Benchmark of deepwater field development projects in the Perdido foldbelt: Evaluating fiscal impacts (Mexico, and US) using a nodal analysis production model

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ABSTRACT

Development of Mexican hydrocarbon reservoirs by foreign operators is now made possible by the energy reforms implemented in 2015. This study benchmarks the economic return of deepwater hydrocarbon field development projects located in the Perdido foldbelt at either side of the maritime border between the United States and Mexico to assess the competitiveness of the respective fiscal frameworks. We use a nodal analysis production model to first history match real field performance in the US Perdido project and then forecast production of an analogous, undeveloped field in the Mexican extension of the Perdido foldbelt, Gulf of Mexico. The new Mexican profit sharing contract imposes basic royalties that appear equitable for both the contractor and the government, albeit slightly less attractive than the to the U.S. federal lease terms. The contracts for deepwater assets in Mexico open up commercially viable options, provided the oil price will recover to render such oil projects profitable. Our sensitivity analysis shows that profitable development of 300 MMbbls oil in place becomes possible when oil prices rise above $75/bbl. For larger reservoirs (~900 MMbbls) the profit hurdle rate of 15% is already met for $60/bbl. Any over-royalty offered by a contractor in the bidding process renders the royalties in Mexican operations slightly higher than in the U.S.

1. Introduction

Policy makers around the world try to create an attractive investment climate to stimulate hydrocarbon development projects in their respective territories. At the same time, petroleum companies are only attracted to make the required investments for field development when the fiscal burden on their corporate portfolio will remain minimal. A major factor that may sway project investment decisions (either favorably or adversely) is a country’s total tax take on hydrocarbon resources: royalty, tax rates and any production share negotiated under a ruling fiscal regime. Countries with undeveloped hydrocarbon resources in frontier plays may consider offering a favorable tax regime (e.g., profit takes of 45–55%) in order to attract oil companies that are prepared to invest and take the risk to open up the play. For comparison, the average global tax take on net income (profit) from operations in the upstream oil and gas activities amounts to 70% (IMF, 2012; Weijermars et al., 2014; Weijermars, 2015a).

Numerous studies are available that analyze natural resource taxation mechanisms (Daniel et al., 2010; Ploeg and Venables, 2011; Bentham and Stroebel, 2013). However, studies based on any detailed production model applied to a real resource occurrence commonly remain proprietary and are rare, if not completely absent in the public peer-reviewed domain. Our study aims to fill the gap and shows what capacity can be brought to bear with current, leading edge analysis tools and methods. Our approach is unique in several ways. This is the first in-depth study of deep-water assets in the Gulf of Mexico that compares the fiscal regimes and legal constraints in Mexico and the US. Our study calculates operator take versus government take for each fiscal regime using the taxation rates and royalties specified in Mexico’s new deepwater model contracts and compares the results to the typical U.S. federal royalty and tax rates applicable to similar deepwater assets in the U.S. Our economic benchmark is based on a detailed geological analysis of largely analogous deepwater fields in the Perdido fold belt (Appendix A) and subsequently applies a unique nodal analysis model (Appendix B).

The Perdido foldbelt is a geological structure that contains numerous hydrocarbon traps and the structure stretches hundreds of miles across the U.S.-Mexico maritime border. Proved reserves already have been identified and developed on the U.S. side of the maritime border in the Shell-operated Perdido Project (Littell et al., 2011). The Perdido

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project (named so after its location in the Perdido foldbelt) currently is
the world’s deepest offshore project with the mud line over 9000 ft
below sea level. Some of the wells in Perdido’s main Great White field
are located only 8 miles from the Delimitation Line (DL) central to the
Transboundary Zone (TBZ), see Section 2 for legal details and
implications. More recently, prospective resources have also been
identified in the Perdido foldbelt at the Mexican side of the maritime
border (CNH, 2015a). Companies now have a practical choice to
develop reservoirs that are located within the Transboundary Zone
(TBZ) either from U.S. territorial waters or from Mexico territorial
waters. Developing such assets from the Mexican side becomes possible
for foreign operators under the new Hydrocarbon Law. For projects
that are located near the TBZ, the Mexican Hydrocarbon Law requires
at least 20% participation by Pemex (HL, Article 17, DOF, 2014).
Pemex participation in projects advocated by Mexico’s Secretary of
Energy may not exceed 30% of the investments in tendered projects
according to the new Hydrocarbon Law (DOF, 2014, Article 6).

We developed a detailed economic appraisal of operator returns
versus government takes in an integrated analysis of the geological
subsurface conditions and petroleum engineering solutions for Perdido
deepwater assets applying the fiscal regimes and legal constraints of
both Mexico and the United States (U.S.). We systematically compare
the economic performance of the field projects under each jurisdiction
to identify the competitiveness of each fiscal framework. The insights
from our analysis are useful both for policy makers trying to create
an attractive investment climate for hydrocarbon development, and
for petroleum companies that must ensure the fiscal burden on their
corporate portfolio will remain minimal.

Our analysis follows a systematic approach which is consolidated in
this comprehensive research article as follows. Section 2.1 summarizes
the essential legal issues related to prospective hydrocarbon develop-
ment in national, transboundary and international waters of the Gulf of
Mexico. Section 2.2 outlines the Mexican energy reform and some
details related to the auction of Mexico’s deepwater prospects. Current
production and future potential in the Gulf are briefly reviewed
(Section 3.1). We next adopt plausible deepwater reference fields in
the Perdido foldbelt and outline the pertinent hydrocarbon traps and
the petroleum system (Section 3.2). Section 4 highlights the field
development solution realized by the operator of the Perdido project in
the U.S. Gulf (Section 4.1), and briefly reviews its financial perfor-
mance and fiscal takes (Section 4.2). We consider original field
development solutions for the Mexican assets which currently lack
infrastructure. Section 5 gives our proposed development solution(s)
for the Mexican deepwater prospects in the Perdido foldbelt (Section
5.1), and presents our after tax cashflow model (Section 5.2). A
production system model was constructed applying nodal analysis
using historic performance of analogous wells in the U.S. Perdido fold
belt in order to base our economic benchmark on plausible production
scenarios. The results of our sensitivity analyses are given in Section
5.3. A discussion follows in Section 6, conclusion and policy
implications are highlighted in Section 7. Appendix A details the geological
setting. Appendix B presents the production system model developed in
order to obtain analogous production profiles for the Mexican
Perdido project. Appendix C summarizes the bidding guidelines and
key rates used for Mexican profit sharing agreement for deep water
assets.

2. US-Mexicomaritime border and Mexico energy reforms

This section first outlines the complex nature of the maritime
border and the status of its hydrocarbon assets (Section 2.1) and
proceeds with a brief overview of the Mexican energy reform and
auction process of Mexico’s deepwater prospects (Section 2.2).

