Estimating oil and gas reserves is one of the most important functions for petroleum companies to support portfolio management and revenue forecasting. The investment community uses reported reserves to assign values to companies or to individual projects, which is important to the stock markets and for financing projects. Governments use reported reserves for regulatory oversight and for forecasting national petroleum production. In 2008, one of those government agencies, the U.S. Securities and Exchange Commission (SEC), published “Modernization of Oil & Gas Reporting.” The document was based on numerous recommendations to update reporting rules for oil and gas companies to reflect the advance in technologies.

The new rules took effect in 2009, and set the stage for a stronger integration of geophysical technologies in petroleum resource estimation and reserves reporting. In 2008, SEG set up the Oil & Gas Reserves Committee to facilitate the involvement of the geophysical community in the field of reserves estimation. It was recognized that geophysics has an important and perhaps expanding role in reserves calculations. The contribution of geophysics can be divided into static and dynamic reservoir characterization. For static modeling, any geophysical methods that can delineate the reservoir, estimate the lithology, porosity, or fluid content; or estimate the relative depth of the reservoir to the fluid contacts are of particular importance. Seismic AVO and flat-spot methods, acoustic and elastic inversion, and depth conversion are but some of the clear examples of geophysical technologies used in static modeling. Emerging new technologies like CSEM also have the potential for fluid delineation. For dynamic modeling, 4D seismic is now a proven technology, and can help not only in reservoir management but also directly in reserves estimation. Experience tells us that all these methods sometimes work really well and sometimes not, depending on geological setting and production history. Integration of geophysical and geological analyses results with available production data is necessary to estimate reserves. It is therefore important and up to the individual companies to justify that given technologies are reliable in the context they are being used on a case-by-case basis.

This month’s special section is the first collection of papers to address the role of geophysics in petroleum resources and reserves estimation. The articles comprise a wide range of different perspectives and experiences, from review of guidelines for classification of resources, use of seismic data to establish fluid contacts, to examples and reliability of direct hydrocarbon indicators. The focus of the articles is on the impact of seismic technology on resource evaluation.

The first paper, “Introduction to the Petroleum Resources Management System and the implications for the geophysical community,” by Lorenzen et al. is a review of the industry guidelines for resource classification and estimation also known as PRMS. Sponsored by many of the leading technical societies (SPE, AAPG, WPC, SPEE, as well as SEG), PRMS has become a global standard for resource evaluation. One of the fundamental criteria for a petroleum accumulation to be called reserves is that it can be commercially recovered by application of development projects under defined conditions. Projects are therefore essential to the classification of resources and broadly dependent on the project’s chance of commerciality. The three classes of resources are: Reserves, Contingent Resources, and Prospective Resources. While the classes reflects the maturity of the projects, the uncertainty in estimated sales quantities of petroleum is given by a best estimate together with a low and a high estimate. The paper also discusses a couple of hypothetical examples relating the value or use of seismic data in classification and categorization of resources.

The second paper, “The role of geophysics in petroleum resources estimation and classification—new industry guidance and best practices,” by Kloosterman and Pichon, zooms in more specifically on the guidance provided in the PRMS Application Guidelines issued in 2011, supplemented with some case study examples from several IOCs illustrating the impact of applying geophysical technologies for assessing structural definition, reservoir development, fluid contacts and movements and for flow surveillance.

An integrated interpretation with production history, static and dynamic data is the most effective way of assessing reservoir extent and performance. In “Resource assessment based on 4D seismic and inversion at Ringhorne Field, Norwegian North Sea,” Johnston and Laugier discuss how $V_p/V_s$ from elastic impedance and 4D seismic together helped extend the mapped oil-bearing part of the reservoir based on the observation that 4D seismic showed water sweep in an area previously thought to lie below the original oil-water contact. This area had no well control, so the 4D data in addition to the fluid response from the water sweep help constrain the time-to-depth conversion. The $V_p/V_s$ interpretation helped extend the mapping of thin sands updip. The implied increase in volumetrics was supported by production data suggesting larger in-place volumes than previously estimated.
In “Seismic technology supporting reserves determinations: Gorgon Field, Australia,” van der Weiden et al. describe a strategy for using seismic and inversion data to estimate reservoir continuity. Gas condensates are located in fluvial channel sands that are acoustically soft. The strategy includes defining with reasonable certainty the reservoir tank, then establishing the internal continuity of the reservoirs, and finally the reservoir properties and their continuity. The analysis of seismic and well data creates a case static model, which is then combined with uncertainty analysis in a probabilistic way. The emphasis is on reasonable certainty to demonstrate clearly the reliability of the data. In this way, the seismic interpretation and quantitative interpretation in combination with integrated reservoir modeling and engineering data were used for reserves booking purposes under the principle-based SEC rules.

