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RESEARCH ARTICLE

IMPLEMENTATION OF RESERVOIR MANAGEMENT APPROACH IN IMPROVING OIL RECOVERY PROCESSES

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ABSTRACT

This paper discusses the recent trend in the approach used by various companies in reservoir management indicates the utilization of teamwork and integrated operations concepts. This is particularly evident in enhanced oil recovery (EOR) projects due to the wide scope, complexity and high cost associated with various EOR processes. Reservoir management of typical EOR projects includes reservoir evaluation, geology, process design, surface facilities, performance monitoring, production data analysis, operational aspects and environmental as well as contractual considerations. Reservoir management is based on cooperative participation and input from various professionals involved in a given EOR project. Participants include geologists, reservoir engineers, reservoir simulation engineers, production engineers, facilities (design and construction) engineers and field management team personnel. With such a wide variety of background among participants, it is necessary to establish a common understanding of fundamental concepts, key parameters and data requirements throughout various phases of project implementation. With the fact that an oil reservoir can only be produced practically once, operators pay special attention to the reservoir management of such EOR projects in order to obtain optimum results and avoid costly mistakes. Recently, many operators have come to the conclusion that utilizing teamwork in an integrated operation manner, allowing enough flexibility and designing an adequate performance monitoring will assure an efficient and practical reservoir management. It is clear that each of the above elements require the participation and input from several professionals of various disciplines. This participation, coupled with a cooperative effort, increases the reliability of the results and assures the right selection of producing methods and development plans. When an EOR process is implemented in a given field, the degree of success of its reservoir management program is directly related to the teamwork efficiency of the professionals associated with the project.

Keywords: Reservoir management, Improvement oil recovery, Teamwork, Effective, Efficient

INTRODUCTION

Oil reservoirs vary in geologic nature, fluid content and confining conditions that prevail within the reservoir. Accordingly, the optimum method for recovering the maximum amount of oil from a given reservoir will vary from one to another. The operator usually performs several studies to select the appropriate method based on all available data for the reservoir under consideration. When the enhanced oil recovery (EOR) process is selected, operators spend an extra effort during all phases of implementation. This is primarily due to the sizable investments required and high cost of EOR materials utilized. The typical oil recovery operations will involve the following elements:

1) Gathering all available geological and engineering data for the given reservoir.
2) Identifying all available resources and existing limitations which might impact the oil recovery operations.
3) Reviewing all data to determine the extent of necessary field test, laboratory experiments and estimation of physical and chemical properties.

4) Conducting a preliminary reservoir study to determine the possible alternatives for producing the reservoir.
5) Evaluating the selected producing alternatives to determine their economics and operational requirements.
6) Conducting a detailed engineering study for the most efficient recovery process selected.
7) Designing and installing the required surface facilities and implementing the recommended development program.
8) Monitoring the production performance and recommending any appropriate changes in view of observations.

Efforts to improve the ultimate oil recovery factor usually start with extending the development plan by drilling more wells or completing more intervals and supplementing the reservoir energy by injecting water or gas. Further efforts entail utilizing processes aimed at enhancing the displacement efficiency and enlarging the contacted region of the reservoir (increasing the volumetric sweep efficiency). These processes are referred to as enhanced oil recovery (EOR) methods.

EOR methods are not necessarily applied as a tertiary phase following the primary and secondary phases, they could be applied early in the production life of a field. For example, a polymer waterflood, a miscible gas injection or a steamflood may start right after the completion of field development. However, time is usually allowed for extensive laboratory work, reservoir studies and pilot field tests prior to implementing EOR methods due to the many uncertainties and large investment involved. EOR methods involve the injection of materials which may change the reservoir oil composition, reservoir temperature or the interactive rock-fluid properties. Microscopic oil recovery factors (also known as displacement efficiency) achieved by some EOR method, could reach value over 90% for laboratory core floods and the overall recovery factors range from 45% - 75%.

IMPLEMENT STEPS IN IOR/EOR PROJECTS

Practically, an oil reservoir can only be developed and produced once. This puts a specific importance on the selection of its development plan and producing method. Oil companies strive to maximize not only the amount of oil recovered, but also the profit generated. Thus, factors such as economic climate, risks, crude market and available resources have to be taken into account. The selection process is not an easy task especially for enhanced oil recovery projects since they are typically associated with large investments, high operating costs and reservoir risks. Because of that, certain basic steps are usually followed prior to and during implementation of oil recovery processes.

