Final Report

Evaluation of Economic Logic of Lease Evaluation Models Used by the State of Alaska and United States Geological Survey

by

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Summary

This paper contains a short evaluation of several economic issues related to the lease evaluation and bidding system evaluation model (BONUS) being used by the State of Alaska Division of Minerals and Energy Management, as developed by Garrett Computing Systems, Inc., Dallas, Texas. I compared this model with the Monte Carlo Range-of-Values program being employed by the United States Geological Survey to evaluate Alaska tracts in their oil and gas leasing program.

The major findings are as follows:

1. Neither model contains an ideal formulation of risk, and one must be careful to specify the correct probabilities in either model in order to estimate the expected value of the income stream.

2. The state program does not directly incorporate market risk, while the USGS program does. However, since in the case of market variables the problem is really that the distribution of outcomes is unknown, risk evaluation is less important than sensitivity analysis.

3. The USGS program contains a more elaborate method for calculating reserves; however, it is not clearly superior if the state program is used properly.

4. The USGS program calculates field decline and investment costs directly; the state program incorporates these as inputs from an analysis done offline (outside the model) by a petroleum engineer once reserves are estimated. It is therefore easier to investigate alternative investment and decline scenarios with the USGS model. In addition, the state model as currently implemented using a production scenario for the expected value of

reserves almost surely overstates the expected costs of production. This paper recommends a simple method of curing the problem.

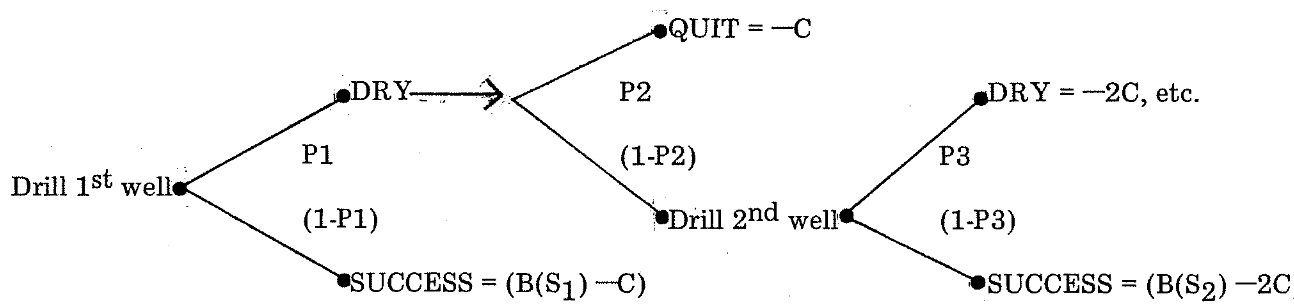
5. The royalty (and other risk-sharing) systems are evaluated incorrectly in both models, since field investment and decline is not affected by the royalty rate. I recommend that alternative production scenarios be constructed for use in the case of potentially high royalty bids. The USGS model does not accommodate net profit-sharing systems.

6. State taxes are not currently included in the USGS model. The state model is therefore superior in this respect in the treatment of state tracts.

In general, the state model, while less elaborate than the USGS model, is not clearly a poorer tool for analysis. It does suffer from a handful of defects which can, in principle, be overcome at relatively low cost.

Treatment of Exploration Risk

An oil firm's main problem is to estimate the expected value of several possible results when the firm submitting a winning bid begins drilling exploratory wells. The bid evaluation program should replicate the firm's view of the possibilities before the bidding starts, where the firm knows some exploratory wells will be drilled. We can formalize the decision process by using a "decision tree." Suppose P_1 equals the probability of a dry hole on the first well; C, its cost; $B(S_1)$, its expected value if successful; P_2 the <u>a priori</u> chance of drilling a second well if the first is dry; and P_3 is its probability of failure,[1] etc. Then the firm's decision tree for a prospect is as follows:



The firm has some idea of its probability of hitting a dry hole, P_1 (chances of success are rated at $(1-P_1)$ and its after-tax cost, C. If the hole is a success, then there is some expected net present value of the success after operating and capital costs, taxes, rents, and royalties have all been subtracted. This is $B(S_1)$, with the "1" subscript specifying that this is the value if the first well is a success. The firm knows that if the hole is dry, it may still provide information on the geology of the prospect which will cause the firm to reestimate the likelihood of a dry hole and (possibly) revise the estimate of the value

