Eagle Ford Shale play economics: U.S. versus Mexico

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ABSTRACT

The decline of domestic natural gas supply and rising demand requires Mexico to import 1/3 of its annual gas consumption of 2.5 trillion cubic feet (Tcf). Yet, Mexico’s estimated resource of technically recoverable shale gas (545 Tcf) is the 6th largest such gas resource in the World. Much of Mexico’s shale gas resource is in the Eagle Ford Shale, which is a mature shale gas and oil play in the U.S. To aid in determination of whether development of the Eagle Ford Shale in Mexico could reduce the country’s dependency on natural gas imports, we evaluated the potential of Mexican shale acreage by comparing the after-tax net present value (NPV) and internal rate of return (IRR) of Eagle Ford shale wells on either side of the U.S.-Mexico border. The initial development of Mexican acreage occurs with a much larger well-spacing (leading to higher acreage acquisition cost per well), which would require 25% higher development cost as compared to Texas acreage. Consequentially, Texas wells have better net present value (NPV) and higher internal rate of return (IRR) than Mexican wells, in general. The principal explanation is that the signing bonus will be much higher in Mexico than in Texas, partly effectuated by the lower well spacing for unrisked acreage. Results of our study provide potential operators and investors with a preliminary indication of Eagle Ford Shale well economics in Mexico. Our study includes sensitivity analyses for both non-escalated and escalated gas prices, for drilling and completion (D&C) costs, and for leasehold cost. The economic appraisal accounts for both single- and multiple-well development scenarios with P10, P50 and P90 production forecasts.

1. Introduction

Mexico hosts an estimated 545 trillion cubic feet (Tcf) of technically recoverable shale gas resources (TRR), the 6th largest shale gas occurrence in the global assessment sponsored by the U.S. Energy Information Administration (EIA, 2013a). The development of such onshore hydrocarbon assets in North America occurs in a highly competitive business environment. Operating companies and their investors (equity and debt) interested in extracting oil, gas and condensates compare potential locations based on the most favorable business conditions.

This study evaluates the development potential of Mexican shale acreage, by comparing typical Eagle Ford well economics on the U.S. side with similar wells on the Mexican side of the border. The circumstances for shale development in Mexico are more favorable than before due to two major developments. The first development is that Mexico has become a net importer of natural gas since 2002 due to rising demand and lagging domestic supply. The supply gap grew further after domestic natural gas production peaked in 2010 (Seeke et al., 2015). As a result, concurrent natural gas prices in Mexico are substantially higher than in the U.S.; the decline of domestic supply and rising demand requires Mexico to import 1/3 of its 2.5 Tcf annual gas consumption (2013 data; IMF, 2014). Mexican gas prices are inflated primarily because of partial dependency on costly LNG imports ($13/Mcf in 2013). LNG landing terminals in Costa Azul, Altamira and Manzanillo have a joint capacity of 2.1 Bcf/day (Fig. 1a). Meanwhile, U.S. gas pipeline export capacity to Mexico has grown from 4.7 Bcf/day in 2013 to 7.0 Bcf/day in 2015 (IMF, 2014) and further expansion is planned (Fig. 1b). Competitively priced U.S. pipeline gas supplies at about $4 per thousand cubic feet (Mcf) in 2013 have already resulted in Sempra’s Energia Costa Azul LNG terminal, with a capacity of 1 Bcf/day, being underused; some of its LNG under contract has been diverted to Asia. The U.S. history of $40 billion prematurely sunk in the development of 15 Bcf/day LNG import capacity since late 1990s and subsequently made redundant by cheaper domestic shale gas (Weijermars, 2014a), may or may not repeat itself in Mexico, depending on the sustained supply of U.S. shale gas and...
development of Mexico’s own shale provinces.

The second development favorable to shale gas development in Mexico is that competitive E&P investments by foreign operators are made possible by the recent implementation of reforms of the legal framework for the energy sector (DOF, 2014). Before the energy reform, effective as of January 2015, foreign operators could work in Mexico only as subcontractors for Pemex. The reforms allow foreign companies, registered as Mexican residents for tax purposes, to bid for E&P licenses after auction announcements by the Secretariat of Energy (SENER). The nascent shale play development in Mexico could benefit from bringing on board U.S. operators experienced in shale play development.

In this paper, we assess the opportunities for Mexico to duplicate the U.S. commercial development of the Eagle Ford Shale. The U.S. provides the benchmark for what could make a competitive hydrocarbon investment climate in Mexico for a range of hydrocarbon assets. To the best of our knowledge, this is the first study to compare the after-tax net present value (NPV) and internal rate of return (IRR) of Eagle Ford shale wells at either side of the U.S.-Mexico fiscal border. A previous study on shale gas economics in Mexico (Medlock, 2012), using the Rice World Gas Trade Model (RWGTM), established a high uncertainty for economic viability of the shale resources in Mexico, with breakeven prices higher in Mexico than in the U.S. and Canada, and consequently a delayed developmental activity in Mexico was assumed. This assumption was in part attributed to domestic impediments to development and to limited exploration. However, this was a generalized study on Mexican shale gas potential, conducted prior to the announcement of the Mexican energy reforms. Morales Velasco (2013) evaluated the before-income tax (BFIT) economics of estimated reserves (as of 2012), assuming a constant gas price of $4.22/Mscf. The BFIT NPV at 10% discount rate (NPV10) was reported to range from -$1,848,443 to $8,189,942 depending on the well type curve used. The corresponding IRR ranged between -0.8% and 25.8%. Subsequent to the study of Morales Velasco (2013), no further research has been published on the development potential of the Mexican Eagle Ford.

We stress that our study evaluates the after income-tax (AFIT) economic performance of the Eagle Ford shale gas wells in Mexico. Ours is the first study to draw a comparison between the commercial environment newly brought about by the reformed Mexican energy sector and the one presently existing in the U.S. To assess the potential for economic Mexican Eagle Ford gas and liquid production, we: (a) summarize the geological characteristics (target depth, petrophysics, and hydrocarbon maturity) and assumed drilling efficiency; (b) review representative production type curves that are crucial input parameters for the cash flow model; (c) present the fiscal models and benchmark results for both single-well and multi-well development strategies and, finally; (d) compare the split of revenues and profits between government and the company, in the Texas Eagle Ford and its Mexican continuation. The potential volatility of future gas prices has been factored into our study by reproducing the analysis under various pricing assumptions.

2. Eagle Ford Shale reservoir characteristics

In evaluating the reserves and economic performance in the Mexican side of the Eagle Ford, this study assumes that the reservoirs in the Texan and Mexican Eagle Ford are analogous and with similar production type curves. A careful comparison of the geology and reservoir characteristics between the two is warranted in order to understand the scope and limitations of this analysis. To this end, we discuss below the Eagle Ford shale reservoir characteristics in the Mexican and Texas acreages. Until the slowdown by low oil prices throughout 2015, production output of the Eagle Ford in the U.S. had been rapidly expanding. In early 2015, Eagle Ford daily production reached 1.75 million barrels of oil and 7.5 Bcf of natural gas (Fig. 2a). The Eagle Ford was initially developed as a horizontal gas play, after successful production was demonstrated with horizontal, hydraulically fractured wells in the Barnett Shale. However, the decline in U.S. natural gas prices provided a strong incentive for Eagle Ford shale operators to drill shallower horizontal wells in the oil and liquid-rich zones (Fig. 2b). Oil wells in self-sourced shale plays are shallower than gas wells (Fig. 2b); this zonation is in contrast to that of conventional reservoirs, where oil wells generally occur deeper than gas wells (Fig. 2c). From North-West (NW) to South-East (SE), Eagle Ford hydrocarbons transition from relatively shallow black oil to volatile oil, to gas condensate and finally, to dry gas with increasing depth and thermal maturity (Tian et al., 2013, 2014).

2.1. Mexican acreage

The Mexican acreage used in our benchmark as a hypothetical target lies near the U.S. border and is close to a region initially scheduled for lease auction by the Mexican government (Fig. 3). This lease region was later excluded from Round 1 (R1) bids, due to the low oil price. Although the R1 blocks are likely located in the black oil maturity window, we selected for our fiscal benchmark a nearby asset that is located in the wet gas window (Fig. 4a and b). We expect this acreage to be offered for bids in the future, when oil and gas prices rebound.

Pemex began exploring for shale gas in 2010/2011, and first well tests showed gas in April 2013, just south of the U.S. border (Morales Velasco, 2013). Two wells were completed in the dry gas window (Habano-1 and Emergente-1, Fig. 4b) in Coahuila province.
adjacent to the boundary of Maverick and Webb Counties (Texas). Both wells were drilled along highway MEX-2 (which runs largely parallel to the Mexico-Texas border), approximately 90 km south of the twin cities, Piedras Negras/Eagle Pass, and 70 km north of the twin cities, Nueva Laredo/Laredo (Araujo et al., 2012). Our benchmark acreage in Mexico is assumed to be located nearer to the R1 exploration region (Fig. 4b), and it differs from the Habano-1 and Emergente-1 well locations, in that we assume wet-gas conditions.

