RESERVOIR SOLUTIONS

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SPE-PRMS guide to be released for comment shortly

Example applications of the 2007 Society of Petroleum Engineers Petroleum Resources Management System are scheduled to be released in written draft form for general comment before year end, said **Satinder Purewal**, the application document's editor.


Harrell at conference

Originally, plans called for the AD to be released in October, but Purewal said that SPE editors took longer than expected to prepare final draft versions of the chapters. **Ron Harrell**, chairman emeritus, told an audience at the Ryder Scott Reserves Conference earlier this year that the 100-page AD has taken four years to develop because "it takes a while to understand what is in the PRMS ."

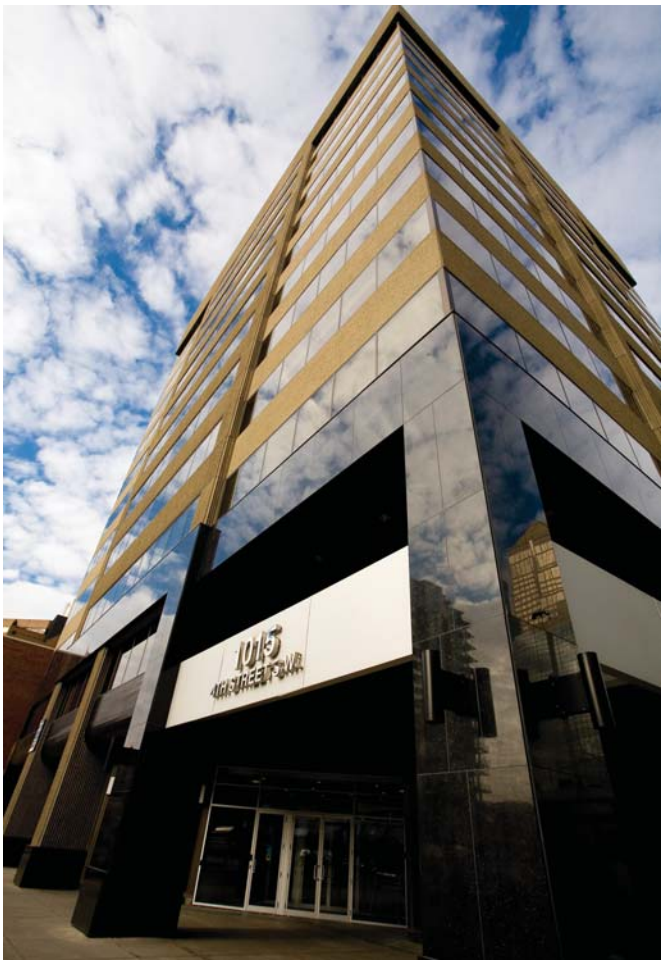
Initially, SPE sought case-history examples from industry to develop the AD. Feedback was tepid with only 10 responses. In 2008, sponsors of the Canadian Oil and Gas Evaluation Handbook and the SPE-PRMS discussed aligning COGEH and the AD but nixed it.

Also, during AD development, the knowledge base for unconventional hydrocarbons rapidly evolved. Of the 11 planned chapters, the one with guidance on evaluating unconventionals was written by six authors. All other chapters have either one or two authors.

In December, discussion focused on the inadequacy of the SPE-PRMS in addressing unconventionals. The AD is expected to provide guidance. One issue is the unpredictability of reservoir performance without initial production rates from a well, said Harrell.

He expects SPE to allot two months for comments and that SPE, World Petroleum Congress, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers and the Society of Exploration Geophysicists will approve the AD by the end of the first quarter 2011.

The presentations of Harrell and other speakers at the conference are posted at www.ryderscott.com.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PUD rule clarified

Jennifer Fitzgerald, vice president, presented "How do you count to five? The SEC five-year rule for PUDs revisited," at the Ryder Scott Reserves Conference earlier this year. The U.S. Securities and Exchange Commission added the disclosure requirement to Regulation S-X 210.4-10 almost two years ago.

