RESERVOIR SOLUTIONS

Published quarterly by Ryder Scott Co. LP June–August 2010/Vol. 13, No. 2

SEC to industry: More details on technology, geography

The U.S. Securities and Exchange Commission wants more detail in year-end petroleum reserves disclosures and may issue additional guidance this year, said **H. Roger Schwall**, assistant director in the Division of Corporate Finance at the SEC. He made his remarks at a financial reporting session of the United Nations Economic Commission for Europe in Geneva in late April. Schwall said his views did not necessarily reflect those of the SEC.

He remarked that the SEC wanted more specificity in disclosures related to the use of technology, new and significant bookings, credentials of reserves evaluators, costs of converting proved undeveloped reserves, use of average prices and assigning PUD locations more than one offset from a producing well.

He also said that the SEC received disclosure by groupings of continents that were not in close proximity, such as Australia and South America. Under the new rules, public issuers are required to disclose reserves by continent or country if they represent 15 percent or more of total reserves. SFAS 69 requires reserves disclosures to be separately reported for the company's home country and foreign geographic areas.

The SEC stated in the new rules, which went into effect for the first time at year end, that geographic reporting should provide greater specificity than simply disclosing reserves within groups of countries and may be necessary to meet requirements of Item 102 of Regulation S-K.

At the session, **Kathryn A. Campbell**, a partner at Sullivan & Cromwell LLP law firm, said that in surveying the year-end filings of 30 large cap oil and gas companies, there were various interpretations of what constituted continents. She also noted that no company reported reserves by continent that would have resulted in field-level disclosure.

"Only a few companies provided discussion of specific technologies and additions. Most provided lists of general types of technologies."
— Campbell

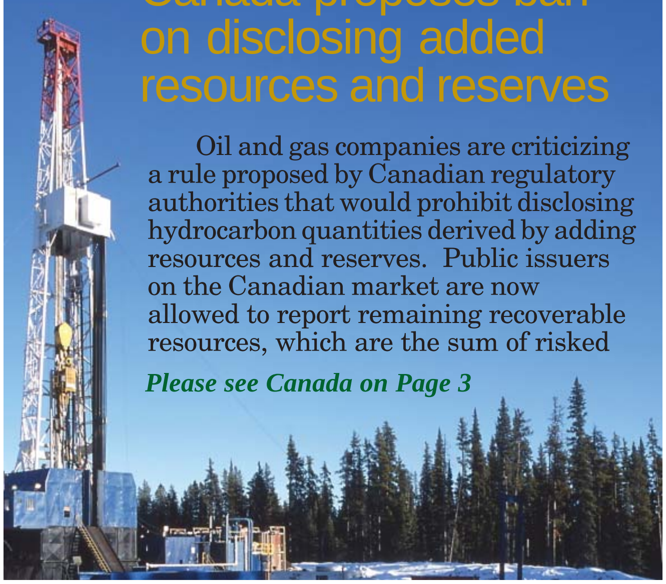
Originally, companies objected to geographic reporting based on potential competitive harm, saying that in certain cases, such detail would put reserves in particular fields in the public domain.

Consistent with Schwall's remarks, Campbell said, "Only a few companies provided discussion of specific technologies and additions. Most provided lists of general types of technologies." The SEC permits the

Please see SEC on Page 2

Inside Reservoir Solutions newsletter

Canada proposes ban on disclosing added resources and reserves



Oil and gas companies are criticizing a rule proposed by Canadian regulatory authorities that would prohibit disclosing hydrocarbon quantities derived by adding resources and reserves. Public issuers on the Canadian market are now allowed to report remaining recoverable resources, which are the sum of risked

Please see Canada on Page 3

SEC—Cont. from Page 1

use of new technologies to determine proved reserves if those technologies are shown to empirically lead to reliable conclusions about volumes.

Use of the latest technology had a limited impact in boosting reserves at year end for some large companies, said **Danny Trotman** at Ernst & Young accounting firm, as he noted the following language in filings:

- Chevron Corp.—The ability to use new technologies in reserves determination did not impact reserves significantly, as most reserve additions and revisions were based on conventional technologies
- BP Plc—Application of technical aspects resulted in an immaterial increase of less than 1 percent to BP's total proved reserves.
- Anadarko Petroleum Corp.—Less than 1 percent of …total proved reserves ...were added as a result of pressure-gradient analyses, well control or seismic reliable technologies.

For Royal Dutch Shell Plc, with a reported 14 billion BOE proved oil and gas reserves, the application of reliable technologies contributed 150 million barrels, the company said, adding that the most significant increases were related to the use of wireline pressure gradients and wireline testing.

