PROBABILISTIC NODAL ANALYSIS AND ECONOMIC APPRAISAL OF CASCADE & CHINOOK DEEPWATER FIELDS TO OPTIMIZE DECISION MAKING ABOUT FIELD DEVELOPMENT OPTIONS

A Thesis

by

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ABSTRACT

This study provides an integrated technical and economic assessment of the Cascade and Chinook deepwater field development using Probabilistic Nodal Analysis (PNA), incorporating oil and gas price uncertainty to optimize decision making about field development options. The petroleum industry in North America has been focusing heavily on unconventional reservoirs, while deepwater reservoirs (Federal Offshore) account for 10% of gross oil production in the United States. This integrated approach will help determine the optimum field development options for an ultra-deepwater field in the Gulf of Mexico (GoM) including a sensitivity analysis accounting for future oil price uncertainty.

Unlike the traditional Arps Decline Curve Analysis (DCA), Probabilistic Nodal Analysis as a production forecasting method takes into account the reservoir properties, the production facilities and historic production data, while capturing the uncertainty of key parameters. PNA provides a range for the estimated ultimate recovery (EUR) from P10-P90, with the most likely value at P50. Assessing the possible outcomes increases the odds the optimal decision will be taken for a project, optimizing field development decisions including number of wells, the facilities to be used and whether the field should be produced under natural drive, artificial lift or waterflooding.

Economic analysis based on the probabilistic production curves, along with oil price sensitivity, will help determine the respective project’s minimum commodity price to be economically viable, which is essential since the volatility of oil prices may threaten

profitability of offshore projects more than onshore projects. For the base case of $60/bbl, the P50 EUR for Cascade and Chinook increases by 42% and 45% respectively when using artificial lift compared to natural drive. Despite the increase in production, the P50-NPV@10 for Cascade and Chinook remains negative for the current development using a base case oil price of $60/bbl. Only with the addition of new wells using artificial lift in the Chinook field will the NPV@10 become positive at $146 million when produced with two wells, and $163 million by adding a third well, with the latter option having a higher risk; these are base case results for $60/bbl. In addition, project viability is assessed in a sensitivity analysis with oil prices ranging from $30 to $90.

DEDICATION

This thesis is dedicated to my mother, Dinorah Barnes, whose unconditional love and encouragement made it possible for me to be here. She taught me by example that anything can be achieved through perseverance and hard work, and has always inspired me to strive for excellence. I also include my siblings whose kindness and friendship boost my desire to never stop improving; my whole family who motivated me throughout my studies; and a special person who gave me strength when I encountered difficulties.

ACKNOWLEDGEMENTS

I would like to thank my committee chair, Dr. Weijermars, for his guidance and the opportunity to assist him in a shared passion for current projects relating to the Mexican energy reform. I would also like to thank Dr. Alves for his constant support and insightful conversations; Dr. Blasingame for inspiring me to strive for perfection and the search of knowledge; Dr. Ayyoubi from Petrobras for his valuable assistance on using FieldPlan®; Terri Smith for her constructive suggestions; John Richardson for his help in writing VBA codes used in my study.

Thanks also go to my family for their unconditional support and encouragement during my studies, and friends for making my time at Texas A&M University a great experience.

CONTRIBUTORS AND FUNDING SOURCES

Contributors Section

Part 1, faculty committee recognition

This work was supervised by a thesis committee consisting of Professor Dr. Weijermars [advisor] and Dr. Alves, Professors of the Department of Petroleum Engineering; and Professor Dr. Blasingame of the Department of Petroleum Engineering and Geology.

Part 2, student/collaborator contributions

Dr. Ibere Alves provided me with the deterministic Nodal Analysis model, and John Richardson helped develop the VBA code to automate the economic model. All analysis for the thesis were completed independently by the student.

Funding Sources Section

There are no outside funding contributions to acknowledge related to the research and compilation of this document.

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INTRODUCTION

A paradigm shift occurred in the deepwater Gulf of Mexico (GoM), spearheaded by the development of the Cascade and Chinook fields using a Floating Production Storage and Offloading (FPSO) unit. The use of the FPSO solution in the GoM required legislation changes in the US (Jones Act, see later). The FPSO development, launched by Petrobras, is now adopted by Shell in the Stones Project. In an earlier study, we demonstrated the FPSO solution is the most economical solution for deepwater assets under certain conditions, like when a pipeline network is not available (Weijermars et al 2017; Blasco et al 2016). The FPSO field development solution is likely to become increasingly popular in the development of the Mexican GoM, which is why this thesis will focus on an in-depth technical assessment of Cascade and Chinook field development options, based on probabilistic nodal analysis.

Decisions should be carefully analyzed to optimize the project's net present value (NPV). The economic viability of the Cascade and Chinook projects was greatly diminished by the low oil prices in 2015 and 2016, along with many others. Performing a sensitivity analysis using various oil price scenarios and the probabilistic production forecasts to calculate the current project NPV will determine whether to continue or kill the project, or explore different development options to overcome the adverse effects in field economics of the low oil prices.

A generalized schematic of the work flow used in this study is shown in Figure 1. The production forecasting is shown in green, the economic appraisal shown in blue, and the sensitivity analysis and recommendations are shown in orange and grey respectively.

The first step in this study was to collect reservoir and fluid parameters, and monthly production data for each well analyzed in the Cascade and Chinook fields. The historic production data was used to calibrate and validate the nodal analysis model. The reservoir and fluid parameters were used to generate probabilistic production indices, *J*, which were used to generate probabilistic production forecasts (PPF).

The economic model used the PPF to calculate the project's NPV frequency distribution as well as the internal rate of return (IRR). The capital expenditure (CAPEX) and the operational expenditure (OPEX) were obtained using FieldPlan® software by Landmark. We analyzed the project under a range of oil prices to determine the price threshold for which the project would remain economically viable, and to determine which well development promises the highest NPV value.

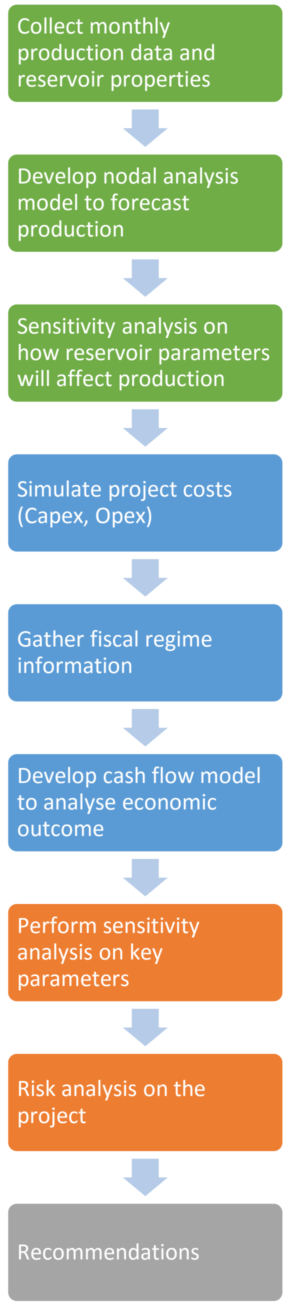


Figure 1 schematic for Probabilistic Nodal Analysis and economic appraisal of an asset. The production section is shown in green, the economic section in blue, and the sensitivity analysis and recommendations in orange and grey respectively.

BACKGROUND

Assets Studied: Cascade and Chinook Fields

The Cascade and Chinook fields, located in the Walker Ridge Outer Continental Shelf, were discovered in 2002 and 2003 respectively. Cascade is located 160 miles south of the Louisiana coast, and Chinook 15 miles southwest of Cascade, at water depths greater than 8,000 ft (Syrio 2013). Cascade is 100% owned by Petrobras while Chinook is operated by Petrobras America Inc. (Operator, 66.67%) in a joint venture with Total E&P USA, INC (33.33%).

The Cascade and Chinook fields both produce from the Wilcox trend, also known as Lower Tertiary, which is characterized by thick pay sections and low permeability (less than 100 mD), high temperatures and high pressures around 250° F and 19,500 psi, respectively, and a low gas/oil ratio of 200 scf/bbl (Moraes 2016). The Wilcox trend in these fields is composed of fine-grained sandstones of the Paleocene and Eocene age, with oil trapped in a salt-cored anticline (Syrio 2013). Net pay for the Cascade and Chinook reservoirs is up to 700 ft, with an average porosity of 20% and oil gravity of 25° API. Oil viscosity ranges from 5-15 cp and the bubble point pressure is 1,000 psi (Mattos 2013).

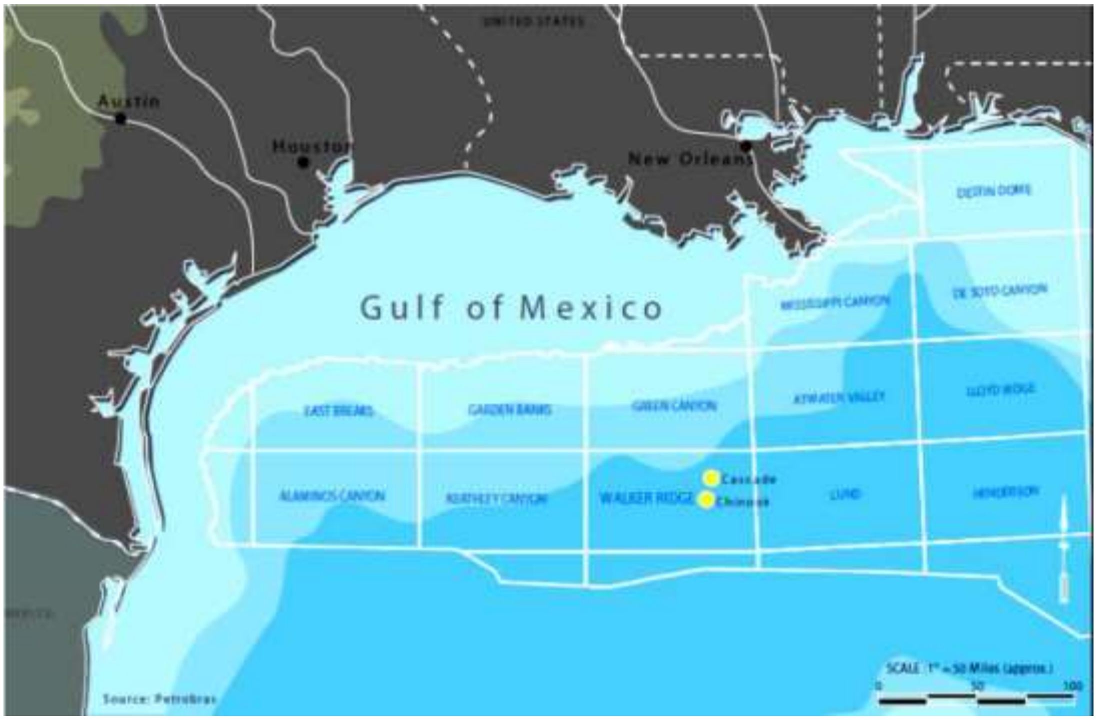


Figure 2 Location of Cascade and Chinook fields (from Mattos 2013)

A total of 8 wells have been drilled: 6 in Cascade and 2 in Chinook (Bagci 2016). The first well in Cascade, CA#1, found oil in Wilcox 1 and Wilcox 2 stratigraphic members. Additional wells appraisal wells completed in the Cascade field are: by CA#BP1, CA#2ST0, CA#2ST1 and CA#3. The appraisal wells were followed by producing wells CA#4 and CA#5BP1. Cores were taken from two wells: 612 ft from Wilcox 1 and 240 ft from Wilcox 2 (Syrio 2013). The two wells in Chinook, CH#3 and CH#4BP2, have taken a total of 540 ft of core from Wilcox 1 and Wilcox 2 (Syrio 2013).

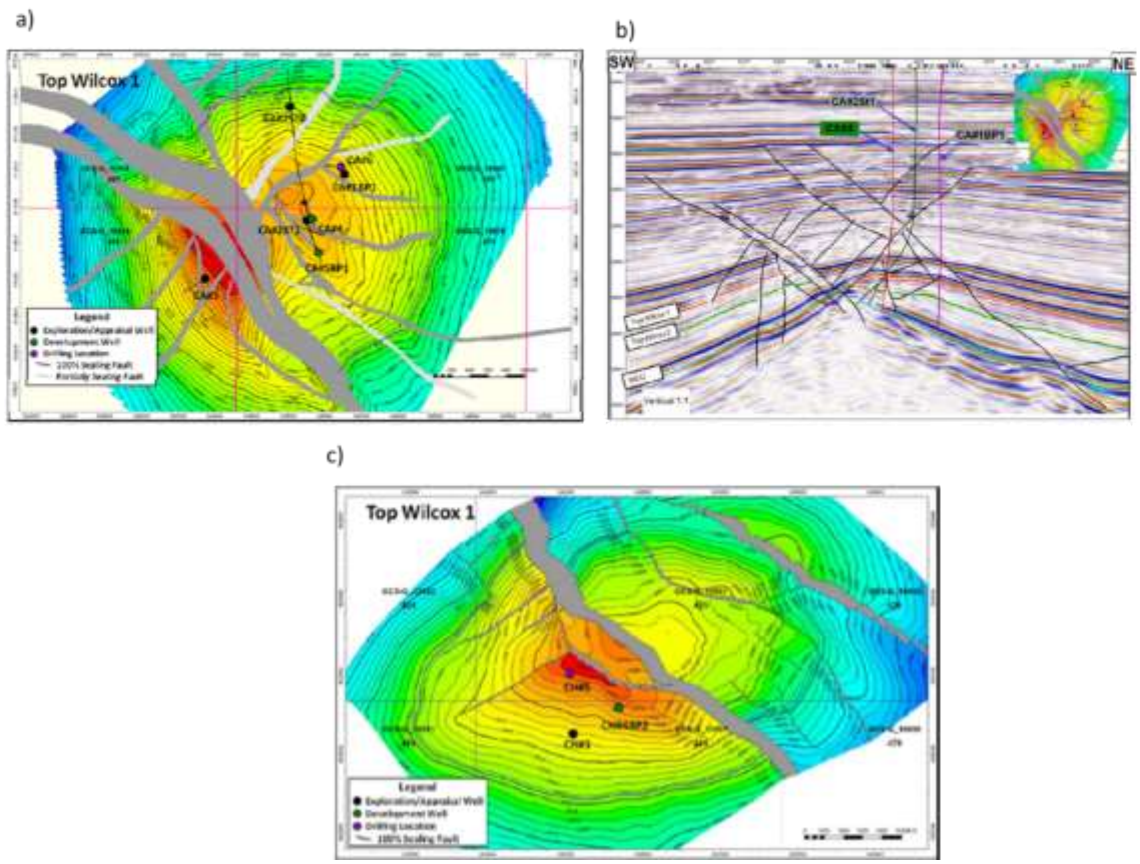


Figure 3 a) Well location in Cascade on the structure map at the top of Wilcox 1, b) the seismic line illustrating Wilcox 1 and Wilcox 2 with the structural interpretation, and c) Well location in Chinook on the structure map at the top of Wilcox 1 (from Syrio 2013).

The remote location of the Cascade and Chinook fields (Figure 4), far from the existing pipeline network, forced Petrobras to look for a more economically viable method of transportation, the FPSO. This FPSO, the BW Pioneer, produces from both fields, with a production capacity of 80,000 barrels per day and a storage capacity of 520,000 barrels (Mattos 2013).

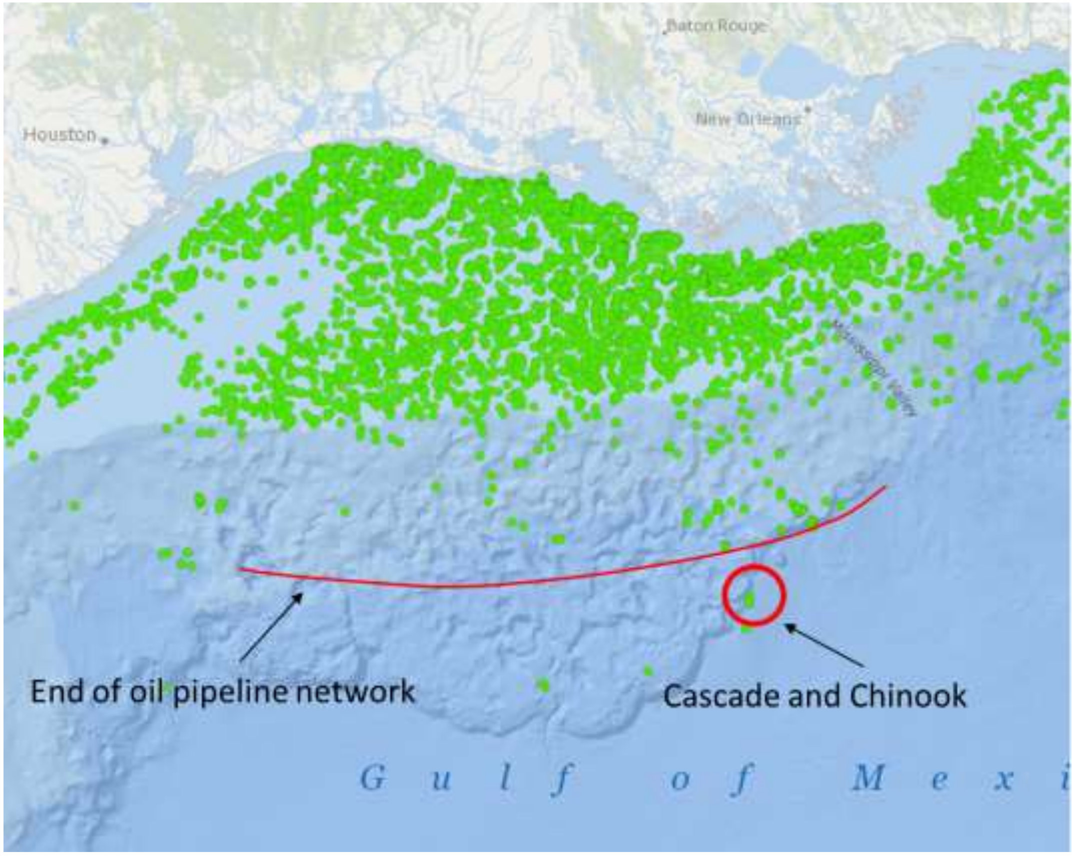


Figure 4 Map showing the location of the Cascade and Chinook fields. No significant oil pipeline capacity existed beyond the red line to keep building outward at an economical price, which is why Petrobras chose the FPSO over a fixed structure (modified from NOAA, 2017)

FPSO Solution in the GoM

FPSOs have been used throughout the world since the 1970s. Shell was the first company to use this development in Spain's Castellon field in1977 (Ganguly 2013). Petrobras followed shortly after with their first FPSO in 1978 in Brazil. This option became increasingly popular in the 1990s. In the US, the concept of the FPSO was accepted for proposals as early as 2002. However, the first FPSO did not come to the US GoM until 2008, with Petrobras' Cascade and Chinook fields. The BW Pioneer became the first FPSO in US waters, and at the time was the world's deepest FPSO lifting production from a mudline at 8,200-ft water depth (Mattos 2013). The flat surface of the GoM coast, and the gradual shift from shallow water platforms to deeper water production devices made oil transportation by pipeline economically feasible (Parshall 2016).

The pipeline network was gradually extended as contractors pursued deeper waters, building outward from the existing network. Once the development of deepwater fields began, pipeline installation became more complex/costly- that is when the FPSO concept gained interest in the GoM. What hindered the use of FPSO in the GoM is the Jones Act, which all vessels in the US must conform to. The Merchant Marine Act of 1920, also known as the Jones Act, was written to promote the growth of commerce in the Unites States. The Act encourages all transportation vessels to be the best equipped and most apt vessels to transport commerce, so they may also serve in the military in time of war or emergency. The Jones Act requires that all vessels used in transportation within ports of the United States and its properties be US-built, the crew had to be US citizens, and the carrying company was to be at least 75% US-owned. Foreign-built vessels that are entirely rebuilt in the US (e.g., the structure of the vessel or the components of the hull), are allowed to transport commerce within the US (LII). Petrobras had to overcome many technical and legislative challenges. They held meetings with regulatory agencies and industry professionals to find a solution for the FPSO. The shuttle tankers used in the GoM must conform to the Jones Act, which can double or triple the price of a tanker compared to that of a non- Jones Act tanker (Lovie 2010). Another challenge was hurricane activity in the GoM: for example, hurricanes Ike, Katrina and Rita together destroyed 172 offshore platforms (Lovie 2010).

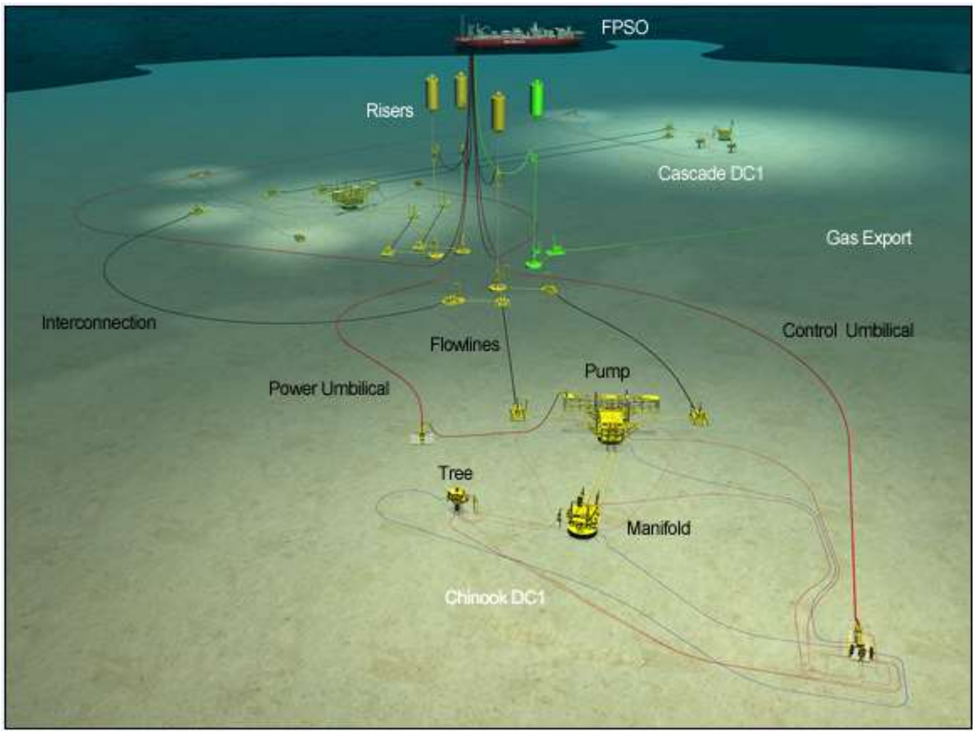


Figure 5 Subsea development diagram for the Cascade and Chinook fields (from Mattos 2013)

METHODOLOGY FOR PRODUCTION FORECAST

Nodal Analysis

Nodal analysis, also called systems analysis, has been used for many years to optimize field development and production. First introduced by Gilbert (1954), nodal analysis integrates every component in the system: from the reservoir conditions, the production string, all the way to the separator (Brown and Lea 1985). Nodal analysis is used to identify the most economical development, to determine whether or not artificial lift is needed and the optimal time to install it, and to determine which component in the system is restricting production (Brown and Lea 1985). Basically, nodal analysis equates the fluid inflow to the fluid outflow at a node, typically at the bottom of the well (Figure 6). For an offshore application, the pressure drop can be classified in the following categories: pressure drop in the reservoir, pressure drop in the production string (including production risers), pressure drop across the choke, and pressure drop in the pipeline (Samizo and Shirakawa 1991).

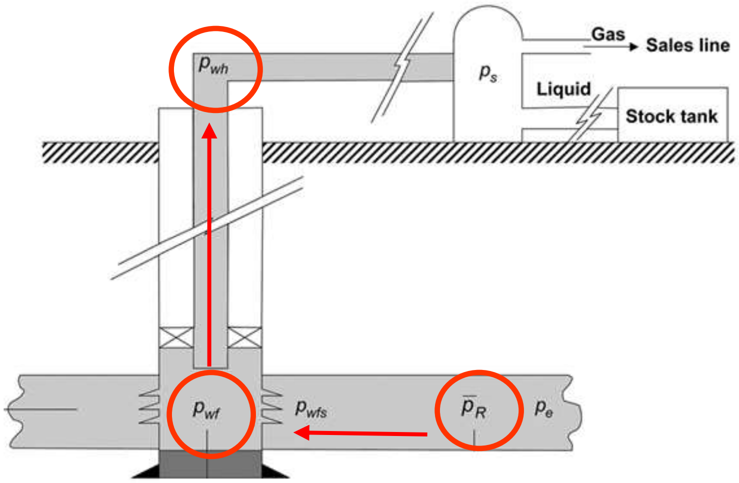


Figure 6 Diagram showing the petroleum production system. We assume a node at the bottom of the well (pwf) to equate the fluid inflow from the reservoir to the fluid outflow going to the separator. While the average pressure $\bar{p}_r$ *in and outflow pressure are equal in* p_{wf} *at all times. Modified from Mach 1979.*

Outflow Performance Relationship

As of July 2016, five production wells were completed in the Wilcox formation pay zones: three are in Cascade and two in Chinook. All the wells in Cascade are producing, while Chinook only has one producing well.

Table 1 List of production wells in the Cascade and Chinook fields with the first production year and their current status

Field	Production Well	First Production	Status
Cascade	CA003	2012	Producing
	CA004	2014	Producing
	CA006	2014	Producing
Chinook	CH002	2012	Shut in
	CH003	2014	Producing

The average measured depth and total depth of the wells was used to provide the geometrical description that represents the lift system by a single model well. We assumed the model well has a diameter of 0.583 ft, a total vertical depth of 25,235 ft and a measured depth of 27,061 ft. The bottom hole pressure required, $p_{wf\,required}$, to produce liquid at a certain flow rate is calculated by the sum of the pressure drops due to potential energy (ΔP_{PE}) given by the fluid density and the true vertical depth, pressure drop due to friction over the entire length of the well (ΔP_F), and the pressure at the wellhead (Figure 6). We assume the pipe diameter remains constant along the wellbore, so the pressure loss due to kinetic energy is neglected. This procedure, as shown in Weijermars et al. (2017) is used to determine the outflow performance relationship at the bottom of the well.

Inflow Performance Relationship

To calculate the inflow performance relationship (IPR) at the node (the bottom of the well in this study), we assume a cylindrical reservoir space with drainage radius r_e and a well with radius r_w. The drainage radius is calculated using the total oil in place divided by the number of wells (Weijermars et al 2017):

$$A_{reservoir} = \frac{5.615N(stb)B_{oi}(rb/stb)}{\phi(1-S_w)h(ft)} \Rightarrow A_{well} = \frac{A_{reservoir}}{\text{number of wells}} \Rightarrow r_e \qquad (1)$$

Where A is the area, N is the original oil in place, B_{oi} is the oil formation volume factor, ϕ is the porosity, S_w is the water saturation, and h is the net pay.

Darcy's equation for pseudo-steady state is used to calculate the IPR above the bubble point, while Vogel's equation (Vogel 1968) is used below the bubble point.

The productivity index, J will dictate the volumetric flow rate (q_o) above the bubble point at a specific wellbore pressure (p_{wf}) and specific reservoir pressure ($\bar{p}_r$).

$$q_o = J(\overline{p_r} - p_{wf}) \tag{2}$$

Where

$$J = \frac{k(mD)h(ft)}{141.2B_o(rb/stb)\mu_o(cp)} \times J_D \tag{3}$$

And

$$J_D = \frac{1}{\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4} + s\right]} \tag{4}$$

The productivity index encompasses essential reservoir and fluid parameters such as permeability (k), net pay (h), oil formation volume factor (B_{oi}), oil viscosity (μ_o), the skin factor (s), and drainage radius (r_e). These parameters are used to calculate the initial productivity index deterministically, and, as shown in Weijermars et al (2017), the final form of the IPR can be quantified by

$$q_o = J(\overline{p_r} - p_b) + \frac{Jp_b}{1.8}\left[1 - 0.2\frac{p_{wf}}{p_b} - 0.8\left(\frac{p_{wf}}{p_b}\right)^2\right] \tag{5}$$

Where q_o is the oil flow rate, p_b *is* the pressure at the bubble point.

Inflow-Outflow Relationship

Nodal analysis is based on the node at the bottom of the well, where the bottom hole pressure, p_{wf}, is shared by both equations used to calculate the fluid inflow and the fluid outflow. We refer to the pressure used to calculate fluid inflow as the pressure available in the reservoir, $p_{wf,\ available}$, and is dependent of the average reservoir pressure, and the pressure used to calculate fluid outflow is referred to as the pressure required, $p_{wf,\ required}$, which is the pressure required to move the fluid from the bottom of the well to the surface. We plot both the IPR and the OPR (also called VLP) as shown by Figure 7, where the intersection of the curves denotes the flow rate the system can produce using natural drive. Over time, the average reservoir pressure will decrease, shifting the IPR curve to the left (blue line to the green line) and thus lowering the flow rate the system can produce (Figure 8). Artificial lift can be used to supply additional pressure to $p_{wf,\ available}$, decreasing the rate at which flow rate declines.

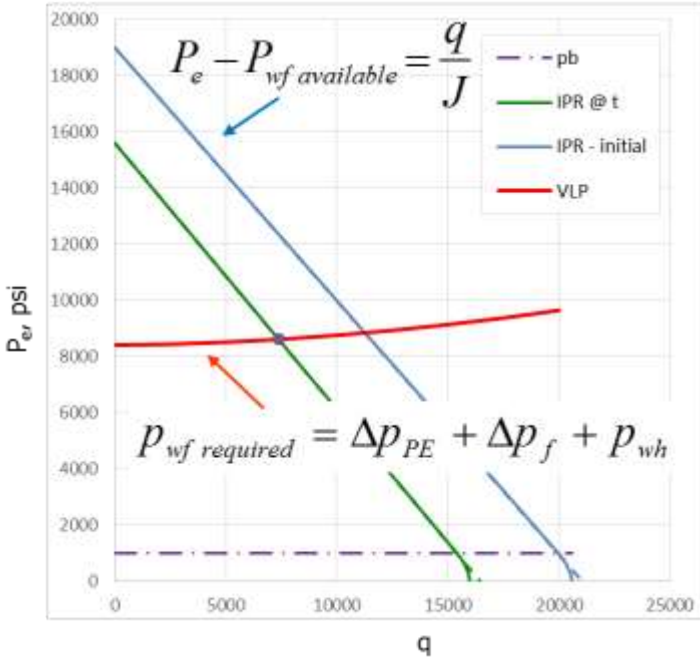


Figure 7 Graph of the IPR curve and the VLP curve used to calculate the oil flow rate. The initial IPR curve (blue) will shift to the left over time as the average reservoir pressure decreases. The new IPR curve (green) will be used to calculate the new oil flow rate.

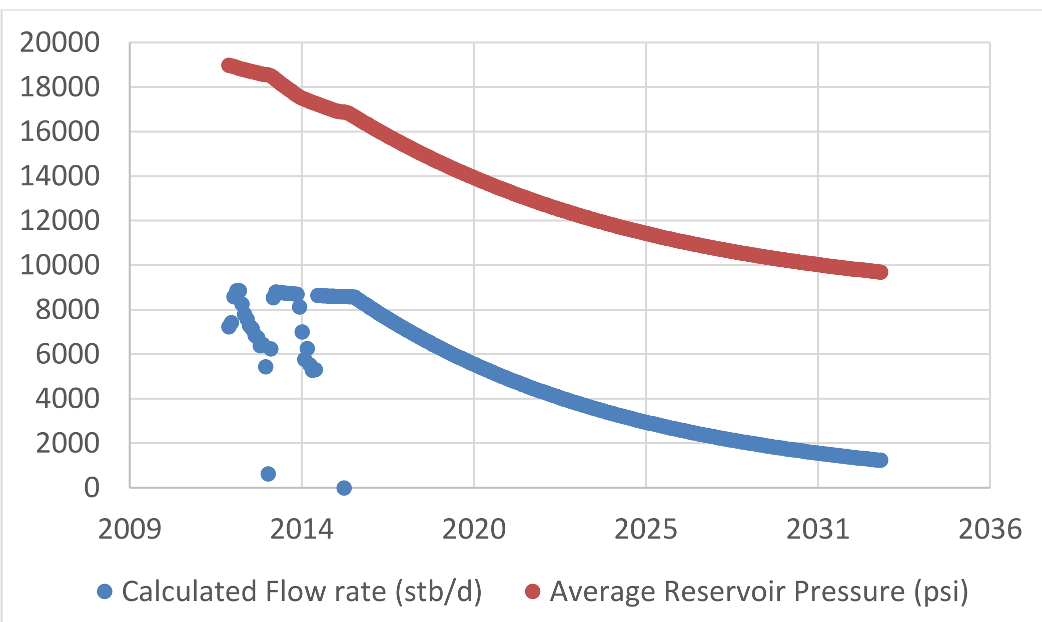


Figure 8 Graph showing the change in the reservoir pressure over time and how it affects the calculated flow rate for P50 Chinook field development using 2 wells and natural drive.

History Matching and Forecasting

The historic monthly production data was matched with the nodal analysis model to determine the pressure drawdown each month. We rearranged Equation 2 to solve for the bottom hole pressure, using the parameters in Figure 9 to calculate the productivity index. The corresponding bottom hole pressure in the IPR curve, $p_{wf,\, available}$, was matched with the required pressure for the OPR, $p_{wf,\, required}$. If the pressure available is larger than the pressure required at a certain flow rate, the system may require choking at the wellhead.

The model is calibrated using the maximum allowable drawdown pressure to calculate the maximum obtainable flow rate and adjusting the reservoir parameters to change the productivity index shown in Equation 2. Figure 10 shows how the production calculated with the model compares to the historic data. The model is considered calibrated when the monthly production (left) calculated with the maximum draw down pressure matches or exceeds most historic data points, and the calculated cumulative production (right) exceeds the historic cumulative production. This approach is like the model validated in Weijermars et al (2017) using the Shell Perdido project, detailed information can be found in section A1 of that paper. The basic nodal analysis model used in Weijermars et al (2017) and in the present study was developed by Dr. Ibere Alves Nascentes (Faculty at A&M). The strength of the model is its excel embedding with a minimum amount of VBA coding to perform the nodal matching of pressures at all time in the history in the history matching procedure. My contribution was to develop the deterministic nodal into a probabilistic model.

Reservoir & Fluids Properties	Value	Unit
Initial reservoir temperature	250	F
Initial reservoir pressure	19000	psi
Bubble Point Pressure	1000	psi
Total compressibility Factor	3.0E-05	psi^{-1}
Permeability	35	mD
Height	562	ft
Skin factor	0	-
Total Oil in Place	2.49E+08	BOE
Water Saturation - initial	0.35	-
ϕ - Porosity	0.167	-
Reservoir volume	2.41E+09	rb
	1.35E+10	ft^3
Reservoir Area	2.41E+07	ft^2
	552.3	acres
Number of wells draining	2	-
Reservoir Area per well	1.20E+07	ft^2
	276.1	acres
drainage area radius, r_e	1956.7	ft
wellbore diameter	7.625	in
wellbore radius, r_w	0.318	ft
API Gravity Oil	19.4	°API
Oil specific gravity	0.938	-
Gas Specific Gravity	0.70	-
Oil viscosity @ p_i	15.1	cp
Compressibility Oil	1.5E-05	psi^{-1}
B_{ob} - (Oil FVF @ pb)	1.380	rb/stb
B_{oi} - (Oil FVF @ pi)	1.053	rb/stb
B_{wi} - (water FVF @ pi)	1.030	rb/stb

Figure 9 Required reservoir inputs (shown in blue) for the nodal analysis model to calculate the productivity index J and to generate production curves

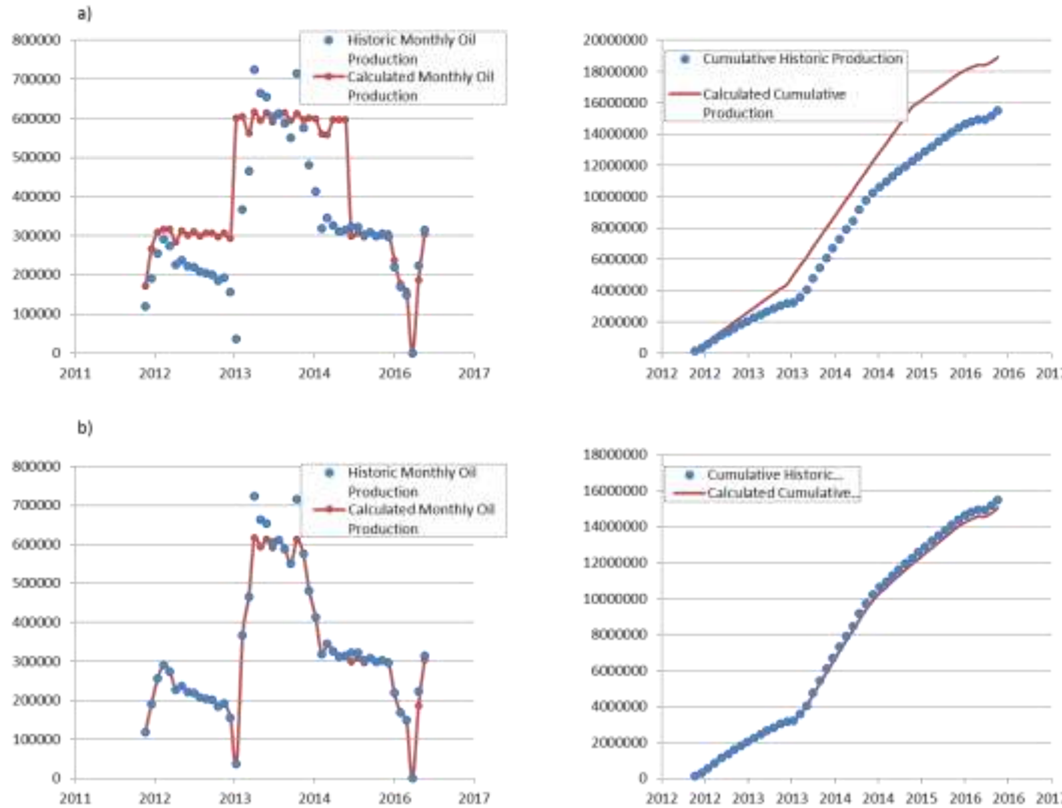


Figure 10 a) Comparison between the historic production (blue) and the calculated production data using the maximum allowable drawdown pressure (red) during calibration of the model. Ideally, the calculated monthly production will reach most of the historic points, and the calculated cumulative production is larger than the historic cumulative production data since the real well will not produce at the maximum drawdown pressure the entire time. b) After the model is calibrated, the model will calculate the drawdown pressure to match the historic production.

