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RYDER SCOTT COMPANY LP
TEXAS

RESERVOIR SOLUTIONS

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Production forecasts from unconventional plays too high, says Lee

Decline curves, type wells and parent-child wells at root of problem

Reservoir engineers forecasting production from unconventional plays, generally, could do a better job, said **John Lee**, professor at Texas A&M University and a leading reserves evaluation expert. He made his comments at the Ryder Scott reserves conference in Houston in September.

Shale revolution matures

For background, Lee discussed a *Wall Street Journal* article last year that tracked forecasts of oil production from America's four hottest drilling regions, including the crown jewel of the Permian, the Wolfcamp Delaware basin.

"Two-thirds of projections made by the fracking companies between 2014 and 2017 …appear to have been overly optimistic, according to the analysis of some 16,000 wells operated by 29 of the biggest producers in oil basins in Texas and North Dakota," stated the *WSJ* article.

The publication also reported that producers began using the term EURs (estimated ultimate recoveries) when prices dropped this decade to de-emphasize reserves, which are commercially recoverable under current economic conditions.

Please see, "WSJ, Forbes send mixed signals on production forecasts," in *Reservoir Solutions* newsletter, April-June 2019, Page 2 at https://www.ryderscott.com/wp-content/uploads/2019NL%E2%80%A2April.pdf.

Overestimation has become a pervasive problem across U.S. unconventional plays, signaled Lee. It comes at a critical time in the industry, as some financial backers have fled and capital is starting to dry up.

Lee suggested that the first step to remedy the situation is for industry to use reliable forecasts based on flow regimes, characteristic declines and fracture geometry between parent and child wells.

"Type wells are really the source of the estimates that the *Wall Street Journal* and others have used for comparison with actual outcomes," said Lee. "These type wells are based on averages of production profiles of existing wells and undeniably, they have tended to be overly optimistic."

He cited problems with fundamentals in three areas — creating type wells, formerly called type curves; plotting decline curves; and spacing and timing parent and child wells — all of which are part of the technical work scope underpinning reserves reporting, economic analyses and further field development. They, in turn, influence investment decisions and success levels in the oil patch.

Fewer players in the patch

Despite record oil production from North America shale plays (or because of it), low prices and credit lines have clobbered the E&P industry. At the end of the third quarter, 33 bankruptcies in North America had rubbed out $13 billion in secured and unsecured debt, according to the latest count at press time by Haynes and Boone LLP.

Approach Resources Inc. filed for chapter 11 bankruptcy in November, all but assuring that 2019 would be the roughest year yet for the oil patch.

Late last year, a strong U.S. economy boosted market caps in the E&P sector five points from 25 percent down on an annualized basis in November to 20 percent a month later.

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"Interference is a big issue, particularly in the press and with investors"

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Decline curves, flow regimes

Evaluators in the shale have typically used the Arps empirical equation with a single b-factor to plot the expected production decline from hyperbolic to terminal. The trouble with that is b-factors change over time as flow regimes change.

Some evaluators get around that by using varying b-factors, including **Brent Biseda**, a senior engineer at Seneca Resources Co. LLC, at the time of his SPE paper, "Modified Arps Equation for Changing B-factor."

He stated "modifications allow a single equation to be used with a vectorized b-factor … to model a well as it transitions from linear … to boundary-dominated flow and eventually back to pseudo-linear flow."

Lee said b-factors in early flow regimes will be high (> 1) and the final b in the boundary-dominated flow regime, is going to be much lower (<1).

He added that Arps b-factors have tended to be too high, particularly as used to forecast long-term production, so evaluators typically switch to a terminal decline late in the production history to lower the final decline rate and EURs.

He showed log-log diagnostic plots from the Bakken shale play that he said were a good way to identify flow regimes.

"What we see is an early ramp-up during hydraulic fracturing, cleanup and choke-back flow. That is followed by a long, transient flow regime, as the reservoir drains further away from the fractures prior to interference between adjacent fractures," he said.

That's followed by a transition period that is "pretty long, more than one log cycle." With enough history, the final BDF regime is evident and signifies when all fractures along the well exhibit interference.

Lee recommended that evaluators be more realistic about the decline rate during early transient flow in horizontal wells with multiple fractures. See chart of the Arps hyperbolic model with 30-percent decline rate at switchover to transient flow.

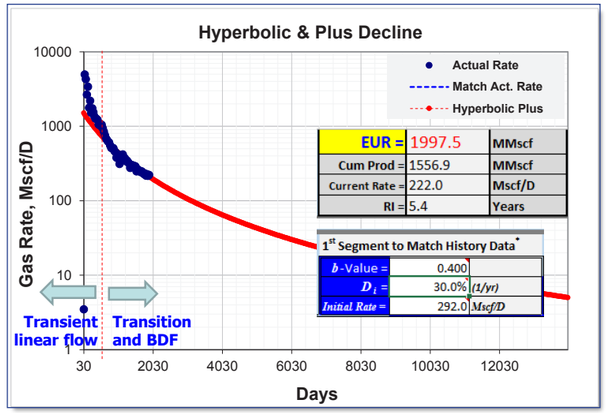
"The decline rate at the time we switched flow regimes was not 5 percent or 10 percent per year. It was 30 percent per year because of the effects of boundaries," he said. "I didn't cherry pick data to come up with an example like this. It is quite common."

Type wells: Not just averages

Lee said that creating type wells requires more than averaging production profiles. "We need to consider carefully placing wells with similar decline characteristics into individual bins and make sure we have a statistically significant sample size of wells in each bin," he remarked.

Please see, "High-side forecasts with type wells caused by 'survivor bias,' says Lee," in *Reservoir Solutions* newsletter, July-September 2017, Page 5 at www.ryderscott.com/wp-content/uploads/2017NL_July.pdf.

Arps Hyperbolic Model Fitted with BDF Data Only for Forecasting



The article discusses survivor bias, binning, probit charts, off-trend data and scaling.

Lee said, "It's important to scale data as needed with the goal of minimizing the number of separate bins and maximizing the number of wells in each bin."

He recommended sorting wells based on permeability-thickness, number of fracture stages and drawdown — all factors that affect post-peak rate well performance in unconventional plays.

Parent, child wells: Interfere, but not too much

Lee also pointed to production from infill and pad wells that either causes too much or not enough interwell interference. Too much is overkill. Too little lowers recovery efficiencies. Wider spacing increases EUR per well but decreases EUR per section.

"We shouldn't try to avoid interference. If we do, we're going to leave large areas undrained in acreage we're developing," he said. "We need some interference – if we don't have it, we're not draining all the rocks."

This issue has not gone unnoticed in the press.

"Interference is a big issue, particularly in the press and with investors," he said. "We're not properly taking interference into account."

Lee suspects that to estimate the EURs of infill wells, industry is using production profiles based on older wells and looser spacing, which underestimates interference.

"We think if we have a typical P90 production profile for a well and drill a couple infill wells, we can just multiply that profile by a factor of three, and we've got a good forecast," he said. "Well, it doesn't turn out to be that simple."

Lee said that history-matched dynamic modeling cited in SPE paper (No. 191799-MS) published in 2018 by Defeu et al from Schlumberger Ltd. has provided insights into the parent-child relationship in drilling offsets.

The study showed that in the Wolfcamp Delaware Basin, hydraulic fractures in wells closer to the parent well grow toward adjacent, depleted areas. Those child wells experience increased depletion times and up to a 50 percent reduction in production compared to the parent, the paper states.

At the same time, the adjacent parent well may suffer from "frac hits" from the child well undergoing fracture treatments, which can cause premature production decline in the parent.

"At large well spacing, little impact is observed because of limited interference between wells," said Lee.

Not only does well spacing matter, so does timing for infill drilling and production, the SPE paper concludes. Fractures from a child well tend to propagate selectively into the pressure-depleted areas near the parent well vs. spreading into undrained immediate areas.

"That's going to lead to poor overall recovery, which leads to overoptimistic estimates of ultimate recovery from this parent/child well combination," said Lee.

Authors of the paper have observed significant propagation of fracturing from the child well to pressure-depleted areas of the parent well 36 months after the parent has been on production.

Please see Production Forecasts on page 8

Facilities engineer joins Houston office

Sandeep Khurana

The new head advisor–upstream and midstream integrated services is **Sandeep Khurana**. He joined Ryder Scott in October.

Khurana is the team lead for surface facilities and midstream areas. He collaborates with reservoir engineers and geologists to determine various midstream options.

The addition of Khurana enables Ryder Scott to offer inhouse expertise beyond the subsurface and wellhead.

Previously, he was head of advisory development & operations at Granherne, a subsidiary of KBR Inc., where he worked more than five years. He advised governments and NOCs on assets and master plans.

Khurana analyzed midstream business, contractual issues, LNG value chain, plants and pipelines. He also evaluated onshore development plans, appraised commercial plans and provided concept selection, contracting strategies and bids for floaters and subsea installations.

Before that, he was manager development, major projects group, at Noble Energy Corp. from 2010 to 2014. He ensured front-end loading, planning, and execution for major assets and projects. Khurana also managed integration of drilling, environmental and regulatory considerations, and lease requirements in the frontier areas. Khurana also performed concept screening for gas export infrastructure for unconventional resource plays and assisted in the sanctioning of an onshore mini LNG plant.

During 2010 to 2016, he worked at Devon Energy Corp. as a facility advisor in international operations, then as a senior advisor in domestic and international operations. He provided technical counsel during farm-ins and farm-outs in exploration and exploitation-support initiatives and managed operations upgrade work on offshore facilities, pipeline, and onshore gas LPG plant in Cote d'Ivoire.

Khurana also won government and partner approvals on a $750-million development plan for a subsea tieback to an FPSO in Equatorial Guinea. Later at Devon, he headed and managed oil and gas projects, and provided technical expertise in field development planning with a multidisciplinary team, including subsurface, drilling, operations, and commercial. Much of the work was in Brazil, China and Gulf of Mexico.

During 2003 to 2006, he was a project manager, subsea systems & facilities at Kerr-McGee Corp. and at Anadarko Petroleum Corp. as a consultant after the acquisition. He managed subsea tieback projects from concept engineering to equipment installation followed by commissioning and operations support.

Before that, he was a principal facilities engineer at Halliburton from 2000 to 2003. Khurana performed field development evaluations, reduced capital costs, and developed new technology with a multi-disciplinary team. He also performed studies on rigless well intervention, wireline, coiled tubing, hydraulic workover techniques and applications, and technical issues in subsea well intervention.

Khurana was also a facilities project engineer at Paragon Engineering Services Inc. during 1996 to 2000. He conducted facilities engineering work on onshore plants and offshore facilities developments, including those in Nigeria, West Africa and the Gulf of Mexico.

He began his career as a marine engineer at Brown & Root Energy Services in 1989, and then joined Petro-Marine Engineers of Texas Inc. as a senior engineer in 1994.

Khurana has an MS degree in science from Rice University. He is a registered professional engineer in Texas, registered Project Management Professional and member of SPE.

Artificial intelligence to liberate workforce, says Cagle

Adam Cagle, data science coordinator at Ryder Scott, is a liberator armed with artificial intelligence. He's not a super hero. Or even an avenger. Disguised as a mild-mannered petroleum engineer, Cagle is on a crusade to free those who typically spend more than half their work time to integrate, format, route, compile and cross-reference data.

He understands that the goal is to analyze the data.

"I want to liberate them (employees) from mundane tasks so they can spend more time on activities they actually enjoy and that are fulfilling. This will unlock their full potential," he said.

Cagle presented, "Talking Shop: Data Science at Ryder Scott," at the firm's Houston conference late last year. It updated progress on the firm's data science initiative that began a year ago.

He showed a slide on a recent *New York Times* article that found project teams spend 50 to 80 percent of their time "munging," which is manually cleaning up data sets.

Some have referred to it as data wrangling. Practitioners in the reserves sector often have to wade through large quantities of data – an all-too-familiar occupational drudgery that cannibalizes productive time.

"For technical people nothing is more frustrating than having a great idea, but not having the time, tools and resources needed to experiment. Our goal is to provide that," said Cagle.

End game

Cagle has his sights on developing a machine learning system or other type of artificial intelligence with petroleum engineering input that would enhance current prediction techniques. However, he is taking a data first approach, initially focusing on data integrity.

That step comes before leveraging data science and creating infrastructure, tools and routines to statistically analyze those quality data sets.

The end game is increased efficiency and more reliable production forecasts. For instance, supervised, calibrated machine learning improves estimates of uncertainty in probabilistic production forecasts, some studies have shown.

New product in the making

The earlier stages of the work will also open up opportunities for Ryder Scott to provide a new deliverable to clients — a quick-look report with a statistical summary that will be "there when you need preliminary, reliable, fast answers of the highest quality."

While providing useful information, the automated report will be based on public data, and will not replace reserves or resources studies.

The plan is for the client to provide a list of wells in a geographic area to Ryder Scott, and in return, the firm will produce a report with technical volumes for oil, water and gas, and ultimate recoveries over time.

Ryder Scott is no stranger to database work to improve forecasts. Please see sidebar on Page 5.

No tearing down the silos

Ryder Scott possesses project data that is confidential and restricted. Various evaluation teams keep and protect project data and interpretations in silos "because each project should only use the data to which it is entitled," said Cagle.

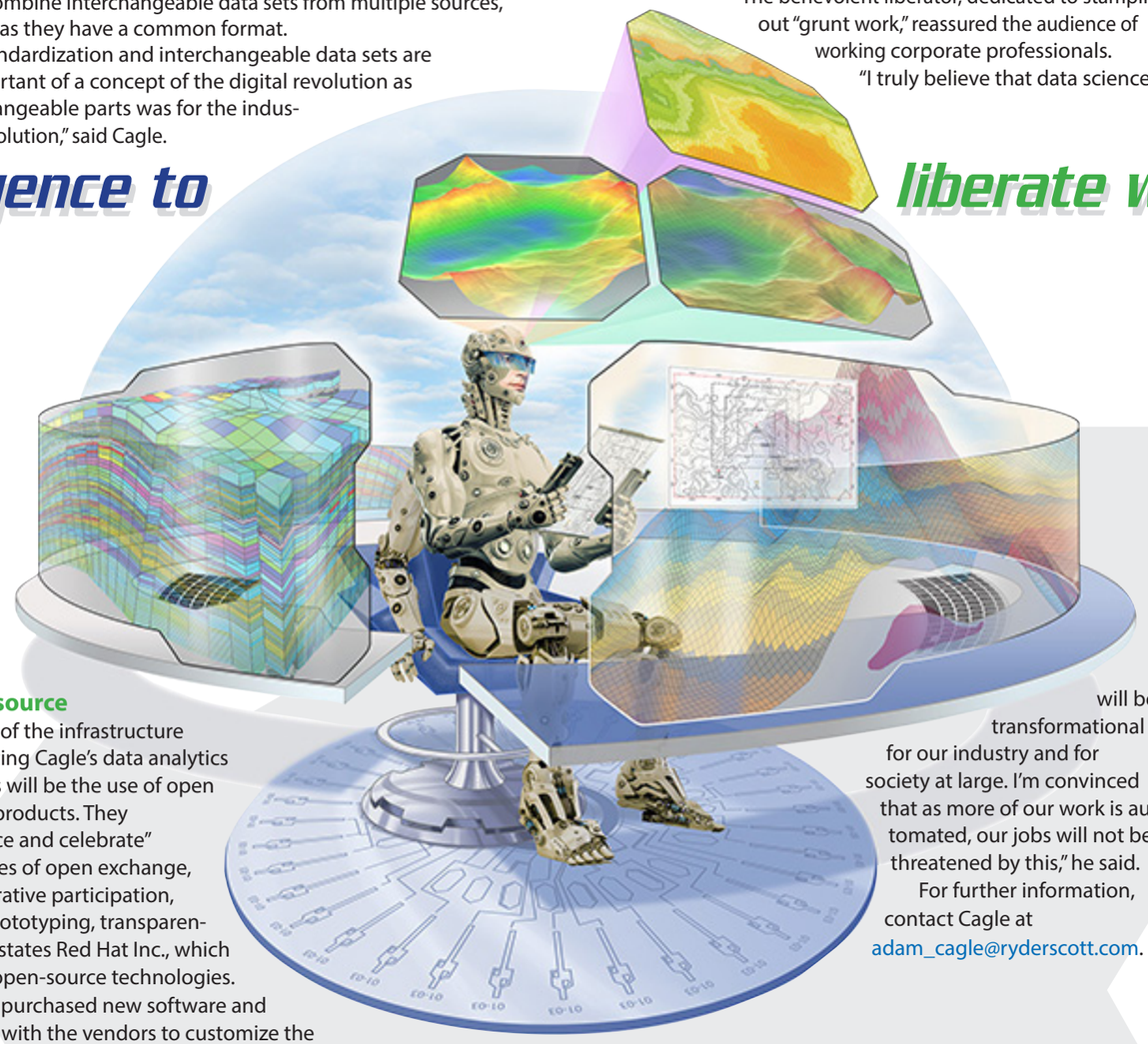
That said, petroleum geologists and engineers do not operate in a vacuum. They gain knowledge through project work and leverage that experience to accelerate learning curves and ultimately, improve forecasting in oil and gas trends.

