

Chapter 2

Oil Company Finances

It is really very simple. Oil and gas companies are in business to make money for their shareholders—individual shareholders, or in the case of state-owned companies, the owning government. Making money means that revenue is greater than expense. The devil is in the details.

2.1 How Oil Companies Make Investment Decisions

To better understand how oil companies make their decisions, we will look at a very oversimplified financial example for drilling a small oil prospect. An oil company is in the business of finding, producing, and selling oil and its refined products. Some companies do only one or two of these things, whereas the large integrated oil companies are involved from the initial discovery well to the sale of gasoline to a final customer. Indeed, a similar sort of financial model is used for almost every investment decision made by any corporation within a market economy. While this basic model is developed for shareholder-owned private oil companies, the economic factors are essentially the same for state-owned oil companies as well.

An oil exploration company will always be on the lookout for good places to drill. Suggestions come from all sorts of places; historically a natural oil seep might suggest a good location; other oil wells certainly indicate an interesting area, although whether there is an available location for additional well(s) is another matter; property owners, ranging from single homeowners to national governments, may suggest that they have a good prospective area; other oil companies may offer to share the risks of exploring a specific location; and an oil company of any size will have employees whose job is simply to suggest locations. The history of the oil industry is full of tales, sometimes humorous, about when and why various people decided to drill where they did.

Once an exploration target is identified, the oil company has a prospect. Our simple prospect will be small—to better understand the finances we will assume that only one well will suffice to produce all of the oil (this is unrealistic). With our prospect identified, we now have to begin investing some money. One of the most important features of the oil business is that large amounts of money need to be spent before we have anything to sell as a result. As the work goes along, the company will always be asking the question “is this going to make us money?” Many projects are abandoned at various points along the way. It is worth noting that the profits from the successful prospects need to be sufficient to cover the expenses of those that are not successful.

2.2 Who Owns the Resource?

The first requirement is to make sure that this is a location in which a well can be drilled, and that our company has the legal right to do so and potentially profit from a success. In most of the world, minerals and resources at depth belong to the government; in the United States (and a few other places) the land surface owner is presumed to own everything beneath the land. Either way, the owner of the resource will want some compensation, a royalty,¹ for the oil and gas produced. The oil company employees who negotiate with the landowners are called landmen in the industry. In the USA and other places of private mineral ownership landmen visit property owners with offers to either lease or purchase the mineral rights. They spend time in county courthouses researching property ownership records, and talking with landowners or anyone else who can help them find the owners of the mineral rights. The company is generally interested in the minerals now, so the standard starting point for the negotiation is to lease the mineral rights in return for a fee called a “signature bonus” plus the future royalty. There are as many variations in lease terms as one can imagine; price per acre for the signature bonus, percentage of revenue from the well, and so forth. Because the mineral rights are private property, they can be bought and sold separately from the surface property, causing complex ownership problems. The landmen have to sort all this out before drilling. In this context J. Paul Getty is reported to have quipped, “the meek may inherit the earth, but not its mineral rights”.

Outside the USA the situation is much different; generally the government owns the mineral rights and landmen might better be called “commercial diplomats,” negotiating directly with government officials. The government will typically create fairly large areas, often called blocks, which are, in effect, leased to an oil company.

¹The term royalty goes back to when government ownership of the land meant it was owned by the king.

Again, terms of the lease can be almost whatever one can imagine—I once heard of an oil company agreeing to invest in a bicycle manufacturing operation as part of a lease negotiation.

While the landmen are working on the ownership terms, the company will continue to study the area to refine the assessment of the oil likely to be present. From regional geologic studies, from data that is bought and sold within the oil industry, and by using various models (Moscariello 2016), the company will examine everything it can about this prospect. The most important data are generally seismic surveys that have been done.

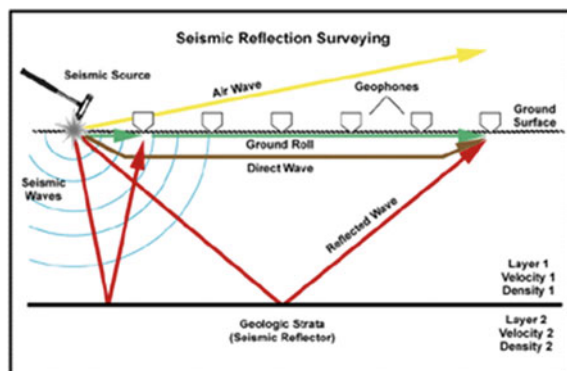
2.3 Seismic Surveys: Assessing the Resource

The basic principle of a seismic survey is to create vibrations at one point and then see how long they take to be reflected back to another point as shown in Fig. 2.1.

When oil companies first started doing seismic surveys they used small dynamite explosions for the seismic source; today they use vibrating trucks on land or air guns at sea to produce the seismic signal. Moving the source and geophone collectors along a line, and then processing the results using computing power, results in a type of cross section of the rocks underneath. An interpreted version of such a seismic section is seen in Fig. 2.2. In this example, the sedimentary layers of the Karoo rocks can be seen as having been tilted and folded; these sedimentary beds have also been offset by faults. Beneath the sedimentary layers one can see some nonlayered “basement” rock, which is generally not thought to be of interest for petroleum.

Seismic processing uses the biggest and fastest computers, and today instead of simply progressing along a line, the geophones are frequently arranged in a grid so the resulting processing can provide a 3-dimensional view of the rocks and likely oil or gas accumulations.

