7PROCEEDINGS, Thirty-First Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, January 30-February 1, 2006
SGP-TR-179

A COMPARISON OF GEOTHERMAL WITH OIL AND GAS WELL DRILLING COSTS

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ABSTRACT

The costs associated with drilling and completing wells are a major factor in determining the economic feasibility of producing energy from geothermal resources. In EGS power plants, estimates place drilling costs as accounting for 42%-95% of total power plant costs (Tester et al., 1994) depending on the quality of the EGS reservoir. An earlier correlation first developed by Milora and Tester (1976) and later refined by Tester and Herzog (1990) created a drilling cost index based on oil and gas well data from the *Joint Association Survey (JAS) on Drilling Costs* and used this index to compare the cost of drilling hot dry rock (HDR) and hydrothermal wells to the cost of oil and gas wells drilled to similar depths. This study updates and extends their earlier work. Oil and gas well costs were analyzed based on data from the 2003 JAS for onshore, completed US oil and gas wells. A new, more accurate drilling cost index that takes into consideration both the depth of a completed well and the year it was drilled was developed using the JAS database (1976-2003). The new index, dubbed the MIT Depth Dependent (MITDD) index, shows that well costs are up to 30% lower for wells over 4 km (13,000 ft) deep than those based on previous indices. The MITDD index was used to normalize predicted and actual completed well costs for both HDR or EGS (Engineered Geothermal Systems) and hydrothermal systems from various sources to year 2003 US dollars, and then compare and contrast these costs with oil and gas well costs. Additionally, a model for predicting completed geothermal well costs, called WellCost Lite (Mansure et al., 2005), is explained and demonstrated. Results from the model agree well with actual geothermal well costs. The model is used to identify factors that lead to rapid, non-linear increases in well cost with depth, such as increases in the number of casing strings required as depth increases with a resulting increase in rig capacity (embodied in mobilization, demobilization and daily rental costs), costs of casing and cementing the well, and changes in the rate of penetration.

GENERAL TRENDS IN OIL AND GAS WELL COMPLETION COSTS

Tabulated data of average costs for drilling oil and gas wells in the US from the *Joint Association Survey (JAS) on Drilling Costs* (1976-2003) illustrate how drilling costs increase non-linearly with depth. Completed well data in the JAS report are broken down by well type, well location, and the depth interval to which the well was drilled. The wells considered in this study were limited to onshore oil and gas wells drilled in the United States. The JAS does not publish individual well costs due to the proprietary nature of the data. The well cost data is presented in aggregate and average values from this data are used to show trends. Ideally, a correlation to determine how well costs vary with depth would use individual well cost data. Since this is not possible, average values from each depth interval were used. However, each depth interval was comprised of data from between hundreds and thousands of completed wells. Assuming the well costs are normally distributed, the resulting averages should reflect an accurate value of the typical well depth and cost for wells from a given interval to be used in the correlation.

In plotting the JAS data, the average cost per well of oil and gas wells for a given year was calculated by dividing the total cost of all onshore oil and gas wells in the US by the total number of oil and gas wells drilled for each depth interval listed in the JAS report. These average costs are tabulated in Table 1. Wells in the 0 - 1249 ft (0 - 380 m) and 20,000+ ft (6100+ m) depth intervals were not included because wells under 1250 ft (380 m) are too shallow to be of importance in this study, and not enough wells over 20,000 ft (6100 m) are drilled in a year to give an accurate average cost per well.

Table 1. Average costs of oil and gas onshore wells drilled in the US during the year 2003 from JAS data for listed depth intervals.

Drilling Interval (feet)	**Average Depth (meters)**	**Average Depth (feet)**	**Average Cost (Year 2003 US M$)**
1250-2499	557	1826	0.227
2500-3749	964	3162	0.267
3750-4999	1329	4359	0.300
5000-7499	1912	6272	0.543
7500-9999	2613	8572	1.010
10000-12499	3380	11087	2.033
12500-14999	4092	13424	2.949
15000-17499	4868	15969	5.168
17500-19999	5648	18526	11.177

A cursory analysis quickly shows that well costs are not a linear function of depth. A high order polynomial, such as:

$$\Phi_{\text{well}} = c_0 + c_1 z + c_2 z^2 + c_3 z^3 + \ldots \qquad (1)$$

where Φ_{well} is the completed well cost, z is the depth of the well, and c_i are fitted parameters, can be used to explain well costs as a function of depth. However, it is not obvious what order polynomial would best fit the data, and any decent fit will require at least four parameters, if not more. By noting that an exponential function can be expanded as an infinite series of polynomial terms:

$$e^x = 1 + x + \frac{x^2}{2!} + \frac{x^3}{3!} + \ldots \qquad (2)$$

one might be able to describe the well cost data as a function of depth using only a few parameters. As Fig. 1 shows, the average costs of completed oil and gas wells for the depth intervals from 1250 feet (380 m) to 19999 feet (6100 m) can be described as an exponential function of depth, that is:

$$\Phi_{\text{well}} = a \cdot \exp\left(b_1 \cdot \text{depth}\right) = a \cdot \exp\left(b_1 z\right) \qquad (3)$$

where a and b_1 are fitted parameters. Thus a plot of $\log_{10}$(well cost) vs. depth results in a straight line:

$$\log_{10}\left(\Phi_{\text{well}}\right) = \log_{10}\left(a\right) + b_2 z \qquad (4)$$

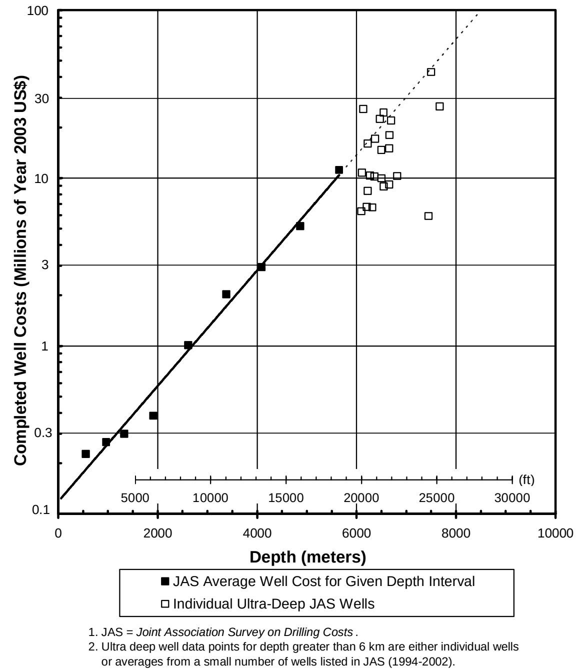


Fig. 1. Completed onshore oil and gas well costs in year 2003 US$ as a function of depth.

The “Oil and Gas Average” trend line in Fig. 1 shows that an exponential function adequately describes year 2003 JAS average completed well costs as a function of depth for the depth intervals considered while requiring only two parameters. The correlation coefficient (R^2) value for the year 2003 JAS data, when fit to Equation (4), was 0.994. This indicates a very high degree of correlation between the log of the completed well costs and depth. Similar plots for each year of JAS report data from the years 1976 - 2002 also show high levels of correlation between the $\log_{10}$ of well costs and depth, with all years having an R^2 value of 0.984 or higher. Fig. 2 shows how the regressed slope (b) and intercept ($\log_{10}(a)$) vary from year to year.

