PROJECT X-MEN

Abstract
Field development plan and economic analysis for a fictious reservoir in Permian Basin using Decline Curve Analysis

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Overview

The following report documents a well development plan of a fictious reservoir in Permian basin.

ABC corporation has strategically acquired around 1×2 mile asset in the Permian Basin during Covid-19 downturn at fire sale prices.

Initial analysis such as volumetric calculations, PVT analysis (which includes relative permeability curve plot) allowed for a clear understanding of the reservoir characteristics such as original oil and gas in place. Decline curve analysis was executed to provide a forecast of the oil and gas productions, thus, allowing for an accurate picture of the production of the reservoir via different simulations on number of wells drilled.

Furthermore, an economic analysis of this plan was examined to conduct the sensitivity for the number of wells based on NPV and RQI for this reservoir on two scenarios:

1. **Scenario 1 – No restriction on CAPEX**
2. **Scenario 2 – CAPEX Restriction of $20 Million**

All the calculations have been done using Python and excel and copy of the code has been attached with the email.

Introduction & Assumptions

This development plan evaluates the reservoir conditions which is shown in the picture below. The box represents 1X2 mile asset which has been recently acquired by ABC. My job in this project is to investigate several production forecasting scenarios to maximize the primary oil recovery from the reservoir and perform economic analysis to consider the estimated profits.