A general description of the Eagle Ford Shale in Mexico is given by Román Ramos et al. (2011), Morales Velasco (2013), and Morales Velasco et al. (2014). Eagle Ford total organic content (TOC) is estimated to average 5%, and average thickness is 200 m (Morales Velasco, 2013). For the R1 exploration block acreage, TOC ranges between 2 and 4% (Fig. 4a). Our study area is assumed to encounter wet gas window conditions typical for the western edge of the Maverick basin in Texas, with condensate pressure (P) and temperature (T) conditions (Fig. 4b). Although the geology across the Mexican border changes significantly, the Eagle Ford is present in both the Burro-Picachos and Sabinas basins (Fig. 5a and b). We assume the offset of thermal maturity windows across the U.S.-Mexican border (Rio Grande; Fig. 4b) may be unrealistic and reflects a mapping discontinuity that will be resolved as more data become available.

Based on the above data, we assumed analogy of reservoir petrophysics and followed earlier assessments that suggest well productivity for Eagle Ford acreage in Mexico will be similar to that of South Texas Eagle Ford wet gas production regions PR-1 and PR-2 (Gong et al., 2013), both of which correspond to the Southern Mature (A1) area outlined in Morales Velasco et al. (2014). Technically recoverable hydrocarbons in area A1 are estimated to be 343 Tcf of shale gas and 6.3 billion stock tank barrels (stb) of tight oil (Morales Velasco et al., 2014). Mexico, as a whole, hosts an estimated 545 Tcf of technically recoverable shale gas resources, the 6th largest in the EIA global assessment (EIA, 2013a). Based upon currently available data, we cannot exclude differences in structural history and principal stresses across the Rio Grande River, which may have resulted in diverging thermogenic paths that may require adjustment of our geologic model as further data become available.

2.2. Texas acreage

The U.S. Eagle Ford type locality used for our benchmark study is located in the deeper section (Maverick basin) of the Eagle Ford Shale fairway, South Texas. The Maverick basin occurs SW of the San Marcos Arch (Fig. 6a), which acted as a depositional facies barrier for Eagle Ford age strata. NW of the Arch, the Eagle Ford thins and interfingers with the Manesha Shale, Woodbine Group, and Pepper Shale (Fig. 6a-c; Hentz et al., 2014). The evolving Eagle Ford-equivalent shale play NW of the San Marcos Arch is commonly referred to as the Eaglebine play (Condon and Dyman, 2006). The upper and lower Eagle Ford thin over the San Marco Arch (Fig. 7a and b). From approximate 50 ft thick at the San Marcos Arch, the
Fig. 4. a: TOC distribution in Eagle Ford Shale in the subsurface of the Burro-Picachos and Sabinas basins (see cross-section A-A’ in Fig. 5). b: Thermal maturity (Ro) of the Eagle Ford Shale (after presentation by Mexican government, Heller-Green, 2014). Location of our benchmark study area, near the R1 lease region, is in the wet gas window and is outlined by the blue square near Piedras Negras. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

Fig. 5. a: Seismic section across Burro-Picachos and Sabinas basins (for location see section A-A’ on Fig. 4a). b: Interpreted seismic section with Eagle Ford Shale formation marked by green line (Heller-Green, 2014). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)
Eagle Ford thickness increases southwestward to more than 600 ft in the Maverick basin (Tian et al., 2012), near the Mexican border, reflecting the paleo-depth of the Western Interior Basin. Parts of the Western Interior Basin have been exhumed, exposing the Eagle Ford Shale in the walls of Lozier Canyon (Donovan et al., 2012).

The Eagle Ford (Upper Cretaceous: i.e., Turonian/Cenomanian) overlies the Buda limestone and is overlain by the Austin Chalk (Childs et al., 1988; Hentz and Ruppel, 2010). These strata extend from the Texas–Mexico border to east Texas, and dip gently (2–3°) southeastward into the Gulf of Mexico basin. The Eagle Ford Shale is composed of interbedded limestone and shale. The lower Eagle Ford is present throughout South Texas and ranges from 50 to
200 ft thick; the Upper Eagle Ford reaches its maximum thickness of 400 ft in the southernmost part of the region (Figs. 6 and 7). The Lower Eagle Ford has higher shale and TOC contents (ductile constituents) than does the carbonate-rich (brittle) Upper Eagle Ford (Tian et al., 2012); therefore, the latter may accommodate hydraulic fractures more effectively. However, thin interbeds of volcanic ash (only several inches thick) in the upper member have transformed into clay minerals, which may impede the propagation of hydraulic fractures and hydrocarbon production (Ruppel et al., 2015). Mineral composition of the Eagle Ford is dominated by calcite (making up 50–60% of the formation); the remainder is 20–30% clays and 5–10% quartz (Mullen et al., 2010). The Eagle Ford’s mineralogical composition and litho-texture suggest it should be classified as a laminated muddy limestone rather than shale.

Well log analysis revealed that the number of limestone beds increases (and thickness of individual beds decreases) toward the

Fig. 7. Isopach maps of (a) Upper and (b) Lower Eagle Ford shale members (after Tian et al., 2012).
Sligo Shelf Margin and the Maverick basin depocenter (Tian, 2014; Tian et al., 2012, 2014), which may result in variable spacing of natural fractures and differing characteristics of hydraulically induced fractures. Eagle Ford rocks exposed in Lozier Canyon, West Texas, exhibit sub-horizontal, layer-parallel fractures and vertical joints (Donovan and Staerker, 2010). The joints are parallel to the minimum stress direction and perpendicular to normal faults (growth faults) with downthrown blocks on the Gulf side. Therefore, hydraulic fractures are likely to open with steep dips and trend normal to the NW-SE oriented least principal stress. Horizontal well sections in the Eagle Ford are typically drilled parallel to the least principal stress direction (NW/SE).

For drilling efficiency, we assumed technology mastery that matches the success of Marathon, a leading operator in the Eagle Ford that drilled individual wells in 2014 at a rate of 1435 ft/day and completed wells in about 10 days (Fig. 8). Well spacing in the Eagle Ford ranges from 60 to 160 acres/well (Drillinginfo, 2013). Fluid pressure of the Eagle Ford basin exhibits a steep gradient from 0.5 psi/ft in the (South-West) SW near the Mexican border to 0.85 psi/ft near the San Marcos Arch, with the lower gradient occurring at reservoir depths of 14,400 ft in the SW versus 5500 ft in the NE (Gong et al., 2013). The southern region is closer to hydrostatic pressures, whereas the NW section is markedly over-pressured. Artificial lift is installed in some Eagle Ford wells.

3. Well productivity type curves

We adopted the well productivity type curves established for a pertinent Eagle Ford region by Gong (2013). To account for the heterogeneity in geological complexity, fluid types and production performance in the Eagle Ford, Gong (2013) and Gong et al. (2013) partitioned the play in Texas into eight productivity regions (Fig. 9). The fluid types were characterized by the initial gas-oil-ratio (GOR) and production performance by the second-month production. The presence or absence of the Upper Eagle Ford was also taken into account while partitioning the play. Our acreage is assumed located in the wet-gas region in the vicinity of the US-Mexican border. Hence, we focused on the productive region PR2, covering parts of three Texas counties (Maverick, Dimmit and Webb; Fig. 9).

Decline curve analysis was used to enable the valuation of monthly production data from type curves (P10, P50, P90) that can be applied in the analogous shale plays at either side of the U.S.-Mexico fiscal border. The type curves also allow the estimation of proved reserves (P90) required for accurate property tax payments in Texas acreage and establishment of asset value collateral for equity and debt financing of a typical growth company. The economic model uses after-tax cash flow analysis and can compare the economic performance (IRR, NPV) of individual and multiple wells subject to different sets of taxes due under each specific fiscal regime. We compared the economic performance of Eagle Ford PR2 type curves under the Texan/U.S. federal fiscal regimes with the

Fig. 8. a: Drilling efficiency improvements reported by Marathon (MRO) over peer group. b: Well completion time gains between 2001 and 2014 (after Rutledge, 2015).
Mexican fiscal framework. The specific business terms for onshore concessionary agreements in Texas/federal U.S. and Mexico are detailed in Appendices A and B, respectively.