Fig. 2.1 Seismic Reflection Methodology [Source Illinois State Geological Survey (2012)]



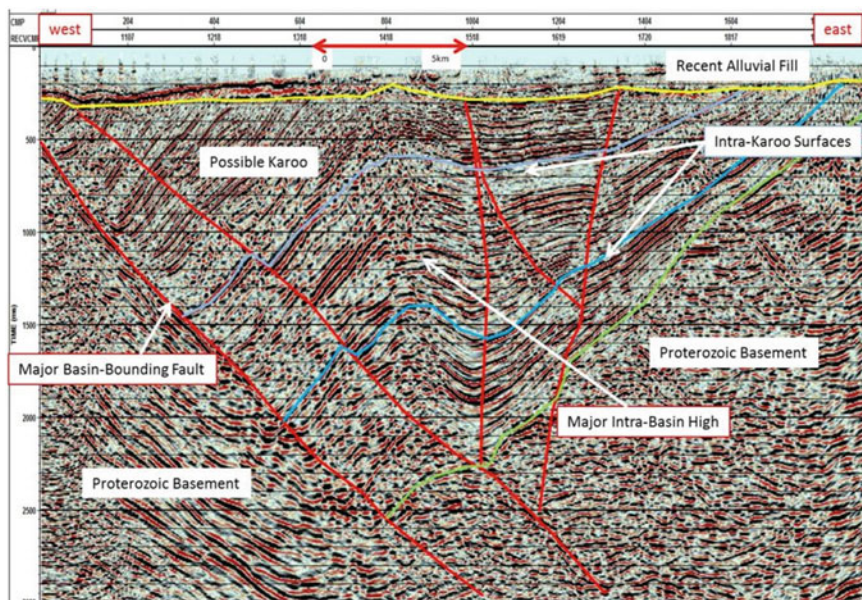


Fig. 2.2 An interpreted seismic line [Source Swala Energy, PennEnergy (2013)]. The “Karoo” is a group of layered sedimentary rocks. The *black and dark red lines* represent geological strata, the *bright red lines* faults; there might be oil trapped in the folds at the top of the Major Intra-Basin High

2.4 Drilling a Well

Presuming that our analysis so far indicates that we should drill a well, our oil company decides to go ahead. This is the big expense! Our simple prospect will be on land; there are additional considerations for offshore operations that make them even more complex and expensive. Civil engineers will prepare the site for all the facilities needed to support the actual drilling. Specifically, the site needs to be accessible, which may require building an access road; the working area will need to be leveled and well drained; either lined holding ponds or storage tanks will need to be available for the drilling mud; and provisions made for fuel storage, electricity, water, and sewage facilities for crews. The area will need to be fenced and gated to keep wildlife out and for security. Usually an oil or gas company will contract each aspect of the operation to a firm that specializes in that particular task. A contract will be given to a specialist drilling company, which will provide the drill rig and crew to do the actual drilling; subsidiary contracts will be given to companies to monitor the well’s progress, provide safety equipment, do specific tasks such as cementing casing, engineer the drilling mud, do geophysical logging, and whatever else is needed to ensure, as best as possible, that all will go to plan.

The drilling itself starts when the drill bit first enters the ground. This is the *spud date*, which is one of the statistics frequently reported and used for analysis. After drilling has progressed into solid rock, a large diameter pipe called casing will be fitted into the hole and any space between the outside of this pipe and the rock is filled with cement. When this is done properly it ensures that the inside of the well and the rock through which it has been drilled remain isolated from each other. Particularly at shallow depths this isolation is important; it protects fresh water aquifers. The drilling then progresses at a slightly smaller diameter. As the well gets deeper, casing may be used repeatedly; there is an obvious trade-off between necessary isolation of the well from the surrounding rock and the fact that each time a new casing is installed it makes the well smaller. Figure 2.3 illustrates a typical casing program for gas prospects in the Marcellus shale of western Pennsylvania.

When wells have problems, one of the most frequent causes is some sort of problem with the cement between the casing and the surrounding rock.

During the drilling process, the drill bit turns against the rock at the bottom of the well, breaking up the rock. The drill is at the bottom of a heavy steel pipe, the “drill stem.” A heavy fluid called mud is pumped down the inside of the drill stem; it both cools the drill bit as it cuts and circulates back to the surface between the drill stem and the inside of the casing, carrying chips of the drilled rock with it. The mud is a carefully engineered clay slurry; both the physical and chemical properties can be critical, as the properties of the rocks through which the well is being drilled will also vary. The rock chips, called cuttings, are continuously returned to the surface by the circulating mud and are examined. Up to this point, all the information at this particular location has been gathered indirectly, but the cuttings are direct samples of the geology. The information gathered is plotted against the depth, with the result being the well log. Other measurements, for example electrical properties, are also plotted against depth, providing electric logs. These used to require periodic interruption of the drilling so that specialized instruments could be lowered into the well on a cable, with the readings being recorded as “wire-line logs”; today this type of wire-line log may still be used, but many of the measurements now can be made in real time with instruments mounted close to the drill bit and results telemetered to the surface in real time.

When the target depth and rock formation has been reached, it is time to test the well. Almost everything depends on these first tests, which will determine whether the well will produce sufficient oil or gas for it to be an economic success. The tests will measure the rate of production over a period of time. Rates for producing oil wells can be between a few tens of barrels per day up to over 10,000 barrels per day. What is considered “good” will depend on specifics of the individual prospect, e.g., well depth, onshore or offshore location, infrastructure to move the oil to market, and many other factors. Gas wells can produce from a few tens of thousand cubic feet per day to over 50,000,000 cubic feet per day (cfd). Presuming the tests are satisfactory, the next step will be to prepare the well for its life as a producing well; if not, the well will be sealed off with concrete and considered plugged and abandoned.



