illusory or collusive gas purchase contracts. If a lessee makes a sale at the wellhead to an affiliate at a price which is the same as the lessee would have received in an arm's-length transaction, that is not an illusory or collusive sale. There is no reason to believe that courts in Oklahoma would hold otherwise. See, Craig v. Champlin, 435 F.2d 933 (10th Cir. 1971) (applying Oklahoma law).

of the same directors, there was no evidence that Texas Oil and Gas treated Delhi as anything but an independent company.

This case illustrates that the mere existence of an affiliate in a transaction should not be considered a per se breach of the express or implied covenants of a lease and that the question of whether a breach has occurred should be determined applying the same principles as with arm's length sales, i.e., by considering the facts and circumstances of the case and what a reasonably prudent operator in the lessee's shoes would have done to market the gas.

There have also been several cases involving sales at the wellhead where affiliates provided downstream services (gathering or processing) and courts have allowed the lessees to pay royalties on their wellhead sales price. In each of these cases, the Courts examined the reasonableness of the charges of the affiliates rather than presuming unfairness. See, for example, Craig v. Champlin Petroleum Co., 435 F.2d 933 (10th Cir. 1971) (involving a joint venture to construct a gasoline plant; Champlin was a 51% owner and the operator of the plant); Kretni Development Co. v. Consolidated Oil Corporation, 74 F.2d 497 (10th Cir. 1934) (holding that the sales price represented the market value in the field and that the lessors were not entitled to any portion of the transportation charges received by the lessee from its 50% ownership in transportation facilities connecting its field to the facilities of its wellhead purchaser); and Barby v. Cabot Corporation, 465 F.2d 11 (10th Cir. 1972) (holding that the lessors were not entitled to share in the proceeds from the lessee's sale of liquids less reasonable processing costs where the lessee sold gas at the well in an arm's-length transaction but reserved and exercised an option to process the gas).

These cases also illustrate the principle that the duty to obtain the highest price obtainable by the exercise of reasonable effort (a standard statement of the implied covenant to market) does not require the lessee to sell gas to a more profitable downstream market when there is a market at the well.

Finally, until the proposed oil valuation regulations, it has never been the practice with federal lessees to presume by virtue of a sale to an affiliate that the sales price does not represent the reasonable value of the production. To the contrary, even before the 1988 Valuation Regulations were adopted, the selling price in a transaction between affiliated companies could be used as the royalty value if it was comparable to the price negotiated between nonaffiliated parties of adverse economic interests. Getty Oil Co., 51 IBLA 47 (Oct. 31, 1980) (a contract, if the same as others with unrelated parties, will be treated as establishing fair market value). See also, PanEastern Exploration Co., GS-156-O&G (Mar. 10, 1980) (where it is determined that the price of gas sold by a wholly owned subsidiary to the parent company was arrived at in an arm's-length manner, the price should have been accepted for royalty computation purposes); Gas Producing Enterprises, Inc., GS-174-O&G (Mar. 16, 1981) (a contract for the sale of gas between a seller lessee company and a purchaser who owns controlling interest in the seller will be treated as establishing a fair market value if the contract is the same as others with unrelated parties).

Where the selling price is not comparable to other arm's-length transactions, the practice has still never been to jump immediately to the affiliates resale price to value production. Instead, value based upon comparable sales are used. For example, in the case of Transco Exploration Co., 110 IBLA 282, 96 I.D. 367 (1989), GFS (OCS) 144 (1989), Transco Exploration Co., a 15% working interest owner in a federal lease, entered into a gas sales contract with its interstate pipeline affiliate, Transcontinental Gas Pipeline Corporation. The original contract entered into in 1977 was held to represent fair market value because it resulted in a price reflective of the other contracts entered into at that time. Id. at 286, fn. 2. Specifically, it resulted in a price which was comparable to the prices received by the other working interest owners in the lease.

At issue in the case was the voluntary action of Transco in reducing the price Transcontinental had to pay for Transco's gas. This action was taken in response to the adverse market conditions Transcontinental was experiencing in the early 1980s which were common to many interstate pipelines. The other working interest owners in the lease refused to voluntarily reduce their prices. Instead, through annual price redetermination and quarterly price escalations, they renegotiated and obtained higher prices during the period.

The Director of the MMS determined that the prices which were received by Enstar, a 45% working interest owner in the lease, represented the reasonable value of production under the applicable regulations. The IBLA agreed in a lengthy decision which contrasted the actions of Enstar in its arm's-length dealings with Transcontinental with those of Transco in virtually identical situations. Nowhere in this lengthy decision was there any suggestion that the gross proceeds received by Transcontinental on resale were relevant to the inquiry.

B. Proposed Rule (Netback As The Only Resort)

Notwithstanding the foregoing overwhelming weight of authority, the MMS is now proposing the netback method as the only allowable valuation method when oil is not sold in an arm's-length sale prior to refining. The effect of the proposal is to create an irrebuttable presumption that the lessee's selling price does not represent the value of the product at the lease and that the only way to determine such value is through the netback methodology. This is not reasonable. Outside this proposal, the view of the courts has been that only if there are no comparable sales or a current market price, must the courts look to other factors to establish market value at the well. In this situation, the workback or netback method may be used.

The netback method has historically been reserved to the method of last resort because it is more difficult to apply. In Ashland Oil, Inc. v. Phillips Petroleum Co., 554 F.2d 381, 387 (10th Cir. 1975) the Court stated that "the comparable sales-current market price is by far the preferable method when it can be used" and that the netback or "work-back" valuation method "is more difficult to apply." Similarly, the MMS has previously characterized that the routine use of a net-back analysis was impractical and labor-intensive. Preamble to the 1988 Valuation Regulations, 53 FR 1184, 1201, 1203. Nevertheless, the MMS is now proposing that methodology in §102(a)(2) to value production sold or transferred to an affiliate and resold by the affiliate under an arm's-length contract. (MMS is also proposing that methodology in §103(b)(2) - the second valuation benchmark for the Rocky Mountain Area).

V. Calculating a Netback Value (What's in a Name?)

Under the netback method, a point is selected where there is an established price and the value added between the lease and the selected point is subtracted in order to determine the value at the lease. See generally, Ashland at 387. The object of the netback valuation method is to arrive at the same value at the wellhead as if the lessor had taken its share of production in kind or the lessee had sold the production at the lease in an arm's-length sale. This purpose has been recognized in the context of valuation of production for federal lessees as previously discussed in Section I of these comments.

A. Proposed Section 102

In the proposed oil valuation regulations, the MMS is proposing to depart from the principle that it is not entitled to any of the profits of downstream activities. For oil valued based upon the gross proceeds in the first arm's-length sale prior to refining, the only allowed deduction is the reasonable, actual costs to transport oil from the lease to that point of sale. Proposed §109(a). This means that if two working interest owners in a federal lease sell their share of oil production at the lease for the same selling price, but one sells to an affiliated midstream marketer and the other sells to an independent marketer, such as Scurlock Permian Corporation, there will be a significant difference in the value on which royalties will be owed.

Scurlock Permian Corporation will calculate the price it is willing to pay based upon all of the costs of its midstream marketing business, not just transportation, and will also include a profit for itself. The working interest owner selling to Scurlock Permian Corporation will be able to value its oil production for royalty purposes based upon its gross proceeds from Scurlock Permian Corporation. The working interest owner selling to its affiliate in the midstream marketing business will have to start with its affiliate's arm's-length resale price and will only be able to subtract transportation costs to the point of resale. This result is unreasonable and discriminatory.

If the proposed regulations are adopted, it will be the rule rather than the exception that oil production from a particular federal lease will have to be valued based upon an affiliate's arm's-length resales of many times the quantity of that purchased from the lease. It is the common practice in the midstream marketing business for the marketer, prior to making any resales, to aggregate and commingle oil production from leases (federal, fee, state and Indian) covering wide geographic areas (multiple states would not be uncommon) with such production typically varying in price, duration, terms, quality, volume and other factors. Under the proposed rule, royalties would in effect be payable on the "weighted average value" of the commingled production, not on the value of the oil purchased at a particular federal lease.

B. Proposed Section 103

For oil which is not sold in an arm's-length transaction by the lessee or an affiliate prior to refining, value must be based upon the index pricing in section 103 of the proposed regulations (with certain exceptions for Rocky Mountain production). Against such index pricing, the MMS is only proposing to allow a deduction for certain location and quality differentials and certain transportation costs. See proposed §§ 112 and 113. Again, these deductions are insufficient to cover all of the value added by midstream marketers which is reflected in the index prices. Furthermore, the differentials between various locations are in constant flux, thus assuring that the location/quality differentials determined by MMS based upon the weighted average reported differentials for a previous reporting year will never accurately reflect the current market. Therefore, this is unreasonable and discriminates against lessees who deal with affiliates.

C. When "Marketing" Is Deductible Under the Mineral Leasing Laws

The royalty payment obligations of a federal lessee do not justify these proposed rules. As described in detail above, the activities of the companies who purchase oil at the nearest available market are very different from those of producers. While those purchasers perform midstream marketing services for the oil and gas industry, the "marketing" which they perform is not the duty of any federal lessee. The midstream marketing business is an entirely separate business.

That the midstream marketing business is a separate business from the E&P business is most dramatically illustrated by the fact that producers who sell their production at the wellhead in an arm's-length transaction are not required to add to the selling price any of the costs of their purchaser's mid-stream marketing business. If the purchaser were performing a service which was part of the federal lessee's obligations, the producer would have to add the costs of such service to its selling price. Exxon Co. v. U.S.A., 121 IBLA 234, 247 (1991). Thus, although the activities of midstream marketers are called "marketing," the costs of such activities must be fully deductible in order to arrive at a value at the wellhead.

