A PRELIMINARY COMPARISON OF PRESSURE DROP MODELS USED IN SIMULATING GEOTHERMAL PRODUCTION WELLS

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SUMMARY - Many empirical correlations and mechanistic models exist for estimating pressure gradients in the two-phase flow region of a discharging geothermal well. Previous comparisons of such models have been limited by the accuracy of the relationships available for representing geothermal fluid properties. In this study a preliminary comparison of seven pressure drop models is performed utilising a wellbore simulator that incorporates an accurate module for determining the fluid properties of H_2O-CO_2-NaCl systems. The performance of each pressure drop model is evaluated using production data that covers a wide variety of fluid types and operating conditions. No single model can simulate all of the test wells, although the most appropriate model for a given category is suggested.

1.0 INTRODUCTION

Multiphase flow processes have been studied for decades in the petroleum industry. Extensive work has been done to develop methods to predict pressure drops in wellbores producing two-phase mixtures (oil and gas). These have resulted in industry-accepted "flow correlations". The basic mechanisms of multiphase flow are defined by the fluid properties, operating conditions and the geometry configuration of the flow path within the reservoir-wellbore system. Pressure drop correlations developed in the petroleum industry can be used to model geothermal systems providing that the assumptions involved are applicable. however, in both industries there has been little work in defining the range of applicability for these correlations. Furthermore, correlations providing good all-round modelling of oil and gas situations, will not necessarily be as applicable to geothermal conditions.

This study utilises a customised version of the commercially-available WELLSIM geothermal wellbore simulator to compare the performance of seven vertical flow pressure drop models using a small, but diverse set of geothermal production data. The results are used to suggest preliminary criteria for selecting the most appropriate pressure drop correlation for a given set of operating conditions.

2.0 TWO-PHASE PRESSURE DROP MODELS

The pressure drop for fluid flowing through a wellbore is the sum of the pressure losses due to the frictional, gravitational and accelerational forces. For single-phase systems, the pressure drop can be easil determined provided fluid properties are well defined: However, for two-phase systems the problem becomes more complex because the liquid and vapour phases can distribute in different "flow regimes". This affects the difference between vapour and liquid velocities (termed the "slip velocity").

Numerous models to predict ressure drops in two-phase systems have been proposes. Early methods involve empirical correlations, whereas more recent approaches consider the fundamental mechanisms of two-phase flow. Most of these methods use multiple correlations that are applied to specific fluid flow regimes generally referred to as: bubble, slug, churn or transition, and annular/mist flow. The pressure drop models evaluated in this study can be summarised as follows.

Ansari Model

This model is the most recent of those investigated, and is a mechanistic model incorporating the physical phenomena of fluid flow. The entire problem cannot be solved analytically, and the model includes some empirical correlations. The model has been tested using field data for 1775 oil and gas wells, and is described in *Ansari* et *al.* (1990).

Aziz Model

The *Aziz* pressure drop model (Aziz et *al.*, 1972) is a flow regime dependent method developed using a combination of experimental and field data. Aziz developed an empirical flow regime map and mechanistic models to predict the pressure drop in bubble and slug flow regimes. Methods adopted from the Duns and Ros model *(see* below) were used for the mist flow regime, and for the interpolation used in the transition flow regime.

Beggs and Brill Model

The Beggs and Brill correlation (Beggs and Brill, 1973) was developed from experimental data obtained at a small scale test facility using air and water, and in contrast to the other models evaluated in this study which are intended for vertical flow only, it considers the effect of all possible flow angles. However, the flow correlation was derived based on the fluid flow regime that would exist if the pipe were horizontal, making corrections for the actual flow angle, and thus the flow regimes differ from the other correlations and include: segregated, transition, intermittent and distributed flow regimes.

Duns and Ros Model

The Duns and Ros correlation (Duns and Ros, 1963) was developed from a large scale laboratory investigation with modifications using field data. The range of the laboratory data used for their evaluation is the most complete taken in this field of work. Although the correlation was developed for oil and as mixtures, the authors claim that the method should also %e accurate for water-gas mixtures.

