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By Adrián Lajous

OCTOBER 2015

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EXECUTIVE SUMMARY

The collapse in global oil prices since mid-2014 and the current price outlook have drastically affected the investment climate in the international oil industry. While the decline in oil revenues has naturally translated into pain for all major oil economies, for Mexico it has also complicated the energy reform plan, as energy companies are postponing upstream oil investments and exercising greater fiscal discipline. The first invitation to bid was a major setback for Mexico's reform effort, as the fourteen shallow-water exploration blocks on offer did not incite much interest and only two blocks were allocated in the end. The second auction for shallow-water development blocks showed better results. Given the difficulty of the current environment, it is critical that Mexico's government take time to examine the lessons that can be gleaned from this experience and move carefully in the bidding process for oil fields open to foreign participation to ensure that it creates maximum long-term benefit. The auctions for the extra heavy oil and deepwater acreage will be far more important to Mexico than the much smaller bidding rounds seen so far this year.

Critically, the Mexican government must be highly selective in the acreage that it will bid out in the coming months, cautiously sequence and pace tenders, and carefully consider a number of deferrals. Many projects with high break-even prices will only be viable after the market rebalances and begins to recover. Government authorities and Pemex should explore the consequences of alternative courses of action regarding proposed farmouts and contractual conversions, as well as open invitations to bid for their hydrocarbon resources. Amid any changes, however, the government must clearly and firmly reiterate its commitment that the reforms will continue. This paper expands upon these points and examines other ways in which Mexico can adapt the reform process to the current realities of the oil sector to obtain the maximum benefits from the oil upstream auctions that will lead to farmout agreements with private oil companies, as well as the conversion of existing integrated exploration and production service contracts, and financed public works service contracts, to new production sharing agreements.

In short, the paper finds:

- The government should make a rigorous postmortem evaluation of the first two bidding cycles. It should take into consideration the effect of allowing Pemex to place bids and then withdraw them at the last minute in the first auction, as well as the impact of modifying a number of bidding guidelines and contractual clauses that were questioned by private parties, and critically, the loss of appetite for exploration risk under current market conditions. However, it should go forward with the next leg of the Round 1 bidding process on December 15, 2015, for onshore acreage, which could provide additional information that may help decision-making for the next tenders, which are more important for Mexico.
- Projects at the higher end of the global cost curve, including a significant part of the assets that Mexico will put up for bid, are at greater risk of being deferred in the current oil price environment. If Mexico is to go ahead with opening them up for bid at the present time, it must have evidence that these assets are economically more attractive than other global projects due to lower costs, greater expected production volumes, better contractual terms and conditions, or lower government take.
- The fourth bidding round announced in August 2015, which includes ultra-deepwater blocks, deepwater natural gas assets, and extra-heavy offshore oil fields, Pemex farmouts, and contractual conversions, is startling in size and will find Mexico competing against itself in a highly constrained market. It would be far more prudent to separate these very different and critical assets into a well-ordered sequence to test the market, better understand market conditions, and learn from each new invitation to bid.
- It is crucial that the open bidding process and potential farmouts—which would allow Pemex to take on joint venture partners to develop fields into which it has already sunk substantial capital resources—are logically sequenced to ensure maximum results. Deepwater and extra-heavy crude farmouts must be appraised in conjunction with other properties that will be put out to bid in Round 1. Given their vicinity, potential common infrastructure, and similarity, their value might be affected positively by either joint operations or joint planning.
- In addition, defining who may be the operator in farmout agreements is a key decision that will have to be resolved. Ownership, control, and other governance issues have to be dealt with as contracts are structured and guidelines for shareholder and operating agreements are adopted. These have to be attractive to investors in order to incent them to participate in the bidding of these production sharing contracts.
- In cases where the government has also authorized Pemex to convert some of its current service contracts to production sharing agreements in order to better serve the interests of both parties and to share some of the same benefits to be derived from the proposed farmouts, a fair market value should be attributed to existing contracts.

INTRODUCTION

One of the central objectives of the energy reform underway in Mexico is the opening to competition and private investment of its upstream oil and gas industry, thus breaking up a state monopoly that was established seventy-seven years ago. However, Pemex, the national oil company, will continue to play a dominant role in this industrial sector if it effectively manages to become internationally competitive. The Mexican government has structured a five-year, three-round bidding program for a large, diverse and rich portfolio of exploration and development blocks, both offshore and onshore. Three invitations to bid have been made in the first round, and at least one more is expected this year. Two other invitations have been deferred given current market and oil industry conditions. Prior to Round 1, the government granted Pemex an initial allocation of exploration and production rights to continue with its activities in Mexico, representing 85 percent of the country's proved reserves and 20.6 billion barrels of oil equivalent (billion boe) of proved and probable reserves (2P) in what was called Round 0. Entitlements also included 23.4 billion boe of prospective resources for its exploration activities. The government may assign, on an exceptional basis, additional exploration and production areas to Pemex. However, other acquisitions will be subject to competitive bidding.

One major factor complicating Mexico's reform effort has been the collapse of oil prices that began in the middle of 2014. The effect of low prices has been mainly appraised in terms of the oil revenue levels attained by major resource holders and oil companies, focusing on the depth of the fall. As the period of low prices has extended, concern has grown with respect to their volatility and, more importantly, to the length of the time they might remain at $50 per barrel or less. Interest has also been shifting to the evaluation of the impact of prices on upstream investment flows and eventual production capacity. Mexico illustrates these changes. Initially it was thought that the government's oil revenues were well protected and public finances could absorb the price shock with a certain degree of ease, given the country's relatively diversified economic structure and vast 2015 and 2016 oil hedging programs. More recently, as the preparation of the 2016 government budget advanced, concerns grew due to short- and midterm oil price expectations, the cost of the new hedging program, higher interest rates, and exchange rate depreciation.

