RESERVOIR SOLUTIONS

Published quarterly by Ryder Scott Co. LP Sept.–Nov. 2010/Vol. 13, No. 3

YE09 economics, development plans targeted by SEC

Roesle fields question at Ryder Scott Reserves Conference, Aug. 27.

Registrants in the U.S. market are revamping their approaches to filing year-end 2010 petroleum reserves based on feedback from regulators currently calling for more granularity in the previous year's filings. "The SEC (U.S. Securities and Exchange Commission) was not generally pleased with the level of specificity from filers in key areas," said **Don Roesle**, CEO. "The agency may issue additional comment letters this year."

Roesle's comments were part of his opening remarks at the Ryder Scott Reserves Conference, Aug. 27 in Houston.

To comply with Item 1202 of Regulation S-K for YE09, companies that relied on third-party evaluators for reserves estimates provided "discussion of primary economic assumptions," which amounted to relatively detailed hydrocarbon pricing, application of differentials and costs. That economic data was published in third-party report letters appended to YE09 10-Ks and 20-Fs after independent review.

In the review process for YE09, regulators, through comment letters, are asking for more information in report letters. The SEC wants economic data organized by geographic area. The agency also is requesting effective sales prices for each product.

Ryder Scott has incorporated a table in its third-party report letter that itemizes each oil, gas or NGL product and its sales price derived from a specified benchmark, reference point and price differential. "Nothing is particularly difficult about this," said Roesle. "It's simply not a general discussion of primary economic assumptions."

To justify proved undeveloped reserves estimates, the SEC wants assurances in the report letter that under a given proposed field development plan, undeveloped locations will "definitely be drilled" and that secondary and tertiary projects will "definitely be developed." Regulators believe that those assurances

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Inside Reservoir Solutions newsletter

RYDER SCOTT 2010

- With 270 attendees, the Sixth Annual Ryder Scott Reserves Conference eclipsed last year's mark of 225. About 200 guests attended as well as Ryder Scott personnel. This year's event represents the largest gathering of senior reserves evaluators.
- All presentations are posted on the Ryder Scott website, except for those of **Dr. John Lee** and **Don Roesle**, CEO.
- **Ron Harrell**, chairman emeritus, discussed current work on the SPE-PRMS applications document draft. **Delores Hinkle**, former SPE OGRC chair, discussed probable reserves without proved. **John Hodgin**, president, presented, "Reserves or resources: What do you do if you don't have a well penetration?" **Jennifer Fitzgerald**, vice president, discussed the SEC five-year rule for PUDs. All four will be summarized in the December newsletter.
- **Wayne Wisniewski** presented, "Entrepreneurial ethics: Why it's important."

Reliable technology rule didn't spur extensive reserves adds, survey shows

According to a Ryder Scott survey, less than two percent of public companies in U.S. markets booked material reserves additions for year-end 2009 based on the use of "reliable technology" as defined by the U.S. Securities and Exchange Commission. Of the 111 surveyed 10-K filers, 20 provided statements on the impact of technology on the estimation of their YE09 proved reserves.

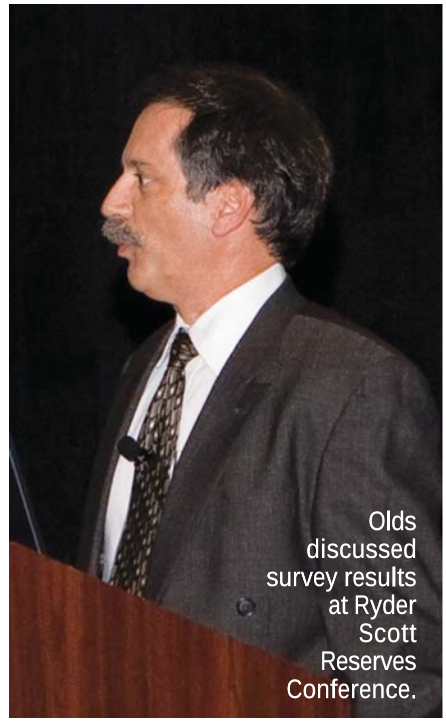
Of those 20, 15 companies, without disclosing magnitudes, stated that reliable technology had no or minimal effects. Three stated 2-percent-or-less increases in proved reserves. Two filers—**NGAS Resources Inc.** and **Petrohawk Energy Corp.**—disclosed material proved reserves additions.