Modified Hagedorn and Brown Model

The Hagedorn and Brown correlation (Hagedorn and Brown, 1965) was originally developed from experimental data taken on 1" to $2\frac{1}{2}$" pipes, including data from a 450 m experimental vertical well. The resulting correlation considered the slip between the vapour and liquid phases, but did not consider different flow regimes. The correlation has been modified a number of times subsequently, and the present study assumes no slip occurs in the calculations, as this tends to provide better results.

Orkiszewski Model

The Orkiszewski correlation (Orkiszewski, 1967) resulted from an analysis of published methods to determine the pressure drop in oil and gas systems. The best methods were selected for each flow regime by comparing correlation predictions to field data. A new slug flow correlatson was developed using the data of Hagedom and Brown. This model has separate correlatsons for water and oil continuous phases, and is one of the more widely used correlauons applied for geothermal systems. It uses the mist flow model of Duns and Ros.

WELLSIM, or Hadgu and Freeston Model

Version 1 of the WELLSIM simulator (Gunn and Freeston, 1991) contained only one pressure drop model, from Hadgu and Freeston (1990), which was developed from a large number of empirical methods. As in the Orkiszewski evaluation, the most applicable correlations were selected for each flow regime. Unlike the other models, the correlations were selected solely for their application to geothermal systems, rather than to oil and gas systems. The model has since been slightly revised as outlined in Gunn (1992).

Version 2 of the WELLSIM simulator incorporates not only the Version 1 pressure drop model of Hadgu and Freeston, but also the Aziz, Duns and Ros, Hagedom and Brown, and Orkiszewski models. For this study, Version 2 of the WELLSIM simulator has been customised for UNOCAL's in-house use to also perform simulations utilising the *Ansari* and the Beggs and Brill pressure drop models.

3.0 PREVIOUS STUDIES

Unlike the oil and gas industries which have large databases of production tests available for evaluating various pressure drop models, considerably less data is available to geothermal researchers. However, various models have been assessed for their applicability to geothermal applications, with the pioneer in this area being Gould (1974). Gould evaluated the performance of two modificatsons of the Hagedorn and Brown correlation, and also the Aziz and Orkiszewski correlations, for simulations of production data mainly taken from wells in the Wairakei and Broadlands fields in New Zealand. As the data was noted to not be particularly accurate, Gould tentatively concluded that one modification of the Hagedom and Brown correlation was the most consistent. Gould only considered the effect of dissolved salts on fluid density, and ignored the effects of non-condensable gases.

Upadhyay *et* al. (1977) compared the Hagedorn and Brown, Beggs and Brill, and Orkiszewski correlauons on five sets of well test data, assuming pure water. They concluded that the Orkiszewski correlation provided the most satisfactory results, and that the Beggs and Brill correlation was not adequate for simulating the geothermal wells examined.

Ambastha and Gudmundsson (1986) noted that the generalisability of flow correlations cannot be demonstrated where a number of pressure drop models are compared on a single or only a few data sets. They suggested that the Orkiszewski correlation performs as well as any other method for geothermal wellbore flow, and decided to determine under which geothermal conditions it can be considered to perform satisfactorily. For this purpose they collected well test data from ten geothermal wells exhibiting a wide range of characteristics, although pure water was assumed in all cases. They concluded that the Orkiszewski correlation is generally applicable, although it obtains better results where the steam mass flux is greater than 100 kg/s.m^2. They commented that ignoring non-condensable gas content was one of a number of possible reasons for cases where the matches of simulated to measured data were poor.

Barelli *et al.* (1982) were probably the first to incorporate the effects of non-condensable gases in addition to dissolved salts into a wellbore simulator. The significant effect that the non-condensables, modelled as CO_2, have on the fluid saturation pressure was modelled, as this significantly alters the predicted flash point de th and the pressure gradient. The effect of both salts an8 gases on fluid density were considered, although only the salts were modelled as affecting fluid enthalpy. Barelh compared two correlatsons on four tests of wells containing significant salts and gases, and on two tests of a well containing significant salts only. They clearly demonstrated the significant effect that even very small quantities of CO_2 have on simulated pressure profiles.

Tanaka and Nishi (1988) compared the Orkiszewski correlation with another correlation, for sixteen tests of eight wells, thirteen of which incorporated significant CO_2 content. All production data exhibited wellhead dryness fractions of 10% or less. The Orkiszewski correlation was not considered to perform satisfactorily.

