INTERACTION BETWEEN SURFACE FACILITIES AND WELLS AT AN OPERATING GEOTHERMAL FLASH PLANT

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ABSTRACT

Geothermal wells are usually flow tested individually, using surface facilities whose main requirements are to provide accurate measurement of flow and enthalpy while safely disposing of the produced fluids. Such facilities provide a poor model of the complex gathering system to which a typical well may ultimately be connected. Without careful analysis, such test results can lead to unrealistic expectations of well output under operating conditions. All production wells on a gathering system are affected by changes to any component of that system, whether it be a new well connected to the system or a piping modification. Such changes alter the operating pressures throughout the system, including wellhead pressures at all the wells. All well outputs will therefore be affected, regardless of their location. As a result, connecting a new 10 MW well to the system may only add 5 MW or less to the plant output. This paper presents a method to account for such surface interference effects, and determine the true net effect of such changes as adding a new well or modifying the piping system.

INTRODUCTION

Unlike a stand-alone test facility where a well's wellhead pressure and flowrate can be varied without consequence to any other well (except through reservoir interference), any changes made to a well connected to a gathering system will have an impact on all other components of that system including wells, pipelines, separator vessels and turbines. Bringing a new well on-line, for example, may increase plant output, but it will also increase frictional pressure drops in pipelines, increase separator pressures and decrease the output from other wells on the system. The net gain in output may be substantially less than the nominal stand-alone capacity of the new well.

A similar situation applies to changes to any system component; modifications to pipelines or wellheads will cause the wells and separators to operate at different pressures. In turn, this changes well production rates and the separator flash proportions.

These effects are the result of interaction between the well production characteristics and the surface facilities. In order to accurately assess the effect of making any changes to a gathering system, it is necessary to understand the processes involved and the nature of the interaction.

Figure 1 shows a simple conceptual model of a typical flash plant gathering system. For the purposes of this analysis it is assumed that the plant is operated as a base load plant, and that it is steam limited so that the governor valves are fully open. Separator pressures are allowed to vary rather than being controlled to a set point.

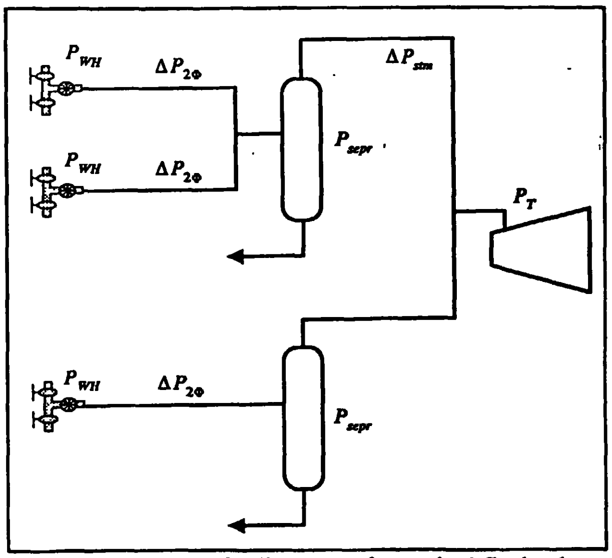

Figure 1: Schematic diagram of a typical flash plant, illustrating the nomenclature used in this paper for system pressures.

The pressure at any point in this system can be described in terms of the pressure at some other point and the pressure drops between the two points. For example, the separator pressures are equal to the turbine inlet pressure plus the pressure drops in the steam piping:

$$P_{sepr} = P_T + \Delta P_{stm} \qquad (1)$$

P_{sepr} - separator pressure
P_T - turbine pressure
ΔP_{stm} - pressure drop in steam lines

Similarly, wellhead pressures can be described in terms of the pressures of the separators they supply:

$$P_{WH} = P_{sepr} + \Delta P_{2\Phi} \qquad (2)$$

P_{WH} - wellhead pressure
$\Delta P_{2\phi}$ - pressure drop in two phase lines

Each of the terms in Equations 1 & 2 is a function of flowrate. The flowrates, however, are determined by the wellhead pressures at the production wells. By quantifying the relationships between wellhead pressure and well production rates, and between wellhead pressure and gathering system flowrates, it is possible to construct a complete pressure and flowrate profile for the system. The effect of any change to a system component can then be evaluated and the net overall impact assessed.

