Society of Petroleum Engineers

SPE 52966

Valuation of the Total Federal Economic Benefits Associated With the U.S. Dept. of Energy's NOSR 1 and 3 Properties in Western Colorado: A Case Study

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Abstract

Recently, the U.S. government decided the Naval Petroleum and Oil Shale Reserves (NPOSR) were no longer strategically significant to the federal government. This prompted the U.S. Congress to order an evaluation of various options that included retention, transfer, or sale of the NPOSR by the Department of Energy (DOE).

The DOE retained Gustavson Associates, Inc. in 1996 to conduct a portion of the studies ordered by the U.S. Congress. For this paper, we profile the evaluation of NOSR 1 and 3, since it presented unique challenges. These include the evaluation of both surface and mineral rights, complex economic and regulatory issues specific to each option, the determination of applicable discount rates to government versus industry, and the effects of costs associated with environmental liabilities and compliance.

The following strategies were used to meet the challenges: 1) a multidisciplinary effort for evaluation of both the surface and mineral rights, 2) calculation of different discount rates that would apply to both government and industry, 3) use of a specialized model for projection of economic benefits to the federal government under each scenario, 4) research on comparable sales of similar surface and mineral properties, 5) adherence to appraisal standards for estimation of Fair Market Value, and 6) application of the unit rule when appraising both surface and mineral rights.

Introduction

From 1912 to 1924, the federal government established three petroleum reserves and three oil shale reserves in four western states. These lands were set aside as strategic fuel supplies for the U.S. Navy. The properties are commonly referred to as Naval Petroleum Reserve (NPR) numbers 1, 2, and 3 and Naval Oil Shale Reserve (NOSR) numbers 1, 2, and 3. The total acreage set aside was approximately 232,000 acres.

In 1977, the federal government transferred the subject properties to the newly formed Department of Energy (DOE) for continued operations and maintenance. Recently, the Naval Petroleum and Oil Shale Reserves (NPOSR) were deemed to be no longer strategically significant to the federal government. This prompted the U.S. Congress to order an evaluation of various options that included retention, transfer, or sale of the NPOSR by the DOE.

The general scope of work advised that four options or scenarios be analyzed:

1) Retention and continued operations of the properties by the DOE,
2) Transfer of all or part of the properties to the Department of Interior (DOI) for leasing to private industry and/or individuals,
3) Transfer of all or part of the properties to another federal agency,
4) Outright sale of the federal government's interest to the market.

The options were to be ranked according to the potential for "maximizing economic value" to the federal government.

Property Summary for NOSR 1 and 3

With the exception of 600 acres of private oil shale claims, the United States of America owns 100 percent of the mineral rights in the NOSR 1 and 3 properties. This 56,577.15 acre area is located in Garfield County in Western Colorado (**Fig. 1**). These tracts were set aside as an oil shale reserve for the U.S. Navy by an Executive Order of President Wilson in 1916. NOSR 1 and 3 consists of approximately 88 square miles in Townships 5 and 6 South, Ranges 93 to 95 West. At the time of the study, management of NOSR 1 and 3 was the responsibility of the DOE.

NOSR 1 and 3 are located in the rugged highland country of western Colorado. The two NOSR sites are adjacent to one another and consist of approximately 36,406 acres on NOSR 1 and 20,171 acres on NOSR 3. The high mesa that characterizes NOSR 1 is underlain by the oil shale deposits of the Green River formation that were resistant to erosional processes over geologic time. This forms a spectacular escarpment known as the Roan Cliffs. NOSR 1, at a peak elevation of 9,300 feet above sea level is on top and to the north of Roan Cliffs. The terrain is typified by large gently rolling mesa to canyons that are gently rolling on the eastern end of the parcel and very deep and steep-sided as they traverse the property to the west.

NOSR 3 to the south stands at an elevation of 6,000 feet above sea level. The terrain is moderately steep on the lower end of the Roan Cliffs and extremely steep higher up on the cliffs. This parcel contains little to no level ground.

Characterization of the physical terrain was an important consideration in the study. Topographic variations affect physical access; hence, drilling and operating costs depend on well location. Oil and gas operators in the Piceance Basin prefer low relief or valley acreage because it is generally less expensive to drill and conduct well operations there. High plateau acreage may even be periodically inaccessible in the winter months. This results in curtailed production for wells situated in these difficult areas. The above factors were considered in the overall evaluation of the NOSR 1 and 3 properties.

The Secretary of the Navy and, through subsequent transfer of responsibility, the Secretary of Energy, were authorized to "explore, prospect, conserve, use and operate" the Naval Petroleum and Oil Shale Reserves, including NOSR 1 and 3. This authority was given provided that use and operation be for 1) the protection, conservation, maintenance and testing of the reserve, or 2) production of petroleum whenever such production is required for national defense.[1]

Geologic Setting

The NOSR 1 and 3 properties are located in the central portion of the Piceance Basin of northwestern Colorado (Fig. 1). The Piceance Basin is a Mesozoic/Tertiary-age structural and topographic basin which trends northwest-southeast across portions of Delta, Garfield, Rio Blanco, and Moffat counties.[2] The basin is strongly asymmetrical with a steeply dipping and thrust-faulted northeastern flank and a gently dipping southwestern limb. The basin axis lies at the toe of the steep eastern limb.

Stratigraphy. A thick sedimentary package of Paleozoic, Mesozoic, and lower Tertiary rocks underlies the NOSR 1 and 3 properties. The principal established gas-bearing horizons are restricted to the Tertiary and Cretaceous units, with most of the production confined to sandstones within the Eocene Wasatch Formation and the underlying Upper Cretaceous Mesaverde Group. For the purposes of this paper, only the Upper Cretaceous/Tertiary stratigraphy will be discussed in detail. A type log for the vicinity of NOSR 1 and 3 shows the main gas-producing intervals within the Wasatch and Mesaverde sequences **(Fig. 2)**.

Wasatch Formation. The Paleocene/Eocene Wasatch Formation is the stratigraphically highest gas-producing zone in and adjacent to NOSR 1 and 3. The formation consists of a thick sequence of sandstones interbedded with varicolored shales, claystones, and siltstones of continental origin. The sandstones are lenticular bodies that are laterally very discontinuous and randomly distributed throughout the section. They were deposited in river channels cut into alluvial shales and claystones.

