RESERVOIR SOLUTIONS

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COGEH to address "highly debated" interpretation

Industry is poised to challenge Alberta Securities Commission interpretations of a 2015 regulation that requires a reporting issuer (RI) to cashflow oil and gas production net of abandonment and reclamation costs (ARC). The ASC rule, Item 2.1(3) (b) of NI 51-101F1, includes ARCs for wells, surface facilities and pipelines up to the sales point. RIs have been more selective in their disclosures.

One RI said recently, "The cost of abandoning an exploration well, which is unrelated to reserves cash flows, should not be included." ARCs for fewer wells boost undiscounted future net revenues (FNRs).

The Society of Petroleum Evaluation Engineers chapter in Calgary has all but finalized its position on the ARC rule after receiving industry feedback and tweaking its new Canadian Oil & Gas Evaluation Handbook (COGEH). NI 51-101 refers to COGEH as "the standard of practice for evaluation and classification."

Oil and gas companies want "clarity on the inclusion of ARCs," said **Doug Wright**, a past chapter chairman, in December. "The chapter is currently updating COGEH and targeting a late Q1 2018 release. ARC is a topic that will be addressed in the handbook and has been the subject of much debate."

Wright was a speaker at the Ryder Scott Reserves Conference in Calgary last May.

Short history of chapter, verse

Under Instruction 3 to Item 2.4 of the F1 form, issued in late 2007, industry was to calculate and disclose, at a minimum, cash flows net of abandonment costs for wells.

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RIs

ARCs

DCF

FNR

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Items 2.1 and 2.2 also referenced the rule. Industry practice was to apply those costs to producing and future, planned wells.

The second requirement then was to disclose the rest of ARC under Item 6.4 of NI 51-101. Cost liabilities in 6.4 applied to all surface leases, other wells, facilities and pipelines.

"The (2007) requirement was for both abandonment and reclamation costs, not just abandonment," said **Craig Burns**, manager petroleum at the ASC. "In reality, what we experienced was issuers excluding the reclamation component."

The trigger

The 2015 rule repealed Item 6.4 thus eliminating the financial accounting "bucket" for other separate disclosures of cost items outside the FNR. The old way of bookkeeping took a hit. Industry began estimating cash flows from well production by including ARC for up- and midstream facilities, with some companies all over the board.

In 2016, the ASC issued further guidance, insisting on full disclosure and recognition of decommissioning costs in both FNR and net present value (NPV) calculations.

As it stands now

RIs are required to return oil and gas properties, both surface and subsurface, to a standard imposed by applicable government or regulatory authorities after disturbances caused by oil and gas activity. The ASC defines "oil and gas activity" relative to the sales point and comports with Canadian Securities Administrators Staff Notice 51-324, which states that any activity downstream of the point of sale is excluded from being an "oil and gas activity." Conversely, costs to remediate all activity upstream of the sales point have to be factored into the ARC calculation.

The CSA notice supports the inclusion of ARC for exploration wells in the discounted cash flow (DCF) model by stating that "searching for a product type in its natural location," is an oil and gas activity. The ASC is insisting that ARC, where applicable, should include costs to reclaim and restore all wells, not just producing and planned wells.

In addition, the DCF model should include decommissioning costs for surface facilities dedicated to those wells and pipelines upstream of the point of sale.

Latest fallout, dubious impact

In its reviews of YE 2016 reporting, the ASC reportedly compared ARC disclosures in cash flows to present values of asset retirement obligations (AROs) in the audited financial statements. ARC and ARO cost obligations differ but also share common ground. ARO liabilities are equal to the fair value of the estimated costs to dismantle oil and gas production facilities and for site restoration.

Full disclosure was an issue. For instance, one RI recorded undiscounted estimated cash flow to settle its AROs to be $600 million, but ARCs were considerably lower because the company excluded surface facilities. The RI counted approximately $145 million in abandonment costs for producing and undeveloped wells only.

Over the life of the assets, that boosted the $5-billion undiscounted FNR 9.5 percent — below a 10-percent materiality hurdle, which is arbitrary and not a regulatory "line in the sand."

Doug Wright at the 2017 Ryder Scott Reserves Conference in Calgary.

