Financial Sustainability in the Oil Industry

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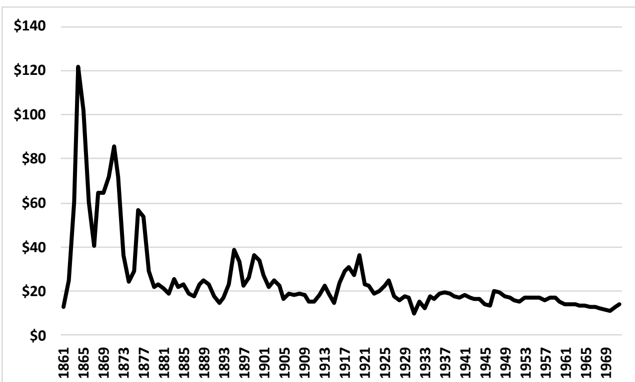
From the beginning of the oil industry in 1861 to 1877, oil prices were extremely volatile as seen in Figure 1.[1] Fortunes were made and lost in relatively short time as drillers responded to high oil prices by drilling as many wells as possible. The Achilles Heel of free market capitalism is that price tells you when to add capacity, but not how much. As long as oil prices remained high, wells were drilled with wild abandon. The mistake of drilling too many wells was not apparent until after the supply of producing wells overwhelmed demand. But by then, not only had too many wells been drilled, but many more were in the pipeline, which for the most part would be completed. Excess oil supply depressed prices to the point where the wooden barrel was worth more than the oil within. Bankruptcy was a virtual plague among drillers. Depressed times lasted until expanding demand eventually caught up with stagnant supply fostering another oil boom where price gave no hint on how much supply was needed to match demand.

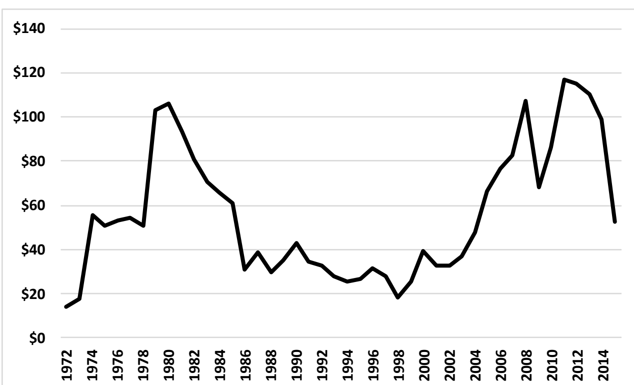
Figure 1: Oil Price$/Barrel 1861-1972 (2015 $)



There was little challenge in forecasting oil from 1877 to the 1973 oil crisis. Why did oil hover around $20 per barrel in constant 2015 dollars for nearly a century making forecasting of oil prices a moot point? It started with Rockefeller. Rockefeller looked askance at drilling and decided that there was no means of controlling drillers driven by their wild dreams of striking it rich. But he realized that he could take over the oil industry through refining.[2] In 1877 Rockefeller achieved a horizontal monopoly by acquiring, one means or another, over 90 percent of the nation's refining business. In this position, he could dictate the price of oil as he was the only purchaser and he could also dictate the price of kerosene to consumers and his profit would be in the refining margin – the difference between what he paid for oil and what he received for kerosene. (Kerosene for lighting was the original basis for the Rockefeller fortune.) Since Rockefeller made his money on the refiner's margin and wanted to keep the price of kerosene competitive with other lighting fuels such as alcohol and whale oil, it was not in his interest to support a high price of oil. The price he set was enough for drillers to recoup their cost and maybe earn a little on the side. His profit margin was not as large as one might think because Rockefeller could not stop speculators from building refineries challenging his monopoly. Ultimately Rockefeller would be forced to buy these refineries to maintain his near-monopoly. His strategy was to keep the difference between prices of kerosene and oil at a level that dissuaded prospective investors from building new refineries. Nevertheless Rockefeller's margin and control over the oil industry were more than sufficient to create the world's largest fortune on volume, not price; an approach repeated by Ford in selling millions of Model T's with a low profit margin.

When Rockefeller went into retirement, the mantle of control over oil prices passed to a cartel of major oil companies headed by Deterding of Shell Oil. The leading oil men of the day parceled out geographic spheres of influence among themselves to limit destructive competition. They also established a formula-based price for oil sold in the western hemisphere regardless of its source as the price of crude oil in the US Gulf plus shipping. Oil prices remained low because new supplies were being discovered at a pace that challenged the cartel to keep oil prices from falling. The cartel was eventually overwhelmed by the enormous supplies of oil emanating from the newly discovered east Texas oil fields. Here the state governments of Texas and Oklahoma came to the rescue of Big Oil by giving the Texas Railroad Commission authority to prevent drillers from selling a finite and valuable natural resource at too low a price. The Texas Railroad Commission controlled the price of oil by regulating the output for oil wells in Texas and Oklahoma. With the Texas Railroad Commission controlling the price of oil in the US Gulf for conserving a critical resource, the Shell cartel could manage world prices by its already existing formula. The Texas Railroad Commission lost control of price via production quotas in 1971 when it was forced to authorize full production of all wells under its jurisdiction to meet demand. This was an unheeded warning of a transition from a buyers' to a sellers' market, which manifested itself with the 1973 oil crisis. When OPEC gained the upper hand, they mimicked the Texas Railroad Commission of influencing price by controlling volume. Rockefeller, Shell, and the Texas Railroad Commission succeeded in keeping stable (and low) oil prices for a long time. Rockefeller failed when he could no longer control global refining capacity, the Shell Oil cartel and Texas Railroad Commission failed when they could no longer control non-cartel oil production. OPEC differed fundamentally from its predecessors, who were bulwarks against price erosion: OPEC stood for price enhancement. Figure 2 measures their success.