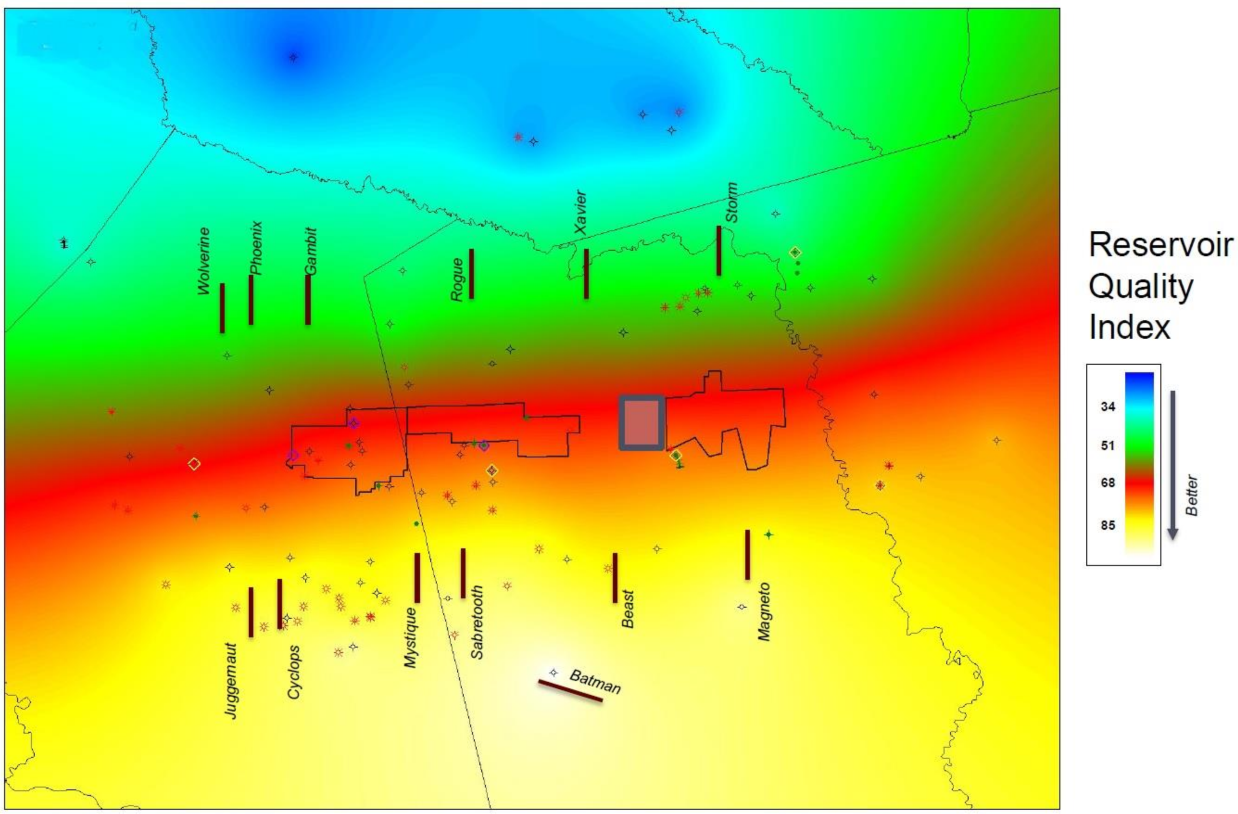

Figure 1: Map showing acquired asset in black box in Permian Basin

I downloaded all the public data and found 13 different pads in the area in the same formation. I averaged well data per pad and all wells have their own separator. (Production data for all the 13 well pads have been attached)

Furthermore, I am assuming that the formation which we are targeting is upper Wolfcamp B, single bench (i.e. no stacking, "wine racking" to be considered), no 'parent-child' effects. Also, spacing-wise, I am assuming no edge well effects (i.e. edge wells are impacted as much as wells in the middle of the pad).

I have also assumed Black Oil, single phase system. For simplification, gas has been fixed at GOR = 3MSCF/BBL and Watercut = 70% constant.

Below I have summarized the assumed reservoir properties which will be used in our calculations.

Reservoir Properties	
Average Thickness (h)	200 ft
Average Porosity (ϕ)	0.3%
Initial Water Saturation (S_{wi})	20% in the oil zone
Average Reservoir Pressure (P_i)	7584 Psia
Initial Oil formation volume factor (B_{oi})	2.57

Table 1. Reservoir Properties characterizing the proposed reservoir.

Volumetric Calculations

The original oil in place (OOIP) or **'Reserves'** can be calculated by formula below:

$$OOIP = \frac{A \times h \times 7758 \times \emptyset \times (1 - S_{wi})}{B_{oi}}$$

Where,

OOIP = Original Oil in Place in Stock Tank Barrels (STB)

Φ is the average porosity

S_w is the average water saturation
A is area of the reservoir in Acers
h is average thickness of the oil zone
B_{oi} is the Initial Oil formation volume factor in Rbbl/stbbl

As we know, ABC has acquired 1×2 mile asset, whose total area is **2 square miles or 1280 Acres**.

1 section comprises of 1 square mile area. Therefore, ABC has 2 sections each of 640 acres. The reason why I am mentioning the area of the asset is because it will be used in calculating our total of that area of reservoir acquired by ABC.

When we put all the values in our reserves equation, our OOIP comes out to be:

$$\boldsymbol{OOIP = 1854675\ STB\ or\ 1855\ Million\ STB}$$

PVT Property Analysis

To better optimize the production of the reservoir it is important to understand the permeability of the porous media to both oil and gas. The necessary data to construct the relative permeability curves was collected and presented to us for analysis. The saturation and permeability data can be found in Table 2.

S_g	S_o	k_{rg}	k_{ro}
0.03	0.97	0.00	0.849
0.11	0.89	0.01	0.530
0.19	0.81	0.03	0.311
0.27	0.73	0.08	0.168
0.35	0.65	0.16	0.081
0.43	0.57	0.27	0.033
0.51	0.49	0.42	0.010
0.59	0.41	0.59	0.002
0.67	0.33	0.79	0.000
0.75	0.25	1.00	0.000

Table 2: Relative permeability data for oil and gas as a function of saturation.

Using this data, the relative permeability curves were constructed. The relative permeability curves are presented in Figure 2 (next page).