The rule limits the reporting of proved undeveloped reserves to five years from the initial proved reserves booking with some exceptions. The industry at large has not received formal guidance from the SEC on when the "clock" starts for the five-year rule or if the rule applies to probable and possible reserves.

Fitzgerald, however, shared guidance that Ryder Scott received from the SEC on those issues.


Fitzgerald at conference

"Clarification from the SEC staff indicated that the five-year rule is retroactive and starts when reserves from the project are first reported," she said.

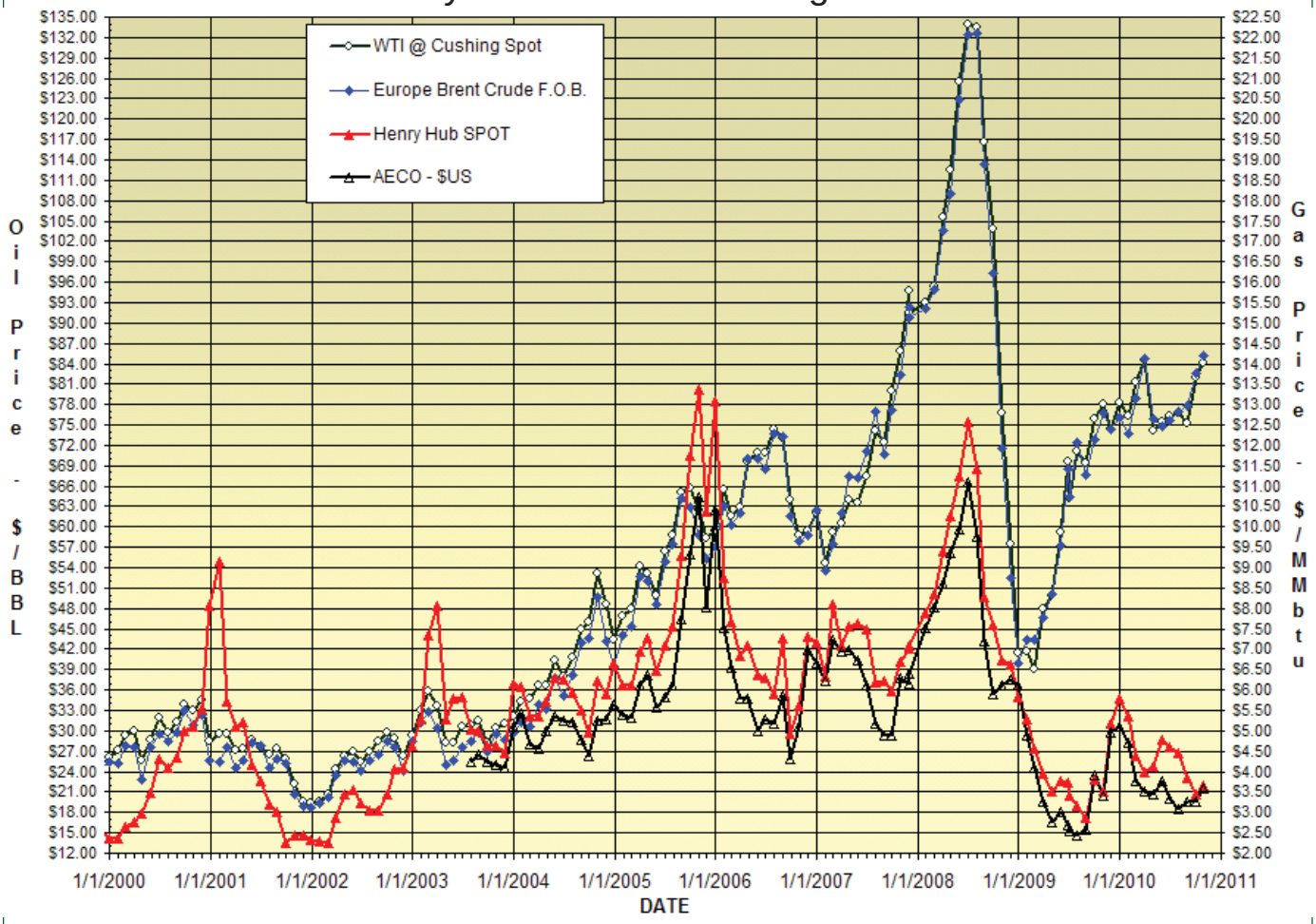
If the project is uneconomic at year end because of lower oil and gas prices, PUDs are converted to contingent resources. If the following year, prices rise and the project becomes economic again, then PUDs can be rebooked and the clock will start over again, Fitzgerald added.