Figure 2: Oil Price$/Barrel 1972-2015 (2015 $)



How well did OPEC do in controlling world oil prices to maximize revenues by having a high oil price since 1973? If we assign a high price being above $80 per barrel in terms of 2015 constant dollars, OPEC was successful in maintaining high prices from 1979 to 1982 and again from 2007 to 2014 excepting 2009, a combined total of 9 years. If weak oil prices are defined as being below $40 per barrel, OPEC failed to maximize revenues from 1986 to 2003 excepting 1990, a sixteen-year hiatus between periods of high oil prices. Their grade for maintaining high oil prices is about a "C", certainly no higher.

Forecasters' Performance

How well did forecasters of oil prices do since volatility returned to the oil markets after a century-long lull? For a positive trend in prices, the most common forecast is a continuation of the current trend. Why? It's the easiest forecast to make. A forecast of the market turning and heading south would demand an explanation, which would entail examining supply and demand factors in detail to project when they would diverge sufficiently to affect price. But trends are also affected by “wild card” events, whose nature, timing, influence, and significance are impossible to assess and justify before the fact.

For a negative trend in oil prices, the typical forecast calls for 1-3 years of continued decline with a subsequent recovery at some modest rate of improvement for a wide assortment of reasons. This is the famous or rather ubiquitous “check” forecast. Why are forecasts done during rising and falling markets so fundamentally different? Think about who pays for these forecasts. Check forecasts made in 1986, 1997, 2001 would have been essentially correct. But were there forecasts of a major shift to rapid rises or falls in oil prices before they occurred in 1978, 1986, 2004, 2008, 2009, 2015? Not in the author’s experience.

Let’s consider a forecast made in 2015 when oil was $100 per barrel. The forecaster was well known. He made it abundantly clear that his forecast was based on extensive interviews and conversations with just about every major oil producer and oil company and oil expert in the world. Obviously these should be the most knowledgeable and qualified people to judge the future price of oil. But they are also the most biased and most apt to deliver up a self-serving forecast. The near-unanimous consensus, which was his forecast, was that $100 per barrel crude oil was here to stay: the easiest forecast to make. Incremental supplies of crude oil in the form of fracking shale, Canadian oilsands and deep ocean drilling required high priced oil to justify their investments as the oil industry reacted to rising demand and declining supply of low cost legacy oil. Moreover OPEC members needed $100 per barrel oil or more to pay for their social welfare programs placed on the books to placate their populations in the form of free education, housing, medical, social services, and a plethora of paper-shuffling government jobs to assure incomes. These nations, all suffering from the Dutch Disease, had failed to create any economic base beyond oil. With no manufacturing infrastructure, most needs were satisfied by imports, which required large positive trade balances. Thus social stability depended on high priced oil.

No objections were raised when this forecast was made; it was widely received as valid, pertinent, logical, and reliable. Yet within months, prices fell precipitously when Saudi Arabia purposely lowered the price of oil by increasing production. One reason given for dealing this “wild card” that wrecked the price structure was to preserve Saudi Arabia’s historic share of the oil market in the face of a resurgence of cheap legacy oil from Iran with the lifting of sanctions and from Iraq to rebuild its war ravished infrastructure. Other reasons were to starve Iran of funds to pursue its nuclear weapon plans, punish Russia for supporting Assad of Syria, and somewhat belatedly, bankrupt the US fracking oil industry. Who would have stuck his or her neck out to predict these events before the fact?

In 2016, the most common forecast is a check forecast where additional production from Iran and Iraq will keep oil prices weak in the short term, but growing global demand for oil coupled with declining US frack oil production will eventually bring about a better match between supply and demand fostering higher oil prices. The recovery would be aided and abetted if Saudi Arabia resumed its role of swing producer or if OPEC could demonstrate some cohesion to control production. These forecasts are normally accompanied by the warning of a major spike in price if Middle East war breaks out between Iran and Saudi Arabia. No surprise here except no one is predicting whether such a war would occur or if it did occur, its timing, magnitude and duration of an interruption of oil flowing through the Strait of Hormuz. A few venturesome forecasters are predicting a prolonged period of low oil prices. They eschew the conventional forecast as Pollyanna. Their view is focused on the global economy being unable to sustain growth from an aging and declining working population in Europe and Japan (with China to follow) coupled with the potential financial and economic repercussions of being at the end of a truly gargantuan debt cycle.

How Does One Forecast Oil Prices If Forecasting Is Fruitless?

