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Some Aspects Concerning the Steamflood Reservoir Management

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Abstract

This work deals with some aspects concerning the Hydrocarbon Reservoir Management and, particularly, the management of oil recovery by steam injection processes. The reservoir management purposes, the data required for a pertinent analysis, the steps in designing and implementing steamflood processes, the possibilities of estimating their performance by analytical and empirical methods, as well as the operational and performance parameters which must be evaluated for establishing the feasibility of the field application projects are presented.

Key words: *hydrocarbon reservoir management, steamflood, reservoir modeling, economic analysis*

General Considerations

In the frame of oil field production terminology, the reservoir management can be defined as a system for optimal use of the available technology to economically recover hydrocarbons from the reservoir, particularly by steamflooding, according to a preset series of operational restrictions.

Although the tendency exists to consider the Reservoir Engineering as the only technical relevant domain for the Hydrocarbon Reservoir Management, the specialists who carry out such type of engineering studies recognize, without caution, the value of Geology as contributor both in understanding the behavior of the considered system and in using these perceptions to manage the respective reservoir. As this management becomes more rigorous and more complex, the synergism between these two disciplines turns more important and has to be extended to the others domains as Well Drilling, Facility Engineering, Production Operations, Environmental Protection, Fluid Transport, Marketing and Tax Legislation.

Reservoir management can become very complex when appealing to material and energy balances, reservoir simulation, as well as structural characterization. Groups of specialists having various technical expertise abilities, consisting in engineers, geologists, field operators and managers, constitute extremely useful multidisciplinary teams for the hydrocarbon reservoir management.

In Figure 1, the structure of a multidisciplinary team assigned to the approach of reservoir management in relevant conditions is shown.

The purpose of the reservoir management mainly consists in economically maximize money returns from oil and gas production. For the steamflood projects, this design is accomplished by a set of management activities as: reservoir characterizing; project planning, evaluating and monitoring; data gathering and analyzing; reservoir modeling; oil production optimizing and, obviously, economics analyzing.

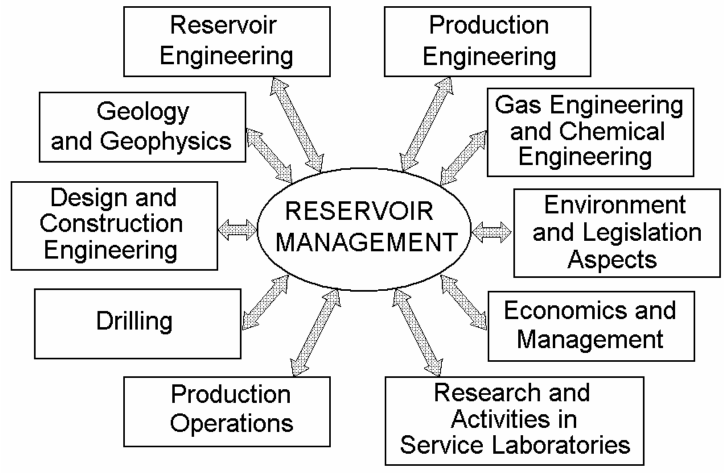

Fig. 1. Structure of a multidisciplinary team for reservoir management

Consequently, the reservoir management affords facts, information and knowledge necessary to the operations of supervision and recovery of hydrocarbons from reservoirs in optimal economic terms.

The types of data gathered and the steps of the performance analysis used in a typical Steamflood Reservoir Management (SRM) Program are as follows:

- geological evaluation and reservoir model definition based on cross-sections, structural maps, fluid saturation logs, equal-thickness and equal-porosity maps, fluid and rock property data;
- information concerning both injection and production wells, relative to: completion (perforating) data, well repairing, injection and production data, wellbore effluent data, produced fluid composition and allocation, as well as streamline temperatures;
- well investigation data relative to: steam flow rates and temperatures at both wellhead and producing layer entrance, steam injection profiles, transient pressure data, well survey data, static temperature and pressure, produced fluid inflow into the well, tracer used between two wells, well seismic data, data from cores taken upstream and downstream the steam front;
- elements of performance analysis as: performance curves, recovery efficiency, heat use, multi-zone assignation, material balance and energy balance;
- modeling and predicting the performance in terms of: geologic model updating, reproducibility simulation by history matching, forecast updating and operational strategy evaluation.