It is improper to attempt to fit the activities of midstream marketers into the historical labels of deductible "transportation" or nondeductible "marketing." These labels have been sufficient under the current and prior regulations because the government has not previously attempted to determine royalty value by starting with the resale price in the secondary or midstream market or MMS-selected index points. Where the only issue was how to determine value at the wellhead when there was no market at the wellhead and the lessee had to transport its crude oil to the nearest market, allowing a deduction for the costs of transportation (including a return on investment) was sufficient to calculate a wellhead price. No midstream marketing activities were occurring in such a situation. The netback price calculated by taking the sale price in the nearest market and subtracting transportation costs was, in that situation, equivalent or reasonably equivalent to the price the lessee would have received had there been a market at the well. In that situation, it was also equivalent or reasonably equivalent to the value the government would have realized had it taken its oil in kind at the lease.

However, under the proposed oil valuation regulations, the MMS is now proposing to start its netback calculation with the resale price in the secondary or midstream market under section 102(a)(2) or with MMS-selected index prices under section 103. The MMS cannot simply assume that the only value added in the section 102 situation is "transportation" or that the MMS-proposed location and quality differentials plus authorized transportation allowances capture all of the value added in the section 103 situation. In order for the MMS' proposed regulations to be lawful under the mineral leasing statutes, the MMS must allow a deduction for all of the costs involved in the midstream marketing business and for a profit in that business (for section 102 transactions) and for all of the value added reflected in the MMS-selected index prices (for section 103 transactions) ***even though such activities are called "marketing."*** That is the only way to achieve equivalency or reasonable equivalency.

Again, the government is only entitled to a royalty in amount or value of the production at the lease. It is not entitled to a royalty on any value which the product realizes away from the lease. The only way to limit the royalties to what the government is entitled to receive under the mineral leasing laws is to allow a deduction for all of the value added by the midstream marketing business, whether such value is reflected in an affiliate's arms-length resale price or in an MMS-selected index price. See again, the discussion of the Petro-Lewis case in Section I of these comments.

VI. What is the Effect of the Proposed Oil Valuation Regulations?

A. Excessive Royalties

As explained in the prior section, the effect of the proposed oil valuation regulations is to increase the value of oil for royalty purposes in those situations where the lessee does not sell the oil in an arm's length transaction. This increase in value is the result of :

1. Basing royalty value on either (i) an affiliate's gross proceeds from the arm's-length resale of the oil in the secondary or midstream market, or (ii) specified indices where the oil is not sold in an arm's-length sale before refining, and

2. Not allowing a deduction for all of the costs of the aggregation and other value activities which occur between the lease and the proposed starting points for a netback calculation.

That this is unreasonable is evidenced by that fact that if the lessee sold its oil production at the lease in an arm's-length transaction, its sales price would reflect a deduction for all of the costs of its purchaser's midstream marketing business and a profit as well. The proposed oil valuation regulations are thus unreasonable.

B. Discriminatory Royalties

Additionally, because the proposed oil valuation regulations will result in more royalties being paid by federal lessees who sell their production to an affiliate than the lessees who sell identical production in arms-length transactions at the lease, the proposed oil valuation regulations are improperly discriminatory. This situation appears to be similar to the situation addressed by the IBLA decision in Shell Western E&P, Inc., 112 IBLA 394, 399, GFS(O&G) 5 (1990), which involved the issue of whether Federal and state income taxes could be deducted as part of the actual costs of transportation incurred by a lessee for transportation of CO2 by its affiliate. The MMS took the position that they could not. The IBLA disagreed on the grounds that the MMS was arbitrarily and without justification imposing a penalty on lessees who are affiliates of pipeline owners because the MMS allowed the deduction of Federal and state income taxes as transportation costs for the lessees who were not affiliated with the pipeline owners.

This potential for discrimination was recognized by the MMS in connection with the current valuation regulations. In the preamble to the 1988 Valuation Regulations, the MMS responded to an industry comment that "the prioritized benchmark system 'imposes a prejudicial valuation on an affiliated lessee' because a nonaffiliate receiving the same price as an affiliate would pay on actual proceeds received, whereas the affiliate may have to pay a higher royalty under, for example, benchmark 206.102(c)(2)." 53 FR 1184, 1202. The MMS responded that, "[t]he situation described could occur." Id. However, the MMS was not concerned about that potential under the 1988 Valuation Regulations. The MMS stated, "[h]owever, MMS believes that, generally, posted prices for like-quality oil in the same field or area will be comparable. Thus, there likely will be little or no disparity in the values in most situations." Id. As discussed above, the same cannot be said for the proposed oil valuation regulations. The proposed regulations guarantee that there will be disparity in value in most situations.

C. Royalties on Value at Other Leases

Because it is the exception, rather than the rule, that an affiliate will resell the lessee's oil production from a federal lease without commingling that production with other oil from other leases, proposed section 102(a)(2) will result in royalties being paid on a weighted average value of the commingled production rather than the value of the oil from the federal lease. This is the same result when value is determined starting with an MMS-selected index price under section 103.

D. Exception Authority Not a Cure

In the preamble to the proposed oil valuation regulations, the MMS stated that if a lessee could demonstrate to MMS' satisfaction that the section 103 benchmarks for valuation of production from leases in the Rocky Mountain Area result in an "unreasonable value" as a result of circumstances regarding that production, the MMS Director could establish an alternative valuation method. However, the MMS proposed this as the last alternative "to be used only in very limited and highly unusual circumstances." 63 Fed. Reg. 6119 (Feb. 6, 1998). Similarly, the proposed oil valuation regulations provide that a lessee may apply to the MMS Director for approval to use a value representing the market at the lessee's or its affiliate's refinery if it believes that use of the index price is unreasonable. §206.103(e). There is similar authority to a transportation allowance in excess of the limitations in the proposed rules or to propose a cost allocation method. Section 109(c)(2), section 110 (b)(2).

These provisions are not sufficient to overcome the problems with the proposed oil valuation regulations identified above. These problems apply across the board to all producers who do not make arm's-length sales prior to refining. These problems are not the exception but the rule. Therefore, authority to provide for approval to use alternative values in certain situations will not address all of the other situations adversely and unfairly impacted by the proposed rules.

VII. Conclusions

The government is only entitled to the amount or value of its share of production at the lease. It is not entitled to more than its share of production would bring if it took that share in kind at the lease. Whether or not the government desires to actually take its royalty share in kind, lawful oil valuation regulations must limit the value of crude oil to the value at the lease which the government could have realized had it taken its royalty share in kind and sold it at the lease. If the government wants royalties on more than that value, it can take its royalty share in kind and become involved in the midstream marketing business or contract with entities in that business. The proposed oil valuation regulations are designed to establish a royalty value much higher than the equivalent take-in-kind value at the lease in all situations where oil is not sold by the lessee in an arm's-length transaction. The irrebuttable presumption of control from ownership of as little as 10%, the irrebuttable presumption that the selling price in a non-arm's length transaction does not represent the value of the oil, the irrebuttable presumption that only the netback methodology, starting with an affiliate's arms-length resale or index prices, can be used to determine value at the lease, and the disallowance of all of the costs associated with the value added by midstream marketing activities beyond the lease causes the proposed oil valuation regulations to be arbitrary, capricious, an abuse of discretion and not in accordance with the mineral leasing laws.

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Attachment 6

DEPARTMENT OF THE INTERIOR

U. S. GEOLOGICAL SURVEY

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[illegible] AND GAS

[illegible] of February 25, 1920 ([illegible] Stat. 437); Act of June 4, 1920 ([illegible] Stat. [illegible]) and Act of March 4, 1923 (42 Stat. 1448); and under special [illegible] by the United States

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CONTENTS

FORMS

OPERATING REGULATIONS TO GOVERN THE PRODUCTION OF OIL AND GAS UNDER THE ACT OF FEBRUARY 25, 1920; THE ACT OF JUNE 4, 1920; THE ACT OF MARCH 4, 1923; AND UNDER SPECIAL AGREEMENT BY THE UNITED STATES [1]

INTRODUCTION

DEFINITIONS

The following terms as used in these regulations shall have the meanings here given:

Supervisor.—An agent appointed by and with the power to act for the Secretary of the Interior under the direction of the Director of the United States Geological Survey, in supervising all operations under these regulations within the district to which he is assigned.

Representative, local representative—Any employee of the Department of the Interior who is designated by a supervisor to act for him in any specified part or all of the supervisor's district.

Lessee.—Any holder of an oil and gas prospecting permit or lease issued under the general leasing act of February 25, 1920 (41 Stat. 437), the naval appropriation act of June 4, 1920 (41 Stat. 812, 813), or the act of March 4, 1923 (42 Stat. 1448), or under special agreement by the United States.

Permittee.—The holder of an oil and gas prospecting permit and a potential if not actual lessee who is regarded as such and is subject to the provisions of these regulations in so far as they are applicable to his operations.

Leased lands, leased premises, leased tract.—Any lands or deposits occupied under permit or lease granted to a lessee.

WITH WHOM TO DEAL

In matters pertaining to drilling and producing operations and to the handling and gauging of oil or gas the lessee should deal with the supervisor or his representative in the district where the land under permit or lease is located. Should the lessee not know with whom to deal, he should inquire by letter to the Director, Geological Survey, Washington, D. C.