NGAS said it added "15.9 Bcfe (of gas) in new horizontal PUD (proved undeveloped) locations supported by reliable technology." Petrohawk "recognized additional PUD reserves totaling 1,771 Mbbls of oil and 1,115,334 MMcf of natural gas resulting from the application of reliable technologies in determining reserves."

Dan Olds, senior vice president, presented the findings of the survey at the Ryder Scott Reserves Conference, Aug. 27. He said a cursory review of 20-F filings showed similar results.

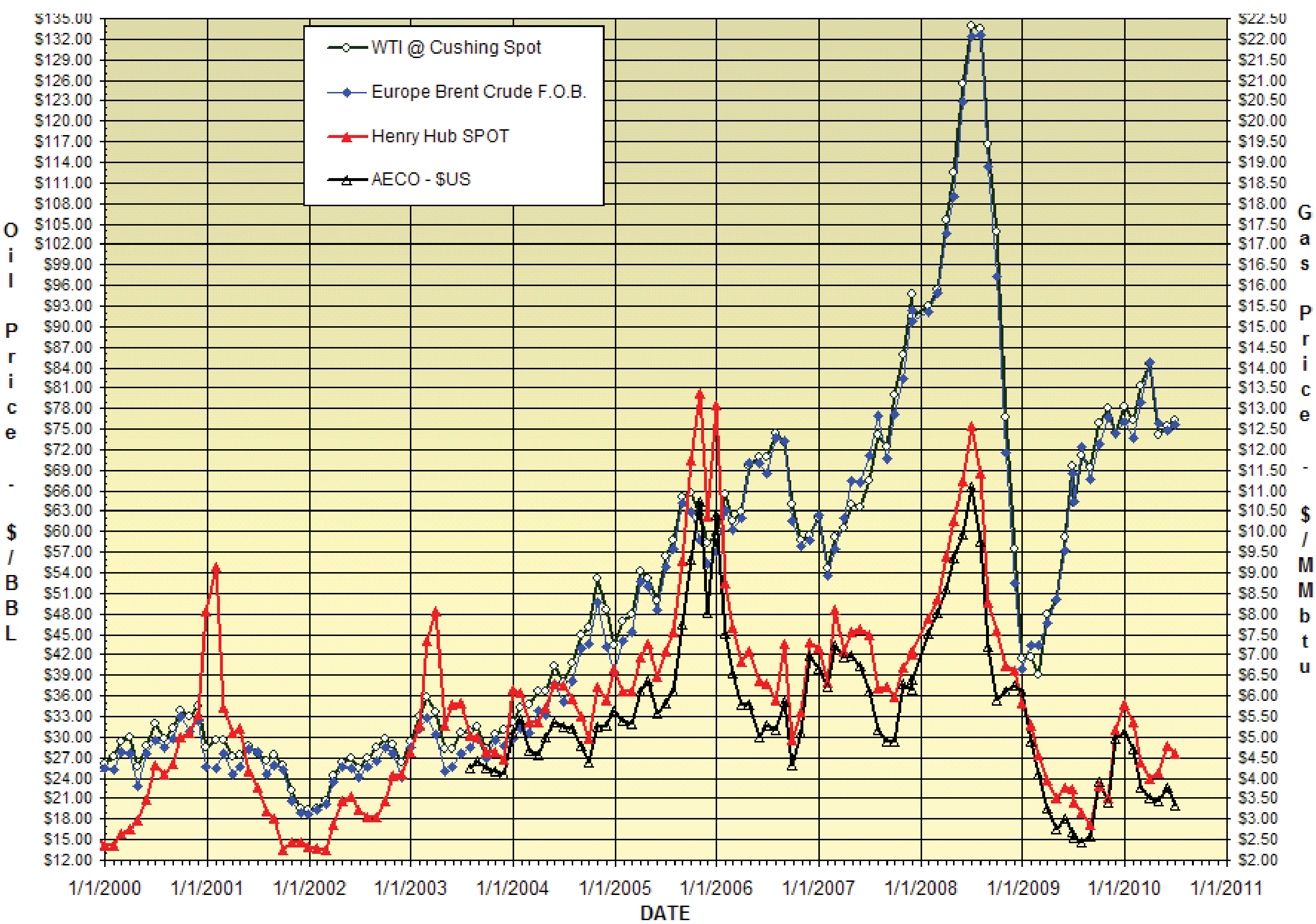
Some observers believed that the SEC broader acceptance of reliable technology to justify reserves for YE09 would result in significant adds, especially by shale gas producers, but that didn't occur.