The Wasatch Formation in this portion of the Piceance Basin has been divided into three members (Fig. 2). The lowest member, the Atwell Gulch, rests on strata of the Mesaverde Group and is correlated to the Fort Union Formation of Wyoming. Overlying the Atwell Gulch Member, is the Molina Member that contains the "G" sandstone, the main gas-producing Wasatch zone in the fields surrounding NOSR 1 and 3. This sand interval, unlike many of the others in the Wasatch Formation, is more continuous and can be correlated over several townships in the area around the Naval Reserves. It varies from less than 30 feet to over 100 feet in thickness,[3] and changes abruptly both in quality and thickness. The uppermost Wasatch consists of the Shire Member. This latter member is exposed in the Colorado River Valley and is considered of no economic significance.

In the vicinity of NOSR 1 and 3, the Wasatch Formation varies in thickness from about 3,500 to 5,900 feet. Wells immediately northwest of NOSR 1 encountered from 5,500 to 5,900 feet of Wasatch strata.

Mesaverde Group. The Upper Cretaceous Mesaverde Group includes the basal Iles Formation and the overlying Williams Fork Formation. The Iles Formation includes, in ascending order, the Corcoran, Cozzette, and Rollins Sandstone members. Tongues of the Mancos shale separate these regressive shoreline/marine sandstones. The Iles is approximately 700 to 750 feet thick.

The overlying Williams Fork Formation varies in thickness from 2,800 to 2,700 feet in thickness. The formation has been divided into units on the basis of environments of deposition[4]. These units consist of the lower paludal, the middle fluvial, and the upper paralic zones.

The basal unit is the Cameo paludal zone, comprised of interbedded sandstone, siltstone, shale, and coals. These rocks were deposited in a variety of lower delta plain paludal environments including delta front, distributary channels, swamps, and marshes. Sand body geometries vary from thin blanket deposits to laterally discontinuous lenticular channel sands. The coals are considered to be the main source rocks for the gas contained in both the Wasatch and Mesaverde reservoirs. The lower middle zone of the Williams Fork is referred to as the coastal zone and consists of lenticular upper delta plain distributary bodies. The upper middle portion of the formation is the fluvial zone, consisting of numerous composite sand bodies deposited in river meander belts as coalesced point bars. The upper 500 feet of the Williams Fork Formation is a paralic section with marine-influenced sedimentation in a coastal setting marking the beginning of the next transgressive cycle.

Gas reservoirs in the Mesaverde Group occur throughout the gas-saturated portion of the section, which encompasses most of the Iles Formation and all but the upper few hundred feet of the overlying Williams Fork Formation. To date, most Mesaverde production has been from sands and coals within the Williams Fork Formation.

By their very nature, Mesaverde sand bodies are discontinuous, complex and rather erratic in size, shape and distribution and result in compartmentalized reservoirs. Individual sand bodies may only be on the order of 750 feet in areal width and only 2 to 13 feet thick.[4] They are commonly stacked in a random fashion, typically resulting in composite meander belt sandstone reservoir units of 20 to 60 feet in thickness and 1,300 to 1,700 feet in width. As a result of the compartmentalization, well spacing for Mesaverde wells in the fields adjacent to and underlying NOSR 3 has been progressively reduced from 320 acres to as little as 40 acres, and in some cases 20 acres, in order to effectively drain the reservoirs.

Structure. NOSR 1 and 3 straddle the Piceance Basin axis and a portion of the gently dipping southwestern flank of the basin. Consequently, at the Wasatch and Mesaverde horizons, the regional dip is to the northeast. The regional homoclinal northeast dip is interrupted by a series of north to northwest plunging anticlines that are mappable in the Grand Valley, Parachute, and Rulison gas fields on the south side of the NOSR 3 property (see Fig. 1 for field locations).

No closed structures are present at the Mesaverde level and only minor ones are present at the shallower Wasatch horizon. Trapping of gas is not controlled or limited to structural closures at either horizon.

Analyses of two modern seismic lines across portions of NOSR 1 and 3[2,5] reveal a broad southwest-plunging anticlinal nose at the Wasatch and Mesaverde horizons with 250-280 feet of structural relief. Fracture development in the crestal portions of this feature may be significant in the enhancement of reservoir permeability within the Wasatch/Mesaverde sandstone reservoirs and also in deeper sandstone targets in the Dakota/Entrada formations.

Reservoir Characteristics

The Wasatch "G" sand net pay varies from less than 30 feet to more than 100 feet in individual wells, and is estimated to average about 70 feet on a field-wide basis.[2,3] The "G" sand log-derived porosity averages about 14 percent in productive wells but can be as high as 18 percent. Core-derived porosities are generally less, often in the range of 6.5 percent, as is the case in Rulison Field. Permeabilities are extremely low, generally less than 1.0 md and commonly less than 0.2 md.

Reservoir geometry and quality of individual sands in the Mesaverde Group are highly variable and erratic. Like the Wasatch sands, Mesaverde sands typically are moderately porous (10-12 percent log-derived, 7-9 percent core-derived). Similarly, permeabilities are extremely low, generally less than 0.1 md (Fouch et. al., 1994). The typical Mesaverde well contains about 260 feet of net sand pay on the average. In addition, about 50-70 of net pay is found in the Cameo coal beds. Most Mesaverde zones are commingled for production purposes.

Wasatch/Mesaverde Regional Gas Development

The U.S. Geological Survey has characterized the Wasatch/Mesaverde gas accumulation in the vicinity of NOSR 1 and 3 as a basin-center, continuous-type accumulation.[7] Similar accumulations have been identified in several of the deep Rocky Mountain intermontane basins.

In a basin-center accumulation, the deep basin gas-saturation zone cuts across formation boundaries. Within the zone of saturation, essentially water-free gas production can be established wherever the permeability is sufficient to yield commercial rates. Structural closure or updip stratigraphic pinch-outs are not required for trapping gas in this type of accumulation. In general, sandstone reservoirs in these deep-basin continuous accumulations are characterized by low porosities and extremely low permeabilities (usually less than 0.1 md). Artificial fracture enhancement of permeability is generally required for commercial gas production.