She also said that the SEC had indicated to Ryder Scott that the rule does not apply to probable or possible reserves.

SEC prices on website

Annual average prices used to report YE 2010 petroleum reserves to the U.S. Securities and Exchange Commission are posted on ryderscott.com. WTI crude is $79.43 a barrel. Henry Hub gas is $4.38 per MMBTU. Other benchmarks and information on using differentials are posted. E-mail inquiries to fred_ziehe@ryderscott.com

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.

Reserves in unpenetrated fault blocks examined

John Hodgin, president, presented, "Reserves or resources: What do you have if you don't have a well penetration," at the Ryder Scott Reserves Conference earlier this year. He focused on criteria to consider when deciding on a classification for unpenetrated fault blocks.

Referring to the non-sealing type, Hodgin said, "You must establish a compelling case that the unpenetrated fault block is in communication with the adjacent one that contains proved reserves and hence is an extension of a known reservoir."

Hodgin cited five requirements to justify reserves assignments to non-sealing fault blocks:

1. Proximity—Fault block must be adjacent to one with established reserves.
2. Juxtaposition—Fault displacement must be less than formation thickness.
3. Communication—Fault must be non-sealing and transmissible.
4. Economic producibility—Fault block must have similar reservoir quality to adjacent one with established reserves and have sufficient volume to establish economic producibility.
5. Analogs—To establish fault transmissibility, correlation to seismic amplitude or seismic inversion volume must indicate hydrocarbon presence, potential reservoir thickness/quality and economic producibility.

For unpenetrated, sealing (pressure-separated) fault blocks, the U.S. Securities and Exchange Commission only allows resources to be assigned. The Society of Petroleum Engineers Petroleum Resources Management System, while advising caution, recognizes that documented evidence can support the valid assignment of reserves to undrilled, pressure-separated fault blocks in certain cases.

Referring to conventional reservoirs, Hodgin said that "if there is communication up the fault plane or


Hodgin at conference

there was a common reservoir with communication across the fault in the geological past, then probable and possible reserves may be able to be assigned to the unpenetrated fault block." For unconventional reservoirs, such as coal seam or shale gas, a company may be able to book reserves across sealing faults as an exception under the SPE-PRMS because hydrocarbons were formed in place vs. being emplaced via migration.

Hodgin advised companies to be extremely cautious about presenting empirical evidence of high success rates in drilling sealed fault blocks in statistical plays to justify reporting reserves to the SEC. The agency's "reliable technology" rule allows issuers to file reserves if they can document the successful performance of "consistent and repeatable" field-tested technology in subject or analog fields.

"Companies should consider a pre-booking opinion directly from the SEC staff if the proposed volumes are material," he said. Hodgin's presentation is posted on the Ryder Scott website.

Hinkle discusses probable reserves without proved


Hinkle at conference

Can probable reserves exist without proved? The U.S. Securities and Exchange Commission, through website guidance, said yes more than a year ago. An issuer can disclose unproved reserves without associated proved reserves, but only in exceptional cases, the agency clarified.

Cases with unproved reserves and no proved include field development projects ready for startup except for final regulatory approvals and improved recovery projects awaiting production responses. According to the SEC, exceptions don't include unpenetrated reservoirs or volumes that are not economically producible.

