A Hedonic Cost Study of Well Drilling and Completion Costs in Western Canada

by Andy Baldwin
Input-Output Division

Abstract:

Exploratory and development drilling constitutes an important component of expenditures on non-residential construction in Canada, and particularly in Western Canada, where the majority of activity is located. Therefore, it is important that changes in drilling costs be measured precisely so that changes in the volume of activity can be distinguished from changes in spending due to cost pressures. This paper uses the Well Cost Studies for 1994 and 1995 to perform hedonic cost regressions for Western Canada over this period. It was found that drilling costs increase disproportionately with depth, although the hypothesis that drilling costs increase proportionately with depth could not be rejected. Sour wells are significantly more expensive to drill than sweet wells. The northern part of B.C. and Alberta and the foothills region were found to be the most expensive areas to drill in, southwestern Saskatchewan the least expensive.

Hedonic price indexes for drilling costs were calculated in two ways, first by taking the exponent of the year dummy variable from the regression equation as the index number, and otherwise by calculating a matched-model index for wells, with the index number from the first approach proxying the price movement for 1995 wells with no match in 1994. Both methods yielded comparable results, indicating an increase between 1.3% and 2.1% in drilling and completion costs in 1995.

NAED Drilling Deflator

The annual movement for the NAED (National Income and Environment Division of Statistics Canada) deflator for exploratory and development drilling, which is also used by Input-Output Division (IOD), is obtained from Gary Howe of the Alberta Department of the Treasury, who in turn gets his estimate from Roger Soucy of the Petroleum Services Association of Canada (PSAC). The source of the annual estimate has been the well cost studies commissioned by PSAC, and produced by Winterhawk Petroleum Consulting Services Ltd of Calgary (hereafter Winterhawk).

Table 1: Comparison of Measures of Oil & Gas Well Drilling Costs

	1990	1991	1992	1993	1994
NAED deflator	118.1	119.1	119.1	122.3	122.4
% change		0.8	0.0	2.7	0.1
Average cost/m.	$369	$370	$322	$383	$351
% change		0.3	-13.0	18.9	-8.4
Average cost/well	$439,207	$452,117	$396,045	$406,546	$406,847
% change		2.9	-12.4	2.7	0.1

Source: internal IOD listing; PSAC's *Midstream '95 Activity Update, May 1995*

As can be seen from Table 1 above, the NAED deflator doesn't match the movement of either average cost per well drilled (last row) or average cost per metre drilled (second row), although in 1993 and 1994 it shows the same increases as the unit cost per well and in 1992 it shows only a slightly smaller decrease from the unit cost per well. This is because Roger Soucy will not always use the movement of the unit cost of wells as the drilling cost measure, but will adjust that estimate if he thinks changes in the mix of wells make it inappropriate.

The purpose of this paper is to explore how a matched models or hedonic index approach might be used to obtain an alternative drilling cost deflator using the same data. The hedonic cost approach is also of interest because it permits the testing of hypotheses concerning exploratory and development drilling such as the relationship between drilling costs and depth. To the best of my knowledge, this is the first study that has used this rich source of information to try to find out what is driving costs of drilling oil and gas wells.

Data

The data used come from the *Well Cost Study* for 1994 and 1995. These studies have been conducted every year by Winterhawk for the PSAC from 1982 forward, except for

1988 and 1992. The original 1982 study covered only British Columbia and Alberta. All other studies have included wells from all four provinces of Western Canada.

The *Well Cost Study* divides Western Canada into 12 areas for the purpose of sampling wells. These areas do not correspond to the 10 standard Potter-Liddle areas, which have been used in other studies of the Canadian petroleum industry, for example, Uhler and Eglington[1986]. The Potter-Liddle areas were considered quite unacceptable for a study of drilling costs since the same area may contain wells that are drilled to 1,000 feet and wells that are drilled to 18,000 feet.

The 12 areas of the *Well Cost Study* were not defined by geological formations or plays, because the same play, if it covers a large area, may have quite different drilling costs from one area to another. The Cardium play, which contains the huge Pembina field, is found in central Alberta but also in Alberta's northern foothills, where it is much more expensive to drill.

Instead, areas were defined more according to whether their wells were shallow or deep, and whether they contained light or medium crude oil, heavy crude oil or gas.
For example, area 1 contains mostly deep wells with sour gas, area 2 is also mostly sour gas and there is a lot of seasonal drilling in this area, area 3 is mostly sweet gas and area 4 is mostly wells for heavy oils.

It would have been possible to cross-classify wells in terms of geographic area with wells in terms of geological epoch but this could become unwieldy. Uhler and Eglington note that for Alberta alone cross-classification of the Potter-Liddle areas with areas based on geological horizons yields a potential 100 areas.[i] One of the tasks of the present study is to establish if geological horizon seems to explain drilling costs independently of geographical area or other variables such as drilling depth.

Table 2: Breakdown of Areas for the Well Cost Study 1994 and 1995 by Province

Area	B.C.	Alta	Sask.	Man.
1	x(95)	x		
2		x		
3		x		
4		x	x(94)	
5		x		
6		x		
7		x		
8	x			
9			x	
10			x	
11			x	
12				x

x indicates that part of a particular province belongs to the designated area.