Pichon et al. discuss the use and confidence assessment of direct hydrocarbon indicators (DHI) for resources evaluation. In their paper “DHI support for resources evaluation: Confidence assessment examples,” they provide three examples to illustrate the integration of seismic DHI with well results. The examples are in contact and compartmentalization evaluations. Confidence assessment methodology necessary to evaluate the DHI robustness and certainty are emphasized. The methodology includes assessment of the seismic and petrophysical data quality, and their ability to properly represent the seismic response for the known (or expected) reservoir and fluid characteristics. Then the geophysical information is evaluated for consistency with the geological and dynamic knowledge of the field including their uncertainties. It is the cross-view between seismic technology and field production behavior that is key to confidence for reserves and resources evaluation.

DHI reliability and statistical significance is also discussed in the next paper: “Relating seismic interpretation to reserve/resource calculations: Insights from a DHI consortium” by Roden et al. Based on well results from 217 prospects around the world, analysis was made between AVO classes, DHI characteristics, DHI grades and success or failures of the wells. Most of the wells were exploration wells. The analysis of the full database allows for computation of a DHI index given a specific DHI prospect interpretation. A high index number implies a high reliability of the particular DHI in question; if the index number is low, then so is the reliability. The paper outlines a strategy for using the DHI index for resource calculations in exploration with regard to area determination or thickness determination. For instance, for area determination a weighted sum of the areas defined by geological observations and the area defined by the DHI extent can be used. In addition, for thickness determination, the potential of seismic tuning also need to be considered.

Reservoir connectivity is important to reservoir engineering developments projects, as it directly impacts the planning of well patterns and well completion. In their paper “Stochastic volume estimation and connectivity analysis at the Mallik gas hydrate field, Northwest Territories, Canada,” Dubreuil-Boisclair et al. provide a probabilistic estimation of the spatial heterogeneity of gas hydrate grades and assess the connected natural gas volumes, at different grade cutoffs. Gas hydrate layers have an ice-like structure of hydrates, which increases the stiffness of the sediment matrix. This causes the P-wave velocities to be significantly larger in highly saturated gas hydrate layers. Acoustic impedance from 3D seismic together with gas hydrate grade data from wells is used to obtain many gas hydrate grade realizations. A stochastic connectivity analysis is computed for each 3D gas hydrate grade scenarios. The connected natural gas volumes can be estimated together with its uncertainty, for each layer, at different cutoffs.

Eastley et al. in “Case study: Using seismic inversion to constrain proved area definition” provide an example of the integration of seismic impedance data with production data as a basis for Proved Area determination. The depositional model is of a high net-to-gross large turbidite system composed of feeder channels that feed and incise into a background of lobes. Well test data clearly highlight that parts of the reservoir are producible at commercial rates. P-impedance data showed consistent low values for good well (production) areas, and high values for bad well (production) areas. The seismic inversion was thus deemed capable of discriminating between good and bad wells with reasonable certainty, and it was therefore used to extrapolate the lateral extent of the Proved Area into adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it.

The last paper is by von Lunen et al. and titled “Strategies in geophysics for estimation of unconventional resources” and is a discussion of the issues and techniques special to these plays. In unconventional resource plays, the deliverability system is a principal area that must be addressed by geophysics. This includes reservoir effectiveness, geomechanics, and stimulation treat. Reservoirs are often heterogeneous or fractured; identifying the fracture network and the stimulated rock volume is therefore an important component. Multicomponent 3D seismic surveys and 4D seismic surveys are established techniques for reservoir characterization. For gas shales with low permeabilities, the emerging technique of microseismic data is the geophysical tool of choice for estimating stimulated rock volume, future production, and recovery factor, because it is the only technique that can directly observe the creation of a drainage network within the stimulated resource container.

These papers show a wide range of applications of seismic data for resource and reserves estimation. A common theme is correlation of seismic to well results and production data. Many different uses of statistical analysis, either qualitative or quantitative, serve to underline the importance of reliability of technology for the problems considered. While the issue of reliability of technology is central to rules governing reserves reporting, it is also important to any other applications of geophysical technology. Geophysics in reserves estimation is a new field. We hope that these papers can help our profession understand the associated issues and possibilities. At the SEG Annual Meeting in Las Vegas in November, a workshop organized by the SEG Oil & Gas Reserves Committee will offer an opportunity to share and discuss issues around these TLE special-section papers.

Corresponding author: robert.lorenzen@maerskoi.com