KEY ECONOMIC DRIVERS IMPACTING EAGLE FORD DEVELOPMENT FROM RESOURCE TO RESERVES

A Thesis

by

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ABSTRACT

The Eagle Ford shale of South Texas has become one of the most active and most important shale plays in the U.S. This success has been possible because of the unique geology and richness of the play, allowing significant production of natural gas, condensate liquids, and oil; the rapid improvement of long horizontal lateral drilling and multi-stage hydraulic fracturing completion technologies; and a long-term period of sustained high oil prices.

This study develops a probabilistic before-tax economic model to estimate the reserves of the Eagle Ford shale, under different stochastic parameters and scenarios usually not considered by evaluators. The model is used to assess impact and sensitivity on reserves and economic yardsticks considering the variability and uncertainty of project inputs such as production streams, commodity prices, capital investments, and operational costs.

We use existing probabilistic methodologies for production and price forecasting and use public and private sources to develop statistical distributions for additional parameters, including differentials for commodity prices, natural gas content for the different production regions, and water/gas and water/oil ratios.

We consider three evaluation scenarios–single-well, 100-well, and Full-well–in each of the proposed production regions of the Eagle Ford shale, with calibrated probabilistic inputs for each region. Single-well results show how it is hard to produce complete distributions of reserves all across the play, although production regions with better productivity are identified. Results from the scenarios with multiple wells, show how the commerciality of the considered development projects is achievable in liquid-rich production regions and with moderate to high price forecasts.

This study provides useful information and results to oil and gas professionals about key areas that influence the commercial development of Eagle Ford shale. The methodology to perform evaluations with probabilistic components enables better project development and investment decisions and can be applied to other shale plays.

DEDICATION

I dedicate my thesis to my parents Nelson and Marina, my siblings Bibiana, Felipe, and Lina for their support and love.

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NOMENCLATURE

AAPG	American Association of Petroleum Geologists
API	American Petroleum Institute
Avg OpEx	Average operational expenses
bbl	Barrel
Bbbl	Billion (10^{12}) barrels
BCF/Bcf	Billion (10^{12}) cubic feet
BO/Bo	Barrel of oil
BOE/Boe	Barrel of oil equivalent
BW/Bw	Barrel of produced water
CapEx	Capital Expenditures
CPI	Consumer Price Index
D&C	Drilling, completion, and tie-in
DCA	Decline curve analysis
DD&A	Depreciation, depletion, and amortization
EIA	U.S. Energy Information Administration
EUR	Estimated ultimate recovery
F&D	Finding and development
GOR	Gas/oil ratio
IHS	Inverted hockey stick
HP/HT	High-pressure and high-temperature

LOM	Level of maturity
Mcfe	Thousand cubic feet equivalent
MCMC	Markov Chain Monte Carlo
MLIS	Mixed-Layer Illite/Smectite
MM$	Million (10^6) U.S. dollars
Mmbtu	Million (10^6) British thermal units
Mscf	Thousand standard cubic feet
nd	Nano (10^{-9}) darcy
NPV	Net present value
OpEx	Operational expenses
PDCA	Probabilistic decline curve analysis
$P_{ceiling}$	Ceiling or high limit price
$P_{current}$	Current commodity price
P_{floor}	Floor or low limit price
P_{max}	Maximum historical present-day price
P_{min}	Minimum historical present-day price
PRMS	Petroleum Resources Management System
SGS	Sequential Gaussian Simulation
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
SS	Schwartz-Smith two-factor price model
TRR20	Technically Recoverable Resources of 20 years

TCF/Tcf	Trillion (10^{12}) cubic feet
TOC	Total organic carbon
WGR	Water/gas ratio
WI	Working interest
WOR	Water/oil ratio
WPC	World Petroleum Council
WTI	West Texas Intermediate

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CHAPTER I

INTRODUCTION AND LITERATURE REVIEW

We begin this chapter with a brief introduction to the Eagle Ford shale development and the challenges and difficulties associated with the estimation of the oil and gas reserves. Then we discuss published evaluations of resources and reserves in the Eagle Ford shale and existing probabilistic methodologies to perform these evaluations. Finally, we explain the objective of the current study and the methodology used to achieve it, and then describe the organization of the other chapters of the thesis.

Problem statement

Since 1970, the exploration and production of hydrocarbons have been taking place in complex, deeper, and more hostile plays such as deep off-shore, artic, high-pressure and high-temperature (HP/HT), and unconventional shale gas and oil reservoirs. The Eagle Ford shale of South Texas is an unconventional formation long known as a resource rock, which since 2008, has become a successful and productive play. This has been possible due partially to its excellent geologic and reservoir properties, with the clear identification of three production areas–black oil, condensate-rich, and dry gas–and the resulting high production of liquid hydrocarbons (Chaudhary et al. 2011; Martin et al. 2011).

Two other key factors related to the success of the Eagle Ford development are (1) the advances in long-lateral horizontal drilling and multi-stage fracture technologies and (2) the current period of high oil prices and favorable market conditions for oil and condensate liquids (Chaudhary et al. 2011). All these factors have resulted in rapid development strategies for the Eagle Ford shale, with the exception of the dry gas production area where low natural gas prices that have been a major burden for operators and projects during the last two years (Martin et al. 2011; Wan et al. 2013).

Development of reservoirs like the Eagle Ford shale have brought new technical and economic challenges that affect estimation and evaluation of reserves, which constitute a key aspect of exploration and production projects in the oil and gas industry (Gonzalez et al. 2012). Evaluators and companies have mainly used deterministic methods to estimate reserves for their projects. However, methodologies that do not address uncertainty can lead to project evaluations that are either overestimated or underestimated and adversely impact the effectiveness of project development and investment decisions (Caldwell and Heather 1991).

In the Eagle Ford shale case, this becomes a critical issue. Because this play is still in an early stage of production and development, it is subject to high uncertainty in production modeling and forecasts, lack of optimization in drilling and completion strategies, and expensive finding and development (Bazan et al. 2012).

A study published in 1976 (Capen) demonstrated how engineers and professionals working in the oil and gas industry failed to handle uncertainty correctly even in very simple tasks. More recently, Dossary and McVay (2012) discussed how even when the perception of high profitability and project success in the oil and gas industry is generalized, projects and evaluators are still underperforming. Moreover, the study concluded that mishandling uncertainty ultimately is very costly.

Status of the question

As of April 2013, the following studies have been published to estimate resources and reserves in the Eagle Ford shale:

- The U.S. Energy Information Administration (EIA) (2011) published an assessment for technically recoverable resources in different U.S. shale plays, including the Eagle Ford shale. The results obtained for the Eagle Ford were 21 Tcf of gas and 3 Bbbl of oil. However, the EIA also reported major uncertainty in the results and stressed that more information was needed to improve them.
- Baihly et al. (2010) performed a comparison of gas production from different unconventional plays in the U.S. The analysis for the Eagle Ford shale included 46 wells drilled during 2008 and 2009 in Dimmit, DeWitt, LaSalle, Live Oak, McMullen, and Webb counties with lateral length averages of 5,000 ft. and 12-14 fracturing stages per lateral. They reported an Estimated Ultimate Recovery

(EUR) of 3.793 Bcf with a breakeven price of $6.24/Mscf, considering deterministic evaluation parameters of:

Drilling and completion costs:	MM$5.8/well
Operating costs:	$1.5/Mscf
Royalty:	25%

- Fan et al. (2011) presented an analysis of the potential of gas and oil reserves in the Eagle Ford shale, where high productivity areas, also known as production sweet spots, were identified considering geologic properties trends and the production data from 862 horizontal wells. An average potential of 600,000 bbl/well over a 60-month period was identified, with the best gas producers in LaSalle and Webb counties. The best condensate producers were found in Live Oak, Karnes and DeWitt counties. This study did not include any economic component in its analysis.
- Swindell (2012) performed an analysis of EUR for the 10 most active counties in the play (Atascosa, DeWitt, Dimmit, Gonzales, Karnes, LaSalle, Live Oak, Maverick, McMullen, Webb) for a total of 1,041 horizontal wells. An average EUR of 206,800 BOE/well was estimated; the best results were found in DeWitt (403.715 BOE/well), Live Oak (248,818 BOE/well), and Karnes (210,801 BOE/well) counties. This study included economic limit analysis with the following deterministic parameters:

Interests:	100% working, 75% net revenue
Oil price:	$100/bbl (constant)

Gas price: $4/Mcfe (constant)

Operating costs: $3,000/month/well

Taxes: Texas severance for oil 4.6%, for gas 7.5%, and 2.5% ad valorem.

