PROCEEDINGS, Thirty-Eighth Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, February 11-13, 2013
SGP-TR-198

THERMAL STIMULATION OF GEOTHERMAL WELLS: A REVIEW OF FIELD DATA

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ABSTRACT

Available data indicates that, in the normal case where injectate is cooler than the reservoir, injectivity of a geothermal well should be expected to increase with time at a rate like t^n where n = 0.4-0.7. Injectivity is also strongly temperature-dependent, increasing greatly with increased temperature difference between injectate and reservoir. The increase in permeability with time can be up to two orders of magnitude. It is also observed that nearly all wells drilled with cold water, are greatly stimulated by the effects of drilling and completion testing. Thermal stimulation is a very common, but often unrecognised phenomenon.

INTRODUCTION

It has been observed many times that the performance of geothermal injection wells improves with time, provided there are no deposition problems. It has also been observed that cold water injection improves well permeability. This improvement is usually attributed to cooling of the rock near the wellbore, with consequent expansion of fractures. This thermal stimulation is distinct from hydraulic stimulation, where fractures are created or expanded by raising fluid pressure sufficiently.

The first step is a review of the relevant available data which can be used to define or test any model. Performance of injection wells can be monitored by measuring the injectivity index (dQ/dp) using the wellhead pressure (where the injectate temperature is constant), or downhole pressure and monitoring its change with time. The expected pattern is an increase like t^n, where n is 0.4-0.7 – there should be a linear trend on log-log plot. A sustained deviation below this trend suggests deposition.

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AVAILABLE DATA

Variation with time – Injectivity measured downhole

Figure 1 shows the observed changes of injectivity in BR23 (Grant et al. 1982, p311). There was a first period of injection. Then the well was produced for a period, followed by a second period of injection. During both injection periods injectivity increased, and decreased over the period of production. Slope of the trend during injection is 0.6.

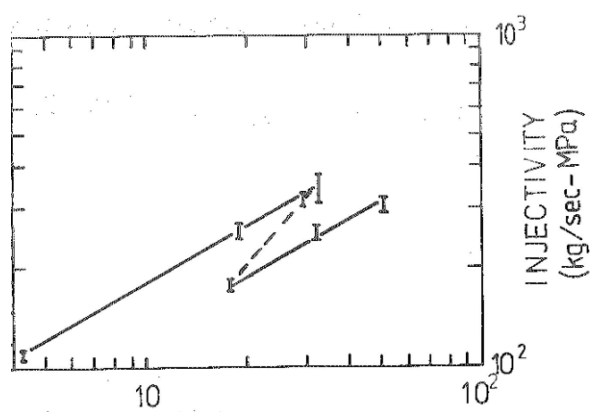

Figure 1. Injectivity changes in BR23 against cumulative injection of cold water (kt) Reservoir temperature 270°C.

This example demonstrates that thermal stimulation is reversible. Injectivity increased during injection, decreased during warmup and subsequent production, and then increased again with the second round of injection. In this as in subsequent examples, the injected water is around 20°C and reservoir is a high temperature field. Figure 2 shows the injectivity measured in KA44, KA50 and RK21 during

stimulation after completion of drilling. Slopes on the log-log plot are 0.37 for RK21,0.58 for KA44 and 0.76 for KA50.

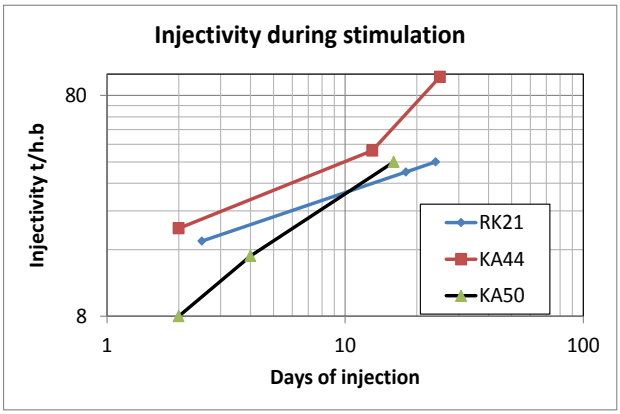

Figure 2. Injectivity of RK21 and KA44 during stimulation.