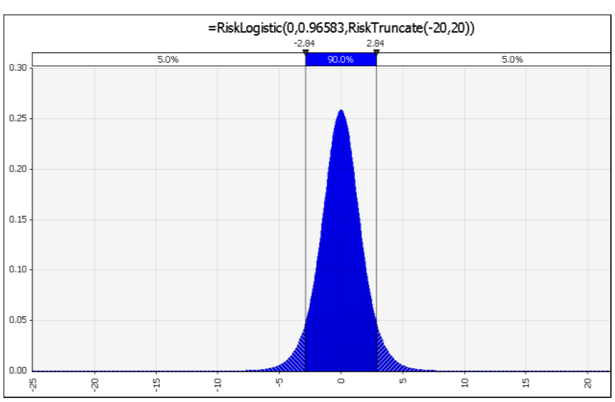
Or put another way, how do companies project a cash flow if single valued price forecasts cannot be used? The three-estimate approach of a high, expected, and low price scenarios is nearly as useless because the expected scenarios keep the same price for twenty or more years. After reviewing the history of oil prices, perhaps a cash flow projection relying on a single valued price forecast should carry a warning that explicitly states that it does not reflect reality. Acknowledgement of uncertainty should be part and parcel of any oil price forecast. The key question now is how to assess that uncertainty. Unfortunately any measure of uncertainty must contain high and low oil price estimates, which of themselves, affect perceived risk. This uncertainty exists for the three-estimate approach in assessing high and low and expected price scenarios. Actually the three-estimate approach is readily transformable to a simulation model in that a triangle or pert probability distribution consists of three estimates for high, low and expected values. But instead of prices remaining constant at three different levels for the entire projection period, prices change daily, or monthly, or annually bounded by the upper and lower limits with a higher probability of being around the most likely price. Simulating oil prices can also be based on probability distributions for daily or monthly or annual price changes that can be derived from past data. The “risk” of this approach in judging uncertainty is that measuring vagaries in price changes based on past data does not mean that vagaries are replicable when simulating the future. This “risk” is also inherent in the three-estimate model when assessing price estimates; how does one know whether the high and low and expected estimates are valid before the fact for the entire projection period?

One caveat is in order when using price changes to forecast price. It may be possible to get an unreasonable price that is either too high or too low. It is even possible to get negative prices. MAX and MIN functions can be used to control prices within a desired range. Alternatively one can increase the propensity to buy when prices enter a lower range and a propensity to sell when prices enter an upper range. For instance, suppose the random function is being used to determine whether a price change is positive or negative: IF(RAND<.5,-1,1). A propensity to buy can be set up by changing 0.5 to 0.2 if price falls below a certain level (this would mean a 20% chance of generating a -1 versus an 80% chance of generating a 1). Changing the 0.5 to 0.8 sets up a propensity to sell when price rises above a certain level (now there is an 80% chance of generating -1 versus a 20% chance of generating a 1). Regardless of the method selected, guarding against unrealistic price assessments is necessary in formulating revenue.

A Model for Financial Sustainability

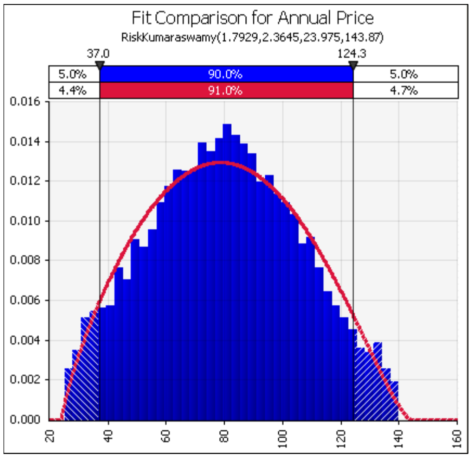
The best fitting distribution of daily price changes shown in Figure 3 was obtained from a seven-year data base of daily oil price changes.

Figure 3: Daily Price Changes in $/Bbl



This distribution was used to obtain a one year (250 trading days per year) of daily price changes. Daily prices were obtained by taking the previous day's price and adding in the price change. Safeguards were put in place to prevent the price of oil falling below $25 per barrel and rising above $140 per barrel (see Pricing Model tab in Excel spreadsheet ForecastPalisade). A simulation was run on the price of oil on day 250 to obtain a best fitting distribution to model annual prices shown in Figure 4.

Figure 4: Annual Price in $/Bbl



This distribution was then used to obtain annual prices changes for a 30-year time horizon. A review of the history of actual annual prices from *BP Energy Statistics* showed that the extreme price change between any two successive years was $55 per barrel and this proviso was incorporated in the pricing model. Figures 5, 6 and 9 refer to the Cash Flow tab in spreadsheet PalisadeForecast.