2.1. Maritime border, Delimitation Line and Transboundary Zone

The maritime border in the Gulf of Mexico between the U.S. and
Mexico and its agreed economic exclusion zone are subject to various
treaties intended to ensure mutually beneficial use and development of
areas where the 200 nautical mile (nm) zone leaves gaps for inter-
pretation (Hagerty, 2014; Hagerty and Uzel, 2013). Meanwhile,
petroleum companies have moved to progressively deeper water and
have the capability to drill in ultra-deep water (~10,000 feet).
Technology innovations have recently overcome the practical obstacles
that previously limited access to deepwater Transboundary hydrocar-
bon reservoirs, such as occurring in the Perdido foldbelt.

In 2014, the U.S. lifted its moratorium on drilling in the so-called
Transboundary area (Seele et al., 2014) and auctioned more E&P
licenses in a gap between the mutual exclusive economic zones (EEZ).
The moratorium agreed in previous treaties with Mexico covered a
swath of seafloor with a width of 2.8 nm (1.4 nm on either side of the
so-called Delimitation Line - DL), termed here the Transboundary Zone
(TBZ). The TBZ stretches over a 550 nm long section of the maritime
boundary between the U.S. and Mexico in the Gulf of Mexico, which
includes sections where the mutual economic exclusion zones (EEZ)
leaves gaps (Hagerty and Uzel, 2013). Fig. 1a shows at least two such
gaps occur in the Gulf of Mexico, a Western Gap and Eastern Gap. The
Western Gap is particularly interesting because within that zone occur
hydrocarbon prospects, producing fields and awarded licenses, beyond
the U.S. 200 nm EEZ (but still north of the agreed DL). Fig. 1b
highlights the Western Gap, in which E&P leases already have been
awarded by the U.S. Department of the Interior (DOI).

The U.S.- Mexico Transboundary Hydrocarbons Agreement (THA) is
a landmark treaty adopted between U.S. and Mexico for the offshore areas
(Hagerty, 2014) where international law might otherwise leave ambiguous
who holds the rights to award certain resources for commercial extraction.
The bill (U.S. Bill S. 812) related to the THA passed the U.S. Senate on 12
October 2013, and authorizes the Secretary of the Interior to implement
the Agreement’s terms, including: (1) approving unitization and related
arrangements for the exploration, development and production of oil or
gas from, transboundary reservoirs and geological structures; (2) disclos-
ing information, as necessary, regarding exploration, development, and
production of a Transboundary reservoir or geological structure that may
be considered confidential, privileged, or proprietary information under
law; and (3) accepting and taking actions not inconsistent with an expert
determination under the Agreement (THA, 2013).

The THA (2013) is particularly important for clarity of title to
hydrocarbon resources that straddle the mutual EEZ border in the so-
called Transboundary reservoirs. The THA established the process
through which companies can develop the resources at each side of the
border while protecting the nations’ interests and resources. The fiscal
terms related to exploiting hydrocarbons are governed by the agree-
ment as follows (Hagerty, 2014; THA, Article 13):

“Income arising from the Exploitation of Transboundary Reservoirs
shall be taxed in accordance with the legislation of the United
Mexican States and the United States of America respectively, as
well as the Convention between the Government of the United
States of America and the Government of the United Mexican States
for the Avoidance of Double Taxation and the Prevention of Fiscal
Evasion with respect to Taxes on Income and Capital, signed on
September 18th, 1992, as amended (and as may be amended in the
future), or any Convention superseding that Convention as the
Parties may enter into in the future.”

Components of any process and steps for any Unitization agree-
ment are also outlined in the THA (Hagerty, 2014, THA, Article 6),
including “requirements to measure production; procedures for
ensuring accurate payments of royalties and other proceeds; and
safety and environmental measures to be taken under the national
laws of each party.” (Hagerty, 2014).
Fig. 1. a: Active wells and platforms around the Gulf of Mexico in the U.S. (blue dots) and Mexico (yellow dots). The map highlights the lack of any deepwater activity, limited shallow water production and in Mexican part of the Gulf. Onshore production activity is also more limited than in the U.S., all of which may be changed by the Mexican energy policy reforms. Map after Seelke et al. (2014). b: Enlargement of the Western Gap area between the economic exclusion zone (EEZ) of U.S. and Mexico. Major E & P activity in the U.S. has advanced to ultra-deep water beyond the leading edge of the Sigsbee Escarpment (a tectonic feature due to a canopy of rock salt that controls the bathymetry of the escarpment; e.g., Hudec and Jackson, 2006, 2009; Weijermars, 2015b; Weijermars and van Harmelen, 2015; Weijermars et al., 2015c). The Perdido fold belt straddles the TBZ at either side of the Delimitation Line. Blue rectangles outline deep water blocks offered by Mexico in the 2016 auction of Perdido region prospects. Map after Hagerty and Uzel (2013). Auction blocks from Mexican government. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)
Major sections of the maritime boundary in the Gulf between the U.S. and Mexico comply with international law which entitles nations to any resources within the 200 nm zone seaward from state shorelines, that zone is commonly referred to as the EEZ (Hagerty and Uzel, 2013). A previous treaty between the U.S. and Mexico that designates the Delimitation Line avoids dispute about entitlements where seafloor between them lies further than 200 nm from their respective shorelines (DL Treaty, 2000; Hagerty and Uzel, 2013). The DL covers the EEZ maritime boundary starting 9 nm from the coastline of Texas, from where onwards U.S. offshore resources are governed exclusively by federal royalties, taxes and regulations. The DL currently ends 550 miles to the east at the western point of the Eastern Gap, which has not yet been apportioned by any agreement between the two neighboring nations (Fig. 1a). In contrast, the Western Gap is an area that lies beyond the respective EEZ of Mexico and the U.S., and has been partitioned between them according to the agreed DL.

Bill S.812 passed by the U.S. Senate in effect authorizes the secretary of the Interior to award E&P rights under the agreement. The bill (S.812) has not the status of a U.S. Law, which would need endorsement by the House and the U.S. President. However, the THA has the same standing in Mexican congress which approved implementation of the agreement in 2013 (Hagerty, 2014; Seeleke et al., 2014). The title to resources in the Western Gap are de facto partitioned with assets in the region to the north of the DL and the TBZ pertaining to the U.S. and those to the south to Mexico. The U.S. has already some 20% of the Western Gap area licensed to E&P companies (Hagerty and Uzel, 2013) in lease sales 218 (Dec 2011) and 222 and 229 (Oct and Nov 2012), see BOEM (2014). Blocks near the TBZ in the Western Gap have been awarded during lease sale 238 (August 2014). U.S. Gulf lease blocks that cover and provide access to Transboundary reservoirs are (as of 1 Dec 2014; BOEM, 2014): Western Planning Area: G31204, G31205, G32994, G25772, G33530, GR35164 (GR35162 & GR35163); Central Planning Area: G27783, G27785, G27786. An interactive GIS tool of the Bureau of Ocean Energy Management shows the detailed locations of these lease blocks, wells and facilities (http://www.boem.gov).