The basic deterministic nodal analysis model forecasts future production using the IPR-VLP diagram (Figure 7) to calculate monthly production rates. Material balance is performed after each month to calculate the new average reservoir pressure, generating a new inflow-outflow diagram used in the next month. The drawdown pressure used in the model is the lower of either the maximum allowable drawdown pressure or the difference between the average reservoir pressure and the required bottom hole pressure

($p_{wf,\ available}$ - $p_{wf,\ required}$). The monthly production rate is computed using the productivity index and the pressure drawdown.

Deterministic to Probabilistic

As mentioned in the previous section, the production index contains all the intrinsic parameters of the reservoir and the fluid. *J* is directly proportional to the flow rate; as the production index increases, so will the flow rate as seen in equation 6:

$$J = \frac{q}{p_e - p_{wf}} \tag{6}$$

In what follows, we consistently use lower case 'p' for pressure and capital 'P' for probability. We use the probabilistic porosity and net pay to obtain the probabilistic drainage radius of the reservoir as shown in Equation 7. Then the rest of the probabilistic input parameters are used to obtain the probabilistic *J* in Equation 8. The only probabilistic parameter that affects the outflow performance is the oil gravity. The probabilistic potential energy is calculated using Equation 9.

$$P(A_{reservoir}) = \frac{5.615N(stb)B_{oi}(rb/stb)}{P(\phi)(1-S_w)P(h)(ft)} \Rightarrow P(r_e) \tag{7}$$

$$P(J(t)) = \frac{P(k)(mD)P(h)(ft)}{141.2B_o(t)(rb/stb)P(\mu_o(t)(cp))\left[\ln\left(\frac{P(r_e)}{r_w}\right) - \frac{3}{4} + s\right]} \tag{8}$$

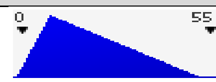
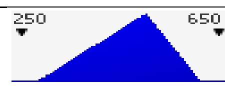
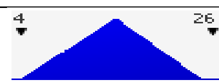
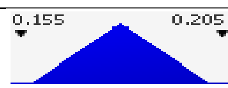
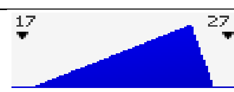
$$P(p_{PE}(t)) = P(\rho_o(t)API) \times TVD \tag{9}$$

Where the oil density is converted from degrees API using Equation 10

$$\rho_o = \frac{141.5}{^{o}API + 131.5} \times 62.4 \quad (10)$$

We used @Risk® to run 50,000 Monte Carlo simulation to generate the probabilistic *J*, assuming 0 skin and the distributions given in Table 2.

Table 2 Probabilistic distributions for the key reservoir parameters used to calculate the productivity index, J, and the ranges for each parameter used for the Cascade and Chinook fields.

Parameter	Distribution	Cascade	Chinook
Permeability (mD)		2-50	2-100
Net Pay (ft)		300-600	300-600
Porosity		16-20	16-20
Oil Gravity (°API)		18-26	18-26
Viscosity (cp)		8-19	5-19

We used the results for *J* with their respective parameter data that correspond to the 10th, 50th, and 90th percentile to generate probabilistic production forecast used for the economic model.

The probabilistic values of *J* and their respective parameters for each corresponding percentile for the Cascade and Chinook fields are shown in Table 3 and Table 4, respectively. The probability density function and the cumulative probability distribution function for both the Cascade and Chinook fields are shown in Figure 11 and Figure 12, respectively.

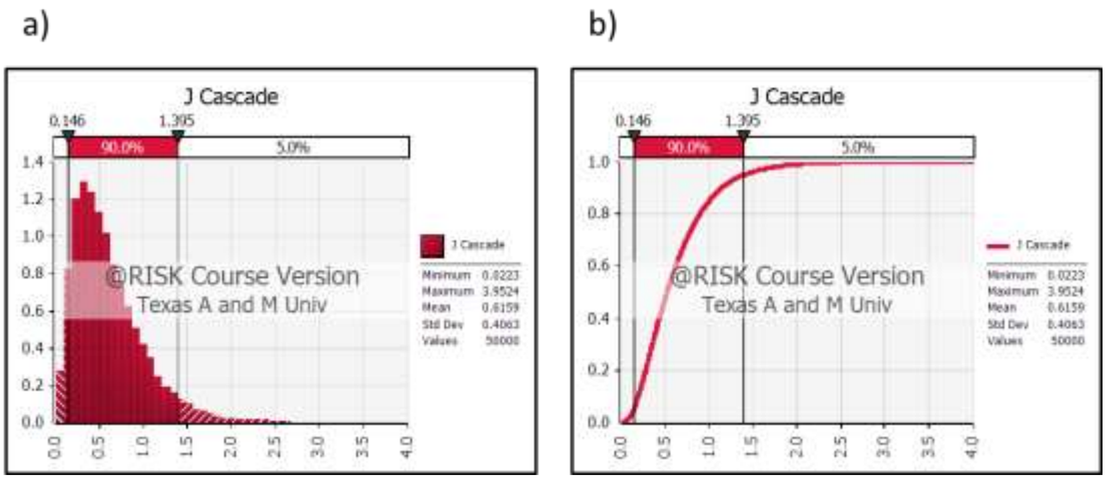


Figure 11 a) Cascade field's probability density function and b) Cascade field's cumulative probability distribution function for the productivity index J

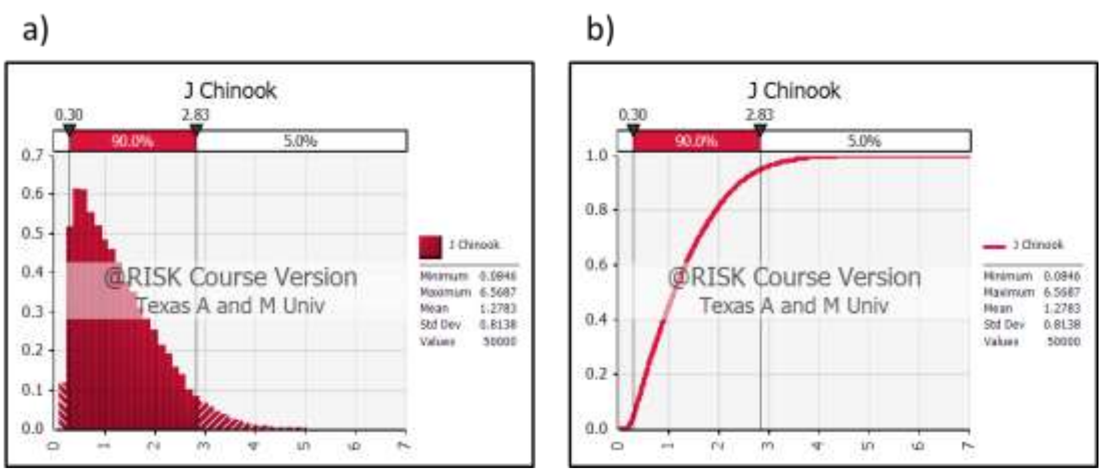


Figure 12 a) Chinook field's probability density function and b) Chinook field's cumulative probability distribution function for the productivity index J

The tornado diagram in Figure 13, generated by @Risk, shows how each probabilistic input parameter affects the values of *J*. Uncertainty about permeability has the largest effect on the production index because the uncertainty of its value is very high (the range is very wide), followed by oil viscosity and net pay, while porosity is shown to have the least impact on *J*. Oil gravity was not shown in the graph because it does not impact the production index *J*.

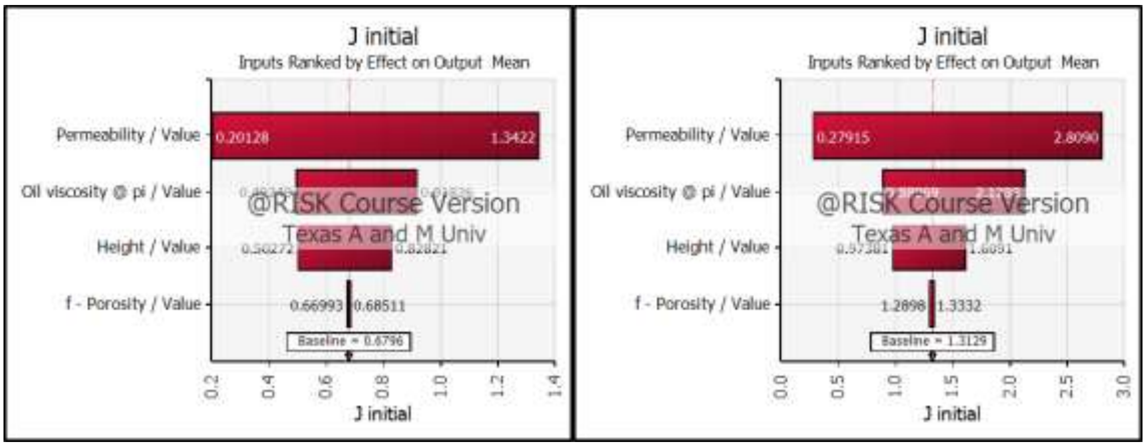


Figure 13 Tornado graph representing the effects the parameters have on the productivity index for Cascade (left) and Chinook (right). Permeability's wide range produces the largest change for J. Porosity's range, on the other hand, is narrow and has little impact on J. The impact of Oil Gravity was negligible and @Risk omitted it from the graph.

Table 3 Probabilistic key fluid and reservoir parameters corresponding to J-P90, J-P50, and J-P10 used for subsequent production analysis for Cascade field

Cascade	**J**	**Permeability (mD)**	**Height (ft)**	**Porosity (fraction)**	**API Gravity Oil**	**Oil viscosity @ Pi (cp)**
J-P90	0.20	9.99	398.8	0.1660	24.0	17.31
J-P50	0.53	25.87	446.8	0.1880	23.9	19.26
J-P10	1.14	32.08	589.2	0.1774	21.8	14.74

Table 4 Probabilistic key fluid and reservoir parameters corresponding to J-P90, J-P50, and J-P10 used for subsequent production analysis for Chinook field

Chinook	J	Permeability (mD)	Height (ft)	Porosity (fraction)	API Gravity Oil	Oil viscosity @ Pi (cp)
J-P90	0.38	10.47	532.7	0.1775	23.4	12.26
J-P50	1.11	35.38	562.4	0.1675	19.4	15.13
J-P10	2.42	77.66	528.4	0.1820	20.9	14.31

The deterministic nodal analysis model is calibrated by adjusting the productivity index and using the maximum allowable drawdown pressure to ensure the reservoir parameters used can provide the flowrate to match historic data. The calculated cumulative production during calibration should be higher than the reported data as we are assuming the maximum drawdown pressure is used the entire production time. The probabilistic model is not calibrated like the deterministic model. For PNA, the probabilistic productivity indices generated are used with its respective reservoir parameters, and the historic data should fall within the P90-P10 range as shown in Figure 14 when using maximum allowable drawdown pressure, with P50 providing the closest match to the historic production data. The J-P10 value was used was to calculate the P10 cumulative production, the J-P50 to calculate the P50 cumulative production, and the J-P90 to calculate the P90 cumulative production.

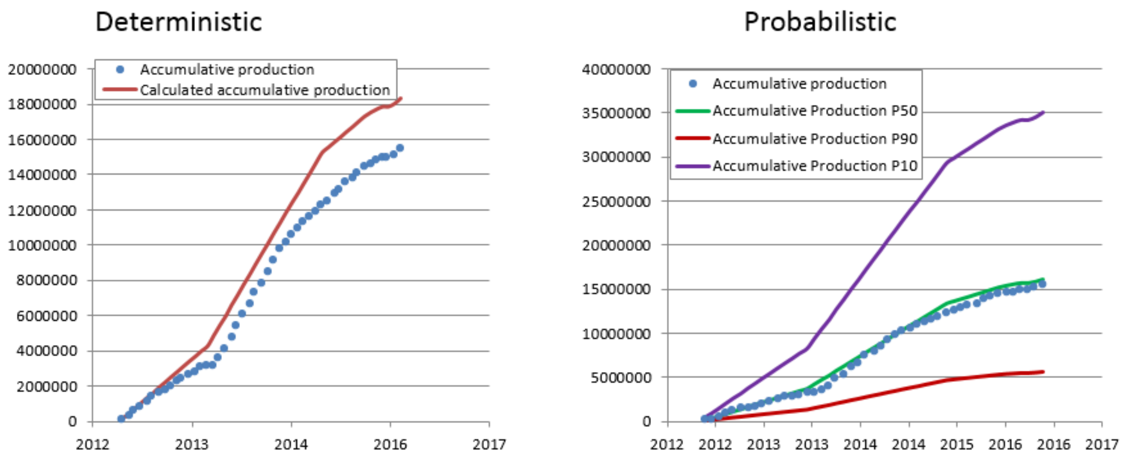


Figure 14 History matching comparison between deterministic model and probabilistic model using the maximum allowable pressure drawdown (used for model calibration in the deterministic model). The J-P10 value was used was to calculate the P10 cumulative production, the J-P50 to calculate the P50 cumulative production, and the J-P90 to calculate the P90 cumulative production.

RESULTS OF PRODUCTION FORECASTING

Hydrocarbon Resource Estimates

The Cascade and Chinook fields are located in the Walker Ridge area, both producing from the Wilcox Play, containing mostly Paleogene age reservoirs. The average recovery factor (RF) of 10% is typically used to estimate reserves in these areas, although many fields have a RF up to 25% using natural drive (Lach 2010). Since, much of the necessary data to calculate original oil in place (OOIP) is confidential, we assumed a 10% RF to back calculate the OOIP. Cascade and Chinook have initial estimated reserves of 19.1 and 24.9 MMbbl (boe), respectively (BSEE 2016). Assuming a 10% RF and the initial reserves given we infer OOIP for Cascade and Chinook to be 191 and 249 MMbbl respectively.

Production Data

Historic production data for the individual Cascade wells (CA003, CA004, and CA006) and Chinook wells (CH002, CH003) were obtained directly from the Bureau of Safety and Environmental Enforcement (BSEE). They provide the individual well monthly production of oil, gas and water, and the number of days per month the well was operating as shown in Appendix B. Oil production data for each well in the Cascade and Chinook fields is shown in Figure 15 and Figure 16, respectively. Chinook only has one remaining producing well since CH002 collapsed on November 2014. All the wells were shut in during May 2016, but production resumed the following month.

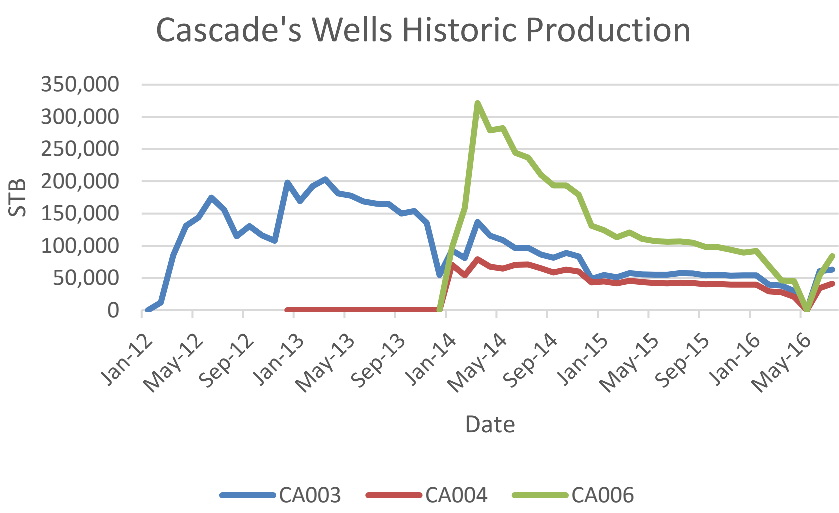


Figure 15 Monthly historic production data for individual wells in the Cascade field (BSEE 2016). CA003 started production January 2012, while the other two wells started producing on January 2014.

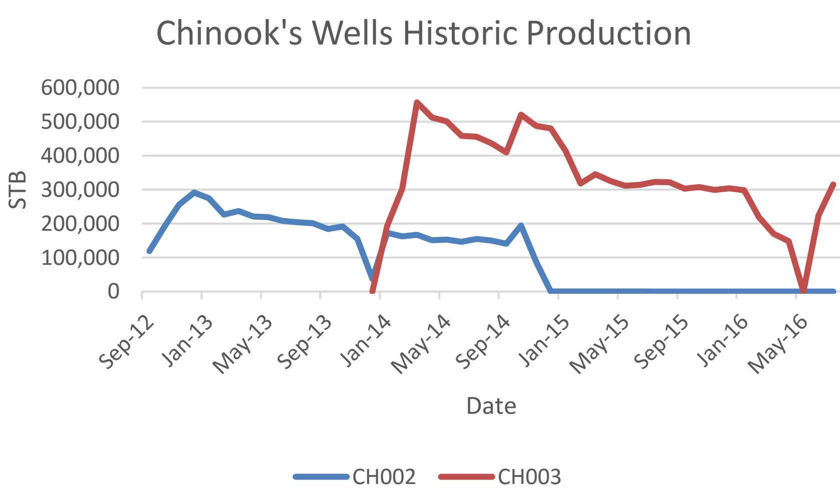


Figure 16 Monthly historic production data for individual wells in the Chinook field (BSEE 2016). Well CH002 started production in September 2012 but stopped producing in December 2014. CH003 began production January 2014.

Production Forecast

We used our probabilistic nodal analysis (PNA) model with the reservoir and fluid parameters in Table 3 and Table 4 to generate the probabilistic production curves. We ran simulations in our model to create six production profiles for each field development analyzed: three production profiles (P90, P50, and P10) assuming the fields would be produced under natural drive and three assuming artificial lift was used. Waterflooding in these fields was omitted since the reservoir has a very active natural aquifer drive. The same probabilistic fluid and reservoir parameters were used for Chinook's field development with either 1, 2 or 3 wells and are given in Table 4. The probabilistic EUR and the recovery factor for the Cascade and Chinook fields assuming natural drive are shown in Table 5, and Table 6 assumes the fields are produced with artificial lift. The significant increase in EUR from natural drive to artificial lift suggest that both Cascade and Chinook should be produced using artificial lift. The minimum EUR estimates for Cascade (19.1 MMbbl) and Chinook (24.9 MMbbl) fields given by BSSEE (2016) were obtained with a deterministic model using volumetric and performance methods, improving the reserves estimates as new data becomes available to them. Our OOIP assumption implied a recovery factor of 10% from the BSEE reported reserves. However, my results give higher recovery factors in all probabilistic cases. If my models used the same initial OOIP, the higher recovery factor claims my reservoir productivity is higher than the one reported by BSSEE (2016). The possible explanation for the difference in EUR estimations (BESSEE vs my results) can be related to the assumed OOIP, to the model used to forecast production, or the reservoir characteristics such as the total compressibility factor. Total compressibility will have a great impact on production, but is not publicly available. Using different values for this parameter will drastically change the results.

Table 5 Summary results for the EUR and their implied recovery factor for the field development of Cascade (3 wells) and Chinook (1 well) fields assuming natural drive

Natural Drive	OOIP MMstb	EUR up to 40 years (MMstb)		
		P90	**P50**	**P10**
Cascade	191	37.4	45.0	45.8
Chinook	249	37.8	53.8	60.6

Recovery Factor	Cascade	20%	24%	24%
	Chinook	15%	22%	24%

Table 6 Summary results for the corresponding EUR and their recovery factor for the current development of Cascade (3 wells) and Chinook (1 well) fields assuming artificial lift

Artificial Lift	OOIP MMstb	EUR up to 40 years (MMstb)		
		P90	**P50**	**P10**
Cascade	191	51.5	63.8	68.8
Chinook	249	43.0	77.9	90.2

Recovery Factor	Cascade	27%	33%	36%
	Chinook	17%	31%	36%

The probabilistic production forecasts from month 55 (August 2016) onward for Cascade's field development with 3 producing wells assuming natural drive and artificial lift are illustrated in Figure 17 and Figure 18 respectively.

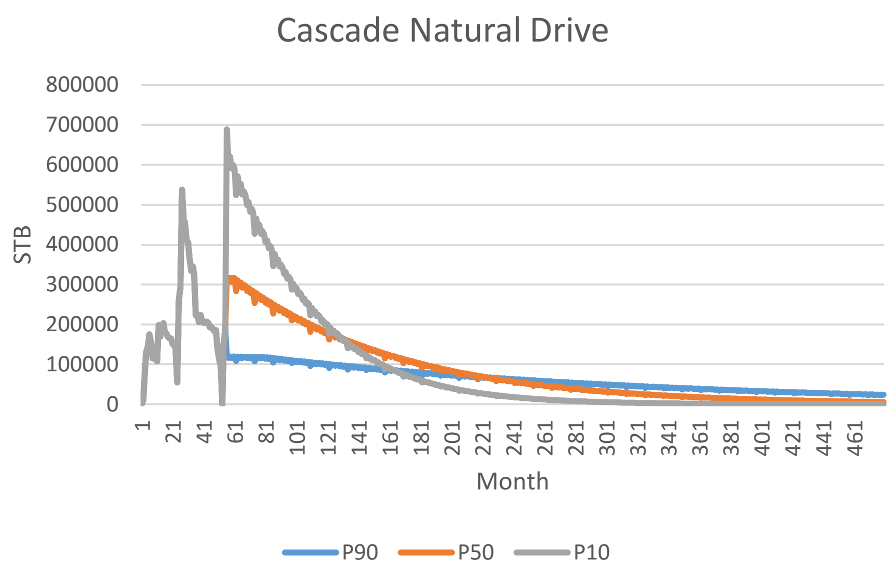


Figure 17 Probabilistic monthly production forecast (STB/Month) for Cascade Field assuming natural drive under current development (3 wells).

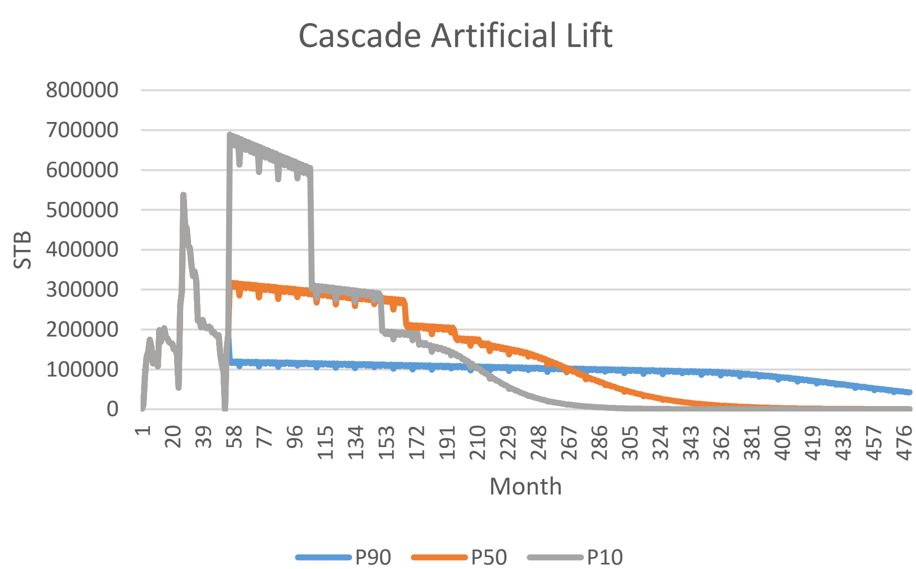


Figure 18 Probabilistic monthly production forecast (STB/Month) for Cascade Field assuming artificial lift is used under current development (3 wells).

The probabilistic production profiles for Chinook's field development with one producing well assuming natural drive and artificial lift are illustrated in Figure 19 and

Figure 20, respectively. The drop in production for the P10 production profile after month 110 is due to the pump. After a certain time, the pump will no longer be able to provide the necessary pressure differential to keep producing at that rate, and thus the flow rate will fall.

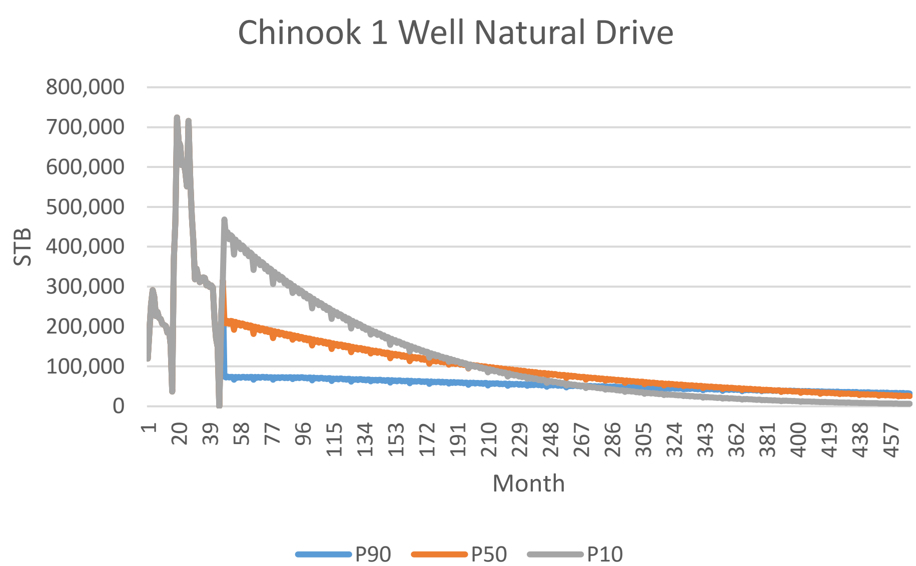


Figure 19 Probabilistic monthly production forecast (STB/Month) for Chinook Field assuming natural drive under current development

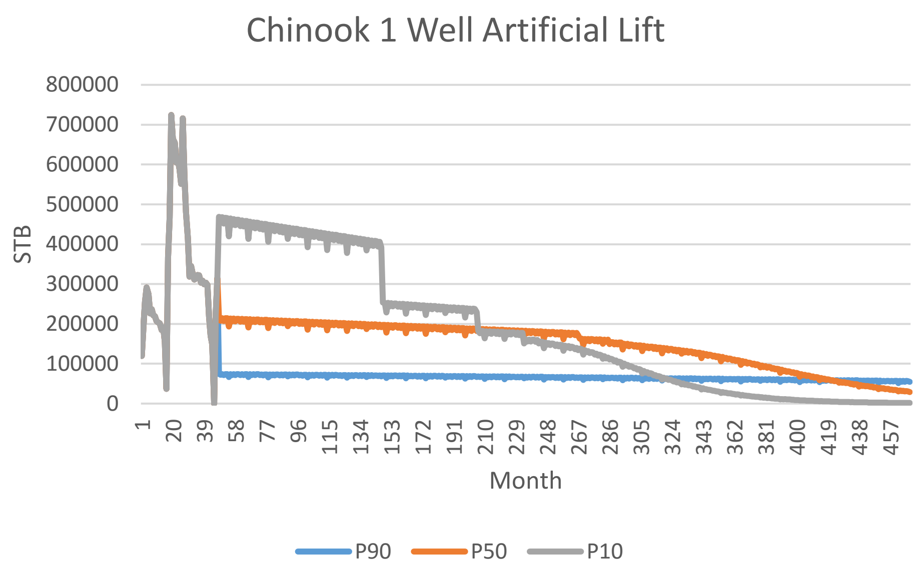


Figure 20 Probabilistic monthly production forecast (STB/Month) for Chinook Field assuming artificial lift is used under current development

Different field development options were analyzed for the Chinook field only, since it is the larger of the two fields and has only one producing well. The two development options analyzed are: 1) using 2 producing wells and 2) using 3 producing wells. Both options were analyzed under natural drive and artificial lift, to give a total of four additional development options for the Chinook field. Table 7 shows the probabilistic EUR estimates for the three development options for the Chinook field assuming natural drive. The probabilistic production profiles for the development options using 2 producing wells and 3 producing wells are illustrated in Figure 21 and Figure 22, respectively. The estimated production increases with each additional well. There is a 34% increase in production for the P50 estimate when we add a second well, and an additional 2% if the field had 3 producing wells using natural drive.

Table 7 Summary results for the Chinook field for different development options assuming natural drive

OOIP MMstb	**Number of Wells**	**EUR up to 40 years (MMstb)**		
		P90	**P50**	**P10**
249	1	37.4	45.0	45.8
	2	50.0	60.1	61.9
	3	56.2	61.2	62.2

Recovery Factor	1	15%	18%	18%
	2	20%	24%	25%
	3	23%	25%	25%

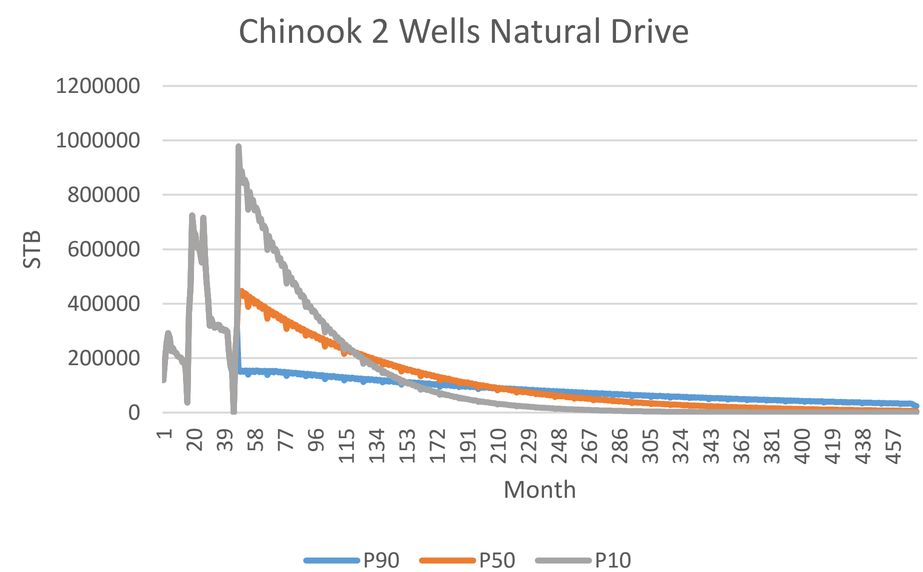


Figure 21 Probabilistic production profile (STB/Month) for the Chinook field with 2 producing wells assuming natural drive

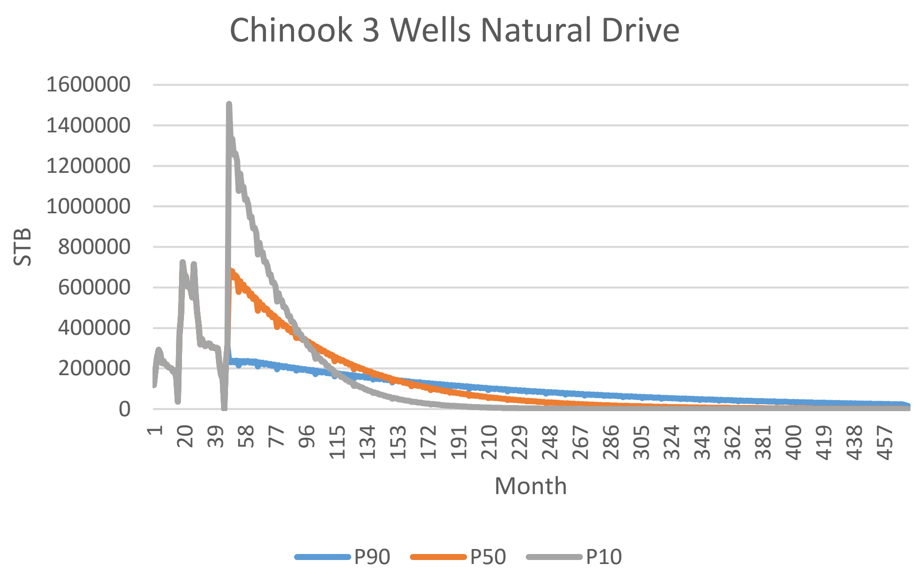


Figure 22 Probabilistic production profile (STB/Month) for the Chinook field with 3 producing wells assuming natural drive

Table 8 shows the probabilistic EUR estimates for the three development options for the Chinook field assuming artificial lift. As we have seen in the previous options for artificial lift, the P10 estimates have a larger impact on the life of the well than on the EUR. The probabilistic production curves for Chinook development options with 2 producing wells and 3 producing wells are shown in Figure 23 and Figure 24, respectively.

If we assume the field to be developed using artificial lift, the P50 EUR increases by 15% when we add a second well, and a 4% increase in EUR estimates when a third well is added. Although the recovery factors in Table 8 are almost identical in all the P10 scenarios (36%, 38%, 38%) for artificial lift, the main difference is that the field development using 2 wells will take 54 months longer to produce than the field development using 3 wells. Producing the field in a shorter time will increase the project's NPV10 from $146 to $163 million.

Table 8 Summary results for the Chinook field for different development options assuming artificial lift is used

OOIP MMstb	**Number of Wells**	**EUR up to 40 years (MMstb)**		
		P90	**P50**	**P10**
249	1	43.0	77.9	90.2
	2	68.7	89.8	93.5
	3	80.1	92.9	93.9

Recovery Factor	1	17%	31%	36%
	2	28%	36%	38%
	3	32%	37%	38%

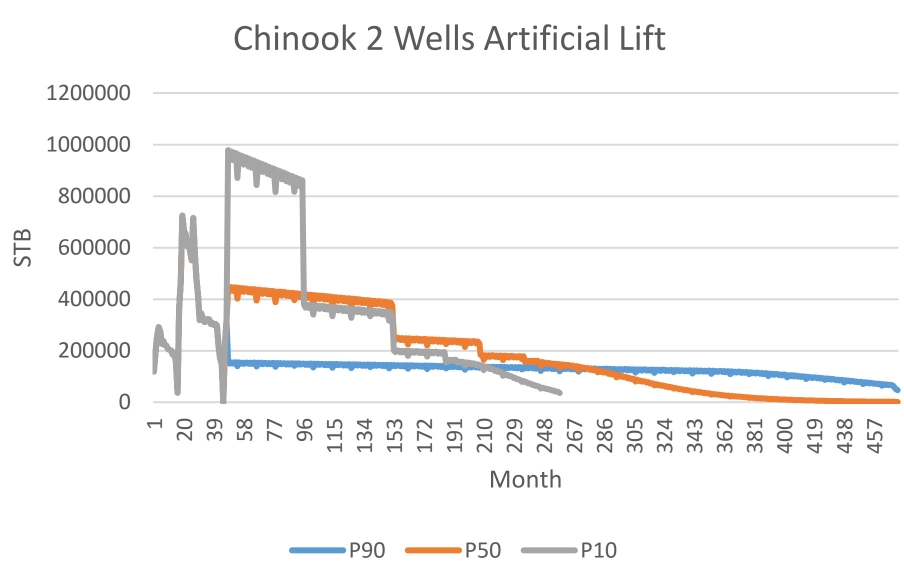


Figure 23 Probabilistic production profile (STB/Month) for the Chinook field with 2 producing wells assuming artificial lift. The P90 curve would last the full 40 year time limit we imposed on the project, while the P50 curve would deplete the field in 30 years, and the P10 curve in 16 years.

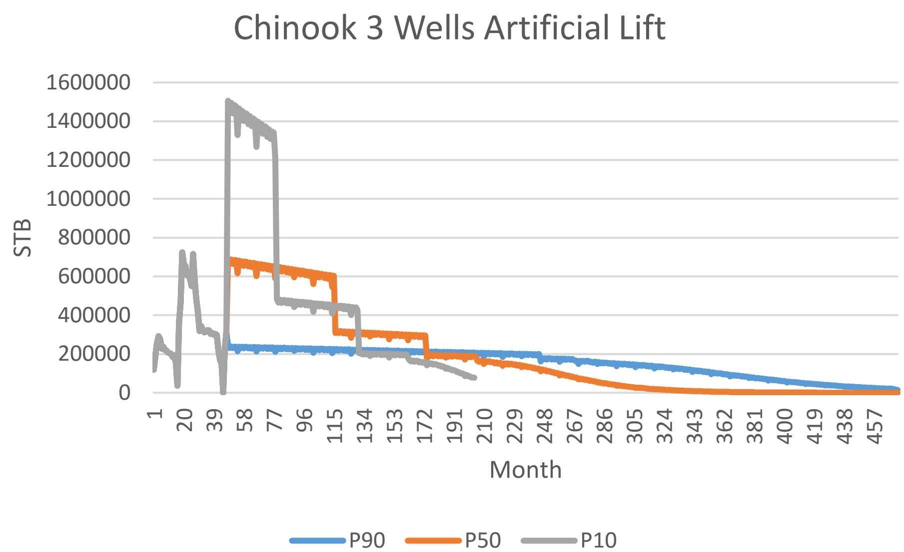


Figure 24 Probabilistic production profile (STB/Month) for the Chinook field with 3 producing wells assuming artificial lift. The P90 curve would last the full 40 year time limit we imposed on the project, while the P50 curve would deplete the field in 19 years, and the P10 curve in 12 years.

CASH FLOW ANALYSIS APPLIED TO PRODUCTION MODEL

Fiscal Terms and Field Development Concept

Our after-tax cash flow model assumes a gross royalty rate of 12.5% since the water depth exceeds 800 m for both developments, and the leases were awarded under the Deep Water Royalty Relief Act of 1995 (DWRRA). With this act the first 87.5 mboe produced are royalty-free for each field.

We generated the field development plan for the Cascade and Chinook fields using Landmark's FieldPlan software. This software was previously validated in Weijermars et al. (2017) using the Shell Perdido project. The Perdido project was modeled using FieldPlan and the results obtained were compared to the results published by Wood Mackenzie. The similarity in the results validated this software.