2.1. Data Gathering

All data pertinent to the field under consideration and in particular to the producing method that will be applied, is gathered. This includes geology, well data, flow test, core analysis, fluid properties, available resources, economical parameters and contractual and environmental constraints, as shown in Table 1.

2.2. Preliminary Evaluation

This phase includes identifying missing data, eliminating erroneous data, recommending necessary laboratory or well tests, defining natural reservoir energies, performing simple analysis using conceptual reservoir models and selecting possible recovery methods.

2.3. Detailed Evaluation

This entails preparing elaborate reservoir engineering studies for the selected recovery methods. The objectives are to formulate an optimum development plan and determine the ultimate recovery, production and injection rates, well requirements and sensitivity to various operating strategies. These evaluation efforts consist of a number of phases and are usually done in stages of increasing complexity and scope. They require full cooperation between various professionals, management and field personnel

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in order to assure reliability of results, as shown in Figure 1 and Figure 2, respectively. The basic steps of an evaluation effort involve:

1) Formulation of geologic and reservoir descriptions.
2) Review of past performance to determine the natural recovery mechanisms and relate them to the geologic and reservoir descriptions.
3) Identification of any limitations due to natural parameters such as depth, pressure, aquifers, gas caps, oil composition, rock type, fracture, or due to operational parameters such as resources, market conditions, contractual terms and environmental constraints.
4) Design of a laboratory tests program consistent with the selected producing method.
5) Prediction of field performance and determining economics of various plans.

Formulation of final development plan.

2.4. Pilot Projects if Needed

In some cases, pilot field trials are conducted prior to fieldwide implementation of a given process. This is done to test applicability of the selected process and to obtain any reservoir data required for accurate performance predictions and fine-tuning of operational parameters. Pilot tests consume smaller amounts of investments and operating costs and as such, minimize the risk of losing large expenditures in case the recommended process does not work.

2.5. Fieldwide Implementation

This phase includes installing required surface facilities and infra-structure, drilling development wells and commencing productions operations on a fieldwide basis. This includes efforts to utilize all existing facilities, resources and nearby infra-structures in the area of operations.

2.6. Project Management

Performance monitoring programs and maintenance procedures for wells and facilities are defines and implemented. This may involve drilling or utilizing some existing wells for observation. The collected data is used to update the reservoir model and determine whether any changes in operating conditions are required.

Table 1.
Data sources for implementation of IOR/EOR processes

Time	Predrilling							During Drilling													Post Development						
Operation	Gravity	Seismic			Geology-Eng. Study		Well Bore Operations														Production					Special Studies	
	Gravity	Time	Velocity	Amplitude	Character	Regional knowledge and maps	Depositional environment	Drill rate	Mud log	Cuttings	Cores	Drillstem	Electric	SP Log	Acoustic Log	Density Log	Gamma ray log	Neutron Log	Well test	Wire line cores	Flow Test	Pressure	Water cut	GOR	History	Analogy	Engineering and geology
Depth markers		2	2			2	2	3	3	2	1	1	1	1	1	1	1	1	2	1	2						1
Structure and area	2	2	1	3	3	2						4									2	2	3	3	1		1
Hydrodynamics						1															2	1			3	1	1
Gross thickness			2		3	2	2	2	2	3	2	4	1	1	1	1	1	1			2						1
Net thickness				2	2	2	2	3	3	4	1	4	1	1	1	1	1				1						1
Lithology			2	2	3	2	2	3		2	1		3	3	2	2	2	3		1						2	1
Mechanical properties			2	2	3	2	2	3		2	1				2	2	2	3		2						2	1
Contacts			2	2	2	4			3	2	2	2	1	2	1	1		1	1	2	1		2	2	2		1
Pressure			2	3		1			3			1							2		1	1				1	1
Porosity			2	2	3	2	2	4		3	1		3		1	1		1		2	4					2	1
Permeability					4	2	2			4	1	1	4		3	3		3	2	3	2	1				2	1
Relative permeability											1										1	2	2	2	2	2	1
Fluid saturation			3	3	3	4			3	3	2	1	1	3	2	2		2	2	3	1		1	1	2		1
Pore sizes						2				2	1	4	4	4	4	4	4	4		3						2	
Producing mechanism		4	3	3	3	2	3																1	1	1	1	1
HC properties			4	4		2			3	4	3	1			4	4		4	2	4	1	2		1		1	1
Water properties						1					4	1							2		1		1			2	1
Production rate						2	2				2	2			4	4		4	2	3	1	1			1	2	1
Fluids produced												1									1		1	1	1	2	1
Well damage																					1	1			1		1
Recovery efficiency																							2	2	1	2	1

Code : 1. Best source. 2. Good data source. 3. Average data source. 4. Poor data source.