### 3.1. Decline curve model

A range of formulas has been proposed for history matching of well rates in order to establish type curves for production forecasting in unconventional hydrocarbon plays. One of the assumptions for applying Arp’s decline curve model is that the well should be in the boundary dominated flow (BDF) regime. Once BDF is reached, the production rate may be expressed using the hyperbolic Arp’s decline curve model (Arps, 1945):

\[
q(t) = q_i (1 + bD_i t)^{-\frac{1}{b}}
\]

However, in the early well life, linear flow occurs, which can be accounted for in the Duong (2010, 2011) decline curve model designed for hydraulically fractured horizontal wells operating in the linear flow regime. The methodology proposed by Duong is summarized in Fig. 10. Linear flow is characterized by a linear relationship between flow rate-cumulative production ratio \(q/G_p\) and time on the log-log plot. The rate-time relationship is (Duong, 2010, 2011):

\[
q(t) = q_i t^{-m} \exp \left( \frac{a}{(1-m)(l^{1-m} - 1)} \right)
\]

Gong (2013) re-parameterized the above equation in terms of \(N_{240}\), cumulative liquid hydrocarbon production for 240 months (or \(G_{240}\) in case of gas production). The resultant decline model adopted for gas in our study is (Gong, 2013):

\[
q(t) = N_{240} a t^{-(1+l)} \exp \left( \frac{a}{(1-m)(l^{1-m} - 1)} \right)
\]

where \(m = 1 + l\). The re-parameterized Duong’s model applies to forecast the production until the onset of BDF, after which an Arp’s hyperbolic decline curve with \(b = 0.3\) is adopted. The rate of minimum decline is equal to the value of nominal decline rate \(D_i\) of the Duong model during the transition. The timing of transition is...
assumed to occur when the slope of the production rate vs. material balance time is closest to unity on a log-log scale. A statistical relationship was established between \( D_{\text{min}} \) and decline parameter \( l \), which for condensates is (Gong, 2013):

\[
\text{Mean}(D_{\text{min}}) = 0.763 \times l + 0.1335, \quad (4a)
\]

\[
\text{SD}(D_{\text{min}}) = 0.2391 \times l + 0.0402, \quad (4b)
\]

3.3. Generation of probabilistic type curves

To establish the production trend of any new well, a type decline curve was generated from historical production data of existing wells in the region under study. Gong (2013) performed the following 6-step procedure to arrive at the type decline curve for region PR-2.

1. Probabilistic production forecast using the Markov Chain Monte Carlo (MCMC) method was performed on all existing wells in PR2. The decline parameter sets \((N_{240}, a, l)\) associated with all MCMC iterations for all wells were saved.
2. Monte Carlo simulation was performed to generate the distribution of decline parameters by sampling 100,000 sets from the previously saved population of decline parameter sets.
3. Monte Carlo simulation was performed to sample values for initial GOR, GOR slope and \( D_{\text{min}} \) for each parameter set \((N_{240}, a, l)\). The values for initial GOR and \( D_{\text{min}} \) were sampled from the statistical models generated, and GOR slope from a uniform distribution with pre-specified boundaries.
4. Each set of decline curve parameters along with the associated initial GOR, GOR slope and \( D_{\text{min}} \) were used to calculate the recoverable condensate and gas resources of 20 years (\( TRR_{20,\text{cond}} \) and \( TRR_{20,\text{gas}} \)). By sorting the values of resources, the values of \( P90 \), \( P50 \) and \( P10 \) condensate and gas estimates for \( TRR_{20,\text{cond}} \) and \( TRR_{20,\text{gas}} \) were obtained.
5. A band of 1000 parameter sets in the vicinity of the \( P90 \), \( P50 \) and \( P10 \) estimates were selected and averaged.
6. The \( N_{240} \) parameter was corrected so that the \( P90 \), \( P50 \) and \( P10 \) estimates calculated from the averaged values of decline parameters equals the corresponding estimates obtained in step 4.

We adopted the values of the averaged parameters reported by Gong (2013) for condensate and gas production from region PR2. Due to proximity in location, the wet gas production trends in the PR2 region were assumed to be representative of those in the A1 region in Mexico, as defined by Morales Velasco et al. (2014). The summary of the parameters and type curves relevant to our study and computed values of \( TRR_{20} \) (20-year EUR) are provided in Tables 1 and 2. The type curves that resulted from our calculations incorporating the key parameters are shown in Fig. 12a,b.

4. Evaluation of economic performance

We benchmark the economic performance of selected Eagle Ford well types under the typical U.S. onshore royalties and various taxes with the fees specified in the contractual options offered by the Mexican government. To successfully attract investments for shale play development, the license terms offered by Mexico in its recent energy reform need to be competitive with, or even better than, the business terms for similar onshore plays in the U.S. Mexico’s fiscal regime and the new royalty mechanism and other fiscal dues are reviewed in Appendix A. There are important differences between the principal stakeholders in Mexican and U.S. shale operations. For example, in Texas, Eagle Ford signing bonus and royalties are due to the lessor of the mineral rights (commonly private landowners), oil and gas property taxes are due to the local county, production and franchise taxes are due to the state and corporate income tax is due to the federal government. In Mexico, mineral rights are solely owned by the federal government, which thus receives all duties: signing bonus, royalties, rental fees and corporate income tax, part of which may be distributed to the local community. For the Mexican investment option, we use the rates detailed for license agreements in the new hydrocarbon law (DOF, 2014) and adjustments of the operational cost to Mexican rates. For

![Fig. 11. Average GOR trend for Eagle Ford condensate wells from historical data, and range of GOR slope (Gong et al., 2013).](image-url)
Texas, we use contemporary costs for drilling and completion, signing bonus, landowner royalty, severance and ad valorem tax, and U.S. federal corporate income tax (detailed in Appendix B).

4.1. Methodology

The after-income tax economic models were built using Microsoft® Excel®. The probabilistic type curves presented in Section 3 are used to compute the net revenue from operations in both Texas and Mexico regions for each probabilistic scenario (P10, P50, P90). Following this, any applicable royalties, various taxes, operating and capital expenditures and allowable depletions (if applicable) are subtracted from the generated revenue to compute the taxable income and thereby, the corporate income tax. The fixed inputs to the model are specified in Table 3. The reader is encouraged to follow the tax and expenditures computation workflow shown in Fig. A1 and B1 (in Appendices), for Mexico and Texas, respectively.

Two main cases are investigated:

- production from a single representative well; and
- production from 25 wells drilled during the first five years of production.

For each case, we considered a production time frame of 40 years or up to economic limit (if we observed negative cash flow before the end of the 40 years period). We programmed a VBA code to compute the aggregated decline curves production for the multiple wells case. The same code was used to update the asset value for the years with newly drilled wells in order to compute the ad-valorem property tax in Texas. Using ActiveX technology, we linked the Excel model to Matlab scripts to perform the sensitivity analysis.

The final deliverables from the Excel model are the after-tax net cash flows. The sensitivity of the results to various input parameters (i.e., fixed prices, escalated price scenarios, drilling and completion costs and bonus costs) were analyzed by varying one parameter at a time (keeping the rest constant). For each sensitivity analysis, we computed the resulting internal rates of return and the net present value at 10% discount rate.

4.2. Economic appraisal of representative hydrocarbon property

Monthly production volumes of gas and condensates (P10, P50, P90) were generated using the type curves graphed in Fig. 12 a,b. The monthly production outputs were subsequently coupled to an economic model to account for all taxes, technical costs and time value of money within the fiscal frameworks of the U.S. and Mexico. We assumed a typical oil and gas industry discount rate of 10% (Harden, 2014). The royalties, taxes and deductibles, including depreciation, depletion and amortization (if applicable), for Mexican and Texas acreage are detailed in Appendices A and B. The respective rates were incorporated in economic spreadsheet models developed separately for each fiscal regime.

The major dissimilarities in the Texas and Mexican after-tax income calculations include, but are not limited to, the following:

Table 1

<table>
<thead>
<tr>
<th>Production Region</th>
<th>Percentile</th>
<th>( N_{240} ) [Stb]</th>
<th>( a )</th>
<th>( l )</th>
<th>( D_{\text{min}} ) [1/year]</th>
<th>( TRR_{20} ) [Stb]</th>
</tr>
</thead>
<tbody>
<tr>
<td>PR2</td>
<td>90</td>
<td>29,819</td>
<td>0.91</td>
<td>0.31</td>
<td>0.37</td>
<td>26,699</td>
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<tr>
<td></td>
<td>50</td>
<td>147,652</td>
<td>0.87</td>
<td>0.20</td>
<td>0.29</td>
<td>127,368</td>
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<tr>
<td></td>
<td>10</td>
<td>488,856</td>
<td>0.85</td>
<td>0.10</td>
<td>0.19</td>
<td>399,560</td>
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</table>

Table 2

<table>
<thead>
<tr>
<th>Production Region</th>
<th>Percentile</th>
<th>( N_{240} ) [STB]</th>
<th>( a )</th>
<th>( l )</th>
<th>( D_{\text{min}} ) [1/year]</th>
<th>( GOR_{I} ) [Scf/Stb]</th>
<th>( GORS ) [Scf/Stb/Month]</th>
<th>( TRR_{20} ) [Bcf]</th>
</tr>
</thead>
<tbody>
<tr>
<td>PR2</td>
<td>90</td>
<td>21,174</td>
<td>0.95</td>
<td>0.35</td>
<td>0.42</td>
<td>21,248</td>
<td>157</td>
<td>0.50</td>
</tr>
<tr>
<td></td>
<td>50</td>
<td>74,178</td>
<td>0.84</td>
<td>0.18</td>
<td>0.26</td>
<td>31,950</td>
<td>164</td>
<td>2.60</td>
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<tr>
<td></td>
<td>10</td>
<td>283,074</td>
<td>0.84</td>
<td>0.09</td>
<td>0.18</td>
<td>24,768</td>
<td>178</td>
<td>8.52</td>
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Fig. 12. Assumed P10, P50, P90 production forecasts in region PR2 for (a) condensates and (b) natural gas.
a. Provision for percentage depletion in Texas but not in Mexico;
b. Property tax (ad-valorem tax) levied on the fair value of oil and gas properties in Texas but not in Mexico;
c. Commodity price dependent royalties levied in Mexico but not in Texas; and
d. Federal rental fees are levied in Mexico but not in Texas onshore operations.

