SPE deliberating whether to introduce concept of sub-economic proved reserves

Proved reserves do not exist unless they are economic. Or do they?

Petroleum reserves evaluators may be facing radical change to the basic definition of proved reserves shortly. The Society of Petroleum Engineers was deliberating in July whether to recommend that the concept of sub-economic proved reserves be included in its soon-to-be revised Petroleum Resources Management System (PRMS).

Under the current system, a company can develop a project on a 2P expected basis that meets investment thresholds, even though the 1P reserves may not be economic. In that case, an evaluator assigns zero proved reserves to the project, even though commercial 2P volumes exist.

"This disconnect can be confusing and potentially misleading because reserves information becomes misaligned with the company commitment and the economics associated with the development activity," said **Ian McDonald**, vice president, reserves at Nexen Energy ULC.

McDonald is a member of the SPE Oil & Gas Reserves Committee (OGRC) charged with making revisions to the PRMS. The OGRC is discussing preliminary plans to recommend that for a committed oil and gas investment, a company could assign and disclose the project's range of reserves without conducting a separate test for 1P, 2P and 3P categories.

"That means that the proved reserves cash flow would not need to be positive if a development commitment exists, 2P case meets investment thresholds and the reserves meet other definitions," said McDonald. On a company aggregate basis, proved reserves quantities would increase, but their economic value would decrease.

A development commitment means that if the project has been "approved for development," all necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is underway, according to SPE.

McDonald said that the OGRC thinking was that once a project meets commercial criteria, including economics, based on a best estimate of recoverable resources, then all associated resources estimates would become classified as reserves. "Proved" and "proved economic," both in existence in the 2007 PRMS, have been highlighted in the unfinished draft to clarify when proved reserves are economic.

If the committee's proposed change makes the final cut and then is adopted by cosponsors, "proved" will exist when the proved-plus-probable case meets the minimum investment evaluation criteria of the 2P economic limit test. "Proved economic" will exist when proved reserves meet minimum investment evaluation criteria.

McDonald cited the implications of changes to the economic definition as follows:

- Low/best/high cases become a reflection of project commitment and can include uneconomic proved reserves if the project's 2P case is economic.
- Allows for low/best/high cases of committed 2P economic investment to be stochastically or probabilistically added.
- If the 2P case is uneconomic, the project cannot be considered to have reserves.

"This recommended change is quite concerning. Where do you draw the line insofar as booking quantities that are uneconomic?" said McDonald.

While the discussed revisions do not allow for the assignment of proved economic reserves below the economic limit, they permit the booking of proved volumes if the net operating cash flow is positive.

The economic limit occurs at the peak of the cumulative net operating cash flow, which is defined as production revenue, after any royalties, less operating costs. Please see graph on Page 3. Produced volumes must have positive net operating cash flows once developed.

"An economic limit test (ELT) must be conducted for each uncertainty level — low, best and high — and is one of the criteria to qualify production profiles," said McDonald. Proved reserves have to meet a minimum investment criterion to be proved economic and 2P reserves also must satisfy a company's 2P reserves ELT.

"When you hit the economic limit, you perform the ELT to determine what is economic and what is not," said McDonald. "To have proved economic reserves, you must have a positive net operating cash flow so it's no different than what we do now."

McDonald said that there is a debate at the committee level as to what economic criterion has to be met. Is it a $1 positive cash flow or 10 percent rate of return? SPE may take a hands-off approach since companies set their own targeted investment criteria and returns.

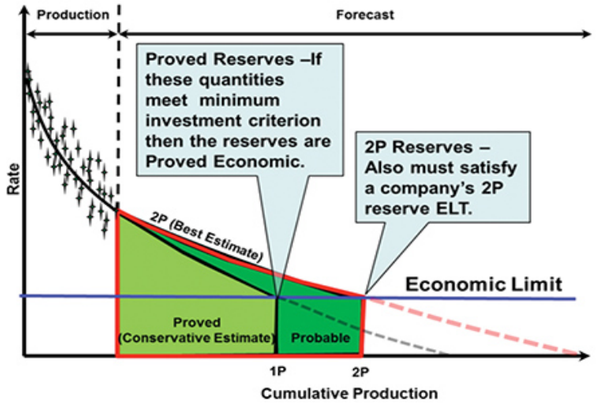
"The idea is that a $1 positive cash flow might be considered as economic for proved reserves. When you are talking about proved reserves, a conservative estimate, the fact that it is economic by whatever measure in itself would be OK. It's not perfect and you may not expect a strong rate of return," said McDonald.

The other side of the return-on-investment argument is that a company must be committed to the project so there has to be more than $1 breaking-even point for the case associated with the commercial decision. "There must be some way to measure this so there is a meaningful ROI or minimum criteria for proved reserves," said McDonald.

In addition to the concept of sub-economic proved reserves, other issues the OGRC is discussing and debating for the PRMS update include the following:

- How should fuel gas and process gas be considered for reserves?
- Should unconventional resource concepts — including discovery, flow test requirements, etc. — be considered as requiring unique definitions?
- Should "standalone" possible reserves be contingent resources?
- How should scenario and incremental evaluation methods be interpreted? What has changed?
- Should resources be required to be broken out by project maturity subclass?

McDonald made his remarks at the Ryder Scott Canada reserves conference in May. At that time, an SPE draft version of the PRMS was scheduled to be nearing completion by an OGRC subcommittee. The next step is for the draft to be shared with sister societies and with stakeholders, including market regulators, during a comment period. Regulators of the London, Hong Kong, Australia and other stock exchanges accept reserves and cash flows prepared under SPE-PRMS guidelines. They are expected to take a close look at the new guidelines and weigh in.



