Context

In Brazil, the most promising frontier for oil exploration and production is the offshore pre-salt oil fields. Pre-salt oil is located at a depth of 7,000 meters: 2,000 meters of Atlantic Ocean water and 5,000 meters of a thick layer of rock and salt. One of the pre-salt oilfields is the Libra field, which extends across an area 800 km by 200 km, approximately 250 kilometers from Brazil’s southeastern coast.

According to preliminary estimates, the Libra field could contain between 8 billion and 12 billion of recoverable barrels of oil (API gravity 27 degrees). In October 2013, the government of Brazil concluded its first, and until today unique, pre-salt licensing auction.

A five-company consortium, including Brazil’s Petrobras (operator, 40% stake), UK’s Shell (20%), France’s Total (20%), and China’s CNPC (10%) and Cnooc (10%) won the auction and signed Brazil’s first production sharing contract (PSC), which is the contractual regime chosen for the offshore fields.

Before the auction Petrobras had taken initial exploration risk and discovered oil in the field, and prospectivity was so great that the consortium agreed to pay a $6.5 billion signature bonus. As we evaluate below, this probably also reflected their expectations that oil prices would stay over $100 per barrel. The project will require huge capital investment, with capex estimates made around the time the PSC was signed as high as $91 billion.

In 2015, Brazil produced 3.2 million BOPD, ranking 9th at in the world for total petroleum and other liquids production. Libra represents the potential to expand production and both satisfy its internal demand and export oil. A breakdown of Brazil’s production for the year 2014 (latest data available from the EIA) already showed that more than 91 percent of production was offshore in very deep water.
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Project Assumptions

The PSC states that the contract will have a duration of 35 years. Public sources suggest the Libra field was intended to have a plateau production around 1.3 million BOPD from 13 large (180 thousand barrel per day) Floating Production Storage and Offtake (FPSO) vessels. The Libra oil is valued at Dated Brent with a discount of 7.9%, primarily linked to the difference in specific gravity (lower API) between the two crudes.

Information regarding the target plateau production rate of 1.3 million barrels per day was released by the consortium after signature. We have developed an indicative production profile by assuming ramp-up over 10 years calibrated against the planned deployed infrastructure, staying at plateau for 6, 9 or 12 years (for the low, mid and high cases) and then declining after plateau at 13% (low), 10% (mid) and 7% (high). These decline rates are consistent with the range of average worldwide deep water decline rates, but have been set arbitrarily so that they result in lifetime production of 8, 10 and 12 Bn barrels when combined with the other parameters. See the chart below.\(^1\)

As further described below, Libra’s production sharing mechanism uses average production per well as an input. In addition to the top-down production profile assumptions just described, we have therefore also built a bottom up well-by-well production profile in the PRODUCTIONSCHEDULE sheet of the model. Using an assumed standard well with an initial production rate of 20 thousand barrels per day we determined a drilling schedule that would result in the same aggregated production schedule as described above, and used this to calculate average production per well. We have limited information on potential individual well performance therefore this is obviously somewhat speculative. See Appendix 1.

The model assumes lifetime capex at around $91 billion. Exploration and appraisal costs (starting from PSC signature) are $1 billion and development capital costs of around $90 billion.\(^2\) The largest component of the development costs (more than 1/3) is the cost of the 13-planned floating production storage and offloading (FPSO) units, which we have assumed will cost around $2.5bn each.

The model assumes operating (lifting) costs of $11 per barrel, consistent with recent Petrobras actuals. We have assumed this reflects indicative cash lifting costs for Libra. In practice cash opex might be lower than current Petrobras reported actuals.

\(^1\)Our 3 scenarios thus show differences in the duration of plateau and post-plateau decline. In reality a different plateau might be reached.

\(^2\)Rodrigues, Larissa Araujo and Ildo Luis Sauer, Exploratory Assessment of the Economic Gains of a Pre-Salt Oil Field in Brazil, Energy Policy (87) 2015 486-495
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Decommissioning cost is assumed to be 15 percent of capex, in line with industry standards, with these incurred over the last six years of production.

Fiscal regime assumptions

The fiscal regime comprises a royalty, production sharing and income tax. The royalty specified in the Libra PSC is 15 percent of gross revenues compared to a 10 percent royalty rate in the concession regime.

Cost recovery is 50 percent of the gross production value in the first two years of production, and thereafter 30 percent, however if the costs remain unrecovered after two years the cost recovery limit will revert to 50 percent until the expenses are recovered.

In the Libra PSC oil remaining after cost recovery is called “Excess Oil” (Profit oil in general PSC terminology). Sharing of Excess Oil is done on a monthly basis, with the government’s share depending on the oil price at the time and the average production per well producing at that time. The government in the auction phase had stipulated a minimum bid corresponding to 41.65 percent of profit oil to the government for an oil price between $100 to $120 a barrel and average production per well of 10,000 BOPD to 12,000 BOPD. The winning consortium offered exactly the minimum bid as established by the ANP and the following table shows the matrix of government shares of Excess Oil for each combination of oil price and well productivity as they apply to the Libra PSC.³

<table>
<thead>
<tr>
<th>Price per Barrel ($/bbl)</th>
<th>4</th>
<th>6-8</th>
<th>6-8</th>
<th>8-10</th>
<th>10-12</th>
<th>12-14</th>
<th>16-18</th>
<th>18-20</th>
<th>20-22</th>
<th>22-24</th>
<th>&gt;24</th>
</tr>
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<tbody>
<tr>
<td>&lt;$60</td>
<td>14.9%</td>
<td>25.7%</td>
<td>32.0%</td>
<td>35.3%</td>
<td>37.3%</td>
<td>39.0%</td>
<td>40.1%</td>
<td>40.7%</td>
<td>41.3%</td>
<td>41.8%</td>
<td>42.3%</td>
</tr>
<tr>
<td>$60-80</td>
<td>15.1%</td>
<td>28.7%</td>
<td>34.1%</td>
<td>36.9%</td>
<td>38.7%</td>
<td>40.1%</td>
<td>41.1%</td>
<td>41.6%</td>
<td>42.1%</td>
<td>42.5%</td>
<td>42.9%</td>
</tr>
<tr>
<td>$80-100</td>
<td>22.2%</td>
<td>32.7%</td>
<td>36.9%</td>
<td>39.1%</td>
<td>40.5%</td>
<td>41.6%</td>
<td>42.3%</td>
<td>42.7%</td>
<td>43.1%</td>
<td>43.5%</td>
<td>43.8%</td>
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<tr>
<td>$100-120</td>
<td>26.6%</td>
<td>35.3%</td>
<td>38.7%</td>
<td>40.5%</td>
<td>41.6%</td>
<td>42.5%</td>
<td>43.1%</td>
<td>43.5%</td>
<td>43.8%</td>
<td>44.1%</td>
<td>44.3%</td>
</tr>
<tr>
<td>$120-140</td>
<td>29.7%</td>
<td>37.0%</td>
<td>39.9%</td>
<td>41.4%</td>
<td>42.4%</td>
<td>43.2%</td>
<td>43.7%</td>
<td>44.0%</td>
<td>44.2%</td>
<td>44.5%</td>
<td>44.7%</td>
</tr>
<tr>
<td>$140-160</td>
<td>32.0%</td>
<td>38.3%</td>
<td>40.6%</td>
<td>42.1%</td>
<td>43.0%</td>
<td>43.6%</td>
<td>44.1%</td>
<td>44.3%</td>
<td>44.6%</td>
<td>44.8%</td>
<td>44.9%</td>
</tr>
<tr>
<td>&gt;$160</td>
<td>35.7%</td>
<td>40.4%</td>
<td>42.3%</td>
<td>43.3%</td>
<td>43.9%</td>
<td>44.4%</td>
<td>44.7%</td>
<td>44.9%</td>
<td>45.1%</td>
<td>45.3%</td>
<td>45.4%</td>
</tr>
</tbody>
</table>

Brazil’s resident legal entities are subject to income tax on their worldwide income at the rate of 15 percent with a surtax of 10 percent for profits exceeding 240,000 reais ($74,900) a year. In addition, Brazil imposes a social contribution tax on corporate net profits at a rate of 9 percent. Therefore, the combined corporate income tax (CIT) rate used is 34 percent (15 + 10 + 9 = 34). This rate applies to both concessions and PSCs.

³ We appear to have a non-final version of the PSC, and the precise mechanism by which this matrix was populated during the bid is not entirely clear; i.e. did the bidders specify the entire matrix, or only the 41.65%? We have seen some sources with slightly different parameters at low price/low average production per well. The user can readily change the parameters in the INPUT sheet of the model.
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Brazil does not apply ring fencing when determining the CIT liability. Similarly, profits and losses from upstream activities can be offset against profits and losses from other activities undertaken by the same legal entity. We model the outcomes for the consortium as a whole and assume there is no other activity in Brazil. In reality the consortium is an unincorporated joint venture and each oil company consortium member will pay income tax separately, and will have a different tax position. Further, we consider Petrobras as part of the consortium and do not include Petrobras net cashflows from its participation in the consortium as part of the government share.

In December 2015, Brazil’s Rio de Janeiro state, because of a budget shortfall partly caused by the plunging oil prices, imposed a flat tax of 2.71 reais ($0.69) on every barrel of oil and gas produced. We have included this tax, though it is not yet clear if it will be applied. We do not model sales tax/VAT, in effect assuming that these do not result in net costs to the project.

Findings

Based on information available in October 2016 and of reasoned assumptions, the model presents three basic production scenarios:

- Low scenario — around 8 BB of oil
- Mid scenario — around 10 BB of oil
- High scenario — around 12 BB of oil

All results that follow are quoted in nominal terms assuming 2% inflation.

At current prices ($50 per barrel, October 2016) the Mid scenario project internal rate of return (IRR before the fiscal regime) is 18.4%, and the consortium post-fiscal IRR is 7.0%.

Assuming an 8% nominal discount rate the project pre fiscal NPV8 is $71bn, but the government takes royalty, profit share and income tax worth NPV8 $77bn leaving the consortium with a negative NPV8 of -$6 billion.

Thus, the project is profitable before the fiscal regime, but unviable after. One reason for this is the 15% royalty, which is a regressive fiscal mechanism. To achieve breakeven (NPV8 = 0 after the fiscal regime) would require $54 per barrel.

The government share is 71% of the undiscounted cashflows, which is broadly in line with oil fiscal regimes internationally, but on an NPV8 basis government share is 109%.

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4 An indicative discount rate for major international oil companies; though they would certainly seek a return higher than this before deciding to invest
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With the same $50 oil price, in the low case the pre-fiscal IRR is 17.4% dropping to 5.5% after tax. Full-cycle consortium NPV8 is negative (-$13 billion) and breakeven is $59 a barrel. We expect that when making investment decisions, it is break-even using the low case that the consortium would focus on, and they would likely require a return somewhat higher than 8%. However, a breakeven price of around $60 per barrel for Libra is consistent with reports from other media sources.5

However, the above assumes the original (2013) development costs of $91 bn. There is good evidence that lower oil prices and cut-backs by oil companies (including Petrobras) are resulting in significant oil project cost savings around the World. If we re-run the same cases assuming that the development costs were 20% lower (readily achieved using the Capital Cost Sensitivity parameter on the model dashboard) results are:

Consortium results post-fiscal with capex reduced by 20%
LOW case: IRR 7.5%; NPV8 of -2Bn; Breakeven price $52/Bbl
MIID case: IRR 8.8%; NPV8 of +4Bn; Breakeven price $47/Bbl

Thus, even with significant cost savings the project remains marginal at current oil prices. We expect that Petrobras and the other consortium members are looking hard at how to make this project work in a low-price environment. This may mean changes in the development approach, and aggressive cost cutting, plus also potentially putting pressure on Brazil to renegotiate the fiscal terms – particularly the royalty. We can see that the project’s development schedule has already slipped somewhat relative to original plans, which we believe reflects the rethink.

Even with the original cost structure Libra would be very profitable at oil prices above $100, as prevailed when the PSC was signed in December 2013. At this price, the Mid scenario would achieve a pre-tax IRR of 38%, an after-tax IRR of 16%, and a full-cycle consortium NPV8 of $62 billion, while the Low scenario achieve a pre-tax IRR of 38%, an after-tax IRR of 15%, and a full-cycle NPV8 of $48 billion. It is on this basis that the consortium was willing to pay $6.5 bn for the privilege of signing the PSC.

The PSC envisaged Libra starting production 4 years after the signature in December 2013. This schedule has already been revised twice, and the latest information has Petrobras installing the first of four FPSOs in 2020, adding one per year through 2023. The first long-term production test will start in Libra’s north-east section in the middle of 2017 in the same north-east area where the commercial systems will be placed. The test is designed to better understand and calibrate the production systems that will start operating in 2020.

5 WOOD MACKENZIE, 70% of Pre-FID Oil Projects Commercial at US$60/bbl, July 13, 2016, in https://www.woodmac.com/analysis/preFID-oil-projects. Also SPLASH, Brazil’s Libra Field Will Need Oil Prices at $55 to Break Even, Oct. 21, 2015, in http://splash247.com/brazils-libra-field-will-need-oil-prices-55-break-even/
Charts
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<table>
<thead>
<tr>
<th>Production parameters</th>
<th>Change</th>
<th>Mid</th>
<th>&lt; Select</th>
<th>2</th>
<th>Low</th>
<th>Mid</th>
<th>High</th>
<th>Other</th>
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<tr>
<td>Year of first production</td>
<td>-</td>
<td>2020 year #</td>
<td></td>
<td></td>
<td>2020</td>
<td>2020</td>
<td>2020</td>
<td>2021</td>
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<td>Production rate first year</td>
<td>-</td>
<td>75 000 BOPD</td>
<td></td>
<td></td>
<td>75</td>
<td>75</td>
<td>75</td>
<td>75</td>
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<tr>
<td>Year in which plateau is reached</td>
<td>-</td>
<td>10 years</td>
<td></td>
<td></td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>Production rate during plateau</td>
<td>-</td>
<td>1,300 000 BOPD</td>
<td></td>
<td></td>
<td>1,300</td>
<td>1,300</td>
<td>1,300</td>
<td>1,300</td>
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<tr>
<td>Plateau duration</td>
<td>-</td>
<td>9 years</td>
<td></td>
<td></td>
<td>9</td>
<td>9</td>
<td>12</td>
<td>9</td>
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<tr>
<td>Decline after plateau</td>
<td>0%</td>
<td>10% % p.a.</td>
<td></td>
<td></td>
<td>13%</td>
<td>10%</td>
<td>7%</td>
<td>10%</td>
</tr>
<tr>
<td>Last year of production</td>
<td>-</td>
<td>2055 year</td>
<td></td>
<td></td>
<td>2055</td>
<td>2055</td>
<td>2055</td>
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</table>

Production results

<p>| | | | | | | | | |</p>
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<thead>
<tr>
<th></th>
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<th></th>
<th></th>
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<tbody>
<tr>
<td>Total barrels produced</td>
<td>9,935</td>
<td>mn bbl</td>
<td>7,887</td>
<td>9,935</td>
<td>11,910</td>
<td>9,864</td>
<td></td>
<td></td>
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<tr>
<td>Production rate in final year</td>
<td>195</td>
<td>000 BOPD</td>
<td>70</td>
<td>195</td>
<td>438</td>
<td>217</td>
<td></td>
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</table>

The Production Profile Scenario According to the Three Basic Scenarios

- Low
- Mid
- High
Information Gap Analysis

1. Production profile & timing assumptions. Start date; time to plateau; plateau rate; plateau duration; decline after plateau.

2. The number of and phasing of FPSO deployments.

3. Revised lifetime development costs and phasing.

4. FPSO unit cost: our initial case ($91bn total capex) assumed a cost of $2.5 billion for each of 13 FPSO units. However, our research shows a wide range of possibilities for this cost depending on the vessel configuration; plus the fact that Brazilian shipyards should get better at building them so the cost could reduce over time. Also the project might choose to lease rather than buy the FPSOs outright, which could improve economics for the consortium depending on the lease terms.

5. A representative individual well production profile or at least an indication of how many producing wells will be required. Our Mid-case currently requires a total of 120 producing wells over the lifetime of the project based on our assumed type-well with average initial production of 20,000 BOPD.

6. Likely lifting costs per barrel; ideally broken down between fixed and variable (our model currently assumes opex is 100% variable)
The primary analysis in the model uses a production profile constructed “top-down” by setting parameters that the model uses to draw an aggregated production profile – start year; ramp up period; plateau rate; plateau years, and decline thereafter. It is this profile that is used in the cashflow analysis.

Development costs and their phasing are driven by the number and user-defined schedule of FPSO deployments, which we have set up to be consistent with our MID case production profile. For simplicity the model does not directly link the costs to the production, so the user should be aware of this when using the model – the quantum and timing of development costs should arguably be revised if there is a material change in production assumptions. In a fully fledged model the drilling schedule would drive production and the timing of costs, but we have aimed to keep this model simple.

To derive the average production per well metric needed for the production sharing we have developed a bottom-up production profile using an assumed type-well and drilling schedule. This is in the PRODUCTIONSCHEDULE sheet. In the base case we have assumed a type-well with initial production (IP) of 20 thousand barrels of oil per day (20 MBOPD), maintained for 3 years, then declining by the Decline after Plateau parameter selected for the top-town production profile. The chart shows that for the MID case the bottom-up profile closely matches the top-down profile, and the resulting average production per well statistic, which declines over time.

20MBOPD is arbitrary – and there are indications that the average Libra/presalt well may have higher production. Rodriguez and Sauer assumed 36MBOPD. We can configure the model to reflect their assumptions, by
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selecting type-well “B” in cell F62 in INPUTS, and selecting MID36MBOPD case in F54 in PRODUCTIONSCHEDULE. This case requires 81 total producing wells to replicate the Mid case production profile.

81 Total producing wells drilled

Bottom-up versus top-down production profiles
36MBOPD type-well

Keeping everything else equal (top-down production profile & the original development costs), this change reduces the assumed number of producing wells and increases the average production per well. This then increases the government share of profit petroleum, and worsens the economics for the consortium.

At $50bbl oil the post-fiscal full-cycle consortium return would be 6.7%, versus 7.0% in our original case.

Obviously this is somewhat artificial as we are holding development costs - and hence assumed drilling costs - constant, when of course these would likely change between an 81 and 120 well case – probably by something in the order of $4Bn (40 x 100 mn per well). However, this does illustrate the working of the PSC Excess Oil sharing mechanism.

We would welcome feedback on the well potential and current consortium thinking on schedule and development costs, and will update the model accordingly. Ideally we will revise the model to derive production, development costs and their phasing from an assumed drilling schedule.