By some accounts, at a more granular level, over the 30-year life of an oil or gas field, a hike in undiscounted FNR from lower ARCs may not be that significant.

Add to that, the long-term reliability of estimated ARCs is fraught with pitfalls. Forecasting exact ARO liability costs over many years in the future is fundamentally difficult, requiring management to make judgements, based in part, on speculation about costs, technology and regulations.

"ARC is a topic that will be addressed in COGEH and has been the subject of much debate."

Abandonment and reclamation costs should reflect full decommissioning obligation, says Burns

Craig Burns, manager petroleum at the Alberta Securities Commission, clarified that reporting issuers (RIs) are to use all future abandonment-and-reclamation costs (ARCs) to the point of sale as inputs to the discounted cash flow (DCF) model. ARCs may apply to wells, surface facilities and pipelines.

Despite continuing guidance from the ASC, industry is still trying to get its bearing on what should be included in ARCs. See article, "COGEH to address 'highly debated' interpretation," on Page 1.

The three-year-old, ASC-amended regulation, Item 2.1(3) (b) of NI 51-101F1, requires a RI to disclose undiscounted future net revenue (FNR) incorporating cost obligations for abandonment and reclamation.

For further guidance, please see 2016 ASC discussion paper at www.albertasecurities.com/Publications/ASC_LIB1-5231258-OCA_Bulletin_-_Abandonment_and_Reclamation_Costs.pdf.

Burns said, "Assumptions on ARCs should be consistent with those underlying the full decommissioning obligation."

The 2015 regulation also defined FNR and ARC as applied to reserves and resources for the first time to clear up any misconceptions.

Average annual oil and gas prices soar 20 percent

Annual average prices for reporting year-end petroleum reserves to the U.S. Securities and Exchange Commission increased about 20 percent for both oil and gas, using WTI crude and Henry Hub benchmarks, respectively. For 2017, WTI crude averaged $51.34 per BOE, up from $42.75 a year ago. Henry Hub gas averaged $2.98 per MMBtu, up from $2.49.

Other benchmarks and information on using differentials are posted at www.ryderscott.com/wp-content/uploads/FDOM_Benchmark_Prices.pdf.

The prices are based on the unweighted, arithmetic average of the first-day-of-the-month price for each month in the calendar year. E-mail inquiries to fred_ziehe@ryderscott.com.

Hardesty elected to SPEE board

Anna Hardesty, senior vice president at Ryder Scott, was elected to the board of directors for the Society of Petroleum Evaluation Engineers (SPEE). She has been an SPEE member for more than 25 years and was program chairman, secretary-treasurer, vice chairman and chairman for the Houston Chapter from 2011 to 2014.