PURPOSE OF SUPERVISION

The supervisor and his representatives will require that lessees comply with these regulations and conduct their operations in a manner [illegible] Inasmuch as any specific and [illegible] for one field or even most fields may not be applicable to certain other fields, the following regulations are purposely broad in scope, the details of interpretation being left to the supervisor. Where they are adaptable, the suggestions for efficient operating discussed in Manual for Oil and Gas Operations (Bureau of Mines Bulletin 232) will form the basis of the department's policy and requirements.

SECTION 1. POWERS AND DUTIES OF SUPERVISOR

It shall be the duty of the supervisor directly or through his representatives—

(a) To visit from time to time leased lands where operations for the discovery or production of oil and gas are conducted, to inspect and supervise such operations with a view to preventing waste of oil and gas, damage to formations or deposits containing oil, gas, or water or to coal measures or other mineral deposits, injury to life or property, or economic waste; and to issue, in accordance with the provisions of the lease and these regulations, such necessary instructions to lessees as will effectively prevent such waste or damage.

(b) To make reports to the Director of the Geological Survey as to the general condition of the leased property and the manner in which operations are being conducted and the departmental orders are being obeyed, and to submit from time to time information and recommendations for safeguarding and protecting the surface property and the underlying mineral-bearing formations.

(c) To prescribe the manner and form in which all records of operations, reports, and notices shall be made by lessees.

(d) To require that tests shall be made to determine the presence of oil and gas, as well as the presence of oil, gas, or water in a well, and to prescribe or approve the methods of making such tests.

(e) To require the correction, in a manner to be prescribed or approved by him, of any condition existing subsequent to the completion of a well which is causing or is likely to cause damage to any formation bearing oil, gas, or water or to coal measures or other mineral deposits or which is dangerous to life or property or wasteful of oil or gas.

(f) To determine the percentage of the potential capacity of any gas well which may be utilized when, in his opinion, such action is necessary to protect the gas-producing formations. He shall likewise specify the time and method for determining the potential capacity of gas wells.

(g) To assist and advise lessees making tests and carrying on experiments for the purpose of increasing the efficiency of operation.

(h) To compile records of production of oil, gas, and natural-gas gasoline and to compute and report the amount and value of accrued royalties.

(i) To sign division orders granting pipe-line companies authority to receive oil from producing leased lands in accordance with Government rules and regulations; to sign run tickets or receipts of other forms for royalty oil delivered to an agent of the United States or to the Government direct.

(j) On receipt of application for relief from any drilling or producing requirement under a lease, (1) to forward such application, together with his report and recommendation thereon, to the Director of the Geological Survey, and, pending action by the Secretary, to grant such temporary relief as he may deem warranted in the premises, or (2) to reject such application subject to the right of appeal as provided in section 6 hereof.

(k) To require, by written notice, immediate suspension of any operation or practice contrary to the requirements of these regulations or to the written orders of the supervisor or his representative until the lessee shall have complied with such requirements or orders.

UNITED STATES
DEPARTMENT OF THE INTERIOR
Washington

January 20, 1931.

ORDER NO. 482.

Section 1(h) of the Operating Regulations to Govern the Production of Oil and Gas under the Act of February 25, 1920 (41 Stat. 437); Act of June 4, 1920 (41 Stat. 812); and Act of March 4, 1923 (42 Stat. 1448); and under special agreement by the United States, revised and approved July 1, 1926 (52 L. D. 1), is hereby amended to read as follows:

(h) To compile records of production and determine the amount and value of royalty, to estimate drainage and compute losses to the United States resulting therefrom, and to estimate the amount and value of natural gas wasted. The supervisor shall order payment to the United States by means of a statement rendered monthly to each lessee or his representative showing for his lease the amount of oil, gas, and natural gas gasoline produced and the amount due the United States as royalty; the losses by reason of estimated drainage and the compensation due the United States as reimbursement; and, except as to any disposal of natural gas that shall have been determined by the Secretary of the Interior to be sanctioned by the laws of the United States and of the State in which it occurs, the amount and full value computed at a price of not less than 5 cents per 1,000 cubic feet of all natural gas wasted by blowing, release, or escape into the air, or otherwise. Statements so rendered shall be subject to the right of appeal as provided in section [illegible] of these regulations.

RAY LYMAN WILBUR,

Secretary.

(*l*) To receive and transmit promptly to the Director of the Geological Survey, for review by the Secretary of the Interior, all appeals from his written orders, together with his report in the premises. (See sec. 6.)

SECTION 2. REQUIREMENTS FOR LESSEES (INCLUDING PERMITTEES)

(*a*) The lessee shall conform to the terms of the lease or permit and regulations and to the written instructions of the supervisor or his representatives and shall take precautions to prevent waste of oil or gas, damage to formations or deposits bearing oil, gas, or water or to coal measures or other mineral deposits, injury to life or property, or economic waste.

(*b*) The lessee shall designate in writing the name and post-office address of a local or resident representative for each permit or lease, on whom the supervisor or other authorized representative of the Department of the Interior may serve notice or with whom he may otherwise communicate in securing compliance with these regulations. The resident representative of the lessee shall be designated before drilling or other operations are begun. If said designated local or resident representative shall at any time be incapacitated for duty or absent from his designated address, the lessee shall designate in writing a substitute to serve in his stead, and in the absence of such representative or of written notice of the appointment of a substitute, any employee of the lessee who is on the leased premises or the contractor or other person in charge of operations shall be considered the representative of the lessee for the service of written orders or notices as herein provided, and service in person or by ordinary mail upon any such employee, contractor, or other person shall be deemed service upon the lessee. All changes of address of the designated representative shall be immediately reported, in writing, to the supervisor or his local representative.

(*c*) The lessee shall not drill any well within 200 feet of any of the outer boundaries of the land covered by a permit or lease except as may be necessary to protect himself against offset wells on lands the title to which is not held by the United States of America, and then only on consent first had in writing from the supervisor or his representative.

(*d*) The lessee shall not begin to drill, redrill, make water-shut-off or formation test, deepen, shoot, plug, or abandon any well, or alter the casing in it without first notifying the supervisor or his representative of his plan or intention and receiving approval prior to commencing the contemplated work.

(*e*) The lessee shall permanently mark all rigs or wells in a conspicuous place with his name or the name of the actual operator and the number or designation of the well, and shall take all necessary means and precautions to preserve these markings. Abandoned wells shall be marked with a permanent monument which shall consist of a piece of pipe not less than 4 inches in diameter and not less than 10 feet in length, of which 4 feet shall be above the ground level, the remainder being embedded in cement. This pipe shall be capped with a screw cap.

(*f*) The lessee shall keep on the leased premises or at his headquarters in the field accurate records of the drilling, redrilling, deepening, plugging, or abandoning of all wells and of all alterations to casing, the records to show all the formations penetrated, the content of oil, gas, or water (and if water, its character) in each formation, and the kinds, weights, landed depths, and sizes of casings used in drilling the wells. He shall furnish such characteristic samples of each formation penetrated as may be requested by the supervisor or his representative. Within 15 days after the completion of any well and

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Amendment to Section 2(m)

On September 14, 1929, the Acting Secretary e Interior amended Section 2(m) of the Regu- ns by adding thereto the following:

The supervisor is empowered to authorize a reasonable deduction, before the royalty is computed, on account of the cost of putting natural gas into marketable condition by special methods of treatment, such methods of treatment to be approved by the supervisor before operations are commenced.

within 15 days after the completion of any further operations on it the lessee shall transmit to the supervisor or his local representative copies of these records on prescribed forms (see sec. 5 of these regulations) furnished by the supervisor. The lessee shall also submit such other reports and records of operations as may be required in the manner and form prescribed by the supervisor. (See sec. 5.)

(*g*) In drilling in "wildcat" territory or in a gas or oil field where high pressures are likely to exist the lessee shall take all proper precautions necessary for bringing the well under control at any time and shall provide at the time the well is started the proper high-pressure fittings and equipment required for such work. Good practice under such conditions requires that the conductor string of casing be cemented around the casing shoe.

(*h*) When drilling with cable tools, the lessee shall provide at least one properly prepared slush pit, into which he must deposi mud and cuttings from clay or shale free of sand that will be suitable for the mudding of a well, except when he is drilling in a proved area where it is known that such precautions are unnecessary. When required, a second pit must be provided for sand pumpings and other material extracted from the well during the process of drilling that are not suitable for mudding.

(*i*) When drilling with rotary tools, the lessee shall provide when required by the supervisor or his representative an auxiliary mud pit of suitable capacity in which he can maintain a supply of extra heavy mud for emergency use in case of blow-outs or lost circulation. When required, surplus mud and cuttings shall be confined in suitable pits.

(*j*) The lessee, by methods approved by the supervisor or his local representative, shall effectually shut off and exclude all water from any oil or gas bearing stratum and shall make a casing and water shut-off test before suspending drilling operations or completing the well and drilling into the oil or gas sand.

The lessee shall also effectually test for commercial productivity all formations that give evidence of carrying oil or gas, the test to be made in a manner approved in advance by the supervisor or his local representative. Unless otherwise specifically approved by the supervisor or his representative, formation tests shall be made at the time the formations are penetrated and in the absence of excessive back pressure from a column of water or mud fluid.

(*k*) The lessee shall not deepen an oil or gas well for the purpose of producing oil or gas from a deeper stratum unless the upper productive strata are properly protected.

(*l*) The lessee shall prevent any oil or gas well from blowing open and shall take immediate steps and exercise due diligence to bring under control any "wild" or burning oil or gas well or water well.