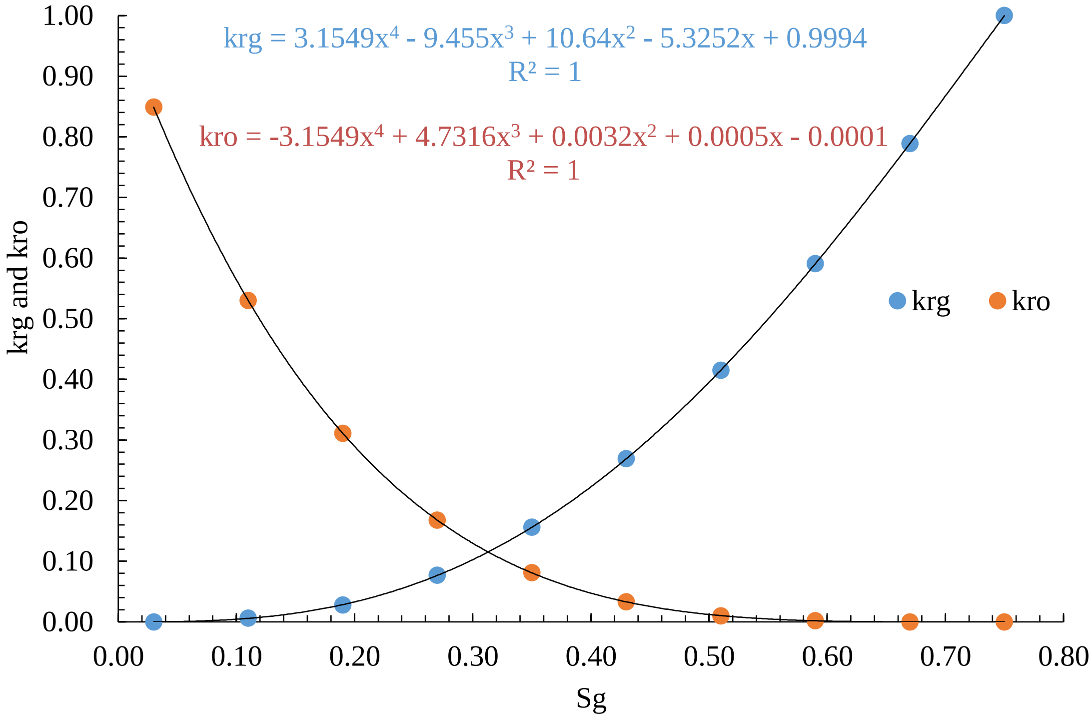

Figure 2: Relative permeability curves.

Forecasting using Decline Curve

When we look at the map, we see that well 'Beast' is closer to the acquired asset. Therefore, we will perform our decline curve on 'Beast' well. Once we perform decline curve using python using powerful library SciPy optimize, we get the results as shown below:

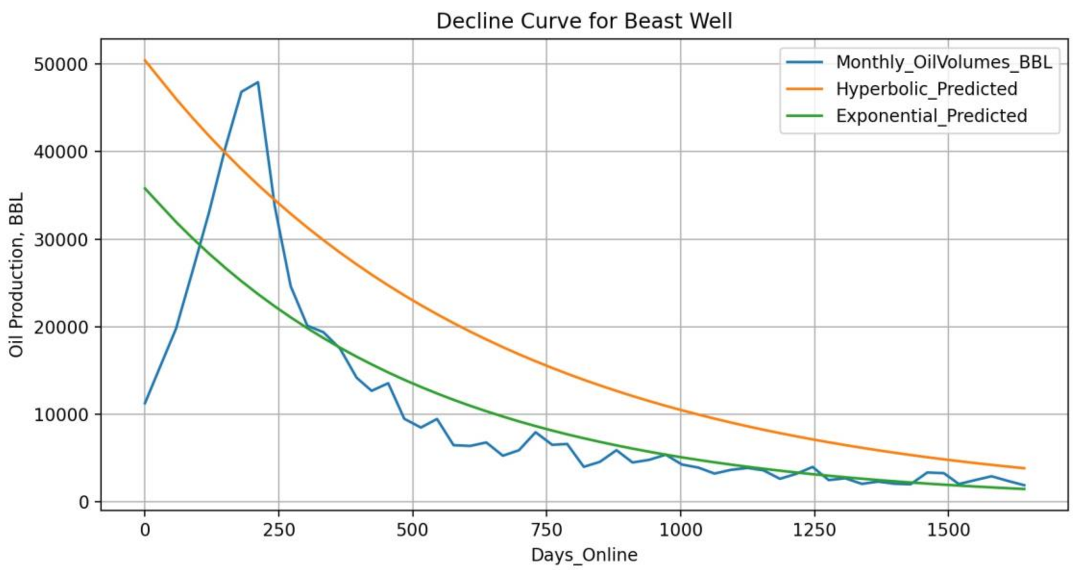

Figure 3: Decline Curve for 'Beast Well'

From the above figure, exponential decline best fits the monthly oil production. Below are the values for exponential decline:

- Maximum initial production, $q_i = 35787\ BBLS/Month$
- Daily Decline Rate, $D_i = 0.0019$
- Monthly Decline Rate, $D_i = 0.0592$

Let us assume that the economic rate is 30 STB/Month, therefore our EUR up to the economic limit and time in months will be:

- **Economic rate = 30 STB/Month**
- **Economic Ultimate Recovery (EUR) = 603 MSTB**
- **Time to reach EUR = 120 months or 10 years**
- **Remaining Reserves = 601 MSTB**

Below we see the figure where we forecast up to the economic limit rate.

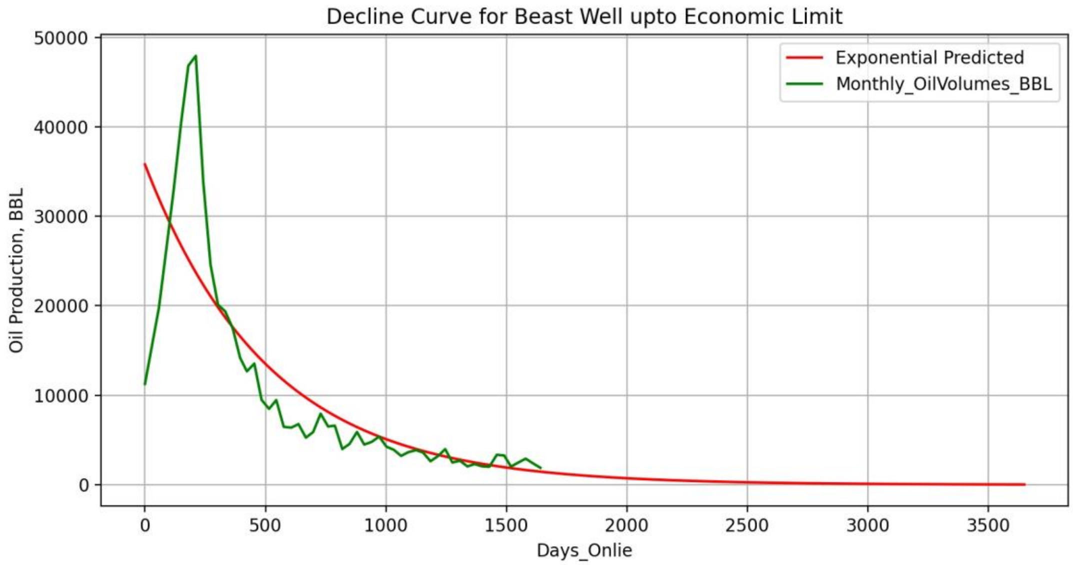

Figure 4: Decline Curve for 'Beast' Well up to the economic limit

After forecasting, we will move towards field development and economic analysis.

