RESERVOIR SOLUTIONS

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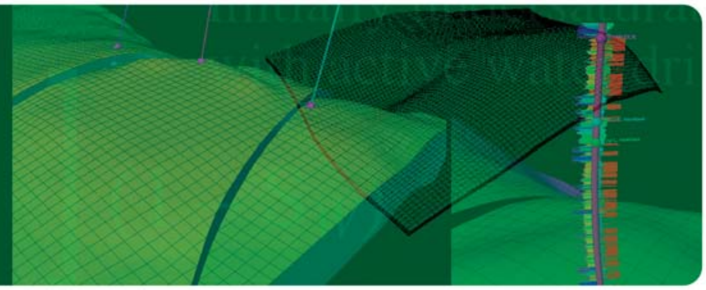

SEC weighs opposition to reserves proposals

The U.S. Securities and Exchange Commission in early December was expected soon to finalize petroleum reserves reporting regulations despite criticism from oil and gas companies that the proposed rules require too much disclosure. Integrated oil companies and large independents with operating units worldwide contend that it may take up to 20,000 hours per registrant for internal staff to prepare additional data, much of it in tabular format, for year-end 2009 filings.

Under proposed rules, companies would have to track field maturity and conversion of proved undeveloped reserves, report material reserves by field or basin and reservoirs as conventional or continuous, account for drilling activities by new well categories—extensions and suspended—and by location, disclose new technology and submit qualifications of evaluation staff.

Both sides are far apart. The SEC estimated compliance costs to average 35 hours per company.

None of the 29 O&G companies fully supported all eight items of Subpart 1200 of Regulation S-K, with most saying that the additional disclosures were overly burdensome, provided little value to investors, compromised competitive positions and, in some cases, were outright illegal in host countries.

Inside Reservoir Solutions newsletter

By the numbers

O&G companies filing with SEC—308
O&G companies commenting—29
- For disclosing evaluator qualifications—5
- For mandated 2P reporting—1
- For mandated 3rd party evaluations—1
- For mandatory disclosure of PUD data—0
- Against indirect measurement technologies—0

Companies were unanimous in their opposition to dual pricing — one for accounting, one for reserves filings — and to any requirements to use third-party evaluators. Likewise, registrants were unified in supporting a guideline to change the standard from "certainty" to "reasonable certainty" for booking PUD reserves more than one location from a producing well.

Companies also overwhelmingly supported the use of indirect measurement technologies, such as wireline formation tests and seismic, to define lower limits and aerial extent of the proved reservoir volumes. Despite urging the SEC to consider the reporting of probable and possible reserves categories to more fully account for assets, several companies, including 10 through the American Petroleum Institute, backed off that position, which originally was intended to benefit investors.

Those companies asked the SEC not to allow optional filing of those less certain categories, remarking that the current system allows management to cite 2P and 3P quantities in discussion and analysis, press releases, etc.

Historical averages for pricing

Most companies wanted to change from a single year-end price to a 12-month historical average for estimating reserves. Some suggested the use of averaged daily prices instead of month-end prices and the use of prices on the first day of the month rather than the last. Comments called for the 12-month reporting period to conclude one to three months before the calendar year-end date to allow more preparation time for March filings.

A handful of companies called for the use of futures pricing market data. Earlier this year, U.S. indepen-

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Ryder Scott asks SEC for transparent, open venue

Ryder Scott submitted a 27-page comment letter drafted by **John Hodgin**, president, to the SEC. See main article on Page 1.

The firm supported the submission of a third-party report letter, referred to as a "report" by the SEC, as an exhibit to the filing. Ryder Scott agreed with the SEC not to require the submission of full reserves reports with detailed data at property, field and well levels.

The SEC proposed a more stringent standard for reasonable certainty where the estimated ultimate recovery is much more likely to increase than to either decrease or remain constant. Ryder Scott suggested that the SEC incorporate guidance aligned with prior industry standards that the EUR is much more likely to increase or remain constant than to decrease. The firm also said that the proposed definition of a deterministic estimate could be construed as applying only to static volumetric estimates and suggested the use of dynamic performance methods as well.