Variation with time – Injectivity computed from wellhead measurements

Figure 3 shows the evolution of the injectivity of MK20 during its use as injector. The injectivity is computed from wellhead pressure and flow records using the relation:

$$WHP = P_r - \rho_w g Z + W/II + C\,W^2 \qquad (1)$$

And assuming that the changes in performance are all due to changes in Injectivity *II*. In particular it is assumed that reservoir pressure has not changed during the period. Injectivity during the latter part of the record is underestimated as no allowance was made for frictional pressure losses in the wellbore, which are important at higher flow rates. The record shows a linear trend on the log-log plot, with a period of near-constant values in the middle before resuming a parallel trend. There was no change in operation during this time and this pause in the trend is unexplained.

Taken together, these observations demonstrate that injectivity increases during injection proportional to t^n, where n = 0.4-0.7

The heuristic observation that injectivity increases along a linear trend on a log-log plot provides a convenient means of monitoring the performance of injection wells. If a well fails to follow such a trend, or follows it initially and then falls back, it suggests that deposition is taking place.

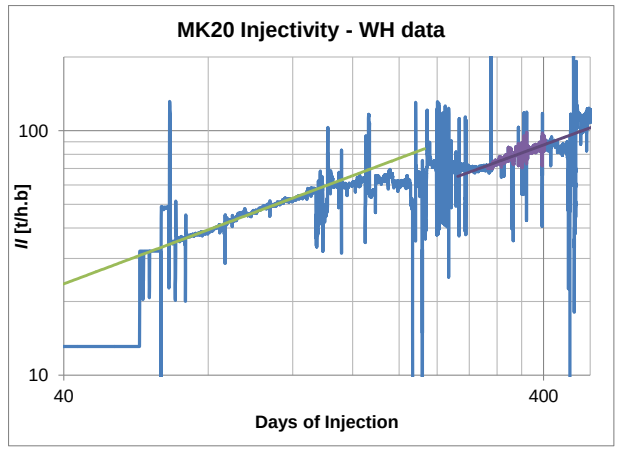

Figure 3. Injectivity of MK20 during use as injector. Slope is 0.7.

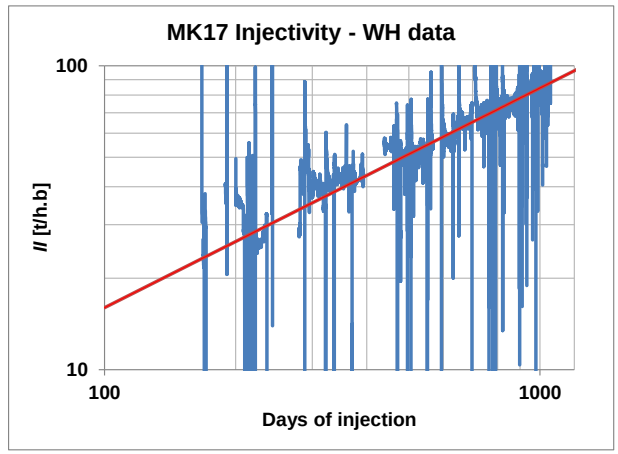

Figure 4. Injectivity of MK17 during service as injector. Slope is 0.7.

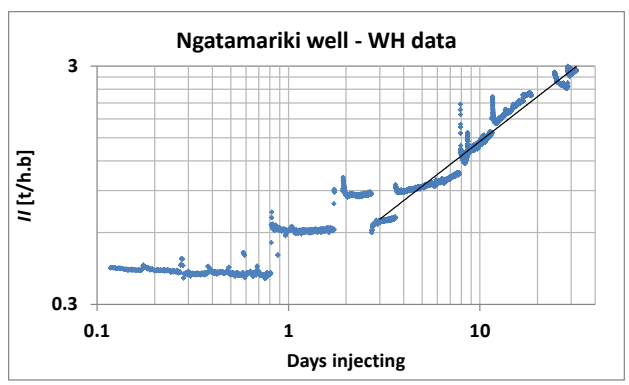

Figure 5. Injectivity of a Ngatamariki well during injection of cold water. Slope is 0.62

Variation with flow rate

A cold water injection test is carried in most wells at completion. Normally these tests show a linear relation between injection flow and downhole pressure. This linearity is an important observation, as it implies that flow in the formation is linear.