SYSTEM COMPONENTS

The key element in analyzing well and surface facility interaction is in determining the relationships between pressure and flow for each system component. While these can often be determined by theoretical calculation or taken from manufacturers' data, for an operating plant it is generally easier and more accurate to use empirical data. Such data will normally be readily available and already incorporates any deviations from design conditions. Some care is necessary in the choice of data to ensure that sources of systematic error such as instrument recalibrations or long-term scale buildup are eliminated as far as possible.

Each component of a typical gathering system has a distinct pressure-flow characteristic. These are described in the following text.

Turbine Characteristics

The turbine is a convenient place to start the analysis since both the condenser pressure and steam enthalpy are virtually constant over normal operating ranges. Because of this, the turbine inlet pressure can be defined directly as a single-variate function of steam flowrate. Data collected during normal operation can be used to quantify this function, which will generally be linear. An example from the 67 MW turbine at Dixie Valley, Nevada, is shown in Figure 2. The data shows a linear trend similar to that expected from the manufacturer's data.

Steam Line Characteristics

The frictional pressure drop within the steam lines will be proportional to the volumetric flow rate through them. This can be expressed in terms of the mass flow rate by correcting for the specific volume of steam at the average line pressure.

$$\Delta P_{stm} = K \frac{SF^2}{\nu^2} \qquad (3)$$

ν - specific volume
SF - steam flowrate
K - constant

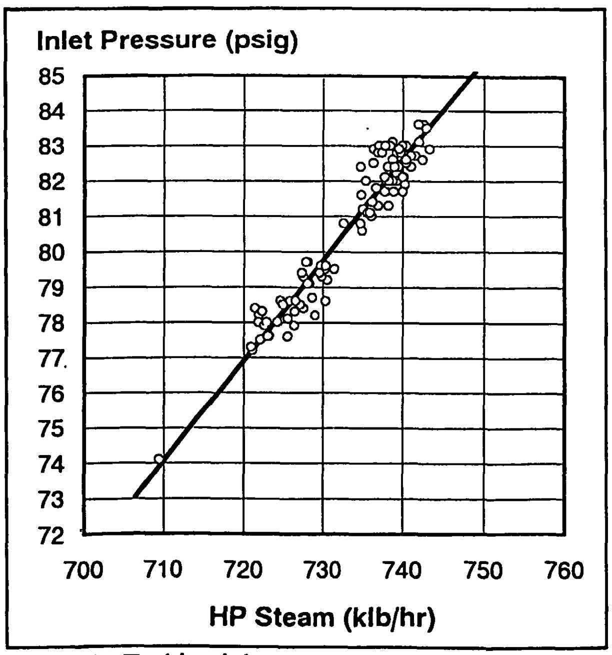

Figure 2: Turbine inlet pressure as a function of high pressure steam flowrate - Dixie Valley 67 MW plant

Generally, pressure drops in steam lines will be relatively small until the line approaches or exceeds its design capacity; at higher flowrates, however, pressure drops can become large and may have a substantial impact on plant performance.

Separator Pressures

The separator pressures are set by the turbine inlet pressure and steam line pressure drops, as described in Equation 1. A plot of pressure against steam flowrate is therefore mainly linear, but with a small non-linear component. This trend is shown in Figure 3.

The separator pressure directly affects the flash percentage; as the pressure rises, the proportion of steam separated from the total flow decreases according to the relation:

$$x = \frac{h - h_f}{h_{fg}} \tag{4}$$

h - fluid enthalpy
h_f - enthalpy of liquid phase
h_{fg} - enthalpy of vaporization

This is plotted in Figure 4 for a fluid enthalpy of 450 BTU/lb.