Please see Olds on Page 6



Olds discussed survey results at Ryder Scott Reserves Conference.

Price history of benchmark oil and gas in U.S. dollars



Published, monthly-average, cash market prices for WTI crude at Cushing (NYMEX), Brent crude and Henry Hub and AECO gas.

SEC curbs potential for rules abuse by calling for details

Through the current comment-letter process, the U.S. Securities and Exchange Commission is asking for more detailed petroleum reserves disclosures to prevent abuse of the more flexible reporting rules, said **Dr. John Lee**, a former engineering fellow at the SEC during the rules-change process. The watchdog agency is calling for filers to discuss certainty provided by the use of so-called "reliable technology" to support proved reserves bookings.

Only a few companies discussed specific technologies and associated reserves additions under principles-based rules used the first time for year-end 2009. Lee, a professor at Texas A&M University, made his remarks at the Ryder Scott Reserves Conference, Aug. 27 in Houston, saying that his opinions were not necessarily those of the SEC.

"Establishing reliability is up to the filer. A company must show empirical evidence that use of the technology leads to correct conclusions about proved volumes," said Lee. "The rules did not provide a reliable technology standard for PDP (proved developed producing) valuations or a list of technologies."

He also said that the SEC's time restriction on the booking of proved undeveloped reserves is intended to limit PUDs to a reasonable total, taking into account that they are validated, in some cases, through reliable technology.

Overall, the SEC is asking for more granularity in reporting to reign in any potential for manipulating rules established to protect the investor. "The SEC believes that filers have many more opportunities to 'game the system' and push the rules well beyond what they were intended to cover," said Lee.

Industry is learning and adapting to the new rules and so is the SEC. Lee remarked that although he no longer works in an official capacity for the SEC, the agency has contacted him to clarify his understanding of the original intent of specific rules changes.

Dr. John Lee presents at 2010 Ryder Scott Reserves Conference.

"The SEC staff is learning and may not know precisely what it wants to see. Roger Schwall (assistant director in the SEC Division of Corporate Finance) is totally dedicated to getting the job done right," he said.

Public issuers are under no requirement to use third-party reserves auditors or evaluators, but there are incentives to use them and to use "credible internal controls," said Lee, adding that this is another example of the SEC adding rigor to flexible rules. He remarked that the SEC's enhanced reporting includes separate disclosure of non-traditional resources since they are riskier and disclosure of concentrated reserves locations to help identify greater political risk.

Filers are required to disclose reserves by continent or country if they represent 15 percent or more of total reserves.

"The SEC is asking registrants to more completely reveal their assets to investors under expanded disclosure requirements," said Lee. "The purpose is to prevent overstatements of reserves leading to an Enron-type destruction of market value. The Enron collapse still lingers in the memories of the SEC staff."

Roesle—Cont. from Page 1

will provide a greater level of comfort to investors that non-producing and undeveloped categories of reserves will move into the producing category within the prescribed time frame.

To confirm development plans with third-party evaluators, companies are providing details on internal- and partner-approval processes. "Some companies are not eager to give that information, because development plans change. A plan today may not be the same plan two or three months from now," said Roesle. He remarked that third parties now are concerned with unanswered questions, such as, "What level of authority is needed within a company to adequately offer assurances to the SEC that development plans will be carried out? Is it division level or corporate level? Is it written or oral?"