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[1]There are actually three possible outcomes: (1) the well is dry and the prospect is dry; (2) the well is dry even though the structure contains hydrocarbons; or (3) the well hits the hydrocarbons and is wet. We combine outcomes 1 and 2 into P_1 for the first well and into P_3 for the second well.

of the tract $B(S_2)$. The firm has some idea of the probability that a second well would be drilled, given that the first is dry, and the chances and value of a success, and so on. The expected value of the string of decisions is then

$$(1) \quad G = (1-P_1) \cdot [B(S_1) - C] - P_1 \cdot P_2 \cdot C - P_1 \cdot (1-P_2) \cdot P_3 \cdot 2C + P_1 \cdot (1-P_2) \cdot (1-P_3) \cdot [B(S_2) - 2C], \text{ etc.}$$

depending upon how many wells the firm thinks it will have to drill to decide whether or not the tract is dry. For purposes of our examples, we will assume a maximum of two wells is drilled. Its bonus bid would equal G, minus a risk aversion premium.

The state's bid evaluation program (BONUS) short-cuts the firm's problem by assuming a specified number of dry holes will be drilled per success over the long run; e.g., 9 out of 10 in frontier areas will be dry. The program multiplies all the dry hole costs and bonus by the probability of failure, divided by probability of success (P(F)/P(S), to get the dry hole cost associated with a success. Consider a firm definitely planning to drill two wells with equal probabilities of success ($P_2=0$, $P_3=P_1$), and with $B(S_1) = B(S_2) = B(S)$.

The dry hole cost of a success would be:

$$(2) \quad \frac{P(F)}{P(S)} \cdot (G + 2C) = \text{dry hole cost of a success.}$$

Over the long run, if the firm bid the expected value of prospects, the value of successes would equal the dry hole costs:

$$(3) \quad B - 2C - G = \frac{P(F)}{P(S)} \cdot (G + 2C)$$

The next step is subtle. In the instructions for the BONUS program, Garrett states that one must use the dry hole risk for the prospect (not the individual well) to estimate the outcome. If more than one well is planned, the dry hole prospect risk is actually the risk that all the holes will be dry, or one minus the probability of at least one success. Returning to equation 1, we note that success can come on either the first or second well, and thus that the overall probability of success on a two-well program is:

$$P(S) = (1-P_1) + P_1 \cdot (1-P_2) \cdot (1-P_3)$$

and the probability of failure (on both holes) is:

$$P(F) = 1 - [(1-P_1) + P_1 \cdot (1-P_2) \cdot (1-P_3)]$$

when $P_2 = 0$, and $P_3 - P_1$, then P(S) and P(F) collapse into

$$P(S) = (1-P_1) + P_1 \cdot (1-P_1) = 1 - P_1^2$$

$$P(F) = P_1^2$$

or 0.19 and 0.81, respectively, in the example. That is, 1/0.19 or 5.26 two-well programs will be failures for every success.[2]

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[2]Referring back to footnote 1, suppose instead that the risk of the prospect's actually being dry is rated at 90 percent = P(A), and that the chance of a well's failing to hit the hydrocarbon accumulation if it is there is rated at 30 percent = P(B). Then, for a two-well program,

$$P_1 = P(A) + P(B) \cdot (1-P(A)) = .93$$

$$P(F) = [P(A) + P(B) \cdot (1-P(A))]^2 = .86$$

$$P(S) = [1 - P(F)] = .14$$

a slightly higher probability of failure.

The Garrett program adjusts the value of the cash flow of a success for risk by multiplying the costs of the drilling program by P(F)/P(S) to get the risked cost of a success, and algebraically adding this amount to the cash flow of the success to get the net profit.

$$(4)\quad [B(S) - 2C - G] + \frac{P(F)}{P(S)} \cdot [-2C - G] = \text{net profit value of success.}$$