Standardization

"We have another challenge as well," said Cagle. "Every client is different, and every job we work is different."

He added that standardization is an essential part of his data management project because it will allow Ryder Scott to easily combine interchangeable data sets from multiple sources, so long as they have a common format.

"Standardization and interchangeable data sets are as important of a concept of the digital revolution as interchangeable parts was for the industrial revolution," said Cagle.



Open source

Part of the infrastructure supporting Cagle's data analytics projects will be the use of open source products. They "embrace and celebrate" principles of open exchange, collaborative participation, rapid prototyping, transparency, etc., states Red Hat Inc., which makes open-source technologies.

"We purchased new software and worked with the vendors to customize the solutions to serve our purposes, but we've also heavily leveraged open-source software tools," said Cagle. "In my view, open source has been as important to the digital revolution as has been any other breakthrough technology. It's amazing that anyone with an Internet connection is able to download these tools for free, find all the resources they need to learn how to use them and get help running them through the large communities that built, use and maintain them."

Cagle developed a new open-source tool, Well Collator, using open source code that anyone can modify and enhance. The "shiny app" is posted on the Ryder Scott website at www.ryderscott.com/software/well-collator/.

See article, "Data Analytics," on Page 1 of *Reservoir Solutions* newsletter, October-December 2019 at https://www.ryderscott.com/wp-content/uploads/1Rs4thQtr•WEB•Oct30th-LinksMSTR.pdf.

The benevolent liberator, dedicated to stamping out "grunt work," reassured the audience of working corporate professionals.

"I truly believe that data science will be transformational for our industry and for society at large. I'm convinced that as more of our work is automated, our jobs will not be threatened by this," he said.

For further information, contact Cagle at adam_cagle@ryderscott.com.

Adam Cagle

*Editor's Note: "When new technology enters the oil and gas scene, talk of layoffs can creep into water-cooler conversations," wrote **Heather Saucier**, correspondent at the AAPG Explorer magazine, in the December issue. Artificial intelligence and machine learning technologies are interpreting seismic data at record speeds "often delivering results that rival, if not surpass, those of humans," she wrote. Companies offering the service advertise it as "real-time" seismic interpretation.*

Ryder Scott no stranger to database work to improve forecasts

Ryder Scott has built large regional databases with public and proprietary information to create maps of oil and gas trends with tens of thousands of data points for each North America unconventional plays and elsewhere, including the following areas:

- Bakken
- Eagle Ford
- Wolfcamp
- Haynesville
- Marcellus
- DJ-Wattenberg Basin
- Powder River Basin
- Scoop/Stack
- Tuscaloosa Marine Shale
- Montney in BC/AB, Canada
- Duvernay in AB, Canada
- Viking in AB/SK , Canada
- Bakken in SE/SK, Canada
- Vaca Muerta in Argentina

Database "building blocks" include well locations in sweet and trouble spots, initial and daily production rates, estimated recovery factors and ultimate recoveries correlated with mapping by area and depth.

Ryder Scott generates and inventories type curves for comparative analyses to identify best-fit performance analogs. The firm's analysis of statistical performance data yields predictable, repeatable reserves estimates in analogous areas.

Ryder Scott evaluates and catalogs well-test results, fluid properties, drilling-and-completion techniques, such as well trajectories, TVDs, lateral lengths, frac stages and proppant amounts. Key geological information, such as thermal-maturity and TOC data, is also stored and indexed.

"Our databases aid and guide our traditional reserves reports," said **Dean Rietz**, CEO. "We work hard to ensure that proprietary data stays within the specific projects and clients to which they belong."

Ryder Scott reserves evaluations for T&T, Abu Dhabi make the news

Countrywide studies featured in November press reports

Ryder Scott independent estimates for gas reserves for Trinidad & Tobago and conventional oil and gas reserves in the United Arab Emirates were good news for both countries recently.

Herman Acuña, executive vice president, spoke at a press conference on Nov. 20 held by the T&T Energy Ministry, saying T&T had a reserves replacement ratio in 2018 greater than 100 percent. *The Trinidad & Tobago Guardian*, *Trinidad & Tobago Newsday, Trinidad Express* and other publishers in the country reported on the press conference.

Through a press release, Acuña also confirmed the Supreme Petroleum Council announcement on Nov. 4 that the Abu Dhabi National Oil Company's (ADNOC) conventional oil and gas reserves base increased 7 billion barrels of oil and 58 Tcf of gas.

T&T: No other report is more important

As published by the *Guardian*, T&T Energy Minister **Franklin Khan** said, "The Ryder Scott Report is probably the most important report that is presented in the country annually because of its importance for the country's economic future. There is no other report produced for this country that is more important than this."

He added, "In a very real sense, this country's future is largely dependent on what the Ryder Scott report says."

Acuña confirmed that gas production for 2018 increased to almost 1.3 Tcf with the "lion's share" of the increase at 61 percent coming from BP Trinidad and Tobago.

Although proved reserves stayed relatively the same year over year, proved plus probable reserves increased 5.6 percent. Oil and gas companies typically build business cases for new field projects on 2P estimates.

UAE leapfrogging

With the updated reserves estimates, the UAE moved up in global rankings of countries — from seventh largest reserves in the world to sixth, said the Minister of State **Sultan Ahmed Al Jaber**. ADNOC said it plans to continue to increase production in the UAE to 4 million BOPD in 2020 and 5 million B/D in 2030, in part, through stakes awarded to international oil companies.

Ryder Scott designed and installed a corporate reserves management system (RMS) for ADNOC last year that helps the company analyze its various potential and existing concessions with IOCs.

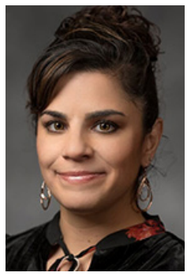
The RMS combines and integrates processes, software and personnel to assist the company in tracking changes in reserves quantifications and classifications and making decisions on its property portfolio.

Acuña said, "After we set up the RMS, we performed due diligence to update our knowledge of the reservoirs and assess proposed changes to the property portfolio."

Over almost two decades of service, Ryder Scott has gained detailed insights into the geology and well performance of UAE oil and gas reservoirs.

Acuña points to T&T gas activity on an energy map of the Caribbean during his presentation at a press conference Nov. 20 in Port of Spain. Photo courtesy of Trinidad & Tobago Guardian newspaper and Nicole Drayton, photographer.

New business development manager named



Pamela Sabo

Pamela Sabo is the new business development and sales manager. Former business development manager **Mike Wysatta** is public relations manager.

Sabo has worked at Ryder Scott 18 years as a business development coordinator, simulation and engineering technician and analyst.

"Over the years, Pamela has demonstrated her ability to perform well under pressure and her desire to move the company forward in terms of workload, quality and reputation," said **Dean Rietz**, CEO.

Wysatta, business development manager for 22 years, will continue to manage external communications, including conceiving, writing and publishing *Reservoir Solutions*, also going into its 22nd year.

To contact Sabo, please send an email to pamela_sabo@ryderscott.com.

Mike Wysatta

Average annual oil price tumbles $10 a barrel

What a difference a year makes. A year ago, Reservoir Solutions newsletter published an article headline, "Average annual oil price for SEC reporting soars 28 percent." The latest headline is a different story.

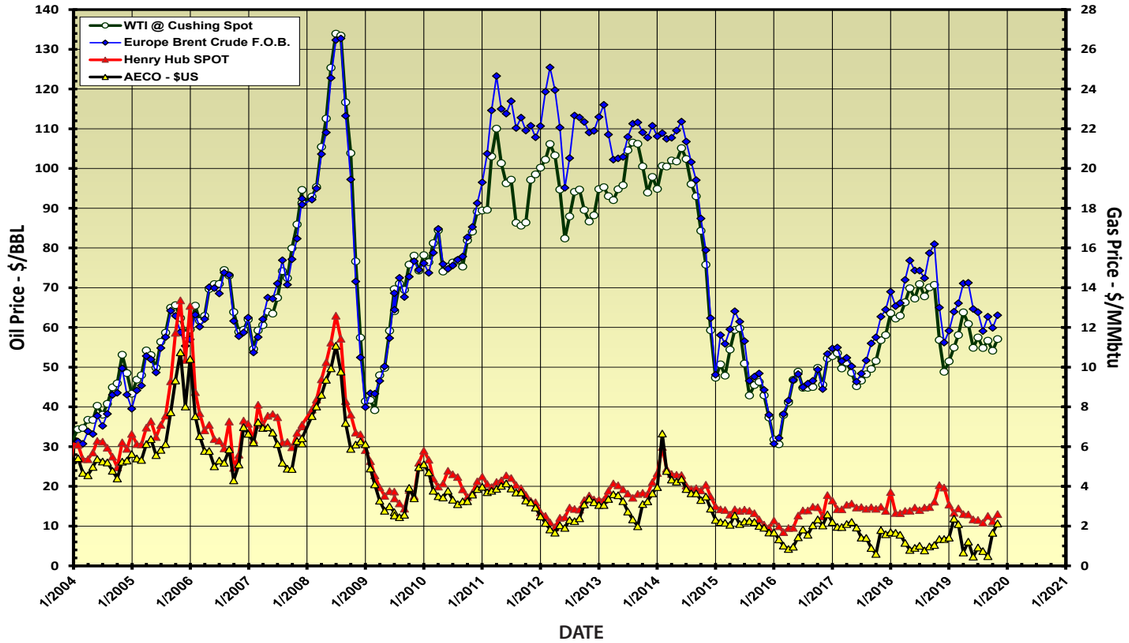
The annual average prices for reporting year-end 2019 petroleum reserves to the U.S. Securities and Exchange Commission showed a decrease in the WTI Cushing crude oil benchmark price from $65.56 per barrel to $55.60, a 15 percent drop. The Henry Hub gas benchmark dropped 17 percent — from $3.101 per MMBTU to $2.577.

The more resilient Brent crude oil benchmark settled in at $63.15, close to a 12 percent annual decline. 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.

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.

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Reservoir simulation is the answer

Lee said how to determine spacing and proper fracture length is not obvious and requires careful economic analysis.

"The only way I now of currently, at least on a design basis, is to model what we think is likely to happen using calibrated history-matched reservoir simulation for various well-spacing schemes and fracture lengths. With that, come up with the basis for the economic analysis and appropriate well spacing."

Editor's Note: Lee's presentation, "Wall Street is Angry: What Can We Do about It," summarizes various approaches to production forecasts with technical and analytical detail, acknowledgements and 14 charts/graphs. It is posted at the following web address: www.ryderscott.com/wp-content/uploads/RSC_Hou_Conf_2019_02_Lee.pdf. Both SPE papers referenced in this article are available for purchase at onepetro.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 oil and gas reserves studies a year. Ryder Scott multi-disciplinary studies incorporate geophysics, petrophysics, geology, petroleum engineering, reservoir simulation and economics. With 116 employees, including 76 engineers and geoscientists, Ryder Scott has the capability to complete the largest, most complex reservoir-evaluation projects in a timely manner.

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"Perfect Storm" hits industry

With a one-two punch, the economic impact of the Covid-19 virus and an oil-price war walloped the upstream industry in March. OPEC and Russia failed to curb output, which bloated inventories. The spreading virus blunted appetites for oil and gas, creating out-of-balance supply-and-demand dynamics.

Like Covid-19, plunging oil prices didn't discriminate.

Like Covid-19, plunging oil prices didn't discriminate. Values of future cash flows dragged down balance sheets of independents, IOCs and NOCs alike.

Prices nosedived to $20 a barrel March 18 before increasing to $24 a day later. The first of the year, the WTI oil price benchmark was $61 a barrel.

U.S. not at a tipping point yet

"Cash flow for shale producers will be down in 2020 as crude oil falls, but few big energy companies have debt maturities coming due this year," reported cable broadcaster *CNBC*.

Of the $53 billion in speculative-grade debt maturities through 2024, less than $2 billion will mature in 2020, the broadcaster reported.

U.S. producers urged the federal government to waive the Jones Act that mandates only American vessels transport goods among U.S. ports, reported *Bloomberg* news service. The U.S. government was considering a federal aid package for the shale industry involving low-interest loans, *Bloomberg* reported. Texas regulators discussed restricting oil production, reported the *Wall Street Journal*.

Please see "Perfect Storm" hits industry on page 8

Data systems in place to work remotely with clients

"Ryder Scott receives most client data electronically, which has helped overcome work and travel limitations," said **Dean Rietz**, CEO. "During the coronavirus pandemic, systems already in place will facilitate meetings, data collection and logistical challenges, as quarantining grows around the world."

Ryder Scott uses the WebEx platform for virtual meeting spaces. "It allows sharing of desktop spaces, audio and video possibilities," said **Ronald Watt**, IT manager. "We can also use Zoom and other conference solutions."

The firm has video and audio conferencing facilities with workspaces. For file sharing, Ryder Scott uses Citrix ShareFile. "This service allows our clients to share files directly with our staff in a secure, 'logged' solution," said Watt.

Staff members have several ways to work remotely. They connect to the Ryder Scott network through VPN to use remote desktop tools and access systems, network data and licenses remotely. Staff can also use Citrix Remote Desktop solutions to connect to most applications, said Watt.

For more information, a client should contact the group leader in charge of the project team or a team member. Emails for personnel in Houston, Denver and Calgary are posted at https://www.ryderscott.com/employees/

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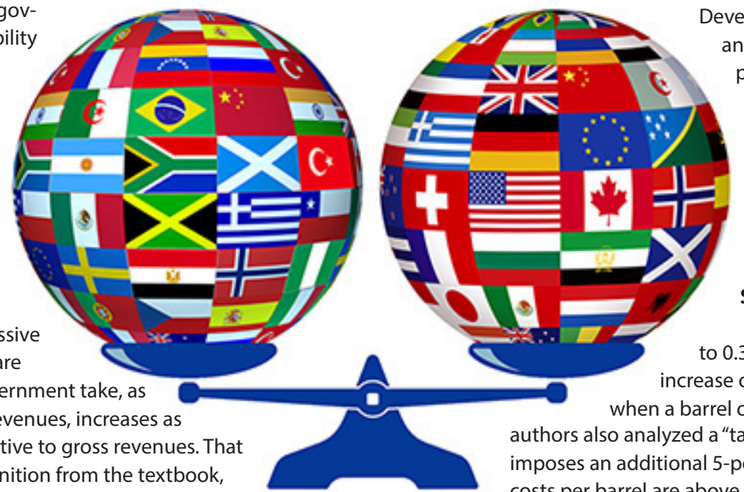
Striking a balance between progressive, regressive fiscal terms

-- **Andrew Wright**, *associate economist*

International oil companies (IOCs) negotiate upstream petroleum contracts based on cost-recovery incentives and profit potential from their shares of gross production under various policy and contract models. They see progressive fiscal systems as opportunities to maximize profits and upside.

At the same time, IOCs are not looking past host countries offering contracts under regressive fiscal systems. Those contractors target consistent cash flows from the exploitation of large, less risky portfolios of reserves with well-developed, profitable oil economies. As countries strike a balance between government take and profitability for IOCs, they are offering exploration-and-development (E&D) tracts under petroleum contracts with both regressive and progressive elements.



Regressive policies, national interests

For some basics, regressive petroleum fiscal regimes are those where the host government take, as a relative percentage of revenues, increases as project costs increase relative to gross revenues. That is a slightly reworded definition from the textbook, "International Petroleum Fiscal Systems and Production Sharing Contracts," by **Daniel Johnston**, PennWell Corp., 1994.

Another way to view regressive elements are as contract terms or laws that could cause a marginally profitable project to have a negative cash flow for the contractor because of government take, as cited in SPE Paper No. 130127-MS, "Designing Efficient Fiscal Systems," by **Mohammad A. Mian**, 2010.

Early in an integrated project's timeline, regressive policies are often in place and applicable to upstream activities. They are unresponsive to material changes in specific project conditions, such as field size, or macroeconomic changes, such as oil price increases or decreases.

Examples of regressive policies are signature bonuses and royalty arrangements. In production-sharing agreements (PSAs), where the contracting oil company has yet to recover all of its costs, cost-recovery caps are regressive.

Governments include regressive policies in their fiscal systems for various reasons to support their national interests. Royalties and cost-recovery caps guarantee the host government a minimum share of oil revenue by establishing an effective royalty rate, even in PSAs, as cited by Johnston.

Regressive policies allow governments to receive payments up front, which is especially important for cash-starved developing economies attempting to diversify away from oil.

The double-edged sword is regressive policies can ding host governments, just as they hurt oil companies. They discourage participation in bidding, licensing rounds and negotiations involving direct assignments. Disincentivizing E&D spending, especially in frontier areas or marginal fields, invariably reduces government revenues.

Consider Nigeria and its proposed, regressive National Petroleum Fiscal Policy (NPFP). Recently, staff at Addax Petroleum Development Nigeria Ltd. analyzed elements of the policy and published their findings in SPE Paper No. 193460-MS, "Nigerian National Petroleum Fiscal Policy – Fiscal Levers & Attendant Impact on Value of Oil Projects," **Segun-Oki** et al, 2018.

They focused on a 0.2- to 0.3-percent royalty increase on value that is triggered when a barrel of oil reaches $50. The authors also analyzed a "tax inversion penalty" that imposes an additional 5-percent income tax when costs per barrel are above 30 percent of the price per barrel.

