OpenOil

Modeling the Mangara-Badila Fields

Analysis of a financial model

OpenOilUG

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Introduction

Transparency of oil contracts is an essential element of good governance. A growing number of countries are now following international best practice and making contracts publicly accessible. Where countries refuse to make these documents public, transparency can sometimes be found in company filings.

In the course of a systematic search of company filings in Canada, OpenOil and Publish What you Pay Canada uncovered three Chadian oil contracts originally signed by Griffiths Energy.

The contracts are important not only because they are the first to be publicly disclosed from Chad and offer potential insight into the fiscal terms governing ten oil contracts signed between 2010 and 2012.

First, the process through which Griffith's Energy secured the three contracts is shrouded in controversy. The negotiations were facilitated by the payment of $2 million to a company owned by the wife of the Chadian Ambassador to Canada. Following an investigation by the Canadian Police, Griffiths was fined $10.3 million.

Second, the current owner of the rights to these concessions, Glencore E&P is also of growing interest given their rapidly expanding role in the Chadian economy. A 2014 report from the IMF on Chad's Public External Debt shows that the Government borrowed $600 million from Glencore in 2013 and another $1.4 billion in 2014.

Technically, these three contracts have been in the public domain since 2011. Practically, they have been in the public domain since the contracts were included in a Publish What You Pay workshop on oversight of the oil sector in N'Djamena in October 2014.

Having the terms in the public domain is an important step towards better governance of the oil sector. But having contracts in the public domain is not an end in itself. The information contained inside these contracts must be used. The economic implications of contractual terms, and particularly their interactions, are most easily interpreted in the context of specific scenarios (See: You don't Know what You've Got Until It's Modeled.)"

Forecasts of future oil revenues are commonplace. The World Bank published such projections for the first phase of oil production in Chad. The IMF routinely publishes such projections, as they have most recently done in the July 2014 (See for example Chad: Oil Sector Prospects and the Impact on Fiscal Revenues). The time has come for the models on which revenue projections are based are made public (See Open Contracts, Closed Models).

The project economic model that accompanies this document is a collaborative effort. It is a tool that allows users inside and outside of Government circles to assess the implications of the contract terms under varying scenarios of oil production, oil price and costs.

Context

Chad is both oil rich and oil dependent. It ranks 10th in Africa based on “proven reserves” with an estimated 1.5 billion barrels as of 2013. Petroleum revenues accounted for more than 50% of government revenues in Chad over the period 2001-2010.

Oil was first discovered in Southern Chad’s Doba basin in early 1970s but it was only in 2003 that oil production began in Chad and was exported via the $4 billion Chad-Cameroon pipeline. Prominent companies involved in the initial development of Chad’s oil sector included ExxonMobil, Chevron, Petronas and CNPC. (Chevron departed Chad in 2014, with the state owned SHT purchasing its stake for a reported $1.4 billion).

Oil production in Chad peaked in 2004 at more than 170,000 barrels per day and has declined steadily ever since, to a low in 2013 of less than 100,000 barrels per day. According to the IMF, new production from Glencore and CNCP is projected to double oil production between now and 2017 with a maximum production of about 88,000 barrels per day. But in the absence of additional exploration success, production thereafter is expected to steadily decline.

Concern over falling production resulted in a second generation of petroleum contracts. These new contracts were based on a new set of laws including:

- Petroleum Law in 2007 (No. 006/PR/2007 dated 20 April 2007)
- Petroleum Ordinance in 2010 (No. 001/PR/2010 dated 30 September 2010)
- Model Production Sharing Contract (10-796 dated 30 September 2010)

According to EITI reports, Chad signed 10 production-sharing agreements between 2010 and 2012 with the following companies: Caracal Energy, ERHC Energy, Global Petroleum, Petra BV, SAS Petroleum, Simba Energy, TCA International and United Hydrocarbon Chad (EITI Report of May 2013 pages 15 and 16). The fiscal terms governing five of these production-sharing agreements are now in the public domain.