Figure 5: Spreadsheet Portion Deriving Net Profit

	A	B	C	D	E	F
1						
2				0	1	2
3						
4		Average	$82.86		$91.85	$55.56
5		Escalation Rate	0%	$80.00	$91.85	$55.56
6						
7	Existing volume bpd	Depletion	2.5%	300,000	292,500	285,188
8	New production bpd				2,982	11,285
9	Total production bpd			300,000	295,482	296,473
10						
11	Revenue in $mm			$8,760	$9,906	$6,013
12		Low	15%			
13	Variable cost	High	20%	$1,379	$1,942	$934
14						
15	Gross profit			$7,381	$7,964	$5,079
16						
17	Fixed cost			$4,000	$3,930	$4,155
18						
19	Net Profit/EBITDA			$3,381	$4,034	$924

Cell F4: =RiskKumaraswamy(1.7929,2.3645,23.975,143.87,RiskName("Annual Price")) derives the annual price for the 30-year projection. Cell F5 prevents the price change between two successive years from exceeding $55 per bbl. If this condition exists, then the price change is reduced to somewhere between $45 and $55 per bbl. An escalation factor (cell C5) on the price of oil has been incorporated for later analysis. Initially there is no escalation of oil prices – all prices are in 2015 dollars.

Cell F5: =IF(E5>F4,1,0)*IF(E5-F4>55,E5-RiskUniform(45,55),F4)…
+IF(F4>=E5,1,0)*IF(F4-E5>55, E5+RiskUniform(45,55),F4)*(1+$C$5)^E2

Existing production declines at 2.5% per year to account for depletion in row 7. New production in row 8 will be described shortly. The total of existing and new production in row 9 is multiplied by price to obtain revenue in row 11.

To obtain variable costs for an actual company, a review of the previous five years may yield a statistical relationship between revenue and variable costs. A X-Y scatter diagram can quickly show whether such a relationship exists; and if so, running a regression analysis between revenue and variable costs creates a regression formula linking the two. A normal distribution can now be constructed using the regression equation to determine the mean with its associated standard deviation being the standard error in the regression output. A similar examination of fixed costs may show a statistical relationship with production volume and capital expenditures with oil price (the higher the price of oil, the greater the incentive to spend corporate funds on capital expenditures). Thus projected variable and fixed costs and capital expenditures would be normal distributions whose means and standard deviations are derived from regression outputs.[3] The translation of capital expenditures into incremental oil production will have to be made either as a factor or a probability distribution based on historical data. It is possible to reverse this process and have incremental production linked to oil prices and from this derive capital expenditures – the approach taken in this paper.

If these statistical probability functions are not available as here, other methods have to be devised. In this model, it's assumed that variable costs in row 13 are between 15 and 20% of revenue to reflect the variable portion of oil well operations plus associated royalties and transportation costs. Gross profit is revenue less variable costs. Fixed costs are modeled referring to total oil production as the driver since a greater number of wells would add to fixed costs, but not in a linear fashion. Fixed costs are plus or minus 5% of the initial fixed costs of $4 billion times the square root of the ratio of current level of production with the initial production of 300,000 bpd shown below.

Cell E17: =RiskUniform(0.95,1.05)*$D$17*(E9/$D$7)^0.5

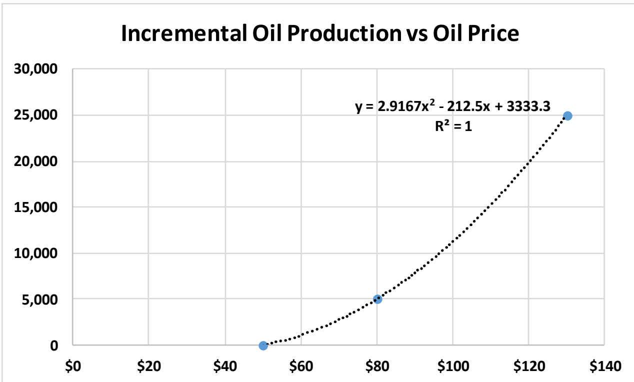
Net profit in row 19 is gross profit net of fixed costs. Deriving new oil production and capital expenditures are calculated in Figure 6.

Figure 6: Spreadsheet Portion Deriving New Oil Production and Capital Expenditures

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
72		Objective		0	1	2	3	4	5	6	7	8	9	10
73		($21,492.50)		$80.00	$58.03	$90.88	$78.12	$97.78	$82.04	$89.89	$91.70	$46.66	$66.50	$70.01
74	New oil				3,000	824	8,112	4,533	10,442	5,532	7,800	8,374	-	2,100
75	Cumulative new oil			Factor	3,000	3,824	11,935	16,469	26,910	32,442	40,243	48,616	48,616	50,716
76	Approx depletion			0.006	2,982	3,778	11,721	16,073	26,103	31,274	38,552	46,283	45,991	47,673
77		MM Per 1000 bpd												
78	Capital expenditures	$101		$0	$309	$109	$1,140	$614	$1,188	$787	$1,112	$962	$0	$274
79														
80	Depreciation													
81		Difference		year 1		$31	$31	$31	$31	$31	$31	$31	$31	$31
82		Dividends and Equity Infusion		year 2			$11	$11	$11	$11	$11	$11	$11	$11
83		$25,879		year 3				$114	$114	$114	$114	$114	$114	$114
84				year 4					$61	$61	$61	$61	$61	$61
85		Difference		year 5						$119	$119	$119	$119	$119
86		in Oil Production		year 6							$79	$79	$79	$79
87		(6,784)		year 7								$111	$111	$111
88				year 8									$96	$96
89				year 9										$0

Row 73 repeats oil prices in row 5. Initial new oil in cell E74 was arbitrarily selected. In cell F74 and succeeding cells, incremental oil production is derived from oil prices derived from Figure 7 (refer to tab Relationships in spreadsheet PalisadeForecast).