If the company bids the expected value of the income stream, the net profit after G is paid will be zero. Equation (4) then can be rearranged:

$$(5)\quad \frac{P(F)}{P(S)} \cdot (2C + G) = B(S) - 2C - G$$

which in the case of our two-well program is

$$(6)\quad \frac{P_1^{\,2}}{(1-P_1^{\,2})} \cdot (2C + G) = B(S) - 2C - G$$

$$(7)\quad P_1^{\,2} \cdot (2C + G) = (1 - P_1^{\,2}) \cdot [B(S) - 2C] + (1 - P_1^{\,2}) \cdot (-G)$$

rearranging and collecting terms:

$$(8)\quad P_1^{\,2} \cdot G + (1-P_1^{\,2}) \cdot G = (1-P_1^{\,2}) \cdot [B(S) - 2C] - 2P_1^{\,2} \cdot C$$

factoring $(1 - P_1^{\,2})$ into $(1+P_1) \cdot (1-P_1)$,

$$(9)\quad G = (1-P_1) \cdot [B(S) - 2C] + P_1 \cdot (1-P_1) \cdot [B(S) - 2C] - 2P_1^{\,2} \cdot C,$$

which is the same as equation (1) when $P_2=0$, $P_3=P_1$ and $B(S_2)=B(S_1)=B(S)$.

That is, the BONUS program does not allow for revision concerning the amount of reserves if the first well is dry since $B(S_1) = B(S_2)$; neither does it allow the probability of the second well's success to be influenced by the fact that the first one is dry ($P_1 = P_3$). Since the probabilities are not truly independent (since both are being drilled on the basis of geological information concerning the same prospect, and the best location on the prospect would be picked first), the expected value-added of the second well will be biased. The direction of bias will vary from case to case, however. The outcome of equations (1) and (9) are identical when only one well is drilled.

In using the BONUS model to evaluate multiple-well programs, the user must be very careful to use the correct probabilities for success and failure.

The USGS program is more complex than BONUS, in that it explicitly recognizes that more than one exploratory well may be drilled and that risk of a dry hole varies among tracts and horizons on any particular prospect. The capability of varying risk is "nice to have," since it reduces the cost of computing expected values of multiple tracts and horizons on a single prospect. Judicious use of the BONUS program would, however, produce the same result, provided that the user is sensitive to the variability issue. The USGS program also mechanically incorporates risk of relative amounts of oil versus gas, but BONUS could be made to incorporate this risk as well, since BONUS works off a certainty-equivalent value of tracts or prospects (that is, $B(S_1)$ is partly calculated outside the model). The incorporation of two-well exploratory program in the USGS model takes the form $P_1=P_3$, $B(S_1)=B(S_2)$, and P_2 equals zero.

In the USGS model, one directly uses the basic dry prospect risk. If P is the risk that the prospect will be found dry and if $B(S_1) = B(S_2) = B(S)$, then

$$(10)\quad G = (1-P) \cdot [B(S) - 2C] + P \cdot (-2C)$$

For a two-well program, with $P_1=P_3$ and $P_2=0$, then $P=P_1^2$. Equation (9) can be rearranged to show this:

$$(9') \quad G = [(1-P_1) + P_1 \cdot (1-P_1)] \cdot [B(S) - 2C] - 2P_1^2 \cdot C$$

$$= (1 - P_1^2) \cdot [B(S) - 2C] - 2P_1^2 \cdot C$$

In other words, the USGS and BONUS models are equivalent. Neither permits the firm to guess how much its assessment of the prospect would change, given dry hole information; nor does either permit the firm to guess how much the chances of success might be altered by a dry hole. However, these problems are probably insignificant compared to those of trying to estimate P_1, $B(S_1)$, and C in the first place and probably could be taken care of by either assuming $P_2=1$ or $P_2=0$, as seems appropriate.

Treatment of Market Risk

The "ideal" way to treat market risk is to permit prices of oil and gas and costs of drilling and equipping wells to be determined by a Monte Carlo process, where the prices and costs on any single trial are selected from a distribution of such prices and costs, and where the escalation factors for these prices and costs are also randomly distributed in a known distribution. The BONUS model does not permit this variation, perhaps because the "ideal" evaluation of market risk requires that the model user know something about how future prices, costs, and escalation rates are distributed. (The USGS model permits some prices and the discount rate to vary.) In reality, these distributions are extremely uncertain, particularly in frontier provinces where there is little development upon which to base cost calculations. Escalation rates are even more troublesome since there is a totally unpredictable political component in both the general rate of inflation and in specific items in business costs (environmental constraints on operating procedures, to name just one example). The preferred approach in the face of such uncertainty regarding the entire distribution of prices and costs would be to assume certain prices, costs, and escalation rates, and then to test the sensitivity of the outcome to changes in these assumptions. This can be done with either model.