The areas have not been delineated the same way from 1982 forward, and have been altered slightly even from 1994 to 1995. The areas used in the *Well Cost Study 1994* and the *Well Cost Study 1995* do not cross provincial boundaries except for area 1 in 1995 and area 4 in 1994 (see Table 2 below). Area 1 as defined by the 1995 study is mainly in Alberta (it includes Banff and Jasper National Parks) but extends into eastern B.C., taking in part of what was region 8 in the 1994 study. The effect of the change is to reallocate the very deep and expensive Sukunka well from area 8 to area 1, a logical change since in 1994 the only well surveyed in area 1 was the Jumping Pound West well, with the highest cost of any well in the sample. There was no other well in the 1994 study that was even half so expensive as these two. There were no wells surveyed in Saskatchewan in 1994 for area 4 so the change in definition of area 4 did not change the area code of any wells in the sample.

The data on wells drilled comes from the *Daily Oil Bulletin.* Winterhawk chooses one or more wells from an area based on scatterplots of all wells drilled within an area against their depth in metres and the number of days over which they were drilled (which is highly correlated with costs), and consideration of other variables. Generally, Winterhawk tries to sample wells that are representative of their areas, or at least wells that are not outliers, but ***they*** also try to obtain a representative sample of wells for Western Canada as a whole. For example, in 1994 there were 129 re-entry horizontal wells drilled in all of Western Canada, so this is hardly a typical well in any area. Nevertheless a re-entry horizontal well was sampled in area 5 since they are a significant and growing part of drilling activity in Western Canada.

The horizontal wells sampled were chosen in areas where there is substantial horizontal drilling activity. The re-entry horizontal well is in Alberta but the other two horizontal wells are in Saskatchewan, where the formations are conducive to horizontal drilling, that is, flat and relatively unfaulted. By contrast, many of the oil-bearing areas of Alberta are hilly and heavily faulted, so that when one drills horizontally one may easily drill out of the oil-bearing formation, and they are also often friable, which makes drilling difficult. Also, there is not much pinchout in Saskatchewan, whereas there is a lot of it in Alberta.[ii]

One of the horizontal wells in the 1995 study is also an underbalanced well. Underbalanced drilling is a technology developed in western Canada, generally but not invariably used in drilling horizontal wells, which substantially increases drilling costs but can also dramatically improve the recovery rates from a formation.

Choice of Explanatory Variables

For non technical reader, may be you should write first the equation and tell what the philosophy of hedonic pricing is and how it is based on the use of dummies representing the qualitative variations.

Dummies were included for gas wells, with the intercept representing oil wells, and sour oil or gas wells, with the intercept representing sweet oil or gas wells. There was no attempt to test for interaction effects, to see if, for example, sour gas wells were more expensive to drill but not sour oil wells. One would expect sour wells to be more expensive to drill than sweet wells, and they are certainly more dangerous to drill, since exposure to hydrogen sulphide is potentially lethal.

There were 11 area dummies in the stepwise regression, based on the area definitions of the 1995 *Well Cost Study* rather than the slightly different definitions of the 1994 study. Area 12 (southwestern Manitoba) was the omitted dummy.

The wells can be grouped according to their geological epoch, which is a common distinction made in economic analysis of the petroleum industry (see, for example, the study by Conn and Christie[1987]). This gives a set of dummy variables that are distinct from but highly correlated with the depth of drilling, since the more ancient the epoch, the deeper the oil-bearing formation. The relationship between age and depth is, however, not uniform. For example, the Devonian stratum is about 1,000 feet thick, but it tilts upwards from west to east so a well to an oil-bearing Devonian formation in British Columbia might be 11,000 feet deep, while a similar well in eastern Alberta might be only 8,500 feet deep.

The relevant epochs are, from earliest to most recent:

1. Devonian,
2. Carboniferous,
3. Permian,
4. Triassic,
5. Jurassic,
6. Cretaceous.

These epochs can be subdivided, and some of them are known under different names. For example, the Manitoba Energy and Mines Department indicates that the Bakken formation belongs to the Mississippian epoch rather than to the early Carboniferous.[iii] The naming of the epochs shown above conforms to the usage of the Geological Survey of Canada.

To some extent, the industrial structure for drilling in formations for the different epochs is different. Smaller firms tend to drill in the Cretaceous formation, which tends to be lower profit but also lower risk than the deeper formations. The highest rents on resources probably come from the Devonian deposits, which are typically reef structures, very porous and under high pressure. At the same time, the massive capital investment required to drill to these deposits means that only larger companies are likely to drill to them.

There were no observations in either year for wells drilled to Permian formations so dummy variables represented the Devonian, Triassic, Jurassic and Cretaceous epochs, with the Carboniferous epoch represented by the intercept term. The Carboniferous was the omitted dummy in the stepwise regression because area 12 (Manitoba) was the omitted area dummy and the Manitoba oil-bearing formations are Carboniferous. Thus the intercept term can be thought of as representing the cost of drilling a sweet oil well in southwestern Manitoba.

For directional and horizontal wells there is a distinction between the depth of a well (DEPTH) and the metres drilled, which are identical for ordinary (i.e. non-horizontal, non-directional) wells. Directional wells are drilled in a straight line but at an angle from a vertical plane. Horizontal wells, as the name suggests, at some depth are drilled almost at a right angle to the vertical plane. For both types of wells, the total metres drilled for a well exceeds its total vertical depth. For example, for the underbalanced horizontal well in Weyburn, Saskatchewan used in the 1995 study, there were 2,500 metres drilled but the well was just 1,400 metres deep.