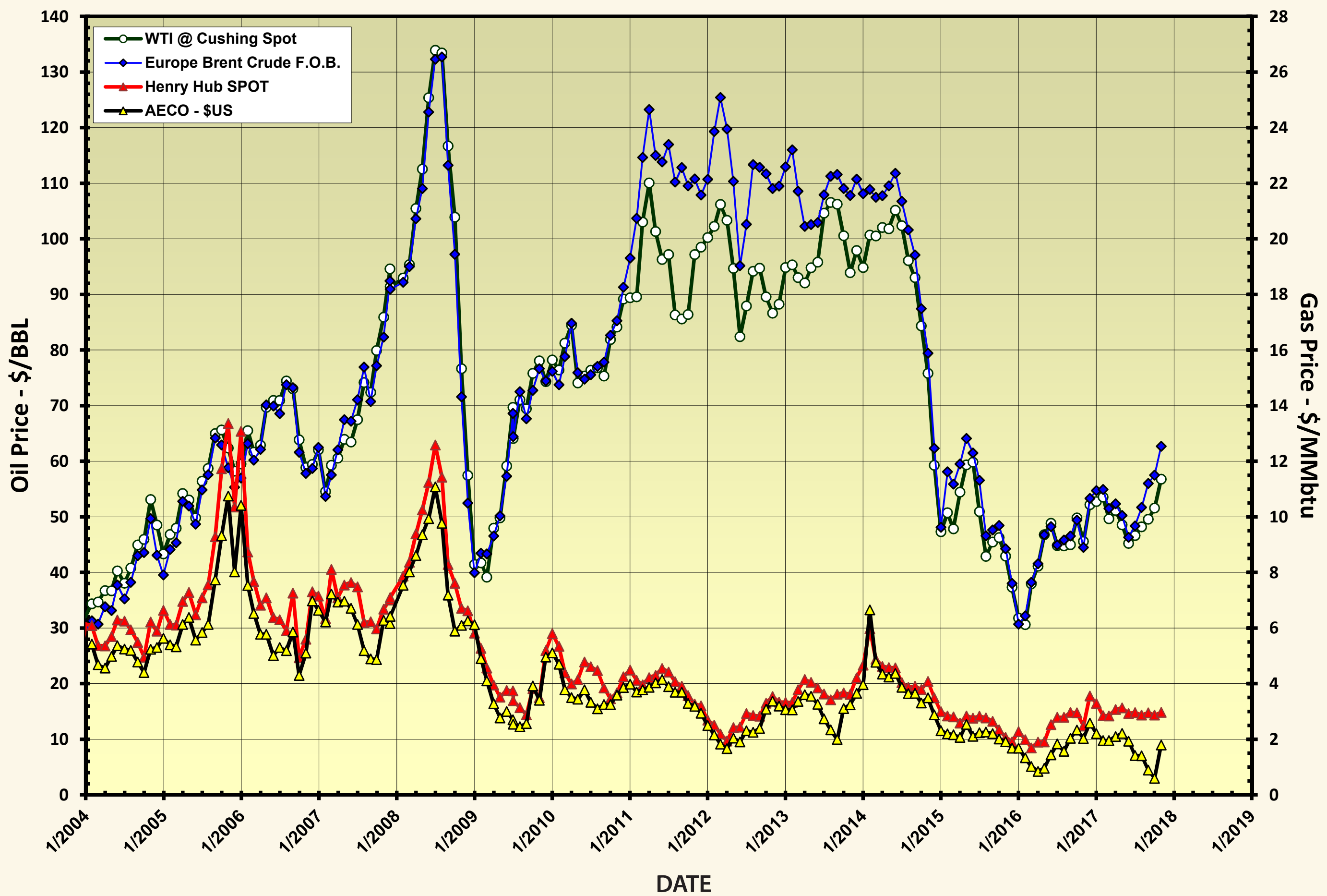
Hardesty has also sponsored engineers applying for SPEE membership.

"She sponsored me," said **Dean Rietz**, president. "This is another example of Ryder Scott folks doing more to improve themselves and our industry. SPEE will benefit from Anna's leadership. She will guide SPEE in meeting various challenges it faces as a professional society in today's challenging environment."

Hardesty will serve for a three-year term.

Anna Hardesty

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.

Oklahoma producers shift from Scoop to Stack

For the last two years, producers in the Anadarko basin in Oklahoma have shifted their drilling focus from the Woodford trend in the Scoop play to the Meramec in the Stack play. On an MBOE/1,000 ft gross perforated interval, Woodford and Meramec EURs appear fairly comparable so far, said **Steve Gardner**, senior vice president at Ryder Scott.

"An argument could even be made that the Woodford has a little higher EURs to date on a well-by-well basis," remarked Gardner at the Ryder Scott reserves conference in Houston late last year.

So why are interest and activity increasing in the Meramec compared to the Woodford? Within the Stack, normalized oil EURs (estimated ultimate recoveries) of the Meramec are generally higher while drilling costs are slightly lower than in the Woodford. EURs of gas in both plays are close to the same.

