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Improved Test Method for Slim Hole and Microbore Exploration Drilling

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ABSTRACT

Drilling cost and risk is the greatest impediment to global geothermal development. In the early 1990s, the use of lower cost slim holes was introduced for geothermal exploration. Although the industry was slow to adopt this method, slim holes are now commonly drilled and tested to evaluate geothermal resource potential. With the advancement of novel drilling techniques and miniaturized instrumentation, microbore exploration wells can reduce drilling cost and risk in EGS and conventional geothermal development.

Of critical importance in the use of a surrogate slim hole or microbore to assess resource capability is the assumption that test results can be accurately scaled to larger, more expensive production bores to be completed after successful discovery of a resource. The accuracy of this scaling varies with test bore diameter, resource conditions and the degree of scale-up to larger bores. Geothermal exploration wells are typically evaluated by discharging the well to surface equipment at atmospheric pressure to measure flow rate, enthalpy, and fluid composition. Reservoir characteristics are further evaluated by conducting injection tests, step-rate production tests, and pressure recovery measurements. However, low temperature resources or small diameter bores are often incapable of continuous, unassisted flow. In such cases, flow to the surface can sometimes be induced, or temporarily maintained, by air- or nitrogen-lift, or pumping, but these methods add significantly to the cost and complexity of the test operation. In addition, atmospheric flow tests require relatively large liquid storage facilities (sumps or tanks) or a nearby injection well, and test duration may be limited due to steam and gas emission considerations, hazardous liquid composition, or water disposal restrictions.

Using innovative test methods, slim hole and microbore resource evaluation can be completed using a drill stem test. This method eliminates errors associated with surface flow tests, and requires substantially less infrastructure and reduce the time required for resource evaluation.

1. INTRODUCTION

Geothermal energy has many benefits, but development continued to be restricted by the high cost and risk of exploration well drilling and resource confirmation. Despite efforts to the contrary, drilling costs continue to increase. This has resulted in the use of slim holes to be used for exploration to lower the upfront ‘at risk’ exploration cost, and then using the slim hole test results to predict the likely productivity of full size development wells. This has worked to some extent, but competitive forces continue and the result is a continued desire for even smaller holes at lower cost. The industry is investigating the use of microbores, where the bottom hole diameter is 2” (50 mm) or less. However, well testing in small bores is less accurate than in full size wells. As the bore diameter decreases, the accuracy of test results degrades due to the increasing friction losses from the smaller well bore. Even with bore sizes of 2” to 4” (50-100 mm), the limits of well bore size and relative error when sizing up needs to be better understood and a better testing method needs to be developed before we achieve additional success in lowering exploration costs by decreasing well bore size.

2. FLOW SIMULATION OF DIFFERENT SIZED BORES

Simulated well flow rates can be used to examine the applicability of flow data from smaller well bores. Using a well bore simulator, assuming identical casing depths and four different Productivity Indexes (PI), we simulated a range of reservoir characteristics from low to high permeability (Figures 1-4). Sizes from core hole to very large production wells describe increasingly larger bore hole diameters at the bottom of the simulated well. The most significant variable in these rates is the friction pressure in the different size bores. The simulation results shown in Figure 1 are for a ‘typical’ PI that would be expected for production wells in an active field, and is between the medium and high PIs shown later. The typical PI was used to simulate flow in well bores of each size. In core holes, the flow is restricted (i.e., “choked”) in the well bore, with little variation in flow rate for different wellhead pressures. Conversely, the very large size bore indicates only minor restriction due to friction at different flow rates. Simulating the same sized wells, but with a low PI, shows all flow rates are much lower (Figure 2), and wells may not be able to lift the brine associated with the steam from the overwhelming friction pressure. This is apparent in the slim hole, but for the larger sizes the simulation indicates no flow. In the simulations using a mid-range PI, between the low and typical PI, the slim hole is not affected, but the standard size is having trouble lifting the water, with the larger sizes dying but at a higher rate (Figure 3). At a very high PI, the large well bores are largely unconstrained (Figure 4), showing that even at the typical PI there is some liquid holdback. Thus, the well bore simulation study for various size bore diameters, at varying PI, shows that for smaller bore sizes, the simulated flow rate does not change substantially with changing wellhead pressure, while flow in larger bores can change significantly.