License agreements under the new Mexican hydrocarbon law [further specified in “Ley de Ingresos sobre Hidrocarburos” — Hydrocarbons Revenue Law (LHR), DOF, 2014] do not allow for capitalization and depreciation of field development investments. Instead, any capital expenditure incurred for field development should be expensed in the year of incurrence (on the cash flow statement).

### 4.3. Benchmark and sensitivity analysis for single wells

The economic benchmark of fiscal regimes in Mexico and Texas uses the representative well productivity (P10, P50, P90) established in Section 3 and other principal input parameters detailed in Table 3. Our base case cash flow model uses discrete inputs. The largest sensitivities are attributable to well productivity (captured by production curves of three likelihoods), gas and condensate prices, signing bonus rates and D&C costs. All these variables are accounted for in the sensitivity analyses described below. The base case capital expenditure (CAPEX) in Mexico is assumed to be 25% costlier than in Texas, due to less competitive market conditions for services. In addition, the assumed well spacing in Mexico is assumed greater than in Texas, because the Mexican acreage needs de-risking, which calls for larger well spacing. That is, fewer wells per acreage will be drilled in Mexico before full drilling will take place once the Mexican Eagle Ford productivity is proved and sweet spots are identified. Since the Texan Eagle Ford has been sufficiently developed, the well-spacing of 57 acres/well has been assumed. On the other hand, we assign the same well spacing (320 acres/well) as Morales Velasco (2013) to the Mexican side of the play, which is still in an early stage of development. Hence, the bonus per well is higher in Mexico. In our model, all wells are assumed successful in the sense that they deliver PR2 region type curve productivity with the probabilities as specified in Section 3.

#### 4.3.1. Sensitivity to non-escalated commodity prices

In this section, we consider a scenario where the commodity prices remain constant throughout the life of the well, in order to study the sensitivity of the NPV and IRR of the three type curves

### Table 3

<table>
<thead>
<tr>
<th>Input parameters for single well economics.</th>
<th>TEXAS</th>
<th>MEXICO</th>
</tr>
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<tbody>
<tr>
<td><strong>Signing Bonus</strong></td>
<td>$3000/acre</td>
<td>$3000/acre</td>
</tr>
<tr>
<td>Bonus per acre</td>
<td>$171,000/well</td>
<td>$960,000/well</td>
</tr>
<tr>
<td>Total bonus</td>
<td>$4,275,000</td>
<td>$24,000,000</td>
</tr>
<tr>
<td><strong>Ownership &amp; Royalty</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Working Interest (WI)</td>
<td>100%</td>
<td>100%</td>
</tr>
<tr>
<td>Landowner royalty</td>
<td>20.9%</td>
<td>2.00%</td>
</tr>
<tr>
<td>Federal royalty:</td>
<td>None</td>
<td>Formula linked to commodity price</td>
</tr>
<tr>
<td><strong>Production properties</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas calorific content</td>
<td>1.11 Mmbtu/Mcf</td>
<td>1.11 Mmbtu/Mcf</td>
</tr>
<tr>
<td>Gas shrinkage</td>
<td>5%</td>
<td>5%</td>
</tr>
<tr>
<td>Water gas ratio</td>
<td>7.5 bbl/MMscf</td>
<td>7.5 bbl/MMscf</td>
</tr>
<tr>
<td><strong>Capital Costs</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>D&amp;C</td>
<td>$6,500,000/well</td>
<td>$8,125,000/well</td>
</tr>
<tr>
<td>Depreciation tangible D&amp;C</td>
<td>33%</td>
<td>No capitalization</td>
</tr>
<tr>
<td>Depreciation intangible D&amp;C</td>
<td>67%</td>
<td>No capitalization</td>
</tr>
<tr>
<td>TDC life</td>
<td>6 years</td>
<td>No capitalization</td>
</tr>
<tr>
<td>Tie-in cost</td>
<td>$100,000/well</td>
<td>$125,000/well</td>
</tr>
<tr>
<td>Abandonment</td>
<td>$15,000,000</td>
<td>$18,750,000</td>
</tr>
<tr>
<td>Facilities</td>
<td>$500,000</td>
<td>$625,000</td>
</tr>
<tr>
<td>Facility depreciation</td>
<td>14 years</td>
<td>No capitalization</td>
</tr>
<tr>
<td><strong>Operating Costs</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fixed</td>
<td>$1500/well/month</td>
<td>$1500/well/month</td>
</tr>
<tr>
<td>Variable gas</td>
<td>$0.5/Mcf</td>
<td>$0.5/Mcf</td>
</tr>
<tr>
<td>Variable cond/NGL</td>
<td>$0.05/bbl</td>
<td>$0.05/bbl</td>
</tr>
<tr>
<td>Water disposal</td>
<td>$1.00/Mcf</td>
<td></td>
</tr>
<tr>
<td>Lease area</td>
<td>not applicable</td>
<td>1.3 km²/well</td>
</tr>
<tr>
<td>Rental fees</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Production Taxes</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ad valorem</td>
<td>1.81%</td>
<td>None</td>
</tr>
<tr>
<td>Severance gas</td>
<td>7.50%</td>
<td>None</td>
</tr>
<tr>
<td>Severance condensate</td>
<td>4.60%</td>
<td>None</td>
</tr>
<tr>
<td>Margins tax (Notes 1 &amp; 2)</td>
<td>0.7%</td>
<td>None</td>
</tr>
<tr>
<td><strong>After Federal Income Tax</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Corporate tax</td>
<td>35%</td>
<td>30%</td>
</tr>
</tbody>
</table>

Note 1: 1% reduced by 30% COGS from gross revenue.
Note 2: Wells that produce < 10 bbl/d for 90 days or < 250 mcf/d are exempt (negligible).
(P10, P50, P90) to fixed commodity prices. The NPV of the type curves assuming a discount rate of 10% (denoted by NPV10), for a range of non-fluctuating commodity prices is shown in Fig. 13a and b. The NPV10 using the typical Mexican fiscal regime for unconventional resources is lower than that using the Texan royalty and tax rates for the P90 case. However, considering P10 production, NPV10 of the Mexican regime surpasses that of the Texas regime at around $3/MMBtu. The royalty for leasehold mineral rights payable to the Mexican government is indexed to the various commodity prices as detailed in Appendix A. The sensitivity analysis to the gas price has been carried out under the assumption that the condensate remains indexed to the gas price. Historical pricing data (from January 2010 till November 2015) were used to establish the historical average of the ratio of gas to NGL prices as $1/MMBtu gas equivalent to $9.61/bbl NGL. This ratio was assumed to hold throughout the life of the well and was used to generate the fixed NGL price from the gas price.

Fig. 13c and d reveal that the economic environment in Mexico appears less profitable to operators in comparison with Texas, which offers a higher IRR for all prices that satisfy the common corporate hurdle rate requirement of 15% IRR. For P10 wells, the IRR will exceed the hurdle rate in both Mexico and Texas for any gas price slightly more than $2/MMBtu (Fig. 13c). However, P50 wells require a gas price above $5.5/MMBtu in Texas and above $6.5/MMBtu in Mexico to satisfy the minimum requirement of 15% IRR (Fig. 13c). The P90 wells are unlikely to be classified as true P1 reserves, as they are merely contingent C1 resources under the currently prevailing gas prices of single digits. While a gas price above $22/MMBtu is required for P90 wells meeting the hurdle rate in Texas, the Mexican IRR for such wells does not appear to exceed the hurdle rate for the range of gas prices considered (Fig. 13d). For both jurisdictions, operator success in realizing a positive return on investment is dependent on the realization of P10 wells rather than P50 or P90 wells under prevalent economic conditions and current technology.

4.3.2. Sensitivity to escalated price scenarios

The prospective NPV and IRR for our representative type curves were further evaluated using three different future price scenarios for natural gas based on energy system models developed by the Energy Information Administration for its Annual Energy Outlook 2015 (EIA, 2015) (Fig. 14).

