RESERVOIR SOLUTIONS
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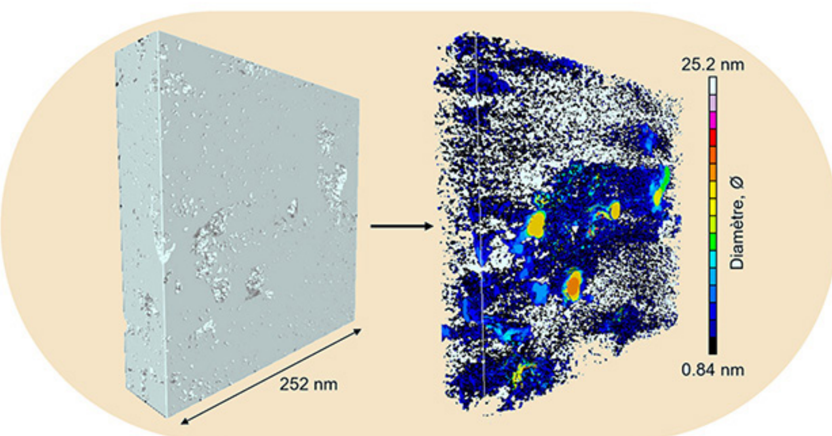
3D imaging of kerogen to improve production forecasts, MIT researchers say

"More accurate predictions of how much oil or gas can be recovered from any given formation" can be achieved through electron tomography of kerogen, said researchers at the Massachusetts Institute of Technology last October. They have used the imaging technique to generate 3D images of the nanostructure of pores in an organic component of oil and gas source rocks with 50 times more detail than previously achieved.

The 3D images have a resolution of less than 1 nanometer or one-billionth of a meter. Previous attempts to study kerogen structure had never imaged the material below 50-nanometers resolution, the researchers said.

The technical paper is posted on the website of the National Academy of Sciences at https://www.pnas.org/content/pnas/early-/2018/11/14/1808402115.full.pdf



Using electron tomography, Pellenq et al probed a kerogen sample to study its internal structure. At left, the sample as seen from the outside, and at right, the detailed 3D image of its internal pore structure. Image credit: MIT News Office.

The industry has long known that thermal maturity of kerogen is a key to its productivity and that pore structure and its interactions with fluids govern the mechanisms involved in hydrocarbon production from shale.

"Our 3D reconstructions confirm the formation of nanopores and reveal increasingly tortuous and connected pore networks in the process of thermal maturation," the study stated. "Relatively immature kerogen tends to have much larger pores but almost no connections among those pores, making it much harder to extract the fuel. Mature kerogen, by contrast, tends to have much tinier pores, but these are well-connected in a network that allows the gas or oil to flow easily, making much more of it recoverable."

In electron tomography, a small sample of the material is rotated within the microscope as a beam of electrons probes the structure to provide cross-sections at one

Please see 3D imaging on page 12

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Oil prices drop to $46 in December, analysts rejigger price decks

Starting in November, the only industry news was oil price. And news it was, as many were caught by surprise. On Nov. 5, the United States reimposed economic sanctions on Iran but gave eight of Iran's biggest oil and gas customers — China, South Korea, Taiwan, India, Greece, Turkey, Japan and Italy — waivers.

"It was only at the start of October that analysts were wondering if oil would soon cost $100 a barrel. Then a trap door opened and oil prices have been in a rapid descent since, losing nearly a third of their value in about eight weeks," the *Wall Street Journal* reported Nov. 27.

Market sentiment is difficult to predict and "turns on a dime." With the "lower for longer" price downturn still fresh on the minds of Big Oil, reality set in for international oil companies (IOCs) ready to test their new financial discipline.

> *"Then a trap door opened and oil prices have been in a rapid descent..."*
> *– WSJ*

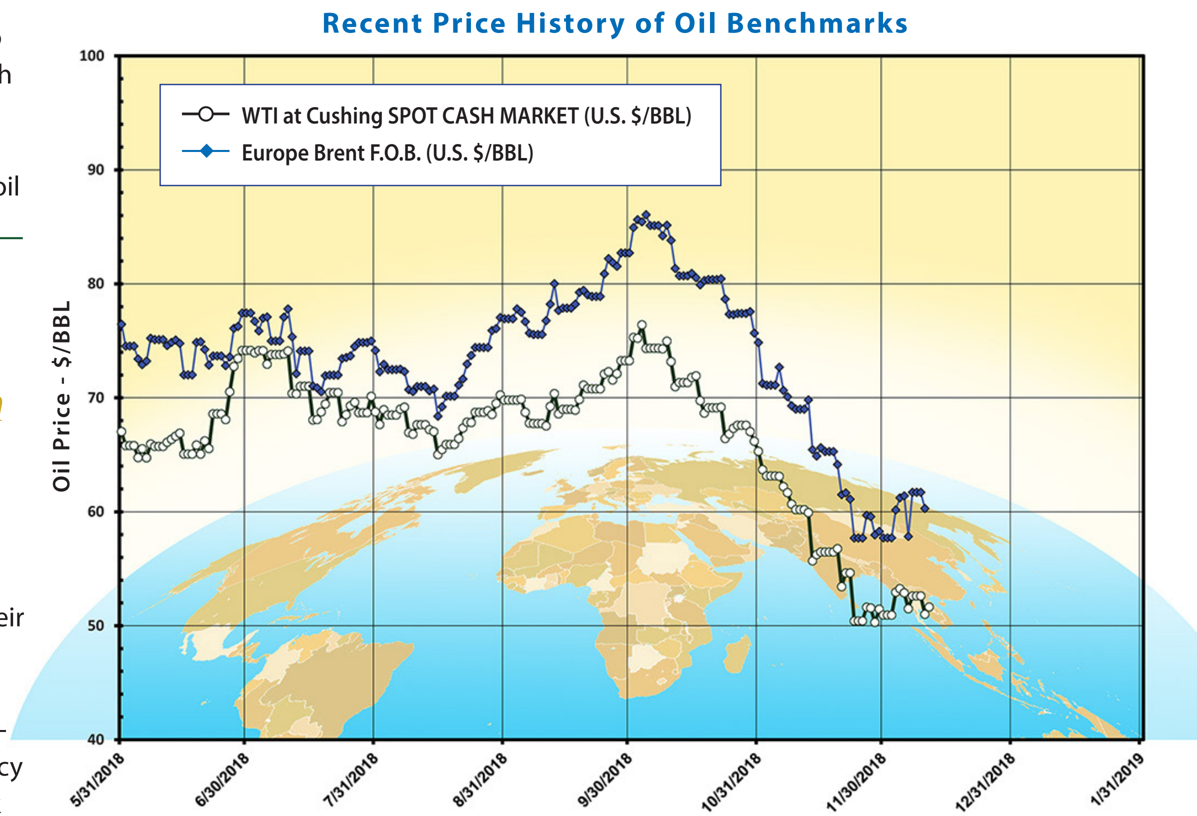
On Nov. 6 — a day after the sanction waivers were effective — the U.S. Energy Information Agency (EIA) released its monthly outlook stating that in 2019, West Texas Intermediate (WTI) would average $65 a barrel, which is close to last year's average of $65.56. Please see "Average annual oil price for SEC reporting soars 28 percent," on next page.