Wasatch and/or Mesaverde gas production has been established in 21 fields within the Piceance Basin (Fig. 1). Many of the fields were discovered in the 1950s or earlier; however, five of the fields were discovered in the 1980s as a result of the increased interest in, and the improved economics of, gas exploration partly driven by the federal tax credits for "tight gas sand" development. Many of these fields fall within the limits of the basin-center gas accumulation as defined by the USGS.

The three fields closest to NOSR 1 and 3 are, from east to west, Rulison, Parachute, and Grand Valley. Each of these fields extends onto NOSR 3 lands, with some wells communitized and operated by either the DOE or by industry operators. All three of the fields produce from both Wasatch and Mesaverde reservoirs and are considered to be part of the basin-center gas accumulation. Rulison Field was discovered in 1956, whereas Parachute and Grand Valley fields were discovered in 1985 and 1986, respectively.

Through December 1995, approximately 525 billion standard cubic feet of gas and associated liquids were produced from Piceance Basin fields, principally from Wasatch and Mesaverde reservoirs with a small component from the deeper Dakota Formation. Of the total basin cumulative gas production, 120 billion standard cubic feet (or 23 percent of basin total) were produced from Rulison, Parachute, and Grand Valley fields that adjoin NOSR 3. By the end of 1997, the same three fields had produced an additional 66 billion standard cubic feet of gas.

Oil and Gas Development on NOSR 1 and 3

Hydrocarbon production at the NOSR sites is from gas-bearing sands of the Mesaverde and Wasatch formations drilled as part of the Gas Protection Drilling Program initiated in the mid 1980s. The philosophy of this program was to drill in areas of the NOSR with offset production from other operators, which could threaten drainage from reservoirs underlying the NOSR property. No systematic development of the NOSR reserves had been undertaken at the time of the study. At that time, DOE had ownership interests in over 50 gas wells on or adjacent to the NOSR 3 property. DOE operated just over half these wells, with interests in the remainder being communitized wells.

In 1996, net DOE gas production was approximately 10 million cubic feet per day with very little associated condensate or water produced. Gas production operations at NOSR 3 were conventional by industry standards. Given the limited development, large amounts of acreage had development or infill drilling potential. However, well economics were very sensitive to gas price, and then current prices made further drilling development largely uneconomic at the time of the study.

NOSR 1 had no oil and gas development and the acreage was considered exploratory. Some areas were more prospective than others based on previous exploration work. Seismic data across NOSR 1 were analyzed for the purposes of identifying geologic prospects or leads on the property. A seismically defined structure had been previously identified in the southeast portion of NOSR 1, just north of the Rulison field. Due to the likely fracture-enhancement of reservoir quality associated with such structural features, this structure would be an attractive exploration prospect.

In addition, amplitude anomalies, which may be associated with improved reservoir quality, were identified at the Wasatch level on portions of the acreage. These characteristics indicated seismic leads and made this specific acreage more attractive than raw exploratory acreage.

As described previously, NOSR 1 contains large deposits of oil shale that prompted its acquisition by the federal government. The oil shale deposits of the Green River formation are estimated to contain 18 billion barrels of oil, of which approximately 3 billion barrels could be recoverable. Some limited oil shale development on the property occurred in the early 1980s, resulting in a spent shale pile that may require environmental remediation in the future.

Oil prices and costs of development and operation are such that it is uneconomic to mine and produce oil shale. Future prospects for oil shale development will require oil prices of over $100 per barrel to enable economic development. Consequently, the oil shale had no current economic value other than a speculative one.

Engineering Analysis – Oil and Gas Reserves

The NOSR 1 and 3 properties had underlying reserves in categories ranging from Proved Developed Producing (PDP) through Possible Undeveloped. All reserve categorization and reserve estimates included as part of the valuation of these properties conforms to the SPE reserve definitions.[9]

Proved Developed Reserves. Proved Developed Producing (PDP) reserves for the more than 50 producing gas wells on NOSR 3 were estimated utilizing decline curve analysis and gas material balance via p/z plots for each producing well. A comparison with the contract operator's reserve report yielded PDP reserves within 20 percent of these reserve estimates. Many of the individual wells that were previously forecast with exponential declines were reinterpreted with hyperbolic declines, reflecting the typical behavior of tight gas formations.

Proved Developed Non-Producing (behind pipe) reserves, primarily from the Wasatch Formation, were estimated volumetrically by using a detailed pore volume analysis with a conservative drainage area (20 acres) and gas recovery factor (60 percent of gas-in-place). Production forecasts for behind pipe reserves were scheduled as recompletions at the time the existing producing formation was no longer economical to produce.

The initial gas price used for economic forecasts at the time of the evaluation was $1.00 per thousand cubic feet, based on an average price of $0.95 per million British Thermal Units (BTU) and an average gas quality of 1,057 thousand cubic feet per million BTU. The initial condensate price used was $18.50 per barrel based on the average price paid by the crude oil purchaser. Both gas and condensate prices were escalated annually at 2.27 percent and 2.57 percent, respectively.

Operating costs were based on data presented by the DOE indicating that the average Wasatch well was operated for about $470 per month, and the average Mesa Verde well was operated for about $1,000 per month. These cost estimates were used only under the scenarios where the property was operated by the federal government. The ownership scenarios wherein the property was operated by industry utilized operating costs that were 5 percent lower.

Undeveloped Reserves. Although the previous reserve report did not include estimates of Proved Undeveloped (PUD) reserves, sufficient geologic and engineering data existed to evaluate potential PUD reserves for offset locations under the SPE reserve definition. In addition, many of the Piceance Basin operators commonly assigned PUD reserves to highly prospective acreage directly offset by a producing well.

The nature of the basin-center hydrocarbon accumulation within the Piceance Basin also resulted in significant areas that could be considered to contain Possible undeveloped reserves. DOE had prepared several studies on the full development of these reserves. We utilized much of the statistical data prepared by the USGS to evaluate full development of these properties. At the $1.00 per thousand cubic feet gas price, only four Wasatch offset locations were economic and so could be classified as having PUD reserves. None of the full field development of Possible reserves was economic; however, the economic viability for development was very sensitive to gas prices. Many of the more prospective locations in the Wasatch and Mesa Verde (both Possible and those which would have been considered PUD if not for the economic conditions) become commercial with only a \$0.50 per thousand cubic feet or \$1.00 per thousand cubic feet increase in wellhead gas price (**Fig. 3**).

