Model for Hot Oil Jobs

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Abstract

This paper describes an Excel spreadsheet used to solve a challenging transient heat transfer problem for a well. A large number of unknown temperatures are solved numerically as a function of time on an R-Z grid. Time steps are controlled by a macro and the formulation is fully implicit for numerical stability. The situation modeled is hot oil injection into a well annulus in attempt to warm the tubing, thus melting wax and allowing its removal. Often the tubing is pumped while it is heating. Hot water or wax solvents are sometimes used in place of hot oil. The annulus may be (and often is) partly empty when annulus injection begins. The location of the injected fluid front is determined from annulus injection rate and other well data. When the injected fluid reaches the annulus sump level near the bottom of the well, that sump level rises rapidly because injection rate generally exceeds annulus drainage rate. This rising sump level slows the possible downward advance of injected heat, which may not reach the needed depth. Examples reveal that the injected fluid cools with depth and that may affect job success.

1. Introduction

Production from low rate oil wells can lead to tubing wax accumulation over time as wax crystals form and deposit at tubing temperatures sufficiently below cloud point temperature. Heat loss to the earth cools produced fluid, and the lower the production rate, the more cooling occurs.[1,2] The gradual formation of a wax deposit inside the tubing is not the subject of this paper, but is an area of great interest in connection with both onshore and offshore production problems now dubbed "flow assurance" issues.[3] As experience is gained in predicting wax deposition rates this will help improve the initial condition of assumed wax distribution in the present model at the time of the required treatment. For this paper the wax distribution is assumed uniform. The spreadsheet described below was used to estimate depths where wax probably formed, prior to the hot oil job.

Generally. the slow accumulation of wax in tubing can lead to a number of production problems, including premature rod wear or rod parting, lost pump efficiency, or increased gear box failure. The direct costs and lost production from these problems provide incentive for ways to economically remove the wax. One method commonly used is to inject a slug of hot fluid into the tubing-casing annulus to heat the tubing and melt the accumulated tubing wax. The success of a treatment depends on many factors, including heating effectiveness and possible wax content in the injected fluid itself. This paper illustrates a model for predicting heating effectiveness during hot fluid injection to remove tubing wax.

2. Model Description

The numerical model estimates transient temperatures and the likely success of the job, based on well depth, injected volume, etc. Fig. 1 shows the physical well elements and fig. 7 shows the R-Z computational grid. Tubing fluid (1) and annulus fluid *(2)* exchange heat across the tubing wall **(A)** and any internally deposited wax layer. The annulus (a) has complex fluid flow during the job and undergoes transient heat exchange with casing (B). All well elements modulate heat exchange by heat capacity effects, denoted by C in equations.

The model of a hot oil job extends the popular analytical models developed for temperature prediction in a flowing well (Ref 1). Principally, the events are short-term (of order minutes) and require account of thermal capacity of cements, pipes, and fluids. The earth immediately around the well undergoes complex heating and cooling as the job proceeds. These events can be handled with temperature superposition in radial geometry', combined with accurate earth heat transfer functions.' Alternatively. a hybrid approach is used here. with earth immediately near the well solved numerically, and an analytical earth model used for remote earth effects. The change in thermal resistance at the tube wall when a wax layer melts is important during the hot oil job. since the thermal resistance with a wax deposit (wax thickness divided by wax thermal conductivity) is higher than the thermal resistance without wax. Counter-current fluid flow exists, with upward flow in the tubing and downward flow in the annulus.

A circuit diagram analog to the thermal problem is shown in fig. 3, with thermal node resistances R and capacities C. Vertical heat conduction is ignored and only radial heat conduction and all convection effects are accounted for.

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The special features of the annulus filling and storage during the hot oil job. fig. 4, include these events;