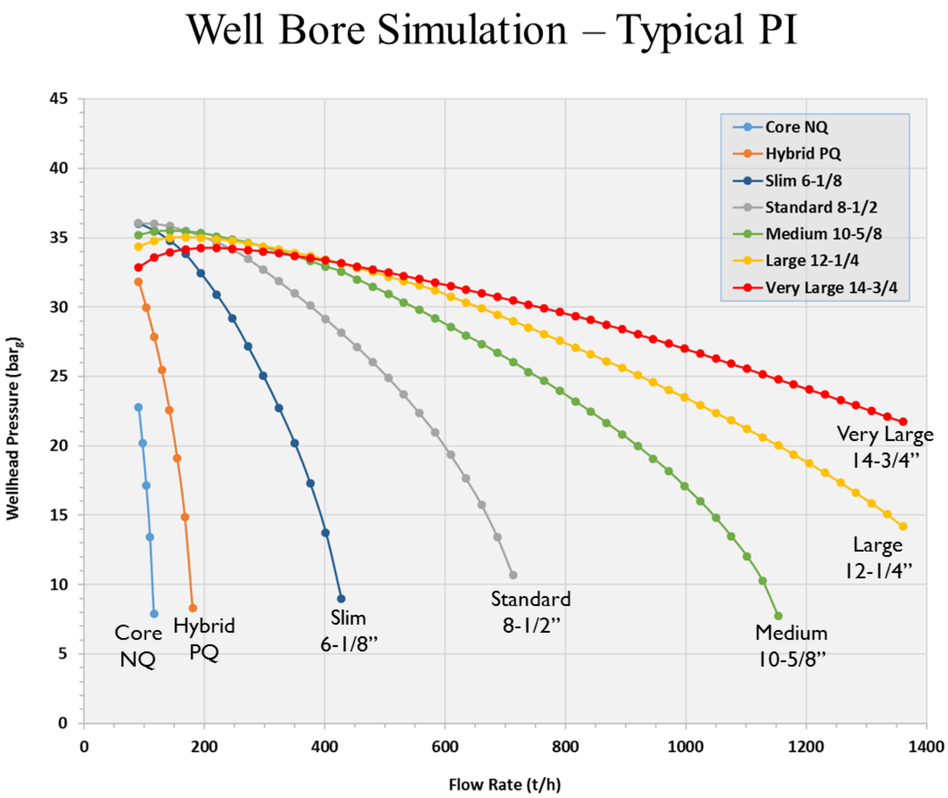


Figure 1: Well bore simulations for various sized wells, showing flow rate as a function of wellhead pressure, using a typical PI of 33.3 t/h/bar. Size indicated is the last drilled hole size in the well.

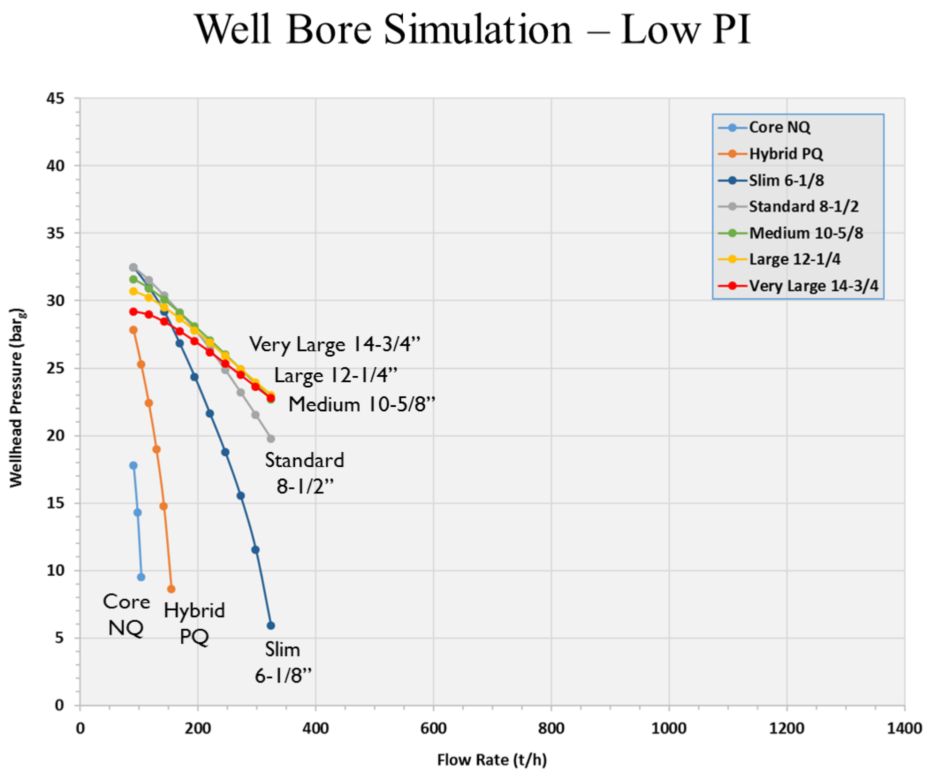
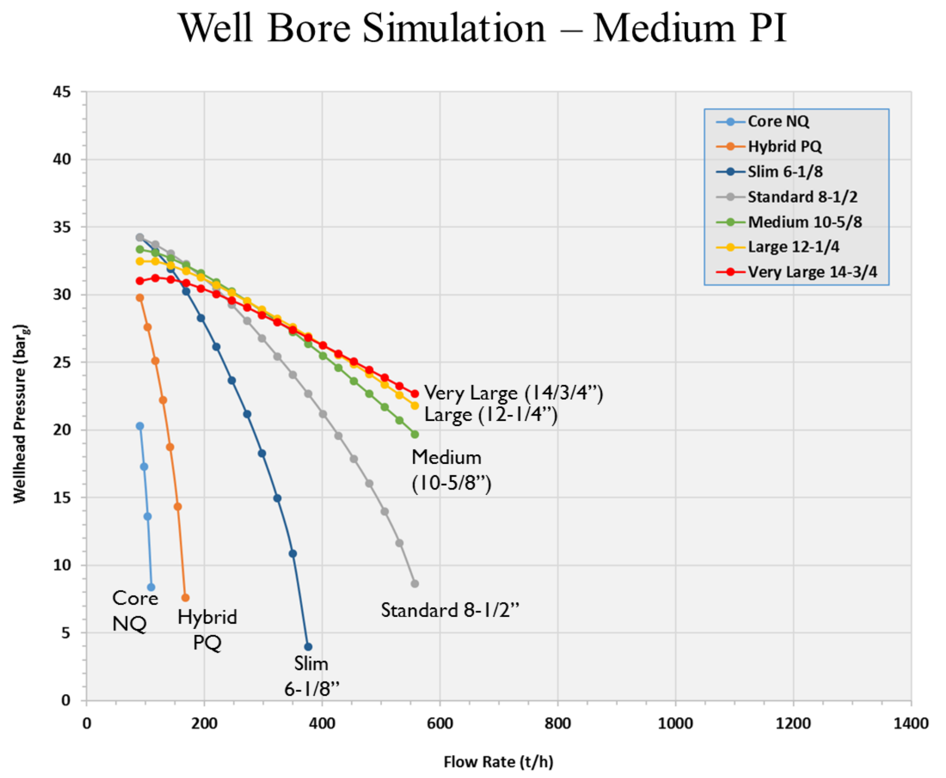
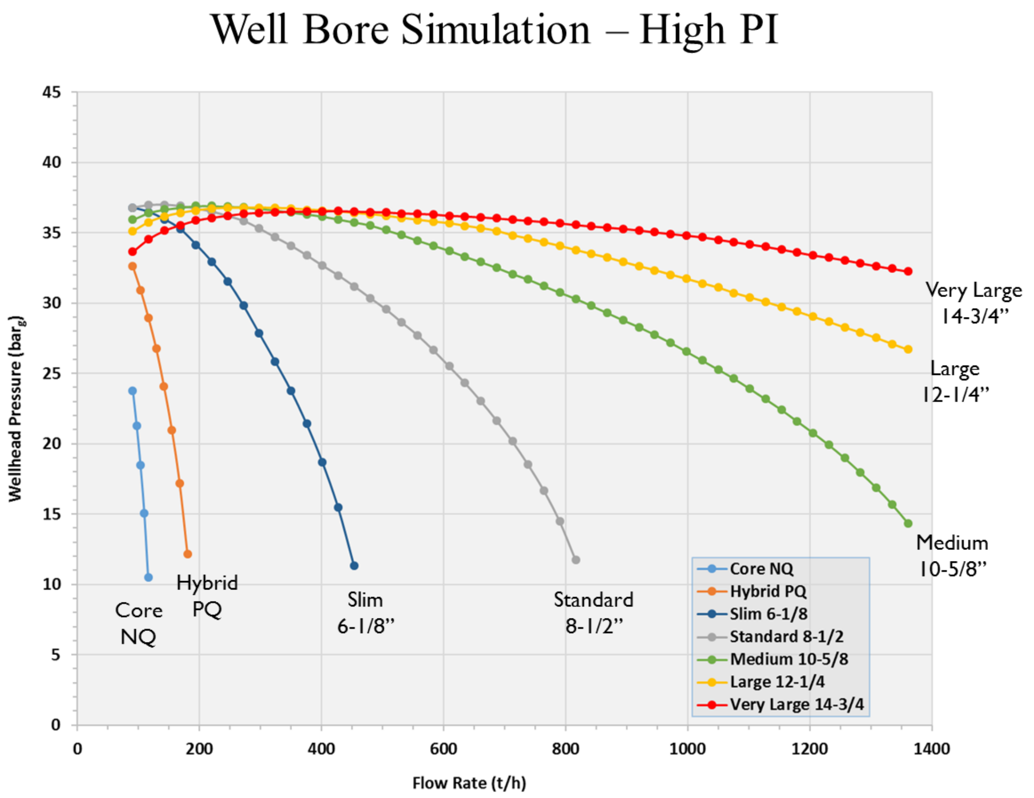


