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Replacement Cost Integration Program Model Description

David B. Reister

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Fossil Energy Program

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Engineering Physics and Mathematics Division

REPLACEMENT COST INTEGRATION PROGRAM

MODEL DESCRIPTION

David B. Reister

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ABSTRACT

The Oak Ridge National Laboratory and subcontractor ICF-Lewin Energy have developed a set of computer models to forecast the replacement cost of domestic crude oil. The Replacement Cost model forecasts the replacement cost in the lower 48 states; the Arctic Economics Model forecasts the replacement cost in Alaska. The two models of the replacement cost system forecast domestic oil supply curves (schedules of the amount of oil available at various costs). The Replacement Cost Integration Program (RCIP) integrates the output from the two models to forecast the annual discoveries and production of domestic crude oil.

RCIP is a user-friendly, menu-driven program designed to run on an IBM personal computer. RCIP allows the user to conveniently edit the input parameters, to calculate the results, and to display the output. In addition, the user can easily store a scenario on a disk and retrieve a scenario from the disk. The built-in output editor allows the user to choose an aggregation scheme for the regional results and retrieve a scenario for comparison. The output can be directed to a file or to the screen.

This Model Description provides an introduction to the models and presents a mathematical description of the oil supply model and of the drilling model.

1. INTRODUCTION

The U.S. Department of Energy's Fossil Energy (DOE-FE) program manages a program of long-term, high-risk research and development (R&D) to develop advanced energy technologies that produce or consume fossil energy. The management of the program continually faces the question: when will an advanced technology be competitive with alternative technologies? The standard method for comparing a set of alternative technologies is to perform a discounted cash flow analysis. Of the many types of discounted cash analyses, a standard method is to calculate a life cycle cost for each alternative technology. The life cycle cost is the constant or levelized cost that will recover all of the costs necessary to produce the product over the life cycle of the project. The technology with the lowest life cycle cost will tend to capture the largest share of the market. DOE-FE supports research to produce liquid and gaseous fuels. The conventional technology to produce these fuels is to drill wells to extract liquid or gaseous fuels. Because the advanced technologies must compete with the conventional technology, the life cycle cost of conventional oil and natural gas is of interest to the management of the program.

Conventional oil and gas are finite resources. As the resources are consumed, the life cycle cost of the next barrel --- the replacement cost --- will tend to increase. As the replacement cost increases and R&D lowers the cost of advanced energy technologies, eventually the advanced technologies will penetrate the market.

The program has sponsored research by the Oak Ridge National Laboratory and subcontractor ICF-Lewin Energy to develop a set of computer models to forecast the replacement cost of domestic crude oil and natural gas and to forecast the contribution to the U.S. oil supply from domestic crude oil and enhanced oil recovery (EOR). The Replacement Cost (REPCO) model forecasts the replacement cost of domestic crude oil for 6 onshore regions and 14 offshore regions. The Arctic Economics Model (AEM) forecasts the replacement cost for 15 regions in Alaska. The Replacement Cost Integration Program (RCIP) uses the output from REPCO and the AEM to forecast the discovery and production of crude oil in 31 regions (16 regions for the lower 48 states and 15 regions in Alaska).

The documentation of RCIP consists of three reports: Model Overview, User's Guide, and this Model Description. The Model Overview provides an introduction to the model and presents some typical results. The User's Guide contains detailed directions for installing and operating RCIP. The Model Description presents a review of the evolution of RCIP. The third section provides an introduction to the onshore oil supply model, while the fourth section discusses the offshore and Alaskan oil supply model. The fifth section provides a mathematical discussion of the drilling model.

2. EVOLUTION OF RCIP

Several versions of RCIP have been created in the last few years. An early version is described in the Supply Analysis Methodology report (Lewin and Associates 1985). In March 1986, the Reserve Replacement (RCIP-RR) version was delivered to DOE (Einstein and Trowbridge 1986). In June 1986, a draft of the Production Schedule (RCIP-PS) version was delivered to DOE. After a careful review of RCIP-PS by DOE, we decided to devote a major effort to the development of an improved version of RCIP. Significant milestones in the development of RCIP were Design Report (February 1987), Draft Model and User's Guide (September 1987), Validation Report (June 1988), and Second Draft Model and Documentation (September 1988). This section provides an introduction to RCIP-RR, RCIP-PS, and the improved version of RCIP.