All of the reserve estimates and engineering data compiled on these properties were plugged into the Federal Benefits Economic Model (discussed below) to estimate total federal economic benefits under numerous ownership scenarios. As stated, these properties had significant upside associated with the development of vast reserve potential which was not economically viable in the pricing environment at the time of this evaluation.

Environmental Expenses and Liabilities

Environmental expenses varied by scenario; however, all scenarios include the cost of a regional Environmental Impact Statement (EIS) and preparation of National Environmental Policy Act (NEPA) compliance documents. These expenses and compliance issues were included in each of the scenarios due to the regulatory framework of the federal government.

In addition, plugging and abandonment liability will be incurred for the existing wells on NOSR 3. The total net plugging and abandonment liability at NOSR 3 was estimated at \$1.2 million.

Federal Benefits Economic Model

The Federal Benefits Economic Model (FBEM) was prepared as part of the valuation of the Naval Petroleum and Oil Shale Reserves. FBEM was used to estimate the total economic benefits to the federal government for five of the Naval Petroleum and Oil Shale Reserves in the western United States which included the subject properties, NOSR 1 and 3. Reserve forecasts, cost estimates, and product pricing are plugged into the FBEM in conjunction with regional land data such as lease bonus and rentals, land maintenance costs, and other land income (such as grazing) to assess the value of a given property under the various ownership scenarios.

The FBEM was constructed in Lotus as three separate files that were linked to enable any given property and any given scenario to be independently evaluated. Development of FBEM was required given the unique evaluation needed for an oil and gas property operated by the federal government. The FBEM was also constructed so that parameters such as product pricing, reserve category risking, and operating costs could be easily changed to perform numerous sensitivities for any combination of these variables.

The various ownership scenarios required that the FBEM develop hypothetical cash flows for both government-operated and industry-operated scenarios. Several different federal ownership scenarios had to be estimated. For example, the "Transfer to the Department of Interior" option required that total federal benefits be estimated through the Bureau of Land Management (BLM), not as the operator, but as the agency leasing the property to industry. Therefore, with respect to the oil and gas cash flows, federal benefits had to be derived from lease bonus and rentals as well as the federal royalty collected on oil and gas production.

Several of the options where the federal government did not operate the properties also required that estimates of total federal income tax generated by the operator of the property be estimated. The model calculated these cash flows as part of the total benefits to the government under any non-operated scenario. These income tax estimates were based on the total income generated to the operator by the subject property.

In summary, the FEBM was developed as part of this project due to the following unique appraisal requirements: 1) federal ownership and operation of the properties, 2) several alternate federal and non-federal ownership scenarios to be considered, 3) interests in partially developed oil and gas properties with additional land costs and income not derived from the development and production of oil and gas, and 4) the need to evaluate several different properties under numerous ownership scenarios and sensitivities to determine the option yielding the greatest total federal economic benefits.

Calculation of Discount Rates

The appropriate discount rate for estimating the net present value (NPV) of a cash flow stream is a function of the recipient's cost of capital and perception of risk associated with realizing the predicted cash flow. Thus it was necessary to calculate separate discount rates for the four different scenarios. These discount rates were then used to estimate the net present value of various different income streams derived from oil and gas production and leasing. The methodology for estimating the various discount rates is described below.

Cost of Capital. The office of NPOSR, as part of the federal government, has the same cost of capital as the U.S. Government. The federal government raises capital through the sale of Treasury bonds and bills (T-bonds and T-bills). The weighted average of the portion of the debt in each of the various denominations determines the government's cost of capital. The resulting value for the one-year period prior to this evaluation ranges between five and seven percent (**Fig. 4**). An estimated cost of capital is based upon the mean for all government interest rates, which is roughly equivalent to the five-year T-bond rates. The rate for the five-year T-bond has risen from a low of 5.25 to a rate over 6.5 percent between mid-February and August 1, 1996. Our analysis assumes the federal government's cost of capital to be 6.5 percent.

The cost of capital is typically higher for private industry than for the federal government. Based on the annual survey conducted by the Society of Petroleum Evaluation Engineers (SPEE), on the average the industry cost of capital was perceived at 10.2 percent in the spring of 1996.

Perception of Risk. To determine the applicable discount rate, the various components of the perception of risk are added to the cost of capital. The risk of achieving the predicted cash flow from producing oil and gas operations can be divided into three major components, the combination of which yields the cash flow risk. These three components are the price, production, and operating cost risks.

Price Risk. Price risk is estimated to equal three percent. The efforts by industry to protect themselves from oil and gas price fluctuations – through the use of hedging, futures selling and other activities – has historically resulted in adding three percent to cost of capital. In other words, those who use these risk-reducing instruments are able to lower their cost of capital approximately three percent.

Production Risk. There is production risk in obtaining oil and gas that is unique to the petroleum industry. As opposed to other sectors of the mineral extraction industry, oil and gas production declines significantly over time. Historically, the sale of mineral extraction operations for other types of minerals, such as aggregate stone, marble quarries, etc., are purchased based upon a lower discount rate than petroleum production operations. For comparable examples, the difference – approximately two percent – is assumed to be attributable to the uncertainty in forecasting oil and gas production.

Operating Risk. Increases in operating cost result in lowering the NPV. The risk of higher than forecast operating cost results in increasing the discount rate by two percent. This difference is apparent when two similar property sales are compared where the only difference between the two sales is the type of interest being purchased. Historically, a working interest purchase is based upon a discount rate that is approximately two percent higher than a similar purchase of only the royalty interest.

Total. Based on our analysis, the total estimated perception of risk is estimated at seven percent over and above the cost of capital. The result of combining the government's cost of capital (6.5 percent) with the seven percent for the perception of risk provides a nominal discount rate of 13.5 percent.

Combining the private industry cost of capital of 10.2 percent with the seven-percent risk perception provides a nominal discount rate of 17.2 percent. This is the discount rate that was applied when evaluating producing reserves from the perspective of the private oil industry.

For the nonproducing NOSR 1 and NOSR 3 acreage, land leasing activities were considered under some scenarios. Such activities include price risk. As such, three percent is added to the 6.5 percent government cost of capital discussed above. The resulting 9.5 percent discount rate was then used to estimate NPV of the land leasing activities.