By Nov. 26, three weeks after the waivers, WTI price was $51 and some change, down 30 percent over the recent high. Three days later oil crashed below $50 a barrel for the first time in more than a year as Russia did not commit to supply cuts, and U.S. crude stockpiles rose 3.58 million barrels in the longest run of gains since November 2015, reported *Bloomberg*.

Adding to the volatility and market uncertainty was a U.S.-China trade war that caused stock markets worldwide to plunge in December. The basics of this latest oil price crash are similar to those discussed in a *Forbes* magazine article, "The Next Oil Price Collapse," published in December 2017.

"The price collapse could occur in response to a bearish U.S. stock market, especially presaging a recession; cheating by Iraq or Russia; or U.S. oil shale production appearing so robust as to threaten OPEC's long-term market share," reported **Michael Lynch**, an energy analyst and contributor to *Forbes*.

On Nov. 30, U.S. oil production, boosted by prolific Permian Basin output, reached an all-time high at 11.7-million barrels a week, adding to the worldwide supply glut, the EIA reported.



Oil prices started their precipitous fall in early October which continued through December.

Oil prices spiked, with WTI holding at more than $53 a barrel, on Dec. 7 after Iran agreed to an OPEC oil production cut of 800,000 B/D, and Russia and non-OPEC producers agreed to curtail 400,000 BOPD — a 1.2 million BOPD overall cutback.

On Dec. 17, oil dipped below $50 a barrel, which analysts attributed to an oversupply in the U.S. market. The dip became a valley on Dec. 20 as stock markets plunged further and WTI oil prices plummeted more than 4 percent to $46.21 a barrel, the lowest level since August 2017. The Dow Jones Industrial average dropped to a 14-month low entering a bear market.

Delaware Basin tops USGS list of oil and gas resource plays

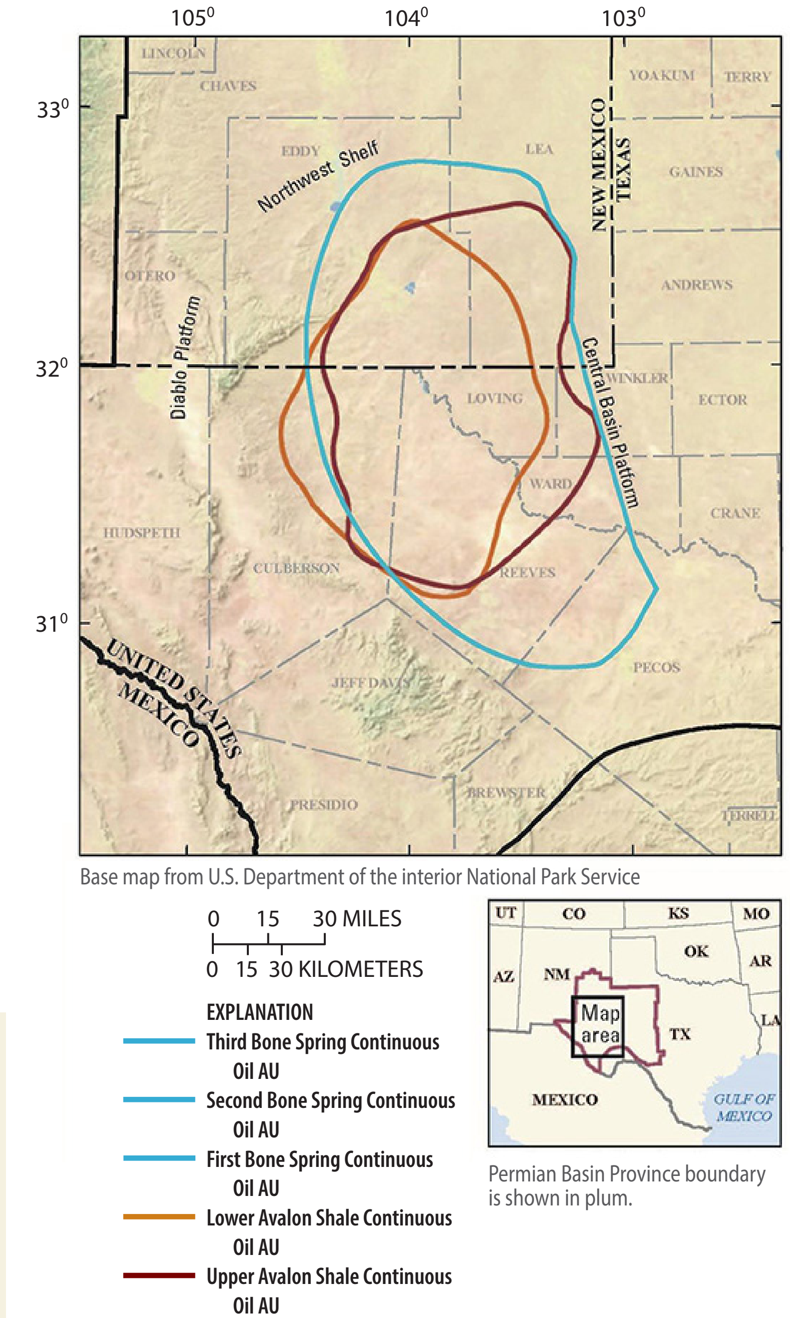
The Delaware Basin in Texas and New Mexico has the most oil and gas resources ever estimated by the U.S. Geological Survey, the USGS announced in December. The Wolfcamp shale and overlying Bone Spring formation in the Delaware Basin portion of Texas and the New Mexico Permian Basin province contain 46.3-billion barrels of oil, 281 Tcf of gas and 20-billion barrels of gas liquids, according to the assessment.