Fig. 2.3 Casing program in the Marcellus area [Source Frantz (2014)]. The vertical scale has been greatly compressed, as oil wells are typically more than 1500 m (5000 ft) deep

A short digression: How to measure oil and gas

Oil is generally measured in barrels. This is a volume, defined as equal to 42 US gallons. The use of 42-gallon barrels dates back to the mid-nineteenth century beginnings of the US oil industry in Pennsylvania. Over the years, most other producing areas have adopted this standard measure. The notable exception is that the former Soviet Union measured oil by weight, and countries that were within that economic area still frequently report oil production in metric tons rather than barrels.

Conversion between barrels and metric tons is not straightforward. Different crude oils have a range of 6.5 barrels per metric ton (the heaviest oils) to 7.9 barrels per metric ton (the lightest oils). A value of 7.33 barrels per metric ton is generally used if a value for the specific oil is not known.

Natural gas is measured by volume. In the USA this is cubic feet; thousands of cubic feet are generally used (confusingly abbreviated mcf or MCF). In many other countries the measurement is in cubic meters, although the influence of the major US companies will sometimes result in cubic feet being used even outside the USA. The conversion is $1 \text{ m}^3 = 35.315 \text{ cubic feet}$ (or $1 \text{ cubic foot} = 0.0283 \text{ m}^3$). Gas is most often bought and sold by its energy content, which will vary somewhat depending on the specific gas source. It happens that one thousand cubic feet of methane (1 MCF) contains approximately one million BTUs (BTU stands for British Thermal Unit, still used instead of calories or joules or kilowatt-hours as an energy measure in the USA). Quoted gas prices are frequently for millions of BTUs (conveniently thousands of cubic feet). North America has the most developed natural gas markets, and a price of \$3.85 per million BTUs is thus approximately \$3.85 per MCF.

One barrel of oil has the approximate energy equivalent of 5.8 MCF of natural gas. Because both gas and oil can vary in their energy content, using 5.8 for gas-to-oil conversions is yet another approximation. Generally an even more approximate ratio of 6 MCF per barrel is used to convert natural gas to oil equivalents when making regional or global comparisons or summations. Comparisons of either oil or natural gas to other energy sources, such as coal or hydroelectric power, have yet more methodological details to consider. Generally the approach is to convert everything to either barrels of oil (the converted amounts become barrels of oil equivalent or boe) or to kilowatt-hours (kwh). Using the SI energy unit of joules is officially recommended. The units in such comparisons are frequently millions, billions, or trillions and care must be taken with this aspect of any conversion.

2.5 How Much Will All This Cost? Will the Company Make Money?

The basic principles of financing our oil prospect are those of project financing. We can see an oversimplified example of a financial model of our project in Table 2.1. The “Profit after tax” is what many would call the “bottom line.”

While oversimplified to the point of being unrealistic, Table 2.1 is a useful example to illustrate some important points in oil company decision-making. Before we start to analyze our financial model, here are a few more details used in this specific example

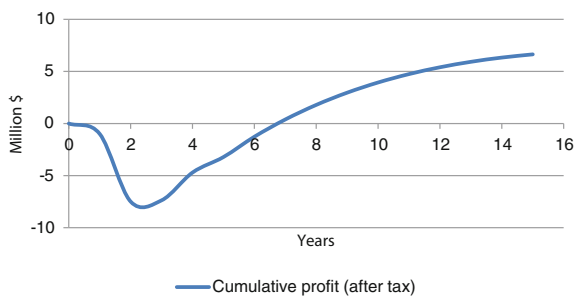
We estimate that the production will decline 12.5% each year from the previous year’s value. This is not realistic, but will allow our model to illustrate some points. More will be said about decline rates later. The oil price will be \$90/bbl throughout our project; this is much higher than the current oil price. Putting in \$40/bbl will make our project uneconomic, but we may keep this in our file and activate the plan if we think prices will return to higher levels in another year or two. The landowner will receive a royalty of 15%. Because of the time to develop the prospect, prepare the site for drilling, and drill the well, we will only see the initial production in year 3. From year 4 the well will produce for 300 days each year; this allows 2 days per month for any maintenance operations, etc.; year 3 will have only a partial year of production. Initially the well will produce naturally as a result of subsurface pressure, but in year 5 we decide that we have to spend an additional \$1 million to install a pump because the pressure is declining. Unrealistically, the production decline curve and days without production in our model are unaffected by this. The operating costs include a flat charge of \$500,000 per year to cover the costs of the corporate office (executives, lawyers, accountants, etc.). In addition, costs directly attributed to this particular producing well will be 10% of the revenue from the well. This governmental jurisdiction has a 10% tax (severance tax), based on the value of oil produced; this is essentially an additional royalty. We will presume that the company is paying a 20% income tax on its profits.

These are very simple assumptions, but they allow us to examine the financial model and call attention to some of the factors that will be considered in making a decision as to whether to drill this well. A first look at this financial model shows that the company will make \$10.2 million from this well before income tax, and \$6.7 million after tax. The after tax number is a guess, because the profits from this project will be combined with profits and losses from other corporate activities to determine the overall company tax.

Figure 2.4 shows the cumulative cash flow for this well.

As we have already noted, the costs are skewed to the beginning of the project. Our company will need to have \$8 million available to invest in this, and it will be only in year 7 that this money will be recovered. If this money is borrowed,

Fig. 2.4 Cumulative profit (cash flow) for a simple project



we would have to pay interest on it; normally a company will include the costs of such investment funds in its financial models to reflect the cost of using money for this particular project.

In addition to the cost of the initial period of negative cash, the time to payout, the time when the company will have at least recovered the money spent, will also be a factor when the company is putting together a portfolio of projects.

Perhaps the first thing that one notices in our financial model is that the price of oil has been kept constant over our project. We are clearly going to have to use an educated guess about this, but it is obvious that whatever this educated guess is, it will be important in the financial analysis. For this reason, oil companies generally adopt a company-wide price forecast that is used in all project evaluations. This allows managers who have to select among projects to have a consistent basis for comparison; the larger oil companies have entire offices whose primary deliverable is the company price forecast.