In addition to disclosing the portion of the total reserves covered by the independent evaluation, third party report letters should specify developed and undeveloped subcategories of that portion of proved reserves, according to the SEC.

The agency is also calling for third-party reserves auditors to compile and disclose specific practices used to estimate reserves. Traditionally, it has been sufficient for the auditor to state that the reserves were prepared in accordance with "generally accepted petroleum engineering and evaluation principles."

Also, the SEC has asked that report letters not contain language to the effect that the report is for the "exclusive use and sole benefit" of the client or that limits audience or investor reliance. "Third parties are now taking on more liability," said Roesle.

He also said that the SEC has asked oil and gas companies to disclose relative levels of uncertainty associated with volumetric and performance methods separately. For more information on that issue, please see, "Companies argue against disclosing uncertainty levels in estimate methods," in the June *Reservoir Solutions* newsletter, Page 4.

Editor's Note: Administrative law mandates that the SEC require the same Item 1202 disclosures from all registrants whether or not they rely on third-party evaluators. The exception is information unique to the use of a third party, i.e., signature of third party in filed report letter, etc.

Technical challenges in estimating reserves Part 4: Production decline curves, operating costs

Editor's Note: This is a revised excerpt from "Oil and Gas Reserves Estimates: Recurring Mistakes and Errors," (SPE Paper No. 91069). To order a copy of the full paper, go to www.onepetro.org.

Ryder Scott personnel see a wide variety of internally produced petroleum reserves estimates and most of them are well prepared. However, the firm has noticed common technical errors in reserves estimates.

This multipart article offers guidelines to help reduce the chance of errors in geoscientific and engineering analysis. This fourth newsletter article in the six-part series focuses on decline-curve analysis and operating costs.

Production decline curves

Performance decline analysis is the most common technique to estimate reserves in mature fields where ample performance data is available for both primary and secondary products. Besides the obvious subjectivity in determining a decline trend, common errors are associated with composite field decline curves and neglecting to apply a minimum hyperbolic decline rate.

Composite field production decline curves—Quite often, an engineer only has production histories for a multi-well lease, production unit, single reservoir or entire field. Individual well-production histories may not be available or can be compiled only through the use of allocations relying upon less-than-perfect well tests. When an aggregate well-production history is displayed as a graph of monthly oil or gas production, the historical trend may show a continual decline over time.

Indeed, this trend may be well defined as an exponential or hyperbolic decline that can be projected into the future with a reasonably high degree of reliability based upon the mathematical "best fit" of the historical data. This is illustrated as Figure 12.

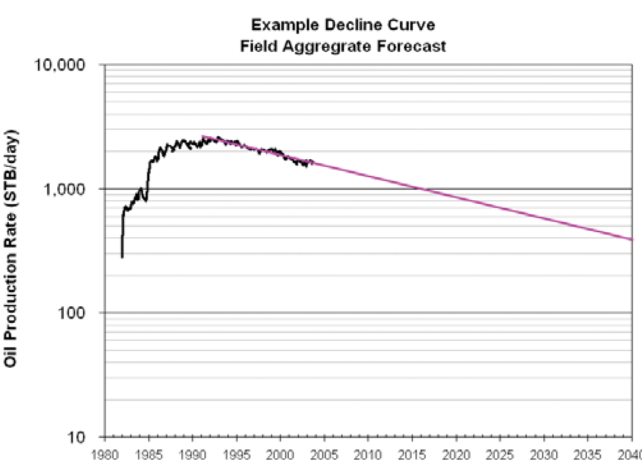


Figure 12. Field aggregate forecast based on apparent trend.

This projection clearly presents an appealing case for using the entire production history to obtain an estimate of proved reserves.

Such a decline projection may be acceptable, however, only under the following conditions:

- Well count is relatively stable.
- Production conditions and methods are largely unchanged over the producing life.
- Wellbore intervention and other remedial work can be classified solely as maintenance.