Private operators with projects and working interests in the Eagle Ford shale also publish reports including reserves estimates, limited to their leases and properties. Although, they usually do not include specific information about evaluation parameters and methodologies used (Swindell 2012).

One way to improve evaluations and to properly assess and quantify uncertainty in reserves estimations is to include probabilistic parameters and techniques. Caldwell and Heather (1991) and Capen (2001) revealed how reserves estimates with uncertainty assessment can be obtained by using probabilistic distributions to model some of the evaluation parameters, which delivered additional useful information for decision makers. Some other important aspects to consider as sources of errors when estimating and evaluating reserves are production decline curves, capital expenditures, operating costs, and commercial economics, which can be handled as probabilistic variables as well (Harrell et al. 2004).

Additionally, variability in oil and gas prices has a major impact on reserves estimations and other economic yardsticks of projects (Hastenreiter et al. 2012).. Flat-price scenarios are widely used by evaluators and companies, but these fail to measure the effect of price changes, either positive or negative, in reserves estimations especially in the short-term when most capital investments take place (Garb et al. 1981; Olsen et al. 2005b).

There are different methodologies to generate commodity price forecasts, such as the Inverted Hockey Stick (IHS) (Akilu et al. 2006) or the Schwartz-Smith (SS) two-factor price model (Jafarizadeh and Bratvold 2012), that can produce price scenarios with variability in the short-term and market price equilibrium in the long-term and, therefore, yield a greater range of possible results of reserves and other project economic yardsticks (Jablonowski and MacAskie 2007; Olsen et al. 2005b).

Research objective

The objective of this research is to:

- Estimate the range of economic outcomes under uncertainty for development projects in the Eagle Ford shale of south Texas.

General approach

This study considers variability and uncertainty related to key factors involved in the process of estimating of reserves in the Eagle Ford shale. It enables improved project development and investment decisions with an enhanced understanding of possible future results.

Probabilistic methods were used to assess uncertainty and to obtain educated and accurate ranges of possible results of evaluation of different development projects in the Eagle Ford shale. A Probabilistic Decline Curve Analysis (PDCA) methodology was used to generate production estimates (Gong et al. 2011a; Gonzalez et al. 2012). Different oil and gas prices scenarios were obtained with using the IHS methodology (Akilu et al. 2006). Similarly, probabilistic distributions for capital expenditures and operational expenses were built and used to assess variability in finding and development economics.

Finally, a probabilistic before-tax cash flow model was built to estimate the reserves of the play. It includes both single and multiple well scenarios including variability among production regions across the play. Likewise, results of comprehensive reserves estimation for the Eagle Ford shale are presented with sensitivity analysis to diverse production profiles, costs optimization, and different price forecast scenarios.

Research overview

In order to achieve the proposed research objective the following tasks were performed.

1. Reviewed the literature of:
    - Probabilistic decline curve methodologies used to assess shale resources
    - Eagle Ford shale reserves and economic evaluations
    - Probabilistic reserves evaluation and uncertainty quantification
    - Oil and gas prices probabilistic forecasting.
2. Identification and collection of data required to perform the study (e.g. production data, technical and economic parameters) from public and private (if available).
3. Definition and selection of appropriate methodologies to conduct the study. The probabilistic before-tax economic model was developed using Microsoft Excel and Palisade @Risk.
4. Estimation of reserves of the Eagle Ford shale in different scenarios. This also included:
    - The definition of probabilistic distributions for the different technical and economic model inputs
    - The integration of probabilistic methodologies for production and commodity prices forecasting
    - The aggregation of the probabilistic reserves to the play level.

Chapter II provides a description of the Eagle Ford shale of south Texas, with an overview of the geology, fluids system, and current drilling and completion strategies applied to the development wells. Then Chapter III presents the before-tax cash flow model used to estimate reserves in the Eagle Ford shale, describing the components of the model and considerations used in all the scenarios. Chapter IV contains the results of estimation of reserves of the Eagle Ford shale calculated under the different scenarios described in Chapter III. Finally, we summarize the main conclusions from this study.

CHAPTER II

THE EAGLE FORD SHALE OF SOUTH TEXAS

In the first chapter we described the approach, objective and methodology used in this study to estimate the reserves of the Eagle Ford shale of south Texas. This chapter provides a general overview and description of the Eagle Ford play geology, fluids systems, and the current drilling and completion strategies used in the development wells. We emphasize the high complexity and heterogeneity of the play, which impose many challenges when forecasting oil and natural gas production, and estimating resources and reserves.

Eagle Ford geology

The Eagle Ford shale of south Texas is an unconventional shale oil and gas play, long known as source rock for the Austin Chalk and Woodbine sand formations. Since October of 2008, when the first horizontal well was drilled and hydraulically fractured, it has been successfully developed as a self-sourcing hydrocarbon reservoir. The play is named after the town of Eagle Ford, Texas, where the formation can be seen on the surface. It covers an approximate area of 11 to 12 million acres (Chaudhary et al. 2011; Martin et al. 2011).

The formation extends from the outcrops found along the northern border of the Maverick basin going northeast through San Antonio, Austin and Dallas. It dips south towards the Gulf of Mexico up to the Edwards and Sligo shelf margins, where its depth exceeds 14000 to 15600 ft. From west to east, **Figure 1** shows how the Eagle Ford spreads from the Texas-Mexico border up to the eastern borders of Lavaca, Brazos and Robertson counties. For the purposes of this study, the eastern borders of Dewitt and Gonzalez counties limit the area of interest.

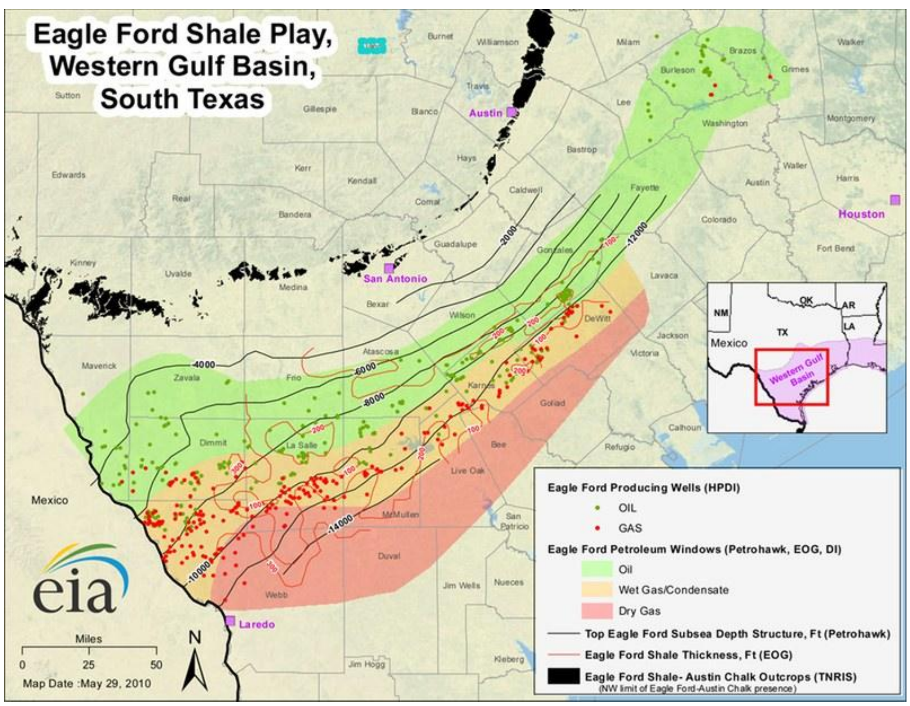

Figure 1—Eagle Ford shale of south Texas (EIA 2011).

The Eagle Ford shale is a highly heterogeneous Late-Cretaceous formation, deposited during the Cenomanian-Turonian boundary event, lying above the Buda limestone and overlain by the Austin Chalk, as shown in **Figure 2**. Wan et al. (2013) categorized the

Eagle Ford formation as an over mature porous shale with significant inter/intra-grain porosity and minimum secondary hydrocarbon migration.