- Forecast 1 (reference case) assumes growth of the real gross domestic product (GDP) at an annual rate of 2.4% from 2013 to 2040, without any drastic change in laws and regulations.
- Forecasts 2 (high oil price case) implies a combination of low demand for petroleum and other liquids in nations outside the Organization for Economic Cooperation and Development (OECD) and higher global supply and reduced cost of technology.
- Forecast 3 (high oil and gas resources case) results from a 50% increase in EUR per unconventional (shale gas, tight gas and oil) well and a 50% decrease in well spacing. In addition, the EUR increases by 1%/year more than the increase in the reference case.

Fig. 15a–d compares the Texas and Mexican NPV10 and IRR for the assumed type curves under the three different pricing scenarios. The condensate price was again indexed to follow the price trend of natural gas (Section 4.3.1). Cash flow analysis shows that the P50 and P90 wells are sub-economical for all three pricing scenarios, both in Texas (Fig. 15a & c) and Mexico (Fig. 15b & d). P90 wells have highly negative IRR and have not been graphed. Only P10 wells are economical in terms of IRR, and more so in Texas (Fig. 15c) than in Mexico (Fig. 15d). The better IRR in Texas can be explained by the lower investment required per well in Texas in comparison with Mexico. However, the Mexican regime appears to be

Fig. 13. Sensitivity to commodity price fluctuations for representative well productivity distinguishing three types of reserves categories (P10-proved reserves, P50-probable reserves and P90-possible reserves): a: NPV10 sensitivity (P10&P50), b: NPV10 sensitivity (P90), c: IRR sensitivity (P10&P50), d: IRR sensitivity (P90) under Texan and Mexican royalty schedules with a hurdle rate of 15%. Principal inputs are given in Table 3.

NPV and IRR sensitivity to reduction in D& costs (Tables 1 and 2) per well. We infer that the discovery of the sweet and 127.4 Mstb condensate. In contrast to these values, the P10 estimate implies a meager EUR (per well) of 0.5 Bcf and 26.7 Mstb, uncertainty about the productivity of the Eagle Ford wells. The P90 offer a higher NPV10 (Fig. 15b) for P10 wells than the Texan regime Historical and future projections of natural gas prices in $/MMBtu (Fig. 14.

4.3.3. Sensitivity to drilling and completion (D&C) costs

A key to improving the return on investment in the Eagle Ford wells, both in Texas and Mexico, is cost reduction. We analyzed the NPV and IRR sensitivity to reduction in D&C costs (Fig. 16) using the gas price scenario of the Reference Case (Forecast 1) in Fig. 14. We conclude that, even with extreme reduction in D&C cost, P90 wells remain unprofitable both in Mexico and Texas, for the assumed type curves. In contrast, the profitability of P50 and P10 wells increases rapidly with decreasing D&C costs. Fig. 16 is compatible with earlier results: technology innovation, leading to simulta-
neous increased well productivity and reduction in well cost, will improve the NPV and IRR at a rate that can counter the negative effects of commodity price falls (Weijermars, 2014b).

4.3.4. Sensitivity to signing bonus rates

The sensitivity analysis (Fig. 17) shows that the NPV10 and IRR are more sensitive to signing bonus rates on the Mexican side than on the Texan side. This is due to the higher well spacing assumed in Mexico (320 acres/well) than in Texas (57 acres/well), amounting to a higher burden per well in Mexico in the total bonus paid. If the Mexican signing bonus is reduced substantially, such shale wells become competitive with a similar wells in Texas. While the NPV10 and IRR of P50 and P90 wells in Mexico fail to surpass those in Texas throughout the entire range of signing bonus rates considered, the P10 wells in Mexico do offer a higher NPV10 for signing bonus rates <$6500/acre. However, for any signing bonus rates greater than $1500/acre, the IRR of P10 wells in Mexico remains lower than those in Texas.

4.4. Benchmark and sensitivity analysis for multiple wells

An economic analysis for a single well does not account for the time value of money effect connected to any realistic drilling schedule; examples applying various types of drilling schedules (well roll-out rates) using Barnett shale play type curves were given by Weijermars (2013a). In our analysis we assume a play develop-
ment with 25 wells drilled over a five year period (Fig. 18a), using a recurrent annual drilling schedule (Fig. 18b). We further assume that the single-well decline curves for the PR2 Eagle Ford type region apply to all wells drilled. Hence, we may simply sum the corresponding P50 (or P90 or P10) production of all wells operating at any one time to obtain the monthly production volumes required as inputs for our economic analysis (Fig. 18a). The seesaw pattern of the total production output (Fig. 18a) is due to our adopted annual drilling schedule (Fig. 18b) with steep increases early in the year when 3 wells are added and a lesser increase in output mid-year when two more wells are added.

Following the aggregation of production from multiple wells, we apply the respective tax models for each region (Texas or Mexico). The input data used for arriving at the net cash flow for each tax model are the same as in Table 3. The flow charts of the fiscal models for Mexico and Texas are in Appendices A and B. Furthermore, we performed sensitivity analyses for commodity prices, D&C cost and signing bonus rates, along with NPV and IRR analyses using the three likely future price scenarios.

4.4.1. Sensitivity to non-escalated commodity prices

The NPV and IRR (after taxation) for the multiple well develop-
ment scenario and their sensitivity to gas prices were comprehensively modeled (Fig. 19a–d). A comparison of the multiple well results (Fig. 19a–d) and single well results (Fig. 13a–d) reveals that multiple-well development with a fixed 40-year field life has NPVs and IRRs both being higher than for the single well appraisals. The explanation lies in the time-value of money, with the discount rate having a lesser effect on tail-end cash flows and consequently lifting the NPV and IRR, accordingly. A similar effect was observed in Weijermars (2013a).

4.4.2. Sensitivity to escalated price scenarios

We also evaluated the economics of the multiple well drilling scenario program using three EIA price forecasts (Fig. 14). The life of each well is assumed to be 40 years, at the end of which price Forecast 2 offers the best NPV and second best IRR, a much higher price than the Reference scenario (Fig. 20). Although Forecast 2 offers higher prices after first 5 years, the aggregate production declines, thereby diminishing the impact of long-term high commodity prices. This reinforces the relative effect of the short-term pricing trends over the long-term ones. In effect, since the range of gas prices predicted by all three forecasts remains narrow in the early years, the NPV10 and IRR vary insignificantly between fore-
casts (Fig. 20). Forecast 1 (Reference Case) offers a marginally better IRR than Forecast 2 (High Oil Price) and Forecast 3 (High Oil and Gas Resources).

The NPV10 analysis using the three different price scenarios (Fig. 14) yields similar trends for multiple wells in both regions (Fig. 20a–b) as those for a single well (Fig. 15a–b), but with an amplification in magnitude. For example, NPV10 values for P10 wells remain positive in the multi-well case but increase by about one order of magnitude as compared to the single wells. Similarly, the NPV10 for P50 and P90 cases, which are negative for a single well, become highly negative for 25 wells. Although this is an obvious outcome it does have an important implication for field development strategy. When well performance is lagging, field development should slow down to search for sweet spots.
Fig. 15. Sensitivity to various EIA (2015) price scenarios for representative well productivity, distinguishing three types of reserves categories (P90-proved reserves, P50-probable reserves and P10-possible reserves). NPV10 sensitivity under (a) Texan and (b) Mexican fiscal regimes. IRR sensitivity under (c) Texan and (d) Mexican fiscal regimes. Principal inputs are given in Table 3.

Fig. 16. Sensitivity to drilling and completion costs for representative well productivity distinguishing three types of reserves categories (P90-proved reserves, P50-probable reserves and P10-possible reserves). a: NPV10 sensitivity, b: IRR (P10&P50 only) under Texan (TX) and Mexican (MX) fiscal regimes, with a hurdle rate of 15%. Principal inputs are given in Table 3.
Reversely, when well performance meets the NPV expectations, the field development pace may accelerate.

Production from multiple wells (Fig. 20c) and a single well (Fig. 15c) in Texas yield nearly similar IRR, and all are higher than in Mexico. This competitive advantage for Texas well development is largely due to lower capex investments required per well, leading to increasing returns with increased drilling. Multi-well P10 production in Mexico offers marginally lower IRR (Fig. 20d) than the corresponding single well production (Fig. 16d) in all pricing scenarios. In contrast, multi-well P50 production offers higher IRR (Fig. 20d) than the respective single-well production (Fig. 15c).

4.4.3. Sensitivity to drilling and completion costs

Fig. 21 shows the sensitivity of NPV10 and IRR for the 25-well development program for a range of D&C costs, for comparison to the single-well sensitivity analysis of D&C costs (Fig. 16). Again, P50 and P10 wells become rapidly more profitable when D&C costs are reduced, compatible with earlier results: technology innovation leading to cost reduction improves the economic performance. Reduction in well cost may improve the NPV and IRR at a rate that can counter the negative effects of any commodity price falls (Weijermars, 2014b).