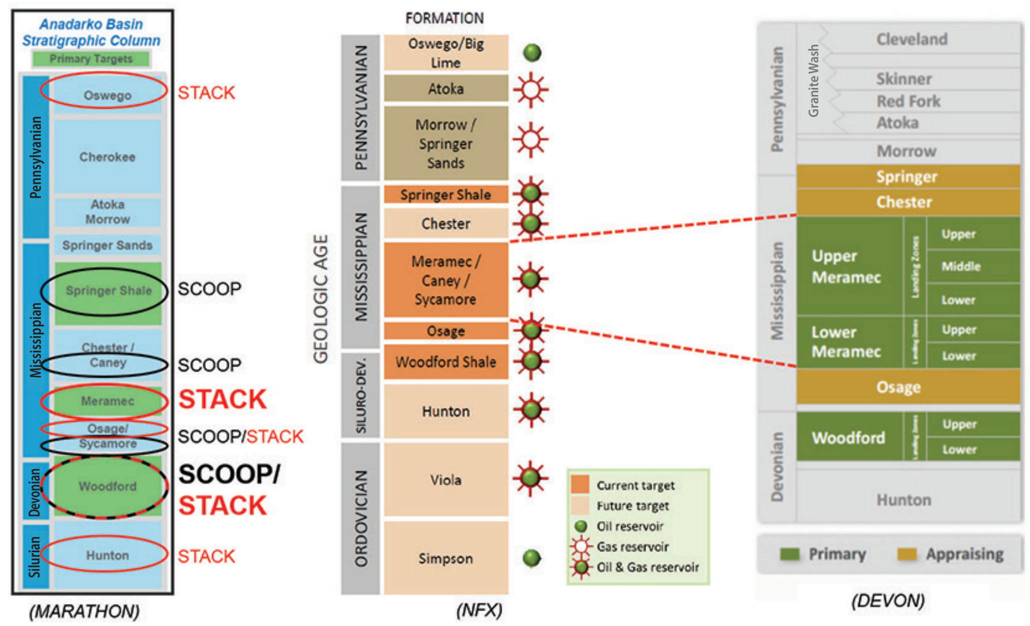
"Development of the Woodford is still very active. However, it very well could end up that the Meramec catches up, or even overtakes the Woodford, in terms of new wells drilled once we look at the final numbers for 2017," said Gardner.

Oilier than the Woodford, for a given area, the Meramec has generally lower gas-oil ratios (GORs) as indicated by early life trends and monthly production averages. Water-oil ratios (WORs) are lower in the Meramec, and substantially lower than in the Mississippi Lime play. See GOR and WOR chart. With oil prices tracking higher than gas, oilier means higher returns in some cases than those for gas sales.

Also, the Meramec is generally much thicker than the Woodford in the Stack, giving potential to drill stacked or wine-rack laterals from a single pad to multiple targets. "Several of the formations are still in delineation mode," said Gardner.

So far, producers have developed mostly the Upper and Lower Meramec formations; however, the Middle is also becoming a separate target. See Stratigraphic Column chart.