Figure 2: Well bore simulations for various sized wells, showing flow rate as a function of wellhead pressure, using a relatively low PI of 7.14 t/h/bar. Size indicated is the last drilled hole size in the well.



Well Bore Simulation – Medium PI

Figure 3: Well bore simulations for various sized wells, showing flow rate as a function of wellhead pressure, using a mid-range PI of 12.5 t/h/bar. Size indicated is the last drilled hole size in the well.



Well Bore Simulation – High PI

Figure 4: Well bore simulations for various sized wells, showing flow rate as a function of wellhead pressure, using a relatively high PI of 100 t/h/bar. Size indicated is the last drilled hole size in the well.

3. ACCURACY OF PRODUCTIVITY INDEX (PI) DETERMINATION

Currently, slim holes and core holes are often used as exploration wells. The test results of these smaller wells are simulated and scaled to estimate the productivity of larger holes to be drilled for commercial production. Accuracy is critical, as major financial decisions rely on these simulations. The key to accuracy is determining an accurate PI from the smaller exploration slim holes or, in the future, microbores. However, as a well bore gets smaller, the determined PI becomes less accurate. Figure 5 combines the curves from three well sizes (core, hybrid, and slim), along with flow curves for each size well for the four different PIs used. Within each set of curves an error bar is inserted that represents a flow rate accuracy of ± 10 t/hr.

For the core hole size, the error bar exceeds the range of the flow curves and, therefore, it is not possible to determine a single PI that defines the characteristics of the well. Thus, this information should not be used to determine the PI. For the hybrid well, the error approximately matches the range, yielding a smaller range of the PI but, again, a well-constrained PI cannot be identified. The flow rate accuracy for a slim well is enough to assign it to one of the flow curves, and a reasonable PI could be determined. The conclusion is that at smaller well bore sizes, determining a PI becomes more problematic. The indication is that using sizes below that of the slim hole (≤6-1/8") will have inadequate accuracy for PI determination.

The error in using the smaller holes can be dramatic (Figures 6 and 7). When the flow characteristics of the four PI cases for a standard size 8-1/2" or the large size 12-1/4" well are plotted with the scaling error bars, for the core size the error range is larger than the four PI ranges, and the hybrid spans is the entire range. The slim well can fit between the flow curves, and would be the only reasonable size from which to predict a larger development well PI. If the core hole is scaled up to an 8-1/2" or 12-1/4" hole, the projected flow would range from 60 t/h to over 600 t/h, and 400 t/h to over 1500 t/h, respectively, which is clearly not accurate enough for use in resource estimates. Slim wells are adequate but could still use an increase in accuracy to scale up to large well bores. Surface flow testing of smaller holes is inadequate for PI determination for a future development well. A different testing method is required to use smaller bore sizes to evaluate geothermal reservoirs and determine expected production capacity.