If these rather stringent conditions are not met, reliance upon this projection to estimate proved reserves may be inappropriate.

Figure 13 has the same production decline curve as Figure 12 but contains additional plotted data reflecting the number of producing wells over the productive life of the field. Often overlooked, this added information has a significant effect on the previous interpretation of remaining proved reserves.

Clearly, the forecast in Figure 12 is not achievable without the continual drilling of additional wells achieving similar, positive results, a highly unlikely condition in most cases. Frequently, estimators use this erroneous approach to estimate proved producing reserves.

In some cases, evaluators compound their mistakes by adding yet even more proved undeveloped reserves assigned to discrete drilling locations.

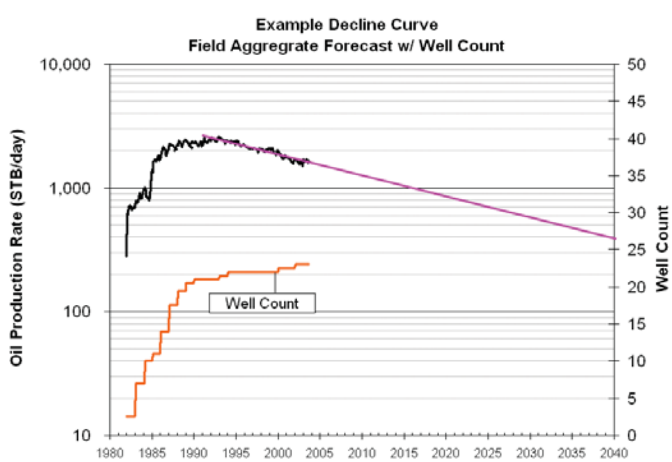


Figure 13. Field forecast based on apparent trend with well count.

In preparing a forecast such as that in Figure 14, which restates the data in figures 12 and 13 based on average monthly production per well, an evaluator should be cautious when using "average well" projections.

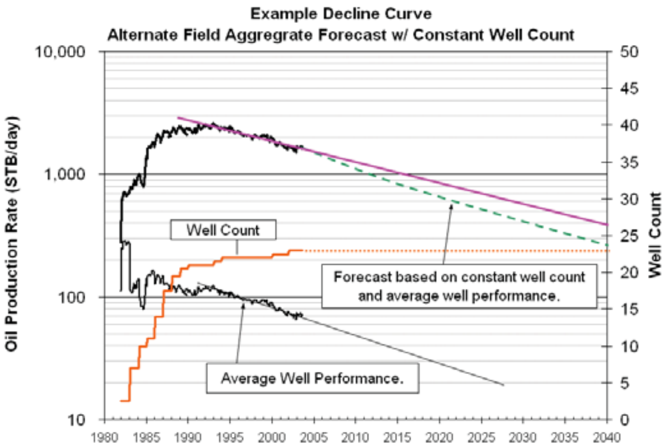


Figure 14. Alternate forecast based on constant well count and average well performance.

The average well production, which is determined by dividing the field production by the well count, may have been sustained by the continuing impact of production from new wells and well-maintenance work.

Figure 15 presents a final forecast without the effects of drilling and single-event workovers on the field trend. The final projection may yet overstate remaining reserves unless the evaluator can be assured of future opportunities for re-completions, stimulation treatments or other types of production enhancements.

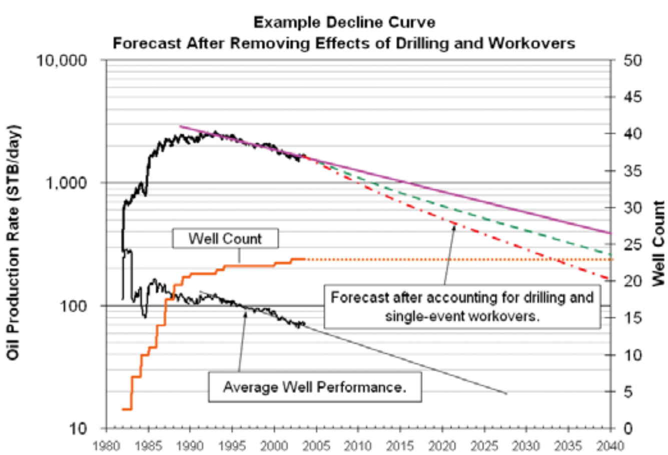


Figure 15. Alternate forecast after removing effects of drilling and single-event well-maintenance work.