Economic Analysis

The most important part in the development of a reservoir is the economic plan/analysis. The objective is to maximize the profit, and this can only be done by achieving maximum production. Of course, the reservoir cannot simply be exploited for maximum production as the reservoir could be depleted resulting in a significantly lower recovery factor. The balance to accomplish both the largest production possible while still maintaining the integrity of the reservoir is the driving force of this economic analysis.

I have assumed following Economic Parameters for our economic Analysis:

Job	Value	Rate
D&C Cost	$2325000	/well
Fracturing	$300000	/well
Oil Price	$60	/STB
Gas Price	$3.1	/MSCF
OPEX	$60000	/Year
Facility Cost	$100000	Beginning
Working Interest (WI)	100	%
Net Revenue Interest (NRI)	75	%
Severance Oil	4.6	%
Severance Gas	7.5	%
Ad-Valorem	2	%
Discount Rate (Annually)	20	%
Discount Rate (Monthly)	0.6667	%
Net Oil Price after taxes	$42	/STB
Net Gas Price after taxes	$2.1	/MSCF

Table 3: Economic Parameters

Net oil and gas prices are calculated by using following equations:

$$Net\ Oil\ Price = Oil\ Price\ \times NRI\ \times (1 - Severance\ Oil - Ad_{Valorem})$$

$$Net\ Gas\ Price = Gas\ Price\ \times NRI\ \times (1 - Severance\ Gas - Ad_{Valorem})$$

One of the main factors in determining the optimal plan for development of this reservoir are the total number of wells drilled throughout the lifespan of the project.

The optimum number of wells can be determined analytically by finding the maximum economic return from an equation that expresses the net present value of the project over its useful life as a function of the number of development wells, following Muskat´s proposed economic method.

We will add wells one by one and calculate NPV for the given economic parameters and total cumulative production of oil and gas. The wells where we get maximum NPV, will be our total number of optimum wells required as shown in below figure.

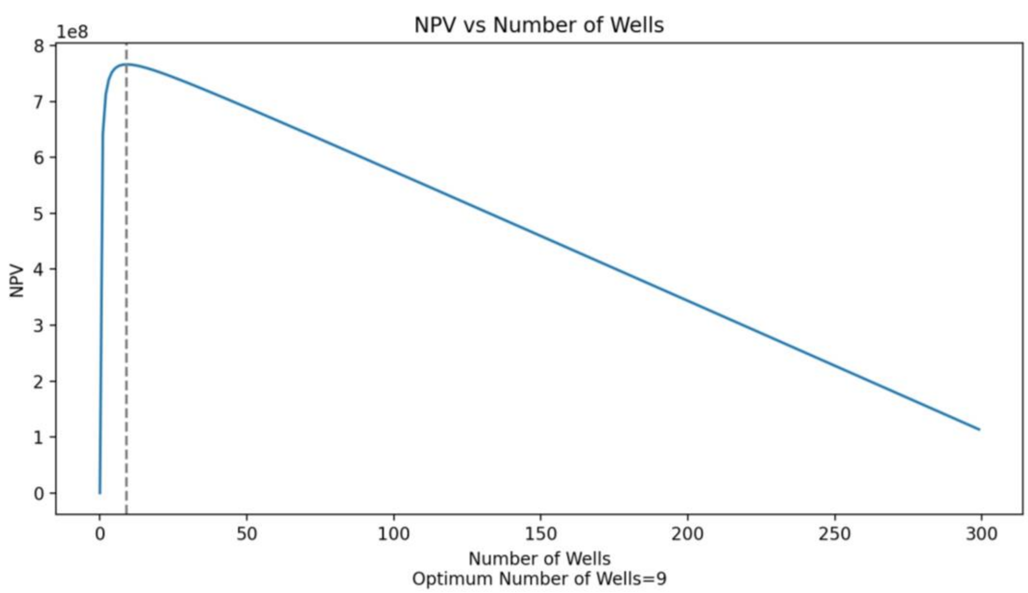

Figure 5: Plot showing optimum number of wells

Maximum wells we can drill are 9 which will give us maximum NPV.

