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OUTSOURCING, FLEXIBILITY AND COST MINIMIZATION FOR OIL WELL-DRILLING

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Abstract

The paper makes an indepth study of drilling economics and related factors that affect drilling costs. Drilling costs are functions of several factors which need be monitored for cost control. Drilling costs can be controlled by reducing duration of non-productive activities forming part of drilling cycle, optimizing mix of ‘owned’ and ‘hired’ rigs in the fleet size in desired proportions, moving rig in ‘assembled condition’ from one site to another wherever feasible; deploying ‘mobile rigs’ wherever applicable; outsourcing activities such as logging and rig transportation to professional service providers, improving labour productivity of drilling personnel and support staff, etc. By carrying out policy experimentation using owned versus hired rigs, it shows how estimates of owned versus hired rigs impact drilling cost per meter, and in the process arrive at a mix which leads to minimum drilling cost per meter and higher value creation. The model presented in this paper thus offers rational basis for deciding optimum combination of owned versus hired rigs in the total fleet and highlights need for minimizing non-productive delays for minimizing drilling costs.

Keywords: Outsourcing, flexibility, drilling costs, productivity and performance measures.

Introduction

Flexibility in outsourcing is important for staying competitive and maintaining cutting edge in the era of cut-throat competition and global meltdown. The suggested model helps analyze impact of reduced operation times following process innovation; and effect of knowledge process outsourcing with varying proportion of owned versus hired equipment and services on select performance and productivity measures in a business firm.

In the case of oil well drilling to which this case example relates, drilling costs can be minimized by reducing length of non-productive activities that forms part of drilling cycle, optimizing mix of ‘owned’ and ‘hired’ rigs in the fleet size in desired proportions, moving rig in ‘assembled condition’ from one site to another wherever feasible; deploying ‘mobile rigs’ wherever applicable; outsourcing activities such as logging and rig transportation to professional service providers, improving labour productivity of drilling personnel and support staff, etc.

Cost of an offshore well depends on the remoteness of the location being drilled. Onland wells can be much cheaper if the field is at shallow depth. Exploratory wells are drilled for information collection in a new area under exploration (Huebsch, 2010). Production testing of a well involves flow rate assessment from proven hydrocarbon accumulation. Production drilling involves drilling at chosen locations within a field for production of oil and gas. After the hole is drilled, sections of steel pipe (casing), slightly smaller in diameter than the borehole are placed in the bore (Brantly, 2007).

The casing imparts strength to the wellbore to withstand pressures of high pressure zones. With these zones safely isolated and the formation protected by the casing, the well can be drilled deeper into potentially much more unstable formations, with a smaller bit and also cased with a smaller size casing. Most wells often have 2-5 sets of progressively smaller hole sizes drilled inside one another, each cemented with a casing (Wikipedia, 2010).

Drill bit aided by the weight of thick walled pipes called 'drill collars' above it cuts into the rock. Drilling fluid (mud) is pumped down inside the drill pipe and exits at drill bit. Rock cuttings from drilling are swept up by the drilling fluid as it circulates back the surface outside the drill pipe. The fluid then goes through 'shakers' which separate the cuttings from good fluid, which is returned to the pit. The drill pipe or drill string to which the bit is attached is gradually lengthened by screwing in additional pipes under the kelly or top drive at the surface. After drilling and casing the well, it is 'completed' which refers to enabling a well to produce oil or gas (Wikipedia, 2010).

Flexibility can be exercised in the choice of technology and rational choice of 'operating parameters' and 'formation evaluation methods'. As a case-in-point, the cumulative drilling time depends on rock type and selection of 'drill bit'. Hard-rock drilling usually needs more drilling time than soft-rock drilling. Exercise of flexibility in selection of bits from wide range of bits available in the industry can make significant difference on productivity enhancement and value creation.