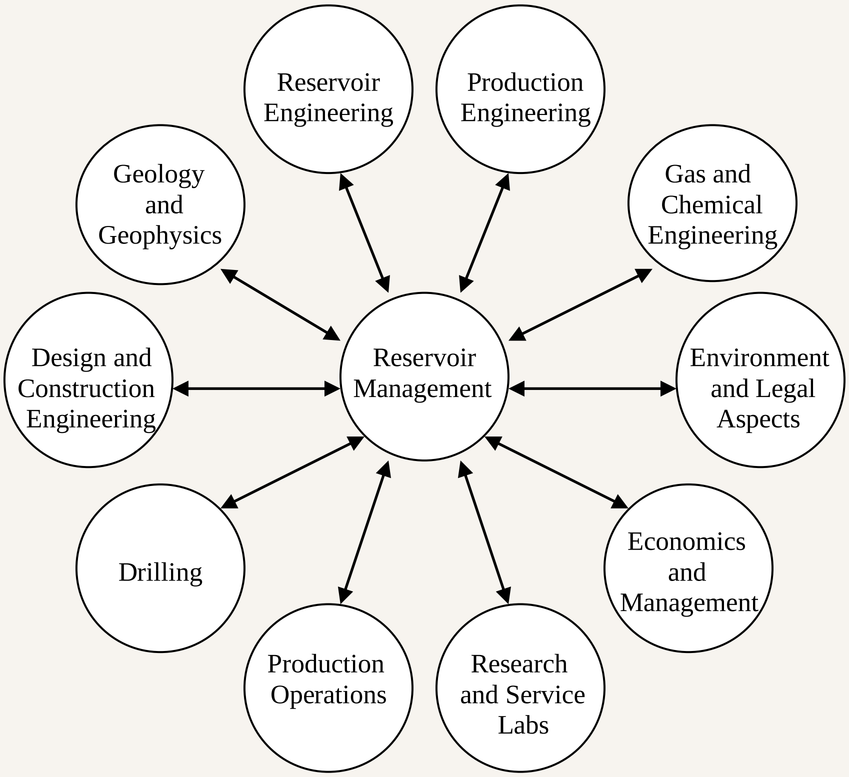

Fig. 1. Reservoir management approach

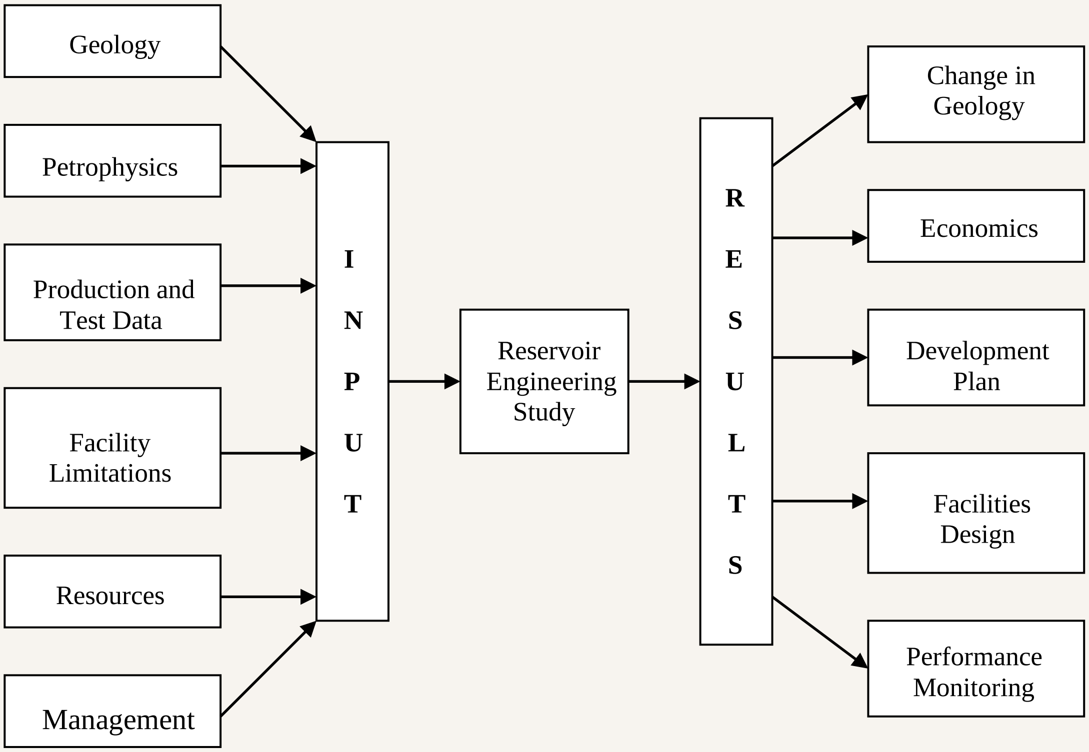

Fig. 2. Schematic of interactions between various disciplines

SELECTING THE APPROPRIATE RECOVERY METHOD

In view of the complexity of oil recovery processes, specially enhanced oil recovery, it is practically impossible to define a set of procedure for selecting the appropriate producing method for a given oil reservoir. An extensive effort is necessary to select, optimize, design and determine the technical and economic feasibility of a specific method for a particular field. This effort is independent of the size of the field if a high level of engineering professionalism is to be maintained. Sometimes, this effort can be reduced by taking advantage of common industry experience in fields having similar nature to the one being considered. Also, there are some basic guidelines, which can be used for eliminating certain producing methods from the selection process for a given field. These guidelines are directly related to the primary mechanisms by which different methods recover oil from the reservoir rock.

3.1. Concept of Incremental Recovery

Considering the basic definition of recovery phases, it follows that the incremental recovery on which a secondary recovery method is evaluated depends on the recovery achieved by primary methods. If the latter value is relatively high, the potential for an economical application of secondary recovery methods diminishes. Similarly, EOR methods are justified based on their incremental recovery over the combined primary and secondary recovery. The simple concept provides an underlying guideline which should receive first consideration. In other words, reservoirs exhibiting adequate natural energy (such as light oil reservoirs with strong aquifers and gas caps) will most likely not be appropriate candidates for secondary recovery or EOR methods.

3.2. Porosity and Remaining Oil Saturation

Another logical general guideline is the current oil saturation present in the reservoir. This is one of the parameters which cannot be changed and directly determines the amount of oil that can be recovered. If this value below a certain limit (which can be determined from economic analysis) secondary recovery methods become marginal and certainly EOR methods become uneconomical. The effect of low oil saturation becomes more pronounced if