Figure 7: Incremental Oil Production (Bpd) versus Oil Price ($/Bbl)

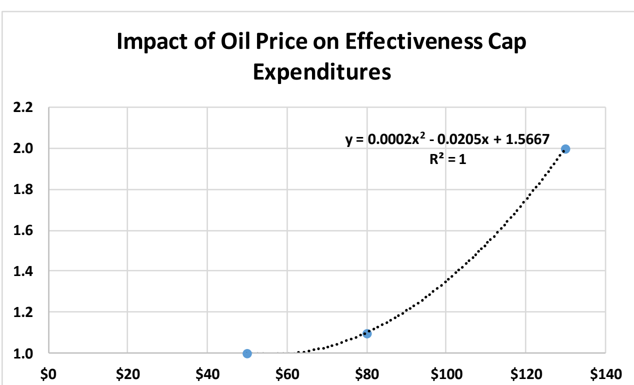


No incremental production, and hence no capital expenditures, occur when oil prices are below $50 per bbl. The formula determining incremental oil production in row 74 for oil over $50 per bbl is embedded in Figure 7. Incremental production refers to the previous year's oil price to model a one-year delay between the expenditure of funds and the initial flow of new oil.

Cell F74: =IF(E73<50,0,2.9167*E73^2-212.5*E73+3333.3)

Row 76 adjusts row 74 for oil depletion and is referenced in row 8 as new oil. Each year's incremental oil production is assessed at an initially arbitrary value of millions of dollars per 1,000 bpd in cell B78 to model capital expenditures when the oil price is $50 per barrel. Capital expenditures are adjusted by Figure 8 to reflect that during times of high oil prices, the rush to increase oil production becomes costlier as drilling companies and suppliers raise prices in response to market demand. Moreover in times of high oil prices, more capital intensive and lower producing oil fields may be tapped.

Figure 8: Impact of Oil Price on Capital Expenditures



Referring back to the Cash Flow worksheet, incorporating Figure 8 in row 78 doubles the cost factor of bringing on new production at $130 per barrel relative to oil at $50 per barrel per 1,000 bpd with 20% uncertainty.

E78: =($B$78*E74/1000)*(0.0002*E5^2-0.0205*E5+1.5667)*RiskUniform(0.8,1.2)

Rows 81 to 110 contain the ten-year depreciation of capital expenditures in row 78 with no residual value for each year of the projection period. These will be summed to obtain annual depreciation of new assets.

It would have been possible to model capital expenditures as a function of oil price from which incremental production is derived. However it turned out to be more difficult because, as set up, the capital factor escalates for higher priced oil. To have capital expenditures drive incremental oil production, it would be necessary to have a constant capital factor. Given that the capital factor is itself a variable linked to oil prices, it was easier, modelbuilding-wise, to have incremental oil production as a driver for capital expenditures. Naturally this can be changed if desired with reformulation.

Debt financing charges are derived in Figure 9.

Figure 9: Spreadsheet Portion for Outstanding Debt, Debt Amortization, and Interest Expense

	A	B	C	D	E	F	G	H	I
21	Depreciation								
22	of existing assets			$5,000	$500	$500	$500	$500	$500
23	of new cap assets				$0	$27	$27	$193	$245
24									
25	Annual capital expenditures				$266	$0	$1,667	$518	$572
26				% Debt					
27	New debt		63	63%	$168	$0	$1,050	$326	$360
28	Equity Input				$98	$0	$617	$191	$212
29	Cumulative Equity				$98	$98	$715	$907	$1,118
30									
31	Existing debt			$2,000	$1,800	$1,600	$1,400	$1,200	$1,000
32	Existing debt amortization				$200	$200	$200	$200	$200
33									
34	Annual amortization of new debt				$0	$17	$17	$122	$154
35	Cum new debt net of cum amortization				$168	$151	$1,184	$1,388	$1,594
36									
37	New and existing debt outstanding				$1,968	$1,751	$2,584	$2,588	$2,594
38	Avg debt for calculating interest				$1,968	$1,859	$2,167	$2,586	$2,591
39		Total Equity Required							
40	Equity investment w/o reinvestment dividends	$9,907			$98	$98	$715	$907	$1,118
41			Estimates	Interest					
42			Low	4%					
43	Interest expense new & existing debt		Expected	5%	$103	$107	$114	$136	$124
44			High	6%					
45	Interest income/Expense wking cap or solvency loan					($20)	($20)	($20)	($20)
46	Total Interest Expense				$103	$87	$94	$116	$104

Depreciation of existing assets is in row 22 and new assets in row 23, which sums the 30 individual years of depreciation in rows 81 to 110. For the sake of simplicity, amortization of debt was also assumed to be ten years, negating the necessity for another 30 rows to cover annual amortization for capital expenditures. At 100 percent debt financing, debt is the same as cumulative capital expenditures and annual amortization is the same as annual depreciation. This can be seen by setting C27 to 100. In fact, setting C27 to 0 and to 50 would aid in understanding the formulation.