Ryder Scott said that unconditionally presenting empirical proof that a specific technology leads to the correct conclusions in 90 percent or more of its applications is problematic. The firm said that the requirement would be "excessively burdensome and in certain instances could represent a concern regarding the disclosure of emerging technology and the loss of a competitive advantage."

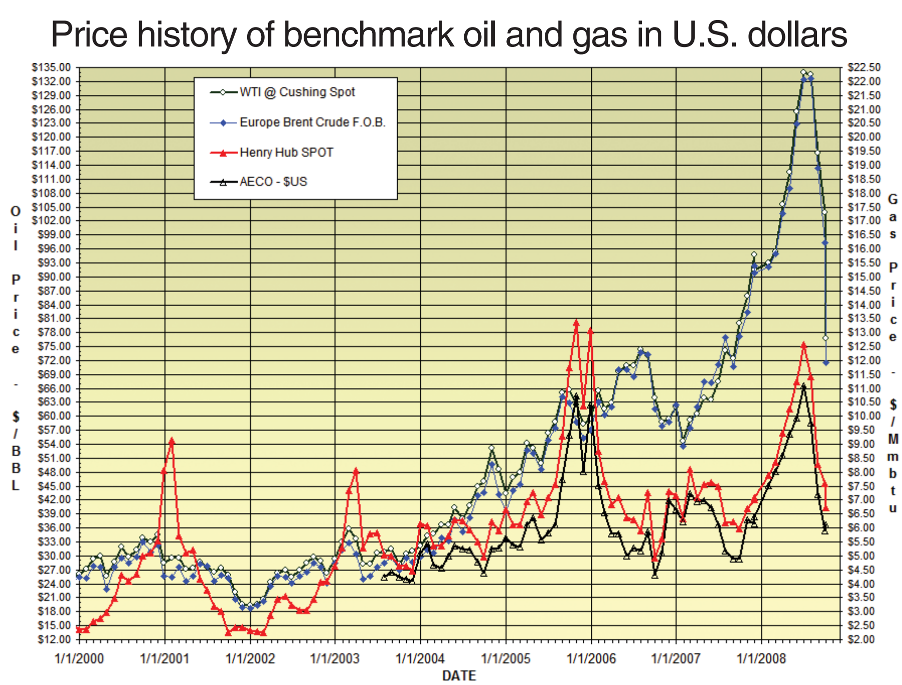
Ryder Scott added that "companies should be ready to provide the SEC compelling evidence supporting all evaluation techniques and the underlying technologies used in their reserve determinations."

The firm also supported the use of technologies that do not provide direct information. Ryder Scott opined on the use of wireline formation tests for detecting lowest known hydrocarbons, saying that "the extrapolation of downdip hydrocarbon limits should be primarily, but not solely, based on pressure vs. depth plots, which include data points obtained from the same hydraulically continuous reservoir for both the hydrocarbon and water phases."

The firm added that "pressure data must be of sufficient quantity and quality to substantiate a unique continuous fluid gradient trend. Extrapolated downdip limits should not conflict with other subsurface geological or geophysical data such as downdip wet wells, seismic amplitude terminations or seismic flat spots."

Ryder Scott also supported "the use of well-calibrated, high-resolution seismic data (that) may also be considered subject to the constraints noted for a clear demonstration of reliability."

While the SEC called for heightened disclosure, Ryder Scott suggested that the agency reciprocate by establishing a "more open and transparent venue in which to engage the SEC for clarification of the regulations." Ryder Scott asked the SEC to conduct a series of presentations with question-and-answer sessions, participate in public forums, publish Q&A content in its already established "topic series" and post clarifications on its Web site.



The historical price chart shows published, monthly-average, cash market prices for WTI crude at Cushing (NYMEX), Brent crude and Henry Hub and AECO gas.

Publisher's Statement

Reservoir Solutions newsletter is published quarterly by Ryder Scott Company LP. Established in 1937, the reservoir evaluation consulting firm performs hundreds of 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.