By creating a decline-curve forecast of government oil revenue, the authors demonstrated that while the proposed changes in the NPFP maximized government revenue, they also choked off investment, because of negative net present values for IOCs at project levels.

A lack of flexibility in regressive contract terms also means that the government take decreases as profitability of the project increases. For example, a flat, volume-based royalty of $2 a barrel cannot respond to major oil price increases, such as those during the 1973 oil crisis or the 2008 spike.

In the government's view, large oil-price increases give oil companies windfall profits at the expense of its national interests and citizens. For those reasons, increasingly, governments are transitioning to contracts with progressive terms, and passing laws regulating oil and gas production.

Shell Nigeria E&P Co. Ltd. has operated the Bonga FPSO offshore Nigeria since 1994. The company anticipates that with further development, the Bonga field will produce more than 200,000 BOPD, although at reduced profits because of an increasingly regressive fiscal system. In November, Nigeria passed an amendment imposing additional royalties when the price of crude exceeds $20 a barrel. Shell and other contractors have criticized the move.

Win-win progressive policies

Progressive policies expose both host governments and contracting oil companies to economic fluctuations relating to oil price, capital and operating costs, reserves and production rates, observes Mian.

Think of progressive policies like the U.S. personal income-tax bracketing system. Those who report higher wages pay higher income tax rates. As the profitability of an oil field development increases (growth of taxable income), so too does the host government take based on a higher percentage of revenues (tax rate increase). Some common mechanisms in progressive policies include R factors, sliding-scale royalties and rate-of-return systems.

In theory, progressive fiscal systems reduce government take, especially on a discounted basis, as payments to governments are received further downstream, and therefore, later in project life, states Segun-Oki et al.

In practice, however, progressive policies arguably bring more investment to the host country than regressive ones. An example is in SPE Paper No. MS-185473, "Uruguayan Petroleum Fiscal Regime," **F. Ferro** et al, 2017.

He and the other authors, who included staff members at national oil company Ancap, stated that Uruguay was able to "revive exploration" despite the fact that "there has never been a hydrocarbon discovery in … (the country) and the exploratory areas which the country offers are a classic example of high-risk frontier exploration."

In addition to "excellent upstream market conditions at the time," the paper attributes the success of the second offshore bidding round to the progressiveness of the PSC terms.

The Uruguayan PSC has no royalties, no bonuses, no surface rentals, and Ancap must reimburse the IOC its share of E&D costs to back in. Ancap staff also created a detailed probabilistic technical and economic model that shows that in a wide range of reserves and economic scenarios, government take is consistent.

Profit-based, progressive contract elements, such as profit-oil splits, also encourage the contracting oil company to keep costs low.

Cost containment is measured by calculating the savings index of a project, as cited by Johnston. The index is only affected by profit-based contract terms, so contractors, under progressive fiscal systems, have more incentives to lower costs.

Without any domestic production or feedstock, Uruguay has one refinery, La Teja at Montevideo, which processes imported oil. A $1.5-billion exploration commitment in Round II bidding eight years ago generated no discoveries so far. However, progressive fiscal terms were partly responsible for attracting the participation of 11 IOCs in eight offshore blocks.

Dealer's choice

With the use of progressive and regressive contract terms, host governments can strike a balance "between increasing economic rent and incentivizing investment," states Segun-Oki et al.

However, for contracting oil companies, conclusions are somewhat tougher to draw. They involve soft, strategic considerations — such as geopolitical risk and relationship with government — and bottom-line considerations, for example, for investors who use capital asset pricing models to determine theoretical required rates of returns of assets if added to their portfolios.

While IOCs can overcome even the most onerous regressive contract terms, if the discoveries are big enough and costs low enough to justify them, exploration in frontier environments often only makes economic sense with highly progressive terms.

Investors seeking exposure to E&P activities should consider whether to target progressive fiscal systems to maximize upside access, or to aim for consistent cash flows from the exploitation of large portfolios of reserves under regressive policies.

Editor's Note: The email address of Andrew Wright is andrew_wright@ryderscott.com. All SPE papers cited in this article are available for online purchase at https://onepetro.org.

PE for oil and gas in flux

-- **Katherine Wauters**, *staff reporter*

At a recent Houston Geological Society panel discussion, professionals in petroleum engineering, law, tax and finance offered advice on the path forward for the E&P industry. Several years into an energy downturn, the buy/drill/flip game is over, said participants at the February event, "The State of Private Equity in Oil and Gas."

Panelist **David Wishnow**, head of energy technology at Darcy Partners LLC, said, "The traditional game of punch a hole in the ground and flip it is done. We have clients today, who two years ago, would have thought, 'I'm not going to operate this asset. Why would I ever need production surface technology?' Today, they say, 'we really could use some sensors and flow meters.'"

Investors expect a high level of operating efficiency now more than ever.

Morrow

Panelist **Gabrielle Morrow**, senior vice president at Ryder Scott, said, "The reluctance by private equity to invest in deals is a loss of trust. If banks and investors trust operators to deliver volumes in a capital-efficient manner, year-in and year-out, then they're probably going to spend money."

Panelist **Chris Micsak**, director of private equity at Pickering Energy Partners LP, opined that while capital is tight, opportunities are available.

"There's all this private equity capital that's sitting there on the sidelines. That's a lot of dry powder," he said. "We're starting to see a lot of interesting opportunities moving toward the operating side, but you have to be at the table to play the game."

During the downturn, teams working in private equity (PE) have scaled back management and operating staffs. Panelist **Clark Sackschewsky** said management firms are slimming down to create more value. He is U.S. natural resources industry leader, tax market leader at BDO USA LLP.

"What we're starting to see is elimination of management and operating teams altogether," said Sackschewsky. "Why have 10 teams when one on the payroll creates greater value? That eliminates a whole level of overhead costs."

The "rightsizing" of private equity teams and oil and gas companies are not the only signs of consolidation. PE firms are considering options to merge companies within their investment portfolios despite obstacles in gaining agreement among shareholders and other parties.

Panelist **Glenn Reitman**, attorney at DLA Piper LLP, said, "The most interesting thing I'm hearing about, but haven't seen yet, is consolidation mergers among portfolio companies. There's a lot of talk about 'expect the unexpected,' because it makes sense from a value perspective."

ESG and carbon neutrality

The latter half of the panel discussion focused on environmental, social and governance (ESG) and fossil-fuel divestments. Some universities have moved their endowment funds out of oil and gas. Insurance companies, pension-fund managers and others have also divested.

PE firms are not divesting for the sake of ESG. However, shedding fossil-fuel investments is a near-term concern of the oil and gas financial community.

"North American E&P companies have a staggering level of debt maturing over the next five years, when they'll likely continue to face tight access to the credit markets," said Moody's Investor Service in February.

Ethical investing, carbon neutrality

"Investors are constantly looking at renewables and other opportunities," said Morrow. "If our industry had a better image, then PE managers might be more willing to invest."

Oil and gas companies support ESG issues, for instance, by buying carbon credits to claim carbon neutrality. Morrow said that the Society of Petroleum Engineers has begun to create awareness of environmental sustainability programs.

Oil not going anywhere

Morrow compared the longevity and economics of oil and gas to other energy sources. "Oil and gas is not going anywhere, not by a long shot," she said.

"To say that solar and wind are going to take over oil and gas doesn't make sense. As for BTUs, solar and wind don't come close," said Morrow.

Oil and gas comprise about 55 percent of global energy sources today, states the latest outlook by Exxon Corp. By 2040, hydrocarbons will supply more than 50 percent of global energy — only a 5 percent drop relative to all energy sources.

Undeniably, investment will be required to arrest natural production declines and to meet demand.

Some prognosticators say that oil and gas will no longer be the dominant energy source by 2040, including BP. It claims that renewable energy will be the world's main power source in 20 years.

Morrow disagrees, "Oil and gas is going to be king for a long time."

Editor's Note: To access the Exxon report, go to https://corporate.exxonmobil.com/Energy-and-environment/Looking-forward/Outlook-for-Energy/Outlook-for-Energy-A-perspective-to-2040. ***Mark Hamzat O. Erogbogbo*** *at Mark@ProsperoOG.com coordinated and produced the HGS event.*

Juniors fall short in meeting production forecasts

Large and midsized public oil and gas companies in Canada are doing a better job of meeting production forecasts than juniors, according 2018 year-end reconciliations. The Alberta Securities Commission published those and other results in its latest Oil & Gas Review.

Senior public issuers slightly overestimated their technical reserves while intermediates slightly underestimated them. Juniors fell short of their forecasts at year-end with a negative 4-percent revision.

The results for seniors and juniors skewed negatively because of outliers. A senior disproportionately influenced its peer group's outcome 42 percent with downward revisions, while one junior accounted for 21 percent of the slide in its group.

Craig Burns, manager petroleum at the ASC, confirmed the disproportionate influences were negative. The published review did not address that.

In its analysis, the ASC summed gross proved-plus-probable reserves by group as disclosed under Item 4.1(2)(c) of Form 51-101F1. The review is at https://www.albertasecurities.com/-/media/ASC-Documents-part-1/Publications/2019_Oil_and_Gas_Review_Report.ashx.

Pipeline constraints in Canada and the rise of take-or-pay contracts have hurt juniors more than larger integrated companies, observers say.

Petroleum engineers join Ryder Scott

Yao Tian

Yao Tian joined the Houston office as a petroleum engineer in the reservoir simulation group. She is an expert in petrophysical interpretations of both conventional and unconventional reservoirs.

Most recently, Tian worked at Ryder Scott as a contractor on a multidisciplinary team estimating the reserves of offshore properties in China. Before that, she was a post-doctoral fellow at the University of Houston during 2016 to 2018.

At the university, Tian conducted petrophysical analyses of several oil and gas properties in the Upper Bakken shale and Upper Three Forks formation. She also used machine learning to select controls for regional production from 2,100 wells in the Bakken play.

Tian also helped develop and teach an unconventional resources engineering class in petrophysics.

Before that, she worked at Marathon Oil Corp. as a petrophysicist, starting in 2014. She conducted analyses of completion designs in the Eagle Ford shale play. Tian also performed studies of formations in the Austin chalk, Mowry shale, Woodford and Caney shales and Marchand and Medrano sandstones.

She has a BS degree in petroleum engineering from China University of Geosciences in Beijing, and MS and PhD degrees in petroleum engineering from Texas A&M University, where she also received a faculty award of excellence.

Tian wrote nine published technical papers while studying and working at the universities.

Steven Beck

Steven Beck joined the newly formed facilities engineering group as a project engineer - integrated services. His experience in process engineering comprises simulation and optimization for facilities, including midstream, pipelines, downstream and petrochemicals.

Beck also developed process data — from design and sensitivity through equipment sizing and cost estimation to financial analysis and investment profiles.

Before joining Ryder Scott, he was a consultant in advisory services at Kellogg, Brown & Root Inc. where he worked on due diligence and related strategy. In 2017, Beck was a process and production engineer at Westlake Chemical Corp. He analyzed cooling-water flows to streamline future design and optimize flow patterns at chemical facilities.

Before that, he worked at P.O.&G. Resources LP as an engineering analyst. Beck evaluated and optimized operating costs of fields in west Texas and Oklahoma.

He has a BS degree in chemical engineering from the University of Texas. Beck is a member of the American Institute of Chemical Engineers.

Ryder Scott integrates upstream, midstream services into turnkey product

-- **Sandeep Khurana**, *head advisor upstream and midstream integrated services*

Ryder Scott has responded to recent increased demand for integrated services by forming an in-house group with facilities engineering expertise. For decades, industry has recognized Ryder Scott for its work in general reservoir engineering, reserves evaluations, field development planning and economics.

We have also conducted management advisory services for more than 20 years. During that time, we have leveraged our multidisciplinary expertise on turnkey projects while calling on trusted alliance partners in facilities engineering, marketing and HSE (health, safety, and environment).

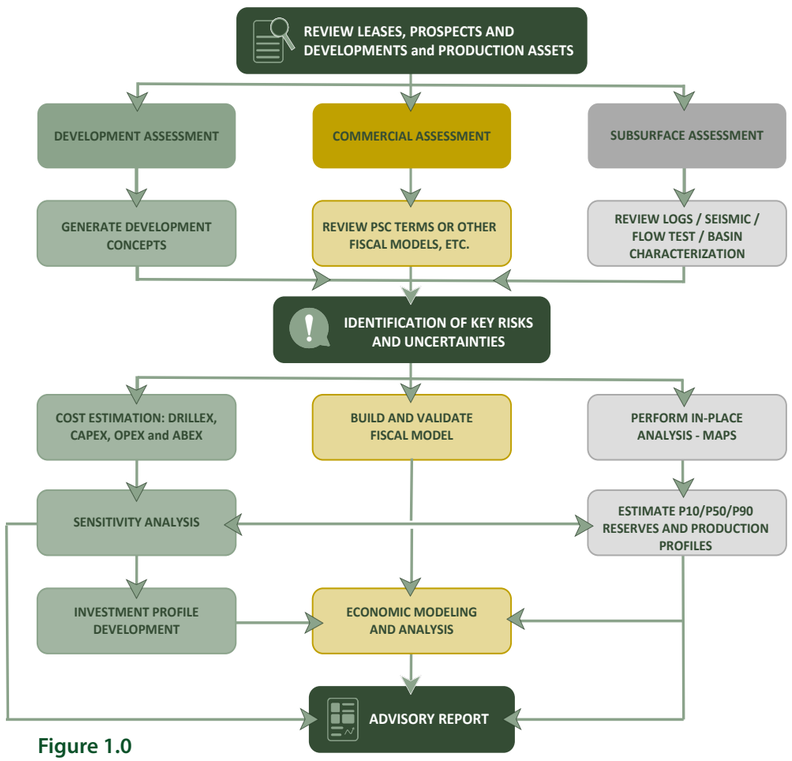


Figure 1.0
Overall Capabilities

While we have continued to fill those requests, we now are glad to announce an expanded focus by creating the Integrated Services Group within our firm. Ryder Scott saw the need to do this because clients increasingly contacted us to discuss development downstream of the wellhead, including facilities engineering and more recently, HSE stewardship that leads to carbon-neutral emissions.

To acquire funding and project contracts, other clients have requested assessments related to financial and legal engagements. Now, with commodity prices falling, Ryder Scott has become part of the solution to put a more resilient approach in play and confirm profitability for our clients.

A flow chart of our overall services is in Figure 1.0. We aim to capture value for our clients by incorporating three independent work streams — subsurface, development and commercial assessments — into one integrated product.

Each work stream has its own objective as follows:

- **Subsurface work stream** — Review basin geology and reservoir engineering work to generate estimated product flow streams subject to technical uncertainties in forecasting. That feeds into the surface facilities to monetize hydrocarbon resources.
- **Development engineering work stream** — Review the drilling, facilities and project execution plan. Project execution entails reviewing major contracts to deliver an in-place project. Execution also addresses HSE with emphasis on regulatory requirements and permits. The objective is to assess the development schedule, costs and related risks.
- **Commercial work stream** — Review fiscal regimes, production-sharing arrangements, etc. The objective is to assess the commercial parameters and assumptions within the business case for each project and simulate an economic or fiscal model. Our services extend to providing advice on the optimum business model.

In just the past six months, we have used those work streams to perform assessments for international unconventional basin entry, midstream and LNG business restructuring, and for an overseas company investment in an operatorship in the U.S. Gulf of Mexico.

The key features of our new, in-house facilities engineering group, as it provides development assessments, are to conduct technical reviews, generate investment profiles, perform HSE evaluations, and conduct risk identification and mitigation advisory services.

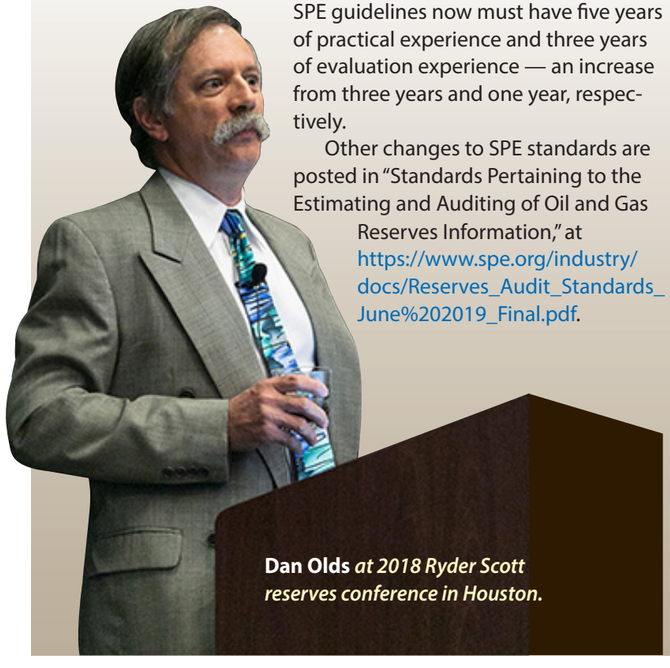
Figure 2.0 – right, depicts a more detailed overview of our methodology.

Using our development-assessment methodology, we generate investment profiles, analyze sensitivities, benchmark against industry norms, review and evaluate operations and liabilities, and, if necessary, perform physical inspections and analyze asset integrity and safety performance.