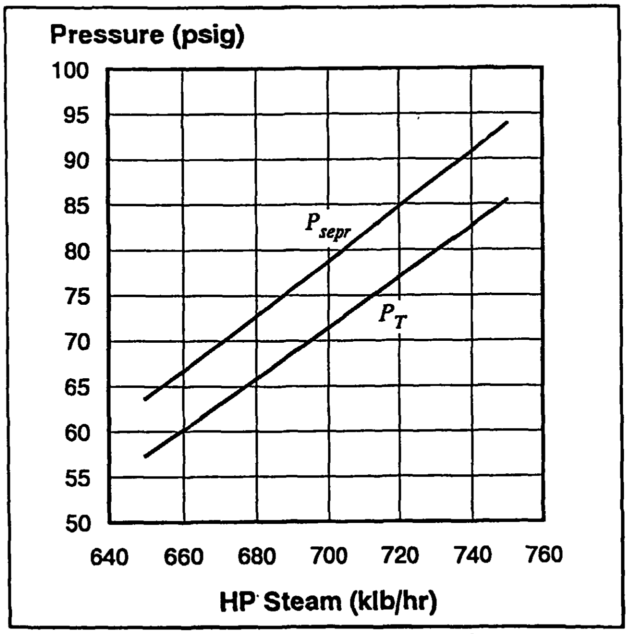

Figure 3: Plot of separator pressures against HP steam flowrate.

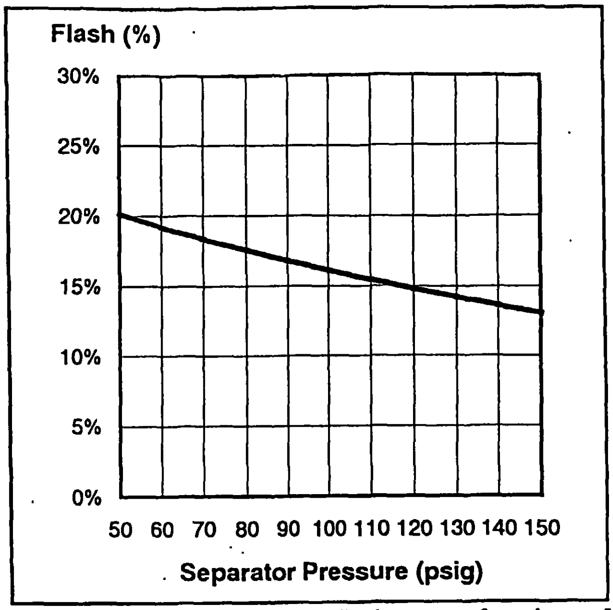

Figure 4: High pressure flash as a function of separator pressure for a constant fluid enthalpy of 450 BTU/lb.

Wellhead Pressures

Wellhead pressures are set by the separator pressures and the pressure drops in the two phase lines as in Equation 2. Two phase pressure drop calculations are notoriously difficult, but in an operating plant, field data can be used to derive an approximate empirical relationship of a similar form to Equation 3.

Well Flowrates

Production well flow characteristics are most usefully represented by productivity curves, where the flowrate is plotted against the wellhead pressure. The shape of the curve is influenced by a number of factors including the well's permeability, temperature and pressure, and the casing diameter and depth. Figure 5 shows productivity curves for typical Dixie Valley wells with 9-⅝" and 13-⅜" casing; the influence of the casing diameter is unmistakable, with the smaller wells having very flat characteristics indicative of the flow being wellbore limited.