An insufficient number of ultra deep wells, with depths of 20,000+ ft (6100+ m), were drilled in 2003 to give an accurate average. Instead, a number of ultra deep well costs from 1994-2002 were corrected to year 2003 US $ using MITDD index values (see below) for the 17,500 – 19,999 foot depth interval and plotted in Fig. 1. Some of the data points represent individual well costs that happened to be the only reported well drilled in the 20,000+ foot depth interval in a region during a given year, while others are an average of several (2 or 3) ultra-deep wells. Extrapolation of the average JAS line in Fig. 1

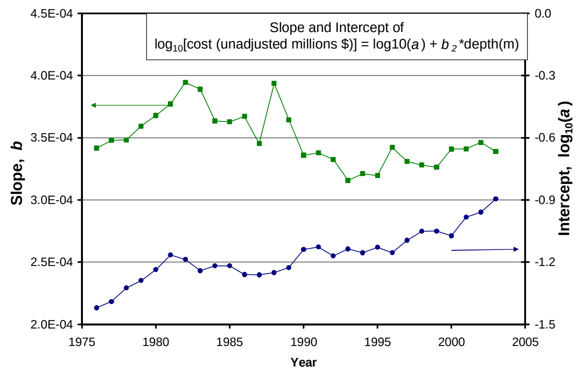


Fig. 2. Slope and intercept of exponential fit of JAS wells cost data vs. depth for years 1976 – 2000.

beyond 20,000 feet (6,000 m), indicated by the dashed line, is generally above the scatter of costs for these individual ultra deep wells. The ultra deep well data demonstrate how much well costs can vary depending on factors other than the depth of the well. It is easy to assume that all the depth intervals would contain similar scatter in the completed well costs.

The JAS completed well cost data show that an exponential fit adequately describes completed oil and gas well costs as a function of depth over the intervals considered using only two parameters. The correlation in Fig. 1 provides a good basis for estimating drilling costs based on the depth of a completed well alone. However, as the scatter in the ultra-deep well cost data shows, there are many factors affecting well costs that must be taken into consideration to accurately estimate the cost of a particular well. The correlation in Fig. 1 serves as a good initial guess, but once more details about a well are known, a more accurate estimate can be made. The well cost model described later in this paper addresses this issue in more detail.

MIT DEPTH DEPENDENT (MITDD) DRILLING COST INDEX

Formulation of Drilling Cost Index

In order to make comparisons between geothermal well costs and oil and gas well costs, a drilling cost index is needed to update the costs of drilling hydrothermal and HDR/EGS wells from their original completion dates to current values. Insufficient geothermal well cost data exist to create an index based on geothermal wells alone. The oil and gas well drilling industry, however, is a large and well established industry with thousands of wells drilled each year. Since the drilling process is essentially the same for oil, gas and geothermal wells, the JAS data provide a good basis for comparison and extrapolation. Therefore, data from the JAS (1976-2003) were used to create a drilling index, and this index was used to normalize geothermal well costs to year 2003 US$.

There are many factors that affect the cost of a completed well, including the final depth of the well, the type of rock formation that is being drilled, hole diameter, the casing program, and the remoteness of the drilling site to name a few. Some of these factors are more important, since they can greatly influence other factors. For example, the hole depth largely determines the casing program that must be used to give the desired bottom hole diameter. The well type generally determines the type of rock formation, and to some extent, the lithology, that will be encountered. The well location can determine rig rental and material costs, especially if the wells being compared are as disparate as onshore vs. offshore wells. A good drilling cost index should take as many of these factors into account as possible, yet most do not. For example, the drilling index published yearly in the JAS, shown in Fig. 3, was considered for updating geothermal well costs, but it was decided the index was inadequate for several reasons. First, it only extends back to 1984, whereas some of the geothermal wells date back to 1972. Second, the JAS published index is normally based on the current year's drilling activity and hence changes from year to year. It does not provide a consistent basis for comparison and is also influenced by the drilling trends, an unusually large number of shallow holes, for example, of the current year. Last, and most importantly, it fails to account for the effect of well depth on drilling costs. Instead, it uses the average cost per well for all onshore US wells. This biases the index towards the cost of the more numerous shallow holes. As will be demonstrated, costs for drilling to different depth intervals have varied greatly over the last 30 years, and lumping all data into one parameter leads to erroneous results.

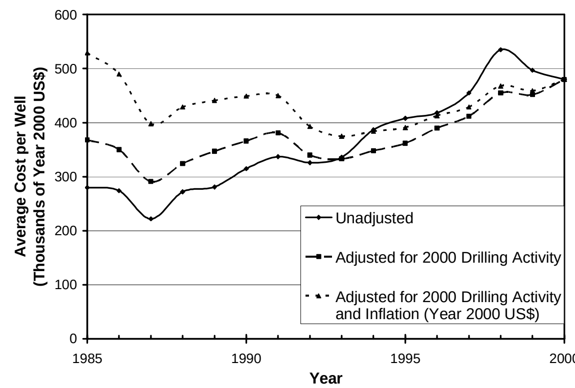


Fig. 3. Drilling cost index adapted from 2000 Joint Association Survey on Drilling Costs. *Average cost per well for onshore US wells vs. year drilled (JAS, 2000).*

Fig. 4 gives the MIT Composite Weighted Average drilling cost index previously developed by Tester and Herzog (1990) which accounts for well type by considering only completed onshore oil and gas wells in the United States. Like the JAS index, it used the average cost per foot of wells drilled each year as its index. This resulted in condensing all information from the various depth intervals into a single index number for each year, thus biasing the index towards the cost of shallower wells, since a larger number of these wells are normally drilled each year. This index is also prone to error in years where a disproportionate number of either deep or shallow wells are drilled. Because of this, it was decided that a better method of developing an index was needed.

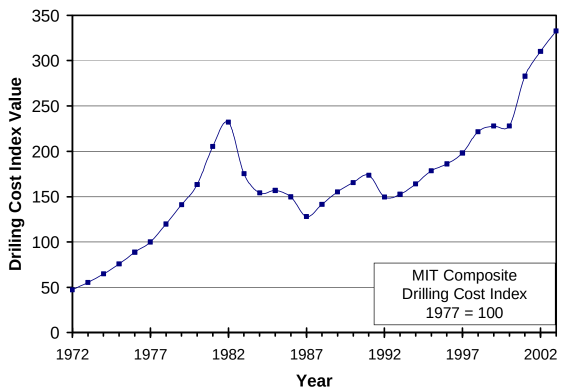


Fig. 4. MIT drilling cost index made using average cost per foot drilled each year for onshore US oil and gas wells (1977 = 100), adapted from Tester and Herzog (1990).

An index made by calculating the average cost per foot at each depth interval and then giving equal weight to each of these intervals was considered. This index avoids the problem of overweighting from the more numerous shallow wells experienced by the MIT Composite index. However, since costs rise non-linearly with depth, the deeper wells would contribute more heavily to the index, resulting in an index that favors changes in drilling costs in deep wells. A drilling index that gives equal weight to each interval would be unfairly biased towards the costs of deep wells. A method for correctly weighting the intervals is not immediately obvious. As Fig. 2 shows, any non-linear weighting correlation would have to change on a yearly basis. It was concluded that any index based on weighted depth intervals risks either over- or underestimating updated well costs depending on the method used.

To avoid these weighting limitations, an individual index was developed for each depth interval. The average cost per well at each depth interval in the JAS reports (1976-2003) was used. A 17% inflation rate was assumed for pre-1976 index points. Only onshore, completed oil and gas wells in the US were considered, since all hydrothermal and HDR wells to date have been drilled onshore. A three-year moving average was used to smooth out short-term fluctuations in price. Since most wells are drilled over a period of weeks to months, and the drilling industry is an industry in which technological change occurs slowly, this smoothing should more accurately reflect actual changes in drilling costs. Nonetheless, there will be situations where rapid changes in rig availability, driven by fuel supply shortages, for example, would cause well price fluctuations on a short time scale of months or less. The index was referenced to 1977, which is the first year for which a moving average could be calculated using data reported by JAS from the previous and following years. Although this method requires slightly more information and more work, it results in superior estimates of normalized drilling costs.