The directional drilling and horizontal drilling technologies have only recently become important, and to my knowledge, this is the first econometric study that has attempted to take account of them.

In the *Well Cost Study* the same directional well is to be found in both annual samples, costed assuming that it is one of four directional wells drilled from a single drilling pad. Many of the cost components, including rig transport, and road and site preparation are reduced when several wells are drilled from a single pad, since these costs are shared between all the wells in the pad. A single directional well is more expensive to drill in terms of cost per metre than a single vertical well, but this is not necessarily the case for a pad-mounted directional well. In fact, the directional well in the *Well Cost Study* has a lower cost per metre drilled than the comparable non-directional well from the same area with the same vertical depth, whether one considers the drilling subtotal only, or total drilling and completion costs.

The horizontal wells in the sample consist of six new-drills and two re-entries. A horizontal re-entry is "an older vertical well re-entered and extended horizontally".[iv] There are more of these wells being drilled every year in Western Canada, since they allow improved recovery rates from existing oil fields.

The re-entry horizontal well in the 1995 sample was drilled from a 1,750m depth in an existing vertical well for an additional 250m. This took the well to a vertical depth of 1850 metres, or 100 metres vertically downward from the starting point. From this one could calculate that if drilled in a straight line the horizontal well would have been drilled at an angle of 66.4° from the vertical. However, by definition, a horizontal well is drilled at an angle of no less than 80° from the vertical, but it curves gradually from the vertical plane towards the horizontal plane.[v] For the re-entry horizontal well in the 1994 sample, there is no indication what were the actual number of metres drilled, and what was the kick-off point for the well (the point at which the well departed from the vertical plane).

Impact of Depth on Drilling Costs

This paper does not deal with offshore wells. Generally the *Well Cost Study* for a given year is limited to onshore wells drilled in Western Canada, although the 1996 study will incorporate offshore wells drilled off the East Coast. The relationship between drilling costs and depth for such offshore wells is much different from onshore wells, firstly, because the costs themselves are much greater whatever the depth to be drilled to, and second, because the depth of water also has an important impact on drilling costs independent of drilling depth.

Livernois, in his doctoral thesis on oil extraction, assumed that the relationship between drilling depth (D)and drilling cost (C) is of the type:

$$C = \beta_0 D^{\beta_1} \text{ or } \log(C) = \beta_0 + \beta_1 \log(D) \qquad (1)$$

which argues for fitting a double-log equation to the data, as was done in this study.[vi] The double-log form has the additional advantage that since both costs and depth are expressed as logarithms, it is unlikely that the assumptions of OLS estimation will be violated due to heteroskedastic disturbances, and in fact the assumption of homoskedasticity was accepted for all equations calculated.[vii] Nevertheless, an interesting followup to this study would involve testing for functional form, here assumed to be double-log.

Franklin M. Fisher, in one of the earliest econometric studies of the oil industry, postulated a relationship between variable drilling costs and depth of the type

$$C = \beta_0 (e^{\beta_1 D} - 1) \qquad (2)$$

which is non-linear, and cannot be fitted using OLS.[viii] This equation falls out of the following assumed relation between changes in variable costs and depth

$$dC / dD = H + \beta_1 C \qquad (3)$$

where $H>0$ is the limit on marginal cost as it goes to zero. Note that if $H\approx 0$ then the appropriate functional form is semi-log and the cost equation can once again be estimated using OLS.

Returning to the adopted double-log equation, if $\beta_1 = 0$ then costs are identical for shallow wells and deep wells, depth having no independent influence on costs, and the intercept coefficient β_0 is then simply the geometric mean of the drilling costs for the wells in the sample. Of course, such a relationship between depth and cost is not of this world, especially for land-based wells such as those in the present sample. However, this is the implicit assumption that SNA makes in basing the movement of the drilling cost deflator on the unit cost for oil and gas wells, even though there are changes in the depth of wells included in the *Well Cost Study* from one year to another.

Generally one would expect β_1 to be close to but in excess of one. If $\beta_1 \approx 1$ then the intercept coefficient β_0 is approximately equal to the drilling cost per metre. However, there are good reasons to believe that drilling costs per metre will increase with depth (i.e. there are diminishing returns to scale with depth) , because larger and more expensive rigs are required to drill deep wells than shallow wells, and these rigs have greater installation costs. Also, it takes more ***more*** time to trip in and out of wells the deeper they are (i.e. to hoist pipe out of and return it to the well-bore, like when a drill bit is being replaced). Using Fisher's equation (2), a positive value for β_1 is consistent with diminishing returns to scale with depth, and this was what he found. Livernois is agnostic on the issue, only stating that a reasonable range for the parameter value is from 0.9 to 1.3.[ix]

Adelman and Ward, working with a combined sample of onshore and offshore wells from Louisiana, used two different non-linear specifications to derive cost equations, taking care to allow for both different intercepts and different interactions with depth for onshore and offshore wells. For both functional forms, costs that vary with depth were found to increase disproportionately with depth, however, the cost per well independent of depth was very substantial. Predicted total cost per metre drilled actually declined with depth over the wells in the sample up to a depth of 1,400 to 2,000 metres and only increased with depth beneath those levels.