Freeston and Hadgu (1988) compared five wellbore simulators, three of which were based around the Orkiszewski correlation, and one being the Barelli et *al.* (1982) simulator, the only one evaluated capable of handling non-condensable gases. They tested the simulators on production data from eleven wells with widely different characteristics, and concluded that none of the five simulators were applicable to all conditions.

4.0 GEOTHERMAL FLUID PROPERTIES

Many researchers who have recognised the importance of the effects of non-condensable gases and dissolved salts on geothermal fluid properties, and thus to accurately simulating geothermal production tests, have unfortunately not concurred on the appropriate approach to modelling these effects. The main differences occur in the method of calculating the partitioning of CO_2 between the liquid and vapour phases. Gunn (1992) has compared the two main methods that are used. The first method applies Dalton's Law, and results in the concentration of CO_2 in the vapour phase being proportional to the component densities. This approach was used by Barelli et *al.* (1982), for example.

The second approach uses the proposal suggested by Sutton (1976), that the concentration of CO_2 in the vapour phase is in fact proportional to partial pressures. Sutton indicated that making this assumption provides a better fit to some ex erimental equilibria data. Tanaka and Nishi (1988) utiised this approach, as did Version 1 of the WELLSIM simulator. Gunn (1992) indicates that there is insufficient evidence to indicate that either method is the more appropriate, and highlights the significant differences that exist between their estimates for geothermal fluid properties.

Andersen *et al.* (1992) overcome this discrepancy by taking a much more rigorous approach to the formulation of a model for the H_2O-NaCl-CO_2 system. Their model has been validated against as much of the available fluid equilibria data as possible, over pressures from 1 to 340 bara, temperatures from *25* to 372°C, CO_2 content from 0 - *5%* by weight, and salt concentrations to 30% by weight. The model is developed from the combination of the heat and material balances, and the phase equilibrium conditions. The condition for phase equilibria is that the fugacities of each component must be the same in both the liquid and vapour phases. In calculating the fugacities the model considers the appropriate fugacity and activity coefficients for the three component system. Accurately accounting for the activity coefficient of CO_2 in the liquid phase is particularly important to the correct modelling of the "salting-out" effect. This is the effect that the NaCl has on the partitioning of the CO_2 between liquid and vapour phases. Fugacity and activity coefficients *are* ignored in the older approaches discussed above.

This new fluid properties model is included in Version 2 of WELLSIM, and so it is utilised in the evaluation of pressure drop models in this study. It seems reasonable to assume that these models can be more appropriately compared when an accurate fluid properties model is used.

5.0 GEOTHERMAL FIELD DATA

The data obtained for this study includes measurements from 21 two-phase production wells representative of a number of geothermal reservoirs. A total of 27 production tests have been studied and are summarised in Table 1.

Bjornsson (1984) has indicated that a number of different feed conditions can result in similar pressure profile predictions, and accurate measurements of such conditions are generally not available. For this reason, comparisons of the pressure drop models have not been made at depths below the first significant feed zone. The depth indicated in Table 1 is not the total wellbore depth, but is the first depth above the shallowest feed zone where a pressure measurement has been taken.

In Table 1 wellhead dryness has been specified as: Very Low (0 - 10%); Low (10 - 20%); Int(ermediate) (20 - 50%); and High (50 - 70%); and, mass flowrate has been specified as: Very Low (0 - 5 t/hr); Low (5 - 50 t/hr); Int(ermediate) (50 - 150 t/hr); and High (> 150 t/hr). NaCl content is "low" when less than 2% by weight of total fluid, whereas CO_2 content is "low" when less than 1% by weight of total fluid.

The well tests have been classified into three broad categories as follows.

- Liquid Feed: these wells all have a primary feed that produces liquid.
- 2-Phase Low Enthalpy: in these wells the shallowest feed produces two-phase fluid, but the wellhead dryness fraction is between 15 and 40%.
- 2-Phase High Enthalpy: in these wells the shallowest feed produces two-phase fluid, but the wellhead dryness fraction is greater than 50%.