1. Annulus tilling occurs by surface fluid injection at a fixed rate, Q_a, at fixed surface temperature for a finite time period, (Thermal transients that persist beyond the injection period are modeled also)
3. Annulus fluid and tubing fluid are incompressible. but the annulus may exhibit storage effects (partial saturation) by the presence of gas in the annulus above the sump level. Z,. (The thermal capacity of the gas is neglected).
3. The annulus empties slowly by gravity flow Q_r into the reservoir (fluid head controlled) until the time the injected fluid front Z_f reaches the sump. At that point annulus fluid sump level generally rises, depending on the rate of gravity flow out the annulus bottom and rate of arrival of injectant reaching the sump.
4. When annulus injection is shut-in (SI), annulus sump level continues to rise until all injected fluid finally reaches the sump. This is modeled with an emptying front Z_e approaching the sump level Z,. The sump returns to a draining, or falling level condition when $Z_e=Z_c$.
5. Annulus fluid may mix adiabatically with reservoir fluid and reservoir rock mass in a user-defined mixing zone below the sump. This mixing gradually changes temperature of tubing fluid entering the tubing nose. Alternatively, annulus fluid may be assumed to slowly drain into the reservoir with no appreciable effect on the tubing nose entrance temperature.
6. The movement of the injected annulus fluid is approsimated as a sharp frontal advance of a wetting front at uniform speed, fixed by a user-selected frontal saturation that allows gas blow upward as liquid falls downward, fig. 5. Both tube and casing are partially wetted by the advancing injectant.
7. A simulated downhole electrical heat strap. fig. 6. attached to the outside of the tubing, was added as an option to help melt wax in the tubing at depth. Some fraction (f) of the electrical energy heats the tubing wall, and the remainder (1-f) heats the annulus fluid.

The model assumes a uniform wax layer exists at the time the hot oil job starts, for depths where temperature is below cloud point temperature, fig. 2. The wax melting point (temperature in excess of the cloud point) is assumed known and constant. The amount of heat and time required to locally melt wax is assumed small compared to the heat injected and duration of the treatment. Further. it is assumed that once melted, wax in the tubing does not re-crystallize and re-deposit somewhere uphole for times of order hot oil job time. although the model can show where this tends to occur. The model neglects the heat of fusion of the melting wax deposit.

It's assumed that wax thickness melted away during the treatment does not significantly change the cross section area for flow in the tubing. Assumptions about wax thickness and effects on flow area can be relaxed. if necessary. Melted wax is assumed to have no effect on the tubing fluid physical properties. because the amount of melted wax is a small fraction of the tubing liquid mass. The decrease in thermal resistance between tubing flow and the tubing wall is important as wax melts, and is accounted for.[6]

A schematic of annulus gravity drainage rate Q_r during hot oil injection is shown in fig. 7. Prior to arrival of the injected fluid front, drainage rate from the annulus sump into the reservoir is slowly decreasing in time due to falling head. At t_{c1} the injected fluid front Z_f arrives at the sump level and the annulus begins to fill rapidly. As the sump level increases the gravity drainage rate from the sump increases. At t_{inj} the hot oil injection ceases, but the sump continues to fill until the emptying front reaches the sump at t_{c2}, where true sump emptying resumes and sump level falls. Sump drainage is explicitly determined based on fluid levels at the beginning of each time step. Sump level has a major impact on downhole heating, as the sump slows the rate of warm fluid transport.

3. Model Equations

Heat balances for all nodes in fig. 3 are used. For the fluid nodes, such as zones 1 and 2 (fig. *2)* heat balances include convective transport along the well, lateral heat transier. and heat storage. The model allows for flow in either direction (uphole or downhole) in the tubing and annulus for generality. For tubing fluid, a heat balance is written for node k as,

$$
\begin{aligned}
&-0.5(I_1 + 1)\dot{C}_1^{k-1,n+1}T_1^{k-1,n+1}\Delta t + I_1\dot{C}_1^{k,n+1}T_1^{k,n+1}\Delta t \\
&-0.5(I_1 - 1)\dot{C}_1^{k+1,n+1}T_1^{k+1,n+1}\Delta t + \\
&V_1^{k,n+1}(c_1^{k,n+1}T_1^{k,n+1} - c_1^{k,n}T_1^{k,n}) \\
&= -Q_{1A}^{k,n+1}\Delta t + (\textit{optional terns for mixing effects})
\end{aligned}
\tag{3.1}
$$

Eq (3.1) is a heat balance over time interval Δt. with current time index n+1. I_1 is the flow direction indicator (+1 for upflow, -1 for downflow) for tubing fluid flow. Heat flus Q_{1A} occurs between the tubing fluid 1 and the tubing A, while $\dot{C}_1$ is the capacity rate for tubing flow, normally fixed. Terms involving V_1, the tubing fluid volume, account for heat storage with fluid volumetric specific heat c_1. Optional terms (not needed for the hot oil simulation) allow for direct mixing of tubing and annulus fluids, e.g., at a gas lift location.