The preferred approach is to rely upon the performance of individual wells whenever possible. Any other approach may lead to an optimistic estimate of future performance and proved reserves.

Make sure to specify minimum decline rates in hyperbolic projections. Virtually all commercial software programs used to forecast future production rates and cash flows provide an option to use a hyperbolic projection with a specified N-factor and final decline rate. This N-factor can also be calculated by using the curve-fitting function of the economic software program.

Allowing the software to default to an unspecified, final decline rate, which is often unreasonable and unsupportable, may have little effect on present value. However, the "added" reserves frequently cause gross overestimations. A review of depleted or nearly depleted area analogs will often guide the selection of an appropriate final decline rate.

Other errors with decline-curve analysis

■ Ultimate recovery not related to volumetric estimates. Apparent decline trends combined with relatively flat flowing-tubing pressures can lead to optimistic reserves estimates, particularly in gas reservoirs with partial to strong water drives.

■ Assuming exponential decline in reservoirs that tend to exhibit hyperbolic decline trends (source of underestimating reserves). These include (i) tight gas reservoirs (enhanced if multiple layers), (ii) naturally fractured reservoirs, and (iii) waterflood reservoirs.

■ Conversely, assuming a hyperbolic decline may lead to overstating reserves in cases where an exponential decline would also fit performance.

Guidelines to reduce mistakes in decline-curve analysis

■ Always attempt to estimate performance decline at a well or completion level for best results.

■ Include trends in secondary products (condensate yields, gas-oil ratios, water cuts) in analysis.

■ When projecting group- or field-level rates, make sure to review the components of the field curve and properly account for well work and associated costs that are required to maintain the decline trend. If well work cannot be sustained, the field curve needs to be adjusted to fit the true decline of existing wells.

■ Use analogous fields or more mature wells in the field or area to establish typical decline behavior, including minimum hyperbolic decline rates.

■ Gain an understanding of reservoir properties — porosity, permeability, lithology and depositional environment — to exercise better judgment in selecting exponential vs. hyperbolic decline models.

■ Attempt to combine various types of evaluation techniques with decline-curve analysis to assure consistency in results.

Operating costs

Operating costs reflect expenses attributable to the daily operations of a field and typically do not include general and administrative expenses or other overhead costs. Operating costs are used to capture expenses, which affect reserves values, and to estimate economic limits, which affect reserves volumes. The economic limit is defined as the rate and time at which revenue from production becomes less than the cost of operations.

Typical errors or mistakes associated with operating costs include the following: (i) use of forecasted or budgeted operating costs that are lower than actual

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Operating Costs—Cont. from Page 5

long-term historic costs, (ii) recurring well or facility costs that are assumed to be single events and therefore excluded from future estimates of cost, (iii) assumption of per unit cost of primary product, dollars per barrel for example, without the proper treatment of fixed cost or costs of producing secondary products, and (iv) failure to evaluate changes to costs caused by the introduction of new recovery mechanisms.

Projected operating costs are lower than historic average costs—Occasionally, forecasted or budgeted operating costs that are lower than average historic costs are used to estimate reserves. This may be based on an assumption rather than established fact.

This approach, in most cases, will result in overstating both income and reserves. In general, regulatory bodies require that operating costs be closely tied to at least one if not several years of observed costs. Any deviation requires sufficient evidence of circumstances and events that will lower future operating costs.

Recurring well or facility expenses—Most reservoir engineers rely on historic facility, lease, and/or well operating cost statements as the basis for calculating historic operating costs, typically expressed as a monthly cost, for mature properties. This may further be subdivided into fixed and variable components when appropriate. Historical costs frequently include expenses that are deemed to be "non-recurring."