Well Enthalpy

In many fields, particularly those with two phase reservoirs, well enthalpies are also a function of wellhead pressure. This further complicates the analysis since the enthalpy used in Equation 4 is then

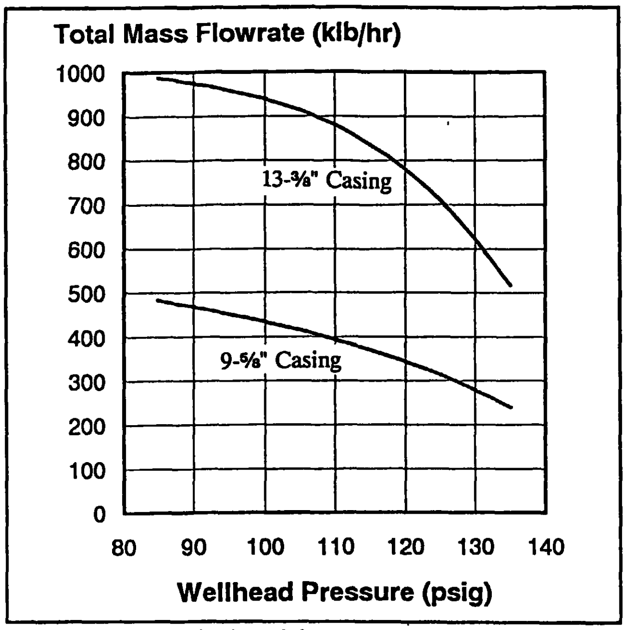

Figure 5: Typical Dixie Valley production well productivity curves

a variable rather than a constant. Most typically, enthalpy decreases with increasing wellhead pressure, so that as separator pressures rise, the flash percentage decreases much faster than it would otherwise. At Dixie Valley, enthalpics are constant over the entire operating range of the wells.

DETERMINING THE SYSTEM OPERATING POINT

By using the productivity curves for each well, the flowrate through any part of the system can be defined in terms of the wellhead pressures of the wells connected to the system. The wellhead pressures, in turn, can be calculated by summing the pressure drops for each of the downstream system components, each of which has been shown to be a function of flowrate. Solving these equations for each well allows the operating point of the system to be found, and a complete profile of system pressures and flowrates can be constructed.

The situation is complicated somewhat by the number of wells and separators connected to the system. Since each well contributes to the flow through the system and thereby affects the system pressures, the above approach needs to be applied to each well simultaneously. This requires setting up and simultaneously solving two equations for each well on the system.

For many applications, precise determination of the operating point is unnecessary, and a simpler method can be used. By combining the productivity curves for all wells, a field productivity curve relating the total field mass production rate to a nominal average wellhead pressure is created. Using the relation given by Equation 4, the field curve can be corrected for the HP flash and expressed in terms of total steam flow, as shown in Figure 6.

The wellhead pressure characteristic derived from Equation 2 (the "system" curve) can be superimposed on this graph, and the intersection of the two curves defines the operating point for the system (Figure 7). Once the operating point has been found, then pressure and flow profiles can be constructed for the entire gathering system.

This simplified method is not rigorous since it replaces individual well and separator relationships with field averages; although the system curve will generally be quite linear, the productivity curves will often be far from linear and the approximation can introduce errors. Nevertheless, over a narrow pressure range where both the system and productivity curves can be considered to be approximately linear, the method can provide sufficient accuracy for most purposes.

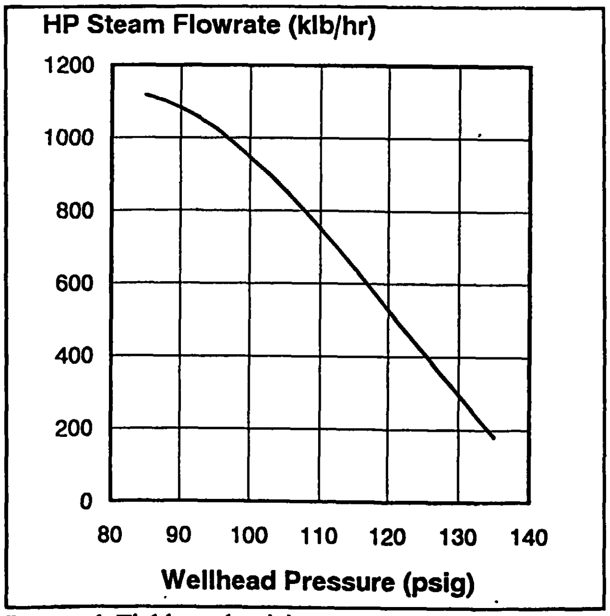

Figure 6: Field productivity curve, expressed in terms of post-flash steam flowrate

