Mexico energy reform: assessment of deepwater royalty mechanism

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The complex royalty system developed by Mexico for deepwater contracts in the Gulf of Mexico (GoM) may deter companies from bidding during the final phase of Bidding Round 1, which is due to close on 4 December, 2016.

The variable royalty system involves an adjustment factor that is triggered once the contractor has recovered the initial investment, rapidly increasing the royalty rate. The variable royalty system leads to a profit split between contractor and government of 42-58% (contractor NPV divided by the sum of the government NPV plus the contractor NPV), with an average royalty of 25% (total royalty collected divided by total gross revenue). The US has a more appealing profit split of 54-46%, in favour of the contractor, with an average royalty of 16.66%. Additionally, the US royalty does not move any higher, only lower when the deepwater royalty waiver applies, which brings down the royalty to 12.5%. However, Mexico's deepwater royalty rate of 25% only applies when a meagre 5% over royalty is offered in the bidding process. Companies that would offer higher royalties are more likely to win the bid, but at the expense of their profits because the average royalty rate will then be even higher than 25%.

The Mexican energy reform aims to demonopolize hydrocarbon development by opening up to foreign companies with access to international capital markets. Privatization of the petroleum extraction sector creates competition with Petróleos Mexicanos (Pemex) and may turn around the 20% decline of oil production output seen over the last decade (Donnelly, 2013). The increase in production will mainly come from deepwater fields and unconventional fields.

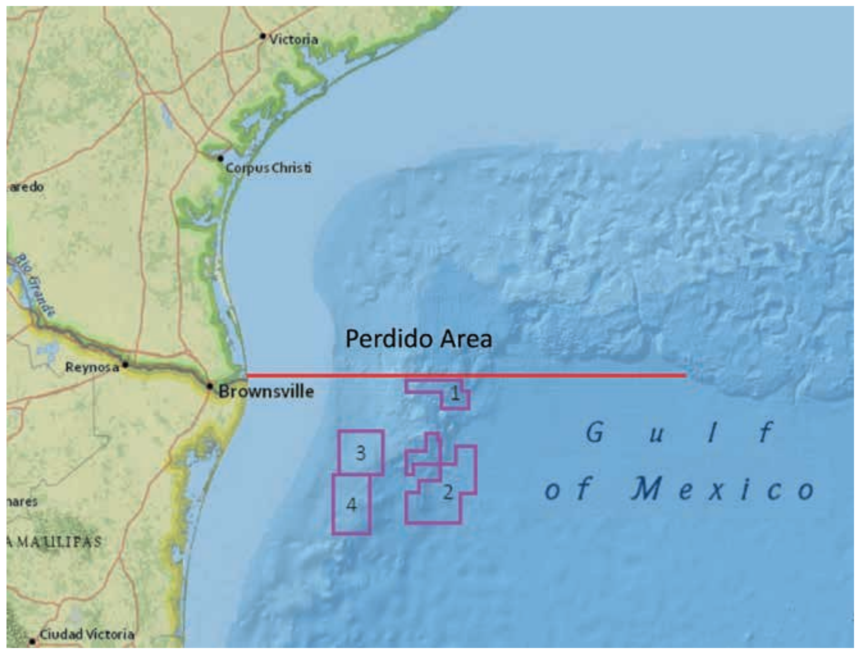

Figure 1 Lease map for deepwater Auction Round 1. The rectangles show the prospect deepwater blocks offered for auction. Adapted from CNH (2016).

Pemex was unable to rapidly exploit such fields owing to lack of technology, expertise, and financial resources.

The 2016 deepwater bidding Round 1 has attracted 21 companies, including majors such as Shell, Chevron, Statoil, and ExxonMobil, who have purchased access to the deepwater database, looking to enter an untapped potential in the Gulf of Mexico (Suarez et al., 2016). The auction blocks for this bidding round, located in the Perdido foldbelt, have prospective resources P50 ranging from 407 to 899 MMbbls (CNH, 2015).

We assessed the development potential of Mexico's deepwater Auction Block 1 in the Perdido foldbelt (CNH, 2015). A nodal analysis production model was adopted by using data from the Shell Perdido project as an analogous field. Shell Perdido lies eight miles north of the Transboundary Zone (TBZ), and Block 1 on the Mexican GoM is located just a few miles south of the border (Figure 1). Two prospective assets in Block 1, of respectively 300 MMbbls and 900 MMbbls, were evaluated. The nodal analysis model was calibrated by matching historic production data of the analogous Great White field (Shell Perdido). We then forecast the production profiles for Block 1 assuming natural drive, artificial lift, and waterflooding for each asset, resulting in six different development options (Table 1).

Our after-tax economic assessment uses base case inputs as follows: oil prices of $70 Brent and $60 Louisiana Light (LLS) and 5% over royalty. For these inputs, Option 1 has a negative

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Production	2 wells – 300 MMbbls OOIP	5 wells – 900 MMbbls OOIP
Natural drive	Option 1: 33.3 MMbbls EUR; RF=9%	Option 4: 166.4 MMbbls EUR; RF=17%
Artificial lift	Option 2: 143.8 MMbbls EUR: RF=48%	Option 5: 324.5 MMbbls EUR: RF=36%
Water flooding	Option 3: 200.6 MMbbls EUR: RF=67%	Option 6: 390.6 MMbbls EUR: RF=43%

***Table 1** Asset development options and EUR solutions. From Weijermars et al., in review.*

NPV, which was therefore excluded from further study. For all other development options, a sensitivity analysis was performed for a broader range of over royalties (different from the 5% base case) varying between 0 and 25% (see later).

Overview of royalty mechanisms

Over royalty

Licences for Mexico's deepwater prospects will be awarded in a competitive bidding process where companies will be ranked based on value points (*VP*) determined by

$$VP = 4\times[ORR + (11.5\times\frac{ORR}{100} + 3.45)\times IF] \quad [1]$$

The over royalty (*ORR*) is an extra percentage offered by the bidder on top of the basic royalty (which is indexed to hydrocarbon commodity prices). The investment factor (*IF*) is a discrete variable that can assume three different values:

- 1.5 if the bidder commits to an additional investment in work units equivalent to two exploratory wells during the exploration period,
- 1 if the bidder commits to an additional investment in work units equivalent to one exploratory well during the exploration period, or
- 0 if the bidder does not commit to the additional investment during the exploration period

For example, if the bidder offers to drill a well during the exploration period, the *IF* will have a value of 1. If the bidder does not offer to drill a well during the exploration period, the *IF* will be 0 (CNH, 2015).

The bid screening formula (*VP*) gives most of the weight to the over royalty offered, increasing the Value Points as the *ORR* increases. However, increasing the *ORR* will decrease the contractor NPV and IRR as follows from our sensitivity analysis for *ORR* (Figure 2). The graph shows how a sensitivity analysis can help companies to determine what *ORR* should be offered. The *ORR* should be high enough to maximize the value points, but low enough for the project to remain economically viable for the bidder.

Royalty adjustment mechanism

The Mexican deepwater contracts use a variable royalty system with an adjustment mechanism based on the cumulative return of investment factor (*FR*):

$$FR_n = \sum_{i=1}^{n}\frac{(VCH_i + CP_i + IEEH_i)}{CT_i} \quad [2]$$

Where

- VCH = gross contractual market value of hydrocarbons.
- CP = all royalty shares paid.
- CT = all capex and opex incurred to explore and extract the hydrocarbons.
- $IEEH$ = all federal exploration and exploitation taxes of hydrocarbon activities paid on acreage of exploration and production.

The adjustment formula, first triggers when *FR* reaches a value of 2, and the second adjustment begins when *FR* exceeds 4. The base royalty is adjusted accordingly by the following equations:

- When *FR* is between 2 and 4,

$$AR_n = [16.65\times CRO_{n-1}\times(FR_{n-1} - 2)]\% \quad [3]$$

- When *FR* is greater than 4

$$AR_n = (33.3\times CRO_{n-1})\% \quad [4]$$

Where

$$CRO_{n-1} : 1 - \frac{Costs\ \&\ Taxes}{MarketValueHydrocarbons} \quad [5]$$

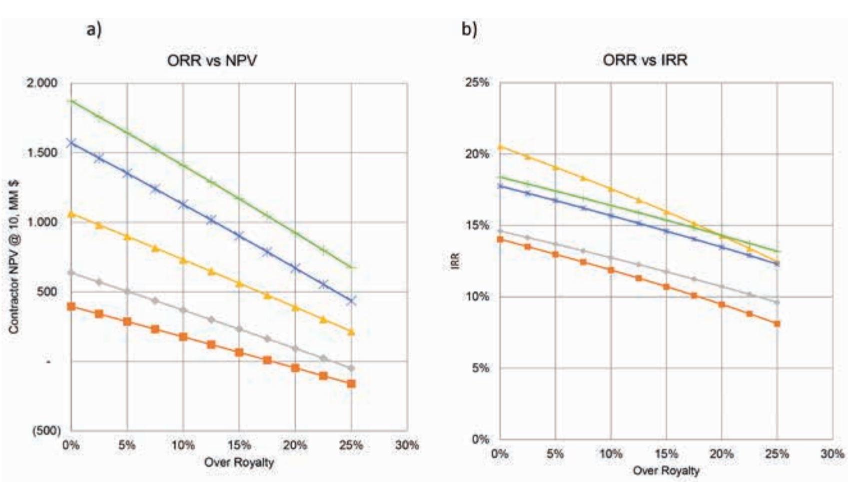

***Figure 2** Sensitivity analysis for contractor NPV10 (left) and IRR (right) for the five remaining development options listed in Table 1.*

Figure 3 graphs the effect of the adjustment factor on the total royalties over time. The royalty rate initially slowly increases, until *FR* reaches above 2. At this point there is a steep increase, which only slows when *FR* reaches above 4, with a more gradual increase on the royalty rate.

Royalties for each development option

The two prospective assets in Block 1 were appraised in our study, each with three development options providing 6 development options (Table 1). The cash flow model used to analyse

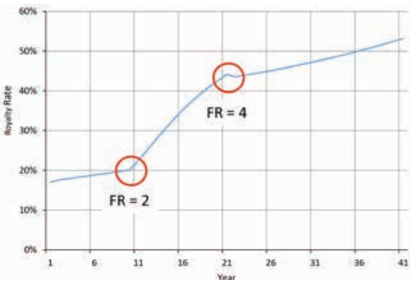

Figure 3 *Effects of the adjustment mechanism on the total royalties. We assumed development option 6 from Table 1 with an oil price of $90 Brent and $80 LLS, and 5% over royalty.*

the variable royalty system is detailed in Weijermars et al. (in review). Production profiles used in our study were based on our nodal analysis model assuming natural drive, artificial lift, and water flooding options for each of the two prospective assets. All options assume field development using an FPSO and a shuttle tanker to transport the oil back to shore. The first asset consists of a reservoir containing 300 million barrels of oil in place and will be produced using two wells. The second asset analysed has a reservoir of 900 million barrels of oil in place, and will be produced using six wells. Option 1 is excluded from this study since this option is not economically viable. This option does not produce a positive NPV under the assumed conditions.

The algorithm used to compute the project NPV and IRR accounts for the initial over royalty offered to the government, the basic royalty due to oil price, and the adjustment royalty triggered by the profit generated. This study assumes a base case 30% income tax, 5% over royalty, and oil price of $70 Brent $60 LLS escalated 2.5% per year to account for inflation. All the results in this study assume this base case unless otherwise stated for a specific figure.

The total royalties to be paid were evaluated for Options 2-6 for the base case. Our economic model computes total royalties, which varies with each option according to increases of the estimated ultimate recovery (EUR), taking into account the cost for each production option. The average royalty for each option was calculated by dividing the total royalties paid by the respective total gross revenue. The results of Figure 4 highlight that for the first ten years of field life only the basic royalty applies to each prospect. After the recovery of cost, the royalty adjustment mechanism is triggered leading to a steeper rise in the royalty rate. For most options the second royalty adjustment will be triggered, showing a more gradual increase in the total royalty rate due.

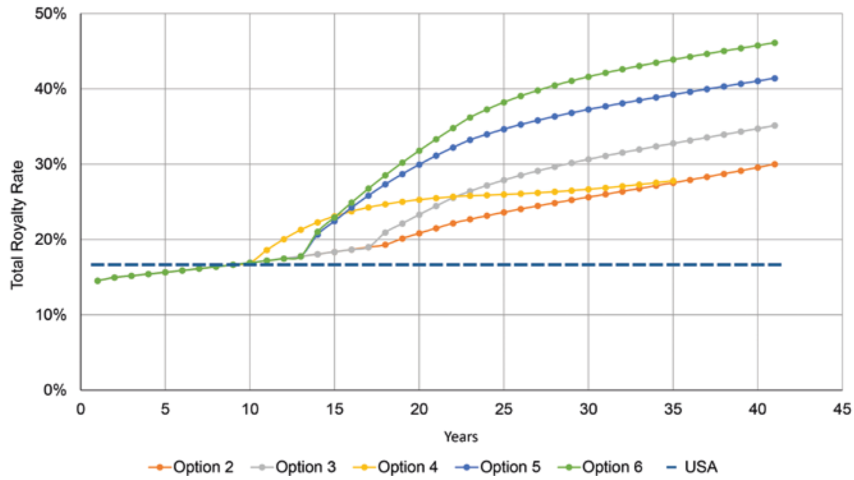

Figure 4 *Total royalties for different development options over time. The royalty adjustment mechanism for the Mexican prospects affects each development option in a different way. For all development options, the royalty rate exceeds the typical 16.66% US royalty for offshore assets (flat slope line).*

The average royalty percentage for each development option is summarized in Figure 5, and demonstrates that all the Mexican prospects have a higher royalty rate than the flat royalty in the US section of the GoM (red line). Development Options 2 and 5 use artificial lift, do not require additional drilling for injection wells and lowers the initial capital investment burden (Fig. 2b) which is why these represent the preferred development solution. A full economic analysis was performed for each development option in Weijermars et al. (in review). The two fields have an average royalty rate of 20% and 25% respectively for the base case.

$$AverageRoyalty = \frac{TotalRoyaltiesPaid}{Gross\,Revenue} \qquad [6]$$

Figure 6 plots the contractor's profit share versus the government take

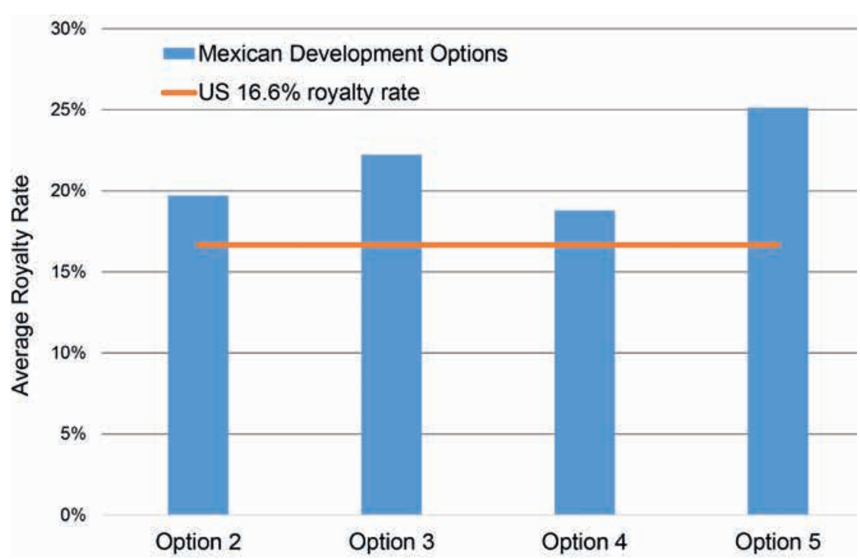

Figure 5 *Average royalty rate for each of the Mexican development options compared to the US average rate of 16.66%.*

Nomenclature

AR	Adjustment Royalty
Capex	Capital Expenditure
CNH	National Hydrocarbons Commission
CP	Royalty Shares Paid
CT	Capex and opex incurred to explore and extract the hydrocarbons
CRO	Contractor's operational results
EUR	Estimated Ultimate Recovery
FR	Correction Factor
FPSO	Floating Production, Storage and Offloading system
Ft	Feet
GOM	Gulf of Mexico
IEEH	Federal exploration and exploitation taxes of hydrocarbon activities
IF	Investment Factor
IRR	Internal Rate of Return
LLS	Louisiana Light Sweet Crude
Mi	Mile
MMbbls	Million Barrels
NPV	Net Present Value
NPV10	Net Present Value discounted at 10%
OOIP	Original Oil in Place
Opex	Operating Expenses
ORR	Override Royalty
Pemex	Petróleos Mexicanos
TBZ	Transboundary Zone
US	United States
VCH	Value of produced hydrocarbons
VP	Value Points

for development Options 2 and 5 for a range of over royalty (*ORR*) that could be offered by the contractor. This is important because the *ORR* will have a major impact on the Value Points received. The Value Points received rapidly increase when a larger over royalty is offered in the bidding process. However, as the *ORR* increases the contractor profit share will decrease. For the basic royalty rate (*ORR*=0) the contractor NPV and government NPV are equally shared for both development options.

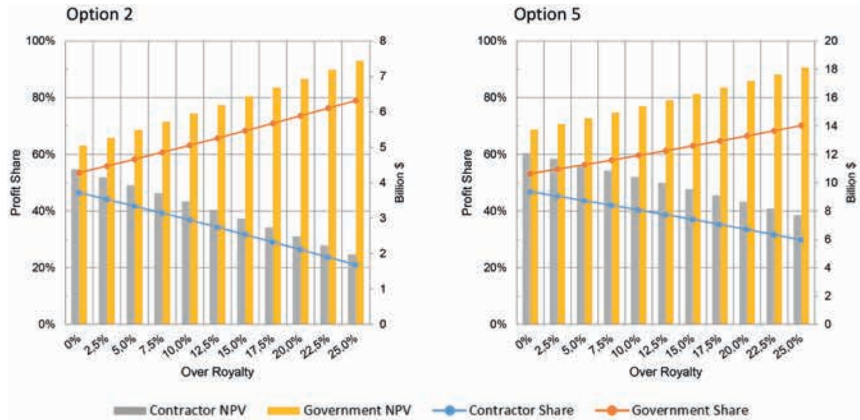

Figure 6 *The effects ORR has on the contractor undiscounted NPV and government NPV with their respective government/ contractor profit share for field development Option 2 (left) and Option 5 (right).*

Conclusions

The royalty rate imposed by the government can have a huge impact on the total revenue for the contractor. For deepwater contracts, the US government contractor profit split is 46-54%, contrasting with a 58-42% split in Mexico [for base case conditions]. The less favourable profit split triggers in the Mexican deepwater contracts may discourage companies from entering the first deepwater Bid Round in Mexico, because field development options in the US GoM are economically more viable.

Using the over royalty as a major factor for awarding the deepwater contracts is an ambitious strategy by the Mexican government. The amount of *ORR* offered is a risk the contractor has to analyse: if the *ORR* is too low, they will not get the contract, if the *ORR* is too high the project NPV might not be enticing enough to pursue. Moreover, the contractor NPV in this study does not take into account the 20-30% participation Pemex is required to have in each contract, adding further complexity to the Mexican field development ventures.

Although the Mexican prospects show promising resource volumes, the variable royalty system may have a negative impact on its economic viability. This may jeopardize the success of Bid Round 1 of Mexico's deepwater auction. Other incentives should be considered to attract foreign investment if the bidding round is not successful, such as lowering the royalty base rate, or making the adjustment factor less aggressive so that the final profit share between the contractor and the government is more equitably shared and closer to the favourable US offshore royalty rates.

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