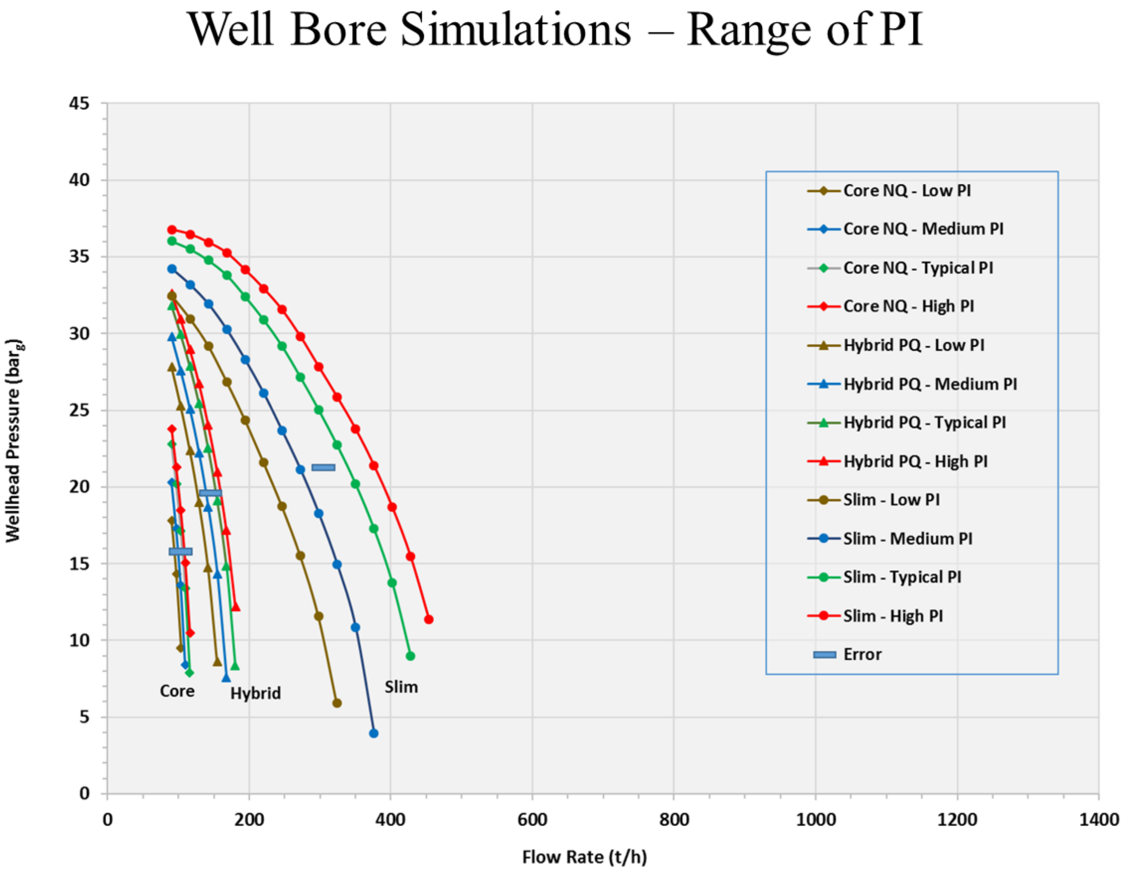


Figure 5: Three sets of curves for three sizes of wells, indicated by the markers, each with four cases of a second variable, PI, indicated by color. The measurement variance of ±10 t/h is also provided to show relationship of measurement accuracy to range of curves for different PI values (horizontal bars).

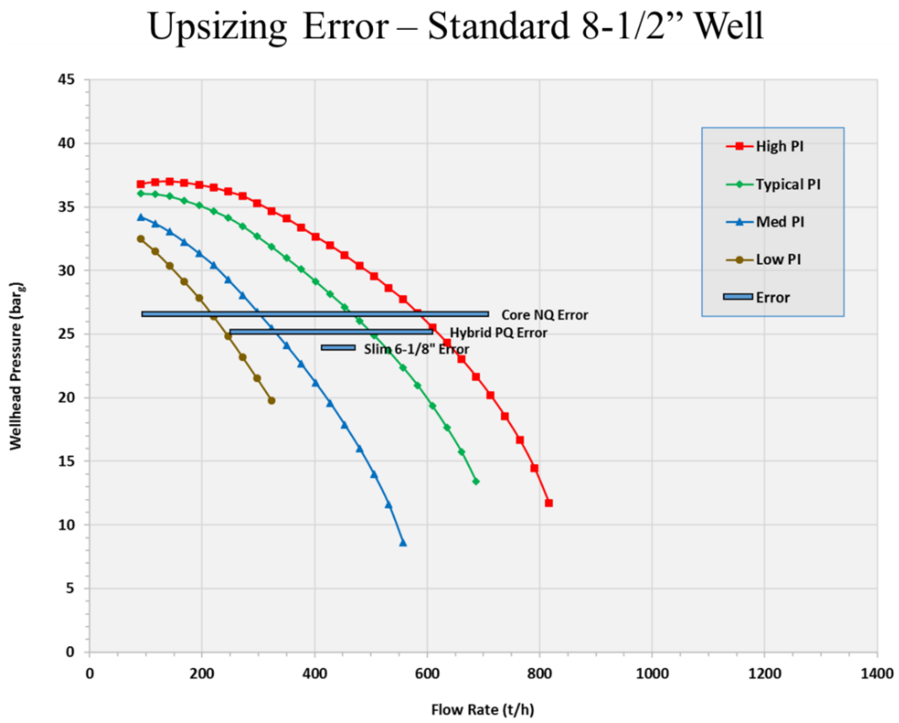


Figure 6: Well bore simulations of scale-up to a standard size well using four PI values. Horizontal bars indicate the degree of error resulting from the use of the three smallest bore sizes used to determine the PI to be upsized and used for this simulation.