Even though it is widely recognized as a shale, it is necessary to point out that the mineral heterogeneity of the play makes it considerably different from other unconventional shale plays (Chaudhary et al. 2011).

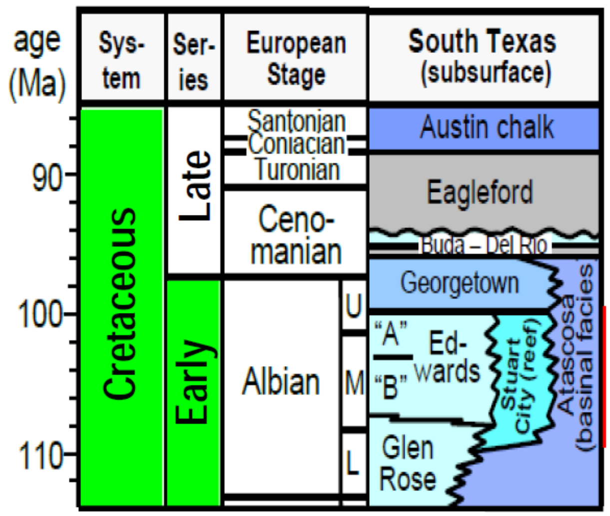

Figure 2—Stratigraphic column of the Upper Cretaceous period showing Buda, Eagle Ford and Austin Chalk south Texas formations (Fan et al. 2011).

The formation can be divided into two geology units: lower and upper Eagle Ford shales (Martin et al. 2011; Tian et al. 2013). The lower Eagle Ford unit is found in the whole area of the play and it is formed by dark, well-laminated shales rich in organic matter, deposited during a transgressive marine interval. On the other hand, the upper Eagle Ford unit is restricted to the west region of the play, and it consists of calcareous shales, limestones, bentonites and quartzose siltstones. This unit corresponds to the beginning of a regressive cycle of near-shore sediments deposition.

Based on the interpretation of gamma ray and resistivity well log results, the upper Eagle Ford unit is further divided into the lower-upper and upper-upper units (Tian et al. 2013). **Figure 3** illustrates the extension and location of the Eagle Ford shale units and the change in average Total Organic Carbon (TOC) throughout them.

Both vertical and areal variations of reservoir and petrophysical properties are seen all across the Eagle Ford shale. A clear example of this is seen with TOC. Tian et al. (2013) analyzed the variation of TOC across the Eagle Ford shale. The lower unit of the play has an increasing trend of average TOC from southeast to northwest. The Lowest TOC values close to 2% are found from Webb to McMullen counties. By contrast, Zavala and Frio counties have maximum TOC values around 12%.

TOC in the lower-upper Eagle Ford unit shows a similar behavior, where higher values are found in the north, and a maximum value of approximately 7% is found in Zavala and Frio counties. The upper-upper Eagle Ford unit shows a different trend of TOC, where the highest values of approximately 5% are located to the east in Maverick and Dimmit counties.

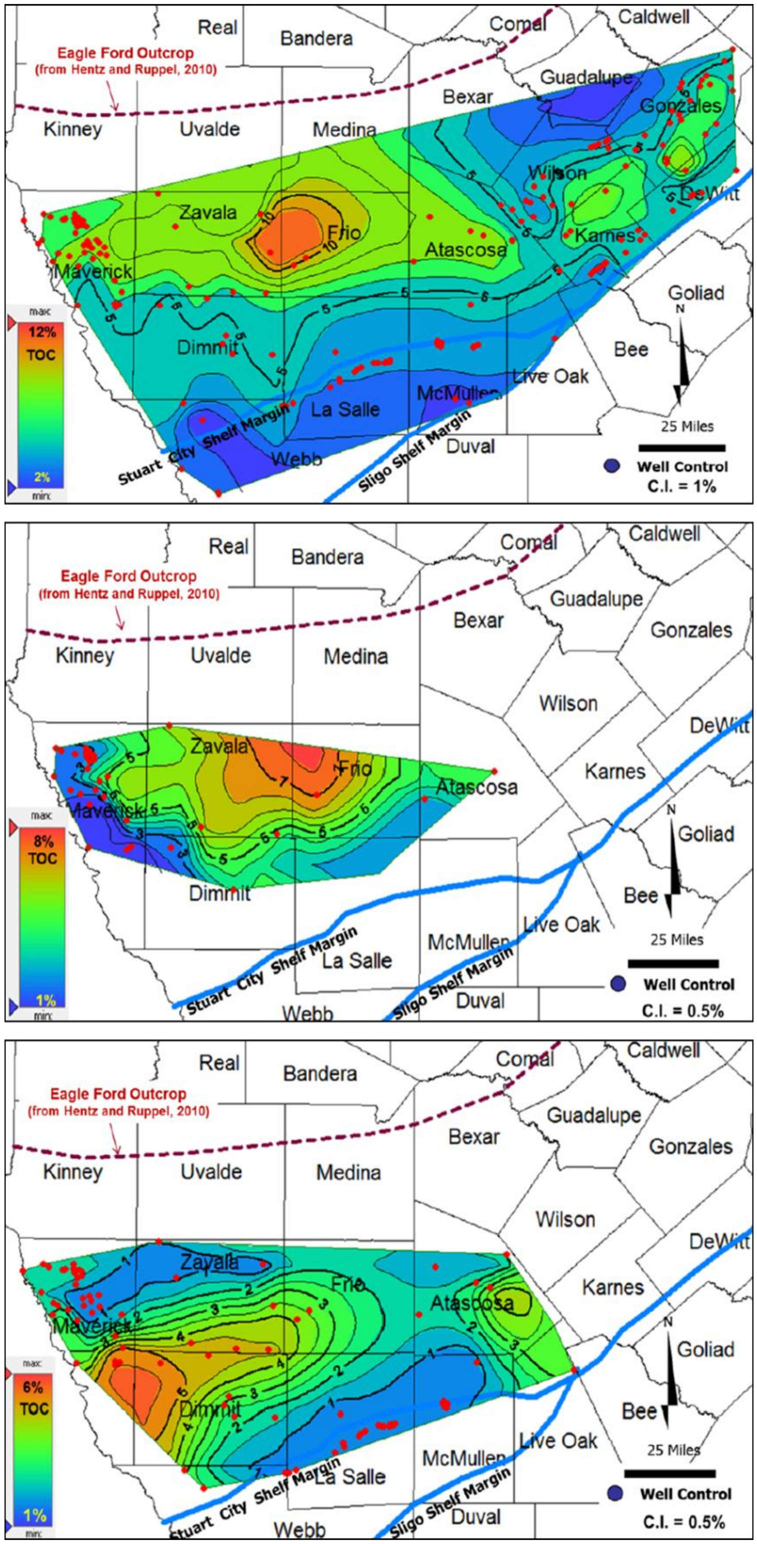

Figure 3—Average TOC for Eagle Ford shale units: lower (top), lower-upper (middle), and upper-upper (bottom) (Tian et al. 2013).

Similarly, Martin et al. (2011) reported values of effective porosity ranging from 3% to 10%, with an average of 6%, and values of permeability ranging from 3 nd to 405 nd, with a mean value of 180 nd. Formation thickness increases considerably from 50 ft to more than 300 ft in the southwest direction. Furthermore, Centurion et al. (2012) identified the same increasing trend for other reservoir and fluid properties such as structural depth, oil API gravity and reservoir pressure as illustrated in **Figure 4**.

