HEAVY CRUDE OIL PRODUCTION THERMAL SYSTEM ANALYSIS ON THE PC

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by

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MSC/pal 2 APPLICATIONS - SUMMARY

- MSC/pal 2 has been successfully used to analyze a variety of structural problems - applications are always increasing.

- MSC's Engineering Services Department has assisted many clients in meeting their analysis requirements through the use of MSC software products and are always receptive to new problems and challenges.

HEAVY CRUDE OIL PRODUCTION - THERMAL SYSTEM ANALYSIS ON THE PC

The production of heavy crude oil is hindered by high oil viscosity and paraffin deposition within the extraction tubing. Both viscosity and deposition rate are strong functions of temperature (see Figures 1 and 2). Since pumping power requirements and tubing scraping expenses depend heavily on these properties, economical recovery requires obtaining optimal oil flow temperatures. As the reserve is typically at an elevated temperature, minimizing the heat loss from the oil flowing through the tubing is desirable for minimizing viscosity and paraffin deposition rates. One approach to this problem specifies the utilization of insulated tubing. To design a cost effective system, the ability to calculate well-bore heat losses over representative production times is necessary given various well configurations, mass flow rates, and tubing overall conductances. Computer codes designed to specifically address this problem tend to pose some difficulties for the average analyst. The numerical and empirical relationships designed into the code are often unknown and cannot be verified; if a problem is "nonstandard" the user has no way to modify the source coding to attempt his problem, the lease or purchase price can be prohibitive, most require mainframe computer facilities, and a basic lack of experimental data in this field makes quality assurance and verification procedures relatively nonexistent.

Formula	M.P. °C	Latent heat of fusion, cal g^{-1}	Formula	M.P., °C	Latent heat of fusion, cal g^{-1}
CH_4	-182.6	14.5	$C_{19}H_{40}$	32.0	51.6
C_2H_6	-172.0	19.2	$C_{20}H_{42}$	37.0	52.1
C_3H_8	-189.9	16.2	$C_{21}H_{44}$	40.5	52.5
C_4H_{10}	-135.0	26.9	$C_{22}H_{46}$	44.5	53.0
C_5H_{12}	-131.5	27.4	$C_{23}H_{48}$	47.5	52.9
C_6H_{14}	-94.5	34.1	$C_{24}H_{50}$	50.5	53.0
C_7H_{16}	-91.0	34.4	$C_{25}H_{52}$	54.0	53.3
C_8H_{18}	-56.5	40.3	$C_{26}H_{54}$	56.5	53.5
C_9H_{20}	-51.0	41.0	$C_{27}H_{56}$	59.5	53.7
$C_{10}H_{22}$	-32.0	44.1	$C_{28}H_{58}$	61.5	53.6
$C_{11}H_{24}$	-26.5	44.6	$C_{29}H_{60}$	63.5	53.6
$C_{12}H_{26}$	-12.0	46.8	$C_{30}H_{62}$	66.0	53.8
$C_{13}H_{25}$	-6.5	47.4	$C_{31}H_{64}$	68.0	54.0
$C_{14}H_{30}$	+5.5	49.0	$C_{32}H_{66}$	69.5	54.0
$C_{15}H_{32}$	10.0	49.4	$C_{33}H_{68}$	71.0	54.1
$C_{16}H_{34}$	20.0	50.8			
$C_{17}H_{36}$	22.5	50.8			
$C_{18}H_{38}$	28.0	51.2			

Figure 1. Latent Heats and Fusion Temperatures - Paraffins (Reference 1).