At the latest Ryder Scott Reserves Conference, **Delores Hinkle**, director of corporate reserves at Marathon Oil Co., remarked that the SEC clarifications have proved to be "less than straight forward in some cases." She said, "While the SEC's modifications were intended to provide an overdue update of definitions and rules

Please see Hinkle on Page 7

Technical challenges in estimating reserves Part 5: Analogy, reservoir simulation, volumetrics

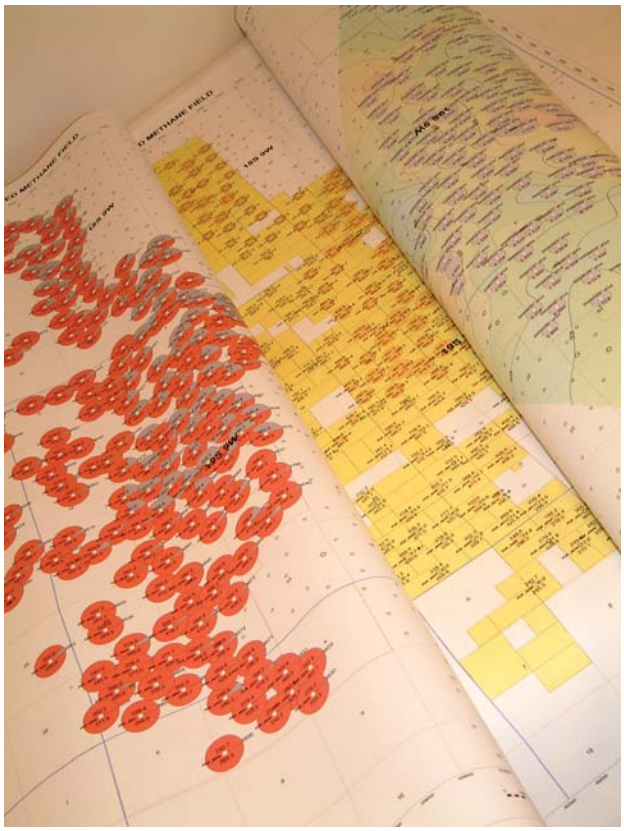
Editor's Note: This is a revised excerpt from "Oil and Gas Reserves Estimates: Recurring Mistakes and Errors," (SPE Paper No. 91069). To order a copy of the full paper, go to www.onepetro.org and access the e-library.

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 fifth newsletter article focuses on analog-, simulation- and volumetric-based reserves estimates.

Inappropriate selection of analogs

Engineers and geologists have historically relied on the use of analogies to estimate several reservoir parameters and performance expectations. An ideal analog is a developed reservoir with well-documented physical parameters and an adequate performance history to rely on for future production and performance expectations. Such a reservoir is an excellent analog for predicting the qualities of a nearby undeveloped reservoir in the same formation assuming the same development plan and operating scenario.



However, given several potential analogs in an area, selecting the best-performing reservoir to compare to a subject reservoir is inappropriate. An evaluator should analyze several potential analogs to more fully understand the extent and impact of variations in performance before selecting a reservoir or family of reservoirs as the analog.

The suitability of a reservoir to be an analog is related to the purpose of the comparison. Estimations of gross rock properties, for example, may be reliably obtained from comparisons with nearby similar reservoirs within the same formation. However, ultimate recovery may vary considerably depending on well spacing, completion practices and other operational details that affect recovery efficiency.

Evaluators estimate reserves by analogy during the early field development stages before definitive performance and geologic data are available. Conversely, analogy is frequently used when new recovery mechanisms are introduced to a mature field, for example, a field undergoing waterflooding, well stimulation or infill drilling.

The analogy method typically involves the following three necessary stages:

- Establish proof of analogy to a mature reservoir and recovery process.
- Study performance and operations of analogous reservoir.
- Apply analogy performance with appropriate adjustments to account for deviations to target reservoir.