Although the government hedged a large part of its oil revenues, Pemex has seen its oil revenues fall dramatically. Its consolidated 2016 operating and capital budget has been reduced 14 percent with respect to the authorized 2015 level. As its net debt continues to increase, Pemex faces serious short-term liquidity problems. These explain the payment delays to contractors. More importantly, cuts are concentrated in its capital budget, given the more limited discretionary leeway of operating expenditures. These painful cuts will necessarily affect productive capacity. However, data in the public domain in mid-September does not allow for a precise assessment of expected capital expenditures. These reductions highlight the importance of farmouts and contractual conversions as a source of additional revenues or lower Pemex expenditure requirements.

Crude oil production in the first three quarters of 2015 was down 8 percent; net natural gas production was down 7 percent in the same period; gas flaring has doubled; and a number of accidents have impaired upstream activities. Conditions in the downstream are not better. Gasoline output was down 11 percent in the first 7 months of the year, diesel fell 6 percent and high sulfur heavy fuel oil 14 percent. Pemex reduced throughput in its refineries because of excess inland supplies of fuel, which cannot be easily transported to export terminals, and increasing difficulties in meeting gasoline specifications. Accidents and downtime due to unplanned maintenance are up and gasoline stock-outs in the Bajío region in Central Mexico and in the North of the country have been exceptionally long.

The government's medium term oil production forecasts have been recently adjusted down to more realistic levels but are still at risk, given Pemex' financing issues. The 2018 production goal is now only 38,000 barrels per day (b/d) above the current 2015 level of 2.26 million b/d. In 2020 the government now foresees production of 2.5 million b/d. Other field-by-field estimates do not support such a recovery

in this time frame. Low production levels, combined with low prices, will generate additional pressure to bid out acreage irrespective of market conditions. This might be particularly harmful in the case of ultra deep-water assets in the Perdido Foldbelt. Unless there is a substantial reduction in costs, or a number of specific advantages related to these fields, exploration and development will not be carried out at current prices or would only advance at a very slow pace. Government officials are giving themselves little time to reflect on these very complex issues. Overconfidence in their own capacity, lack of experience, inadequate advice, unrealistic objectives and bad timing have all conspired to limit Mexico's upstream opening to private investment in the current juncture.

It is worth noting the complexity of the outlook for oil prices at this time. A fundamental transformation of the oil price regime may be underway. The role that OPEC has played in balancing the oil market is rapidly evolving. The Saudis' refusal to continue to be the marginal supplier of crude is modifying global market dynamics. By adopting a strategy that stresses the production of lower-cost oil first, high-cost sources are losing the protective shield that had been provided by OPEC. The international oil market is entering uncharted territory. It is difficult at present to imagine possible contingencies that market actors will have to face, the actual path that will be followed to the new regime, or the disruptions that the transition might entail. The Saudi strategy will continue to adapt to new circumstances. However, a return to its traditional market-balancing role seems unlikely any time soon, although it cannot be totally excluded.

In the near future, greater unease is bound to arise regarding potential international investment in the Mexican upstream sector. If prices are expected to remain low for a longer period, competition in Round 1 bidding might suffer and government take would tend to be further compressed. This would be a devastating blow for the budding Mexican energy reform. At the present time, multiple dilemmas demand enlightened resolution, and optimism can only be found if a longer-term view is adopted.

The new hydrocarbon legislation proposes two concomitant tracks for private investment in the upstream: 1) Pemex joint ventures, often referred to as farmouts, for selected exploration and development areas assigned in Round 0; and 2) the conversion of existing integrated exploration and production service contracts, and financed public works service contracts, to production sharing agreements. In this paper, the three private investment modes are discussed in their respective sections and the main conclusions are presented in a final one. The results of the first and second invitation to bid are analyzed and the remaining call for bids is discussed. They call attention to the timing and sequencing of the Round 1 assets. It is assumed that the government has decided to delay bidding on Chicontepec and unconventional resource plays for now. This allows more concentrated focus on three other asset groups: the Perdido Fold Belt, deepwater natural gas, and extra-heavy shallow-water crude. Pemex farmouts are reviewed, and stress is put on the interaction of these assets and other fields to be bid in Round 1, which requires a certain degree of joint planning and, possibly, joint operation. A last section covers issues relating to the conversion of service to risk contracts.

FIRST BIDDING ROUND

SHALLOW-WATER EXPLORATION BLOCKS

The first round of bids for Mexico's upstream was divided into several different auctions based on the type of fields on offer. The first invitation to bid in July 2015 was a major setback for Mexico's reform effort, as its fourteen shallow-water exploration blocks did not incite much interest, with only two blocks allocated in the end. Overall, there were only seven bidders. Eight blocks did not receive tenders, one block received five bids, and another received two. Six bids were below the minimum level required by the Treasury Department (SHCP). A couple of weeks before the bid date, the Department of Energy (Sener) hedged its expectations regarding the number of successful bids, anticipating that it would be satisfied if it was able to assign between four and seven blocks. Even with the lower expectations, the results were frustrating, to say the least.