This estimate is for undiscovered, technically recoverable, "continuous" unconventional hydrocarbon resources.

Undiscovered resources are those that are estimated to exist based on geologic knowledge and already established production, while technically recoverable resources are those that can be produced using currently available technology and industry practices. Whether or not it is profitable to produce these resources has not been evaluated.

The Wolfcamp shale in the Midland Basin portion of the Permian Basin province was assessed separately in 2016, and at that time, it was the largest assessment of continuous oil conducted by the USGS. The Delaware Basin assessment of the Wolfcamp shale and Bone Spring formation is more than two times larger than that of the Midland Basin.

"The results …demonstrate the impact that improved technologies, such as hydraulic fracturing and directional drilling, have had on increasing the estimates of …resources," said **Walter Guidroz**, program coordinator of the USGS Energy Resources Program.



Assessment units for the Wolfcamp Shale and Bone Spring Formation of the Delaware Basin.

Average annual oil price for SEC reporting soars 28 percent

The annual average prices for reporting year-end 2018 petroleum reserves to the U.S. Securities and Exchange Commission showed an increase in the WTI Cushing crude oil benchmark to $65.56 per barrel, an increase of 28 percent over last year.

The Henry Hub gas benchmark had a more modest increase of 4 percent to $3.101 per MMBTU. The Brent crude oil benchmark settled in at $71.54 per barrel, a 31 percent increase.

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.

Multivariate analysis takes its rightful place in evaluator tool belt

Faced with a myriad of geological and drilling-and-completion (D&C) variables, the reserves evaluation sector has turned to multivariate analytics (MVA) to measure the effect of parameters on well performance. Multiple linear regression, one of many MVA tools, helps evaluators identify which completion variables have the highest impact on production and estimated ultimate recoveries (EURs) in unconventional plays.

When needed, statistical analysis helps bolster an evaluator's professional judgement. For Ryder Scott, the goal is to determine a best-fit production decline curve after statistically analyzing the play. The end game is an optimized field development plan to maximize the value of a producing asset.

"Really, any of you could be concentrating on any one particular variable to optimize your design, but if you only look at one variable, then you might be missing the bigger picture," said **Joshua J. A. Firestone**, an economist at Ryder Scott.

Firestone's remarks were part of his presentation at the Ryder Scott reserves conference in Houston four months ago.

Continuing, he said, "We have all these completion designs and they're changing rapidly. We're trying to absorb this information to improve our insights and make better decisions."

Joshua J. A. Firestone

Not all it seems

The goal of MVA is to understand the relationships of inputs to outcomes to better identify inputs with the most impact on a particular outcome.

Firestone showed a slide with three operators — A, B and C — to introduce an example of variables in D&C technology and geology that determine EURs. See the slide below.

"Initially, we would think the operator with the best geology would have the most success, but, of course, the other operators have their own ideas about how to create completion designs to extract the most value," he said.

On a lateral-foot basis, Operator A may be in the core geologic zone, but isn't doing any better than Operator C, which has relatively poor geology and acreage position.

"We are not sure what is going on here, and that is where multivariate analysis can help provide insights," said Firestone.

Determination of Categorical Differences

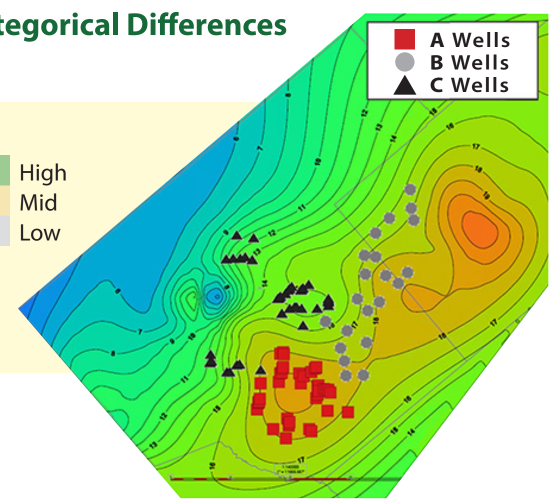
- Completion designs are changing rapidly

	A	B	C
Geology	Best	Good	OK
Lateral Length	5,000	7,500	9,500
Proppant LBS/FT	2,000	1,500	2,500
Stage Length	300	280	200
Well Spacing	262	625	525

High / Mid / Low

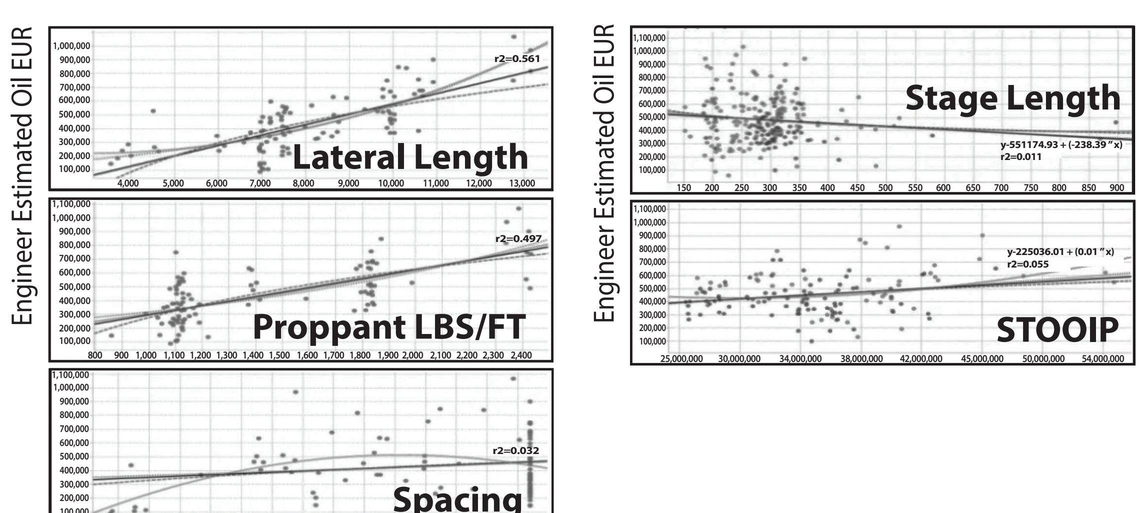
Reserves BBL/LatFT 61 72 60

- Considering all factors, can an operator create a better development plan to maximize value of future wells?