After the project was modified, the SRM process must return to the data gathering step, because the steamflood process parameters change continuously. This cycle of monitoring and adjusting operations continues during the whole project lifetime. Consequently, for each new project the entire SRM process repeats.

Designing and Implementing a Steamflood Process

The two steps in the headline constitute the first task for the Steamflood Reservoir Management and involve the requirement of using special equipment, capable to work in an environment containing high temperature steam. Monitoring and surveying a steam injection well includes research on steam quality and flow rate at wellhead, injectivity profile analysis, pressure and temperature survey, transient pressure variation and investigation of the space between the wells with tracers.

For the effective management of a steamflood project, the periodical monitoring of steam quality and flow rate, based on a well-by-well analysis, is required. Whereas it is not possible to measure steam quality and rate directly in the well under analysis, these parameters are deduced from surface measurements, by metering the steam flow rate and calculating the heat loss in the well. Then, the injected heat is calculated from the estimated steam quality and flow rate. Furthermore, these data are used to confirm if the aimed injection rates are accomplished.

The heat received from generators by the two-phase steam is distributed by a pipeline system to the injectors. Unfortunately, most steam distribution systems emerge on hill areas, making the steam to be non-uniformly allocated on the surface afferent to the project. Precise determination of heat and mass distributions upon the oilfield area requires recurrent measurements of steam quality and rate at the wellhead. Usually, the only device which can do these measurements is the steam separator.

The frequency of these wellhead measurements will mainly depend upon the expected or scheduled changes in steam quality or rate, as well as any major changes in the pipeline network afferent to the project area. Such changes will probably alter the liquid and vapor phase distribution allover the area. If the flow rate and quality of the steam delivered to the distribution system are stable for a long time, frequent wellhead measurements can be absent. In this case, annual quality tests in a few wells could be sufficient to confirm that the distributions of steam quality and rate remain unchanged.

All separator measurements must be taken downstream of the wellhead choke (if present) to reduce the probability of altering the true distribution during the measurement. The distributions of heat and mass entering individual wells within a project area may be calculated from these measurements. If desired, the steam quality upstream of the choke can be calculated assuming isenthalpic expansion across the choke. This calculation requires pressure measurements at both upstream and downstream sides of the choke.

A separator test program should be designed using the following guidelines:

1. Coordinate test program with appropriate foremen and operators to avoid steam supply interruptions or variations during testing;
2. Collect separator data for at least one hour at each well (one-minute sample interval) and pick one well for continuous monitoring during the test program.
3. Use at least two separators (preferably 4) to complete the test program as quickly as possible.
4. Request all separator data in digital format.
5. Check anomalous test data against generator reports.

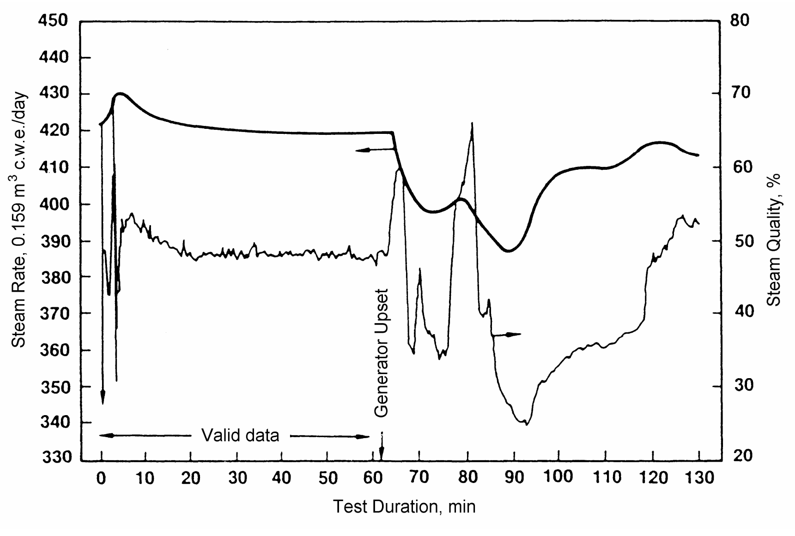

Fig. 2. Steam rate and quality test results, an injector in Field C, California

Coordinating a test program with the steam generator foreman is extremely important because interruptions in steam generator operation or modifications of the generator operating conditions can invalidate the test data. A case in point is shown in Figure 2. Because of the generator upset 61 minutes after initiating the test, the data are valid only up to this moment.