These costs are typically excluded from average costs for use in production forecasts. This approach is acceptable only if the "non-recurring" costs are indeed non-recurring.

All too often, such items as tubing repairs and/or replacement or periodic platform or facility maintenance, are deducted as non-recurring. The failure to recognize the periodic frequency of such maintenance can lead to an overstatement of reserves and future net income.

Assumption of per-unit operating cost—Alternatively, and perhaps of a more serious nature, some evaluators use a future operating cost expressed as a fixed unit cost per volume (barrel, mcf or cubic meter) based on their estimates from a current or past analog. This method does not properly account for variable costs or proper inclusion of secondary products.

This approach is virtually never acceptable as unit costs of production almost universally increase over time with declining production even if the total monthly or annual costs remain constant or slightly decline. This increase in unit costs of production is exacerbated by increasing needs for compression and artificial lift and a continuing growth in maintenance related to corrosion, equipment repairs, water treatment and disposal and ever-expanding environmental concerns. An understatement of operating costs will lead to an overstatement of future net income and reserves.

All performance-derived estimates of reserves are limited by a terminal rate, which is typically described as an economic limit. A unit cost of oil or gas production never leads to an economic limit as the cost will simply remain a fraction of revenue, which illustrates the improper assumption of a constant unit operating cost.

Changes in recovery process—Problems in operating-cost estimates can also occur if future production involves new recovery mechanisms, for instance, the start of a waterflood. In such cases, an evaluator should conduct a careful review to properly account for changes in costs resulting from added operational requirements.

Guidelines to reduce operating-cost mistakes

- Future operating costs need to closely agree with observed historic costs. Incorporate at least two to three years of lease operating expenses into the estimate of future costs.
- Attempt to separate costs into fixed and variable components.
- Include recurring well or facility expenses in operating cost.
- Account for changes in costs caused by new recovery mechanism.
- Avoid simplification by estimating cost per unit volume without fixed/variable split.
- Include cost for handling of secondary products.
- Apply proper escalation of costs if applicable reserves definitions allow for such.

Editor's Note: Part 5 to be published in December.

Olds—Cont. from Page 2

Olds asked, "Has the industry failed to embrace the use of reliable technology or simply chosen not to discuss it unless it had a material impact?"

Early adopters take risks. "Pioneers are the ones with arrows in their backs," said Olds, quoting a Wild West saying. "Companies may be hesitant to book reserves using reliable technology if they are uncertain of how to comply with the SEC rule."

"Pioneers are the ones with arrows in their backs."—Olds

He also said that the survey showed that only four 10-K filers reported proved and probable reserves. They were **Abraxas Petroleum Corp.**, **Dune Energy Inc.**, **Tri-Valley Corp.** and **Whiting Petroleum Corp.** Only two companies, **Newfield Exploration Co.** and **FX Energy Inc.**, reported probable reserves without possible.

Scientific method tests "reliable technology" criteria

Sidle at 2010 Ryder Scott Reserves Conference.

To justify reserves bookings based on use of reliable technology in a given area, industry will need to use a clearly defined approach to demonstrate the consistency and repeatability required by the U.S. Securities and Exchange Commission, said **Rod Sidle**, a lecturer at Texas A&M University.

Without a specific recipe from the SEC, industry should consider adopting the scientific-method standard that the U.S. federal court has established for expert testimony, said Sidle, now retired after 35 years with Shell Oil Co.

Rule 702 of the U.S. Federal Rules of Evidence on expert testimony "points us in the right direction" to establish an industry model "for demonstrating reliability that can satisfy both technical and regulatory standards," he stated.

Sidle, a former SPE Oil and Gas Reserves Committee member, made his remarks at the Ryder Scott Reserves Conference, Aug. 27.

"Irrefutable evidence should be built on both the science behind the technology and the empirical data from sufficient case histories," he said.