FieldPlan software considers key parameters with representative industry values that lead to a reasonable first pass result. This software has many capabilities including production forecasting and economic analysis, but in this study, it was used to obtain an estimation of the CAPEX and OPEX only.

The assumptions are as follows: Cascade and Chinook have average water depths of 8,200 ft and the target zone occurs at a true vertical distance (TVD) around 25,000 ft from the water surface (16,800 ft from mudline). Initial reservoir pressure is 19,000 psi and we have a black oil reservoir. Carbon dioxide (CO_2) and sulfur contents are low, and the reservoirs for Cascade and Chinook contain 191 MMbbl and 249 MMbbl of oil respectively.

Cash Flow Model based on Probabilistic Production Curves

The probabilistic cash flow model in our study uses cost estimates of our field development concept described in the previous section. Production profiles for Cascade and Chinook are based on probabilistic nodal analysis using an integrated approach as seen in the Methodology section. The Excel model allows us to evaluate each scenario to obtain the annual cash flows, royalties to the government, the annual OPEX, with a 35% tax on the net profits. Key inputs for the model are shown in Figure 25. Historic annual oil spot price, obtained from the US Energy Information Administration (EIA), was used up to (and includes) 2015. For forward pricing (2016 onward) we used a price strip of \$30 to \$90 (in increments of \$10), Figure 26, assuming an annual inflation of 2.5%. Figure 27 shows a screenshot of the evaluation page of the model. It shows the parameters needed to calculate the annual cash flow, and shows the annual break down. The project’s oil price sensitivity was evaluated to determine the minimum commodity price needed for the project to become profitable.

General Assumptions	
Start Year	2009
Production Stops	2040
General Inflation	2.50%

Key Inputs			
EUR Estimates			
EUR Oil	mmbbl	(Crude)	68.83
EUR Gas	mmboe	(Gas)	0.00
Benchmark Price			
Crude	$/bbl		
Gas	$/mcf		0.00
Oil Grade			
API			25
Sulfur content	%		2.00
Depreciation			
Permissible Depletion Rate	%		15%
Drillex	%		17%
Exploration / Well	%		7%
E&P Facilities	%		13%
Opex			
Fixed Opex	$mm/year		30
Variable Opex	$ / bbl		8.50
Transportation cost (oil)	$ / bbl		2.50
Transportation cost (gas)	$ / mcf		0.50
Capex			
Cumulative Capex	$mm		1,183.29
Workover/Maintenance Capex	%		0
Abandonment Cost	$mm		120.00
Tax			
Income Tax	%		35
Prices BRENT & LLS for Commodity Forecast			
Brent	$ / bbl		$60
LLS	$ / bbl		$60

Figure 25 Key inputs used for the cash flow model based on the probabilistic production curves.

Cases		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
USER Input Brent	Case 1	$30	$32	$32	$33	$34	$35	$36	$37	$37	$38	$39	$40
USER Input Brent	Case 2	$40	$42	$43	$44	$45	$46	$48	$49	$50	$51	$52	$54
USER Input Brent	Case 3	$50	$53	$54	$55	$57	$58	$59	$61	$62	$64	$66	$67
USER Input Brent	Case 4	$60	$63	$65	$66	$68	$70	$71	$73	$75	$77	$79	$81
USER Input Brent	Case 5	$70	$74	$75	$77	$79	$81	$83	$85	$87	$90	$92	$94
USER Input Brent	Case 6	$80	$84	$86	$88	$91	$93	$95	$97	$100	$102	$105	$108
USER Input Brent	Case 7	$90	$95	$97	$99	$102	$104	$107	$110	$112	$115	$118	$121
Case Number	4	$60	$63	$65	$66	$68	$70	$71	$73	$75	$77	$79	$81

Figure 26 Screenshot of the model's commodity price strip. We used a range from $30 to $90, in a $10 increments. We assumed a 2.5% annual inflation. For the project evaluation, we used historic oil prices up to 2015, and used the oil price strip from 2016 onward.

	Unit	Total	2009	2010	2011	2012	2013	2014	2015	2016	2017
Production											
Crude daily average	mbbls/d	103.2	-	-	-	3.8	5.3	12.1	6.7	6.9	10.4
Gas daily average	MMcf/d	-	-	-	-	-	-	-	-	-	-
Total Production Average	mboe	103.2	-	-	-	3.8	5.3	12.1	6.7	6.9	10.4
Crude	mmbbls	103.2	-	-	-	1.4	1.9	4.4	2.4	2.5	3.8
Gas	bcf	-	-	-	-	-	-	-	-	-	-
Total Production	mmboe	103.2	-	-	-	1.4	1.9	4.4	2.4	2.5	3.8
Gross Revenue											
Crude	$mm	10,395.0	-	-	-	128.8	187.8	411.1	118.7	183.9	284.0
Gas	$mm	-	-	-	-	-	-	-	-	-	-
Total Gross Value (*VCH*)	$mm		-	-	-	128.8	187.8	411.1	118.7	183.9	284.0
Net Revenue											
Gross Royalty Rate		13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
Royalty Payments to Fed Gov	$mm	(1,299.4)	-	-	-	(16.1)	(23.5)	(51.4)	(14.8)	(23.0)	(35.5)
Cumulative Royalties (*CP*)	$mm		-	-	-	(16.1)	(39.6)	(91.0)	(105.8)	(128.8)	(164.3)
Net Revenue Operator	$mm		-	-	-	112.7	164.3	359.7	103.8	160.9	248.5
Costs											
OPEX											
Fixed Opex	$mm	(1,024.0)	-	-	-	(32.0)	(32.0)	(32.0)	(32.0)	(32.0)	(32.0)
Variable Opex	$mm	(876.9)	-	-	-	(11.6)	(16.3)	(37.5)	(20.7)	(21.4)	(32.2)
Transportation Cost - Oil	$mm	(257.9)	-	-	-	(3.4)	(4.8)	(11.0)	(6.1)	(6.3)	(9.5)
Transportation Cost - Gas	$mm	-	-	-	-	-	-	-	-	-	-
Total Opex	$mm	(2,158.9)	-	-	-	(47.1)	(53.1)	(80.5)	(58.8)	(59.7)	(73.7)
Cumulative Opex	$mm		-	-	-	(47.1)	(100.1)	(180.7)	(239.5)	(299.2)	(372.9)
EBITDA											
Total EBITDA			-	-	-	65.7	111.2	279.2	45.0	101.2	174.8
Depreciation			-	-	(46.4)	(167.4)	(184.3)	(184.3)	(184.3)	(184.3)	(184.3)
Field Capex											
Total Capex	$mm	(1,183.3)	(46.1)	(296.1)	(743.8)	(97.2)	-	-	-	-	-
Abandonment Cost	$mm	284.8	-	-	-	-	-	-	-	-	-
Cumulative Capex	$mm		(46.1)	(342.2)	(1,086.0)	(1,183.3)	(1,183.3)	(1,183.3)	(1,183.3)	(1,183.3)	(1,183.3)
Cumulative OPEX + CAPEX (*CT*)	$mm		(46.08)	(342.20)	(1,086.05)	(1,230.36)	(1,283.44)	(1,363.97)	(1,422.80)	(1,482.47)	(1,556.16)
Gross Income											
Taxable Income	$mm		-	-	(46.36)	(101.75)	(73.12)	94.84	(139.31)	(83.12)	(9.54)
Income Tax	$mm	(1,712.34)	-	-	-	-	-	(33.19)	-	-	-
Net Cash Flow (undiscounted)	$mm	**4,041.1**	(46.08)	(296.12)	(743.84)	(31.57)	111.21	245.98	45.02	101.22	174.80
Government take	$mm	(3,012)	0.0	0.0	0.0	(16.1)	(23.5)	(84.6)	(14.8)	(23.0)	(35.5)
Contractor IRR	**11.01%**										
Discount Factor	10%		1.1	1.2	1.3	1.5	1.6	1.8	1.9	2.1	2.4
Discounted Cash Flows			(41.9)	(244.7)	(558.9)	(21.6)	69.1	138.8	23.1	47.2	74.1
Contractor NPV @ 10		**94.6**	(41.9)	(286.6)	(845.5)	(867.0)	(798.0)	(659.1)	(636.0)	(588.8)	(514.7)

Figure 27 Screenshot of the evaluation page of the model. It shows the annual cash flow distribution and the cumulative break down for each category such as OPEX, CAPEX, Government Take and Contractor's NPV.

Results

Four different field development options were appraised in this study. The first two developments were Cascade and Chinook with the existing wells and natural drive. We then analyzed Chinook assuming one more producing well would be drilled for a total of two producing wells, and for Chinook assuming a total of 3 producing wells. Table 9 summarizes the development options analyzed in this study. The probabilistic production curves were used in the cash flow model to calculate the probabilistic NPV of each project Option.

Table 9 Summary of the development options analyzed in this study

Field Development Option	Development Description
1	Cascade under current development (3 producing wells) Natural Drive
2	Cascade under current development (3 producing wells) Artificial Lift
3	Chinook under current development (1 producing well) Natural Drive
4	Chinook under current development (1 producing well) Artificial Lift
5	Chinook assuming a total of 2 producing wells Natural Drive
6	Chinook assuming a total of 2 producing wells Artificial Lift
7	Chinook assuming a total of 3 producing wells Natural Drive
8	Chinook assuming a total of 3 producing wells Artificial Lift

For brevity, we only present the P50 results using both artificial lift and natural drive for Cascade and Chinook under the current development (Options 1,2, 3 and 4 from Table 9), and the P50 results only using artificial lift for the 2 development options proposed for Chinook (Options 6 and 8 from Table 9). The P50 production curves were chosen since these are the curves that most closely represent the reservoir and production facilities. Detailed results obtained for all the field development options analyzed in this study can be found in Appendix C. Figure 28 shows a comparison of the contractor's NPV10 for the field developments listed in Table 9 assuming an oil price of $60 per barrel. None of the development options have a positive P50 NPV10 under natural drive and a $60/bbl, with Option 5 (Chinook with 2 wells) having the least negative NPV10. For artificial lift only Option 6 and Option 8 are profitable, with the latter Option (Chinook with 3 wells) having a P50 NPV10 higher by only $17 million. However, the maximum negative cash flow, shown in Figure 29, for Option 8 exceeds Option 7 by $120 million, making Option 6 less risky than Option 8.

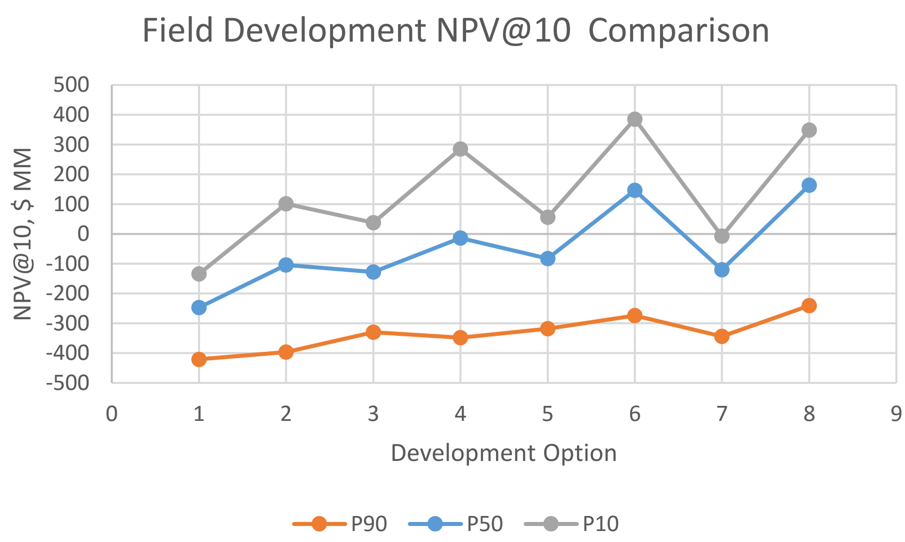


Figure 28 Probabilistic NPV@10 distribution for the Cascade (Options 1 and 2), and Chinook (Options 3 to 8) field developments options listed in Table 9 assuming an oil price of $60/bbl.

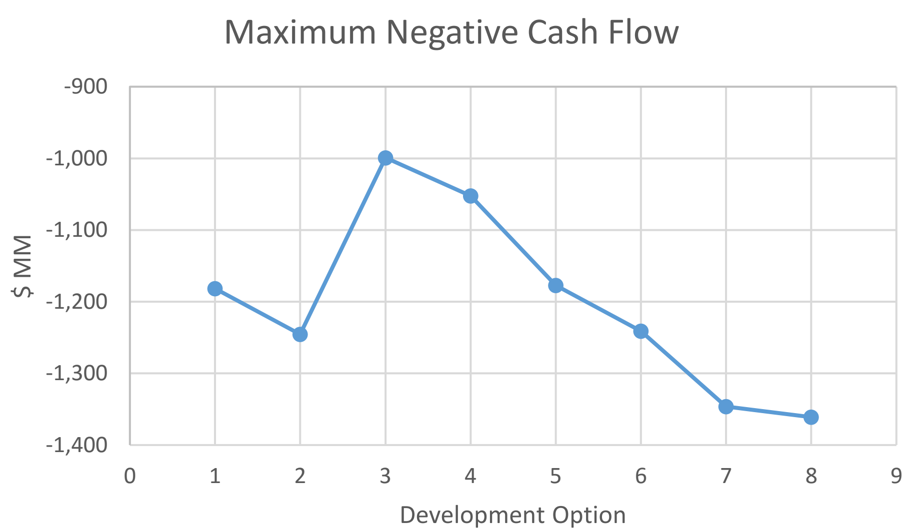


Figure 29 Maximum negative cash flow for the development options of Cascade (Options 1 and 2) and Chinook (Options 3-8) analyzed in this study

Cascade Development

The Cascade field is producing at water depths greater than 8,000 ft, using 3 wells with P50 oil recovery factor of 24% and 33%, using natural drive and artificial lift respectively of the assumed 191 MMbbl OOIP. Figure 28 shows that for the base case of $60/bbl, the contractor's probabilistic NPV@10 has P50 values of $-344 and $-201 million for natural drive (Option 1) and artificial lift (Option 2) respectively, and an IRR of 3.4% for natural drive and 7.2% for artificial lift. These values increase as the price of oil increases as shown in Figure 31. Cascade needs to be developed with artificial lift to have a positive P10-NPV@10 for $60/bbl oil price.

Cascade P50 Natural Drive (Option 1, Table 9). Figure *30* shows the annual cash flow distribution to CAPEX, OPEX, government royalties and taxes, and the contractor's net cash. The pie diagram shows the percentages of the cumulative cash flow over the life cycle of the project. At the base price of $60/bbl the project is not profitable. Figure 31 and Figure 32 show the summary for the oil sensitivity analysis. Figure 31 shows the undiscounted contractor's NPV and Government Take, as well as the contractor's NPV@10 at oil prices ranging from $30 to $90 per barrel. The undiscounted NPV plus the Government Take (gray line) represents the total revenue minus the costs. This quantity is split between the Contractor and the Government. Figure 32 plots the project's IRR against the oil price and the payout time in years at different oil prices. The IRR can determine whether a project is executed or killed depending on the hurdle rate imposed by the company. When the project started the oil prices were high and reached over $100/bbl. It is unlikely this project would be approved with today's oil prices.

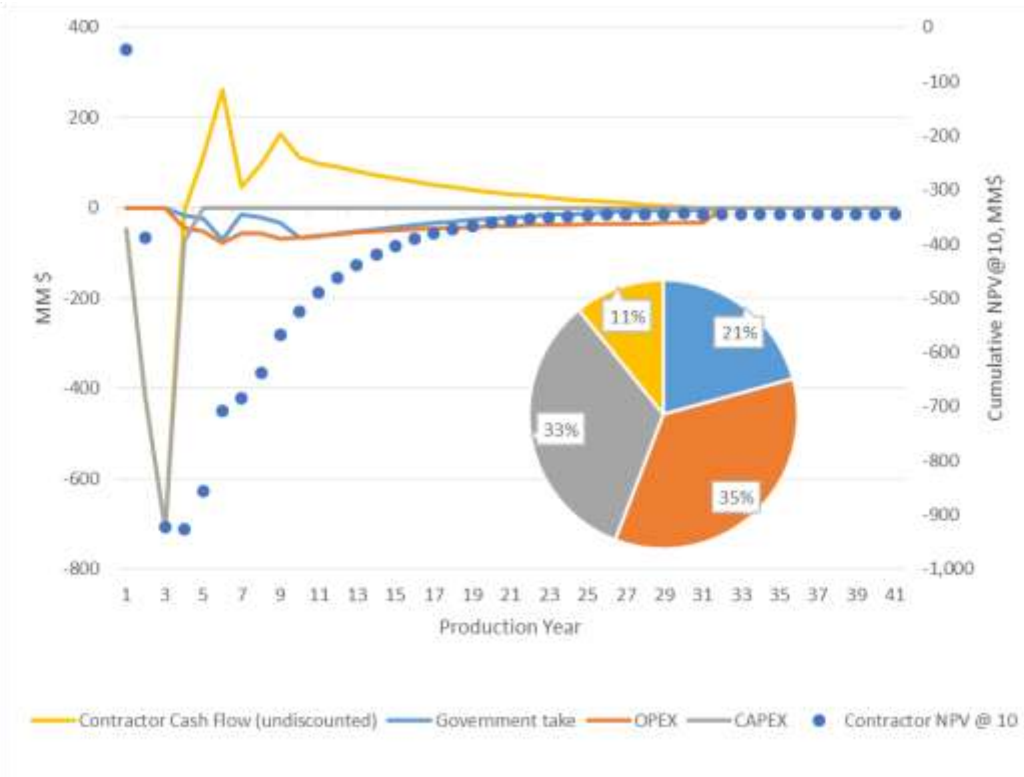


Figure 30 *Option 1. Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash.*

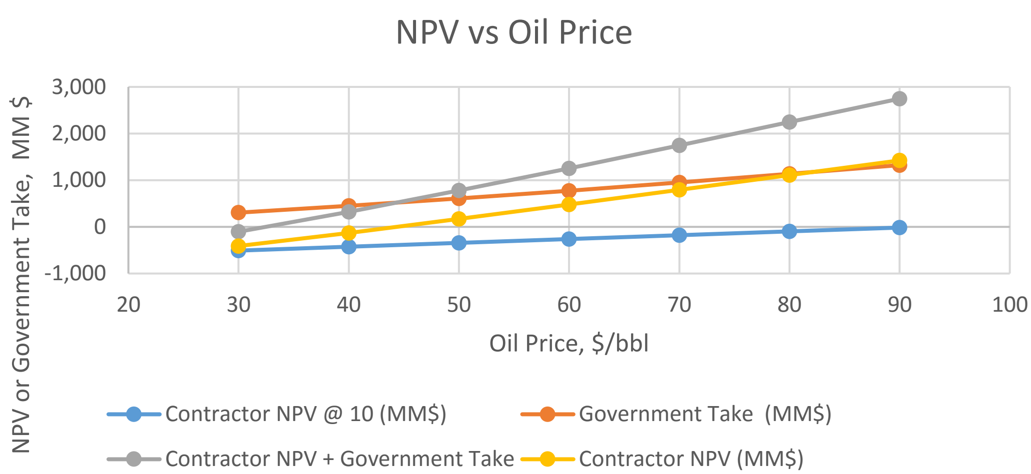
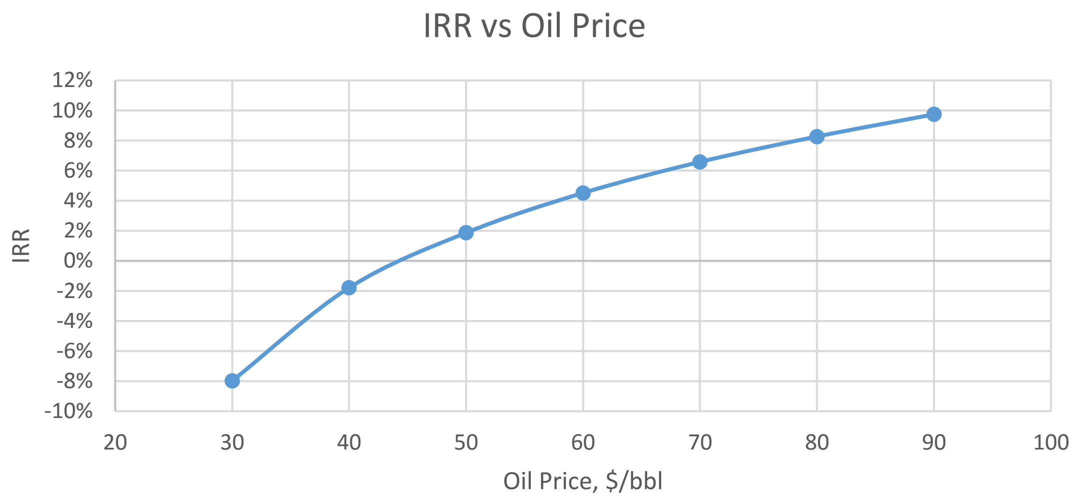


Figure 31 Option 1. Discounted and undiscounted Contractor NPV and Government take for Cascade P50 natural drive at different oil prices.



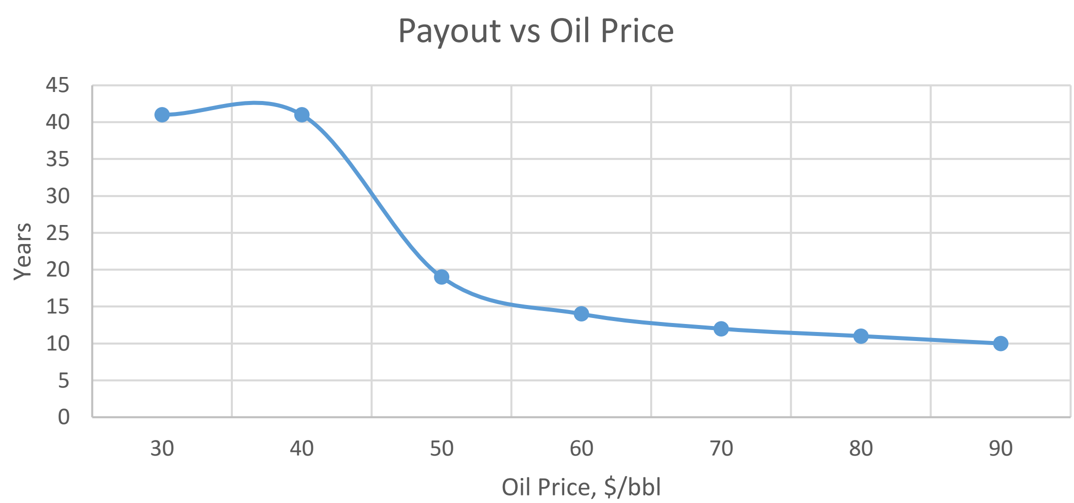


Figure 32 Option 1. (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Cascade P50 natural drive for different oil prices.

Cascade P50 Artificial Lift (Option 2, Table 9) Similarly to the previous section, Figure 33 shows the annual cash flow distribution to CAPEX, OPEX, government royalties and taxes, and the contractor's net cash. Option 2 requires an additional investment of $64 million compared Option 1 (Figure 29), but will increase the NPV@10 by $143 million compared to the P50 NPV@10 under natural drive, which is still negative at an oil price of $60/barrel. The NPV@10 will become positive at an oil price of $78/bbl (Figure 34). The cumulative distribution also changes, increasing the revenue percentages (contractor and government) and reducing the CAPEX and OPEX percentages (Figure 33). The IRR increases from 4.5% to 7.2% for artificial lift at $60/bbl (Figure 35). At this price it would take 13 years to recover the initial investment. Cascade should be produced with artificial lift even if the P50-NPV@10 is negative at an oil price of $60/bbl, hoping for an increase in oil price. Without this field, Chinook would have to assume the full cost for the FPSO negatively impacting its profitability.

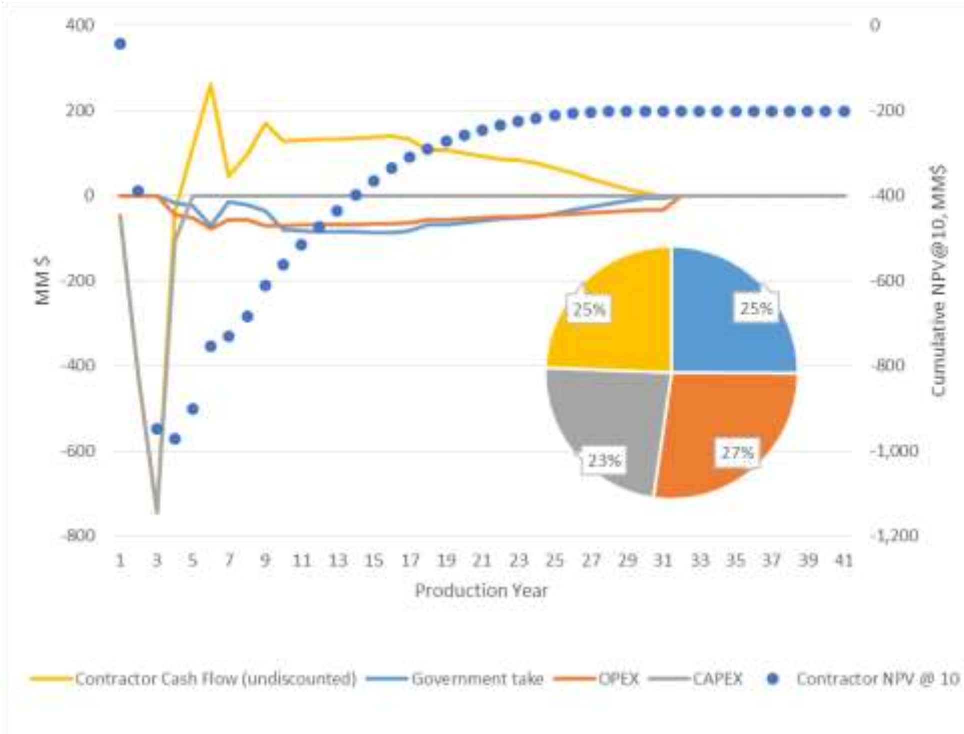


Figure 33 Option 2. Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to the contractor based on $60/bbl. Pie diagram shows respective allocations of total revenue to CAPEX, OPEX, government, and contractor net cash. The government and contractor distribution of 29% and 39% gives a profit split between government and contractor of 43%-57%, respectively.

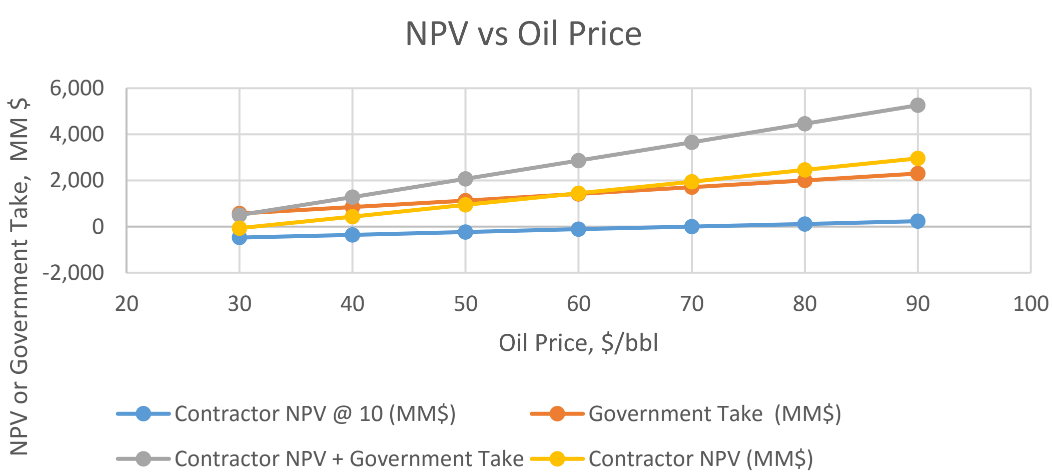
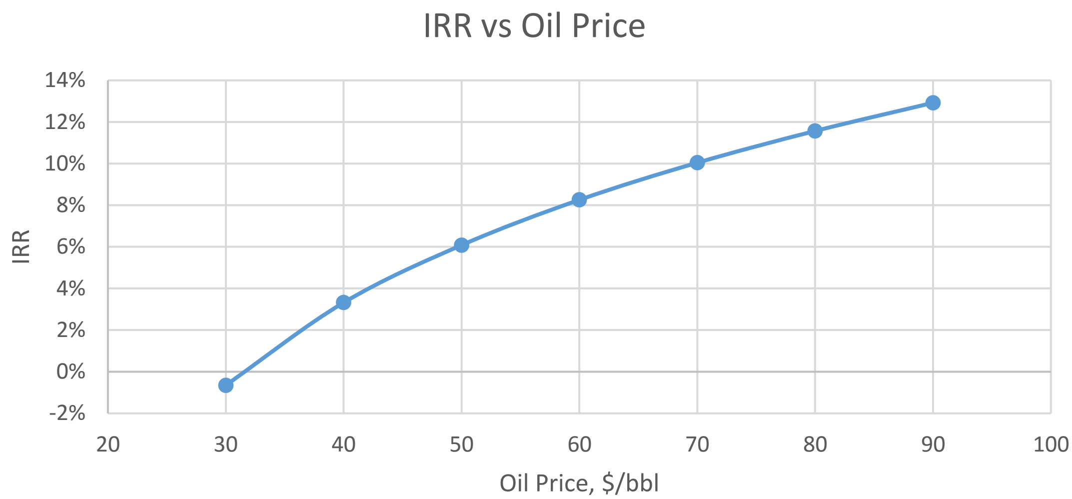


Figure 34 Option 2. Discounted and undiscounted Contractor NPV and Government take for Cascade P50 artificial lift at different oil prices.



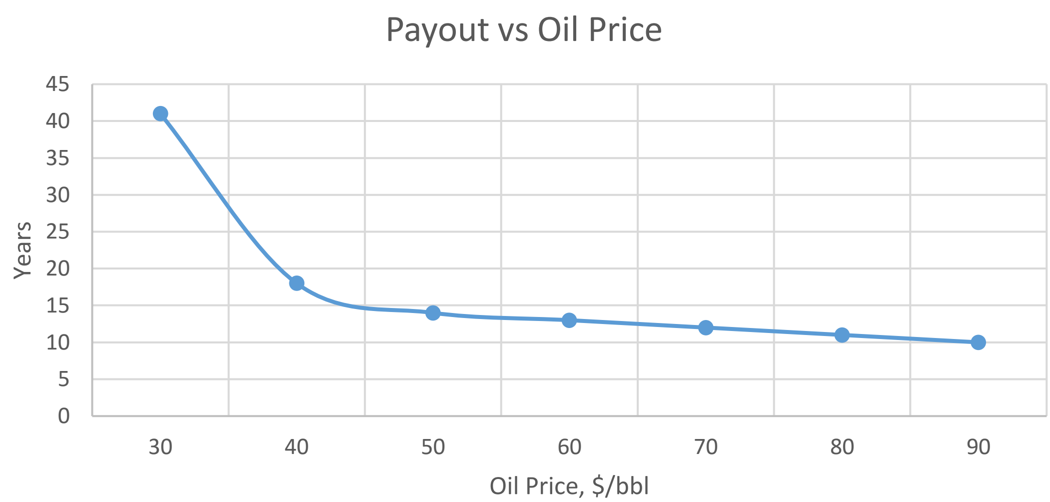


Figure 35 Option 2. (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Cascade P50 natural drive for different oil prices.

Chinook Field Development

Chinook is located 15 miles southwest of Cascade, and has only 1 producing well. Since this is the larger of the two fields (estimated OOIP of 249 MMbbl) and the least developed, two other field development options were generated for this field: 1) the field is produced using a total of 2 wells (Options 5 and 6, Table 9) and 2) the field is produced using a total of 3 wells (Options 7 and 8, Table 9), each under natural drive and artificial lift. The comparison of the probabilistic P50 NPV@10 for the three field developments in Chinook under natural drive and artificial lift is shown in Figure 36. The NPV@10 for the three developments is negative under natural drive, with Option 5 (2 wells natural drive) having the highest value. The NPV@10 for the field development Options 6 and 8 (Table 9) is almost the same, with Option 8 having a maximum negative cash flow $120 million higher than Option 6. The higher risk in Option 8 suggests the field should be developed under Option 6. This Option is less risky since the initial investment is lower and the NPV@10 for natural drive for this field development is higher than the one for 3 wells. For brevity, only the P50 results for the current development (1 well) under natural drive and artificial lift, and the P50 development under artificial lift for both the 2 wells and 3 wells will be shown (field developments 3, 4, 6 and 8 in Table 9).

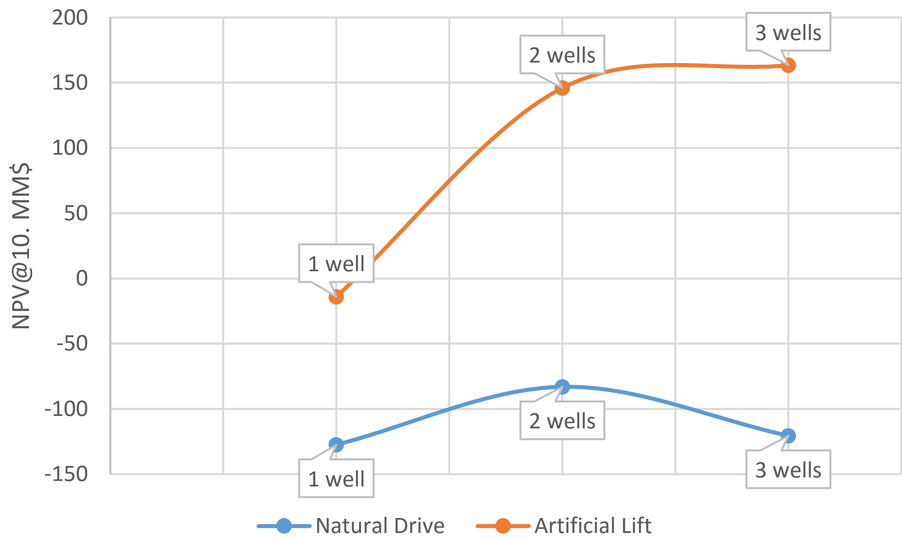


Figure 36 Probabilistic NPV@10 distribution for the different field development options of Chinook field assuming an oil price of $60. The NPV@10 for natural drive has the highest value when producing the field with 2 wells. The NPV@10 with artificial lift plateaus after 2 wells, suggesting that the best option for Chinook is to produce with 2 wells.

<u>Chinook 1 Well P50 with Natural Drive. (Option 3, Table 9)</u>.

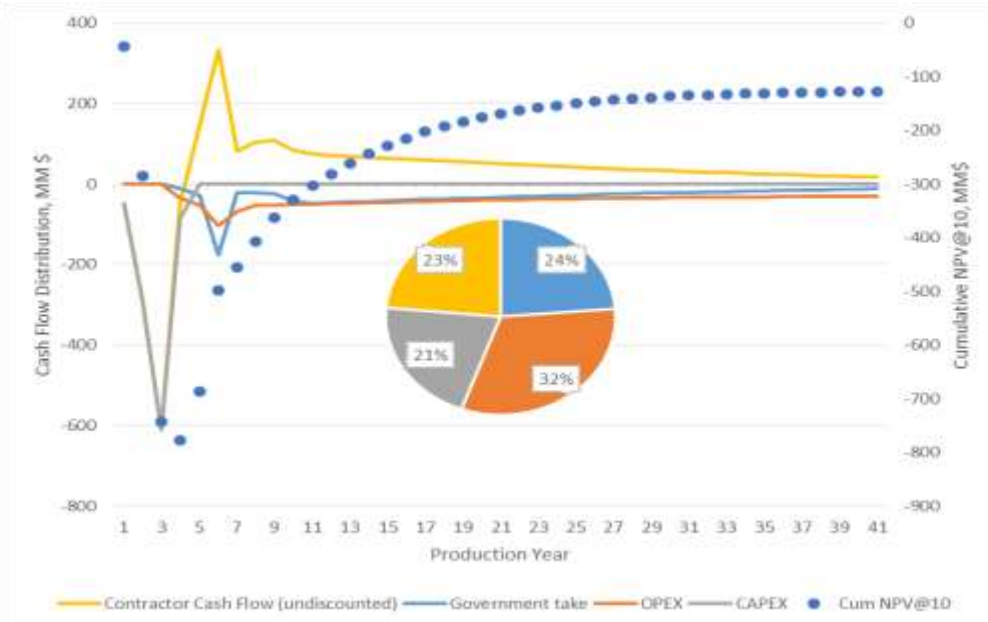


Figure 37 Option 3. Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total revenue to CAPEX, OPEX, government, and contractor net cash. The government and contractor distribution of 28% and 37% gives a profit split between government and contractor of 43%-57%, respectively.