Savings in costs leads to value creation for the organization by reducing delays in rig dismantling at the preceding site, rig transportation from one site to another, and rig building (reassembly) at the succeeding site. Move-in and rig-up occur before well spudding the well, while rig-down and move-out occur after well-completion. Reduction in non-productive activities duration helps in achieving higher levels of productivity (drilling cost/meter). Rig building (including rig dismantling) and rig transportation are important part of drilling cycle which have been covered herein under 'non-productive activities'. Any reduction in 'non-productive activities' following application of industrial engineering, management and quantitative techniques helps achieve higher meterage from the same rig fleet size and associated value creation.

As casing programs for deep high pressure wells can significantly impact drilling costs, drilling crew needs to have flexible casing policy for maximizing value creation. Other parameters that significantly impact the drill rates are proper choice of weight and rotary speeds, mud type and differential pressure exercised during drilling. Selection of optimum penetration rates, choice of type and weight of drill bit, rotary speed, quality of bottom hole cleaning and mud properties, etc., offer range of flexibilities for value creation in oil exploration industry.

Factors which affect bit penetration rate include type and weight of the drill bit, rotary speed, bottom hole cleaning, and mud properties. Increases in bit weight and rotary speed achieves higher drilling rate. Drilling rate is directly proportional to rotary speed in soft formations. In hard formations, the rate of increase in drilling speed decreases with increases with rotary speed. A speed greater than 150 rpm is regarded as high rotary speed which is generally used in drilling soft formations, while a rotary speed between 40 - 75 rpm is appropriate for hard formations (AcrbatPlanet.Com -2010).

In this paper it is attempted to analyze impact of reduced non-productive activities, and levels of outsourcing (varying combination of owned versus hired equipment on) on performance parameters such as the cycle speed, commercial speed, drilling cost, and rig fleet size. The paper develops and describes an optimization model which enables policy experimentation and economic evaluation of different alternatives. The paper analyzes impact of drilling economics and related factors on drilling costs in oil exploration industry. The model shows that if non-productive activity duration during drilling cycle are minimized and/ or owned versus hired rigs in the fleet is changed, fleet size requirement and drilling cost per meter is changed.

Model Description

In the selection of a curve to express the trend of time series, a wide range of options is available, and it is not always easy to decide which type of curve is most appropriate. In general, when data is indicated to grow fairly linearly with time and it can be expressed as linear equation, it is to be preferred to a moving average. While selecting growth curve, the data should be plotted on simple graph paper. When the points fall approximately on a straight line, a straight line equation is indicated. When there is one bend, a second-degree equation is indicated, and when there is a point of inflection, a third-degree equation could be a better fit for the growth curve (Croxton, *et al.,* 1974, p.342).

The available growth trends can also be plotted on semi-logarithmic paper, and when all the points fall approximately on a straight line, an exponential curve could be more apt description of the growth. The period of time to which the trend is fitted often makes considerable difference. If the data cover only 10 or 15 years it may be important to consider the stage of the cycle at the initial and terminal years as for longer periods this is less important (Croxton, *et al.,* 1974, p.344).

A growth curve is defined as one in which the amount of growth at any point of time (or during any period of time) is a function of the level attained at that point of time (or at the beginning of that period of time), which in case of exponential growth curve takes the following form. One common procedure for fitting an exponential is to put the equation in linear form and then to use the method of least squares.

In exponential growth curve while A is constant multiple, the parameter in the time series changes by a constant ratio B per unit of time. The constant B, which is raised to the power of the number of time periods beyond the base period, is always positive. Thus, if B = 1.10, the trend for each year is 110 per cent of the previous year, and the rate of growth is 10 per cent. The exponential curve is also called a compound interest curve, and on a paper with a vertical logarithmic scale it is a straight line (Croxton, *et al.,* 1974, p.327).

$$Y = A.B^{x}$$

$$\text{Log } Y = \log A + (\log B)\, x$$

If, $a = \log A$, $b = \log B$

$$\text{Log } y = a + bX,$$

which is the equation of a straight line.