(*m*) The lessee shall operate his wells in such manner as to eliminate, so far as possible, the formation of emulsion, or so-called B. S. If the formation of emulsion, or B. S., can not be avoided and the oil can not be recovered from the emulsion by usual methods of treatment, the lessee shall treat the oil to put it into a marketable condition if it can be recovered at a profit. The supervisor is empowered to authorize a deduction, before the royalty is computed, on account of the cost of putting the oil into marketable condition by such unusual methods, in order to encourage the conservation of oil and oil products. To avoid excessive losses from evaporation or "burning the oil," the lessee shall not heat emulsified oil for the purpose of breaking down emulsions to temperatures above the minimum temperature required to put the oil into marketable condition.

(n) B. S. and salt water from tanks or wells shall not be allowed to pollute streams or damage the surface of adjoining land. If the B. S. can not be treated or burned and the volume of salt water is too great for disposal by seepage and evaporation, the lessee should consult the supervisor or his representative regarding its disposal and dispose of it under some approved method.

(o) All oil run from leased lands shall be gauged according to methods approved by the supervisor or his representative. The lessee shall provide tanks suitable for containing and accurately measuring the crude oil produced from the wells and shall furnish to the supervisor or his representative at least two acceptable copies of all tank tables. The lessee shall not, except during an emergency and except by special permission of the supervisor or his representative, confirmed in writing, permit oil to be stored or retained in earthen reservoirs or in any other receptacles in which there may be undue waste of oil by seepage or evaporation.

(p) Before abandoning a well the lessee shall submit to the supervisor or his representative a statement of reasons for abandonment and his detailed plans for carrying on the work, together with duplicate copies of the log in case it has not already been submitted, and shall proceed with the abandonment only on receiving the written approval of the supervisor or his representative and in the manner prescribed by such official. No producing oil or gas well shall be abandoned unless it is demonstrated that further operation is commercially unprofitable.

(q) The lessee shall prevent the waste of natural gas or its wasteful utilization. The use of gas in its natural state in engines, pumps, or similar equipment where its pressure is the direct operating force is prohibited unless the exhaust gas is conserved for use as fuel or unless special permission is obtained from the supervisor or his representative.

(r) The lessee shall exercise reasonable precaution in providing against accidents and fires and shall make a full report to the supervisor of all accidents or fires on the leased premises.

(s) The lessee shall file with the Secretary of the Interior, through the supervisor or his representative, triplicate signed copies of contracts for the disposition of oil, natural gas, and natural-gas gasoline produced, except that portion used for production purposes on the land leased, and in the event that the United States shall elect to take its royalties in money instead of in oil or gas or gasoline, he shall not sell or otherwise dispose of the products of the land leased except in accordance with the sales contract or other method first approved by the Secretary of the Interior.

(t) The lessee desiring relief from any drilling or producing requirement under a lease shall file, in duplicate, with the supervisor or his representative an application therefor, including a full statement of the circumstances that in his opinion render relief necessary or desirable.

(u) The lessee must immediately obey all orders intended to carry out the terms and spirit of these regulations, whether they are issued directly by the supervisor or through his representative. Subjects of controversy may be settled in conference between the lessee and the supervisor or his representative, but the supervisor or his representative shall have final authority subject to the right of appeal as provided in section 6 hereof.

SECTION 3. OIL ROYALTIES

(a) Royalties payable in value shall be paid to the Register of the United States Land Office for the district in which the leased land is situated. Royalties shall be due and payable on or before the 15th of each calendar month for all oil produced during the preceding calendar month.

If the Government elects to take its royalties in kind, the lessee shall furnish storage for such royalty oil free of charge for 30 days after the end of the calendar month in which the oil is produced. The oil is to be stored on the leased premises or at such place as the supervisor or his representative and the lessee may mutually agree upon.

(*b*) The sliding-scale royalties are based on the average daily production per well. Ordinarily the average daily production per well for a lease is computed on the basis of a 28, 29, 30, or 31 day month (as the case may be) and the number of wells on the lease counted as producing. (Tables for computing royalty on the sliding-scale basis may be obtained upon application to the supervisor or his representative.) The supervisor will determine the number of producing wells for computing royalties in accordance with the following cases:

CASE I. On a previously producing leasehold, count as producing wells for every day of the month each previously producing well that produced for 15 days or more during the month and disregard those that produced for less than 15 days during the month.

CASE II. When the initial production of a leasehold is made during the calendar month, compute royalty on the basis of producing well days.

CASE III. When a new well or wells are brought in on a previously producing leasehold and produce for 10 days or more during the calendar month in which they are brought in, count such new well or wells as producing every day of the month, in arriving at the number of producing well days. Do not count new well or wells that produce for less than 10 days during the calendar month.

CASE IV. Consider "head wells" that make their best production by intermittent pumping or flowing as producing every day of the month, provided they are regularly operated in this manner.

CASE V. On a previously producing lease where no old well or wells produced for 15 days or more, compute royalty on a basis of actual producing well days.

CASE VI. On a previously producing lease where no wells were producing during the calendar month, but oil was shipped during the month, compute the royalty at the same royalty percentage as that of the last preceding calendar month in which production and shipments were normal.

Special cases not subject to definition, such as those arising from averaging the production from two distinct sands or horizons when the production of one sand or horizon is relatively insignificant as compared to that of the other, shall be submitted to the supervisor.

In the following summary of operations on a typical leasehold for the month of June, the wells considered in computing royalty on the entire production of the property for the month are indicated:

Well No.	Record	Count (marked X)
1	Produced full time for 30 days	X
2	Produced for 26 days; down 4 days for repairs	X
3	Produced for 28 days; down June 5, 12 hours, rods; June 14, 6 hours, engine down; June 25, 24 hours, June 26, 24 hours, pulling rods and tubing	X
4	Produced for 12 days; down June 13 to 30	
5	Produced for 8 hours every other day (head well)	X
6	Idle producer (not operated)	
7	New well, completed June 17; produced for 14 days	X

In [illegible] are seven [illegible] the leasehold, but wells No. 4 and No. 6 are not counted in computing royalties. Wells Nos. 1, 2, 3, 5, and 7 are counted as producing for 30 days. The royalty is taken on the total production of the leasehold for the month (including the oil produced by well No. 4).

Government leases stipulate that the royalty shall be paid on the basis of the actual production from the area leased As a rule the pipe-line runs from a property closely approximate the production from that property over a period of months. Because of the accurate gauging of clean (net) oil when running to the pipe line, the department prefers, when practicable, to compute the royalty on the basis of the monthly pipe-line runs from a leasehold rather than on the basis of the actual monthly production, but it reserves the right to compute royalty on a production basis, taking storage into account, whenever the supervisor or his representative may so elect.

(c) The lessee shall file with the supervisor or his representative the run tickets for all oil run from leased lands except as special conditions may justify other arrangements approved by the supervisor.

SECTION 4. NATURAL GAS AND GASOLINE ROYALTIES

(a) Measurement of Natural Gas

The term "natural gas" as used in these regulations shall be interpreted to mean either gas from gas wells or so-called "casing-head gas" or "trapped gas" produced by oil wells. The term "dry natural gas" applies to natural gas containing so little gasoline that its extraction is not commercially feasible or to natural gas from which gasoline has already been extracted.

All gas subject to royalty shall be measured by meters (preferably of the orifice-meter type), approved by the supervisor or his representative and installed at the expense of the lessee at such places as may be agreed to by the supervisor or his representative. The standard of pressure in all measurements of gas sold or subject to royalty shall be 10 ounces above an atmospheric pressure of 14.4 pounds to the square inch, regardless of the atmospheric pressure at the point of measurement, and the standard of temperature shall be 60° Fahrenheit. All measurements of gas shall be reduced by computation to these standards, no matter what may have been the pressure and temperature at which the gas was actually measured. By reason of higher altitudes in certain portions of the Rocky Mountain district the absolute pressure of the flowing gas in these fields shall be taken as the gauge pressure plus the actual average atmospheric pressure existing at the points of measurement, in order to reduce equitably the quantity of gas to the Government standard of 10 ounces above an atmospheric pressure of 14.4 pounds to the square inch. Tables for this correction have been computed for some of the fields situated at high altitudes. Information relative to these tables may be obtained through the supervisor or his representative.

(b) Payment of Royalties

Natural gas and natural-gas gasoline royalties that are payable in value shall be paid to the Register of the United States Land Office for the district in which the leased land is situated. Royalties shall be due and payable on or before the 15th of each calendar month for all natural gas and natural-gas gasoline produced during the preceding calendar month.

The royalties on natural gas and natural-gas gasoline from permits and leases under the act of February 25, 1920, the act of June 4, 1920, the act of

March 3, 1923, and special agreement by the United States, unless otherwise specified in the permit, lease, or special agreement, shall be computed as stated in the following paragraphs *c* and *d*.

(*c*) Royalties on Natural Gas

The royalty on natural gas, whether gas from which the natural-gas gasoline has been extracted or otherwise, shall be 12½ per cent of the value of the gas as fixed by the Secretary of the Interior where the average production per day for the calendar month is less than 3,000,000 cubic feet, and 16⅔ per cent where the average daily production is 3,000,000 cubic feet or more.

In the sale of dry natural gas there is but one commodity involved, and on it the Government collects a royalty of 12½ per cent, or 16⅔ per cent, according to the average daily production. These royalties are due regardless of whether the gas is produced as dry gas or whether it is the dry residual gas from a plant after natural-gas gasoline has been extracted.