Mexican authorities are still trying to untangle and understand what happened in the first bidding process. They do not appear to have engaged in a formal and rigorous postmortem evaluation, and in any case, if they did, the results have not been released. It is important for Mexico to take a more realistic view of the prospectivity of the blocks that were offered, to understand the effects of allowing Pemex to bid and then having it withdraw at the last minute, as well as the probable impact of a number of bidding guidelines and contractual clauses that were questioned by private parties. Critically, there must also be a better understanding of the appetite for exploratory risk under current oil industry conditions. This appraisal is not an easy task, but it is imperative before proceeding with further bids.

Government authorities would be well advised to embrace a certain dose of skepticism when dealing with recommendations for greater pragmatism, which are limited to demanding better terms and conditions for contractors. They should also show prudence with respect to the blind fatalism that simply argues for accepting market results, whatever they are.

The main factors that limited interest in the Round 1 bids are cyclical and structural. A fundamental change of circumstances took place after this round was announced on August 14, 2014, when Brent crude was still trading at $102 per barrel. The sentiment about oil prices was drastically different then; the US rig count had not yet begun its spectacular drop, and importantly, the first upstream investment surveys that forecasted a significant fall in 2015 and 2016 capital expenditures had yet to be released. Such reports did not appear until the beginning of 2015. Currently, expectations are for a drop of more than 20 percent in exploration and production spending by listed companies in 2015. The deferment of deepwater and ultra-deepwater projects is a more recent event. Drilling of nonconventional resources continues to fall. North American shale expenditures this year are expected to decline by 40 percent. Ominously, in August 2015, the Western Gulf of Mexico lease sales attracted the lowest number of bids since the inception of this program. It included leases in the Alaminos Canyon, close to the Mexican border, in the Perdido Fold Belt, which straddles US and Mexican territory and is considered an important reference for what are perceived to be the richest assets of Round 1. Also, last August's failed Peruvian bidding round is a disturbing sign. In addition to these factors, employment in oil service companies has contracted severely, revealing the deep fall in upstream investment. By January 13, 2015, Brent was trading at $45 per barrel, before putting in fresh 2015 lows under $42 per barrel in August. Oil market conditions continue to deteriorate, as well as the investment climate in the industry. Inventories are at a very high level, and the risk of lower crude oil price is not negligible. In short, the timing of the Mexican invitations to bid could not have been worse.

In February and May of this year, two additional bidding invitations were made. One relates to five development contracts in shallow waters, which include nine fields, and the other encompasses twenty-six mature fields that are in an advanced stage of depletion, many of which were abandoned by Pemex years ago. The first of these bids is for production sharing contracts. The second one, designed to attract Mexican operators, involve licenses. In both cases, individual assets are not materially important, especially those in the onshore package. The CNH expects a peak production of 90,000 b/d from the second tender and 35,000 b/d from the third bid cycle. These numbers are a small fraction

of the expected decline in Mexican oil production. Bidding guidelines, contractual clauses, and fiscal and economic terms for the second invitation to bid were modified to accommodate observations, clarifications, and requests posed by potential contractors, as well as the authorities' tentative conclusions with respect to the first bidding process and the deteriorating industry outlook in the current low oil price environment. A fifth set of modifications was announced on August 25, 2015. The thrust of these changes is unequivocal: they are geared to make terms and conditions more attractive and investor-friendly to incentivize participation. Many of these modifications apply to the third bidding invitation. They cover a very wide range of topics. What is missing from the changes is a detailed set of arguments explaining why they were introduced and why previous terms and conditions were found to be an inferior solution. The CNH only refers to the adoption of best international contractual practices without specifying what they are referring to.

SHALLOW-WATER DEVELOPMENT BLOCKS

At the beginning of September 2015, the minister of energy declared that placing two (out of five) shallow-water development contracts would be a good result for the September 30 bidding round. His political concern regarding the outcome of this call for bids is understandable, particularly after the outcome of the previous auction. However, the signals he sent to the market with this statement were not positive and could have had undesired consequences. In mid-September, the government disclosed the minimum acceptable profit share just two weeks before the submission of the shallow-water development bids, further communicating its own expectations. In the previous exploration bidding process, these levels were not made public beforehand. Such an announcement could have created the risk that the bids would cluster around a lower level than what they might have been otherwise. Surprisingly, minimum acceptable profit share values fluctuated between 30 and 36 percent. These are lower than the ones adopted in nine exploratory blocks (of fourteen) in the first invitation to bid, especially considering that the ones in the second invitation were development blocks with certified reserves, where geological risks are much more limited. The other bidding variable—the minimum value of the proposed increments with respect to the minimum work program—was set at 0 percent, eliminating this variable in practical terms. However, a maximum of 100 percent was set.

The government also improved fiscal terms and relaxed a number of contractual restrictions. The internal rates of return thresholds for the return-based adjustment mechanism were increased. The lower pretax internal rate of return threshold grew from 20 to 25 percent, and the higher threshold from 35 to 40 percent. Given relatively low development costs in these shallow-water assets, potential returns seem attractive under a number of price and government profit share scenarios. Contractors that participated in the second bidding invitation also benefit from exploring different geological formations within their respective blocks. In addition, evaluation periods were extended from two to three years, and some significant contractual restrictions were moderated. Contractor reporting obligations and the level of corporate guarantees have been modified. Limits on the number of bids that the contractor can place in a specific call for bids were eliminated, as was the obligation that the operator must hold the highest share in a consortium, and operators may freely bid individually or as part of a consortium. After having conceded all of these enhancements to incentivize contractor participation, it would have been embarrassing for the government if it only attracted a small number of bidders and if their bids were placed close to the minimum acceptable levels.