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Industry Comments—Cont. from Page 1

By the numbers

Independents commenting—19
IOCs commenting—9
NOCs commenting—1

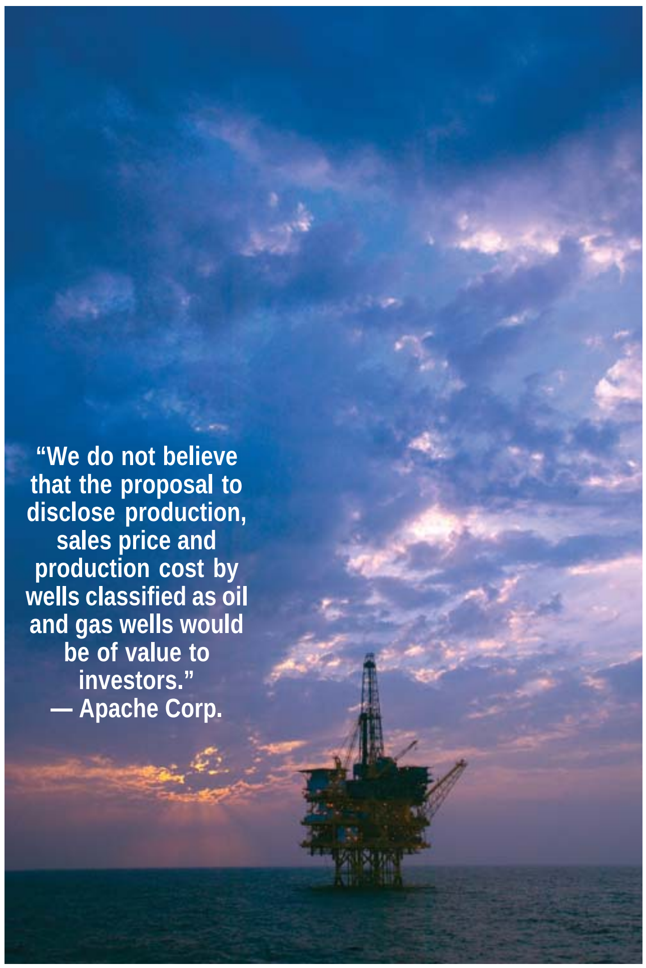
SEC estimated 35 hrs. avg. per issuer to comply
O&G companies estimated up to 20,000 hrs. to comply

Industry-requested deadline for rulemaking—Dec. 31, 2008
SEC-proposed effective date—Dec. 31, 2009

dents Apache Corp., Southwestern Energy Production Co. and Chesapeake Energy Corp. asked the SEC to consider futures pricing. However, they reversed their positions in their latest comments, opting for a historical average.

McMoRan Exploration Co. called for the commission to use forward-looking prices to "more closely reflect the frame of reference that management applies in decision-making," adding that "disclosures would be much more relevant to investors while preserving comparability along companies." The New Orleans-based independent said that "historical prices have little meaning in considering future investments and values."

Joining McMoRan was StatoilHyrdo ASA which said that futures prices ideally represent risk discounted price forecasts. The Norway IOC opined that it is "appropriate to look to the future and not to the past," and expected futures prices "to be less affected by short-term volatility caused by well-understood and short-lived supply disruptions or demand swings."



Sensitivity analysis

The SEC proposed an option for companies to calculate and disclose reserves under varying price scenarios (price decks). Responding companies were split on this issue. McMoRan said that a minimum level of sensitivity analysis should be required and not just optional to facilitate those assessing the impact of prices on reserves. Chesapeake and Evolution Petroleum Corp. supported sensitivities.

Exxon Mobil Corp. did not oppose the disclosure as optional, but said it would not implement it because of cost. Shell International BV and Petrobras, a Brazil-based IOC, opposed price sensitivities.

Just say no to unproved reserves

Exxon led the charge to nix reporting of 2P and 3P reserves, saying, "We strongly prefer that reserves reporting be limited to proved reserves only as prescribed by the current disclosure requirements. However, we view the proposed optional reporting of probable and possible reserves as an acceptable alternative to mandatory reporting." The company warned industry to "be willing to accept a higher risk of additional, unwarranted litigation due to the inherent uncertainty associated with these reserves," if optional reporting is approved.

Oklahoma City-based Devon Energy Corp. also cited the litigation risk in calling for reporting proved only, adding that disclosing unproved reserves can cause "misunderstanding by investors of potential recovery from projects in a company's portfolio of properties." Apache said that voluntary disclosure of unproved reserves would contribute to confusion as "investors may not understand the reasoning as to why one registrant discloses this information and others do not."