Stratigraphic Column

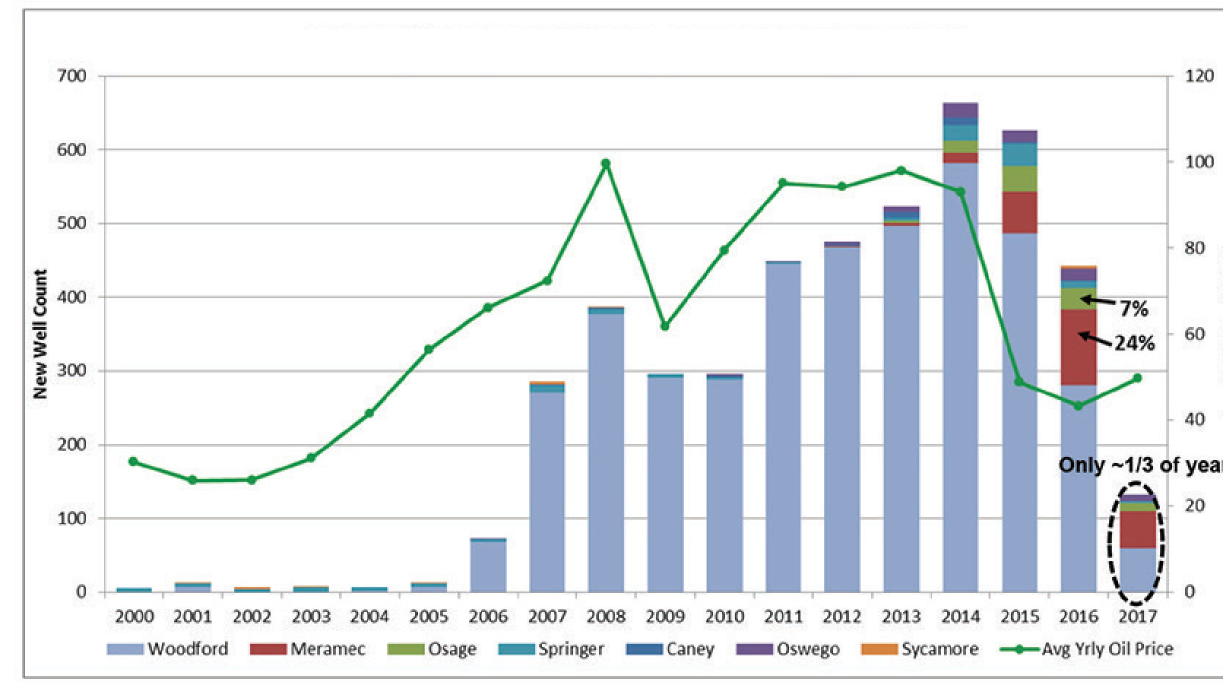


Sources: 2017 Capital Program, Feb. 15, 2017, Marathon Oil Co.; All the "Scoop" about the Stack, Capital One Securities SCOOP/STACK Day, Nov. 28-29, 2016, Newfield Exploration Co.; Devon Energy, EnLink Midstream Team Up for $4 Billion Acquisition from Private Companies, Dec. 7, 2015, Oil & Gas 360 by Enercom

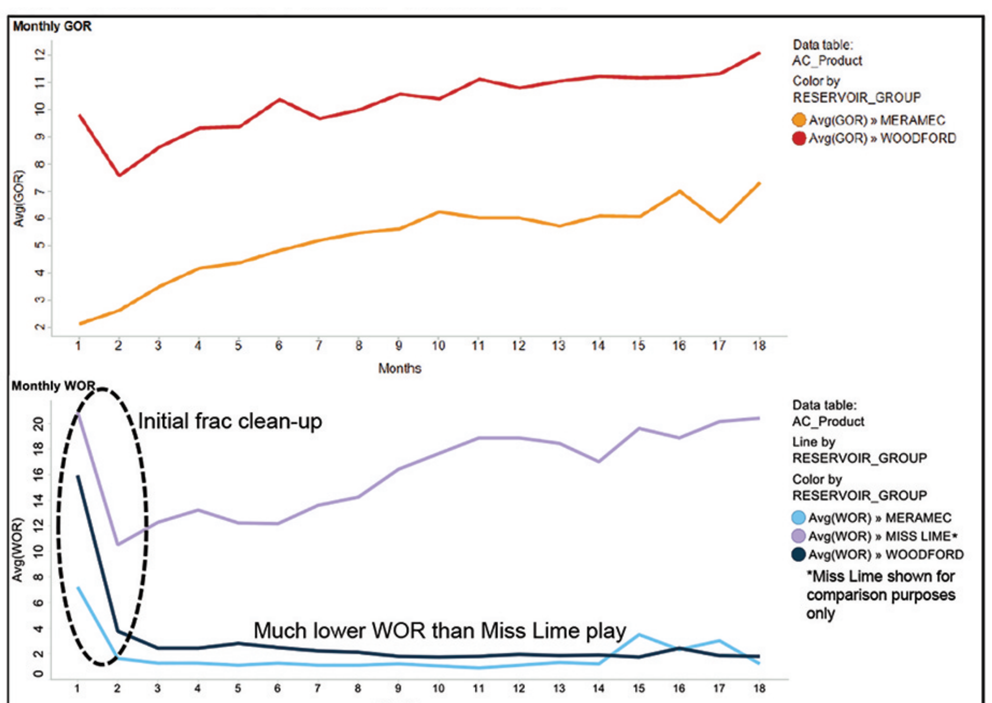
Scoop Stack shows cost resistance

Driven mostly by the Woodford, horizontal development in Scoop/Stack began around 2006 and has also generally tracked with the average oil price, although recent development has shown some resilience to price drops. For instance, prices are lower now than during 2006 to 2010, but the drilling pace in Scoop/Stack is generally higher. See chart below.