In addition to having to estimate the oil price into the future, the rate of production also will be an estimation. If our well is being drilled in an area with existing oil production, the initial amounts and decline percentages may be fairly well known. But in less developed areas there may be more uncertainty in these estimations. Costs also have to be estimated into the future. In short, preparing just this simple model will have required the expertise of a number of specialists; they will have used their professional judgement and made their best estimates. There will always be details that are incorrect; the basic question is how incorrect?

Our simple financial model will form the foundation for deciding whether to drill this well. As such, it will be compared with models for other prospects and projects. How best to compare them? The numbers themselves are important, but some calculations will make the job easier. These metrics are an important part of the process.

2.6 Financial Metrics

The first metric that we will consider is the Return on Investment (ROI). We are discussing finances here, so, strictly speaking, this is the Monetary Return on Investment.² But when used in a financial context, which is the most frequent use, ROI is the monetary or financial return on investment. ROI is a ratio, and the financial ROI is defined as:

$$\text{ROI} = \frac{\text{Gain from investment} - \text{Cost of investment}}{\text{Cost of investment}}$$

In our example, we consider the Gain as being the sales proceeds less the operating expenses, and the Cost of investments as the predrilling, drilling and completion costs

$$\text{ROI} = \frac{\$18,438,900 - \$8,250,000}{\$8,250,000} = 124\%.$$

In the above calculation we have ignored the notional income tax that the company will pay on the project returns. If we include this in the calculation, the we get

$$\text{ROI} = \frac{\$14,901,120 - \$8,250,000}{\$8,250,000} = 81\%.$$

This illustrates one of the major problems with ROI analysis—the result can differ depending on what, exactly, is included in the calculation. While ROI is frequently used to compare projects and companies, care must be taken to ensure that each calculation is made in a similar manner. For example, in our simple project we have considered the “pre-drilling” expenses as a capital (investment) item. But are these expenses really investments if they are made before we take the decision to drill the well? Deciding questions such as this is the daily work of the accounting and tax departments (which may use somewhat different definitions and come to different answers). When using the ROI to compare one project to another, both within or between companies, the first consideration needs to be whether the calculation was done in the same way for each.

A second major issue with ROI calculations is that they do not account for timing. The after tax calculation above gives us 81% after 15 years. But if we only look at 8 years, then the same calculation is

²In Chap. 6 we will discuss at some length an energy equivalent calculation in which all values are in energy units. When calculated with energy units the abbreviation always includes an E, EROI, EROEI and EROIE are all used.

$$\text{ROI} = \frac{\$10,049,320 - \$8,250,000}{\$8,250,000} = 22\%.$$

Which figure should we use?

The calculation of ROI highlights an important issue. The “Cost of investment” or capital expenses are not the only expenses in the project—there are also the operating costs, which have to be deducted in order to arrive at the “Gains from investment.” The latter costs are not considered an investment, and hence not included in the denominator of the ROI calculation. These two categories of disbursement are frequently shortened in discussions to “capex” and “opex” for capital expenses and operating expenses. Not only are they treated differently in the ROI calculation, but also they are treated differently in a number of other accounting summaries, and in the tax treatment they receive. This division of expenditures can be discerned by analysis of the financial reports that public companies are required to publish. Conceptually, capex represents the money that the company is investing in its future, whereas opex is the money that it has to spend just to stay in business. While there are some differences in the way the publicly traded oil and gas companies classify their expenses, the capital investment figures are useful in comparing companies. If a company’s capex falls too low, it means that it is not investing in the future. For this reason, capex comparisons are frequently made when choosing which oil companies will be better investments. Within an oil company, it may be important to understand how much capex is being invested in exploration as compared to how much is invested in refining operations; within the oil and gas industry, one might compare capex in oil exploration with capex in gas exploration; and within society it may be useful to understand the capex put into fossil fuels compared to that put into renewable energy sources.

Because ROI ignores the time dimension, how best should this element be incorporated into our project metrics? We have already noted that most oil and gas projects have long project lives and that the cost of invested money is included in financial projections. Two calculations are frequently used to include time considerations: Net Present Value (NPV) and the Internal Rate of Return (IRR). Both are available as formulae in spreadsheets, making them easy to calculate.

The NPV calculation converts all future cash flows to the present at a specified interest rate. By subjecting all such cash flows to these interest calculations, a single “present value” of the project is determined. One way such a calculation could be useful is if we have decided to go forward with our prospect, but before spending any money on it, another company comes and asks to buy the prospect. What should we sell it for? The NPV would be a starting point for such a negotiation because it represents the value today if all the future revenue were available to be invested at the specified interest rate.³ When using the NPV to compare projects, it

³In this situation the rate would be called the discount rate rather than the interest rate. It is the same thing.

is important that the interest rate used in the calculation be the same; hence an NPV should always specify the interest rate used (e.g., NPV at 3%).

Related to the NPV is the IRR, which is simply the interest rate that results in an NPV of 0. This allows different projects to be compared directly with a single number. If we are evaluating two prospects, one with an IRR of 9% and another with an IRR of 15%, the latter is financially the better project. What IRR does not do, however, is take into account the size of the project, so we do not know whether the 15% project will make a meaningful difference in the amount of oil the company has available to sell in 10 years, or will, perhaps, bankrupt the company before production starts—either extreme is possible. Yet in both cases the individual prospect may make good or poor financial sense. A clear presentation of some of these metrics is provided by Henriksen (2004).