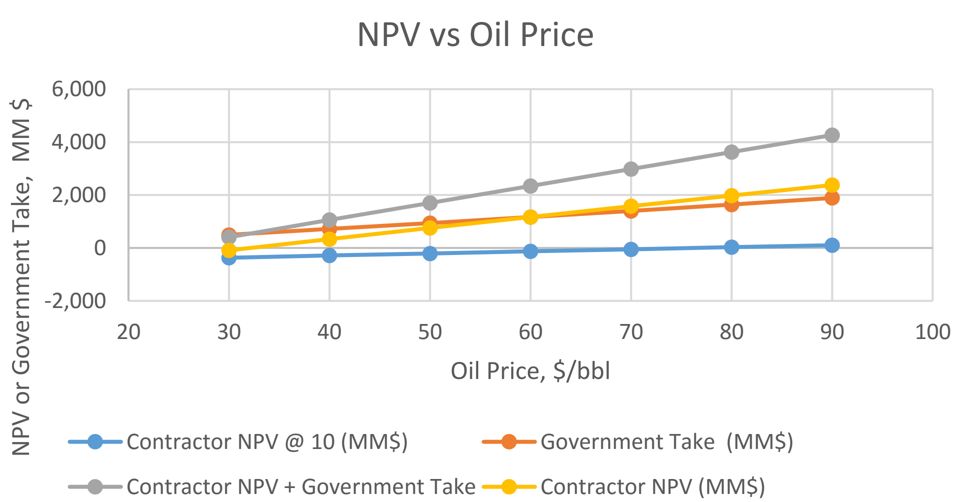
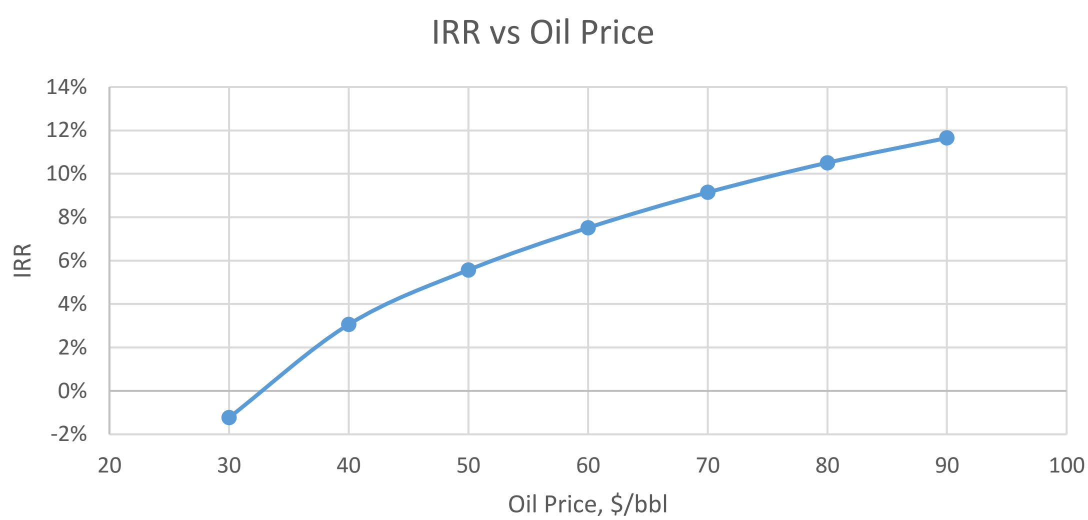


Figure 38 Option 3. Discounted and undiscounted Contractor NPV and Government take for Chinook 1 well P50 natural drive at different oil prices.



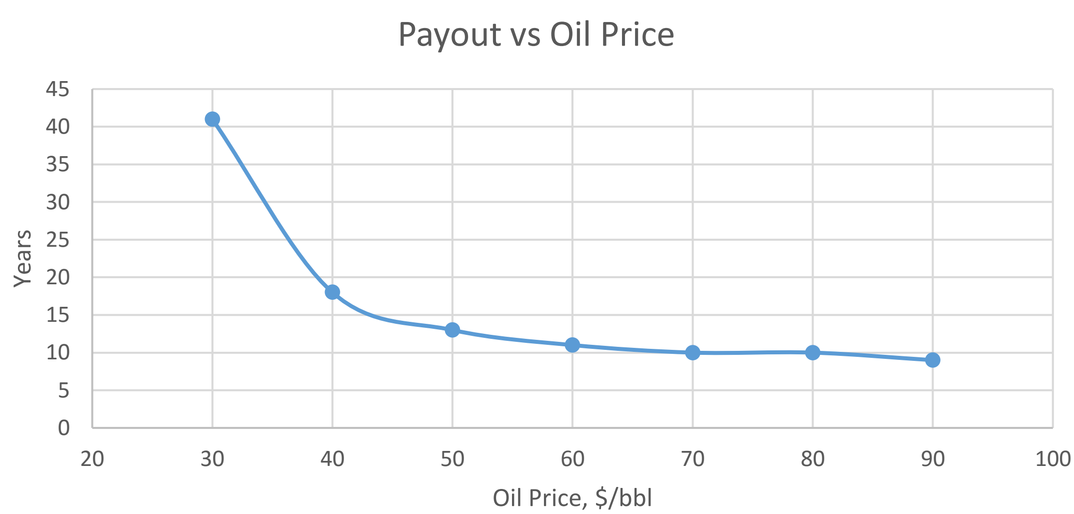


Figure 39 Option 3. (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Chinook 1 well P50 natural drive at different oil prices.

Chinook 1 Well P50 with Artificial Lift (Option 4, Table 9).

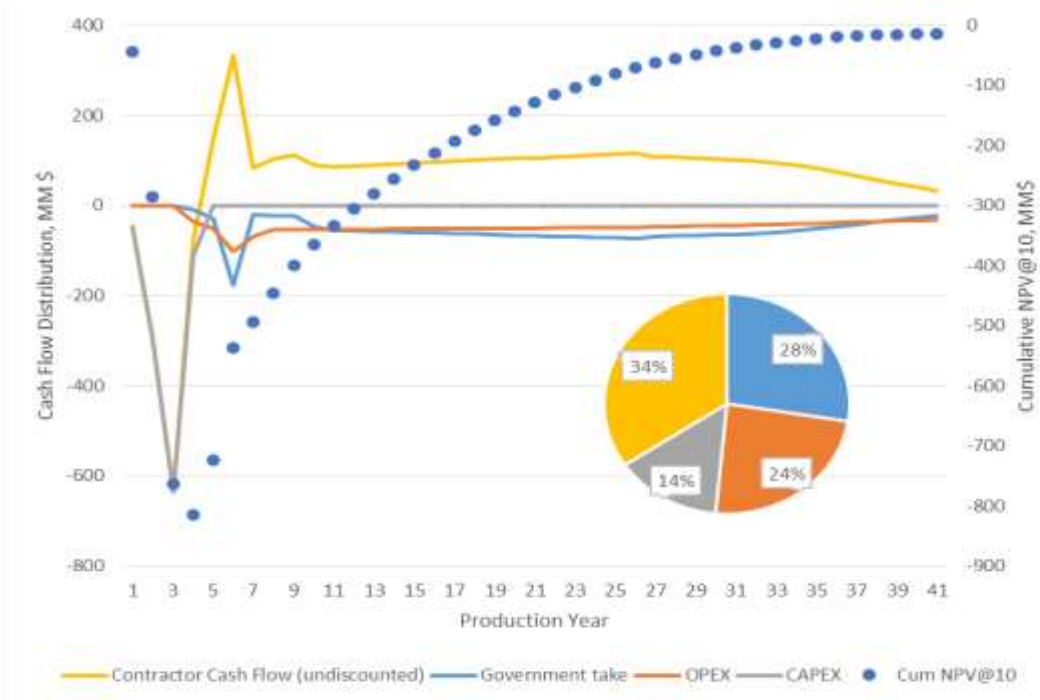


Figure 40 Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total revenue to CAPEX, OPEX, government, and contractor net cash. The government and contractor distribution of 29% and 40% gives a profit split between government and contractor of 42%-58%, respectively.

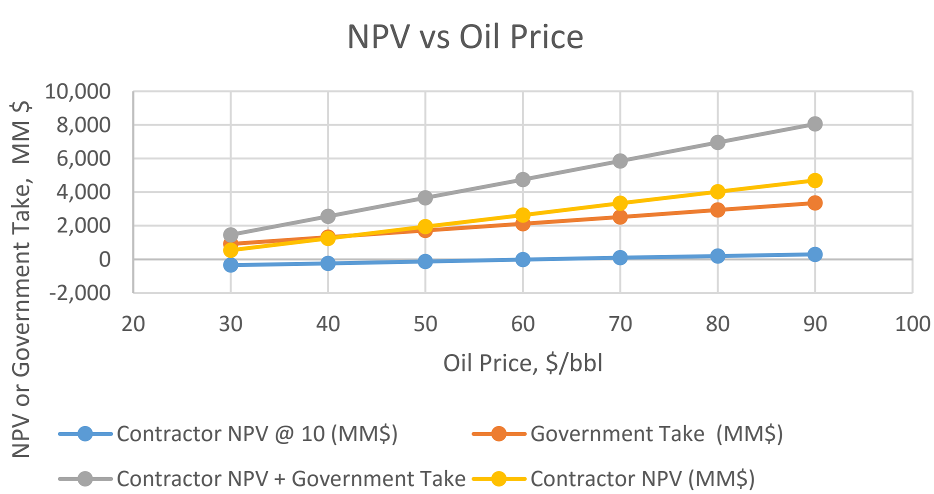
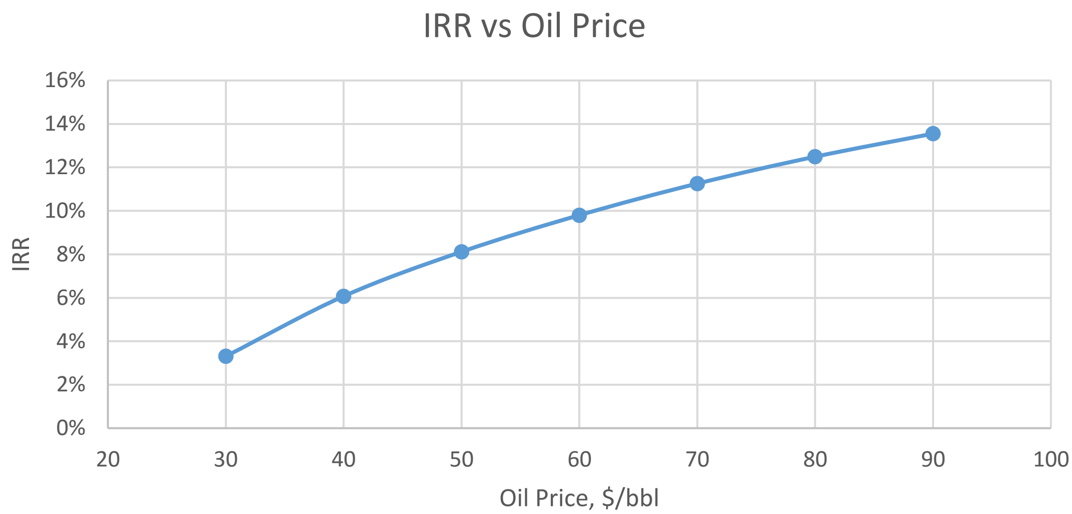


Figure 41 Discounted and undiscounted Contractor NPV and Government take for Chinook 1 well artificial lift at different oil prices.



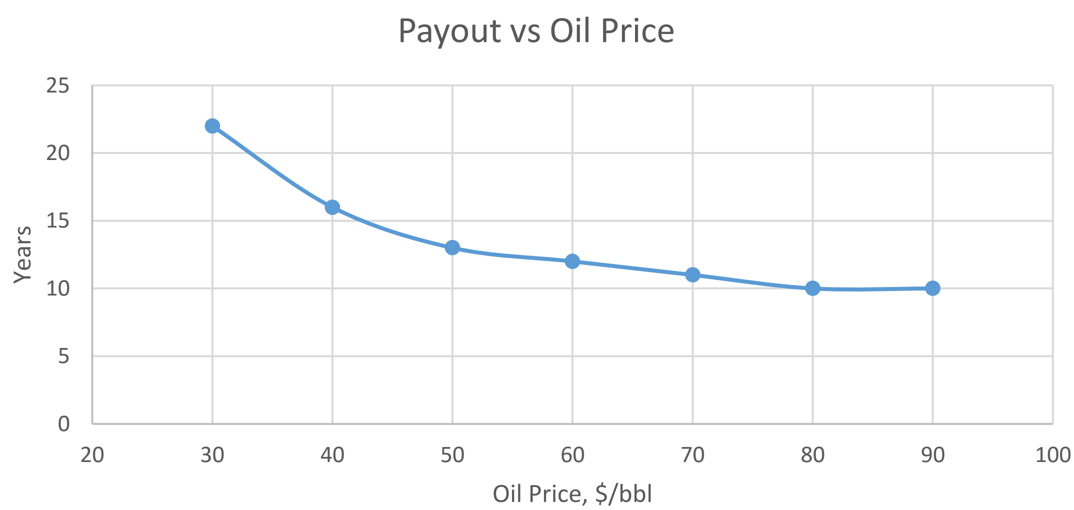


Figure 42 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Chinook 1 well P50 artificial lift at different oil prices.

Chinook Field Development Options

Two field development options were generated for Chinook. We assumed all the reservoir parameters of the current development remained constant, and the costs were estimated using FieldPlan. For brevity, we show only the P50 values using artificial lift. The complete list of results can be found in Appendix C.

Chinook 2 Wells and Artificial Lift (Option 6, Table 9).

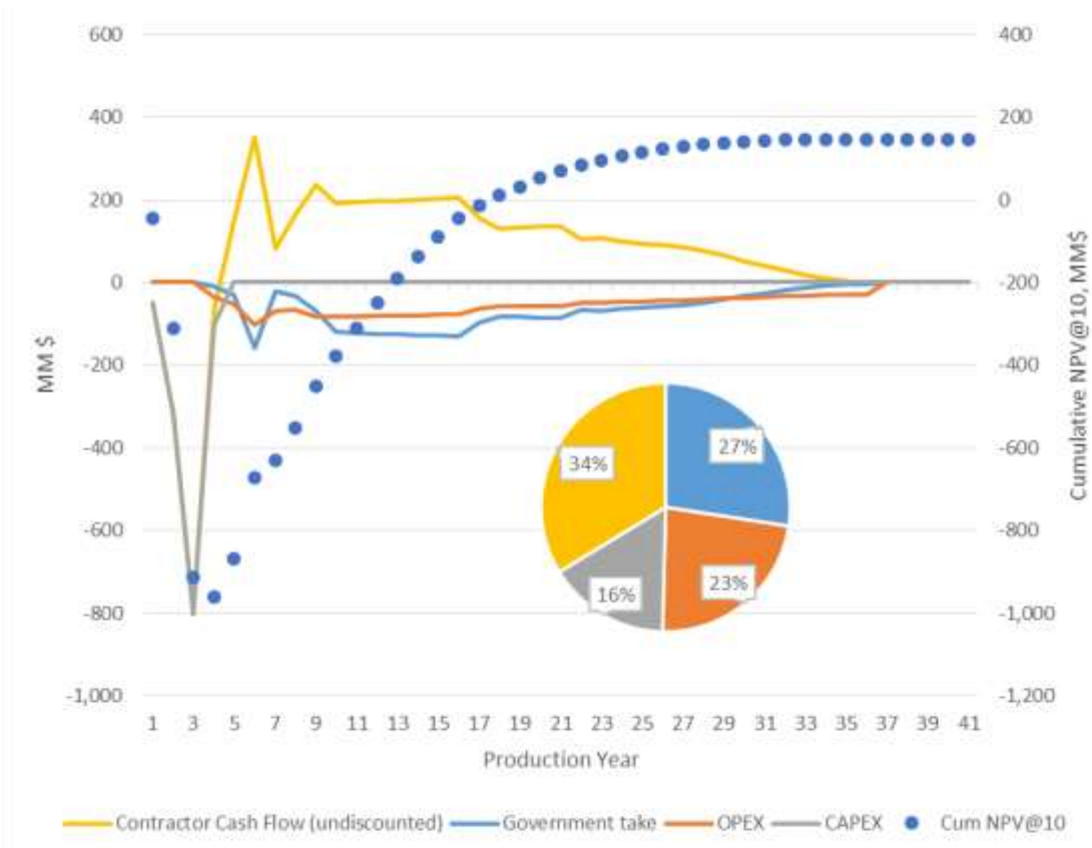


Figure 43 Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total revenue to CAPEX, OPEX, government, and contractor net cash. The government and contractor distribution of 31% and 43% gives a profit split between government and contractor of 42%-58%, respectively.

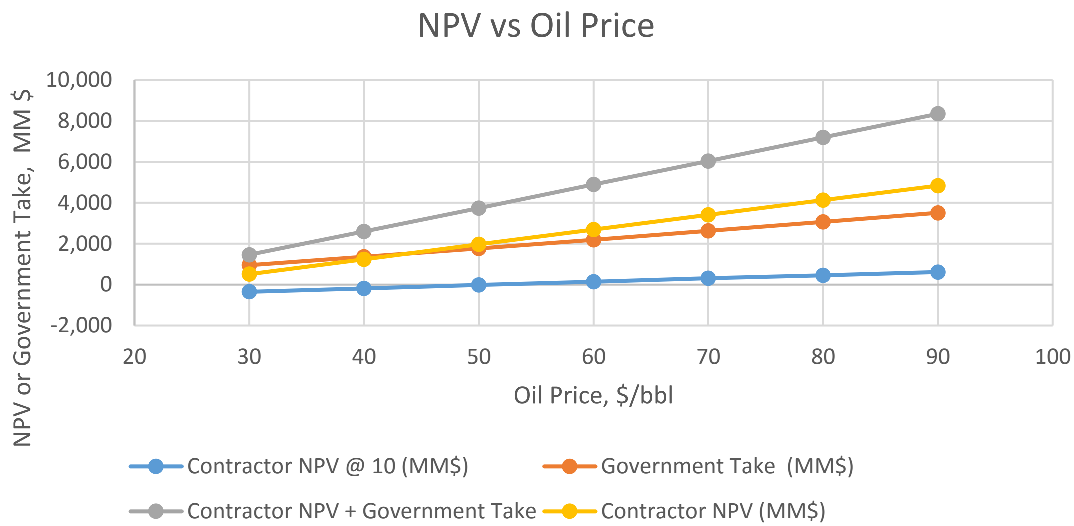
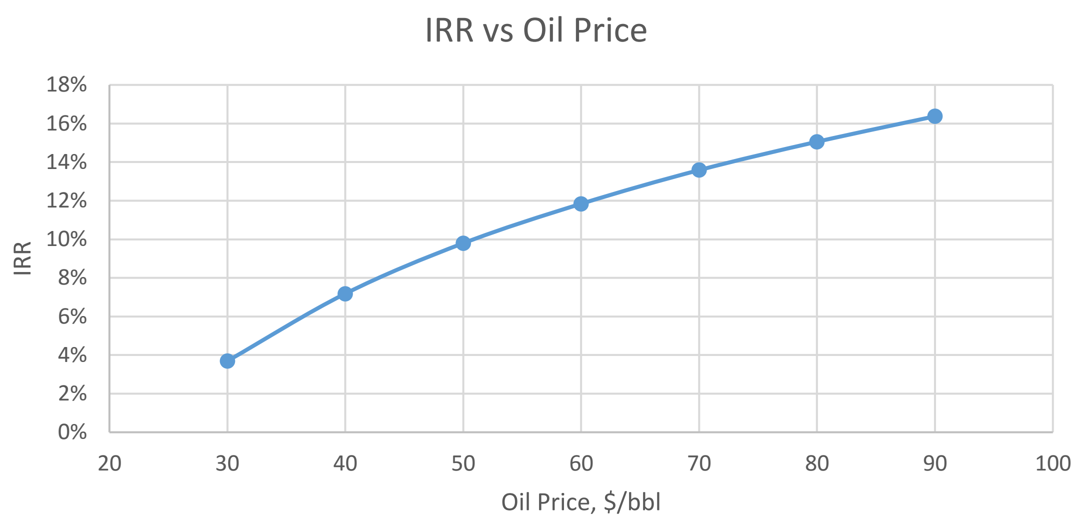


Figure 44 Discounted and undiscounted Contractor NPV and Government take for Chinook 2 wells artificial lift at different oil prices.



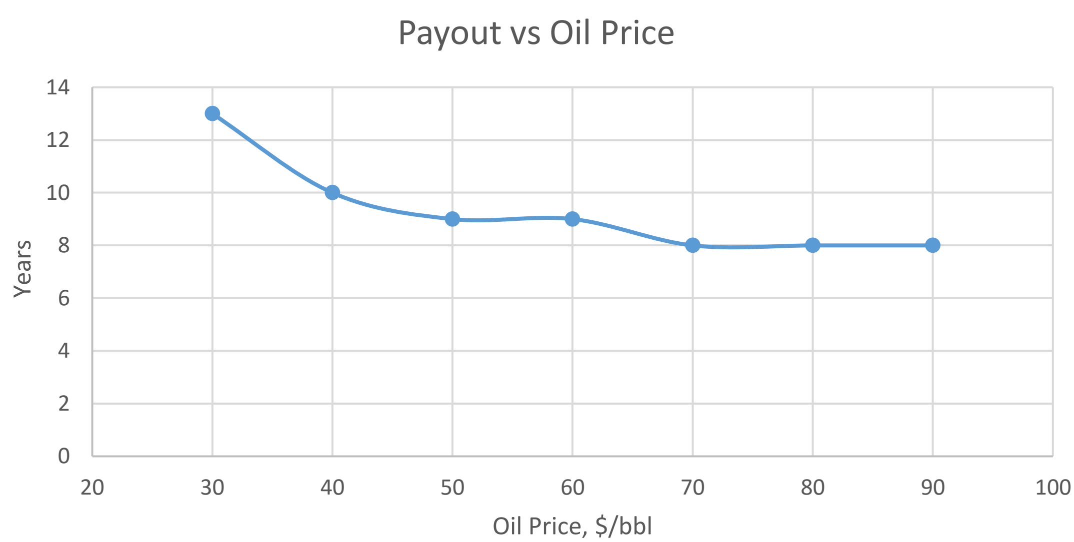


Figure 45 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Chinook 2 wells P50 artificial lift at different oil prices.

Chinook 3 Wells and Artificial Lift (Option 8, Table 9).

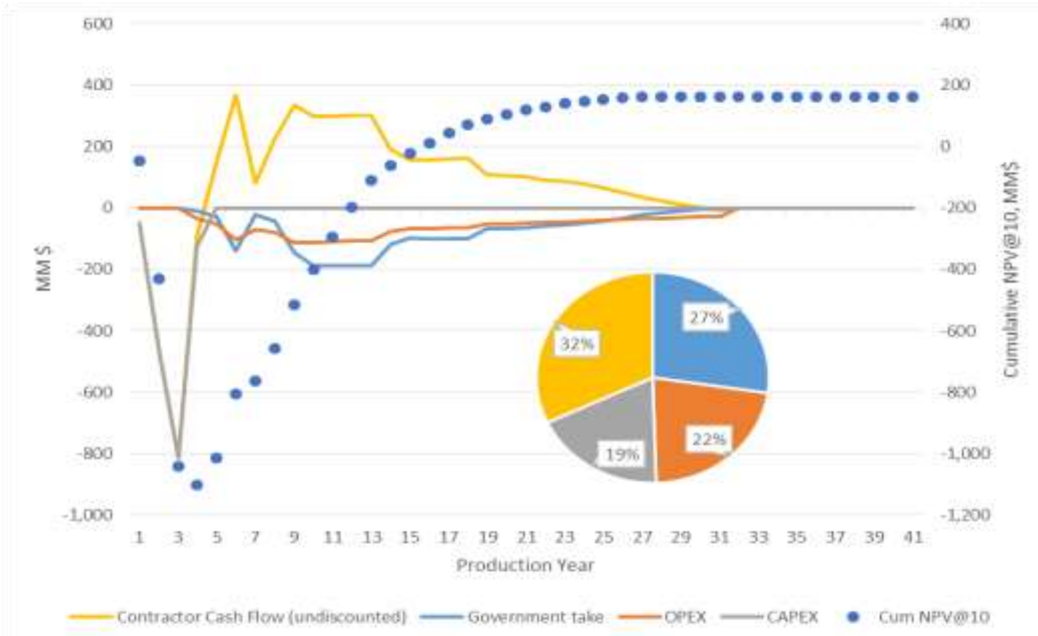


Figure 46 Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total revenue to CAPEX, OPEX, government, and contractor net cash. The government and contractor distribution of 30% and 42% gives a profit split between government and contractor of 42%-58%, respectively.

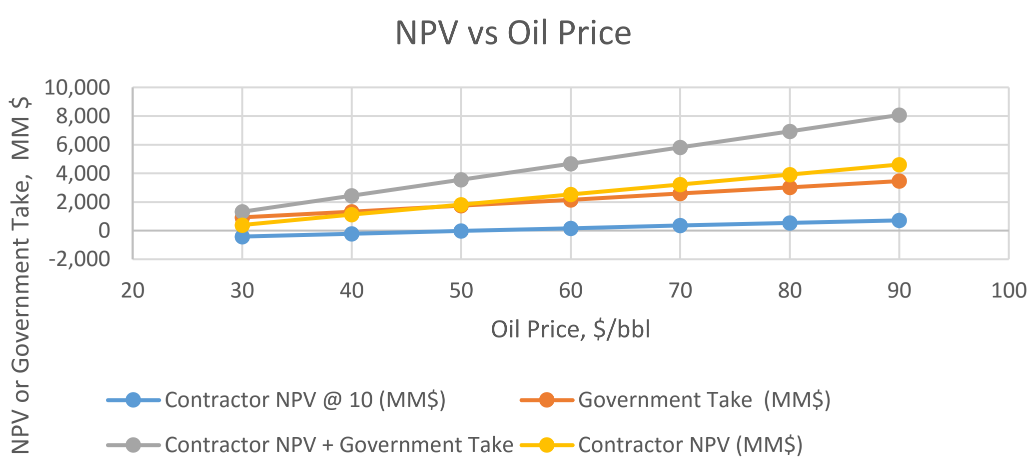
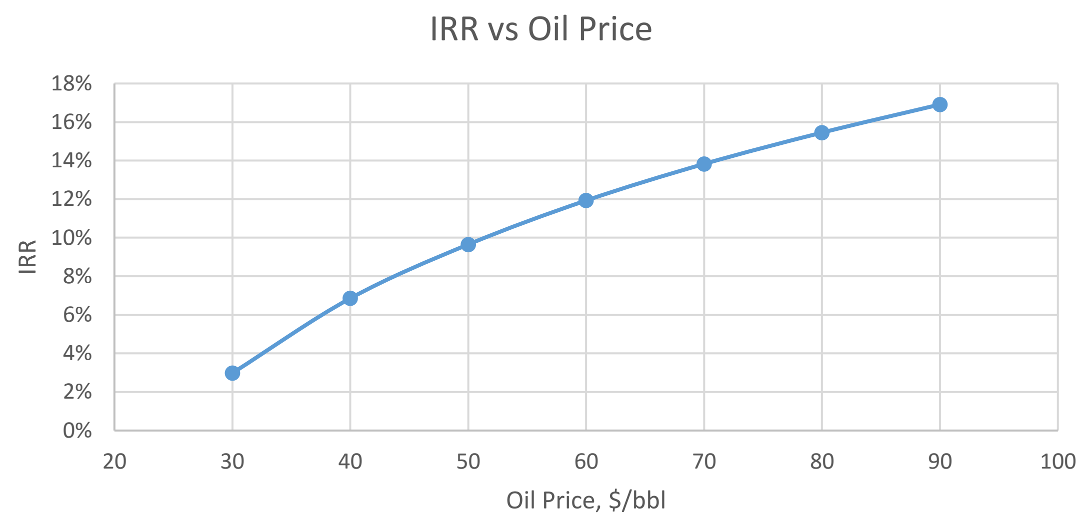


Figure 47 Discounted and undiscounted Contractor NPV and Government take for Chinook 3 wells artificial lift at different oil prices.



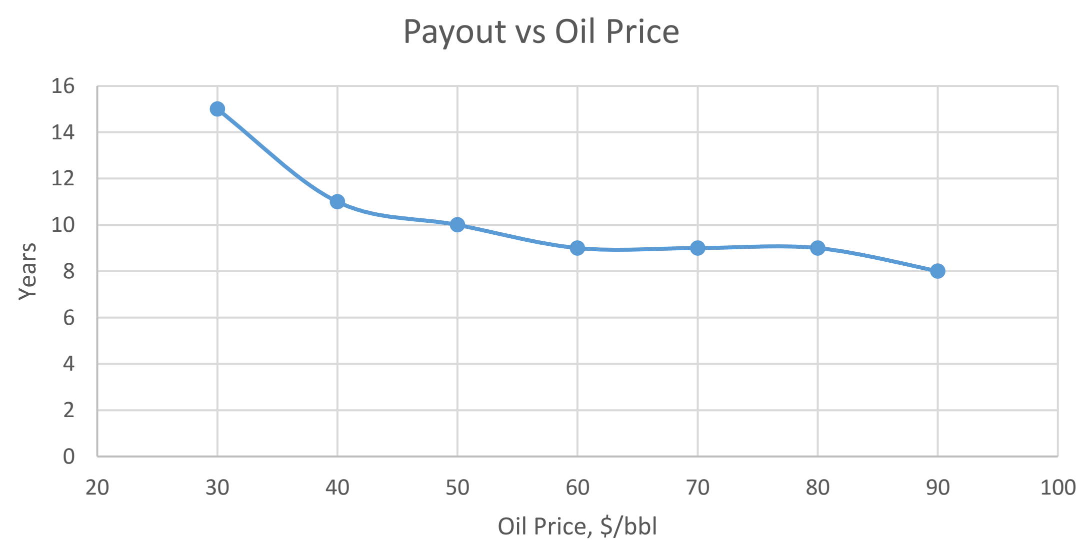


Figure 48 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Chinook 3 wells P50 artificial lift at different oil prices.

DISCUSSION

Oil Price Sensitivity

Producing at higher rates will allow projects to withstand lower oil prices. The low oil price today makes the price sensitivity analysis a crucial factor in the petroleum industry to determine whether to halt production, or to continue operating hoping for oil prices to increase. Choosing the optimum field development will also help projects withstand lower oil prices. Figure 28 and Figure 29 show how different field developments affect the NPV of a project and the investment required for each development option analyzed in this study. An example is shown for the different development options of Chinook. Option 3 (1 well natural drive) requires a minimum oil price of $70/bbl for the P50 NPV@10 for the project to be viable, while Option 6 (2 wells with artificial lift) only needs a $50/bbl oil price. When the project started production in 2012, oil price was very high, peaking above $100/bbl, making both Cascade and Chinook projects economically viable. The rapid decline in oil prices greatly affected both projects. Deciding whether the project should be stopped, continued, or further developed will need to be carefully assessed by Petrobras, especially since the oil price has stabilized around $50/bbl.

Advantages of the FPSO in the GoM's Deepwaters

The use of FPSO in the Gulf of Mexico's deep waters will become more popular once activity begins on the Mexican side. The lack of pipeline infrastructure will make the use of permanent structures economically infeasible, at least during the first decade of deepwater development. The FPSO will significantly decrease the CAPEX for the project, but the OPEX will increase, sometimes double, compared to the use of pipeline export system.

A cost estimate using FieldPlan shows that for a system at water depths of 8,000 ft, 160 miles from shore and with 3 wells drilled the total costs (CAPEX + OPEX) is 27% higher using an FPSO and tanker shuttle than a SPAR and pipeline export over 30 years of production. However, without an existing pipeline network the total cost of a SPAR with shuttle would be 78% higher than that of the FPSO. An advantage of using the FPSO as an early development system is that the CAPEX is lower than for a permanent structure. Another incentive for the FPSO in the GoM particularly is the mobility of the unit. The majority of hurricanes that hit this area have damaged and destroyed numerous fixed platforms. The ability of the FPSO to stop production, detach from the lines and go to a safe area makes this option appealing to future contractors.

Effects of OPEX Caused by the FPSO

The OPEX will be very high for deploying and operating the FPSO with shuttle tanker compared to using pipeline export. Figure 49 shows the effect different annual OPEX has on Chinook's field development Option 6 NPV@10. As the annual OPEX increases the project's NPV will decrease. At a $60/bbl, the maximum annual OPEX Chinook Option 6 can withstand and still be profitable is $83 million, which is only possible since Cascade and Chinook split the FPSO costs evenly in this study. Figure 50 shows the allocations of total revenue to CAPEX, OPEX, government, and contractor net cash at different annual OPEX values.

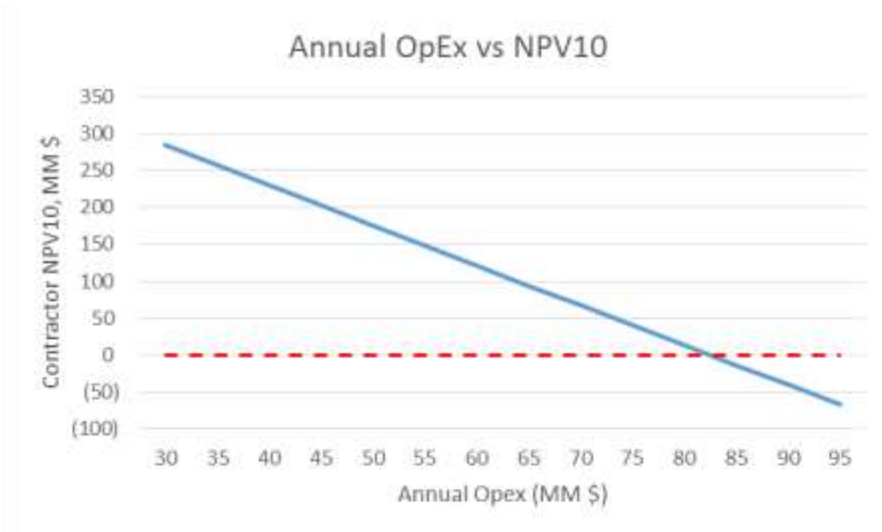


Figure 49 Plot of NPV@10 against different annual OPEX for P50 Chinook field development Option 6 (2 wells with artificial lift at an oil price of $60/bbl.

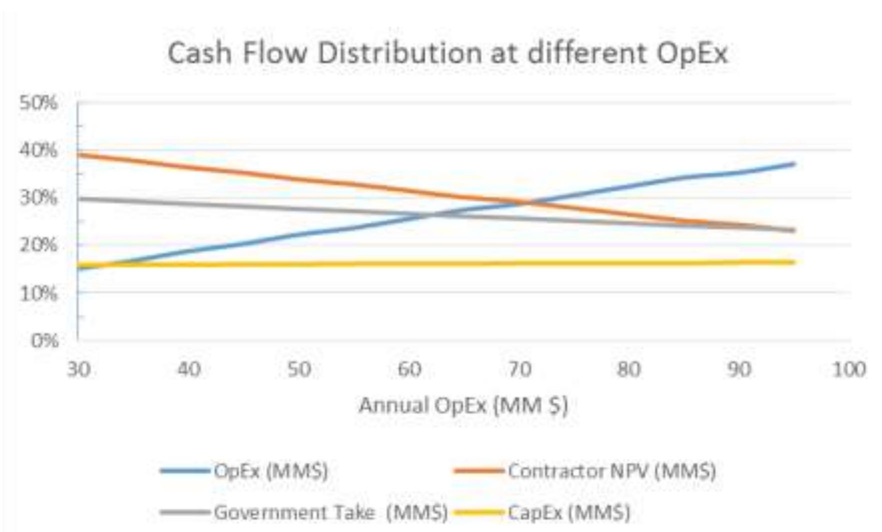


Figure 50 Cash flow allocations of total revenue to CAPEX, OPEX, government, and contractor net cash.

CONCLUSION

This study analyzes the Cascade and Chinook fields and appraises the economic returns for the current developments of both fields and for the new proposed field developments for the Chinook field. This study also validates using Probabilistic Nodal Analysis for production forecasting and to determine the optimum field development for ultra-deepwater fields. PNA can identify the production constraints in a petroleum system. Figure 28 demonstrates there is insignificant change in P90 NPV values for different field developments, indicative the reservoir is the limiting factor, whereas the substantial increase in the NPV values for the P50 and P10 values for different field developments suggest the production facilities cause the bottleneck.

Our P50 estimates conclude that one additional well should be drilled to produce the Chinook field, since using 2 production wells instead of 1 could increase the estimated NPV@10 from $-14 million to $146 million.

The use of the FPSO in the GoM’s deepwaters far from the existing oil pipeline network will help mitigate the project’s risk by lowering the initial investment. The FPSO is the most logical early production system in the Mexican side of the GoM, where the pipeline infrastructure does not exist. Only block 1 offered by the Mexican government in the deepwater bidding, 14 miles south from Shell Perdido Project, could use a permanent structure if they are allowed to share the oil pipelines with Shell to export produced oil.

NOMENCLATURE

A	Area
bbl	Barrel
boe	Barrels of oil equivalent
B_{oi}	Initial oil formation volume factor
BSEE	Bureau of Safety and Environmental Enforcement
CAPEX	Capital Expenditure
cp	Centipoise
DCA	Decline Curve Analysis
EIA	Energy Information Administration
EUR	Estimated Ultimate Recovery
FPSO	Floating Production, Storage and Offloading
ft	Feet
FVF	Formation Volume Factor
GoM	Gulf of Mexico
h	Height
IPR	Inflow Performance Relationship
IRR	Internal Rate of Return
J	Productivity Index
J_D	Dimensionless Productivity Index
k	Permeability
M	Thousand
mD	Milidarcy
mi	Miles
MM	Million
N	Total oil in place
NOAA	National Oceanic and Atmospheric Administration
NPV	Net Present Value
NPV@10	Net Present Value at a 10% Discount Rate
OOIP	Original Oil in Place
OPEX	Operational Expenditure
OPR	Outflow Performance Index
p_b	Bubble point pressure

p_f	Pressure loss due to Friction
PNA	Probabilistic Nodal Analysis
p_{PE}	Pressure loss due to Potential Energy
PPF	Probabilistic Production Forecast
p_r	Reservoir Pressure
psi	Pound per Square Inch
p_{wf}	Wellbore Pressure
q	Flow rate
Q	Flow rate
ρ	Density
RB	Reservoir Barrels
r_e	drainage radius
RF	Recovery Factor
r_w	wellbore radius
s	Skin factor
scf	Standard cubic feet
stb	Stock Tank Barrel
S_w	Water Saturation
TVD	True Vertical Distance
WR	Walker Ridge

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APPENDIX A- VALIDATION OF NODAL ANALYSIS MODEL

We used 2 wells from the Shell Perdido project to validate our probabilistic nodal analysis model that have been producing since 2010. The first 24 months of production data were used to forecast production using probabilistic nodal analysis and the traditional Decline Curve Analysis. All the forecasted data, as well as the actual production data, are shown to the right of the red line in Figure 51.