The discount rates derived in this analysis were applied when considering the different options and types of property being evaluated.

Ranking of Options

Retention Option. Under this option, the future net income is from production of the proved reserves on NOSR 3. DOE would continue to operate the wells drilled as part of the Gas Protection Drilling Program, and develop reserves in other categories described previously.

The bulk of the cash flow stream is derived from the proved producing wells with minor contribution from behind-pipe reserves and one proved undeveloped location. A total of 16.3 billion standard cubic feet of gas was projected to be produced over the next twenty years. Gas prices were relatively low due to restricted access and depressed markets.

Since the U.S.A owns 100 percent of the minerals, the DOE pays no royalties to any other parties. In addition, the DOE is exempt from any state severance or local ad valorem taxes.

The main costs included operating expenses and one-time capital expenditures associated with drilling and completion. One proved undeveloped Mesaverde location was projected to be drilled, since it was scheduled in the DOE operating plan. Costs of participating in a planned regional EIS were estimated at $200,000. Plugging and abandonment expenses were deducted in the years that the wells become uneconomic.

The NPV of this cash flow stream was estimated using the calculated discount rates described previously. For this option, a discount rate of 13.5 percent was used since it involves the federal government.

No income from leasing was included in this scenario, since the DOE does not serve this function. Consequently, no income was derived from NOSR 1 in this option, since it had no established production and no leasing activity. Since costs were involved with maintaining the property and the participation in a regional EIS ($100,000) the value of NOSR 1 was negative under this scenario.

Transfer to the Department of Interior. Analysis of this option required consideration of the Mineral Leasing Act of 1920 and the Mineral Leasing Act for Acquired Lands of 1947. These acts give the BLM responsibility for oil and gas leasing on BLM, national forest and other federal lands where mineral rights have been retained by the federal government.

If the properties were transferred to the Department of Interior, the BLM would be assumed to offer all or portions of the acreage at competitive lease sales in the future. Consequently, this option required simulation of oil and gas lease sale transactions based on a hypothetical offering by the DOI to the market.

Prior to offering the properties for lease sales, BLM would be required to prepare NEPA documents in order to meet compliance requirements. The estimated cost for this was estimated at $600,000 for each property.

Since leasing would be involved, it was necessary to obtain market data from competitive oil and gas lease sales in Western Colorado (**Fig. 5**). The amount of bonus consideration was then posted on a base map for the purposes of comparing acreage throughout the study area. The elements of comparison used in this analysis included topography, proximity to production, geologic trend areas, and time of sale (**Table 1**).

Overall, the NOSR 3 acreage was expected to command higher bonus bids than NOSR 1 at a competitive lease sale.

The areas of NOSR 3 close to existing production and have relatively low surface elevations (in the valley) would be sought after by oil and gas companies seeking to expand the producing areas of Grand Valley, Parachute, and Rulison gas fields.

Approximately 4,761 acres on NOSR 3 have existing production. It was assumed under this option that the BLM would lease all of this acreage at a competitive lease sale. In considering bonus amounts, oil and gas companies would tender bonuses that would result in a reasonable rate of return. In essence, the bonus would be close to what the property would sell for outright (royalty burden considered) since the BLM would be (in most cases) assigning an 87.5 percent lease with existing wellbores.

The market bonus was estimated based on a net present value discounted at 17.2 percent. Since half of this money is required to be shared with the State of Colorado in order to compensate for impacts from mineral development, the net income to the U.S. Government was reduced by half.

There will be royalty income from the existing production based on a 12.5 percent burden. The net present value from this income stream is $540,000. In addition, the federal government will receive income taxes from the producer. Taxable income was estimated after deductions for depreciation and depletion expenses which was calculated by the Federal Benefits Economic Model. This income stream has a value of $551,000.

At the time of the study, it was uneconomic to drill and develop offsetting acreage at the low gas prices. Consequently, this acreage was valued based on market bonuses that might be received in hypothetical lease transactions.

If gas prices increased and stabilized at or above $1.50 per thousand cubic feet, substantial value would be added. A number of undrilled locations would be considered Proved Undeveloped and likely drilled.

Approximately 2,720 acres are in very close proximity to existing production, and for the most part would be considered as Proved Undeveloped locations at a higher gas price. The market bonus for this acreage was estimated at $200 per acre. This was based on recent sales of comparable, undeveloped properties in close proximity to production.

About 4,000 acres in NOSR 3 are on trend with existing fields but are less accessible due to steep slopes. This acreage is expected to receive bonuses in the $65.00 per acre range. Directional drilling may be used to overcome accessibility problems but would increase well costs.

The remaining balance of NOSR 3 acreage (8,700 acres) is considered low-potential acreage and the market bonus is estimated at $5.00 to $15.00 per acre. This acreage is either in structurally low areas or located some distance from production.

Based on this analysis, the weighted average bonus is estimated at $56.50 per net mineral acre for all of NOSR 3 excluding the producing acreage. We assumed that not all of the acreage would be leased at once, but that leasing would be staggered over a two-year period. In addition to cash bonuses, income from rentals are also included. Future income is discounted at 10 percent due to the low risk associated with oil and gas leasing.

The undeveloped acreage had income from both surface and mineral uses, with the majority of the income from mineral leasing. However, because of the high cost of the NEPA compliance and because of the 50 percent revenue sharing with the State of Colorado the resulting value was negative.

When the negative value for the undeveloped acreage is combined with the positive value for the producing acreage, this results in a positive value, lower than that for the retention option.

NOSR 1 was evaluated in a similar manner and the result was a negative value. As mentioned previously, NOSR 1 has no established production and future income from leasing would be less than NOSR 3.

Transfer to Another Federal Agency. Several other federal agencies were considered for transfer, but none were found to be suitable for this purpose. Therefore, no assessment of the value to be derived by the United States from the transfer to another federal agency was made.