All of the metrics for the finances that include the time value of money have one thing in common—the lower the interest rate, the more impact the results many years in the future have on the present evaluation. To put this another way, when interest rates are high, the value of a distant revenue stream is low. Thus, during times of high interest rates projects will skew toward rapid returns. Conversely, when interest rates are low, the time value of money is low and long-term projects become relatively more attractive. Given that many oil and gas industry projects have 30–50 year life expectancies, this is important, although seldom would a one-well prospect be quite so long-lived.

2.7 More Complex Projects

An offshore project may take up to 10 years between the initial decision to go forward and the time of first production. Assuming the first well is a success, several additional appraisal wells may need to be drilled before enough is known about the field to make good decisions about how to produce it. After that, platforms have to be designed, constructed and installed. Then producing wells have to be drilled and completed. Finally, the infrastructure needed to move the oil or gas from the offshore facility to a buyer must be constructed. These projects frequently cost billions of dollars, so our simple one-well spreadsheet is only just the beginning.

But the principles remain the same. It is just that the spreadsheet(s) become much larger and more complex. In practice, specialized industry computer models are used to calculate the projected financial returns and metrics for a prospect.

Developing major gas fields, both onshore or offshore, is typically an equally long-term endeavor. The issue with gas is that it is more difficult to transport than oil. For any significant quantity, either pipelines need to be built or the gas needs to be liquefied. Natural gas is primarily methane, which becomes a liquid when cooled below -162°C . Such a refrigeration plant, when required, is both a major capital expense in the construction budget, and operating it will consume 8% to 15% of the gas originally produced (Foss 2007; Chandra 2014). Again, doing the engineering

design and arranging for construction will consume considerable time and money before the project can be brought “on stream” and the first revenue arrives.

Throughout the development and execution of a prospect the project will always be under financial review. The question is: “are things working out financially?” At some points in the life of the project the question will be given especially close scrutiny. These points will depend, in part, on the amount already invested and the nature of the prospect. For example, in many countries the contract that gives permission to explore and produce oil or gas may require that a certain number of wells be drilled; once such a contract is signed, the question of whether to go ahead with drilling a well takes on a different nature. But, in general, the critical decision points are: whether to acquire the rights and proceed with the project, whether to proceed with drilling, whether to consider the well a success and complete it for production, and at a later time, whether to install a production-enhancing technology (a pump in our simple example), and finally, when to plug and abandon the well.

All business decisions are made with imperfect knowledge. Two of the major risks in our simple oil prospect model are: that the future oil price is not what we have used, and that we do indeed find oil and produce it at the rate projected. There are many factors that affect the future price of oil; experienced, knowledgeable analysts may disagree markedly. In 2014 the commodities group at Citicorp, the global financial institution, projected that oil prices would drop into the \$70 per barrel range while concurrently the CEO of Chevron was saying that “\$110 per barrel oil is the new normal” (Kopits 2014). The only truth is that these two oil price forecasts could not both be correct. We will come back to this issue as we examine the global context of oil in subsequent chapters.

The other major risk is that we will not find the oil we expect. Typical oil fields are at depths of between 1500 and 4000 m (ca. 5000–12,500 ft). While modern seismic surveys, especially 3-D detailed predrilling surveys, can convey a great deal of information about the subsurface, it is only when the prospect has been drilled and tested that we really know the composition of the fluid and rock characteristics. Geologic textbooks notwithstanding, the subsurface strata are not uniform layers of rock; rather, rocks change in their detailed nature both laterally and vertically at a scale of centimeters and meters. So the indirect measurements made from thousands of meters above will naturally be imperfect.

Of course, oil companies do not discover new deposits of oil with “one well” projects. A single-well analysis would be done only as part of developing a larger project—an oil field. But the financial analysis for a multi-well oil field is essentially the same, just more complex. The costs of drilling the wells are all added together, as is the revenue from all the wells, with the calculations being done on the totals. Depending on the geographical remoteness of the oil prospect, the infrastructure costs can easily become significant. This is particularly true when operating offshore, where it will probably be necessary to construct platforms which can easily run into the hundreds of millions of dollars.

2.8 Government Policy Impacts

Before we move on to more than just our single-well prospect, there is one more important aspect that needs to be added to our financial model: government policy. As an example, we will use the government's tax policy with respect to capital investment depreciation. Astute readers will note that Table 2.1 calculates the company tax on the year-by-year results of the cash flow, with no tax if the result is negative and a tax if the result is positive. But capital expenses are generally depreciated; rather than the spending being included in the results of the year it is spent, the amount is spread out over the life of the project. How to spread it out is the province of tax regulations and the way that the company's tax specialists interpret them. To keep our example simple, we will presume that the government where we drill our well taxed entirely on the basis of cash flow at one time (the example already given), but then changed to allow capital expenses to be depreciated in proportion to the amount of oil produced. The revised project finances for this new policy is shown in Table 2.2. What is important to note is that the additional complexity of Table 2.2 relates only to the accounting treatment of various expenses—the real amounts spent and received are the same. These changes, which change only the timing of the income and expenses in the model, result in significantly different project metrics, without changing the cash spent (except for tax payments) or received. Simply by changing the depreciation rules for capital investment in our model the IRR increases from 13% to 78%; the NPV at 3% increases from \$4.4 million to \$6.5 million and the simple cash result from \$6.7 million to \$7.9 million.

There are two underlying reasons for the significant changes in our model. The first is that our simple tax calculation is done year-by-year. When we were investing most of the capital, in years 1 and 2, there was no revenue, and hence no reduction in taxes for these expenses. The negative income, i.e., loss, in years 1 and 2 results in zero tax for those years, without accruing any tax benefit in subsequent years; then in later years the revenue was fully taxed. By taking depreciation in proportion to oil produced, we effectively shift the capital expense to later years in the accounts. The tax in the early years does not change (it is still zero), but the tax in the later years is reduced. That explains the increase in the simple, after-tax result. The second reason concerns the present value and IRR result, and is also an effect of timing differences. For these numbers, the basic issue is that a dollar tomorrow is not the same as a dollar today. A dollar today can be invested at interest, to give more than a dollar tomorrow; viewed in the other direction, it takes a little less than a dollar today to result in a dollar tomorrow, presuming interest is being paid. The amount that needs to be invested today in order to receive one dollar in the future depends on the length of time; the amount today is less for a 50 year investment than for a 5 year investment. As financial people say, "near money is dear money."