Probabilistic Nodal Analysis uses both the reservoir parameters and the production facilities to forecast production. Since the production facilities are known, the only variables are the reservoir parameters. For the deterministic model, we use these parameters to calibrate the model using the historic oil production data. For the probabilistic model, we used @Risk to run 50,000 Monte Carlo simulations using the same reservoir parameter distributions shown in Table 2, to obtain the probabilistic production index, J, and the reservoir parameters associated to that particular *J*. The probabilistic values of *J* and their respective key reservoir parameters for each percentile are shown in Table 10. We assumed the total oil in place for the Perdido Project is 900 MMbbl and skin of 0.

The actual production data falls between the P90 and P10 curves and gets closer to the P50 curve with time, while the DCA approach greatly underestimates the actual production as shown in Figure 51. These results validate our model since the probabilistic production curves encompass the historic oil production.

Table 10 Probabilistic values for Productivity Index, J, for the corresponding percentile, and their respective key reservoir parameters used for the probabilistic nodal analysis.

	J	Permeability (mD)	Net Pay (ft)	Porosity (fraction)	API Gravity Oil	Oil viscosity @ pi (cp)
J-P90	4.76	160	96	0.262	36.8	1.84
J-P50	8.36	165	93	0.286	34.1	1.04
J-P10	13.15	180	108	0.260	36.3	0.84

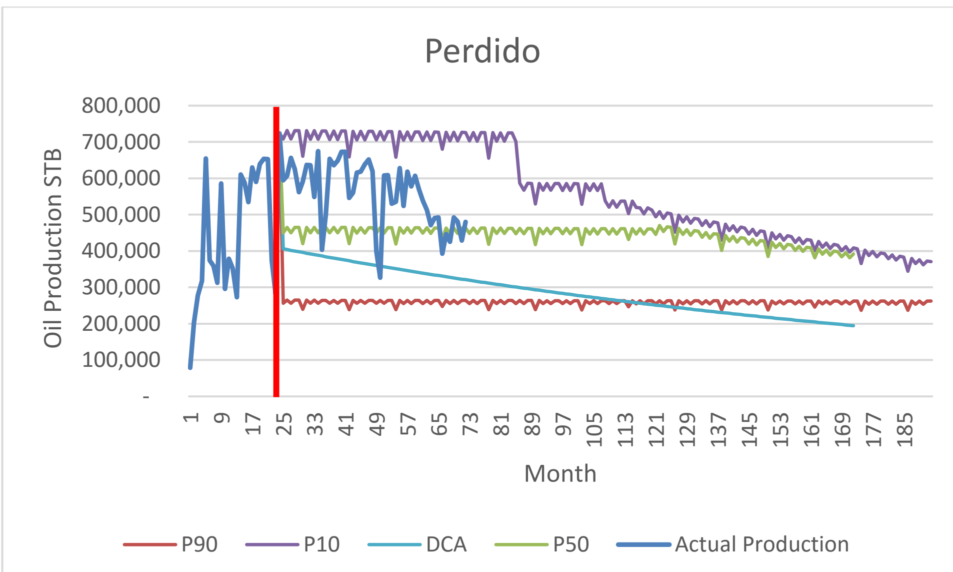


Figure 51 Production forecast using traditional DCA and probabilistic nodal analysis compared to actual production data. Data to the left of the red line was used to produce the forecasts to the right of the red line. Actual production data is plotted in blue as a reference.

APPENDIX B- CASCADE AND CHINOOK MONTHLY PRODUCTION DATA

				use CA003				use CA004				use CA006			
Date	Month	Year	Days on month	Days On TRUE	Oil stb	Gas 1000 scf	Water stb	Days On TRUE	Oil stb	Gas 1000 scf	Water stb	Days On TRUE	Oil stb	Gas 1000 scf	Water stb
1/1/2012	1	2012	31	0	0	0	0								
2/1/2012	2	2012	29	5	11679	4350	1034								
3/1/2012	3	2012	31	31	85348	24058	1086								
4/1/2012	4	2012	30	30	130903	31520	499								
5/1/2012	5	2012	31	31	144049	37575	367								
6/1/2012	6	2012	30	30	174574	37597	304								
7/1/2012	7	2012	31	31	155999	31538	554								
8/1/2012	8	2012	31	30	114769	25375	174								
9/1/2012	9	2012	30	30	130563	31101	325								
10/1/2012	10	2012	31	31	116235	25626	173								
11/1/2012	11	2012	30	30	107741	21955	184								
12/1/2012	12	2012	31	31	198145	33885	7897	31	0	85	0				
1/1/2013	1	2013	31	31	169252	26651	780	31	0	35	0				
2/1/2013	2	2013	28	28	192646	26610	976	28	0	83	0				
3/1/2013	3	2013	31	31	203106	34057	1102	31	0	141	0				
4/1/2013	4	2013	30	30	181252	32399	909	30	0	97	0				
5/1/2013	5	2013	31	31	177537	30293	981	31	0	109	0				
6/1/2013	6	2013	30	30	168619	29006	990	30	0	93	0				
7/1/2013	7	2013	31	31	165289	30223	846	31	0	129	0				
8/1/2013	8	2013	31	31	164628	28715	911	31	0	117	0				
9/1/2013	9	2013	30	30	150083	21619	806	30	0	95	0				
10/1/2013	10	2013	31	31	153783	20447	853	31	0	58	0				
11/1/2013	11	2013	30	30	135748	20081	777	30	0	61	0				
12/1/2013	12	2013	31	31	54377	9503	164	31	0	147	0	23	0	0	1
1/1/2014	1	2014	31	31	92915	7222	918	31	70632	24712	514	31	97404	19627	10518
2/1/2014	2	2014	28	28	81048	9613	835	28	53929	10687	589	28	158878	35672	6692
3/1/2014	3	2014	31	31	137174	28612	1089	31	79059	16552	971	31	321336	70766	11452
4/1/2014	4	2014	30	30	115450	23896	738	30	67318	13960	692	30	278863	58000	7066
5/1/2014	5	2014	31	31	108704	23080	436	31	64382	13585	500	31	282563	57655	7200
6/1/2014	6	2014	30	30	96535	20668	265	30	70505	12363	976	30	244332	50726	4569
7/1/2014	7	2014	31	31	96940	20074	46	31	71015	11987	296	31	236796	49537	3200
8/1/2014	8	2014	31	31	86613	17318	254	31	65011	10574	590	31	210244	43833	6266
9/1/2014	9	2014	30	30	81547	16105	429	30	58772	9808	541	30	193824	40997	5757
10/1/2014	10	2014	31	31	88617	13768	297	31	63124	28329	725	31	193631	30230	10795
11/1/2014	11	2014	30	30	83324	14380	242	30	59884	10838	480	30	179069	30527	10185
12/1/2014	12	2014	31	30	48644	10961	347	30	43309	11317	445	30	130895	30547	10150
1/1/2015	1	2015	31	30	54467	12296	184	30	44803	11438	200	30	124325	27720	7577
2/1/2015	2	2015	28	28	51005	10994	389	28	41605	10140	338	28	113228	24087	11896
3/1/2015	3	2015	31	28	57487	11774	711	28	45638	10567	526	28	120865	24441	16628
4/1/2015	4	2015	30	28	55438	12460	635	28	43845	11150	526	28	110519	24513	15475
5/1/2015	5	2015	31	30	55123	11637	428	30	42223	9963	527	30	107041	20899	15944
6/1/2015	6	2015	30	30	55288	11055	274	30	41759	8648	564	30	106335	19088	17742
7/1/2015	7	2015	31	30	57411	11631	250	30	42783	8952	525	30	106848	19522	20599
8/1/2015	8	2015	31	31	56967	11814	204	31	42360	10571	464	31	104919	23242	22541
9/1/2015	9	2015	30	30	54223	11971	170	30	40365	9045	479	30	98309	19238	22337
10/1/2015	10	2015	31	31	55024	12487	208	31	40537	9270	434	31	97892	19512	22485
11/1/2015	11	2015	30	30	53775	11920	178	30	39595	8790	359	30	94057	18234	21406
12/1/2015	12	2015	31	31	54185	11110	143	31	39478	8084	339	31	89333	15287	25632
1/1/2016	1	2016	31	31	54199	11106	145	31	39788	8147	363	31	91747	16530	23342
2/1/2016	2	2016	29	24	39750	8311	141	24	29296	6122	356	24	68866	12566	16486
3/1/2016	3	2016	31	18	38336	7908	172	18	27833	5803	395	16	46013	9928	11704
4/1/2016	4	2016	30	16	29878	6689	76	16	20958	4764	140	15	45353	8972	8828
5/1/2016	5	2016	31	0	0	0	0	0	0	0	0	0	0	0	0
6/1/2016	6	2016	30	20	60370	12583	153	19	34452	8928	297	19	54150	9946	15069
7/1/2016	7	2016	31	31	62833	14389	116	31	41312	9762	395	31	83645	17321	23664

Figure 52 Monthly Production data for the 3 Cascade wells (CA003, CA004, and CA005). First production started in February 2012 with well CA003, while the 2 other wells (CA004 and CA006) started production in January 2014 (BSEE, 2016).

Date	Month	Year	Days on month	☑ use CH002 Days On TRUE	CH002 Oil stb	CH002 Gas 1000 scf	CH002 Water stb	☑ use CH003 Days On TRUE	CH003 Oil stb	CH003 Gas 1000 scf	CH003 Water stb
9/1/2012	9	2012	30	17	119308	15210	3564				
10/1/2012	10	2012	31	26	190611	28679	2327				
11/1/2012	11	2012	30	30	255574	38199	1846				
12/1/2012	12	2012	31	31	291626	43946	4729				
1/1/2013	1	2013	31	31	274659	38158	4174				
2/1/2013	2	2013	28	28	226661	31010	4260				
3/1/2013	3	2013	31	31	236597	34863	5112				
4/1/2013	4	2013	30	30	221386	34316	6150				
5/1/2013	5	2013	31	31	219018	33113	6794				
6/1/2013	6	2013	30	30	207382	31044	7025				
7/1/2013	7	2013	31	31	203703	30504	8415				
8/1/2013	8	2013	31	31	201123	32612	8169				
9/1/2013	9	2013	30	30	184639	35546	7009				
10/1/2013	10	2013	31	31	191918	36356	8004				
11/1/2013	11	2013	30	30	155243	36353	8004				
12/1/2013	12	2013	31	31	36599	4184	2218	31	0	0	1
1/1/2014	1	2014	31	31	172806	34378	9950	31	193554	18853	10550
2/1/2014	2	2014	28	28	162968	25783	5418	28	303112	46632	6767
3/1/2014	3	2014	31	31	167244	28275	7131	31	557090	96708	16626
4/1/2014	4	2014	30	30	151521	23475	9733	30	512685	79433	14147
5/1/2014	5	2014	31	31	152945	23473	9308	31	501599	77718	13856
6/1/2014	6	2014	30	30	146628	19701	8823	30	458625	72278	13523
7/1/2014	7	2014	31	31	155045	19519	8801	31	455632	71449	11067
8/1/2014	8	2014	31	31	150698	18575	8174	31	437407	65508	9544
9/1/2014	9	2014	30	30	141136	22487	8505	30	410024	65288	7212
10/1/2014	10	2014	31	31	194458	23570	17027	31	521071	85093	4135
11/1/2014	11	2014	30	30	87604	9833	8240	30	488138	62813	4505
12/1/2014	12	2014	31	30	1	0	0	30	480642	65067	7220
1/1/2015	1	2015	31	30	1	0	0	30	414034	55568	6255
2/1/2015	2	2015	28	28	1	0	0	28	318311	41739	4559
3/1/2015	3	2015	31	28	1	0	0	28	345134	45508	5259
4/1/2015	4	2015	30	30	1	0	0	30	326158	40020	5290
5/1/2015	5	2015	31	30	1	0	0	30	311591	37914	4863
6/1/2015	6	2015	30	30	1	0	0	30	314138	40344	4796
7/1/2015	7	2015	31	0	0	0	0	30	322969	41878	4823
8/1/2015	8	2015	31	0	0	0	0	31	321711	35465	5281
9/1/2015	9	2015	30	0	0	0	0	30	303346	35409	5321
10/1/2015	10	2015	31	0	0	0	0	31	307938	36416	5238
11/1/2015	11	2015	30	0	0	0	0	30	299642	33901	4466
12/1/2015	12	2015	31	0	0	0	0	31	303694	38951	5003
1/1/2016	1	2016	31	0	0	0	0	31	297884	36377	5639
2/1/2016	2	2016	29	0	0	0	0	24	219174	25094	4323
3/1/2016	3	2016	31	0	0	0	0	18	169797	20162	3734
4/1/2016	4	2016	30	0	0	0	0	16	148731	18888	2829
5/1/2016	5	2016	31	0	0	0	0	0	0	0	0
6/1/2016	6	2016	30	0	0	0	0	19	224076	27217	5061
7/1/2016	7	2016	31	0	0	0	0	31	314959	41225	5865

Figure 53 Monthly Production data for the 2 Chinook wells (CH002 and CH003). First production started in September 2012 with well CH002 followed by well CH003 on January 2014. There is currently only one producing well in Chinook since well CH002 stopped producing January 2014. (BSEE, 2016)

APPENDIX C- ECONOMIC ANALYSIS RESULTS

Cascade P90 Natural Drive at $60/bbl (Option 1, Table 9)

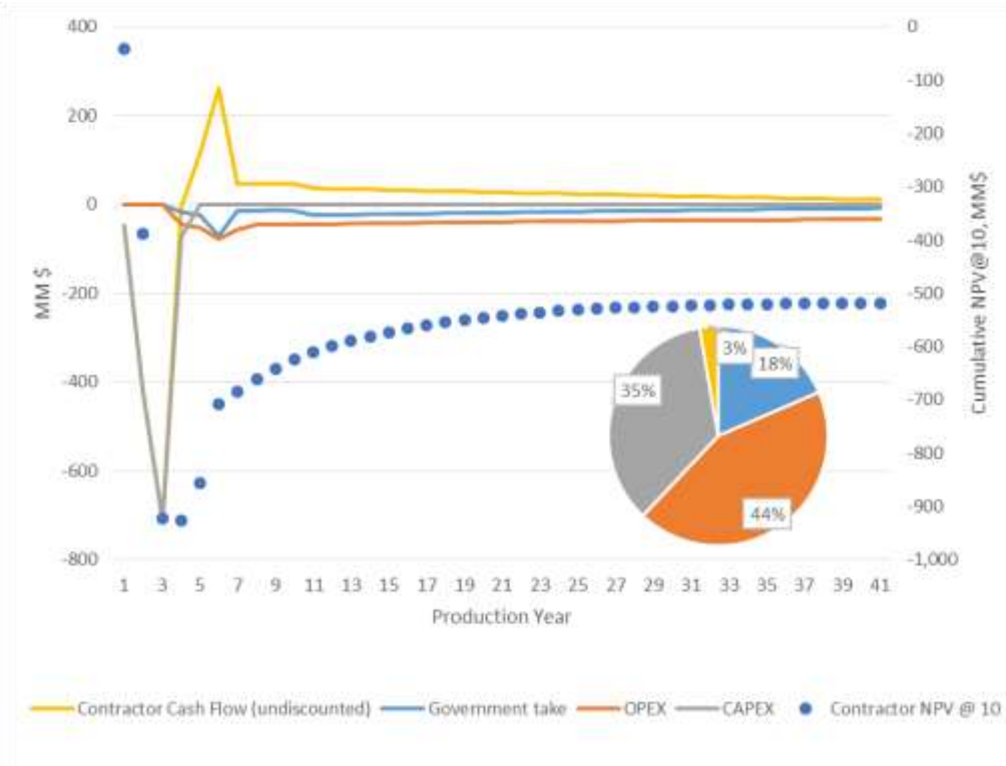


Figure 54 *Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to* contractor *based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash.*

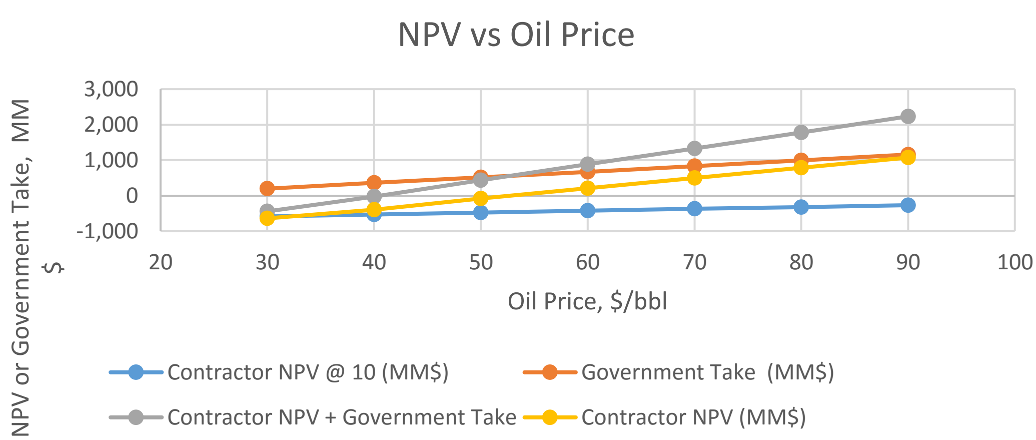
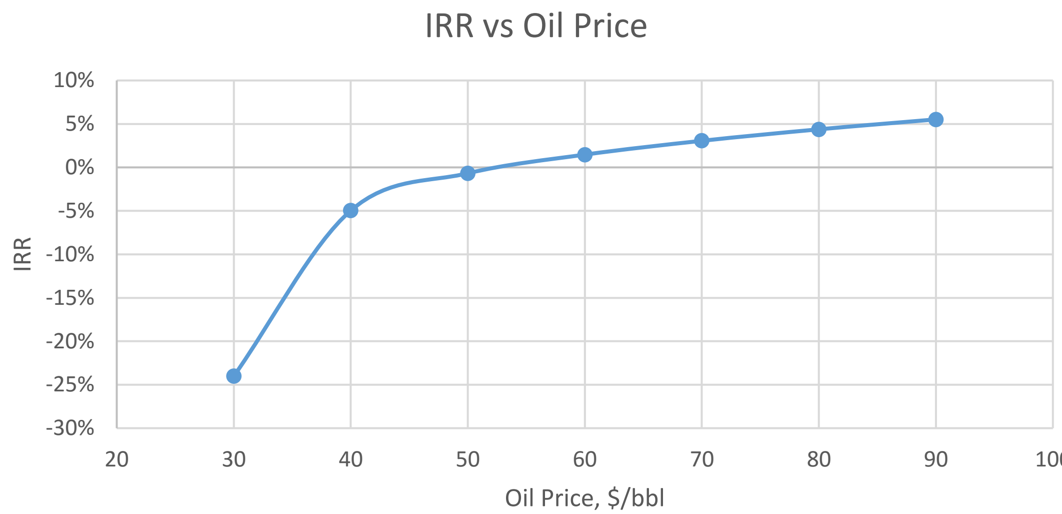


Figure 55 Discounted and undiscounted Contractor NPV and Government take at different oil prices.



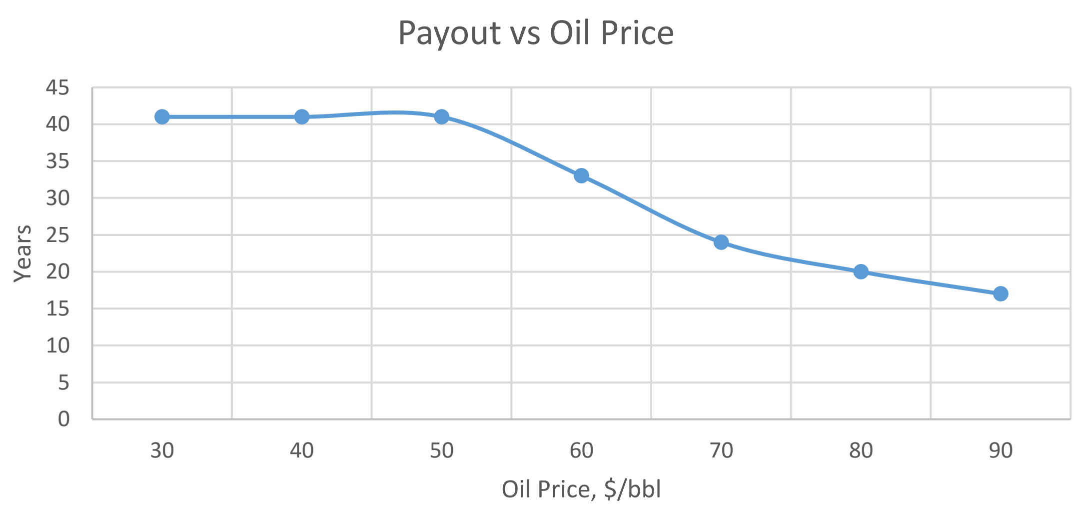


Figure 56 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Cascade P90 natural drive for different oil prices.

Cascade P10 Natural Drive at $60/bbl (Option 1, Table 9)

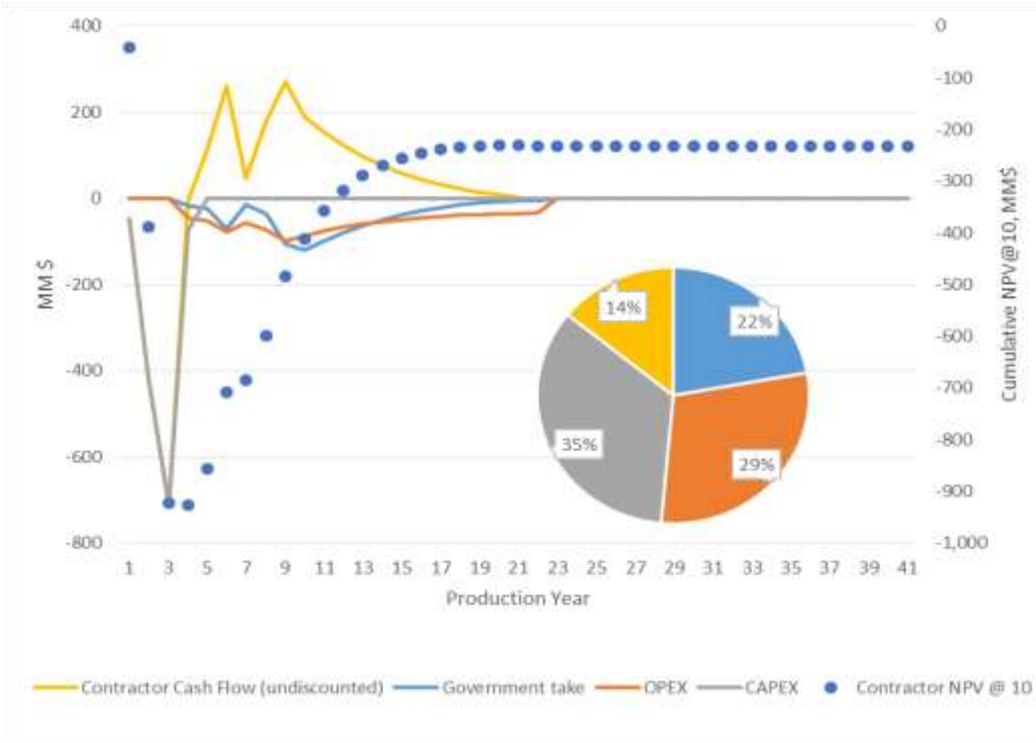


Figure 57Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash

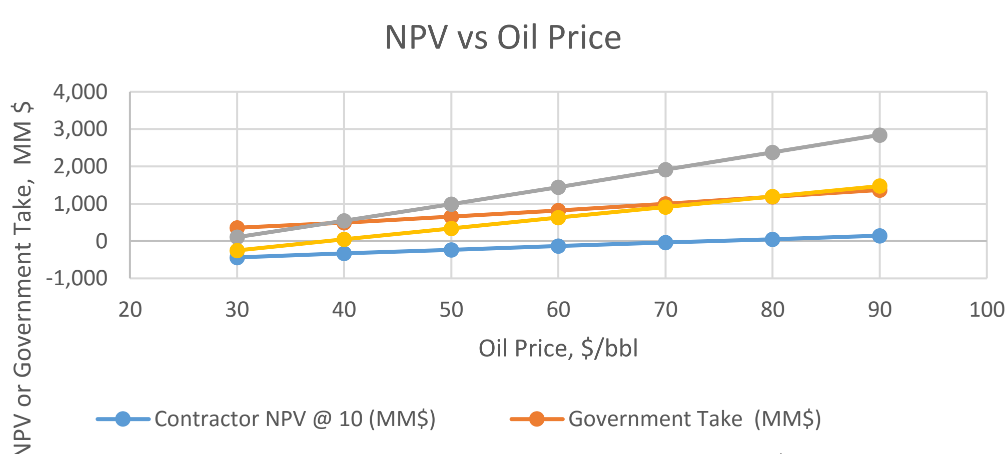
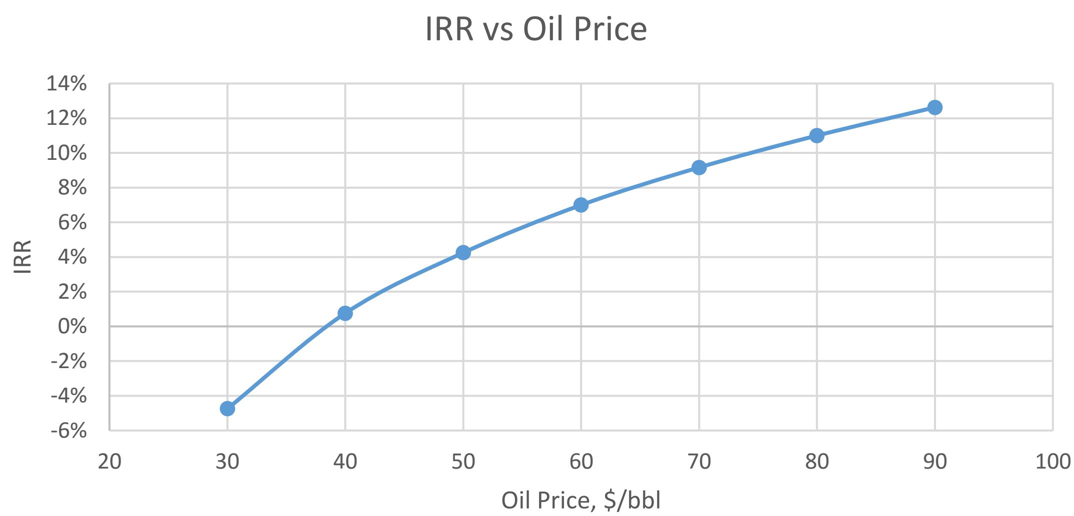


Figure 58 Discounted and undiscounted Contractor NPV and Government take at different oil prices.



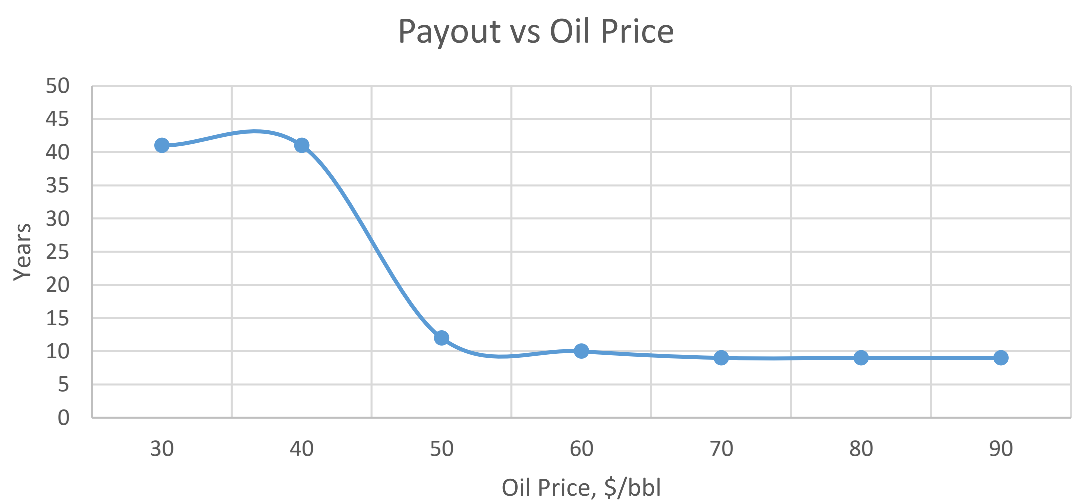


Figure 59 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Cascade P10 natural drive for different oil prices.

Cascade P90 Artificial Lift at $60/bbl (Option 2, Table 9)

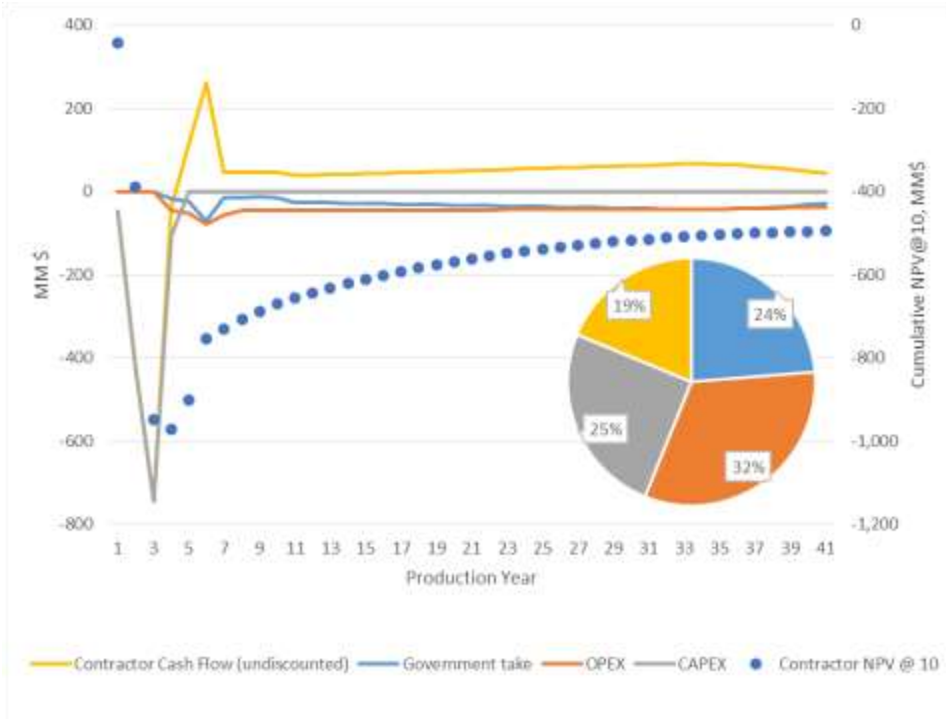


Figure 60 *Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash*

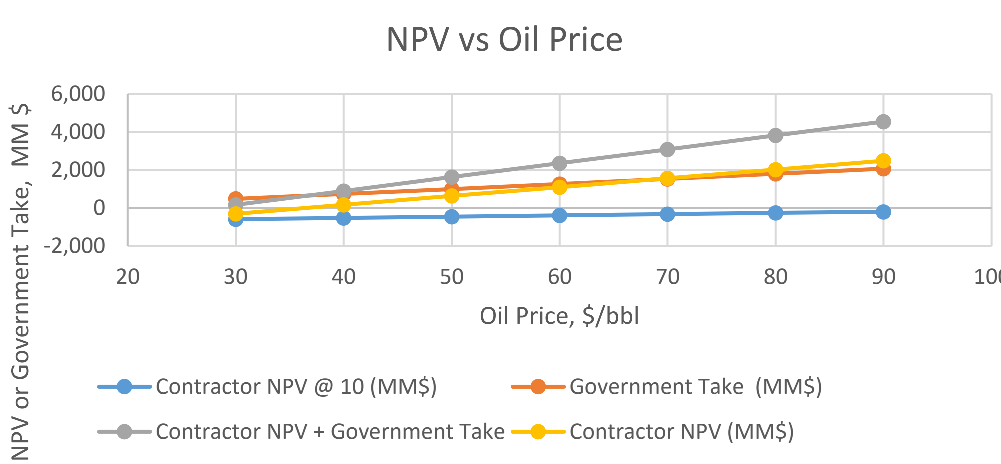
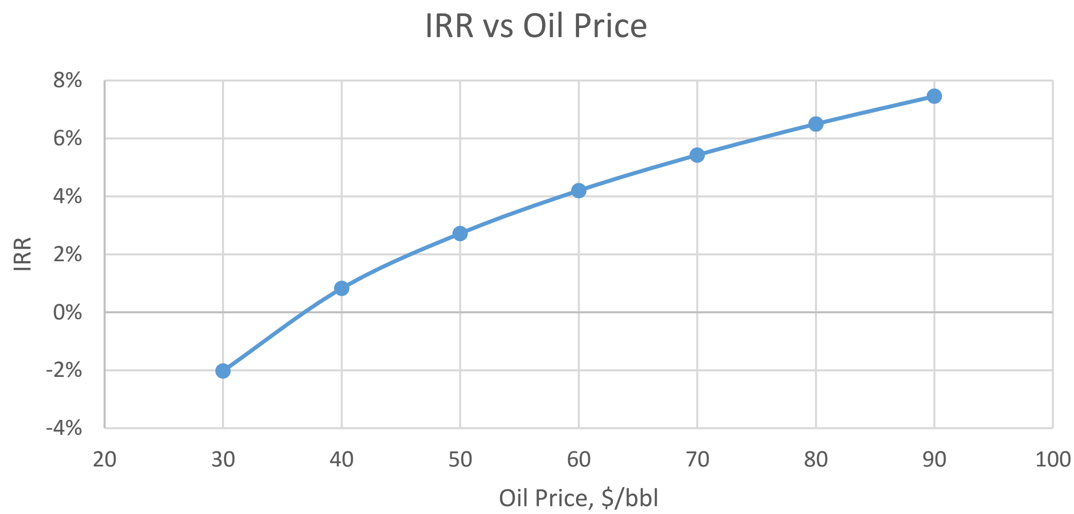


Figure 61 Discounted and undiscounted Contractor NPV and Government take at different oil prices.



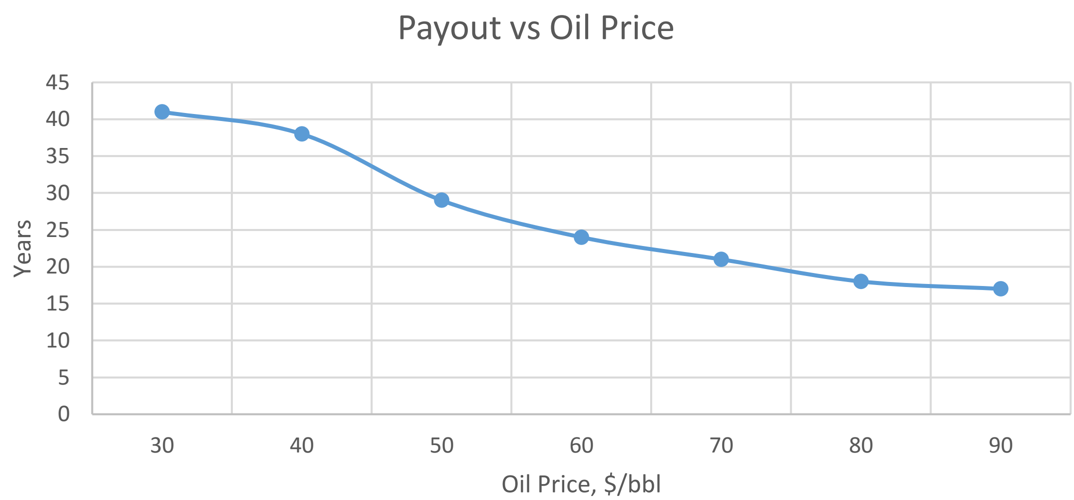


Figure 62 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Cascade P90 artificial lift for different oil prices.

Cascade P10 Artificial Lift at $60/bbl (Option 2, Table 9)

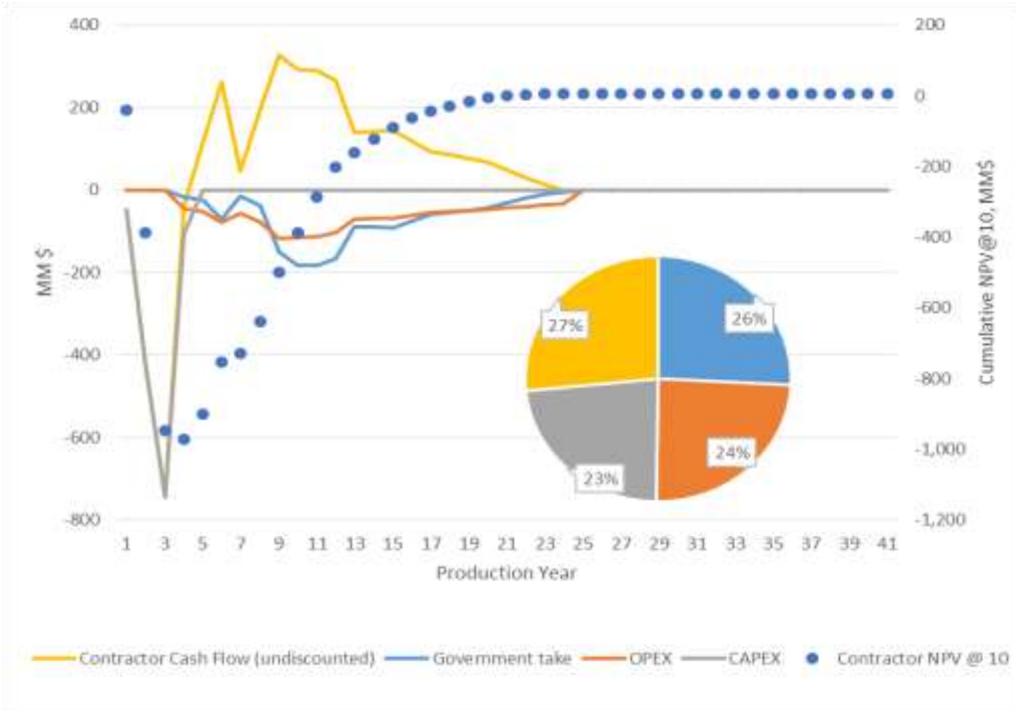


Figure 63 *Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash*

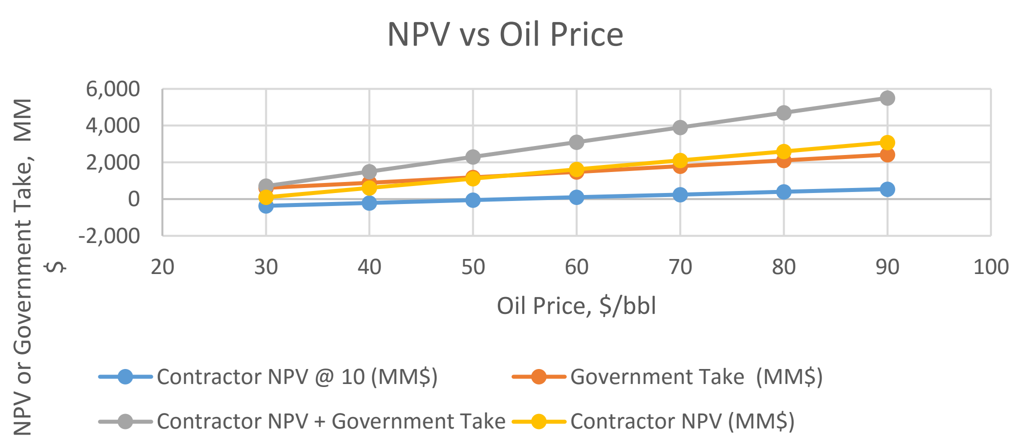


Figure 64 Discounted and undiscounted Contractor NPV and Government take at different oil prices.