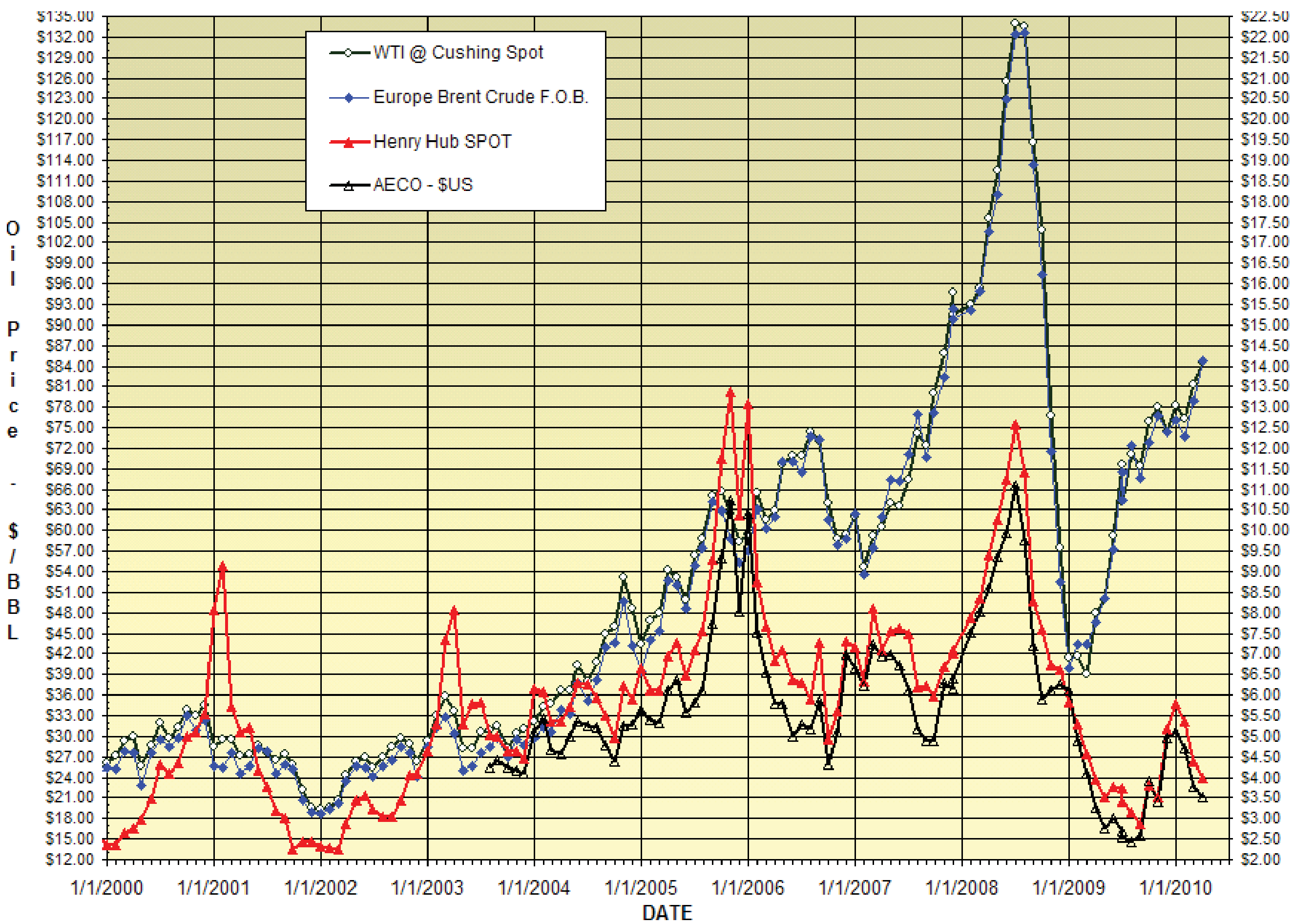
In U.S. shale gas plays, reserves additions from the use of newer completions and production technology were expected. However, Ultra Petroleum Corp., which has a significant Marcellus shale gas position, said "none of these (new) technologies were used to affect a material change to reserve additions."

While the SEC has broadened its acceptance of so-called new technology for justifying reserves adds, some of those measurement tools, such as seismic, have been used for decades. What is new is the agency's recognition of measurement techniques other than flow testing to the surface.

Presentations from the UNECE session are posted at www.unece.org/energy/se/docs/egrc1.html. Besides the presentations cited herein, **Glenn Brady**, project manager at the International Accounting Standards Board, provided an "Update on the IASB Research Project on Extractive Activities."