The data for MESA6, NG11, CP90, OKOY7 and HGPA are from Ambastha and Gudmundsson (1986). No fluid composition measurements are provided with the data, but the compositional data given in Freeston and Hadgu (1988) is used for NG11, and the data in Gunn (1992) for OKOY7. The data for R885, ZK327, WK207 and WK27 are from Freeston and Hadgu (1988). The data for W2-1 are from Barelli et *al.* (1982). The data for the five tests of RK5 are from Gunn (1992). All other data has been provided by UNOCAL, (i.e. UN01 to UN10).

6.0 PRESSURE DROP MODEL COMPARISON

Pressure profiles have been generated for all the production tests using the seven pressure drop models discussed previously. For liquid feed wells, pressure profiles were generated using the measured pressure and temperature at the primary feed. The fluid composition data available thus determines the flash point depth. Profiles generated for wells with a two-phase feed use the surface conditions as the simulation starting point. In these cases the wellhead pressure, enthalpy and fluid composition have been specified. WELLSIM calculates from these conditions the appropriate saturation temperature and the wellhead dryness fraction, using the fluid properties model of Andersen et al. (1992). In this study no attempts have been made to calibrate the simulation input parameters to the field data.

In all cases the effect of heat loss (or gain) to the surrounding reservoir is ignored, which is a reasonably valid assumption given the high flowrates of all but one of the production tests.

The roughness value used for the casing and liner has been chosen in all cases to be 0.000046 m (0.0018"), which is the same as that used by Gould (1974) for the casing. The significance of the wellbore roughness to the pressure drop becomes more important as the enthalpy of the well increases, because the frictional component of the pressure gradient is greater for higher vapour fractions.

One problem in selecting an appropriate value of roughness for the liner is that not all the flow occurs within the liner itself, but a significant portion of the flow can exist in the annulus between the liner and the open hole. It is not clear what error is introduced by modelling the total flow as occuring within the wellbore itself.

The applicability of the pressure drop models has been determined by comparing predictions for the pressure drop from the wellhead to the shallowest feed. Where sufficient measured data is available the pressure drop in both the casing and the liner have been compared separately. This is because, as has been discussed above, it is somewhat unclear as to how the roughness in the liner should be modelled, and this is of significance for the high enthalpy wells in particular.

Furthermore, it has been noted that in some of the cases the pressure drop closely matches the measured value over the entire wellbore, but the predictions for the individual pressure gradients in both the casing and liner are poor. The underprediction found in one section of the wellbore can effectively counterbalance the overprediction in the other.

It is assumed that the pressure drop model which provides the best predictions using default simulation parameters will also provide the best results should the simulations be calibrated to field data.

Table 2 gives the pressure drops predicted by the various correlations for each of the production tests. In a number of cases, the pressure predicted in the well fell below atmospheric, and the simulation stopped. These cases are indicated with the note that the flow "chokes".

Figures 1 to 3 present the differences between the measured and predicted pressure drops against discharging mass flowrate. Each plot presents a particular well category (i.e. liquid feed, two-phase feed/low enthalpy, and two-phase feed/high enthalpy) and the results are grouped according to the seven pressure drop models. Figures 4 and 5 provide a comparison of the average absolute errors and average absolute percentage errors in the pressure drop predictions for each correlation. The averages have been determined separately for each well data category.

It can be seen from Figures 1 to 3 that the errors (in bar) for many cases are particularly high. It is suggested that an error less than 3-4 bar might be considered acceptable. Within this range it is likely that calibration of fluid composition, enthalpy, and possibly roughness (for high enthalpy wells) may provide a significantly better match to measured data: Another factor that may require calibration is the wellbore diameter, due to the effects of scaling. The error in the measured pressure values can probably be considered to be in the order of 1-2 bar.

For liquid feed wells the correlations tend to produce better results at flowrates less than 150 t/hr. The Duns and Ros and Orkiszewski correlations are the clear leaders when compared on the basis of actual error, although the WELLSIM correlation comes second on a comparison of percentage error (see Figure 5). The average error is less than 3 bar for all the correlations except the Ansari and the Beggs and Brill models. It should perhaps be noted that although the Orkiszewski correlation produces some good pressure drop comparisons, that the shape of the resultant pressure profiles are sometimes anomalous. This is due to a discontinuity that can occur in the calculation for fluid density in the slug flow regime. Furthermore, this discontinuity can cause problems in the convergence of the solution algorithm.