Growth targets for different years during plan periods is fixed up based on assumed exponential growth curve. Projections in fixed cost (rig dependent) and variable costs (meterage dependent) are estimated using the linear regression equation given by

$Y_i = a + b. X_i$

where,

$a = [(\sum y).(\sum x^2) - (\sum x).(\sum xy)] / [n\sum x^2 - (\sum x)^2]$

$b = [n \sum xy - (\sum x).(\sum y)] / [n\sum x^2 - (\sum x)^2]$

Trip time for pulling out and running the drill-string into a bore forms significant part of drill rotating time. In terms of its length of duration it is comparable with the on-bottom drilling time, and sometimes it is even more. Trip time depends on well depth, amount of mud trip margin, hole problems, rig capacity and crew efficiency.

The time required to run casing into a well depends on size and depth of casing pipe, hole conditions, crew efficiency, and technology of equipment used. When drilling is more difficult such as directional drilling, operation time for drilling becomes longer due to directional control of the drill bit.

Total drilling cost per meter can be determined using the following relationship,

$C_t = [C_b + C_r (t_b + t_c + t_t)]/ d$

where,

Ct = Total drilling cost, rupees per meter.

C_b = Cost of bit, rupees.

C_r = Fixed rig operating costs, rupees.

t_b = Average bit life, hours.

t_c = Non-rotating time during the bit run such as connection time, hours.

t_t = Trip time, hours.

d = Meterage drilled per bit run, m

Average bit life, t_b, being rotating time in hours includes all on-bottom time with the bit. Trip time t_t refers to the total time needed to pull and return a bit. Non-rotating time during the bit run such as connection time t_c is not difficult to estimate. Total meterage drilled per bit run is not difficult to measure either.

Cycle days refer to the period from the day the digging of the pits for the derrick foundation is started to the day the drilling rig is dismantled following completion of the scheduled jobs.

$t_c = [\sum t_{rb} + \sum t_d + \sum t_{pt}]/n$

n = number of wells

Cycle speed represents the penetration rate of the completed wells and is expressed as meters drilled per rig-month.

V_c = Meterage drilled/ Rig month

= Meterage drilledx30.4/cycle days

$= \sum H x 30.4/ \sum t_c$

where, $\sum$ H is the total meterage drilled for completed wells and $\sum t_c$ is the well construction cycle.

Commercial speed refers to the meterage achieved during drilling period. It is estimated by dividing the penetration of a completed well or a group of wells by the drill-months of the productive time. Commercial speed indicates the possible level of drilling rate with the given drilling equipment and technology when the drilling work is trouble-free and there is no spoilage or outages.

V_t = Meterage drilled/ Drill-month

$= \sum H x 30.4 / [\sum t_d / n]$

where,

$\sum H$ = total meterage drilled for completed wells, m

$\sum T_d$ = total time taken for drilling and removing casing from all the wells

n = number of wells

Drilling cost per meter is the ratio of total drilling cost to total meterage achieved.

$C = \sum S / \sum H$

where,

C = Cost of 1 meter penetration, Rs. /m

$\sum S$ = Actual sum of the well costs for the period under study.

$\sum H$ = Total penetration achieved for the same period, m

The model enables to estimate projected cycle and commercial speeds, rig year requirement, drilling cost by owned rigs, drilling cost by hired rigs, total drilling costs, and estimation of all the drilling costs on per meter basis.

Analysis and Results

The case pertains to drilling economics of a petroleum exploration company in which fixed costs relate to rig depended costs while variable costs are function of meterage drilled. As typical in any industry, cost analysis is carried out with respect to fixed and variable costs. In this paper, fixed costs include salary of drilling crew, overhead costs, equipment depreciation, etc. while variable costs relate to: costs of materials, casings, cementing materials, etc which increase linearly with meterage drilled (Table 1).

Fixed costs were projected to grow linearly during the plan period (Table 2). Value of the meterage in the terminal year of the planning horizon was taken as multiple of value in the first year for fixing annual drilling meterage targets during the 20-year plan period. Value of meterage drilled during the plan period was assumed to be governed by the exponential growth curve after analyzing the growth trends of meterage drilled in the organization for past several years.