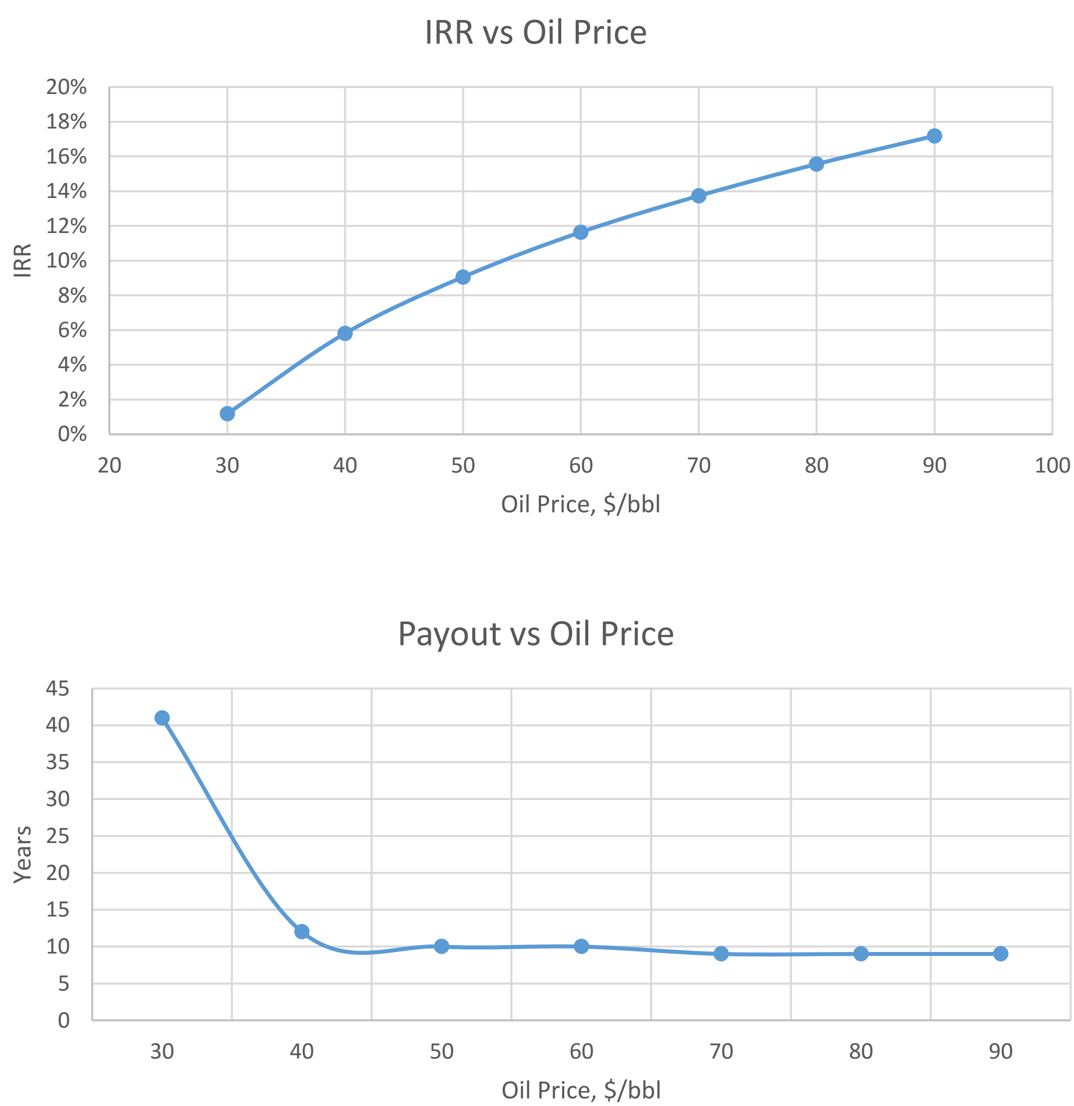


Figure 65 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Cascade P10 natural drive for different oil prices.

<u>Chinook 1 Well P90 Natural Drive at $60/bbl (Option 3, Table 9)</u>

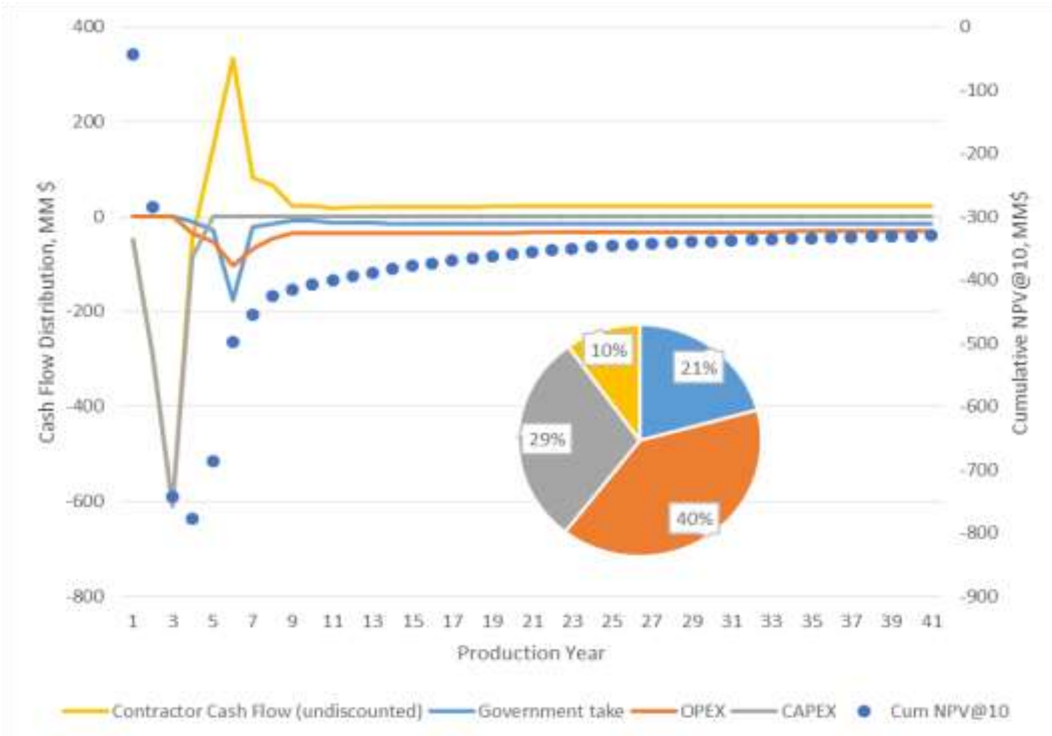


Figure 66 *Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash*

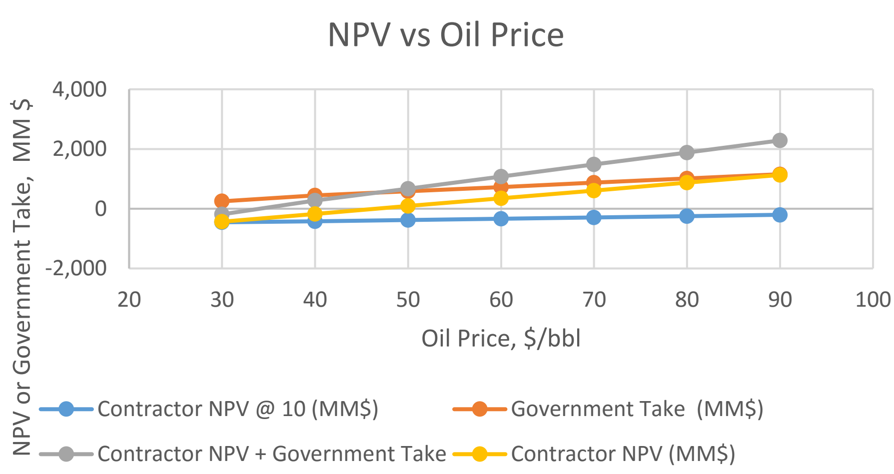
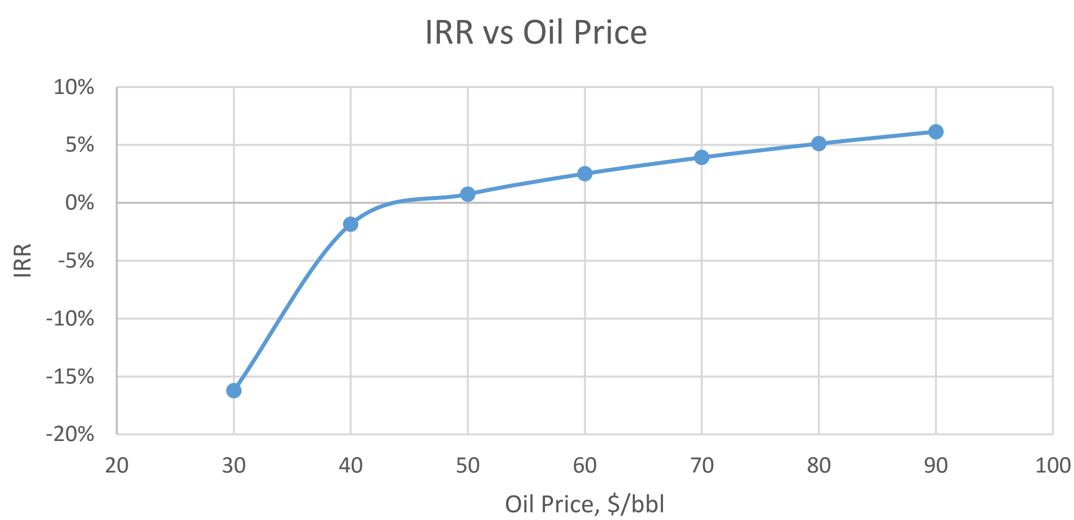


Figure 67 Discounted and undiscounted Contractor NPV and Government take at different oil prices.



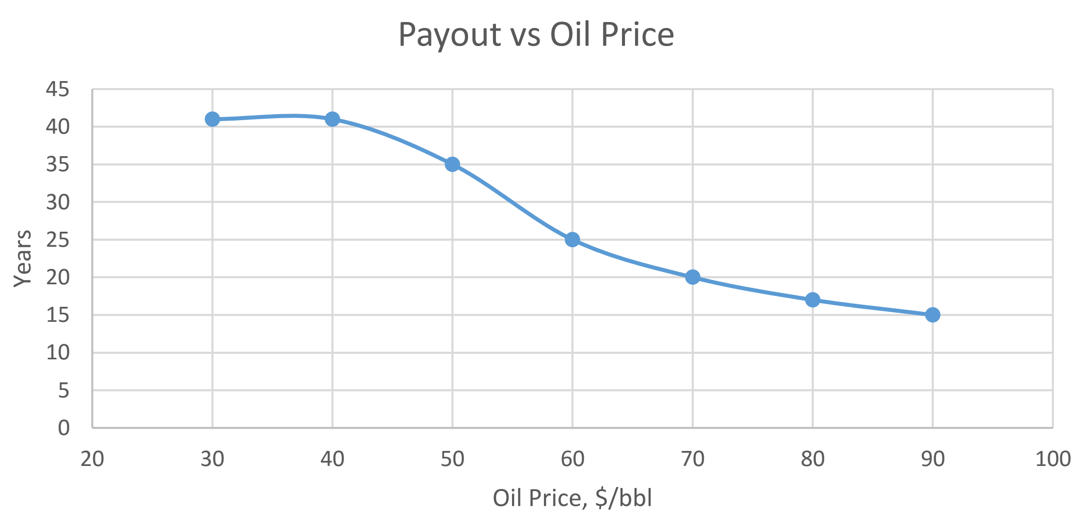


Figure 68 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Chinook 1 well P90 natural drive for different oil prices.

Chinook 1 Well P10 Natural Drive at $60/bbl (Option 3, Table 9)

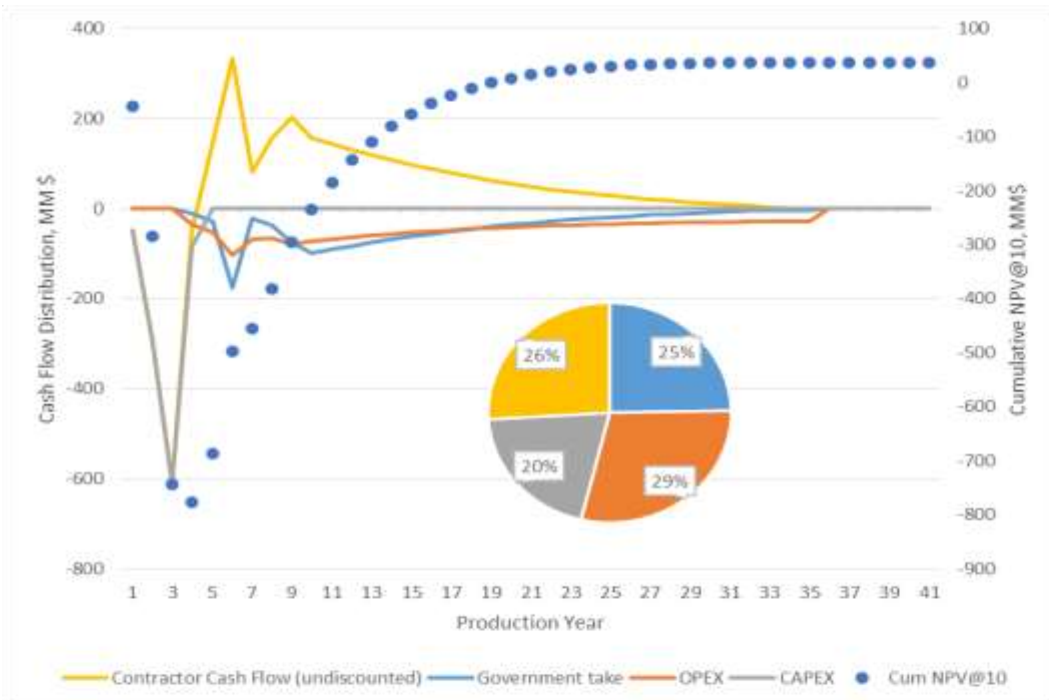


Figure 69 Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash

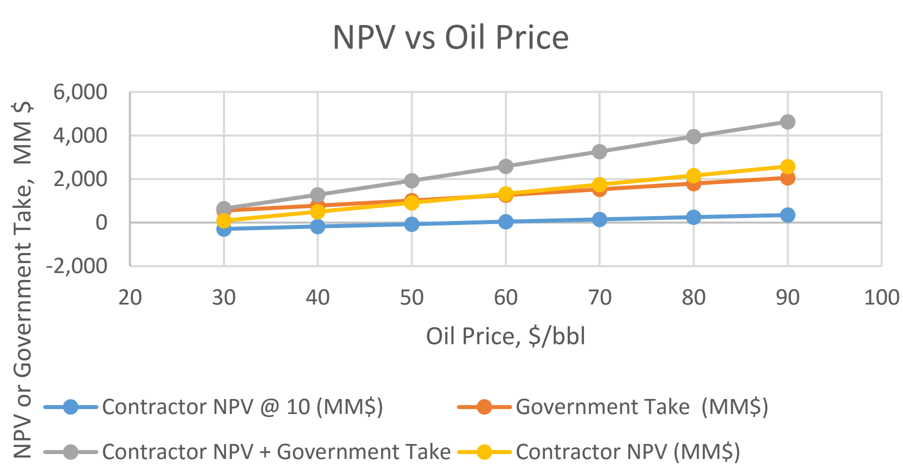
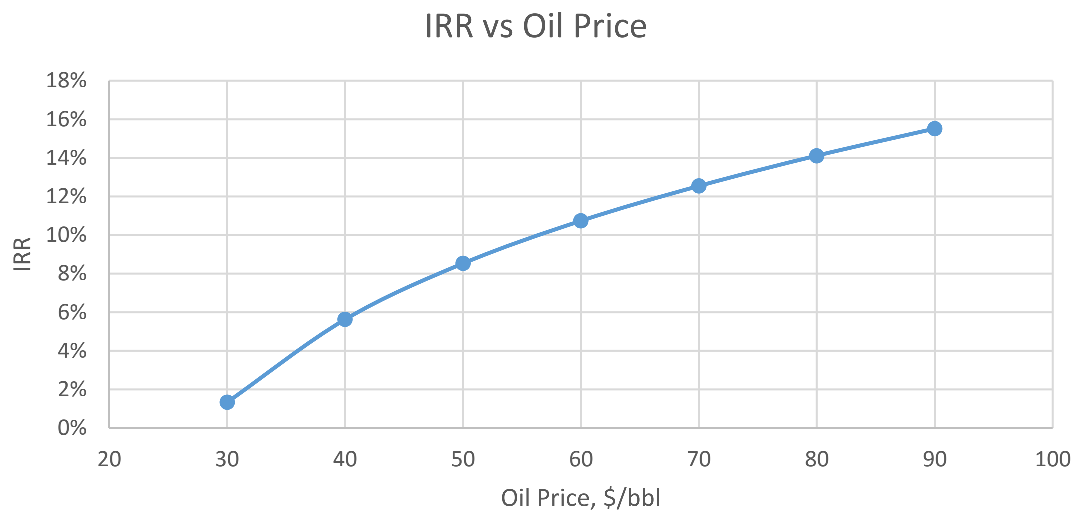


Figure 70 Discounted and undiscounted Contractor NPV and Government take at different oil prices.



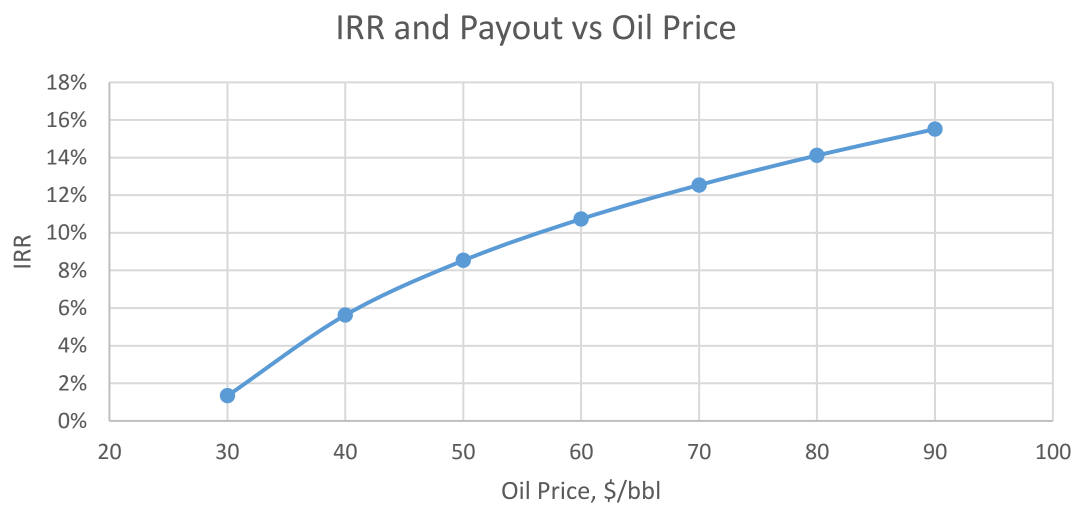


Figure 71 (Top) (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Chinook 1 well P10 natural drive for different oil prices.

Chinook 1 Well P90 Artificial Lift at $60/bbl (Option 4, Table 9)

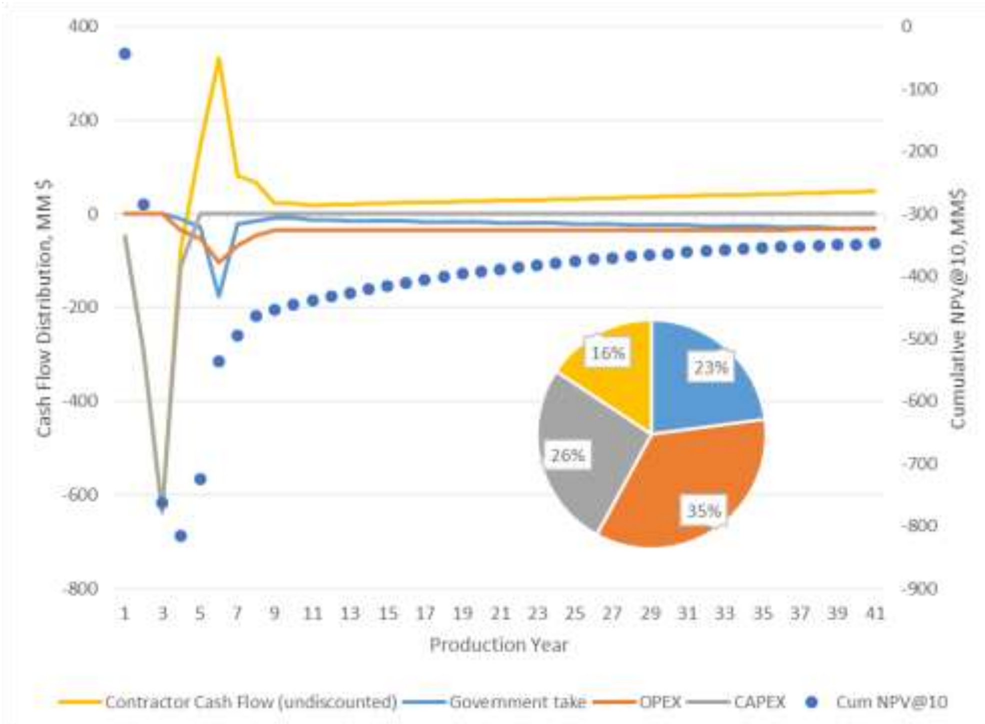


Figure 72 Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash

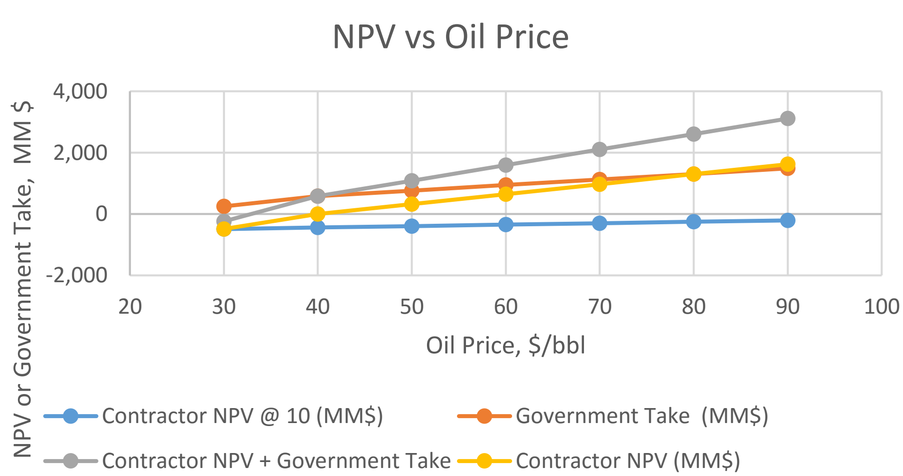
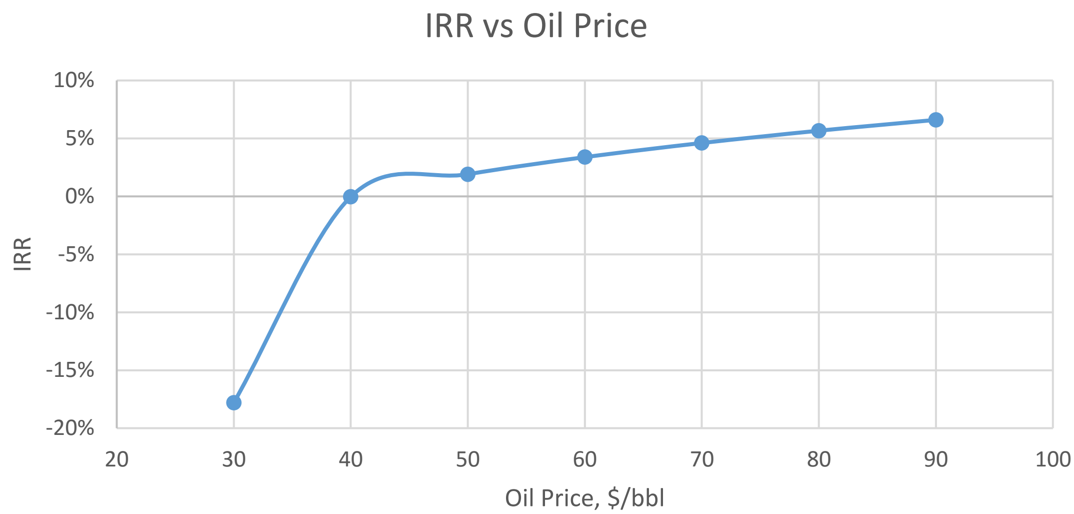


Figure 73 Discounted and undiscounted Contractor NPV and Government take at different oil prices.



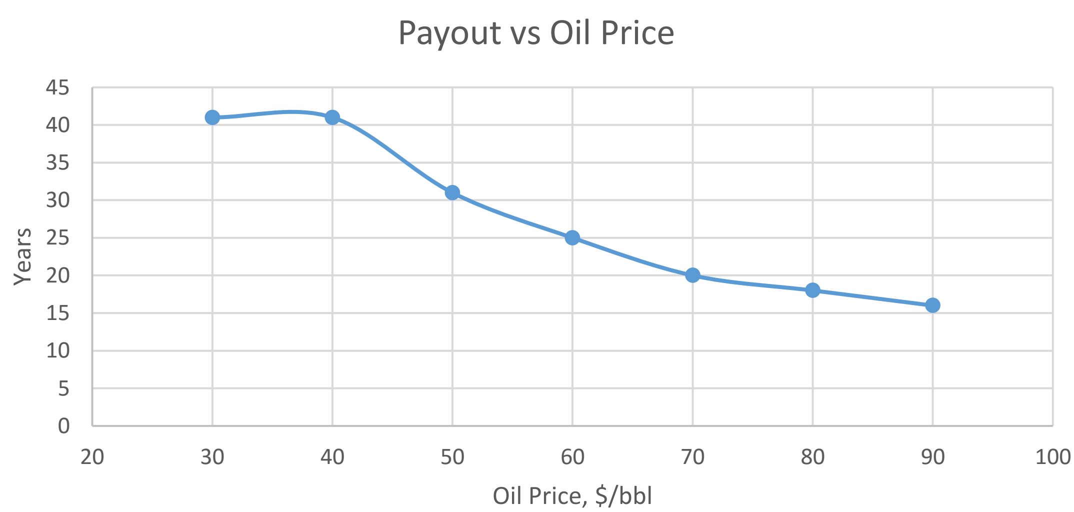


Figure 74 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Chinook 1 well P90 artificial lift for different oil prices.

Chinook 1 Well P10 Artificial Lift at $60/bbl (Option 4, Table 9)

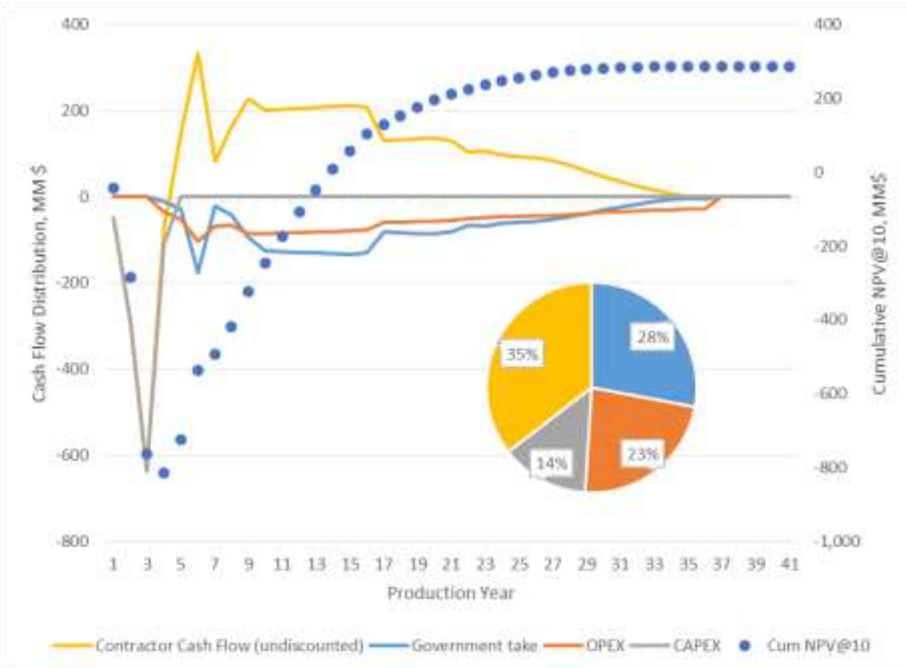


Figure 75 Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash

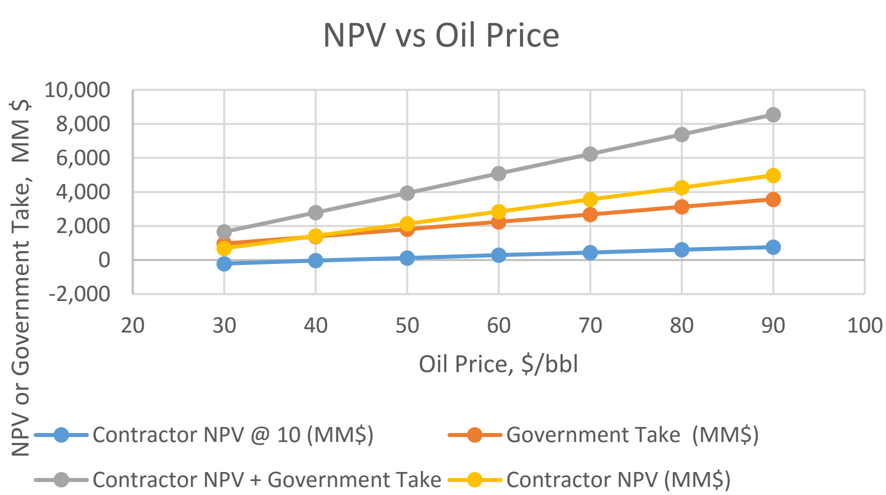
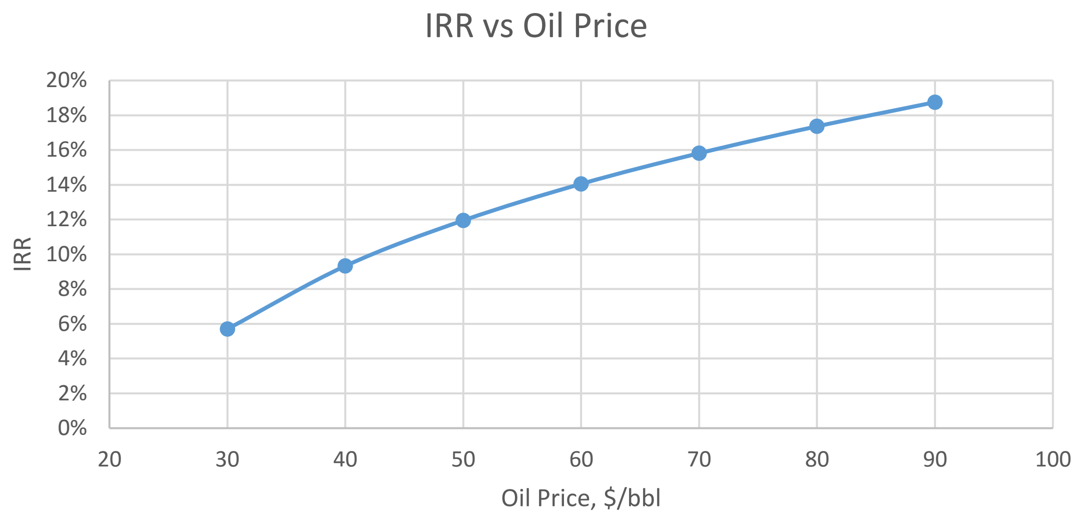


Figure 76 Discounted and undiscounted Contractor NPV and Government take at different oil prices.



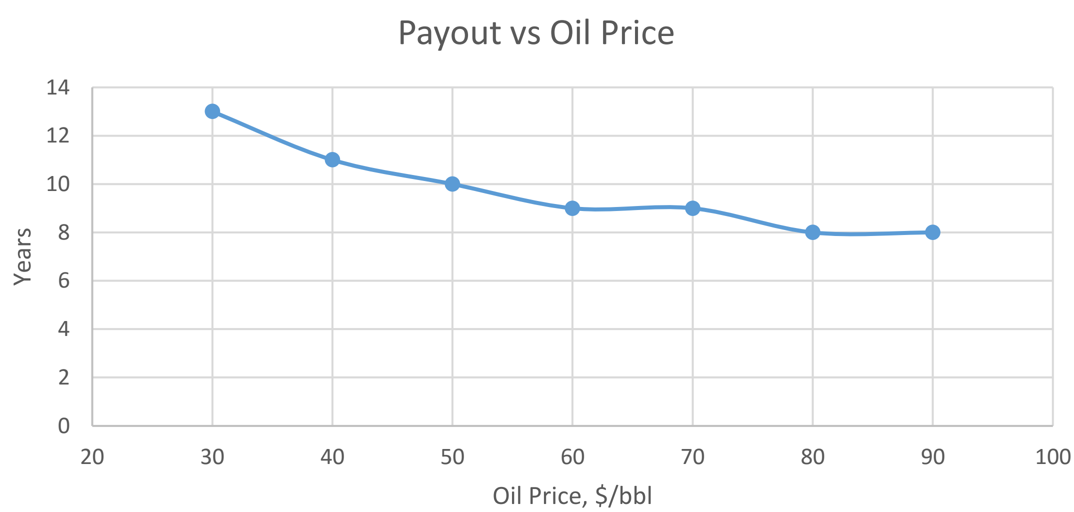


Figure 77 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Chinook 1 well P10 artificial lift for different oil prices.

Chinook 2 Well P90 Natural Drive at $60/bbl (Option 5, Table 9)

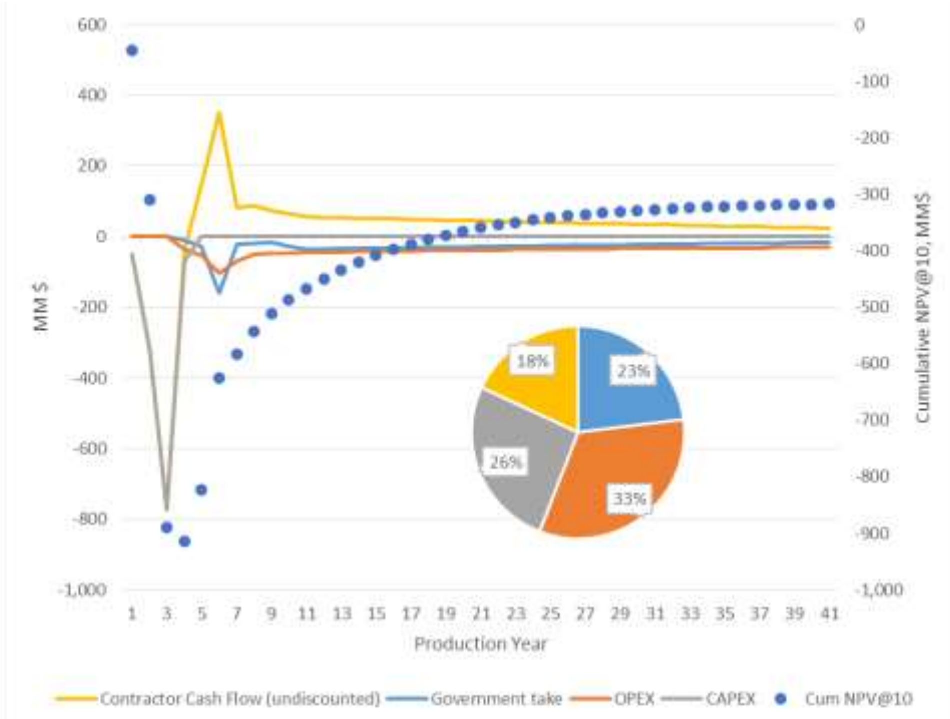


Figure 78 Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash

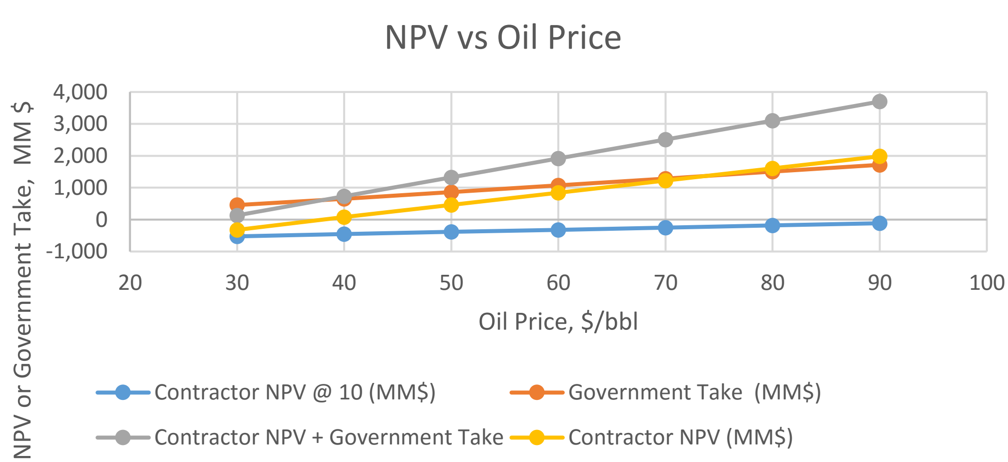
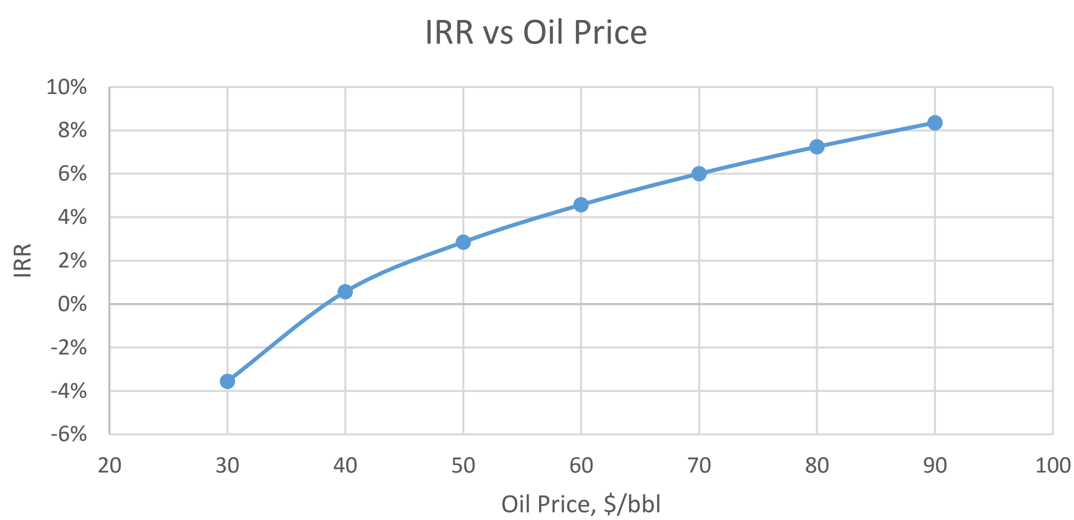


Figure 79 Discounted and undiscounted Contractor NPV and Government take at different oil prices.