Calculation of Reserves

Both the state and USGS bid evaluation systems include Monte Carlo simulation of the size of the exploration prospect. The principal differences appear to be that the state system calculates the expected size of field, and then this is entered by hand into the BONUS program. The USGS program directly and simultaneously estimates the expected size of the prospect and up to three potential production horizons in seven possible combinations. The state system is somewhat more cumbersome to use in a multiple horizon case since the program must be rerun for each combination. Nor is the state program apparently as quick at estimating relative expected outcomes with different possible combinations of gas and oil. The USGS program has an additional feature which translates the expected reserves contained in the exploration prospect by horizon into horizon estimates for individual tracts. The USGS Monte Carlo program retains the random numbers for each trial and applies the selection of randomly distributed terms to each tract's evaluation. This is not done by the state program, so tracts must be treated as if they were individual prospects with similar distributions of parameters which determine the amount of reserves.

Calculation of Field Decline and Extraction Costs

The state and USGS systems differ considerably in their treatment of field decline and costs of extraction. In the state system, using the program BONUS, the decline of and investments in any prospective field are estimated outside the model. A best judgment estimate is made by petroleum engineers in Department of Natural Resources concerning the representative schedule of investments in wells, platforms, and support services for an oil field of the expected size given by the Monte Carlo estimate of field size (also done outside the model). The USGS system relies on a series of parameter estimates supplied by geologists and engineers concerning the prospect, tract, and technology of development (e.g., number of wells per platform, maximum and minimum number of platforms, etc.). On each Monte Carlo trial, the program randomly selects values for field parameters (productive acres, thickness of pay zone, recoverability factors, number of production streams, reservoir decline parameters) for each potential production horizon and combination of horizons, and then states which horizons contain hydrocarbons. The model then estimates preliminary production schedules, calculates the number and size of platforms and distribution of wells, calculates associated discounted costs for each potential combination, and selects the combination with the highest present value for the value of that trial. One thousand or so trials constitute one run of the model.

A reason to prefer the USGS model over the state model is that once the production stream parameters have been chosen, the USGS model estimates the composite decline curve and associated net cash flow for <u>each</u> trial. This permits the investment schedule to be sensitive to the distribution of reserves as well as the expected value of reserves. This is important because oil field investment is not linearly proportional to reserves; therefore, the expected value of investment (and hence, the discounted cash flow) is <u>not</u> equal to the investment required to produce the expected value of reserves, which is the way investment is estimated in the state system. In particular, if there are economies of scale in developing large fields, the cost will be overstated by the state model. Consider the following example, where field costs are computed as:

(11) $Y = a \cdot \ln(x)$,

where a is a constant and x the size of reserves.

The ln is the natural (base e) logarithm function, which increases as x increases, but at a decreasing rate. Suppose for purposes of this example that there are only two sizes of field possible, with equal probability. These sizes are x_1=100 barrels and x_2=500 barrels. The expected value of costs is

$$(12)\ E(y) = \frac{\Sigma(a \cdot \ln(x_i))}{n} = \frac{a \cdot \ln(100) + a \cdot \ln(500)}{2} = a \cdot (5.4099)$$

which is the (correct) answer given by the USGS model.

Using the same cost function, but this time estimating the costs of the expected reserves, the answer is

$$(13)\ a \cdot \log\ (\frac{\Sigma x_i}{n}) = a \cdot \log\ (\frac{100+500}{2}) = a\ (5.7038),$$

a larger number. The example is specific, but the result is general for cost functions of the type which increase regularly at a decreasing rate.

It would be possible, however, to estimate the degree of bias in the state estimates by assuming a triangular distribution for the size of field around the expected value. An estimate of the present value of field costs could then be done at the 5 percent, most likely, and 95 percent probability field size, and the expected cost be estimated in the same manner as expected field size for a limited number of cases. The results of this analysis can then be compared to the usual estimate of the cost of developing the expected reserves and the degree of bias estimated. Finally, if after several experiments of this type the degree of bias appears consistent, an adjustment can be made to the usual estimated cost of field development by multiplying these costs by an adjustment constant derived from the experiments. In the example above, the constant would have been 5.4099/5.7038, or .9485.