By integrating our subsurface, development and commercial assessments into one product, we can appropriately value an asset, understand technical risk, price risk into the investment and ensure that our client reaches its financial goals. At Ryder Scott, we will assess oil and gas resources, guide the development of projects, safeguard investments, lower transaction costs, quantify profitability, increase confidence in investment decisions and realize full development potential to add maximum value.

For more information, please contact Sandeep Khurana at sandeep_khurana@ryderscott.com.

SPE adds rigor to experience levels, audit standards



Dan Olds *at 2018 Ryder Scott reserves conference in Houston.*

A "qualified reserves evaluator" under SPE guidelines now must have five years of practical experience and three years of evaluation experience — an increase from three years and one year, respectively.

Other changes to SPE standards are posted in "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information," at https://www.spe.org/industry/docs/Reserves_Audit_Standards_June%202019_Final.pdf.

The society also recommended that "an entity reserves audit should represent all or at least 80 percent of an entity's reserves," and that "the portion of reserves audited must be clearly stated."

Dan Olds, managing senior vice president at Ryder Scott and vice-chairman of the SPE Oil & Gas Reserves Committee, said, "A significant change was to align the threshold level of reserves to review in an audit with the 80-percent level already required in an evaluation."

The change has not altered industry practice, just formalized it. For decades, practitioners have had options to use an 80-20 methodology in an entity reserves audit.

In that approach, fields in the upper 20th percentile, as ranked by size, typically comprise 80 percent of the reserves base.

Changes in the SPE audit standards document, published last year, also included minor edits and word changes. "The document received full treatment of the SPE style guide," said Olds.

For perspective, the Society of Petroleum Evaluation Engineers requires 10 years of experience for a full membership, with five of those in evaluations.

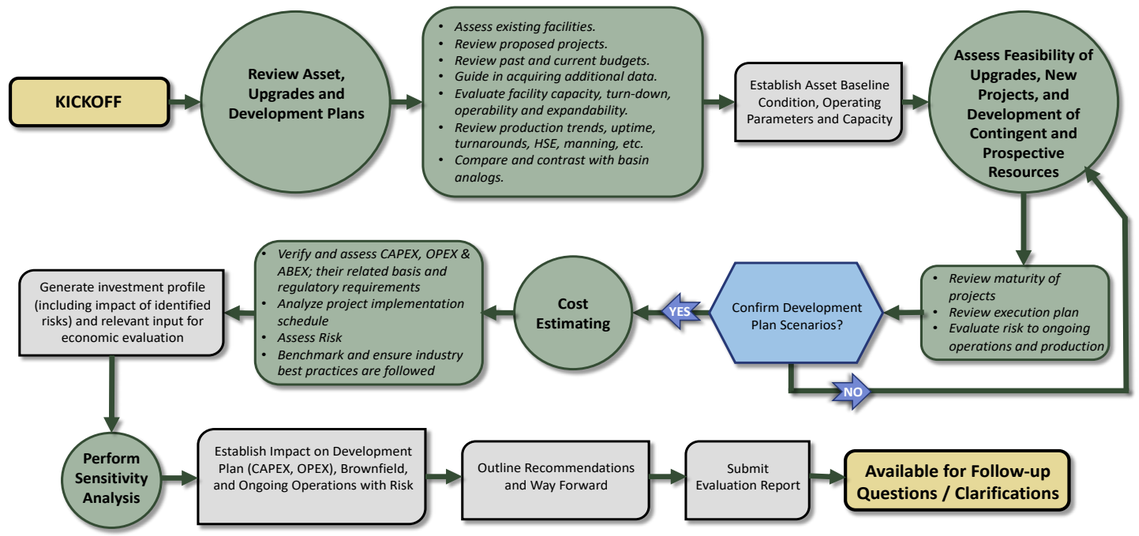


Figure 2.0 Development Assessment Methodology

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"Perfect Storm" hits industry – Cont. from page 1

Worldwide markets

The world hunkered down in quarantines, as risks to human capital spiraled. One of the more interesting forecasts for not only oil demand, but for the proliferation of the virus, was the second edition of the "Covid-19 Report," published March 17 by Rystad Energy AS. It is posted at https://www.rystadenergy.com/globalassets/pdfs/covid-19-report-week-12_final-version.pdf.

The energy research company stepped outside its area of expertise to model the future spread of Covid-19 in several countries.

"Our advanced analytical tools have already been utilized to create a system dynamics model of global oil price fluctuations, and applying the same tools to the Covid-19 situation allows us to build a very sophisticated model of the virus spread," the report stated.

The takeaway was quarantine, quarantine, quarantine.

Rystad studied the behavioral changes that follow quarantines, and forecast the trends making assumptions.

Rystad also forecast oil demand. On March 11 in its first edition, it expected global oil demand to fall by 500,000 B/D in 2020 vs 2019. Six days later, the firm stated the epidemic could collapse demand by more than 10 million B/D of oil by April, a staggering downward revision.

Forecasters worldwide in every market whiffed, as the unknown reared its ugly head each day.

Calgary reserves conference canceled due to Covid-19 virus

The sixth Ryder Scott Canada reserves conference, scheduled for May 28 in Calgary, has been canceled due to the Covid-19 pandemic. On March 17, Alberta declared a public health emergency, banning gatherings of groups of 50 or more.

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 116 employees, including 76 engineers and geoscientists, Ryder Scott has the capability to complete the largest, most complex reservoir-evaluation projects in a timely manner.

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RESERVOIR SOLUTIONS

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Sixteenth Annual Reserves Conference slated for mid-September

The 16th Annual Ryder Scott Reserves Conference, originally scheduled for Sept. 17, will be a streaming webinar via the Zoom video platform. Organizers are deciding on the best date or dates for the virtual webinar, and have plans to stick with a mid-September go-live.

How to stream webinar

For those who want to sign up, the process is as follows:

In July, Ryder Scott will send "Save the Date" announcements via email to past attendees or to those requesting more information. Those who want invitations, but are not registered, should send business-card information to **RSCConfHouston@ryderscott.com**. Please put "Invite" in the subject line.

Organizers plan to send invitations through Zoom/Outlook in July or August.

Additionally, those wanting an invitation can register and view details on the Ryder Scott website page at **https://www.ryderscott.com/2020-reserves-conference-webinar/.**

For users who have not downloaded Zoom, the web-browser client will automatically do that when joining the webinar. Zoom is browser independent.

Plans are to stream each prerecorded video feed on a schedule followed by a live Q&A between the speaker and audience. Ryder Scott also plans to post on-demand presentations afterward.

Licensed petroleum engineers at the webinar will receive CEUs (Continuing Education Units) required annually to maintain licensing through continuing education.

The ethics presentation qualifies as a one-hour credit needed to fulfill the annual requirement of most states for licensed engineers. (See summary of the planned presentation later in this article.)

Please see Sixteenth Annual Reserves Conference on page 2

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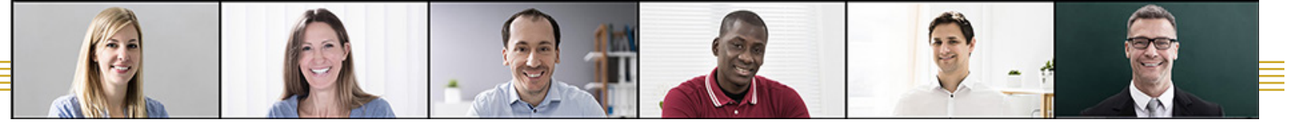


Sixteenth Annual Reserves Conference – Cont. from page 1

Covid-19 forces venue change, lineup still strong

Organizers decided to hold a virtual conference because of concerns about spreading the Covid-19 virus in a large crowd in September. They also anticipated the potential for restrictions on large gatherings by local and state authorities, because of Covid-19.

Meeting rooms at the downtown Houston Hyatt Regency hotel for the events have been at full-seating capacities. Recent conferences drew more than 375 attendees per event, and represented the largest single gatherings of reserves evaluators, a rather select group.

Reserves evaluations require analysis of subsurface geology and engineering by reservoir specialists.

"The event began more than 16 years ago, so over time, speakers and attendees have become a 'community' that gathers in Houston every fall," said **Dean Rietz**, CEO at Ryder Scott.

Organizers expect to exceed prior attendance numbers this year with the virtual conference.

The webinar makes it possible to lift all limits on audience attendance. Past conferences, for the most part, were by invitation, because of the selective audience appeal. Besides reserves evaluators, others regularly attend, including oil and gas executives and allied professionals in law, finance, accounting, academia and government.

"While attendees will miss the full day of hotel amenities and informal conversations among colleagues, the quality of the speakers and presentations will be at the same high level as in the past," said **Ali Porbandarwala**, conference chairman. "Unfortunately, this is a more impersonal way to hold a conference. Social distancing is the new normal, and still may be weeks or months from now."

Virtual conferences are most cost effective. "This year, we expect many of our friends and clients across the globe to attend the first time, because there will be no travel time or expenses," said Rietz.

Lineup Highlights

The planned lineup includes speakers and presentations 60 to 70 days out from the event. Speakers and agenda may change closer to the event dates. Updates will be posted at **https://www.ryderscott.com/2020-reserves-conference-webinar/** and sent through emails.

No reserves conference would be complete without **John Lee**, professor at Texas A&M University, former engineering fellow at the U.S. SEC and well-known reserves evaluation expert.

He will present, "How Can We Take Possible Well Interference into Account in Production Forecasting?" He will focus on new research and quicker evaluation methods to improve analyses of well interference, infills and "parent-child" issues in unconventional plays.

"Typical well-production profiles have failed to take well interference into account," said Lee. "That results in overestimates of future production."

Rigorous reservoir simulation, including coupling of geomechanical and flow models, will produce reliable forecasts, he added. However, those methods are too time consuming and expensive for routine application.

Dan DiLuzio, a reserves consultant at Chevron Corp., will present, "PRMS: Maintaining the Global Standard and Addressing Key Concerns." He will present an early history of petroleum resources definitions and why they were needed more than 100 years ago. He will trace their evolution, including the involvement of SPE beginning in 1962.

The most recent revision of the reserves evaluation standards was two years ago. They were ratified by sister societies WPC, AAPG, SPEE, SEG, SPWLA and EAGE.

"The PRMS is recognized as the globally referenced language of reserves and resources evaluations," said Diluzio.

He plans to review the SPE-PRMS fundamentals, including the resources classification framework and project-based approaches.

"We will cover a few commonly encountered issues in resources evaluations with examples to clarify everyday application of the PRMS," said Diluzio, who also plans to discuss hot topics.

Ron Harrell, Ryder Scott chairman emeritus, plans to moderate a panel discussion on CO_2 carbon capture. Scheduled panelists include **Logan Burt**, managing director at Morgan Stanley; **Christine Ehlig-Economides**, professor at the University of Houston and **John Hessenbruch**, retired and a former manager of technical resources at Occidental Petroleum Corp.

"Engineers and earth scientists have extensive opportunities to study hundreds, even thousands of unique oil and gas reservoirs. Some may have rock and fluid properties where CO_2 injection offers the likelihood of enhanced oil and gas recovery," said Harrell. "They may offer underground storage, sequestration or aquifer-disposal opportunities as well."

The panel discussion will focus on the operational, financial and research sides of carbon capture in the mid- and downstream sectors. The International Energy Agency estimates that carbon capture/storage and other energy efficiencies will have a greater "impact" on reducing CO_2 than renewables by 2040. Carbon reduction is a major component of the environmental, social governance (ESG) programs.

The discussion also will focus on private equity-funded producers, which are managing investor concerns about carbon emissions. Other challenges include gaining more technical know-how in handling CO_2.

The U.S. Treasury Department released rules on May 25 that guide companies in claiming a 45Q federal tax credit designed to spur investment in carbon capture and sequestration projects. The panel will discuss planning projects to capture and inject sufficient CO_2 to meet federal guidelines.

Jamie Jost, founder and managing shareholder of Jost Energy Law PC will make the ethics presentation, which focuses on oil and gas development that supports ESG criteria in regulations.

Using Colorado as an example, her presentation will explore environmental stewardship in the administrative law context. Included are key components of establishing and maintaining relationships with local governments, ENGOs (environmental non-governmental organizations) and citizen groups.

Jost plans to offer practical considerations for avoiding conflicts of interest.

Sandeep Khurana, head advisor of upstream and midstream integrated services at Ryder Scott, will make a presentation on deepwater-development enablers. He will outline the process of "promoting" oil and gas volumes from contingent resources to reserves.

"The presentation will cover best practices, cost-reduction strategies, new technologies and creative commercial solutions that have made deepwater profitable and sustainable in this wildly fluctuating, rather depressed commodity pricing environment," he said.

Khurana will provide attendees with insights in evaluation, assessment and development planning to generate value in deepwater. The presentation will cover industry best practices in development planning, cost-reduction strategies, new technologies and trends and creative commercial arrangements in deepwater infrastructure financing.

See article, "OTC paper: Private equity, third-party infrastructure will grow GOM," on Page 8.

Dan Olds, managing senior vice president at Ryder Scott, will present, "Practical Applications of Total Recoverable Resources (TRR)."

TRR, a new term in the 2018 SPE-PRMS, are those quantities of petroleum producible by using current technology and industry practices.

TRRs indicate oil and gas recovery potential regardless of commercial considerations. TRRs are reported on projects, groups of projects or geographically, for instance, by basin.

Olds said, "TRR is a way to show the expected maximum volume associated with a particular projection. The term was meant to clearly convey that the projection has not been truncated by an economic limit."

"TRR was intended to be an acceptable substitute for the often-heard, but always incorrect term, 'technical reserves,'" added Olds.

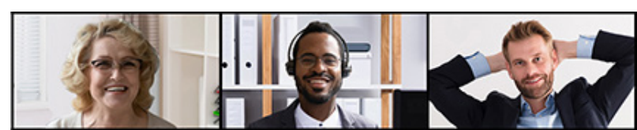
Lehi Woodrome, vice president at Ryder Scott, will present the "Supply and Demand Imbalance Leading into Oil Price Volatility." He said, "With storage capacities at recent highs, rig counts falling, and investors wary about the future of oil and gas, how long will it be before the demand returns and supply remains limited? Will price volatility be our new normal? "

Full Lineup

The following speakers and titles for all presentations at the webinar are as follows:

- **Dan DiLuzio**, reserves consultant at Chevron Corp., "PRMS: Maintaining the Global Standard and Addressing Key Concerns"
- **Jamie Jost**, managing shareholder at Jost Energy Law PC, "Ethics – Environmental, Societal, Governance"
- **Sandeep Khurana**, head advisor upstream and midstream integrated services at Ryder Scott, "Deepwater Development Enablers – Promoting From Contingent to Reserves"
- **John Lee**, professor at Texas A&M University, "How Can We Take Possible Well Interference into Account in Production Forecasting?"
- **Dan Olds**, managing senior vice president at Ryder Scott, "Practical Applications of Total Recoverable Resources"
- **Miles Palke**, managing senior vice president at Ryder Scott, "Latest Themes in SEC Comment Letters – What to Expect"
- **Sal Patoli**, managing director at Energy Group of Societe Generale Group, "Capital Solutions – Where Do We Go From Here?"
- **Lehi Woodrome**, vice president at Ryder Scott, "The Supply and Demand Imbalance Leading Into Oil Price Volatility"

Please see Sixteenth Annual Reserves Conference on page 10



The day oil went to *minus $37 and some change*

The WTI oil futures price collapse on April 20 *had never happened in global market history let alone for the most heavily traded benchmark crude oil contract in the world. The close of NYMEX trading that day was -$37.63 a barrel.*

"What took place was 20 minutes of unalloyed chaos, followed by another 24 hours of teeth gnashing, confusion, and bewilderment as the market collapsed in the face of the global Covid-19 pandemic and arguably the swiftest economic downturn the world has ever seen," wrote ***Leah McGrath Goodman*** *in her article, "Inside the Biggest Oil Meltdown in History," published by Institutional Investor LLC, May 06, 2020.*

The 2,500-word article is the most comprehensive chronology of that day, with numerous interviews and background peppering the story behind the plunge. It is posted at https://www.institutionalinvestor.com/article/b1lhy2h328jhpt/Inside-the-Biggest-Oil-Meltdown-in-History.

According to the timeline of the article, the first-ever zero oil trade happened at 2:08 p.m. ET on April 20, during what is typically a "sleepy hour" leading to the daily market settlement. She wrote, "On paper, 83,000 barrels — or 3.5 million gallons of oil — effectively went off the market for free."

The article continues, "At 2:29 p.m. , one minute before settlement, a single May crude futures contract traded at the jaw-dropping price of -$40.32 a barrel, marking the lowest handle ever witnessed in the most liquid crude oil contract in the world — a previously unimaginable nadir."

One of the interviewees during the descent said, "No one really knows what's going on. The screen was just going nuts."

Traders hurried to sell off positions in the near-term May crude oil futures contract because it was expiring the next day and set to mature, Tuesday, April 21.