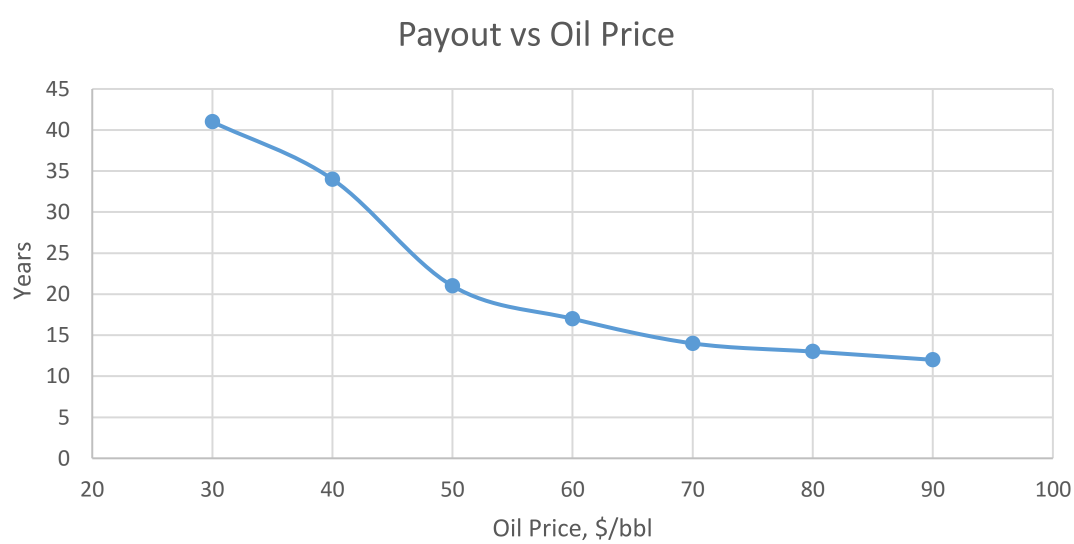


Figure 80 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Chinook 2 wells P90 natural drive for different oil prices.

Chinook 2 Well P50 Natural Drive at $60/bbl (Option 5, Table 9)

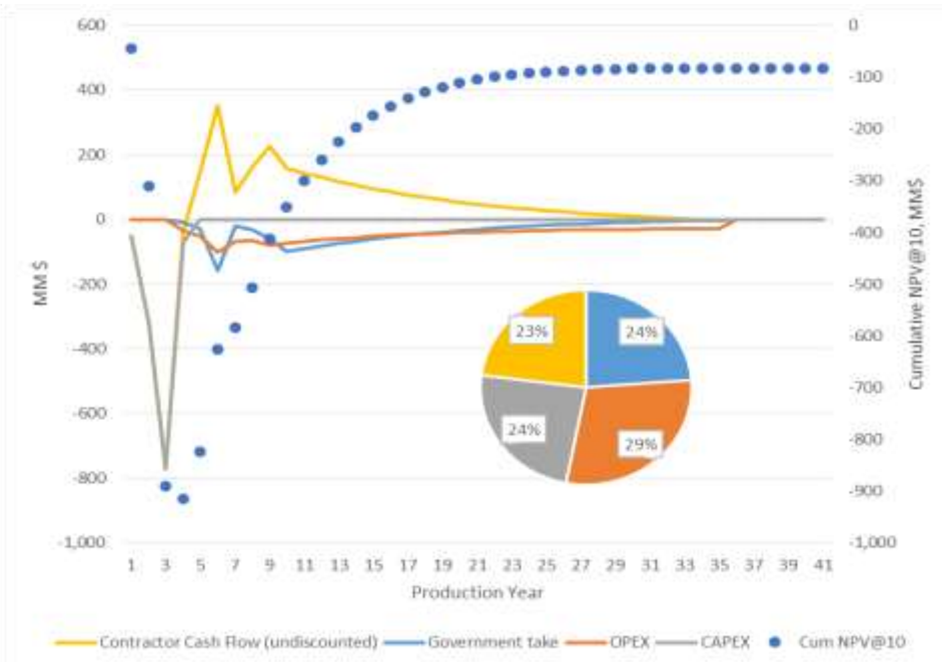


Figure 81Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash

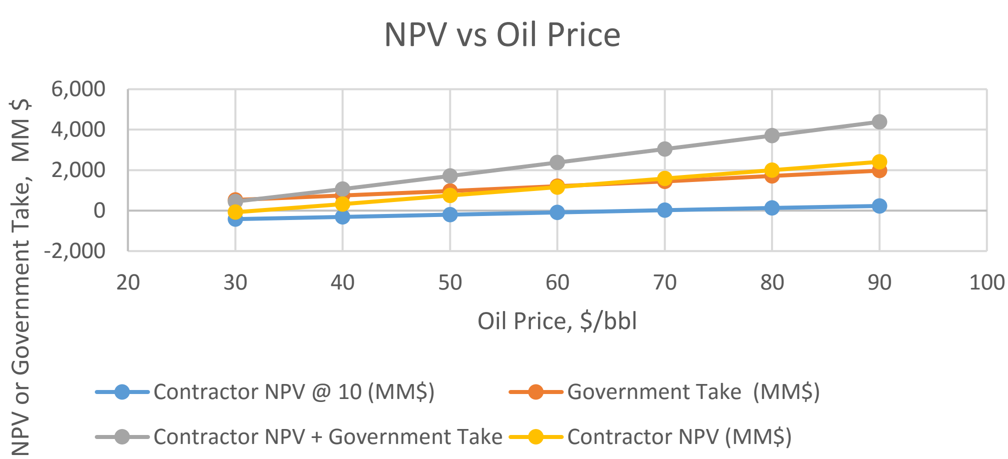
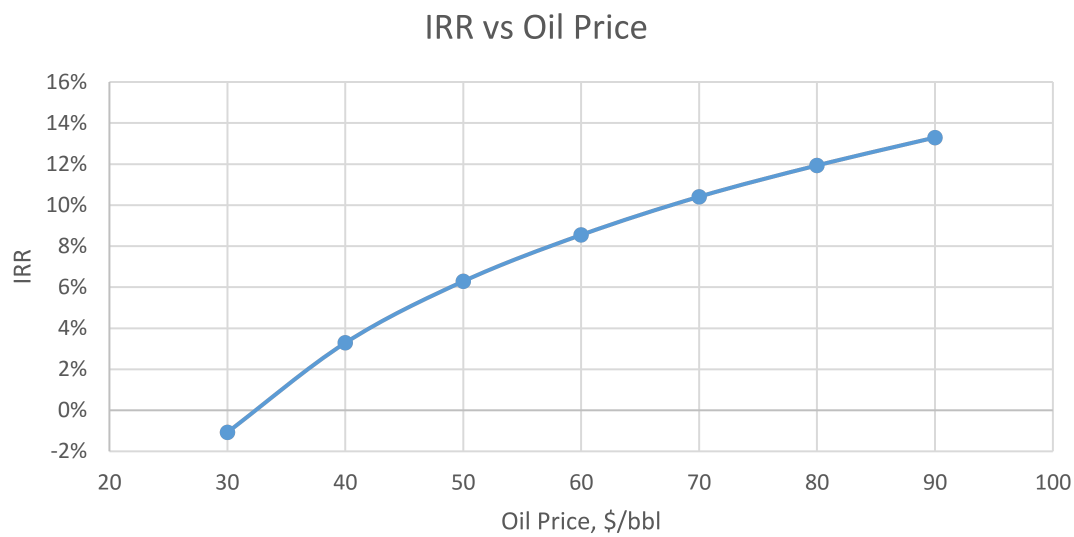


Figure 82 Discounted and undiscounted Contractor NPV and Government take at different oil prices.



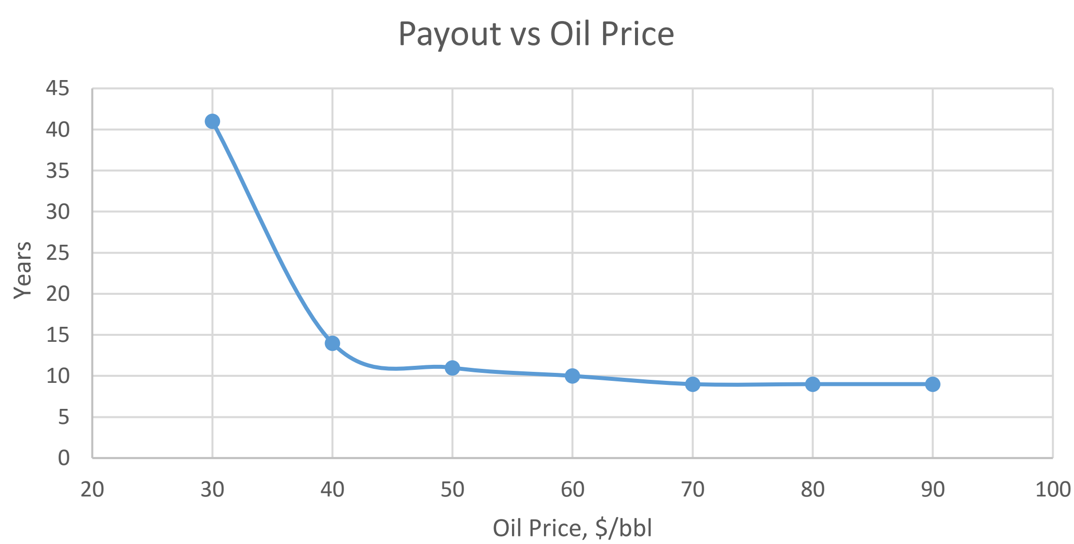


Figure 83 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Chinook 2 wells P50 natural drive for different oil prices.

Chinook 2 Well P10 Natural Drive at $60/bbl (Option 5, Table 9)

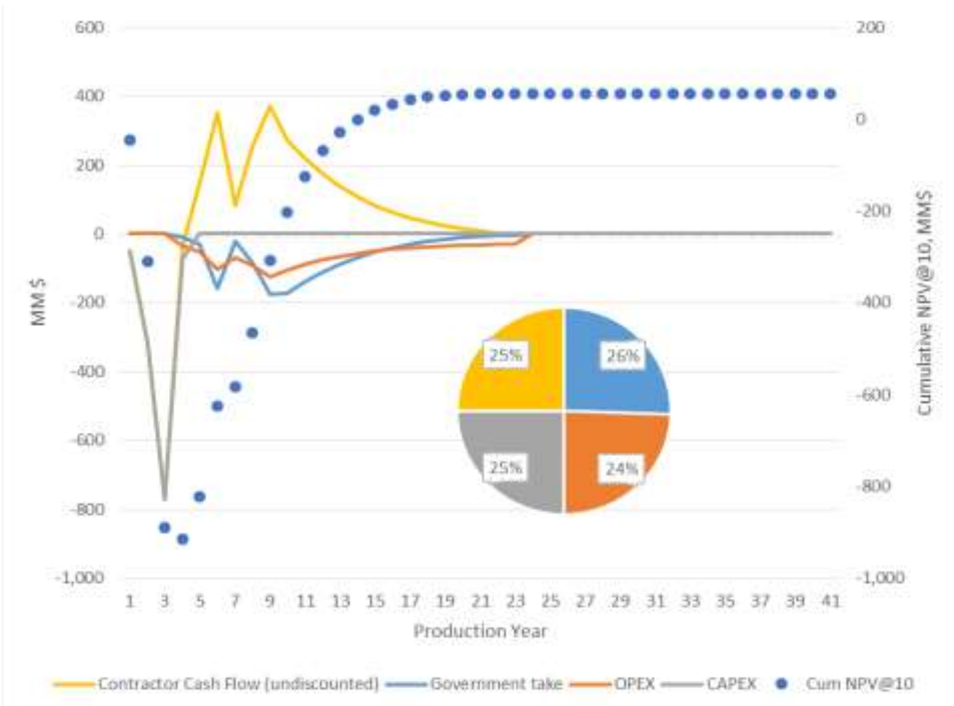


Figure 84 Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash

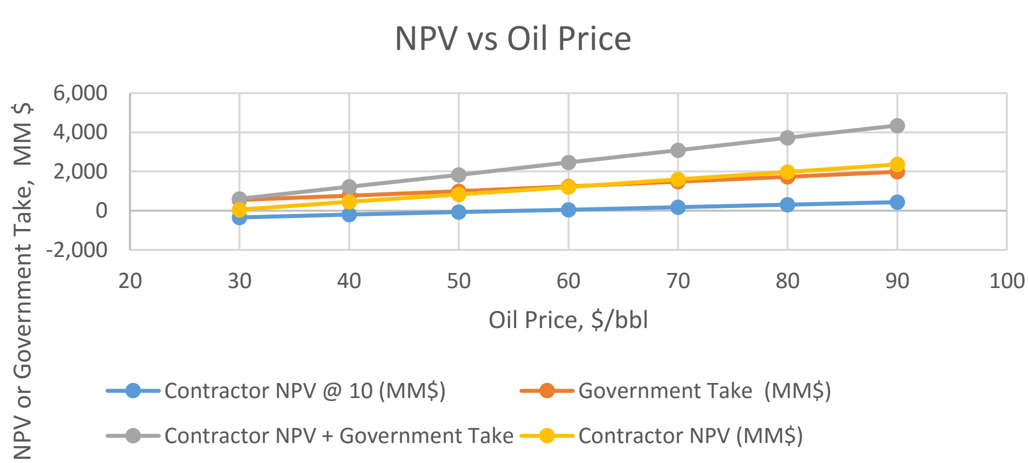
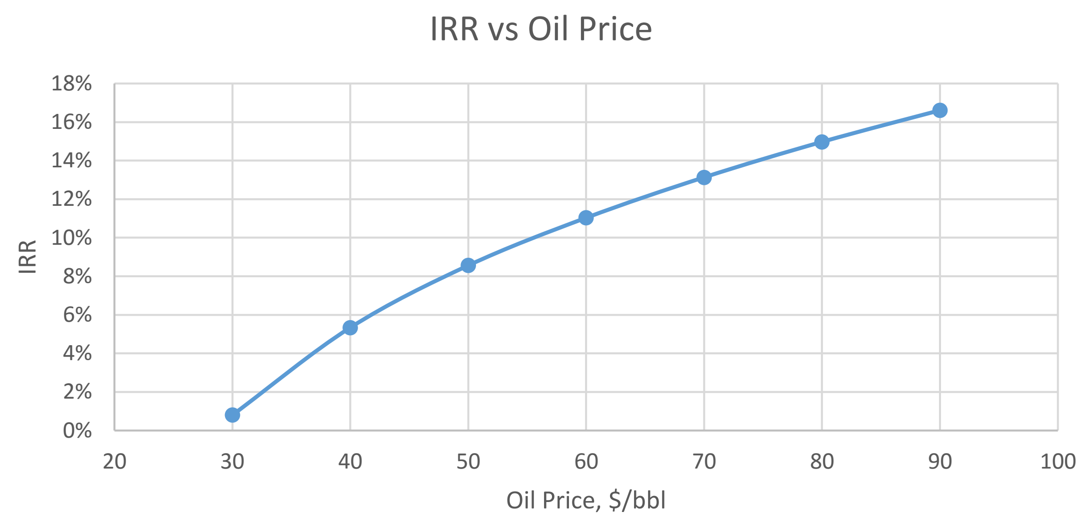


Figure 85 Discounted and undiscounted Contractor NPV and Government take at different oil prices.



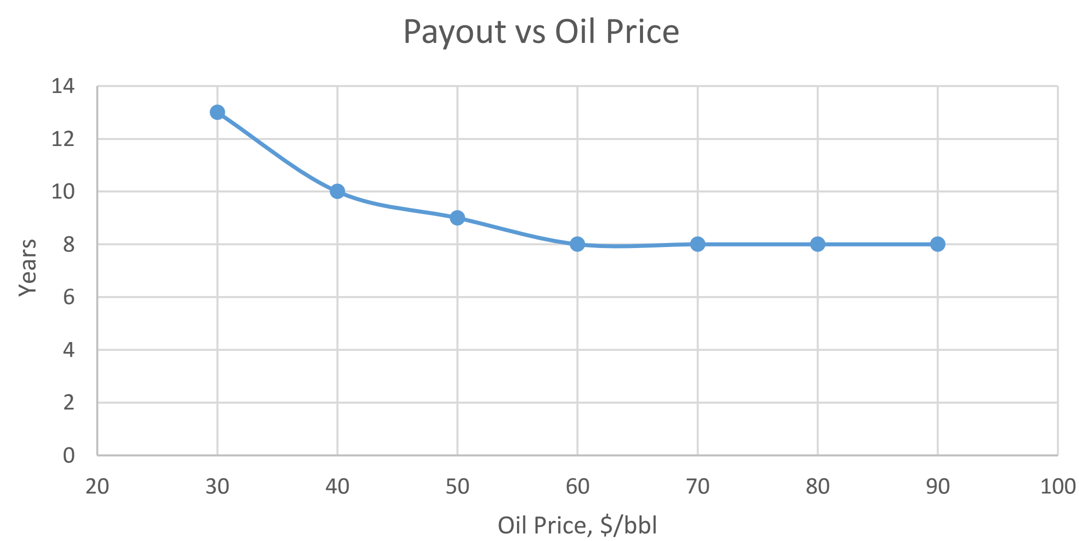


Figure 86 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Chinook 2 wells P10 natural drive for different oil prices.

Chinook 2 Well P90 Artificial Lift at $60/bbl (Option 6, Table 9)

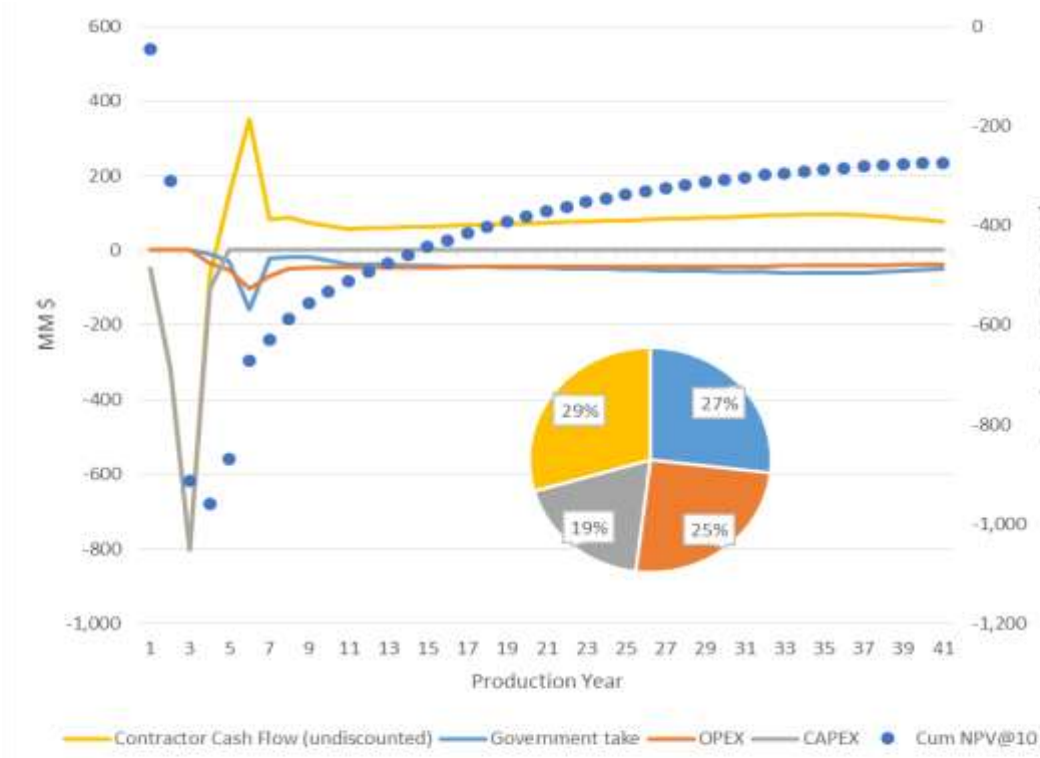


Figure 87 *Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash*

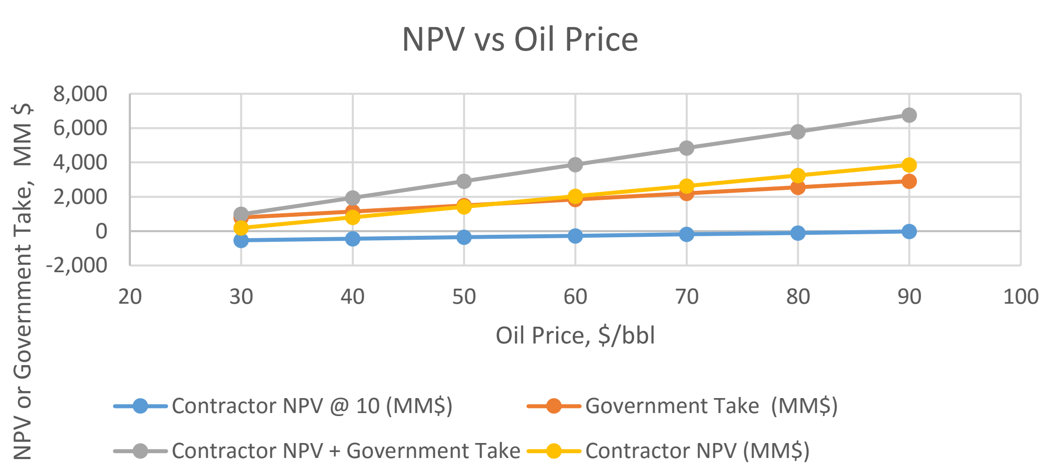
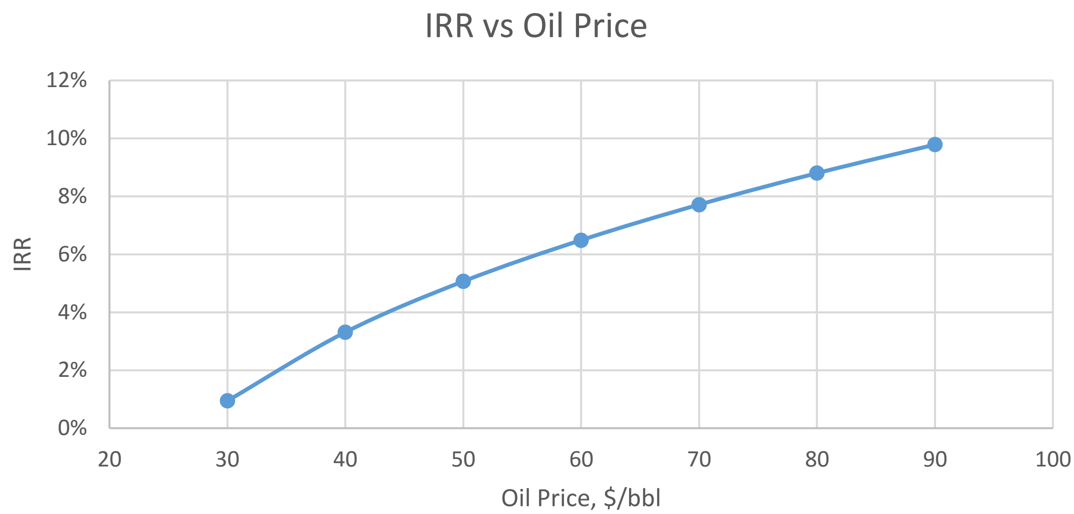


Figure 88 Discounted and undiscounted Contractor NPV and Government take at different oil prices.



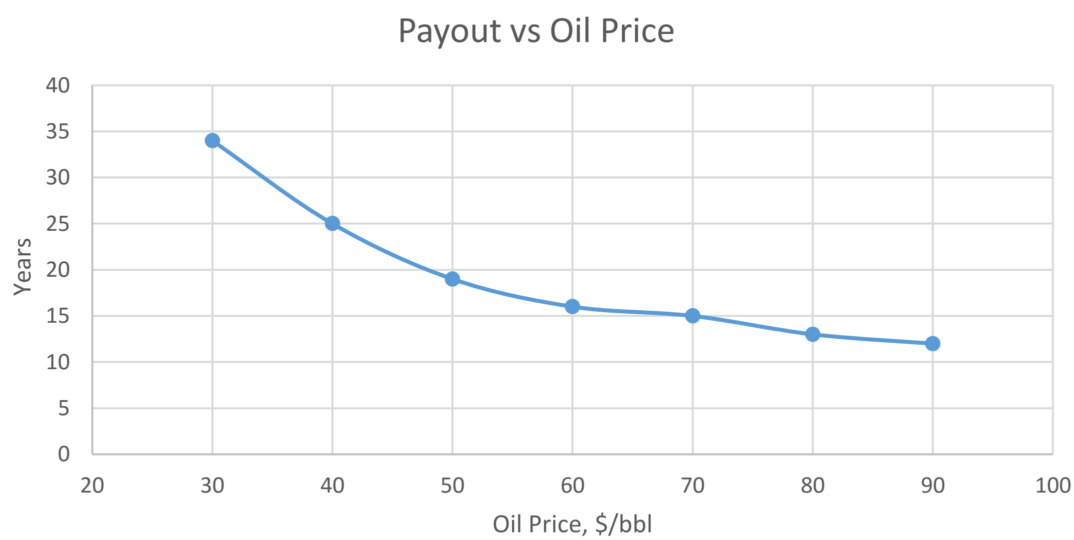


Figure 89 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Chinook 2 wells P90 artificial lift for different oil prices.

Chinook 2 Well P10 Artificial Lift at $60/bbl (Option 6, Table 9)

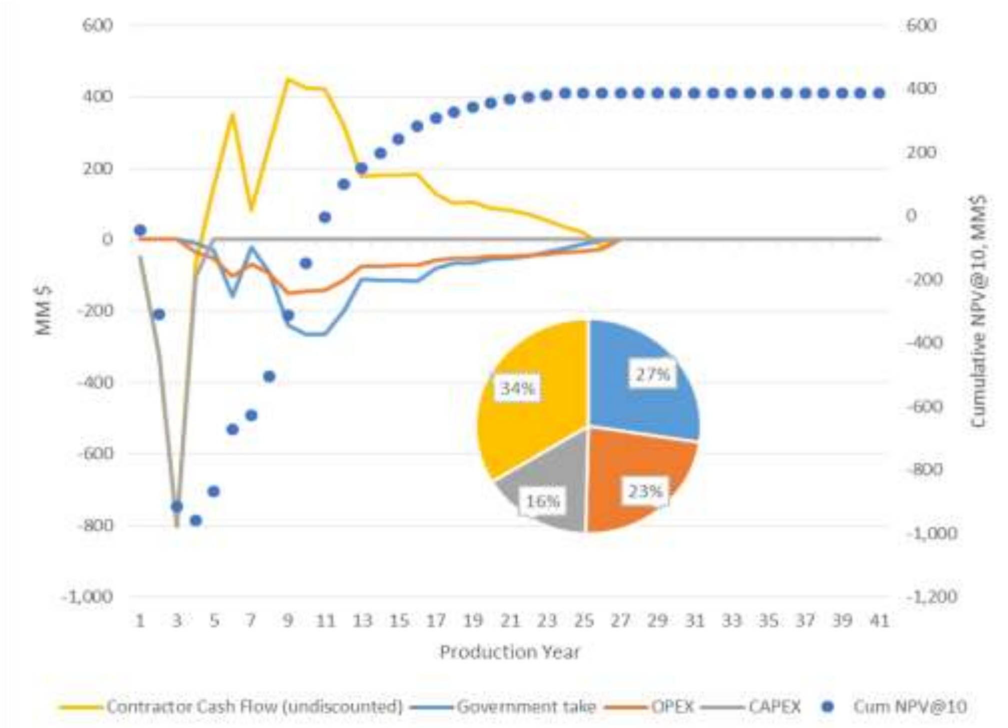


Figure 90 Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash

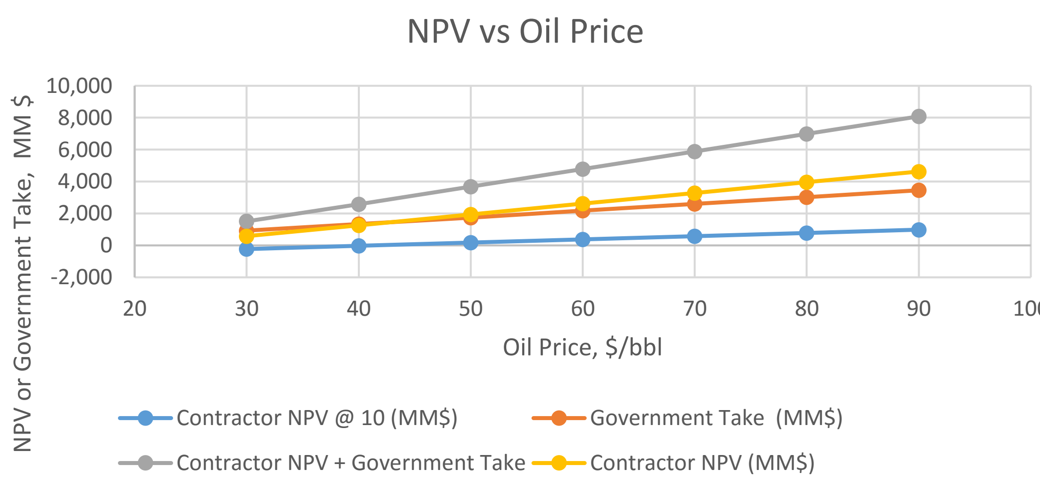
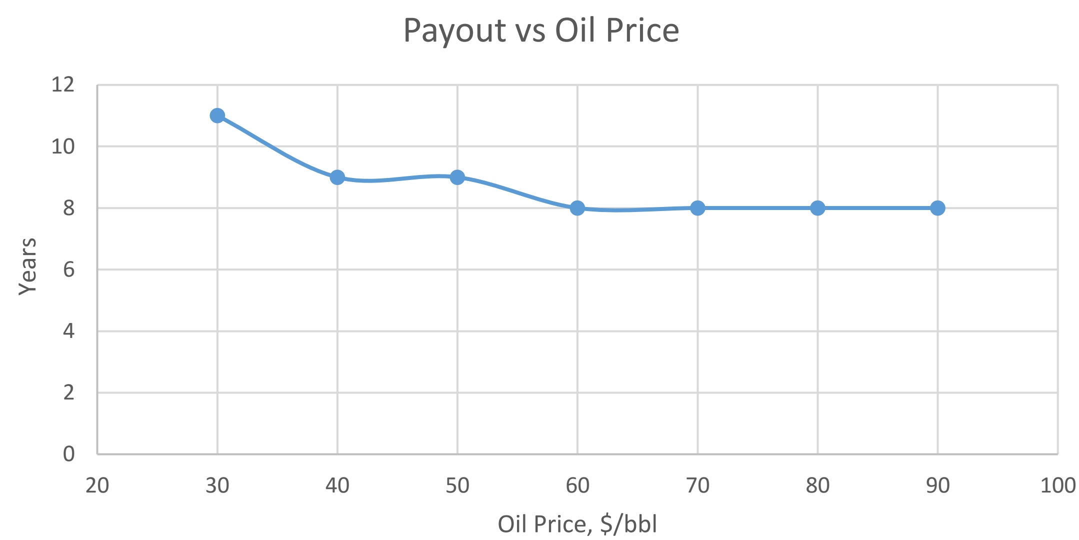


Figure 91 Discounted and undiscounted Contractor NPV and Government take at different oil prices.



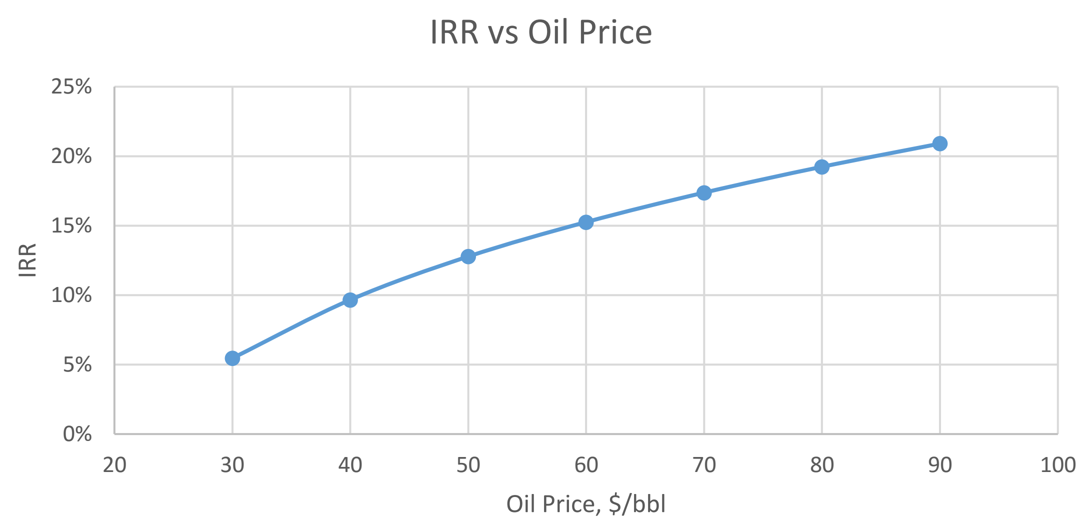


Figure 92 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Chinook 2 wells P10 artificial lift for different oil prices.