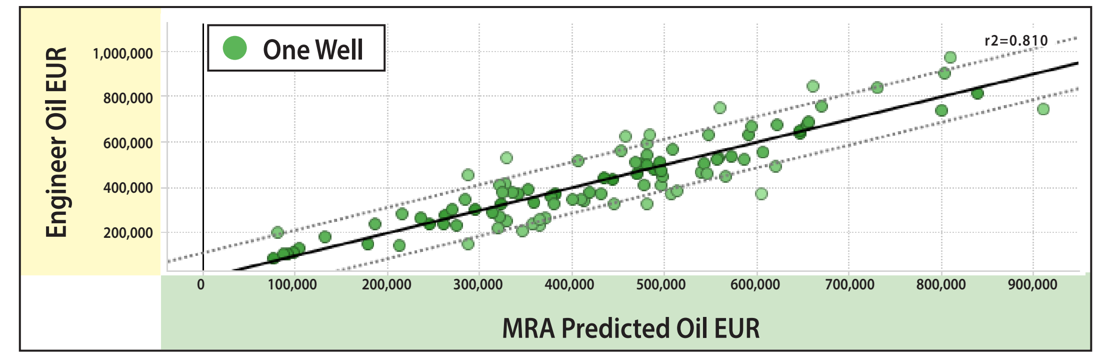
Multivariate regression analysis (MRA)

Firestone showed bi-variate relationships between D&C parameters and the engineer's EUR on separate charts as shown below.



He then "visualized" the combining of these variables in a multivariate relationship, where predicted oil EUR is plotted against engineering forecasts of oil EUR. See chart as follows:

Combined Multivariate Relationship



"MRA allows us to better understand aspects of these fields," said Firestone. "For instance, if the operator sees that the lease is not in the core geologic zone, then the company can explore alternative ways to complete the wells."

"What are the impacts of each of the individual variables? If I drill longer laterals, or include more proppant, how is that going to impact my reserves value? The solution is to combine those sensitivities or individual variables to analyze the completion design as a whole," said Firestone.

Regression basics

A simple linear regression equation is based on the slope-intercept formula, y = mx+b, where x is the independent variable (IV) and is assumed to be causing a change in y, which is the dependent variable (DV). The slope is equal to the change in y divided by the change in x. The slope, designated as m, measures the rate of observed change in variable y as a function of changes in variable x.

Finally, the y-intercept is b, i.e., the value of y when x = 0. This well-understood function applies to the relationship between only one IV and DV. In multiple linear regression, the equation changes slightly, but the underlying mechanics of the formula remain the same. The new equation for the predicted value is $y = m_1x1 + m_2x2 + \ldots + m_ixi + b$.

"One of linear regression's important assumptions is in the name, linearity, thus implying a constant rate of change in the DV when the IV changes," said Firestone. "For example, consider the impacts of drilling an incremental lateral foot and the expected change in reserves or production."

A linear-relationship implies that an incremental foot drilled at the heel of the well will yield the same expected reserves or production as an incremental foot drilled at the toe. "This may not be the case, but since it is an assumption of the methodology, it is important to keep in mind," Firestone remarked.

"Other relationships, such as a logarithmic fit, imply a diminishing return in reserves or production for each additional foot drilled," said Firestone.

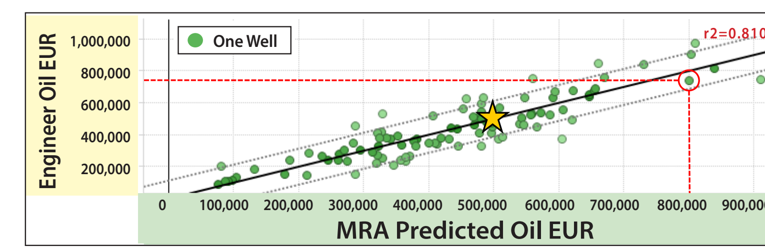
If an engineer determines a logarithmic or other form of fit better describes the underlying aspects of the geology or completion, the variable can be "transformed" by taking the natural log of the variable before including it in the linear regression equation to better capture the curvilinear relationship between variables.

A summary of regression basics, including method of least squares, is at http://faculty.cas.usf.edu/mbrannick/regression/regbas.html. Least squares is the most common technique for fitting a linear regression line.

Industry applications of regression analysis

Firestone showed a chart of regression analysis with engineering-estimated EUR as the DV on the Y axis and MRA-predicted EUR of 800,000 barrels on the X axis.

Please see as follows:



Variable List	MRA Weights		Well Values		MRA Equation
• Intercept	- 200,000			=	- 200,000
• Lateral Length	56	x	7,000	=	392,000
• Proppant LBS/FT	120	x	1,200	=	144,000
• Well Spacing	300	x	500	=	150,000
• Stage Length	- 400	x	350	=	- 140,000
• STOOIP (MMBLS)	8,000	x	19	=	152,000
				Σ	498,000

Examination of the errors — also called residuals or deviations from the best-fit line to the observed values — enables the evaluator to investigate the validity of assuming a linear relationship. In Firestone's example, the difference between engineering and statistical estimates is the residual.

The goal of the equation is to minimize those residuals. "We are trying to explain as much of the variation as reasonably possible," said Firestone.

Please see Multivariate Analysis on page 6

Multivariate Analysis – Cont. from page 5

Calculating an R^2 value shows the amount of variation in the DV explained by the IVs. "In this case, it's 0.81, meaning 81 percent of the variation in the reserves of these wells has been explained by our variable list," said Firestone.

MRA predictions for each of the IVs — lateral length, proppant LBS/FT, well spacing, stage length and STOOIP (MMBLs) — are combined to generate an equation, which is a series of weightings. Also included in the weightings is the intercept — the y value of the point where the regression line intersects the y-axis. Firestone multiplied the weightings by each individual well value and summed the results.

The MRA generated an example well with an EUR of 498,000 barrels of oil, indicated with a star on the regression line in the chart as shown on the prior page.