The results of the second invitation to bid on acreage for Mexico's oil upstream were made public in what was an exceptionally transparent process. Government officials are rightly proud of this and are happy with the results of the bidding process, with three of the five contracts auctioned (Table 1). Two contracts elicited significant competition, with one attracting nine bidders and the other five. A third contract only received one bid. The government's profit share of the winning bids was much higher than anticipated, as was, in one case, the expenditure commitment above the minimum work program.

The profit share offered by the three wining bidders was 84 percent, 74 percent and 70 percent, respectively. The Ministry of Finance may be a bit embarrassed having set exceptionally low minimum acceptable bid values. They are now obligated to explain the assumptions that led the government to fix such levels for what were low cost, shallow-water fields with certified reserves. Fortunately, the bidders paid little attention to the minimum bid levels as their offers were two or more times higher than the set minimums.

Table 1: Results of Second Bidding Round

Amoca/Mizton/Tecoalli	
Minimum bid:	34.8%
Winning bidder:	ENI (83.8%)
Other bidders:	8
Lowest bid:	Talos/Sierra/Carso (48.0%)
Bid average:	54.4%
2P Reserves:	121.6 Mboe
Hokchi	
Minimum bid:	35.9%
Winning bidder:	Panamerican/Bridas (70.0%)
Other bidders:	4
Lowest bid:	CNOOC (50.2%)
Bid average:	62.0 %
2P Reserves:	66.7 Mboe
Pokoch/Ichalkil	
Minimum bid:	33.7%
Winning bidder:	Fieldwood/Petrobal (74.0%)
Other bidders:	0
2P reserves:	85.8 Mboe
Misón/Nak	
Minimum bid:	35.2%
Winning bidder:	---
Other bidders:	0
2P reserves:	63.9 Mboe
Xulum	
Minimum bid:	30.2%
Winning bidder:	---
Other bidders:	0
2 P reserves:	17.7 Mboe*

* Has not yet booked 1P reserves.

Low government expectations were the result of the reading made by public officials of the disastrous first invitation to bid. They reacted by modifying contractual terms and conditions, fiscal terms and bidding guidelines in the second bidding process, in order to make them more investor friendly. Some, but by no means all, were needed improvements. It could be argued that the Mexican officials did not fully comprehend the very different risks involved in exploration and development contracts and, more importantly, the low prospectivity of the exploration blocks that were first put to bid. Their mistaken diagnosis was more generally conditioned by the need for additional government revenues and foreign investment flows. Also, the low threshold of the government's definition of success was politically motivated, as it sought to protect itself from expectations that might not be realized.

Despite the results of the bidding round, it is worth mentioning that important pre-qualified oil companies—Shell, Chevron, ONGC, CEPSA and Plains—dropped-out at the end. Of the three winning bidders, only ENI is a substantial oil company with worldwide experience. Panamerican/Bridas is a regional Argentine oil consortium and Fieldwood/Petrobal is a consortium formed by a US financial portfolio company and a recently established Mexican oil company owned by billionaire Alberto Bailleres, who chairs a diversified conglomerate. First production of the three contracts is expected in the second half of 2018 and an aggregate peak production of 90,000 b/d could be reached three years later. Given minimum work programs, total capital expenditures are estimated around $3 billion over the life of these projects. Production costs are assumed to be $20 per barrel, so that they are economically viable at current and even lower prices.

The results of the second invitation to bid should have a positive impact on future upstream auctions. The third one, although open to international competition, is directed to medium and small Mexican companies. There appears to be ample interest in this bidding process. The fields that will be auctioned are mostly depleted and have been abandoned by Pemex. They are not materially important. More interesting will be the fourth auction, which will probably include shallow water extra-heavy crude oil fields, as well as a number of adjacent Pemex farmouts. Invitations to bid for these assets should be made at the end of October or in early November 2015. Ultra deep-water oil fields might have to wait until early 2016. These are high cost, large-scale complex projects that are unequivocally affected by international market and oil industry conditions.

FUTURE AUCTIONS

The results of the first auctions should offer additional insights that might help government decision-making in the next tenders, which are much more important for Mexico. One of the major flaws of the very tight bidding calendar is that it does not allow the government to derive relevant lessons from one bidding cycle to the next. This learning process is particularly important, given the understandable lack of experience in managing this type of auction in Mexico. Although there have been some minor delays in the process, these have not offered sufficient time to reflect on the results of the first and second bidding invitations, assimilate the information generated up to now, or have a fuller understanding of changing oil market and investment climate. The desire for short-term results marked the original calendar. A sense of utmost urgency was unwarranted, as was the anxious avidity for substantive quick wins. They were not good guides for a long and complex reform effort. Initially the Treasury Department expected almost immediate results from the announcement effects of substantial foreign investment flows triggered by energy reform, as well as significant increases in government oil revenues. It took time to come to the realization that these benefits would mature and be reaped much more slowly, practically all of them in the next administration. Significant lags are naturally bound to appear in the buildup of investment, cost recovery, production, and government revenue.

Projects that face greater risks in the current lower oil price environment are those placed high on the global cost curve, the more expensive plays. Canadian oil sands, US shale and tight oil, as well as Gulf of Mexico, West African, and Brazilian ultra-deepwater projects stand out. While projects with significant sunk costs will most likely move forward, many projects that still lack a final investment decision will likely be deferred. In Mexico, a significant part of the assets that will be put up for bid is in this class, including Perdido, close to the US maritime border, as well as high-cost natural gas in deep waters and unconventional oil and gas resources. In the United States, these types of projects are at risk of being postponed. If Mexico is to go ahead with them at the present time, it must have evidence that its assets are economically more attractive than the US projects because of lower costs, greater expected production volumes, better contractual terms and conditions, or lower government take. Alternatively, potential bidders must see a high strategic value of these assets, the outlook for market conditions must become more bullish, or the financial constraints that are limiting investment by international oil companies must relax. In the next section, some of these projects are analyzed in connection with Pemex's farmouts due to their strong linkages.