Sale of the Property. This task required an appraisal of the Fair Market Value for the NOSR 1 and 3 properties. The appraisal was conducted in accordance with appraisal standards, which included a determination of highest and best uses for the various components of the property, utilization of different appraisal methods and application of the unit rule. It is beyond the scope of this paper to provide detailed descriptions of underlying appraisal theory. The reader is referred to referenced publications listed at the end of this paper.[7,8]

For the developed portions of NOSR 3, the highest and best use is for income from oil and gas production from the gas wells on the property. At the time of the study, it was not economic to drill offset or undeveloped locations.

On the undeveloped portions of NOSR 1 and 3, the highest and best use is for income from leasing that would be tendered by oil companies seeking to explore and develop the properties. Alternatively, the undeveloped mineral rights could be sold to a party interested in speculating on the future development of the acreage.

Based on the above highest and best use determinations, the Comparable Sales Method and the Income Method were utilized to estimate Fair Market Value. Research for comparable sales of similar properties included sales of producing and non-producing properties.

Approximately three to four sales were found that involved a cash consideration for producing gas reserves in the Piceance Basin. Analysis of these sales indicated an average unit price of $0.46 per thousand cubic feet in the ground.

Sales of undeveloped acreage in the Piceance Basin were also researched and analyzed for this study. These sales involved outright purchases of fee mineral rights wherein the unit price is typically reported on a dollar per acre basis. Indicated values were in the range of \$5.00 to \$220 per net mineral acre depending on the level of oil and gas development on the property.

The average value to the NOSR 1 acreage was estimated to be in the range of \$25.00 per net mineral acre. The vast majority of the property was considered exploratory; however, it does contain a seismic structure on the eastern side, which would generate interest for a deep exploratory target.

Excluding the producing acreage, some of the NOSR 3 acreage was expected to command a sale price in the range of \$200 per acre given its proximity to existing production. Other acreage would sell for much less. We estimated that the property would sell for \$75 per net mineral acre on average.

As described previously, the oil shale resources at NOSR 1 and 3 had no economic value for mineral production but rather a nominal value for speculative uses in the future. We have estimated this nominal value at \$10.00 per acre, since every right has a value.

The Income Approach was also utilized for evaluation of the properties in order to estimate Fair Market Value. The approach was similar to that used in the retention option for the producing wells. A discount rate of 17.2 percent was used in order to reflect private industry. In addition, the revenue from income taxes was considered as a benefit to the federal government.

The undeveloped acreage could also be anticipated to generate income from leasing. A fee mineral owner could expect to receive bonuses and rentals in exchange for granting leases. In this regard, leasing income was projected in a model similar to the one described in the previous option.

The Comparable Sales and Income Approaches were then reconciled in order to estimate Fair Market Value for the mineral interest. It was then necessary to value the property as a whole for inclusion of the surface rights. This required the application of the unit rule, which is part of appraisal standards. Simply stated, the unit rule does not allow separate components of a fee simple estate to be simply added in order to estimate value. To put it another way, the value of the surface plus the value of the minerals does not equal Fair Market Value.

The separate components of a fee simple estate must be considered in light of their overall contribution, and must not be mutually exclusive with other uses. In the case of NOSR 1, the surface appeared to be the dominant estate because of established uses (recreation and livestock grazing), versus being an undeveloped oil and gas property.

The case is the opposite for NOSR 3, given the established production on the property and its proximity to existing oil and gas fields versus limited surface uses. In both cases, the surface and mineral uses of the properties were not found to be mutually exclusive. These factors were taken into account in the final estimate of Fair Market Value for the entire fee simple estate of the NOSR 1 and NOSR 3 properties.

Sale of the subject property would be considered a major federal action and would require the preparation of an EIS as a result. The estimated cost for preparation of an EIS was deducted from the estimated sale price. Additional expenses for the sale option were the costs associated with divestiture. These costs, estimated to be in the range of \$1.5 million, were also deducted from the sale price.

Taking all of these factors into account, the estimated value from the sale option was considerably higher than the value from the other options (**Fig. 6**).

Summary of Ranking. The various options were ranked as follows:

1. Sale of the Properties
2. Retention by DOE
3. Transfer to DOI

The Sale Option was substantially higher in value for NOSR 1 and only slightly higher in value for NOSR 3 than retention by the DOE.

Retention by DOE is second because of the established revenue stream from oil and gas production and the fact that this agency is exempt from revenue sharing and taxes. However, development of the acreage for oil and gas is limited to protection from drainage, which does not allow maximum development of the acreage.

Transfer to DOI ranked last primarily because of revenue sharing with the State of Colorado. The federal government bears all of the costs to maintain the properties and conduct the sales but only receives one half of the revenues. In addition, the revenue received from surface leases is minimal compared to the cash received from selling it on the market.

Conclusions

The recent work for the DOE provides a unique insight for valuing oil and gas properties from the perspective of both the federal government and private industry. Proper evaluation of complex surface and mineral estates properties requires a multidisciplinary approach in order to address the full range of issues that will likely be encountered.

Evaluation of the NPOSR properties from the federal government standpoint required the calculation of applicable discount rates based on the government's cost of capital and perception of risk. Appropriate discount rates will be lower for the federal government than for industry when estimating the net present value of a future cash flow stream from oil and gas properties.

The use of a Federal Benefits Economic Model was necessary for evaluating the four options in this study, given the sometimes intricate and complex issues involved with the federal government.

The unit rule should be applied when the property contains separate components of the fee simple estate and it is a requirement to estimate the Fair Market Value of the whole property. The separate uses of the property should be considered in light of their contribution to the value of the property and not simply be summed or added together.

Of the scenarios considered, the Sale Option was first-ranked because cash considerations from the market had a higher value than continued operation by other federal agencies. Retention by the DOE was ranked second and transfer to DOI ranked third. The transfer to DOI was ranked last, mainly because of 50 percent revenue sharing with the state government.

Nomenclature

p = *average reservoir pressure*
z = *gas compressibility factor*

Acknowledgements

We thank Department of Energy, Office of NPOSR, and Gustavson Associates for permission to publish this paper.