Jeff Tenzer, manager of corporate reserves at Chevron Corp., presented, "New SEC Oil & Gas Reporting Rules - Company Viewpoint." **David Elliott**, chief petroleum advisor to the Alberta Securities Commission, presented "Classification Issues Associated with Unconventional Resources."

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.

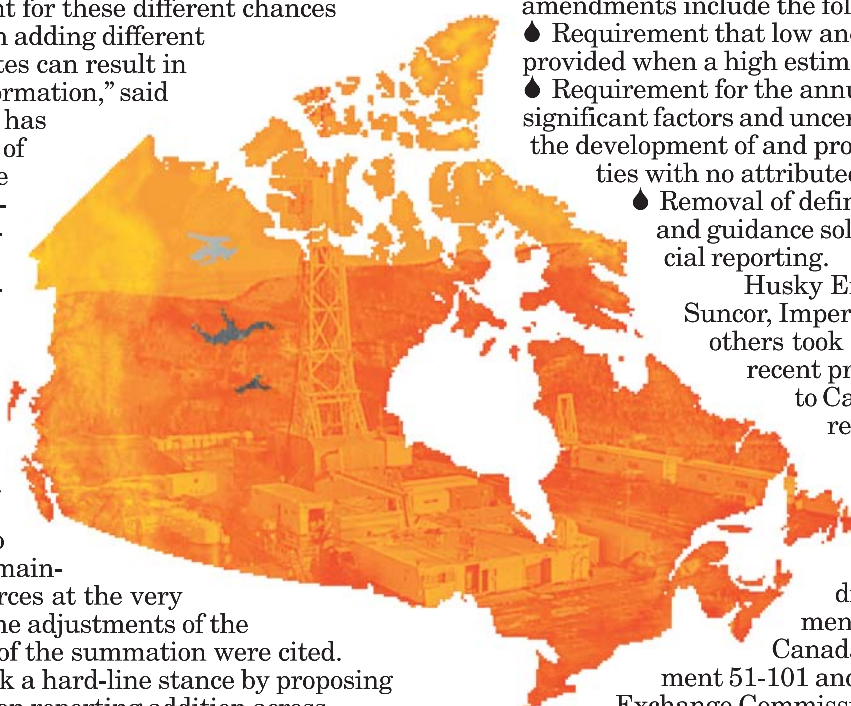
Canada—Cont. from Page 1

or unrisked reserves and resources. The industry also reports reserves and resources classifications separately.

That industry practice is consistent with the Canadian Oil and Gas Evaluation Handbook Vol. 1, Section 5.2, which states that "when resource categories are combined, it is important that each component of the summation also be provided." The bigger issue for regulators though has been whether to allow the aggregated unrisked number to be disclosed.

After reviewing year-end 2008 filings, the Alberta Securities Commission said that reserves and contingent/prospective resources reported on an aggregate basis without associated risks were likely to be misleading to investors. The Canadian Securities Administrators earlier this year cited Section 5.3.3 of COGEH Volume 1 as applicable guidance on risks involving chances for commerciality.

"Failure to account for these different chances of commerciality when adding different resource class estimates can result in highly misleading information," said the CSA. The agency has allowed the reporting of remaining recoverable resources if the disclosure contains cautionary language on whether those quantities are risked in the aggregation process and if the components of the aggregation, i.e., reserves and resources classes, are identified.



Industry anticipated being allowed to continue reporting remaining recoverable resources at the very least if risked and if the adjustments of the components (classes) of the summation were cited. However, the CSA took a hard-line stance by proposing a blanket prohibition on reporting addition across resource classes while being silent on risk.

The proposed amendment would prohibit a reporting issuer from disclosing a summation of quantity or value estimates from the combination of two or more of the following: reserves, contingent resources, prospective resources, unrecoverable portion of discovered petroleum initially in place, unrecoverable portion of undiscovered PIIP, discovered PIIP and undiscovered PIIP.

In disclosing risks, the industry in Canada follows COGEH guidelines for estimating commerciality chances, which are 100 percent for reserves. Companies factor in the chance of development for contingent resources and chances of development and discovery for prospective resources. Chances of discovery in a given structure are estimated in geological risk assessments which factor in trap, timing and migration, reservoir and source.

Nexen Inc. said that disclosing remaining recoverable resources "allows an issuer to provide a resource quantity that illustrates the purpose and potential of a capital project, transaction or business strategy." The company remarked that in addition to COGEH, CSA Staff Notice 51-237 and the Society of Petroleum Engineers Petroleum Resources Management System offer guidance on how to report remaining recoverable resources.

Suncor Energy Inc. also cited those references, saying that the CSA can achieve its goals without outright prohibition. "This (remaining recoverable resources) disclosure provides investors with valuable information relating to the long-term viability of the company and the associated risks across Suncor's oil and gas portfolio," the company stated. Cenovus Energy Inc. also commented against the proposed ban.