Estimating the Performance of a Steamflood Oil Recovery Process

Marx-Langenheim Model

Thermal oil recovery processes as cyclic or continuous steam injection involve heat and mass transport into the reservoir. This transport can be mathematically described by a set of coupled differential equations whose solving can be done by numerical simulation methods which impose the use of computers in presence of extensive information concerning the reservoir.

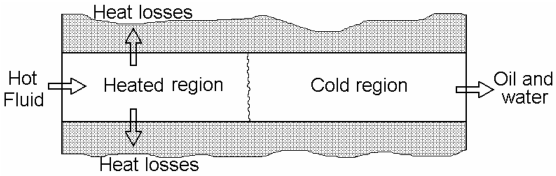

Fig. 3. Heat and mass balance into the reservoir.

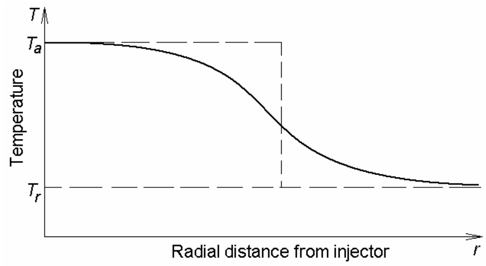

Fig. 4. Radial distribution of the temperature.

The reservoir heating model conceived by Marx and Langenheim is based on the suppositions of hot fluid injection by a single well, at constant rate and temperature, in the physical conditions shown in Figures 3 and 4 [2].

Admitting that the thermal front temperature drops suddenly into the reservoir from T_s to T_r, where T_s, T_r are the injected steam and original reservoir temperatures, respectively, from the equation of balance between the heat amounts injected into the reservoir, confined into the producing zone, and dissipated into the layers bounding upwards and downwards the reservoir, respectively, as well as neglecting the heat transfer through the steam front which has a radial-plane movement, we get for the steam front area the relationship

$$A(t) = \frac{q_{res} (\rho c)_{res} \, h \, a_s \, F(u)}{4 \lambda_s^2 \, \Delta T} , \tag{1}$$

where q_{res} is the thermal flux injected into the reservoir, a_s, λ_s – diffusivity and thermal conductivity of the layers bounding downwards and upwards the reservoir, respectively, $\Delta T = T_s - T_r$, h – reservoir thickness,

$$F(u) = \mathrm{e}^{u^2} \operatorname{erfc}(u) + \frac{2u}{\sqrt{\pi}} - 1 , \tag{2}$$

$$\operatorname{erfc}(u) = 1 - \operatorname{erf}(u) , \tag{3}$$

$$\operatorname{erf}(u) = \frac{2u}{\sqrt{\pi}} \int_0^u \mathrm{e}^{-y^2} \mathrm{d}y , \tag{4}$$

$$u = \frac{2\lambda_s}{(\rho c)_{res} \, h} \sqrt{\frac{t}{a_s}} , \tag{5}$$

$$(\rho c)_{res} = m(\rho_o c_o s_o + \rho_w c_w s_w) + (1-m)\rho_r c_r . \tag{6}$$

The other notations in these relationships have the following significances: t – injection time, $(\rho\, c)_{res}$ – volumetric thermal capacity of reservoir, m – porosity, c_j – isobar mass specific heat of phase j, including the latent heat of condensation, ρ_j – density, s_j – fluid saturation of the porous medium, with the index $j = o$, w, r corresponding to oil, water and rock phases, respectively.

The functions $e^{u^2}\operatorname{erfc}(u)$ and $F(u)$ are listed discretely, in tabular form, in various references as [4], pp. 314…315.