Statoil asked the commission to prohibit the reporting of possible reserves, but supported disclosure of probables. Petro-Canada was the only company calling for mandated reporting of probables. The Calgary-based independent also supported optional reporting of other unproved reserves categories as well as resources, whether "formally" or through press releases.

U.S. regulators permit companies to cite unproved reserves and resources in non-filed material, such as MD&A, press releases, etc. Securities regulators in Canada require 2P reporting under National Instrument 51-101 with reporting of resources as optional.

Geographic specificity

The SEC has proposed to require reserves disclosures by continent, except where a particular country contains 15 percent or more of the company's global oil or gas reserves or where a particular sedimentary basin or field contains 10 percent or more of the company's reserves. Italy-based Eni SpA said that "once the geographic separation is determined, the same breakdown is required for other data such as production, prices, drilling activity, wells and acreage.

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Cont. from previous page

… Such detailed disclosures in a rigid geographic segmentation will result in many instances in a non-optimal representation." Operating costs would also have to be tabulated geographically.

Eni also said that this rule "may jeopardize the company's negotiating position as well as asset sales." The IOC also cited restrictions in disclosing field-level data, saying that it would be "unfortunate" if disclosure obligations for a U.S. listing put the registrant at a competitive disadvantage.

Non-U.S. IOCs Repsol, Statoil, Total SA, Shell and BP also called for less geographic specificity. Departing from that view, Petrobras encouraged reporting by basin and country at the 10 and 15 percent thresholds, respectively, while sidestepping the issue of field-level disclosures. No other oil and gas company supported geographic breakdowns.

Reliable technology

The commission proposed disclosure of reliable technology, proven empirically to lead to correct conclusions 90 percent or more of the time, in first filings and for material reserves additions. No commenting O&G company fully supported the proposal for technology disclosure.

Chesapeake said that the 90 percent threshold is an "unreasonably high bar for a single technology involving interpretation of data." The company also took exception with a definitional element of reliable technology as "widely accepted," saying that it would exclude proprietary techniques.

Denver-based Questar Market Resources said that it doubts "that the average investor reviewing a …particular alternative technology will be able to grasp whether the appropriate level of certainty has been achieved," while conceding that disclosure is necessary "where traditional technology is not practical, such as flow tests in the Gulf of Mexico." Four other independents questioned the 90 percent criterion.

Exxon said the contribution of a single, disclosed technology is difficult to assess in projects where multiple technologies are used and experience and judgement are key factors. Chevron agreed, saying "development of a major field in the modern era is normally associated with a number of technologies, data sources and interpretation methods, with varying degrees of interdependence. Having such a rule may also result in gratuitous disclosures… "

Shell, Eni, Statoil and Total also objected in part or wholly to the proposal for any one of the previously cited reasons. Pemex, which issues bonds in the U.S. and was the only national oil company commenting, said that investors would require the support of highly specialized personnel and detailed technical data to understand the benefits of new technology. The Mexico City-based company asked the commission to reconsider the proposal.

Analogs

Shell asked the SEC to revise its guidance on analogous reservoirs. The rule now is that a subject reservoir must have the same values or better compared to an analog for porosity, permeability, permeability distribution, thickness, continuity and hydrocarbon saturations.

"This guidance …would reject any analogue where there is an immaterial difference in one of the above categories. We believe that proper evaluation of an analogue should examine the above categories in the 'aggregate' as opposed to individually, where there may be immaterial differences," the company said.

Statoil asked the commission to remove the geographic proximity criterion from the definition of an analogous formation, saying that "it is not the location of the analogue that matters, but its properties established through geologic history."

Reserves or not?

Chevron disagreed with the agency's remarks in the proposed rules that "once a resource is extracted from the ground, it should not be considered oil and gas reserves." The SEC referred to its own "historical treatment" of that issue, but in the past, the agency has not handled the issue that way.

For instance, the commission has generally agreed with SPE that extracted gas reinjected into the native reservoir can remain as reserves under certain circumstances. The argument between regulators and the industry centers on unsold gas injected into a non-native reservoir.