The objective of RCIP-RR is to guide the replacement of reserves as they are produced. The inputs to RCIP-RR are similar to the current inputs to RCIP and include the production rate in million barrels per day, regional estimates of undiscovered oil, and the lease schedule. The process models (REPCO and AEM) provide RCIP-RR with regional estimates of available undiscovered oil and replacement cost.

Given the production rate and the regional estimates of available undiscovered oil, RCIP-RR attempts to direct the replacement of the reserves of oil that have been produced from the available undiscovered oil. Using a set of rules, RCIP-RR discovers the available oil until either the reserves are replaced or the available oil is exhausted. The discovery rules considers cost first (oil with the lowest replacement cost is discovered first) and considers region second (oil from regions with a significant production history is discovered before oil from regions that are remote or require advanced technologies).

Given the same regional estimates of available undiscovered oil and replacement cost as RCIP-RR, RCIP-PS used allocation formulas to estimate the domestic share of total oil supply and the regional share of domestic oil supply. In each year, the regional share depended on the regional cost, and the regional cost was the sum of the replacement cost and the rent. The rent was the maximum value of the discounted present value of the difference between the future oil price and the replacement cost.

At the start of the design of an improved version of RCIP, we defined our goals and objectives. RCIP should be a user-friendly model that simulates the domestic supply of oil from undiscovered resources to proved reserves and then to production. RCIP should allow the user to evaluate the Outer Continental Shelf leasing program and should estimate the impact of low prices on domestic production. The objective is a simple validated model that gives credible results. Where possible, the parameters of RCIP should be determined by econometric studies rather than by judgment.

The first step in the design of RCIP was a review of the literature. We reviewed the working papers of the Energy Modeling Forum (EMF-5) study of U.S. oil and gas supply models (Sweeney 1980). In the past decade, the Energy Information Administration (EIA) has developed a family of oil and gas supply models including: the Alaskan Hydrocarbon Supply Model (EIA 1979), the Midterm Oil and Gas Model (Hoffman and Joel 1980), the Outer Continental Shelf Oil and Gas Supply Model (Farmer 1982), Production of Onshore Lower-48 Oil and Gas model (PROLOG) (Carlson et al. 1982), and the Gas Analysis Modeling System (GAMS) (EIA 1984). The Gas Research Institute (GRI) has developed the Hydrocarbon Supply Model (Vidas et al. 1985). Adelman and his colleagues at the Massachusetts Institute of Technology (MIT) Energy Laboratory have developed an aggregate model of petroleum capacity and supply forecasting (Adelman and Paddock 1980). Recently, Walls has developed an econometric model at Resources for the Future (Walls 1987).

The remainder of this section reviews some of the significant changes in the improved version of RCIP. The first change has been from replacement costs to profits. Given time-series data on capital costs, operating costs and production, and values for financial parameters (the discount rate, the royalty rate, the tax rate, the overhead rate, and the transportation costs), the discounted cash flow (DCF) subroutine can calculate the replacement cost (the constant or levelized cost that will recover all of the costs necessary to produce crude oil over the life cycle of the oil field). Given a constant price track, the subroutine returns a profit or loss. The replacement cost is the constant price track for which the profits are zero. Given a variable price track, the subroutine returns the discounted present value of the profit (or loss).

In earlier versions of RCIP, the process models (REPCO and AEM) provided regional estimates of replacement cost. In the current version of RCIP, the inputs are expected prices for each year (defined by a base price and a growth rate), and the outputs of the DCF subroutine are expected profits in each year.

A related change has been to incorporate the DCF subroutine into RCIP. If the DCF subroutine were not in RCIP, every time that one of the financial parameters or expected prices was changed, a new run of the process models would be required, and the output would need to be archived.

Two methods were used to create the time-series data (capital costs, operating costs, and production rates) required by the DCF subroutine. For the onshore section of the model, the time-series data are calculated in RCIP. For the offshore and Alaskan sections of the model, the time-series data are read from large data sets (OFFANET.BBB and DSKDALK.BBB).

