RESERVOIR SOLUTIONS

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Booking PUDs: A give-and-take proposition under SEC

Booking proved undeveloped petroleum reserves has become a give-and-take exercise under new U.S. Securities and Exchange Commission regulations. Oil and gas companies are reporting both upward and downward year-end PUD revisions in the same properties.

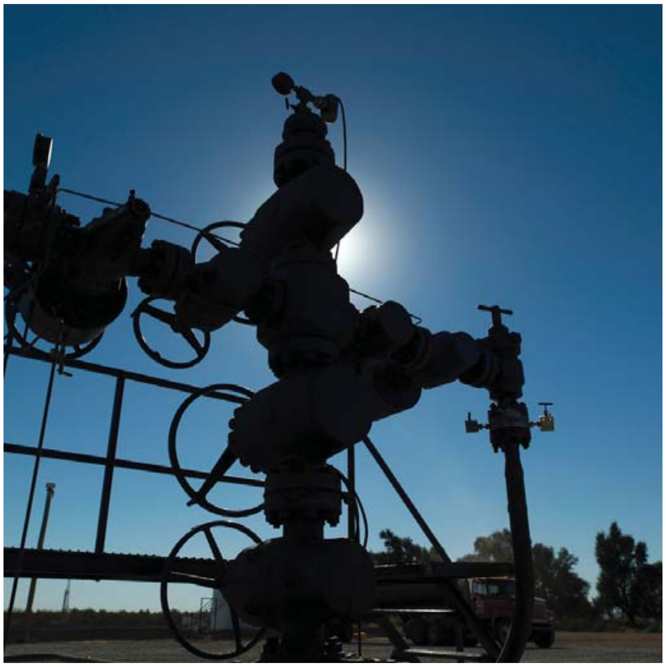
- Based on a reasonable certainty standard, companies reported PUD locations at distances greater than one legal offset from economically producing wells. That boosted PUD reserves, especially from shale gas locations.
- Companies took PUD wells off the books if they were scheduled to be drilled more than five years from initial PUD assignment. Few exceptions were made, but more were expected in 10-Ks filed on or before March 15.

Cabot Oil & Gas Co. said it made an exception for 16 Bcfe of PUD reserves delayed by "external factors." However, it removed 120 Bcfe of PUDs that fell outside of the five-year development window by reclassifying them to probable. That was consistent with a reallocation of its capital program to develop assets in Pennsylvania and east Texas.

Across the industry, proved reserves, including PUDs, also dropped because average commodity prices for the year were lower than year-end prices. The SEC changed from a one-day year-end price to an annual average to lessen the effects of volatility.

Some companies detailed the extent to which the five-year limitation decreased PUDs and multiple offsets increased them. For **Bill Barrett Corp.**, the net effect was to boost PUDs.

The company said it included additional offsetting locations, where warranted, in the Williams Fork formation in Gibson Gulch, a basin-centered, "continuous" accumulation of gas. That increased PUDs for the field by 64 Bcfe. The five-year limitation "had a nominal impact of reducing (Bill Barrett's) reserves by 7 Bcfe."



A shadow silhouettes a Christmas tree of Chesapeake Energy Corp. The company said it used reliable geologic and engineering technology to book PUD reserves more than one location from production in the Barnett and Fayetteville shales. Photo © 2009 by Chesapeake Energy Corp.

For **The Williams Cos. Inc.**, the net effect was a "wash." Williams reclassified 496 Bcfe of reserves from PUD to probable because of the five-year limit while adding 454 Bcfe of PUD reserves through additional offsets.

Companies also assigned PUD locations more than one direct offset from a producer not only in shale, but also in conventional accumulations. Barrett's Williams Fork produces from sandstone reservoirs.

First Quarter Announcements

Newfield Exploration Co. justified half of its 1,342 Bcfe of added proved reserves based on the multiple offset rule. Conversely, the five-year limit on PUDs had "a material impact on the total reserves that could have otherwise been recognized as proved" in "long-

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Inside Reservoir Solutions newsletter

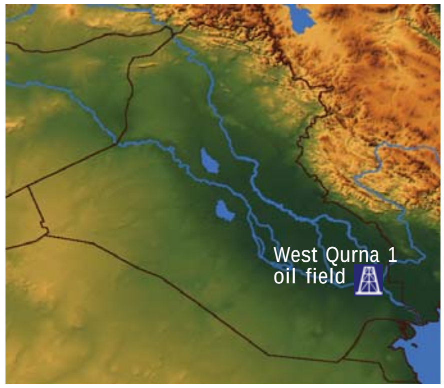
Can reserves be booked under Iraqi service contracts?