In general, where natural gas is delivered or sold for purposes of extracting gasoline, two separate commodities are involved—the natural-gas gasoline and the dry residual gas. If, however, the lessee receives a higher price for such natural gas as a single commodity than the combined value of the two commodities, the natural-gas gasoline and the dry residual gas, as fixed by the Secretary of the Interior, the Government royalty shall be computed on natural gas alone and at the higher price received therefor by the lessee.

(*d*) Royalties on Natural-Gas Gasoline

A royalty of 16⅔ per cent shall be paid on the value as fixed by the Secretary of the Interior of one-third of all natural-gas gasoline extracted and sold from the natural gas produced on the leased land.

Natural-gas gasoline (also known as casing-head gasoline) is a manufactured product. The value of this product is contingent upon the value of the raw material and the cost of its manufacture. The Government does not wish to collect royalty on that part of the value which is derived from the cost of manufacturing inasmuch as the Government's equity is confined to the value of the raw material involved. In computing royalty on natural-gas gasoline the value of the raw gasoline in the natural gas as produced is assumed to be one-third the value of the marketable natural-gas gasoline extracted from such gas, the remaining two-thirds being allowed to the lessee for the cost of manufacture. Thus the Government collects 16⅔ per cent of one-third of the market value as its royalty share of the natural-gas gasoline produced (or in effect one-eighteenth of the market value).

If the lessee derives revenue on natural gas from two sources, from natural-gas gasoline and dry (residual) gas sold, the Government will normally collect a royalty on the two products. Therefore, if there is a market for the dry residual gas from the natural-gas gasoline plant, a royalty on this dry gas as stipulated under headings (*b*) and (*c*) of this section must be paid to the Government.

The present policy of the department is to allow the use of a reasonable amount of dry gas for plant operation, subject to the advice and direction of the supervisor or his representative. The department will attempt to arrive at an equitable basis of settlement in determining what constitutes "a reasonable amount." Moreover, the department will investigate plants where gas is being wasted.

EXAMPLE OF METHOD FOR COMPUTING NATURAL-GAS GASOLINE ROYALTIES

Assume—

That the value of natural-gas gasoline is 18 cents a gallon.

That 3 gallons of gasoline is recovered from each 1,000 cubic feet of natural gas treated.

Then—

The Government takes its royalty on one-third of 3 gallons (per 1,000 cubic feet of gas), or 1 gallon, having a value of 18 cents.

The Government's royalty on gasoline in this case is $\frac{1}{6}$ (=16⅔ per cent) × 1 (gallon) × 18 cents = 3 cents (on each 1,000 cubic feet of natural gas treated).

(e) Relief Measures

Adverse climatic and economic conditions in certain portions of the Rocky Mountain district result in unusually high operating and marketing costs. In order to encourage the most complete practicable utilization of natural gas under such conditions the Secretary of the Interior will, in his discretion and on proper showing of the necessity therefor, modify by specific order the method of computation of royalty on natural-gas gasoline set forth in subsection (*d*) hereof, to provide for a royalty of 16⅔ per cent of the value of not less than one-fifth of all natural-gas gasoline extracted and sold from the natural gas produced on the leased land, such modification to be effective in specific areas and for a definite period to be fixed by him in each order.

(*f*) Royalty on Drip Gasoline

The royalty on all drip gasoline recovered and sold from gas produced on the leased lands shall be the same as that required for natural gas gasoline manufactured within the same district.

(*g*) Determination of Gasoline Content

Tests to determine the gasoline content of natural gas delivered to plants manufacturing gasoline are required to check plant efficiency and to obtain an equitable basis for allocating the gasoline output of any plant to the several sources from which the natural gas treated is derived. The gasoline content of the natural gas delivered to each gasoline plant treating gas derived from leased lands shall be determined by methods approved by the supervisor and under his supervision on the basis of periodical field tests made at each meter.

(*h*) Quantity Basis for Computing Gasoline Royalty

The primary quantity basis for computing monthly royalties on natural-gas gasoline is the monthly net output of the plant at which the gasoline is manufactured, "net output" being defined as the natural-gas gasoline that the plant is able to manufacture and sell, less a deduction of any portion thereof derived from naphtha or other blending materials.

(*a*) If the net output of a plant is derived from the natural gas obtained on only one leasehold the quantity of gasoline on which computations of royalty for the lease are based is the net output of the plant.

(*b*) If the net output of a plant is derived from natural gas obtained from several sources of gas of uniform gasoline content, the proportion of net output allocable to each lease as a basis for computing royalty will be determined by dividing the amount of natural gas delivered to the plant from the leasehold by the total amount of natural gas delivered to the plant from all sources.

(c) If, however, the net output of a plant is derived from natural gas obtained from several sources of gas of diverse gasoline content, the proportion of net output allocable to each lease as a basis for computing royalty will be determined by multiplying the amount of natural gas delivered to the plant from the leasehold by the gasoline content of the gas and dividing the arithmetical product thus obtained by the sum of arithmetical products similarly obtained for all separate sources of natural gas treated at the plant.

SECTION 5. REPORTS TO BE MADE BY LESSEE (INCLUDING PERMITTEE)

INTRODUCTION

In operating, to know the property is to know the individual wells on it. For this reason much of the information requested by the Geological Survey concerns individual wells. Experience has shown that these data are essential to careful operation and are necessary for engineering studies that often enable the supervisor and his representatives to offer valuable advice on the handling of properties. Forms for making reports to the department, described in this section, can be obtained from the supervisor or his representatives, and such forms, unless others are specified by the supervisor, must be used by the lessee. Lessees must fill out all forms completely and file them punctually with the supervisor or his local representative. Failure of the lessee to submit the reports required herein constitutes noncompliance with the terms of these regulations and is cause for cancellation of the lease or permit.

(a) SUNDRY NOTICES AND REPORTS ON WELLS (FORM 9-331A)

Form 9-331a covers all notices and all reports pertaining to individual wells except those for which special blanks are provided. This form may be used for any of the purposes listed, or a special heading may be inserted on the blank to adapt it for use for other similar purposes. Any written notice of intention to do work or of change in plans must be filed in triplicate unless otherwise directed and must reach the supervisor or his representative and receive his approval before commencement of the work. One copy of the form will be returned to the lessee if and when approved and will constitute his authority to begin work. The lessee is responsible for receipt of the notice by the supervisor or his representative in ample time for proper consideration and action. If in case of emergency any notice is given orally or by wire, and approval is obtained, the transaction shall be confirmed in writing as a matter of record. The examples following illustrate some of the uses to which Form 9-331a may be put.

NOTICE OF INTENTION TO DRILL (FORM 9-331A)

The notice of intention to drill a well must be filed in triplicate with the supervisor or his local representative and approval received before the work is commenced. This notice must give the location in feet from property lines and, if possible, the elevation of the derrick floor and the geologic name of the surface formation; also an estimate of the depth at which and the stratum or formation in which the oil or gas is expected and approximately the depths at which specified strings of casing will be set or landed; also the weight of the sizes of casing proposed to be set or landed at these depths, and a statement as to whether any cementing, mudding, or other special work is contemplated.

NOTICE OF INTENTION TO CHANGE PLANS (FORM 9–331A)

Owing to unexpected conditions, it may become necessary to change the plans of proposed work in connection with either the drilling or the repair of wells. Complete details of these changes should be submitted in triplicate to the supervisor or his representative on this form and approval obtained before the work is undertaken.

NOTICE OF DATE FOR CASING AND WATER SHUT-OFF TEST (FORM 9–331A)

As the exclusion of water from oil or gas-bearing formations is one of the most important items of conservation, the supervisor or his local representative will witness as many casing and water shut-off tests as possible. Form 9–331a should be filled out and filed in triplicate with the supervsior or his local representative in advance of the approximate date on which the lessee expects to make the test. Later by agreement the exact day may be fixed.

REPORT ON RESULT OF CASING AND WATER SHUT-OFF TEST (FORM 9–331A)

If the supervisor or his representative authorizes but does not witness a casing or water shut-off test, the lessee shall submit in triplicate a statement, signed by the employee in charge of the work giving details and results of the test. The information given must be complete and include such items as depth of shut-off; head of water found; depth and thickness of water strata penetrated before landing pipe; weight, nominal diameter, and depth of casing in the hole; fluid levels before and after test; length of time the well stood for each test; depth drilled out below shoe, if any; note of oil or gas showing; length and character of bridge, if used; method of shut-off; amount and name of cement and time given for set; and any other pertinent data.

NOTICE OF INTENTION TO REDRILL OR REPAIR WELL (FORM 9–331A)

If it seems desirable to make repairs in or to deepen a well, a detailed written statement of the plan of work shall be made in triplicate to the supervisor or his local representative and approval obtained before the work is started. In work that affects only rods, pumps, or tubing or other routine work, such as cleaning out, no notice of report will be necessary.

NOTICE OF INTENTION TO SHOOT (FORM 9 331A)

Before shooting any well (whether for increasing production or in drilling, repair, or abandonment) notice of intention to shoot shall be given in triplicate to the supervisor or his local representative and approval obtained before shooting is done. When the notice of intention to shoot becomes a part of a notice of intention to redrill, repair, or abandon a well, the supervisor or his representative may accept such notice in lieu of a separate notice of intention to shoot.

The notice of intention to shoot (Form 9–331a) must be accompanied by the complete log of the well to date, provided the complete log has not previously been filed and must state the object of shooting, the size and kind of the proposed shot, the exact location and distribution of the explosive in the well (by depths), and the name of the company that is to do the shooting. The notice shall also contain an accurate statement of the daily oil and water production, if any, at the time the notice is filed or at the date of last production.