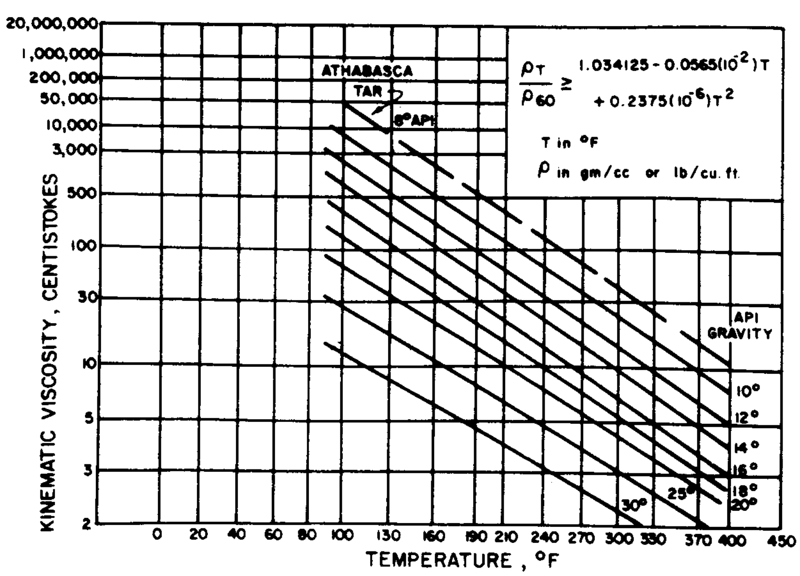

Figure 2. Viscosity Versus Temperature for Some Crude Oils (Reference 2).

The approach presented here attempts to eliminate some of these difficulties by applying a coupled approach to this type of analysis. A commercially available IBM PC finite element heat transfer code is used to perform transient heat conduction in the formation and a user supplied code provides the solution to the conservation equations of the oil flow field. The analysis, modeling, and code coupling techniques are developed and a typical well-bore thermal analysis is detailed.

Figure 3 illustrates a typical well-bore configuration. A packer, located between the tubing and inner casing, may be used to seal off the formation extraction environment from the annular gas region. Multiple casings of varying depths are cemented in place. Any noncemented annular region is typically filled with drilling mud. Additional details for any given well may include the use of a gas lift (staged gas injection to the flow stream from the annulus region), the full or partial use of insulated tubing strings, flow through tubing exposed to sea water in an off-shore recovery operation, a deviated well-bore, shut-in and production schedules, and design flow rate information.

A solution of this class of problem requires a transient analysis of the oil flow through the tubing coupled to the heat diffusion in the formation. This process of oil heat loss results in a mathematical description which is neither steady nor linear due to heat diffusion in a spatially infinite domain and convective and radiative transport through the annulus region. For incompressible flow, a coupled set of parabolic differential equations would describe the fluid flow and heat transfer.