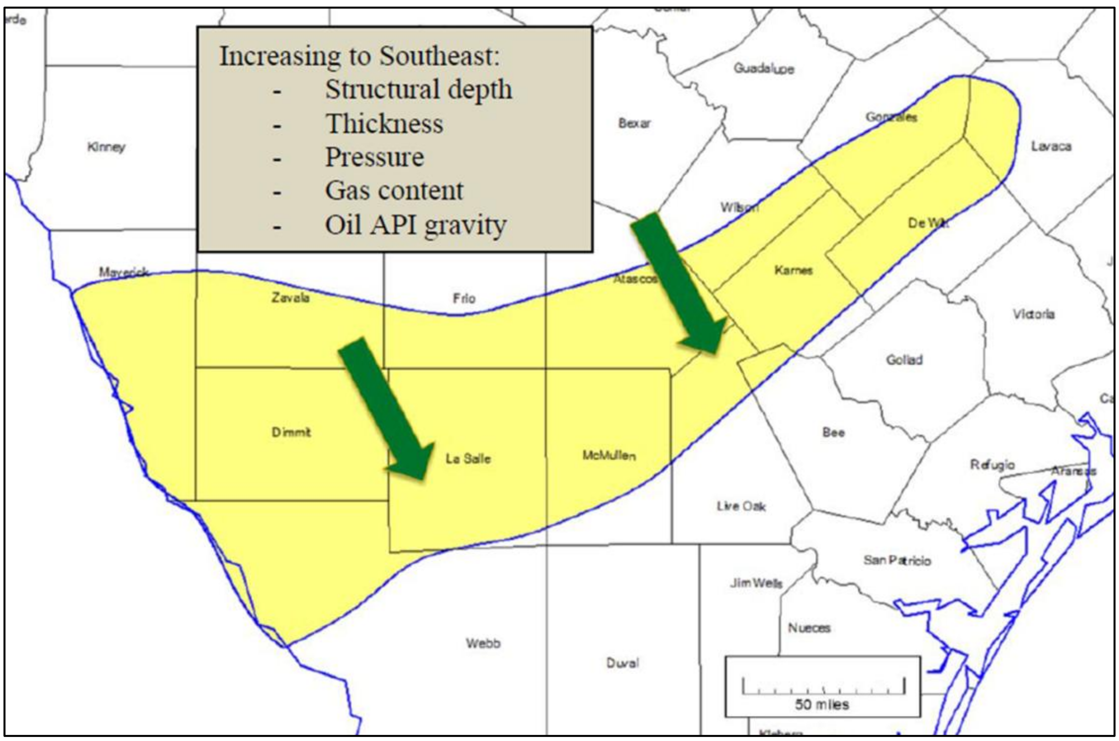

Figure 4—Reservoir and fluids properties increasing to the southwest of the Eagle Ford shale (Centurion et al. 2012).

Another important aspect of a hydrocarbon reservoir is its trapping system. In the case of the Eagle Ford shale, both stratigraphic and structural traps are found. Martin et al. (2011) explained that in the Karnes Trough region (northwest) traps consist of natural fractures and numerous sealing faults associated to the structural features of the area, as depicted in **Figure 5**. On the other hand, trapping structures in the Hawkville area (southwest) are found in the Eagle Ford section within the restricted basin bounded by the Edwards and Sligo shelf edges. Moreover, the Karnes Trough and Hawkville areas are widely recognized as high productivity regions, or production sweet spots, of oil and condensate liquids and natural gas respectively.

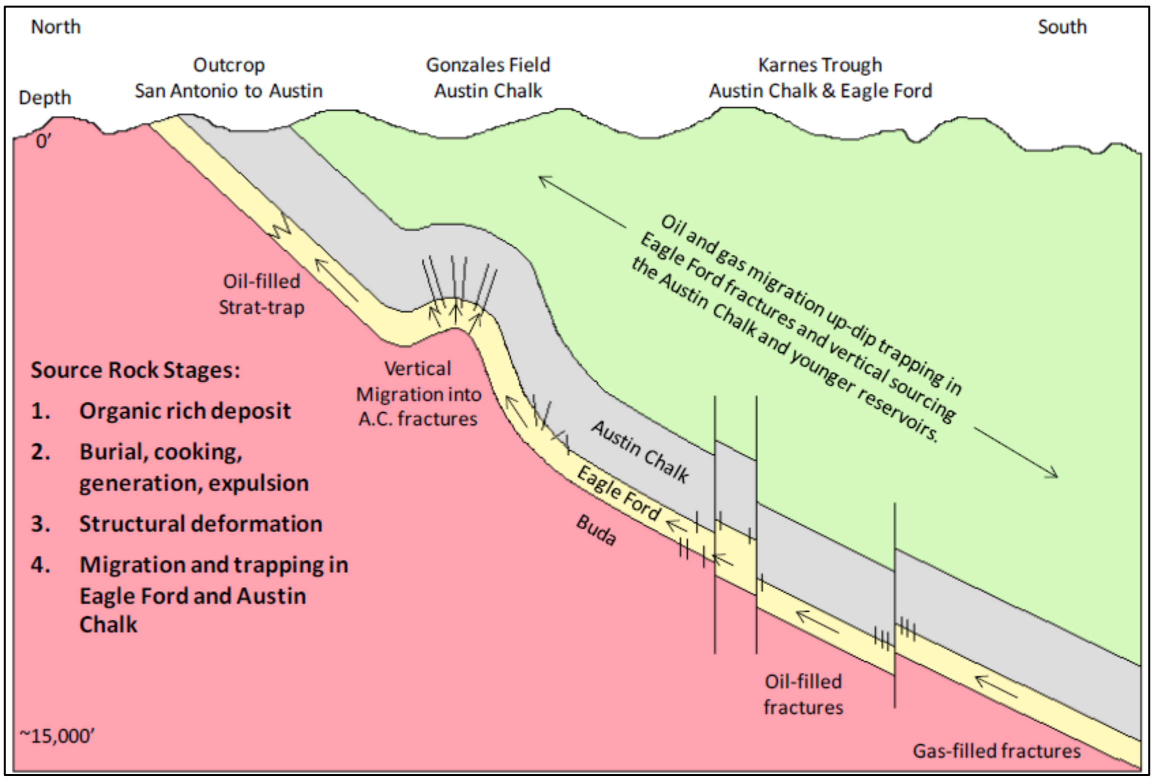

Figure 5—North-south cross section of the Eagle Ford shale through Gonzales field and Karnes Trough (Martin et al. 2011). Both source and producing characteristics of the play can be appreciated.

Eagle Ford fluid system

As previously mentioned, the Eagle Ford shale of south Texas is a self-sourced hydrocarbon reservoir with trapping structures. It is considered a liquid-rich unconventional play given its capacity of producing both hydrocarbon liquids (black, volatile, and condensate oil) and natural gas.

Hydrocarbon fluids found and produced from unconventional shale plays are a function of the type and content of kerogen, and the Level of Maturity (LOM) (Tian et al. 2013; Wan et al. 2013). Fluid maturity depends on the time and temperature at which kerogen is transformed initially to crude oil and then to natural gas. In the Eagle Ford shale kerogen types II, II/III, and III have been detected in different production areas (Martin et al. 2011). LOM in the Eagle Ford is closely related to the structural depth and also to the type of kerogen distribution across the play.

As formation increases depth to the south, fluid maturity changes from black oil to volatile oil, gas condensate, and ultimately to dry gas. Chaudhary et al. (2011) described average depth values of 8,000 ft for oil, 10,000 ft for condensate rich, and 14,000 ft for dry gas windows. Nonetheless, differences in production fluids are found in areas with the same structural depth. This is the case in the Karnes Trough and Hawkville production areas; even with similar depths, in the Karnes Trough area, kerogen type II was predominant and its production was mainly oil and condensate liquids, while in the Hawkville area, kerogen types II and II/III were found, and thus produces natural gas.

Since the Eagle Ford shale is a liquid rich system, recovery is mainly produced by expansion and solution drive mechanisms (Chaudhary et al. 2011; Wan et al. 2013). The recovery of liquids in the oil window is governed by liquid phase transport mechanism; while in the condensate window, where two-phase flow occurs throughout most of the production life, gas phase dominates the liquids recovery. Moreover, the production of gas and other light-end hydrocarbon liquids improves productivity by depressing viscosity and increasing mobility.

Eagle Ford completions

As in other unconventional shale plays in the U.S., all drilled and completed wells within last five years targeting the Eagle Ford shale have been horizontal and multi-stage hydraulically fractured wells. The combination of these two technologies has been a fundamental factor for the successful commercial development of the reservoir. **Figure 6** shows a schematic of a well completed with 10-stage fracture treatment.