The annulus fluid heat balance equation for tempcrature T_2 is similar to the tubing fluid equation, and includes the heat transfer between annulus fluid and both tubing and casing, Q_{A2} and Q_{2B}. The equation allows for a partially filled annulus of fluid volume V_2 and liquid capacity rate $\dot{C}_2$, which change with time and location along the annulus.

$$
\begin{aligned}
&-0.5(I_2^{k-1,n+1} + 1)\dot{C}_2^{k-1,n+1}T_2^{k-1,n+1}\Delta t + \\
&I_2^{k,n+1}\dot{C}_2^{k,n+1}T_2^{k,n+1}\Delta t + \\
&-0.5(I_2^{k+1,n+1} - 1)\dot{C}_2^{k+1,n+1}T_2^{k+1,n+1}\Delta t + \\
&V_2^{k,n+1}(c_2^{k,n+1}T_2^{k,n+1} - c_2^{k,n}T_2^{k,n}) \\
&= (Q_{A2} - Q_{2B})\Delta t + (\textit{optional } \textbf{\textit{terms for}} \textit{ mixing effects})
\end{aligned}
\tag{3.2}
$$

Flow direction I_2 (+1 for upflow, -1 for downflow) may change with grid location k, depending on progress of the injection front and sump drainage rate (fig. 4).

Nodal equations are also written for the elements where only heat conduction occurs, but an analytical equation is used for heat exchange Q_∞ between earth of temperature $T_e(z)$ and the edge of the last annulus g of temperature T_{ew} ,

$$
Q_\infty = \frac{(T_{ew}^{k,n+1} - T_e(z))}{}
\tag{3.3}
$$

where the cylindrical heat transfer function f(t) is taken from ref (5),

$$
f(t) = 0.982 \ln\left(1 + 1.81 \frac{\sqrt{\alpha t}}{k_{Er}}\right)
\tag{3.4}
$$

Algebra allows the 16x31 heat balance equations (T_1, T_A, T_2, T_B, ... T_{ew}) to be combined into a tri-diagonal system of 31 equations for the tubing fluid temperature T_1^k.

4. Solution in Excel

In the spreadsheet the depth nodes are arranged in 31 rows. and radial nodes and time step data in columns, fig. **8.** One of the columns is for assumed earth temperature, $T_e(z)$ (which may be a nonlinear geothermal gradient). Fluid capacity rates along the well and all nodal resistance and capacity values (R,C) are tabulated. Other tabulated data include node temperatures at the previous time, n. the T, coefficient matrix and its Excel inversion. boundary conditions (inlet temperatures and flow rates for fluids entering the system), and a final section of nodal temperatures at the current time (n+1).

A macro controls time step size and copies current nodal temperatures into previous nodal temperatures for the nest time step. Time steps pause to allow the user to inspect temperature and fluid saturation graphs. The spreadsheet uses the full extent of Excel columns available (A-IV). Time steps can be changed during the simulation, for example small steps to emphasize details when fronts move rapidly, or large steps when the injection period has ceased and relaxation occurs.

5. Examples of Hot Oil Jobs

During the injection period the water moviny down the annulus wets part of the casing but more of the tubing, fig. 5. Wetting area is based on assumed saturation of the moving front. In the annulus above sump level, gas flows upward and liquid flows downward. Liquid is approximately confined by the wetted area illustrated between casing and tubing. High heat transfer coefficient h is limited to the wetted surfaces of high flow velocity (behind the moving front, Z_f). Heat conduction that may occur between tubing and casing in direct contact is ignored for this model, and the annulus flow is assumed turbulent with heat transfer modeled by Latzko' and a hydraulic diametsr based on the wetted surfaces.

Table 1 shows assumed well data for a hot oil job where hot water from 50-150 gpm for 30-90 minutes was used to heat the annulus, and the tubing flow is at 95% water cut. 5% oil cut. The annulus sump level was varied from 2500-7500 ft when the hot oil job started, and the well depth is fixed at 9300 ft. Assumed cloud point was varied from 90-115°F. Bottom-hole and surface temperatures were 150°F and 60°F, respectively. Assumed melting temperature was 25°F higher than cloud point.