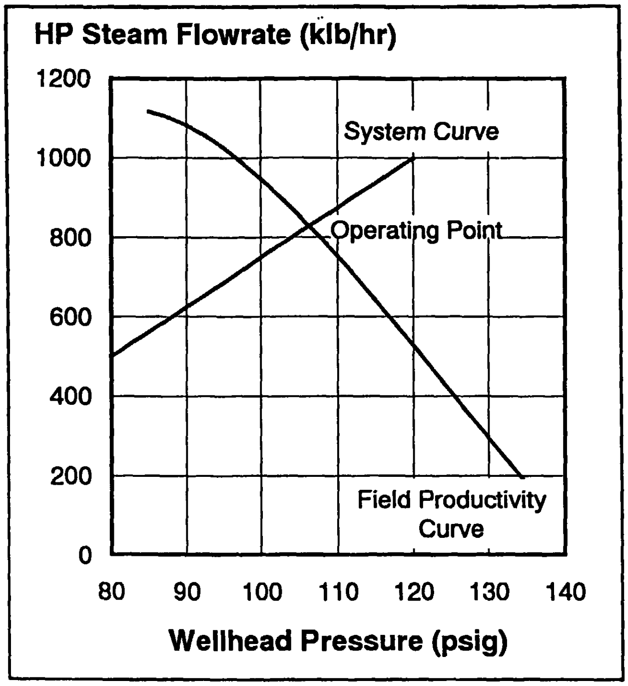

Figure 7 : Determining the system operating point

PRACTICAL APPLICATIONS

Net contribution of a New Well

The analysis of interaction between surface facilities and wells is of major significance in many of the optimization studies undertaken in operating plants. An obvious example is in determining the net increase in plant output that can be obtained by drilling a new production well. At Dixie Valley, a typical new well output is around 1 million lb/hr total mass flowrate, nominally sufficient to generate over 10 MW. When such a well is put on line however, while it may supply this flowrate, it will also back-pressure the other wells so that they reduce their outputs. In addition, the increased system flows will increase separator pressures, reducing the flash percentage and consequently the steam flowrate from all wells. The net increase in plant output is therefore much less than the nominal 10 MW well rating.

An example of such interaction at Dixie Valley is shown in Figure 8. The new well 28-33 increased HP steam flows from separator V101 by 120,000 lb/hr, but there were significant decreases from all the other vessels due to increased separator and wellhead pressures. The increase in steam flow from the entire field was only 60,000 lb/hr. The net impact of the well was therefore only 50% of its stand-alone capacity.

The situation is illustrated by Figure 9, which shows that when the field productivity curve was increased by the addition of the new well, the operating point moved to the new curve along the system curve from point ① to point ②. Figure 9 clearly shows that this has the effect of reducing the magnitude of flow increase achieved.

To quantify the changes, the net change in system steam flowrate can be expressed in terms of the system curve:

$$\Delta SF_{net} = m_s . \Delta P_{WH} \qquad (5)$$

ΔSF_{net} - change in overall steam flowrate
m_s - gradient of system curve

The net steam flow change can also be expressed in terms of the field productivity curve:

$$\Delta SF_{net} = \Delta SF_{gross} + m_p . \Delta P_{WH} \qquad (6)$$

ΔSF_{gross} - gross change in steam flowrate
m_p - gradient of productivity curve