Paul G. Bradley in his study on Alberta natural gas wells decomposed drilling costs into contractor and non-contractor costs. Three different equations were estimated, with depth as the sole explanatory variable in each. For contractor costs, daily rental rates were modelled using a linear equation, and drilling days using a quadratic equation. Bradley's results indicate that Daily rental rates increase less than proportionately with depth, while drilling days increase less than proportionately with depth initially, but disproportionately for wells deeper than 880 metres. Consequently, contractor costs per metre start increasing after about 690 metres. Non-contractor costs associated with depth were modelled using Fisher's equation (1), and increase disproportionately with depth for all wells, however total non-contractor costs per metre are only increasing for wells deeper than 2,000 metres. Finally, total drilling costs per metre increase only for wells deeper than 1,750 metres, which is within the 1,400 to 2,000 metre range indicated by Adelman and Ward's equation.

A recent CERI study provides the only empirical cost estimates I have been able to find for horizontal wells. In 1993 dollars, the study estimates a linear relationship between cost and depth for vertical wells:

$$C = 163{,}300 + 139.2 * D \qquad (4)$$

and a similar equation relating cost to depth and the length of the horizontal segment of the well for a new-drill horizontal (L):

$$C = 1.25 * [163{,}300 + 139.2 * (D + L)] \quad (5)$$

Finally, for a re-entry horizontal, the cost equation used is:

$$C = 2.50 * [44{,}100 + 41.6 * (D + L)] \quad (6)$$

In equations (5) and (6) D stands for the total vertical depth of the horizontal well and not the depth of the well at the kick-off point.

A report of the National Energy Board states that "at present, a typical horizontal well costs somewhat less than two corresponding vertical wells, while a horizontal re-entry well costs approximately the same as a new vertical well"[x]. Using the above equations and the Petroleum Recovery Institute's standardized horizontal well length of 501 metres, a new-drill horizontal well 1,000 feet deep costs 1.54 times as much as a vertical well drilled to the same depth, and a horizontal re-entry well costs 0.88 times as much as a new vertical well, or in line with the NEB statement. If the depth of the typical well is kept constant, while the horizontal well length is increased, the cost ratio rises substantially: a new-drill horizontal well 700 metres long costs 1.65 times as much as a vertical well drilled to the same depth.

Equations Estimated

Separate equations were estimated for

1. the drilling subtotal of costs,
2. total drilling and completion costs.

The equation for the drilling subtotal of costs can be considered as an equation for exploratory drilling costs, since most exploratory wells are dry holes and are not completed. The equation for total drilling and completion costs can then be considered as an equation for development drilling.

Given this framework, all directional wells and horizontal wells were excluded from the sample for the drilling subtotal regressions, since these are invariably development wells. However, for other purposes it would be interesting to calculate equations for the drilling cost subtotal that would include other types of wells besides vertical wells, and this would make a useful extension of the present study.

For the total costs equation, initially vertical wells and directional wells were included in the sample, with the sample later restricted to exclude directional wells, and expanded to include horizontal wells.

Weighting of Individual Observations and Adjustment for Outliers

Ideally, one would reweight the observations in the two samples to make them more representative of exploratory and development drilling respectively, but for these initial estimates, no attempt was made to do so. Table 3 shows the actual provincial distribution of exploratory and development drilling within Western Canada in 1994, as compared to the values from the Well Cost Study used in regression equations for the drilling subtotal and total costs for the same year. What stands out in Table 3 is that British Columbia has a much more important share of exploratory drilling expenditures than development drilling, while the opposite is true for Saskatchewan and Manitoba. British Columbia is overweighted in both equations, mainly due to a single influential observation (the Sukunka gas well), causing Alberta to be underweighted in all equations and Saskatchewan to be underweighted in the total cost equations. Manitoba is overweighted in all equations, as is almost inevitable in a sample of this size (there is only one Manitoba well priced for the *Well Cost Study*).

Table 3: Exploratory and Development Drilling Expenditures in Western Canada, 1994 (in millions of dollars)

	Exploratory			Development		
	Value	%	WCS %	Value	%	WCS %
British Columbia	353.3	17.6	29.0	296.1	8.3	24.0
Alberta	1,550.9	77.2	67.2	2,763.5	77.8	68.0
Saskatchewan	101.8	5.1	2.8	473.0	13.3	6.9
Manitoba	3.5	0.2	1.0	19.8	0.6	1.1
Western Canada	2,009.5	100.0	100.0	3,552.4	100.0	100.0

Some observations frequently showed up as outliers in the regression equations, where an outlier is defined as an observation with a studentized residual that is significant at the 5% or 1% level. The Brazeau River well, the deepest well drilled in the 1995 sample, generally had its costs significantly underpredicted, which is additional evidence that the impact of depth on costs is more substantial than the equations indicate. For an earlier specification that omitted any epoch dummies, the Brazeau River observation was excluded as an outlier only to find that another observation had now become an outlier based on the same criterion. Its exclusion caused a substantial decline in the value of the depth coefficient.

The Jenner well, found in both the 1994 and 1995 samples, was completed with a coiled tubing unit rather than a conventional service rig, which is perhaps why its costs were substantially underpredicted in every equation. Perhaps a dummy variable should have been assigned to this type of well, but there was only one well of this kind in each year's sample.