Comments to other amendments

The primary features of the other proposed amendments include the following:

- Requirement that low and best estimates be provided when a high estimate is disclosed.
- Requirement for the annual disclosure of significant factors and uncertainties pertaining to the development of and production from properties with no attributed reserves.
- Removal of definitions, requirements and guidance solely related to financial reporting.

Husky Energy Inc., Nexen, Suncor, Imperial Oil Ltd. and others took exception to other recent proposed amendments to Canadian petroleum reserves disclosure rules. As U.S. and Canadian registrants, those dual reporters are subject to annual disclosure requirements under Part 2 of Canada's National Instrument 51-101 and U.S. Securities and Exchange Commission rules.

Companies took issue with any implication by the CSA that SEC and Canadian rules would be more comparable because of a proposal to allow industry to optionally disclose reserves using cost and price sensitivities based on the SEC's constant price (base) case. Prices used for SEC reporting are calculated on a 12-month historical average of first-day-of-the-month prices.

If approved, the change will not affect Canada's required base-case disclosure, which is calculated using future market prices and costs escalated in accordance with company assumptions. Nexen said that it was concerned with the CSA's "suggestion" that using SEC costs and prices for an estimate otherwise prepared in accordance with NI 51-101 "will allow for disclosure …comparable to reserves disclosures prepared entirely under the SEC rules," adding that "it is an oversimplification of the differences …that will mislead and

Please see Canada on Next Page

Canada—Cont. from Page 3

confuse investors."

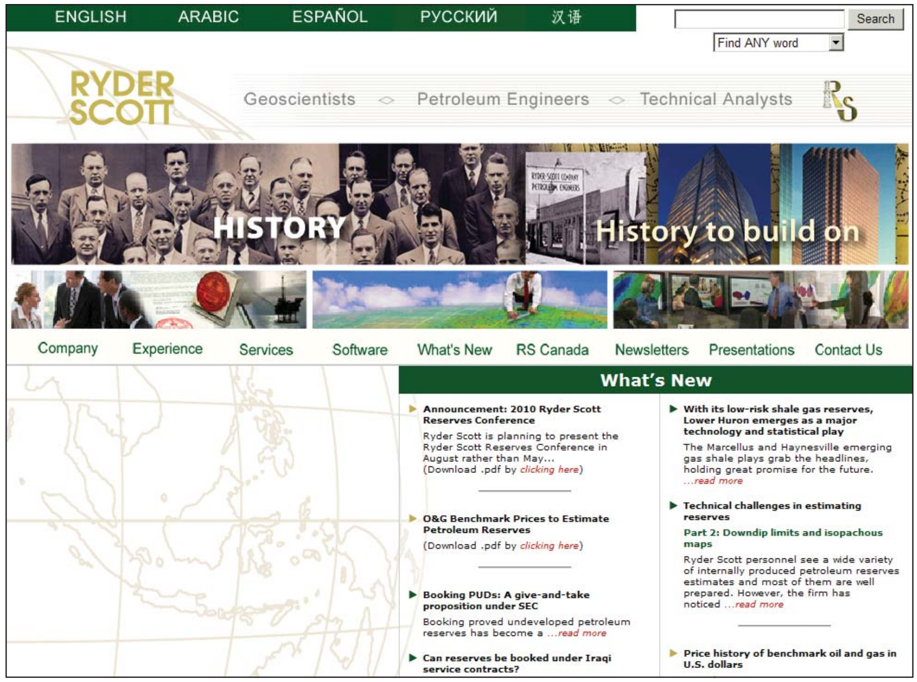
In a separate statement in March, Nexen pointed out differences between the two reporting regimes in areas "such as the use of reliable technology, aerial extent around a drilled location, quantities below the lowest known oil and quantities across an undrilled fault block."

Canada's proposed change to allow optional economic forecasts using SEC prices and costs, nevertheless, will eliminate some variability between each regime's reporting systems if approved. Imperial said it evaluated proved reserves using Canada and U.S. pricing systems separately while "holding technical assumptions and other factors constant" and noted that proved reserves between the two varied up to 20 percent. The company also said that an escalated case may be useful for a company's internal estimates but "comparability between companies' reserves is lessened."

Among other differences between the two regimes, Canadian guidelines call for reserves to be based on sufficient return on investment to justify associated capital costs, while the SEC rules have no such restrictions, said Imperial. The SEC has said that a $1 positive undiscounted cash flow at the entity level for booking proved undeveloped reserves is an acceptable criterion and helps create a standardized measure (common yardstick) for analysts and the investing public to make company-to-company comparisons.