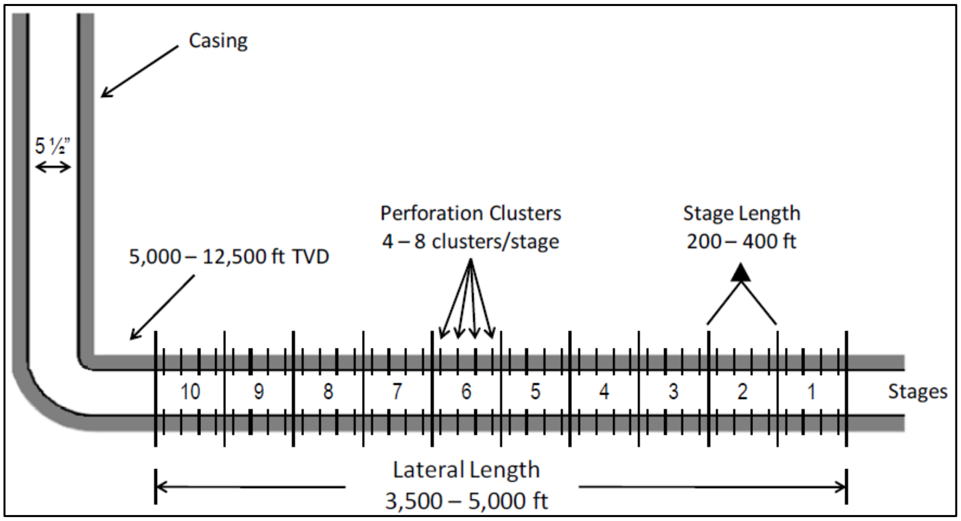

Figure 6—Wellbore diagram of a 10 fracture stages completion in the Eagle Ford shale (Fan et al. 2011).

However, the complex and variable geology, mineralogy, and reservoir properties of the Eagle Ford shale have brought different technical challenges. Completion designs and techniques have been modified from those used and optimized in other reservoirs like Barnett, Haynesville, and Marcellus. This different approach has also meant higher drilling and completion costs when compared with other shale plays (Bazan et al. 2012). While the Barnett and Marcellus shale formations are characteristic of primarily siliceous environments, the Eagle Ford rock makeup is predominantly calcareous mudstones and chalks (Chaudhary et al. 2011). Mineralogy analysis from cores found that the Eagle Ford formation is principally a limestone with high clay and low quartz contents. **Figure 7** shows mineralogy composition from cores from McMullen and Dimmit counties, where average mineral content for the former is 10% quartz, 40 to 80% calcite, and 20 to 30% Mixed-Layer Illite/Smectite (MLIS); and for the latter average values of 30% quartz, 40 to 70 % calcite, and 20 to 30 % MLIS where found (Centurion 2011).

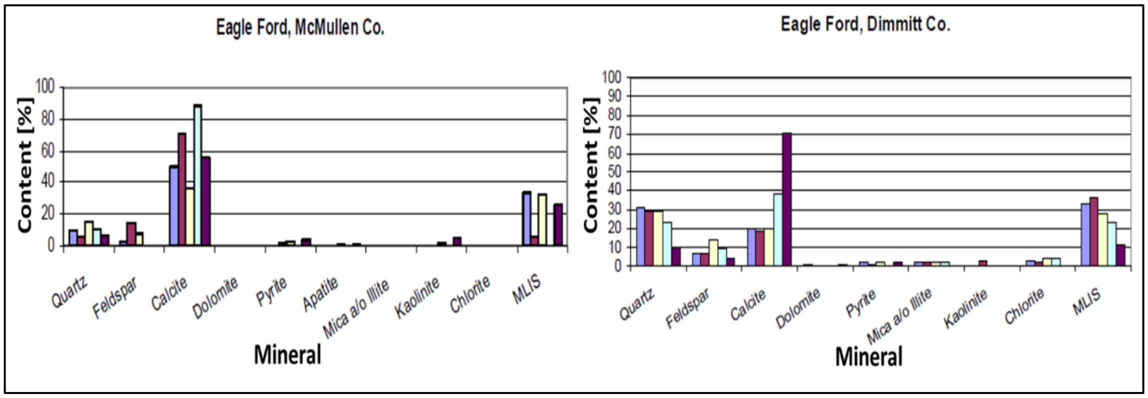

Figure 7—Mineralogy analysis from cores from McMullen and Dimmit counties (Centurion et al. 2012).

Given the particular mineral composition of the Eagle Ford shale, hydraulic fracturing treatments had to be modified from what had been previously successfully used in other unconventional shale plays. The low content of quartz makes the Eagle Ford a more ductile and prone to proppant embedment formation than the Barnett shale. This particularity requires the use of cross-linked fluids and high quality proppant as part of typical well completion, especially in the oil and condensate-rich windows, while increasing costs significantly (Chaudhary et al. 2011; Pope et al. 2012).

Likewise, formation heterogeneity has prevented a generalization and optimization of completion techniques. Gao and Du (2012) identified high productivity wells in Karnes and Gonzalez counties (northwest) that were fractured with much smaller sand volumes than wells from Zavala, Frio, Dimmit and LaSalle with significantly lower productivity. Bazan et al. (2012) stressed the importance of continuous improvement and evaluation of completion designs, in order to achieve more productivity and economic value from wells in the Eagle Ford shale.

In order to perform adequate and accurate project evaluations, it is necessary to understand the heterogeneity and complexity of the Eagle Ford shale. A very important aspect is that values of key reservoir and fluid properties should not be extrapolated to the play level, as significant changes can be seen in different areas of the play even within short geographical distances (Centurion et al. 2012; Gao and Du 2012). The following chapter describes before-tax cash flow model, its components, and all the considerations we used in order to perform an accurate estimation of reserves.

CHAPTER III

PROBABILISTIC RESERVES ESTIMATION MODEL

In the previous chapter, we discussed important aspects of the geology, fluids system, and drilling and completion of development wells strategies of the Eagle Ford shale, which make this play unique in terms of complexity and heterogeneity. In this chapter, we describe a before-tax cash flow model used to evaluate the commerciality of different development scenarios in the Eagle Ford shale and to estimate the reserves of the field. We explain each of the components of the model and the modifications and assumptions necessary to handle the uncertainty associated to the production of hydrocarbons in the Eagle Ford shale.

Reserves and resources

In 2007, the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC), and the Society of Petroleum Evaluation Engineers (SPEE) published the Petroleum Resources Management System (PRMS), a document that provides a universal system for estimation and classification of petroleum volumes that have an "inherent degree of uncertainty" (SPE et al. 2007). The PRMS includes the following definitions of reserves, contingent, and prospective resources as well as a resources classification framework shown in **Figure 8**:

- Reserves are those quantities of petroleum anticipated to be commercially recoverable by the application of development projects to known accumulations from a given date forward under defined conditions.
- Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies.
- Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

The U.S. Security and Exchange Commission (SEC) defines proved oil and gas reserves as “the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating condition” (SEC 1978). In 2009, the SEC published Modernization of Oil and Gas Reporting: Final Rule, which is consistent with the PRMS definitions and guidelines.