"The MRA indicates this is what the well will produce," said Firestone. "We will check that number against the engineer's estimate and gauge how well the equation worked," he said.

Changing completions and estimates over time

The importance of individual variables may change depending on the maturity of the well and geological characteristics. Early-time completion variables have more impact during early production – the same period of time which dictates much of the net present value (NPV).

Conversely, EURs are more dependent on geologic and well-spacing variables. Firestone mentioned that the types of IVs a company may want to investigate most closely depend on whether the company is looking at the economics or reserves of a well. Certain variables have differing degrees of impact depending on which of those analyses is done.

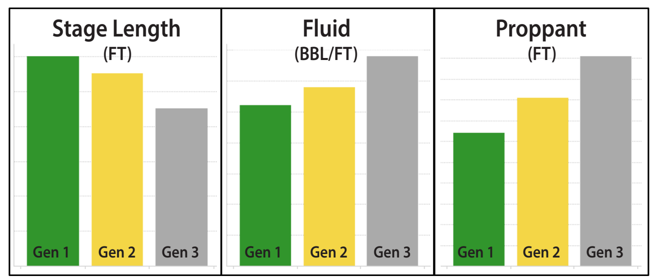
The greater the number of changing parameters for a completion design, the greater the complexity of forecasting production profiles. As an example, Firestone said a client changed stage length, fluid quantity and proppant weights over three generations of wells and indicated that those changes caused IP rates to almost double during the period.

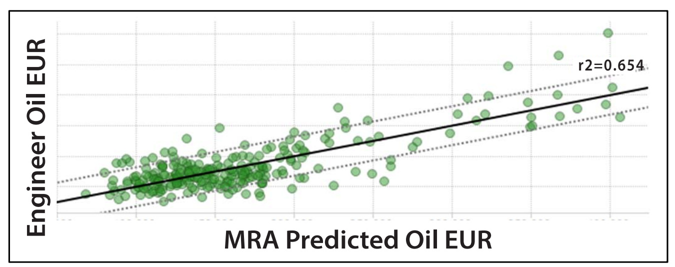
"Our first question as reserve evaluators should be, 'Are these variables actually causing a change in reserves,'" he said. "So, in the MRA, we entered only those three variables and generated a plot with an R^2 value of 0.32 — not a great fit, but it's okay. We're explaining 32 percent of the variation."

When Firestone factored in additional variables, such as the longer drilled laterals and changes in spacing and location over the period of study, he said he got a much better fit, moving from an R^2 value of 0.32 to 0.65. Please see the chart on key variable impact.

Key Variable Impact

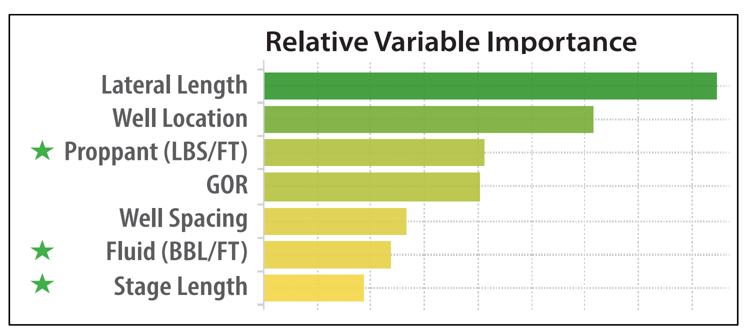
- With completion designs changing, how should reserves volumes be estimated?
- Are these variables actually causing a change in reserves?
- Are there additional variables that should be considered?





R^2 increases from 0.32 to 0.65

For simplicity, Firestone included a relative variable importance table in the slide below to highlight the variables the client initially said were causing the change in reserves.



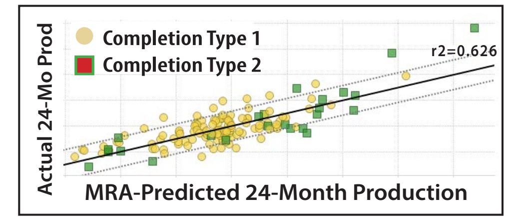
"Lateral length, well location, GOR and well spacing are highly impactful, yet somehow they were just overlooked as being significant because the client was not looking at all of the variables together," he said. "Since we have better identified the key variables, the odds that we are overestimating the impact of an individual variable has been diminished."

Firestone also introduced a case for determining categorical differences. "We have two different completion types. We want to analyze the differences, taking into account all the other relevant differences in the completions or geology."

Please see the following chart of Completion Type 1 vs. Completion Type 2 with an R^2 value of 0.626 for the comparison.

Determination of Categorical Differences

- Is there a difference in completion type performance?
  Completion Type 2 wells produce 35,000 additional bbls in the first two years of production



Variable List
- Effective Lateral Length
- Proppant LBS/FT
- Stage Length
- Well Spacing
- Fluid Properties
- Completion Type

"We see the green wells look a little bit better, but it's still inconclusive," said Firestone. He conducted an MRA and found that Completion Type 2 wells were actually producing, on average, an additional 35,000 barrels of oil in the first two years after normalizing lateral length, proppant, stage length and even geology.

Firestone said other categorical differences can be determined by applying this type of analysis to better understand whether reservoirs act similarly to completions when limited geology is available or whether operators in overlapping areas achieve similar results.

Benchmarking operators in overlapping acreage can be done through MRA. "It will show relative performances taking into account relevant differences between the completion designs of the two operators," said Firestone.

He remarked, "Such benchmarking really cannot always be adequately accomplished without multivariate analysis. If an engineer looks at the company's wells versus competitors, he or she could come to a quick conclusion that because there is a difference in the proppant pounds per foot and fluid barrels per foot, that could be the cause of the difference in observed production."

If the engineer places all variables thought to be relevant into a multivariate analysis, and the equation delivers a statistically significant categorical variable showing a difference between his company and competitors, then a more reliable conclusion replaces the quick one.

"Certainly the proppant and fluid may be part of the story, but there has to be something else the engineer had not previously considered," said Firestone.

He recommended that analysts perform a sensitivity test of the MRA equation to calculate the impact of each individual variable. He showed passing and failing results of a sensitivity test in a chart of D&C parameters and in-place hydrocarbon volumes. Please see the following chart.