Calculation of Bid Variable

Both the state and USGS bid evaluation systems are designed primarily to handle bonus bidding, although both state and federal law permit a wider range of bid variables to be considered. Both models have to be used very carefully to incorporate nontraditional bidding systems, as shown below. Suppose, for example, that one wished to estimate the expected royalty bid on a tract, given a fixed bonus. This cannot be done directly in either system. Instead, the program BONUS generates a table of bonus values versus rate of return for different levels of royalty bid, and a cutoff rate of return is used judgmentally to estimate the bonus. To get a small fixed bonus at a given rate of return, it is necessary to try several different royalty rates until the desired bonus and rate of return match.

In the USGS program, the expected bonus is always the variable produced by the model. If instead one wishes to estimate the royalty bid one could expect, given a fixed bonus, one simulates the model with different royalty rates until the model estimates an expected bonus equal to the fixed bonus one wishes to charge (which can be zero). That royalty rate is considered the expected royalty rate. While the USGS system can incorporate both fixed and sliding scale royalties, it cannot accommodate net profit share systems.

Both programs suffer from a deficiency which is potentially serious for high royalty bids. In practice, royalty payments reduce the income from a tract without reducing costs of production. Compared to a case in which the lease operator sinks a large bonus into lease acquisition but pays a small royalty thereafter, the high royalty case provides incentives for the operator to plan for a slow rate of recovery and to abandon the field somewhat earlier. Both the state BONUS program and the USGS program currently only account for the latter type of effect; when the after-tax and royalty discounted cash flow drops to zero, the field is abandoned. However, neither program accounts for the fact that investment designed to increase the rate of primary recovery might not be made at all in the royalty bidding case. This is because in neither program is the set of investments influenced by changes in net profits.

In the BONUS program, the depletion schedules entered into the model are determined by engineering estimates of required investments given bonus bidding and maximum physical recovery considerations derived from historical experience. To make the discussion more concrete, suppose this results in exploration wells being drilled starting with the first drilling season after the lease sale, and that "optimal" production well spacing is calculated to be 160 acres per well. However, "optimal" spacing is flexible, particularly in depletion drive fields since within broad limits well spacing affects only the rate of oil recovery, not the total recovery. This being the case, spacing is determined primarily by the cost of drilling and equipping wells and the after-tax and royalty recovery per well. If a high royalty is bid, the annual dollar recovery per well drilled is low compared to the bonus case. Therefore, one might expect 320-acre spacing for production wells with royalty bidding in this example. Also, without the financial pressure to recover a large lease bonus, and with reduced prospective income, exploration wells might be delayed in the royalty case. The BONUS program, however, uses the same depletion schedules and same well investments regardless of the bidding system.

The USGS program is no better. In this case, total depletion schedules are determined by the total number of production streams, or by the number of productive acres per well, subject to a number of constraints imposed by field quality parameters and the costs of drilling wells and building production platforms. Again, these determinations are made on physical engineering considerations. The program simply incorporates assumptions concerning maximum production and decline rates for individual production streams, and these are not influenced by the varying economics of recovery. The program drills enough wells and sets enough platforms to produce the reserves as fast as possible, given the decline rates and assumed rates at which wells can be drilled and platforms erected. These rates are not lowered for royalty bidding, nor is the decline rate reduced. The only effect of a high royalty is to cut off production somewhat earlier, when net discounted cash flow becomes negative.

There is a potential means of adjusting either program to introduce more realism without introducing an expensive investment-optimizing loop into the program. The BONUS program requires a new set of prototype field development schedules to account for the slower development that is probable under royalty bidding. A range of royalty rates should also be designated where this set of prototype fields would be used instead of the usual ones. In the USGS program, the same thing could be accomplished by devising an alternate set of production stream decline parameters and lower maximum rates of field investments to be used for royalty bidding.

It may be that the decrease in development caused by the incentives under a royalty bidding system will be of secondary importance compared to uncertainties surrounding the field parameters; e.g., potential recoverable oil, etc. However, it is probably worthwhile investigating whether slower development scenarios are warranted for royalty bidding evaluation.

Treatment of State Taxes

The BONUS program incorporates federal and state taxes, including severance and income taxes, and tax credits in its calculation of after-tax discounted cash flow and rate of return. If the state were to use the USGS model on state tracts, that model would have to be modified to incorporate state tax rates and state tax structure. Since the USGS model was devised to examine federal lease sales on the outer continental shelf, state taxes do not currently play a role in USGS discounted cash flow calculations.

As in the case of royalties, in neither model is the production from the field or field investments influenced by tax rates. The cure for this is the same as in the royalty bidding case.