While that SEC rule is less stringent than the Canadian one, U.S. registrants have to document development plans that support reserves filings, which limits how aggressively they can book reserves. Generally, companies don't plan to drill wells that generate miniscule positive cash flow, so booking PUDs from those undrilled locations is unlikely. An exception to that is when a company is contractually required to drill a submarginal well as part of an economic, commercial field development plan anticipated to yield returns on investment that meet the company target.

Please see Canada on Page 7



The newly designed Ryder Scott home page includes new and updated material, including first-of-the-month benchmark oil and gas prices used for SEC reporting.

Companies argue against disclosing uncertainty levels in estimate methods

In comment letters the first half of the year, the U.S. Securities and Exchange Commission asked oil and gas companies to disclose the percentage of total reserves derived from volumetric and performance methods separately. The agency also asked for relative levels of uncertainty associated with each approach.

Industry has urged the SEC to reconsider its request, arguing that uncertainty is inherent in each category of reserves—proved, probable or possible—but that certainty levels are not associated with a given method of evaluation.

SEC Regulations Part 210.4-10(a) offers definitions for the estimation of uncertainty inherent in reserves categories.

On a given project, reserves evaluators use performance, volumetric and analogy methods singularly or in combination. They base their selections on the following:

- Extent of reliable geoscience and engineering data
- Established or anticipated performance characteristics of subject reservoir
- Producing maturity of the property

Volumetric or analogy methods or combinations of the two are used when historical performance data to establish a definitive trend is not adequate. The volumetric methodology involves interpreting data from well cores and logs and geological maps to estimate in-place quantities and recovery factors.

Later in field life, companies rely more heavily on performance methods—including decline-curve analysis, material balance and reservoir simulation. Evaluators make extrapolations from historical production and pressure data while volumetric analysis is used as a check on those projections.

A misconception persists that the volumetric method has more associated uncertainty than performance analysis. Most likely, the cause of confusion is that companies rely on the volumetric approach to evaluate immature fields when technical uncertainty is high.

However, those levels of certainty are data dependent, not method dependent.

Acuña voted to board, others promoted and hired

Acuña

Herman Acuña, managing senior vice president, was elected to the board of directors in March. He has worked at Ryder Scott for 13 years and is a group leader for one of three international project groups in the firm.

Acuña oversees projects involving management advisory services, integrated reservoir studies, reservoir simulation, probabilistic analysis, reserves and economic evaluations, field operations, well test analysis, artificial lift evaluation and retrograde gas reservoir studies. He has worked on major international evaluation projects for Ryder Scott in the Middle East, Africa, Caspian region, Europe, South America and the Far East.

Before joining Ryder Scott, he worked at Exxon Production Research for five years as a petroleum engineer on reservoir simulation and surveillance projects. He began his career in 1988 as a petroleum engineer at a Tulsa, OK, consulting firm where he performed research to develop artificial lift design software.

Acuña has BS and MS degrees in petroleum engineering from the University of Tulsa and is a Registered Professional Engineer in the State of Texas.

Palke

Miles R. Palke has joined Ryder Scott as a senior petroleum engineer specializing in reservoir simulation, characterization and well-test and material-balance analyses. He has more than fourteen years of reservoir engineering experience with heavy emphasis on reservoir simulation studies.

Areas of expertise include sector and full-field reservoir modeling, fluid characterization, compositional simulation, coalbed-methane recovery, gas storage operations, nodal analysis, well test analysis and material balance evaluations. Palke has evaluated numerous oil and gas properties in Algeria, Brazil, Canada, China, Colombia, India, Indonesia, Kuwait, Mexico and the United States.

Before joining Ryder Scott, Palke was a senior staff reservoir engineer and subsurface engineering manager at BHP Billiton Ltd. for seven years beginning in 2002. He also worked at Ryder Scott from 1998 to 2002 as a petroleum engineer in the reservoir simulation group. Palke began his career as a petroleum engineer at Arco E&P Technology in 1996.

He has BS and MS degrees in petroleum engineering from Texas A&M University and Stanford University, respectively. Palke is a Registered Professional Engineer in the State of Texas.

Benedetto-Padron

Eleazar Benedetto-Padron joined Ryder Scott as a petroleum geoscientist. He has more than seven years of professional experience, including geocellular modeling of clastics, carbonates, CBM, unconventional tight gas and resource plays. Benedetto-Padron also has conducted reservoir characterization, reservoir uncertainty analysis and data management.

Previously, he worked at Roxar Inc. for two years as a senior reservoir geologist/consultant where he managed projects involving geomodeling, simulation, reservoir and field studies. Benedetto-Padron worked at Petrolera Ameriven S.A. from 2003 to 2006 as a development geologist for projects in the Orinoco heavy oil belt in Venezuela. He performed well planning, drilling, wellsite geology, seismic interpretation, core description, well log interpretation and well correlations. Benedetto-Padron has a BS degree in geological engineering from Oriente University.