<u>MITDD Index Results and Discussion</u>

The MIT Depth Dependent (MITDD) drilling cost index is tabulated in Table 2 and shown in Fig. 5. Fig. 5 clearly illustrates how widely the drilling indices vary among the different depth intervals. Before 1986 the drilling cost index rose more quickly for deeper wells than shallower wells. By 1982 the index for the deepest wells is almost double the index for shallow wells. After 1986, the index for shallow wells began to rise more quickly than the index for deeper wells. By 2003, the index for wells in the 1250-2499 ft (380-760 m) range is 25% - 50% greater than all other intervals. Although it has the same general trend as the MITDD index, the MIT Composite index does not capture these subtleties. Instead, it incorrectly over- or under predicts well cost updates, depending on the year and depth interval. For example, using the previous method, the index would incorrectly over predict the cost of a deep well drilled in 1982 by about 20% when normalized to year 2003 US \$. The MITDD indices are up to 30% lower for wells over 4 km (13,000 ft) deep in 2003 than the previous index. The often drastic difference between index values of the MIT Composite index and the new MITDD index shown in Fig. 5 from two given years demonstrates the superiority of the new MITDD index in more accurately updating well costs.

Although the drilling cost index correlates how drilling costs vary with depth and time, it does not provide any insights into the root causes for these variations. An effort was made to determine what factors influence the drilling cost index and to explain the sometimes erratic changes that occurred in the index. The large spikes in the drilling index appearing in 1982 can be explained by reviewing the price of crude oil imports to the US and wellhead natural gas prices compared to the drilling cost index, as shown in Fig. 6. The MIT Composite drilling

Table 2. Values of MIT Depth Dependent (MITDD) drilling cost index made average cost per well for each depth interval from Joint Association Survey on Drilling Costs (1976-2003), with data smoothed using a three-year moving average. MIT Composite drilling cost index included for comparison.

Year	MIT Composite Drilling Cost Index	MITDD Drilling Cost Index								
		Depth Interval (Feet)								
		1250-2499	2500-3749	3750-4999	5000-7499	7500-9999	10000-12499	12500-14999	15000-17499	17500-19999
		Depth Interval (Meters)								
		381-761	762-1142	1143-1523	1524-2285	2286-3047	3048-3809	3810-4571	4572-5333	5334-6096
1972	47.3	49.4	50.3	49.8	50.0	48.5	47.5	49.1	49.5	48.9
1973	55.4	57.8	58.8	58.2	58.5	56.8	55.6	57.4	58.0	57.2
1974	64.8	67.6	68.8	68.1	68.4	66.4	65.0	67.2	67.8	67.0
1975	75.8	79.1	80.5	79.7	80.1	77.7	76.1	78.6	79.3	78.4
1976	88.7	92.5	94.2	93.3	93.7	91.0	89.0	92.0	92.8	91.7
1977	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1978	119.7	114.3	109.1	110.2	112.9	117.4	117.0	116.9	117.1	119.9
1979	141.2	132.8	126.4	127.0	132.6	139.9	136.0	138.0	140.4	154.4
1980	163.3	152.1	149.3	152.4	161.3	169.7	162.3	171.7	180.6	214.8
1981	205.4	161.7	163.1	167.1	180.1	188.3	183.7	206.3	221.4	269.0
1982	232.2	165.5	165.6	169.0	181.6	190.5	185.5	216.5	236.4	279.1
1983	175.3	158.9	160.7	160.0	168.5	173.6	168.6	203.6	225.5	270.2
1984	154.1	155.1	155.3	150.4	154.9	153.7	144.8	165.1	193.6	216.6
1985	156.8	151.7	155.1	144.8	150.6	148.3	139.0	149.0	176.7	181.3
1986	149.7	150.8	149.1	136.3	140.5	142.3	133.1	138.8	171.4	162.6
1987	128.1	152.3	127.4	125.1	127.4	134.4	131.9	132.4	150.4	146.5
1988	141.5	162.4	129.3	127.8	124.5	136.5	133.5	129.2	146.2	153.4
1989	155.3	177.3	148.0	140.3	132.1	147.6	142.6	135.8	157.2	162.9
1990	165.6	183.7	190.0	152.2	138.6	153.7	145.3	139.3	164.9	174.3
1991	173.6	190.1	199.3	157.0	138.5	145.4	140.5	127.1	153.3	162.5
1992	149.6	198.3	196.6	154.0	133.9	134.9	134.9	118.2	136.3	161.5
1993	152.6	201.7	173.7	147.4	129.8	128.9	132.4	114.5	111.3	150.8
1994	164.1	202.7	169.4	149.9	135.4	131.4	134.7	123.7	110.3	142.7
1995	178.6	198.6	165.8	151.2	144.2	141.0	137.4	136.2	125.2	153.9
1996	186.1	210.0	178.2	160.5	159.3	151.8	133.7	143.7	142.7	167.1
1997	198.1	226.6	191.0	170.0	170.4	163.6	136.3	157.3	165.4	180.9
1998	221.7	238.8	202.7	179.2	177.9	169.8	142.8	161.3	170.8	182.3
1999	227.9	237.1	205.7	186.5	185.0	179.2	157.3	169.1	181.8	190.8
2000	227.9	231.5	200.0	186.0	185.7	182.5	165.6	167.8	189.4	189.9
2001	282.8	287.8	231.4	212.8	224.8	226.6	198.4	203.9	233.7	253.2
2002	310.3	364.6	265.0	228.3	220.3	248.4	229.0	222.4	247.8	307.9
2003	332.8	396.3	273.0	228.2	219.8	250.0	232.7	224.7	254.3	311.1

1. Depth interval indicates vertical well depth.
2. Index for years prior to 1976 made assuming 17% annual inflation factor.

index was used for simplicity. Fig. 6 shows a strong correlation between crude oil prices and drilling costs. This correlation is likely due to the effect of crude oil prices on the average number of rotary drilling rigs in operation in the US and worldwide each year, shown in Fig. 7. Therefore, the drilling cost index maximum in 1982 was in response to the drastic increase in the price of crude oil, which resulted in increased oil and gas exploration and drilling activity and a decrease in drilling rig availability. By simple supply and demand arguments, this led to an increase in the costs of rig rental and drilling equipment. The increase in drilling costs in recent years, especially for shallow wells, is also due to decreases in rig availability. This effect is not apparent in Fig. 7, however, because very few new drilling rigs have been built since the mid 1980's. Instead, rig availability is dependent in part on the ability to salvage parts from older rigs to keep working rigs operational. As the supply of salvageable parts has decreased with time, drilling rig rental rates have increased. Since most new rigs are constructed for intermediate or deep wells, shallow well costs have increased the most.