The DOI has awarded three lease bocks to ExxonMobil in the Western Planning Area (lease sale 233 in 2013) that cover the U.S. half of the TBZ near Alaminos Canyon, directly southwest of the Perdido Project. Our study uses the U.S. Perdido project as a sample field to quantify the government and operator takes under federal U.S. royalty and corporate income tax rules. The Perdido foldbelt continues on the Mexican side of the Gulf where analog hydrocarbon field have been explored and well tests confirmed oil occurrences (Section 3).

2.2. Mexican energy reform

A new era of competitive development is heralded by the revised energy framework adopted by the Mexican Government ["Ley de Hidrocarburos" - Hydrocarbon Law (HL), DOF (2014)]. As of January 2015, the upstream oil and gas sector will be progressively liberalized to allow for the awarding of licenses and concessions in a competitive bidding process, open not only to Pemex but also to any other operator or a consortium that is a tax resident in Mexico. Eligible parties must comply with a number of requirements, such as prior experience with offshore projects, qualified personnel with a minimum of 10 years of experience, and market capitalization of at least $10 billion with an investment-grade credit rating, or shareholder's equity of at least US$1 billion ($600 million for the lead operator in a consortium, and the remaining $400 million to be covered by partners). The goods and services procured for oil and gas operations under the PSA should observe a minimum national content percentage of 13% for the exploration period, 25% during the development period, and must subsequently grow to at least 35% by 2025.

Competition with Pemex is one of the explicit goals of the energy reform according to the new Hydrocarbon Law. At the same time, the interests of Pemex are accounted for in the new Hydrocarbon Law ("Ley de Hidrocarburos" - Hydrocarbon Law, HL), which states any leases near the cross-border region governed by the U.S.-Mexico Transboundary Hydrocarbons Agreement require at least 20% participation by Pemex (DOF, 2014, Article 17). Pemex participation in projects are further advocated by the Secretariat of Energy (SENER) not to exceed 30% of the investments in tendered projects (DOF, 2014, Article 16).

The Mexican government scheduled in 2015 leasing Round 1 four distinct auctions, each limited to a specific type of assets. The first type of assets comprised 14 shallow-water exploration blocks located on the Mexican seaboard directly west of the Pemex operated Cantarell heavy oil field complex. Only two blocks were awarded and low company response could be explained in part by concerns about certain contractual aspects (Weijermars and Zhai, 2016). The second type of assets auctioned included nine oil fields in five production lease areas of which three were successfully auctioned (see Weijermars and Zhai, 2016). The third type of assets comprised onshore conventional and unconventional assets; the latter were benchmarked in a recent companion study applying U.S./Texas and Mexican license conditions to representative Eagle Ford Shale production profiles (Weijermars et al., 2017). The fourth type of assets are deepwater fields, assessed in the present study, with block dimensions and locations redefined several times before the final bidding guidelines became available on 17 Dec 2015. Some exploration wells with hydrocarbon discoveries have already been drilled (Pemex contractors) in this deepwater region.

3. Gulf production performance and Perdido foldbelt prospects

This section outlines the strategic importance of hydrocarbon production in the Gulf region for North American energy supply (Section 3.1), and then proceeds to a geological description of the Perdido reservoir structure and hydrocarbon discoveries (Section 3.2).

3.1. Gulf Production

The US Gulf of Mexico has produced 22.19 billion bbls of oil and 193 trillion cubic ft gas since major offshore production began in 1953 (BOEM, 2013). Companies first started exploring and producing in shallow federal waters, and gradually moved to deeper and technologically challenging hydrocarbon fields. The Gulf currently accounts for 17% of US crude oil production and 5% of US dry natural gas production (EIA, 2016a). Proved reserves held in US Gulf assets are estimated at 3.67 billion bbls and 11.3 Tcf of natural gas (BOEM, 2013). On the US side, the Perdido Project is an ultra-deep water project, with vertical depths of about 2500 ft below the mudline and extending laterally 7000 to 9000 ft.

Mexico lacks both the capacity and the resources to develop the deepwater prospects in its part of the Gulf. In 2016, Mexico produced 1.7 million b/d primarily from the shallow Bay of Campeche oil fields and another 0.6 million b/d from onshore fields (EIA, 2016b). Although domestic oil production covers 120% of crude oil consumption, allowing for exports, the refinery capacity is limited and Mexico imports refinery products at a rate of 740,000 bbls/day (EIA, 2016b). The domestic production of natural gas in Mexico falls short of consumption, which has been reviewed in detail elsewhere with particular focus on the potential of shale gas development (Weijermars et al., 2017). The Mexican energy reform clearly intends to accelerate the development of hydrocarbons in order to maximize the resource value for the country (Suarez et al., 2016). Some of the first prospects auctioned include the Perdido fold belt assets (Blasco Flores et al., 2016), which makes our assessment timely and relevant.
3.2. Perdido foldbelt prospects

Our Mexican reference field in the Perdido foldbelt (including a portion of the adjacent Port Isabel foldbelt; see Appendix A) comprises two separate tracts, both delineated as Block 1 in deepwater auction Round 1 (Fig. 1b). The two blocks are separated by a region in which several exploration wells were drilled by Pemex in 2012 and 2013. The structure map of Fig. 2 includes the locations of these wells.

**Fig. 2.** Structural province map of northeastern Mexico and adjacent offshore areas, including the Perdido fold belt. The two tracts occupied by auction Block 1 (Dec 2015) are outlined (blue traces). Seismic profiles outlined are given in Fig. 3a,b. Detailed map of U.S. Perdido Field project (red-dotted region) is given in Fig. 4a. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

**Fig. 3.** a: Regional seismic section interpretation across principal tectonic provinces outlined on Fig. 2. The Perdido structural province is characterized by compressional salt-cored folds (boxed region). The zone of extension is in the west; the provinces indicated refer to those shown in Fig. 2. Vertical exaggeration 3.5:1. b: Detailed seismic section interpretation showing hydrocarbon traps in faulted, salt-cored anticlines of the Perdido fold belt (drilled by PEMEX: Maximino-1, Supremus-1) and adjacent western anticlinal trap on flank of a salt ridge in the southern continuation of the U.S. Port Isabel fold belt (structural region 5 on Fig. 2). Green dots: oil reservoir. For Maximino: Wilcox & Frio; For Supremus: Miocene; for Trion: Frio. Vertical exaggeration 2:1. (Upper section from CNH, 2015a; Lower section modified from Colmenares, 2014).
Fig. 4. a: Lease map with outlines of the fields in the Perdido Project (courtesy Wood Mackenzie). b: Great White amplitude and structure map shows the development wells and contingent wells. A submarine canyon meanders at the SE outline of the field. The Great White structure is a doubly plunging salt cored anticline, with crestal collapse due to normal faulting (Eikrem et al., 2010). c: Synthetic depositional process-based model of delta sands displaying internal barriers and baffles due to compositional and grain size changes. Left panel shows top view and horizontal section, right panel shows vertical cross-sections proximal and distal to the sediment supply source. Such process-based models can provide analogs and statistical inputs for architectural elements of the Perdido reservoir model (after Hongmei et al., 2009).
(Exploratus, Supremus, Trion, Maximino and PEP). Only PEP was dry, but the other wells had prospective resources estimates at 75–200 MMbbls each. The reservoir for Maximino is Early Eocene Wilcox, with flow test showing oil rate at 3796 bbl/d and associated gas at 15 bcf/d (Pemex data). Pemex has indicated it is open to 75% partner share in a farm-out of the oil prospects sourced by Exploratus, Supremus, Trion and Maximino. Our field development concept leaves open the possibility of a future tie-in of these fields with Pemex 25% profit share in production.