Special reference must be made with respect to the Chicontepec Basin, which holds a large proportion of Mexico's 2P and 3P reserves. The government has apparently deferred bidding on these assets. Chicontepec is close to being classified as a nonconventional asset. Pemex never managed to characterize these resources adequately nor give a clear definition of the engineering work required for an economically efficient exploitation. Pemex's failure in this region is well documented. Under these conditions, bids would likely come in very low and the interest of private investors will be limited. There are other options that could enhance the value of these assets without allocating massive funds. At this stage, knowledge development, experimentation, and innovation should be prioritized and not production results. The government must recognize that this long-term project cannot harvest significant oil revenues in the present decade or the beginning of the next.

A more difficult decision is the development of extra-heavy crudes located close to the Ku-Maloob-Zaap complex in shallow waters. These fields are part of the fourth invitation to bid. It would be wise to further postpone the publication of the bidding guidelines to later in the fall, after the results of the second invitation to bid—also a development project in shallow waters—are fully appraised. In this area, Pemex discovered and is developing a giant field, Ayatsil, in which it has sunk significant investment. Exploiting this field and its adjacent reserves will not be easy because of their high sulphydric acid (H_2S) content, which needs a totally segregated, high-specification infrastructure that can better resist corrosion. The development of these fields will also require a floating production, storage, and offloading vessel (FPSO) and blending facilities to move the extra-heavy oil to market.

On August 28, 2015, Mexico's Department of Energy announced that the fourth invitation to bid would simultaneously include ultra-deepwater oil blocks, deepwater natural gas assets, extra-heavy offshore oil fields, Pemex farmouts, and contractual conversions. A new date has not been set. The size of the package is startling. It is also imprudent. Mexico would be competing against itself in a highly constrained market. The government should structure and separate these very different and important assets in a well-ordered sequence to test the market, better understand prevailing conditions, and learn from each new invitation to bid. It must also consider the possibility of deferring the bidding on some of these assets for better times. In any case, further invitations to bid should be postponed until late in the fall, after the results of the shallow-water development bids are fully appraised, as well as the early October results of the thirteenth Brazilian round.

PEMEX FARMOUTS

The Mexican government has given Pemex permission to farm out a number of fields in which it has sunk substantial capital resources. This move recognizes the investment Pemex has made in past exploration and production efforts, and allows for the partial monetization of these assets through the contribution by third parties to future capital and operational expenses. It also allows for the transfer of technology, know-how, and managerial skills to Pemex along with the learning benefits derived from joint venture operating experience in upstream projects. The underlying general purpose of the farmouts is to obtain incremental volumes of crude oil and natural gas more rapidly, by sharing both risks and returns with private parties, and raise much-needed capital.

As unequivocally set by law, Pemex must adopt the new form contracts issued by the Department of Energy, as well as the economic and financial terms and conditions set by the Treasury Department. The new contracts will be subject to an open bidding process managed by the upstream regulator (CNH). Pemex needs to provide the Department of Energy with a favorable opinion regarding the technical bidding guidelines pertaining to farmouts and offer its opinion to the CNH with respect to the qualifications of potential partners. Pemex must also propose a joint operating agreement consistent with key terms and conditions provided by the Department of Energy, which would be included in the bidding documents. This is an awkward arrangement. Acquiring a joint venture partner through a bidding process is unusual in the oil industry. However, Congress defined this when it passed the new hydrocarbon law. These cumbersome procedures are dictated by the precedence given to transparency in upstream bidding and contractual matters. All players are well aware that any doubts regarding the probity of the process could derail energy reform.

A new fiscal regime is applicable to the new contractual arrangements that govern exploration and production activities conducted in Mexico. The hydrocarbon revenue law establishes the fiscal terms to be applied to the contracts granted by the Mexican government to Pemex and other companies in connection with competitive bidding rounds. The operation of assets granted to Pemex in Round 0 is subject to the old tax regime and does not qualify for the new regime before the assets migrate to the new contractual framework. The introduction of the new tax mechanisms will be selective and gradual, given government revenue requirements. Effective tax rates under the new regime are lower than in the old one. Also, in the old regime, tax rates are applied to revenues, while the new one is basically profit based. As such, these fundamental changes constitute a very strong incentive in favor of farmouts and contractual migration. It is difficult to understand why Pemex has not promptly presented its proposals, complied with governmental guidelines and legal provisions, and proceeded with a greater sense of urgency in structuring the new contracts and partnerships.

Pemex may enter into fourteen farmout arrangements in a total of fourteen specific oil and natural gas fields, as authorized in Round 0. The portfolio is an attractive one. It is diverse and materially important, as can be seen in Table 2. It includes mature onshore and shallow-water producing fields with relatively high reserves-to-production ratios, as well as other fields being developed that contain extra-heavy crudes, also in shallow water. However, those in ultra-deep waters will probably attract special attention because of their vicinity to the United States. Although they have significant 3P certified reserves, proven and probable reserves have not yet been booked in the Mexican Perdido Fold Belt. Finally, two significant natural gas fields in deep water are included. At current prices they are probably not competitive, although they should benefit from the infrastructure being built for a sister field being developed near Coatzacoalcos, in Southern Veracruz. Overall, these fourteen properties have 2P reserves of 1.7 billion boe. In late July, Pemex announced its intention to apply for additional farmout authorizations. Apparently the list now includes the Tsimin, Maximino, and Samaria, all of them major fields.