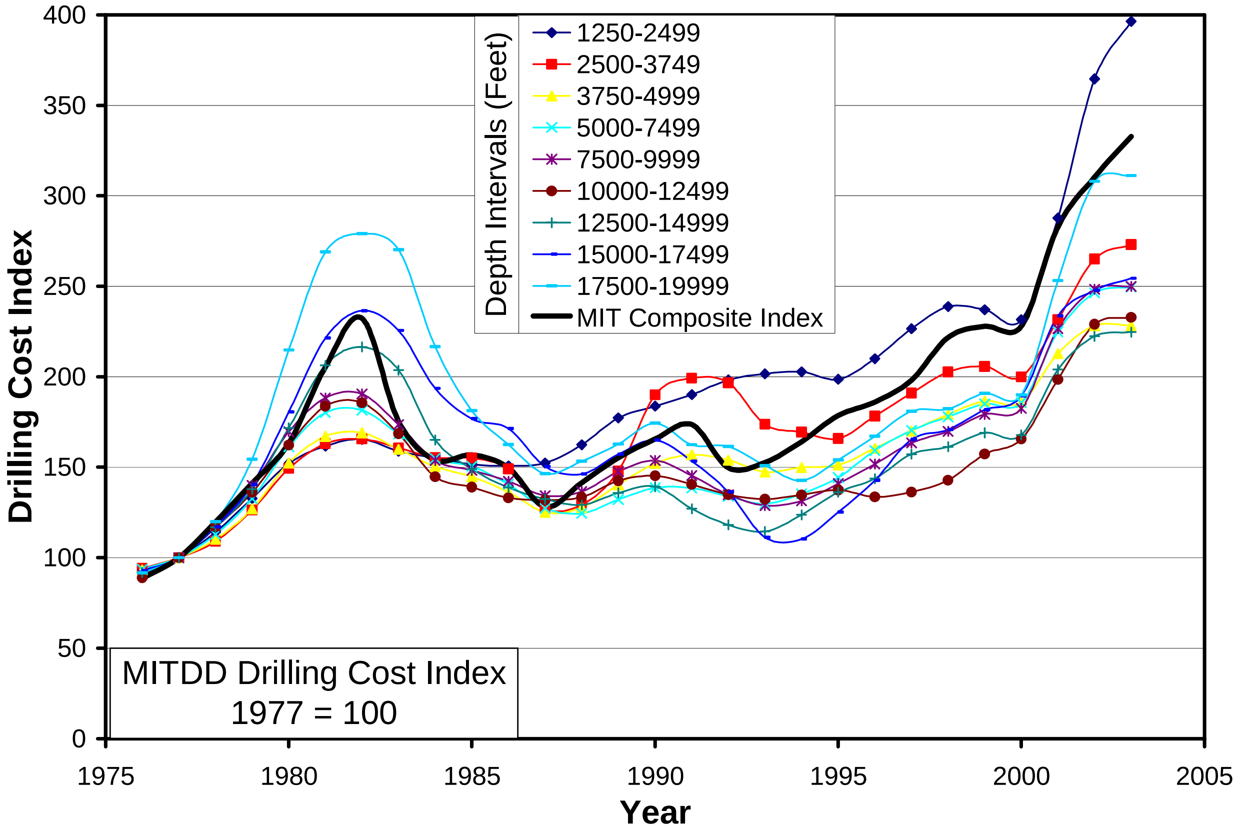


Fig. 5. MITDD drilling cost index made using average cost per well for each depth interval from Joint Association Survey on Drilling Costs (1976-2003), with data smoothed using a three-year moving average (1977 = 100 for all depth intervals, 1 ft = 0.328 m).

This line of reasoning is supported by Bloomfield and Laney (2005), who used similar arguments to relate rig availability to drilling costs. Rig availability, along with the non-linearity of well costs with depth, can account for most of the differences between the previous MIT index and the new depth dependent indices.

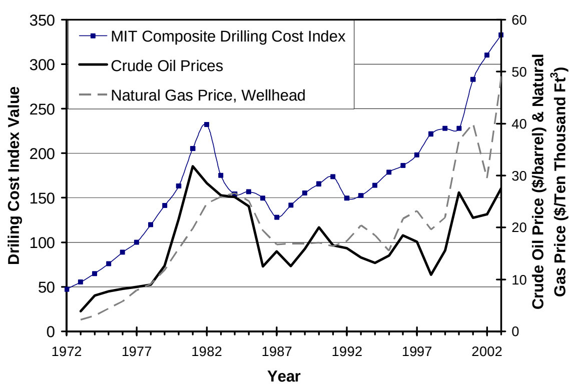


Fig. 6. Crude oil and natural gas prices, unadjusted for inflation (Energy Information Administration, 2005) compared to MIT Composite Drilling Index (see also Fig. 4).

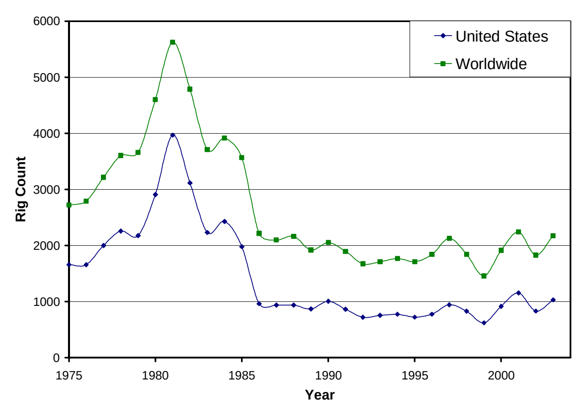


Fig. 7. Average operating rotary drilling rig count by year, 1975-2003 (Baker Hughes, 2005).

The effect of inflation on drilling costs was also considered. Fig. 8 shows the gross domestic product (GDP) deflator index (US Office of Management and Budget, 2005), which is often used to adjust costs from year to year due to inflation, compared to the MITDD drilling cost index. Fig. 8 shows that inflation has been steadily increasing, eroding the purchasing power of the dollar. For the majority of depth intervals, the drilling cost index has only recently increased above their highs in 1982, despite the significant decrease in average purchasing power. Since the MITDD index does not account for inflation, this means the actual cost of drilling in terms of present US $ had actually decreased in the past two decades until recently. This point is illustrated in Fig. 9, which shows the drilling index adjusted for inflation, so that all drilling costs are in year 2003 US $. For most depth intervals shown in Fig. 9, the actual cost of drilling in year 2003 US $ has dropped significantly since 1981. Only shallower wells (1250-2499 feet) do not follow this trend, possibly due to rig availability issues discussed above. This argument is further supported by the drilling cost index for onshore wells from the 2000 JAS report, shown in Fig. 3. The JAS index shows unadjusted drilling costs, costs adjusted so that all years reflect year 2000 drilling activity, and costs adjusted for both year 2000 drilling activity and inflation. The adjustment for inflation further verifies that when inflation is taken into account, the cost of drilling wells has decreased in terms of current US $. This decrease is likely due to both technological advances in drilling wells, such as better drill bits, more robust bearings, and expandable tubulars, as well as overall increased experience in drilling wells.

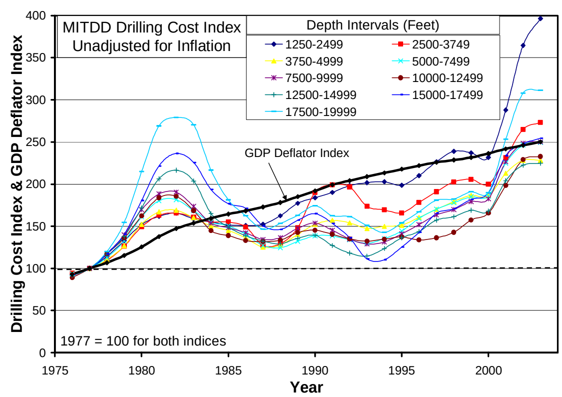


Fig. 8. MITDD drilling cost index compared to GDP deflator index for 1977-2003 (US Office of Management and Budget, 2005).

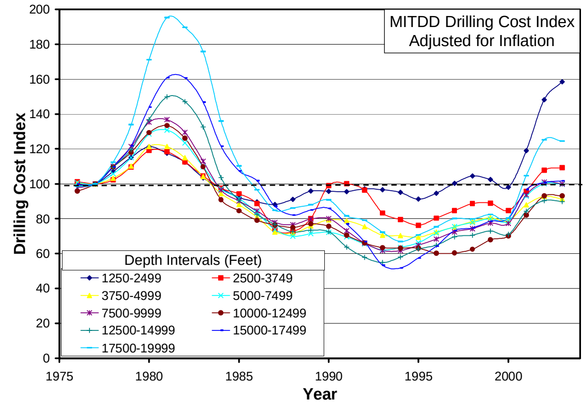


Fig. 9. MITDD drilling cost index made using new method, adjusted for inflation to year 2003 US $. Adjustment for inflation made using GDP Deflator index (1977 = 100).

