Review of DOE's Enhanced Oil Recovery Technology Screening Criteria

DOE's Tertiary Oil Recovery Information System (TORIS) consists of a reservoir database, EOR project database, EOR predictive models, preprocessors, and related programs. The process-specific predictive models predict oil production based on the limited available reservoir information and average properties. In the early 1980s the National Petroleum Council (NPC) established screening criteria (published in *Enhanced Oil Recovery* by NPC in June 1984) for each EOR process based on currently implemented and advanced technology. Since EOR technology has advanced over the past 10 years, these screening criteria need to be reevaluated.

Screening criteria were evaluated by comparing them to currently available information. The best source of information on EOR projects is DOE/BPO's EOR Project Data Base (NIPER-583), which contains information on 1388 EOR projects in 569 oil fields. A second source of information is the *Oil & Gas Journal (OG&J)* which publishes a list of current EOR projects every other year since 1980. The third source of information, especially for advanced screening criteria, is DOE/BPO and NIPER experts.

Tables 1 and 2 list the screening criteria developed in 1983 by NPC. Table 3 shows screening criteria that are read into the preprocessor programs. Suggested changes and reasons for making them are discussed in the following paragraphs and listed in Table 4.

THERMAL

Steam: Based on projects in DOE's EOR project database, the API gravity limits of 10°–34° for implemented projects are reasonable. Several of the profitable projects listed in the *O&GJ* 4/92 list the API gravities as ranging 7°–13° which suggests the lower limit could be decreased to 7°. A recent NIPER report (NIPER-580 *Practical Aspects of Steam Injection Processes – A Handbook For Independent Operators*, by Partha Sarathi and David Olsen) includes an excellent discussion of criteria for evaluating steam injection prospects (Chapter 2). It states that crude oils with API gravities from 6° to 50° are amenable to steam injection, and the process is usually successful in heavy oils of 8°–25° API. Based on the foregoing and discussions with Partha and Thomas Reid (DOE's project manager for thermal projects), recommended limits are 7°–34° for implemented technology. No limits are deemed necessary for advanced technology. The high upper limit formerly included known light oil steam projects. The only problem with this criterion is that the upper limit passes too many candidates. In this case, many which could be waterflooded are included. If viscosity is known, it is a better criterion for these projects.

Based on the same EOR database, an oil viscosity of less than 15,000 cp could be increased to 20,000 cp. A new minimum viscosity of 10 cp is recommended to eliminate many of the reservoirs where waterflooding would probably be more economical. The lowest viscosity for successful and profitable projects in the DOE database is 10 cp.

Depths of 3300 and 4400 ft are reported as profitable in the database and indicate that the depth limit could be raised from 3000–4500 ft. The *OG&J* (4/92) lists a profitable project where depth ranges from 2500–4500 ft. The upper limit for advanced projects could be increased from 5000–8500 ft, since a project at 8200 ft was run in Venezuela (NIPER-580, p. 21). If reservoir pressure is above 3208.2 psi (estimated depth of 7367 ft), the critical pressure for steam, steam flooding is practically impossible.

A maximum current reservoir pressure of 1500 psi for implemented projects is reasonable, based on data in the EOR database. The highest pressure for a profitable project is 1100 psi. As long as pressure is the actual pressure at project start and not estimated from depth, this is a good upper limit. At 4500 ft estimated initial pressure is 1965 psi (0.4335 times depth plus atmospheric pressure of 14.7). Reservoir pressure in the 8200-ft-deep project mentioned earlier was about 900 psi. For advanced projects the upper limit of 2000 psi is still reasonable, since projects at this pressure would require operating pressures close to 3000 psi (NIPER-580).

A pay zone thickness of 20 ft is reasonable, based on data in the database. A few projects between 16 and 20 ft thick (with high porosity and oil saturation) have been reported as profitable in the literature, which would suggest the lower limit could be reduced to 15. The upper limit of 50,000 is not a real limit and could be eliminated or lowered to 1000 to eliminate erroneous data without losing any reasonable projects. Projects are being conducted in Edison (CA) with 12 ft of pay (NIPER-580), which suggests the limit for advanced projects could be lowered to 10 ft. As with many reservoir variables, pay thickness is confusing and strongly related to other parameters. Is it net pay or gross pay? Heat loss to over- and underlying formations is related to gross pay. The ratio of net to gross also effects heat loss. Economics are determined by net pay (with porosity and oil saturation).