Nonlinear flow, such as turbulent or Forchheimer flow, or frictional flow in a pipe, produces a pressure drop proportional to the square of the flow rate. This effect is not present in single phase liquid geothermal reservoirs.

Variation with temperature

There are two types of contrasting temperature data available: comparison between completion (injection 20°C) and production (reservoir temperature); and comparison between completion (injection 20°C) and waste injection (80-130°C)

Comparison between completion and waste injection

Lim et al (2011), Fig 2 shows the RK21 data with the addition of the injectivity derived from operation as injector. In April all flow was diverted into RK21 to produce a positive wellhead pressure. From this wellhead pressure and the existing wellbore model the injectivity was computed. This estimate is subject to significant error as casing and liner friction may have changed due to deposition – could be rougher or could be smoother (thin layer of glassy quartz).

The injectivity appears to be on a parallel trend from the completion test data. Values on service are about half those for the same time of stimulation. The final stimulation value is 40 t/h.b at 24 days. The value on the trend line during service at the same time is 19 t/h.b.

Figure 3 shows the injectivity of MK20, as computed from WHP and flow, without correction for frictional losses. This will make the later values underestimates. Injectivity at the completion test was 35 t/h.b, which, similarly to RK21, lies well above the trend during service as injector. There is a discrepancy in that the injectivity plot gives a static pressure 10 bar higher than later measured – there may be some effect from residual drilling materials, either cuttings or drilling fluids. This makes comparison with later injectivity difficult. MK20 takes Mokai waste which is not supersaturated with respect to amorphous silica, so deposition should not be an issue here.

In both cases, at comparable times, injectivity is greater when the injected fluid is colder. There is no available well test information with all three sets of permeability data: completion, waste injection and production.

Comparison between production and injection

Table 1 shows the measured injectivity and productivity of wells at Rotokawa. and, Kawerau , plus other wells from Grant (1982). The injectivity was measured in the completion test, ie after drilling and about a day of injection during the test.

The (geometric) mean of the ratio of injectivity to productivity is 3.5 – that is, injectivity is 3.5 times productivity, on average. The data suggests that this average varies between fields, but is insufficient to be certain. For Rotokawa the mean ratio is 8.

However the viscosity of hot water is less than cold water – depending on precisely the temperature of the injected water, as viscosity of the cold water injected is up to 6 times that of reservoir water; implying that the permeability during the completion test is on average 20 times greater than on subsequent production. If this observation is correct it implies that a very great degree of stimulation has already occurred by the time of the completion test. This stimulation is presumably a consequence of fluid losses during drilling and the completion test itself. To advance this interpretation further it would be necessary to use drilling data to combine the completion injectivity with data of the length of time the relevant zone had been taking cold water.

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The amount of stimulation present can be estimated by a comparison between productivity and injectivity. For both *PI* and *II*, there is a simple relation with permeability-thickness (Grant & Bixley (2011), eq A1.22):

$$\frac{1}{PI} = \frac{\nu}{2\pi kh}[2.303 \log_{10}(\frac{r_o}{r_w}) + s] \qquad (2)$$

Where r_o is an outer radius at which pressure is undisturbed. Comparing injectivity and productivity gives

$$\frac{(kh)_{cold}}{(kh)_{hot}} = \frac{II}{PI}\frac{\mu_{cold}}{\mu_{hot}} \qquad (3)$$

Using this relationship, the permeability ratio of hot *kh* to cold *kh* has been computed in Table 1 below.

Table 1. Injectivity and productivity (t/h.b) of various wells

Well	*II*	*PI*	*II/PI*	$\frac{(kh)_{cold}}{(kh)_{hot}}$
RK1	24	1.5	16.0	192
RK4	6	1	6.0	72
RK5	50	7	7.1	86
RK6	20	3.5	5.7	68
RK9	60	5.9	10.2	122
RK13	30	5	6.0	72
RK14	9	7.5	1.2	14
RK16	13	1	13.0	156
RK17	200	33	6.1	73
RK18	9	1	9.0	108
RK25	22.5	1.1	20.5	245
RK26	108	50	2.2	26
RK27	15.7	1	15.7	188
RK28	25.1	1.2	20.9	250
NG2	5	9	0.6	5
NG3	22	2	11.0	92
NG4	110	200	0.6	5
NG8	8	12	0.7	6
NG11	42	25	1.7	14
NG18	10	4	2.5	21
BR9	20	1.5	13.3	135
BR13	9	3.3	2.7	28
BR18	8	3.2	2.5	25
BR22	14	12	1.2	12
BR23	26	11	2.4	24
BR25	21	35	0.6	6
BR27	9	5.5	1.6	17
BR28	50	15	3.3	34
PK3	46	4	11.5	118
PK6	90	36	2.5	26
PK7	40	15	2.7	27
KA41	60	110	0.5	6
KA24	10	3	3.3	34
KA19	42	22	1.9	20
KA8	300	100	3.0	31