Finally, no observations were discarded from the regressions as outliers. This was partly to preserve degrees of freedom, stretched to the limit as it was, but mainly because Winterhawk Consultants had carefully chosen these wells based on scatterplots of all wells as representative of their areas, so it would seem counterproductive to delete any of them from the sample. An additional consideration was that the outlying values were invariably for Alberta wells, and their deletion from the sample would have left an unweighted sample very badly underrepresenting the main oil-producing province.

Analysis of Covariance

Table 4 shows the results of the principal equations tested. Standard errors are shown in brackets beneath the coefficient values. In all equations, the drilling costs were expressed as logarithms.

Stepwise regressions were calculated first for a drilling subtotal equation based on vertical wells only and a total costs equation based on vertical and directional wells only. The stepwise procedure chose explanatory variables for the total cost equation using a depth variable defined as metres drilled rather than total vertical depth, which only affected the two observations in the dataset related to pad-mounted directional wells.

Separate regressions for the years 1994 and 1995 were run based on the same variables chosen by the stepwise procedure for the pooled sample and an analysis of covariance indicated that the assumption of unchanged slope coefficients between the two years was acceptable.

An F test run on total cost regressions estimated with and without the two pad-mounted directional wells supported the assumption of common structure for directional and vertical wells. Surprisingly, analysis of covariance also indicated that there was common structure between the new-drill horizontals and the other wells in the sample, so that it was legitimate to calculate a single equation for both. There is no way to calculate separate equations for directional wells or for horizontal wells separately because there are so few observations.

Modelling of Total Metres Drilled

In modelling the total cost equations that included non-vertical wells, I first tried to include both total vertical distance and metres drilled as variables, but this did not give good results. For 55 of the observations the two variables are identical, and for the two directional wells the differences between their values are not great. In a stepwise regression where one of the variables is forced to be included, the other variable will not be chosen. If both are entered, then essentially the value of the depth coefficient is just shared between the depth and total metres drilled variables, so high is the multicollinearity between the two variables.[xi]

As an alternative, the total metres drilled variable was replaced with an interaction term, which would take a zero value for vertical wells, and a value equal to the logarithm of total metres drilled. This had the correct positive sign, but was not statistically significant in the cost equation, probably because of inappropriate scaling. (The zero value for vertical wells would actually correspond to one metre drilled, if one took the antilogarithm.)

My involvement in this project stems from a previous study on the incorporation of resources in estimates of multifactor productivity for the oil and gas industry. The depth of an oil or gas pool is one of the fundamental quality attributes to be considered in determining the quality of the petroleum resource, so it seemed essential, if these hedonic cost equations are at some time to be used in tracing the influence of resource quality on capital costs, to keep total vertical depth as an explanatory variable. What one would like then is some measure of the additional effort involved in drilling a non-vertical well to a certain depth, and an obvious choice would be the drilling-to-depth ratio (DDR), defined as:

DDR = TMD / D

where TMD is total metres drilled. The advantage of this variable is that it is appropriate to both directional and horizontal wells, assuming, as analysis of covariance with small sample sizes would lead us to believe, that it is appropriate to model drilling costs for vertical and non-vertical wells in the same equation. In the total cost equations, the DDR variable itself was used rather than its logarithm, which is equal to the difference in the logarithms of total metres drilled and total vertical depth. Thus the cost equation, ignoring other explanatory variables, would look like this:

$\ln(C) = \beta_0 + \beta_1 \ln(D) + \beta_2 (TMD / D)$ or

$$C = e^{\beta_0} D^{\beta_1} e^{\beta_2 (TMD/D)} \qquad (7)$$

Equation (7) is an awkward hybrid of the semi-log and double-log functional forms. If the logarithm of DDR were the explanatory variable, we would have

$\ln(C) = \beta_0 + \beta_1 \ln(D) + \beta_2 \ln(TMD / D)$ or

$$C = e^{\beta_0} D^{\beta_1} (TMD / D)^{\beta_2} \qquad (8)$$

which is a cleaner looking formulation.

For this initial study, choice of functional form was not the principal focus of concern, but for cost equation (2) in Table 4 I also tried using the logarithm of the drilling-to-depth ratio as an explanatory variable, and it made virtually no difference to the outcomes.

Equation for Vertical and Directional Wells

For equation (2), which included vertical wells and directional wells, it was not possible to introduce a dummy variable PAD for pad-mounted directional wells because for this particular dataset PAD is a linear combination of the intercept and DDR variables.[xii] The dummy variable by itself would have little explanatory power; it was never introduced by the stepwise procedure into any equation during the modelling process.

