IN-PLACE HYDROCARBON VOLUME CALCULATION TECHNIQUES

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Four principle techniques are used by Esso Production Malaysia Inc.'s explorationists for the calculation of in-place hydrocarbon volumes. The selection of any one method or combination thereof depends on the number of well control points, vertical and lateral reservoir variability and the geometry of the hydrocarbon accumulations.

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The first method is usually used early in the exploration phase of a field or prospect when well control is either absent or limited. Minimum, most likely and maximum values of each of the basic reservoir parameters such as hydrocarbon-bearing area, net pay, porosity, etc., are input into the computer. These are sampled using the Monte Carlo simulation technique to obtain the in-place hydrocarbon in each of a specified number of trials. All the results are then plotted as a curve showing volume of in-place hydrocarbon against the probability of occurrence.

The second method is used when limited well data is available and a quick analysis is required. This procedure utilizes a plot of the areas enclosed by structure map contours of the top and base of the reservoir versus depth, together with the known or estimated fluid contacts, from which is calculated the gross rock volume of the hydrocarbon-bearing part of the reservoir. This is then multiplied by the appropriate average net to gross sandstone ratio, hydrocarbon saturation, porosity and formation volume factor to obtain the in-place hydrocarbon.

The third method is used when well control is good and reservoir quality is relatively uniform both laterally and vertically. In this technique net hydrocarbon sandstone isopach maps are constructed, net rock volumes are then calculated with various formulae and these then multiplied with the field average values of porosity, water saturation and formation volume factor to derive the original in-place hydrocarbon.

The last method, known as the $\phi \times H \times S_h$ technique, is used when a field is well into the development phase and when there is considerable lateral and vertical variation in reservoir quality. In this method, isoporosity, isopach net sand/pay maps and isohydrocarbon saturation maps are constructed for each reservoir and these are then cross-contoured to obtain the $\phi \times H \times S_h$ map. If desired, the product of the net pay, average porosity and hydrocarbon saturation of the net pay in the mapped reservoir in each well can be plotted and contoured directly to obtain the $\phi \times H \times S_h$ map. Various formulae are then used to obtain the in-place hydrocarbon volume.

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