All financial models incorporate not just engineering estimates of costs, but also a number of assumptions about the policy and fiscal environments. Government policies with respect to tax treatment are only one policy area that can make a

Table 2.2 A slightly more complicated economic model of a one-well oil field

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Totals
Revenue																
Oil (bbls per day)			250	219	191	167	147	128	112	98	86	75	66	58	50	
Price/bbl	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	
Sales revenue	0	0	21,60,000	59,13,000	51,84,000	45,09,000	39,69,000	34,56,000	30,24,000	26,46,000	23,22,000	20,25,000	17,82,000	15,66,000	13,50,000	3,99,06,000
Expenses																
Predrilling	5,00,000	10,00,000														
Drilling		50,00,000														
Completion			7,50,000		10,00,000											
Total capex	5,00,000	60,00,000	7,50,000	0	10,00,000	0	0	0	0	0	0	0	0	0	0	82,50,000
Royalty			3,24,000	8,86,950	7,77,600	6,76,350	5,95,350	5,18,400	4,53,600	3,96,900	3,48,300	3,03,750	2,67,300	2,34,900	2,02,500	59,85,900
Operating costs	5,00,000	5,00,000	7,16,000	10,91,300	10,18,400	9,50,900	8,96,900	8,45,600	8,02,400	7,64,600	7,32,200	7,02,500	6,78,200	6,56,600	6,35,000	1,14,90,600
Severance tax			2,16,000	5,91,300	5,81,400	4,50,900	3,96,900	3,45,600	3,02,400	2,64,600	2,32,200	2,02,500	1,78,200	1,56,600	1,35,000	39,90,600
Total opex	5,00,000	5,00,000	12,56,000	25,69,550	23,77,400	20,78,150	18,89,150	17,09,600	15,58,400	14,26,100	13,12,700	12,08,750	11,23,700	10,48,100	9,72,500	2,15,30,100
Total expenses	10,00,000	65,00,000	20,06,000	25,69,550	33,77,400	20,78,150	18,89,150	17,09,600	15,58,400	14,26,100	13,12,700	12,08,750	11,23,700	10,48,100	9,72,500	2,97,80,100
Results																
Operating results	-5,00,000	-5,00,000	9,04,000	33,43,450	28,06,600	24,30,850	20,79,850	17,46,400	14,65,600	12,19,900	10,09,300	8,16,250	6,58,300	5,17,900	3,77,500	1,83,75,900
Depreciation ^a	0	0	4,46,549	12,22,429	10,71,719	9,32,172	8,20,535	7,14,479	6,25,169	5,47,023	4,80,041	4,18,640	3,68,403	3,23,748	2,79,093	82,50,000
Profit before tax	-5,00,000	-5,00,000	4,57,451	21,21,021	17,34,881	14,98,678	12,59,315	10,31,921	8,40,431	6,72,877	5,29,259	3,97,610	2,89,897	1,94,152	98,407	1,01,25,900
Taxes (20% of profit)	0	0	91,490	4,24,204	3,46,976	2,99,736	2,51,863	2,06,384	1,68,086	1,34,575	1,05,852	79,522	57,979	38,830	19,681	22,25,180
Profit after tax	-5,00,000	-5,00,000	3,65,960	16,96,817	13,87,905	11,98,943	10,07,452	8,25,537	6,72,345	5,38,302	4,23,408	3,18,088	2,31,917	1,55,321	78,725	79,00,720
Metrics																
NPV @ 3%	-5,00,000	-4,85,437	3,44,953	15,52,828	12,33,136	10,34,218	8,43,726	6,71,237	5,30,755	4,12,563	3,15,055	2,29,794	1,62,662	1,05,766	52,047	65,03,302
IRR	70.5%															

^aThis is oversimplified, as the portion of the capital expense for installing the pump is included in the depreciation for the years before it is installed

difference. Similarly, changes in policy with respect to various operating procedures can change both cost estimates and other aspects of the model. As we have seen, such policy changes have the potential to result in major changes to the metrics of the financial model. It does not matter whether the policy is depreciation rules, tax rates or policies, regulations, subsidies, or whatever, the effect on the financial returns of a project can be significant. Often such policy changes are the result of governmental actions. And this introduces another dimension for risk: political risk. The existing government may “change the rules” by imposing new taxes, changing subsidies, changing regulations, and so forth. One major area of concern for oil and gas companies are the regulations for oil and gas operation: matters as how to dispose of water that is produced along with the oil and natural gas (there is always some), what must be done when a well is finally plugged and abandoned, what weight of trucks will be allowed on the roads, and a host of other issues. Additional political risk can be the changes of government (particularly in countries that do not have long histories of stable governments) and, in some areas of the world, armed conflict.

2.9 Additional Financial Considerations

The finances of our single-well oil prospect illustrate important metrics that oil companies use in assessing their overall projects and programs. Of course, nothing ever works out exactly as planned. Oil geologists are all familiar with “technical successes,” where the exploration concept was essentially as predicted, the well found oil, but some detail meant that the oil could not be produced economically. While the geologist might consider the well a success, for the accountant this was a “dry hole.”

For a company in the oil business, there will always be a number of prospects under evaluation. The business of the company is producing and selling oil, and so to stay in business it must keep finding replacements for the amount that it is currently producing. The process is continuous, with the projects that have the best financial prospects being the ones in which the company will invest its money.