Challenges in proper selection and application of analogs are associated with all three stages, but typically the first and third stages are the most problematic.

Problems with establishing proof of analogy

In most cases, omitting or misinterpreting the effect of key parameters causes errors. Proof of analogy requires establishing geologic/petrophysical, reservoir engineering and operational similarities. Operational similarity is assured in a scenario where the target field is operated similarly to the analogous field.

The following bulleted summaries list parameters under geoscience, engineering and operational areas that are analyzed to make a case for the analogy method.

- Geoscience—Structural configuration, lithology and stratigraphy, principal heterogeneities, reservoir continuity, average net thickness, water saturation, permeability, porosity, areal proximity
- Engineering—Pressure and temperature, fluid properties, recovery mechanism, fluid mobilities, fluid distribution, reservoir maturity, well productivity, EOR specifications, areal proximity
- Operational—Well spacing, artificial lift methods, pattern type and spacing, injector-to-producer ratio, annual injection volumes, fluid handling capacity, stimulation design, areal proximity

For the target reservoir, all parameters have to be as favorable or more favorable than for the analog,

especially for a proved reserves classification. Not all items necessarily apply to each case. The key is to identify the main performance drivers that will influence the intended, analogous treatment and to determine if similarity can be established.

The importance of areal proximity is emphasized in the Society of Petroleum Engineers "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information." It states, "If performance trends have not been established with respect to oil and gas production, future production rates and reserves may be established by analogy to reservoirs in the same geographic area having similar characteristics and established performance trends."

Incorrectly applying analogous performance to the target field will cause mistakes in establishing proof of analogy and include the following:

- Assuming similarity because of areal proximity and same formation without proper evaluation of all parameters.
- Field not located in same geographic area.
- No similarity in critical parameters that have been overlooked in the analysis.
- Bias toward trying to force analogy if a few key parameters match.

Problems applying analogy to target field

When an evaluator establishes an analogy but key parameters are slightly different, he may apply the analogy method by making appropriate adjustments. Inappropriate applications of analogous behavior are caused by the following:

- Not designing for operational similarity, particularly well density.
- Not making appropriate adjustments to account for operational differences, including costs.
- Not making appropriate adjustment to account for differences in quantified geoscience and engineering parameters. For example, the evaluator must calculate displacement efficiency resulting from differences in fluid properties or he must account for differences in stratification that may affect vertical sweep.

Examples

- When estimating future recovery from a planned waterflood by analogy, the evaluator must establish similarity between geoscience and engineering parameters to assure similar displacement and sweep behavior and design the target waterflood similarly to the analog for well spacing, pattern type and annual injection volumes. Operational dissimilarity frequently causes overly conservative or aggressive projections.
- Similarly, differences in mobility may not necessarily disqualify an analogy as long as the evaluator makes proper adjustments to account for the change in displacement efficiency.

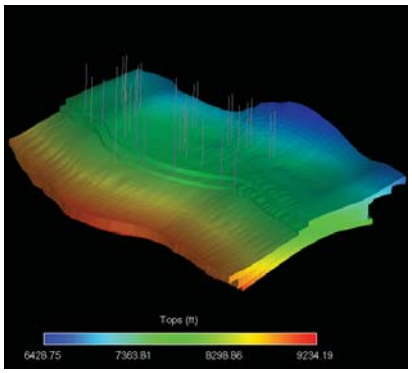
Guidelines to reduce mistakes using analogies

Give preference to analogies in areal proximity to target field.

- Follow a strict process where the evaluator tabulates and compares key parameters that need to be similar.
- Accept analogy only if a good match exists or if adjustments can be quantified to account for differences. Qualitative or "instinct" adjustments need to be weighed carefully and may be cause for downgrading to a lower reserves classification.
- Review, and if necessary, design for operational similarity. This will also capture appropriate costs.