Scoop/Stack Regional Development Pace



Woodford vs. Meramec: GOR & WOR*



*Data is included for the oil and volatile oil phase windows. Localized conditions may vary significantly.

Drilling-and-completions (D&C) advancements in the Meramec are driving some of the growth.

"Larger fracs are contributing to increasing recoveries, which is a familiar story for other horizontal plays around the country," said Gardner. Multiple operators are increasing proppant loadings within the Stack to the 2,000- to 3,000-lbs-per-ft range or even more.

"As wells drill on tighter spacing, it remains to be seen whether these larger and larger fracs will result in interference and acceleration or incremental recovery," said Gardner. "At some point, it would be expected to find a balance between spacing, frac size and returns on investment."

"This resilience to price could be caused by lower D&C costs, more drilling in the Meramec and Osage, enhanced completions and other factors," said Gardner.

Producers across Scoop/Stack are experimenting with spacing-density pilots. "It is still early to draw any sweeping conclusions, especially from public data," said Gardner.

However, by YE 2017 or early 2018, several online pilots, including some drilled by Cimarex Energy Co. and Devon Corp., will have 6-to-12 months of production data. "It will be interesting and important to begin looking for the effects of frac hits and longer-term interference," said Gardner.

He also said several operators are testing three to six laterals or more per mile and per zone, even after subdividing formations like the Meramec and Osage into multiple zones.

For more information, please contact Gardner at steve_gardner@ryderscott.com

Steve Gardner

SPE, endorsing organizations to hammer out industry guidelines this year

Professional societies, tasked with evaluating comments on the latest draft of the new SPE-PRMS guidelines, aim to finalize them this year.

The draft of the 2017 Society of Petroleum Engineers Petroleum Resources Management System is posted at http://www.spe.org/industry/docs/Petroleum-Resources-Management-System.pdf.

SPE, Society of Petroleum Evaluation Engineers (SPEE), World Petroleum Council, American Association of Petroleum Geologists and Society of Exploration Geophysicists plan to jointly approve the guidelines.

The SPE-PRMS is a de-facto international standard for reserves classification used by industry. The guidelines have been integrated into a United Nations model.

The classifications and categories include proved, probable and possible petroleum reserves and contingent and prospective resources.

The SPE Oil and Gas Reserves Committee asked each company or organization, on its behalf, to consolidate comments and email a single response representing the view of the company or organization by Nov 14. Unlike the U.S. Securities and Exchange Commission, which published industry comments to its 2008 proposed reserves reporting rules, the sanctioning societies traditionally do not publicly post responses, and did not plan to do that this year.

In addition to comments from industry and stakeholders, SPE planned to invite market regulators to provide their remarks. Regulators of the London, Hong Kong, Australia and other stock exchanges accept reserves and cash flows prepared under the SPE-PRMS.

The draft does not refer to "sub-economic proved reserves," terminology that was originally proposed but then rejected. See *Reservoir Solutions* newsletter article, "SPE deliberating whether to introduce concept of sub-economic proved reserves," July-Sept. 2016, Vol. 19, No. 3, Page 2.

As in the past, reserves classifications for projects, where appropriate, can include 2P and 3P reserves and zero proved reserves. Evaluators can reclassify projects from contingent resources to reserves when the low estimate (1P) is economic by itself as a standalone.

The proposed guidelines prohibit "split classifications," which is basically mixing resources and reserves for a single project, for instance, 1C (sub-class of contingent resources) with 2P and 3P reserves. Rather the evaluator assigns a distinct sub-class with its uncertainty range to the project.

Some of the comments underscored the need to retain industry terms vs. new, unfamiliar terms. For example, the proposed guidelines refer to gas quantities consumed in operations (CIO), rather than to more common terminology, such as fuel gas.

On that subject, the PRMS draft states that CIO gas may be included as reserves or resources, but must be stated and recorded separately from the sales portion, which is industry practice for the most part, but not entirely consistent internationally.

The draft language comports with U.S. SEC rules that production of gas should include only marketable production on an "as sold" basis.

"The CIO fuel replaces the requirement to purchase fuel from external parties and results in lower operating costs," the draft states.