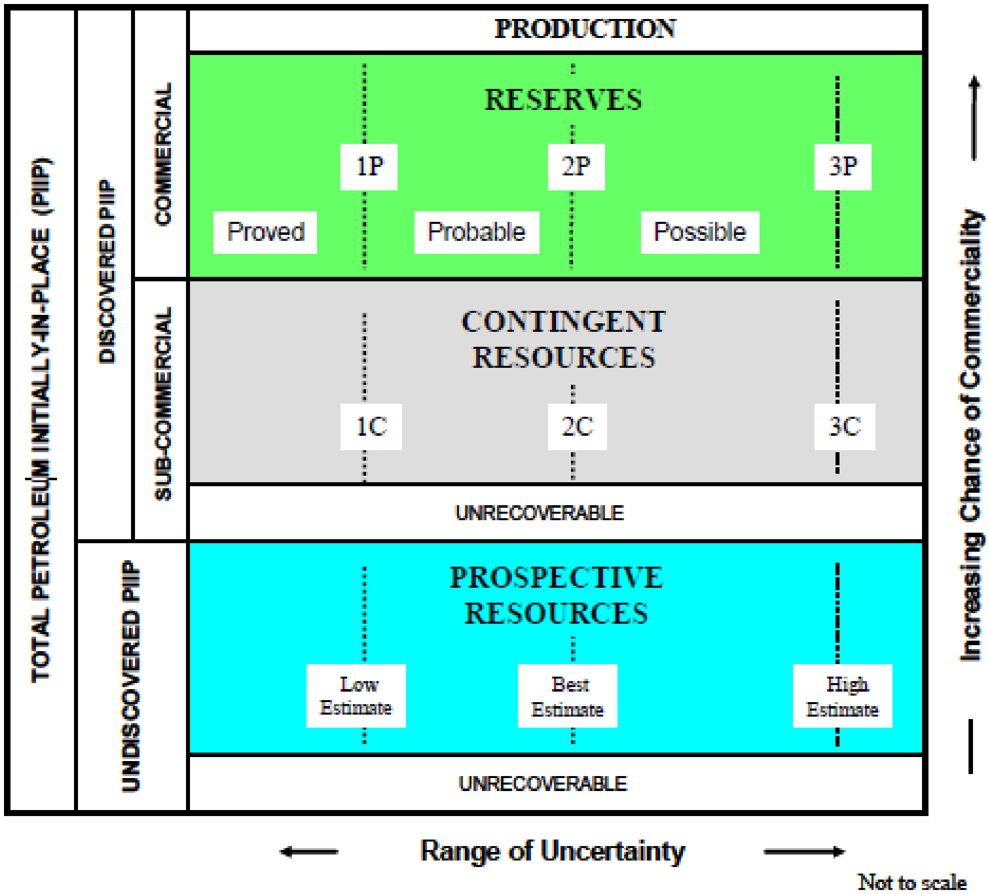

Figure 8—Resources Classification Framework (SPE et al. 2007). This classification methodology is based on the chance of commerciality (vertical axis) and the range of uncertainty (horizontal axis) associated to the petroleum volumes.

It is important to note that there are four key conditions that petroleum volumes must meet in order to be classified as reserves: (1) they must be discovered and associated with current development projects; (2) they have to be technically recoverable; (3) they are considered remaining as of a given date, and (4) they must be commercial. In fact, commerciality is the most important aspect when moving petroleum volumes from resources to reserves, as seen in Figure 8. Listed below are conditions included in the PRMS as required to determine the commerciality criteria (SPE et al. 2007):

- There is an entity with an established project and firm intention to develop these resources
- The project has a reasonable timetable for development
- The development has a reasonable assessment of the future economic conditions that meet defined investment and operating guidelines
- There is reasonable expectation that the appropriate market will exist for produced quantities to be sold and justify the development
- The necessary production and transportation facilities are reasonably expected to be available
- Legal, contractual, environmental, and other social and economic conditions will permit the implementation of the project.

Before-tax cash flow model

In the oil and gas industry, investment decisions for a given development project depend on future commercial conditions, production forecasts, and associated cash flow schedules that a company or entity considers feasible. Mian (2011) defined cash flow of an investment as the cash spent during a specified period. Likewise, net cash flow are the result of the cash received–or gross revenue–minus cash spent, as capital expenditures (CapEx) or operational expenses (OpEx), during the same period of time.

Contingent resources and reserves evaluations using cash flow models consist of adding the future net cash flows of the project, yielding estimated future net revenue, and then discounting it at a determined discount rate to calculate the net present value (NPV) of the project. SPE et al. (2007) indicate that this calculation should consider:

- The expected production volumes over specified periods
- Estimations of the development, recovery, and production costs for the project
- Future price forecasts or models that will determine the expected revenues from the production volumes
- A reasonable period for the project to be developed and evaluated
- Taxes and royalties expected to be paid by the company during the project life. Royalties are payments due to the mineral rights owner, or lessor, in return for the depletion of the reservoir. Royalties can be paid to the lessor in production volumes or in the corresponding proceedings from their sale at a current market price. In either case, the company or contractor must deduct the royalty volumes from the production that is used to calculate revenue
- Finally, the economic criteria used to determine the feasibility of the project. This can be expressed in terms of a discount rate or a minimum rate of return that reflects the economic expectations of the company or investor.

Additionally, the PRMS (SPE et al. 2007) defines the economic limit of a project as the production rate beyond which the net operating cash flows of the project are negative, and therefore defines the economic life. It is recommended that the determination of the economic life of the project should exclude any considerations of corporate taxation, depreciation, depletion, and amortization (DD&A), which is the reason why it is called a before-tax cash flow model (Mian 2011; SPE et al. 2007).

Production forecast model

There are different methods to forecast production of a hydrocarbon reservoir. Cronquist and SPE (2001) categorize this methods as analogy or statistical, volumetric, and performance or decline trend analysis including material balance, reservoir simulation, and decline curve analysis (DCA). Baihly et al. (2010) discussed how most of these methodologies have limitations to calculate of EUR accurately in shale reservoirs:

- Analogy methods have much uncertainty given the differences in the petrophysics, drilling and completion techniques among the plays being developed
- Volumetric methods depend on the accuracy recovery factor parameters and the drainage area, which in the case of shale plays, is still inexact.
- Material balance is rarely used in shale reservoirs due to the lack of reservoir pressure data, which is particularly hard to obtain in shales.
- Reservoir simulation has been limited to analyze single well models and the effects of the hydraulic fracture (Chaudhary et al. 2011).

Unlike other methods, DCA has been widely used to estimate production in different shale reservoirs. Arps (1945) has been extensively applied to shale reservoirs, but there is significant uncertainty in the resulting estimations given that in most cases the wells are not in boundary dominated flow (BDF), which is necessary in this method (Gong et al. 2011a)

As an attempt to address this issue, different deterministic DCA models have been introduced since 2008 to evaluate contingent resources and reserves in shale reservoirs (Clark et al. 2011; Duong 2010; Ilk et al. 2008; Valko and Lee 2010). Gonzalez et al. (2012) performed a study of comparison of these DCA models showing that they fail to effectively quantify uncertainty in production forecasts and estimation of reserves.

A different approach to overcome this issue has been followed by different studies, consisting of integrating probabilistic components and techniques to DCA models. Benninger and Caldwell (1991) used Monte Carlo simulation to generate distributions for the input parameters of the Arps' model, and Jochen and Spivey (1996) included the bootstrap method to generate synthetic data sets to perform evaluations.

A new PDCA methodology has been developed by Gong et al. (2011a), integrating a Bayesian methodology and a Markov Chain Monte Carlo (MCMC) algorithm to estimate a probability function of parameters used as inputs for different DCA, based on historic production data. This methodology has been successfully used to generate production forecasts and reserves estimates with good quantification of uncertainty in the Barnett shale, with best results when used with the Doung DCA model (Gong et al. 2011b).

In the case of the Eagle Ford shale, Gong (2013) used this PDCA methodology to estimate technically recoverable resources of 20 years (TRR20) in the U.S. portion of the Eagle Ford shale. Production forecasts were generated using Duong DCA model with an Arps' exponential tail after BDF was reached. Based on the number and time distribution of wells likely to be drilled the production volumes were classified as prospective resources, contingent resources, and reserves; however no economic parameters were considered by the author. Morales (2013) used the same PDCA methodology to estimate and classify TRR20 for the Mexican portion of the Eagle Ford shale.

In both studies the results proved the effectiveness of the methodology to provide good ranges of resources and reserves in the reservoir with adequate assessment of uncertainty. We decided to use this methodology to perform the estimation of reserves in the Eagle Ford shale, using production forecast model applied by Gong (2013).

Eagle Ford shale production regions

Given the high heterogeneity and the production of different types of hydrocarbon fluids of the Eagle Ford shale, it is not prudent to extrapolate values of reservoir properties and DCA inputs to the play level (Gao and Du 2012). In order to address this issue, Gong (2013) divided the Eagle Ford shale in to eight different production regions based on the type of production fluids, historic production data, and the geology and location of the lower and upper Eagle Ford units. **Table 1** shows the criteria used to determine the type of production fluids, and **Table 2** contains the definition and characteristics of the production regions.