Table 4: OLS Regressions for 1994-95 Well Costs

	Drilling Costs	Total Drilling and Completion Costs					
	(1)	(1)	(2)	(3)(a)	(3)(b)	(3)(c)	(4)
Intercept	4.6069	5.4513	5.0611	5.6166	5.0198	4.6471	4.6513
	(0.5360)	(0.3647)	(0.8435)	(0.3724)	(0.5641)	(0.3872)	(0.3830)
Year95	0.01715	0.007847	0.007812	-0.01303	-0.01148	-0.00962	-0.00823
	(0.0505)	(0.0411)	(0.0399)	(0.0399)	(0.0395)	(0.0394)	(0.0384)
Log(depth)	1.0833	1.0379	1.0379	1.0132	1.0180	1.0217	1.0216
	(0.0704)	(0.0513)	(0.0507)	(0.0525)	(0.0522)	(0.0519)	(0.0514)
DDR			0.3901		0.5559	0.9008	0.8967
			(0.7148)		(0.3973)	(0.1190)	(0.1159)
Area1	1.2622	1.1456	1.1456	1.1311	1.1314	1.1325	1.1331
	(0.1413)	(0.1283)	(0.1268)	(0.1331)	(0.1319)	(0.1317)	(0.1304)
Area3	-0.1854	-0.1227	-0.1227	-0.10815	-0.1009	-0.0994	-0.0997
	(0.0810)	(0.0645)	(0.0637)	(0.0646)	(0.0642)	(0.0641)	(0.0635)
Area6	0.7336	0.3496	0.3496	0.3420	0.3535	0.3584	0.3579
	(0.1587)	(0.1243)	(0.1229)	(0.1276)	(0.1267)	(0.1264)	(0.1252)
Area7	0.4375	0.3560	0.3560	0.3603	0.3679	0.3703	0.3701
	(0.0795)	(0.0617)	(0.0609)	(0.0621)	(0.0618)	(0.0617)	(0.0611)
Area8	0.3440	0.2200	0.2200	0.2377	0.2297	0.2321	0.2330
	(0.1220)	(0.1273)	(0.1259)	(0.1223)	(0.1213)	(0.1211)	(0.1199)
Area10	-0.5879	-0.3770	-0.3770	-0.3671	-0.3590	-0.3567	-0.3571
	(0.0907)	(0.0731)	(0.0723)	(0.0739)	(0.0734)	(0.0732)	(0.0725)
Area11	-0.3641	-0.2282	-0.2282				
	(0.1448)	(0.1123)	(0.1111)				
Sour	0.4146	0.3227	0.3227	0.3594	0.3592	0.3563	0.3559
	(0.1041)	(0.0866)	(0.0856)	(0.0887)	(0.0879)	(0.0877)	(0.0868)
Gas	0.1550						
	(0.0579)						
Triassic		0.1417	0.1417	0.1692	0.1717	0.1705	0.1701
		(0.0985)	(0.0974)	(0.1014)	(0.1004)	(0.1003)	(0.0993)
Cretaceous	-0.1239						
	(0.0726)						
Horizontal				0.5421	0.2197		
				(0.0731)	(0.2415)		
Re-entry							-0.4959
							(0.1333)
n	55	55	57	63	63	63	65
R2	0.9755	0.9781	0.9782	0.9736	0.9746	0.9742	0.9744
RB2	0.9693	0.9725	0.9722	0.9679	0.9685	0.9686	0.9685
DW	2.371	2.194	2.196	2.260	2.256	2.244	2.286

(1) excluding directional and horizontal wells
(2) including directional wells
(3) including directional and horizontal wells, re-entry horizontals excepted
(4) all wells, including re-entry horizontals
MD= metres drilled
DDR=drilling-to-depth ratio

For equation (2), the coefficient for DDR implies that the cost of drilling a directional well 1040 metres to a total vertical depth of 900 metres is

$$e^{0.390147*(1040/900-1)} = e^{.060689533}$$

which amounts to a cost premium of 6.3% over a vertical well drilled to the same depth. Although the coefficient for DDR is not statistically significant even at the 20% level of significance, its parameter value appears to be plausible. As it happens, there is a vertical well drilled to a depth of 900 metres in the same area as the directional well that is also part of the well cost studies. The ratio of total costs between the directional well and vertical well is 6.4% in 1994 and 3.6% in 1995, which brackets the cost premium indicated by equation (2).

Equations for Horizontal Wells

Although it was not intended to reexamine model selection for the total costs equation with the introduction of non-vertical wells, the dummy for southeastern Saskatchewan, Area11 was dropped from the equations including horizontal wells. Significant at the 5% level in the total cost equations (1) and (2), it was not even significant at the 15% level in the equations including horizontal wells, which is the entry criterion for variables in the stepwise procedure. This is hardly surprising, since the Area11 dummy had a negative coefficient based on two vertical wells, and three of the six new-drill horizontals added to the dataset are in area 11.

Equations (3)(a) and (3)(b) showing the values for the horizontal dummy in the equations containing only new-drill horizontals are included for completeness. Note that in equation (3)(b), the coefficient of the horizontal dummy implies that costs are 72% higher for horizontal wells than for vertical or directional wells drilled to the same depth, which is consistent with the NEB's belief that a horizontal well cost slightly less than two vertical wells drilled to the same depth. However the hypothesis that the value of the horizontal dummy is exactly equal to 2.0 is rejected using a t test at the 5% level of significance.

The condition number of the matrix of explanatory variables for equation (3)(b) indicates a high degree of multicollinearity between the horizontal dummy HZTL and the drilling-to-depth ratio, DDR. Since the horizontal dummy is not statistically significant it was dropped from the equation, giving equation (3)(c), which is the best of the three equations including only new-drill horizontals in terms of its coefficient of correlation adjusted for degrees of freedom (RB2).