4.4.4. Sensitivity to signing bonus rates

The Mexican project is more sensitive to signing bonus rates, in comparison to a similar Texas project (Fig. 22). A higher NPV10 may be expected for the Mexican project, in the case of P10 production, if the signing bonus is below $6500/acre, but for higher lease cost, Texas wells perform better. These conclusions concur with those derived for the single well case (Section 4.3.4).

5. Discussion

5.1. Tax distortions

States and provinces with substantial income from oil and gas activities must ensure their fiscal climates remain attractive for the development of oil and gas resources (IMF, 2014; Weijermars, 2016; Weijermars and Zhai, 2016). The surplus money left after all taxes have been deducted from the taxable income is referred to as after-tax income. This represents the amount of usable income that the company has to expend on future or present consumption. Any tax distortion is unwarranted: no resources should remain undeveloped due to the imposed royalties and tax burden. In the U.S., a central tax policy for onshore hydrocarbon resources cannot be developed, because the royalty rates in each U.S. state are mostly
negotiated with private landowners. This means that when commodity prices are low, oil and gas resources that are sub-economic (P90 and P50 wells in our case for Texas PR2 region) may remain undeveloped, unless landowners agree to substantially lower royalty rates. For Mexico, the situation is different in that the government can set the royalty rate, which currently seems low enough to make development of wells with P50 and P10 type curves profitable under prevailing gas prices and the specified range of future price scenarios.

5.2. Revenue slices and profit split

The apportionment of the gross revenue between governmental entities, operating expenditure (OPEX), capital expenditure (CAPEX) plus signing bonus, and the operator is illustrated in Fig. 23 for both the Texas and Mexican regimes, considering either single or multiple (25) wells. Governmental entities and royalty owners joint receive the highest proportion of P10 gross revenue in Texas (Fig. 23a–b). For P50 production, the governmental entities and royalty owners receive a higher proportion than the operator in all cases considered (Fig. 23c–d). Furthermore, well productivity decrease from P10 to P50 production leads to a drastic increase in the relative proportion of revenue spent on CAPEX and signing bonus. This effect is more severe in Mexico, where each well drilled requires larger investment due to increased well spacing in an undeveloped, unrisks shale play. OPEX rates were assumed the same for both countries (Table 3). A slight difference in OPEX occurs in Mexico’s licenses on onshore assets is applied when production exceeds certain thresholds (CNH, 2015b). The royalty adjustments due in Mexico’s licenses on onshore assets may be that economies of scale increases revenues more than cost and therefore justifies a larger fiscal rent extraction. However, for very large development projects, royalty adjustments will increasingly lower the rate of return for the operator. The adjustment mechanism therefore gives a competitive advantage to smaller operators. The justification for imposing larger royalty on bigger field development projects raise the production output above the daily thresholds. For our multi-well development with only 25 wells in operation, the royalty adjustment factor remains very small (see Appendix A). However, for very large development projects, royalty adjustments will increasingly lower the rate of return for the operator. The adjustment mechanism therefore gives a competitive advantage to smaller operators.

5.3. Royalty adjustment mechanism

The royalty adjustments due in Mexico’s licenses on onshore assets is applied when production exceeds certain thresholds (CNH, 2015b). The royalty increase will affect the operator take when larger field development projects raise the production output above the daily thresholds. For our multi-well development with only 25 wells in operation, the royalty adjustment factor remains very small (see Appendix A). However, for very large development projects, royalty adjustments will increasingly lower the rate of return for the operator. The adjustment mechanism therefore gives a competitive advantage to smaller operators. The justification for imposing larger royalty on bigger field outputs may be that economies of scale increases revenues more than cost and therefore justifies a larger fiscal rent extraction. However, such royalty adjustments mechanisms may be a disincentive for investments by larger operators.

5.4. Market dynamics and wellhead price volatility

Natural gas supply in Mexico currently is 2/3 from domestic production (mostly associated natural gas from conventional oil fields). In 2012, Mexico imported 620 Bcf of natural gas via pipeline from the US. An additional 159 Bcf came in as LNG shipments from overseas (mostly through the re-gasification plants at Altamira (East-coast) and some via Manzanillo and Energia Costa Azul (West-coast; EIA, 2013b). An oversupply of natural gas in a closed
North American market may lead to wellhead prices below marginal cost, such as was triggered in the U.S. from 2009 until present, due to domestic shale gas production increases outpacing demand (e.g. Weijermars, 2014a). Therefore, modeling the North American oil and gas market system is important to avoid negative price pressure due to oversupply.

5.5. Sovereign risk

Mexico's sovereign credit rating is BBB + as compared to AAA for the U.S. Pemex credit rating concurs with the sovereign rating for Mexico. The sovereign rating for Mexico was in junk bond terrain before the Millennium turn (1995–2000: BB/BB+), but since has been hovering in a bankable debt-ratings ranging between BBB- and BBB+. The USD/Mexican Pesos valuation has fluctuated between 1/9th and 1/15th over the past decade, which implies considerable exchange risk, as well as opportunities for currency exchange gains. Our benchmark study assumed currency risk is hedged with a neutral fiscal impact.

5.6. Scope for future work

This study assumed that well productivity in Texas wet gas fields should be reproducible in the corresponding regions in Mexico. A future comparison of Eagle Ford geology in Texas and Mexico may provide better estimates of reserves and subsequent economic analysis. The fair value of assets required for the calculation of advalorem tax in the Texas regime has been replaced by the net present value of the property. Although this is an acceptable proxy, it does not adhere to the elaborate rules set down by the Comptroller of Texas. Incorporation of these detailed calculations is left for future work. Our study accounts for the sensitivity to commodity prices of key profitability indicators of project feasibility, such as NPV and IRR. However, future commodity prices assumed in this study may not reflect the actual future scenario, since the global oil and gas markets are currently passing through a period of high volatility that is closely connected to price volatility in North American markets. Separately, variety in facility and well development cost due to regional differences in the cost of available resources.
service providers is in our study accounted for by assuming 25% higher development cost in Mexico (Table 3). This study has not attempted to estimate the broader impact of infrastructure development cost. Since the Mexican Eagle Ford is in a very early stage of development, infrastructure development (with opex charges to operators by third parties for pipelines, disposal wells, NGL plants) may be slower in Mexico than in Texas. Future work should also account for any emerging differences in average target depth between the two regions, as these may also affect the cost inputs.

6. Conclusions

Rapid shale-gas development may help reverse the decline of Mexico’s natural gas output. For example, the Burro-Picachos and Sabinas basins in Mexico host the geological continuation of the U.S. Eagle Ford Shale. In order for Mexico to attract the intended foreign investments for the development of its hydrocarbon resource plays, offered terms must be competitive with the conditions for similar plays in the U.S. The new concessionary type of contract is intended and reserved for the stimulation of investment in Mexico’s emergent unconventional shale plays. Our comparative analysis suggests that the new hydrocarbon law reforms introduced by the Mexican government offer competitive terms for shale resource development. The average rate royalty prevalent in Texas used in our study (20.9%) is generally much higher than the Mexican royalty (linked to commodity prices, see Appendix A), and direct taxes on production (severance tax) and property taxes (ad valorem) applied in Texas are absent in Mexico (Table 3). For the best P10 wells, the operator in Mexico retains 61% of profits with government take of 39%, whereas in Texas, operators retain 51% of profit and remaining 49% is paid out as landowner royalties, state taxes and federal income tax (Section 5.2). The Mexican royalty
adjustment mechanism that applies when output exceeds certain threshold volumes (Section 5.3) favors smaller operators over bigger operators. We infer that the Mexican fiscal regime offers competitive terms to smaller oil and gas companies for de-risking shale acreage. Given that the shale boom started in the U.S., the competitive rates of taxation and royalties announced in Mexican energy reform make it highly likely a similar shale boom may occur in Mexico. Once global oil and gas prices recover, Mexico’s new license terms provide a positive incentive for foreign investment in Mexico’s unconventional plays.

Acknowledgement

This study evolved out of a graduate class at Texas A&M University (PETE664) that typically studies decline curve analysis and reserves based on well productivity until the economic limit, using SEC guidelines. The case study developed here benefited from advice and data provided by many A&M colleagues and alumni. Special thanks are due to George Voneiff for guest lecturing and sharing practical excel models for decline curve analysis. Carlos Morales Velasco is thanked for sharing MS Thesis data under embargo.