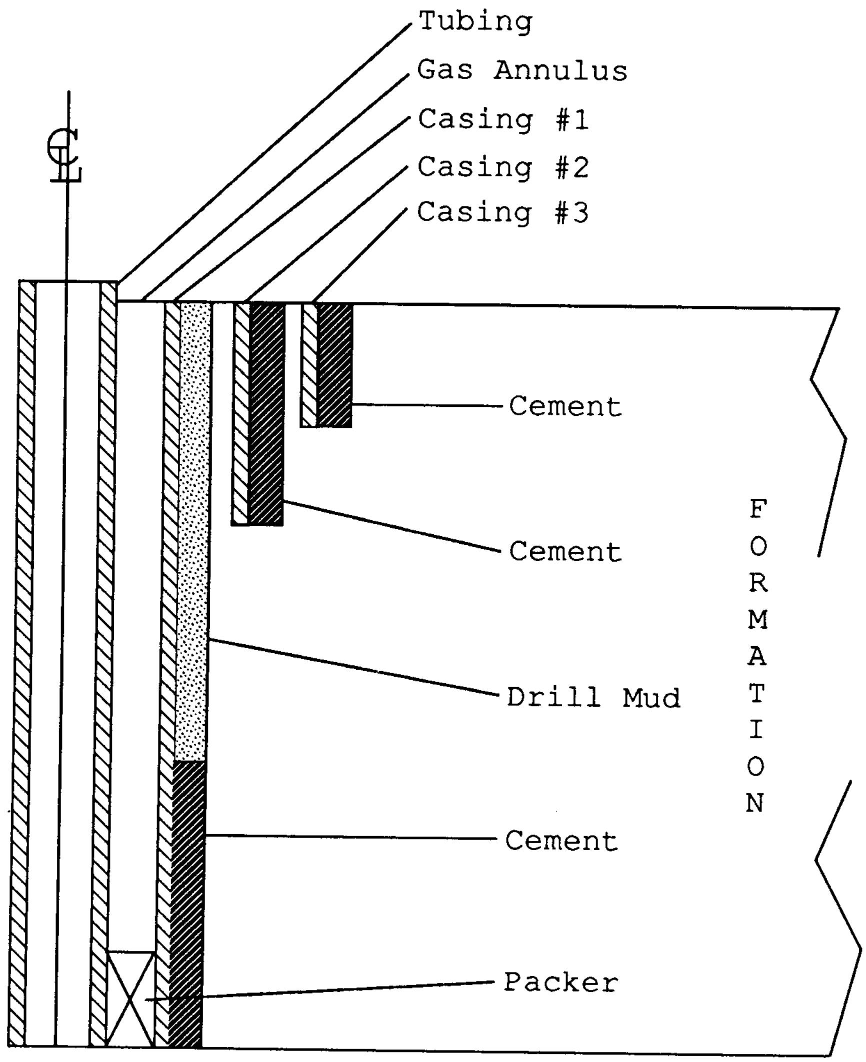

Figure 3. Typical Well-Bore Configuration.

Their solution yields the local oil velocity, temperature, and pressure and the formation temperatures for any location and time. The coupling between the fluid flow and the formation temperature physically occurs at the tubing wall where the local thermal gradient in the fluid provides the heat flux boundary condition for the formation.

In a nonrigorous sense, the solution of this coupled set of equations is complicated by the basic difference in time scales between the fluid flow convection speed and the heat diffusion thermal wave speed. The numerical solution of differential equations with large disparities in characteristic time scales is aggravated by the concept of stiffness. Special techniques are usually required for their solution due to the stability difficulties encountered. Certain problems faced with this complication can have their mathematical models modified slightly enabling the decoupling of the governing differential equations. The best solution process can then be applied to each set of governing equations separately and the stability criteria and time step size of one method will not abnormally control that of the other.

For the oil recovery problem, the solution of the fluid mechanics is separated from the formation heat diffusion analysis and iterative coupling occurs through the tubing wall convection behavior. A simple user-generated computer routine is developed for the flow field simulation using a bulk property approach where no attempt is made to recover the exact behavior of the velocity and temperature profiles. Rather, an energy balance, in an average sense, is applied to a representative control volume of the fluid as shown in Figure 4.

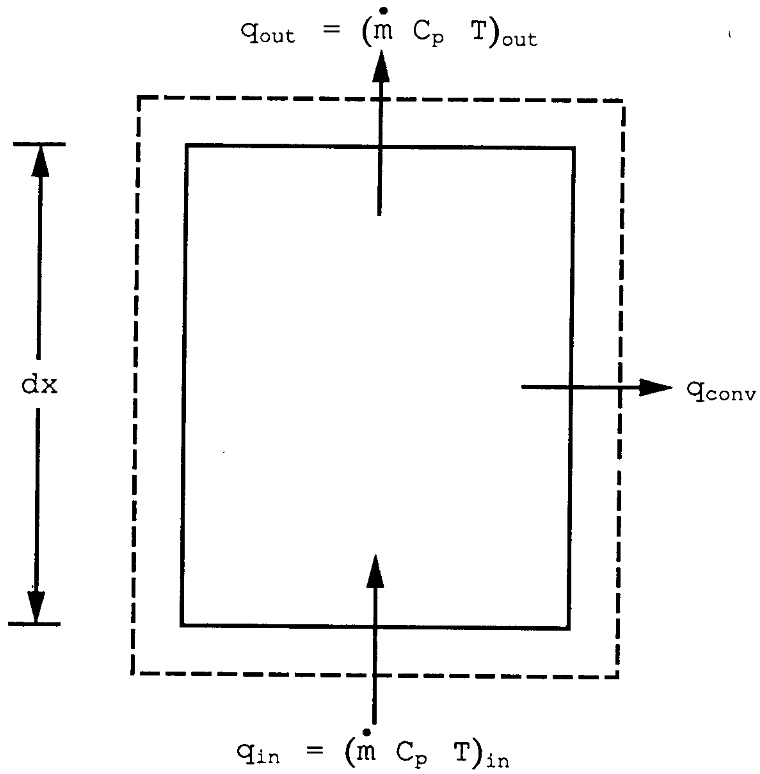

Figure 4.