Confusion reigned supreme on the issue during the first quarter

Early this year, news media, Wall Street and the petroleum industry speculated on whether regulators will allow oil and gas companies under new Iraqi service contracts to book reserves from the fields they operate. Misinformation was rampant.

A *Dow Jones Newswires* article stated that Exxon Mobil Corp. and Royal Dutch Shell PLC will not be able to book reserves from the West Qurna 1 oil field in Iraq. The consortium is under a technical service contract that was won in Round 1 bidding and finalized Jan. 25.

A week later, an analyst from Barclays Capital said that he presumed that Exxon would "not be allowed to book any reserves under the SEC (U.S. Securities and Exchange Commission) definition." An international lecturer, opining in a Society of Petroleum Engineers online forum, said that unless host country Iraq characterizes hydrocarbon volumes as reserves, companies in service contracts cannot book them that way.



Despite the naysayers, Exxon, Statoil ASA, Gazprom and other contractors— negotiating or finalizing 20 agreements won in two bid rounds—plan to book reserves from their Iraqi upstream operations.

David S. Rosenthal, Exxon vice president of investor relations, told the Barclays analyst, "When we look at the contract in Iraq and we look at SEC rules, right now we don't see any reason at this time why we would not book reserves. So again, consistent with the guidelines in the contract right now, we think we will be able to book reserves."

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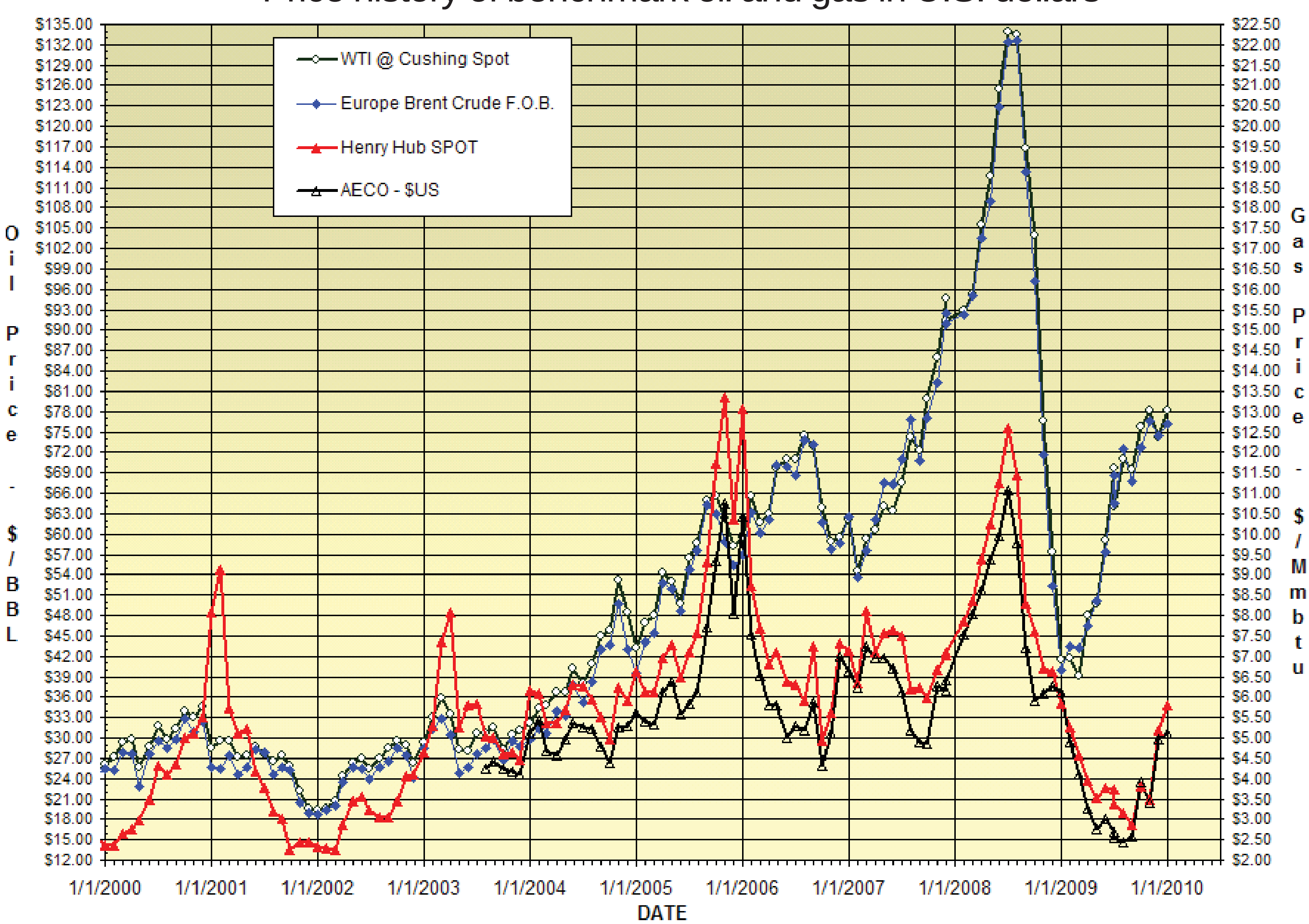
Price history of benchmark oil and gas in U.S. dollars