Annual debt accumulation and amortization payments based on depreciation of capital expenditures need only be multiplied by the percentage of debt utilization or leverage to obtain the amount of outstanding debt and annual amortization. The difference between capital expenditures and new debt is the equity infusion.

Row 27, new debt, is annual capital expenditures multiplied by the leverage in cell D27. Equity input in row 28 is the difference between capital expenditures and new debt, which is accumulated in row 29. Row 40 is a repeat of row 29 to judge financial sustainability. Existing debt and debt amortization are in rows 31 and 32. Annual amortization of new debt in row 34 is the degree of leverage in cell D27 times annual depreciation in row 23. Row 35 accumulates new debt net of annual amortization to obtain the amount of outstanding new debt. Row 37 is the total of new and old outstanding debt. Row 38 is the average outstanding debt between the start and end of a year. Row 43 is the interest expense calculated with a triangle distribution whose parameters are in cells D41 to D43. Row 45 contains the interest income on positive balances in the working capital account and interest expense on the solvency loan, which represents the negative balances in the working capital account. Total interest expense is in row 46.

Taxes, cash flow and the solvency loan are derived in Figure 10.

Figure 10: Spreadsheet Portion for Taxes, Cash Flow, and Solvency Loan

	A	B	C	D	E	F	G	H	I	J
48	Earnings before tax (EBT)				($230)	$4,512	$2,528	$2,095	$3,020	$1,734
49										
50	Tax basis				($230)	$4,282	$2,528	$2,095	$3,020	$1,734
51	Tax payable	40%			$0	$1,713	$1,011	$838	$1,208	$694
52	Earnings after tax (EAT)				($230)	$2,569	$1,517	$1,257	$1,812	$1,040
53	(Shareholders' net income)									
54										
55	Cash flow				$70	$2,879	$1,827	$1,629	$2,202	$1,452
56	NPV at 15%			$8,117						
57										
58	Working capital	Max	2	$2,000						
59										
60	Starting working capital				$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
61	W.C. plus cash flow	Total dividend			$2,070	$4,879	$3,827	$3,629	$4,202	$3,452
62	Dividend flow	$35,631			$70	$2,879	$1,827	$1,629	$2,202	$1,452
63	Ending working capital		Initial		$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
64		Average Return	Equity							
65	Return on Equity	15.0%	$3,000		1%	56%	32%	28%	36%	23%
66										
67	Solvency loan		Max	$1,714	$0	$0	$0	$0	$0	$0
68		Investment to	Count	3	0	0	0	0	0	0
69		restore working cap								
70		$0								

Earnings before tax in row 48 is net profit less depreciation of old and new assets and interest expense. Row 50 and 51 calculate taxes based on tax loss carryforwards.[4] Net cash flow in row 55 is earnings after tax plus adding back in the non-cash expense, depreciation, less the cash outflow of debt amortization for both existing debt and new debt. The working capital account accumulates cash flows throughout the projection period paying out dividends on funds in excess of the minimum working capital balance in cell D58 and supplying funds during times of negative cash flows. No dividends can be paid if the working capital account is below the minimum balance. Exhausting the working capital account by a succession of negative cash flows is funded by a drawdown of the solvency loan, an imaginary infinite line of credit. The degree of usage of the solvency loan both in frequency and amount is an indicator of the inherent financial risk of a company. This risk is measured by the maximum solvency loan balance for every iteration of a simulation (cell D67) and the number of times for every iteration when there is a balance in the solvency loan (cell D68).

Dividend flow in row 62 is the dispersal of funds from the working capital account in excess of its minimum balance. Dividend reinvestment is not done on a year-to-year basis because the annual net cash flow and the equity infusion rarely match. Rather dividends are accumulated and then compared with total required equity at the end of the projection period to see whether full reinvestment of dividends would have been sufficient to cover the necessary equity infusions. This can be easily done by comparing accumulated dividends in cell B62 with total equity required in cell B40. Any excess will provide risk mitigation associated with drawdowns of the solvency loan. If not employed in risk mitigation, the excess of accumulated dividends over total equity required would presumably be paid out as cash dividends to shareholders. Return on equity in row 65 is annual dividends as a percent of outstanding equity. The starting point for equity is the initial equity in cell C65 plus the starting minimum balance in the working capital account in cell D58 for a total of $5 billion. Obviously the amount of the starting equity and the minimum balance in the working capital account affect the rate of return, whose average throughout the projection period is in cell B65.

Financial Sustainability

Financial sustainability is defined as generated cash funds being sufficient to provide the equity infusions necessary to support annual capital expenditures for a stable company not undergoing significant increases or decreases in output. In other words, a corporation can sustain itself without equity infusions from outside sources on a status quo basis. In this example, a stable company would have oil production at the end of the projection period essentially the same as at the start. Even then, the company would still have an expanding equity account associated with new investments, but the funds for the incremental equity would be internally generated if the company is financially sustainable. The company can survive if the actual capital factor is above the maximum for sustainability, but this would require a continual issuance of new stock to fund a larger equity account without any improvement in overall output. Risk in terms of drawdowns on the solvency loan rises while profitability declines.