The coefficient for DDR in (3)(c) is significant at the 1% level. Its value of 0.900794 implies that the cost of drilling a new horizontal well 2500 metres to a total vertical depth of 1400 metres is

$$e^{0.900794*(2500/1400-1)} = e^{0.7077667}$$

which amounts to a cost premium of 102.9% over a vertical well drilled to the same depth. This is reasonably close, but somewhat larger than the cost premium predicted by the NEB study, which would be somewhere under 100%. Note that the 1995 well cost study provides an actual cost ratio for this comparison between an underbalanced horizontal and a vertical well in southwestern Saskatchewan. The actual cost ratio of 1.87 suggests that the DDR coefficient in (3) may be too large. Also, equation (3)(c) pertains to directional wells in addition to horizontal wells; recalculating the cost premium for the directional well from the previous section gives:

$$e^{0.900794*(1040/900-1)} = e^{.14012}$$

or a cost premium of 15.0%, which is out of line with the actual cost ratios for 1994 and 1995.

Equation for New-Drill and Re-entry Horizontals

A test on common structure between all other wells and the re-entry horizontals indicated that the re-entry horizontals did not have the same structure as the other wells, however, with the addition of an intercept term, an F test indicated that the re-entry horizontals shared common slope parameters with the other wells in the sample.

The value of the reentry coefficient is consistent with a 39.1% discount on re-entry horizontals compared to new-drill horizontals since

$$e^{-0.4959} = 0.60902254$$

The cost of drilling a reentry horizontal 2000 metres to a total vertical depth of 1850 metres would be about 1.45 times greater than drilling a vertical well to the same depth, since

$$e^{-0.4959} \times e^{0.896(2000/1850)} = 0.6090 \times 2.3853$$

This is substantially more costly than the NEB states a re-entry horizontal is compared to a vertical well with the same depth. However, the coefficient of the reentry dummy is significant at the 1% level with the correct negative sign.

Analysis of Coefficient Values

In all of the equations, the depth coefficient was greater than one, consistent with increasing drilling costs per metre with deeper wells. However, the coefficient values are always close to one. In no case would the hypothesis that the depth coefficient equals one be rejected at even the 10% level of significance. As one might expect, the depth coefficient is larger in the drilling subtotal equation than in any of the equations for total costs. In that equation, the coefficient is greater than one at the 25% level of significance, and a doubling in depth for a well would entail a 12% increase in drilling cost per metre.

For the equations based on total costs, the depth coefficient varies between 1.018 and 1.038, with the higher value corresponding to the equation that excludes horizontal wells. This is as expected, since horizontal wells are generally more expensive in terms of drilling cost per metre than other wells (three of the six most expensive wells in the 1995 sample are new-drill horizontals), and it may not be appropriate to include horizontals in the same equation with vertical wells. A depth coefficient of 1.0138 implies that a doubling in depth for a well would entail a 1.9% increase in total drilling and completion costs per metre.

None of the epoch dummy variables seemed to explain much of the variation in drilling costs. The Cretaceous dummy was barely accepted for the drilling costs model; it carries the correct sign, since the Cretaceous pools tend to be shallower and cheaper to drill into than other pools.

The Triassic dummy was accepted for the total costs model with a positive sign, as would be expected since it is an early epoch, and wells to Triassic strata are therefore generally deeper and more costly to drill. According to equation (1) in Table 4 for the total costs model, total drilling costs would be about 15% higher for a well drilled to a Triassic strata than to another strata. As can be seen from the standard error in brackets beneath the coefficient, the Triassic dummy is not statistically significant at the 5% or even the 10% level. (The stepwise procedure will keep a variable in the model if it is only significant at the 15% level.) In some of the subsequent equations for total costs, the Triassic dummy was not even significant at the 15% level, but it was kept in the model since it was always significant at least at the 20% level.

Because of the inclusion of these epoch dummies, it is unlikely that the depth coefficient is overestimated, since one would expect, for example, the Triassic dummy to explain higher drilling costs for Triassic wells that might otherwise be attributed to the depth of these wells. The dummies were nevertheless tested for and included if significant because there may be other reasons why drilling costs would be higher in one formation than another. Not having the background knowledge to accept or reject the role of these dummies in the cost equations, I included them wherever the stepwise procedure indicated appropriate.

The same applies to the area dummies, since as mentioned, the area boundaries were defined partly in terms of whether they contained deep or shallow pools. These dummies had a much more important impact on the cost equations than the epoch dummies, since they were often signficant at the 1% level in the equations. All of the areas for British Columbia and northern Alberta and the foothills region were identified as high-cost areas (Area1, Area6, Area7 and Area8), while southwestern Saskatchewan (Area10) is identified as a low-cost area. The most expensive area to drill in by far was area 1; its coefficient in the drilling subtotal equation of 1.2622 implies that this area was 3.5 times more expensive to drill in than other areas. Since the two wells drilled into this area were both deep wells (the Sukunka well was the second deepest well in the 1995 sample), it may be that the equations have attributed some of the higher cost of these wells due to depth to the area in which they occur. However, the collinearity diagnostics never indicate any severe problems of collinearity between the depth variable and any of the area dummies.

Hedonic Price Indexes for Drilling and Completion Costs

There are many different ways of calculating price indexes that make some use of hedonic regression analysis. In this study, analysis of covariance supported the use of a dummy variable for the year 1995 to measure cost change for that year. The limited number of degrees of freedom very much discouraged a characteristics approach to calculating the hedonic price index or any other approach not based on dummy variables. So only two methods were used to calculate the indexes, both using dummy variables:

1. the direct approach, taking the exponent of the coefficient of the 1995 dummy as the index number,
2. the composite approach, taking the geometric mean of the ratio of costs for the same wells in 1994 and 1995, using the index number obtained by the direct approach as a proxy where there is no match in 1994 for a well that is part of the 1995 sample.