So far our analysis has looked at finding and producing oil, but there is also the question of when does a well or project reach the end of its life. From our model, one can guess that it is when the project is no longer showing a profit. Because the capital costs are primarily at the beginning of the project, and because the amount of oil produced over the years declines, there will come a point at which the operating costs are no longer covered by the revenue being received. At this point, continuing to produce oil from the well creates losses for the company. Plugging and abandoning a well has some one-time costs; just as for the start of the project, these can be modeled and decisions taken in exactly the same way as for the start of the project. This course of action results in the best financial returns for the

company. But unlike the new well, the costs of this operation have to be met from oil or gas that has already been produced.

Two important points need to be made about this end-of-life analysis. The first is that the decision will be made in context. For example, an offshore project will be analyzed on the basis of the entire production platform, not just of a single well. Offshore platforms are expensive to operate and maintain; the decision to decommission and abandon a platform obviously must apply to all the wells on that platform. Some onshore projects have similar infrastructure constraints; hence the operating costs of the Alaska pipeline become a factor when considering costs of continuing to produce oil from Alaska's North Slope.

The second end-of-life point is that just as projects can be bought and sold at the beginning of their lives, so too can this happen as they approach their end. Particularly with small, onshore wells in the USA, the company that started with the well is often not the company that finishes with the well. At any point during the production history of such a well, the future projected production, revenues and costs can be used to calculate project metrics from this time forward. Frequently a smaller operator will have lower overhead costs, and may therefore be able to profitably operate a well longer than a larger company. There is an environmental risk here; as production declines, the well may be successively sold to smaller companies that have lower operating costs, until eventually a well is sold to a company created just to buy this one well, produce it until its purchase price has been recovered, and then declare bankruptcy and walk away, without ever properly decommissioning the facility. Regulation can help, but is unlikely to completely resolve such problems.

2.10 Combining Prospects into Programs

The financial success of an oil or gas company depends on more than the financial success of a single prospect. Indeed, statistics show that US exploration wells are only approximately 50% successful (Petrostrategies 2012). This figure is substantially better than the exploration success ratio in the 1970s and 1980s, which was below 25% (Alfaro et al. 2007); the higher success rates are due primarily to advances in data processing capacity. Outside the USA the exploration success rate has generally been lower, although the fields may be larger. The wisdom in the oil industry is that geologists have to have very thick skins because so many of their recommendations end up as dry holes.

But the higher success rate for the USA does not mean that more oil is found. In 2012 in the USA, the amount of oil discovered was 3 billion barrels, whereas in all the rest of the world it was 28 billion barrels, despite there being fewer wells drilled outside the USA (BP 2014). The conclusion is that, on average, the US discoveries were far smaller than the international ones. But remember that the goal of the company is not to drill wells that produce large volumes, but rather to drill wells that make money by producing oil, whether in small or large amounts. Thus the

success of finding oil by a well is, for a company, only one part of the result; the total picture will be governed by the economic analysis of the costs to exploit the resource discovered and the projected revenues.

2.11 Finding Oil: A Risky Business

Drilling for oil or natural gas is sometimes considered a risky business. But over the past century it has not been so risky from a statistical viewpoint. The insurance industry and the gaming (gambling, bookmaking) industries are, in essence, the same business. Both make money by understanding the risk of a specific action and putting a price on a specific outcome. What makes them both profitable is that the risk profile is known. From actuarial tables or from bets which determine odds, the company can calculate the risk of having to make a payment and therefore determine a price for its service. This is risk. With risk, the outcome of a specific event may be unknown, but because the prediction can be quantified a price can be put on taking the risk. Traditional oil and gas exploration has been a risky undertaking.

Uncertainty is a different sort of thing. In the [in]famous words of Donald Rumsfeld, these are the “unknown unknowns” (Rumsfeld, 2002). Or as expressed by Laurence Peter of The Peter Principle, “some problems are so complex that you have to be highly intelligent and well informed just to be undecided about them”.⁴ There is no way to predict a chance of success because the parameters of the situation are not sufficiently understood to be able to make such a prediction. This distinction between risk and uncertainty and its implications in finance were described by Knight (1921) in what has become an economic classic.⁵

Given that oil exploration is a risky business, but not an uncertain one, the construction of a financially successful exploration program depends on applying appropriate risk adjustments to the financial model or models used. At a program level, “don’t put all your eggs in one basket” is just as valid as for an investment portfolio. Portfolio management professionals have an entire library of methods that are used to design a well-balanced portfolio, but seldom do they discuss the case that a rather high percentage of the investments made will need to be written off entirely, which is the case for traditional oil and gas exploration. When an exploration well is a dry hole, the investment in it is for naught. The obvious conclusion is that the projects that are successful have to be very successful to compensate for the inevitable dry holes.

⁴Quoted in Mainelli and Harris (2011) p. 2.

⁵Uncertainty was a major topic at the time Knight was developing his ideas; his book predates Heisenberg’s better known uncertainty principle in physics by 6 years.