It also advises that "future ADR (abandonment, decommissioning and reclamation) costs are included in the economic analysis NPV for all projects," which is not a change. However, for the first time, the draft defines ADR and states that "examples include but are not limited to the removal of surface facilities…" which is consistent with a project-based approach.

One commenter stated, "The 2017 PRMS is a clarification, not a rewrite." The draft is more than a rewrite though because for instance, it recognizes for the first time, the role of the learning curve and associated step changes in the field. The recognition of those step changes will influence resources evaluations.

"In unconventional oil and gas developments with high well counts and a continuous program of activity, the use of a 'learning curve within a resources evaluation' may be justified to predict improvements in either the time taken to carry out the activity, the cost to do so, or both," the draft states.

Learning curves can be recognized in a "forecast case" that assesses cashflow estimates based on an entity's forecasted economic scenario conditions. Distinct from that are "forecasts based solely on current economic conditions" that are determined using an average of those conditions -- including historical prices and costs -- during a period of one year, for instance.

A forecast case opens the door for arguments that development of proved undeveloped reserves will accelerate beyond a producer's historical pace and price-sensitive future estimated operating costs will unilaterally drop along with the economic limits while reserves estimates will increase.

Light at end of tunnel is brighter "few short" months after RS conference

At the latest Ryder Scott reserves conference a little over three months ago, **Don Roesle**, CEO, predicted improving conditions in the oil and gas industry. In the short term, he is on the mark.

"It's been tough over the past 2-½ years but I see some improvement out there and perhaps so do you," he told a crowd of about 350. "Industry has been resilient and has shown an ability to deal with stress situations in developing the assets it has."

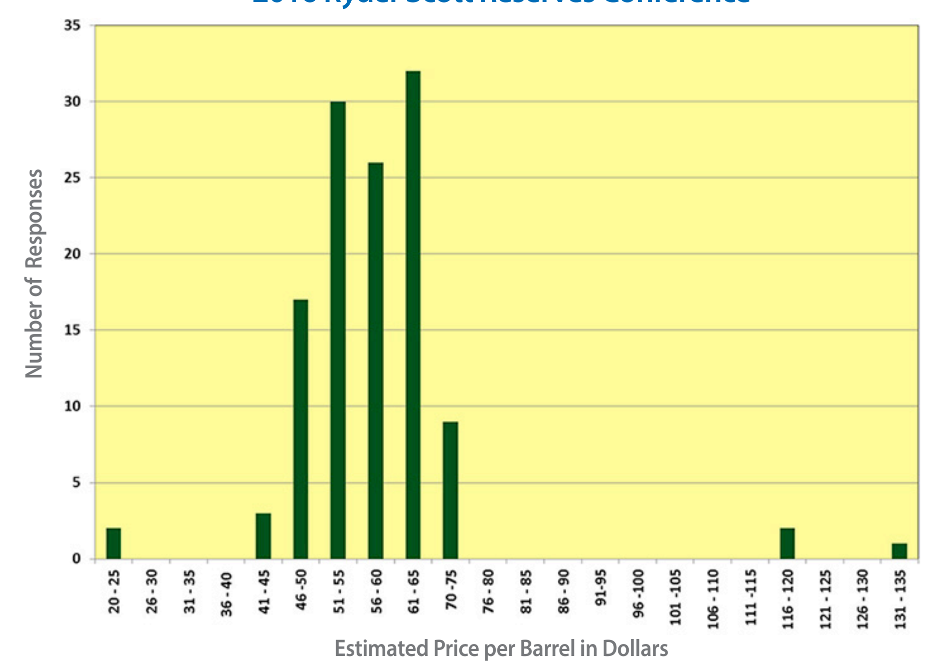
He remarked that pricing in the $50 range was helping industry be more aggressive in development plans despite financial constraints.

At the September conference, the average WTI spot price for the month was $47.29. In December, it shot up more than $10 to $58.36.

Roesle also noted that industry expectations of future prices were more realistic than the year before, according to a survey of conference attendees. At the 2016 conference, 122 respondents predicted on average a $58.68 barrel of oil by September 2017, which proved to be premature by only about three months, considering the December 2017 price.