Updated Geothermal Well Costs

The MITDD drilling cost index was used to update completed well costs to year 2003 US $ for a number of actual and predicted EGS/HDR and hydrothermal wells. Table 3 lists and updates the costs of geothermal wells originally listed in Tester and Herzog (1990) as well as geothermal wells completed more recently. Actual and predicted costs for completed EGS and hydrothermal wells were plotted and compared to completed JAS oil and gas wells for the year 2003 in Fig. 10. Fig. 10 contains the “Oil and Gas Average” trend line and ultra-deep JAS wells included in Fig. 1 and described above. Although actual and predicted geothermal well costs vs. depth are clearly non-linear, no attempt has been made to add a trend line to this data, due to the inadequate number of data points.

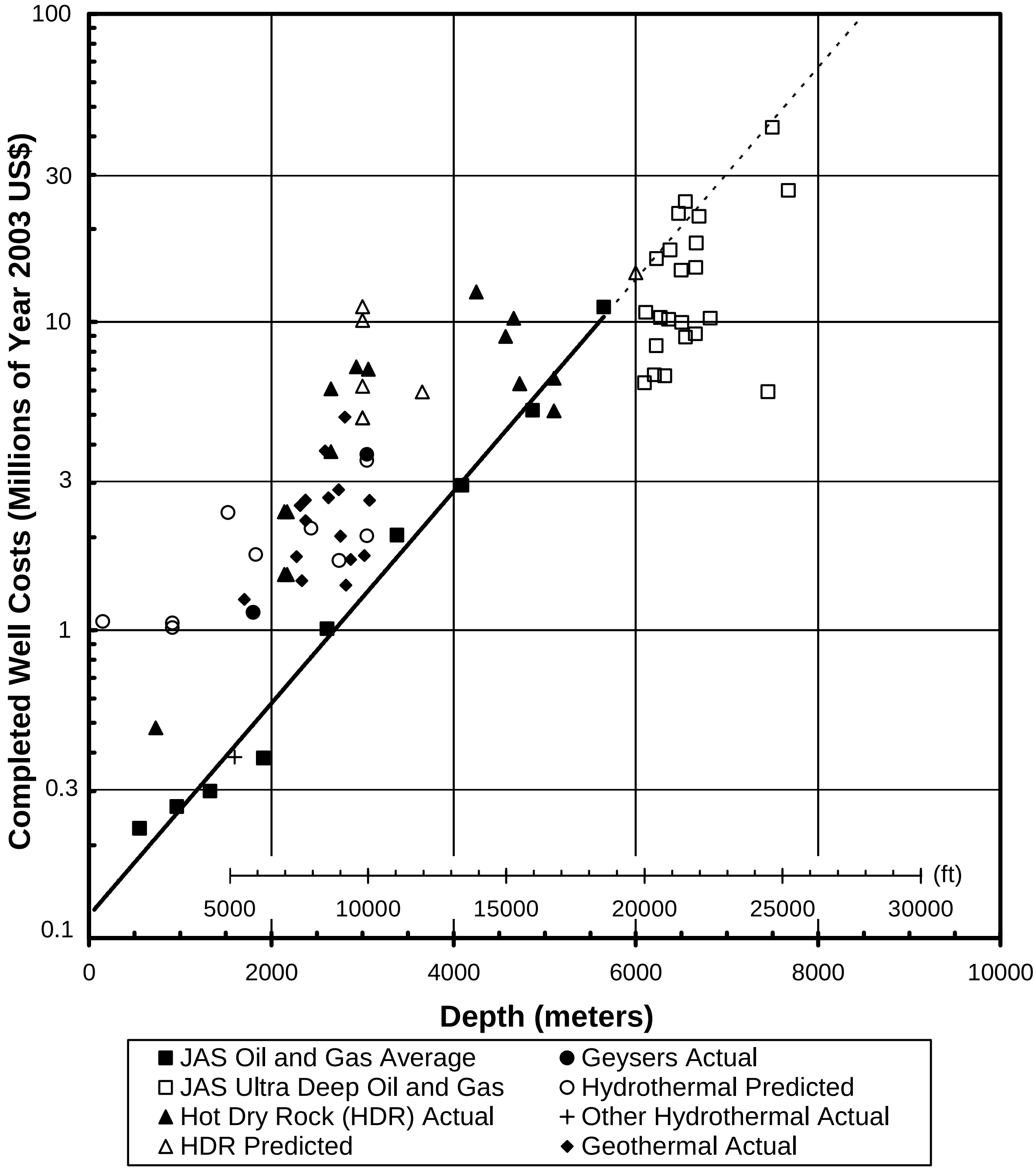
Like oil and gas wells, Fig. 10 shows that geothermal well costs appear to increase non-linearly with depth. However, EGS and hydrothermal well costs are considerably higher than oil and gas well costs – often 2-5 times greater than oil and gas wells of comparable depth. It should be noted that several of the deeper geothermal wells approach the JAS Oil and Gas Average. The geothermal well costs show a lot of scatter in the data, much like the individual ultra-deep JAS wells, but appear to be generally in good agreement, despite being drilled at various times over the last 30 years. This indicates that the MITDD index properly normalized the well costs.

Table 3. Actual and predicted geothermal well drilling and completion costs in year 2003 US $.

Well ID	Depth (meters)	Depth (feet)	Cost When Drilled (M$)	Year Drilled	Cost Year 2003 (M$)	Comments
GT-1	732	2402	0.060	1972	0.48	Fenton Hill Site, New Mexico, USA. Actual Costs (Tester and Herzog, 1990)
GT-2	2932	9619	1.900	1974	7.15	
EE-1	3064	10052	2.300	1975	7.03	
EE-2	4660	15289	7.300	1980	10.28	
EE-3	4250	13944	11.500	1981	12.53	
EE-3a	4572	15000	5.160	1988	8.97	
RH-11 (low)	2175	7136	1.240	1981	1.51	Rosemanowes Site, Cornwall, UK. Actual Costs. (Tester and Herzog, 1990) Low: $1 = 1£ GBP High: $1.6 = 1£ GBP
RH-11 (high)	2175	7136	1.984	1981	2.42	
RH-12 (low)	2143	7031	1.240	1981	1.51	
RH-12 (high)	2143	7031	1.984	1981	2.42	
RH-15 (low)	2652	8701	2.250	1985	3.79	
RH-15 (high)	2652	8701	3.600	1985	6.07	
UK (Shock, 1987)	6000	19685	8.424	1985	14.46	Camborne School of Mines ($1 = 1£ GBP)
Bechtel (1988)	3657	11998	3.359	1987	5.93	Predictions for Roosevelt Hot Springs, UT
Hori et al. (1986)	3000	9843	6.000	1985	10.11	Predicted Costs
Entingh (1987) I	3000	9843	6.900	1984	11.22	Predicted Costs based on Heat Mining
Entingh (1987) II	3000	9843	3.800	1984	6.18	
Entingh (1987) III	3000	9843	3.000	1984	4.88	
Heat Mining (1987)	3000	9843	3.000	1984	4.88	Predicted Costs
The Geysers	1800	5906	0.486	1976	1.14	Actual costs - Milora & Tester (1976)
The Geysers	3048	10000	2.275	1989	3.71	Actual costs - Batchelor (1989)
Other Hydrothermal	1600	5249	0.165	1976	0.39	Actual costs - Milora & Tester (1976)
IM-GEO IV-FL	1829	6001	1.123	1986	1.76	Meridian predictions of hydrothermal wells from their IM-GEO data base (Entingh, 1989). Only base well costs are shown.
IM-GEO IV-BI	2743	8999	0.956	1986	1.68	
IM-GEO BR-FL	2438	7999	1.217	1986	2.14	
IM-GEO BR-BI	914	2999	0.556	1986	1.02	
IM-GEO CS-FL	3048	10000	2.032	1986	3.55	
IM-GEO CS-BI	914	2999	0.576	1986	1.05	
IM-GEO YV-FL	1524	5000	0.906	1986	2.41	
IM-GEO YV-BI	152	499	0.406	1986	1.07	
IM-GEO GY-DS	3048	10000	1.155	1986	2.02	
SNL – Non-US	2317	7603	1.539	1996	2.53	Actual geothermal well costs from Sandia National Laboratories (SNL) (Mansure, 2004)
SNL – Non-US	2374	7789	1.729	1997	2.64	
SNL – Non-US	2377	7800	1.377	1996	2.27	
SNL – Non-US	2739	8986	1.867	1997	2.85	
SNL – Non-US	2760	9055	1.320	1997	2.02	
SNL – Non-US	2807	9210	2.979	1996	4.91	
SNL – Non-US	2819	9249	0.915	1997	1.40	
SNL – Non-US	2869	9414	1.030	1996	1.70	
SNL – Non-US	3021	9912	1.060	1996	1.75	
SNL – Non-US	3077	10096	1.514	1996	2.64	
SNL – US	2277	7471	1.186	1985	1.73	
SNL – US	2334	7658	0.822	1986	1.44	
SNL – US	1703	5588	0.804	1986	1.26	
SNL – US	2590	8496	2.220	1991	3.82	
SNL – US	2627	8618	1.760	1997	2.69	
GPK-3	5101	16731	6.571	2003	6.571	Soultz, France. Trouble costs excluded. (1 USD = 1.13 EUD) (Baria, 2005)
GPK-4	5100	16728	5.14	2004	5.14*	
Cooper Basin, Australia -Habenero 2	4725	15498	6.3	2004	6.3*	Trouble costs excluded. (1 USD = 0.724 AUD) (Wyborn, 2005)