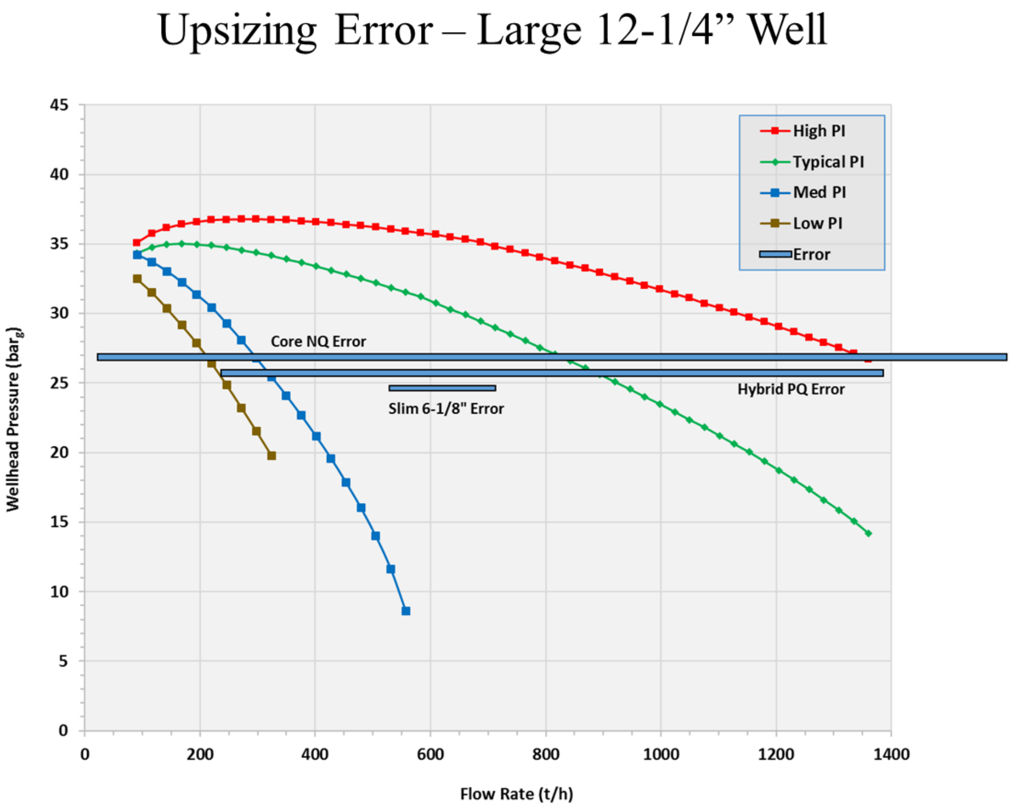


Figure 7: Well bore simulations with 4 different PI for a large size well. Horizontal bars indicate the degree of error resulting from the use of the three smallest bore wells used to determine the PI to be upsized and used for this simulation.

4. OTHER FLOW FACTORS

Other resource and well characteristics, like enthalpy, can also impact flow rate. Wells with an average enthalpy may flow, but if the same well had an enthalpy that was higher or lower, it may not. In the previous discussion of simulation results, the flow was assumed to be of moderate enthalpy. For the current discussion, we have created a 3-dimensional plot where the three axes are bottom hole diameter, productivity index, and enthalpy. A fourth variable, choke rate, can be represented by an isosurface in this space (choke rate represents the flow rate at which the well will no longer sustain flow).

In a 3000 ft deep well, a high or low enthalpy well may not flow, whereas a mid-enthalpy well would flow (Figure 8). This problem is even more pronounced for smaller bores, as shown by the larger curvature of the choke rate surface for the smaller bores apparent at the left side of the plot. Figure 9 is a slice the same matrix figure, through the 1744 kJ/kg (750 BTU/lbm) enthalpy level. It is apparent that at the smaller well bore diameters there is almost no change in flow for different PIs (it is almost a vertical line for the 223 t/h flow rate), but as the bore diameter increases, the variation in PI increases, and for a given well bore diameter, a distinct PI could be more accurately determined.

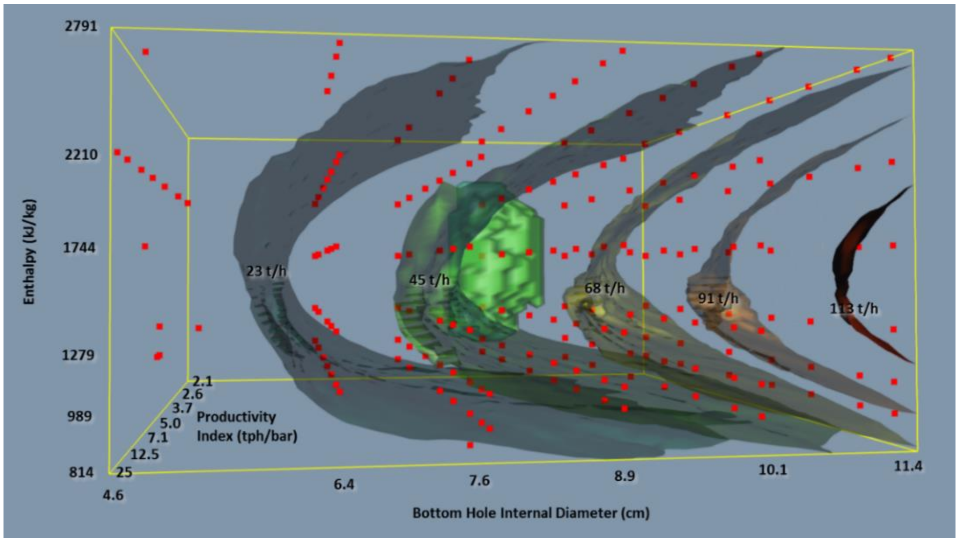


Figure 8: Figure 2. Isosurfaces of choke rate (ton/hr) from a 914 m (3000 ft) well bore based on simulated variation in hole size (x-axis), productivity index (y-axis) and enthalpy (z-axis). Each well bore simulation is represented by a red dot.