Tests of injection at different temperatures were carried out in Iceland (Gunnarson, 2011). One of the results is shown in Figure 6 below. Reservoir temperature in the area is approximately 200°C. Productivity values are not given.

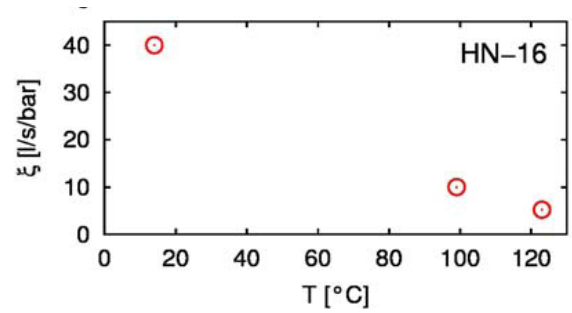

Figure 6. Injectivity (ξ) at different temperatures in Húsmúli injection zone.

A similar experiment was carried out at BR30 at Ohaaki, New Zealand at the same time as the BR23 tests shown in Figure 1. BR30 demonstrated highly nonlinear injection performance, explained as pressure-dependent permeability Reservoir temperature was about 250°C. Incremental permeability, measured by transients at flow changes, varied exponentially with pressure, and increased 30-fold over the range of the injection rates. Further, there was no significant change with time over the period of injection. In this case hot and cold water produced similar injection curves. This example indicates that the discussion and theory of this paper applies only when performance is linear, and not when permeability is being significantly modified by pressure.

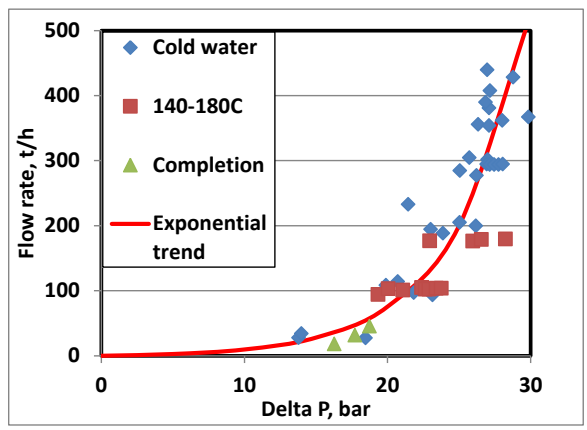

Figure 7. Nonlinear injection characteristic at different temperatures in BR30.

The *kh* ratio for all the wells in Figure 6 and Table 1 is plotted against *ΔT*, the difference between reservoir temperature and injection temperature, in Figure 8 and Figure *9* . For the Húsmúli wells, productivity values were assumed that provided the best agreement with the trend of the other data. These values are 1, 3, 3 respectively.

Data for three Japanese fields, Oguni, Kirishima and Sumikawa is reported by Garg et al. (1995a,b, 1998) and has been added to the plot.