Table 2: Pemex: Round 0 authorized farmouts, reserves, crude type, and block size, December 31, 2014

	Area		Reserves (Million boe)	
	(Km2)	ºAPI	1P	2P
Onshore				
South				
Cárdenas	82.7	40.5	64.8	80.6
Ogarrio	147.9	38.0	48.9	66.8
Mora	52.3	38.2	44.2	49.9
Rodador	23.6	35.0	15.0	19.5
Offshore				
Shallow Water				
Ek	16.6	19.5	113.0	203.2
Sinán	68.1	31.6	73.7	138.5
Bolontikú	34.7	35.0	49.0	78.0
Deepwater				
South				
Kunah*	21.2		0.0	184.9
Piklis*	33.7		0.0	111.4
Perdido				
Trión**	22.4	26.9	0.0	0.0
Exploratus**	12.7	31.0	0.0	0.0
Extra-Heavy				
Ayatsil	59.5	10.5	316.2	567.7
Tekel	16.4	10.0	60.3	136.1
Utsil	12.8	9.5	26.8	46.7
Total	**604.6**		*811.9*	**1683.3**

Notes: *Natural gas. ** Only 3P reserves: Trión 280.4 and Exploratus 513.8.

Source: Sener, Plan Quinquenal de Licitaciones para la Exploración y Extracción de Hidrocarburos: 2015–2019, http://sener.gob.mx/res/index//plan/Plan Quinquenal.pdf.
Sener, Ronda Cero, Documento, Ficha Ejecutiva de Asociaciones de Pemex, http://www.energia.gob.mx/webSener/rondacero/_doc/Ficha_tecnica_asociaciones.pdf.

The joint sequencing of the open bidding process and potential farmouts is crucial. Deepwater and extra-heavy crude farmouts must be appraised in conjunction with other properties that will be put out to bid in Round 1. Given their vicinity, potential common infrastructure, and similarity, their value might be affected positively by either joint operations or joint planning. Interactions, externalities, and synergies might pose complex issues in a competitive process. Although similar terms and conditions will be set for both mechanisms, critical decisions must be finalized. Pemex has made significant drilling investments in the Perdido area. It has also drilled a number of deepwater wells in natural gas fields in the Southern Gulf of Mexico and begun the construction of infrastructure in nearby gas processing facilities. Offshore in Campeche, Pemex has drilled a large number of shallow-water wells in extra-heavy oil fields and is putting in place the infrastructure for three of these fields.

Defining who may be the operator in farmout agreements is a key decision that will have to be resolved. It is not only a managerial prerogative under current legislation but also a policy matter. The objectives of forming joint ventures with Pemex must be explicitly spelled out. Ownership, control, and other governance issues have to be dealt with as contracts are structured and guidelines for shareholder and operating agreements are adopted. These have to be attractive to investors in order to incent them to participate in the bidding of these production sharing contracts. Why would Pemex aspire to remain the operator if it wants to draw in private capital and also acquire technology, know-how, and managerial capabilities? Would it be content to be the formal operator but effectively transfer this role to private parties? Would it only seek a financial partner? If Pemex holds a majority share in the joint venture and continues to be the operator, turning around the management of these assets may prove to be difficult and relations with the Pemex trade union with respect to these fields would not be easily modified. It may also forgo larger injections of capital. The government will need to have clear views on these issues, come to an agreement with Pemex, and draw in private investments to these farmout bids. Pemex still aspires to be the operator in some of the fields to be farmed out. It might be tempted to partner with financial institutions instead of industrial companies. Given its track record, Pemex would clearly benefit from direct access to upstream industry experience in large, complex projects.

Pemex holds four commercial deepwater discoveries in the Perdido Fold Belt in the Gulf of Mexico. It has been authorized to farm out two of them—Trion and Exploratus—but might ask for an additional government authorization in the area for Maximino. These fields are located close to Shell's Perdido spar that serves as a hub to the Great White, Tobago, and Silvertip fields in US waters. Currently it is the deepest oil and gas production and drilling platform in the world and is connected to a pipeline system through which crude is evacuated. These facilities make Shell a natural partner for the development of adjacent Mexican fields but creates increasingly complex issues in the design of the bidding process, as competition issues are bound to arise. The government must decide if the three Pemex fields are to be farmed out in Round 1 and if they will be part of one or two different contracts. At the end of 2014, estimated 3P reserves of these fields were more than 1 billion boe.

The extra-heavy offshore crude oil fields in Campeche Bay pose unique technical, economic, and commercial challenges. There are few analogs to such large offshore developments of these types of crudes, with a gravity range of 14º to 8º API. Additional issues arise as fields will be bid out under both farmout and open bidding arrangements, issues that go beyond the question of sequencing. As can be seen in Table 3, four fields dominate because of their size: two—Ayatsil and Tekel—are to be farmed out, while the other two—Pit and Kayab—will be subject to open bidding. These four fields contribute to more than 80 percent of 2P reserves. There are ten other much-smaller satellite fields. However, current estimates of 2P reserves are bound to change as delimitation wells are drilled; Kayab could well turn out to be the largest. It will be particularly interesting to see how these assets are bundled into different contracts in the bidding documents and if the fields to be farmed out form a single package. Other concerns will center on the limitations, if any, regarding the number of bids that a single operator may win and bidder qualifications relating to its experience in producing and handling extra-heavy crudes with high H_2S content.