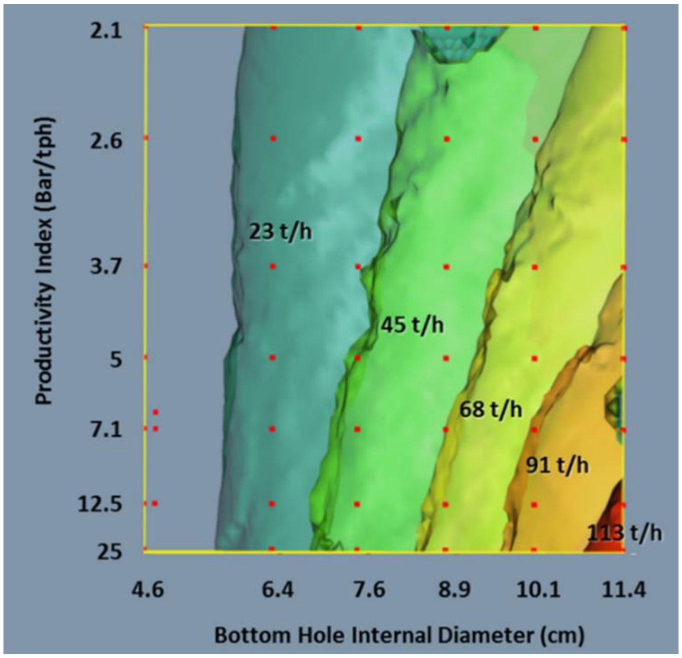


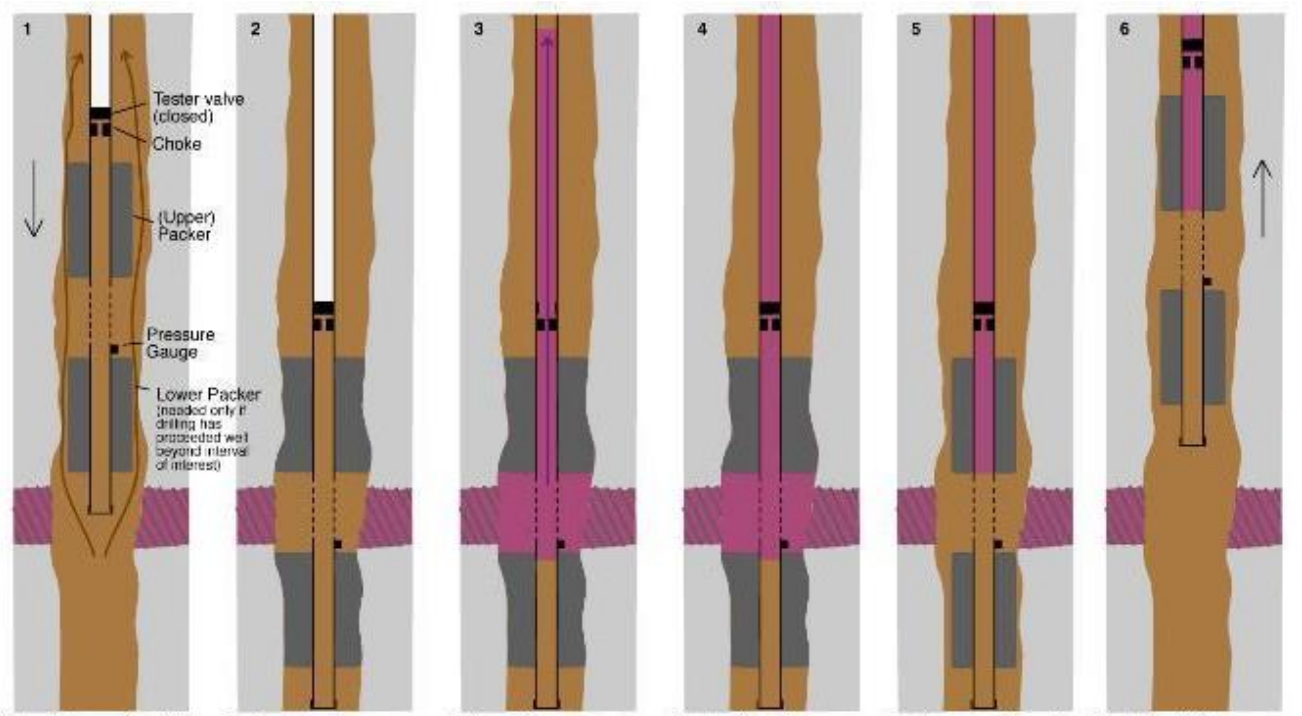
Figure 9: Isosurfaces of choke rate (ton/hr) for 914 m (3000 ft) bore, excluding enthalpy greater than 1744 kJ/kg (750 BTU/lbm), showing sensitivity to enthalpy and bore diameter.

5. NEW TEST METHODS

If an exploration well will not flow, or the data produced by the small bore cannot be reliably scaled to a larger diameter bore planned for development drilling, another well test method must be utilized. Thus, to assess the reservoir characteristics of a microbore, an alternative test method must be utilized. This can be accomplished by measuring resource parameters at the bottom of the well instead of at the surface. One way to do this is by conducting a drill stem test (DST).