Drilling costs can be reduced by either reducing non-productive activity durations such as rig building days, dragging the rig in assembled form wherever feasible, advance site preparation at next location, even before the operations at the previous site have been completed (leap frogging), or using mobile rigs in future wherever possible, etc. Drilling costs can also be minimized by reducing non-productive activity times during actual drilling and production testing periods.

Deployment of work over-rigs in place of main rigs during part of production-testing operations, for making the main rig available at the next site sooner for drilling operations, minimizes expensive main rig time to be confined for main drilling activity only. In overall terms it enables higher drilling efficiency to be achieved.

Drilling costs are affected by several factors, which need to be individually monitored and controlled (AcrbatPlanet.Com-2010). Flexible outsourcing by having a varying mix of owned and hired rigs affects drilling costs per meter in overall terms as the drilling costs for the two groups are different (Behl, 2009, p.7). Policy experimentation for this study is carried out by hypothetically changing mix of owned versus hired rigs in the fleet.

Non-productive delays could be due to waiting for instructions from senior technical staff, appropriate weather, completion of rig repair, etc. Reducing such delays helps improve drilling economics. Mobile rigs facilitate rig transportation from one site to another in assembled conditions. Several types of modern rigs can be dragged from one site to another in assembled conditions. Dragging rig in assembled condition drastically reduces rig building time but it is possible when the rig design and road conditions so permit. The paper analyzes results for five different combinations of owned versus hired rigs, namely, 30:70, 30:70, 40:60, 40:60, 40:60, and 40:60; and non-productivity activity durations as depicted in Fig 2.

Due to paucity of space, in this case analysis impact of non-productive activities duration on value creation in terms of drilling cost per meter accrued, and estimated rig fleet size during plan period is discussed only with respect to one particular variant, namely, 60 per cent owned and 40 per cent hired rigs. The impact was analyzed corresponding to two different levels of non-productive activities, i.e., (i) status quo (no change), and (ii) and 10 per cent reduction in non-productive activity durations.

By multiplying savings in drilling costs per meter with total meterage planned during planning horizon, it is possible to arrive at savings in drilling costs. This model helps determine optimum mix of owned versus hired rigs that an organization should have for best economic gains. The model does not offer a one time choice, but offers flexibility of choices of owned versus hired rigs to be made in future during planning horizon as future unfolds with the availability for new data every year (Table 3).

Concluding Remarks

By carrying out policy experimentation using owned versus hired rigs, it shows how estimates of owned versus hired rigs impact drilling cost per meter, and in the process arrive at a mix which leads to minimum drilling cost per meter. The model presented in this paper thus offers rational basis for deciding optimum combination of owned versus hired rigs in the total fleet and highlights need for minimizing non-productive delays for minimizing drilling costs.

By achieving higher standards of performance through a flexible choice from available options, it is always possible to reduce unit operation costs or more outputs from the same inputs. There are as such no set rules for enhancing productivity that leads to higher value creation but there are some standard rules that foster enhanced productivity levels. In case of oil well drilling to which this case summary pertains, there is one standard rule that faster one drills the less expensive it would be.

Similarly, in oil industry, deploying work-over rig in place of main rig during the production testing stage would enable the main rig to start drilling at the next site ‘sooner’ as it will predate rig building and well spudding at the next site. Similarly, preparing site at next location in advance even before the operations at the preceding site have ended, would reduce length of ‘drilling cycle’ following start-up of operations at next site in parallel (leap frogging).

Crew efficiency is an important factor in efficient well completion. By performing all bore/well operations efficiently, it is possible to achieve higher drill penetration rates. In general, faster a bore is drilled, the less expensive it would be (UV International, 1999). Higher standards of drilling productivity can be achieved by regulating and controlling drilling performance parameters such as drill rate, case running rate, well completion rate, quick resolution of bore problems, etc. Variety of hole problems faced during drilling impact drilling efficiency. Hole problems faced during drilling are due to variety of factors such as fishing, mud loss, job squeeze, wash out, caving, etc.

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Biography

Dr. K.M.Mital is presently working as Professor teaching Strategic Management and CSR at the IILM Institute for Higher Education, Lodhi Road, New Delhi. He has earlier worked in three major public enterprises in energy sector, namely, BHEL for sixteen years, ONGC for nine years and EIL for twelve years.