There were 32 wells in the 1994 sample and one more in the 1995 sample, so the version of the composite approach used gives a slightly lower weight to the matched-model part of the index than would an implementation that instead of looking for a match in 1994 for all 1995 wells, looked for a match in 1995 for all 1994 wells.

The composite index is calculated based on geometric means for compatibility with the direct index. Because the dependent variables in the cost regressions are logs of costs, the dummy variable is consistent with a price index number based on geometric means of costs. In fact if the matrix of explanatory variables were limited to an intercept and the year 1995 dummy variable, the exponent of the coefficient of the year dummy would be identical with a geometric mean index of costs.

For the composite index of drilling costs only, unmatched wells used the index movement from equation (1) for drilling costs only as proxy. For the composite index of total costs, non-vertical wells were proxied based on equation (2), new-drill horizontal wells based on equation (3)(c) and re-entry horizontal wells based on equation (4).

There were only 16 matched wells in the sample, and three of these were directional or horizontal wells and so were excluded from the drilling costs index. Thus, it is not altogether surprising that each matched-models index shows a substantially higher movement from the direct-approach hedonic index. The composite index is closer in movement to the direct-approach hedonic index (obviously), but shows an increase of 1.3% for total costs where the direct-approach index shows a decrease.

Of the three sets of indexes, the composite-approach hedonic indexes would seem to provide the best indicators of price change, and to be the most consistent with accepted price index practice. There are too few matched models and they are too unrepresentative of drilling activity in western Canada to favour the matched models index, but the composite approach permits some use of matched-model pricing while still incorporating information from other wells in the sample.

Conclusion

This first attempt to calculate hedonic cost indexes for oil and gas wells has been successful enough to justify its further development. It has generated separate deflators for exploratory and development drilling, something SNA has needed but has never had before. SNA should continue to receive the *Well Cost Study* every year and derive deflators based on manipulation of the data therein rather than depending on PSAC for an estimate, although any estimate received from that source would of course still be of interest.

Table 5: Hedonic and Matched-Models Cost Indexes for Oil and Gas Wells, 1994-1995

	Drilling Costs	Total Drilling and Completion Costs					
	(1)	(1)	(2)	(3)(a)	(3)(b)	(3)(c)	(4)
Direct Approach	1.017	1.008	1.008	0.987	0.989	0.990	0.992
Composite Approach	1.033						1.013
Matched-Models Index	1.050						1.021

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[1] See Uhler and Eglington[1986], p.5.

[ii] Langenkamp defines pinch-out as "disappearance or 'wedging out' of a porous, permeable formation between two layers of impervious rock; the gradual, vertical 'thinning' of a formation, over a horizontal or a near-horizontal distance, until it disappears".

[iii] See *Oil Activity Review 1987*, p.55.

[iv] See PSAC[1995], p.4.

[v] See Chan et al[1994], Appendix B.2.

[vi] See Livernois[1984], p.135.

[vii] An asymptotic test for heteroskedasticity was employed, using the SPEC option of the REG procedure in SAS. See *SAS User's Guide: Statistics, Version 5 Edition*, p.682.

[viii] See Fisher[1964], p.41-53.

[ix] See Livernois[1984], p.135.

[x] See National Energy Board[1994], p.7-7.

[xi] The sum of the two coefficients was 1.024313 in an equation identical to 3(a) except for the inclusion of a variable for total metres drilled and a dummy for AREA11, which compares with 1.0132 for total vertical depth in 3(a).

[xii] Specifically, PAD=-6.4286*INTERCEPT+6.4286*DDR, an equation that equals 0 for any vertical well. Generally it would not equal one for all directional wells, but there is only one directional well in each year, and the 1995 well is just the 1994 well with its costs updated.

A Hedonic Cost Index for
Petroleum Drilling in Western Canada

by Andy Baldwin
Prices Division

Abstract:

Exploratory and development drilling constitutes an important component of expenditures on non-residential construction in Canada, and particularly in Western Canada, where the majority of activity is located. Therefore, it is important that changes in drilling costs be measured precisely so that changes in the volume of activity can be distinguished from changes in spending due to cost pressures.

This paper describes hedonic cost indexes for Western Canada, covering the period from 1982 to 1996. It was found that drilling costs increase disproportionately with depth, although the hypothesis that drilling costs increase proportionately with depth could not be rejected. Sour wells are significantly more expensive to drill than sweet wells. The northern part of B.C. and Alberta and the foothills region were found to be the most expensive areas to drill in, southwestern Saskatchewan the least expensive.

Hedonic price indexes for drilling costs were calculated in two ways, first by taking the exponent of the year dummy variable from the regression equation as the index number, and otherwise by calculating a matched-model index for wells, with the index number from the first approach proxying the price movement for given-year wells with no match in the previous year. Both methods yielded comparable results.

This is one of the first studies of the oil industry that considers the impact of directional drilling and horizontal drilling on drilling costs; especially in a well-developed basin like the Western Canadian Sedimentary Basin directional and horizontal wells offer distinct advantages over vertical wells.

These indexes are compared with Input-Output Division's deflator for oil and gas wells, which both derive from the same basic data source, Winterhawk Petroleum Consulting Services Ltd's Well Cost Studies.