Nomenclature and Abbreviations

| AFIT | After Income Tax |
| API | American Petroleum Institute gravity |
| B | Billion (prefix) |
| BDF | Boundary Dominated Flow |
| boe | Barrel of Oil Equivalent |
| CAPEX | Capital Expenditure |
| cf | Cubic Feet |
| D&C | Drilling and Completion |
| EIA | U.S. Energy Information Administration |
| EUR | Estimated Ultimate Recovery |
| ft | feet |
| GOR | Gas Oil Ratio |
| IRR | Internal Rate of Return |
| LNG | Liquefied Natural Gas |
| M | Thousands (prefix) |
| MCMC | Markov Chain Monte Carlo |
| MM | Million (prefix) |
| NE | North-East |
| NGL | Natural Gas Liquid, Condensate |
| NPV | Net Present Value |
| NW | North-West |
| OPEX | Operating Expenditure |
| P | Pressure |
| P10 | Possible reserves with 10% certainty of being produced |
| P50 | Probable reserves with 50% certainty of being produced |
| P90 | Proven reserves with 90% certainty of being produced |
| RWGTJ | Rice World Gas Trade Model |
| scf | Standard cubic feet |
| SE | South-East |
| stb | Stock Tank Barrel |
| scf | Standard cubic feet |
| SW | South-West |
| T | Trillion (prefix) or Temperature |
| TOC | Total Organic Content |
| TRR20_cond | recoverable condensate resources of 20 years |
| TRR20_gas | recoverable gas resources of 20 years |

From Equation (1)

- $q$: Production rate
- $b$: Decline exponent for Arps model, dimensionless
Initial decline rate, 1/year
Cumulative gas production
Initial production rate
time

From Equation (2)
m Duong slope constant
a Duong intercept constant, 1/month

From Equation (3)
N_{240} Cumulative oil (or condensate) production for 240 months
l Decline curve parameter in re-parameterized Duong model.

From Equation (4a)
D_{min, oil} Minimum decline rate for oil (or condensate)

From Equation (4b)
SD Standard deviation

Appendix A. Fiscal framework onshore license agreements Mexico

The applicable rates for license agreements offered by the new fiscal framework in Mexico are briefly outlined below based on the approved law texts by the Mexican Government (DOF, 2014). Fig. A1 shows the key steps built into the fiscal models for the Mexican acreage.

Fig. A1. Flow chart for after tax cash flow in Mexican fiscal model, accounting for both the corporate income tax and cost of capital (at 10% discount rate).
The following taxes are due:

1. **A signing bonus** ("bono") as a lump sum payment the amount of which will be determined by the Energy Secretariat during the bidding process for the lease. The signing bonus for the unconventional acreage is not expected to represent a significant percentage of the estimated resources, but merely is a tool to guarantee seriousness of the economic bids (Parker et al., 2014).

2. **Federal royalties** ("regalías") for oil, gas and NGL’s are negotiable but are revenue-based, with the royalty rate (R) fixed by a reference price (P) according to the following formulae:

   - **Basic oil royalties:**
     
     \[
     R = (0.125 \times P + 1.5)\% \text{ for } P \geq \$48/bbl
     \]
     
     \[
     R = 7.5\% \text{ for } P < \$48/bbl
     \]

   - **Basic gas royalties** (associated gas):
     
     \[
     R = (0.01 \times P)\%
     \]

   - **Basic gas royalties** (non-associated gas):
     
     \[
     R = (0.01 \times P)\% \text{ for } P \geq \$5.5/Mmbtu
     \]
     
     \[
     R = (60.5 \times (P - 5))\% \text{ for } \$5/Mmbtu < P < \$5.5/Mmbtu
     \]
     
     \[
     R = 0\% \text{ for } P \leq \$5/Mmbtu
     \]

   - **Basic condensates Royalties**:
     
     \[
     R = (0.125 \times P - 2.5)\% \text{ for } P \geq \$60/bbl
     \]
     
     \[
     R = 5\% \text{ for } P < \$60/bbl
     \]

3. **Royalty adjustments**. The contract stipulation for assets auctioned in the 3 t h phase of Bidding Round 1 (2015) are detailed in the bidding guidelines issued by the National Hydrocarbons Commission (CNH, 2015b). There is a royalty adjustment mechanism applied for operators producing oil in excess of 30 Mbbls/day, which switches to another algorithm when production exceeds 80 Mbbls/day. For gas and condensates the royalty adjustment mechanism is triggered when production exceeds 80 Mboe/day (326 Mcf/day) and another algorithm applies when production surpasses 240 Mboe/day (~1 Bcf/day). In our study total production for multiple wells exceeds the 326 MCF threshold from year 3–6 (Fig. 18a). The royalty adjustment formula for gas and condensate production over 80 Mboe/day and below 204 Mboe/day is (CNH, 2015b):  

   \[
   AR = (10\% - \text{BasicRoyalty}) \times \frac{\text{ActualOutput} - 80,000}{160,000} \text{ where } AR \text{ stands for adjusted royalty. The ActualOutput should be entered in boe/day. Assuming a base case royalty of } 3\% \text{ (linked to current gas and condensate prices) and using the actual average output between year 2 and 6 is } 500\text{Mcf/day} (-123,000 \text{ bbl/day}) \text{ means a royalty adjustment of } AR = 1.75\% \text{ needs to be applied.}
   \]

4. **Landowner compensation** ("contraprestación") for oil, gas and condensates which is negotiable and within the following bandwidths:

   - Non-associated gas royalty no less than 0.5% and up to 3% of operator’s share after payment of federal royalties and fees to the Mexican Petroleum Fund.
   - Associated gas and other liquids royalty no less than 0.5% and up to 2% of operator’s share after payment of federal royalties and fees to the Mexican Petroleum Fund.
   - Compensation for damage to roads, easements of land use, and any rentals due to use of surface facilities are to be negotiated with the landowner. Additionally, a social impact study is also due (Ley de Hidrocarburos, Chapter V, Articulos 118–121; DOF, 2014).

5. **Federal over-royalty** ("sobre-regalía") may be applicable in addition to the regular royalty ("regalía básica") depending on commodity price development as agreed in each particular license negotiated with the Energy Secretariat.

6. Federal exploration rental fee ("cuota contractual") of 1150 pesos/km2 (~$78/km2 @31 Dec 2014) for the first 60 months of exploration and 2750 pesos/km2 (~$187/km2 @31 Dec 2014) from the 61 t h month onward.

7. Federal production rental fee ("cuota contractual") of 6000 pesos/km2 (~$407/km2 @31 Dec 2014).

8. **Corporate income tax** at a rate of 30%. Since depreciation is not allowed, field development investments should be expensed in the year of incurrence. Corporate tax payers must make 12 advance payments on the 17th day of the month. All corporations must use the calendar year for fiscal reporting. The annual tax return must be filed no later than 31 March of the year following the tax year, with any balance of the income tax over the year due at that time (Deloitte, 2014).

Illustration of gross revenue apportionment by various entities, as concluded in this study, is provided in Fig. A2a,b.
Appendix B. Fiscal framework U.S. onshore concessionary agreements (Texas)

In the U.S., offshore resources are leased by the federal government, but onshore tracts of land leased for oil and gas extraction may originally be owned by private landowners, or are public land. Some states host Native American nations who own their mineral rights and are considered as private landowners administered by the chosen representatives of the nation. Leasing of land from private mineral right owners in the U.S. is concisely covered by Tinkler (1992) and McFarland (2006). Fig. B1 shows the key steps built into the fiscal models for the Texan acreage.

Fig. A2. Percentage of gross revenue apportioned by various entities in case of (a) Mexico single-well production; (b) Mexico multiple-well production.
Onshore mineral rights may be part of a unified estate (Fig. B2a), but more often than not, the mineral rights have been judicially separated by mineral severance, which enables leasehold transactions of large acreage tracts (Fig. B2b). Onshore operators typically
pay the following fees to specific stakeholders: (1) signing bonus to lessor (either a private or public entity), (2) royalties over gross revenues of oil and gas sales to the lessor, (3) severance (production-based) tax to the state, (4) property (ad-valorem) tax based on fair-value of oil and gas properties to the county, (5) franchise (now called margins tax) to the state, (6) corporate income tax to the federal government. Each of these fees is briefly highlighted as applicable to Eagle Ford oil and gas properties in Texas.

1. Bonus

When an E&P lease is obtained for mineral rights of private land, any signing bonus and all royalties pertain to the lessor. The bonus should reflect the value of the anticipated recoverable volume of hydrocarbons on the acreage, and is negotiated between the lessor and the lessee. The signing bonus is paid to the lessor either in full or in agreed installments upon signing of the lease agreement. The bonus or lease transfer cost can be expressed as a price per acre. For leases of public land, fees (signing bonus, rents and royalties) paid by the operator to the federal government (via the responsible office of the Department of the Interior (DOI)) are generally split 48/52 between the state and the federal governments, except for Alaska, which receives 90% of all revenues collected on public domain leases in accordance with the Mineral Leasing Act (MLA; Humphries, 2008). Private and municipal landowners negotiate their own royalties.

Average surface land cost of split estates in Texas sold for around $2354/acre in 2014, up 9% from $2160/acre in 2013 (TSL, 2014). However, the leaseholds for oil and gas rights below such split estates have appreciated considerably in value. For example, Chesapeake in 2007 paid a signing bonus of $192 million for drilling and production lease of the Dallas Fort Worth Airport (Weijermars, 2013b). The cost of drilling rights has risen from less than $4000/acre at the beginning of 2010 to more than $20,000/acre in 2012. Selected examples of acquisition cost for leaseholds in Eagle Ford shale acreage are given in Table B1.