During 2003-04 for one year he taught as Professor at the Department of Management Studies, IIT, Roorkee on deputation from the Engineers India, where he joined back in May 2004 and worked till December 31, 2004 as General Manager (HR).

Dr. Mital holds a B.Sc. degree from erstwhile Agra University, B.E. (Mech.) and M.E. (Prod.) degrees from the erstwhile University of Roorkee, and PhD in Industrial Engineering/ Management from the IIT Delhi.

Dr. Mital is author of over one hundred and fifty papers and five books in the field of management and energy. Dr. Mital is having considerable editorial experience and is currently the editor of the IILM Journal ‘Management & Change’, and GIFT Society (a society for promotion of flexibility in management) Newsletter “Flexibility”.

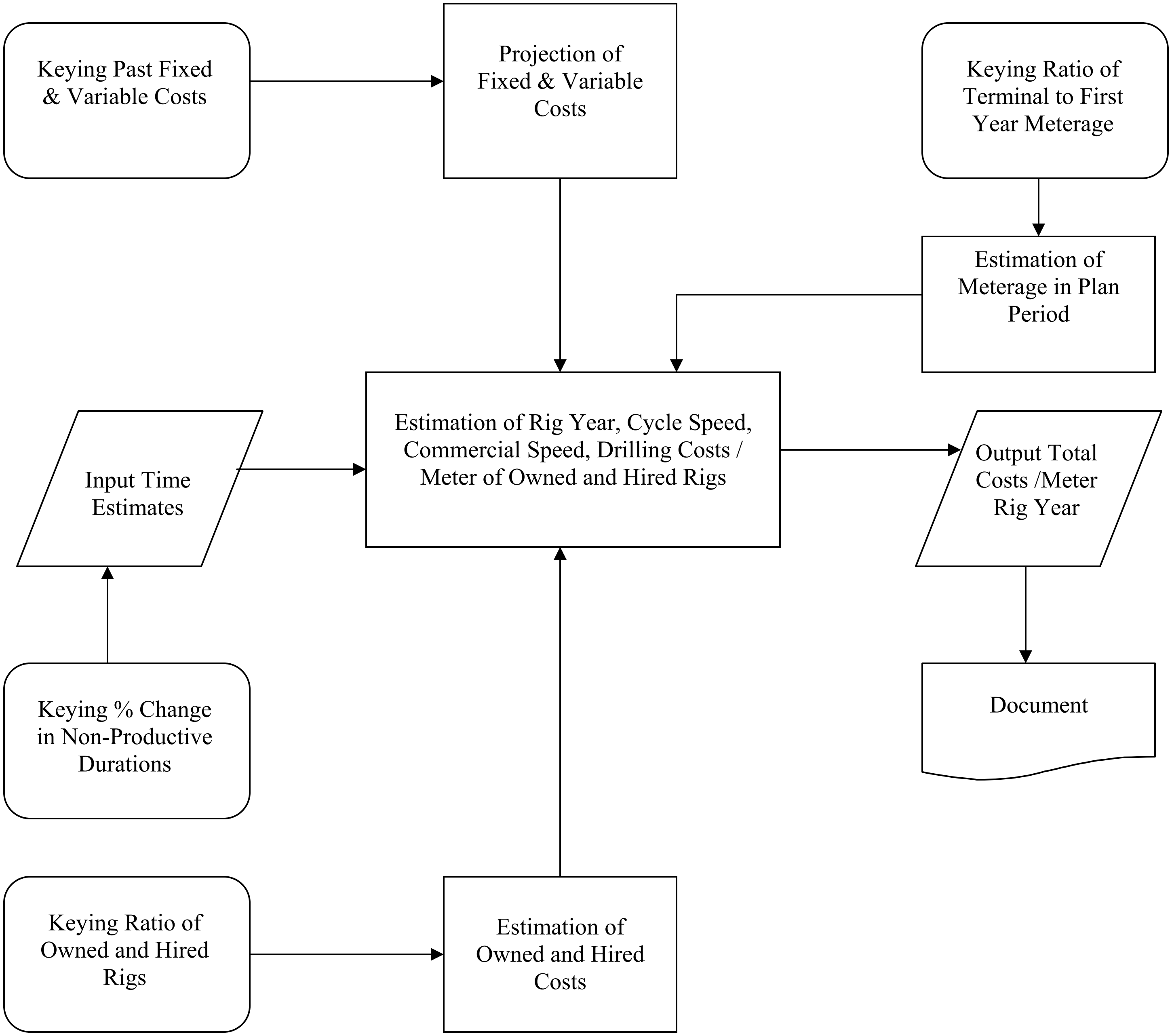

Fig 1 System Diagram for Drilling Cost Minimization Model

Table 1 Comparative Variation in Fixed and Variable Costs for Owned and Hired Rigs for Oil well Drilling by ABC Exploration Company during past 5 year period

Period	*Fixed Costs (Rs. Lakh)*	*Variable Costs (Rs. Lakh)*	*Rig Year*	*Meterage (m)*	*Fixed costs / Rig Year (Rs. Lakh)*	*Variable Costs / Meter*	*Total Cost / Rig Year/ neter*
Owned Rigs (O)							
(t – 1)	7338	2317	4.99	90326	1470	2565	10790
(t – 2)	8969	1623	3.44	74547	2607	2178	14210
(t – 3)	4913	1400	1.83	51837	2684	2701	12180
(t – 4)	4191	964	1.87	33263	2241	2899	15500
(t – 5)	464	204	0.37	7860	1255	2656	8703
Hired Rigs (H)							
(t – 1)	6027	1567	2.98	64000	2022	2449	11686
(t – 2)	6252	1390	2.83	60776	2209	2287	12371