1. M$ = millions of US$.
2. A listing and discussion of the origins of many of the actual and predicted well costs is given in Tester and Herzog (1990).

* Year 2004 data not normalized to year 2003 US$ due to absence of index values.



1. JAS = *Joint Association Survey on Drilling Costs*.
2. Well costs updated to US$ (yr. 2003) using index made from 3-year moving average for each depth interval listed in JAS (1976-2003) for onshore, completed US oil and gas wells. A 17% inflation rate was assumed for years pre-1976.
3. Ultra deep well data points for depth greater than 6 km are either individual wells or averages from a small number of wells listed in JAS (1994-2002).
4. "Geothermal Actual" data include some non-US wells (Mansure, 2004)

Fig. 10. Completed well costs in year 2003 US $ as a function of depth. Well costs are tabulated in Table 3.

GEOTHERMAL WELL COST MODEL

Although the correlation from the JAS data and drilling cost index discussed above allow one to make a general estimate of drilling costs based on depth, they do not explain what drives drilling costs or allow one to make an accurate estimate of drilling costs once more information about a drilling site is known. To do this, a detailed model of drilling costs is necessary. Such a model, called the "WellCost Lite" model, was developed by Livesay and co-workers (Mansure et al. 2005) to estimate well costs based on a wide array of factors. This model was used to determine the most important driving factors behind drilling costs for geothermal wells.

Attributes and Assumptions of the "WellCost Lite" Model

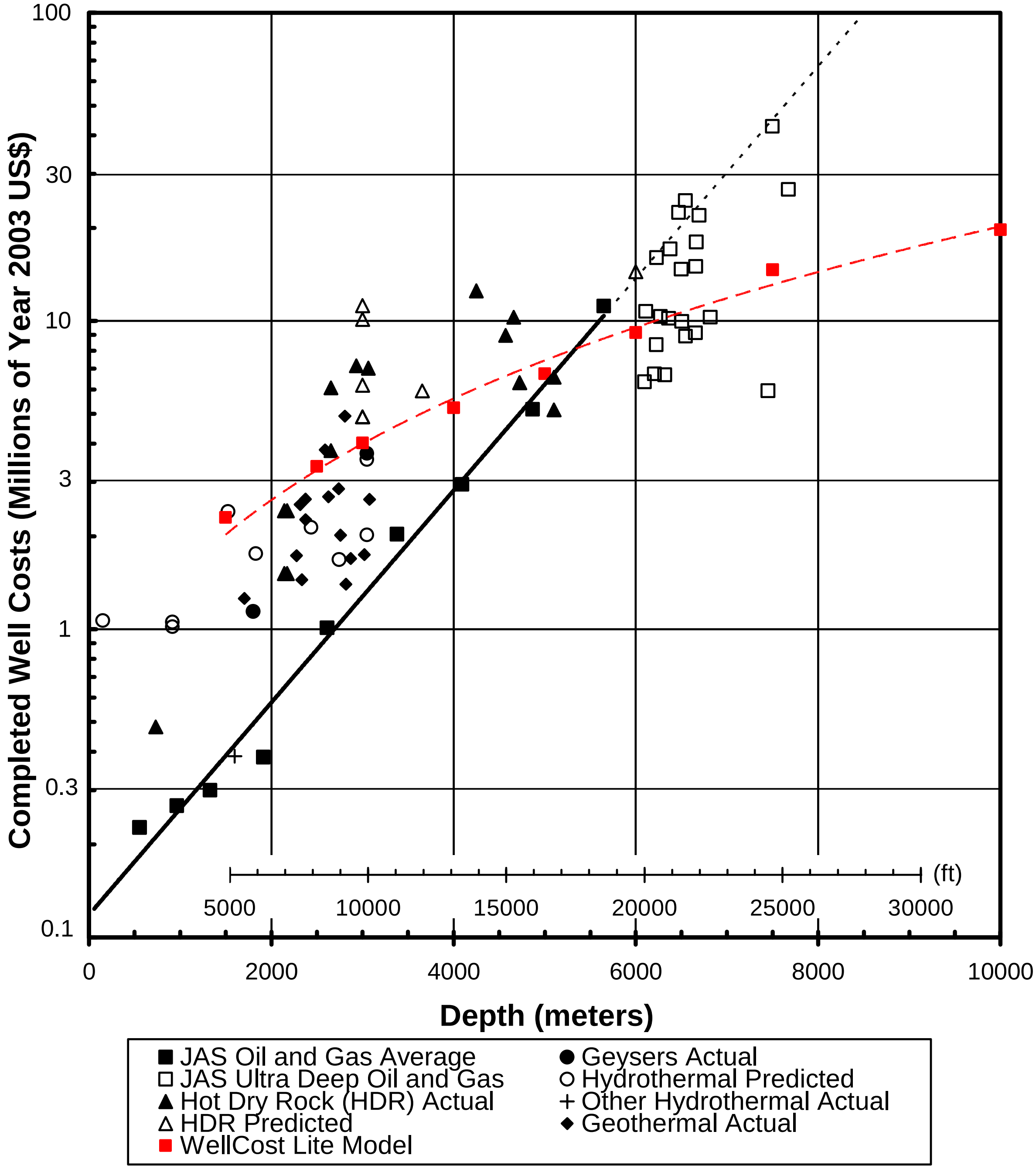
Well drilling costs for oil and gas and for geothermal wells are subdivided into five elements: 1.) Pre-spud costs, 2.) casing and cementing, 3.) drilling - rotating costs, 4.) drilling - non-rotating costs, and 5.) trouble costs. Pre-spud costs include move-in and -out costs, site preparation and well design. Casing and cementing includes the cost of casing and cementing materials as well as running casing and cementing it in place. Drilling - rotating related costs are incurred when the bit is rotating, including all costs related to the rate of penetration such as bits and mud costs. Drilling - non-rotating costs are those costs incurred when the bit is not rotating and include tripping, well control, waiting, directional control, supervision and well evaluation. Costs for trouble during drilling that can not be planned ahead include stuck pipe, twist-offs, fishing, lost circulation, hole stability problems, well control problems, cementing and casing problems and directional problems.

The trouble costs and the drilling - rotating costs are directly related to the geology of the site, the depth of the well and, to a lesser degree, the well diameter. Casing and cementing costs depend on the depth and diameter of the hole as well as the fluid pressures and to some extent the geology encountered during drilling. Non-rotating drilling costs depend on depth and the geology, as it affects bit life and therefore tripping time. The pre-spud costs are related to the rig size which is a function of hole diameter, length of the longest casing string and the depth of the hole.