The core of the improved version of RCIP is the drilling model. Given the expected profits in a year, the drilling model forecasts the level of drilling and of the resulting additions to proved reserves. The domestic oil price reached a peak of $40.61 per barrel (in 1985 dollars) in 1981. In 1986, the oil price tumbled to $14.44 per barrel. Profit maximization would have concentrated all of the drilling in 1981. Although the drilling level was very high in 1981, drilling occurred before and after 1981 and was significant in 1986.

Most models introduce constraints to dampen the 1981 drilling boom. For example, the PROLOG model (Carlson et al. (1982) has a constraint on drilling rigs and on regional drilling levels. In PROLOG, the maximum size of the rig inventory is determined by the revenue of the current year and the previous two years and by the remaining stock of rigs. The GRI model (Vidas et al. 1985), contains user-specified regional inertia constraints and capital constraints.

We were reluctant to introduce constraints because each constraint introduces a new variable to simulate. Fundamentally, the constraints reflect the fact that an industry cannot expand without limits in a single year. Rapid expansion creates shortages of drilling rigs, skilled labor, and capital. We introduce a constraint by assuming that the profits are reduced at high levels of drilling. We assume that the profits are

calculated at a nominal level of drilling; at higher drilling levels the profits are reduced, whereas at lower levels the profits are increased.

For the onshore region, the parameters in the drilling model were estimated by approximating historical data (see Reister and Christiansen 1988). For the offshore and Alaskan regions, the parameters were determined by judgment. Although we are pleased with our drilling model, the model can be improved. In the first volume of this report, we discussed the problem that RCIP is discovering only a small fraction of the potential exploratory reserve additions for the West Coast region.

REPCO and AEM simulate the life cycle of oil exploration, development, and production. Thus, in the process models, developmental drilling occurs several years after exploratory drilling. However, exploratory and developmental drilling are independent decisions. In response to the price increases from 1978 to 1981, both exploratory drilling and developmental drilling increased in the onshore region. The lag in response to the price increases was one year or less. In the onshore module of RCIP, we treat exploratory drilling and developmental drilling as independent activities.

In the offshore and Alaskan modules of RCIP, exploratory and developmental activities remain coupled. We offer three reasons (in diminishing order of importance) for coupling exploration and development: oil exploration and development in remote or hostile environments requires a massive long-term investment; the data support a long response time in offshore and Alaskan drilling, and the offshore and Alaskan process models were too complex to incorporate in RCIP.

In previous versions of RCIP, we assumed the existence of a fixed-production profile. However, oil production depends on oil price. Oil fields offer many opportunities to invest money and increase production. Examples include infill drilling, reworking wells, completion of wells in multiple zones, and enhanced oil recovery (EOR). At a high oil price, investment and production will increase. All wells reach an economic limit where production costs become greater than revenues. At low oil prices, more wells are at their economic limits. To simulate the response of production to price, we have added a price elasticity factor to RCIP.

3. ONSHORE OIL SUPPLY MODEL

This section discusses the oil supply model for the onshore region. The oil supply model is primarily an accounting system that tracks cumulative discoveries, additions to proved reserves, inferred plus indicated reserves, and oil production. The key variables in the oil supply model are displayed in the data set RCIPSUM.ON (see Appendix B of the User's Guide). The notations used in this section are as follows:

AU	Available Undiscovered Oil
CD	Cumulative Developmental Additions to Proved Reserves
CE	Cumulative Exploratory Additions to Proved Reserves
DD	Annual Developmental Additions to Proved Reserves
DE	Annual Exploratory Additions to Proved Reserves
DP	Domestic Oil Price
EF	Elasticity Factor
FD	Developmental Feet
FE	Exploratory Feet
H	Hubbert Field Growth Factor
IR	Inferred plus Indicated Reserves
O	Oil Production
PO	Potential Oil Production
RD	Developmental Finding Rate
RE	Exploratory Finding Rate
UD	Undiscovered Oil for Developmental Finding Rate
UE	Undiscovered Oil for Exploratory Finding Rate

Consider the annual additions to proved reserves (DE and DD). The annual reserve additions are forecast by the drilling model described later. The exploratory additions to proved reserves (DE) reduce the available undiscovered oil (AU):

$$AU = AU - H*DE \ , \tag{1}$$

where H is the Hubbert Field Growth Factor (H = 7.58). If the DE additions are large enough to make H*DE greater than AU, then DE is reduced such that H*DE = AU and AU is zero in the next period. Additions to AU occur in 1987 and 2001 and are determined by the total estimate of undiscovered oil (input screen three) and the lease schedule (input screen five).