Table 2 summarizes the results for cases for the well dsscribed in Table 1. The main results are the depth intervals where wax deposit exists before and during the job. For the 90°F cloud point, initial wax (at the time of the job) was limited to the depth of 0-2100 ft. During the low rate (50 gpm) hot water injection the wax was reduced to 900-2100 ft, and was further reduced to 1200-2100 fi by 120 minutes. For the high rate case (150 gpm) at 90°F cloud point wax was completely melted by 30 minutes.

For the 90°F cloud point at low rate (50 gpm) for 90 minutes of injection wax was reduced to 1800-2100 ft at the end of injection, and wax was completely removed by 120 minutes. This shows that if the cumulative heat injected is comparable (50 gpm for 90 minutes or 150 gprn for 30 minutes). both high and low rate of injection can adequately melt wax, but the lower rate does so more slowly due to the longer contact tims with the reservoir.

For the 90°F cloud point an alternative to longer injection is to use a supplemental electrical heat via a strap on the tubing. A 200 kW heat strap was applied within the depth range 1900-2150 ft, combining with hot fluid injection at 50 gpm for 30 minutes. The wax extent at 30 minutes of hot fluid and supplemental heat applied in this manner was 900-1500 ft, compared to 900-2100 ft without the supplemental heat. At 120 minutes (90 minutes after shut-down of injection and supplemental electrical heat) the wax was reduced further to 1200-1500 ft. Maximum tubing temperature was 400°F, however, and a more distributed heat would be needed for safe operating temperarures using the electrical heat method to supplement hot fluid.

For the 100°F cloud point, initial wax is deposited in the depth range of 0-3300 ft. At the end of the 30 minute injection period the 50 gprn rate injection case has achieved little wax melting, leaving wax in depth range 600-3300 ft. This was reduced with time and became 900-3300 ft at 120 minutes. With 150 gpm injection rate, wax was reduced to 2100-3300 ft at the end of injection, and to 2400-3300 fi at 120 minutes. Thus, the wax was not completely removed by the 150 gpm injection rate for this higher cloud point fluid (100°F), whereas complete wax removal was achieved for the lower cloud point fluid (90°F).

The effect of a shallow sump level (2500 ft) is a reduction in effective wax removal for this well. At the 150 gpm rate, wax remaining at the end of injection for a 2500 ft sump level was 1800-3300 ft, compared to 2100-3300 ft with the 7500 ft sump level at the end of injection. At 120 minutes the 2500 ft sump level created a remaining was at 1800-3300 ft, whereas the remaining wax for the 7500 ft sump level was 2400-3300 at 120 minutes, or about 600 ft more wax remaining as a result of the shallow sump level.

6. Summary and Conclusions

For the simplified hot oil job model, Excel is a powerful tool to find temperature at all locations in and around the well during the simulation. A more sophisticated model. with pressure as an additional unknown, a flash calculation, or with highly nonlinear heat transfer. would probably require mors capability than Excel and macros were designed to handle.

The numerical model for a hot oil job was applied to high cloud point fluids for which wax is deposited on the inside of the tubing during normal production operations. Removal of this wax deposit can be achieved if the heat moving down-hole is sufficient to melt the wax, which occurs at a tempcraturs around 15-25°F higher than the cloud point temperature. The delivery of adequate down-hole heat to melt the depositsd wax depends on many factors, including the amount of fluid injected, sump level, heat transfer behveen injected fluid and the elements of the well, and time. It is possible to examine all factors involved with a model that runs quickly, but approximately accounts for heat transfer coefficient changes as a result of wax layer changes on the inside of the tubing, and for the dynamics of the advancing fluid in the annulus. Accurate accounting of the heat transfer by annulus convection is essential for stable temperature prediction and arithmetic elimination of the unknowns to a single equation for T_1.

For a particular range of cloud points the examples shown above reveal that successful wax removal by hot fluid injection can be achieved, provided enough heated fluid is injected in the annulus, and provided that the annulus sump level does not interfere with heat movement. A down-hole heating element strapped around the tubing can supplement wax melting capability for power in the range of 100-200 kW, but the overheating of tubing is possible if not submerged in liquid and of sufficient linear extent.

The spreadsheet model can be used to estimate success of a hot oil job if the depths of wax are known, and if reasonably accurate cloud point and melting point data are available.