The thermal flux injected into the reservoir can be written as

$$q_{res} = M\, i_s \ , \tag{7}$$

with

$$i_s = x_{res}\, l_v + i_l - i_{wr} \ , \tag{8}$$

where i_s is the mass specific heat of the steam at pressure and temperature conditions p_s, T_s up against the reservoir initial conditions p_r, T_r; M – mass rate of the injected steam, x_{res} – steam quality at reservoir's inlet, l_v – mass specific latent heat of vaporization-condensation for water at the average temperature T_{av} of the heated region, i_l – mass specific heat of liquid water at temperature T_s, and i_{wr} – mass specific enthalpy of liquid water at the reservoir initial temperature T_r.

The cumulative oil production at injection time t is expressed as

$$N_p = V_p\, A \ , \tag{9}$$

where

$$V_p = m\, h\left(s_{oi} - s_{or}\right)\frac{1}{b_o} \ , \tag{10}$$

h is the producing layer thickness, s_{oi} – oil saturation before steam injection, s_{or} – residual oil saturation in the steam-swept zone, b_o – oil volume factor, and A is given by equation (1).

Based on relationships (1), (9) and (10), the oil flow rate has the expression

$$Q_o = \frac{q_{res}\, V_p}{(\rho c)_{res}\, h\, \Delta T}\, e^{u^2}\operatorname{erfc}(u) \, . \tag{11}$$

Considering that the investment expenses are amortized, or including the amortization quota and the quota concerning the other disbursements involved in the process into the expense C_s per unit of thermal energy injected, we can use as a criterion for defining the economically-limited duration of the steam injection process the following equation

$$q_{res}\, C_s = Q_o\, v_o \ , \tag{12}$$

where v_o is the specific value of oil, expressed in \$/m^3. By putting expression (11) into relationship (12) we obtain the quantity

$$e^{u_l^2}\operatorname{erfc}(u_l) = \frac{C_s\,(\rho c)_{res}\, h\, \Delta T}{v_o\, V_p} \ , \tag{13}$$

to which corresponds, for the economically-limited duration of the process, according to equation (5), the expression

$$t_l = \left[\frac{u_l\,(\rho c)_{res}\, h}{2\lambda_s}\right]^2 a_s \ . \tag{14}$$

In order to account for the latent heat of vaporization of the steam, the specific enthalpies i_o, i_w, i_g of reservoir oil, water and gas, respectively, must be used instead of the mass specific heats, i.e.

$$(\rho c)_{res} = m\left(\rho_o\, i_o\, s_o + \rho_w\, i_w\, s_w + \rho_g\, i_g\, s_g\right)\frac{1}{\Delta T} + (1-m)\rho_r\, c_r \ . \tag{15}$$

For estimating the performance of the steamflood process into an oil reservoir, the oil-steam rate at breakthrough, defined as

$$R_{os} = \frac{\rho_w N_p}{M\, t} , \tag{16}$$

can be used, where $N_p = N_{p\ bt}$ is the cumulative oil production at the breakthrough time of producing wells ($t = t_{bt}$), calculated with equation (9) in which $A = A_{bt}$ is the area of the region swept by steam and water at the injection time t_{bt}, and M – mass flow rate of injected steam, supposed as constant.

For comparison purposes, in Table 1 are listed the values $R_{os\ c}$ computed with the Marx-Langenheim method and the actual values, $R_{os\ a}$, obtained for five steamflooding projects [3] implemented during the early times of such processes, where h_n is the net thickness, h_t – gross thickness (including the shale-clay intercalations), H – reservoir depth, and for the residual oil saturation the value $s_{or} = 0.15$ was accepted.