The developmental additions to proved reserves (DD) reduce the inferred plus indicated reserves (IR), whereas the DE increase the IR:

$$IR = IR - DD + (H - 1)*DE \ . \qquad (2)$$

If DD is larger than IR, then DD is set to be equal to IR. The initial value of IR is determined by input screen seven.

The cumulative additions to proved reserves (CE and CD) are increased by the annual additions:

$$CE = CE + DE \qquad (3)$$

$$CD = CD + DD \ . \qquad (4)$$

The initial values of CE and CD are determined by the input parameter, Qstart (discussed in Appendix B of the User's Guide):

$$CE = Qstart/H \qquad (5)$$

$$CD = Qstart - CE \ . \qquad (6)$$

The amounts of undiscovered oil used for the finding rate equations (UE and UD) are reduced by the annual additions to proved reserves:

$$UE = UE - DE \qquad (7)$$

$$UD = UD - DD \ . \qquad (8)$$

The initial values of UE and UD are read from the input data set ONPARAM.DAT.

Potential oil production (PO) is increased by the annual additions to proved reserves. There are two production profiles: 15 and 20 years. The choice between the production profiles depends on the estimate of the field size. The method for estimating the field size is described on p. A-26 of the REPCO methodology report (Lewin 1985).

In each year, actual oil production (O) is related to PO by the price elasticity factor (EF):

$$O = PO*EF \ , \qquad (9)$$

where EF is defined as:

$$EF = (DP/25)^{\epsilon} , \tag{10}$$

where ϵ is the price elasticity determined on the first input screen.

The initial values for PO are determined by data read from ONPARAM.DAT. The values read from ONPARAM.DAT are scaled to make the total production (O) from the inital values of PO equal to the regional estimate of proved reserves when the value of the price elasticity is $\epsilon = 0.1$.

The finding rates (RE and RD) are the ratios of additions to proved reserves (DE and DD) and drilling footage (FE and FD):

$$RE = DE/FE \tag{11}$$

$$RD = DD/FD \quad . \tag{12}$$

The finding rates are proportional to the undiscovered oil:

$$RE = \beta E*UE \tag{13}$$

$$RD = \beta D*UD , \tag{14}$$

where the parameters (βE and βD) are read from ONPARAM.DAT.

We conclude this section by describing the calculation of annual additions to proved reserves (DE and DD). Because the method is the same for both exploratory and developmental reserve additions, we simplify our notation and consider both cases at once. We describe the drilling model in Sect. 5 and adopt that notation for the rest of this section.

Let b be the additions to proved reserves. Let P be the expected value of the profits. Given P, the drilling model forecasts b. However, the oil supply model introduces a lag when the drilling rate is increasing. Let NEW be the reserve additions forecast by the drilling model and let OLD be the reserve additions from the last period (in the first period, OLD = NEW). If NEW is less than OLD, then b = NEW. If NEW is greater than OLD, there is a lag in the increase in reserve additions:

$$b = (1 - \mu)*OLD + \mu*NEW \ , \tag{15}$$

where μ is a parameter fixed at $\mu = 0.5$.

4. OFFSHORE AND ALASKAN OIL SUPPLY MODEL

This section discusses the oil supply model for the offshore and Alaskan regions. The oil supply model is primarily an accounting system that tracks additions to proved reserves and oil production. The key variables in the oil supply model are displayed in the data sets RCIPSUM.OFF and RCIPSUM.AL (see Appendix B of the User's Guide). The notations in addition to those from Sect. 3, are as follows:

AP	Average Profits
AU	Available Undeveloped Oil by Field Class
D	Additions to Proved Reserves by Field Class
DP	Domestic Oil Price
DT	Total Additions to Proved Reserves
EF	Elasticity Factor
O	Oil Production
P	Expected Profits by Field Class
PO	Potential Oil Production
W	Distribution of Undeveloped Oil by Field Class

The offshore and Alaskan models work at the field class level [the field class boundaries have been defined by the U.S. Geological Survey (USGS)]. For the offshore model, the number of field classes varies by region; the maximum range is from class 4 to class 20. For the Alaskan model, the range of the field classes is 15 to 22. For each region, the undeveloped oil has a field class distribution (W). The distribution does not vary with time or development (in a future version of RCIP, we would like to incorporate the Arps-Roberts model and allow the distribution to vary with development).