Ovalle

Hugo Armando Ovalle has joined Ryder Scott as a petroleum engineer. Before that, he was a contractor at the firm beginning in 2008. Ovalle performs evaluations of reserves, field performance and economics using deterministic and probabilistic methods.

He has experience evaluating oil and gas properties in Algeria, Argentina, Australia, Bolivia, China, Colombia, Mexico and Trinidad & Tobago. Ovalle began his career at Petroleum Services Inc. in 2005 where he conducted research, performed data analysis and assisted in petrophysical modeling of numerous reservoirs. He has a BS degree in petroleum engineering from the University of Oklahoma.

The following professionals were promoted to the following positions: **Anna Hardesty**, **Martin Cocco**, **Olga Basanko**, **Keven Fry**, **Eric Nelson** and **Jennifer Fitzgerald** to vice president; **Elizabeth DeStephens**, **Timour Baichev** and **Ryan Wilson** to senior petroleum engineer; **Michael Lam** to senior petroleum geoscientist and **Eric Sepolio** to petroleum engineer.

Full professional experience, educational and licensing credentials, geographic areas of focus, area of specialization and other qualifications of Ryder Scott petroleum engineers and geologists are posted at www.ryderscott.com/Experience/Employees.php.

Technical challenges in estimating reserves Part 3: Isochore maps and attic volumes

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 third newsletter article focuses on isochore maps (Cont. from Part 2, March 2010 *Reservoir Solutions*) and attic volumes.

Net pay isochore maps—Downdip wedge zone (Cont. from Part 2)—The use of an average net-to-gross ratio in a reservoir where the net-pay distribution varies over the vertical interval will likely lead to misstating reserves. The following three figures illustrate the relationship between net-to-gross ratios and reservoir volumes.

The net-to-gross ratio for the well illustrated in Figure 8 is 0.50. However, most of the net pay occurs in the upper 20 ft of the 80-ft gross interval.

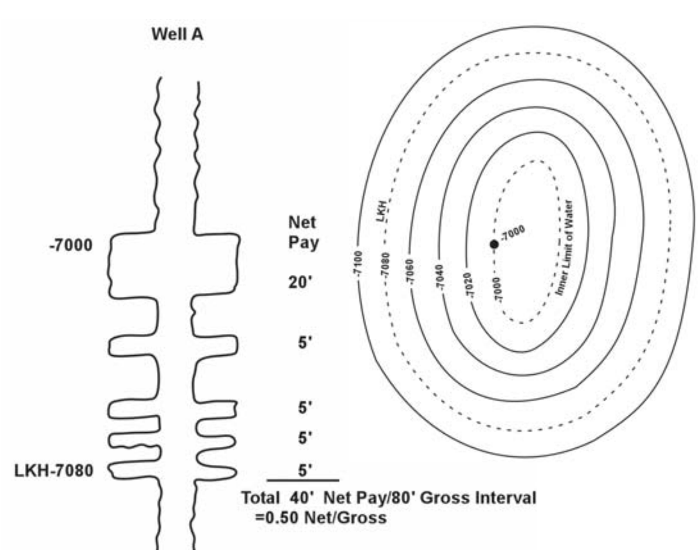


Figure 8. Example of a well log from a reservoir where most of the net pay occurs near the top. Structure map with well locations also shown.

Figure 9 illustrates a net pay isochore map constructed using the average net-to-gross ratio of 0.50 in the wedge zone.

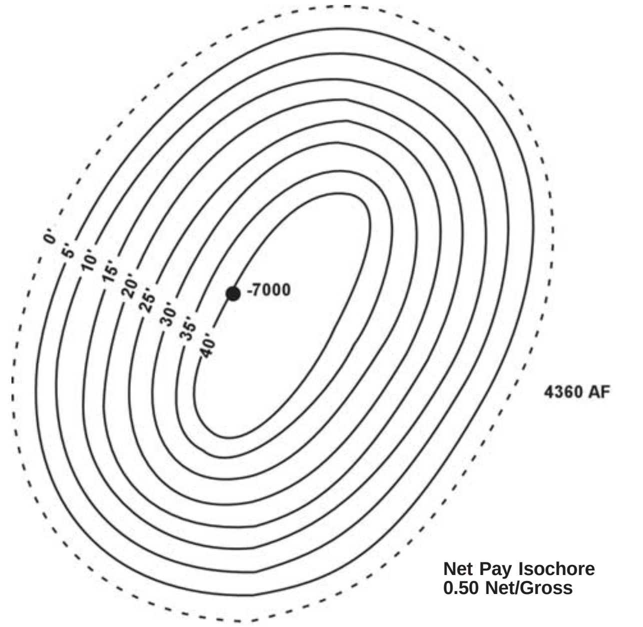


Figure 9. Illustration of net pay isochore with a wedge zone mapped using average net-to-gross approach.