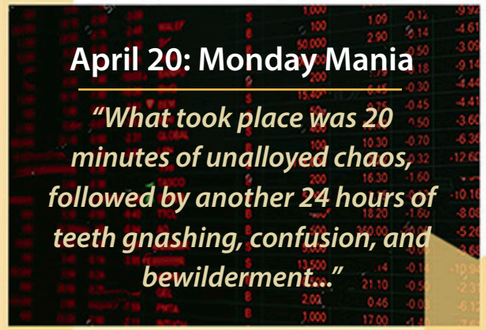
At the same time, Cushing storage facilities had no spare capacity, so sellers had to pay buyers to store the oil, causing the May WTI contract to plummet into negative territory.

In all, 14,913 crude oil contracts exchanged hands at negative prices on April 20, according to data from CME Group, a derivatives marketplace. "In other words, on average, sellers were paying buyers to take oil off their hands at a rate of more than 31 million gallons a minute," wrote McGrath Goodman.

On April 21, WTI closed at $10.01. "In the end, the total amount won — and lost — by oil traders active in the negative price range on April 20 came to well over half a billion dollars," stated the article.

One interviewee said the "futures market demonstrated no convergence with the physical market that day. It demonstrated no convergence with reality."

Some are calling for immediate reforms by the U.S. SEC and the Commodity Futures Trading Commission.



$17.73
8 a.m. (Tokyo)
Price of May forward WTI contract on Monday morning as NYMEX market opens

$15
8:10 a.m. (Tokyo)
NYMEX futures traders start following price drop

<$11
9 a.m. (NY)
The contract price was down 37%, the biggest intra-day drop since the WTI futures started trading in 1982

<$10.35
11 a.m. (NY)
WTI crude passed the low set in the oil bust of 1998

<$10
12:01 p.m. (NY)
Prices slide. By this time, they're already in uncharted territory

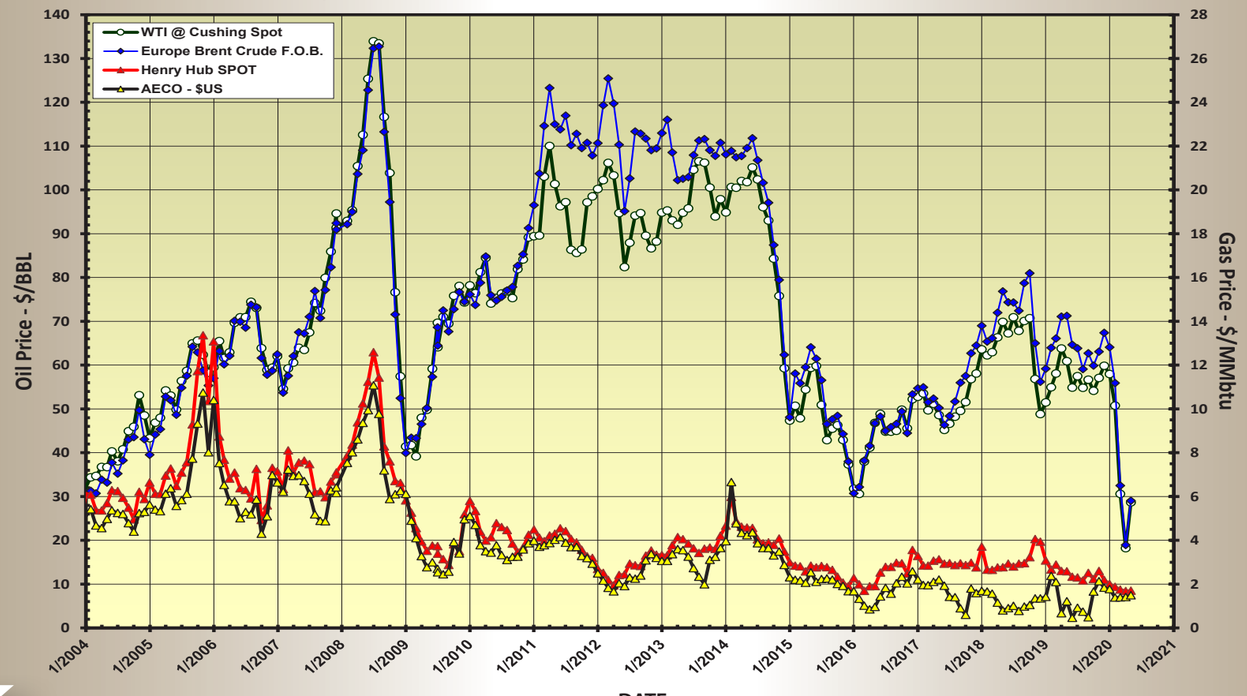
<$1
1:50 p.m. (NY)

<$0
2:08 p.m. (NY)

- $40.32
2:29 p.m. (NY)
Session low

- $37.63
2:30 p.m. (NY)
WTI crude price @ close

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.

Industry bracing for mid-year impairments, reserves writedowns

U.S. shale companies expect a spate of asset impairments in balance sheets this year. Accounting firm Deloitte in June reported that companies could write off as much as $300 billion, which will trigger insolvencies and restructuring.

Analysts, however, may not completely trust those numbers, because oil and gas companies do not report under a single "standardized measure" for impairment testing, which makes use of forward-price assumptions and discounted net present values from oil and gas production forecasts. Lower forecasts result in reserves writedowns.

Accounting and Reserves Evaluations

Companies have the flexibility to handle balance-sheet asset impairments differently. Therefore, company-to-company results are not comparable.

That is the status quo. Oil and gas accountants say the most reliable numbers in financial statements are cash and short-term payables.

Dan Olds, managing senior vice president at Ryder Scott, believes impairment in the oil and gas industry is subject to allowable variances used by reporting companies.

"Some companies use only proved reserves while others use the 2P reserves case, which adds another level of complexity," he said. "When the process allows companies so much discretion in picking a forecast case from which to base estimated future values, inconsistencies are the result."

Dan Olds

Olds is author of SPE technical paper, "Basic Petroleum Accounting for Petroleum Engineers," Society of Petroleum Engineers, No. 162907-MS, 2012.

If the reserves report's values—typically, discounted future cash flows—are less than the net book value of the assets, which is an accounting metric, then the property is impaired, said Olds.

Please see Industry Bracing on page 6

Industry Bracing – Cont. from page 5

Q1 and Q2: Pay me now or pay me later

Keith Myers, president of research at Westwood Global Energy Group (WGEG), wrote an insightful analysis of big differences in recording impairments within the oil and gas industry.

"A significant fall in oil prices would typically trigger an impairment test, but there is considerable management discretion allowed as to the timing, forward oil prices, and discount rates used," he wrote in an article published by *Offshore Engineer* magazine June 16.

At that time, oil prices used in Q1 impairment tests were all over the board.

Some companies recognized the fall in prices while others used year-end 2019 oil price assumptions, as shown in a table accompanying the *OE* article at www.oedigital.com/news/479383-e-p-players-widely-differing-views-on-oil-price-future.

Some companies did not impair their assets in Q1, and are likely to write down asset values in mid-year financial statements, wrote Myers.

Q1 short-term price forecasts for the Brent crude benchmark varied widely, stated the WGEG survey. Gran Tierra Energy Inc. and Talos Energy Inc. used the SEC ceiling-test methodology based on an average price over the previous 12 months, which was $67.50 a barrel, stated Meyers, while Repsol SA was using $65 for 2020.

Bearish companies in 2020 include Equinor ASA, Aker BP ASA, Africa Oil Corp. and Hess Corp. with short-term forecasts ranging from $31 to $33 a barrel based on the forward curve at end-March.

Many long-term oil price forecasts remain unchanged, the *OE* article stated.

Royal Dutch Shell assumes $60 a barrel unescalated while Total SA was at $70 a barrel. Repsol was at $74 a barrel by 2025 while Equinor was at $77 a barrel that year.

Hess Corp. had the lowest long-term Brent oil price assumption at $55 a barrel. BP Plc reduced its long-term oil price assumption for 2021-2050 from $70 a barrel to $55, the lowest in its peer group.

Book value, accounting methods and impairment

To understand how impairments are calculated, understanding book value and full cost (FC) vs. successful efforts (SE) accounting methods is essential.

Olds explained that book values are adjusted to account for capital spending for field development and production of associated reserves through an annual DD&A (depreciation, depletion and amortization) process. Typically, an accountant uses the net book value and a reserves report to calculate a depletion rate and then applies it to annual production to determine book value that was lost because of production.

Olds cited the formula for adjusting book values through a depletion rate calculated as follows:
Depletion rate = book value/reserves; Annual DD&A = depletion rate x annual production.

He also examined how DD&A is treated under both FC and SE accounting methods. Under FC, all exploration and drilling costs are capitalized into a single, full-cost pool for each country. That approach dilutes the financial impact of a discovery or dry hole during the reporting period and results in more stable financial results.

SE companies capitalize drilling costs for discoveries or development wells, but expense exploration dry holes. The pool concept is limited to a single well, reservoir or field. Under SE, a significant discovery or dry hole is more immediately reflected in the financial reporting period.

FC companies factor in all categories of proved reserves in the depletion-rate calculation. SE companies adjust the book value of producing properties using proved developed reserves only, but consider the total proved reserves for amortizing acquisition costs, such as bonus payments or lease acquisitions.

Impairment

Impairment and reserves de-booking processes are different between FC and SE accounting as follows:

- **FC impairment**—Discounted net present values in the reserves report are compared to the net book value (full-cost pool). If the ceiling test finds that the net book value is higher, then it is written down to the discounted NPV. Impairment is more likely for FC companies, because the FC pool may include unsuccessful wells that would be expensed under SE accounting.
- **SE impairment**—Net book value is compared to the reserve report as in full cost, but adjustments can be made. A public issuer can consider changes to expected future prices and costs. An appropriate discount rate can be used. Companies also make adjustments for income taxes.

Early Signs, Future Warnings

Out of the gate first in Q4 was Royal Dutch Shell, which wrote down more than $2 billion on a weaker economic outlook months before the price plunge April 20. Chevron Corp. took a non-cash, after-tax impairment charge of $10 billion in its Q4, which surprised some analysts.

The list of companies taking their lumps for Q1 included Chesapeake Energy Corp., which recognized an $8.3-billion non-cash impairment because the carrying value exceeded the market value as of March 31.

Oasis Petroleum Inc., reported non-cash impairment losses of $4.8 billion for Q1 associated with the plunge in commodity prices. Harvest Oil & Gas Corp. reported $1.6 million of impairment primarily related to the writedown of properties in Michigan to their fair value for Q1.

Zargon Oil & Gas Ltd. announced an $8.54 million impairment loss on its Williston Basin properties.

On June 15, BP Plc warned that it will write off "exploration intangibles in the range of $8 billion to $10 billion" at end of Q2. Others will follow.

For a detailed analysis of petroleum accounting, reserves and impairments, please reference Olds' SPE paper for purchase at www.onepetro.org.

For more information on book values and reserves, please see presentation by Olds at https://www.ryderscott.com/wp-content/uploads/2014/03/RSC-2012-Reserves-Conference_4BookValue_Olds.pdf.

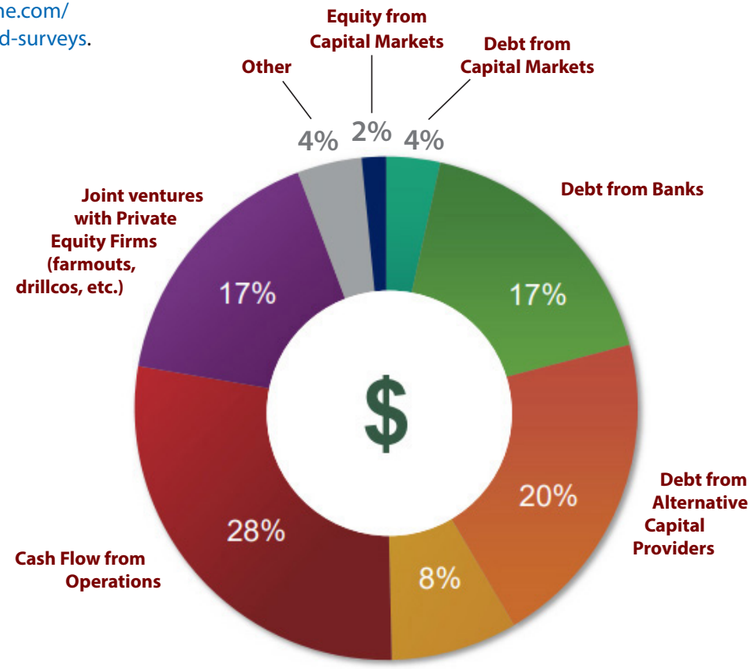
Reserves-based lending survey shows "deep pessimism," says Haynes and Boone

Results of the spring borrowing-base redeterminations survey of Haynes and Boone LLP yielded the following expectations for reserves-based lending:

- Most respondents — comprising producers, oilfield service companies, energy lenders, private equity firms and others — indicated deep pessimism for the spring 2020 borrowing base outlook. This was attributable to "a rapid deterioration in market conditions that started on March 8," stated Haynes and Boone.
- Respondents expect producers to see downward adjustments of 20 percent or more in their upcoming redeterminations.
- Oil and gas companies remain well hedged, which generates a key question for banks and borrowers — what should producers do with these highly "in the money" hedges?
- When compared to the fall 2019 responses, survey participants who see private equity as a source of E&P capital have dropped by nearly 50 percent. They plan to make up the difference with debt from alternative capital providers.
- A growing focus on ESG will be impactful on producers' future access to capital, but the respondents are mixed on the depth of that impact.

For the full survey results, which include charts and graphs, please go to https://www.haynesboone.com/publications/energy-bankruptcy-monitors-and-surveys.

Planned sources of capital for 2020



Source: Haynes and Boone LLP

OTC paper: Private equity, third-party infrastructure will grow GOM

Sandeep Khurana

A head advisor at Ryder Scott, **Sandeep Khurana**, said private equity (PE) firms will continue to turn to creative financing models to increase investments in infrastructure, including tiebacks, in the U.S. Gulf of Mexico.

He helped develop a chart that shows PE taking a bigger bite of facilities costs historically and over the next five years. Khurana was on a team that conducted an in-depth survey and analysis of the evolution of ownership and financing for upstream and midstream infrastructure in deepwater provinces worldwide.

"Whatever may come, there are a lot of opportunities and a foundation here to leap forward in this fluctuating market and rather depressed oil prices," said the leader of the Ryder Scott midstream services group.

He had planned to present at the 2020 Offshore Technology Conference (OTC) in Houston in early May. However, organizers canceled the event for the first time because of the Covid-19 pandemic and health and travel concerns.

By posting a video of Khurana's slides and commentary, OTC 2020 organizers sidestepped the philosophical question, "If a tree falls in a forest and no one is around to hear it, does it make a sound?" OTC videos and associated technical papers are available at www.onepetro.org by searching by paper number, author, subject, etc.

Khurana, with **Justin Rostant** and **Julie Wilson** at Wood Mackenzie, wrote the posted paper, OTC-30806-MS, "Private Equity Financing and Third-party Infrastructure: Future Enabler."

They wrote it before the collapse of oil prices April 20 and the current aftermath. However, Khurana had the benefit of weighing recent events in his video, indicating little had changed in the conclusions of the paper.

The paper and others in the OTC technical-session series took into account historical perspective in keeping with the theme, "Floating Memories – Look Back to Leap Forward."

In his OTC video, Khurana showed since 2014, industry has steadily reduced development capital costs. Innovations, such as digitalization leading to unmanned facilities, are poised to lower breakeven oil prices to below $30 per BOE for life-cycle deepwater developments.

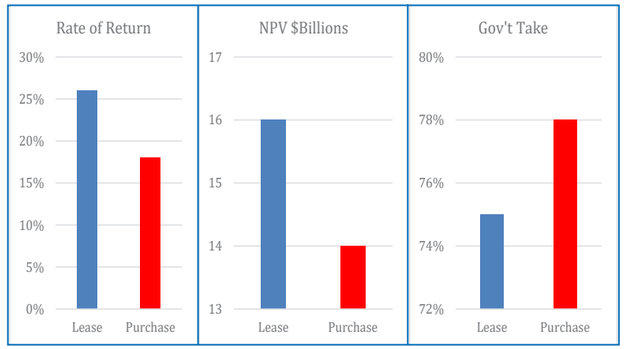
Khurana traced the history of ownership and financing beginning in the late 1980s, when oil companies began building offshore facilities in deeper waters. For deployment in the Campos Basin in Brazil, companies designed and built FPSO (floating production storage and offloading) facilities under contracts with shipyards.

In the 1990s, the model shifted to leasing. Shell was the first operator to start leasing FPSOs then.

"The trend has grown stronger over time, especially among majors," said Khurana. "The decision criterion for an oil company to lease vs. purchase is usually a financial one based on fiscal regime and incentives."

Khurana took a deep dive into financial drivers behind build-or-lease decisions, including balance-sheet impacts, ring fencing, low cost recovery and high value-added taxes. The paper detailed fiscal metrics in Brazil, and concluded that incentives to lease outweigh ownership, considering the low cost recovery and high taxes.