Table 3: Mexico: Extra-heavy crude oil fields to be farmed out by Pemex
(Million barrels of oil equivalent)

	Area* (Km2)	Gravity (ºAPI)	Reserves on December 31, 2014 P	2P	3P
Farmouts	**88.7**		**403.3**	**750.5**	**855.0**
Ayatsil	59.5	10.5	316.2	567.7	592.8
Tekel	16.4	10.0	60.3	136.1	158.2
Utsil	12.8	9.5	26.8	46.7	104.0
Open bids	**412.5**		**335.6**	**797.1**	**1, 948.8**
Pit	61.6	10.8	151.3	313.5	461.9
Kayab	80.9	8.6	184.3	231.7	889.4
Kach	32.9	13.0	0.0	66.4	95.7
Baksha	20.8	9.6	0.0	43.1	43.1
Alak	23.3	14.0	0.0	42.4	51.0
Pohp	45.7	8.0	0.0	34.4	94.0
Mene	18.4	8.0	0.0	25.5	25.5
Tson	32.8	8.2	0.0	24.3	76.1
Chapabil	60.9	10.0	0.0	15.9	153.2
Kastelán	15.2	13.0	0.0	66.4	95.7
Zazil-Ha	20.0	9.0	0.0	0.0	18.9
Total	**501.2**		**738.9**	**1,547.6**	**2,803.8**

*For the fourth invitation to bid, the area allocated is the size of the blocks. As to the farmouts, it is the current area assigned to Pemex.
Source: Sener, op. cit., Table 1.

In the first half of 2015, farmout projects did not noticeably advance in spite of Pemex's pressing liquidity needs. When the results of Round 0 were made public, it was thought that the farmout projects would move forward swiftly, contributing to incremental production gains and giving Pemex a much-needed cash injection or reducing its investment and operating expenses. However, it appears that Pemex and the federal government differed on a number of issues regarding implementation. This resulted in an impasse that begs for resolution. It was clear from the beginning that both farmouts and service contract transition implied greater complexity than the straightforward open bidding process carried out by the government. However, Pemex and the government clearly underestimated the problems that would arise and the nature of the cooperation that was required.

Pemex initially believed that it would be allowed to directly negotiate production sharing agreements with potential upstream joint venture partners and acted accordingly. Once Pemex realized that this was not the case, it postponed engaging with the government on these matters. More recently Pemex explored conceptual alternatives, called synthetic farmouts, by which it would formally be the operator and, through creative contractual arrangements, partner with other financial and industrial firms that would absorb part of the risk. At the end of July, Pemex announced that it had sought government approval for eleven of a total of sixteen farmout projects. The remaining five are deepwater assets that will be submitted in September. It was not until September 7 that Pemex requested formal authorization for the migration from Round 0 licenses to exploration and production contracts, a pre-requisite for farmout auctions. On September 22 and 24 the CNH gave its favorable opinion to the proposed migration of ten contracts.

Pemex, as well as a number of other large oil companies, has seen its credit ratings come under review by credit agencies. Low oil prices have undercut cash flow generation and resulted in rising balance sheet leverage. Further deterioration is expected next year. Pemex has been increasing its debt for a number of years and will have larger borrowing needs in the near future. The Mexican government will not be able to provide additional equity capital or reduce taxes significantly. The Treasury Department has been alerting the public that substantial overall budgetary cuts are inevitable in 2016 in order to maintain macroeconomic balances. Under these circumstances, a Pemex credit rating downgrade is likely, but given its linkages with the government, it might only be limited to a notch. Farmouts are an attractive option in this context. However, it is critical to realize that net cash flows to Pemex will not be immediate.

CONTRACTUAL CONVERSIONS

The government has also authorized Pemex to convert some of its current service contracts to production sharing agreements, in order to better serve the interests of both parties and to share some of the same benefits to be derived from the proposed farmouts. The main stumbling block has been the valuation of current contracts, as no bidding is involved. A fair market value should be attributed to existing contracts. However, the conversion option should not negatively affect expected state revenues under existing contracts. Meanwhile, Pemex has selectively restructured original partnerships. The value of the transactions has not been revealed nor their eventual impact on contractual valuations when conversion takes place.

Reasonable and balanced solutions can be given to proposed contractual conversions. Convergence of both parties' interests should allow for additional investment and production. Valuing the contracts will not be easy, but it can be done. Some partners will prefer to continue work under current contractual conditions. In some cases they are close to their termination dates. Although there are clear advantages in transitioning to risk contracts, the importance of this initiative does not match that of farmouts, both in terms of reserves and production. It should be noted that a large part of the estimated 2P reserves of these twenty-two service contracts are located in the Chicontepec Basin, as can be seen in Table 4. The buildup of production in this area faces, at present, serious technical and social obstacles.

Table 4: Pemex service contracts authorized to migrate to production sharing agreements

			Reserves (Dec 2014)		Annual
	Contracts	Area (Km2)	1P (Mboe)	1P (Mboe)	Production (1,000 bpd)
Burgos*	7	252	71	102	8.3
Chicontepec	6	992	127	1,244	1.8
Poza Rica/Altamira	6	2,901	109	132	4.1
Tabasco	3	210	120	278	1.3
Total	**22**	**4,355**	**427**	**1,756**	**15.5**

* Integrated exploration and production contracts. All others are financed public works contracts.

Source: Sener, op. cit., Table 1.