In general, the correlations are particularly unsuited to modelling the two-phase feed/low enthalpy wells, although it should be remembered that production tests for only five wells have been evaluated. The WELLSIM, Duns and Ros, and also Aziz correlations appear better suited to these wells.

The percentage errors for the high enthalpy cases are generally large, but it should be noted that generally the magnitude of the pressure drop in these wells is significantly smaller than for the liquid feed wells. Calibrating the value of roughness for these wells (within sensible limits) may provide significantly better matches. From Figure 3, the WELLSIM, Duns and Ros, Orkiszewski, and Hagedorn and Brown correlations all provide acceptable results for the high enthalpy wells for tests with mass flowrates greater than 50 t/hr. The Ansari and Beggs and Brill models again provide very poor predictions at all mass flowrates. An example of the performance of the seven pressure drop models is shown in Figure 6 for UN08.

Well UN04 has the highest NaCl content of all the wells evaluated, and also has a high CO_2 content. The *Aziz*, Duns and Ros, Hagedom and Brown, and Orkiszewski correlations all provide good predictions of the pressure profile. Figure 7 examines the pressure profile predictions found using the Duns and Ros correlation for three *cases:*

WELL	Location	Feed Depth (m)	Wellhead Diameter (in)	Deviation (deg from vertical)	Mass Flowrate	Wellhead Dryness	Total Dissolved Solids	CO_2 Content	Reference (Wellhead/ Feed)
LIQUID FEED WELLS									
R885	NZ	100	4 1/2"		Very Low	Very Low	-	Very Low	Feed
ZK327	China	110	13 3/8"		Int	Very Low	Low		Feed
MESA6	USA	2134	9 5/8"	-	LOW	LOW	NA	NA	Feed
WK207	NZ	1000	8 5/8"	-	LOW	LOW			Feed
UN01	USA	1067	9 5/8"		Int	Low			Feed
w2-1	Italy	1355	13 3/8"		Int	LOW	LOW	High	Feed
wK27	NZ	608	8 5/8"		Int	LOW	LOW	LOW	Feed
NG11	NZ	902	8 5/8"	-	High	Very Low	Low		Feed
UN02	Indonesia	1295	9 5/8"	-	High	Low	Low	LOW	Feed
UN03	Indonesia	2557	9	<5	High	Low	LOW	LOW	Feed
CP90	Mexico	1299	7 5/8	-	High	LOW	NA	NA	Feed
UNO4	USA	975	13 3/8"	-	Very High	Low	Very High	Low	Feed
ASE FEED LOW ENTHALPY WELLS									
7	Philippines	1200	9 5/8"	-	LOW	LOW	High	-	Wellhead
RK5	NZ	1106	9 5/8"		4 x Int, 1 x High	5 x Low		5 x Low	5 x Wellhead
UN05	USA	1149	13 3/8"	<15	High	LOW			Wellhead
UN06	Philippines	1498	13 3/8"	>15	LOW	Int	Low	Low	Wellhead
UN07	Philippines	1128	9 5/8"	-	High	Int	LOW	Low	Wellhead
2-PHASE FEED HIGH ENTHALPY WELLS									
UNO8	Philippines	1170	9 5/8"	-	Int	High	Low	High	
UN09	Philippines	1357	13 3/8"	>15	LOW	High	Low	High	
HGPA	USA	1925	9 5/8"	-	2 x Low, 1 x Int	3 x High	NA	NA	3 x Wellhead
UN10	Philippines	618	13 3/8"	>15	Int	High	LOW	High	Wellhead

Table 1: Production test data used for the pressure drop model comparisons. NA - information not available.