Table 1—Definition of fluid type base on initial gas/oil ratio (GOR) (Gong 2013)

Fluid Type	Initial GOR [SCF/STB]
Black Oil	0-1,500
Volatile Oil	3,200-10,000
Condensate	10,000-100,000
Dry Gas	>100,000

Table 2—Definition and characteristics of the eight production regions of the Eagle Ford shale (Gong 2013)

Production Region	Fluid Type	Initial Oil Rate	Formation	Depth [ft.]	Area [Acres]
PR1	Black Oil	Low	Upper and Lower	4,056	799,836
PR2	Condensate/ Volatile Oil	Medium-Low	Upper and Lower	6,505	942,734
PR3	Black Oil	Medium	Upper and Lower	7,719	1,617,410
PR4	Condensate	Medium-Low	Upper and Lower	10,874	584,070
PR5	Black Oil	Medium-High	Lower	9,450	977,484
PR6	Volatile Oil	High	Lower	12,286	338,000
PR7	Condensate	Medium	Lower	13,470	478,888
PR8	Dry Gas	None	Upper and Lower	10,532	1,201,185

Figure 9 shows probabilistic oil production type curves for production regions 1 to 7, and **Figure 10** displays a map with the location of the regions and the predominant type of wells in each of them.

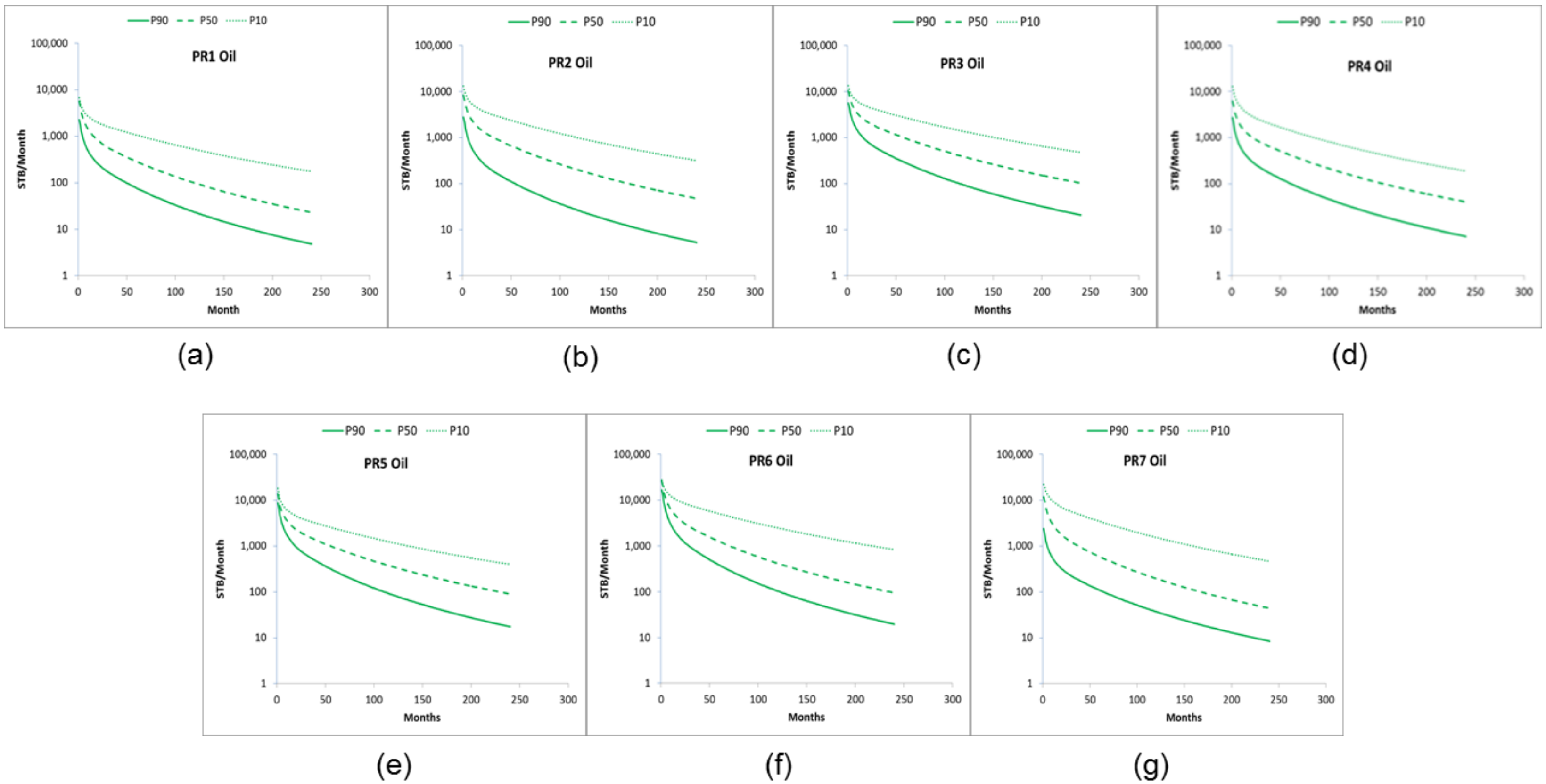

Figure 9—Probabilistic type curves for oil production of PR1 to PR7 (a) to (g) (Gong 2013).

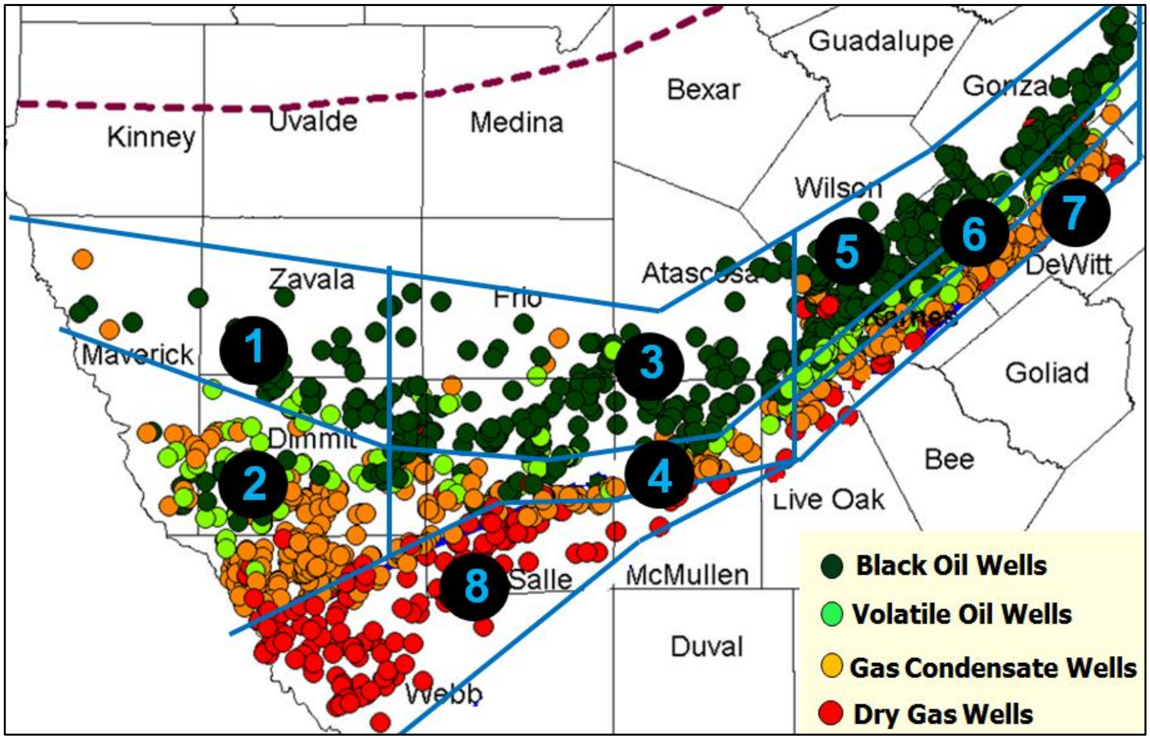

Figure 10—Production regions of the Eagle Ford shale. This figure shows the predominant types of wells in each of the regions (Gong 2013).

Gas production

Monthly natural gas production is calculated using a GOR model according to the type of crude oil in each region–black, condensate, or volatile oil–and multiplying it to the corresponding monthly oil production, with the exception of PR8 where the dry gas production is calculated using the PDCA methodology (Gong 2013). **Figure 11** shows the GOR straight-line models for each type of crude oil produced, and **Figure 12** depicts probabilistic gas production type curves for production regions 1 to 8. Additionally, we have applied a gas shrinkage factor of 5% to all natural gas production to yield the net sale volumes.