Simulation-derived estimates of proved reserves

E&P companies manage most significant oil and gas reservoirs worldwide through the use of detailed reservoir models. They are excellent tools for decisions on development, operations and reservoir management. **Dean Rietz**, manager of reservoir simulation at Ryder Scott, and Ryder Scott petroleum engineer **Miles Palke** have documented their concerns about using even the most robust models for proved reserves estimates under given definitions.



They support using simulation of immature reservoirs to estimate recovery efficiencies and for testing the ranges of other parameters, including permeability and aquifer support. Rietz and Palke further recommend that models of mature reservoirs be used for proved reserves estimates only when reasonable history matches of the reservoir and wells have been obtained.

They do not reject reserves estimates based on reservoir simulation. However, Rietz and Palke warn

Please see Simulation on next page

Simulation—Cont. from Page 5

about the dangers of estimating reserves without a detailed review of the model to fully understand associated assumptions, limitations and applicability. Failure to review the model may cause significant overstatement of proved reserves.

Failure to incorporate early-life performance data into volumetric estimates

Early-life production and pressure-decline trends may not be sufficiently definitive to provide the sole basis for reserves estimation but should be continuously reviewed to fine tune a volumetric-, analogy- or simulation-derived reserves estimate. Quite frequently, this early-life data, including initial rate and pressure data and any available trends, has not been used to calibrate static estimates until well past the half life of a reserves estimate.

Disregarding early performance data and potential warning signs may lead to significant positive or negative reserves revisions. Common errors include the following:

- Not revising reserves expectations for undeveloped locations based on performance data of producing wells.
- Not anticipating the impact of unexpected increase in water or gas production.
- Not accounting for effects of pressure depletion on behind-pipe and infill locations over time.

Updating undeveloped locations based on performance data

Reserves estimated for undeveloped locations at the beginning of field development are typically based on drainage area and recovery factor assignments frequently in combination with analogies from nearby fields. As performance data becomes available, the evaluator needs to review and revise (calibrate) volumetric calculations and recovery-factor estimates.

Deviations from the initial estimates may require adjustments to recovery factors, rate projections and numbers and locations of future development wells. Some of the largest errors often occur if existing wells are adjusted for lower productivity but ultimate reserves are maintained by extending field life.

This situation creates two critical problems. Lower initial rates may indicate lower productivity, thinner pay, interference effects and smaller drainage areas. Therefore per-well reserves and in-place volumes may be overestimated.

Secondly, capital allocations may be underestimated as more wells may be necessary to achieve the previously estimated volumes and therefore the resulting net present value will be overstated.

Early or unexpected water production, increases in GOR

An unexpected increase in water production in downdip wells or gas-oil ratios in updip wells may affect reserves booked in wells throughout the field. Problems with unexpected changes in water or gas production typically result from uncertain drive mechanisms.

For example, consider the following:

- Undeveloped locations may have been booked updip of an existing location based on an expected strong water drive, but existing wells are experiencing increased gas-oil ratios indicating a secondary gas cap or a smaller-than-anticipated reservoir.
- Conversely, undeveloped reserves may have been set up on strike with existing wells that water out prematurely because of expectations of a depletion or weak aquifer drive. Under such circumstances, not only do the affected wells need to be re-evaluated but any undeveloped or behind-pipe reserves need to be reviewed as well.

Effect of depletion on behind-pipe and infill locations

Evaluators establish behind-pipe reserves and infill wells at certain points in time under existing pressure and depletion (or sweep) conditions. Often, oil and gas companies keep those reserves and wells "on the books" for several years or longer depending on the allocation of capital spending and timing of other projects.

Over time, the reserves engineer should re-evaluate volumes assigned to behind-pipe and infill wells as existing wells may have drained some or essentially all of these volumes, even in low-permeability reservoirs. A recommended approach to avoid carrying reserves that may have already been drained is to compare produced volumes with the expected ultimate recovery for the entire reservoir. This approach allows timely adjustments to the remaining volumes for behind-pipe or infill wells.

The reserves evaluator should reasonably expect that the remaining volumes will be drained by the proposed behind-pipe completion or undeveloped locations.