SUBSEQUENT RECORD OF SHOOTING (FORM 9–331A)

After shooting any well a subsequent record of shooting must be filed in triplicate with the supervisor or his local representative. This record shall be filed separately on Form 9–331a within 30 days after the shooting is done, except where such shooting record constitutes a part of the log (Form 9–330) or a part of a record of other subsequent work done (Form 9–331a) or a part of an abandonment record filed within that period.

The subsequent record of shooting shall include a statement of the size of the shot and the nature, exact location, and distribution of the explosive used in the well (by depths). The record shall contain also an accurate statement of the average daily production of oil and water for at least a 10-day period prior to the filing of the report. In addition, thi report should include other pertinent information, such as depth of cleaning out, time spent in bailing and cleaning out, and possible injuries to the asing or the well.

RECORD OF PERFORATING CASING (FORM 9–331A)

Usually a statement covering the details of perforated casing in a well is made on the log form. When perforations are made after the log has been sent in a report of the work shall be made in triplicate (Form 9–331a) to the supervisor or his local representative. Prior notice need not be given for such work, except that if it is intended to perforate casing that has excluded water from the well a notice in triplicate of intention to perforate and approval of the supervisor or his local representative are necessary before the work is begun.

NOTICE OF INTENTION TO PULL OR OTHERWISE ALTER CASING (FORM 9–331A)

If it is desired to pull a portion or all of a string of casing, or to rip, perforate, or otherwise alter casing that has excluded water from a well, a notice (Form 9–331a) of such work must be given in triplicate and the approval of the supervisor or his local representative obtained before the work is started. When it is desired only to [illegible] casing without deepening the well and without altering the water string already in the well, it will be sufficient to report the operations on a subsequent notice of work done.

NOTICE OF INTENTION TO ABANDON WELL (FORM 9–331A)

Before beginning abandonment work on any well (whether drilling well, oil or gas well, water well, or so-called dry hole) notice of intention to abandon shall be filed in triplicate on Form 9–331a with the supervisor or his local representative and approval obtained before the work is started.

The notice of intention to abandon must show the reason for abandonment and must be accompanied by a complete log, in duplicate, of the well to date, provided the complete log has not been filed previously, and must give a detailed statement of the proposed work, including such information as kind, location, and length of plugs (by depths) and plans for mudding, cementing, shooting, testing, and removing casing as well as any other pertinent information.

SUBSEQUENT REPORT OF ABANDONMENT (FORM 9–331A)

After abandoning or plugging a well a subsequent record of work done must be filed in triplicate with the supervisor or his local representative. This record shall be filed separately (on Form 9–331a) within 30 days after the work is done except where such record constitutes a part of the log (Form 9-330) or record of other subsequent work done (Form 9-331a) and is filed within that period.

The subsequent report of abandonment shall give a detailed account of the manner in which the abandonment or plugging work was carried out, including the nature and quantities of materials used in plugging and the location and extent (by depths) of the plugs of different materials. Records of any tests or measurements made and the amount, size, and location (by depths) of casing left in the well, as well as a detailed statement of the volume of mud fluid used, the pressures attained in mudding, and the names and positions of employees who carried on the work. If the well was shot this report must include a complete statement of the shooting, giving the details as called for on page 12 of these regulations.

SUPPLEMENTARY WELL HISTORY (FORM 9-331A)

A report of all work done on any well since the filing of the log form (Form 9-330) or the last report covering work on the well shall be filed in triplicate with the supervisor or his local representative on Form 9-331a within 30 days after completion of the particular work, or before, if called for by the supervisor.

(b) LOG OF WELL (FORM 9-330)

The lessee shall furnish to the supervisor or his representative, upon his demand, a partial or complete log of any well and shall file in duplicate with the supervisor or his representative not later than 15 days after the completion of each well a complete and accurate log on Form 9-330.

The lessee shall require the drillers, whether company labor or contract labor, to record accurately the depth, character, fluid content, and fluid levels, where possible, of each formation as it is penetrated, together with all other pertinent information called for by this form. The practice of compiling well logs from memory, some times after the work has been completed, will not be permitted.

(c) LESSEE'S MONTHLY REPORT OF OPERATIONS (FORM 9-329)

A separate report for each lease or permit is to be made for each calendar month, beginning for a lease with the month in which lease is issued and for a permit with the month in which drilling operations are initiated, and filed in duplicate with the supervisor or his local representative on or before the 6th day of the succeeding month, unless an extension of time for the filing of such report is granted by the supervisor or his representative. The report on this form constitutes a general summary of the status of operations on the property and, whatever such status may be, the report must be submitted each month until the permit or lease is terminated.

In order that the supervisor or his representative may obtain from this form the desired information, it is particularly necessary that—

(1) The lease or permit be identified by insertion of the name of the local United States land office and the serial number in the space provided in the upper right corner;

(2) Each well be listed separately by number, its location be given by 40-acre subdivision (¼ of ¼ sec.), section number, township, and range;

(3) The actual number of days each well produced, whether oil or gas, be shown for the calendar month;

(4) The proper columns show the quantity of oil actually produced, the total amount of natural gas measured, and the total amount of gasoline recovered (total sales as distinguished from the total production here required should be shown in the footnote);

(5) In the "Remarks" column, the depth of wells being drilled, the reasons for every shut down, the date and result of gasoline tests, and any other noteworthy information on operations not specifically provided for in the form should be shown. Separate reports on this form may be submitted by the lessee for oil and natural gas and gasoline.

The only information called for in this report that may occasion inconvenience to the operator is the statement of the number of barrels of oil and water produced by each well. Usually a method of gauging individual wells can be devised that will check, with a reasonable degree of accuracy, the production of the entire leasehold. The supervisor or his representative will advise the operator as to methods of gauging on the leased lands.

The lessee must report with accuracy the status of all wells on the leased lands, as this information is essential in computing royalties. (See sec. 3, b.)

(d) Daily Report of Gas-Producing Wells (Form 9–352)

Unless otherwise directed by the supervisor or his representative, the readings of all meters showing production of natural gas from leased lands shall be submitted daily on Form 9–352, together with the meter charts. After a check has been had the meter charts will be returned.

(e) Lessee's Statement of Oil and Gas Runs and Royalties (Form 9–361)

When directed by the supervisor or his representative, a monthly report shall be made by the lessee in duplicate, on Form 9–361, showing each run of oil and all sales of gas and gasoline and the royalty accruing therefrom to the Government. When use of this form is required it must be completely filled out and sworn to.

(f) Special Forms

Because of the special conditions in certain localities, special forms other than those shown in these regulations, such as run or sales statements, may be necessary. Instructions for the filing of such forms will be given by the supervisor or his representative.

SECTION 6. APPEAL TO THE SECRETARY OF THE INTERIOR

The lessee must immediately obey all orders intended to carry out the terms and spirit of these regulations, whether issued directly by the supervisor or through his representative (see section 2) or sent to the lessee or his agent by ordinary mail, but any such order after being put into effect by the lessee shall be subject to review by the Secretary of the Interior upon appeal to him filed by the lessee with the supervisor or his representative within 30 days after the order has been served.

The administration of these regulations shall be under the direction of the Geological Survey.

Geo. Otis Smith,
Director of Geological Survey.

Approved.

E. C. Finney,
First Assistant Secretary.

Form [illegible]
(Feb., 1926)

U. S. Land Office ....
....
Serial number ....
Lease or permit ....

DEPARTMENT OF THE INTERIOR

GEOLOGICAL SURVEY

Sundry notices and reports on wells

Notice of intention to drill..........	Record of perforating casing..........
Notice of intention to change plans..........	Notice of intention to pull or otherwise alter casing. ....
Notice of date for test of water shut-off..........	Notice of intention to abandon well..........
Report on result of test of water shut-off..........	Subsequent report of abandonment..........
Notice of intention to re-drill or repair well..........	Supplementary well history..........
Notice of intention to shoot..........	....
Subsequent record of shooting..........	....

(Indicate above by check mark nature of report, notice, or other data)

.........., 192

Following is a {notice of intention to do work / report of work done} on land under {permit / lease} described as follows:

....
(State or Territory) (County or Subdivision) (Field)

Well No. ....
(¼ sec. and sec. No.) (Township) (Range)

....
(Meridian)

The well is located ...... feet {N / S} of ...... line and ...... feet {E / W} of ...... line of sec. ......

The elevation of the derrick floor above sea level is ...... feet.

DETAILS OF PLAN OF WORK

[State names of and expected depths to objective sands; show sizes, weights, and lengths of proposed casings; indicate mudding jobs, cementing points, and all other important proposed work]

....
....
....
....
....

Approved .... Company ....
(Date)

.... By ....

Title .... Title ....
(Geological Survey)

Address .... Address ....

NOTE.—Reports on this form to be submitted in triplicate to the supervisor for approval.

Form 9-329
Revised March 10, 1926

U. S. Land Office__________
Serial Number___________
Lease or permit___________

DEPARTMENT OF THE INTERIOR

GEOLOGICAL SURVEY

Lessee's monthly report of operations

State___________________ County_______________ Field_________________

The following is a correct report of operations and production (including drilling and producing wells) for the month of____, 192__ ________________________________

Agent's address____________________ Company_____________________________

____________________________________ Signed________________________________

Phone_____________________________ Agent's title____________________________

Section and ¼ of ¼	Town-ship	Range	Well No.	Days pro-duced	Barrels of oil	Gravity	Cubic feet of gas (in thousands)	Gallons of gasoline recovered	Barrels of water (if none, so state)	Remarks (if drilling, depth; if shut down, cause; date and result of test for gasoline content of gas)

NOTE.—There were__________runs or sales of oil; __________runs or sales of gas; __________runs or sales of gasoline during the month. (Write "no" where applicable.)