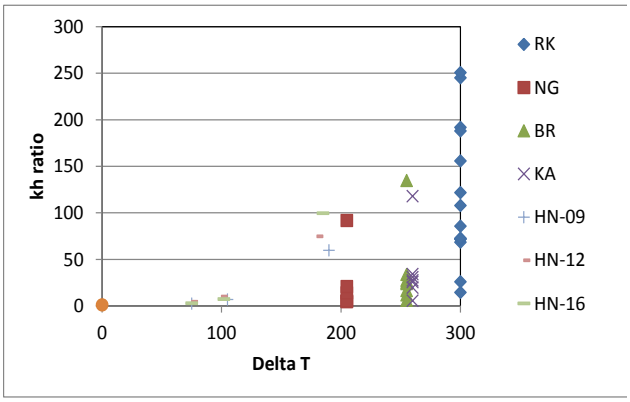

Figure 8. Permeability ratio against temperature difference, linear plot

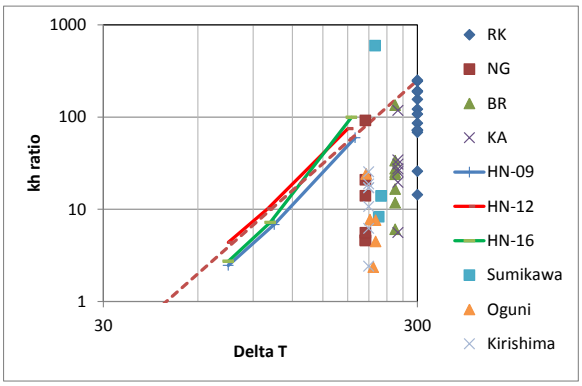

Figure 9. Permeability ratio against temperature difference, log-log plot.

Not surprisingly, there is a lot of scatter on the data. It is clear that there is a strong variation with temperature difference. Figure 8 suggests that the variation is not linear with ΔT, and it is probably closer to ΔT^3. The dashed line on Figure 9 shows such a cubic dependence. Because of the paucity of data at lower values of ΔT, this is not well constrained. The Icelandic results, which are the best quality data as they contain a range of values from the same well, are consistent with a ΔT^3 variation.

The permeability changes during thermal stimulation are not normally due to any hydraulic fracturing. They occur at all overpressures, and are reversible. This points toward thermal expansion and contraction as the driving mechanism.

Further interesting data is given by Clotworthy (2000). This describes the results of injecting waste water at 150°C into a cooler formation, at around 50°C. Injectivity was less than when the wells were first completed and tested with cold water; however there was little change with time on continued operation as injector. It would be expected from the discussion above that injectivity to hot water would be less than to cold water. A continued decline would also be expected but probably asperities and self-propping prevent the fractures from fully closing.

CONCLUSION

Observation shows that permeability of fractured hot rock increases strongly with decrease in temperature. The permeability increase can be as much as two orders of magnitude when cold water is injected into a high-temperature reservoir. The increase is due to thermal contraction of the rock, and causes permeability changes much greater than those due to pressure changes. This process cannot continue indefinitely, as it depends on the existence of a temperature contrast; but it has been observed to continue for a few years.

Most wells drilled with water are normally considerably stimulated at the end of drilling; and with continued injection, injectivity continues to increase.

ACKNOWLEDGEMENTS

We thank Mighty River Power, Contact Energy and Tuaropaki Power Company for permission to publish field data and theory.

LIST OF SYMBOLS

D	constant
II	injectivity index
h	thickness
k	permeability
K	thermal conductivity
PI	productivity index
Q	heat flow
R	radial distance
T	temperature
t	time
α	coefficient of expansion
σ	Poisson's ratio
ν	kinematic viscosity

APPENDIX: A SIMPLIFIED THEORY

The permeable zone is modelled as a uniform aquifer of thickness h and porosity φ. The rock on either side of the aquifer contracts as a result of cooling, expanding the thickness of the permeable zone. The injectivity of the zone is assumed to increase linearly in proportion to this contraction.

Injection at a uniform rate q starts at time $t = 0$. Ignoring the effects of dispersion or lateral conduction, the chemical front lies at radius r_c:

$$qt = 2\pi\varphi h r_c^2.$$

Assuming that heat transfer within the fracture zone is greater than the lateral losses, the thermal front lies at radius r_t:

$$\rho_w C_w q t = \pi \rho_f C_f h r_t^2.$$

Or $$r_t = \sqrt{\beta t}$$

At a radius r, the fluid is at reservoir temperature until time $t = r^2/\beta$, after which it is at injection temperature. Thus the top and bottom boundary of the aquifer is subjected to a step change in temperature at this time, with temperature constant before and after the step change.

The temperature change is $\Delta T = T_r - T_{inj}$. At time $t > r^2/\beta$, the total heat flux, per unit area, from the formation at each of the top and bottom boundary up to time t is given by (solution of the 1D heat conduction equation):

$$Q = (2K\Delta T/2\sqrt{\pi})\sqrt{((t - r^2/\beta)/\kappa)}$$

If the formation were free to contract, this heat loss to the permeable zone would cause a contraction of

$$\Delta h = 2\alpha Q/\rho C$$

The factor of two comes from the contraction at each side of the fissure. It does not matter how the temperature change is distributed laterally away from the permeable zone – as long as the formation has linear properties the total volume loss is the same. Assuming all this volume loss is transferred to volume loss at the zone boundary gives the equation above.