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SI Metric Conversion Factors

acre × 4.046 873	E-01	= ha
bbl × 1.589 873	E-01	= m^3
ft × 3.048*	E-01	= m
ft^3 × 2.831 685	E-02	= m^3
md × 9.869 233	E-04	= μm^2
mi^2 × 2.589 988	E+02	= ha

*Conversion factor is exact

Table 1—Ranking and market bonus for NOSR 1 and 3 acreage

Acreage Description	Acres	Market Bonus per Acre
NOSR 3		
Acreage with production	4,761	$893
Acreage close to production	2,720	$200
Trend acreage	4,000	$65
Structural low areas	2,150	$15
Exploratory acreage	6,540	$5
Weighted average bonus		***$246***
NOSR 1		
Seismic structure acreage	5,000	$75
Amplitude anomaly acreage	13,000	$10
Exploratory acreage	18,406	$5
Weighted average bonus		***$16.50***

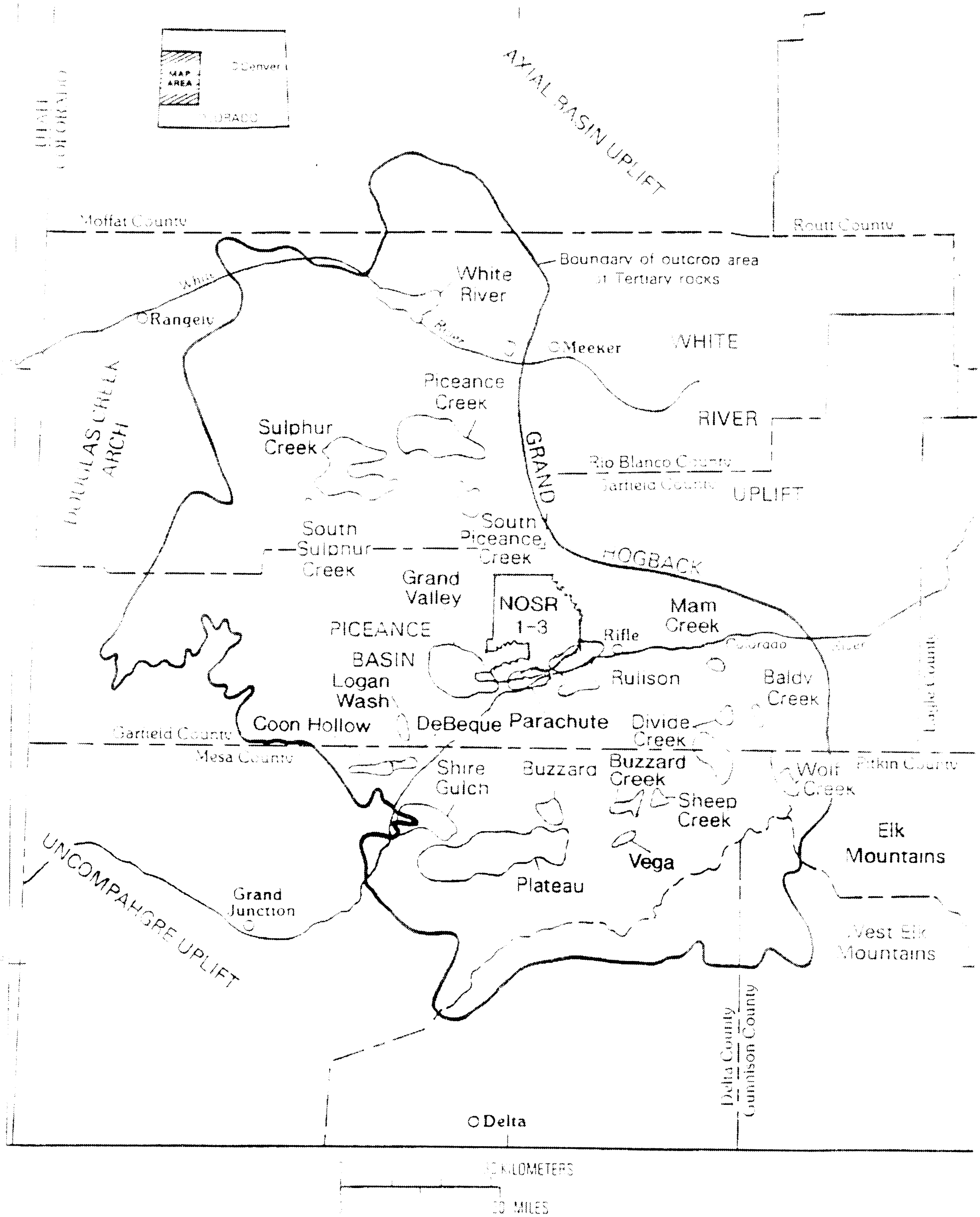

Fig. 1—Locator map of area showing the Piceance Basin, NOSR 1 and 3, and major gas fields in the area. (Modified version of figure, Ref. 9.)