Table 1. Calculated and actual values of the oil-steam rate at breakthrough [3]

Reservoir	m	h_n, m	h_t, m	T_s, °C	T_r, °C	s_{oi}	M, kg/hour	H, m	t, yrs.	$R_{os\ c}$, m^3/m^3	$R_{os\ a}$, m^3/m^3
Kern River	0.384	30.5	36.6	232.2	32.2	0.50	2,385.5	213.5	4.0	0.27	0.23
Schoonebeck	0.300	24.4	24.4	252.2	37.8	0.85	6,849.2	854.0	6.0	0.36	0.38
Winkleman Dome	0.248	25.9	56.4	288.3	29.4	0.75	1,587.6	372.1	3.5	0.08	0.21
Tia Juana	0.330	30.6	36.6	222.2	45.0	0.75	4,898.8	430.0	5.3	0.56	0.62
Slocum	0.292	13.7	18.3	241.6	23.9	0.65	6,803.9	152.5	3.0	0.20	0.21

Myhill-Stegemeier Model

This model is a more advanced form [5] of the Marx-Langenheim method and it is based on the Mandl-Volek model [9] which was conceived for calculating the volume of the injected steam area using the equation

$$\mathrm{e}^{\bar{t}_c}\ \mathrm{erfc}\left(\sqrt{\bar{t}_c}\right) = 1 - f_{ct} , \tag{17}$$

where erfc(u) is the error function complementary defined by relationships (3) and (4), f_{ct} – fraction of thermal energy injected into latent heat form, expressed as

$$f_{ct} = \frac{x_{res}\, l_v}{c_w \left(T_s - T_r\right) + x_{res}\, l_v} , \tag{18}$$

and the critical dimensionless time has the expression

$$\bar{t}_c = 0{,}48 \left(\frac{f_{ct}}{1 - f_{ct}}\right)^{1{,}71} , \tag{19}$$

along with the dimensionless time defined as

$$\bar{t} = \frac{4 \lambda_s \left(\rho c\right)_s}{h_t^2 \left(\rho c\right)_{res}^2} t , \tag{20}$$

where $(\rho\ c)_s$ is the volumetric thermal capacity of layers adjacent to the reservoir, and h_t – producing layer gross thickness.

The volume V_s of the steam region has the expression

$$V_s = \frac{Q_s\, \rho_w\, t \left[c_w \left(T_s - T_r\right) + x_{res}\, l_v\right] E_t}{\left(\rho c\right)_{res} \left(T_s - T_r\right)} , \tag{21}$$

in which Q_s is the injected steam flow rate, expressed in m^3 cold water equivalent (c.w.e.) per second, and E_t – thermal efficiency of the steamflooded area.

If the dimensionless time $\bar{t}$ defined by equation (20) is less than the critical dimensionless time $\bar{t}_c$ given by relationship (19), the heat transfer through the steam front will be dominated by the thermal conduction process, and the thermal efficiency must be determined with the equation

$$E_t = \frac{1}{\bar{t}}\left[e^{\bar{t}} \operatorname{erfc}\left(\sqrt{\bar{t}}\right) + 2\sqrt{\frac{\bar{t}}{\pi}} - 1 \right], \tag{22}$$

for $\bar{t} < \bar{t}_c$.

When $\bar{t} > \bar{t}_c$, the heat transfer through the steam front will be dominated by the thermal convection process and E_t has the expression

$$E_t = \frac{1}{\bar{t}}\left\{ F_1(\bar{t}) + (1-E_t)\frac{F_2(\bar{t}-\bar{t}_c)}{\sqrt{\pi}}\left[2\sqrt{\bar{t}} - 2(1-E_t)\sqrt{\bar{t}-\bar{t}_c} - \int_0^{\bar{t}_c} \frac{e^y \operatorname{erfc}\left(\sqrt{y}\right)dy}{\sqrt{\bar{t}-y}} - \sqrt{\pi}F_1(\bar{t}) \right]\right\} \tag{23}$$

where

$$F_1(\bar{t}) = e^{\bar{t}} \operatorname{erfc}\left(\sqrt{\bar{t}}\right) + 2\sqrt{\frac{\bar{t}}{\pi}} - 1 \tag{24}$$

and

$$F_2(\bar{t}-\bar{t}_c) = \begin{cases} 0 \text{ for } \bar{t}-\bar{t}_c < 0 \, , \\ 1 \text{ for } \bar{t}-\bar{t}_c > 0 \, . \end{cases} \tag{25}$$

The function E_t is plotted versus $\bar{t}$ and f_{ct} in reference [2] as Figure 7.23, p. 205.