Estimating Variable Impact

Passing Results

Variable List	Sensitivity
• Intercept	
• Lateral Length	7.9 %
• Proppant LBS/FT	2.9 %
• Well Spacing	3.0 %
• Stage Length	-2.8 %
• STOOIP (MMBLS)	

Screen for outsized individual variable impacts

Failing Results

Variable List	Sensitivity
• Intercept	
• Lateral Length	19.4 %
• Proppant LBS/FT	6.5 %
• Well Spacing	1.4 %
• Stage Length	-2.2 %
• Fluid BBLS/FT	2.2 %
• Well Location	

Sensitivity testing the equation evaluates the impact of each individual variable

Sensitivity testing seeks to measure the extent of a single IV's impact.

"This helps sanity check an equation," Firestone said.

He looked at how a 10-percent change in a particular variable affected the reserves estimate. The 10-percent increase in the lateral length of a 'median type well' caused a 7.9-percent change in reserves, as can be seen in the passing results on the left side of the chart above.

"This could be a little low, but it is certainly not unreasonable – there may be some kind of diminishing effectiveness of extracting the reserves as this well becomes longer," said Firestone.

The equation for the right side of the chart, however, has an unreasonable sensitivity to lateral length. Increasing a well's lateral by only 10 percent when holding all other factors constant, should not yield a change in reserves greater than 10 percent.

"If this was the case, we would drill the well for miles and miles," he said.

Really independent?

IVs are not always truly independent because, in the real world, there are dependencies between them. The contributions of lateral lengths, pounds of proppant, number of stages, etc. are related and not mutually exclusive. Sensitivity testing helps decipher the degree of IVs impact.

"Multivariate analysis aids in our understanding of which D&C parameters contribute the most to increases in reserves," said Firestone. "However MVA is just a tool.

Please see Editor's Note on page 8

Editor's Note – Cont. from page 7

Engineering and geology judgement still apply."

*Editor's Note: Six years ago, **Adam Farris**, in Analytics magazine, wrote that "the idea of a 'data scientist' was new, and should be considered alongside the petrophysical, geophysical and engineering scientists."*

He asked, "How does the industry bridge the vocabulary and cultural gap between data scientists and technical petroleum professionals? Ideas, applications and solutions generated outside the oil and gas industry rarely find their way inside. Other industries seem to have bridged this gap, but in talking to experts in the broader technology industry, the oil industry is seen as a no man's land…."

With no slight to the assertions of Farris, six years is a lifetime in the fast moving world of business and technical metrics. The upstream industry has been driven by data analysis and strong collaboration with geologists, petrophysicists, geophysicists, operations, etc., for decades. The sector is no stranger to predictive, interactive multivariate statistical models that predict geologic sweet spots and compare completion practices

Early leader at Ryder Scott, creator of "Fickert sheet" dies

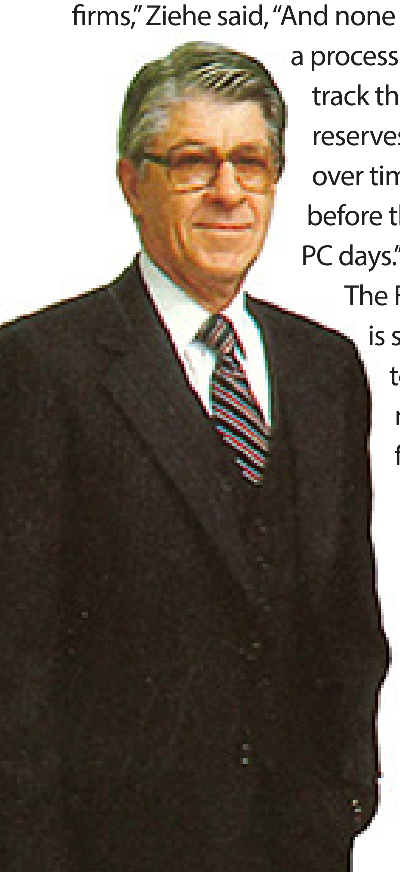
— *Katherine Wauters, contributing writer*

William "Bill" Eugene Fickert, who began working at Ryder Scott in Wichita Falls in 1958, died Nov. 20. He was 94. One of his contributions to the firm was the "*Fickert sheet*," created to establish and maintain historical records from previous studies.

Fred Ziehe, advising senior vice president who joined Ryder Scott in 1976, said, as a new employee, he began using the sheet.

"I reviewed work from other consulting firms," Ziehe said, "And none of them had a process in place to track their historical reserves estimates over time. This was before the 'modern PC days.'"

The Fickert sheet is still in use today in a modified PC format using modern technology.



William "Bill" Eugene Fickert

"Every day with Bill was a teaching moment," said **Nina Roberts**, a technical analyst who joined Ryder Scott in 1981. "You had better 'buckle up' and be ready when you entered his office. He was an expert extraordinaire at organization and expected the same from me and everyone."

Fickert's management style was different from most. Roberts said, "He taught me the finesse of directing people without making them feel less than equal. He was the ultimate team player."

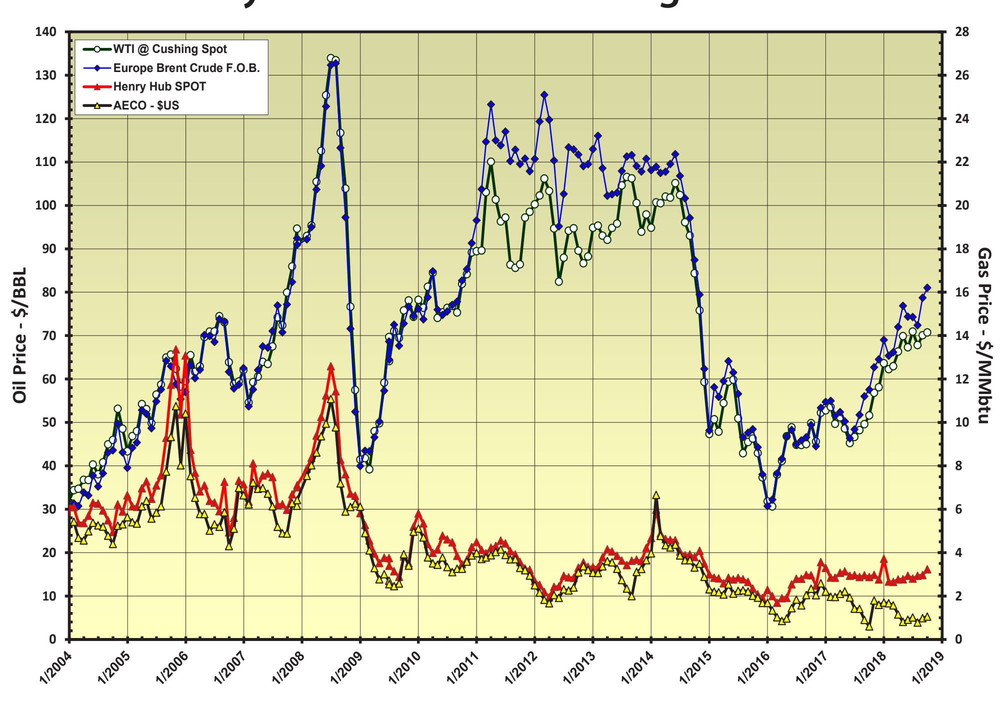
In the mid-1970s, Ryder Scott wasn't organized into groups, so younger engineers were exposed to and learned from senior engineers with varying backgrounds.