the reservoir porosity is low. This is obvious since a combination of low porosity and low oil saturation results in very low oil in place per unit reservoir bulk volume. Therefore, in setting up a minimum oil saturation value, porosity should be taken into account. A more meaningful parameter for defining such values is the product of porosity and remaining oil saturation.

3.3. Favorable Conditions for Secondary Recovery

Secondary recovery methods include immiscible gas floods and waterfloods. These methods will result in reasonable incremental oil recoveries for solution gas drive reservoirs specially those which contain light, low viscosity crudes. The low viscosity will result in a lower mobility ratio for the displacement and hence improves the sweep efficiency. High permeability is always preferred, but more important is the permeability variation as it has more impact on oil recovery. High permeability variation or presence of thief zones reduce the vertical sweep efficiency. Areal reservoir continuity is also important specially if large flood patterns are used. The choice between gas injection and water injection depends on the availability of both and on some specific reservoir characteristics. For example, if the permeability to water is drastically reduced due to dispersed clays, water injection may not be preferred. Some reservoirs exhibit high permeability near their crests and are tight near the base or periphery. These reservoirs will not be good candidates for water injection. On the other hand, gas injection always corresponds to higher mobility ratios than water injection. This makes gas injection less favorable for medium gravity crudes which have relatively high viscosity. Because of this reason, many gas injection projects are only implemented if large amounts of natural gas are available and there is not market for them. Even in these situations, the incremental oil recovery should be weighted against the investment and operating cost for gas compression and recycling. Figure 3, shows the management process of waterflood. When we will implement the waterflood, we have to perform economics analysis for various start up time by considering the factors such as revenue stream (oil and gas), injection requirements, cost of fluid handling and treatment, and cost of facilities. Furthermore, there are three possibility choices for waterflood based on pressure as follows:

- Operate at initial pressure (or above) minimize compaction producing well PI's,
- Operate at or above bubble point pressure (P_b) minimize remaining stock-tank volumes left in reservoir oil viscosity minimized,
- Operate below P_b (free gas saturation to form) oil trapped in waterflood portion of reservoir increases residual oil saturation to water drops longer fill up times and delayed oil production response.

Generally, the parameters that will be effects on the oil production result of waterflood both for pilot project and full scale are as follows:

- Displacement phase based on the fractional flow data, as shown in Figure 4.
- Remaining movable oil at the area of waterflood (pilot project)
- Reservoir quality, connectivity and heterogeneity
- Reservoir pressure above or under saturation pressure
- Drive mechanisms
- Quality of water injection
- Cement bonding
- Voidage replacement ratio (VRR)
- Increasing pump capacity (gross up).

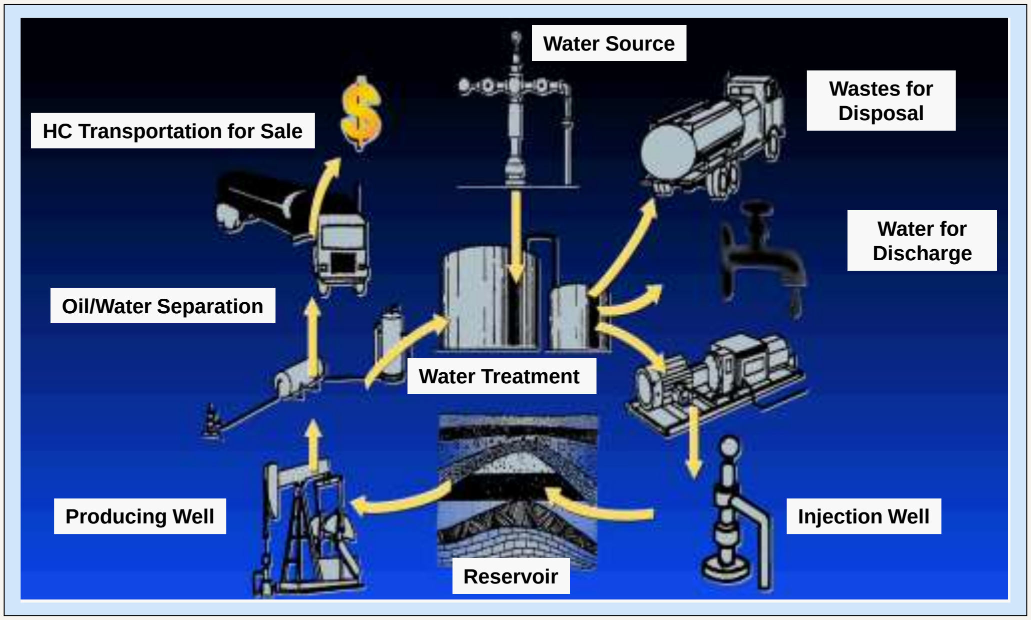

Fig. 3. Management process of waterflood

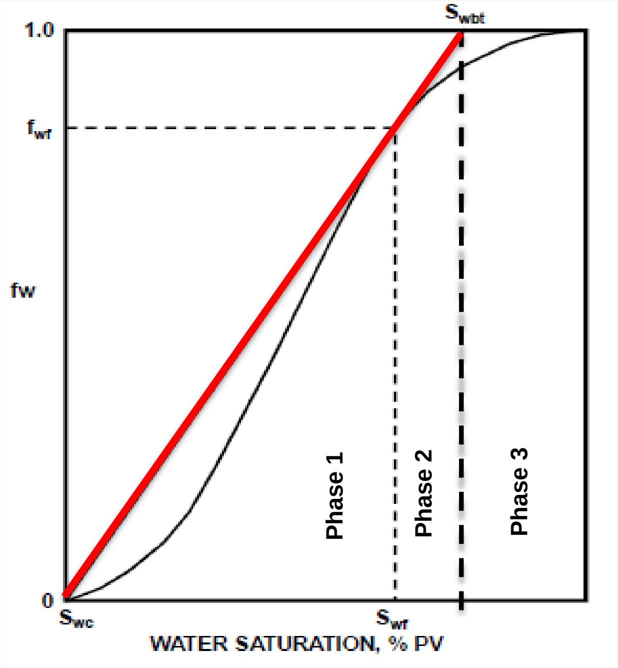

Fig. 4. Phases of water displacement process on waterflood based on fractional flow curve

Based on the Figure 4, there are three phases of displacement processes as follows:

- Phase 1: Fill-up condition - a condition where displacement occurs through gas release being production, hence the oil production recovery of waterflood will be higher. This is the best time for implementation of waterflood.
- Phase 2: Fill-up until breakthrough - a process where water begin to produce in the production well (water breakthrough), hence the oil production of waterflood will be medium or not too high.
- Phase 3: After breakthrough - a period where the injected water was not displaced oil in the reservoir to production well, but only drag the oil in the reservoir to production well, hence the oil production recovery will be lower.

3.4. Enhanced Oil Recovery Guidelines

In view of the basic mechanisms associated with the various EOR methods, some general screening guidelines can be deduced, as shown in Table 2. The concept for these guidelines is simply to make sure that the reservoir provides an adequate medium for the EOR process mechanism to be effective and to allow establishing the required operating conditions at reasonable cost and low risk. Aside from these basic guidelines and limitations, the literature also contains some specific guidelines, which provide typical favorable ranges for various parameters. Such specific guidelines should not be taken as conditions, which guarantee the applicability of particular processes to particular reservoirs. They should be considered only for preliminary evaluations. Laboratory measurements using reservoir core and fluid samples as well as reservoir engineering studies utilizing actual production history provides a more accurate basis for the selection process.