Ian McDonald

Presentations from the Calgary conference, including McDonald's, are posted at www.ryderscott.com/presentations.

Editor's Note: At press time, SPE had not released its draft of the 2017 PRMS for public comments. This article is based on a presentation by Ian McDonald, a member of the OGRC. Any expressed opinions are those of Mr. McDonald exclusively. They do not reflect the views of Ryder Scott, nor do they necessarily reflect the views of the OGRC. While the article may provide some insight into possible planned changes in the PRMS, it is not intended to report on any final decisions by OGRC.

Investment in Alberta O&G more attractive than in competing provinces thanks to new royalty framework

Light Oil, Vertical Well Outcomes

	ARF	MRF	Sask	BC
Royalty % Gross Revenue	17.52%	13.40%	15.84%	11.68%
Royalty % Value*	48.80%	33.36%	44.14%	27.98%
NPV $_{10}$ ($MM)	1.2298	1.3929	1.1688	1.4259

*Value = Gross Revenue less opex and capex

Ryder Scott Canada conducted a study of Alberta's new Modernized Royalty Framework equations introduced in April and found that they improve the competitiveness of investing in the province's oil and gas. The Calgary-based firm compared the MRF, which only applies to wells spudded in 2017 and thereafter, to the existing framework and to the current British Columbia and Saskatchewan royalty regimes.

"We asked the question that, all else being equal, how does the impact of different royalty regimes on company cash flow vary," said **John MacDonald**, vice president at Ryder Scott Canada.

The new MRF model emulates the revenue-minus-cost global standard for sharing profits from production between oil and gas companies and resource owners. Under MRF, all wells have a 5-percent royalty until gross revenue from all products equals an industry average drilling and completion cost allowance (C*). Thereafter, royalty depends on rate and commodity price. Once the well rate declines to a maturity threshold, the royalty reduces as the rate continues to fall. C* is a function of total vertical depth, total lateral length and total proppant placed.

Oil sands wells operating under the conventional royalty regime will be included under MRF however the details have not been released by the government.

MacDonald and **Vitaliy Charkovskyy**, reserves evaluator at RS Canada, created a hypothetical vertical well for light oil, heavy oil and dry gas. For each well type, they created a cost and performance profile consisting of a production profile, capital-cost and operating-cost profiles plus a vertical depth. Those profiles were evaluated under existing and MRF royalty burdens in Alberta as well as in Saskatchewan and British Columbia. Then they graphed the resulting company cash flow to examine the competitiveness of each royalty regime.

John MacDonald

Historically, increasing prices have influenced Alberta to change its royalty structure. "As oil prices increased, so did the criticism that royalty rates were too low so the government raised and lowered them again during a period of change and upset," said MacDonald. "The new mandate is different and not as simple as going up or down. The purpose is to provide optimal returns to Albertans as owners of the resource."

The MRF is to be calibrated to target the same industry returns and provincial revenues as the current royalty regulations, added MacDonald at the Ryder Scott Canada reserves conference in May.

His comparisons led to the following conclusions:

- Investment in an Alberta vertical, light oil well will be more attractive than in Saskatchewan and is substantially closer to the value in British Columbia
- Investment in an Alberta vertical, heavy oil well will be even more attractive than in Saskatchewan.
- Investment in an Alberta vertical, sweet dry gas well will be even more attractive than in British Columbia or Saskatchewan.

Please see Investment in Alberta on page 6

New manager at Ryder Scott Canada is David Haugen

David Haugen

The new manager of Ryder Scott Canada petroleum consultants is **David P. Haugen**, also named a senior vice president. "David plans to lend more visibility to our Canadian operations," said Dean Rietz, president at Ryder Scott Co. LP. "Over his 26-year petroleum engineering and management career, David has gained professional recognition throughout the western Canadian oil and gas region and we are pleased to have him on board."

Haugen, P. Eng., has been involved in petroleum reserves and resources characterization, acquisitions and divestitures, property valuations and unconventional gas development and planning. He has conducted detailed engineering and economic evaluations of oil and gas properties throughout the Western Canada Sedimentary Basin.

Haugen joined Ryder Scott from Quicksilver Resources Canada Inc. where he was vice president, engineering. He previously managed the corporate reserves position for Quicksilver's U.S. and Canadian properties and held key roles for regulatory reporting, internal and external audits and the eventual marketing and sale of the company's Canadian assets.

Before that, he was the team lead, market development – natural gas economy at EnCana Corp., which he joined in 2000. In that position, he evaluated and directed gas economy market development initiatives for the United States and Canada and led an evaluation team that was advancing business initiatives for increasing the use of gas in transportation.

Haugen was also a team lead planning at Encana where he built and led a new group that provided technical and business support during the construction of the company's North American budget portfolio. While there, he was also an engineering advisor in the Bighorn business unit and a team lead for the Cutbank Ridge and Horseshoe Canyon coalbed-methane resource plays.

Haugen started his career in 1989 working for Coles Gilbert Associates Ltd., Wascana Energy Inc. and Northrock Resources Ltd. over an 11-year span in which he conducted detailed engineering and economic evaluations of various oil and gas properties in the WCSB.

Haugen has a B.Sc. degree in petroleum engineering from the University of Alberta and has been a registered professional engineer in APEGA since 1991. He is also a member of the Society of Petroleum Engineers.

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Investment in Alberta – Cont. from page 4

- Investment in light and heavy oil and dry gas will be more attractive under the MRF than under the current system.

The MRF release on April 21 was not the final word – just the release of the general equations. In his slide presentation, MacDonald cited a dozen "loose ends" that the government has yet to tie up.

His presentation and others from the conference are posted on the Ryder Scott website at ryderscott.com/presentations.