$$q_{in} = \dot{m}\ C_p\ T_m$$

$$q_{out} = \dot{m}\ C_p\ T_m + \frac{d}{dx}(\dot{m}\ C_p\ T_m)\ dx$$

$$q_{conv} = \frac{T_m\ (x) - T_w\ (x)}{RES} \qquad \text{where } RES = \frac{1}{hA}$$

$$\frac{d}{dx}(\dot{m}\ C_p\ T_m\ (x))dx + \frac{T_m\ (x) - T_w\ (x)}{RES} = 0 \qquad (1)$$

Given values for $\dot{m}$, C_p, T_{wall}, RES, and T_{oil} $(x = 0)$, Equation 1 can be numerically integrated to yield average oil temperatures along the tubing. A check of this simple integration scheme is performed by setting $\dot{m}$, C_p, T_{wall}, and RES equal to constant values for which the analytic solution of Equation 1 is trivial following a temperature normalizing change of variable.

Along with local temperature calculations, viscosity, Reynolds number, friction factor, and density are computed. With this technique it is a simple matter to add turbulent flow relations for convection with higher flow rates, include gas injection effects, perform power requirement analyses, and extend the flow field from well-bore applications to pipeline installations.

The formation heat transfer analysis is calculated using the commercially available IBM PC heat transfer code MSC/cal. When coupled to the fluid code through convection at the tubing wall, simulation of the entire well-bore and formation heat transfer is performed. Axisymmetric elements provide an efficient modeling capability. Heat transfer is considered to be negligible in the vertical direction which allows elements of large aspect ratio to be used without appreciably annoying the solution. Confidence in the formation heat transfer solution is easily obtained by testing mesh size, spacing, and stretching with only a small section of the formation, imposing representative boundary conditions over real time simulation periods. Again, simple axisymmetric problems with an analytic solution can be used for verification. The annulus region is one of mixed mode heat transfer and requires development of an effective thermal conductivity representing enhanced conduction due to free and/or forced convection and radiation heat transfer. The convection contribution is necessarily empirical and is calculated accounting for flowing or static gas conditions, elevated pressure, gas composition, tubing and casing diameters and estimated quasi-static temperatures of the tubing and casing. The radiation heat transfer contribution is acquired by using the simple relationship for heat transfer between concentric cylinders. Estimates are made of emissivities and surface temperatures and geometric information is used to determine the component of heat transfer associated with radiation effects. The quasi-static nature of this system allows steady-state analysis of the conduction, convection, and radiation annulus components to be developed into the effective thermal conductivity. After calculating each component, the total heat transfer is equated to an equivalent conduction problem and the effective conductivity is recovered. Correction can be made to this value for differences due to elevation and to account for improved estimates of the wall temperatures after initial calculations have been performed.

The analysis proceeds as follows. The fluid flow program is executed using the formation initial condition temperatures for the initial tubing wall temperatures. The oil inlet temperature is set equal to the reservoir temperature. At the end of this analysis, local oil temperatures are known. These temperatures are applied in the MSC/cal formation model as the film convection temperatures which provide, through a heat transfer coefficient, the controlling boundary condition on the inner radius of the tubing. Experimentation is required to determine the coupling frequency between updates of fluid temperatures and subsequent periods of heat diffusion into the formation. The objective is to achieve a sufficiently accurate solution while minimizing computation time. With complete control over the I/O of the fluid temperature program, the output data is arranged to provide the direct convection input section for the MSC/cal program. MSC/cal provides automated restart control files with updated temperature initial conditions based on the last solution, automatically accesses any specified external file of commands or data, and stores print and plot file temperatures in a sequential manner from one transient calculation to the next. These capabilities significantly enhance the practicality of this type of analysis.

The code coupling approach described above is applied to the well-bore configuration of Figure 5.