The oil-steam ratio has the expression (16), with

$$N_p = m V_s (s_{oi} - s_{or}) \frac{h_n}{h_t} \, , \tag{26}$$

where h_n is the net thickness, h_t – gross thickness, and V_s is defined by equation (21).

Table 2 includes the oil-steam ratio values calculated ($R_{os\ c}$) and obtained from production data ($R_{os\ a}$), as functions of the dimensionless amount of steam injected $\overline{V}_s$, as well as the dimensionless volume of the steam region $\overline{V}_{sr}$, for several steamflooded reservoirs, using the Myhill-Stegemeier method [2, 5].

Table 2. Calculated and actual values of the oil-steam ratio for several steamflood projects

Reservoir	$\overline{V}_s$	$\overline{V}_{sr}$	$R_{os\ c}$	$R_{os\ a}$
Brea	0.50	0.150	0.13	0.14
Coalinga	0.94	0.450	0.16	0.18
El Dorado	1.60	0.315	0.05	0.02
Inglewood	1.26	1.256	0.41	0.28
Kern River	1.92	1.139	0.32	0.26
Schoonebeck	0.95	0.617	0.43	0.35
Slocum	1.41	1.202	0.29	0.18
Smackoven	1.23	0.756	0.27	0.21
Tatums	1.54	0.397	0.13	0.10
Tia Juana	0.47	0.551	0.59	0.37
Yorba Linda F	0.54	0.280	0.16	0.17

Simulators for Oil Recovery by Steam Injection into the Reservoir

The analytical, semi-analytical and correlation methods are useful tools for evaluating the reservoir response to steamflooding, but all available methods currently include numerous suppositions which reduce their accuracy. Consequently, these procedures must not be the only basis for estimating the performance of the great commercial projects which involve large financial resources, much manual labor and extended time.

During the last three decades, independent software companies and consulting agencies produced and sold many simulators designed for oil reservoir steamflooding. Some examples are: 1. ECLIPSE, owned by Schlumberger Company, 2. STARS, developed by Computer

Modeling Group from Calgary, Canada, 3. THERM, produced by Scientific Software Intercomp from Denver, Colorado, 4. TETRAD, developed by Servipetrol Ltd. from Calgary. In addition, a number of major oil companies, including Chevron, Elf Aquitaine and Mobil, have their own thermal simulators.

All these simulators are similar regarding the mathematical formulations adopted (concerning the mass and heat balance equations), but they differ in both solving methods and simulation capabilities. Besides the modeling of mass and heat transfer, a steamflooding simulator also considers reservoir geology, rock and fluid properties, well networks and production systems.

For the multi-panel steamflood projects, the performance estimation at field scale can be done by well level or average panel level prediction, associated with an operational plan.

In California and Indonesia there are a lot of field-scale steamflooding simulation projects that use this computer-aided technology.

Data Gathering for the Economic Evaluation of an Oil Recovery Process

Between the various cases of oil recovery from the reservoir, the one of producing a maximum amount of oil could not represent the optimum variant, because the time-variable value of the produced oil and the associated production costs were not included into this production forecast. The actual optimal operational strategy can be established only by an economic analysis of the forecast and operational and investment plans, at field scale. In this case, the economic analysis needs gathering the following data:

o produced rates of oil, water and gas;

o injected rates of steam and water (if water is used as a complementary injection fluid);

o number of wells contributing to the annual oil production;

o number of injection wells operated each year;

o number of new production and injection wells included each year into the project;

o facilities and equipment needed, as well as their costs;

o year of installing facilities and equipment;

o tangible and intangible drilling costs;

o operational unit costs (ex. $\$/m^3$, \$/(well·day) etc.);

o injection unit costs (ex. $\$/m^3$, \$/(well·day) etc.);

o well repairing schedules and costs;

o devaluation programs, taxes and dues.

Computer software for economic evaluation of EOR projects is widely available. Input data types can slightly vary between them, and they may be different from the above mentioned.