Figure 10 illustrates a net pay isochore map constructed using the relationship of net pay thickness to height above the downdip fluid contact. In this example, the net pay isochore volume in Figure 9 is 18 percent smaller than the volume in the correct map from Figure 10.

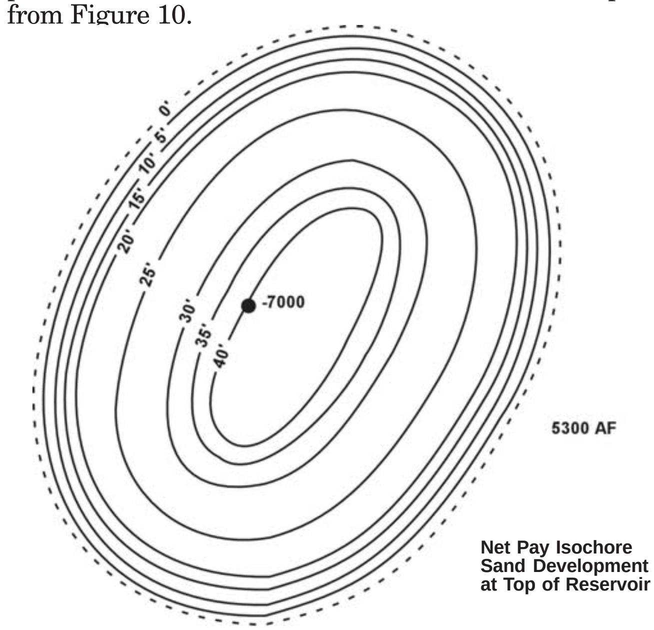


Figure 10. Same data mapped with wedge zone based on correct application of a vertical net-to-gross ratio.

A similar but inverse error occurs if the vertical net pay distribution is inverted from that shown in Figure 8. In this case, a map constructed using the average net-to-gross ratio overstates the productive reservoir volume.

In both examples, the "average" net-to-gross approach results in mechanically equal-spaced thickness contours in the wedge zone which do not represent the vertical distribution of net pay in the well.

Net pay isochore maps—Thickness within area of maximum fill-up—The area of maximum fill-up as illustrated in Figure 7 (in March 2010, *Reservoir Solutions* newsletter, Page 6) is the region updip from the intersection of the fluid contact and the structure on the base of the effective reservoir unit. Above this inner limit of fluid, the placement of net pay thickness contours is governed by the lateral change in the net effective reservoir thickness.

A common shortcut used in computer-aided mapping calculates the gross rock volume from the vertical difference between the top and base of the reservoir. Net pay thickness is generated by applying a net-to-gross ratio to the gross rock volume. A few of the potential inherent errors are as follows:

- Use of an arithmetic average of the net-to-gross ratio from multiple well penetrations may not represent lateral variation from well to well. A more rigorous approach is to represent the lateral variation by contouring the net-to-gross ratio from well data. The resulting interpolated distribution of net pay thickness should tie or be adjusted to match the well-data points. Evaluators should consider the validity of estimates of interpolated net-to-gross ratios greater than the maximum value obtained from well data.
- As previously noted, errors in the selection of the top or base of the contributing reservoir unit will result in overestimating the gross interval thickness and gross rock volume. The interpolated lateral distribution of the gross reservoir thickness should tie to or be adjusted to match actual well-data points. When the top or base of the reservoir unit is based on seismic data, the evaluator should consider the quality and resolution of seismic data. The evaluator should also consider the validity of estimates of interpolated gross reservoir thickness greater than the maximum value obtained from well data.
- Similarly, consideration should be given to the validity of lateral variations in interpolated net pay thickness derived from uncalibrated seismic amplitudes that result in values greater than indicated by the actual well-data points.

Attic volumes

Frequently, evaluators assign reserves to volumes updip to the last well penetration point in a reservoir. The level of confidence in the structural and stratigraphic continuity of the reservoir and recognition of the appropriate drive mechanism are critical to correctly attributing reserves.

Figure 11 shows net pay thickness projected in association with structural gain only and exceeding the maximum net effective sand thickness updip to the wedge zone from the downdip well penetration.