Published, monthly-average, cash market prices for WTI crude at Cushing (NYMEX), Brent crude and Henry Hub and AECO gas.

PUDs—Cont. from Page 1

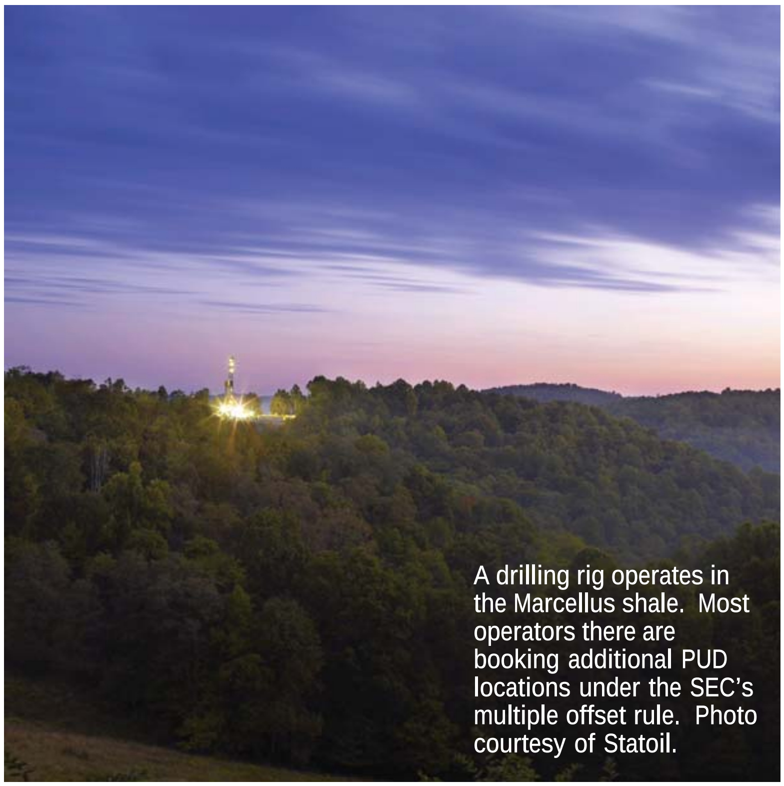
lived resource plays with a lengthy inventory of drilling locations, such as our Woodford shale and Monument Butte plays," the company said.

Pioneer Natural Resources Co. said that all of its PUD reserves, which total 375 MMBoe, are scheduled to be drilled before the end of 2014. The company called the SEC rule a "controversial item," but with 40 rigs scheduled to drill over the next several years, Pioneer said that it will be "fairly easy" to develop its PUDs within the time frame.