The SEC considers that gas can remain reserves only if it was reinjected into the reservoir from which it was produced. SPE-PRMS definitions allow more leeway so that gas can be injected into other reservoirs located on the same property and still be considered as reserves. The argument for that position is that those volumes do not have transfer of ownership or payment of royalties and although extracted, they are not produced for sale.

The industry has recently challenged the SEC's hard-line approach. Often industry views the key issue to be transfer of ownership rather than whether volumes are reinjected or injected.

If ownership has not been transferred, then the gas is considered to be reinjected and reserves regardless of whether the gas goes into to the same or non-native reservoir.

Qualifications

Most companies were against disclosing the qualifications of internal or outside evaluators. Exxon said that citing the qualifications of each employee would be burdensome and of little value to users of financial statements. The company also questioned how standards could be established considering differences in educational systems, licensing and certification requirements and professional bodies from country to country.

Exxon said that if the SEC insisted on the disclosure of qualifications that it be limited to the chief technical person who oversees the internal reserves estimation process. API said that the disclosure of qualifications would be a violation of privacy laws in some countries.

Total also said that the requirement was not practical considering its number of geoscientists and engineers evaluating reserves. However, the Paris-based IOC reiterated its support for the international certification of reserves evaluators to ensure "homogeneity of training and qualifications." Total suggested as an alternative that the commission require that issuers conduct training programs certified by an appropriate professional organization.

Calgary-based Encana Corp. was one of five companies—including Petro-Canada, Petrobras, Southwestern and McMoRan—supporting disclosure of qualifications, saying that companies should "provide information with respect to those involved in the preparation of reserves, their qualifications, experience, methodologies employed and level of independence." Petro-Canada also agreed with disclosing evaluator qualifications meeting minimum standards but did not support the proposal that evaluators be limited to those in an internal audit group.

"Reserves evaluators within the operating groups will be most familiar with the assets and will be in the best position to utilize professional judgement …," stated the company.

PUD vintaging

No companies gave blanket support to the annual disclosure of a table showing PUD reserves converted to proved developed reserves over five years. The table would also show net investments required to convert PUDs. Chesapeake generally supported the PUD table but said that mandatory disclosure of those details is not practical and called for optional reporting.

Few companies supported the five-year maximum time frame to convert PUDs to the proved developed category. Chesapeake suggested a 10-year time frame, saying that continuous accumulations, such as the U.S. shales, take decades to fully develop.

Questar supported the five-year limit, saying that the "standard forces a degree of discipline on companies claiming such locations as proven by forcing an assessment of likely prices, drilling and completion costs, geologic quality and access to market during that period before making such disclosure. As a result, we support the five-year standard and believe it affords the desired transparency and comparability to investors."

Odds and ends

No company supported the mandated use of third-party reserves evaluators or auditors except Petrobras, which suggested that companies use outside parties for reserves estimates every three years. Most companies supported filing summaries or letter reports from third party consultants rather than full reports. Statoil supported filing a third-party report containing disclosures proposed by the SEC.

The SEC asked whether it should require the issuer to demonstrate financing for a project to be reasonably certain of implementation, which is requisite for booking proved reserves. Comments varied.

Evolution said proof of financing should not be required, because "this would create a chicken-or-egg scenario for companies that develop projects and then solicit financing. Reservoir engineers will not sign off on proved status due to lack of confirmed funding, and financing sources won't commit funds or will demand onerous terms due to lack of proved status."

Most companies supported the recognition of bitumen, shale gas and other unconventional resources as reserves if the end product is hydrocarbons, regardless of extraction methods. That opens the door for reporting mined bitumen converted to oil as reserves.

Sasol, which also has mining operations, was the lone dissenter, saying that hydrocarbon quantities only should be counted as reserves if production occurs through wells.

Postponement

Companies recommended that if the SEC makes no decision by Dec. 31 that it postpone compliance until year-end 2010. Chevron asked the SEC to

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Four engineers, geologist join Ryder Scott in Houston

Ojo

Ryder Scott supplemented its Houston staff with the addition of four petroleum engineers and a geologist. **Bukky Ojo**, geologist, interprets and correlates well logs and seismic data, maps stratigraphic and structural features and analyzes formation pressures. As a geoscientist at Shell Exploration & Production Co., she interpreted 3D seismic data, mapped Gulf of Mexico fault systems and interpreted and integrated seismic horizons with paleo data.