Scenario - 1 (No cap on CAPEX)

For this scenario, as to how many total wells were used for production and in which year they would be drilled. Table 4 presents the scenario for which this analysis was conducted.

Time Years	Wells Added	Total No of Wells
0	1	1
1	1	2
2	0	2
3	1	3
4	1	4
5	1	5
6	3	8
7	1	9
8	0	9
9	0	9
10	0	9

Table 4: Well Pattern Drilled in Total 10 years

NPV plot was generated for this scenario in figure 6 below.

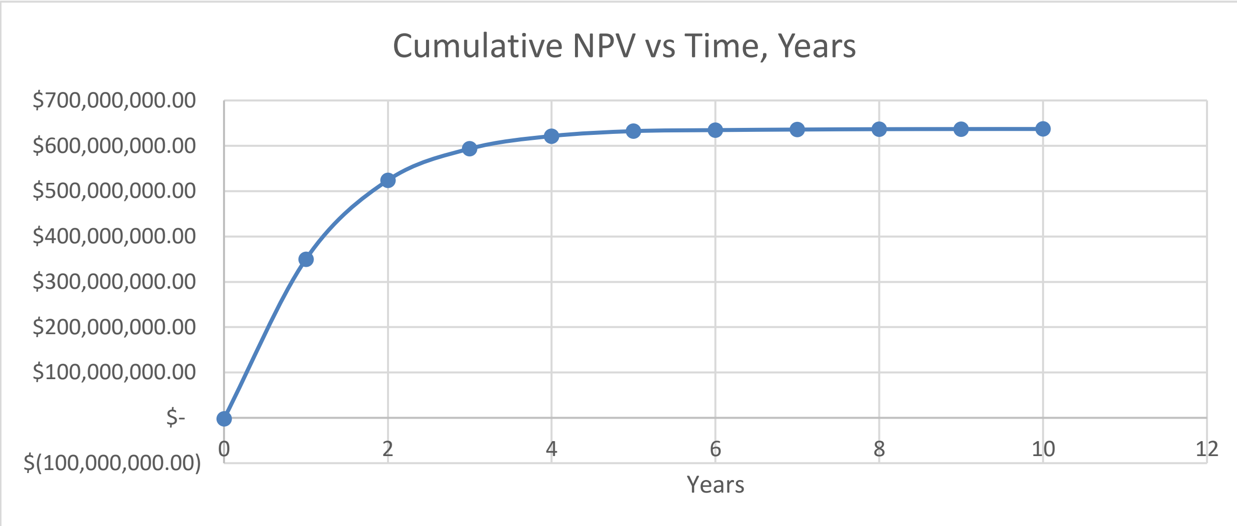

Figure 6: Cumulative NPV for scenario-1 vs Time in years

In this scenario, following things can be inferred:

1. Total NPV - **$ 637,072,728**
2. Total CAPEX - **$24,625,000**
3. We are breaking even within the 1st year the first well goes into production

Scenario - 2 (Maximum CAPEX - $20,000,000)

For this scenario, we have a cap on our capital expenditure of 20 Million Dollars. The only way we could have achieved this target was to drill a smaller number of wells. We will only drill 7 wells in total instead of 9 in the previous scenario. Below is the well pattern drilled in this scenario.

Time Years	Wells Added	Total No of Wells
0	1	1
1	1	2
2	0	2
3	0	2
4	1	3
5	0	3
6	2	5
7	0	5
8	0	5
9	2	7
10	0	7

Table 4: Well Pattern Drilled in Total 10 years for scenario 2

Total NPV plot for scenario 2 is shown below.