EQT Corp., with about 70 percent of its 3P reserves in the Lower Huron/Berea shale play, said that its PUD reserves increased because of the elimination of the one-offset rule but dropped because of the five-year rule. See article on Page 4 on EQT with discussion of PUD rules.

Despite increasing PUDs 227 percent, **Petrohawk Energy Corp.** said that it was "governed by development scheduling criteria of five years or less." The company told financial analysts that "new SEC reserve booking rules …added PUD locations in some cases." Petrohawk produces from the Haynesville, Eagle Ford and Fayetteville shale gas plays.

Noble Energy Inc. said its 820 MMBoe of proved reserves reflected an 18 MMBoe reduction because of the five-year rule. Those reserves are expected to be re-booked to proved with future drilling.



A drilling rig operates in the Marcellus shale. Most operators there are booking additional PUD locations under the SEC's multiple offset rule. Photo courtesy of Statoil.

Range Resources Corp. recorded an average 1.2 offset drilling locations as PUD reserves for each of its proved developed wells in the Marcellus shale play. The company also elected not to disclose probable and possible reserves in its filings with the SEC.

Public issuers now have the option to file reserves using price sensitivities. Because of low gas prices, **Bill Barrett Corp.** calculated and reported proved reserves using the five-year strip price in a sensitivity analysis.

Williams cited reserves based on forward-market gas-price scenarios. The company also disclosed probable and possible reserves but said it would not file those categories in its 10-K. Public issuers under the new rules now have the option to file probable and possible reserves.

Ultra Petroleum Corp. said it did not include any material additions attributable to the new SEC rules. The company also said that PUD reserves are limited to a three-year development period.

"The only thing we could do to be more conservative would be to book no PUDs," said **Mike Watford**, CEO, on a conference call with financial analysts. Ultra said it did not book any PUD locations in its Marcellus properties.

Some companies issued statements disclosing reserves under the SEC rules and Society of Petroleum Engineers Petroleum Resources Management System guidelines. In two cases, the SEC regulations, despite recent modernization, proved to be more restrictive than the SPE-PRMS considered the best technical set of definitions.

OAO Novatek, an independent oil and gas company in Russia, said proved reserves in accordance with SEC standards increased to about 6,900 MMBoe compared to approximately 7,700 MMBoe under the PRMS.

Rosneft, Russia's largest oil company, said its proved reserves under the PRMS stood at approximately 23 billion BOE compared to about 15 billion BOE under the SEC rules, which it said took into account reserves under duration-limited license agreements.

On the other hand, SEC reserves definitions allowed more reserves than the SPE-PRMS for Brazil's **Petrobras**. The national oil company reported an 8.5 percent gain in proved reserves for recently discovered subsalt oil under SEC rules while reserves fell slightly under the SPE-PRMS, reported *Dow Jones* in mid January. Also, the company's reserves replacement index in 2009 was 110 percent under the SPE-PRMS and 264 percent under the SEC.

Reliable Technology

SEC rules now allow producers to book proved reserves based in part on the use of field-tested technology that provides "reasonably certain" results with consistency and repeatability in subject or analogous formations.

Ultra said that it uses "reliable technology—such as seismic wire line formation testing, geophysical logs and core data—to assess and optimize the value of its resources, (but that) none of these technologies were used to affect a material change to reserve additions."

Chesapeake Energy Corp. said it used and developed reliable geologic and engineering technology to book PUD reserves more than one location from production in the Barnett and Fayetteville shales, but has booked only direct offset locations in all other asset areas.

With its low-risk shale gas reserves, Lower Huron emerges as a major technology and statistical play

The Marcellus and Haynesville emerging gas shale plays grab the headlines, holding great promise for the future. The Barnett shale is the "poster boy."

Innovative horizontal drilling and slick water frac techniques tested there in the 1990s ushered in America's "natural gas revolution."

The Fayetteville, the most productive shale play in the U.S. behind the Barnett, ranks as one of the nation's 10 largest gas fields. The Eagle Ford shale trend in south Texas is one of the newer plays, creating a buzz at the 2010 North American Prospects Exposition in February.