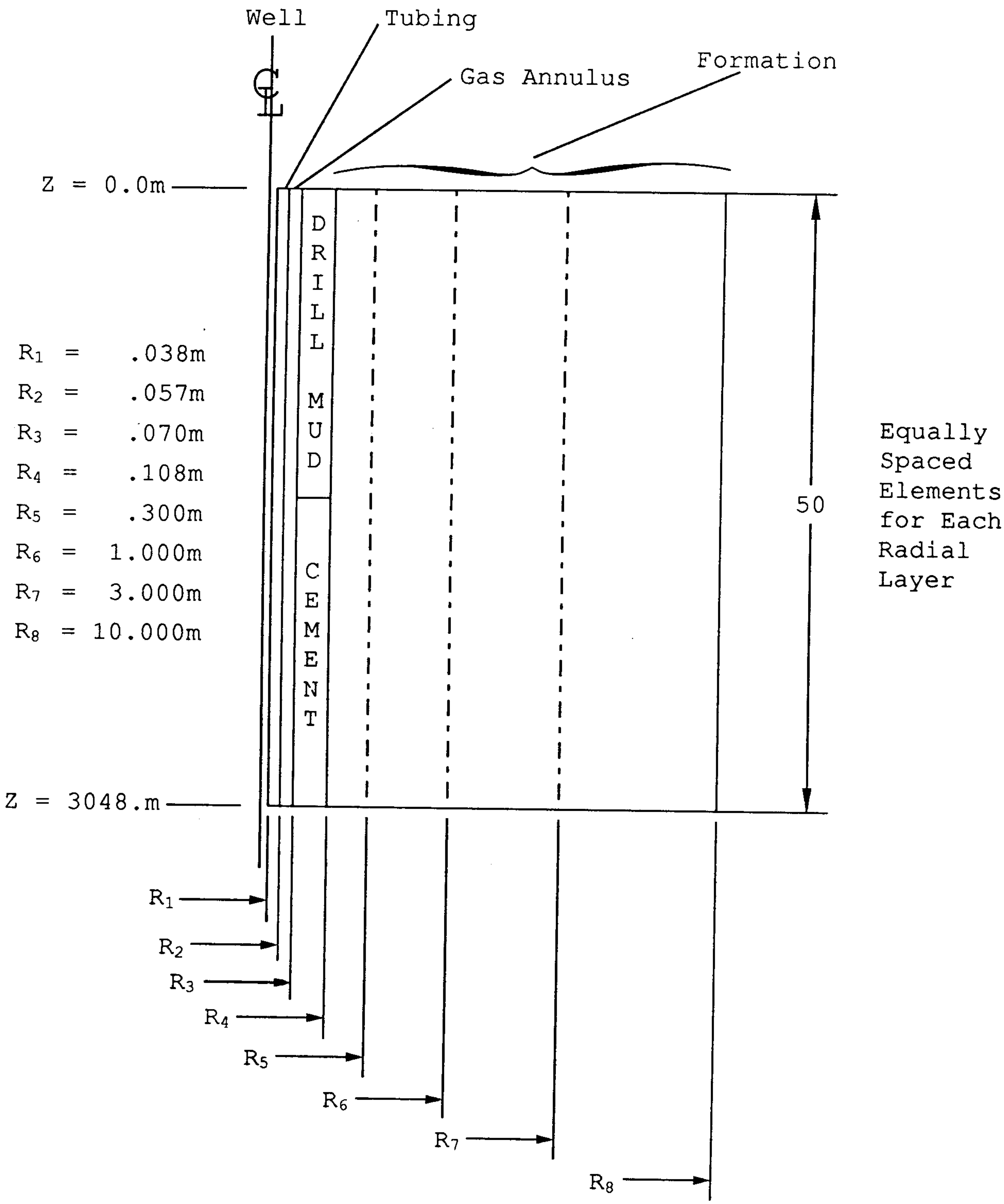

Figure 5. Analysis of Well-Bore Configuration and Element Arrangement.