CONCLUSION

The projects opened up for investment in Mexico will mature in very different time frames. First production in Perdido might be attained six or seven years after final investment decisions are made. Farmouts can bring this forward a couple of years. It is doubtful that deepwater natural gas farmouts will see production in this decade, given high break-even prices. Extra-heavy crude should begin to flow in significant volumes in 2018 and offshore development fields in late 2017. Only onshore mature fields could build up production in 2017, if all outstanding contractual, regulatory, and social issues are resolved. However, their contribution to incremental production volumes will not be materially relevant. The converted service contracts can possibly give additional production a bit earlier, with the exception of those in Chicontepec. Delays and longer than initially expected development periods diminish the relevance of these projects in helping to bridge the gap to higher oil output levels. Thus, the feasibility of a recovery of Mexican production by 2020 is increasingly doubtful. The state's share in operating profits will only begin much later, once costs are recovered.

The collapse in oil prices since mid-2014 and the somber short-term price outlook have drastically affected the investment climate in the international oil industry, leading to the announcement of substantial cuts in capital expenditures and head-count reductions, the postponement of final investment decisions of complex, large-scale offshore projects, and calls for greater financial discipline. In this environment, the Mexican government must act cautiously in its pursuit of private investment for the oil industry. It must be highly selective in the acreage that it will bid out in the coming months, cautiously sequence and pace tenders, and carefully consider a number of deferrals. A commitment to continue with the paradigm shift in the energy sector has to be firmly reiterated while the government fully considers cyclical conditions. Many projects with high break-even prices will only be viable after the market rebalances and begins to recover. Difficult choices will have to be made in the context of creatively constructed scenarios. Government authorities and Pemex are obliged to explore the consequences of alternative courses of action regarding proposed farmouts and contractual conversions, as well as open invitations to bid for their hydrocarbon resources. They must adjust to new realties. Under current conditions they would also be well advised to consider tilting their priorities from upstream to midstream and downstream reform objectives, which can bring benefits to Mexico regardless of the evolution of oil prices.

NOTES

1 Sener, *Plan Quinquenal de Licitaciones para la Exploración y Extracción de Hidrocarburos: 2015–2019,* http://sener.gob.mx/res/index/plan/Plan Quinquenal.pdf.

2 Pemex, *20F 2014 Annual Report to the US Securities and Exchange Commission, 15*, http://www.sec.gov/Archives/edgar/data/932782/000119312515162672/d913051d20f.htm. Sener, Round Zero, http://www.energia.gob.mx/webSener/rondacero_Ingles/9600.html.

3 Adrián Lajous, "The Impact of Low Oil Prices on the Mexican Economy," Center on Global Energy Policy at Columbia University, December 2014, http://energypolicy.columbia.edu/on-the-record/impact-lower-oil-prices-mexican-economy.

4 The federal government hedged a large part of its oil revenues—228 million barrels at a 2015 average strike price of $76.40 per barrel of the Mexican mix, paying a fee of $3.39 per barrel. In 2016, the hedge covers 212 million barrels at a price of $49 per barrel and a fee of $5.14 per barrel. The fee increased 52 percent.

5 Sener, *Plan Quinquenal de Licitaciones para la Exploración y Extracción de Hidrocarburos: 2015–2019,* http://sener.gob.mx/res/index/plan/Plan Quinquenal.pdf.

6 Pemex, *20F 2014 Annual Report to the US Securities and Exchange Commission,* 15, http://www.sec.gov/Archives/edgar/data/932782/000119312515162672/d913051d20f.htm. Sener, Round Zero, http://www.energia.gob.mx/webSener/rondacero_Ingles/9600.html.

7 Adrián Lajous, "The Impact of Low Oil Prices on the Mexican Economy," Center on Global Energy Policy at Columbia University, December 2014, http://energypolicy.columbia.edu/on-the-record/impact-lower-oil-prices-mexican-economy.

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9 An earlier version of this section can be found in Adrián Lajous, "Las Próximas Licitaciones," Nexos, July 28, 2015, http://www.nexos.com.mx/?p=25690.

10 Argus, "Producers Show Scant Interest in Western US Gulf," August 19, 2015, http://www.argusmedia.com/News/Article?id=1089871.

11 Energy Information Administration, "Europe Brent Spot Price FOB (Daily)," http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=rbrte&f=d.

12 CNH, Final modifications to the bidding guidelines and contractual model of the second invitation to bid of Round 1, 2015, http://ronda1.gob.mx/Espanol/pdf/PDF-L-02/R01L02_Boletin008_20150825.pdf.

13 Wood Mackenzie, "Mexico's Round One Final Terms—Shallow-Water Development," September 2015.

14 Originally, deepwater assets were going to be bid separately from extra-heavy oil fields. Somewhere along the way they became part of the same call for bids.

15 Ley de Hidrocarburos, Article 13, http://www.cnh.gob.mx/_docs/Leyes/Ley_de_Hidrocarburos.pdf.

16 Ley de Ingresos sobre Hidrocarburos http://www.dof.gob.mx/nota_detalle.php?codigo=5355983&fecha=11/08/2014.

17 Pemex has produced a new list that varies slightly from the original Round 0 authorizations.

18 Moody's, "Moody's places Pemex's A3/Aaa.mx ratings under review for downgrade," August 25, 2015, review-for-downgrade--PR_332685?WT.mc-id=AM~WWFob29fRmluYW5jZV9TQl9SYXRpbmcgTmV3c19BbGxfRW5n~20150825_PR_332685.

19 Ley de Hidrocarburos, op. cit., article 28, transitional.

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