WELL	Data	Ansari	Aziz	Beggs and Brill	Duns and Ros	Hagedorn and Brown	Orkiszewski	WELLSIM
LIQUID FEED WELLS								
R885	6.1	5.4	5.8	5.7	5.7	4.9	6.3	5.7
ZK327	6.6	6.5	6.9	6.8	6.7	6.1	6.5	6.9
MESA6	90.7	Chokes	89.3	Chokes	91.0	Chokes	89.5	Chokes
WK207	41.5	40.2	41.6	41.5	41.4	37.9	40.9	43.2
UNO1 Cas	17.2	13.2	11.7	16.3	13.6	12.7	11.5	18.1
UNO1 Lin	25.4	26.8	25.9	27.7	26.5	26.0	26.0	26.5
w2-1	79.8	80.1	81.3	76.7	79.2	73.7	81.6	80.3
wK27	19.0	17.3	15.9	19.9	17.3	16.8	15.0	20.7
NG11	59.4	60.9	58.2	60.7	59.6	58.9	58.8	61.0
UN02	46.3	Chokes	40.8	Chokes	51.2	46.1	44.3	49.5
UN03	147.3	Chokes	140.0	Chokes	145.2	147.0	145.5	149.7
CP90	47.6	59.3	47.5	59.7	52.2	51.8	51.1	56.9
UNO4	53.5	58.9	51.0	59.6	54.1	53.5	53.4	59.4
2-PHASE LOW ENTHALPY WELLS								
OKOY7	30.1	29.1	30.4	33.4	34.9	18.5	53.7	39.1
RK5	43.5	38.8	42.9	36.3	38.6	24.2	53.5	40.2
RK5	42.5	35.6	29.1	35.1	33.4	23.9	45.2	38.9
RK5	39.0	32.5	22.9	35.0	30.0	24.1	25.0	38.1
RK5	37.9	31.8	22.6	35.2	28.9	24.3	24.3	37.8
RK5	34.2	32.8	19.4	36.7	25.9	25.3	24.3	34.2
UNO5 Cas	3.7	15.8	3.0	12.5	5.4	8.2	6.4	11.2
UN05 Lin	14.8	37.1	5.0	30.5	12.5	15.4	12.4	30.6
UN06 Cas	6.4	12.4	14.6	38.1	25.1	4.4	41.9	10.4
UN06 Lin	8.6	6.6	3.6	19.9	11.7	4.3	24.0	8.4
UN07 Cas	7.2	17.9	6.2	21.5	7.7	13.2	11.9	12.3
UN07 Lin	9.2	17.7	6.4	17.0	11.0	11.6	12.9	10.8
2-PHASE HIGH ENTHALPY WELLS								
UNO8 Cas	3.8	5.6	3.4	18.3	3.1	3.7	3.1	3.7
UN08 Lin	6.6	17.7	10.1	19.8	8.4	9.5	8.9	7.5
UN09 Cas	1.6	4.4	1.4	8.2	4.8	8.9	1.3	3.2
UNO9 Lin	1.8	1.6	1.3	2.5	1.2	1.8	1.3	1.6
HGPA Cas	5.7	3.9	2.2	6.0	5.0	3.4	2.2	4.9
HGPA Lin	21.7	9.5	6.7	16.3	9.2	11.0	7.4	12.4
HGPA Cas	3.8	3.6	2.2	5.2	2.3	3.2	2.1	3.7
HGPA Lin	15.2	11.1	7.8	16.9	7.2	9.9	7.9	10.0
HGPA Cas	2.7	5.7	4.5	8.7	4.0	4.6	4.0	2.4
HGPA Lin	10.8	15.3	12.0	20.9	11.1	10.1	11.1	8.5
UN10	3.7	3.4	3.2	6.1	2.7	3.5	2.7	3.3

Table 2: Measured and calculated pressure drops for all production tests (in bar).
Cas - pressure drop in casing. Lin - pressure drop in liner.

model built into WELLSIM Version 2, and specifying the measured fluid composition: secondly, using the new fluid properties model but specifying the geothermal fluid as pure water; and finally, using the older fluid properties model used by WELLSIM Version 1, discussed above.

From Figure 7, the first case using the reasonably accurate fluid composition measurements along with the new fluid properties model provides an excellent match to the measured pressure and temperature profiles. Leaving out the fluid composition information, in the second case, results in an error for the predicted pressure drop of about 10 bar. It is important to note that ignoring the fluid impurities not only incorrectl edicts the two-phase pressure gradient, but even

7.0 RECOMMENDATIONS

Although the measured data may well be subject to measurement or interpretation errors, and appropriate fluid composition data is not avalable €or all cases, it can be concluded that none of the correlations can be considered to be generally applicable for all eothermal well test conditions. However, wells with liquid feeds can be more accurately modelled than wells with two-phase feeds.