Two of the highest project-cost items are drilling and facility outlays. Khurana analyzed the economics for the Mero field project in Brazil, and identified the ownership structure of the facility that generates the biggest returns to field owners. The authors of the paper also conducted a sensitivity analysis of the field to evaluate returns to the field owner based on either purchasing or

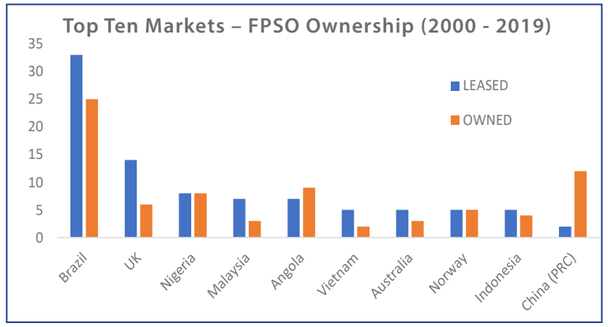


Economic indicators for field owners of FPSO leases vs. purchases (Source: Wood Mackenzie Global Economic Model)

leasing the FPSO, as shown in the above chart.

In Angola, field owners opted for owning over leasing to amortize all pre-investments before paying taxes.

The following chart shows the top ten markets for leased vs. owned FPSOs by country over the past 20 years. A cumulative count for that duration shows 50 percent owned and 50 percent leased.



Ownership decisions during 2000 to 2019
Brazil had more leased vs. Angola with more owned.

In case of early lease terminations or contract non-extensions, service companies may have to deal with minimal residual values of facilities and the potential for high abandonment liabilities. To avoid demobilizations and lay ups, service companies redeploy FPSOs, but this requires field matching with, at times, high capital costs to upgrade.

BW Offshore Ltd. has a successful model to ensure it redeploys its FPSOs to offshore projects. The company becomes the operator. BWO says it looks for opportunities to buy marginal properties from majors and develop them more efficiently at reduced costs.

"This is a total paradigm shift where the oil company turnkeys the project, controls and manages capex and derisks the reservoirs with appraisal wells," said Khurana.

The model worked for redeploying BW's Murphy Azurite FPSO as the Adolo FPSO in 2018 for Dussafu field offshore Gabon. BW Energy is the E&P operator of the field. No oil and gas operations are immune to the market crash of 2020, however.

In late May, BWO recorded a non-cash impairment to the book value of its FPSO fleet and other assets of $233 million for Q1 because of uncertainty on redeployment amid market turmoil and pressure on oil prices.

Of the 15 owned FPSOs, BW impaired six. IPO spinoff BW Energy Ltd. more than halved its 2020 capital-spending program from $250 million to $115 million, of which $49 million was spent in the first quarter.

Last year, BW Offshore planned to use its "repeatable model" after receiving approvals by Brazil to assume participating interests in the Maromba field as the operator. The company also planned to redeploy the Berge Helene to Maromba.

U.S. GOM: Innovation over 20 years

The U.S. Gulf of Mexico (GOM) has been at the forefront of ownership and financing innovation for more than 50 sanctioned FPS (floating production storage) facilities since 1993.

Major oil companies in the U.S. GOM deepwater — a royalty tax fiscal regime — normally purchase facilities rather than lease.

Drivers for decisions to purchase are no ring-fencing, lower costs of capital and accelerated depreciation. With less favorable credit ratings, service companies typically pass on higher capital costs to oil companies.

Leasing may be the only viable option for smaller, capital-constrained oil companies. In the early 2000s, several GOM deepwater developments stalled because of low commodity prices and high upfront capital costs, the paper stated. That was particularly financially distressing to independents and smaller private companies, so to ameliorate that, a new model emerged — the multi-operator approach.

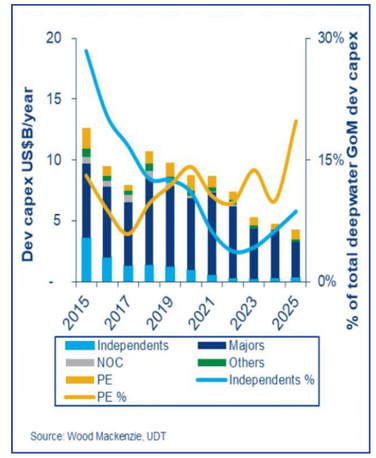
At the same time, third parties invested upfront capital to become owners of the infrastructure and collect monthly fixed fees operators. That reduced risks and freed up capital for independents to focus on core E&P activities.

In 2005, Anadarko Corp. pioneered the multi-operator, third-party FPS approach in the GOM with Independence Hub project. Five independent E&P companies and a midstream energy company collaborated to facilitate the development of six gas fields in the Atwater Valley, DeSoto Canyon and Lloyd Ridge GOM blocks.

Immediate followers with partnering groups contracted third-party FPS facilities in the Marco Polo, Devil's Tower, and Thunder Hawk offshore projects. The repeatable model in 2014 was the Tubular Bells project. Hess Corp. and its partners had a facilities agreement with Williams Partners to construct and operate Gulfstar1 FPS and related export pipeline system.

Private equity and the future

While the annual capital expenditure in the U.S. GOM from PE-backed companies is less than 15 percent, as seen in the chart below, their strategy is to focus on subsea tiebacks with opportunities for higher returns, providing a good fit for PE capital, the paper states.



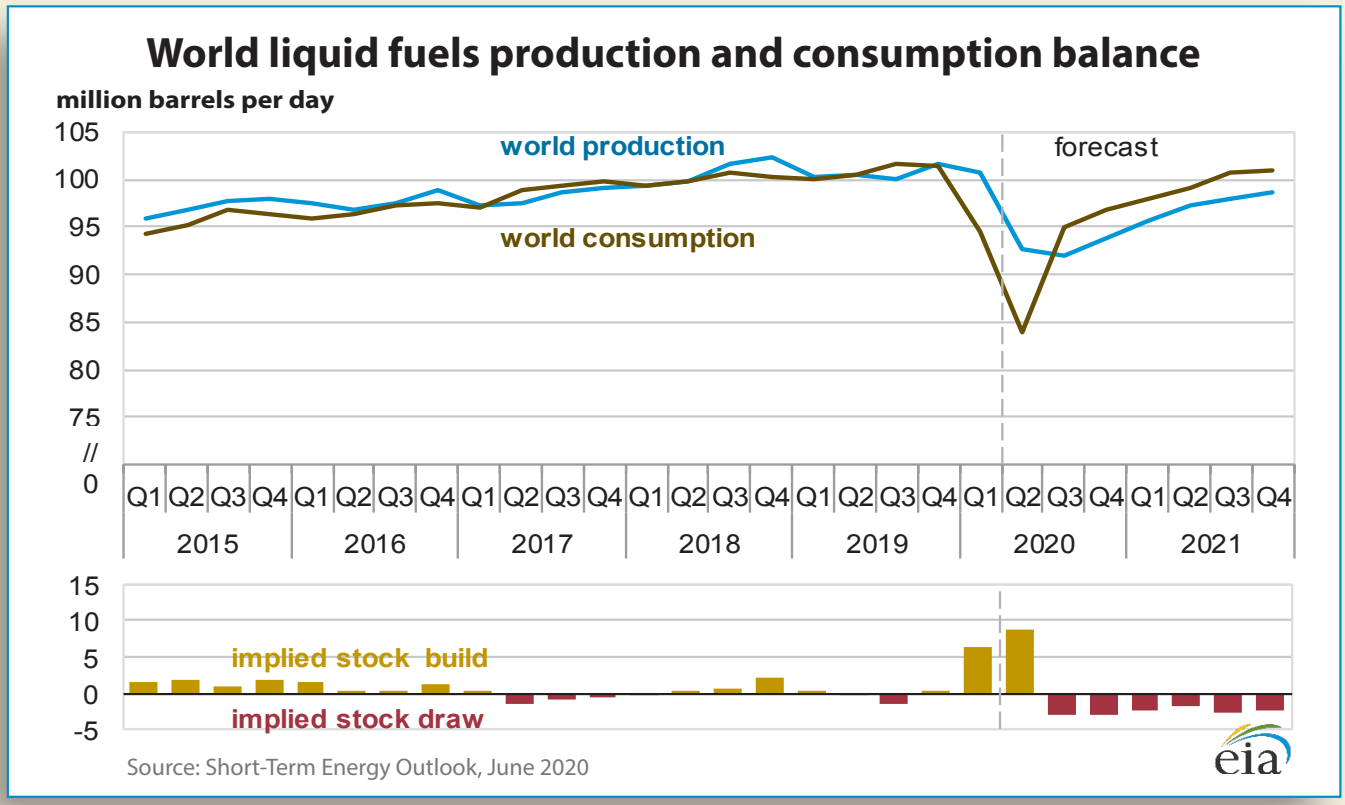
U.S. GOM development capex by company type

These smaller, infrastructure-led projects, usually immaterial to majors, fit very well with the PE model, which requires quick payback. The average cycle time for these subsea tieback projects from discovery to first production is only three years, with some fields able to come online within 12 months of discovery.

Financing of the FPS and export pipelines for the Delta House project four years ago involved PE firm Arclight Capital Partners LLC and LLOG Exploration Co. LLC, the operator. PE-backed infrastructure in the GOM became a repeatable model with the King's Quay FPS project, which is 50-percent owned by Arclight.

The schedule calls for the project to go into service in 2022. Murphy Oil Corp. is the E&P operator and owner of 50 percent, with Ridgewood King's Quay LLC owning the other 50 percent.

"The future could be PE taking both sides of E&P and infrastructure in the GOM to connect the dots — whatever it can for smaller, quick-turnaround developments," said Khurana. "Another possibility is to monetize existing infrastructures. Major oil companies and large independents may just bring in third parties to own the FPS facilities. That way, the FPS can be expanded by third parties and becomes a separate midstream business for them."



In the June Short Term Energy Outlook, the U.S. EIA said it expects that sharper declines in global oil production starting in June and higher-than-expected global oil demand will reduce global liquid fuels inventories an average of 2.5-million BD through the end of 2021.

Sixteenth Annual Reserves Conference – Cont. from page 3

Herman Acuna, executive vice president at Ryder Scott, will make a presentation on "Greenhouse Gas (GHG) Management at an unspecified date after the live webinar." Acuna plans to discuss GHG initiatives in the United States, Canada, Europe and worldwide. Ryder Scott is planning to make his presentation the first on-demand one.

Ryder Scott Promotions

The following personnel at Ryder Scott received promotions: **Brett Gray** to senior vice president, **Gilly Rosen** to vice president, **Anton Siyatskiy** to vice president and **Andrew Wright** to economist.

Publisher's Statement

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Oil & Gas: Tough times, *but we're ready*

Rietz likened today's environment to a "gut punch"

Ryder Scott CEO **Dean Rietz** expressed both concern and hope for the oil and gas industry at the 16th Annual Ryder Scott Reserves Conference on Sept. 16 and 17 via Zoom. He likened today's environment to a "gut punch," calling times tough.

Rietz cited the pandemic, dwindling demand, low oil and gas prices, bankruptcies, continued slander against fossil fuels, unrelenting pressure to reduce carbon footprints and election-year politics.

"We expect bankruptcies to progress throughout the remainder of the year and perhaps into next year as well," said Rietz.

Last year, in his opening remarks, Rietz discussed supply and demand, but said that was "out the window" in the current climate. He referred to annual surveys of conference attendees and their oil price forecasts 12 months out.

Please see Oil & Gas: Tough times on page 2

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Oil & Gas: Tough times – Cont. from page 1

The bar chart on this page shows 2018 and 2019 predictions for 2019 and 2020, respectively.

The plot's normal distribution revolved around a $59-a-barrel prediction last year.

"Only a few folks predicted a price lower than what it is today. It seems the concept, 'lower for longer,' was generally accepted by last year's participants, but no one could have predicted the events leading up to today's price hovering around $40," said Rietz.

In 2018, the plot's normal distribution revolved around a $75-a-barrel forecast by the audience.

"Until we start getting back to 'normal,' perhaps after a Covid-19 vaccine, we won't see an increase in demand anywhere close to recent years," said Rietz.

Changing with the times

Rietz affirmed Ryder Scott's commitment to its clients, given the pandemic, increased demands for green or sustainable energy and the resulting effects on the industry.

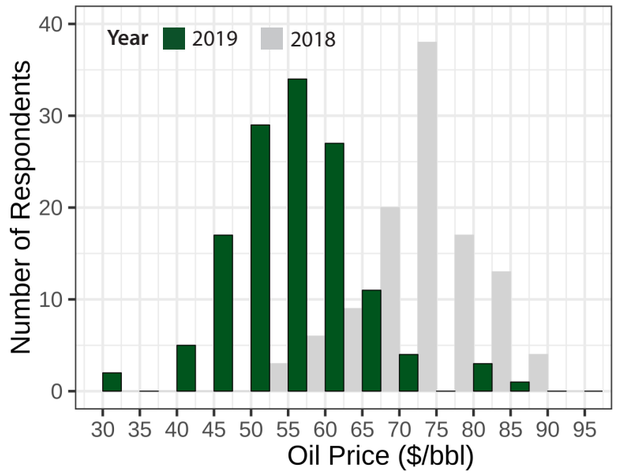
He mentioned several initiatives underway. Ryder Scott is working on a new venture with SLU Enterprise to develop a ratings system and to provide advice on a platform for tradable securities supported with future cash flows of undeveloped Permian Basin acreage.

SLU selected independent consulting firm Ryder Scott to develop the rating system and perform third-party evaluations.

"The Permian Basin has been the most important resource base in the world for nearly a decade, but its historical sources of capital have gone missing," the SLU website states.

Another venture, to be handled by Executive Vice President **Herman Acuña**, will expand services to include greenhouse gas management and sustainable energy consulting.

"We plan to have a major announcement about this in a separate webinar in the next few months," Rietz said.



Ryder Scott plans to assist the upstream and midstream operations of companies in environmental, social and corporate governance (ESG) activities. Deliverables will include independently certified sustainability reports and audits to verify and certify any one of several ESG programs and processes.

"More than 500 attendees to this year's webinar eclipsed previous attendance numbers at brick-and-mortar reserves conferences."

More than 500 attendees to this year's webinar eclipsed previous attendance numbers at brick-and-mortar reserves conferences. The webinar included audiences from Angola, Argentina, Bolivia, Brazil, Canada, China, Colombia, Ecuador, France, Great Britain, Italy, Kazakhstan, Kuwait, Indonesia, Japan, Malaysia, Mexico, Netherlands, Nigeria, Russia, Spain, and UAE.

"For those working some distance away from the greater Houston area, who have always desired to attend but couldn't for a variety of reasons, Ryder Scott extends a very special welcome to you," said Rietz in his opening remarks.

Ryder Scott considered posting videos of the conference to be available on demand, as the July newsletter indicated, but in the interim, the firm changed its plans.

Slide decks from webinar presentations are posted in PDFs at www.ryderscott.com/latest-presentations/.

Comment letters only public source for SEC interpretations of reserves disclosure rules

The U.S. SEC (Securities and Exchange Commission) has not adopted a regular program to disseminate general guidance on reserves reporting rules. In contrast, the Alberta Securities Commission publishes its Oil and Gas Review annually. The review summarizes filings of the previous year and specifies problem areas needing attention.

In lieu of that, the SEC provides feedback embodied in comment letters it publishes on the online public database EDGAR. Although these letters indicate how the SEC staff interprets or expects the rules to apply in a specific case, the interpretations are not intended to be general guidance.

"The letters allow us to understand the thinking of SEC staff," said **Miles Palke**, managing senior vice president, and speaker at the Ryder Scott reserves conference this year.

"Comment letters cannot change the regulations and are not considered definitive for many circumstances. However, they provide insight with an understanding that the SEC issues specific responses to specific filings by specific filers," he said. "Companies (reporting to the SEC) are expected to interpret the rules reasonably and consistently and provide the necessary information based on their interpretations."

Latest comments

Palke said that occasionally, the SEC issues compliance-and-disclosure interpretations to provide guidance on reserves-related issues.

Filers are obligated to respond to comment letters. Generally, the SEC will release all correspondence related to the review, including comment letters, for posting on EDGAR, once the regulator has no further comments.

"Certain details of the correspondence may be redacted and, in some cases, filers may ask for confidential treatment for a period of time," said Palke.

He surveyed comments from May 2018 to May 2020, and put them in categories that show the most frequently cited issues in reserves disclosure oversight. Please see the chart below.

The most numerous SEC comments are related to disclosures and reconciliations.

"Under disclosures, the filer has not, in the SEC's opinion, disclosed enough information," said Palke. "To comply, the filer has to provide year-on-year reconciliation of the changes in reserves with an explanation of why they changed over time."

He has noticed that filers have a propensity to improperly categorize changes or lump them together. "For example, if reserves dropped due to both technical revisions and lower prices, the filer is expected to break them into separate items," said Palke.