The DST has long been used in oil and gas applications, but historically not in the geothermal industry. DST tool temperature limitations and the difficulty of zone isolation in fractured reservoirs (i.e., using downhole packers) have limited the implementation of this technique in geothermal applications. A DST is essentially a small flow test conducted in the well bore. Pressure transient testing techniques, typically applied to high volume surface flow data, are also applied to the smaller flow volumes produced by the DST. As an oil and gas well is drilled, and drilling returns begin to suggest a possible producing horizon, the operator may decide to test the zone before finishing the well by performing a DST test (Figure 10). This involves pulling out of the hole, putting on the tester, and running back into the hole (Panel 1). The tester's packers inflate and isolate the horizon (Panel 2), and then the tester opens to allow formation fluids to move into the hole (Panel 3). After the flow rate is measured, the tester value is closed and the pressure exerted by the formation fluids is measured for a build-up test (Panel 4). Packers are released (Panel 5) and the tester is tripped out of the hole (Panel 6). In a geothermal setting, only the top packer would be used and it would be set at the casing shoe. This allows the entire open hole section to be part of the test and ensures a seal in faulted formations.

DST test results could be used to quantify the characteristics of the resource penetrated by a microbore (Figure 11). While the tool is running in the hole, pressure increases with depth. A slight variation in pressure occurs as the packer is set, and a sudden large drop occurs when the tool is opened. The pressure increases during the test as the fluids are filling the empty drill string. Fluid does not have to reach the surface. When the tool is shut-in, pressures are typical of a build test; this interval of test data is used to determine the permeability of the interval. This data is accurate enough to use in well bore simulation, as well as reservoir pressure and skin damage assessment. Immediately after recovering the tool, a quantitative evaluation of the DST test results can be conducted to determine if the zone is viable, or whether the bore needs to be deepened or sidetracked (Figure 12).



Tester is lowered into hole; gauge records increasing pressure of mud column.

Packers are set; gauge records slight pressure increase as packers expand.

Tester valve opens and pressure drops; formation fluids enter hole; rate of flow measured.

Tester valve closes; gauge records increase of pressure to shut-in pressure.

Packers are released; gauge records abrupt pressure increase under mud column.

Tester is withdrawn; gauge records decreasing pressure of mud column.

Figure 10. Mechanics of using a DST tool (shown for oil & gas application). Modified from gly.uga.edu/railsback/PGSG/PGSGmain.html

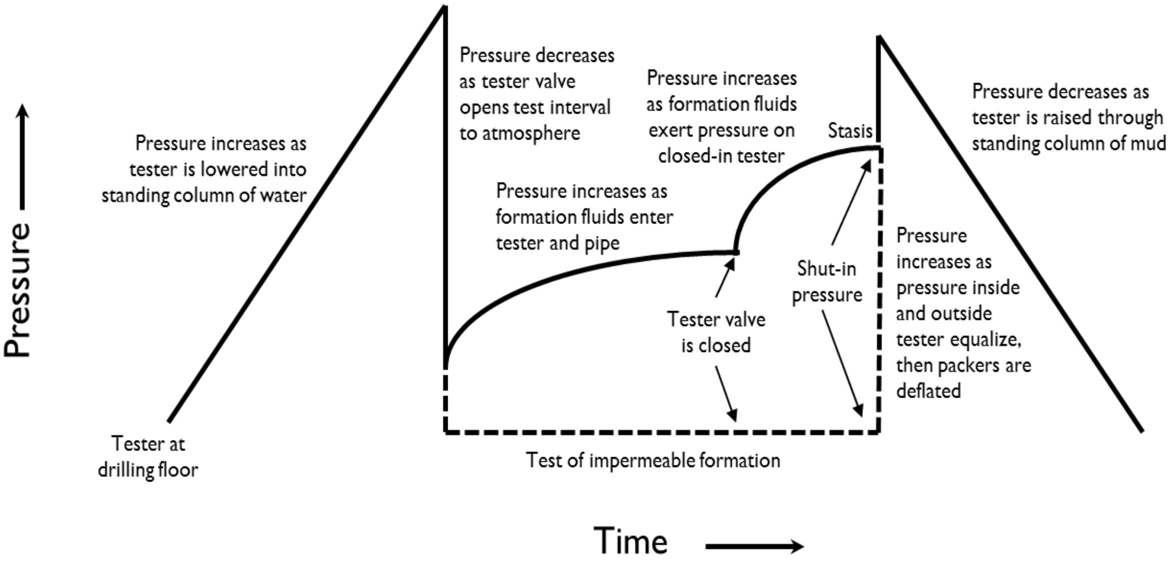


Figure 11. Generalized interpretation of a typical DST profile. Modified from gly.uga.edu/railsback/PGSG/PGSGmain.html