"Bill took me under his wing," Ziehe said. "I sure learned the importance of having a process to generate repeatable results and to explain the reasoning I used to estimate reserves."

Organized, methodical, detail-oriented, a fast eater and walker, friend and mentor

Please see Early Leader on page 10

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.

Reservoir simulation: A tool for making informed decisions on well spacing in unconventional plays

Miles Palke

The results of dynamic modeling as applied to well-spacing optimization in various unconventional plays were presented by **Miles Palke**, head of the reservoir simulation group at Ryder Scott. He recently made his remarks at the SPE Hydrocarbon Economics and Evaluation Symposium in Houston.

JPT magazine published an article in late November, "How Close is Too Close? Well Spacing Decisions Come with Risks," featuring Palke and others.

"There is no formula for properly spacing wells in unconventional plays. When a reservoir consultant recently described conversations with clients about how many wells they could drill per acre, it sounded like a doctor advising a patient considering back surgery," the article stated.

"I am not trying to tell producers what their spacing should be," Palke told the magazine, adding that the modeling and production history matching that Ryder Scott offers is part of "a process to help clients make informed decisions."

The question on spacing of wells has always been, "Where is the point of diminishing returns as well spacing gets tighter?"

Conventional vs. Unconventional Reservoirs

Conventional Reservoirs

- Matching static pressures dominated by reservoir parameters.
- History matches focus purely on reservoir parameters.
- Well productivity (completion, skin, PI) more directly considered in predictions than during history matching.
- Many uncertain parameters to adjust.
- Difficulty achieving a history match.
- Frequently full-field simulation models with many wells.

Unconventional Reservoirs

- Matching flowing pressures dominated by a combination of reservoir and wellbore parameters.
- History match about result of completion as much as purely reservoir parameters.
- Well productivity (completion, skin, PI) directly considered during entire process, not just for predictions.
- Many more uncertain parameters to adjust.
- Nature of data makes history matching more difficult.
- Frequently models of single wells or small groups of wells.

Most reservoir simulation models constructed in the industry use the familiar black oil formulation, but Ryder Scott uses compositional or chemical tools as needed, said Palke, who added that he uses an equation of state (EOS) PVT (pressure volume temperature) model to develop detailed EOS-based fluid characterizations for inclusion even in black oil models.

History matching is frequently the only information available to help identify the value of parameters that determine the outcome of the sensitivity analysis, Palke told the audience. The history-matching process narrows down the value of key parameters that determine optimal spacing.

"The best well spacing may depend on fracture half-length, or other parameters whose effective values are estimated through history matching."

Fracture half-length is the distance from the wellbore to the outer tip of a fracture propagated from the well by hydraulic fracturing.

He has also used rate-transient analysis to "precondition" simulation models to make history matching more efficient, but has experienced mixed results. "Translating (RTA) results into the simulation grid sometimes has a limited benefit because of inconsistency in modeling approaches," said Palke.

Relative permeability is a large driver of reservoir performance, especially regarding fractional flow of different fluids, however the use of relative permeability and PVT data remain an area of interest for research on unconventional reservoirs.

Although he cautioned about generalizing from the information he provided on individual unconventional plays, Palke

Please see Reservoir Simulation on page 10

Reservoir Simulation – Cont. from page 9

summarized the following "take-aways" from his reservoir simulation work.

"Operators turn to consultants such as Ryder Scott for history-matched reservoir models..."
– *JPT* Magazine

General observations

- Optimization of spacing has a strong relationship to fracture half-length.
- Half-length is usually varied in the history matching exercise, but . . .
- History matches are non-unique, and depend on other input parameters.
- Allow other sources of information to influence the history matching:
  - Micro-seismic
  - Presence or absence of frac hits
  - Fracture analysis
  - RTA
- Consider conducting sensitivity studies to cover uncertainty in other unmatched parameters, such as petrophysical values.
- Fracture half-length contributes to the optimal well spacing.
  - Other parameters, such as permeability and layering, can make a significant difference.
- Fracture half-length can be history matched, but is usually highly dependent on fracture height.
- In these cases, the challenge is in matching the pressure history along with each phase rate.
- Equivalent matches were achieved for varying fracture half-lengths, making the selection of the optimal well spacing subject to a residual uncertanty.
- Information from outside the simulation study must be considered in the decision-making.

"Operators turn to consultants such as Ryder Scott for history-matched reservoir models because they want results that line up with the output from actual wells," the *JPT* article stated. "But that leaves a lot of room for judgment calls."

Palke told the magazine, "Using the same wells for an equivalent history match, you can arrive at a range of options from 80 acres to 120 acres per well. If you have a big land position, that (difference) is a lot of wells. You would want to do a lot of work to decide which of those is the best decision."

Early Leader – Cont. from page 8

are just a few of the words employees used to describe Fickert. He was the embodiment of order in all aspects of his life.

Ziehe said, "I remember a time when Bill invited me to go deer hunting in Fredericksburg. He gave me a multi-page map, beginning with a Texas state map and star marking the town."

In true engineering fashion, the maps became increasingly detailed, each page showing another level, from Fredericksburg to the highway exit, then turns off small roads to dirt roads.