Out of the limelight and tucked away in the Appalachian basin is the Lower Huron shale play as thick as 3,000 ft. and containing low-risk gas reserves. Below it, the deeper, higher-pressured Marcellus and Utica shale formations in the basin get most of the attention and rightly so because of potential measured in hundreds of trillions of cubic feet.

However, new horizontal drilling and completion technologies—including multi-stage cementless fracture treatments—in the Lower Huron around the West Virginia-Kentucky border region are boosting production in this resource play to 200 MMcfd of gas, said Advanced Resources International Inc. this year.

EQT drills into the Lower Huron shale at this eastern Kentucky well site.

Granddaddy of shale gas plays

Of 14 major U.S. shale gas plays, the Lower Huron is the only one at a mature development stage. Tens of thousands of wells have been spudded in the Appalachian Devonian-age shale starting in 1821 in Fredonia, NY.

The granddaddy of all shale gas fields, Big Sandy, is the major producer in the Lower Huron. It is the first field-scale development of shale gas with first production in the early 1920s. At early stages, the Lower Huron's shales had enough pressure to "breathe" gas through natural fractures.

Producers used temperature logs in the thermally mature 3,000-sq-mile Big Sandy in the mid 1930s to locate points of gas entry in open vertical wells. Downhole temperature measurement began at that time.

Wells with primary production are becoming marginal now as the reservoir pressure is down to 250 pounds per square inch or less in the play. Recently, the industry has given Big Sandy new life by developing the field with horizontal-well technology.

Producers are re-entering old wells or drilling new ones and fracturing the shale with nitrogen gas or foam injection, with and without proppants, to access bypassed reserves.

Technology play

EQT Corp., the largest producer in the Lower Huron, drilled the first horizontal well there in late 2006 and continued to pioneer the application of that technology to the play, experimenting with multilaterals and extended-reach laterals in 2008 and 2009. The company also tested pad drilling and stacking.

EQT drilled 347 horizontal wells there last year, including 20 multilaterals and 13 extended laterals. The company said that it's too soon to make conclusions about unit and finding-and-development costs and EURs of wells drilled with multi- and extended laterals, but it anticipates F&D costs will be lower than for single laterals.

"Results from horizontal unfractured multilaterals vs. horizontal fractured wells vary from field to field in the Lower Huron, but are generally comparable," said **Greg Wozniak**, completions engineer at EQT. He added that nitrogen fracs generally work better on the underpressured Huron shales than foam (water).

EQT has also used proppants to keep the fractures open, but has not determined whether that technique is worth the added costs.

"The well completion process is still the pivotal piece of the puzzle," said **Marty Puskar**, senior engineer at EQT. "We just do more stages in the horizontals. The idea is that with the horizontals, we can contact more reservoir and potentially more natural fracture networks to increase productivity."

EQT also introduced horizontal air drilling to the shale play, which works well in formations that are

A mishmash of frac trucks cram together at this Lower Huron well site in Letcher County, KY, to prepare for EQT nitrogen-fracing operations in the Big Sandy field last May. The granddaddy of all shale gas fields, Big Sandy has undergone a resurgence.

dry with no influx from water, condensate or oil. Drilling with air is faster than with liquids, helps eliminate lost circulation in low-pressure formations, minimizes formation damage and extends drillbit life.

"The formation will not carry a full column of fluid because of the low pressure, so straight air or an air/foam mixture are our only options," said **Mike Butcher**, director drilling at EQT.

Those new drilling and completions applications are enabling the company to develop previously stranded gas from the Big Sandy's Lower Huron that would not have been produced from existing vertical wells. "Horizontal EURs are in the range of two to three times those of vertical wells," said Puskar.

Per-well estimated ultimate recoveries are between 0.75 to 1.50 Bcf of gas with recovery factors of up to 40 percent per single lateral.

Reserves and risk

Not everyone in the industry is jumping on the shale-gas bandwagon. Critics point to optimistic predictions of shale gas field performance in general and point to the Barnett as an example, where some type curves aggregated from historical production show terminal declines of 15 percent, not the 8 percent or less that are advertised.