It was fortuitous in the design of this model that the oil company was producing approximately the same volume of oil at the end of the 30-year projection as at the start. In examining the magnitude of the investments in new production each year, it can be seen that a great deal of effort is required just to maintain the status quo! The idea of financial sustainability where a company is growing in output requiring outside sources of funds to support such growth would require a more careful thinking of what financial sustainability means under these circumstances. As an introduction to the subject of financial sustainability, it is advantageous to initially approach this subject on the basis of a stable company before tackling a more challenging situation of a company expanding or shrinking its level of activities.

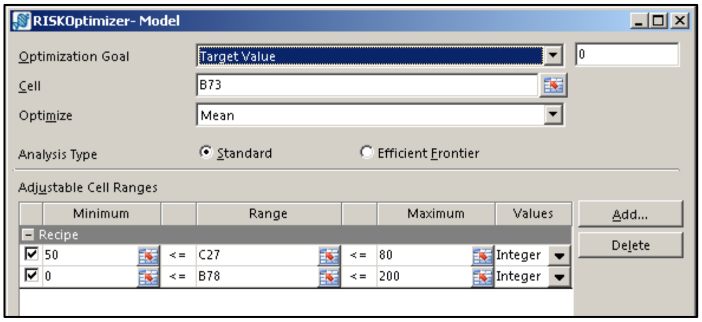
Once this model is set up and tested, RISKOptimizer can determine the appropriate capital factor associated with incremental production and degree of leverage to ensure financial sustainability. To guard against too much reliance on debt, financial risk in the form of the frequency and magnitude of the solvency load were taken into account. The RISKOptimizer objective was for the equity required for capital expenditures be equal to dividends generated throughout the projection plus any cash needed to fully fund the working capital account at the end of the projection period plus an allowance to cover financial risk. Financial risk was represented by the largest outstanding balance of the solvency loan and by the number of occurrences of resorting to the solvency loan during any iteration of the simulation. A factor of one thousand was applied against the number of occurrences to weigh it sufficiently for RISKOptimizer to sense its relative importance compared to the largest solvency loan balance.

To gauge an appropriate capital factor before running RISKOptimizer, suppose that a desired payback is 8 years for oil at $80 per barrel. At $80 per barrel and 1,000 bpd and 360 operating days per year, annual revenue is $28.8 million. Suppose that variable and fixed costs reduce cash generation to $20 million per year. An 8-year payback would imply a capital factor of $160 million per 1,000 bpd for a conventional oil well with a 20 to 30-year life. The RISKOptimizer result for a maximum capital factor was less than the 8-year payback. The lower capital factor than the back-of-the-envelope payback calculation reflects the financial benefit of a well continuing to produce some twenty-odd years after payback.

The RISKOptimizer objective in cell B73 is =B40-B62+D67+1000*D68+B70

B40 is the total equity required and cell B62 is the total dividends generated. This difference also restores the working capital balance back to its original value, if necessary, in cell B70, and provides coverage for financial risk. Financial risk was defined as the highest balance in the solvency loan during any iteration, cell D67, and 1,000 times the number of occurrences of drawing down on the solvency loan, cell D68. RISKOptimizer was to set the value in cell B73 closest to zero. This can only be achieved by maximizing the capital factor. Figure 11 is the RISKOptimizer menu.

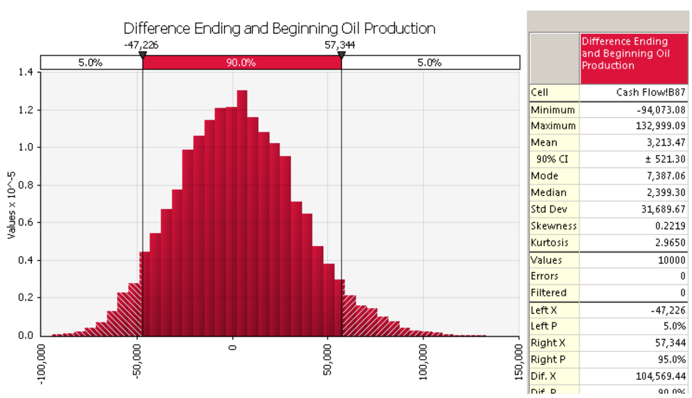
Figure 11: RISKOptimizer Menu



The variables are the degree of debt leverage in cell C27 and the capital factor in terms of $mm/1,000 bpd in cell B78. The target value for cell B73 is to be as close to zero as possible by varying leverage between 50 or 80, which in the spreadsheet becomes 50% to 80% and by varying the $mm for 1,000 bpd of incremental production for an oil price of $50 per bbl between 0 and 200. The boundaries on leverage were selected on the basis that a company would like bank loans to cover at least half of capital expenditures and bank reluctance to fund over 80% of an investment in oil wells. The upper boundary on the capital factor was selected as a result of the payback calculation. RISKOptimizer solutions close to 50 or 80 for leverage or 200 for the capital factor should lead one to expand these boundary limits. Integers were selected to speed up the optimization process.

The RISKOptimizer solution was a degree of leverage of 63% in funding capital expenditures and a maximum $101 million per 1,000 bpd. The lesser capital factor compared to that associated with payback calculations reflects the financial impact of the remaining long life of a well after the payback period is over. It turned out to be coincidental that the arbitrarily selected incremental oil production from new wells was close to keeping oil production almost steady throughout the projection period. Figure 12 is the ending production in relation to the starting production of 300,000 bpd.