NOTE.—Report on this form is required for each calendar month, regardless of the status of operations, and must be filed in triplicate with the supervisor by the 6th of the succeeding month unless otherwise directed by the supervisor.

Form 9-330

U. S. Land Office_________________
Serial number__________________
Lease or permit_________________

Locate well correctly

DEPARTMENT OF THE INTERIOR

GEOLOGICAL SURVEY

Log of oil or gas well

Company_______________________ Address__________________________________

Lessor or tract________________ Field______________ State_________________

Well No____, section____, township____, range____, meridian____, county____

Location____feet $\left\{ \begin{matrix} N. \\ S. \end{matrix} \right\}$ of____ line and____ feet $\left\{ \begin{matrix} E. \\ W. \end{matrix} \right\}$ of____line of____elevation____
(Derrick floor relative to sea level)

The information given herewith is a complete and correct record of the well and all work done thereon so far as can be determined from all available records.

Signed____

Date_____________________________________ Title____________________________________

The summary on this page is for the condition of the well at above date.

Commenced drilling______________, 19__ Finished drilling______________, 19__

Form 9-330 (Continued)

Oil or gas sands or zones

(Denote gas by G)

No. 1, from____________to____________ No. 4, from____________to____________
No. 2, from____________to____________ No. 5, from____________to____________
No. 3, from____________to____________ No. 6, from____________to____________

Important water sands

No. 1, from____________to____________ No. 3, from____________to____________
No. 2, from____________to____________ No. 4, from____________to____________

Casing record

Size casing	Weight per foot	Threads per inch	Make	Amount	Kind of shoe	Cut and pulled from	Perforated From—	Perforated To—	Purpose

Mudding and cementing record

Size casing	Where set	Number sacks of cement	Method used	Mud gravity	Amount of mud used

Plugs and adapters

Heaving plug—Material________________ Length____________ Depth set______
Adapters—Material________________ Size______________________________

Shooting record

Size	Shell used	Explosive used	Quantity	Date	Depth shot	Depth cleaned out

Tools used

Rotary tools were used from ___ ___ feet to ___ feet, and from ___ feet to ___ feet
Cable tools were used from___ ___ feet to ___ feet, and from ___ feet to ___ feet

Dates

__________________________, 19____ Put to producing ____________, 19____

The production for the first 24 hours was ____ barrels of fluid, of which ____ per cent was oil, ____ per cent emulsion, ____ per cent water, and ____ per cent sediment. Gravity, °Bé. ____________

If gas well, cubic feet per 24 hours ________ Gallons gasoline per 1,000 cubic feet of gas __________________

Rock pressure, pounds per square inch ________________

Form 9-330—Continued.

Employees

-------------------------, Driller. -------------------------, Driller.
-------------------------, Driller. -------------------------, Driller.

Formation record

From—	To—	Total feet	Formation

HISTORY OF OIL OR GAS WELL

It is of the greatest importance to have a complete history of the well. Please state in detail the dates of redrilling, together with the reasons for the work and its results. If there were any changes made in the casing, state fully, and if any casing was "sidetracked" or left in the well, give size and location. If the well has been dynamited, give date, size, position, and number of shots. If plugs or bridges were put in to test for water, state kind of material used, position, and results of pumping or bailing.

Form 9-352

U. S. Land Office----------
Serial number ----------
Lease or permit----------

DEPARTMENT OF THE INTERIOR

GEOLOGICAL SURVEY

Daily report of gas-producing wells

Operating company --
--¼ sec.-----, township-----, range-----. Well No. -----. Date---------------
Orifice No. ----. Size----. Hourly coefficient----at 10 ounces above 14.4 pounds.
Specific gravity-----. Gasoline per thousand----gallons. Date tested----------

Time	Static pressure gauge	Inches water differential	Extension	Temperature	Remarks
A. M.					
12 to 1					
1 to 2					
2 to 3					
3 to 4					
4 to 5					
5 to 6					
6 to 7					
7 to 8					
8 to 9					
9 to 10					
10 to 11					
11 to 12					
P. M.					
12 to 1					
1 to 2					
2 to 3					
3 to 4					
4 to 5					
5 to 6					
6 to 7					
7 to 8					
8 to 9					
9 to 10					
10 to 11					
11 to 12					
Total extension					

Total delivery for day--------------------thousand cubic feet.
Total gasoline for day---------------- ----gallons.

Form 9-361
February, [illegible]

U. S. Land Office ________
Serial number ________
Lease or permit ________

DEPARTMENT OF THE INTERIOR

GEOLOGICAL SURVEY

Lessee's monthly statement of oil and gas runs and royalty

Lessee ________________________ Month ______________ 192 .
Location ________________________________
Section. T. R. M.
Field ______________ County ______________ State ______________

Following are the *only* runs and sales made this month. Omission of data means *none*.

Oil						Gas		
Tank number	Date	Net barrels run	Gravity	Price per barrel	Value	Sales in 1,000 cubic feet	Price per 1,000 cubic feet	Value
						Total sales	Average price	Total value

Purchaser of above gas

Gasoline

Sales in gallons	Price per gallon	Value
Total sales	Average price	Total value

Purchaser of above gasoline

Total barrels run	Average price	Total value

Number of oil-producing wells affecting royalty computation

Name of pipe-line company	Method of paying oil royalty

Form 9-361—Continued

GOVERNMENT ROYALTY				ACKNOWLEDGMENT
Sales	Royalty factor	Royalty in units	Value of royalty	I have read and examined the statements made hereon and find them true, accurate, and complete.
				(Signature and title of officer authorized to sign for lessee)
Oil (barrels)		(1)		(State) } ss:
Gas (1,000 cubic feet)		(1)		(County) }
Gasoline (gallons)		(1)		Subscribed and sworn to before me this ...... day of ...., 192
Total value of royalty)				*Notary Public in and for the above county and State.* My commission expires.....................

[1] Where applicable state "None."

This form to be properly prepared, sworn to, and filed with the supervisor on or before the 20th day of the succeeding month. Runs of oil, gas, or gasoline may be listed on any other convenient form and attached to this report.

Attachment 7

Duty to Market			
Lease Form	**Statutory Authority**	**Pertinent Lease Language**	**Regulatory Requirements**
4-208 e (1933)	Mineral Lands Leasing Act of 1920, 30 U.S.C. § 181 et seq.	None	Lessee to remove emulsion from oil... "supervisor is empowered to authorize a deduction, before the royalty is computed, on account of the cost of putting the oil into marketable condition by such unusual methods..." Amendment to §2(m) Operating Regulations to Govern the Production of Oil and Gas, 1926 Effective September 14, 1929
4-208 f (May 1936)	Mineral Lands Leasing Act of 1920, 30 U.S.C. § 181 et seq.	None	"Production of oil and gas...shall be limited by the market demand for oil" Effective November 1, 1936 1 Fed. Reg. 1996 (1936)
4-208 f (Jan. 1943)	Mineral Lands Leasing Act of 1920, 30 U.S.C. § 181 et seq.	"When paid in amount of production...royalty products shall be delivered in merchantable condition on the premises where produced without cost to lessor..."	"[T]o avoid physical waste of gas the lessee shall consume it beneficially or market it or return it to productive formation" "The production of oil and gas...shall be limited by the market demand... for oil" 30 C.F.R. § 221.35 (1942) Effective June 1, 1942 7 Fed. Reg. 4132 (1942)

Duty to Market			
4-213 (Dec. 1949)	Mineral Lands Leasing Act of 1920, 30 U.S.C. § 181 et seq.	"When paid in amount of production...royalty products shall be delivered in merchantable condition on the premises where produced without cost to lessor..."	"[T]o avoid physical waste of gas the lessee shall consume it beneficially or market it or return it to productive formation" "Production of oil and gas...shall be limited by the market demand... for oil" 30 C.F.R. § 221.35
4-1130 (Sept. 1954)	Mineral Lands Leasing Act of 1920, 30 U.S.C. § 181 et seq.	"When paid in amount of production...royalty products shall be delivered in merchantable condition on the premises where produced without cost to lessor..."	"[T]o avoid physical waste of gas the lessee shall consume it beneficially or market it or return it to productive formation" "Production of oil and gas...shall be limited by the market demand... for oil" 30 C.F.R. § 221.35
4-1158 (Sept. 1954)	Mineral Lands Leasing Act of 1920, 30 U.S.C. § 181 et seq.	"When paid in amount of production...royalty products shall be delivered in merchantable condition on the premises where produced without cost to lessor..."	"[T]o avoid physical waste of gas the lessee shall consume it beneficially or market it or return it to productive formation" "Production of oil and gas...shall be limited by the market demand... for oil" 30 C.F.R. § 221.35