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Table 2.
Enhanced oil recovery screening criteria guidelines

Screening Parameters	Surfactant Flood	Polymer Flood	Alkaline Waterflood	CO_2 Flood	Steam Stimulation	Steamflood	Fireflood
Viscosity-cp at reservoir condition	<10 cp*	<200 cp	<300 cp	<10 cp	<400 cp	NC	NC
Gravity-^{0}API	>28^0	>18^0	>15^0	>25^0	>16^0	>10^0	10-40^0
Oil Saturation in Area to be flooded (before EOR)-%PV	>30%	>50%	>50%	>25%	>50%	>50%	>50%
Oil Concentration-B/AF	NC	NC	NC	NC	>1000 B/AF	>800 B/AF	600 B/AF
Porosity x Oil Saturation	-	-	-	-	>0.13	>0.10	>0.08
Depth-ft	NC	NC	NC	>2000	<3000*	<4000	<500
Temperature-^{0}F	<200*	<150*	Low preferred	NC	NC	NC	NC
Original Bottom hole Pressure-Psi	NC	NC	NC	>1100	NC	NC	NC
Net Pay Thickness-ft	NC	NC	NC	NC	>50	>15	>10
Permeability-md	>50 md	>10 md	>1 md	NC	>100 md	NC	NC
Transmissibility (Perm. x Thicknes/Visc.)	NC	NC	NC	NC	NC	>50	>20
Natural Water Drive	None to weak	None to weak	None to weak	None to weak	None to weak	None to weak	None to weak
Gas Cap	None to minor	None to minor	None to minor	None to minor	None to minor	None to minor	None to minor
Fractures	None to minor	None to minor	None to minor	None to minor	NC unless extreme	NC unless extreme	None to minor
Lithology	Sandstone only*	NC	<0.5% gypsum, low clay	NC	Low clay	Low clay	NC
Salinity-ppm TDS	<100,000*	Low preferred	NC	NC	NC	NC	NC
Hardness-ppm-calcium and magnesium	<5000*	Low preferred	Not excessive	NC	NC	NC	NC
Comments NC = not a critical factor * considered a constraint under current technology	Homogeneous formation preferred. Low clay content. Porosity x thickness (high). Prefer waterflood sweep 50%.	Use with or prior to waterflood. Low calcium and clay content. Low salinity and hardness preferable.	Use prior to, during, or after waterflood. Use where waterflooding is applicable. Oil acid no. >0.1	Thin pay preferred, high dip preferred. Homogeneous formation preferred. Porosity x thickness low. Natural CO_2 availability. Low vertical permeability in horizontal reservoir.	Porosity x thickness (high). Economic fresh water available. Economic fuel available. High net to gross pay. Homogeneous formation preferred. Adequate reservoir pressure in thin sand.	Porosity x thickness (high). 10 acre spacing or less. Economic fresh water available. Economic fuel available. High net to gross pay.	High dip preferred. Porosity x thickness (high). <40 acre spacing. Low vertical permeability preferred. Preferred temperature >150^{0}F. High net to gross pay.