If the formation is constrained that it cannot contract in the transverse directions, there will be an increase in transverse tension, and the contraction at the formation boundary is given by

$$\Delta h = 2\alpha Q \times (1 + 2\sigma)$$

Now further assume that the transmissivity of the permeable zone increases linearly in proportion to the increase in thickness:

$$kh = (kh)_o(1+\zeta\Delta h)$$

Note that this assumption differs from that for flow between smooth plates, where $kh = h^3/12$. Combining the equations,

$$kh = (kh)_o(1+\xi\sqrt{(t - r^2/\beta)})$$

$$\xi = 2\zeta(\alpha/\rho C)(2K\Delta T \times (1 + 2\sigma)/\sqrt{(\kappa\pi)}$$

Note that ξ has the dimensions of $t^{-0.5}$, so that multiplying it by $t^{0.5}$ gives a dimensionless number.

Injectivity is typically measured in isochronal tests with about an hour at each rate. It is assumed that the radius of influence in these tests lies within r_t, ie that the entire pressure transient is measured at constant (injection) temperature. Then the pressure gradient at any time is given by

$$\frac{\partial P}{\partial r} = \frac{q\mu}{2\pi kh}\frac{1}{r}$$

$$\Delta P = \frac{q\mu}{2\pi\,(kh)_o}\int_{r_w}^{r_o}\frac{1}{1+\xi\sqrt{(t - r^2/\beta)}}\frac{dr}{r}$$

where the limits of integration are from the well radius to the radius of influence

If we assume the radius of investigation of the isochronal test lies well within the radius of stimulation, ie $t >> r^2/\beta$, then this simplifies

$$\Delta P = \frac{q\mu}{2\pi\,(kh)_o}\int_{r_w}^{r_o}\frac{1}{1+\xi\sqrt{(t}}\frac{dr}{r}$$

$$\Delta P = \frac{q\mu}{2\pi\,(kh)_o}\frac{1}{1+\xi\sqrt{(t}}\ln\left(\frac{r_o}{r_w}\right)$$

$$II = W/\Delta P$$

$$= (\gamma + 1)\frac{2\pi(kh)o}{\nu}\frac{1}{\ln\left(\frac{r_o}{r_w}\right)}$$

And again at long time

$$II = \xi\sqrt{t}\,\frac{2\pi(kh)o}{\nu}\frac{1}{\ln\left(\frac{r_o}{r_w}\right)}$$

$$= D\frac{\Delta T}{\nu}\sqrt{t}$$

Where D is a constant. This describes the variation of injectivity with time and with temperature of the injected fluid.

If the permeability is assumed to take the form of smooth plates

$$kh \sim h^3$$

then the asymptotic form of the injectivity becomes

$$II = D\frac{\Delta T^3}{\nu}\sqrt{t^3}$$

Discussion

The $\sqrt{t}$ dependence is basically the same as the $\sqrt{t}$ dependence in the linear flow regime of a fractured well pressure transient. The assumption that heat transfer within the fracture is the dominant process is a significant assumption. Presumably there is also a regime analogous to the bilinear regime, with corresponding $t^{0.25}$ dependence. This might explain the range of exponents observed.

The observations confirm that the injectivity increases with time at a rate near to $\sqrt{t}$. But in contrast the dependence on the temperature difference is more like ΔT^3. It is concluded that the present theory is only partly correct and some further theoretical development is needed. However the observations provide a basis for monitoring injection well performance. The observations appear to be consistent with a model

$$II = D\frac{\Delta T^3}{\nu}t^n$$

Where n = 0.4-=0.7, but at present no theoretical model for this has been found. Possibly the bilinear flow regime will lead to this – if $h \sim \Delta T\, t^{0.25}$, then a cubic dependence would give

$$II = D\frac{\Delta T^3}{\nu}t^{0.75}$$

A similar problem – a well intersecting a fracture where the well is in the plane of the fracture rather than at right angles as here – is solved by Nygren et al. (2005). An analytic solution is found, which for long time also gives $h \sim \sqrt{t}$.

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