For a project to be economically feasible it must accomplish for the operational and performance criteria imposed. Such criteria are difficult to establish, because all operational domains have specific rules, restraints and tax structures, as well as a large variety of market conditions and price structures.

In Table 3, the operational parameter range afferent to steam injection projects from California are outlined, at price levels from the year 1995 [5]. According to the data in this table, for a typical steamflood process to be economically feasible, an initial investment expense ranging between $\$0.5\cdot10^6$ and $\$1.5\cdot10^6$ is needed, counting on: average oil rate of (6.4…12.7) m^3/day, project duration of about 10 years, fuel cost comprised between $\$0.75\cdot10^6$ and $\$1.5\cdot10^6$, corresponding to a minimal oil price equal to \$13/barrel or $\$82/m^3$.

Table 3. Operational and performance parameter range for steam injection processes in California [5]

Operational and performance parameters	Parameter range for feasible projects	Prime variables affecting the project parameter range
Average production rate, m^3/day	6.4…12.7	Oil properties and content Reservoir thickness
Average steam injection rate, m^3 c.w.e./day	23.9…47.7	Reservoir thickness Reservoir pressure
Project duration, years	5…15	Reservoir permeability Oil content Geology
Cost of surface facilities, 10^6 $	0.25…0.75	Steam generation and distribution requirements
Specific cost of injection, $/$m^3$ c.w.e.	6.3…9.4	Steam quality Cost Water quality
Specific cost of produced oil (fuel excluded), $/$m^3$ produced oil	18.9…31.4	Water-oil ratio Well repairing
Cost of drilling and perforating, 10^6 $	0.25…0.75	Reservoir depth Well spacing

Conclusions

Defined as a system for optimal use of available technology for an economically feasible recovery of hydrocarbons from reservoirs, while complying with a set of pre-established set of operational restraints, the Hydrocarbon Reservoir Management and, particularly, the steamflooding oil recovery management is intended to establish the optimal operation strategy, calling in a lofty economic analysis of the forecast and operation and investment schedules, oriented on a field scale.

Operating with mass and energy balances and using reservoir simulators, the synergy between Reservoir Engineering and Geology, extended to other matters as Well Drilling, Production Facilities Engineering, Environmental Protection, Fluid Transport, Marketing and Tax Legislation, the Hydrocarbon Reservoir Management became increasingly more rigorous and more complex.

Groups of specialists with various technical expertise abilities form multidisciplinary teams very useful in the hydrocarbon reservoir management.

Designing and implementing a steamflooding process in an oil reservoir are major goals of the management and the periodic monitoring of the quality and rate of the injected steam are of extreme importance.

The Marx-Langenheim, Mandl-Volek and Myhill-Stegemeier evaluative methods correlated to field data allowed, with increasing accuracy, the performance estimation of steam injection processes, customized to a series of reservoirs submitted to this recovery method during the early years of implementation of this technology.

Appealing to the numerical simulation method to estimate the performance of commercial oil recovery processes must not be the only way of approach, taking into account that this action involves important financial resources, much manual labor and extended time.

Despite their diversity, simulators afferent to oil recovery by steam injection into the reservoir are based on similar procedures relative to the mathematical formulations adopted regarding the mass and heat balances compliance, taking into account reservoir geology, rock and fluid properties, well networks and their production systems.

Centered on the economic maximization of the money returns from hydrocarbon production, the reservoir management and, particularly, the steamflooding management involves a wide range of activities as: reservoir characterization, process design, project evaluation and monitoring, data gathering and analysis, reservoir modeling, production processes optimization and, obviously, economic analysis.

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Unele aspecte privind managementul spălării cu abur a unui zăcământ de țiței

Rezumat

Lucrarea abordează unele aspecte privind managementul zăcămintelor de hidrocarburi, cu particularizare la procesele de recuperare a țițeiului prin injecție de abur. Sunt prezentate obiectivele managementului de zăcământ, datele necesare pentru analiză, etapele proiectării şi implementării proceselor de spălare cu abur, posibilitățile de estimare a performanței acestor procese prin metode analitice sau experimentale, precum şi parametrii de operare şi de performanță care trebuie evaluați în vederea stabilirii fezabilității proiectelor propuse.