The Lower Huron is not the Barnett, however, and both differ in their geological characteristics, including rock matrices, fracture networks and permeabilities. EQT pegs its terminal declines for the Lower Huron at 3 percent. The type curve, normalized for downtime from interventions, is based on initial production and analogous production from horizontal and vertical shale wells.

Generally, high IP rates and hyperbolic declines are characteristic of well performance in shales and estimates of future production from terminal declines are relatively lower than for those exhibited in conventional gas production. Further diminishing the impact of terminal declines is that their associated, estimated cash flows are discounted at 10 percent per year as a present value using an unescalated price deck under the U.S. Securities and Exchange Commission.

EQT estimates that the average present value after taxes discounted at 10 percent is more than $400,000 per Lower Huron well. First-month production rates from the $1-million horizontal wells are 200 to 900 Mcfd of gas.

Another critical view of shale gas reserves estimates is that there is a weak correlation between IP and EUR. Without extensive production histories from laterals in the Lower Huron, EQT relies on analogy and reservoir simulation to overcome the challenges of decline-curve predictions and high variabilities. Simulation results suggest very low terminal decline rates in the range of 2 to 3 percent per year, said EQT.

This year, EQT has about 70 horizontal wells with at least two years of historical production to use as analogies as well as vertical wells completed in the same formations

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In an ethereal, nocturnal scene, vapor from EQT's nitrogen-fracing operations is illuminated by flood lights through a silhouetted canopy of tree branches.

Technical challenges in estimating reserves Part 2: Downdip limits and isopachous maps

Editor's Note: This is a revised excerpt from "Oil and Gas Reserves Estimates: Recurring Mistakes and Errors," (SPE Paper No. 91069). To order a copy of the full paper, go to www.onepetro.org.

Ryder Scott personnel see a wide variety of internally produced petroleum reserves estimates and most of them are well prepared. However, the firm has noticed common technical errors in reserves estimates.

This multipart article offers guidelines to help reduce the chance of errors in geoscientific and engineering analysis. This second newsletter article focuses on downdip limits and isopachous maps.

Downdip limits in vertically stratified reservoirs

The down-dip extent of a productive area is defined by fluid contacts and lateral limits from structural or stratigraphic barriers. Assuming vertical communication and a common downdip contact in stratified or layered reservoirs without adequate support from pressure data is likely to result in an overestimation of in-place volumes.

Figure 6 illustrates a log section marked to indicate three porous intervals shown as A, B, and C. These three zones, all assumed to be capable of commercial production, may be part of a single pressure-connected reservoir or may collectively comprise three separate reservoirs. Well data alone may not resolve this uncertainty.

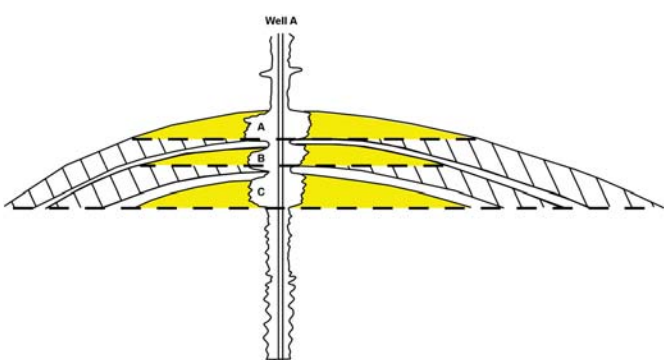

Figure 6. Potential error—Assuming a common downdip contact in a stratified reservoir

The cross section in Figure 6 illustrates the difference between the productive volume of the three zones with a common downdip contact (lowest known hydrocarbon or LKH)—represented by cross-hatched and shaded (yellow) areas—and those same shaded areas in each zone with separate LKHs.

Most reserves definitions require that the evaluator, in estimating proved reserves, assume that the three reservoirs have separate downdip limits, if additional data does not contradict this.

Isopachous maps

The estimation of volumetric reserves depends on three main types of isopachous maps: (i) map of gross thickness of reservoir unit, (ii) map of net effective thickness generally based on application of a minimum porosity cutoff value, and (iii) map of net effective pay thickness generally based on the application of a maximum saturation cutoff value.

Figure 7 illustrates the two main regions of a net pay isopach map; the wedge zone and the area of maximum fill-up.