EFFICIENT UTILIZATION ON FACILITIES AND RESOURCES

One of the important phases of EOR feasibility studies is the identification of existing and required additional facilities and resources. The importance of this phase stems from the fact that it determines the required capital investment and project life and hence has a direct impact on project economics. Optimum implementation in this regard means that the study team recognizes and maintains the following guidelines, are maximum use of existing wells, maximum use of existing facilities, efficient utilization of equipment, and maximum use of available resources.

4.1. Maximum Use of Existing Wells

The proposed development plan for the EOR project should make maximum use of existing well in the field. Existing wells can be used as pattern producers or injectors if their locations and conditions are satisfactory. Sometimes, the development well pattern shape and size could be slightly adjusted in order to fit most of the existing wells as long as the effect on process performance is small. In some cases, if the conditions of existing wells are below required standard, they can be worked-over or re-drilled to improve their conditions. If none of these alternatives are possible, the existing wells which cannot be used as producers or injectors may be utilized as observation wells for performance monitoring.

4.2. Maximum Use of Existing Facilities

As part of the effort to minimize the capital investment required for implementation of a given EOR project, use of existing facilities is usually considered to the maximum possible extent. These include production and injection facilities, surface locations and roads, field transportation systems, data gathering equipment, existing infra-structures, etc. Such facilities could be within the field under consideration or unutilized facilities in nearby fields which could be easily moved to the field. The feasibility study should include options for renovating existing facilities and equipment to become suitable for the proposed EOR process. Comparative economic analysis on various alternatives should be done for example, new facilities versus renovating and expanding existing ones.

4.3. Efficient Utilization of Equipment

Once a set of surface facilities and equipment has been selected and designed, its utilization in the EOR project should be made as efficient as possible. This involves comparing development plan alternatives which explore the use of vertical stages (for multi-zone reservoirs) and areal expansions (for reservoir of large areal extents). Such analysis should take into consideration the effects of production life on discounted profit and practical operating life of equipment and should include equipment renovation and moving costs between stages and areal expansions.

4.4. Maximum Use of Available Resources

All EOR processes involve the injection of fluids and chemical solutions into the reservoir. It is important that the project feasibility study include evaluation of available resources for such fluids and chemicals. Nearby resources should always be given first consideration. In some cases, the quality of materials in such resources may not be consistent with optimum design criteria and a sensitivity analysis will be required to determine the effect of reduced quality on reservoir performance and hence on project economics.

OPTIMIZATION OF EOR OPERATING PARAMETERS

After a particular EOR method has been selected for implementation in a given reservoir, the optimum operating parameters of the selected process are determined. This is usually done through detailed optimization studies using performance prediction tools such as reservoir simulators, and in many cases involve performing additional laboratory tests. Occasionally, some field tests on individual wells or on small pilot projects are conducted to provide the required data for optimization.

The optimization studies also indicate the risk areas and point out possible ways to minimize such risk in the proposed process and its development plan. These studies yield specific plans which are consistent with reservoir properties, available resources and basic relationships between reservoir and operational parameters. In case where the choice is not obvious, engineering judgment and common industry practice is used. The optimization procedure is as follows:

1) Select the operating parameter to be optimized (optimization parameter).
2) Define the lower and upper limits for the optimization parameter value.
3) Select the criteria on which the optimization will be based (optimization criteria).
4) Determine the sensitivity of the optimization criteria to variations within the two limits defined for the optimization parameter.
5) Analyze the results to select the parameter value which satisfies the optimization criteria. This is usually done by constructing a plot of optimization criteria versus optimization parameter and finding the maximum or minimum point on the plot.