2.12 Gambler's Ruin—The Risk of Failure

Mathematically one of the essential calculations for a company is how to avoid “gambler’s ruin.” This is the situation in which the person or company placing bets on known risks runs out of money before the known risks provide the projected return. To illustrate the point, in a frontier area if we estimate that the success rate of an oil exploration well is 15% it means that we have a failure risk of 85%. If we have \$50 million to invest in the area and each well costs \$7.0 million, then we can drill seven wells before running out of money. Our mathematical risk of running out of money without a success is thus

$$\text{Risk of complete failure} = (85\%)^7 = 0.85^7 = 0.32 = 32\%.$$

However, if we find another company that also has \$50 million to invest in exploration, together we can afford to drill 14 wells and our risk of total failure is

$$\text{Risk of complete failure} = (85\%)^{14} = 0.85^{14} = 0.10 = 10\%.$$

To look at it another way, taking a partial interest in more wells will significantly lower the chance that we will go bankrupt before we find any oil. This explains why so many large exploration and development projects are shared between oil companies. The giant Kashagan oil field in Kazakhstan’s portion of the Caspian Sea, for which cost estimates range from \$46 billion to \$116 billion (Demytrie 2012; Hargreaves 2012), has had at least eight large oil companies involved in the exploration and development at one time or another. As with the individual leasing arrangements discussed earlier with respect to ownership rights, the variety of arrangements, joint ventures, buy-ins, dry-hole contributions, etc., which companies use to balance their risk in such joint projects are infinite in their variety.⁶

Of course, sharing an exploration program with another company requires that the financial model developed in the last chapter will be different. Not only will it show only a portion of the costs because they will be split, but it will also only show the company’s portion of the revenue. Furthermore, the starting point of our model is just that—for entire programs, the company will start by simply adding all the revenues and expenditures together, coming up with a combined financial analysis. Thus, one can speak of an entire program’s IRR or NPV at 10% or whatever.

But to just combine more prospects together presumes that each has the same chance of success. In reality, we may have some prospects that we think have a 50% chance of success, others that have a 40% chance, and so forth. Combining these relies on the concept of expected value, developed by the seventeenth century French scientist and mathematician Blaise Pascal. Pascal developed the basic approach in order to better understand when to place wagers when gambling (Ore 1960). It is a simple concept: multiply the result by the chance of its happening in

⁶For details of the many ways an oil company can spread its risks see Quick and Buck (1983).

order to get the expected value. The expected value from our financial model can be combined with the expected value from other prospects to give an expected overall result.

The same concept can also be applied within the financial model for a single project. Thus, one might apply different chances to the price of oil, to the production rates, to the operating costs, and potentially to a host of other risks within the program. Using computers to test a variety of options quickly becomes a necessity.

2.13 Selection of Projects

What is important is that a company's management will select projects and programs that will provide the best financial returns to the shareholders. As the exploration budget is built up from individual prospects to the entire program the decisions will be made based on the combination of the potential of specific prospects as well as how well the specific prospect fits into the total program.

This bottom-up analysis skews a company towards making a "business-as-usual" set of investment decisions. So long as there are prospects and projects available for which the financial return is positive, this is where a company is likely to invest its money. As project competes against project for management selection, the people who work on specific projects will attempt to "sell" their best projects in this internal process. Indeed, careers frequently depend on successfully doing this. Each time a project comes up for review within the management decision process it will have gathered support from the people who have worked on it and believe it is worth the company's investment. In a large company this effect is replicated as various regional offices compete with one another for funding for their portfolios of projects. And in integrated oil companies, the exploration division must then compete against the refining division and the marketing division, because it is at the corporation level that there is a limit on the amount of capital available.

Management texts, MBA programs and management courses exist to teach ways of combining long-term strategic outlooks with the budgeting process. Most large oil companies are integrated, which is to say that they not only explore and produce oil and gas, they also ship it, refine it, and sell it. There is a story, believable but not verified, that a major oil company had a two-day board of directors meeting each October at which the budget, including the capital budget, for the coming year was decided. Each division of the company—the big requests for capital were from the Exploration and Production Division, the Refining Division and the Marketing Division—had worked long and hard on their presentations for the board, checking their figures and believing that their proposals would be of great benefit to the overall financial and strategic development of the company. So, of course, over the years they spent more and more time and effort on these presentations. Then one

year an outside board member discovered that each division was hiring advertising agencies at the cost of millions of dollars for help in making their sales pitches.

Whether true or not, the tale is believable, because those working within a company are focused on their specific jobs. An exploration office of an oil company exists to explore for and find oil; when one has a hammer everything looks like a nail. Thus, the office will focus on finding oil and the associated planning of exploration and development of oil and gas discoveries; the employees in that office may go home to worry about alternative energy or climate change, but their daily job is to find and promote the best oil or gas prospects that they can. This description of decision-making explains why all industries, not just the oil industry, have a tendency to follow a “business as usual” path.

There is considerable debate both within and outside the oil industry as to how many good prospects are still available. As we will see in Chap. 4, we live on a finite earth, and at some point the supply of good prospects must come to an end. But the history of the industry is full of dire projections which have not come to pass. Today’s view of the oil industry is shaped to a great extent by the period since 1945, and forgets that the world has been “running out of oil” before. Even in the period since 1945, the decade of the 1970s raised concerns that oil would never be plentiful again, only to have two decades of plenty from 1985 to 2005.⁷ The high oil prices that characterized the industry from 2005 until 2014 again raised the question of what alternative sources for oil, and more broadly for energy, exist. At every turn these alternatives do seem to be expensive, although pursuit of them has resulted in at least a temporary oversupply of oil and collapse of prices. But the financial analyses show fewer and fewer good prospects that have the potential to replace oil production over the long term. So having rejected far-fetched alternative investments, many oil companies are turning to providing oil from “unconventional” sources, although as Berman (2015) has noted, “unconventional” in this context is basically a synonym for “expensive.”

From initial idea to abandonment, oil wells and projects are undertaken based on the financial rewards to the company. At every point along the way, the decisions are made by making the best projections of revenue and expenses possible and then comparing opportunities. No company, or even country, can long survive if their decisions are consistently incorrect, which goes some way toward explaining why “business as usual” is the normal evolution of the economy. But this evolution is not always obvious—companies of any size are looking at multiple projects, thus making each company-wide forecast a complex combination of the individual pieces.

⁷Two interesting histories of the oil industry are Sampson (1975) and Yergin (1991).

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