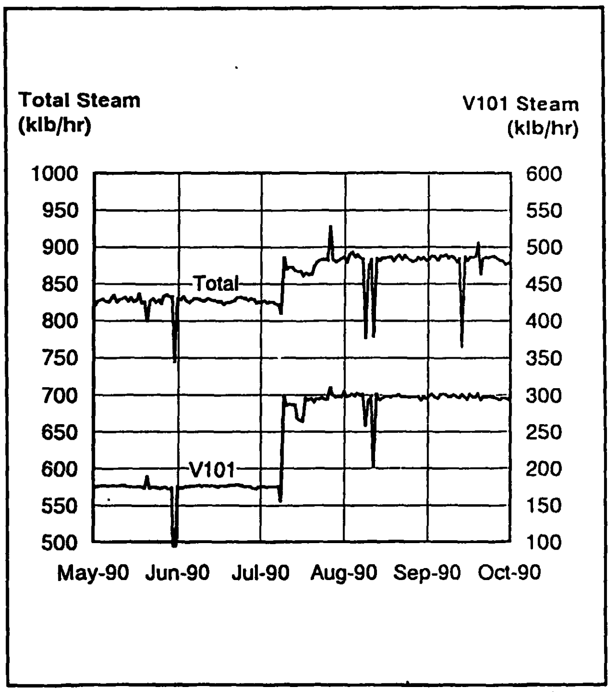

Figure 8: Changes in steam flow due to bringing a new well on-line at Dixie Valley

Solving Equations 5 and 6,

$$\Delta P_{WH} = \frac{\Delta SF_{gross}}{m_s - m_p} \tag{7}$$

and

$$\Delta SF_{net} = \frac{m_s}{m_s - m_p} \cdot \Delta SF_{gross} \tag{8}$$

From Equation 8 it can be seen that the ratio of net to gross output is a function of the slope of the productivity curve. The higher the gradient, the lower the ratio. Since the gradient of a typical productivity curve tends to increase with wellhead pressure, and the wellhead pressure increases with plant output, it is apparent that the surface interference effects will be greatest at high plant outputs. This means that a 10 MW well brought into a system operating at 60 MW may add 6 MW to the overall plant output, while the same well connected to a plant operating at 50 MW may add 7.5 MW to the output.

Experience has indicated that net flow changes are best calculated by determining the loss in output from the other wells on the system and deducting this from the gross contribution of the new well. The total steam flow loss from these wells is:

$$\Delta SF_{loss} = \sum_{wells} m_p \cdot \Delta P_{WH} \tag{9}$$

ΔSF_{loss} - loss of steam flow from other wells

Before 28-33 was brought on-line, Dixie Valley was supplied by five wells with productivity curves closely matching the 13-⅝" casing curve in Figure 5, and three wells matching the 9-⅝" casing curve. The gradients of these curves in the vicinity of the normal operating point are approximately -1.4 and -0.9 klb/hr/psi respectively, expressed in terms of post-flash steam flow. Substituting these values into Equation 9, the total production loss expected from the existing wells is:

$$\Delta SF_{loss} = 9.7\, \Delta P_{WH} \tag{10}$$

Substituting Equation 8 into 10:

$$\Delta SF_{loss} = 0.44\, \Delta SF_{gross} \tag{11}$$

$$\frac{\Delta SF_{net}}{\Delta SF_{gross}} = 56\% \tag{12}$$

This means that at Dixie Valley, when the plant is operating with wellhead pressures around 100-110 psi, a new well can be expected to increase plant output by approximately 56% of its nominal stand-alone output. This percentage is close to the 50% actually measured when 28-33 was brought on-line.

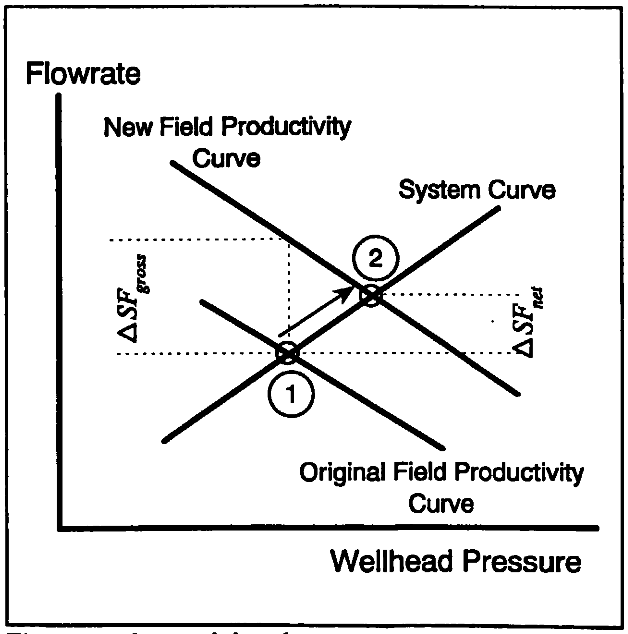

Figure 9: Determining the new system operating point after bringing a new well on-line