In performing the optimization analysis, the relationships between various operating parameters as well as any operational guidelines (such as fracturing pressure, well injectivities, field safety measures, use of existing wells, etc) should be taken into account. The parameters to be optimized are different from one EOR method to another as well as from one field to another. Key parameters which receive higher priority are usually determined by the study team based on the existing logistics at time of project implementation. Examples of optimization parameters are injection rates, pattern shape and size, number of vertical stages in the flood, equipment utilization, slug sizes of chemical solutions or solvents and concentrations of chemical in injected slugs. Of course, it is not practical to include all operating parameters in the optimization study. Only those on which the operator has some control and show strong economic justification are included. Optimum values for the selected parameters are determined based on maximizing or minimizing a certain criterion such as:

- Maximizing net oil recovery.

- Maximizing present worth profit
- Maximizing utilization of existing facilities
- Minimizing fuel consumption
- Minimizing total investment
- Minimizing project life.

The correct choice of optimization criteria ensures the reliability of optimization results.

Examples and Efficient of Team Work

The following examples illustrate some of the team work resulting from interactions between professionals from various disciplines:

1) Data gathering for reservoir evaluation requires input from geologists, petroleum engineers, reservoir engineers and field personnel. The assumptions and limitations embedded in the geological and well test data are important to the reservoir engineer conducting the evaluation. Based on such information, he will able to determine which data to be given more weight, which parameters to be adjusted or modified and whether any data should be disregarded.
2) In designing surface facilities for a given project, most design parameters used by facility engineers are based on the results of reservoir studies. These parameters include plant capacities, injection pressures, gross fluid rates, injected material specifications and volumes of fluids to be disposed-off. On the other hand, the limitations on operating parameters used in reservoir engineering studies are obtained from facility engineers. These limitations include amounts of available resources, practical equipment sizes, practical operating conditions and unit costs required for economic analysis.
3) In some cases, during the production phase, the operator is faced with new environmental laws and constraints that should be adopted. This may involve changing an injection material, equipment or fluid disposal method. Full cooperation and input from the environmental engineers, facility engineers, reservoir engineers, geologists, economics experts and management personnel are required in order to minimize the cost of implementation and avoid risk of losing oil recovery due to possible deviations from the original process design.

The above discussion and examples illustrate the need for continued cooperation and teamwork among various professionals involved in the oil recovery processes. This will ensure the reliability of results and avoid errors and misunderstanding in moving from one step to another during the implementing such expensive projects. In many cases, engineering judgment common sense and personal experience of team members play on equal role as the input data itself in arriving at reliable results.

When an EOR process is implemented in a given field, the degree of success of its reservoir management program is directly related to the teamwork efficiency of the professionals associated with the project. Team work becomes more efficient and productive if the following factors are understood and implemented throughout the various phases of the process as follows:

- Full cooperation in providing data and explaining any limitations or drawbacks associated with it.
- Frequent exchange of ideas and benefiting from personal experiences of various team members. This usually done during conducting studies but should also be continued during the implementation and performance monitoring phases.
- Frequent reviews of results at various stages to avoid errors and to recommend appropriate changes in procedures.
- Clear understanding of every member responsibility and experience and extent of knowledge.
- Familiarity of various members with the scope of work of others and maintaining an appropriate amount of knowledge about definitions and significance of reservoir and operational parameters.
- Clear understanding of Company's objectives and economic factors which govern priorities and screening guidelines utilized in the area of operations.

CONCLUSIONS

1) The implementation of reservoir management approach is based on cooperative participation and input from various professionals involved in a given IOR/EOR project.
2) The objectives of reservoir management are not only to improve recovery, but also to minimize operating and investment costs.
3) The selection process is not an easy task especially for enhanced oil recovery projects since they are typically associated with large investments, high operating costs and reservoir risks.
4) The optimization studies yield specific plan which are consistent with reservoir properties, available resources and basic relationships between reservoir and operational parameters.
5) Utilizing teamwork in an integrated operation manner, allowing enough flexibility and designing an adequate performance monitoring will assure an efficient and practical reservoir management.
6) The degree of success of its reservoir management program is directly related to the teamwork efficiency of the professionals associated with the project.

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DECLARATION OF COMPETING INTEREST

The authors have no conflict of interest to declare.

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