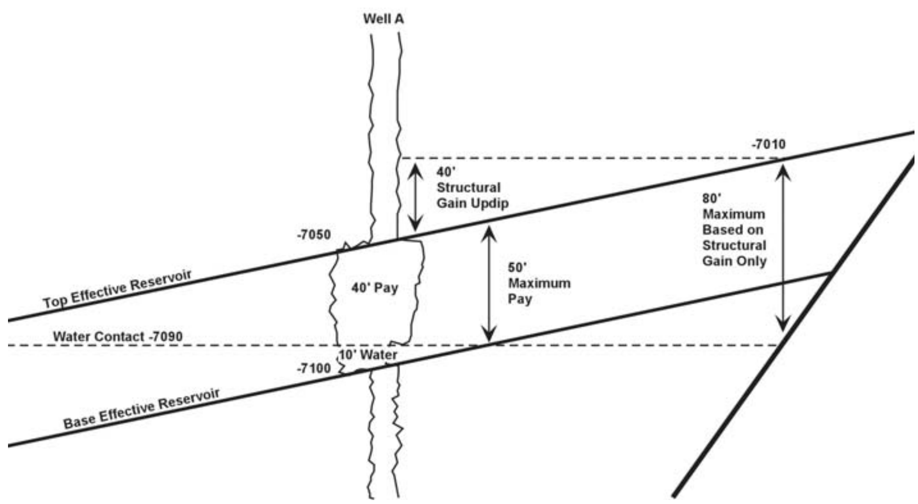


Figure 11. Potential error in estimating attic volumes based on projecting structural gain greater than maximum sand thickness.

Evaluators must consider the level of confidence in the position of faults and stratigraphic conditions away from the existing subsurface well control. Seismic fault placement should be collaborated by subsurface well control. Stratigraphic continuity verified in zones above or below the interval in question increases the level of confidence for the attribution of reserves.

Though not necessarily a geoscience issue, evaluators must consider the possibility of a gas-saturated attic above a highest-known oil limit. They must also consider that in a water-drive reservoir, the attic volume may not be recovered from existing wells.

Canada—Cont. from Page 1

Regulators in Canada expect to finalize approvals by August or September and publish the new amendments in September or October. The effective date will be in late December. The CSA will not request further comments but will provide responses to those received.

David Elliott, chief petroleum advisor to the ASC, said, "We do not expect the amendments to have a significant effect on the preparation of evaluation reports, but they could, in some circumstances, have an effect on the preparation of disclosures."

Seven companies responded in mid to late March through comment letters on the proposed amendments to NI 51-101. Industry comments were published by the ASC in mid May at www.albertasecurities.com.

Ryder Scott Co. LP
1100 Louisiana, Suite 3800
Houston, Texas 77002-5218
Phone: 713-651-9191; Fax: 713-651-0849
Denver, Colorado; Phone: 303-623-9147
Calgary, AB, Canada; Phone: 403-262-2799
E-mail: info@ryderscott.com
Web site: www.ryderscott.com

Donation from UH board boosts petroleum engineering program

The year-old University of Houston undergraduate petroleum engineering program—designed to help meet the industry's workforce demand—received a boost from **Ron Harrell**, chairman emeritus, and **Dean Rietz**, managing senior vice president, who along with other UH petroleum engineering advisory board members, made $13,500 in personal donations to benefit students and the school.

"We looked at the gift like it was part of the board's function—to be a supporting family for the program," said Harrell, a former CEO at Ryder Scott and chairman of the UH board. He challenged members late last year to donate their own money to fund seven $500 monetary awards for students and board members. The board tripled that amount.

"I am not surprised. We are all very passionate about education and have worked on getting an undergraduate degree program established at UH for years," Harrell said. He also chairs the Joint Committee on Reserves Evaluator Training which develops courses for industry. Rietz is an adjunct professor at UH and group leader of the Ryder Scott simulation staff.

Ron Harrell (left), chairman emeritus, and Dean Rietz (right), managing senior vice president, present a check from the UH petroleum engineering advisory board to Raymond Flumerfelt, director of the UH petroleum engineering program. Harrell also chairs the Joint Committee on Reserves Evaluator Training which develops courses for industry. Rietz is an adjunct professor at UH and group leader of the Ryder Scott simulation staff. Photo by Jeff Fantich.

Reservoir Solutions

Editor: Mike Wysatta
Business Development Manager

Ryder Scott Company LP
1100 Louisiana, Suite 3800
Houston, Texas 77002-5218
Phone: 713-651-9191; Fax: 713-651-0849
Denver, Colorado; Phone: 303-623-9147
Calgary, AB, Canada; Phone: 403-262-2799
E-mail: info@ryderscott.com

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 115 employees, including 81 engineers and geoscientists, Ryder Scott has the capability to complete the largest, most complex reservoir-evaluation projects in a timely manner.