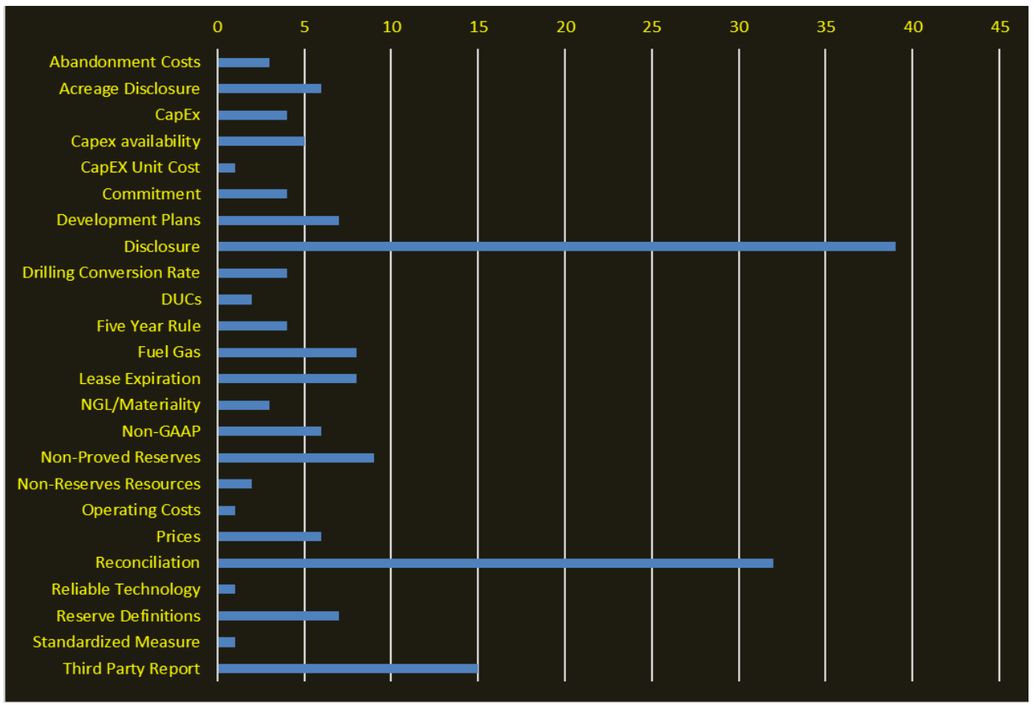
He added that reconciliation also includes instances where the SEC scours a filing and finds numbers that don't agree.

"The disagreement may be between the body of the 10-K filing and the reserves report," said Palke.

He also told the webinar audience that Ryder Scott is winding down support for its SEC Seeker search engine of EDGAR, which is linked via the Ryder Scott website.

"Ryder Scott developed and maintained the Seeker application to facilitate searches in EDGAR filings to find relevant content. Since then, the SEC has improved the searchability of the database," said Palke.

He encouraged Seeker users to shift their focus to EDGAR, and provided a brief demonstration for finding relevant comments on the SEC search engine. Palke outlined those steps in his slide presentation posted at www.ryderscott.com/latest-presentations/.



Before rules changes, SEC excelled at industry dissemination

Before the "modernization" of reserves reporting rules in 2008, the U.S. Securities and Exchange Commission staff was out front with general industry guidance. Twenty years ago, staff members participated in question-and-answer sessions at events sponsored by the Society of Petroleum Evaluation Engineers.

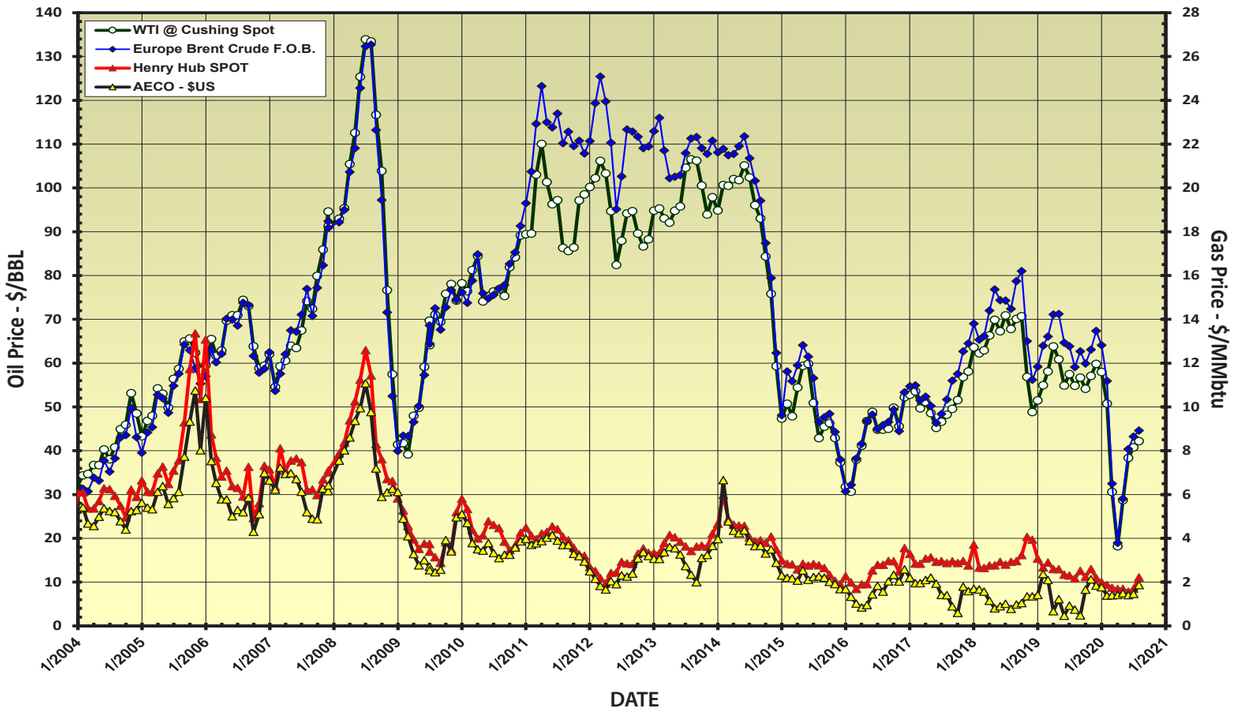
SPEE was the right crowd of evaluators. To be eligible for membership, candidates have to have specific college degrees, 10 years direct experience as an evaluator and, in some cases, state licensing. Members nominate and approve candidates.

In 2000, SPEE sponsored a two-day forum in Houston with SEC engineer **Ron Winfrey** and 160 in attendance. Winfrey took questions and clarified reserves reporting issues, including controversial ones.

Next year in 2001, Winfrey returned with another SEC engineer, **Jim Murphy**. They participated in a second SPEE forum of one day. They addressed issues involving seven actual cases disguised to protect confidentiality. Houston was the location again, and for the remaining forums.

Please see Before rules changes on page 14

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.

Why reserves evaluators should care about CO_2 capture and storage

The panel discussion at the 16th Ryder Scott Reserves Conference in mid-September focused on the operational, financial and research sides of carbon capture in the mid- and downstream sectors. The International Energy Agency estimates that carbon capture and storage (CCS) and other energy efficiencies will have a greater "impact" on reducing CO_2 than renewables by 2040. Carbon reduction is a major component of ESG (environmental, social, governance) programs.

"The core premise of the PRI is to incorporate ESG factors into investment decision-making."

Why should reserves evaluators care about CCS? For one, the financial health of the oil and gas industry may depend on it. Private equity funded producers are trying to assuage growing investor concerns about ESG and specifically, carbon-emission issues.

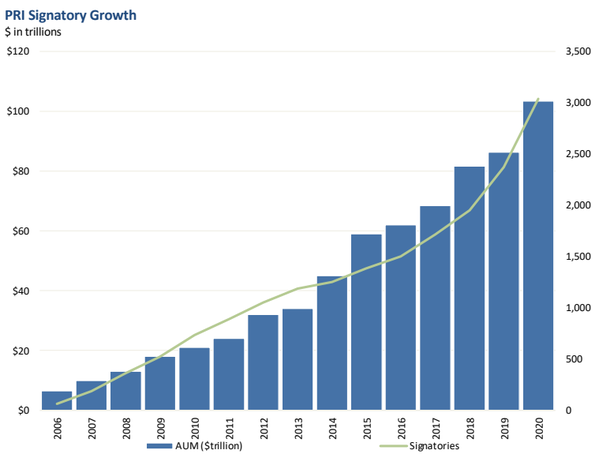
Investors that have traditionally bankrolled oil and gas projects, such as EnCap Investments and Yorktown Partners, are moving into the renewables space. Public companies — such as Total SA, Repsol SA, BP Plc and Royal Dutch Shell — are pledging to cut emissions to "net zero" as their stock prices tumbled during the Covid-19 pandemic.

Increasingly, public and private funding for E&P projects will come from "impact investors" looking to support oil and gas companies that reduce their environmental footprints and manage CO_2, a major greenhouse gas (GHG).

Morgan Stanley

Capital Markets Perspective

Increasing Focus on Responsible and Sustainable Investments



More than 3,000 organizations have signed up for the Principles for Responsible Investing (PRI). "Those asset owners and managers control more than $100 trillion of capital globally," said panelist **Logan Burt**, managing director at Morgan Stanley Energy Partners. See the chart below.

The core premise of the PRI is to incorporate ESG factors into investment decision-making.

Burt also said asset managers have mandates to invest in companies with sustainable business practices. Over the past six years, those investments have more than doubled and now account for more than $30 trillion in assets under management.

The two most pressing GHG issues in the upstream sector are methane emissions and carbon capture projects, he said.*

Why it matters

Engineers and earth scientists have extensive opportunities to study hundreds, even thousands, of different oil and gas reservoirs.

"The two most pressing GHG issues in the upstream sector are methane emissions and carbon capture projects," Burt said.

"Some may have rock and fluid properties where CO_2 injections offer the likelihood of enhanced oil and gas recovery," said moderator **Ron Harrell**, chairman emeritus at Ryder Scott. "They may offer underground storage, sequestration or aquifer-disposal opportunities as well."

Applied technical expertise has fueled the development and deployment of carbon-handling technologies. "Energy professionals are naturally positioned to lead this effort through their technical knowledge of gas separation, CO_2 transportation as well as geologic storage," said Burt.

He also discussed the 45Q federal tax credit recently released by the U.S. Treasury Department. It allows companies to claim a tax break for investments in carbon capture and sequestration projects.

The credits are $50 per metric ton of CO_2 for projects that sequester carbon and $35 per ton for projects that capture carbon and use it in enhanced recovery projects. The credits, effective from the date of installation, are valid for 12 years and transferable.

"Transferable credits are very helpful in raising financing and encouraging JV partners for CCUS (carbon capture use and storage) projects," said Burt.

The panelists generally agreed that $35 per ton is an insufficient incentive for EOR projects.

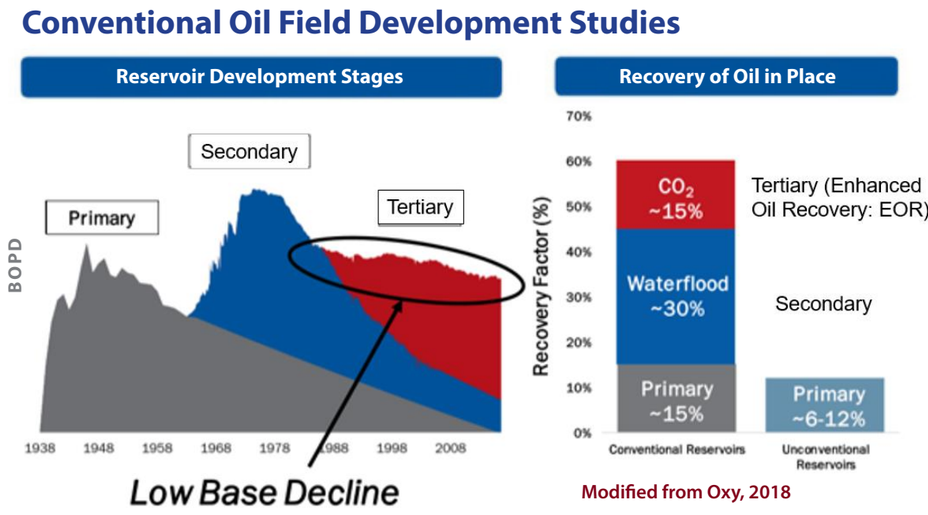
Currently, energy companies, across the globe, have planned 30 new CCUS projects that would more than double capacity over the next decade. More than 60 percent are slated for permanent geologic storage.

Development of carbon-handling technologies is robust in North America, not only because of the geology in the U.S. and Canada, but because the transportation infrastructure is in place.

Sequestration and EOR

John Hessenbruch, retired from Occidental Petroleum Corp., focused on carbon sequestration with EOR development. He showed a slide of conventional oilfield development strategies using primary/secondary/tertiary recovery as follows:

"Using tertiary recovery, as most of you know, involves



Modified from Oxy, 2018

CO_2 implementations," said Hessenbruch. "It has been demonstrated that up to 15 percent of the remaining oil in a reservoir can be produced using these techniques."

Producers in the U.S. have implemented more than 130 EOR programs using CO_2. As an example of a closed-loop system, 40 percent of the CO_2 is sequestered back into the reservoir while 60 percent is produced through the wellhead, recycled and reinjected into the reservoir to improve recovery.

Hessenbruch said 13 companies — IOCs and NOCs — have pledged $100 million each to support the Oil and Gas Climate Initiative investment fund launched in 2014. The goal is to reduce manmade GHG emissions worldwide, including upstream methane intensity to 0.25 percent by 2025.

Another chart showed leading companies in the U.S. with CO_2 EOR and sequestration projects, such as Occidental Petroleum Corp., Denbury Resources Inc. and Kinder Morgan Inc. The chart graphed the number of CO_2 injection wells vs. number of CO_2 projects.

Academia and Research

Christine Ehlig-Economides, professor of petroleum engineering at the University of Houston, reviewed the efforts of academics in CO_2 capture and management. She cited major funding sources for university research comprising the U.S. Department of Energy (DOE), National Energy Tech Lab (NETL), National Science Foundation (NSF) and industry consortia.

"It's rather attractive to work with NETL, because funding is usually in collaboration with industry," she said. NETL funding focuses on carbon capture, advanced storage, storage infrastructure and carbon use and reuse.

For private funding, Stanford University and Columbia University have major CCUS programs. In some cases, they are leveraged with the DOE and NSF. Columbia offers an MS degree in carbon management and Heriot-Watt University in the U.K. offers an MSc degree in CCS.

Ehlig-Economides concluded, among other observations, that natural gas with CCUS offers carbon neutral electricity. Furthermore, CCS and CCUS depend on core petroleum engineering skills.

Slide decks for this discussion and for all webinar presentations are posted in PDFs at www.ryderscott.com/latest-presentations/.

** Last year, Permian Basin methane emissions from oil and gas production were estimated to be 2.7 million tons per year, representing the largest methane flux ever reported from a U.S. oil/gas-producing region. Methane is at least 25 times more potent at trapping the earth's heat than CO_2.*

Heat-induced microfractures have potential to boost shale gas recoveries economically

Will thermally induced microfractures stimulate incremental tight gas production enough to justify enhanced recovery costs? Without deployment and rigorous field testing, the oil and gas industry has more questions than answers.

With budgets too lean for trial-and-error in the field, the North America industry is turning to modeling to uncover clues on the feasibility of thermal microfracturing.

A recent study examined "Thermally Induced Microfractures and Improved Recovery from Shale" in SPE Paper No. 200457-MS, 2020. By applying heat to shale and creating thermally induced microfractures, the authors mimicked processes that are naturally occurring.

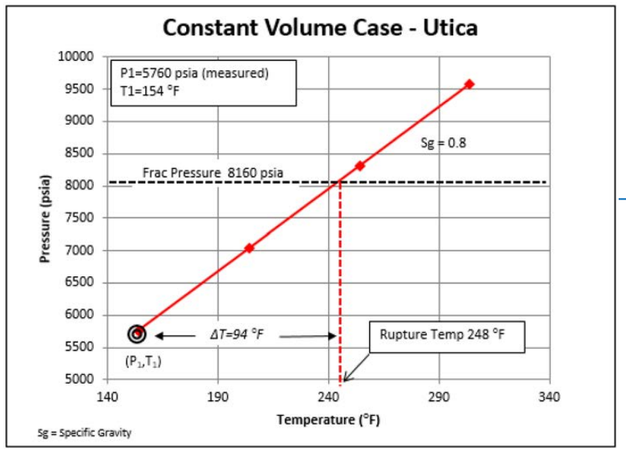
Numerical modeling clues

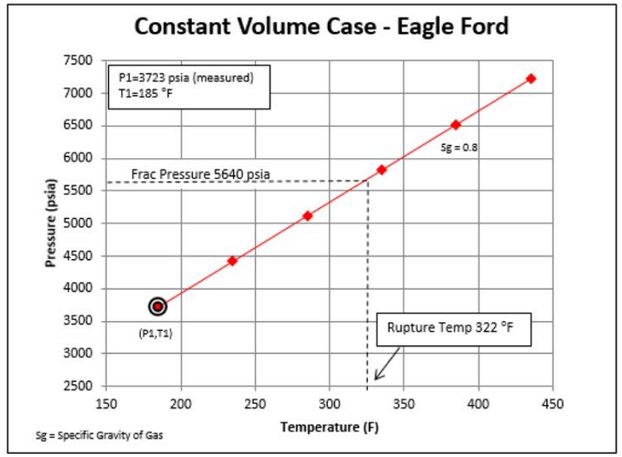
Former and current Ryder Scott petroleum engineers **Don P. Griffin**, retired from Ryder Scott, and **Dean C. Rietz** and **Miles R. Palke** at Ryder Scott — collected geological and well data from the Utica and Eagle Ford shale plays and used a modified ideal gas law and linear heat-transfer equation to investigate thermal recovery of gas from microfractures.