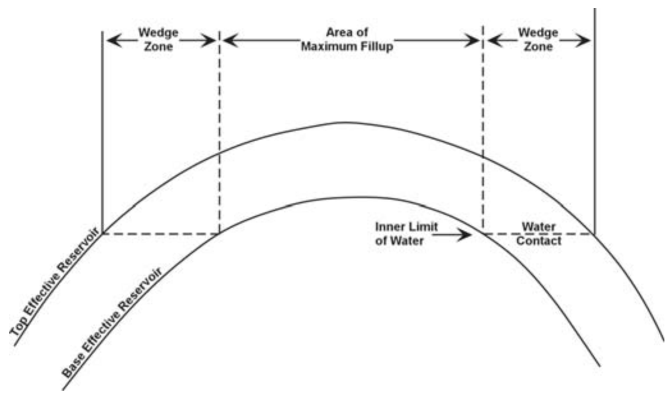

Figure 7. Illustration of wedge zone and area of maximum fill-up

Net pay isopach maps—Downdip wedge zone—The wedge zone in Figure 7 defines the rock volume in areas where the fluid contact intersects the reservoir top and base. The correct placement of contours representing net pay thickness in the wedge zone is governed by the rate of structural gain above the elevation of the downdip fluid contact and the vertical distribution of net pay.

A common technique in both hand-drawn and computer-aided mapping involves the use of a net-to-gross ratio to represent the change in vertical net pay proportionate to the change in elevation above the intersection of the fluid contact and the structure on the top of the effective reservoir unit. A net-to-gross ratio based on the net pay thickness of the reservoir unit to its gross thickness represents an average distribution for the entire interval.

In zones where the vertical distribution of net pay is fairly constant, average net-to-gross ratio may be a fair representation. However, the use of that ratio in a reservoir where the net-pay distribution varies over the vertical interval is unlikely to be correct.

This misapplication may lead to overstating or understating reservoir volumes and associated reserves. The next article, Part 3 in June, will display three figures illustrating the relationship between net-to-gross ratios and reservoir volumes and provide more information on isopach mapping.

Iraq—Cont. from Page 2

A Gazprom vice president in December suggested the possibility of booking reserves at West Qurna 2 in Iraq, the *Motley Fool* reported. Partner Statoil later said it anticipated counting reserves from the field, which was a first-round award.

When "no" doesn't mean "no"

The Iraq government is opposed to foreign companies claiming entitlement to its hydrocarbon resources as reserves. Article 108 of the Iraq constitution states that the people of Iraq own all oil and gas and the federal government and regional governorates manage the country's hydrocarbons.

However, that's not a "show stopper." Even when the government has explicitly declared whole ownership of those reserves and the foreign company doesn't hold the legal title, companies in risked service contracts have been allowed to file proved reserves with the SEC, not as working interests, but based on the economic interest method under GAAP successful efforts accounting.

For justification, they have cited SEC Section S-X, Rule 410-b that offers guidance on ownership and reserves recognition. That rule tends to recognize proved reserves if the contractor has the right to extract oil or gas, to take volumes in kind, has a clear mineral interest and is exposed to risk and potential reward. Not all four are needed, but the ability to book proved reserves increases as more of the ownership indicators are in place.

For background, the five fiscal systems that generally involve degrees of ownership, from least to most, are loan agreements, pure service contracts, revenue sharing contracts, production sharing contracts and concessions. Producers don't claim ownership of reserves based on lending covenants or pure service contracts. However, pay-for-performance, risked service contracts break over into the realm of reserves.

Risked service contracts and Iraq reserves

The contract for the West Qurna 1 field development is a producing field technical service

The 310,000-B/D Baiji refinery, the largest in Iraq, and other plants are planning for significant crude increases. Estimates were that seven oil development deals finalized at year end could boost countrywide production to 12 MMBOPD from the current 2.5 MMBOPD within seven years.

contract. Exxon not only has the right to extract oil and gas, a criterion for reserves recognition, but an obligation to meet its plateau production commitment of 2,325,000 BOPD to earn a remuneration fee of $1.90 a barrel for incremental production above a baseline of 258,505 BOPD.