(t – 3)	6332	1300	2.09	49667	3029	2619	15368
(t – 4)	3676	1087	1.52	34254	2312	3174	13903
(t – 5)	1206	522	0.75	22002	1608	2372	7855
Combined (O+H)							
(t – 1)	13366	3885	7.97	154326	1677	2227	11174
(t – 2)	15221	3013	6.27	135323	2427	2227	13475
(t – 3)	11245	2701	3.92	101504	2868	2661	13740
(t – 4)	7867	2052	3.46	67521	2273	3039	14690
(t – 5)	1670	726	1.12	29682	1491	2445	8075

Table 2 Projected Increases in Fixed and Variable Costs for Owned and Hired Rigs

Period	*Owned*		*Hired*		*Total*	
	Variable Costs	*Fixed Costs*	*Variable Costs*	*Fixed Costs*	*Variable Costs*	*Fixed Costs*
(t + 1)	2662.5	2314..1	2560.2	2498.1	2613.7	1760.7
(t + 21)	2714.8	2451.1	2597.4	2605.4	2662.4	1815.2
(t + 3)	2767.1	2588.0	2634.6	2712.6	2711.0	1869.6
(t + 4)	2819.4	2725.0	2671.8	2819.8	2759.7	1924.1
(t + 5)	2871.7	2861.9	2709.0	2927.1	2808.4	1978.5
(t + 6)	2924.0	2998.9	2746.1	3034.3	2857.0	2023.9
(t + 7)	2976.3	3135.8	2783.3	3141.6	2905.7	2087.4
(t + 8)	3028.6	3272.8	2820.5	3248.9	2954.3	2141.8
(t + 9)	3080.9	3409.7	2857.7	3356.1	3003.0	2196.2
(t + 10)	3133.2	3546.7	2894.8	3463.4	3051.7	2250.7
(t + 11)	3185.5	3683.7	2932.0	3570.6	3100.3	2305.1
(t + 12)	3237.8	3820.6	2159.5	3677.9	3149.0	2359.6
(t + 13)	3290.1	3957.6	3006.4	3785.1	3197.7	2414.0
(t + 14)	3342.4	4094.5	3043.5	3892.4	3246.3	2468.4
(t + 15)	3394.7	4231.5	3080.7	3999.7	3295.0	2522.9
(t + 16)	3447.0	4368.4	3117.9	4106.9	3343.7	2577.3
(t + 17)	3499.3	4505.4	3155.1	4214.2	3392.3	2631.8
(t + 18)	3551.7	4642.3	3192.3	4321.4	3441.0	2696.2
(t + 19)	3604.0	4779.3	3229.4	4428.7	3489.7	2740.6
(t + 20)	3656.3	4916.2	3266.6	4536.0	3538.3	2795.1