At the 2015 conference, attendees predicted $68.94 by September 2016, more than $25 higher than the actual $43.16 WTI price. "This just shows you the value of our crystal balls," said Roesle.

Forecasts for 2017 Oil Prices from 122 Respondents at 2016 Ryder Scott Reserves Conference



He also said that he was seeing indications of favorable supply-and-demand dynamics from the International Energy Agency. "The agency says world oil demand will grow more than expected this year, helping to ease a global glut despite rising production in North America and weak compliance by OPEC as far as production cuts. We still need a growth of consumption to remove some of the volume in storage," he said.

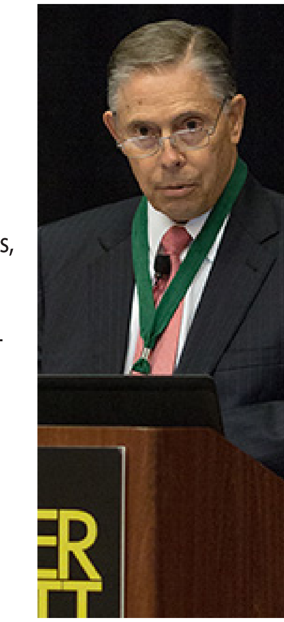
The IEA in December said that global oil supply rose in November to 97.8 million B/D, the highest in a year, on the back of rising US production. However, overall output was nonetheless down.

Roesle said the severity of the downturn over 2-½ years was reflected in the bankruptcies of North America oil and gas producers — 44 in 2015, 70 in 2016 and 14 by September 2017. "This is quite a striking number," he remarked.

Secured and unsecured debt connected with bankruptcies over that period exceeded $100 billion. The Haynes and Boon law firm, which tracks oil and gas bankruptcies, said late last year that "bankruptcy filings by producers have slowed considerably since the surge in mid-2016" — another positive sign.

Roesle also pointed to rig count as a positive. In mid-December, a Baker Hughes rig-count summary saw a 314-rig utilization increase over a year internationally.

Roesle pointed to the Saudi Aramco planned IPO as an indicator of what may be ahead.



Don Roesle

He asked, "How many of you would have ever thought of the possibility that Saudi Aramco would launch an IPO in public financial markets because they were concerned about cashflow from the oil production in low-price environment? Or that some of the other mega producers in Middle East would be considering transparency in their reserves process in case they have to go to public markets?"

"It's been tough over the past 2-½ years but I see some improvement out there and perhaps so do you."

Saudi Aramco plans to launch the IPO this year and list its shares on Tadawul, the Saudi stock exchange. The stock sale could be the largest in history based on the government's $2 trillion valuation of the company.

The New York, London, Hong Kong, Singapore, Tokyo and Toronto stock exchanges also are competing for the offering.

Roesle pointed to other areas that "have given the industry some optimism that we have turned the corner," including the "resurgence of activity in west Texas in the Permian and Delaware basins and other areas." He cited positive developments in management changes in some companies that now have a "new outlook for operating in a low-price environment."

"When we meet in 12 months, what will be the new norm," he asked the audience. The next Ryder Scott Houston conference is Thursday, Sept. 13.

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Olds joins SPE OGRC

Dan Olds

Managing senior vice president **Dan Olds** is a member of the SPE Oil and Gas Reserves Committee (OGRC) this year. He began his term last October.

The OGRC is the most influential decision-making body for establishing and revising petroleum reserves definitions used by the industry worldwide.

Olds and fellow committee members are now working with a draft of the 2017 Society of Petroleum Engineers Petroleum Resources Management System (SPE-PRMS). He served on the Society of Petroleum Evaluation Engineers committee that recommended changes to the 2007 SPE-PRMS draft. Those revisions were incorporated into the final definitions.

Over the years, several Ryder Scott professionals have served on any one of several committees and organizations involved in drafting and approving the SPE guidelines.

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 oil and gas reserves studies a year. Ryder Scott multi-disciplinary studies incorporate geophysics, petrophysics, geology, petroleum engineering, reservoir simulation and economics. With 115 employees, including 80 engineers and geoscientists, Ryder Scott has the capability to complete the largest, most complex reservoir-evaluation projects in a timely manner.

Reservoir Solutions

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