Effect of Wellhead Modifications on Plant Output

A somewhat different example is the evaluation of pipeline modifications to decrease frictional pressure drops. The flow through the production wellheads at Dixie Valley incurred pressure drops of 5-15 psi, primarily through the flow Tee. By replacing the flow Tee with a long radius elbow and making other minor changes, it was calculated that the pressure drops could be reduced to 2-3 psi. From Figure 10 it can be seen that this moves the operating point from ① to ②, reducing the operating pressure and increasing the flowrate.

The gradient of the field productivity curve has an important impact on this effect. For wells with a very flat curve where the flowrate is largely independent of

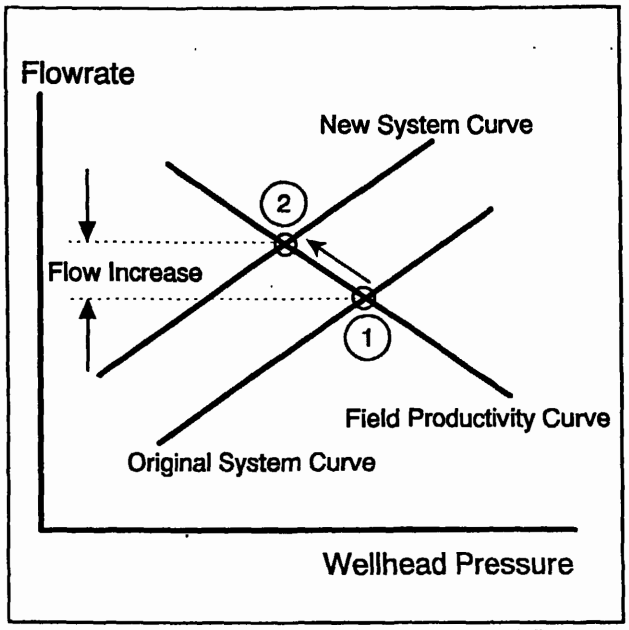

Figure 10: Evaluation effect of wellhead modifications on flowrates

wellhead pressure, changes in the operating pressure will have little impact on plant output. Conversely, wells with a very steep gradient will be very sensitive to operating pressure. To correctly assess the economics of the wellhead modifications, it was therefore necessary to consider each well independently. The conclusion was that for wells with small diameter casing (9-5/8") and flat productivity curves, the modifications could not be economically justified since they did not increase plant output significantly. On the other hand, modifying the larger diameter wells (13-3/8") was clearly justified. These wells have subsequently been modified, and plant output increased by over 4 MW.

CONCLUSIONS

The pressures throughout a gathering system are a function of the flowrates through that system. The flowrates, however, are a function of the production wellhead pressures. Using data collected from an operating plant it is possible to quantify the various pressure flow relationships for each system component, and derive a set of equations which can be solved to give a complete pressure and flow profile throughout the system. In many cases a simple graphical method is adequate to predict the impact of changes to the system.

The net increase in plant output from drilling a new well will often be significantly less than the well's stand-alone output due to its impact on other wells on the system and the effect of increased separator pressures on the flash. This surface interference effect is greatest at high plant outputs, and when the production well characteristics are steep. This situation will often arise when wells are operated close to their maximum discharge pressure.

A good understanding of the flow characteristics of the entire system can assist in optimizing pipeline configurations. Wellhead modifications to reduce pressure drops are one example of this; other examples include determining the optimum place to tie a new well into the system, and modification of steam lines to reduced pressure drops.

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