It should be noted that with the small Sample size of the data available, particularly for the wells with two-phase feeds, that any conclusions drawn are qualitative and not statistically significant. However, it is suggested that the Duns and Ros model can be used with reasonable confidence for liquid feed wells. Where possible wellbore simulator input parameters should be calibrated to obtain better matches than those found from using default values. This is particularly important when the simulations are modellmg wells which have more than a single feed zone.

For lower enthalpy wells with a two-phase feed it is suggested that the Aziz or WELLSIM models can be used. However, the overall accuracy of these simulations is poor, and it may well be worth trying either Duns and Ros, or Hagedorn and Brown correlauons as well. For higher enthalpy wells, particularly at high mass flowrates, it is suggested that the WELLSIM correlation can be used

The Ansari and the Beggs and Brill models do not appear to be suitable for geothermal wellbore simulation. However, this should not preclude examining their performance on similar studies of this nature where larger data sets are available. Although the Orkiszewski correlation has been a traditional favourite of geothermalists, and it shows a reasonably good performance, it is suggested that because of the anomalous behaviour it can sometimes exhibit, the Duns and Ros correlation should be used instead. This is because the Duns and Ros correlation has been found to perform better than the Orkiszewski correlation for most types of geothermal wellbore conditions.

In conclusion, the authors maintain that meaningful cornpansons of wellbore pressure drop models can only be performed where geothermal fluid properties are determined accurately. Now that such calculations are possible, larger databases need to be collated in order that more statistically significant criteria for selecting appropriate flow correlations may be developed.

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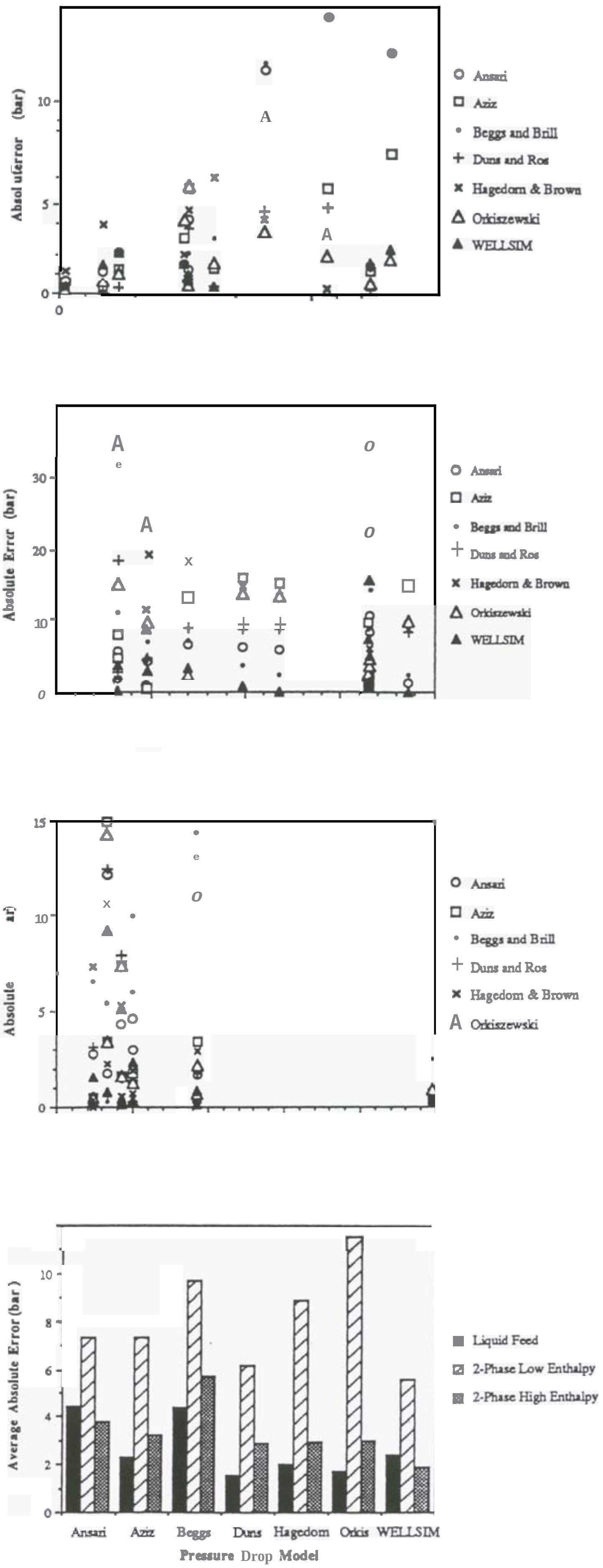