Usually, the contractor under a PFTSC receives a per-barrel maintenance fee for production levels at or below the baseline. That information has not been disclosed.

The signature bonus of $400 million for West Qurna 1 project paid to Iraq is cost recoverable, stated the *Middle East Economic Survey*. Typically, the contractor cannot recover costs until the end of a rehabilitation period defined in months or at a specific percentage of production increase above the baseline.

It's certainly clear that Exxon is risking capital to develop the field. The remuneration levels (rewards) to recover costs and meet an acceptable rate of return are dependent on the performance of the field. In return for capital investment and operating costs—including expenditures on reassessing reserves, rehabilitating infrastructure and drilling wells—the contractor is paid back through a remuneration fee linked to a weighted index.

Exxon has a clear mineral interest because it controls the hydrocarbons from the reservoir to the transfer point and along the way, is not necessarily under a purchase agreement. As lead contractor, it has 60-percent interest while Oil Exploration Co. (owned by Iraq) has 25 percent and Shell has 15 percent.

If a long-term service contract guarantees a minimum volume with an option to be paid in kind, the fourth criterion, then the producer can include that in a compelling case to book reserves. Exxon may have the right to take volumes in kind. **Ruba Husari**, Middle East bureau chief for *Energy Intelligence Group*, said that contractors in Iraq "can choose to be paid in kind and the long-term contract will guarantee a minimum

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EQT—Cont. from Page 5

as analogs. EQT has also found that older Kentucky commingled wells, many producing since the mid 1900s, have terminal declines of less than 3 percent annually.

"We feel comfortable that completions in our Lower Huron horizontals will result in similar terminal-decline behavior as the vertical wells," said **Erin Elkin**, director reservoir engineering.

The continuity of the formation and high degree of well control reduces drilling risks in the Lower Huron, which is both a technology and statistical play. Well control verifies sufficient in-place gas for drilling and allows EQT to high grade reservoir areas of interest.

The biggest obstacle for booking proved undeveloped reserves in the Lower Huron is the new SEC rule restricting PUD classification to a five-year limit. EQT said that it has "many more locations available to drill than it can reasonably expect to drill over the next five years."

Although the five-year limit restricts recognition of relatively low risk reserves, it provides EQT with an opportunity to continue to book reserves as it develops the Huron fields year to year. The company believes that it has many probable locations that are much higher in quality than probables in other plays. "Many of our probable locations are actually 'unbooked' PUDs that we don't have scheduled to be drilled in the next five years," said Elkin.

For year-end 2009, EQT's probable reserves increased 69 percent to 5.6 Tcfe in part because 2.1 Tcfe of reserves from locations that would have been classified as PUDs were booked as probable. Proved reserves in its Huron/Berea play increased from approximately 1.56 Tcfe to 2.02 Tcfe at year end.

For its annual reserves filing, EQT relied on Ryder Scott as its third-party evaluator. Over the last 10 years, Ryder Scott has prepared more SEC-case reserves reports than any other independent consulting firm.

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Iraq—Cont. from Page 7

volume of oil, (so) they will be able to book reserves."

More than meets the eye

Other speculation focused on how sub $2-per-barrel compensation fits in with expected returns targeted by Exxon and other contractors. Thirteen of the 20 bids won in rounds 1 and 2 were service contracts with remuneration fees of $2 or less per barrel.

In a model PFTSC, a contractor not only receives remuneration fees but also maintenance fees and any pre-defined recoverable costs. Round 1 awards included recovery of bonuses paid up front while Round 2 did not, reported *MEES*.

The full details of fees and billable expenses for the Iraqi projects were not disclosed but if included, they are additive to $2-per-barrel fees.

Just how many barrels of oil or cubic feet of gas will be counted as reserves for 2010 remains to be seen. Contractors in Iraq under SEC reporting rules don't have to disclose historical production or reserves separately by country unless they account for 15 percent or more of total global proved reserves.

Editor's Note: This article is based on public-domain information. Ryder Scott makes no claims for the accuracy of public information. The firm has not evaluated PFTSCs for any companies cited in this article. Ryder Scott has working knowledge of PFTSCs in Iraq and experience in analyzing service contracts for filing reserves compliant with regulations.