The difference in geology, hole diameter, well control needs, fluid chemistry, site accessibility and weather can cause very large variations in cost for wells of the same depth. This is much more apparent when the geothermal well cost data in Fig. 10 is considered. Here, most of the costs are for individual wells. They vary in well bore diameter, completion, geology, fluid chemistry and accessibility. For instance, two sources of geothermal well costs were for steam wells in The Geysers and high temperature hydrothermal wells in the Salton Sea area. While most wells at The Geysers are completed with the same casing diameter, the area is known for hole stability and directional control problems related to geologic differences. The Salton Sea, with more uniform geology, requires large diameter wells which use expensive casing materials to produce very high volumes of extremely high TDS, corrosive fluid. As a result, the cost range varies from $1,000,000 to $3,050,000 for the 20 geothermal wells drilled between 7,500 and 9,999 ft.

In order to separate the impact of these geologic and site related differences in the cost of drilling from the factors related to depth, a well costing model was developed (Mansure et al., 2005). The model, WellCost Lite, calculates the cost of drilling by casing intervals. The model is EXCEL spreadsheet based and allows the input of a casing design program, rate of penetration, bit life and trouble map for each casing interval. The model calculates the time to drill each interval including rotating time, trip time, mud and related costs and end of interval costs such as casing and cementing and well evaluation. The cost for materials and the time required to complete each interval is calculated. The time is then multiplied by the hourly cost for all rig time related cost elements such as tool rentals, blow out preventers (BOP), supervision and so forth. Each interval is then summed to obtain a total cost. The cost of the well is displayed as both a descriptive breakdown and on the typical authorization for funds expenditure form used by many companies to estimate drilling costs.

For this paper, the cost of drilling geothermal wells, including enhanced geothermal wells and hot dry rock wells exclusive of well stimulation costs, was modeled for similar geologic conditions and with the same completion diameter for depths between 1,500 m and 10,000 m. The geology was assumed to be an interval of sedimentary overburden on top of hard, abrasive granitic rock with a bottom hole temperature of 200 ^{o}C. The rates of penetration and bit life for each well correspond to drilling through typical poorly lithified basin fill sediments until a depth 1000 m above the completion interval is reached, below which granitic basement conditions are assumed. The completion interval varies from 250 m for a 1500 m deep well to 1000 m for wells 5000 m and deeper. The casing programs used assumed hydrostatic conditions typical for geothermal environments. All the well plans for determining base costs with depth assume a completion interval drilled with a 10 5/8" bit. The wells are not optimized for production and are largely trouble free. For the base case wells at each depth the assumed contingency is 10%, which includes non-catastrophic costs for troubles during drilling.



1. JAS = *Joint Association Survey on Drilling Costs*.
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3. Ultra deep well data points for depth greater than 6 km are either individual wells or averages from a small number of wells listed in JAS (1994-2002).
4. "Geothermal Actual" data include some non-US wells (Mansure, 2004)

Fig. 11. Completed well costs as a function of depth in year 2003 US $, including estimated costs from WellCost Lite Model.

Well Cost Model Results and Discussion

The modeled wells are plotted in Fig. 11 for comparison to the JAS and geothermal well cost data. The estimated well costs fall well within the historical data for geothermal wells for depths below 4,000 m and then cross below average oil and gas well costs above 6,000 m, but are still well within the scatter for ultra-deep wells. The trend line fit to the WellCost Lite predictions was made using a 3 parameter, 2nd order polynomial. The model results, like the JAS oil and gas wells and actual geothermal well data, increase non-linearly with depth. An exponential fit could have been used as well, but the 2nd order polynomial better captures how the model predicts a departure from the rate of well cost increases seen below 5,000 m – 6,000 m for JAS oil and gas and geothermal wells.

Fig. 12 shows the wells modeled over the 1,500 m to 10,000 m interval, along with three actual wells modeled using real rates of penetration and casing programs: RH15 from Rosemanowes, GPK4 from Soultz and Habenero-2 from Cooper Basin. The figure also includes actual costs from GPK4 from Soultz and Habenero-2 from Cooper Basin. This figure shows that the assumed model wells and their costs are representative of actual geothermal wells. It also demonstrates further that model estimates are in line with actual drilling costs.

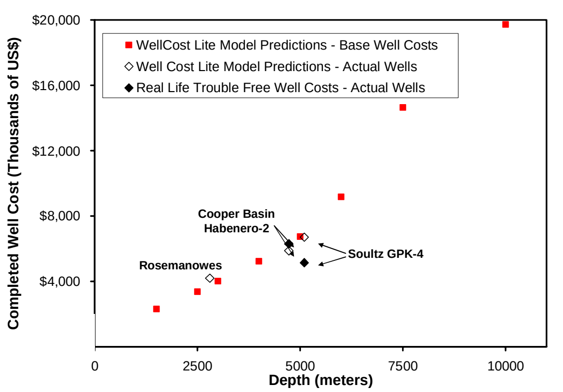

Fig. 12. Estimates of total well costs for EGS wells made using WellCost Lite Model compared to several actual geothermal well cost data.

A comparison of cost breakdown with depth for the five cost centers is shown in Fig. 13. Rotating related drilling costs and casing and cementing costs clearly dominate the cost of the well at all depths, While drilling-rotating, drilling-non-rotating and pre-spud expenses are linear with depth, casing and cementing costs and trouble costs both show a step change in cost at depths greater than 6000 m. This depth is also the point where the well design requires a change from three casing strings and a cemented liner to four casing strings and a cemented liner.

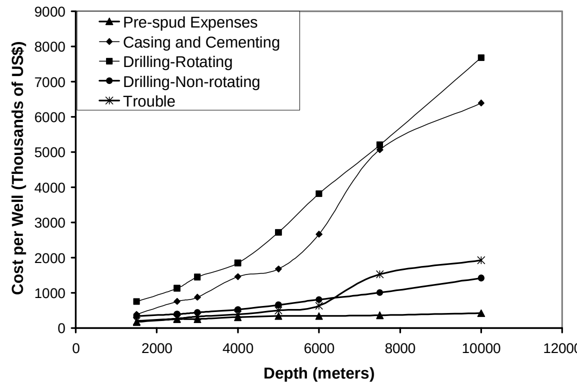

Fig. 13. Breakdown of drilling cost elements vs. depth from WellCost Lite model results.

The effect of the number of drilling strings on completed well costs is further demonstrated in Fig. 14, which shows the cost of wells with the same number of casing strings for different depths. Fig. 14 shows the impact of adding an extra casing string to the well plan at different depths. Increasing the number of casing strings in the 5,000 m well results in an increase in total cost of 18.5%. Increasing the number of casing strings from 5 to 6 results in a 24% increase in well cost. As the number of casing strings increases, the slope of the line fit to well costs vs. depth increases about 18% for each extra string.

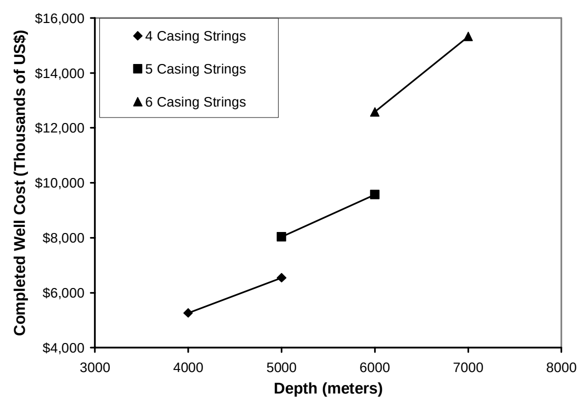

Fig. 14. Change in WellCost Lite model estimates vs. depth and number of casing intervals.