The Perdido foldbelt contains all the elements of a robust and proven petroleum system. The traps are mostly four-way closures formed by the salt-cored anticlines (Jackson and Hudec, 2017), with source rock, reservoirs, and seals all within the structures (see details in Appendix A). Shallow reservoir levels may be dissected by normal faults and thus compartmentalized, as is visible on seismic sections for the Mexican continuation of the Perdido foldbelt (Fig. 3a,b). These faults, as well as deeply cutting unconformities, may negatively impact seal and containment on some of the more landward traps. Comparison of the U.S. Perdido structures (Appendix A, Figs. A1 and A2) and Mexican Perdido style (Fig. 3b) suggest the Mexican continuation of the Perdido foldbelt (Fig. 3a,b). These faults, as well as deeply cutting unconformities, may negatively impact seal and containment on some of the more landward traps. Comparison of the U.S. Perdido structures (Appendix A, Figs. A1 and A2) and Mexican Perdido style (Fig. 3b) suggest the Mexican continuation of the Perdido foldbelt (Fig. 2). The detailed location of each field is outlined on Fig. 4a. Great White, discovered in 2002, is the largest field of the Perdido Project, hosted in a very large, heavily-faulted anticline of the Perdido foldbelt (Fig. 4b). The Great White structure is cut by a deep submarine canyon and fault-controlled escarpments in the sea floor may rise 1500 feet (457 m) high (Fig. 4b). These escarpments indicate neotectonic activity that continues into the Pleistocene and present day. Exploration and appraisal took place in 2004. Compartmentalization of the reservoir is not only due to faulting; depositional barriers and baffles are also likely to occur throughout the reservoir (Fig. 4c). Some of the fine-grained deposits (blue hues in Fig. 4c) may prevent reservoir communication. Individual reservoir sections have to be drained by individual wells, some of which may be side-tracks of wells that earlier depleted other sections of the reservoir (Ju et al., 2010).

Perdido’s first wells were drilled from mobile offshore drilling units, which allowed development of the field to start while the spar was being built (Lohr and Smith, 2010; Snyder and Townsley, 2010). A deepwater record was set in December 2008, when a production well was completed in 9356 feet (2852 m) of water. A further 22 wells were pre-drilled to about 2500 feet below the mud line near the planned spar location about 215 miles from shore. As of 2016, nine production wells have been deepened to the hydrocarbon target zones and the remaining wells will be stepwise developed. The original field development plan scheduled for all wells to be completed by 2020 (Eikrem et al., 2010).

4. Economic appraisal of U.S. Perdido field development project

In order to benefit from the analogy of the hydrocarbon field assets at either side of the TBZ, we first describe the Perdido field project developed in the U.S., 5 nm north of the maritime border with Mexico defined by the Delimitation Line. Partly based on the details of the Perdido Project on the U.S. side, the field development concept and costing for the Mexican deep water reference field (Block 1) are subsequently developed (Section 5).

4.1. U.S. Perdido project details

The Perdido project on the U.S. side comprises four oil fields: Great White, Gotcha, Silvertip and Tobago. All these fields are located in the core region of the Perdido foldbelt (Fig. 2). The detailed location of each field is outlined on Fig. 4a. Great White, discovered in 2002, is the largest field of the Perdido Project, hosted in a very large, heavily-faulted anticline of the Perdido foldbelt (Fig. 4b). The Great White structure is cut by a deep submarine canyon and fault-controlled escarpments in the sea floor may rise 1500 feet (457 m) high (Fig. 4b). These escarpments indicate neotectonic activity that continues into the Pleistocene and present day. Exploration and appraisal took place in 2004. Compartmentalization of the reservoir is not only due to faulting; depositional barriers and baffles are also likely to occur throughout the reservoir (Fig. 4c). Some of the fine-grained deposits (blue hues in Fig. 4c) may prevent reservoir communication. Individual reservoir sections have to be drained by individual wells, some of which may be side-tracks of wells that earlier depleted other sections of the reservoir (Ju et al., 2010).

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![Fig. 5. Field development outlay of the Perdido project at U.S. side of the TBZ (Lohr and Smith, 2010).](image-url)
The Perdido Project field layout and development solution is illustrated in Fig. 5. The central spar facility ties-in production from fields within a 30 mile radius (48 km). Water depth ranges between 8000 and 9500 feet. Tables 1a–1e provide key parameters used in our costing and development of the Perdido project. Total operating expenditure (opex) for the Spar is estimated at $50 million per year, which is prorated over the various project accounts according to production throughput. Additional variable opex is also a function of which is prorated over the various project accounts according to expenditure (opex) for the Spar is estimated at $50 million per year, costing and development of the Perdido project. Total operating eight fields within a 30 mile radius (48 km). Water depth ranges between fields for each are expected to produce at initial rates of 7000–9500 bbl/day. Expected production profiles for each field are given in Fig. 6 (left panel).

### 4.2. U.S. cash flow performance

For the U.S. we make use of the proprietary assessment of the Perdido project based on Wood Mackenzie’s proprietary Global Economic Model (GEM). The model uses operator data and constructs a discounted cash flow model based on standard financial accounting principles and takes into account depreciation allowed under a given fiscal regime. Fiscal terms are 12.5% royalty because the water depth exceeds 800 m. Leases were awarded when the Deepwater Royalty Relief Act (DWRRA) was in place, which translates to a royalty suspension volume of 87.5 mboe of initial production. Oil and gas prices used for the NPV and IRR estimation given in Table 1c are for oil $53.50/bbl in 2015 with future price adjustments equating to $81.47/bbl from 2019 onward. For the gas price $2.90/mcf was used for 2015 with adjustments equating to $3.61/mcf from 2019 onward. Assumed field life is 39 years for Great White, 20 years for Silvertip and 16 years for Tobago.