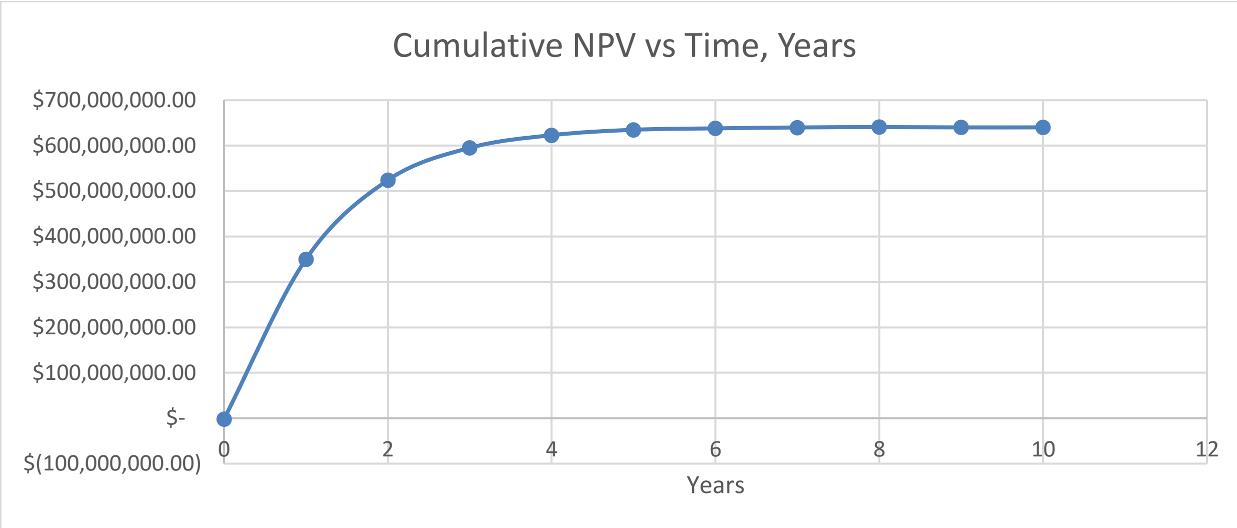

Figure 7: Cumulative NPV for scenario-1 vs Time in years

Following things can be inferred in this scenario – 2:

1. Total NPV - **$ 640,240,965**
2. Total CAPEX - **$19,375,000**
3. In this scenario as well, we are breaking even within the 1st year of production.

As we can see, our total capex (**$19,375,000)** is less than the maximum CAPEX of **$20,000,000.**

Next, we will tabulate and compare the results.

Results

<u>**Parameters**</u>	<u>**Scenario - 1**</u>	<u>**Scenario - 2 (Max CAPEX - 20 $M)**</u>
Total NPV	$637,072,728	$640,240,965
Total CAPEX	$24,625,000	$19,375,000
Total No of Wells	9	7

Table 5: Results Table

With these results, the proper recommendations can now be made.

Conclusions and Recommendations

In terms of NPV, the most favorable scenario was found to be scenario-2 when we drill only 7 wells. Though the NPV margin between scenario 1 and scenario 2 is of just roughly 3 $M, there are multiple reasons which made me recommend scenario 2.

We have passed the golden era of 2010 where the crude oil price was more than $100. In coming decade, I believe the prices will be in the range of $50 - $60. Therefore, we need to have an alternative approach of maximizing the profits. We can achieve this by:

1. Smart Drilling: Drilling smaller lateral instead of usual 10,000 feet. By doing so we will drastically reduce our drilling cost, thus reducing our overall CAPEX.

2. Smart Fracking: We know that not all fractures contribute to the production. The tracers we ran on one of the ABC well showed that heel was contributing more than the toe. We should spend money on 3D seismic and logs such as NMR and sonic logs to identify the sweet spot area and drill through more brittle rocks.

3. Last but not the least, I may go as far as to saying that we should keep the drilling to minimum and think about refracking the existing wells, thus maintaining the production for longer period.