Specifically, the authors of the paper sought to answer the following questions: What incremental temperatures are needed for the pressure within the confined pore to rupture that pore? What time frames are needed to heat a significant area of the matrix to rupture temperatures? What are the distances that microfractures can be induced to form within a timeframe?

Griffin et al. assumed linear heat transfer in hydraulically fractured wells and radial transfer for unstimulated wells.

They plotted pore pressure vs. temperature for a range of specific gas gravities for the Utica and Eagle Ford shale plays in an equation-of-state approach.





The chart shows reservoir parameters at the gas-oil contact and assumes a specific gas gravity (Sg) of 0.8. In contrast to the Utica, the Eagle Ford shale has relatively high temperatures and low pressures near its 6,000-ft deep gas-oil contact. The required temperature to rupture a confined pore was found to be 322°F — an incremental temperature increase of 137°F above the reservoir temperature (T1) of 185°F.

Griffin et al. considered heat sources, operational issues and various applications.

"If it can be demonstrated that the creation of thermally induced microfractures in shale leads to improved hydrocarbon recovery and economics, then many currently uneconomic properties may become worthwhile," stated Griffin et al.

They examined hydraulically fractured and drilled-but-uncompleted properties as well as areas where fracing was banned.

They stated that thermally induced microfracturing has the potential to improve the economics in properties with the following characteristics:

- Lower gravity, higher viscosity oils
- Structural limits or lease restrictions requiring shorter lateral lengths
- Productive shales deeper than currently developed

Griffin et al. investigated the following heat sources: air injection, steam injection and electrical heating. They did not evaluate microwaves.

The chart shows reservoir parameters at the gas-oil contact and assumes a specific gas gravity (Sg) of 0.8. The estimated required temperature to rupture a confined pore is 248°F — an incremental temperature increase of only 94°F above the 154°F initial reservoir temperature (T1).

Findings for Linear Heat Transfer

In one to seven days, thermal operations may be able to create microfractures extending one to five feet from a heating source.

- The required incremental temperatures, relative to the reservoir temperature, are low and may be less than 100°F in some cases, e.g., the Utica shale.
- The extension of this work to light oils appears to be promising based on the results of high specific gravity gases as proxies.
- The authors investigated sustained heating sources of 500°F and 800°F and identified two mechanisms to deliver heat — air and steam injection. They did not consider electrical heating.
- Hydraulic fractures should provide the permeable conduits needed to transport heat significant distances from the wellbore.
- Creating structurally weak, microfractured zones a few feet deeper than the existing fractures appears feasible. Such zones can provide entry points (soft spots) for hydraulic fracture treatments to contact new reservoir matrices to increase ultimate recoveries of wells.

Unstimulated well – Radial Heat Transfer

- Thermally induced microfractures in the shale matrix before hydraulic fracturing may be beneficial.
- Microfractures may be an optional stimulation in areas where hydraulic fracturing is banned or not feasible.

The 20-page paper has 17 charts/illustrations, 14 references and numerous equations and formulas used in the model. It is available at www.onepetro.org.

After 22 years, print edition of *Reservoir Solutions* discontinued

Ryder Scott discontinued the print edition of *Reservoir Solutions* newsletter beginning with the July issue. The Covid-19 pandemic and proliferation of virtual home-based offices have rendered printed business-to-business (B2B) materials semi-obsolete.

"We may bring back the printed version as business operations globally go back to normal," said **Mike Wysatta**, public relations manager.

The hard-copy publication made its way to thousands of offices around the world via domestic and international mail for 22 years.

Ryder Scott continues to email the publication. To receive the e-newsletter, please send business card information to Wysatta at mike_wysatta@ryderscott.com. Canadians are required to opt-in to receive B2B emails.

In addition, the newsletter is posted at the Ryder Scott website at www.ryderscott.com/latest-newsletter/. Over its run, the hard-copy *Reservoir Solutions* was referenced by the *Wall St. Journal, Oil & Gas Journal* and other business and trade publications.

Recent studies measure bias in production forecasts

Proved reserves filed with the SEC were within 1 percent of actual reserves, one study reported

Historical oil and gas production has not measured up to production forecasts, say industry "scorekeepers." They say that on average, companies filing with regulators have let bias creep into reserves estimates and production profiles. Compounding the situation is few companies look back at production records to compare them to forecasted numbers to recalibrate, according to these researchers.

For estimated future production to be reliable, operators have to follow a development plan and drilling schedule. An operator may veer from its plans for various "unforeseen" reasons, including poor drilling results, new well and other technical information, mid-year budget revisions, increased costs, decreased commodity prices, transportation bottlenecks, new regulations, mechanical failure, divestitures, acquisitions, change in ownership and direction, change in drilling priorities, delays by service companies, delays for government approvals and even pandemics.

All that makes recalibration more difficult. In addition, bias does not necessarily play a role in 100 percent of extraneous factors that change company plans, execution and therefore, forecasts.

This article will summarize recent findings of two surveys on the effect of bias in reserves and production forecasts.

One surprising conclusion was that proved reserves estimates filed with the SEC were within 1 percent of actual reserves, although this says nothing about outliers and ranges of reserves values. By definition, estimates of proved reserves have at least a 90-percent probability that the actual amount produced will equal or exceed the estimate.

Authors of the paper, "Technical Revisions Reveal Overconfidence in U.S. and Canadian Reserves Estimates," SPE Paper No. 201116-PA, stated the following:

"Because U.S. companies are not required to distinguish between (1P and 2P) categories, their single estimates end up somewhere in between, and apparently, closer to the P50 value. The U.S. 1P estimates disclosed seemed to satisfy only the certainty criterion for 2P reserves," the authors stated, while recognizing other possible causes.

The U.S. data set covered more than 10 years of information during 2007 to 2017 on 32 companies, raising questions as to what constitutes a representative sample size of public issuers in the U.S. market. The data set was limited because only companies, with revisions of previous estimates and revisions caused by price variations, fit the survey design.

"The U.S. analysis could be biased toward companies that provided this information," stated the authors.

SEC-case reserves reports

Several press reports this year have focused on questionable disclosures of reserves and production forecasts, especially in the Permian Basin, where infill or extension wells are robbing parent wells of pressure and production.

Weighing in on the topic, CEO **Dean Rietz**, said, "We strive to keep our clients compliant with SEC reporting rules while documenting full value of their assets as permitted. SEC-case proved reserves are considered conservative by many."

Producers plan their business cases, including field development projects, on 2P (sum of proved and probable) reserves, not proved.

"We look for consecutive, upward, year-to-year reserves revisions in proved reserves since we know the SEC frowns on the opposite. We know we are doing a good job, if the forecasts are not far off from actual production and upward revisions are not significant," said Rietz.

Bias: Overconfidence and optimism

Quantifying bias in decision-making is not a recent trend. Researchers have measured bias in reserves disclosures for 44 years, beginning with **E.C. Capen**, who recognized tendencies for overconfidence and optimism and published his findings in the *Journal of Petroleum Technology*.

Before that, psychologists **Amos Tversky** and **Daniel Kahneman** introduced the notion of cognitive biases in 1972.

Biased thinking and decision-making are rooted in human nature. They arise in budget-justification processes. Incentives and bonuses for meeting reserves targets encourage bias. The causes for bias include motivators toward high-side forecasts, excessive pride of ownership, emotional carryovers, delusion and deception.

The upstream sector has distilled the reasons for bias to two measurable human tendencies — overconfidence and optimism.

Overconfidence

Humans, including reserves evaluators, have a natural tendency for overconfidence, which is an underestimation of uncertainty. Evaluators gauge uncertainty levels in their production forecasts to reflect a range of possible outcomes from the P10 high to the P90 low.

The ability to do this objectively and generate reliable estimates is directly related to the overconfidence/underconfidence continuum.

An overconfident evaluator has a narrower range of possible outcomes, leaving little room for a missed call at early field development stages when data is insufficient.

Optimism

Optimistic forecasts give greater weight to the upside. Evaluators can develop optimistic forecasts by reacting to motivators or by overlooking human error. Underestimating downside causes unpleasant surprises — more downtime than anticipated, longer-than-expected durations for drilling and completions and lower-than-expected actual oil production.

Pessimism, on the other hand, is responsible for undervaluing oil and gas assets. That bias handicaps a company in trying to take advantage of opportunities in acquisitions and divestitures and in portfolio management.

In the A&D world, sellers seldom undervalue assets. It is widely known that "seller's reports" boost reserves volumes to the high side to entice buyers. Taken to an extreme, biased reports underpin "pump and dump" schemes.

Bias in Charted Territory

Reserves engineers don't have to take a Psychology 101 course to realize underlying human tendencies get in the way of objectivity. Certainly, the evaluation sector has attempted to reduce bias by increasing reliance on automated routines, machine learning, blind fitting and artificial intelligence, which has been an option in decline-curve analysis programs for 40 years. The problem with black boxes is bias-influenced, erroneous assumptions and notoriously

Please see Recent studies measure bias on page 12

Recent studies measure bias – Cont. from page 11

bad data — garbage in, garbage out — can skew model results.

The chart, opposite, shows an estimated reserves distribution represented by the red curve. It is overconfident with a narrower estimated probability range than the true distribution (blue curve). Ideally, actual reserves fall within the P10/P90 range approximately 80 percent of the time.

The curve also has shifted to the right of the mean P50 value of the true distribution, indicating an optimistic forecast of reserves.

Quantitative analysis

Through quantitative analyses, two Society of Petroleum Engineers technical papers, finalized this year, studied the effect of bias in production forecasts and reserves.

One of the papers, peer approved in February, outlines due diligence procedures for evaluators, investors and regulatory agencies.

The SPE paper, previously cited in this article, was written

"...proved reserves estimates filed with the U.S. Securities and Exchange Commission were within 1 percent of actual reserves." — Gomez et al.

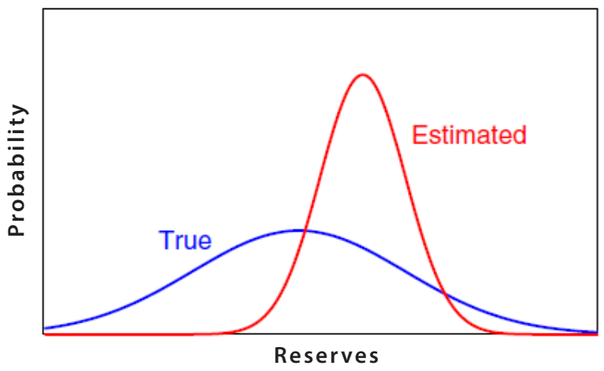
by first author **Diana Gomez** at Texas A&M University. Professor **John Lee** is also an author as well as **Duane McVay**, both at Texas A&M.

They analyzed bias in 1P or P90 reserves reported to the SEC and Canadian Securities Administrators (CSA) as well as 2P or P50 reserves also filed with the CSA. Public issuers in Canada report proved and probable reserves under National Instrument 51-101.

As previously stated, Gomez et al. tracked technical revisions (TRs) from reserves reconciliation reports during 2007 to 2017. They analyzed the reliability of a group of probabilistic assessments on calibration plots to compare the number of actual outcomes to the probabilities of outcomes.

Their tracking of TRs allowed for the review of changes attributable to "the skills and practices of the assessors" with no effect from economics, including price, a major change agent. The authors use the term ROTP (reserves other than price). A common industry term is "technical reserves." However, that expression ignores that evaluators estimate reserves under economic limits.

The method presented by Gomez et al. may also prove to be valuable to the business and trade press and to financial analysts who follow public oil and gas companies in U.S. markets. While filers in Canada report TRs separately, filers in the U.S. market combine technical and economic revisions,



Estimated reserves distribution that is overconfident and optimistic.

making it difficult to isolate TRs.

To overcome this, Gomez et al. calculated ROTPs by subtracting price-related revisions from revisions of previous estimates. The difference is desired TRs are subject to some assumptions.

They stated, "TRs occur primarily because of new subsurface information acquired over the year." As examples, they cited production data, new wells and test data.

Gomez et al. examined TRs by year, company and company size. For companies reporting to Canada authorities, the authors evaluated TRs by fluid type (light/medium oil, heavy oil and gas) and resource type (conventional vs. unconventional). They found several relationships between reliability and categories.

The other paper, "Production Forecasting: Optimistic and Overconfident – Over and Over Again," (SPE Paper No. 195914-MS) was also peer approved in February. **Reidar B. Bratvold** at the University of Stavanger (UiS) is the first author. Also contributing were **Erlend Mohus** at the UiS and **David Petutschnig** and **Eric Bickel**, both at the University of Texas.

They analyzed private filings received by the Norwegian Petroleum Directorate (NPD). Bratvold et al. reviewed initial annual oil production forecasts at the time of the financial investment decision through the fourth year. Several international oil companies have a sizable presence in Norway.

The authors started with company filings on 85 oil and gas fields. They eliminated 30 fields that did not produce oil, had poor or missing associated data, experienced startup delays and had associated data past 2017. Oil production was the only focus.

In their paper, the authors did not comment on any effects from reducing the sample size. In some cases, a select group of qualified fields may not represent the larger, unculled population.

Bratvold et al. tracked technical revisions on the fields to

compare probabilistic estimated (P90/mean/P10) volumes to actual production. In total, they analyzed 549 forecast years from 55 oil fields in the Norwegian continental shelf.

The paper offers a method to reduce bias by encouraging and rewarding evaluators for providing unbiased forecasts. Bratvold et al. cited one method, reference-class forecasting, that provides an outside view of a given project by referencing past comparable projects. They plan to elaborate on that method in a subsequent paper.

Referring to his paper recently, Bratvold said, "We argued that there are two categories of biases: cognitive and motivational. We did not argue that one is more important than the other. However, we did suggest that motivational biases stemming from organizational structures and incentive systems may be significant."

Several disciplines depend on forecasting and refining their models over time.

"Weather forecasting …has experienced significant improvements over the last two decades: 7-day forecasts made today are as accurate as 5-day forecasts 22 years ago," stated Bratvold et al. "Unfortunately, in the oil and gas industry, the development of probabilistic forecasting systems has not been accompanied by commensurate effort in developing procedures to assess the performance of …forecasts."

Differentiation between deterministic and stochastic methods is a distinction without a difference to Gomez et al.

"Reserves estimates are probabilistic assessments regardless of whether the reserves are estimated deterministically or probabilistically," they stated.

Bratvold et al. reviewed fields operated by companies under the NPD resource classification system. It requires companies to file petroleum volumes in low, base and high uncertainty categories.

Although base-case estimates are calculated using deterministic or stochastic methods, all forecasts they used were probabilistic.

Gomez scorecard

- Gomez et al. found that filers in Canada overestimated 1P reserves and underestimated 2P reserves. U.S. filers over estimated reserves more often than Canadian public issuers.
- Filers in U.S. markets reported positive revisions of 51 percent for 1P reserves, a significant departure from the 90-percent reasonable certainty level in definitions of proved reserves. The irony: Proved reserves estimates were within 1 percent of actual reserves.
- U.S. filers were neutral to completely overconfident and moderately to completely optimistic.
- Overall, filers in Canada were moderately overconfident and slightly pessimistic.
- Canadian filers showed no improvements in overconfidence or pessimism in reserves reconciliations over 11 years. U.S. filers do not disclose the data necessary to track the two components of bias.

Bratvold scorecard

- Bratvold et al. found an 84-percent chance that the actual production in the first four years will be less than the P50 (mean) forecast, and a 59-percent chance it will be less than the P10 forecast.
- Empirical data shows there is only a 31-percent chance that the actual production will fall within the P10-to-P90 range.
- The production shortfall relative to production forecasts is as poor now as it was 22 years ago.
- There were no signs of performance improvements, despite advances in uncertainty modeling, which suggests biased input is at work.

Both of these papers outlined assumptions and hypothesized likely reasons for bias. The authors defined the scope and design of the surveys, detailed their procedures, and presented instructive charts and graphs. Gomez et al. analyzed the relationship between bias and company size, product type, etc. The papers are available for purchase at www.onepetro.org.

Before rules changes – Cont. from page 5

In 2002, SPEE hosted its third forum with the addition of division supervisor **Roger Schwall**. Industry experts urged the SEC to allow companies to book proved reserves from Gulf of Mexico deepwater discoveries without having to conduct costly, unsafe production flow tests.

In 2003, Schwall, Murphy and Winfrey took questions from an audience of 200 at the fourth SPEE forum. Schwall said that industry's reliance on so-called "can't-miss" technology had resulted in reserves writedowns over two preceding years.

That was the last SPEE reserves forum with the SEC. At an event organized by the Energy Forum in 2004, Schwall made a major announcement — in lieu of a flow test, the SEC decided not to object to the use of seismic and well data to justify booking proved undeveloped reserves from GOM deepwater discoveries.

Over the past 16 years, the SEC has been largely missing in events designed to clarify regulatory reporting for the industry. **John Hodgin**, a petroleum engineer at the SEC, spoke at a 2015 technical session and 2016 annual meeting, both hosted by SPEE.

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 116 employees, including 76 engineers and geoscientists, Ryder Scott has the capability to complete the largest, most complex reservoir-evaluation projects in a timely manner.

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