Figure 12: Difference Between Starting and Ending Production Bpd



The mean difference between starting and ending oil production was 3,200 bpd based on a starting production of 300,000 bpd with a 5 percentile of -47,000 bpd and a 95 percentile of 57,000 bpd. This was fortuitous for measuring financial sustainability. Had oil production declined or increased substantially during the projection period, more attention would have to be paid to defining financial sustainability.

Table 1 summarizes the results for financial sustainability.

Table 1: Simulation Results of Critical Parameters Capital Factor of $101 mm/1,000 bpd

Parameter	5 Percentile	Mean	95 Percentile
Difference between dividend & equity infusion	$9,000 mm	$32,000 mm	$53,000 mm
Return dividend/equity	7.7%	15.7%	21.7%
Risk – Count of solvency loan drawdowns	40% chance of 0	4	16
Risk – Maximum drawdown	40% chance of 0	$245 mm	Max $10,000 mm

The positive difference between the inflow of dividends and equity infusions reflects both ensuring that the working capital account is fully funded at the end of the projection period and risk mitigation associated with minimizing the frequency and magnitude of drawdowns of the solvency loan. Risk in terms of the number of times a solvency loan was drawn down often had a maximum of 30 drawdowns on individual simulations, the entire length of the projection period. Thirty years of low oil prices is truly a rare event indeed, but it is an event that occurred creating a huge solvency loan balance more than sufficient to bankrupt the firm. In Table 1, the mean drawdown of the solvency loan is $245 million with an imposed maximum of $10 billion. The imposed maximum was selected on the basis that a drawdown above this amount would probably result in the bankruptcy of the firm. The probability of a drawdown above $10 billion, or the risk of bankruptcy, was 11 percent. Profitability, in terms of dividends as a percent of equity, had a mean rate of return on equity of nearly 16 percent, about triple the interest rate on borrowings. But this should not be taken at face value as there is a distinct chance of bankruptcy.

The capital factor was increased to $150 million per 1,000 bpd to judge what would happen if a company choose to invest at a higher capital factor than that associated with financial sustainability. The results are in Table 2.

Table 2: Simulation Results of Critical Parameters Capital Factor of $150 mm/1,000 bpd

Parameter	5 Percentile	Mean	95 Percentile
Difference between dividend & equity infusion	-$1,000 mm	$18,500 mm	$38,000 mm
Return dividend/equity	5.3%	11.4%	16.5%
Risk – Count of solvency loan drawdowns	20% chance of 0	8	22
Risk – Maximum drawdown	20% chance of $0 mm	$1,600 mm	Max $10,000 mm

The difference between dividend generation and equity infusion shrank as did the dividend return. This implies additional risk, which is manifest in the greater number and larger amount of solvency loan drawdowns. In addition the probability of the maximum drawdown being above $10 billion increased to 29%, nearly triple the risk of bankruptcy under financial sustainability.

The escalation rate in cell D5 was made a variable along with the degree of leverage for a capital factor of $150 million/1,000 bpd incremental production. The RISKOptimizer solution was for a long-term secular escalation rate of 1.77% based on oil prices in constant 2015 dollars with 63% leverage, unchanged from the original RISKOptimizer run. Table 3 shows the results.

Table 3: Simulation Results of Critical Parameters Capital Factor of $150 mm/1,000 bpd with Oil Price Escalation

Parameter	5 Percentile	Mean	95 Percentile
Difference between dividend & equity infusion	-$7,000 mm	$25,000 mm	$52,000 mm
Return dividend/equity	8.2%	14.4%	19.0%
Risk – Count of solvency loan drawdowns	16% chance of 0	5	16
Risk – Maximum drawdown	16% chance of $0 mm	$1,700 mm	Max $10,000 mm

There is a 14% chance of exceeding $10 billion maximum balance of the solvency loan. Although Table 3 is not an exact replica of Table 1, it is similar in many respects and a distinct improvement over the results in Table 2. Thus if one can justify a secular annual increase in the price of crude of at least 1.7% in terms of constant dollars, then higher capital factors (here $150 per 1,000 bpd) for financial sustainability can be entertained. Naturally if the escalation rate were over 1.7%, the measures of reward and risk would commensurately improve.

Normally @RISK simulation is employed to measure profitability. Here the application is to demonstrate financial sustainability for a company under stable conditions. It is hoped that this paper paves the way for others to examine the concept of financial sustainability for other applications or on a more general fashion.

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[1] Oil price data from *BP Statistical Review of World Energy*, British Petroleum, London, 2016.

[2] Background to oil industry from *Energy Economics* by R. Nersesian published by Routledge, London, 2016.

[3] A detailed description of this methodology is in Section 21 - Funds Flow Financing from *Energy Risk Modeling* by R. Nersesian published by Palisade, Ithaca, NY, 2013.

[4] The formulation details for calculating taxes with tax loss carryforwards, the working capital account, and solvency load are in Section 20 - Oil Project Financing from *Energy Risk Modeling.*