The signing bonus can be capitalized according to the ruling IRS Oil and Gas Handbook (IRS, 2013). Further capitalization related to the acquisition of a lease include commission fees paid to the broker, attorney fees for title check, any landman expenses and transfer fees and taxes. G&G expenses relevant for lease acquisition decisions can also be capitalized.

2. Royalties

Royalties on public land are typically set at 1/6th of gross revenue from oil and gas sales. The royalty percentage due to private landowners is negotiable but must be no less than 12.5%, which is the minimum rate stipulated by the regulations of the Texas RRC. The average royalty rate for Texan leases is 20.9% (Fitzgerald, 2015).

3. Property tax

The state comptroller of Texas sets guidelines for the appraisal of fair value of oil and gas properties (Combs, 2012; Hegar, 2015).
county in which the property is located sets the actual rate of the ad-valorem property tax (Peppard, 2009). Counties in Texas collect an average of 1.81% of a property's assessed fair market value as property tax per year. Each county in Texas has its own method of assessing and collecting taxes, which is why property tax rates vary across Texas. Beginning with the 2012 tax year, it is mandatory for each county assessor-collector to post on the county website certain tax rate information for each taxing unit in the county. (http://www.window.state.tx.us/taxinfo/proptax/taxrates/).

4. Severance tax and regulatory tax

Tax on split estates, i.e. mineral rights are legally severed (separated) from the surface assets and therefore may be separately taxed. The severance or production tax rate in Texas for oil and condensates is 4.6% and for gas 7.5% of market value (which is sales revenue minus any marketing cost). Flared gas is not subject to severance tax, and high-cost gas wells may have adjusted tax rates varying between 0 and 7.4%. Texas RRC regulations provision for deductions of marketing cost, which are expenses incurred to bring oil and gas to market before any severance tax is paid. The basis for allowances for deductions is to equalize the tax burden for those operators distant to the market, which have to treat gas before selling, unlike operators selling at or near the point of production. Examples of deduction allowances include the cost of compression, sweetening, dehydration, NGL cooling and transportation to the selling point (RRC, 2015). Marketing costs may not be carried forward from one month to the next, but capitalized cost of marketing equipment can be depreciated over the useful life (20 years or more is permissible for useful plants) at 10% per year or less if the useful life is longer than 10 years. In addition to the severance tax, a regulatory tax is due for oil field cleanup equal to $0.0625/ bbl when the state fund balance falls below $10 million, and until it exceeds $20 million. Gas is charged a clean up fund regulatory fee of $0.000667/Mcf. Non-participating royalty interest owners (NPRI) are expense free which means they are not accountable for any share of production taxes. NPRI is not receive a share of bonus when the leasehold is sold on nor any part of royalties negotiated between working interest owners. In our analysis we assume the company pays all production taxes and the share of severance tax due by the lessors is subtracted from their monthly royalty checks.

5. Margins tax

Franchise tax in Texas was replaced in 2008 by margins tax, which is 1% of annual gross receipts less the cost of goods sold (COGS; or wages (e.g., for services) or 30% of gross receipts), which means effective tax is 0.7% of gross receipts. Stripper wells that produce less than an average of 10 bbls/day over a 90 day period and gas wells producing less than 250 Mcf/day over the same period, are excluded from margins tax. Texas margins/franchise tax due date is May 15 following the tax year’s completion. Texas law does not require the filing of any intermediary reports or installment payments of expected taxes due (OCT, 2016).

6. Federal income tax

The statutory rate of the U.S. federal income taxes on corporate profits is 35%. According to a critical study by Taxpayers-for-Common Sense (TCS), an NGO, the effective tax rate is closer to 24% after deductions, mostly related to depreciation of capitalized assets (TCS, 2014a,b; Keightley and Sherlock, 2014). The federal fiscal regime for U.S. oil and gas activities is defined by the U.S. Internal Revenue Service (IRS, 2013). For example, expenses for leasehold acquisition may be capitalized and constitute depreciable property. The depreciation or depletion rate is over the useful life of the asset. However, for shale acreage it is difficult to establish the useful life of the asset. Two methods of depletion are possible: cost depletion or percentage depletion allowance. With cost depletion, the actual capital investment is recovered throughout the period of income production. A portion of the original capital investment is deducted each year equal to the fraction of the estimated remaining recoverable reserves that have been produced and sold that year, less previous deductions. The cumulative depletion under this method may not exceed the original capital investment.

When the producer prefers to apply the percentage depletion, the allowance deduction for recovery of the capital investment is calculated using a fixed percentage of the gross income (sales revenue). Independent producers and/or royalty owners may use for leasehold assets in the U.S. a depletion rate of 15% of the annual gross income from the property based on the average daily production of domestic crude oil or domestic natural gas up to the depletible oil or natural gas quantity. When percentage depletion is applied, the cumulative depletion deductions may become greater than the capital amount spent by the taxpayer to acquire the property, which is permissible.

The IRS further details the recovery period for each group of assets used in the petroleum industry: e.g., assets and services used in drilling of wells (6 years), offshore drilling vessels, platforms and equipment (7.5 years), E&P facilities (14 years), and LNG plant (22 years). Corporations expected to owe estimated income tax for the year of $500 or more must make installment payments for four periods. Installment payments are due by the 15th day of the 4th, 6th, 9th and 12th month of the corporation’s tax year (IRS Publication 542). Assuming the corporation files its annual return synchronous with the calendar year ending 31 December 31 (other financial reporting periods are possible if approved by the IRS), then the due dates for installment payments are April 15, June 15, September 15 and December 15.

The installments are estimations of income taxes due and the final tax settlement is made based on the annual tax filing and corporations must file and settle the annual income tax by the 15th day of the 3rd month following the completion of the fiscal year. If the company's financial reporting follows the calendar year, due date is March 15 of the year following the tax year. In the end, the mechanics of actual disbursements does not affect our annual filing, which settles the total income tax due for the full year. The tax auditor bases any final settlement of annual income tax on that year’s annual tax return filing.

In summary, for Texas, the following rates were applied for respective payments (see Appendix A for details):

**To the lessor (which may be a private or public entity):**

1. A negotiable and capitalizable signing bonus reflecting the value of the anticipated recoverable volume of hydrocarbons on the acreage
2. Royalties over gross revenues of oil and gas sales, typically set at 1/6th of the gross revenue on public lands and a minimum 12.5% on private lands. The average royalty for Texas leases is 20.9%. We applied a sensitivity analysis for variations in the negotiated Texas royalty rates.

**To the county:**

3. Property (ad-valorem) tax based on the appraised fair-value of oil and gas properties based on guidelines by the state comptroller of Texas (Combs, 2012). Even though the actual rate of ad-valorem property tax depends on the county in which the property is located (Peppard, 2009). An average value of 1.81% has been used in our study.

**To the state:**

4. The severance or production tax rate in Texas for oil and condensates is 4.6% and for gas 7.5% of market value (which is sales
revenue minus any marketing cost). Flared gas is not subject to severance tax, and high cost gas wells may have adjusted tax rates varying between 0 and 7.4%. The regulations of the Texas Railroad Commission (RRC) provision for deductions of marketing cost, which are expenses incurred to bring oil and gas to market before any severance tax is paid. Marketing costs may not be carried forward from one month to the next, but capitalized cost of marketing equipment can be depreciated over the useful life (20 years or more is permissible for useful plants) at 10% per year or less if the useful life is longer than 10 years.

5. A regulatory tax is due for oil field clean-up at $0.0625/bbl when the state fund balance falls below $10 million, and until it exceeds $20 million. Gas is charged a clean-up fund regulatory fee of $0.000667/Mcf. This minor tax deduction has not been considered in this study as it will not affect the outcome of our analysis.

6. Margins tax which is 1% of gross receipts less the cost of goods sold (COGS, here set at 30% of gross receipts, see Table 3). Stripper wells that produce less than an average of 10 bbls/day, over a 90 day period, and gas wells producing less than 250 Mcf/day over the same period are excluded from margins tax.

7. Corporate income tax of 35% is subject to deductions based on depreciation and depletion. Two methods of depletion are possible. **Cost depletion** wherein the actual capital investment is recovered throughout the period of income production. A portion of the original capital investment is deducted each year equal to the fraction of the estimated remaining recoverable reserves that have been produced and sold that year, less previous deductions. The cumulative depletion under this method may not exceed the original capital investment. **Percentage depletion** wherein the allowance deduction for recovery of the capital investment is calculated using a fixed percentage (usually 15% for independent producers) of the gross income (sales revenue). When percentage depletion is applied, the cumulative depletion deductions may become greater than the capital amount spent by the taxpayer to acquire the property, which is permissible.

A detailed illustration of gross revenue apportionment by various entities, as concluded in this study, is provided in Fig. B3a,b.

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**Fig. B3.** Percentage of gross revenue apportioned by various entities in case of (a) Texas single well production; (b) Texas multiple well production.