Nomenclature

a =thermal diffusivity, sq ft/d
c = specific heat, BTU/cu ft-F
C= node capacity, BTU/F
$\dot{C}_1$, $\dot{C}_2$= capacity rates for tubing and annulus flows. BTU/d-F
At= time increment, d
f(t)= earth analytical heat transfer function, dimensionless
h= heat transfer coefficient, BTU/sq ft-d-F
I_1= flow direction indicator (+1 is upflow, -1 is downflow)
k= vertical node index (k=1,2,...,31)
k_{Er}= earth themal conductivity. BTU/d-ft-F
Q_{1A}, Q_{A2}, Q_{2B}= heat transfer rate between flowing fluids (1,2) and surfaces (A,B) by forced convection, BTU/d
Q_r= sump drainage rate, bbl/d
R= node resistance, d-F/BTU
t= elapsed time, d
T^k= node k temperature, F
$T_e(z)$= assumed earth temperature far from well, F
T_{ew}= temperature at interface between numerical model and analytical earth, F
V= nodal volume, cu ft
Z_f= depth to advancing front of annulus injectant. ft
Z_c= depth to sump level in annulus, ft
Z_e= depth of trailing end of annulus injectant, ft

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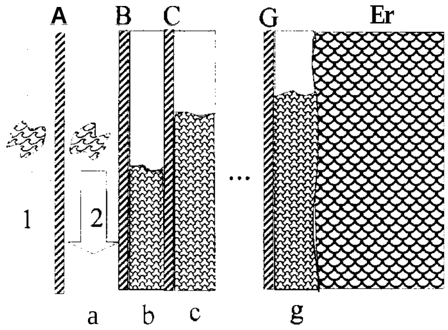
Table 1 - Basic Well Data for Example Hot Oil Job

Tubing OD: 2.375 in.	Wax thickness: 0.1 In.	Q_{ro} (sump rate): 50 bpd
Tubing ID: 2.000 in.	Injected water: 200°F	Q_{rp} (derivative): 0.02 bpd/ft
Production casing: 7 in.	K_{Er} (earth): 40 BTU/d-ft-F	V_m (bulk mixing volume): 500 bbl
Surface casing: 8.625 in.	Production rate: 45 bpd	V_f (pore mixing volume): 50 bbl
Well length: 9300 ft	Fluid 1 capacity: 0.94 BTU/lb-F	Heat element: 200 kW
Production casing: 8800 ft	Fluid 3 capacity: 1.0 BTU/lb-F	Element mass: 1100 lb
Reservoir top: 8900 ft.	S_{or} (residual annulus film): 0.05	Element capacity: 0.23 BTU/lb-F
Surface casing: 1500 ft.	S_{of} (frontal annulus sat): 0.50	Element heat factor f: 1.0
Prod. casing cement: 500 ft.	Reservoir temperature: 150°F	Element length: 150 ft
Surf. casing cement: 100 ft.	Surface temperature: 60°F	Element location: 1900-2150 ft

Table 2 - Results of Wax Depths (ft) for Hot Oil Jobs

cloud pt., °F	Inj rate, bpm	Sump **level,** ft	Hear strap	**wax** @ 0 min.	wax @ 15 min.	wax @ 30 min.	Wax @ 120 min.
90	50 for 30 min.	7500	No	0-2100	600-2100	900-2100	1200-2100
90	150 for 30 min.	7500	No	0-2100	1200-2100	None	None
90	50 for 90 min.	7500	No	0-2100	600-2100	900-2100 (1800-2100 @ 90 min.)	None
90	50 for 30 min.	7500	Yes	0-2100	300-1800	900-1500	1200-1500
100	50 for 30 min.	7500	no	0-3300	300-3300	600-3300	900-3300
	150 for 30 min.	7500	no	0-3300	900-3300	2100-3300	2400-3300
100	150 for 30 min.	2500	no	0-3300	900-3300	1800-3300	1800-3300
115	150 for 30 min.	7500	no	0-4800	600-4800	1500-4800	1500-4800



A,B,...,G - capacity, no-resistivity
a,b,...,g - capacity and resistivity
Er - earth (wet or dry)
cement
— stagnant fluid
moving fluid