Variable Cost: Depth Dependent Cost, Fixed Cost: Rig Dependent Cost

Table 3 Estimates of Rig-Year Requirement, Total Costs and Costs-Per-Meter A Combination of 30 Per Cent Owned and 70 Per Cent Hired Rigs for each Successive Year in 20-Year Planning for Horizon and Corresponding to Existing Level of Non-Productive Delays.

Period	*Meterage*	*Rig Year Requirement*			*Total Costs (Rs Lakhs)*			*Cost per Meter (Rs)*		
		Owned	*Hired*	*Total*	*Owned*	*Hired*	*Total*	*Owned*	*Hired*	*Total*
(t + 1)	88600.00	1.45	3.38	4.83	4063	10039	17102	15286.20	16186.70	15916.55
(t + 21)	154500.00	2.53	5.90	8.43	7456	18179	25635	16085.67	16809.09	16592.06
(t + 3)	252000.00	4.12	9.62	13.74	12765	30749	43514	16885.13	17431.48	17267.57
(t + 4)	308500.00	5.05	11.78	16.83	16367	38987	55354	17684.59	18053.86	17943.08
(t + 5)	45300.00	0.74	1.73	2.47	2512	5922	8434	18484.06	18676.25	18618.59
(t + 6)	227500.00	3.72	8.69	12.41	13161	30733	43894	19283.52	19298.64	19294.10
(t + 7)	227500.00	3.89	9.08	12.97	14333	33174	47507	20082.98	19921.03	19969.61
(t + 8)	236300.00	3.87	9.02	12.89	14804	33981	48785	20882.45	20543.41	20645.12
(t + 9)	230900.00	3.78	8.81	12.59	15019	34210	49229	21681.91	21165.80	21320.63
(t + 10)	227100.02	3.72	8.67	12.39	15317	34637	49954	22481.38	21788.19	21996.14
(t + 11)	255873.02	4.19	9.77	13.96	17871	40140	58011	23280.84	22410.58	22671.66
(t + 12)	288291.50	4.72	11.01	15.73	20826	46486	67307	24080.30	23032.96	23347.17
(t + 13)	324817.31	5.31	12.40	17.71	24244	53786	78030	24879.77	23655.35	24022.68
(t + 14)	365970.87	5.99	13.97	19.96	28194	62195	90389	25679.23	24277.74	24698.19
(t + 15)	412338.50	6.75	15.75	22.49	32755	71871	104626	26478.70	24900.13	25373.70
(t + 16)	464580.78	7.60	17.74	25.34	38019	83001	121020	27278.16	25522.51	26049.21
(t + 17)	523442.00	8.56	19.98	28.54	44091	95797	13988	28077.62	28077.62	26724.72
(t + 18)	589760.81	9.65	22.51	32.16	51092	110504	161596	28877.09	26767.29	27400.23
(t + 19)	664482.00	10.87	25.37	36.24	59159	127400	186559	29676.55	27389.68	28075.74
(t + 20)	748670.25	12.25	28.58	40.83	68449	146803	215252	30476.02	28012.06	28751.25

Note:

1. Rig building days: 2.55, drilling days: 26.25, production testing days: 7.66 days lost in non-productive activities: 3.42, days lost in non-productive waitings: 1.14, cycle days: 41.02, cycle speed: 1528.0, commercial speed: 2034.4.
2. Meterage in 20th year is 8.45 times of the first year.
3. The above values are only estimates and not actual values.