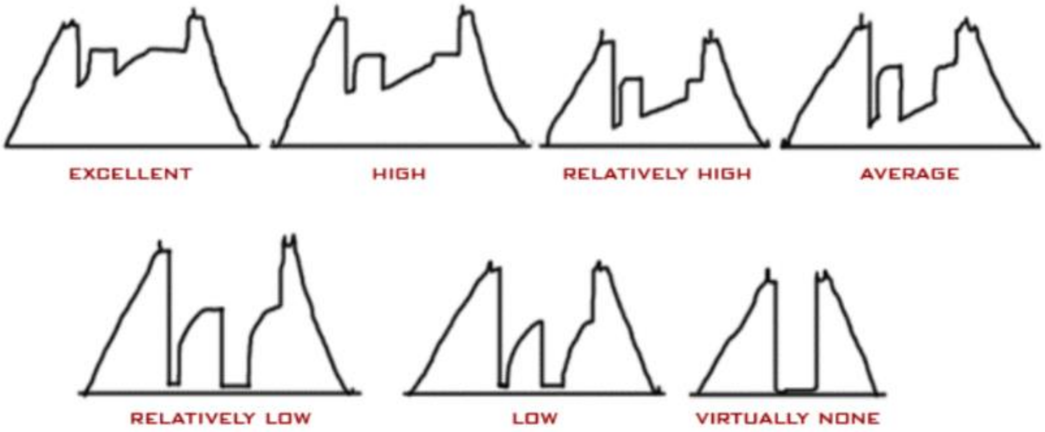
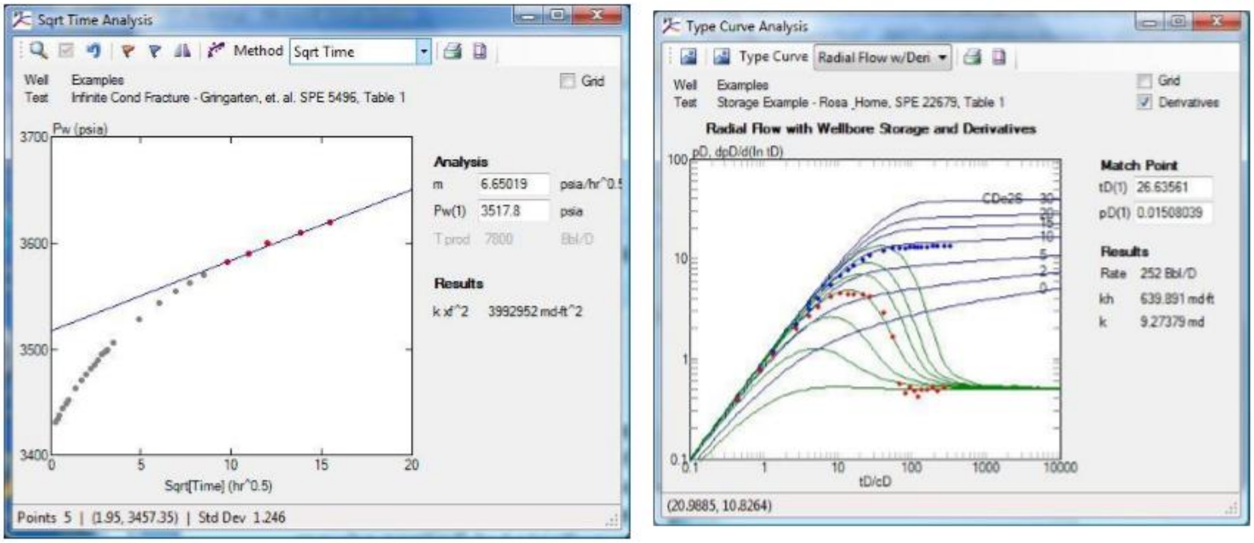


Figure 12. Qualitative assessment of a drill stem test. Source: dstdata.com/dstpress.htm.

Pressure transient testing is not used frequently in geothermal due to phase changes that occur in geothermal fluid flow. The storage component is very difficult to calculate and the period lasts too long in most geothermal wells, in most cases preventing a definitive analysis. A DST performed at elevated temperature could solve the storage component problem in geothermal applications. With the DST tool emplaced downhole, where there is less drawdown and higher pressure, geothermal fluids will typically be single-phase liquid. Even in two-phase reservoirs, the steam fraction typically does not change significantly. With stable conditions, pressure transient analysis can be used to determine typical parameters, including permeability and skin (Figure 13).



Method Sqrt Time

Well Examples

Test Infinite Cond Fracture - Gringarten, et. al. SPE 5496, Table 1

☐ Grid

Analysis

m 6.65019 psia/hr^0.5

Pw(1) 3517.8 psia

T prod 7800 Bbl/D

Results

k xf^2 3992952 md-ft^2

Points 5 | (1.95, 3457.35) | Std Dev 1.246

Type Curve Radial Flow w/Deri

Well Examples

Test Storage Example - Rosa_Horne, SPE 22679, Table 1

☐ Grid

☑ Derivatives

Match Point

tD(1) 26.63561

pD(1) 0.01508039

Results

Rate 252 Bbl/D

kh 639.891 md-ft

k 9.27379 md

(20.9885, 10.8264)

Figure 13. Example of a pressure buildup analysis to determine reservoir pressure, kh, and 'skin' damage of the tested formation. kappaeng.com/software/

The temperature limitation of currently available DST tools is 232°C (450°F), but could be increased with relatively minor modifications for even greater thermal stability. Zone isolation can be achieved by setting the DST at the bottom of the last cemented string. The smallest DST tool currently available is 3-1/2" in diameter, which could be run in a PQ core size hole. We propose also using this technique in slim wells to extend the enthalpy range of tests, to increase the accuracy of the results, and eliminate the need for the handing of large volumes of produced fluid. As the geothermal DST method is applied more frequently, existing technology can be adapted to build a tool with a diameter of 2" or less, with higher temperature limits. In addition, DST tools typically have a sample chamber and can capture in-situ samples of reservoir fluid during the test for geochemical analysis, without the need for additional sampling tools or a surface flow test. For oil and gas applications there is currently a 'downhole laboratory' that can analyze fluids in-situ. Adapting this for geothermal would allow for better analysis and samples, and analysis of reservoir fluids in wells that do not flow to the surface. When a custom geothermal DST test tool is built, after initial 3-1/2" size runs, the downhole analysis can be built into a new, smaller tool specific for geothermal wells.

6 CONCLUSION

Testing of geothermal wells can be greatly enhanced by using downhole flow measurements. Using drill stem testing techniques would allow a more accurate upsizing of the test results of slim holes, and opens the door to the use of microbores for geothermal resource exploration. We have demonstrated that evaluation of some slim wells, core holes and microbores, using current production test methods, is not sufficient for measurement of the critical parameters required for scaling-up well performance to larger development wells. Accurate and reliable evaluation of these smaller bores may be accomplished using a DST tool, modified from designs currently used in oil and gas applications.

Combining microbore drilling, DST technology, and downhole geochemical measurement has the potential to yield rapid, lower cost assessment of geothermal resources and allow for exploration in more restrictive or hard to reach locations. Benefits are also applicable to currently sized wells.

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