The estimated revenue and net cash flow performance for the principal fields of the U.S. Perdido project are detailed in Fig. 6 (right panel) using the assumed production profiles (Fig. 6, left panel) and inputs detailed in Tables 1a–1e (royalties, transportation tariffs and commodity prices are given in Section 4.1). The revenue partitioning due to the field owners is 27.4% versus 23.4.5% government share (royalties plus income tax) and capex plus opex consuming 49% of revenues (Fig. 6, pie diagram). The profit splits into 54% contractor take (23.3/50.7) and 46% government take (27.4/50.7).

### 5. Economic appraisal of Perdido prospects in Mexico

After tax cash flow models, one using the typical U.S. federal tax regime (Section 4.2), the other one using the Mexican profit sharing fee structure (Appendix C), were assessed to compare the economic performance of the adopted Perdido deepwater projects at either side of the U.S.-Mexico fiscal border. Section 5 outlines our assumptions and results for the Mexican cash flow model. Subsequently, Section 6 compares the Mexican field project economics of Section 5 to that of the U.S. Perdido project performance detailed in Section 4.
Table 1e
Details SPAR weight and capacity; pipelines.

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Fig. 6. Left panel a–c: Production profiles for fields in the U.S. side Perdido Project. Camel hump profiles of each field are due to assumed work-over and sidetracking of wells halfway through the field life-cycle. Right panel a–c: Breakdown of annual revenue into cost, government take and net cash remaining for the operator (undiscounted). Bottom Pie-diagram: Total revenues over lifecycle of project breakdown in operator cost (capex, opex), taxes (royalty and income tax) and net cash attributable to the company (Courtesy Wood MacKenzie).
We generated a field development plan for the Mexican prospects in northern auction Block 1 (Fig. 2) using Schlumberger FieldPlan offshore software to obtain cost estimates for field development as inputs for our fiscal benchmark study. FieldPlan takes into account production facilities, subsea architecture, wells and export options to develop an economic model of the field. The software uses representative industry values for key facility components that lead to a reasonable first pass results. Although this software has many capabilities, we limited its use to the estimation of the capital expenditure (CAPEX) and the operational expenditure (OPEX) only.

Adoption of the field development solution of the Perdido project on the U.S. side of the border is not possible for Perdido prospects in Mexico. A major difference is that the Mexican prospects are best developed with a Floating Production, Storage and Offloading (FPSO) system rather than a spar, which eliminates the need for a fixed pipeline connection to shore. Instead, the FPSO system uses leased shuttle tankers to bring the oil to market. Water depth is assumed to be 8500 feet and the target zone occurs 15,000 feet below the mudline. Reservoir pressure is 10,000 psi and we have a black oil reservoir. We assume the well fluid has low sulfur and low CO2 content. Auction block 1 in the Perdido foldbelt currently has estimated risk-adjusted prospective resources of 232 MMbbl. Our field development plan is contingent upon future exploration establishing minimum P50 reserves to be 200 MMbbl.

In order to benchmark the numbers for OPEX and CAPEX obtained from FieldPlan we first used the known US Perdido project. The project consists of a SPAR connecting three fields. The main field, Great White/Gotcha, is the closest of the three being underneath the production facility. The two satellite fields, Tobago and Silver Tip, are 6 and 8 miles from the production risers respectively.
assumptions critical to the calculation of the OPEX and CAPEX for the US Perdido project cost benchmark are given in Table 2.

Experienced engineers (Mr. Joseph Ayyoubi, Petrobras, Houston) recommended adding 30% to the cost produced by FieldPlan as only the main components of the field development concept are accounted for in the modeling template. The 30% cost up mark is a common industry practice based on historical results obtained with this software to ensure a more realistic outcome. Using this approach, the total development cost previously estimated by Wood MacKenzie (Table 3) only differs by 1.07% from the result obtained using FieldPlan with a cost database module of November 2014. We interpret the convergence of results summarized in Table 3 as a validation of OPEX and CAPEX obtained using FieldPlan.

Next, the FieldPlan software was used to estimate OPEX and CAPEX for the Perdido field development project at the Mexican side of the TBZ. Some differences in the field development concept of Mexican GoM include the use of a Floating Production Storage and Offloading (FPSO) instead of a SPAR, the number of wells and the oil export system. Mexico does not have an infrastructure similar to the US, and it would be cost-prohibitive to build a pipeline connection to an onshore terminal. The FPSO eliminates this problem as it has storage capacity, and a shuttle tanker transports the oil to an onshore base. Table 4 shows the input parameters used for the estimation of the field development costs. Table 5 summarizes the total opex and capex cost estimates for our initial field development concept for the Mexican Perdido prospects.

### 5.2. Mexico production profiles and cash flow model

The cash flow model developed in our study for the Mexican case is developed independent from GEM (Section 4.2) in order to properly account for the detailed royalty structure in Mexican contracts. Production profiles for the Mexican Perdido project were based on nodal analysis using an integrated production system approach (detailed in Appendix B). The production system model allows us to generate analogous production profiles for wells with natural drive and artificial lift (with and without waterflooding) assuming a material balance method and analytical expressions detailed in Appendix B. The coupling of such a detailed (history matched) production model with a detailed cash flow model is unique and has not been achieved in any previous study.

The Mexican model contract for deepwater assets was published in the guidelines that govern the bidding process (CNH, 2015b, 2016). Our economic appraisal and sensitivity analysis below uses the key algorithms specified in the model contract, which may be characterized as elaborate and complexly formulated. For purpose of a comprehensive and reproduceable research approach we summarize the key rate formulas for quick reference in Appendix C. The fiscal algorithms of Sections C1 to C3 were built into an EXCEL spreadsheet accounting for oil price scenarios, production output, costs, lease block rental fees, various royalties (base royalty, override royalty (ORR) and any royalty adjustments triggered by operator profit thresholds) and corporate income tax.

### Table 6
Six asset development options and EUR solutions evaluated in our cash flow model.

<table>
<thead>
<tr>
<th>Production</th>
<th>2 wells – 300 MMbbls</th>
<th>5 wells – 900 MMbbls</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural drive</td>
<td>Option 1: 33.3 MMbbls</td>
<td>Option 4: 166.4 MMbbls</td>
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<tr>
<td>Artificial lift</td>
<td>Option 2: 143.8 MMbbls</td>
<td>Option 5: 324.5 MMbbls</td>
</tr>
<tr>
<td>Waterflooding</td>
<td>Option 3: 300.6 MMbbls</td>
<td>Option 6: 390.6 MMbbls</td>
</tr>
<tr>
<td></td>
<td>EUR: RF=9%</td>
<td>EUR: RF=17%</td>
</tr>
<tr>
<td></td>
<td>EUR: RF=48%</td>
<td>EUR: RF=43%</td>
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<td></td>
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<tr>
<td></td>
<td>EUR: RF=67%</td>
<td>EUR: RF=43%</td>
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### Table 7
Input parameters cash flow models.