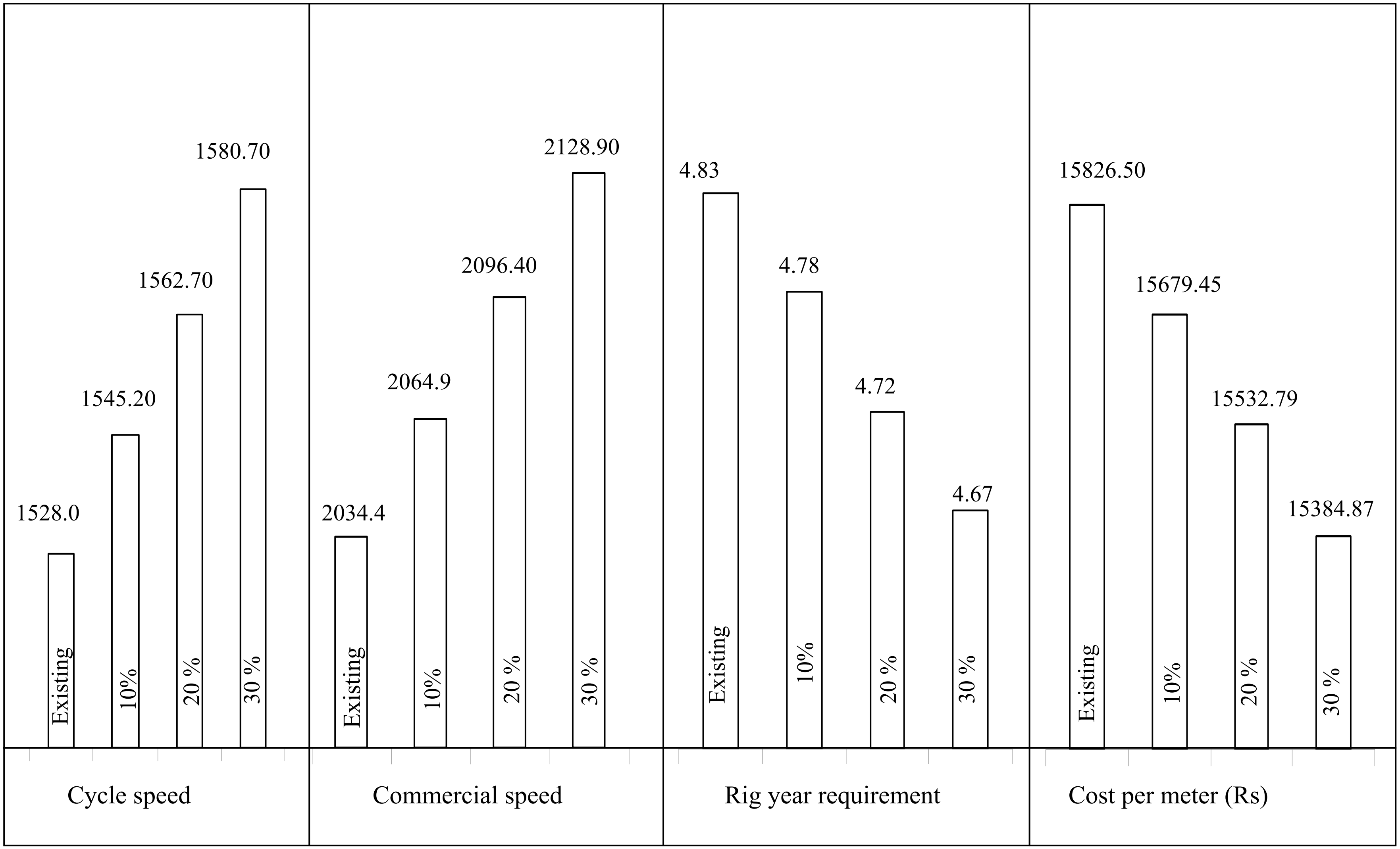

Fig 2 Effect of 10, 20 and 30 per cent reduction in timings of non-productive activities on cycle speed, commercial speed, rig year requirement and drilling cost per meter in oil well drilling