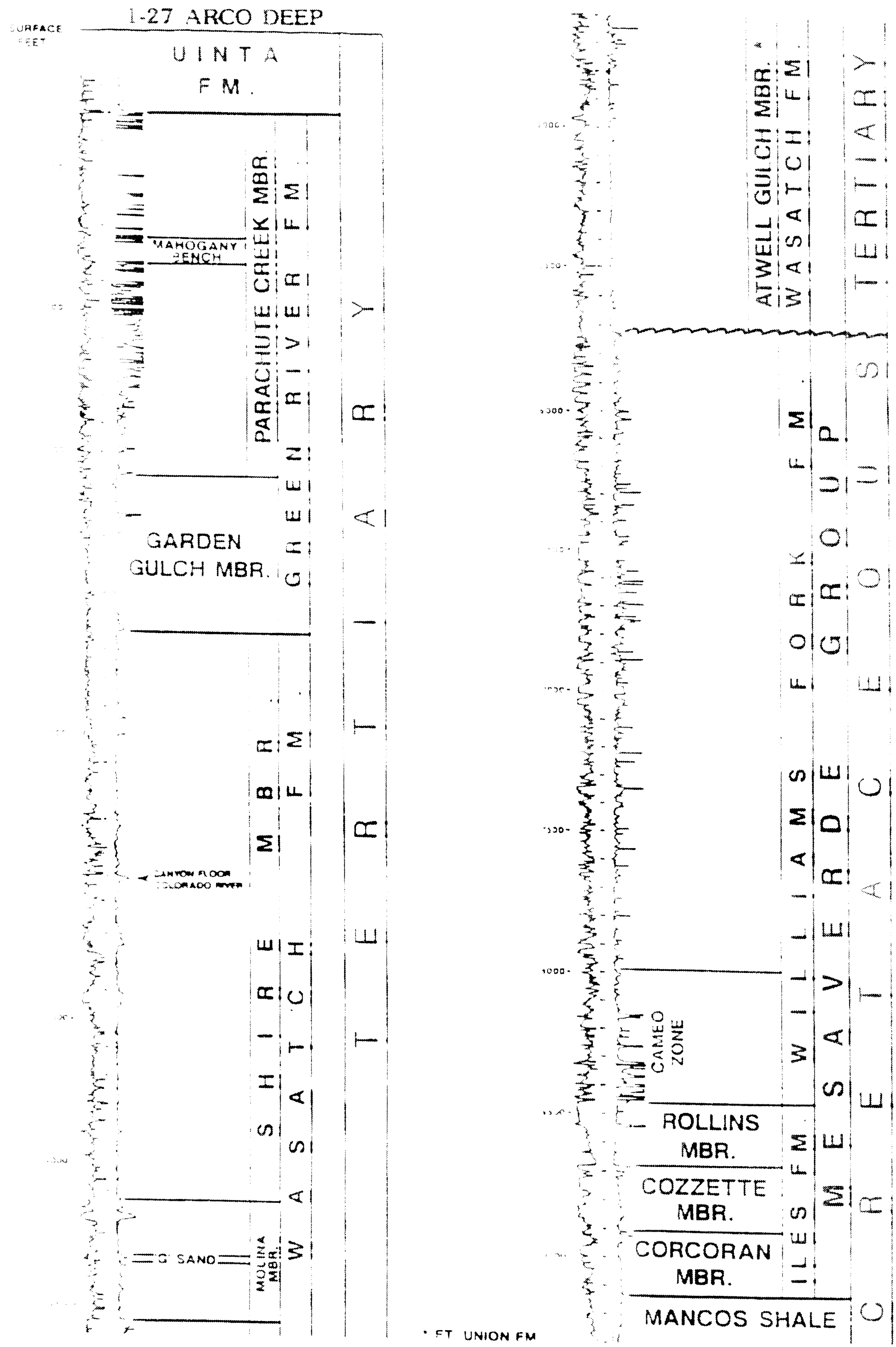

Fig. 2—Type log showing productive intervals in NOSR 1 and 3 area. (Modified version of figure, Ref. 3.)

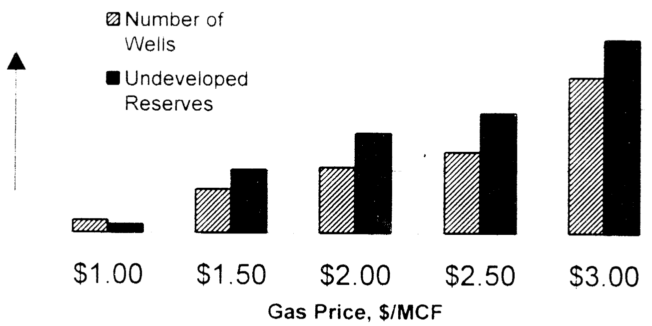

Fig. 3—Sensitivity of undeveloped reserves and locations to gas price.

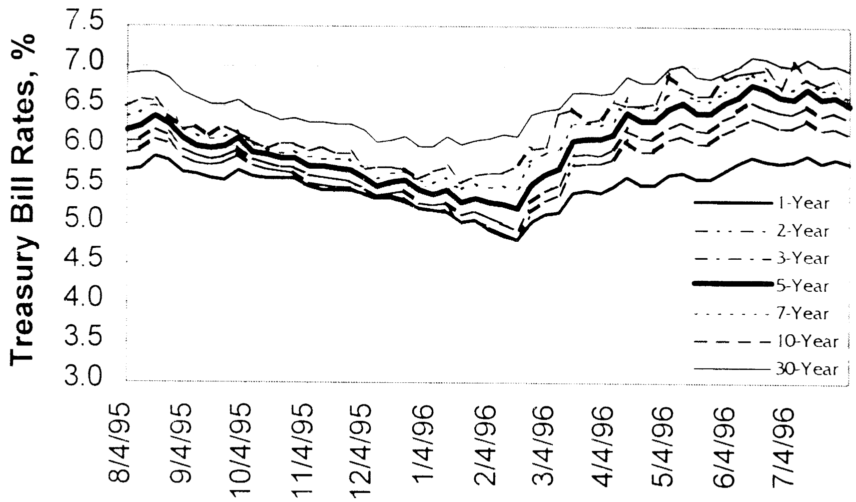

Fig. 4—Interest rates for government securities, August 1995 through August 1996.

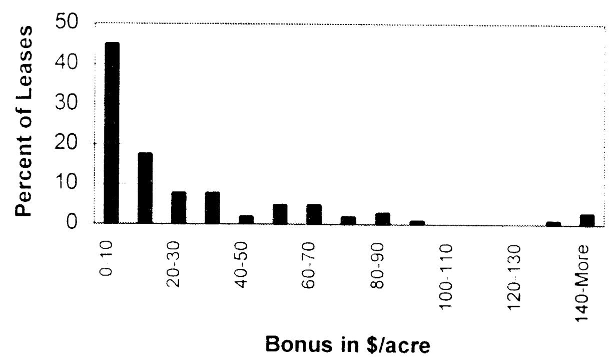

Fig. 5—Histogram of leasing activity in the area of NOSR 1 and 3.

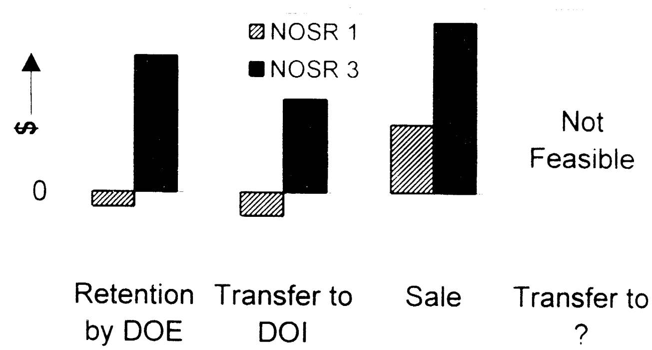

Fig. 6—Comparison of value under various options.