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<th>General Assumptions</th>
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<td>Start Year</td>
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<td>Production Stops</td>
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<td>General Inflation</td>
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</table>

<table>
<thead>
<tr>
<th>Key Inputs</th>
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</table>

**Acreage Rental Fees Mexico**

<table>
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<tr>
<th>Acreage</th>
<th>km²</th>
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<tr>
<td>Exploration Period Cutoff</td>
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<tr>
<td>Pre-cutoff</td>
<td>$ / km²</td>
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<tr>
<td>Post-cutoff</td>
<td>$ / km²</td>
<td>187</td>
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<tr>
<td>Production Rental</td>
<td>$ / km²</td>
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**EUR Estimates**

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<tr>
<th>EUR Oil</th>
<th>MMbbls</th>
<th>(Crude)</th>
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<tbody>
<tr>
<td>EUR Gas</td>
<td>MMboe</td>
<td>(Gas)</td>
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</table>

**Benchmark Price**

<table>
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<tr>
<td>API</td>
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<tr>
<td>Sulfur content</td>
<td>%</td>
</tr>
<tr>
<td>Threshold Price An Oil Royalty 2015</td>
<td>$/bbl</td>
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<tr>
<td>Abandonment Cost</td>
<td>$MM</td>
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</table>

**Overriding Royalty Rate as Per Contract Bid**

<table>
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<tr>
<th>ORR</th>
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<th>5%</th>
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<table>
<thead>
<tr>
<th>Tax</th>
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</thead>
<tbody>
<tr>
<td>Income Tax</td>
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</table>

**Prices BRENT & LLS for Commodity Forecast**

| Brent | $ / bbl | 70 |
| LLS   | $ / bbl | 60 |

Changes to the royalty percentage to be paid to the government are triggered by 3 mechanisms: (1) fixed royalty override offered as per contract agreement after bidding (Appendix C, Sections C1), (2) basic royalty changes due to oil price levels (Appendix C, Sections C2), and (3) royalty adjustments triggered by operator return on investment factor (Appendix C, Section C3). The royalty adjustment mechanism takes into account the basic royalty plus any override royalty rate (ORR) offered in the bid offer. We evaluated the impact of ORR values of 0–25%, using a range of oil prices \( P_{COIL} \) between $20/bbl and $140/bbls (in increments of $20/bbl). The split of total project NPV and IRR (after tax) between the contractor and operator is computed for a range of variable input parameters.

The algorithms used to calculate the cumulative of the annual cash flows (NPV) and the internal rate of return (IRR) account for the activation of any royalty change triggers due to oil price changes and adjustment mechanism due to company return on investment factor. We also account for the effect of a range of override royalty offered. The EXCEL-based cash flow model allows us to evaluate the annual cash flows, royalties, and taxes due to the government, including 30% corporate tax on net profits. Because the future prices of LLS and
Brent oil are not known, we assumed in our sensitivity analysis oil prices (Eq. C3a-c) ranging between $20–140/bbl (with increments of $20/bbl and annual inflation of 2.5%). The project performance and sensitivity to oil price fluctuations were evaluated using annual cash flow projections.

5.3. Results of cash flow models for Mexican prospects

Two sizes of assets were appraised in our analysis, each with natural drive, artificial lift and waterflooding options, representing 6 discrete field development options (Table 6). The production profiles for Options 1–3 are given in Figs. B6 and B7 and Options 4–6 closely match Fig. B5 (Appendix B). Our economic appraisal of these options uses base case input parameters as specified in Table 7. The initial oil price given is escalated by 2.5% per year to account for inflation. We developed tailor-made excel spreadsheets for after tax cash flow analysis applying the Mexican royalty structure as explained in Appendix C.

The contractor NPV at 10% discount rate and IRR of field development Options 1–6 were each evaluated for the base case as summarized in Fig. 7a & b. Our results show that the NPV increases for the larger EUR options, but as can be expected decreases with increasing over-royalty percentages (Fig. 7a). We also established that the IRR of project Options 2–6 tend to cluster in a bandwidth confined between 9% and 21% IRR, assuming over-royalties ranging between 0% and 25% (Fig. 7b).

Below we present for brevity only detailed results for development Options 2 and 5. Illustration and discussion of these two project options give sufficient insight in the systematic effects of the taxation regime on the various development solutions and asset sizes.

5.3.1. Field development Option 2

Project Option 2 as distinguished in Table 6 considers a 2 well production model with 48% oil recovery of 300 MMbbls assumed oil in place. The well performance is enhanced by artificial lift using the nodal production system model as detailed in Appendix B.

Fig. 8a,b show the revenue split and total royalty rate, respectively, for the base case over-royalty of 5%, oil price of $70/bbl (Brent with...
escalation of 2.5%) and other parameters as given in Table 7, and the production profiles for artificial lift specified in Fig. B6. Option 2 gives for a $70/bbl a contractor NPV@10 of $287 million (Fig. 9a) and IRR of 13% (Fig. 9b). This is a marginal return on investment, which improves for higher initial oil price assumptions (see later).

We checked for equitable partitioning of revenues between the contractor and government. Fig. 8a separates the annual revenue allocation in field expenses (capex, opex) and government taxation (royalties and income tax), and what net cash remains for the contractor (cash flow). The pie diagram breaks down the total revenue over the field’s life cycle into percentage of revenue spent on capex, opex, government takes and cash remaining for the contractor. The revenue split of 27% contractor and 37% government equates to a 42:58 profit split between contractor and government.

Fig. 8b shows the total royalty percentage of gross revenue due to the government as it evolves over time for initial oil prices ranging between $30 and 150/bbl (Brent with escalation of 2.5%). Early royalty is only comprised of basic royalty (see Section C2) and any over-royalty offered by contractor to the government (see Section C1); 5% ORR was assumed in the sensitivity analysis of Fig. 8b. After recovery of cost, the contractor’s annual profit will increase, which is when the royalty adjustment mechanism is activated (Section C3) leading to steeper increase of total royalty for higher initial oil prices (Fig. 8b). In spite of the royalty increases as oil prices rise (Fig. 8b), the contractor NPV and IRR improve with oil price (Fig. 9a,b). Additionally, the split of undiscounted revenue between government and contractor/operator in terms of percentages remains almost unchanged (Fig. 10).

5.3.2. Field development Option 5

Project Option 5 (Table 6) considers a 5 well production model with 36% oil recovery of 900 MMBbls assumed oil in place. The production profile closely matches the Option for artificial lift in Fig. B5. Fig. 11a,b shows the revenue split and total royalties, respectively, for a base case with 5% over-royalty, initial oil price of $70/bbl (Brent with escalation of 2.5%) and other parameters as given in Table 7. Option 5 gives for $70/bbl a contractor NPV@10 of $1353 million (Fig. 12a) and IRR of 16.8% (Fig. 12b). This project option is clearly profitable for the contractor even with a $60/bbl oil price.