Three contracts were disclosed on 22 November 2011 by Griffiths Energy based on corporate filing requirements by Canadian securities regulators. Griffiths was subsequently renamed Caracal Energy and in 2014 was acquired by Glencore E&P. The three contracts are:

PetroChad Mangara (DOBA Basin) 2011
Griffiths Energy (DOH) 2011
Griffiths Energy (Chari-Ouest) 2011

ERHC Energy disclosed summary terms for a production-sharing contract signed in 2011 covering three oil blocks in Chad (Manga, Chari-Ouest and BDS 2008 Blocks) as required by the US Securities and Exchange Commission (See ERHC Energy PSC Summary). The fiscal terms for a production-sharing contract signed in 2012 by United Hydrocarbon International Corporation (UHIC) covering 3 blocks in the Doba Basin and one around Lake Chad were disclosed in an investor document in 2013 (see UHIC: Management's Discussion and Analysis). The fiscal terms across these five contracts are nearly identical. This is clearly the case for the main fiscal instruments: the royalty rate, the share of production and the percentage of state participation. There are differences however in other provisions including the size of signing and production bonuses. The latter is not unusual, as such bonuses may be set either through a competitive process, or negotiated based on perceived geological prospectivity.

Fiscal Terms

The basis of the fiscal regime applied to the Glencore contracts is a royalty, a profit-sharing mechanism and the option of state participation in the consortium. These are all laid out in the Production Sharing Contract signed on March 18th, 2011.The royalty is set at a flat 14.25 percent of net production for crude oil (and also five percent for gas though none has been discovered in commercial quantities).

The central fiscal instrument is the government's share of production, also known as "profit oil", remaining after the consortium recovers project costs. Cost recovery is capped at 70 percent of available revenues (net of royalty) in any given year, using the Market Price of the oil at the point it leaves the field/enters the pipeline. There is unlimited carry forward of costs until they have all been recovered and a prioritisation of categories of costs: first exploration, then development costs, then operating expenditure, and lastly decommissioning costs. The Accounting Procedure annexed to the main contract stipulates that administration costs are capped at a maximum of one percent of total costs, and allows reimbursement of project financing provided interest rates "as long as they do not exceed commercial rates". The administration costs administratoion have not been modeled on the grounds that they are unlikely to be material. Financing costs are discussed further below. We have not been able to find a reference to any depreciation of capital expenditure and so have assumed that all expenditure is immediately available for cost recovery , subject to the cost recovery limit.

Summary of PSC Contracts for Modeling					
Country	**Chad**				
Contracts	**Chad PSC Mangara 2011**	**Griffiths Energy (DOH) Limited 2011**	**Griffiths Energy (Chad) Limited 2011**	**United Hydrocarbon International Corp (UHIC) 2012**	**ERHC Energy (BVI) Limited 2011**
Term				Exploration License: 5 years (renewal up to 3 years). Exploitation License: 25 years (renewal up to 10 years).	Exploration License: 5 years (renewal up to 3 years). Exploitation License: 25 years (renewal up to 10 years).
Minimum Work Obligation	$3,000,000 Exploration - $1,000,000 Development and Exploitation - $2,000,000	$3,000,000 Exploration - $1,000,000 Development and Exploitation - $2,000,000	$3,000,000 Exploration - $1,000,000 Development and Exploitation - $2,000,000	Initial term: $75,000,000 Renewal term: $5,000,000	
Royalty					
Oil	14.25%	14.25%	14.25%	14.25%	14.25%
Gas	5%	5%	5%	5%	5%
Type	% of total production	% of total production	% of total production	% of total production	% of total production
Bonuses					
Signature	$40,000,000	$13,000,000	$40,000,000	$86,000,000	$6,000,000
Exploitation	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000
Recoverablability	Non-recoverable	Non-recoverable	Signature bonus is a petroleum cost recoverable up to 25% of the total amount which is $10,000,000. The exploitation bonus is not recoverable.	Non-recoverable	
Fees					
Counsel	$3,200,000	$1,040,000	$3,200,000	$6,240,000	
Miscellaneous					
State Participation	25%	25%	25%	25%	
Type of carry	Minimum of 10% of total participating interest must be carried by other entities comprising the contractor for exploration and development operations. It may also be carried for production operations. These costs and related interest shall be reimbursed by the State using the carried participating interest share of cost oil.	Minimum of 10% of total participating interest must be carried by other entities comprising the contractor for exploration and development operations. It may also be carried for production operations. These costs and related interest shall be reimbursed by the State using the carried participating interest share of cost oil.	Minimum of 10% of total participating interest must be carried by other entities comprising the contractor for exploration and development operations. It may also be carried for production operations. These costs and related interest shall be reimbursed by the State using the carried participating interest share of cost oil.	The State shall be responsible for its proportionate share of back-costs for the interest it backs-in for as well as itsparticipating interest share of all future costs. All costs for which the State is responsible shall be paid by an advance from the Company which shall accrue interest at the London Interbank Offered Rate ("LIBOR") rate plus 3% from the date due and shall be repayable out of the State's share of Cost Oil.	Minimum of 10% of total participating interest must be carried by other entities comprising the contractor for exploration and development operations. It may also be carried for production operations. These costs and related interest shall be reimbursed by the State using the carried participating interest share of cost oil.
Cost Recovery	70%	70%	70%	70%	70%
Method of Determination	Value of cost oil will be based on sale price.				
Profit Oil	R-Factor	R-Factor	R-Factor	R-Factor	
Government Share, P	R ≤ 2.25; P = 40% 2.25 < R < 3; P = 50% R > 3; P = 60%	R ≤ 2.25; P = 40% 2.25 < R < 3; P = 50% R > 3; P = 60%	R ≤ 2.25; P = 40% 2.25 < R < 3; P = 50% R > 3; P = 60%	R ≤ 2.25; P = 40% 2.25 < R < 3; P = 50% R > 3; P = 60%	
Surface Rental Fees	$ per square km per year	$ per square km per year	$ per square km per ye	$ per square km per year	$ per square km per year
Exploration	Initial: 1 Renewal: 5 Extension: 10	Initial: 1 Renewal: 5 Extension: 10	Initial: 1 Renewal: 5 Extension: 10	Initial: 1 Renewal: 5 Extension: 10	Initial: 1 Renewal: 5 Extension: 10
Exploitation	Initial: 100 Renewal: 150	Initial: 100 Renewal: 150	Initial: 100 Renewal: 150	Initial: 100 Renewal: 150	Initial: 100 Renewal: 150
Production	45	45	45	45	
Corporate Income Tax (CI	None	None	None	None	None
Training and Development Contributions	$750,000	$750,000	$750,000	$100,000: Chadian nationals $250,000 (exploration) and $500,000 (exploitation): Ministry of Petroleum and Energy Personnel	$100,000: Chadian nationals $250,000 (exploration) and $500,000 (exploitation): Ministry of Petroleum and Energy Personnel

The Government profit-share is calculated using an “R-Factor” which is the ratio (hence the “R”) of contractor’s gross revenues over the contractor’s gross costs. Hence an R-Factor of 1.00 would mean the contractor’s cumulative revenues equalled cumulative costs. The government’s share is 40% while the R-Factor is under 2.25 and rises to 60% if the R-Factor exceeds 3. Thus the government profit share is “progressive”: it increases with the profitability of the project.

The contract allows the government a 25 percent participation in the [contractor] consortium alongside Griffiths/Caracal (and now Glencore). In practice, this is now a 15% stake since the government sold a 10 percent stake to Glencore directly, before Glencore took over Caracal.

The contract is exempt from corporate income tax. This is a sharp distinction from Chad’s first generation of contracts with the consortium led by ExxonMobil to develop the Doba Basin. Chad’s 2012 EITI report shows that 85% of payments by ExxonMobil to the government in 2012 were corporate income tax, or $542 million, the same proportion as for Chevron, another member of the consortium. The first contracts were royalty-tax, with no dividends or profit share paid to the State or the NOC at all. Whereas the second generation of contracts, based on a 2010 model contract, contain profit sharing but remove corporate income tax. In purely economic terms there is no material difference between a profit share and income tax. However, there are potential governance considerations, if the project is in effect removed from any institutional oversight by Chad’s tax authorities.

Other terms not modeled are a signature bonus of $40 million; land surface rentals as these not material; capital gains tax of 25% on assignment, since this is only applicable on assignment of an exploration license not an operating license; and also interest charges on state participation, since these apply only on late payments after first oil has been triggered, not on the period since the costs were first incurred, and so considered immaterial.

Preliminary Model Results

Economic models provide insight into the scale, source and timing of government benefits from oil production under hypothetical scenarios. They are subject to significant uncertainty and variability as circumstances change: even modest changes in oil prices can have a big impact on the size and timing of government revenues. It is therefore important not to overstate the reliability, and the model should therefore not be considered to produce projections of revenues that will flow to the government in future years. Also, a range of outcomes should be considered . Estimates of oil reserves are speculative and in some cases turn out to be exaggerated. As the staggering fall of oil prices in recent months illustrates, it is a mistake to assume that oil prices will be high or that they will increase at a steady rate. The costs of production are also variable with capital cost overruns common and good evidence that operating costs have outpaced inflation in recent years. Ultimately, the most stable element of most project economic models are the fiscal terms contained in contracts and tax law though even these can be subject to renegotiation.

Potential Government Revenue

The base scenario assumes the fields produce out the 2P reserves listed by Caracal in their documents to investors in 2013, and that the low EIA price scenario prevails. Under those assumptions, Chad stands to earn between $2.5 and $2.9 billion over the lifetime of the project, depending on how much debt financing Glencore uses.

This outcome is of course very much determined by using the EIA low price scenario as a base case. Taking a middle price scenario (which the EIA calls its "Reference" case) - which might have seemed more reasonable when Griffiths Energy and the government of Chad signed the contract in 2011 and indeed even up until the middle of 2014, produces radically higher revenues.

Chad might then expect to earn some $5.7 billion out of the project over its lifetime assuming production of 115 million barrels. Costs drop to 28% of total project revenue, compared to 43% under the default scenario.

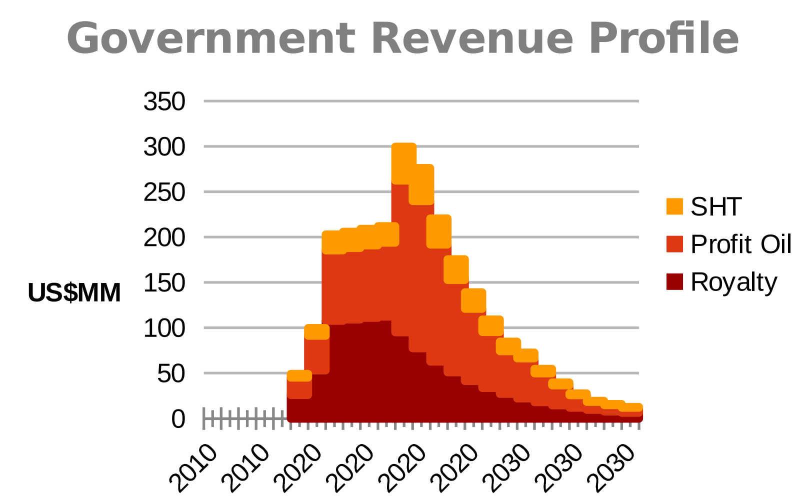


Illustration 0: Chad government revenue profile under 2P reserves and low EIA price

Different production scenarios also have considerable impact on government revenues. The base case uses the "2P" assumption used by Caracal in its documentation to investors in 2013 because it explicitly based development costs on it. But in the absence of historical data, both a lower 1P scenario and a higher 3P scenario still need to be taken into consideration. For the Mangara and Badila fields these are 1P 45 MMBbl; 2P 115 MMBbl; 3P 240 MMBbl.

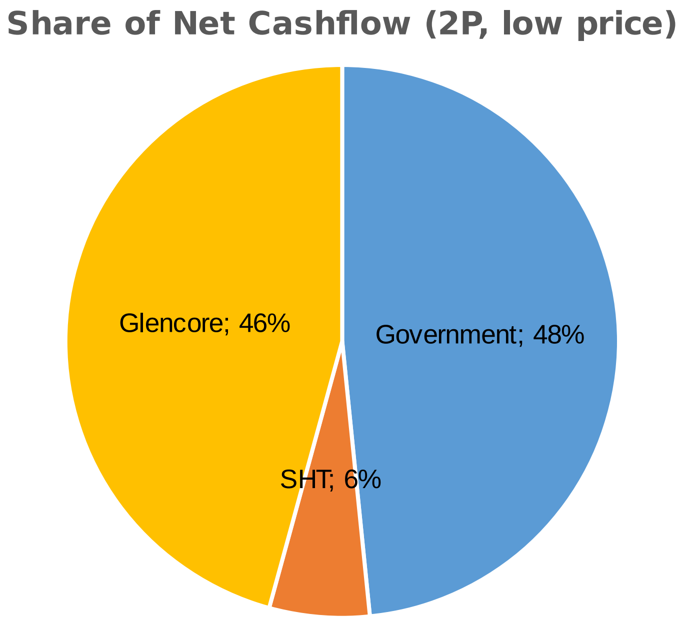
At 1P government revenue drops to just $700 million over the life of the project under a low price scenario. At 3P it rises to $7.7 billion.

A further key finding from the modeling is that - irrespective of production or oil prices - how the project is financed also makes a critical difference to government take. In the base case this could reach 62% if zero debt/100% equity financing is used, while dropping to 55% (direct government share and SHT's combined) if Glencore were to use 100% debt financing at a 7 percent interest rate. This is a key area where Chad government oversight is required.

Government Take

Under the base scenario, government take (defined as total government revenue as a proportion of the net cash flow generated by the project) varies between 54% (including both direct government share and that of the state oil company SHT) and 62% (55% direct to government and 7% to SHT) depending on how the project is financed. At a middle assumption of 50% financing, government take is 58%.

This range of 55% to 62% appears low for what is a second generation oil project, in the relatively geologically low-cost and low-risk exploration context of Chad. In terms of infrastructure, the Mangara and Badila fields require only a short trunk line to connect to the main Chad-Cameroon pipeline established in the early 2000s for the Doba Basin project and Chad has now been exporting oil for over a decade. As such, it no longer represents a pure “frontier province”.



Of course caution should be exercised in trying to determine how this government take compares to those from other fields, since the basis of comparison is critical. The Mangara-Badila contract appears to show almost identical fiscal terms to four other contracts derived from the 2010 model contract (see Fiscal Terms above). Projected costs and reserves for those other fields are not available, making modeling and comparison impossible. Comparison with the Doba Basin project started by ExxonMobil could yield some insight, but again neither the contract or reliable inputs are available, and comparison would have to be tempered by the different circumstances surrounding each deal. Comparison with fields in other countries would also be theoretically possible, but there would need to be careful consideration of perceived below and above ground risk in each case, and is not straightforward. Open Oil hopes that such analysis was done by or for the Chad government as part of the design and negotiation of these deals.

The contract is progressive against rising production. At 3P, for example (240 million barrels), government take, assuming 50% Glencore financing, rises to 65%. Government take also rises dramatically in a lower 1P scenario, to 93% reflecting the regressive effect of the Royalty.

However, the 1P scenario is by definition very conservative, with around 90 percent chance that actual production will exceed this level. Under that production point, and with EIA low case prices, project costs dominate the project revenue profile, and royalties dominate the revenue stream, leaving negligible profit oil.

The project is also progressive against profitability, but only mildly so. Government take rises from 58% to 63% under the middle price forecast from the EIA, and to 65% under the high price scenario.

Consortium Outcomes

Under the base case, with 115 MMBbl 2P reserves, the Project (before sharing between the consortium and government) would have a Net Present Value, using a 10% discount rate (NPV10) of $1.1 Billion. The consortium#s share of that would be an NPV10 of $331 Million[1]. The Consortium’s Internal Rate of Return (IRR) would be around 15%. This would likely be considered a marginal or only modestly profitable project.

With 1P reserves the Project NPV10 would be negative $237 Million, and Consortium NPV10 negative $480 Million; clearly strongly negative. With 3P production the Project NPV10 is $3.5 Billion and Consortium NPV10 of 1.2 Billion; clearly strongly positive. This wide range of results - changing only reserves - illustrates both the sensitivity of model outcomes to the assumptions made, but also the significant real risks, and opportunities, faced by the oil company when making the decision to invest. The investors faced a real risk of an absolute loss, and in return need a chance to make a significant profit.

1 This shows that on a discounted NPV10 basis the Government share is higher at 71%. Great care is needed when quoting government take statistics to ensure these are on a comparable basis.

Project economics	
Project Internal Rate of Return (Full-cycle)	23%
Project NPV10 ($MM) (Full-cycle)	1,124
Glencore NPV10 ($MM) (Full-cycle)	331
Glencore Internal Rate of Return (Full-cycle)	15%
Glencore NPV10 ($MM) (2015-on)	2,146
Breakeven oil price 2016	17.3

However, these results are measured over the entire life of the project (known as “Full-cycle” in the industry), prior to making the decision to invest. The exploration and development has now been done, and those costs irrevocably invested, or “sunk”. When measured from the start of 2015, Consortium NPV10, excluding all the money spent before 2015 would be 1P $786 Million; 2P $2.1 Billion and 3P $3.5 Billion respectively. Thus the project is a very valuable asset to the company now, irrespective of which reserves outcome is realized.

Another way of considering this is calculating what oil price is necessary to keep the project in production - the “breakeven” price at which revenues would just cover royalty, transport and and operating costs. With 2P production the 2016 breakeven oil price is in the region of $20. As long as the price realized at the field remains somewhat above this the project remains viable to produce.

Sources of Government Revenue

The three principal revenue streams to the government are the royalty, the direct share of profit oil and the participation of SHT. Other revenue streams such as the signature bonus and land surface rentals (up to $10 per year per square kilometre at the exploration stage and $150 per square kilometer per year within the production area) have not been modeled because they do not have a material effect on the major indices over the lifetime of the project.

Within these revenue streams royalties naturally predominate in the early years of the project, while cost recovery is still a major feature and there is relatively little profit oil. Under the 2P reserves and low EIA price scenario, royalties outweigh profit share until year six of production (and year 11 of the project), when profit oil jumps as a result of development and exploration costs being fully recovered .

Debt financing would again make a considerable difference in the transition out of major cost oil recovery. Assuming 100% financing by the Contractor keeps profit oil depressed for an additional two years relative to the royalty. This is a double effect: less profit overall, compounded by a slower ramp-up in the R-Factor which reduces the government’s share of profit oil.

Once capital expenditure has been recovered, profit oil dominates government revenue streams for the rest of the lifetime of the project.

These proportions alter significantly against either or both of production and price. With higher production or price, costs are recovered more quickly, and higher profit oil reached earlier. Higher consortium/contractor profitability pushes the R-Factor up and increases the Government share of the increasing profit oil. Thus the progressive profit oil share will dominate the royalty and lead to rising government take overall. With lower production or price the opposite is true. Profit oil is lower and reached later, while the royalty - being a fixed percentage of revenues - captures an ever higher share of falling profits. It is a regressive instrument. At the margin, the SHT stake in the consortium acts as a brake on the greater progressivity of the profit share, since its own share decreases with the Contractor’s as a whole. But especially since the SHT stake has been reduced to 15%, the greater effect is of the progressivity of the government’s direct stake in response to rising price and/or production.

Although the 2011 contract specifies that SHT may take a stake of up to 25%, in 2013 the government sold ten percent of that stake to Glencore. Glencore subsequently bought Caracal, taking over the operatorship of the project and 85% of the equity of the consortium. One question of high public interest, then, is how much the ten percent stake may have been worth at sale. At this point, the Contractor is already committed to development of the field but production has not begun.

The model uses a Net Present Value calculation of the value of the SHT stake at the start of 2013. By adjusting the percentage SHT holds in the project, we can estimate an NPV for the percentage that was sold.

There is strong dependency on assumptions around price and production. At 1P reserves (45 million barrels and a middle EIA price scenario (broadly consistent with actual market prices since 2010 at that point), a 25% SHT stake is worth $92 million using NPV10 (Net Present Value discounted at ten percent per year), whereas a 15% stake achieves NPV10 of $55 million. The difference between the two - $37 million - could then be said to represent the value of the ten percent stake that was sold. But if assumptions about produced reserves are raised to 2P, the basis for Caracal’s estimates to investors of development costs that year (and a more appropriate basis for such a sale), the value rises sharply. Under the medium EIA price scenario, the difference between a 25% and a 15% stake for SHT is then $172 million using the NPV10 metric.

Model Inputs and Assumptions

Where possible, inputs and assumptions have been taken from primary sources: either the government of Chad or the companies which signed the PSC.

Production Assumptions

Field size

The PSC governs both the Mangara and Badila fields. Caracal's Initial Public Offering (IPO) document of 2013 estimates "2P" reserves for the two fields at 114.6 million barrels, which the model rounds up to 115 million barrels as the default amount of recoverable oil. There is a 1P scenario of 45 million barrels (90 percent chance of being exceeded) and a 3P scenario of 240 million barrels (10 percent chance of being exceed) in the drop down box on the Dashboard.

Production Profile

The model assumes a generic production profile of 20 years, with a two-year ramp up to a four-year plateau and then a gradual decline. The pace at which reserves are produced will materially affect the timing of government revenues. The model would therefore benefit from a project-specific production profile.

Cost assumptions

Exploration Costs and Profile

We could not find direct exploration costs for Griffiths or Caracal and so used an investor document from a similar project, the UHIC PSC for four fields in Chad, as a basis for comparison. The UHIC investor document estimated expenditure on exploration of a field with 100 million barrels at $154 million. We raised that slightly to $180 million to account for the fact that the UHIC project had not yet reached production and so more expenses could be incurred. Adjusted to the larger field in this PSC, this came to $207 million, rounded down to $200 million and expressed as a lump sum. We assume an exploration spend profile over the first three years of the projection of 40/40/20.

Development Costs and Profile

Caracal's IPO document estimates total future capital expenditure as $1,091 million against P2 reserves of 115 million barrels. Costs are slightly different in each field but the model aggregates a weighted average of $9.48 per barrel, rounded up to $9.50. The expenditure profile is currently set over years 3 to 5 of the project at 40/40/20. The IPO document was released in 2013; it is assumed that any expenditure incurred prior to 2013 was exploration.

Caracal's IPO document estimates operating expenditure in Chad across all four fields it holds contracts for at $1,516 million on "proved plus probable" (2P) reserves of 179 million barrels. This is equivalent to $8.40 per barrel. The model assumes 70 percent of operating costs are fixed and 30 percent variable.

Transportation Costs

The Mangara and Badila fields use the Chad-Cameroon pipeline. Caracal issued a press release in 2013 estimating total transportation costs at $8 per barrel for the trunk Chad-Cameroon pipeline and, indirectly, approximately another $1.50 per barrel for transport over a local trunk line to reach the main line, making a total of $9.50 per barrel.

Pricing Assumptions

Caracal assumes a five percent discount to Brent in both its IPO document and a 2013 press release, which the model adopts. The model forecasts Brent using the EIA April 2014 long-term forecast low price scenario which projects $68.90 for Brent in 2015 and assumes two percent price inflation during the lifetime of the project. The discount of five percent from these fields is less than for Doba Blend, the main export grade from Chad to date, which according to an EITI report was sold at an 8.7% discount to Brent in 2012. But the company also describes the grade of oil in these fields as light or medium, and therefore higher quality to Doba Blend, which is heavy.