The initial values of the available undeveloped oil are determined by the input screens (see Appendix A of the User's Guide). For the offshore region, the total available undiscovered recoverable oil as determined by the third input screen and the fifth input screen is distributed to the field classes by using W. For the Alaskan region, the total available undiscovered recoverable oil as determined by the fourth input screen and the sixth input screen is distributed to the field classes by using W. The estimates of inferred and indicated reserves from the seventh input screen are allocated to the following regions: Onshore Alaska is added to region

31 [North Slope (Other)], Offshore West Coast is added to region 7 (West South Shelf), and Offshore Gulf Coast is added to region 11 (Gulf Shelf).

The process models (REPCO and AEM) provide time-series data on capital costs, operating costs, and production by region and by field class in the data sets OFFANET.BBB and DSKDALK.BBB. Given the process data, financial parameters, and expected prices, RCIP calculates expected profits by field class. We assume that additions to proved reserves will follow the distribution function (W), and we use W to calculate average profits (AP) for the region.

Given the average profits, the drilling model forecasts the total additions to proved reserves for the region (b). By using W, the total additions are distributed to the field classes to calculate D. The reserve additions by field class (D) are subtracted from the available undeveloped oil (AU). If D is larger than AU, D is set to be equal to AU, and AU is zero in the next period. The regional total for actual additions to proved reserves is DT. In the summary output (RCIPSUM.OFF and RCIPSUM.AL), b is the potential additions to proved reserves and DT is the annual additions to proved reserves.

In previous versions of RCIP, the field classes with the lowest replacement cost were developed first. In cases where the total amount of developed oil was less than the USGS estimate of undiscovered oil, the available oil was renormalized to increase the amount of developed oil (see Appendix A of Einstein and Trowbridge 1986). By using a distribution function and developing all field classes at the same rate, we avoid the need to renormalize the estimates of undiscovered oil.

The process models provide a production profile for each field class. Given reserve additions by field class (D), the production profiles are used to calculate the potential oil production (PO). The actual oil production (O) is related to PO by the price elasticity factor (EF) [see Eqs. (9) and 10)].

5. DRILLING MODEL

This section provides a mathematical description of the drilling model for the RCIP. Given expected profits, the drilling model forecasts the level of drilling. The same drilling model is used for all three regions of RCIP: onshore, offshore, and Alaska.

The input to the drilling model is a time series of expected profits [P(U,t)]. The profits may depend on the amount of undiscovered oil (U) through the finding rate and depend on time through the price and the growth rate for price. The profits are discounted back to a common date.

The objective of the drilling model is to forecast drilling footage (f). However, because the finding rate relates footage and reserve additions, we can forecast reserve additions (b) and then compute footage. As with our initial model, we assume that total profits are maximized:

$$J = \int_0^T P(U,t)*b \, dt \quad . \tag{16}$$

To maximize profits, reserve additions should occur when the profits are high. In a previous paper (Reister and Guth 1987), we assumed that there was a constraint on the level of reserve addition and that the optimum solution depended on the parameter K. When the profits are more than K, oil is developed at the maximum rate. When the profits are less than K, no oil is developed. In the jargon of optimal control theory, the optimal solution is a bang-bang control.

To avoid an exogenous constraint on reserve additions, we assume that the profits have diminishing returns:

$$J = \int_0^T P(U,t)*G(b) \, dt \quad , \tag{17}$$

where G(b) is a diminishing function of b:

$$G(b) = b*(\delta - \gamma*b) \quad , \tag{18}$$

where δ and γ are parameters (we discuss the values of the parameters at the end of this section). We assume that the profits are calculated at a nominal rate (b_0). At the nominal rate, $G(b_0) = b_0$. Thus,

$$\delta = 1 + \gamma * b_0 \ . \tag{19}$$

The optimal discovery rate is given by

$$b = (\delta - K/P)/2*\gamma \tag{20}$$

when b is positive, where K is a constant. The optimal discovery rate is zero until the profits are greater than K/δ. As the profits increase, the rate increases but never exceeds an asymptotic limit ($\delta/2*\gamma$).

We assume that there are many independent oil producers in each region and that each producer has different values for the expected profits and for the value of K. To simulate independent producers, we assume that there is a distribution of values for K and that the average value of K [<K>] is given by

$$\langle K \rangle = \int_0^\infty u*g(u)\ du \ , \tag{21}$$

where g(u) is the distribution function for K.

Using the relationship between profits and reserve additions [Eq. (20)], we can calculate the average value for the reserve additions:

$$\langle b \rangle = \int_0^{\delta*P} [(\delta - u/P)/2*\gamma]*g(u)\ du \ . \tag{22}$$

Given a distribution function, Eq. (22) can be used to calculate the regional discovery rate. We have chosen to use the Weibull distribution function, because it is relatively easy to integrate. The Weibull distribution function is given by

$$g(u) = (\rho/\sigma)\ (u/\sigma)^{\rho-1} \exp[\ -(u/\sigma)^{\rho}]\ , \tag{23}$$

where ρ and σ are parameters (we discuss the values of the parameters at the end of this section).

For the Weibull distribution function, the average value of K is given by

$$\langle K \rangle = \sigma\ \Gamma(1 + 1/\rho)\ , \tag{24}$$

where $\Gamma(x)$ is the gamma function. The parameter σ controls the mean value of the distribution, while the parameter ρ controls the width of the distribution. As ρ increases, the distribution becomes narrow and $\langle K \rangle$ approaches σ.

For the Weibull distribution function, the average value of the reserve additions is given by

$$\langle b \rangle = (\delta/2*\gamma)\ [1 - e^{-x} - \Lambda(a,x)/y]\ , \tag{25}$$

where $y = P*\delta/\sigma$, $x = y^{\rho}$, $a = 1 + 1/\rho$, and the incomplete gamma function $\Lambda(a,x)$ is defined by

$$\Lambda(a,x) = \int_0^x e^{-t}\ t^{a-1}\ dt\ . \tag{26}$$

Equation (25) is our drilling model. Given the expected value for the profits (P) and values for the four parameters (δ, γ, σ, and ρ), Eq. (25) determines the average rate of additions to proved reserves in the region. Given the the reserve additions and the finding rate (R), the drilling footage (f) is given by

$$f(t) = \langle b \rangle(t)/R(t)\ . \tag{27}$$

Figure 1 displays the discovery rate ($\langle b \rangle$) as a function of y for several values of ρ. As ρ increases, $\langle b \rangle$ approaches the asymptotic limit

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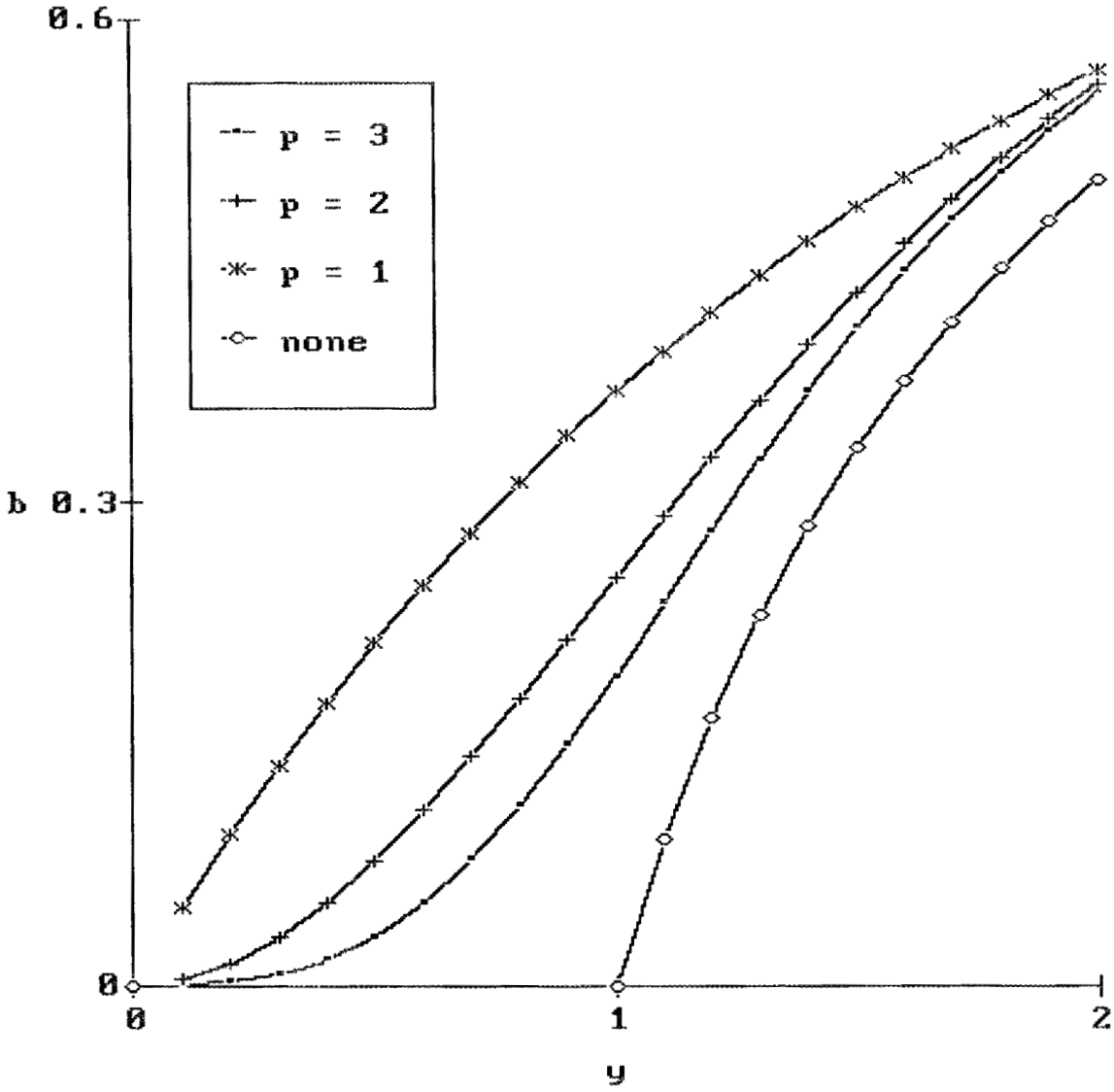

Fig. 1. The reserve addition rate (b) as a function of y for several values of Rho.

given by Eq. (20); the limit is $\langle b \rangle = 1 - 1/y$ when y is greater than 1 and the limit is zero when y is less than 1. The model derived using the Weibull distribution function allows the discovery rate to be positive when y is less than 1.

The remainder of this section discusses our method for determining the four parameters in the drilling model. By examining Fig. 1, we concluded that $\rho = 2$ was an appropriate value. Hence, ρ was set equal to 2 for all 31 regions. On the basis of Eq. (19), we assumed that $\delta = 1.5$ for all 31 regions. Consequently, $\gamma = 1/(2*b_0)$. For the RCIP data sets, b_0 is the input value and γ is calculated.

The nominal rate of additions to proved reserves (b_0) is the most important parameter in the drilling model. For the onshore region, the drilling model parameters were estimated from historical data and b_0 ranged from 93 million barrels (MB) to 670 MB for developmental reserve additions and from 5.7 MB to 55 MB for exploratory reserve additions. For the offshore and Alaskan regions, the parameters were determined by judgment and b_0 ranged from 4 MB to 2000 MB for the offshore region and from 10 MB to 1500 MB for the Alaskan region.

Using Eq. (20) with $\delta = 1.5$, the constant K is related to the nominal profits by $K = P_0/2$. If we assume that σ is approximately equal to K, then σ is approximately equal to of 50% of the nominal profits. For the offshore region, the values of σ ranged from \$2 to \$4 per barrel. For the offshore region, the values ranged from \$1 to \$3 per barrel. For all regions in Alaska, $\sigma = \$0.50$.

In the validation of the onshore section of RCIP, we introduced an adjustment factor that increases the finding rate because the profits were negative for most of the years in the validation period (1970-1986). When determining the parameters for the offshore and Alaskan regions, we decided not to introduce any adjustment factors. We chose the parameters b_0 and σ by trial and error. Our criterion was that a reasonable fraction of the available undeveloped oil should be developed by 2020 for the base case expected prices.

For small values of y, the slope of <b> decreases (see Fig. 1). We decided it was better to reduce σ than to increase b_0 to very large values. Our general goal was to have uniform values for the parameters and make adjustments if too much or too little oil was developed.

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