Fig. 11a separates the annual revenue allocation in field expenses (capex, opex) and government taxation (royalties and income tax), and what net cash remains for the contractor. The pie diagram breaks down the total revenue over the field’s life cycle into percentage of revenue spent on capex, opex, government takes and cash remaining for the contractor. The revenue split of 34% contractor and 44% government equates to a 44:56 profit split between contractor and government is equitable and identical to the profit split for U.S leases (see Section 4.2).Fig. 11b shows the total royalty percentage of gross revenue due to the government as it evolves over time for initial oil prices ranging between $30 and 150/bbl (Brent with escalation of 2.5%). Comparing Fig. 11b with 8b, we see the rise in royalty percentage is steeper for Option 5 than for Option 2, due to larger profit being generated for field Option 5 so that the royalty adjustment mechanism applies faster (see Section C3). Again, in spite of the royalty increases as oil prices rise (Fig. 11b), the contractor NPV and IRR will benefit when oil prices rise (Fig. 12a,b). Also the split of undiscounted revenue between contractor and government remains equitable (Fig. 13).

6. Discussion

6.1. Fiscal issues: tax takes

The petroleum industry must continually integrate reservoir and well productivity models with other factors that may affect field economics. A major factor that may sway project investment decisions (either favorably or adversely) is a country’s total tax take: royalty, tax rates and any production share negotiated under a ruling fiscal regime. Countries with frontier plays such as ultradeep-water assets may consider offering a favorable tax regime (e.g., tax takes of 45–55%) in order to attract oil companies that are prepared to invest and take the risk to open up the play. Both the U.S. and Mexico's tax takes for deepwater projects fall into this range fiscal takes split equitably between the contractor and government.
Fig. 11. a: Breakdown of annual revenue into expenditure (capex, opex), total government take (royalty and income tax) and net cash attributable to operator for Option 5. Inset pie diagram shows respective allocations of total revenue to capex, opex, government, and operator net cash. Revenue split is 44% government and 34% contractor. b: Total royalties due to government change with oil price. Ramp in royalty curves is due to royalty increase after contractor has recovered costing first decade of operations. Assumed ORR=5% and initial oil price is $70/bbl.

Fig. 12. a: Contractor NPV at 10% discount rate versus IRR and sensitivity to oil price for Option 5. b: IRR sensitivity directly plotted against oil price show minimum price required for Option 5 to be profitable is about $60/bbl. Assumed ORR=5% and initial oil price is $70/bbl.
This study benchmarked the economic return of deepwater hydrocarbon field development projects located in the Perdido foldbelt at either side of the maritime border between the United States and Mexico. Development of Mexican hydrocarbon reservoirs by foreign operators is now made possible by the energy reforms implemented in 2015.

Our study benchmarked the economic performance of largely analog deepwater fields in the Perdido foldbelt under each jurisdiction to assess the competitiveness of the respective fiscal frameworks. Mexico’s tax take is for deepwater assets is relatively modest amounting for smaller fields (field Options 2, Table 6) to a split of total revenues between government and contractor 37:27 (Fig. 14a), which corresponds to a profit split of 58:42 (see also Fig. 8a). For bigger fields (field Option 5, Table 6) the total revenue split for government and contractor is 44:34 (Fig. 14b), which corresponds to a profit split of 56:44 (see also Fig. 11a). The U.S. profit split resulting from a 23:27 government versus contractor take of total revenues gives a profit split of government:contractor of 46:54 (Fig. 14c, see also Fig. 6). For comparison, the average global tax take on net income from operations in the upstream oil and gas activities amounts to 70% (IMF, 2012; Weijermars et al., 2014), which means fiscal takes of 56-58% in Mexico and 46% in the US for deep-water assets in the Gulf are well below the global average. Unlike the Mexican 2015 production sharing contracts for shallow-water assets, which were evaluated as less attractive for company investments (Weijermars and Zhai, 2016), profit sharing contracts for deepwater assets in Mexico equitably share profits between the contractor and the government and thus will stimulate investments.

6.2. Auction Outcome

Mexico’s first deep water assets in the Gulf came up for auction after invitation to bid, December 2015 (Bidding Round 1, Phase 4), with license awards announced in December 2016. Block 1 studied here was awarded to China National Offshore Oil Corporation (CNOOC) E & P Mexico (CNH, 2017), which offered in its bid an investment factor of 1.5 and 17.01% over-royalty (ORR). Our independent academic study (non-partisan) was completed before the auction results became available. The following insights were added in proof print stage.

According to our cash flow assessment (Fig. 7 b), the ORR of 17% offered by CNOOC for Block 1 may result in a minimum contractor IRR of 15% or higher for the following options: when the reserves exceed 166 MMbbl with the production mechanism being natural drive (Option 4, Table 6), when reserves exceed 325 MMbbl assuming artificial lift (Option 5, Table 6), or when reserves exceed 390 MMbbl assuming water-flooding (Option 6, Table 6). The corresponding NPVs are given in Fig. 7 a for each option (assuming $70/bbl oil price), and for ORR=17% gives an NPV of $600 million (Option 4), $1,000 million (Option 5), and $1,200 million (Option 6).

Our sensitivity analysis of contractor NPV and IRR for the larger asset size (Option 5, Fig. 12 a,b) showed that oil price needs to exceed $60/bbl for the project to meet the hurdle rate (15%). However, our analysis in Fig 12 a,b used a modest ORR of 5%, and the oil price needs to be $70/bbl or higher for CNOOC to be able to realize the minimum IRR of 15% for the offered ORR of 17% (Fig. 7 b).

Several important conclusions can be drawn from our cash flow and sensitivity analysis in combination with the actual bid of CNOOC. First, the company apparently expects long-term oil prices to recover above $70/bbl for their project to become profitable. Second, if oil prices indeed rise above $70/bbl, additional profit sharing triggers will benefit the Mexican government, but contractor IRR will still climb, and reach...
about 25% royalty for a $100/bbl oil price (see Fig. 12 b for trend). Third, the profit-sharing contract offered by the Mexican government in Bid Round 1 provided enough incentives for a major company like CNOOC to assume the risk for deep-water development and act as a play opener on the Mexican side of the Gulf. Fourth, the contract terms seem equitable for both the government and the contractor, while leaving little room for even sharper fiscal rates. Our assessment confirms that even when a company offers a considerable over-royalty to the Mexican government (17%), the IRR for the contractor still remains in an acceptable 15-17% range (Options 4-6; Fig. 7 b) for an assumed oil price of $70/bbl.