Lowering the porosity from 20% to 18% is recommended since projects at that level were reported profitable. Porosity is mentioned in the NPC report but not the program. An upper limit of 50% would prevent the use of erroneous data without eliminating reasonable projects.

Information in the database indicates the lower permeability limit could be decreased to 60 mD. The upper limit could be lowered to 10,000 mD to eliminate erroneous data without losing any current or planned projects. Permeability along with pay and viscosity determines injectivity. A transmissibility factor (the product of net pay and permeability divided by viscosity is a more reasonable screening criterion when all are present and especially when a project may be eliminated due to the single value screen. A value of less than 5 mD for the transmissibility factor is in the NPC report but may not have been used. This value is reasonable according to data in the database, where 7.5 mD is lowest for a profitable project.

The minimum oil content variable of oil saturation times porosity (both expressed as fractions) of 0.1 could be lowered to 0.09 (porosity 0.18) to include all profitable projects or to 0.08 (preferred) to include all projects. The two projects between 0.08 and 0.09 had no evaluation reported. An upper limit of 0.5 could be used to prevent the use of erroneous data without eliminating reasonable projects.

In Situ Combustion: Based on projects in DOE's EOR project database, the API gravity limits of 10°–35° for implemented projects are reasonable. However, these limits pass too many candidates. The high upper limit was used to include known projects. If viscosity is known, it is a better criterion for these projects.

Based on the same EOR database, an oil viscosity of less than 5000 cp could be decreased to 3000. A new minimum viscosity of 6 cp is recommended to eliminate some of the reservoirs where waterflooding would probably be more economical. The lowest viscosity for successful projects in the DOE database is 6 cp. New projects that could be called unconventional in situ combustion, where the important factor is the gases generated resulting in pressure maintenance or gas flooding, have been successful at viscosities less than 1 cp. Therefore no lower limit should be used for advanced in situ combustion.

The database shows depths of 11,200 and 11,500 ft as successful, indicating that the depth limit should remain at 11,500 ft. Depth is not a limiting criterion for advanced (unconventional) in situ combustion projects.

A pay zone thickness of 20 ft is reasonable, based on data in the database. One project at 19 ft was reported technically successful, but no profitable projects less than 24 ft were reported. The upper limit of 50,000 is not a real limit and could be lowered to 1000 to eliminate erroneous data without losing any current projects. As with many reservoir variables, pay thickness is confusing and strongly related to other parameters. The question of net pay or gross pay remains. Gross pay is what must be heated. In conventional in situ combustion, heat that lowers the oil viscosity is important to oil recovery. Heat loss to over- and underlying formations is also related to gross pay. The ratio of net to gross also effects heat loss. Economics are determined by net pay (with porosity and oil saturation). Heat loss is not critical for the unconventional in situ combustion projects (which rely more on the miscible gas process). These unconventional projects are reported to work for 2–12 ft of pay (average 4.4). Therefore the lower limit for advanced in situ combustion projects should be lowered to 2 or eliminated (preferred).

Porosity is also mentioned as a criterion for in situ combustion. If used porosity could be lowered from 20% to 15%. The lowest value for a successful project in the database is 16%. An upper limit of 50% would prevent the use of erroneous data without eliminating reasonable projects. Since heat loss is not critical for recent unconventional in situ combustion projects (which rely mainly on miscible gas processes), porosity limits should be eliminated for advanced projects.

Information in the database indicates the lower permeability limit of 35 mD is reasonable, but the upper limit could be lowered to 10,000 mD to prevent passing erroneous data without missing any reasonable projects. Permeability along with pay and viscosity determines injectivity. A transmissibility factor (the product of net pay and times permeability divided by viscosity) is a more reasonable screening criterion when all factors are known in order to prevent a project's being eliminated due to the single value screen. A reasonable value of less than 5 for the transmissibility factor is in the NPC report, but it may not have been used.

A maximum reservoir pressure of 2000 psi for implemented projects could be increased to 3500 psi (highest successful project in the database is 3200). According to experts at NIPER, unconventional in situ combustion projects are being conducted at 4200 and 4800 psi. Current equipment is limited to 6000 psi, a reasonable upper limit for advanced projects.

The minimum oil content variable of oil saturation times porosity (both expressed as fractions) of 0.08 is reasonable. Lowest value for a successful project is 0.09. This value is reasonable also for advanced projects.