Other common problems with performance adjustments

- Recovery factors based on optimistic but unconfirmed drive mechanisms
- Assumed well drainage areas or reservoir areas, such as updip locations or seismic amplitudes
- Setting up offset locations without compelling evidence of reservoir continuity

Events that should trigger review of all reserves

- New wells with unexpected changes in reservoir thickness, fluid contacts, pressures or productivity
- Early or unexpected water production or unanticipated increases in gas-oil ratio
- Significant deviations from expected production or pressure-decline trends
- Reserves for undeveloped and behind-pipe locations that have not been reviewed in several years.

Guidelines to reduce frequency of mistakes

- Always review the potential field-wide implications of new data.
- Do not assume that, by chance, only poor locations are drilled and good ones are yet to come.
- Exercise caution placing undeveloped locations where drive mechanisms or efficiencies are uncertain.

Editor's Note: The Part 6 article in the March 2011 Reservoir Solutions newsletter will conclude this series and focus on the impact of partial waterdrive and overpressured reservoirs on gas material balance. Also examined will be undrilled fault blocks and economics projection programs.

Geologist, petroleum engineer join Ryder Scott

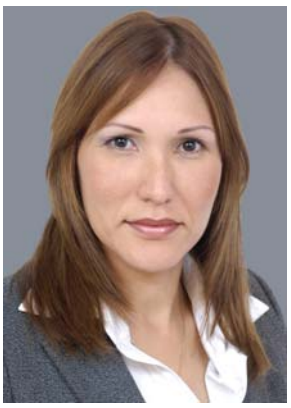
Hanko

John Hanko, a former vice president of geology at Ryder Scott Canada, has rejoined the firm as a geologist. He worked at Ryder Scott Canada for nine years beginning in 1996. Hanko joined Sproule Assocs. Ltd. in 2006 from Pengrowth Corp. and was a senior geologist for four years. He was also acting manager of Sproule's domestic geoscience group for two years.

Hanko will manage geology for reserves projects for Ryder Scott's Canada branch. His regional areas of expertise include Western Canada, East Coast offshore, Northwest Territories, United States, Ecuador, Colombia, Argentina, Australia, Egypt, Tunisia, Nigeria, Russia, India, Bangladesh, France and North Sea.

Hanko has correlated oil and gas zones and surrounding strata; assessed depositional environments, stratigraphy, lithology and reservoir geometry and structure; determined net pay thickness and reservoir parameters using well logs, core analysis, DST and completion data and generated structure and isopach maps for the volumetric determination and categorization of reserves and in development planning.

He began his career as a contract geologist at Sproule in 1988 after graduating with a BSc degree in geology from the University of Calgary. Hanko was contractor at Sproule from 1989 to 1994 and a wellsite geologist at T.I.H. Consulting Ltd. during 1994-96.



Garcia

Marylena Garcia joined Ryder Scott in Houston as a petroleum engineer from Conoco Phillips Inc. where she was a senior reservoir engineer evaluating resources and reserves and developing economic models during 2007-09. Before that, she was a reservoir engineer at Occidental Petroleum Corp. for two years where she planned and executed CO_2 flood expansions and improved reservoir sweep efficiency.

Garcia also developed infill drilling programs to improve oil recovery, prepared production and injection forecasts and developed expected production and injection performance plots to improve monitoring of reservoir behavior.

She was a reservoir engineer at Petroleos de Venezuela SA from 1998 to 2003. Garcia conducted compositional reservoir simulation and built integrated, dynamic reservoir models. She also monitored high-pressure gas injection, validated PVT data and generated equations of states. Garcia conducted material balance analysis in gas condensate reservoirs to determine reservoir communication and oil and gas reserves estimates.

She also supervised buildup, falloffs and production logging tests at PDVSA. She has BS and MS degrees in petroleum engineering from Universidad de Oriente and Texas A&M University, respectively.

Hinkle—Cont. from Page 3

for disclosing reserves, many questions regarding their proper application still remain."