Chinook 3 Well P90 Natural Drive at $60/bbl (Option 7, Table 9)

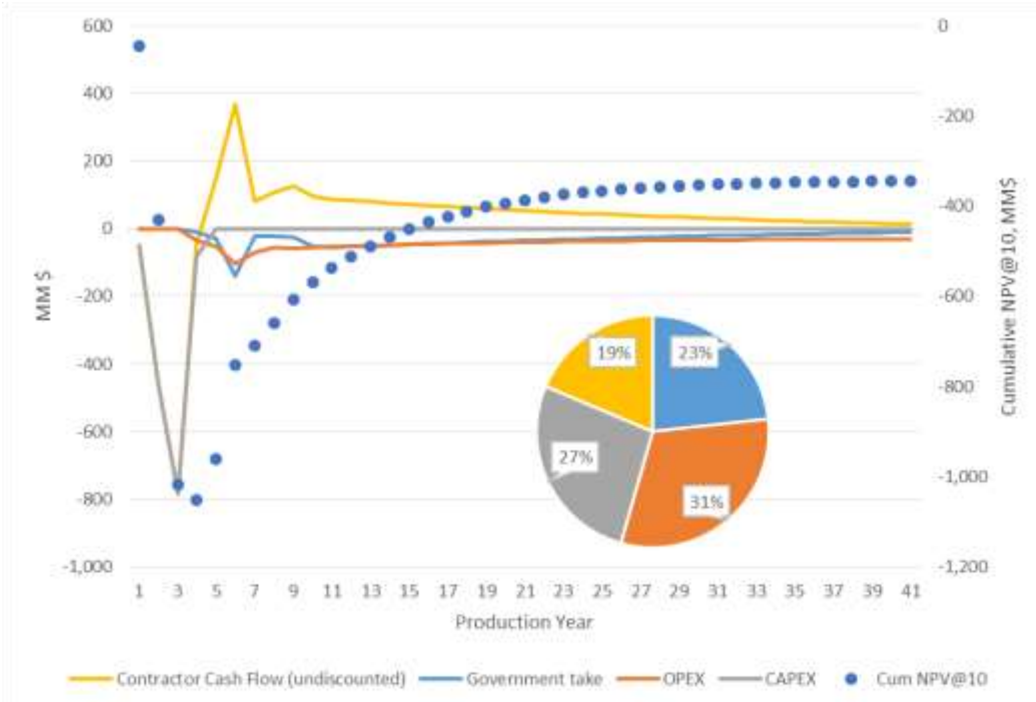


Figure 93 Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash

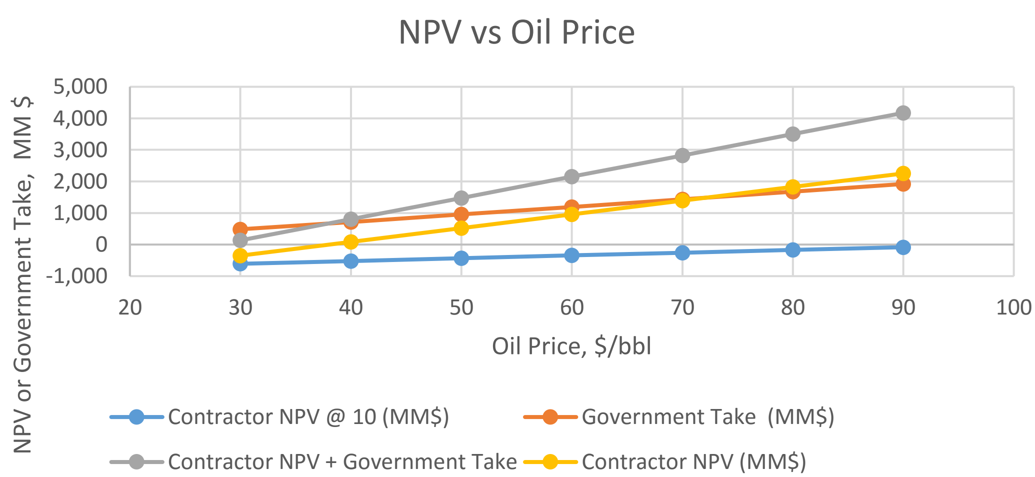
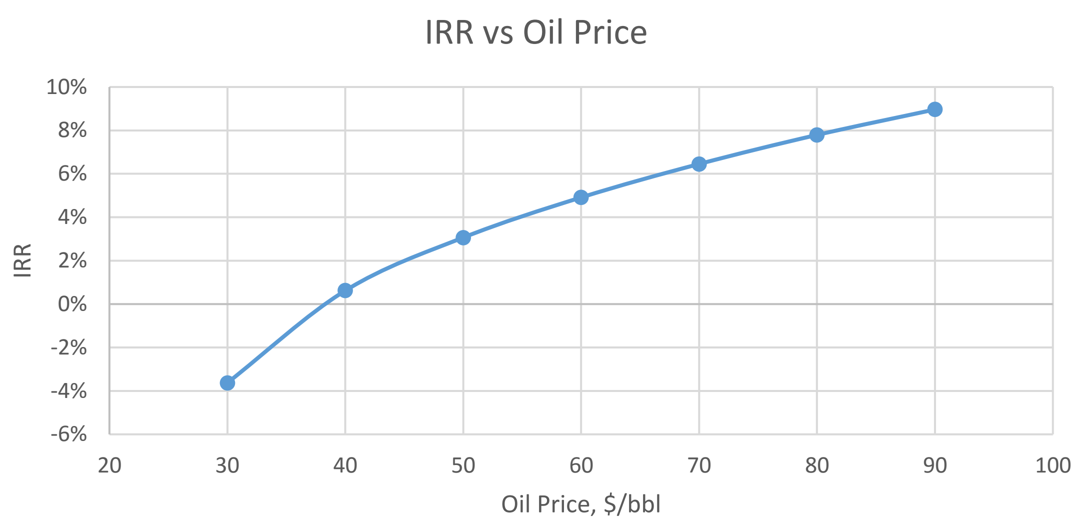


Figure 94 Discounted and undiscounted Contractor NPV and Government take at different oil prices.



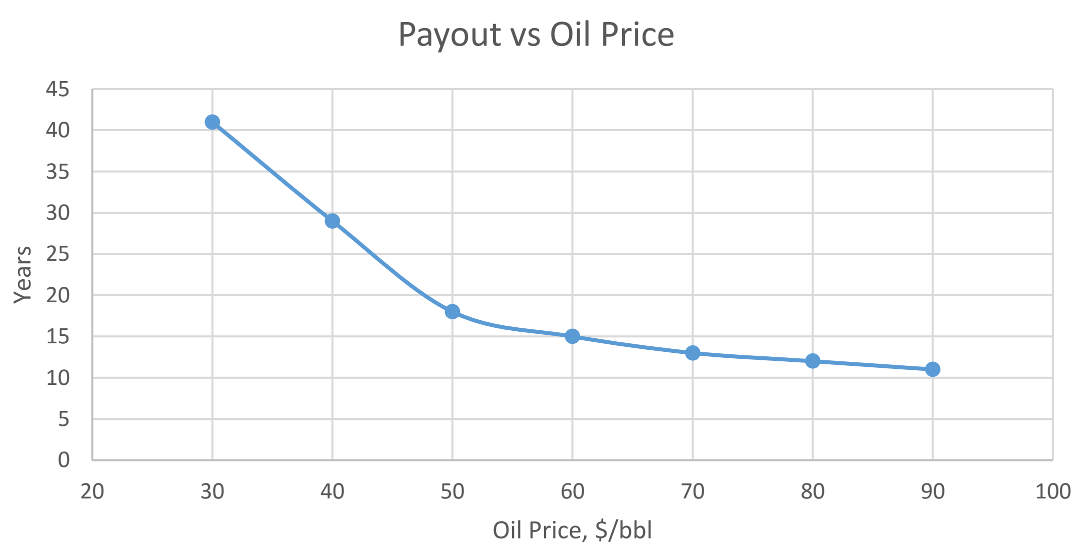


Figure 95 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Chinook 3 wells P90 natural drive for different oil prices.

Chinook 3 Well P50 Natural Drive at $60/bbl (Option 7, Table 9)

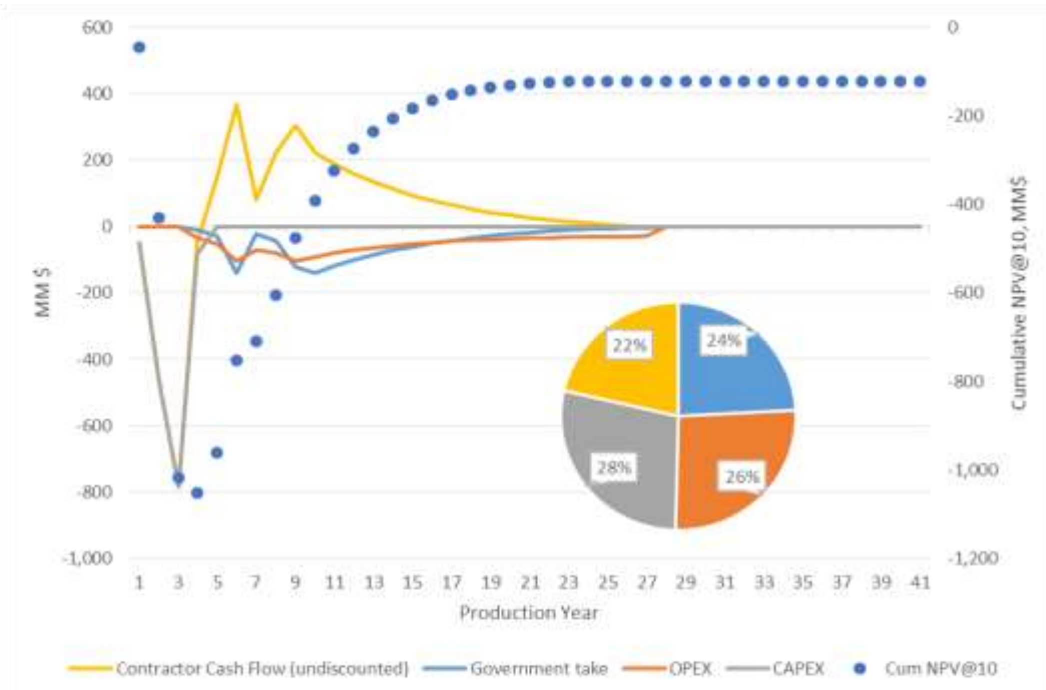


Figure 96 Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash

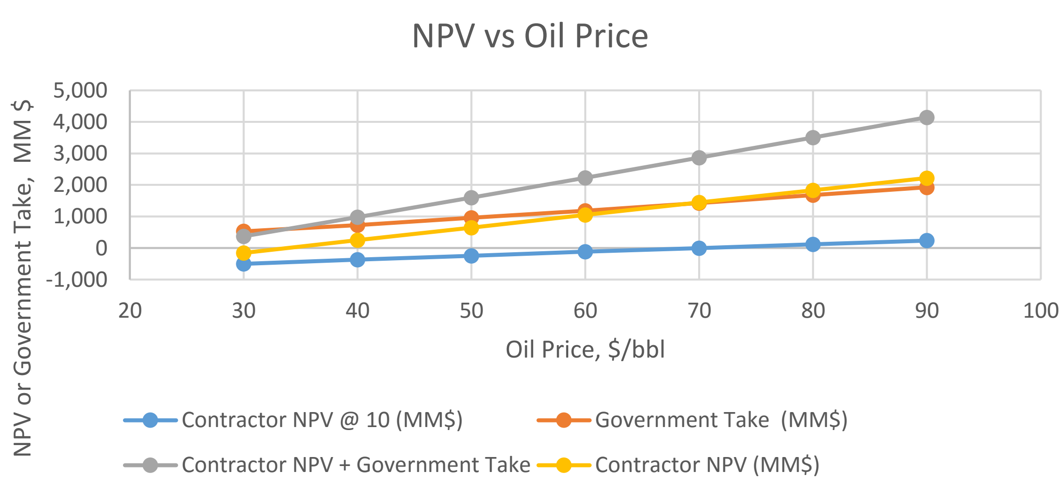
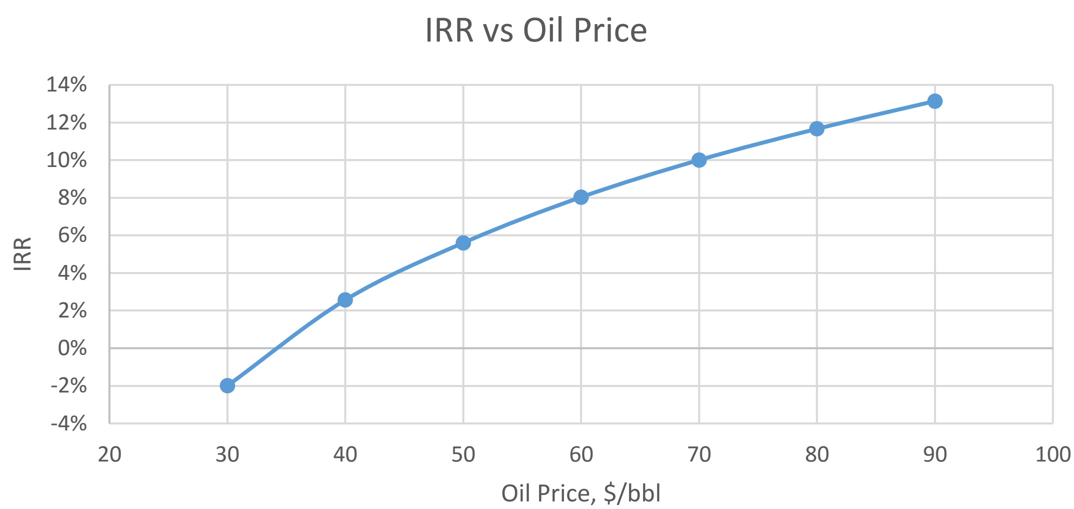


Figure 97 Discounted and undiscounted Contractor NPV and Government take at different oil prices.



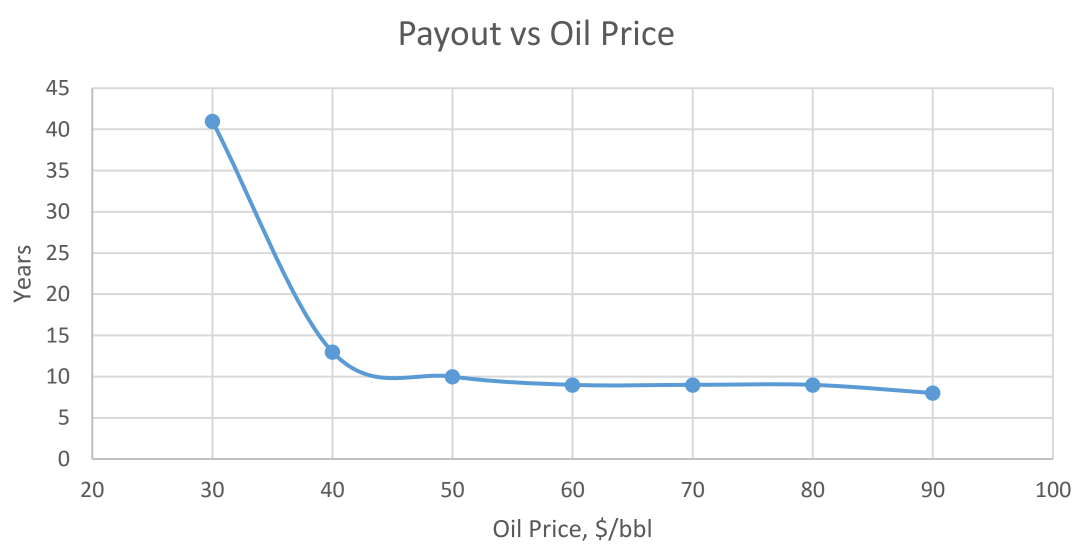


Figure 98 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Chinook 3 wells P50 natural drive for different oil prices.

Chinook 3 Well P10 Natural Drive at $60/bbl (Option 7, Table 9)

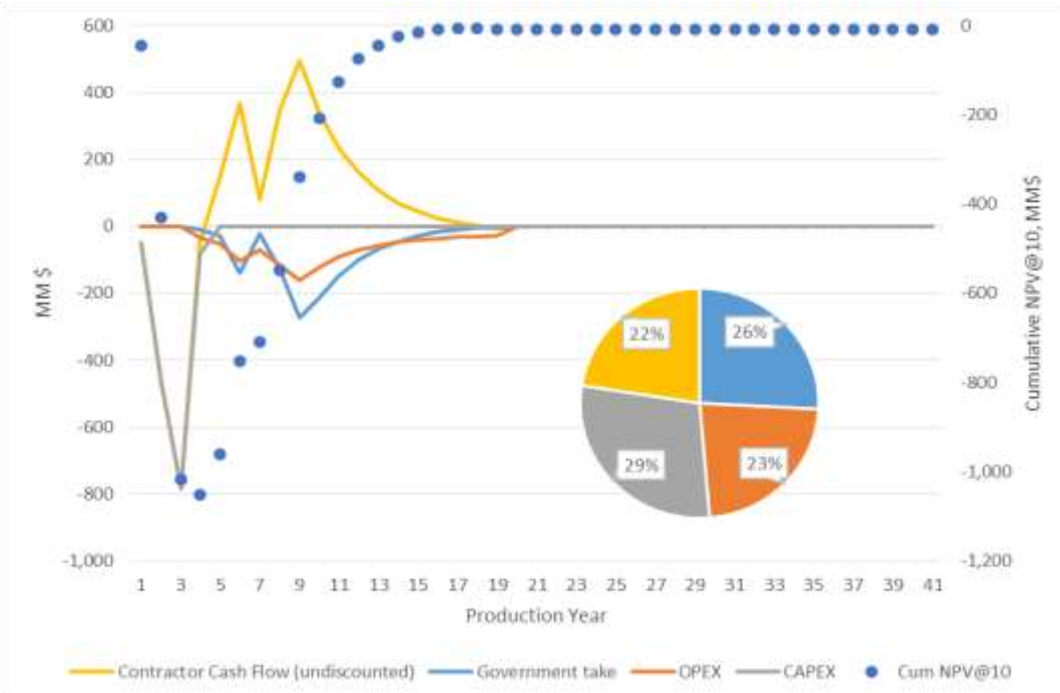


Figure 99 *Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash*

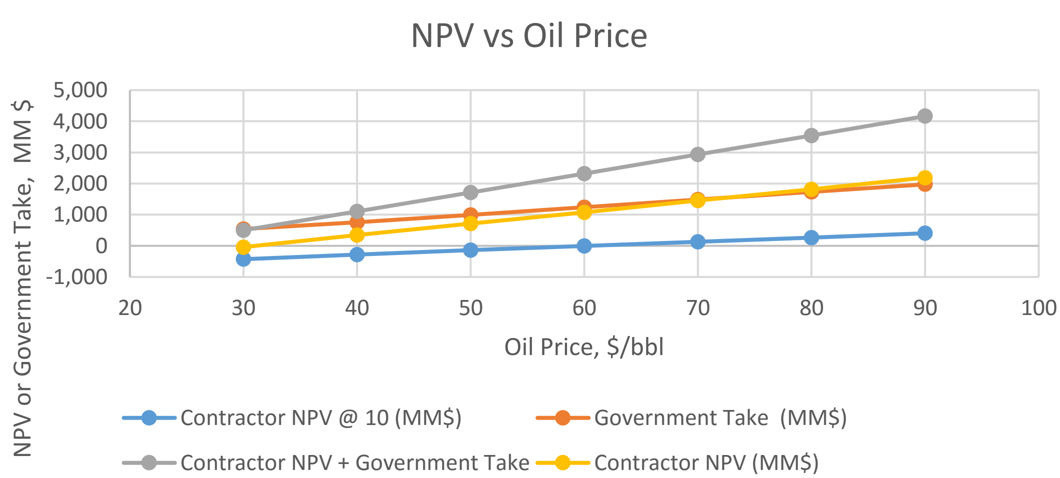
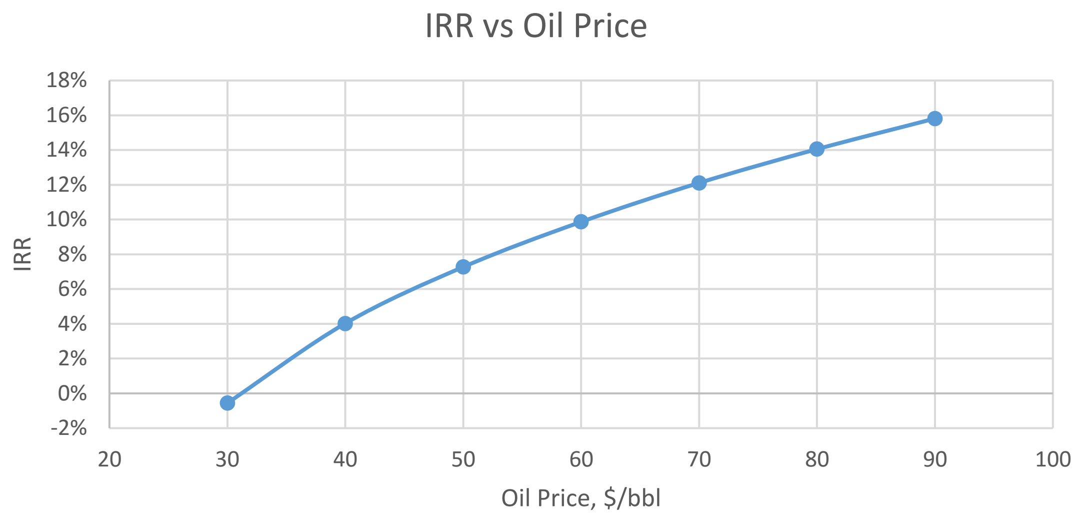


Figure 100 Discounted and undiscounted Contractor NPV and Government take at different oil prices.



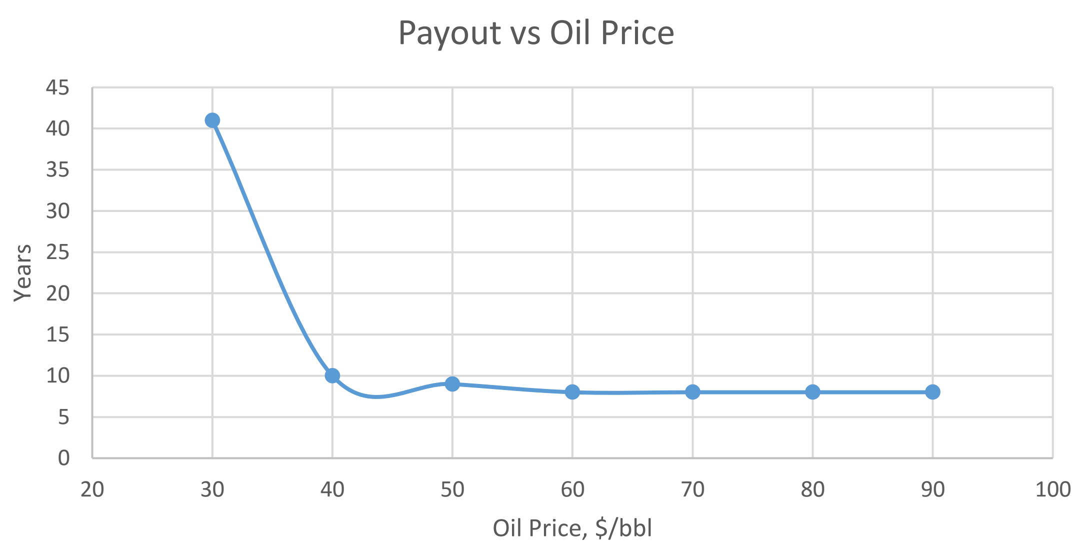


Figure 101 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Chinook 3 wells P10 natural drive for different oil prices.

<u>Chinook 3 Well P90 Artificial Lift at $60/bbl (Option 8, Table 9)</u>

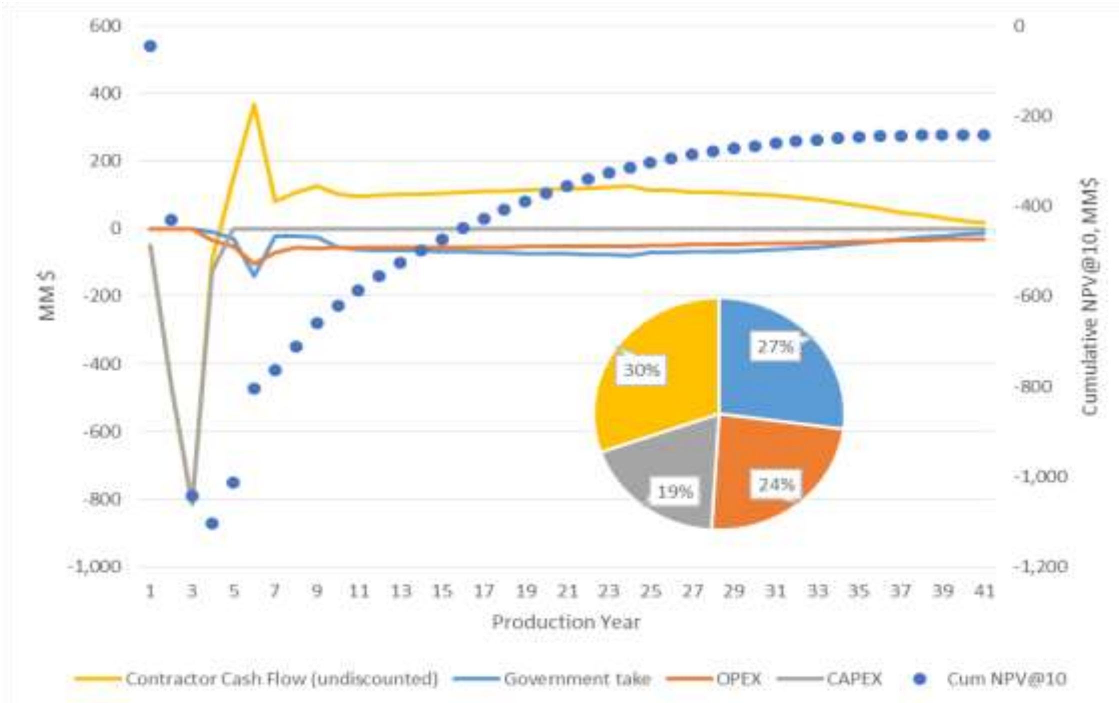


Figure 102 *Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash*

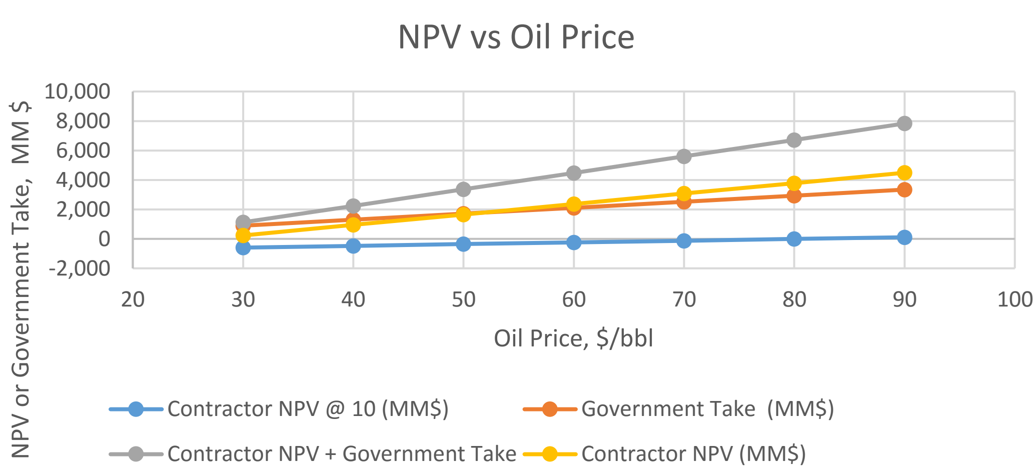
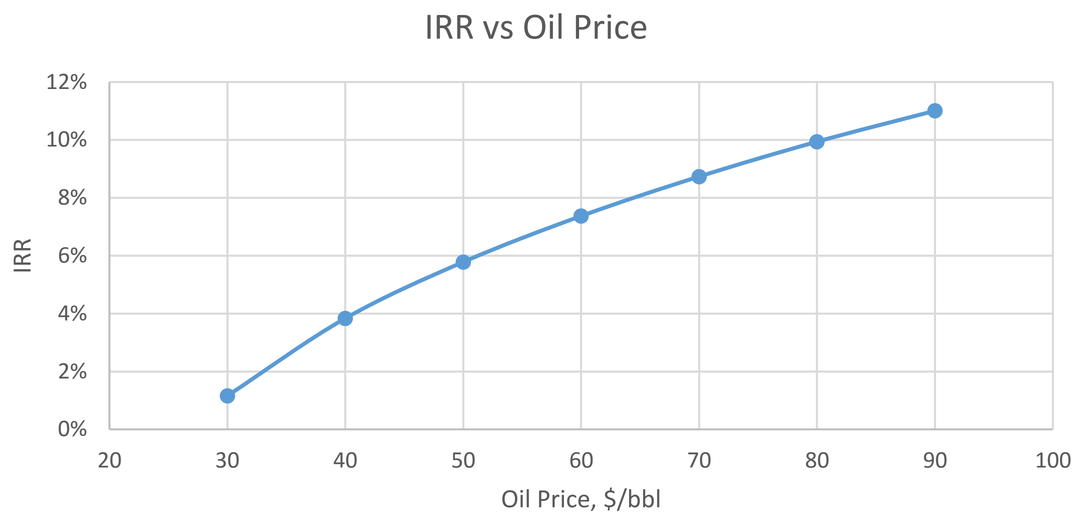


Figure 103 Discounted and undiscounted Contractor NPV and Government take at different oil prices.



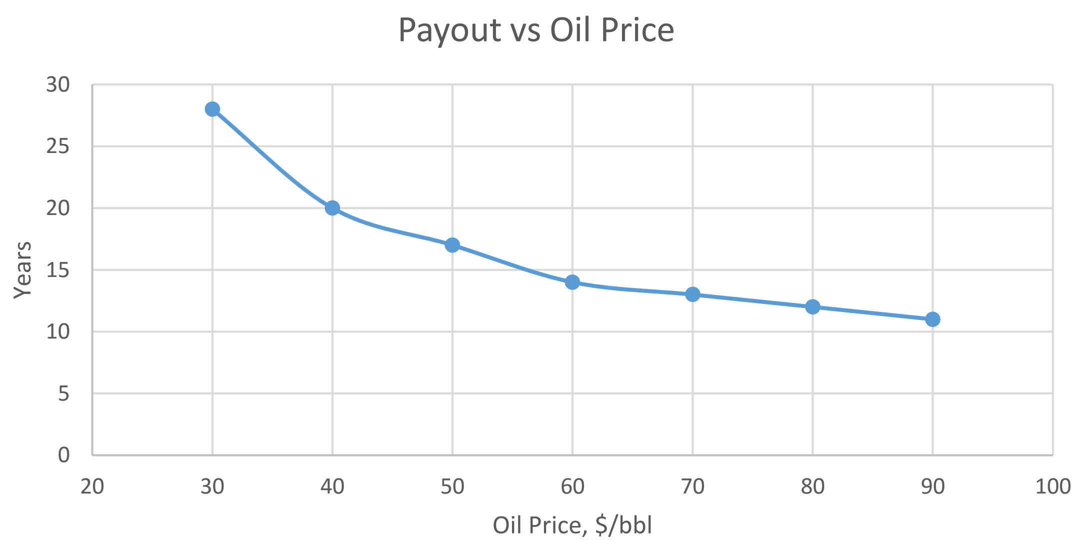


Figure 104 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Chinook 3 wells P90 artificial lift for different oil prices.

Chinook 3 Well P10 Artificial Lift at $60/bbl (Option 8, Table 9)

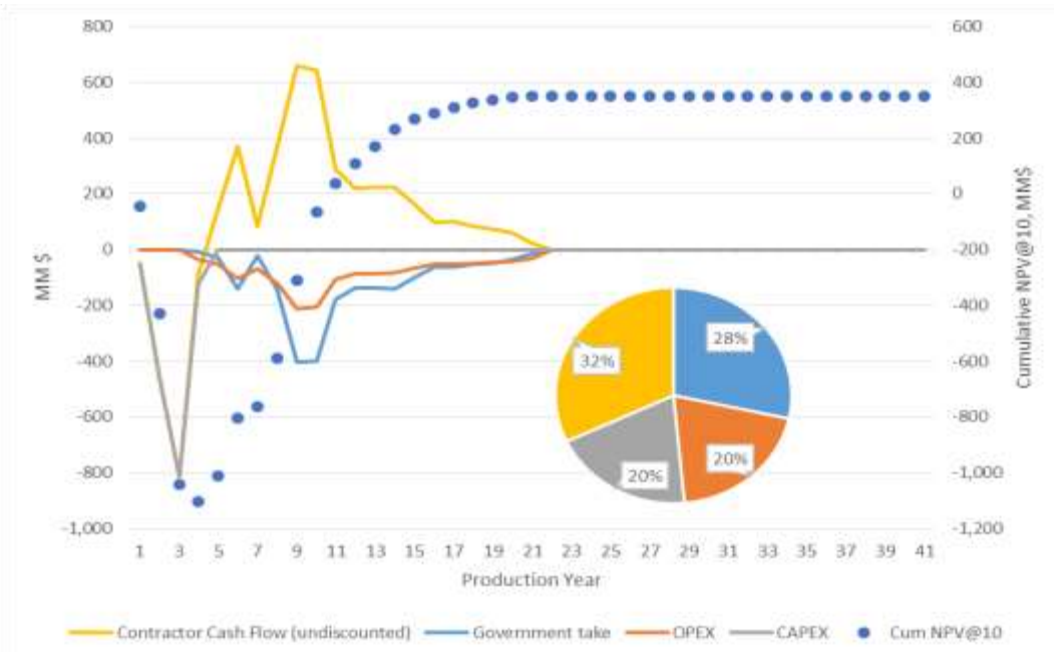


Figure 105 *Breakdown of annual revenue into expenditure (CAPEX, OPEX), total government take (royalty and income tax) and net cash attributable to contractor based on $60/bbl. Pie diagram shows respective allocations of total cumulative revenue to CAPEX, OPEX, government, and contractor net cash*

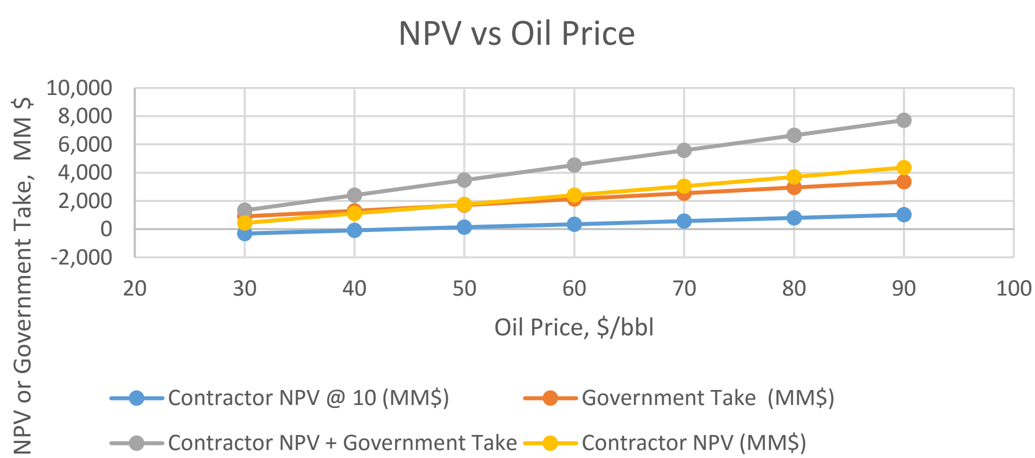
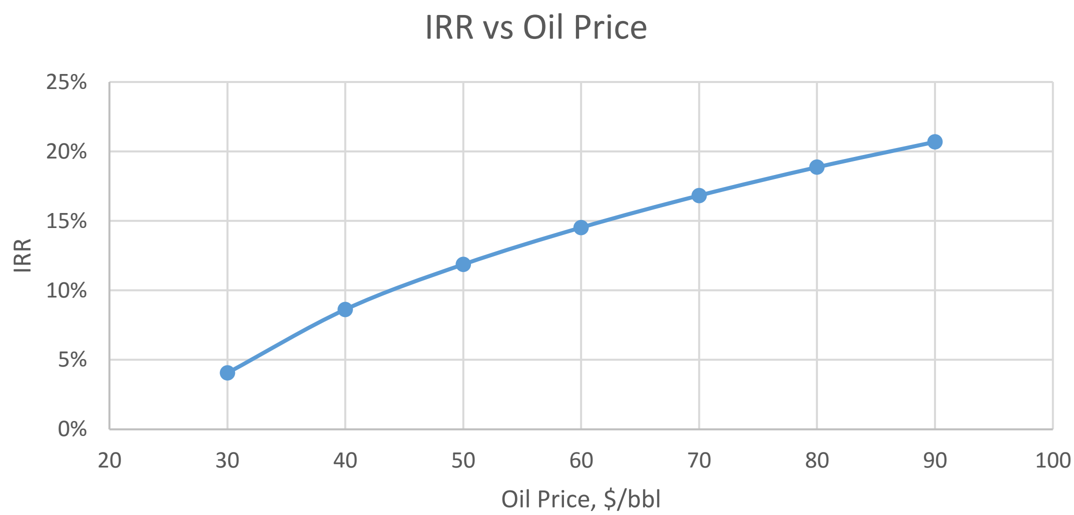


Figure 106 Discounted and undiscounted Contractor NPV and Government take at different oil prices.



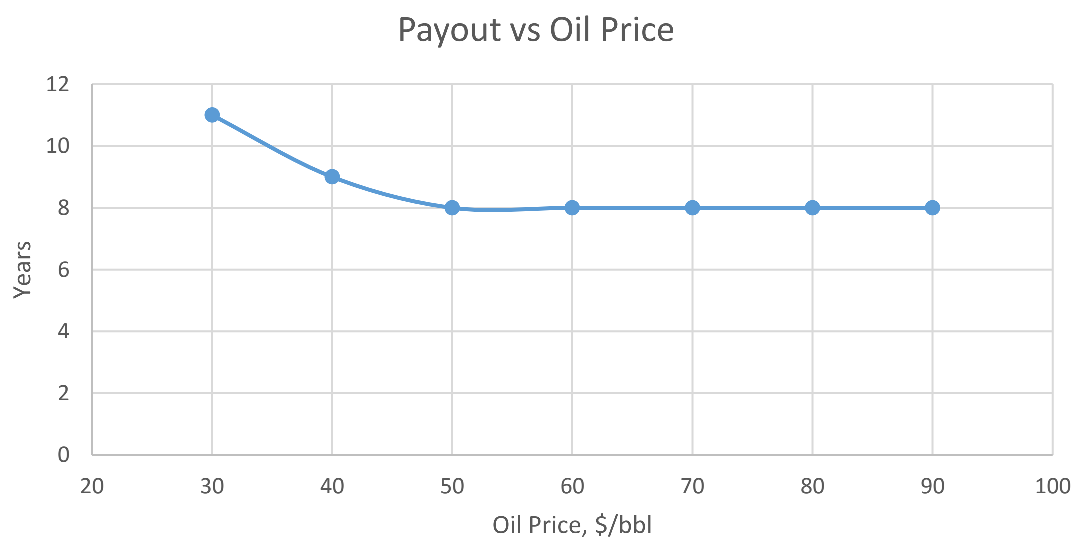


Figure 107 (Top) Plot of the IRR against oil price to show minimum commodity price for the project to overcome the hurdle rate imposed by each company. (Bottom) Payout time for Chinook 3 wells P10 artificial lift for different oil prices.

APPENDIX D- DATA MANAGEMENT

All the work used in this study was preserved using a data management plan, with the intention that other students in this research group may reproduce and expand on the work presented here, and on papers and articles written previously. This work includes the preservation of input data, codes, spreadsheets, papers, documents, sources used, and this thesis. All the work was saved under their respective sub-folder in the DM repository of Dr. Weijermars' research group, and a manual was created on how to use the tools and models developed. The structure of my data management plan is shown below: