Report on
Proposed Mexico Model Contract and Bid Conditions
for the Onshore Bid Round

(Bid Round 1, Call 3)

November 2, 2015

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EXECUTIVE SUMMARY

On December 15, 2014 and April 14, 2015 we published reports[3] on the First Shallow Water Bid Round (Bid Round 1, Call 1). The April 14, 2015 report concluded that significant improvements were made in the bid conditions and contract, subsequent to our December report. Nevertheless, in that report we expressed concern that the issues remaining could significantly reduce the interest in the first bidding round. In fact, limited interest was expressed in this bidding round. Nevertheless, Mexico successfully demonstrated that it had achieved the capability of conducting a transparent bid process.

Subsequently, a Second Shallow Water Bid Round (Bid Round 1, Call 2) was held with further improvements in the bid conditions and contract. This bidding round was clearly more successful. This is encouraging in view of current low oil and gas price conditions. The Second Shallow Water Bid Round also demonstrated that there is no need for SHCP to be pre-deterministic in terms of minimum fiscal conditions. The market forces surrounding the Mexican bidding rounds are clearly sufficiently robust to permit reliance on these forces for the establishment of competitive levels of government take in the contracts.

Despite the large number of improvements in the bid conditions and model contract, we believe that further adjustments are necessary if Mexico wants to increase the level of investment and achieve the policy objectives of the Government of Mexico. It is for this reason that we have prepared this report on the Onshore Bidding Round (Bid Round 1, Call 3). It is written by us as independent international petroleum experts in response to CNH's request for public commentary. It was not commissioned by any party, and was not reviewed by any party prior to its release. This report is based on the October 2, 2015 version of the Bid Conditions and the September 15, 2015 version of the Onshore Model Contract as published on the CNH website.

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[3] Free copies of these documents are available on www.petrocash.com.

For the Onshore Bidding Round the blocks are very small by international standards and are only selected based on the possible potential of further development of existing fields. The obvious rationale for this framework is to encourage small Mexican companies to participate in the petroleum industry. The fact that as much as 40 Mexican companies expressed interest in the bidding round is already a remarkable success.

Nevertheless, it should be expected that a number of the blocks are not sufficiently geologically attractive and therefore may not receive bids. Also the fact that certain onshore areas are in regions where operations may be dangerous may reduce interest in the bid round.

The current very low Henry Hub gas price of slightly above $ 2 per MMBtu will make uneconomic all fields consisting primarily of dry gas. The proposed fiscal terms do not effectively deal with the current gas economics.

As far as the bid conditions are concerned, some of our earlier observations remain. The competitive framework in terms of the type of consortia that can be created remains unnecessarily restrictive. The bid formula remains excessively oriented towards the additional royalty percentage rather than the amount of work, which leads to over-bidding as it did in the last two bidding rounds.

The contract includes a number of provisions that are detrimental to Mexico's interest, such as:

(1) The lack of a clear right to explore,

(2) Lack of clarity on permitted operations,

(3) A potential mismatch between the minimum work obligations and the evaluation report obligations,

(4) Potentially counter-productive unitization provisions,

(5) Unnecessary Accounting Procedures,

(6) Gas flaring provisions that could be too restrictive, and

(7) Overly zealous termination provisions.

From a medium and long term policy perspective we remain concerned that the above issues lead to an overall policy framework that may not result in maximizing the benefits for Mexico from the oil and gas resources. The Mexican upstream petroleum policy that seems to be emerging consists of the following:

(1) An excessive focus on rent collection on a dollar per barrel equivalent basis, rather than a focus on broad based development of a wide range of Mexican oil and gas resources in order to enhance production, revenues, employment and economic growth;

(2) The creation of an overly complex administrative and fiscal framework, which will have the potential of crippling the effective development of the Mexican resource base and could lead to a relationship of conflict between government and investors;

(3) Significant reliance on "applicable norms" (regulations), which create an environment in which the current policies of opening the Mexican petroleum industry to foreign investment can be easily reversed in the future under different political frameworks; and

(4) Incorporation of significant discretionary decision making powers for government officials, which in certain cases could create opportunities for corrupt behavior.

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1. INTRODUCTION

This report contains a review of the proposed Mexico Onshore Model Contract and Bid Procedure. During the announcement, not only interested parties, but also the public was requested to make comments on the documents provided.

This report is written by us as independent international experts in order to provide such comments. This report was not requested by any party, nor was this report reviewed with any party prior to its release.

The comments in this report are provided from the view of ensuring a further successful implementation of the policies of the Government of Mexico.

The comments are based on the September 15, 2015 version of the Model Contract and October 2, 2015 version of the Bid Conditions as published on the CNH website.

Our December report contains a description of the approach that we take to evaluating a petroleum regime, petroleum contract and award procedures. It also contains descriptions of features such as gold plating and other concepts which are discussed (without further explanation) in this report. Consequently, readers of this report who are not familiar with our December report may find it useful to review.

2. IMPROVEMENTS IN THE BID PROCEDURES AND MODEL CONTRACT

2.1 Improvements prior to the publication of the Onshore Model Contract

On December 11, 2014 Bid Conditions and a Model PSC for the First Shallow Water Bid Round (Round 1, Call 1) were announced.

On December 15, 2014[4] and April 14, 2015[5] we published reports on the First Shallow Water Bid Round. The April 14, 2015 report concluded that significant improvements were made in the bid conditions and contract, subsequent to our December report. Nevertheless, in that report we expressed concern that the issues remaining could significantly reduce the interest in the bidding round. In fact, limited interest was expressed in this first bidding round. Nevertheless, Mexico successfully demonstrated that it had achieved the capability of conducting a transparent bid process.

Subsequently, a Second Shallow Water Bid Round (Round 1, Call 2) was held with further improvements in the bid conditions and contract. This bidding round was clearly more successful.

Most of these improvements were carried over in the Onshore Model Contract, proposed for use in Round 1, Call 3.

2.2 Improvements in the Bid Conditions

The main improvement in the bid conditions since Call 1 has been the fact that consortia formation has now been made more flexible.

2.3 Improvements in the Onshore Model Contract

The Onshore Model Contract is a License Contract, not a Production Sharing Contract. This in itself is a significant improvement, since this will make it much easier to administer the small marginal blocks that are being offered, in Call 3. Administrative complexity was one of our main concerns with the PSCs of Call 1 and Call 2.

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[4] http://petrocash.com/documents/free/63201020.pdf

[5] http://petrocash.com/documents/free/63201022.pdf

The September 15, 2015 version of the Onshore Model Contract contains a significant number of improvements relative to the May 25, 2015 initial version of this contract.

The main improvements are:

(1) The Contract now includes the possibility for Exploration,
(2) The Work Commitment and Corporate Guarantee provisions were made more flexible,
(3) The contract termination provisions were significantly improved from the rather tough provisions that existed earlier,
(4) Clear provisions are now included with respect to pre-existing abandonment and environmental obligations,
(5) The Evaluation and Development Plan procedures now provide possibility for the Contractors to interact with CNH on the approval process,
(6) The contract renewal provisions now only require continuation of commercial production, not commitment to additional investments,
(7) The commitment to comply with international treaties is now included, and
(8) Joint Measurement Points are now possible.

There is no question that these improvements have made the Onshore Model Contract much more attractive. Most important is that there is now a much greater sense in the wording of the contract that the Contractor will be dealt with fairly and the possibility for unilateral decisions without Contractor input is reduced.

Nevertheless, there remain areas of concern and in fact, some new concerns have been created in the September 15, 2015 version.

3. FISCAL TERMS

3.1 The rentals, royalties and corporate income tax.

As discussed in our December report, the rental (Cuota Contractual), royalty and corporate income tax provisions of the LISH provide a viable starting point for fiscal terms for all of the resources of Mexico.

3.2 Adjustment Mechanism – the Additional Gross Revenue Share

3.2.1 The Additional Gross Revenue Share

The Additional Gross Revenue Share will not result in any gold plating. This is a significant improvement relative to the IRR concept used in the PSCs for shallow water. This is a very significant improvement in the overall fiscal structure of the contract.

The proposed Additional Gross Revenue Share is also progressive with volume. This is another significant improvement on the previous PSC concepts.

The Adjustment Mechanism now consists of the bid percentage plus a volume based sliding scale in order to increase the percentage where high volumes of oil and gas are produced.

For oil the extra percentage is 0% for volumes of less than 30,000 bopd for the Contract Area. The percentage is 20% for volumes in excess of 120,000 bopd. In between these two points there is a linear sliding scale. The royalty rate is deductible from the extra percentage rate. This means that under very high oil prices, the extra percentage is actually zero, since the royalty would be 20% or higher.

For gas the extra percentage is 0% for volumes of less than 80 million cubic feet per day for the Contract Area. The percentage is 10% for volumes in excess of 240 million cubic feet per day. In between the scale is linear and again the royalty is deductible.

The Bid Conditions specify so-called Type 1 Areas and Type 2 Areas. In total, 21 of the blocks on offer are Type 1 Areas. These are areas that contain an estimated remaining volume of hydrocarbons of less than 100 million barrels.

It is very unlikely that most of the Type 1 areas will ever produce 30,000 bopd. This means that for these areas the extra percentage based on volume is not applicable in practice. This is not in the interest of Mexico. Fields producing 30,000 bopd could be quite profitable under onshore conditions. It can therefore be recommended to reduce the oil volume levels for the Additional Gross Revenue Share.

Recommendation 1: To reduce the volume benchmarks for oil for the Type 1 Areas to a range of 10,000 bopd to 60,000 bopd, with 20% applicable at 60,000 bopd.

With respect to gas, the possibility for a level of 80 million cubic feet per day maybe a realistic possibility for some of the Type 1 Areas. Therefore, there is no need to adjust the gas scales.

At this time the Henry Hub gas price is excessively low at just over $ 2 per MMBtu. About half the blocks are gas fields with either dry gas or gas and condensates. This will create a significant risk for investments in such fields, because under current Henry Hub pricing conditions such blocks would not be economic. This situation may create very difficult bid conditions for these blocks and could lead to very modest or no bid results for the blocks containing primarily gas.

Therefore, it is not realistic to expect the same base bid percentage for the Additional Gross Revenue Share for oil and for gas. **The percentage for gas has to be lower.**

It can be recommended to make the base Additional Gross Revenue Share for gas at least 10% lower than for oil and condensates. This means that the bid percentage Clause 15.2 (c) in the Onshore Model Contract and in paragraph 3.1 of Annex 3 of this contract should only apply to oil and condensates. The percentage for gas should automatically be 10% less, but not negative, of course. This means that if the bid percentage is less than 10% the gas percentage would be 0%. If the bid percentage would be more than 10%, the gas percentage would be the percentage applicable to oil less 10%. For instance, if the bid percentage would be 12%, the percentage applicable for gas would be 2%.

It is our understanding that even the dry gas blocks contain some condensates. Also by permitting exploration, even blocks that currently produce only dry gas may produce condensates or crude oil in the future as a result of new discoveries. Therefore the percentage bid for oil and condensates is meaningful under all circumstances.

Focusing the bid percentage on oil and condensates only will very likely result in higher bids for government. This is because companies can compete without having to discount their bids to the same degree for gas economics.

Recommendation 2: To provide for the fact that the bid percentage contained in Clause 15.2 (c) of the contract and clause 3.1 of the Annex to the Contract should only apply to oil and condensates. The percentage applicable to gas should be automatically 10% less. Where the bid percentage for oil and condensates is less than 10%, the percentage for gas would be set at 0%.

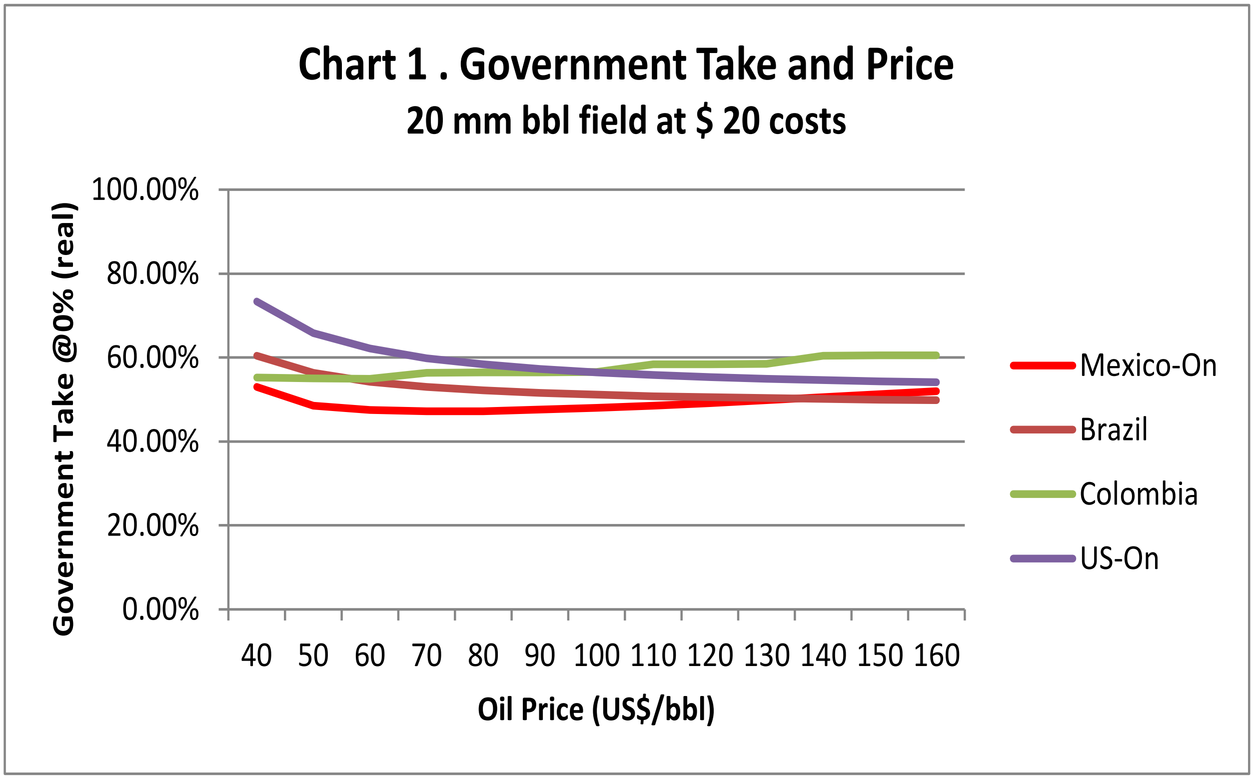
3.2.2 Economic Analysis of the Proposed System

An analysis was done on the fiscal terms contained in the Annex 3 of the Onshore Model Contract, assuming an Additional Gross Revenue Share of 5%.

The proposed terms were compared with onshore terms for Brazil, Colombia, the US Gulf of Mexico and the UK. These are jurisdictions whose petroleum regimes will be competing for private investment capital that Mexico will want to attract.

Government Take Analysis. The undiscounted government take ("GT0") in real terms was evaluated for changes in price, volume and costs. The results are provided in Charts 1 through 3.

With respect to **price**, in Chart 1 the GT0 for Mexico is generally less than competing countries for the entire price range and is therefore fiscally competitive.



With respect to **volume**, Chart 2 illustrates how the Mexican system would be competitive for the entire volume range for Type 1 and Type 2 areas.

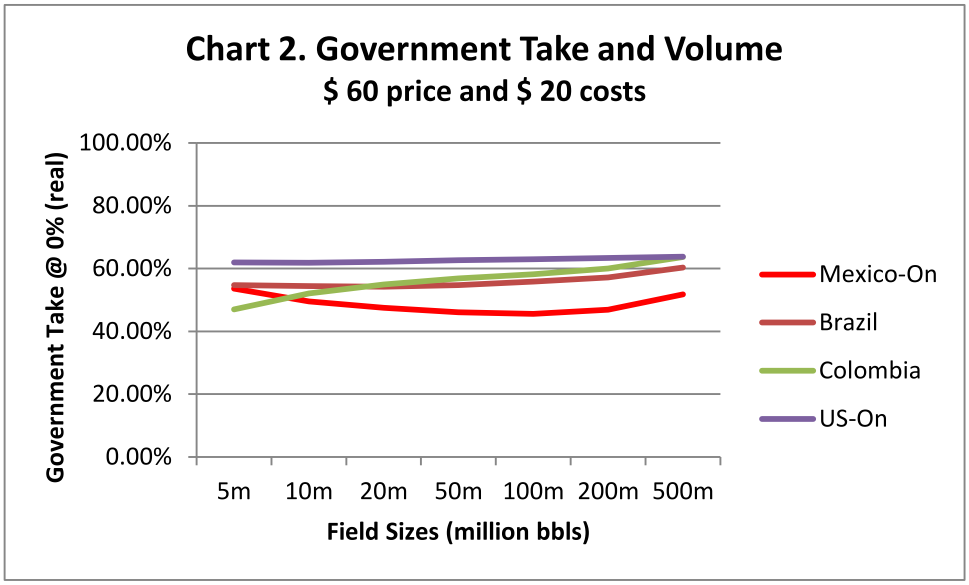
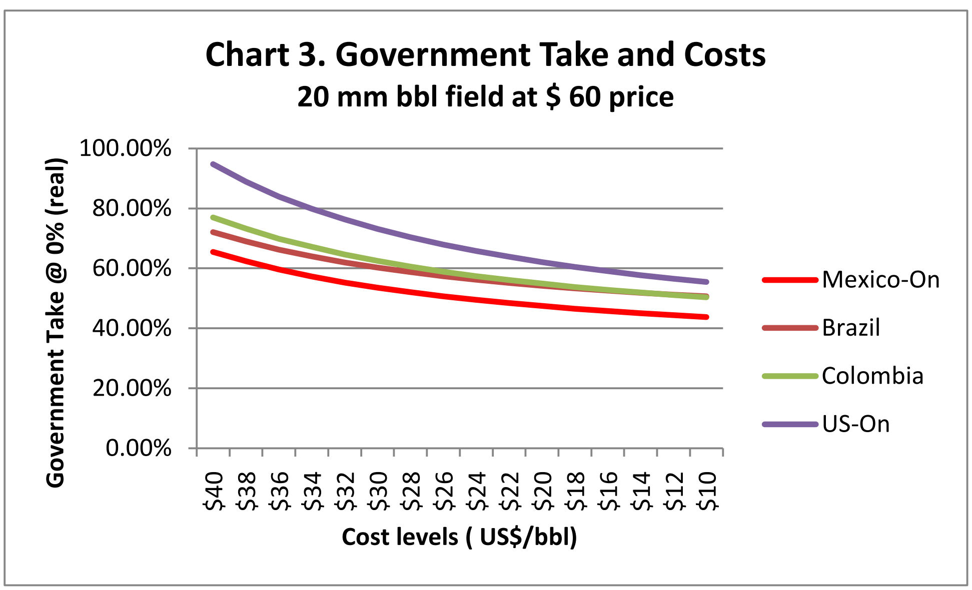


Chart 3 illustrates the economics under different **costs.** The Mexican system is again competitive for the entire cost range with competing countries.



Un-risked Profitability Analysis. Charts 4 and 5 show the un-risked profitability analysis.

The IRR is competitive with other jurisdictions up to $ 100 per barrel. Above this price level the IRR becomes somewhat less due to the fact that much of the government take consists of the royalties and additional royalties, which means the system becomes relatively front end loaded.

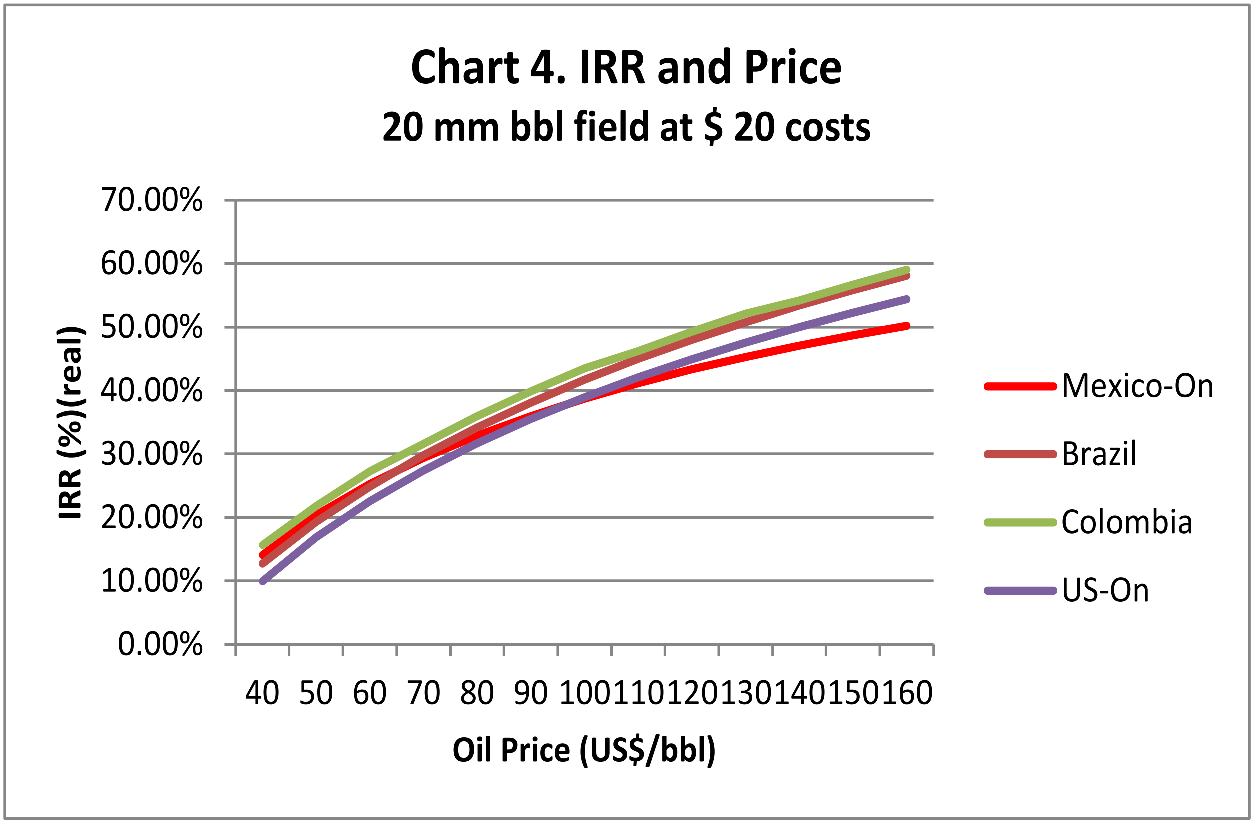
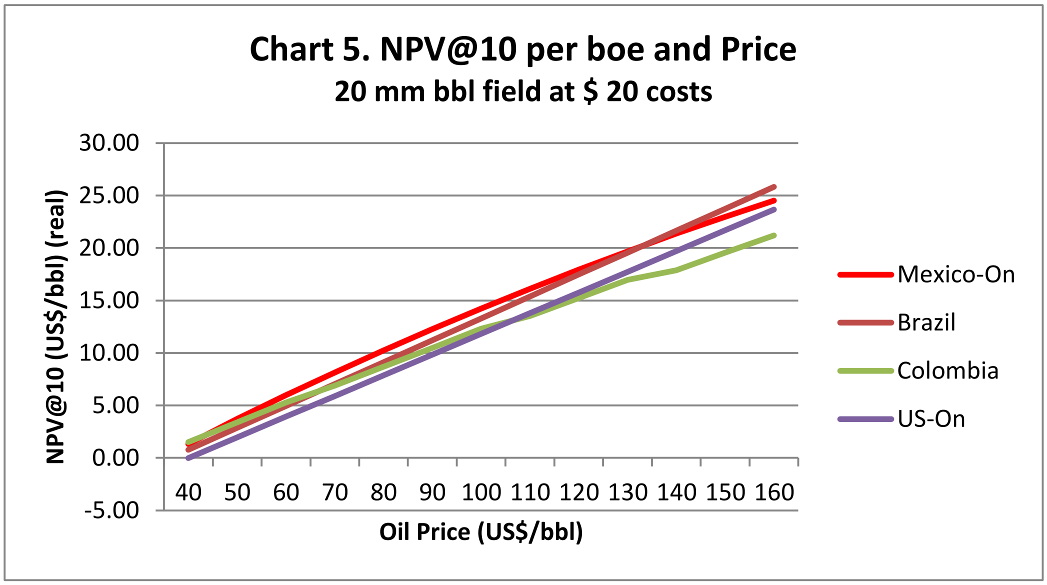
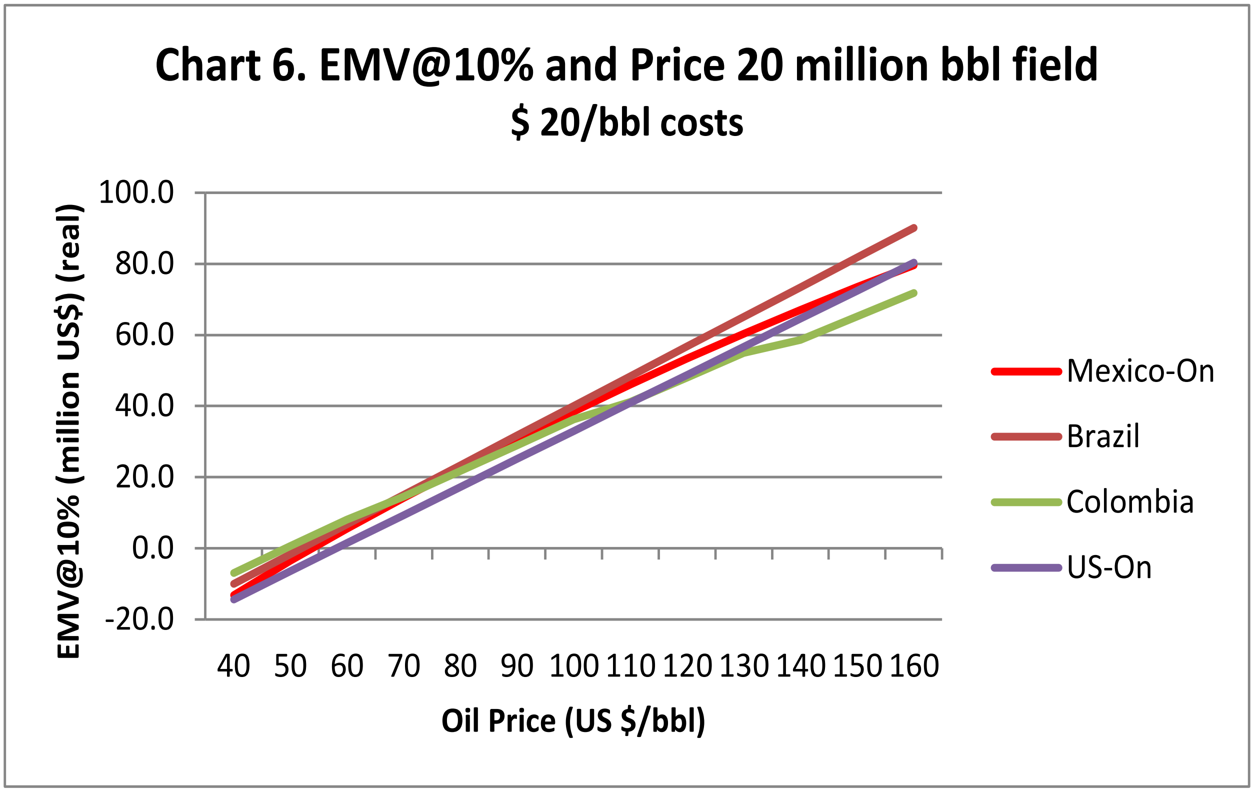


Chart 5 shows the NPV@10% per barrel for different price levels. This analysis shows how the Mexican system is fully competitive.

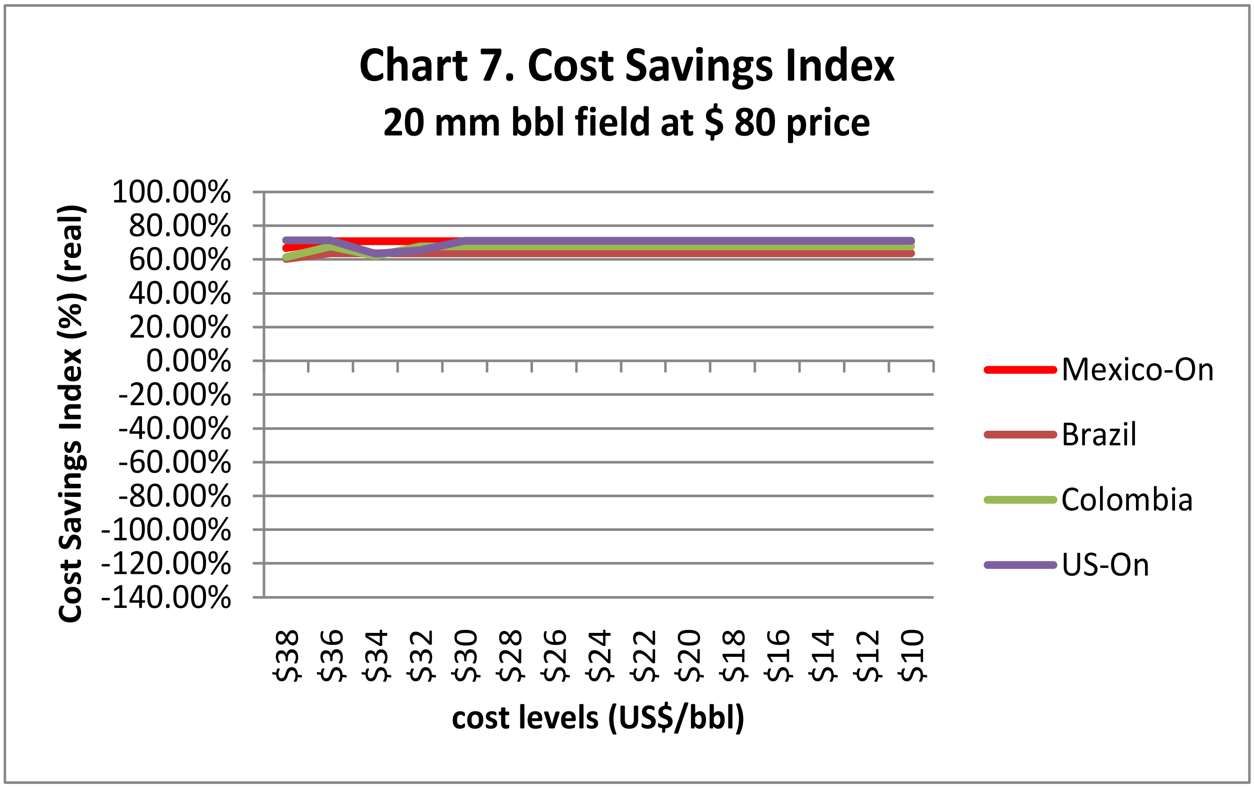


Risked Profitability Analysis. The Expected Monetary Value @ 10% ("EMV@10%) is calculated for an exploration project assuming a probability of a dry hole of 80% and a probability of discovering a 20 million barrel field of 20%. The EMV@10% is the weighted average of the dry hole cash flow and the discovery cash flow.

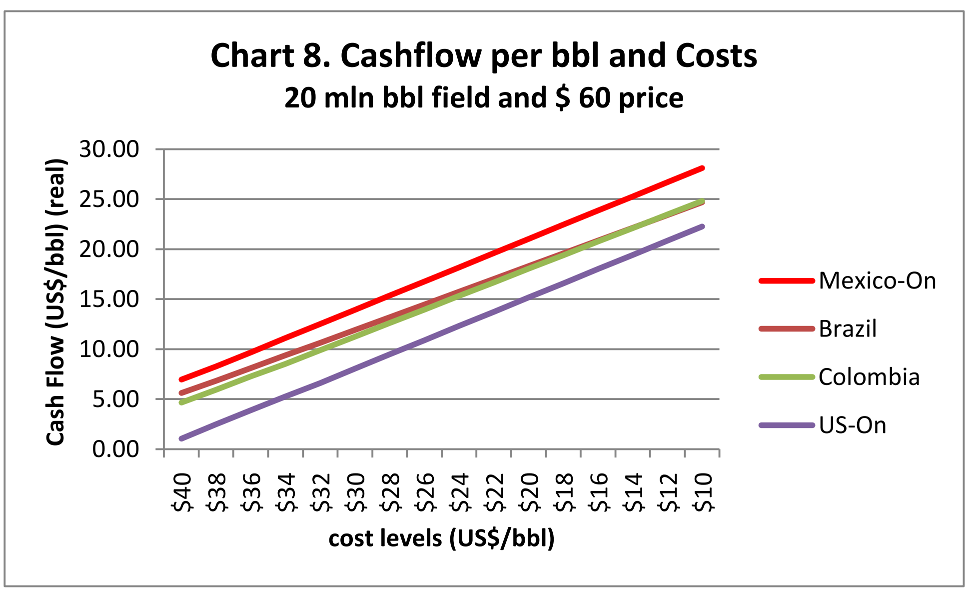
It can be seen in Chart 6 that the Mexican system is fully competitive for exploration, despite the fact that the Onshore Model Contract does not have exploration as prime objective.



Gold plating and Cost Savings Index analysis. Chart 7 provides the cost savings index. The cost savings index measures how much an investor retains when saving a dollar of cost. In other words, if the cost savings index is 60%, the investor retains $0.60 when it reduces cost by a dollar. If the cost savings index is below 20% the system becomes very difficult to administer from a cost control concept, since the Contractor has little incentive to minimize costs. A negative cost savings index indicates gold plating, which means that the investor has no incentive to save and in fact has an incentive to increase costs. Chart 7 shows how the proposed system does not involve any gold plating and has a very healthy cost savings index compared to most countries in the world.



Cash Flow per barrel Analysis. Chart 8 shows the Undiscounted Cash Flow per barrel. This chart shows that the Mexican system is fully competitive and quite attractive from a cash flow per barrel point of view.



3.2.3 Conclusion and recommendations on fiscal terms

It can be concluded that the proposed Mexican system, assuming a minimum bid percentage of 5% additional royalty is fully fiscally competitive with other countries with respect to crude oil economics. Also the system is structurally sound.

As explained and recommended above, gas economics needs to be supported with a special base percentage for gas.

The fact that the terms are competitive for oil, does not necessarily mean that bids will be received on all blocks containing primarily oil. Companies may not wish to present offers because the geology is unattractive or because of dangerous operating conditions in some blocks due to local crime.

The Second Shallow Water Bidding Round (Round 1, Call 2) showed without question that the bidders are actively competing. In this framework there is absolutely no need for SHCP to set any minimum bid percentage.

With 60 companies interested in the 25 onshore blocks and with all of these blocks offering further development opportunities and containing existing oil and gas reserves, there should be absolute no doubt that the bid environment will be fully competitive. As a result there is no benefit in SHCP together with SENER second guessing what a competitive government take should be. In fact, this could be counter-productive in attracting the maximum number of bids.

If very low bids would be received for a block, it is because the geology is unattractive. In this case Mexico does not lose if operations continue in the block under such terms. At least Mexico gets the employment and business opportunities and all the fiscal benefits provided under the LISH.

<u>Recommendation #3:</u> The Government of Mexico should avoid setting minimum fiscal conditions for the Onshore Bidding Round and it can be recommended to announce this policy early in order to attract the maximum number of bids, in particular to marginal areas.

3.2.4 <u>Oil and Gas Pricing Issues</u>

Annex 3 of the Onshore Model Contract contains significant sections on how the value of oil, condensates and gas will be determined.

However, the reality is that for most of these small onshore areas, all oil, condensates and gas will have to be sold initially to PEMEX. This puts PEMEX in a monopsony position. PEMEX could drive prices down in their negotiations since the small contractors have no other way of selling oil, condensates and gas. This is not in the interest of the contractors and Mexico.

The Government of Mexico should recognize this monopsony situation.

Recommendation 4: The Government of Mexico should issue guidelines to PEMEX for the purchase of oil, condensates and gas from the small onshore contractors in order to ensure that the contractors receive fair market value for their Hydrocarbons. These guidelines should also apply to onshore COPF and CIEP contracts that are migrated to CEEs.

4. CONTRACT STRUCTURE

Our earlier reports noted that the Model PSC used for Call One gave significant discretionary decision-making powers to the government, and included and early termination provisions that pose risk to oil companies. The Onshore Model Contract for Call Three contains many of the same provisions, albeit with some improvements to ensure that administrative rescission requires due process with notice and opportunities for oil companies to respond and remedy.

4.1 Early Termination Provisions

As in the Model PSC, the Onshore Model Contract contains two types of early termination provisions.

Clause 22.1 deals with administrative rescission, defining a series of serious breaches which entitle CNH on behalf of the government to terminate the petroleum contract, after the Contractor is given 30 days to respond and rectify its default. This clause implements in the Onshore Model Contract the required provisions for administrative rescission contemplated by Article 20 of the Hydrocarbon Law. Disputes in respect of administrative rescission are to be dealt with in Mexican courts.

Clause 22.4 expands the list of causes which entitle CNH to terminate the petroleum contract beyond the list established in Article 20 of the Hydrocarbon Law. Some of the listed grounds are reasonable and suitable (for example, insolvency or bankruptcy of the Contractor, or breaching the anti-corruption clause). However, a number of the grounds for termination are much less serious grounds. For example, termination of the contract will occur where:

- any delay of 180 days in implementing any work program or development plan[6]
- failure to perform 90% of the work units[7]
- any assignment or change of control occurs without CNH approval[8]
- violation of any provision contained in Clause 31 (which includes failure to file proper reports, acts of corruption, failure to maintain procedures to prevent corruption, and conflict of interest)

The administrative rescission provisions of Clause 22.1 can be triggered only with an investigation process and a due process involving notice, opportunity to remedy and object on the part of the company, as described in Clauses 22.2 and 22.3. However, these provisions do not apply to the contractual early termination provisions of Clause 23.2.

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[6] See clause 22.4(A)

[7] See clause 22.4(E).

[8] See clause 22.4(F). A more suitable remedy would be to provide that any such assignment is invalid and has no legal effect

Early termination is the state's 'nuclear weapon' for enforcing compliance with a petroleum contract. It is an appropriate power for CNH to have in its toolbox, but it should only be used for significant, material breaches following notice and a reasonable opportunity to remedy. Improvements to Clause 22.4 are needed, and will give comfort to investors that their petroleum contract has reasonable assurance of stability.

<u>Recommendation # 5:</u> Early termination provisions of Clause 22.4 of the Onshore Model Contract should be subject to the same due process as contemplated in Clauses 22.2 and 22.3 in relation to administrative rescission.

<u>Recommendation # 6:</u> Early termination for failure to file reports, conflict of interest or failure to maintain procedures to prevent corruption is unduly harsh remedy, so the reference in Clause 22.4(G) should be to "Clause 31.2" (except the last line thereof), rather than to Clause 31.

It should be noted that paragraph 22.4 (e) is now in contradiction with the provisions of the last paragraph of 4.5 (d), which specifically permits the contractor to pay for unrealized work commitments. This paragraph should therefore be deleted.

<u>Recommendation # 7:</u> Delete paragraph 22.4(e) of the Onshore Model Contract.

4.2 Quantity of Administrative Decisions and Reports

Our December report highlighted the many decisions which are to be taken and reports to be delivered pursuant to the Model PSC (excluding its annexes) used in Call One[9]. With the adoption of a License contract for Call Three, it was expected that the number of decisions and approvals would be significantly less, because unlike a PSC, the provisions of a License contract typically do not involve so large a number of approvals. The principal reason for this is that a PSC involves cost recovery and the determination of 'profit'. The state is then interested in how much cost is to be incurred, which justifies budget approvals and rigorous procurement procedures. The state is also concerned about cost recovery, so tough audit provisions are justified.

The Onshore Model Contract for use in Call Three does not adopt any cost recovery or profit based fiscal provisions, so the scope exists to create a significantly simpler contract with less administrative burden to the state and companies. Unfortunately, the Onshore Model Contract did not seize this opportunity. Significant and excessive reporting provisions, approvals and procurement procedures are retained from the Model PSC form, even though the justification for them is either absent or significantly less than under the Model PSC.

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[9] In particular, see Annexes A and B of the December Report.

While all of these seem to be laudable goals in contract management and procurement, there is no justifiable interest in the state in regulating these matters. Under the License Contract fiscal structure, the state does not have any commercial interest in how the Contractor procures its services (so long as it does not do so in a corrupt manner), because Contractor cost is not a factor in determining the state's share of petroleum revenues. As noted in the fiscal analysis above, the cost savings index under the Onshore Model Contract creates a very strong incentive for the Contractor to reduce costs, so it need not be part of what the state regulates. Contractors will do it out of their own interest, and even if they overspend, it does not affect the state.

It seems that the approval, reporting and audit provisions of the Model PSC provisions, which were extensive but at least were based on a recognized state interest in minimizing costs, have not been retained without adequate consideration in the Onshore Model Contract. Reducing these provisions would be in line with international practice in host government contracts which adopt the License structure.

<u>Recommendation # 8:</u> All reporting, accounting and procurement provisions contained in the Onshore Model Contract be reviewed in light of the fact that a License contract structure does not create the same state interest in cost control. This should permit significant simplification and reduction of administrative controls and reporting.

The same reasoning applies to the recommendations made in Section 7 of this report regarding the removal of the Accounting Annex and the Procurement Annex.

5. TIME LINES AND PHASES

Many Governments seem to believe that creating unrealistically short time lines is good management and will lead to early production of oil and gas. In fact, often the opposite is true. Reports and plans prepared in time frames that are too short are usually deficient and need to be redone. Therefore, regulation and contracts should permit for time lines that enable the work to be carried out properly.

5.1 Mismatch between timelines for evaluation, work units and development.

An important issue is that there is a mismatch between the time lines for evaluation, minimum work unit requirements and the criteria contained in Annex 9 of the Onshore Model Contract for presentation of Development Plans.

The Onshore Model Contract provides for an initial evaluation period of one year and a possible additional year if the contractor commits to an additional well. Therefore, the evaluation period is possibly two years.

The Minimum Work Program in terms of Work Units is for most blocks 4,600 Work Units, which means the requirement of one well. In order to have a total Evaluation Period of two years, two wells will have to be drilled in this period.

A specific geological issue in particular in Northern Mexico is that geological formations contain a large number of separate reservoirs. For instance the Oligocene Frio formation may contain as many as 10 separate reservoirs. These reservoirs are not necessarily contained in the same fault blocks or formation features. Therefore, these reservoirs could not be drilled in a single evaluation well. In order to properly evaluate the opportunities in the 10 reservoirs, 10 or more evaluation wells may be required, often drilled in different fault blocks. The same is true for the Eocene formations.

In order to comply with the detail required in the Development Plan in Annex 9 one might need to drill as many as 10 evaluation wells. Yet, an evaluation period of only 2 years is certainly not enough to drill 10 evaluation wells, some of which may be 4000 meters deep or more.

Nor does it make economic sense to drill all the possible evaluation wells prior to starting the field development. Contrary to the offshore, in the onshore there is no need for central platforms or FPSO's for the production of the field. In the onshore a field can be developed in phases. There is no need to understand the entire field in detail before development can start. Development can start once economic wells have been identified and it is established that the production from such wells will not damage the reservoir or other reservoirs.

This means development of certain reservoirs can start while evaluating others. Also with multiple reservoir possibilities in a single well, it makes sense to produce the deeper reservoirs first and re-complete the well in the shallower reservoirs once the lower reservoir is depleted. This is the most economical way of operating an onshore field and is standard international practice.

Therefore, the concept of a single evaluation phase and a single development phase as contemplated in the Onshore Model Contract does not make sense.

It can therefore be strongly recommended to permit the development of the Contract Area in various phases. The first evaluation phase should correspond to the minimum work program that is committed for this phase.

Recommendation # 9: It can be strongly recommended to permit the development of the Contract Area in phases. The Evaluation Period would relate to phase 1 and this phase would correspond to the minimum work program that is committed. The development plan related to phase 1 could then include evaluation work to be done for phase 2. Once this evaluation work is completed, phase 2 of the development plan can be presented, etc. There should be no limit to the number of development phases that can be implemented during the initial 25 year term of the contract.

The recommendation to permit the development of the field in phases, implies a modification to Clause 6.1 (b) of the contract, which deals with relinquishments. It can be suggested that areas destined for future evaluation should not be relinquished. A simple provision would be to require the relinquishment after year 10 of the contract. This would encourage companies to do all the evaluations in the first 10 years of the contract.

Recommendation # 10: It can be recommended that in the context of the phased development approach, Clause 6.1(b) of the Contract be amended to state that this clause applies upon the termination of year 10 of the Contract.

5.2 Commercial Production

It should be noted that a large number of the 25 blocks on offer are already producing petroleum. Yet, it is not clear from the contract how this existing production interacts with the Start of Commercial Production and the Development Plan approval.

Recommendation # 11: It can be recommended to include in the Contract a clarification that states that production in existence at the Effective Date of the contract can continue normally and that any production from Evaluation Wells can be produced prior to the approval of the Development Plan and qualifies as Commercial Production. This is in particular important with respect to Clause 11.2 of the Contract.

5.3 Time Lines for evaluation and development

In our first two reports we expressed concern about time lines. In onshore areas and particular with respect to small contract areas, time lines could be faster than in the offshore.

The following timelines now apply in the onshore:

- Clause 4.1: 90 days to submit and evaluation plan
- Clause 5.2: 120 days to submit a Development Plan after the evaluation period.

This timelines are reasonable for onshore operations, in particular if the phased approach to field development is adopted.

5.4 Timelines for bid preparation

The final version of the Onshore Model Contract will be available November 10, 2015. The bid date is December 15, 2015. This is reasonable for the smaller onshore ventures, carried out by smaller companies.

However, this matter will be a serious issue in the deep water bidding round, whereby large companies will need more time to decide on large investments.

6. COMPETITION FRAMEWORK

The new Bid Conditions now omit two provisions that were rather damaging in prior versions of the contract, which were:

1. Restrictions on working interest percentages, whereby Non-Operators could not have a higher working interest percentage than the Operator, and
2. Restrictions on amount of blocks that can be bid (5 for the First Shallow Water Bidding Round).

These two provisions have now been deleted. This is a very positive step.

However, two rather counterproductive provisions remain in the Bid Conditions:

1. Prohibition of consortia that include more than one company producing 1.6 mmboepd (III.4.1 (e)).
2. Prohibition for a company to participate in more than one consortium (III.12.2(c)).

6.1 Large company association prohibition

The large company association prohibition will not have much impact on the Onshore Bidding Round, since mainly small companies will be interested anyway. It is also unlikely that large companies would be willing to share the small value contained in most of the blocks on offer.

However, continuing this policy for deep water will have very damaging results for the interest in the bidding round. Therefore, the sooner this restriction is removed the better. It is therefore that our earlier recommendation remains.

<u>Recommendation # 12:</u> To delete the prohibition of consortia of large companies in section III.4.1(e) of the Bid Conditions.

6.2 Prohibition to participate in more than one consortium

The prohibition for a company to participate in more than one consortium does not make sense at all for the Onshore Bidding Round. This is particular in view of the large number of blocks on offer and the fact that these blocks are located in very different areas in Mexico.

In our April 15, 2015 report we already explained while this policy is contrary to the national interest and therefore it is not necessary to explain this again in this report. We continue to make the same recommendation.

<u>Recommendation # 13.</u> To delete III.12.2 (c) of the Bid Bases.

7. OTHER ISSUES

7.1 Relinquishment of Deep Formations

The Hydrocarbon Law includes the innovative concept of relinquishing deeper formations. This is a modern concept that is now increasingly necessary to promote the development of unconventional resources and deeper formations.

Clause 6 of the Onshore Model Contract does not include a relinquishment provision of deep formations.

The concept of deep formation relinquishment and possible subsequent bidding rounds for these areas, requires that the concepts of Field Areas or Appraisal Areas are no longer exclusive. Field Areas of shallower formations can overlap Field Areas of deeper formations. The same applies for Appraisal Areas. New Contract Areas may be created below existing Field Areas or Appraisal Area. This makes administration more complex.

Mexico will have a very significant challenge to establish the proper petroleum administration in the coming years. So it seems logical not to introduce right away the concept of deep rights relinquishment and delay this extra complication for later implementation.

The Contractor should be provided the reasonable opportunity to fully develop the Field in the Development Area.

<u>Recommendation # 14:</u> For these reasons, it can be suggested to include a Clause 6.3 in the Onshore Model Contract requiring deep rights relinquishment upon the termination of the initial term of 25 years.

7.2 Bid formula

The bid formula is the following:

VPO = 0.9 * Additional Royalty Factor + 0.1 * Additional Investment Factor

The Additional Investment Factor is furthermore limited by applying the following formula:

Additional Investment Factor = (2500 (Investment Increment))^0.5

In other words a proposed increase in investment of 100% results in an Additional Investment Factor of only 50%.

Finally, provision 17.1 (m)(ii) of the Bid Bases includes the somewhat absurd provision that a company is not allowed to offer more than a 100% increment in the work.

This means that the formula is excessively oriented towards the Additional Royalty.

As was concluded in our April 15, 2015 report, the bid formula suggests that the goal of the Government of Mexico is to squeeze every last dollar out of only the most profitable oil and gas reservoirs, without having a broader based strategy of developing the Mexican oil and gas resource base to the maximum benefit of the nation.

This bid formula is in particular highly detrimental for onshore areas were we have a large number of reservoirs stacked in the formations. In order to win the bid, companies will have to offer the highest possible additional royalty for the entire block. This means that the bidder will only consider the most profitable reservoirs in his bid and will take the decision that other reservoirs are not economic to produce under the high additional royalty. This means a significant loss of production.

The lack of a substantial work program benefit in the bid formula will also mean that the company can relinquish the entire contract area relatively easily without penalties after having completed the minimum work program.

This means if oil prices are less than expected or reservoir tests indicate less production than anticipated and further development of the area is not economic, it is easy to relinquish the entire block without penalties.

It is a widely accepted international principle that you cannot require an oil company to make investments in exploration and development in a block that are considered uneconomic by the investor (other than the committed minimum exploration or evaluation work program).

Therefore, the bid formula does not make sense if the goal of the Government of Mexico is to achieve the maximum benefit from its oil and gas resources through encouraging the maximum level of production.

The bid formula encourages over-bidding. Actually, the bid results of the first two bidding rounds are a strong indication that over-bidding did occur as a result of the bid formula.

Assuming that the Government does want Mexico to achieve a maximum benefit from its oil and gas, a re-balancing of the formula can be strongly suggested.

<u>Recommendation # 15.</u> To re-balance the bid formula as follows:

(1) Change the formula to:

VPO = 0.5 * Additional Royalty Factor + 0.5 * Additional Investment Factor

(2) Delete the Additional Investment Factor formula,

(3) Delete paragraph 17.1(m)(ii) of the Bid Bases, and

(4) Base the increment in work units simply on the percentage additional work units offered above the minimum required.

Based on this formula the bidder would be encouraged to offer a large number of additional work units, with the result of a more complete evaluation of the Contract Area in the first two years. The lower additional royalty factor would make more reservoirs economically viable.

7.3 Exploration

It was certainly a positive step to permit exploration under the Onshore Model Contract. A large number of blocks will have deeper and sometimes shallower formations that could be explored.

An important reason for a company to offer a high bid is if the bidder assumes that there is a good potential for discovery of new productive reservoirs in the Contract Area. It is difficult to understand what the advantage to Mexico would be of prohibiting an oil company to explore deeper and shallower formations and reservoirs.

It is a widely accepted international practice that companies are entitled to continue to explore areas under development and exploitation.

Therefore, it is counter-productive to make the exploration activity subject to a special approval by the CNH as in now the case in Clause 5.5 of the Onshore Model Contract.

The right to explore any part of the contract area should be inherent in the contract.

Recommendation # 16: It is recommended to include "Exploration" in the definition of "Petroleum Activities" and to clarify in Clause 5.5 that the contractor has the right to explore.

7.4 Significant Gas Discovery provisions

The Onshore Model Contract does not have a Significant Gas Discovery procedure after a possible discovery or after completion of the evaluation period. Yet, the Contract does contemplate LNG projects.

As stated in our previous report, Mexico needs more gas for its growing economy. Yet, due to the low gas prices at this point in time, the development of gas discoveries will be a challenging proposition. Often whether or not gas discoveries are commercial or not, can only be determined after commitment to pipeline and gas processing infrastructure are made. Also often several gas discoveries need to be combined to create a commercial project. It is for this reason that it is common to permit the Contractor to make a "Significant Gas Discovery". A significant gas discovery is a discovery that may be commercial subject to infrastructure and other discoveries.

After declaring a significant gas discovery the Contractor is typically permitted a certain time frame, say up to a maximum of 10 years, to evaluate whether such a discovery can be developed for the domestic markets or as part of an LNG or other project.

Recommendation # 17: It can be recommended to include in the Onshore Model Contract the possibility for a Significant Gas Discovery declaration and include a 10 year period for the evaluation of possibilities for the commercial development of such discovery.

7.5 Unitization provisions

Clause 8 of the Onshore Model Contract now includes a new clause regarding Unitization. This clause is not consistent with international practices and could cause major negative impacts on the petroleum operations of the Contractor.

The clause is written as if every reservoir that extends beyond the boundaries of the Contract area **has to be unitized.** This is not the case. Unitization is only required if a unitized operation is necessary in order to avoid damage to the reservoirs. If separate production of the same reservoir in two contract areas does not impact negatively on the recovery factor or the operating practices of the production operations than there is absolutely no need to unitize.

In Canada and the United States it is a widely accepted practice that unitization of reservoirs is not necessary among individual leases if there is no good industry practice to require such unitization. Most leases, often not larger than one square mile, are being produced without unitization of the common reservoirs.

The unitization process is a complex process that often requires years of negotiation. Therefore, one does not want to initiate such process if there is no need to do so. For the vast majority of the reservoirs under consideration in this bidding round in the 25 blocks unitization is not necessary for the effective and optimal production of these reservoirs.

It should be noted that several of the 25 blocks already have reservoirs that extend beyond the boundaries of the blocks. If Clause 8 would be maintained as currently written this would mean that Contractors would be obligated to unitize their operations with PEMEX, who holds the adjoining rights under allocations from Round Zero. PEMEX does not have the cash to actively pursue the development of the various contract areas, because, as described in our December report, the fiscal terms applicable to the PEMEX allocations in Round Zero (which appear in Title III of the Hydrocarbon Revenue Law) imposes a tough fiscal regime on PEMEX. Developing a unitized reservoir under different fiscal terms within the unit area will be a significant challenge to the joint venture that is created upon formation of the unit. This would create an instant development problem and would greatly diminish the value of the various blocks.

It can therefore be very strongly recommended to amend Clause 8 in a manner to only require the unitization process where this is required by Best Industry Practice as defined in the Contract.

<u>Recommendation # 18:</u> It is very strongly recommended to amend Clause 8.1 of the contract to only require the Contractor to start the process of unitization where Best Industry Practice requires the unitization of common reservoirs.

It should be noted that the Contract Areas under consideration are already very small. It should also be noted that most of the fields will be marginal undertakings. This applies in particular for fields with significant gas volumes. Therefore, forcing a unitization process on such fields in case reservoirs extend in open acreage would significantly deteriorate economics. It is for this reason that it can be recommended that if certain reservoirs extend beyond the Contract Area in open acreage that the main option that SENER should consider is simply enlarge the Contract Area to include such reservoir extensions.

<u>Recommendation # 19:</u> It is recommended to amend Clause 8.2 of the contract in such a manner that the main option to be considered by SENER would be to simply enlarge the contract area if reservoirs extend in open acreage and that other options are only considered where this is of important national interest.

7.6 Upstream vs Midstream lack of clarity

Since the earlier versions the Contract has been significantly clarified as to the operations permitted under the Contract and which operations are not permitted.

Commercialization Installations are now clearly downstream of the Measurement Point and not part of the Contractor operations. However, for greater clarity it can be suggested to include gas processing in Commercialization Installations.

<u>Recommendation # 20:</u> Include gas processing in the definition of Commercialization Installations.

The Model Contract continuous some to have some confusion about what is permitted in the petroleum operations and what is not. The definition of <u>Hydrocarbons</u> includes natural gas liquids.

A revised definition of <u>Net Hydrocarbons</u> was introduced which now requires all Hydrocarbons at the measurement point to be in commercially acceptable conditions.

In order to obtain natural gas liquids of commercially acceptable quality, or to obtain natural gas liquids at all, gas processing is required. Yet, gas processing is not allowed as part of the upstream petroleum operations. However, it may be that some deep cut separation in the contract area producing natural gas liquids may be permitted. So there remains some lack of clarity as to what operations can be precisely carried out under the contract.

<u>Recommendation # 21:</u> It can be recommended to review the Contract in more detail in order to precisely define what operations are permitted under the Contract and what are not.

7.7 Accounting Procedure

One of the most important advantages of a License Contract over a Production Sharing or Profit Sharing Contract is that the verification of costs in order to determine the Contraprestacion is not required.

Therefore, it is not necessary to have an Accounting Procedure under a License Contract.

Similar international royalty, additional royalty or production tax systems do not require an Accounting Procedure.

Therefore, it is somewhat baffling that the Contract maintains the requirement of an Accounting Procedure.

For certain purposes, such as statistical purposes or local content monitoring certain cost reporting may still be required, but this does not require a complete full scale Accounting Procedure.

Nor is there a need for heavy cost auditing and possibilities for terminating the contract if the Accounting is not properly carried out.

<u>Recommendation #22:</u> It can be strongly suggested to delete the Accounting Procedure (and adjust Clause 10 accordingly) and replace it with some simple cost reporting procedures where this is necessary for statistical and local content requirement purposes.

7.8 Procurement Procedure

For the same reason that Accounting Procedures are no longer necessary, the Procurement Procedure of Annex 11 is no longer necessary either.

These types of provisions are sometimes contained in a PSC in order to ensure that competitive costs are established for all major equipment and service items. However, there is no such need under a License Contract.

<u>Recommendation #23:</u> It can be suggested to delete the Procurement Procedure.