Production of 31° API oil from a depth of 10,000 ft. is desired. The undisturbed geothermal temperature is governed by:

$$T = A_0 + A_1 Z + A_2 Z^2 + A_3 Z^3 \qquad (2)$$

where $A_0 = 179.85$

$A_1 = -11.642E-03$

$A_2 = -1.0432E-06$

$A_3 = .11228E-09$

The annulus between the tubing and casing is packed off and pressurized from the surface to 2500 psi with dry methane gas. A design volumetric flow rate of 60 kiloliters per day is considered. The evaluation time is set at 330 days during which continual production is performed. Two tubing strings are evaluated to allow comparison of standard bare tubing versus an insulated tubing (K = .014 W/m-C). The coupling frequency was highest during the first sixty days of production analysis and reduced thereafter. The analyses were repeated with successive coupling schedule frequencies doubled until the changes in the total solution were deemed insignificant from one schedule to the next. The flow field was integrated with 50 steps aligned with the 50 elements in the finite element discretization of the formation.

The calculated output is summarized in Figures 6 and 7 where we find significant improvements in oil operating temperatures using insulated tubing. Figure 8 is included to illustrate the effect of reduced mass flow rate on the same well configuration with insulated tubing.

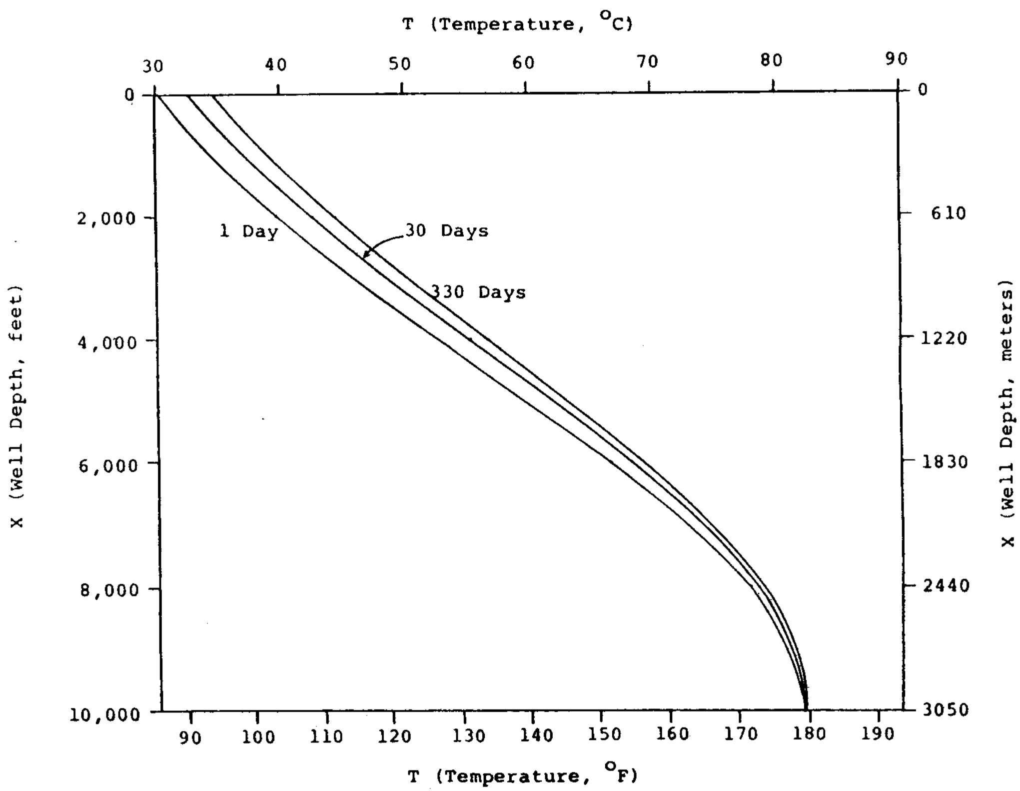

Figure 6. Oil Temperature Versus Well Depth Versus Time. (Bare Tubing: Q = 60 KLPD)