In pointing out these gray areas, Hinkle said that a compelling case can be made to book unproved reserves without proved in the following scenarios:

- Owning interests in a probable area (formerly offset location) that is an extension of another company's proved area.
- Owning interests in zones within a wellbore that are adjacent to proved intervals but are not reasonably certain of recovery.
- Accumulations updip of and in communication with proved volumes may justify the assignment of probable reserves.
- Data from a well penetrating the aquifer may also allow unproved downdip volumes.
- Upside to proved recovery factors may be booked as probable.

Hinkle stressed that justification for probable volumes must be based on proven technology and reasonable economic assumptions, including the same hydrocarbon price decks used for proved reserves. "Handle each situation on case-by-case basis, clearly and carefully documenting the justification for all bookings," she said.

For more detail on this topic and others from the 2010 Ryder Scott Reserves Conference, please visit www.ryderscott.com/presentations.

A Ryder Scott survey presented at the conference showed that only four 10-K filers optionally reported probable and possible reserves for year-end 2009. 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.

SEC filers should ensure that unproved reserves cited in MD&A and press releases are SEC compliant even if they are not filed.

For more information on that issue, see "Reserves in MD&A should comply with SEC rules, says attorney," *Reservoir Solutions* newsletter, December 2009, Page 4.

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OU wins SPE Petrobowl at ATCE

At this year's Society of Petroleum Engineers Petrobowl, students from the University of Oklahoma hoisted the championship trophy as the last team standing. SPE student members from 20 universities worldwide competed at the quiz-bowl-style tournament in September by buzzing in the quickest to answer hundreds of toss-up and bonus questions.

The triumphant Sooners, with its third win in four years, returned to Norman, OK, with a $2,500 scholarship check for the petroleum engineering department. This year's SPE Annual Technical Conference and Exhibition in Florence, Italy, was the host site for the ninth running of Petrobowl. **Lucas Smith**, a petroleum engineer at Ryder Scott, helped organize and manage the contest.

A record number of teams, including 11 outside the United States, were paired in first- and second-round, single-elimination, "one-and-done" matches. At the end, second-place finisher Missouri S&T bowed to OU in the final round. Texas A&M University and University of Texas tied for third.

Petrobowl questions ranged from technical to non-technical and included such categories as drilling, reservoir, production, facilities, geology, history, politics and current events in the oil industry. **Matthew Paradeis**, a graduate student at Missouri S&T, was MVP. He answered 21 of 35 total buzz-ins or 60 percent correctly.

Q&As from the final round at Petrobowl IX

Petrobowl contestants correctly answered the following questions from final and bonus rounds. Can you answer all four correctly? Answers at page bottom.

1. Baker Hughes completed its $5.5 billion acquisition of this company in April 2010. Name the company known for its pressure-pumping, cementing and coiled-tubing services.

2. What theory popularized by Russian scientists in the 1950s postulated that hydrocarbons did not originate from living organisms, but were created deep within the earth's crust by carbon deposits at high heat and pressure?

OU students, from left, Kristin Weyand, Bachir Mahomad, Yashwath Chitrala, Michael Aman and Brian Edge won SPE's Petrobowl this year in Florence, Italy, at the ATCE.

3. SPE membership numbers increased by almost 4,000 in 2008. How many members were in SPE in 2009 plus or minus 5 percent?

Try the following final bonus question that was a crowd favorite, but was not answered correctly.

4. Much to Jay-Z's dismay, it was Exxon geophysicist Dr. **Andy Hildebrand** who developed this technology based on his experience with seismic interpretation. Name this technology used by pop music artists from Cher to T-Pain.

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 86 engineers and geoscientists, Ryder Scott has the capability to complete the largest, most complex reservoir-evaluation projects in a timely manner.

Answers:

1. BJ Services; 2. Abiogenic; 3. SPE had 92,173 in 2009. Answer is 87,500 to 96,800; 4. Auto-tune