CHEMICAL

Surfactant: Based on the small amount of data in the EOR database, the upper limit of 40 cp is reasonable. A 36 cp project had encouraging results. Only one project with a higher value (43) was reported, but no evaluation was reported. The upper limit of 100 cp for advanced projects is still reasonable.

Insufficient information exists on reservoir temperature in the database to recommend changes in the 200°F limit. This value is intuitively reasonable for this process. An upper limit of 250°F remains acceptable for the advanced projects.

Although the data are limited, a case could be made to lower the permeability limit from 40–35 mD to include two projects at 39 mD. Transmissibility (discussed earlier), injection rate, or even production rate would be a better criterion. The lower limit of 10 mD for advanced projects is reasonable.

Based on one project at 117,000 ppm, evaluated as encouraging, the limit for salinity could be raised from 100,000 to 120,000 ppm. The 200,000 upper limit for advanced projects is acceptable.

Polymer: The upper limit of 100 cp for oil viscosity is reasonable, since 85 cp is the highest value for a profitable project in the database. The 150-cp upper limit for advanced projects is also reasonable.

A temperature limit of 200°F is reasonable, based on data in the database. Highest value for a successful project is 190°F. The upper limit of 250°F for advanced projects is still reasonable.

The permeability limit of greater than 20 mD could be eliminated, since a project of 4 mD and several projects with lower permeabilities (probably fractured) are reported to be successful. The 10-mD lower limit for advanced projects would also be eliminated. Again transmissibility (discussed earlier), injection rate, or even production rate would be a better criterion.

Insufficient information on salinity exists in the database to recommend changes in the 100,000-ppm limit. This value is intuitively reasonable for this process. The 200,000-ppm upper limit for advanced projects is acceptable.

Alkaline: In the early 1980s the most important factor for alkaline floods was thought to be the acid number. Acid number is not widely available but roughly correlates with API gravity. Therefore, an upper limit of 30° API was used for this process. Based on very limited information in the database, the upper limit for this process could be raised to 45° to include a successful project at 43°. The upper limit for advanced (alkaline surfactant or alkaline surfactant polymer) projects should be eliminated since neither acid number or API are considered critical.

Not enough information is available in the database to recommend changing the upper viscosity limit of 90 cp. For advanced projects the upper limit of 100 cp is still reasonable.

Not enough information is available in the database to recommend changing the upper temperature limit of 200°F. The same limit is still acceptable for advanced projects.

A successful project at a permeability of 7 mD indicates this criterion could be lowered from the present 20 mD. Lowering this criterion to 5 mD would drastically reduce its usefulness. Advanced projects would have to be lowered to the same level. Transmissibility (injection or production rate) would be a better criterion.

GAS

Miscible (CO_2): Based on data in the database, the lower limit of 25° API gravity is reasonable. Profitable carbon dioxide projects are reported with APIs of 26° and 29°. The upper limit of 60° was not meant to be a limit. Highest API for a profitable CO_2 miscible project is 44°. Other miscible gases go up to

54° for profitable projects. The highest API for any gas project was 60°. No change is recommended for this criterion.

All profitable miscible CO_2 projects that had sufficient data (43 projects) to calculate minimum miscibility pressure passed this screening criterion. Minimum miscibility pressure is calculated based on reservoir temperature alone and in combination with crude oil composition (estimated from API gravity). The lower result of these calculations is used. These calculations are in the subroutine SPECSC (special screens) of the preprocessor program and also described in SPE 14105 "Factors to Consider When Designing a CO_2 Flood," by Holm and O'Brien (March 1986) and "Interpretation of Pressure-Composition Phase Diagrams for CO2/Crude Oil Systems," by F.M. Orr Jr. and C. M. Jensen, *SPEJ* October 1984, p. 485–497. The upper limit on reservoir pressure (psi) is estimated at 0.6 times depth, which is usually below fracture pressure.

Immiscible: Limits are shown in Table 3. The lower limit of 14° API is reasonable based on data in DOE's EOR database. The lowest value in the database is 14°, and one of the four projects at that value is profitable. The highest value in the database is 60°, the upper limit. API gravity for the highest profitable project is 44°.

Two profitable projects with initial oil saturation of 28% and another at 44% indicate the lower limit for this criterion could be reduced from 50% to 28%. The upper limit of 100% is useful to eliminate erroneous data.