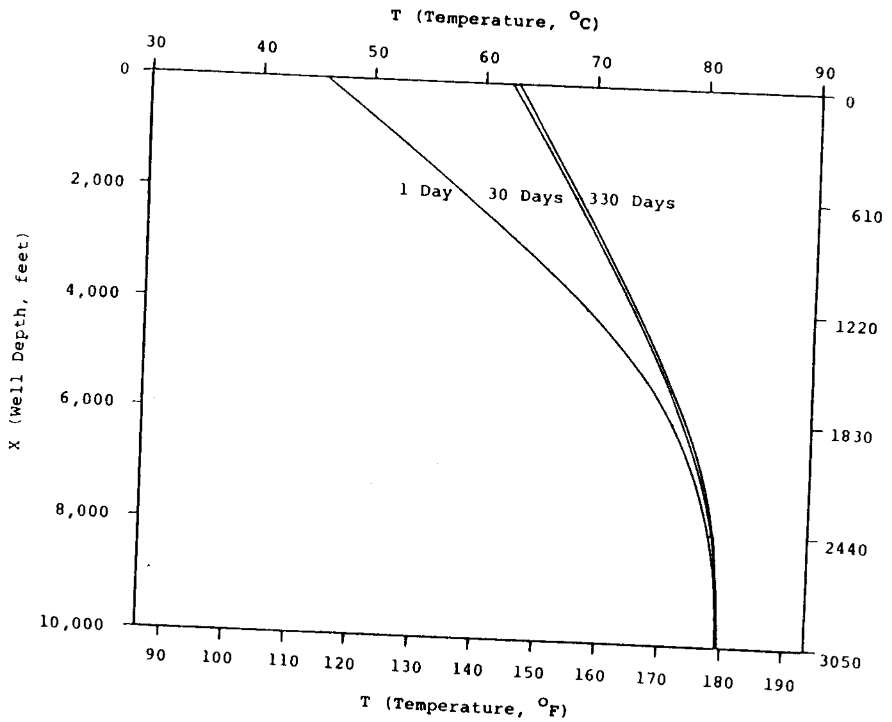

Figure 7. Oil Temperature Versus Well Depth Versus Time. (Insulated Tubing: Q = 60 KLPD)

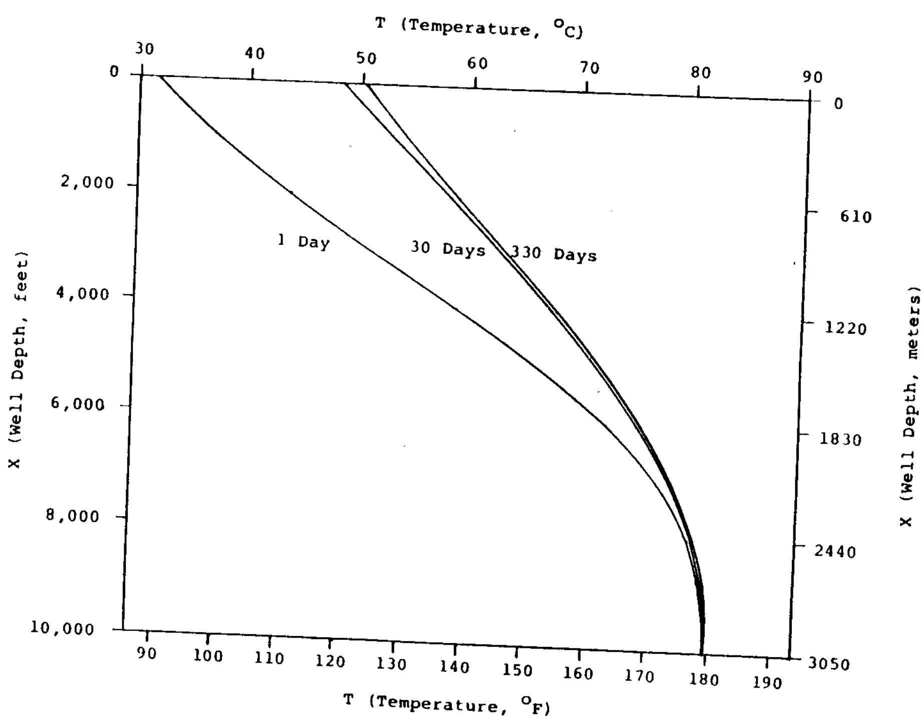

Figure 8. Oil Temperature Versus Well Depth Versus Time. (Insulated Tubing: Q = 30 KLPD)

Table 1 data can be used to perform thermal expansion analyses of the tubing string and casing as well as power required to overcome viscous effects. Table 2 details the local temperature differences driving the heat loss between the oil and tubing wall for each analysis at various depths. The regions of largest ΔT are responsible for the greatest heat loss.