Figure 1 - Physical Well Elements

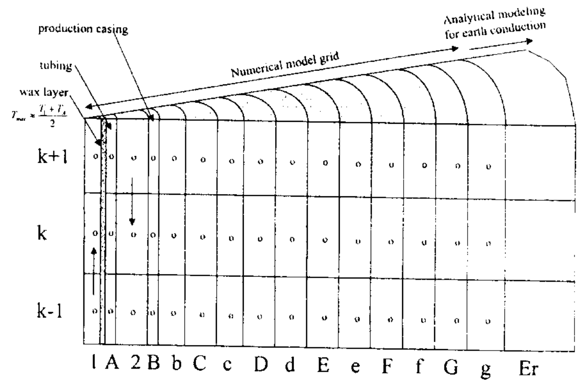


Figure 2 - Wellbore R-Z Model Grid

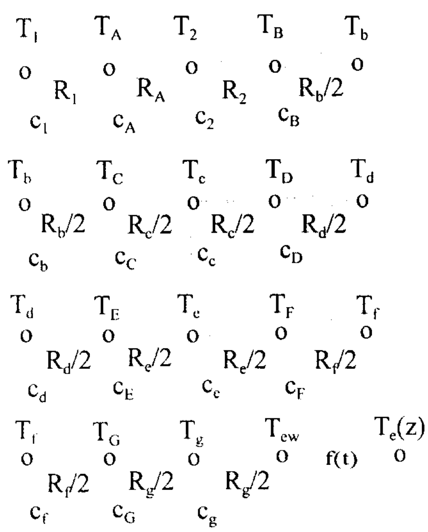


Figure 3 - Circuit Diagram Analogy

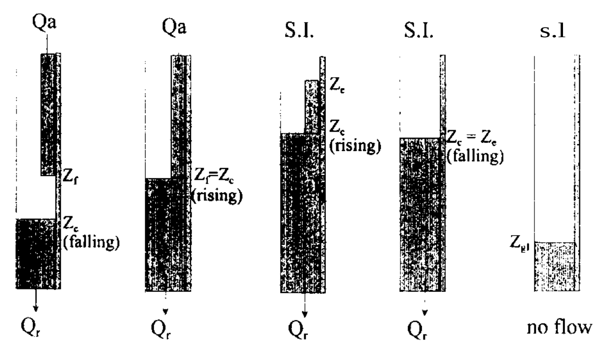


Figure 4 - Stages of Annulus Storage and Drainage

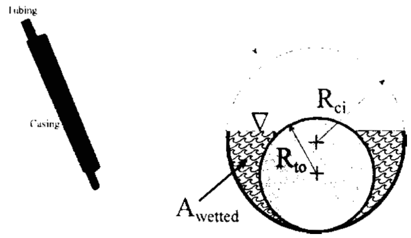
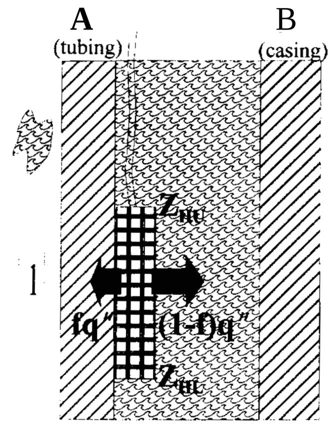


Figure 5 - Physical Well Elements



$q'' = Q_s/(Z_{HL} - Z_{HU})$

Figure 6 - Tubing Heat Strap
(electrical heat on outside of tubing)

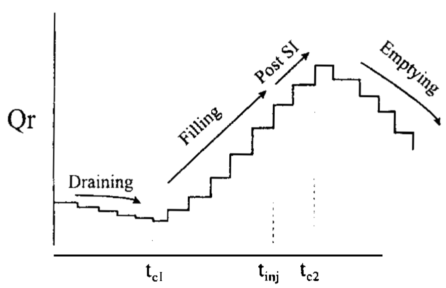


Figure 7 - Annulus Drainage Rate Versus Time
(changing fluid head)

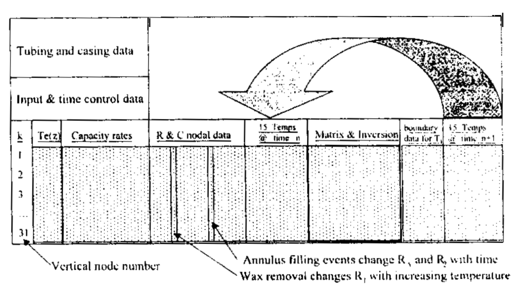


Figure 8 - Spreadsheet Layout