Duty to Market			
4-1255 (May 1954)	Outer Continental Shelf Lands Act, 43 U.S.C. § 1331 et seq.	None	"The lessee shall put in marketable condition, if commercially feasible, all products produced from the leased land and pay royalty thereon without recourse to the lessor for deductions on account of costs of treatment" 30 C.F.R. § 250.41(b)(1956) Effective May 8, 1954 19 Fed. Reg. 2656 (1956)
4-213 (April1956)	Mineral Lands Leasing Act of 1920, 30 U.S.C. § 181 et seq.	"When paid in amount of production...royalty products shall be delivered in merchantable condition on the premises where produced without cost to lessor..."	"[T]o avoid physical waste of gas the lessee shall consume it beneficially or market it or return it to productive formation" "Production of oil and gas...shall be limited by the market demand... for oil" 30 C.F.R. § 221.35
4-213 (Sept. 1961)	Mineral Lands Leasing Act of 1920, 30 U.S.C. § 181 et seq.	"When paid in amount of production...royalty products shall be delivered in merchantable condition on the premises where produced without cost to lessor..."	"[T]o avoid physical waste of gas the lessee shall consume it beneficially or market or return it to productive formation" "Production of oil and gas...shall be limited by the market demand... for oil" 30 C.F.R. § 221.35

Duty to Market			
4-1255 (July 1962)	Outer Continental Shelf Lands Act, 43 U.S.C. § 1331 et seq.	None	"The lessee shall put in marketable condition, if commercially feasible, all products produced from the leased land and pay royalty thereon without recourse to the lessor for deductions on account of costs of treatment" 30 C.F.R. § 250.41(b)
4-1255 (Sept. 1963) Revised	Outer Continental Shelf Lands Act, 43 U.S.C. § 1331 et seq.	None	"The lessee shall put in marketable condition, if commercially feasible, all products produced from the leased land and pay royalty thereon without recourse to the lessor for deductions on account of costs of treatment" 30 C.F.R. § 250.41(b)
5-154 h (Oct. 1964) Indian Lease	25 U.S.C. § 396	"marketable product"	"[T]o avoid physical waste of gas the lessee shall consume it beneficially or market it or return it to productive formation" "Production of oil and gas...shall be limited by the market demand... for oil" 30 C.F.R. § 221.35

Duty to Market			
3380-1 (Feb. 1966)	Outer Continental Shelf Lands Act, 43 U.S.C. § 1331 et seq.	None	"The lessee shall put in marketable condition, if commercially feasible, all products produced from the leased land and pay royalty thereon without recourse to the lessor for deductions on account of costs of treatment" 30 C.F.R. § 250.41(b)
3120-7 (Feb. 1968)	Mineral Lands Leasing Act of 1920, 30 U.S.C. § 181 et seq.	"When paid in amount of production...royalty products shall be delivered in merchantable condition on the premises where produced without cost to lessor..."	"[T]o avoid physical waste of gas the lessee shall consume it beneficially or market it or return it to productive formation" "Production of oil and gas...shall be limited by the market demand... for oil" 30 C.F.R. § 221.35
3380-1 (Oct. 1969)	Outer Continental Shelf Lands Act, 43 U.S.C. § 1331 et seq.	None	"The lessee shall put in marketable condition, if commercially feasible, all products produced from the leased land and pay royalty thereon without recourse to the lessor for deductions on account of costs of treatment" 30 C.F.R. § 250.41(b)

Duty to Market			
3300-1 (Feb. 1971)	Outer Continental Shelf Lands Act, 43 U.S.C. § 1331 et seq.	None	"The lessee shall put in marketable condition, if commercially feasible, all products produced from the leased land and pay royalty thereon without recourse to the lessor for deductions on account of costs of treatment" 30 C.F.R. § 250.42(b) Effective, August 22, 1969 34 Fed. Reg. 13546 (1969)
3300-1 (May 1976)	Outer Continental Shelf Lands Act, 43 U.S.C. § 1331 et seq.	None	"The lessee shall put in marketable condition, if commercially feasible, all products produced from the leased land and pay royalty thereon without recourse to the lessor for deductions on account of costs of treatment" 30 C.F.R. § 250.42(b)
3300-1 (Dec. 1976)	Outer Continental Shelf Lands Act, 43 U.S.C. § 1331 et seq.	None	"The lessee shall put in marketable condition, if commercially feasible, all products produced from the leased land and pay royalty thereon without recourse to the lessor for deductions on account of costs of treatment" 30 C.F.R. § 250.42(b)

Duty to Market			
3110-2 (Feb. 1977)	Mineral Lands Leasing Act of 1920, 30 U.S.C. § 181 et seq.	"When paid in amount of production...royalty products shall be delivered in merchantable condition on the premises where produced without cost to lessor..."	"[T]o avoid physical waste of gas the lessee shall consume it beneficially or market it or return it to productive formation" "Production of oil and gas...shall be limited by the market demand... for oil" 30 C.F.R. § 221.35
3120-7 (Feb. 1977)	Mineral Lands Leasing Act of 1920, 30 U.S.C. § 181 et seq.	"When paid in amount of production...royalty products shall be delivered in merchantable condition on the premises where produced without cost to lessor..."	"[T]o avoid physical waste of gas the lessee shall consume it beneficially or market it or return it to productive formation" "Production of oil and gas...shall be limited by the market demand... for oil" 30 C.F.R. § 221.35
3300-1 (Sept. 1978)	Outer Continental Shelf Lands Act, 43 U.S.C. § 1331 et seq.	None	"The lessee shall put in marketable condition, if commercially feasible, all products produced from the leased land and pay royalty thereon without recourse to the lessor for deductions on account of costs of treatment" 30 C.F.R. § 250.42(b)

Duty to Market			
MMS-2005 (Aug. 1982)	Outer Continental Shelf Lands Act, 43 U.S.C. § 1331 et seq.	None	"The lessee shall put into marketable condition, if commercially feasible all products produced from the leased land. In calculating the royalty payment, the lessee may not deduct the costs of treatment" 30 C.F.R. § 250.42 Effective October 26, 1979 44 Fed. Reg. 61892 (1979)
3100-11 (March 1984)	Mineral Lands Leasing Act of 1920, 30 U.S.C. § 181 et seq.	"When paid in kind, production shall be delivered unless otherwise agreed to by lessor, in merchantable condition on the premises where produced without cost to the lessor"	"[T]o avoid physical waste of gas the lessee shall consume it beneficially or market it or return it to productive formation" 30 C.F.R. § 206.100 (1983) Effective August 5, 1983 48 Fed. Reg. 35639 (1983)
MMS-2005 (March 1986)	Outer Continental Shelf Lands Act, 43 U.S.C. § 1331 et seq.	None	"The lessee shall put into marketable condition, if commercially feasible all products produced from the leased land. In calculating the royalty payment, the lessee may not deduct the costs of treatment" 30 C.F.R. § 250.42

Dc- 8082

Attachment 8

by any Party of its proportionate share of the Production shall be borne by that Party. Any Party taking its share of Production in kind shall be required to pay for only its proportionate share of the part of the Unit's surface facilities that it uses. Each Party shall execute such division orders and contracts as may be necessary for the sale of its interest in Production from the Unit Area, and, except as provided in Article 28, shall be entitled to receive payment directly from the purchaser thereof for its share of all Production.

6.5 Failure to Take in Kind. Should any party fail to take in kind or separately dispose of its share of Production, the following provisions shall apply:

A. Disposition of Oil. If any Party fails to take in kind or separately dispose of its proportionate share of the oil produced from the Unit Area, Unit Operator shall have the right (which right is subject to revocation at will by the non-taking Party), but not the obligation, to purchase such oil or sell it to others at any time and from time to time for the account of the non-taking Party, after first giving the non-taking Party 10-days' written notice of the intended purchase or sale and the price to be paid or the pricing basis to be used. An owner of oil production shall always have the right, exercisable at any time, to take in kind, or separately dispose of, its share of all oil not previously committed to a purchaser. Any purchase or sale by Unit Operator shall be only for such reasonable periods of time as are consistent with the minimum needs of the industry under the particular circumstances, but in no event for a period in excess of 1 year. Any purchase or sale by Unit Operator shall be in a manner commercially reasonable under the circumstances, but Unit Operator shall have no duty to share any existing market or transportation arrangement or to obtain a price or transportation fee equal to that received under any existing market or transportation arrangement. Unit Operator may discontinue the purchase or sale of oil for any non-taking Party by giving the non-taking Party 10-days' prior written notice. The sale or delivery by Unit Operator of a non-taking Party's share of oil Production under the terms of any contract of Unit Operator shall not give the non-taking Party any interest in or make the non-taking Party a party to the contract. Unit Operator may deduct from the revenue payable to the non-taking Party the actual costs that Unit Operator incurs for making the oil marketable and delivering the oil to market, as well as any Lease Burdens and production and severance taxes paid for the non-taking Party's account that are attributable to the non-taking Party's proportionate share of oil Production.

B. Disposition of Gas. If any Party fails to take in kind or separately dispose of its proportionate share of gas produced from the Unit Area, Unit Operator shall have the right (which right is subject to revocation at will by the non-taking Party) but not the obligation, to purchase such gas or sell it to others at any time and from time to time, for the account of the non-taking Party, after first giving the non-taking Party 30-days' written notice of the intended purchase or sale and the price to be paid or the pricing basis to be used. An owner of gas Production shall always have the right, exercisable at any time, to take in kind, or separately dispose of, its share of gas not previously committed to a purchaser. Any purchase or sale by Unit Operator shall be only for such reasonable periods of time as are consistent with the minimum needs of the industry under the particular circumstances, but in no event for a period in excess of 1 year. Any purchase or sale by Unit Operator shall be in a manner commercially reasonable under the circumstances, but Unit Operator shall have no duty to share any existing market or transportation arrangement or to obtain a price or transportation fee equal to that received under any existing market or transportation arrangement. Unit Operator may discontinue the purchase or sale of gas Production for any non-taking Party by giving the non-taking Party 30-days' prior written notice. The sale or