The thermal analysis for well-bore heat transfer presented demonstrates the applicability of inexpensive commercially available finite element software to nontraditional problems. This does not eliminate the need for verification with field data. The notion of coupling a user-developed code to a commercial code may be an economical alternative to dealing with unreliable or unavailable specialty software. It also provides the ultimate in flexibility for the analyst whose problem does not fit into the mold of the specialty code.

Table 1. Well-Bore Temperature Distribution.

Bare Tubing Time = 330 Days, Q = 60 KLPD, Temperature Units °C						
	Depth m (ft)					
Radius	0.0 0.0	610 m 2,000 ft	1,220 m 4,000 ft	1,830 m 6,000 ft	2,440 m 8,000 ft	3,050 m 10,000 ft
R1	29.66	37.07	48.53	61.22	73.67	82.06
R2	28.56	35.47	46.73	59.51	72.57	82.07
R3	25.76	31.40	42.16	57.48	71.28	82.09
R4	24.77	29.97	40.54	55.94	70.30	82.10
R5	23.64	28.33	38.70	54.18	69.18	82.11
R6	22.64	26.87	37.06	52.60	68.18	82.13
R7	22.04	26.00	36.07	51.65	67.57	82.13
Insulated Tubing Time = 330 Days, Q = 30 KLPD, Temperature Units °C						
R1	47.75	55.75	64.88	73.19	79.22	82.01
R2	25.17	29.52	39.41	53.47	68.48	82.12
R3	23.76	27.88	37.81	52.90	68.17	82.13
R4	23.27	27.30	37.25	52.47	67.93	82.13
R5	22.70	26.64	36.61	51.97	67.66	82.13
R6	22.19	26.05	36.04	51.53	67.42	82.13
R7	21.89	25.71	35.71	51.28	67.27	82.14
Insulated Tubing Time = 330 Days, Q = 60 KLPD, Temperature Units °C						
R1	59.31	64.78	70.73	76.05	79.96	82.01
R2	26.71	30.73	40.19	53.77	68.57	82.12
R3	24.68	28.60	38.28	53.12	68.24	82.13
R4	23.96	27.85	37.61	52.63	67.99	82.13
R5	23.14	26.45	35.64	52.07	67.70	82.13
R6	22.41	26.23	36.16	51.57	67.45	82.13
R7	21.97	25.77	35.75	51.27	67.30	82.14

Table 2. Local Oil Versus Tubing Wall Temperature Differences.

Bare Tubing Time = 330 Days, Q = 60 KLPD, Temperature Units °C			
Depth (ft)	T_{oil}	$T_{Wall\ Tubing}$	ΔT
0.0	34.5	29.7	4.80
2,000	44.4	37.0	7.40
4,000	56.8	48.5	8.30
6,000	69.0	61.2	7.80
8,000	78.6	73.7	4.90
10,000	82.0	82.0	0
Insulated Tubing Time = 330 Days, Q = 30 KLPD, Temperature Units °C			
0.0	50.3	47.8	2.5
2,000	58.9	55.8	3.1
4,000	68.0	64.9	3.1
6,000	75.5	73.2	2.3
8,000	80.5	79.2	1.3
10,000	82.0	82.0	0
Insulated Tubing Time = 330 Days, Q = 60 KLPD, Temperature Units °C			
0.0	62.8	59.3	3.5
2,000	68.6	64.8	3.8
4,000	74.1	70.7	3.4
6,000	78.5	76.0	2.5
8,000	81.2	80.0	1.2
10,000	82.0	82.0	0

REFERENCES

1. Speight, J. G., The Chemistry and Technology of Petroleum, Marcel Dekker, Inc., New York, 1980.

2. van Poolen, H. K. and Associates, Fundamentals of Enhanced Oil Recovery, PennWell, Oklahoma, 1980.