Figure 4: Pressure drop prediction absolute errors (in bar).

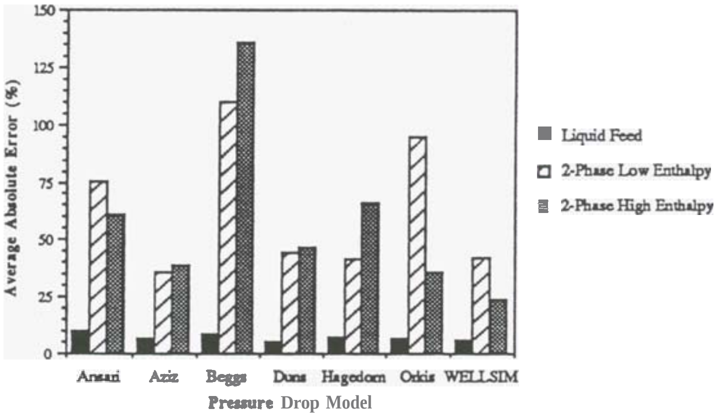

Figure 5: Pressure drop prediction absolute errors (in %).

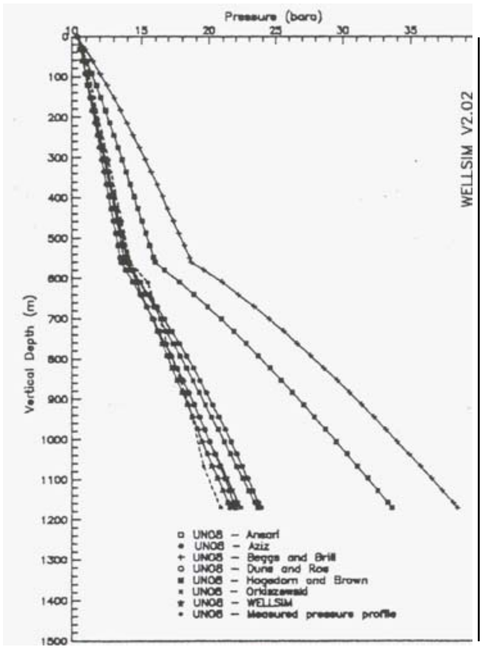

Figure 6: Pressure profile predictions (Well UN08)

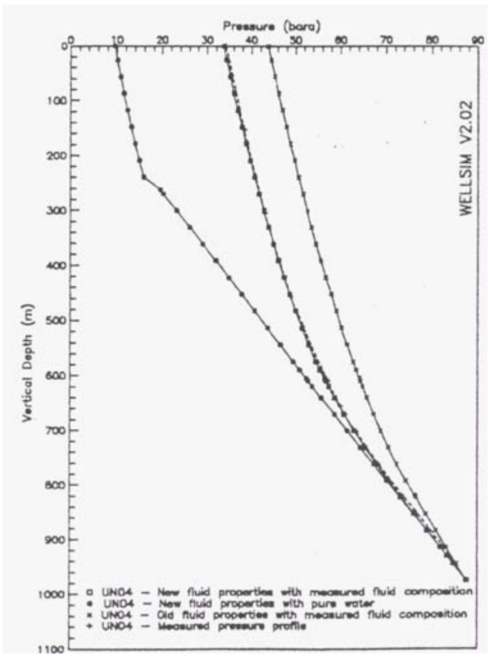

Figure 7: **Fluid** property model comparison (Well UN04).

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