Before that, Ojo worked at Schlumberger Data & Consulting Services as a geoscientist where she analyzed sonic waveform, 3D anisotropy and fracture data from sonic-imaging and scanner-logging tools. She also built and evaluated 3D geological models of reservoirs in the U.K. North Sea and U.S. mid-continent. Ojo has a MS degree in geophysics from the University of Oklahoma.

Porbandarwala

Ali A. Porbandarwala, petroleum engineer, joined Ryder Scott from Deloitte Consulting LLP. Previously, he worked at Exxon Mobil Corp. for seven years where he began his career as a procurement advisor for capital projects in the United Arab Emirates, South Korea, Venezuela and Equatorial Guinea. Porbandarwala tendered, evaluated and negotiated proposals for procurement of offshore platforms, equipment packages and subsea completion systems.

He also was a project engineer for field development in Chad. He planned onshore drilling and coordinated annual budgeting.

In addition, Porbandarwala was an engineering coordinator and process engineer for an Angola gas-gathering project. He conducted hazard and operability studies, risk assessments, design strategies and contractor productivity measurement.

He was a process engineer for the Adriatic LNG terminal for three years. Through modeling and review, Porbandarwala tested handling design for various types of LNG.

He conducted risk assessments and HAZOPS of facility design and managed and approved onsite design changes. Porbandarwala has a BS degree in chemical engineering from the University of Kansas.

Sepolio

Eric A. Sepolio, associate petroleum engineer, served internships at Hilcorp Energy Co., Houston Exploration Co. and Anadarko Petroleum Corp. He received training in evaluating acquisition prospects and preparing production and cashflow forecasts. Sepolio built proved non-producing and undeveloped upside cases based on field development plans and volumetric analysis. He has a BS degree in petroleum engineering from Texas A&M University.

Smith

Lucas Smith, petroleum engineer, previously worked at SBM Atlantia Inc. for three years as a process and marine engineer. He performed design engineering for several international projects, including oil-tanker conversions to FPSOs and construction of oil and gas offloading systems.

In 2003, Smith started at Honeywell Process Solutions as a project engineer for two years involved in deepwater production platform projects and control systems. He supported process startup and all first oil activities.

Smith has a BS degree in chemical engineering from Texas A&M University and an MS degree in petroleum engineering from the University of Houston.

Smith

Timothy W. Smith, senior petroleum engineer, most recently was a consultant for four years. He conducted waterflood and completion engineering, decline-curve analysis, log analysis, reserves evaluations and economic projections. Previously, Smith worked at BASF Corp. and EFP Corp. for 11 years, starting as a site manager, then as a group vice president and then as president of EFP.

He also worked at BASF/Wintershall Energy during 1982 to 1991, starting as a reservoir engineer in waterflood production and well stimulation. Smith became manager of engineering and acquisitions in charge of reserves evaluations and economic analysis.

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Estimating production from hurricane-damaged platforms

Hurricane Ike pounded rigs and platforms in the GOM.

Industry is asking how to properly treat year-end reserves estimates taking into account hurricane damage to offshore platforms and subsequent impaired production. Hurricane Ike in September destroyed 54 production platforms, damaged another 95 and destroyed a jackup drilling rig in the Gulf of Mexico, the latest figures show.

Under advice from accountants and outside engineering firms, operators are downgrading pre-Ike proved producing reserves classifications until repairs are completed, if they intend to restore production.