6.3. Field unitization

We anticipate the Mexican Perdido project for Block 1 to further benefit from potential unitization with Pemex assets (including the fields tapped by the Exploratus, Supremus, Trion, Maximo and PEP wells). Such unitization would multiply the resource volume several times over and would boost the project economics, provided a suitable agreement can be reached with Pemex. Cross-border evacuation of oil via the US pipeline currently serving Shell’s Perdido project may lower opex. Note that Table 5 gives the cost estimates (opex and capex) for Mexican development Option 6 (Table 6) and are different from the values in Fig. 14 which shows the capex and opex for Options 2 and 5. FieldPlan® software, used to estimate total capex and annual opex, assumes a different production profile than the one obtained by using nodal analysis. The latter approach used in our final models forecasts higher production profiles, which increases the field’s life and thus the operational costs (opex) of the project. Additionally, using the FPSO rather than a fixed pipeline for evacuation of the produced oil results in opex being relatively high for the Mexican project development Options.

6.4. Compartmentalization

One of the main challenges in developing certain sections of the Wilcox formation is compartmentalization due to both faulting and the occurrence of internal clay beds deposited by a turbidite system with large distal and proximal permeability heterogeneity (Fig. 4c; Hongmei et al., 2009). A reservoir is compartmentalized if reservoir fluids cannot communicate between compartments over production time scales (Smalley and Muggeridge, 2010). The effect is that field development solutions may need to be adjusted or remain suboptimal when reservoir compartments remain undetected during initial field appraisal based on limited subsurface data (seismic, logs, well tests). Undrilled compartments will not contribute to drainage and, if such compartments were not recognized prior to field development, existing wells will drain a reservoir section that is smaller than anticipated. Thus, unrecognized compartments will negatively impact the economic returns of the monetary investments in the field. As the Wilcox sands are part of a turbidite system (Meyer et al., 2005), the number of wells required to develop the prospects remains conjectural.

6.5. Oil price sensitivity

The contractor and government profit split for MX stays nearly the same for all oil prices (Figs. 10 and 13) and MX government take is somewhat higher than for the US (Fig. 6). Furthermore, the royalty rate for US is fixed at 16.6% (or lower when deepwater royalty cuts are offered) and for MX increases rapidly with oil price. Consequently, the contractor take in the US would for oil prices higher than used in Fig. 6 be increasingly larger than US government take and therefore more advantageous than MX deep-water contracts. In Mexico deep water contracts, profits are split more equitably between contractor and government than in the US. Clearly, US offshore royalties favor the contractor, which explains why the US Gulf of Mexico has succeeded in its role as the world’s prime play to foster industry investments in developing and implementing cutting-edge deep-water technology.

7. Conclusion and policy implications

This study is the first to analyze the effects of Mexico’s new profit sharing contracts and policies for development of its deep-water hydrocarbon assets. This is the next step in the direction of North American energy independence. Our review of profit-sharing contracts for deepwater assets is complementary to the review of Mexico’s new production-sharing contracts for shallow-water assets (Weijsmarns and Zhai, 2016). Development of deepwater assets in the Gulf’s Transboundary Zone is feasible from either side of the maritime border. The federal fiscal takes imposed by the U.S. are more favorable for the contractor than in Mexico. One drawback of the Mexican profit-sharing contracts is the complex formulation of the royalty schedule.

We have systematically appraised the economic returns on deepwater field development project options for the Perdido fold belt in the Gulf of Mexico using after tax cash flow analysis. For large fields, using current cost of technology obtained from FieldPlan and applying production profiles generated with nodal analysis, our sensitivity analysis shows field development is profitable for oil prices above $60/bbl both in the U.S. and Mexican sections of the Gulf of Mexico, assuming a modest over-royalty of 5%. For smaller resource volumes (300 MMbls OOIP or less), the minimum hurdle rate of 15% IRR is exceeded when oil prices rise above $75/bbl. Currently, the largest impediment for rapid development of ultra-deep water assets in the Gulf of Mexico are the low oil price and gas prices prevailing at the time our study was completed (Dec 2016). However, when oil prices continue their rebound and rise above the critical threshold for profitable field development, we expect companies will return to develop new deepwater projects both in the U.S. and Mexican sections of the Gulf, because the NPV and IRR of such fields then become attractive again.

Acknowledgements

Mr. Joseph Ayyoubi (Petrobras, Houston office) is gratefully acknowledged for several discussions in December 2015 on input parameters to be used for FieldPlan. Mr. Jia Zhai kindly arranged for access to Wood Mackenzie files on the U.S. Perdido project. Mr. John Richardson is thanked for helpful support in programming Visual Basic to improve the efficiency of cash flow spreadsheets used in our study. We emphasize our analysis has been performed from an independent vantage point, being sponsored neither by the Mexican government nor any oil company active in the bidding process.

Appendix A. Supporting information

Supplementary data associated with this article can be found in the online version at doi:10.1016/j.enpol.2017.05.001.
Nomenclature

API American Petroleum Institute
AR Adjustment Royalty
Bbl Barrels
Boe Barrel of Oil Equivalent
BOEM Bureau of Ocean Energy Management
Capex Capital Expenditure
CHN National Hydrocarbons Commission
CNH National Hydrocarbons Commission
CP Royalty Shares Paid
CT Capex and opex incurred to explore and extract the hydrocarbons
CR Cost Recovery
CRO Contractor’s operational results
DL Delimitation Line
DOF Diario Oficial de la Federacion
DOI Department of Interior
DWRRA Outer Continental Shelf Deepwater Royalty Act
EBITDA Earnings before Interest, Taxes, Depreciation and Amortization
EEZ Economic Exclusion Zone
E&P Exploration and Production
Eq. Equation
EUR Estimated Ultimate Recovery
FR Correction Factor
FPSO Floating Production, Storage and Offloading system
ft Feet
GALP The Galp Energia Group
GAO Government Accountability Office
GEM Global Economic Model
GOM Gulf of Mexico
GOR Gas-oil Ratio
HL Hydrocarbon Law
HP Horse Power
HRL Hydrocarbons Revenue Law
IEEH Federal exploration and exploitation taxes of hydrocarbon activities
IF Investment Factor
IMF International Monetary Fund
IRR Internal Rate of Return
J Productivity Index
kg Kilogram
km Kilometers
km² Square Kilometers
LHR Hydrocarbons Revenue Law
LLS Louisiana Light Sweet Crude
MD Total Length
mi Mile
MMbbls Million Barrels
MMboe Million Barrels of Oil Equivalent
nm Nautical mile
NPV Net Present Value
OOIP Original Oil in Place
Opex Operating Expenses
ORR Override Royalty
PEMEX Petróleos Mexicanos
Psi Pounds per square inch
PSA Production Sharing Agreement
ROC Result of Contractor
STB Stock Tank Barrels
TBZ Transboundary Zone
THA Transboundary Hydrocarbon Agreement
TVD Total Vertical Depth
US United States
VCH Value of produced hydrocarbons
VOL Volume
VP Value Points
WM10 Wilcox sand Lower Paleocene
WM12 Wilcox sand Lower Eocene

References