Adding extra casing strings adds significantly to cost if the bottom hole diameter is to be maintained. For instance, for a geothermal well to maintain the 9 5/8" completion needed for high flow rates at low pressure drop, the surface casing for a 10,000 m hole must be 42" in diameter. As casing strings are added, the costs of all drilling equipment must increase if the completion size is to remain the same since the rig and tools, pumps and compressors must increase in size to handle the larger casing. Well head well control equipment must also increases in size to fit the larger casing.

Typically, oil and gas wells are completed using a 6 ¾" or 6 ¼" bit and then lined or cased with 4 ½" or 5" casing which is almost always cemented in place, then shot perforated. Geothermal wells are usually completed with 10 ¾" or 8 ½" bits and 9 5/8" or 7" casing or liner which is generally slotted or perforated, not cemented. The upper casing strings in geothermal wells are usually cemented all the way to the surface to prevent undue casing growth during heat up of the well, or shrinkage during cooling from injection. Oil wells, on the other hand, only have the casing cemented at the bottom and are allowed to move freely at the surface through slips. The higher costs for larger completion diameters and cement volumes may explain why in Fig. 10 well costs for many of the geothermal wells considered, especially at depths below 5,000 m, are 2-5 times higher than typical oil and gas well costs.

This trend of higher geothermal well costs than oil and gas well costs at comparable depths may not hold true for wells beyond 5,000 m in depth. In oil and gas drilling, one of the largest variables related to cost is well control. Pressures in oil and gas drilling situations are controlled by three methods: drilling fluid density, well head pressure control equipment and well design. The well design change that is most significant when comparing geothermal costs to oil and gas costs is that extra casing strings are added to shut off high pressure zones in oil and gas wells. While over pressure is very common in oil and gas drilling, geothermal wells are most commonly hydrostatic or underpressured. The primary well control issue is temperature. If the pressure in the well is reduced suddenly and very high temperatures are present, the water in the hole will boil, accelerating the fluid above it upward. The saturation pressure along with significant water hammer can be seen at the wellhead. Thus the biggest method for controlling pressure in geothermal wells is by cooling through circulation. The need for extra casing strings in oil wells as depth and the risk of over pressure increases may cause the crossover between JAS oil and gas well average costs and WellCost Lite predicted geothermal well costs seen in Fig. 11 at 6,000 m. Since no known geothermal wells have been drilled to this depth, a cost comparison can not be made.

Rate of penetration (ROP), which is controlled by geology and bit selection, governs the rotating drilling costs associated with making the hole. Geothermal wells are typically drilled in hard, abrasive high temperature formations which reduce rate of penetration and bit life and in turn control the non-rotating drilling costs by increasing the need for bit trips. However, in most geothermal and potential EGS sites there will at least be some sedimentary overburden before the crystalline basement rock is reached. In oil and gas drilling there are sometimes very hard formations, or very soft and sticky shales which both slow the rate of penetration. However, for the most part, geothermal and EGS rates of penetration and bit lifes are lower than those found in oil and gas drilling. In the last 15-20 years dramatic improvements in bit design have resulted in very large improvements in rate of penetration even in hard, high temperature environments. Fig. 15 compares rotating time and tripping time for the wells modeled using the WellCost Lite model. Note that both rotating and tripping hours are nearly linear with depth for these wells, assuming constant ROP and bit life with depth. However, the assumed constant ROP and bit life may not be realizable to the depths considered in the model.

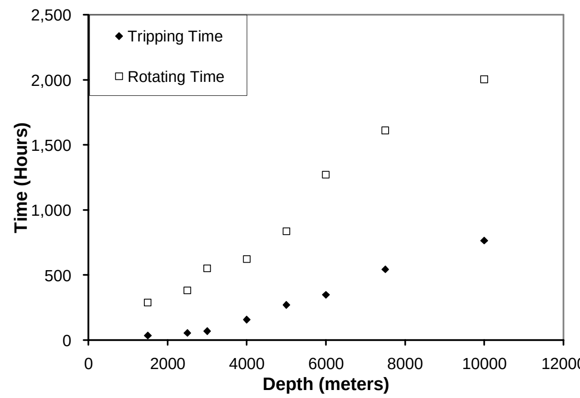

Fig. 15. Comparison of rotating and tripping hours vs. well depth from WellCost Lite Model.

Fig. 16 shows the impact of increasing rate of penetration on total well cost. The total cost of a 4,000 m well was recalculated for four different ROP maps ranging from a medium rate of penetration, such as that encountered in a sedimentary basin, to a very low rate of penetration from top to bottom as would be expected in an area with hard, crystalline basement at the surface. The medium ROP corresponds to drilling at Dixie Valley with a thick layer of poorly lithified basin fill overlying hard crystalline basement rock while the very low corresponds to drilling conditions at Rosemanowes in Cornwall, UK. In all cases, the assumption was made that the best possible bit using current technology was chosen for each interval. While the ROP for the wells in Fig. 16 increased an average of 83% from the lowest case to the highest ROP case, the maximum cost difference from very low to medium ROP was only 20%.

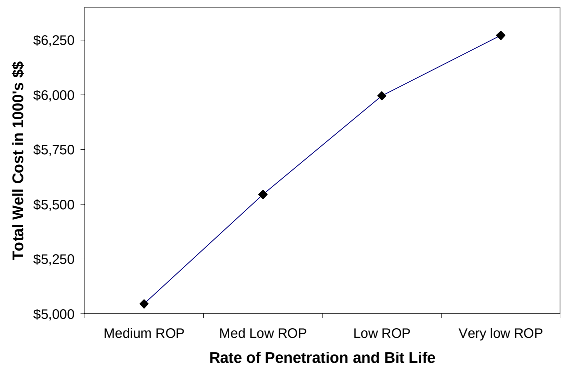

Fig. 16. Completed well costs from WellCost Lite model vs. various rates of penetration.

CONCLUSIONS

The major factors controlling the costs of drilling wells are the well depth, diameter, casing design, and location specific characteristics. Completed well costs data from the JAS drilling reports for the last 30 years show that normalized drilling costs for onshore, completed US oil and gas wells increase non-linearly with depth, and this increase can be adequately described using a two parameter exponential fit of well costs to depth for the depth intervals considered. A new drilling cost index called the MIT Depth Dependent (MITDD) index was created using JAS data in order to update the EGS and hydrothermal well cost data to year 2003 US dollars. The new index consists of a 3-year moving average of the average per well cost for onshore, US oil and gas wells for each depth interval given in the JAS report. The new index is superior to earlier weighted indices that can over predict well costs by up to 30%. Differences between indices are driven by fluctuations in crude oil prices, which in turn drive rig availability. They are also directly related to the inherent non-linear nature of well cost increases with depth. The MITDD index shows that when adjusted for inflation, well costs have actually decreased in the past 30 years for all depths greater than 2500 feet (760 m).

The MITDD index was used to update actual and predicted geothermal well costs from the past 30 years. Despite similar trends, the cost of drilling and completing HDR and hydrothermal wells is considerably more expensive than for oil and gas wells over the depth intervals considered. As Fig. 10 shows, the cost of geothermal wells is often 2-5 times greater than the cost of oil and gas wells of comparable depth.

Well costs were predicted for geothermal wells between 1,500 m and 10,000 m using the WellCost Lite model. The predicted costs vary non-linearly with depth and can be adequately modeled using a 3-parameter, 2^{nd} order polynomial in depth. In general, above 6,000 m of depth, predicted geothermal well costs fall below the extrapolated JAS average well cost line which increases exponentially with depth. The model predicted geothermal well costs are comparable to actual geothermal well costs. Results show that rate of penetration related costs and the cost of casing and cementing are the most significant factors in drilling costs, and that these costs grow more important with well depth. The cost of adding extra casing strings to a well design was also examined and found to have a very strong influence on drilling costs. An extra casing string caused a stepwise increase in the drilling cost of about 18% - 24% between two wells of the same depth. Using realistic ROP, a comparison was made between drilling with a high ROP and a low ROP and a 20% decrease in total cost was found by using the high ROP.

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