- Magnitude of the repair is a key. Minor repairs are considered those that can be accomplished before the effective date of a new reserves report and thus are not an issue.
- Major repairs require large amounts of capital expenditure and construction/fabrication of major components. Examples are the complete replacement of a platform, repair operations with extensive underwater or topsides refurbishment and redrilling of wells. Projects with major repairs should be downgraded to proved undeveloped, if project economics show that repairs are economically feasible. If the economics are not positive or project viability is questionable, reserves should be downgraded to probable, possible or contingent resources under the SPE-PRMS. One possible exception: If damage is to a production facility platform only, then the classification for platforms feeding into the production facility may be revised to proved shut-in, assuming a definite plan to restore the production facility. See final bullet point.
- Situations falling between these two extremes are considered significant repairs and reserves are downgraded from proved producing to proved shut-in.
- Some platforms have received little or no damage, but downstream facilities or pipeline damage prevents production. In some cases, operators are resorting to barges to transport oil or taking other steps to restore the necessary facilities. In those cases, a downgrade from proved producing to proved shut-in may be appropriate. In other cases, the operator may not have a clear plan for restoring production, particularly when plans depend on the actions of other parties, such as pipeline operators. If the operator cannot provide a plan for restoring production or a feasible alternative, the field has essentially become stranded reserves and should be downgraded to contingent resources.

If the structure is insured, repair costs in the reserves report should be the deductible, if those costs are allocated at a property level. However, companies commonly account for insurance premiums, deductibles and receipts at the corporate level with no allocations at a property level.

If repair costs exceed the insurance policy cap, amounts over the cap should be included as repair costs in the reserves report.

For self-insured companies, all repair costs are shown in the reserves report.

Insurance recoupment for operating costs or business interruption is other income and not included in the reserves report. Operating expenses are not netted against business-interruption receipts.

From an accounting perspective, costs incurred to repair damages are likely expensed rather than capitalized. In before-tax reserves reports for U.S. regulatory reporting, those costs are shown in the capital category.

Even when platforms are shut-in, operating costs are incurred during that period. The fixed portion of lease operating expenses is appropriate to use in many cases.

Insurance premiums are climbing. If a company pays higher premiums and allocates those to the property level, LOEs in the reserves report reflect that.

If a company has decided to abandon a well or field instead of returning it to production, the property and its abandonment cost may have to be included in the reserves report. If abandonment costs are covered by insurance, then the reserves report should include the property with zero costs and cash flow with an appropriate footnote.

Companies should document instructions and assumptions regarding repairs, particularly timing estimates, to make it easier to justify proved reserves. In some cases, insurers balk at paying for major repairs on marginal properties, arguing that it is not prudent to restore facilities if the reserves values are less than the payoff amount. Under the Sarbanes-Oxley Act and FAS 144, which addresses impairment or disposal of long-lived assets, companies are required to provide a plan of action

Please see Ike on Page 8

Smith—Cont. from Page 6

He then became vice president of operations where he managed drilling budgets and more than 2,000 U.S. producing properties. Smith also worked at Cities Service Oil Co. for five years starting in 1977 when he began his career as a production engineer.

He later became a project engineer in charge of international evaluations, offshore platform design and installation and reservoir modeling related to potential water coning. He has a BS degree in petroleum engineering from West Virginia University and an MBA degree from the University of Phoenix.

From left, Dmitri Zabrodin, vice president at FDP Engineering LLP in Moscow, and Larry Connor, managing senior vice president at Ryder Scott, look at children's drawings of oilfield scenes displayed at the SPE Moscow conference in late October. The drawings are winners of a contest in Russia sponsored by Mir Nauki (World of Science). The aim is to spark an interest in the oil industry by children of parents in the industry. Ryder Scott sponsors the project, "We are the children of oilmen," and will publish a photo essay in March. Photo courtesy Reed Exhibitions.

Industry Comments—Cont. from Page 5

reconsider the effective date and content of the final rule to allow synchronization with the effort to harmonize and converge accounting regulations of the U.S. Generally Accepted Accounting Principles and the International Financial Reporting Standards.

BP said that it considers the API estimate of 15,000 to 20,000 hours to comply with added disclosures to be "a realistic approximation" and requested that the SEC postpone the implementation date.

Editor's Note: It is not the intention of this summary, which contains excerpted material, to fully represent the positions of cited companies within the full context of their public comments.

For a complete review of all posted comments, go to http://www.sec.gov/comments/s7-15-08/s71508.shtml.

Ike—Cont. from Page 7

Financial wherewithal and company intentions are important. Cover letters to reserves reports should include a discussion of the consultant's assumptions and client instructions regarding those issues.

Some properties will not be restored for years. Companies suffering from cashflow squeezes may be forced into bankruptcy and the reserves report will undergo the microscope of bankruptcy court.

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