Sidle outlined a five-step version of the scientific model as follows:

1. Define how reliable technology will contribute to reserve estimation.
2. Formulate a hypothesis, research the science behind the application and define when results are valid. Questions to ask include the following:
   - How should the reliable technology work in ideal situations?
   - What are the assumptions behind the successful use of the technology?
   - What real-life (non-ideal) conditions will affect the application of the technology?
3. Perform experiments. Test to validate the hypothesis and demonstrate that requirements of reliable technology have been met. One can use both new tests and hindcasting, which is knowing the outcome and confirming the results. Test a statistically significant number of times. Test expected failure situations to confirm limits on successful use. Knowing what failure looks like helps in understanding data.
4. Interpret the data. Draw conclusions and document results, including needed conditions to achieve reliability. For instance, what are the limits on successful application?
5. As necessary, revise hypothesis and repeat steps three and four.

"Be sure to include all test data in your documentation," said Sidle. "Selectively excluding data will raise questions regarding consistency and repeatability. Update your documentation regularly as new data is collected."

As an example, Sidle outlined scientific procedures for examining the reliability of pressure gradient cross plots. He also showed that the determination of fluid contacts is progressively more complex depending on elements of technology application, starting with the least challenging—direct measurement of a penetrated contact by well log analysis. Evaluating proximal wells and measured pressures is more complex and thus more challenging. Seismic analysis is the most complex of these three methods for delineating fluid contacts.

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Reservoir Solutions

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Petroleum engineer, associate petroleum engineer join Ryder Scott

Dani

Moksh N. Dani, petroleum engineer, joined Ryder Scott from Marathon Oil Co. where he worked as a reservoir and production engineer for four years. There, he conducted reservoir simulation and backpressure modeling of the McArthur River field in Alaska's Cook Inlet to estimate reserves. Dani provided technical support to the operations for analyzing well performance and making reservoir management plans in Alaska. He also provided engineering support for reservoir characterization and modeling studies.

Dani also was a drilling and completions consultant at Terra Dynamics Inc. beginning in 2005. He supervised drilling, completions, testing, stimulation and plugging and abandonment of injection wells in Arkansas and Texas. He has a BS degree in petroleum engineering from the University of Texas, MBA degree from the University of Houston and MS degree in finance from Tulane University.

Attorney **Joseph E. Stowers** joined Ryder Scott as an associate petroleum engineer. He has a BS degree in chemical engineering, magna cum laude, from the University of New Mexico, master's degree in petroleum engineering from the University of Houston and JD degree from Baylor University School of Law.

Coursework emphasis was on reservoir simulation studies, including waterflood simulation, full-field history matching, future production analysis and identification of potential drilling locations. Curricula also included decline-curve analysis on three U.S. fields.

Before joining Ryder Scott, Stowers was an attorney for five years at Tekell, Book, Allen & Morris LLP where he managed civil-case litigation, including development and implementation of case strategies, factual discovery, legal research and trial preparation. He was also an attorney at Beirne, Maynard & Parsons LLP from 2003 to 2005. As an attorney over seven years, his practice areas included oil and gas contractual litigation.

Stowers

Stowers is a member of the State Bar of Texas in the litigation and oil and gas sections and State Bar of New Mexico.

Sidle—Cont. from Page 7

Sidle also listed other potential targets for reliable-technology demonstration, including determination of areal extent and reservoir dynamics through simulation, while examining pressure/fluid gradients and seismic methods for contact estimation. He concluded his presentation with a look at how reliable technology relates to the use of analogs.

Drilling ban may justify exception to PUD rule

Experts at the Ryder Scott Reserves Conference said that U.S. regulators should consider the drilling ban in the Gulf of Mexico to be an external factor not under the control of the producer thus qualifying affected companies to take exceptions to a five-year limit on reporting proved undeveloped reserves.

Publisher's Statement

Reservoir Solutions newsletter is published quarterly by Ryder Scott Co. LP. Established in 1937, the reservoir evaluation consulting firm performs hundreds of studies a year. Ryder Scott multidisciplinary studies incorporate geophysics, petrophysics, geology, petroleum engineering, reservoir simulation and economics. With 130 employees, including 84 engineers and geoscientists, Ryder Scott has the capability to complete the largest, most complex reservoir-evaluation projects in a timely manner.