"The last map showed the farm property and house location, and most importantly, the deer blinds," said Ziehe.

Fickert served in the U.S. Air Force in the Pacific Theater during World War II. His next stop was the University of Texas. With petroleum engineering degree in hand, he began a nearly 30-year career at Ryder Scott, which owes its reputation, in part, to Fickert and others who shaped the firm's early history.

He was made a partner in January 1962 and retired in 1986 as a senior vice president. Fickert taught short courses and seminars, including "Economics of Waterflooding the Garyburg Dolomite in South Cowden Field," and "Waterflood Case History Caprock Queen Field."

He was an elder and committee chairman at Christ Presbyterian Church in Midland, TX, and taught Sunday school to junior-high students. Since 1971, Fickert had been a member of Memorial Drive Presbyterian Church in Houston, where he was also an elder and volunteer.

He is survived by a sister, **Joan Finkboner** of Illinois; daughter, **Karen Ann** and son-in-law **Scott McCoy** of Austin; son, **Gary Lee Fickert** of Houston and three grandchildren: **Shawn Thomas McCoy**, **Kristin Nicole Fickert** and **John Austin Fickert**.

In addition to his family, Fickert leaves behind his "Ryder Scott family," including those he helped mold several decades ago.

Liabilities soar for wellsite cleanup costs in Canada

In November, the *Globe and Mail* newspaper in Ontario published articles on abandoned wells and mounting liabilities for cleanup in British Columbia, Alberta and Saskatchewan. The Alberta Energy Regulator, the same month, estimated the costs of cleaning up the province's oilpatch could be as high as $260 billion up, from the previous $58-billion liability to taxpayers from orphaned and abandoned wells.

The Globe reported that "20 percent of all oil and gas wells in the three provinces are inactive, and that there are 54,147 more idle wells there than in 2005. Such wells no longer produce oil and gas, but have not been plugged." The newspaper also counted another 84,569 abandoned wells, some idle for decades.

Reclaiming the well sites and surface facilities and restoring the land to its original state are the responsibility of producers.

"Those wells have been filled with cement and capped because there is no profit left in them, but companies have not yet reclaimed the sites and restored the surrounding land to its original state," the *Globe* stated.

Canada's *National Observer* newspaper also reported in late November at a press conference, the Alberta Energy Minister **Margaret McCuaig-Boyd** threatened to crack down on the oil industry. She said, "Canadians shouldn't be on the hook for actions of irresponsible operators."

In November, the Alberta Liberal Party called for the province to create a bond program that requires companies to put up cash for cleanup costs to protect the government.

"Many U.S. states require companies to seek continuing approvals and post security bonds to keep wells inactive," the *National Observer* stated. "In some cases, they have to show evidence that the wells could be returned to production, if commodity prices improve."

Companies in Alberta have only submitted about $1.6 billion in security deposits to cover the costs. At the same time, unowned orphan wells – some abandoned, others to be abandoned – increased from fewer than 800 to more than 2,000. After Sequoia Resources Ltd. went bankrupt last year, the costs to decommission and clean up 4,000 wells, pipelines and other facilities fell in the lap of the province.

The *Globe* investigation also reported brisk trade in distressed wells and other facilities between major companies offloading those properties to smaller buyers with no ability to pay for abandonment and reclamation costs (ARC). "The deals were approved, even in cases where purchasers didn't meet the Alberta regulator's test for financial fitness," the publication stated.

Recent news has ramifications for the reserves sector. A year ago, *Reservoir Solutions* newsletter reported that the Society of Petroleum Evaluation Engineers chapter in Calgary was poised to challenge the Alberta Securities Commission interpretations of a 2015 regulation that requires a reporting issuer (RI) to cashflow oil and gas production net of ARC for wells, surface facilities and pipelines up to the sales point.

As it played out, SPEE lost whatever bluster it had, and its language in the 2018 Canadian Oil & Gas Evaluation Handbook (COGEH) fell in line with the ASC. COGEH clarified that abandonment-and-decommissioning costs should address producing wells, suspended wells, service wells, gathering systems, facilities and surface land development.

If ADR costs are excluded, COGEH recommends that the RI disclose those omissions to reconcile unaudited (supplemental) information in the 10-K with the audited financial statement. On the accounting side, all ADR costs are reported annually as asset retirement obligations.

In light of the November news on abandoned wells, reporting ARCs may become an even bigger issue in the reserves evaluation sector.

Canada's National Instrument 51-101 governs public issuers in Canada and refers to COGEH as "the standard of practice for evaluation and classification."

Historically, reporting issuers in Alberta have been more selective in their disclosures. "The cost of abandoning an exploration well, which is unrelated to reserves cash flows, should not be included," said one RI.

Just how the Canadian industry treats ARCs in reserves disclosures will be for all to see in year-end 10-Ks released in March.

Ryder Scott Co. LP
1100 Louisiana, Suite 4600
Houston, Texas 77002-5294
Phone: 713-651-9191; Fax: 713-651-0849
Denver, Colorado; Phone: 303-623-9147
Calgary, AB, Canada; Phone: 403-262-2799
E-mail: info@ryderscott.com
Web site: www.ryderscott.com

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3D imaging – Cont. from page 1

angle after another. These are then combined to produce a full 3D reconstruction of the pore structure.

Sampling mature kerogen can be cost-effective. "Analysis can be done on rotary sidewall cores taken when drilling is stopped to acquire logs," said **George Dames**, advising senior vice president geoscience/geologist at Ryder Scott. "Geochemistry and TOC (total organic carbon) analysis is frequently done on cuttings."

Drill cuttings from a siliceous Marcellus formation in Pennsylvania provided the first kerogen sample tested by researchers. The less expensive cuttings process involves removing pieces of broken rock from the well via drilling fluids and raising them to the surface for study.

The paper was written by **Roland Pellenq**, MIT senior research scientist, as well as others at MIT, Shell Technology Center in Houston, and French National Center for Scientific Research and Aix-Marseille University in France.

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

Reservoir Solutions

Editor: Mike Wysatta
Business Development Manager

Ryder Scott Co. LP
1100 Louisiana, Suite 4600
Houston, TX 77002-5294
Phone: 713-651-9191; Fax: 713-651-0849

Denver, CO; Phone: 303-623-9147

Calgary, AB, Canada; Phone: 403-262-2799
E-mail: info@ryderscott.com

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