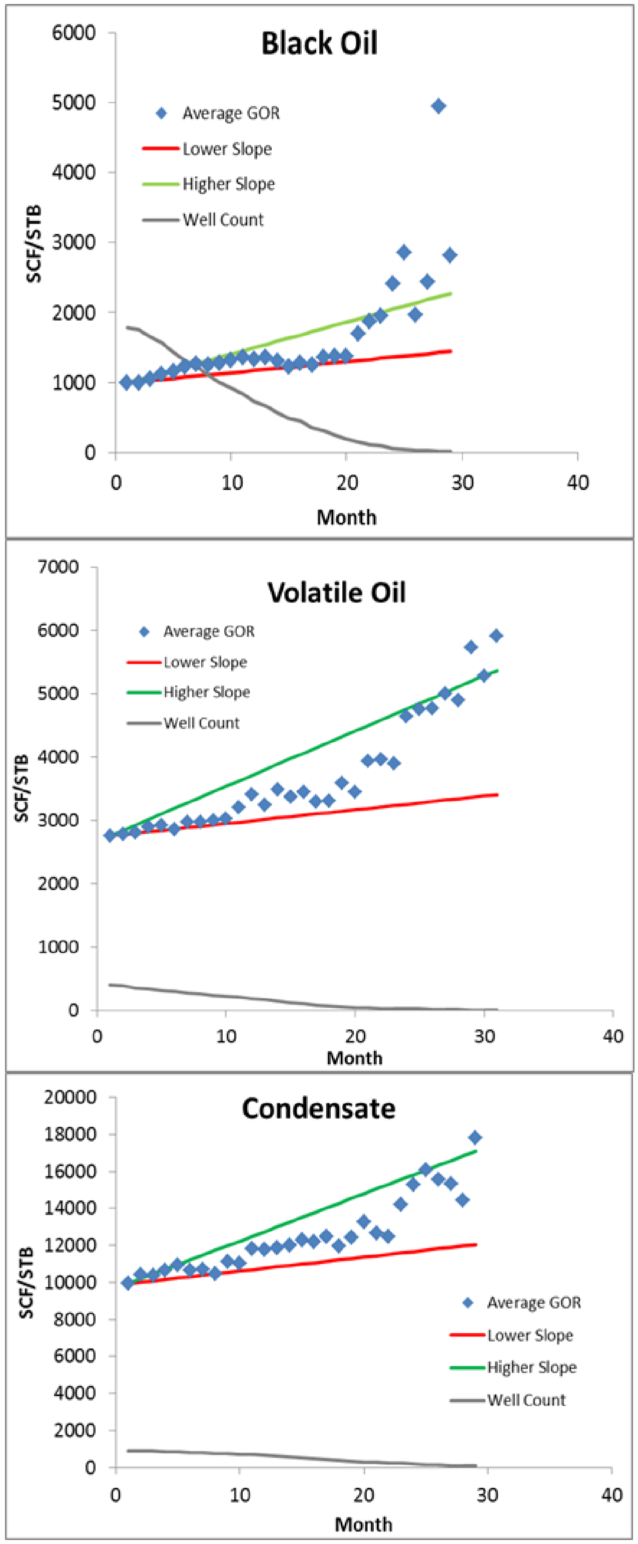

Figure 11—GOR models for each of the crude oil types. Average GOR values for black, condensate, and volatile oils are bracketed by straight linear GOR models (Gong 2012).

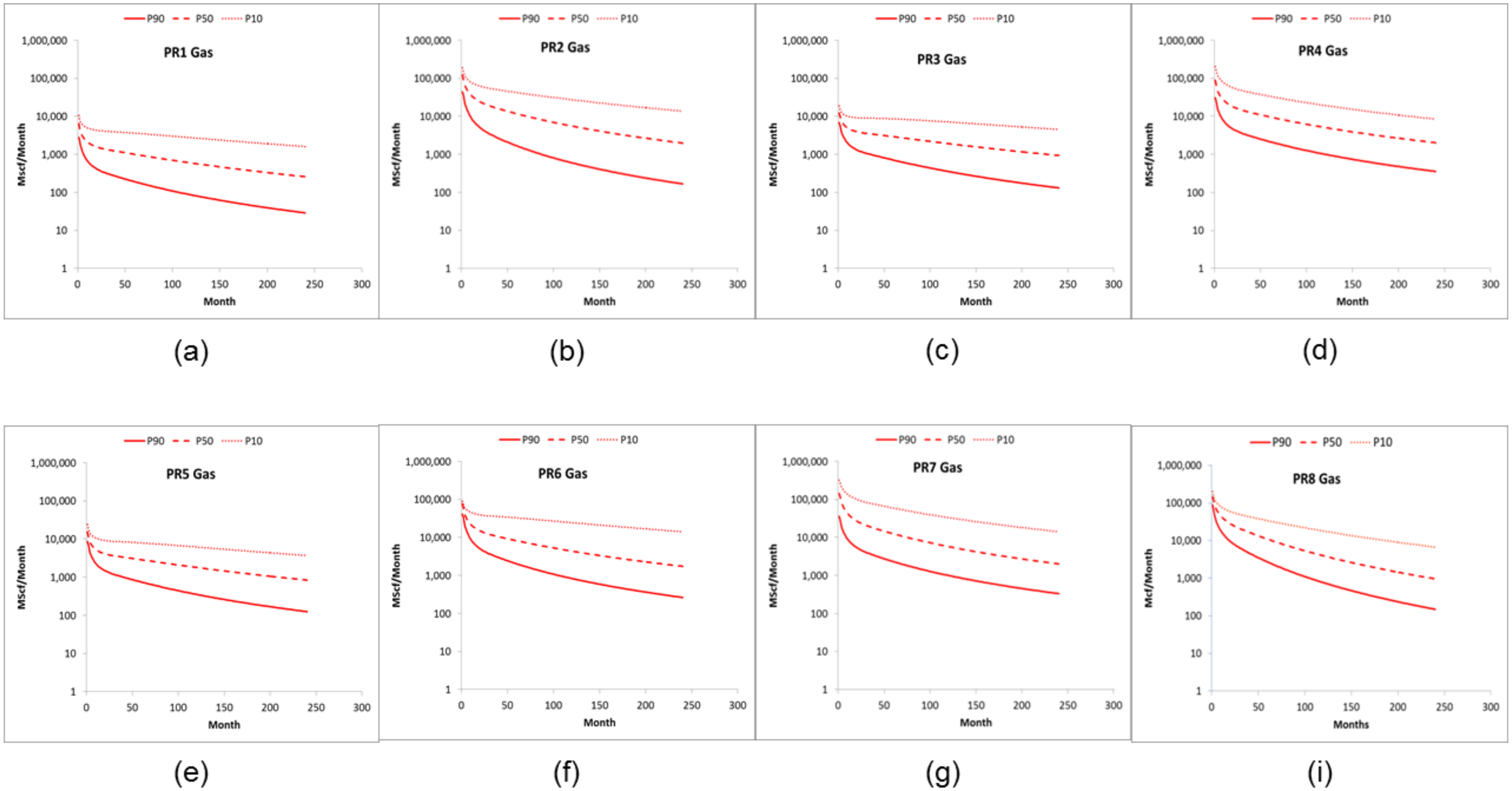

Figure 12—Probabilistic type curves for gas production of PR1 to PR8 (a) to (h) (Gong 2013).

Water production

To calculate monthly water production, a probability function of water/oil ratio (WOR)–in Bw/Bo–was built for each of the production regions, to be multiplied with the monthly oil production. For PR8, the water/gas ratio (WGR)–in Bw/Mcf–and the monthly gas production were used.

Using data of the cumulative production of oil, gas (for PR8), and water from DrillingInfo (as of December 2012), an average WOR or WGR per well was calculated. Then, we used the distribution fitting tool from @Risk to assign an adequate distribution for each production region. For all cases, the exponential distribution was the best fit. **Table 3** contains average WOR and WGR. Fitted distributions for PR1, PR3, PR6, and PR8 are shown in **Figure 13.**

Table 3—Average WOR and WGR values for all productions regions

Production Region	Avg. WOR [Bw/Bo]	Avg. WGR [Bw/Mcf]
PR1	0.174	-
PR2	0.408	-
PR3	0.088	-
PR4	1.969	-
PR5	0.134	-
PR6	0.035	-
PR7	3.165	-
PR8	-	0.004

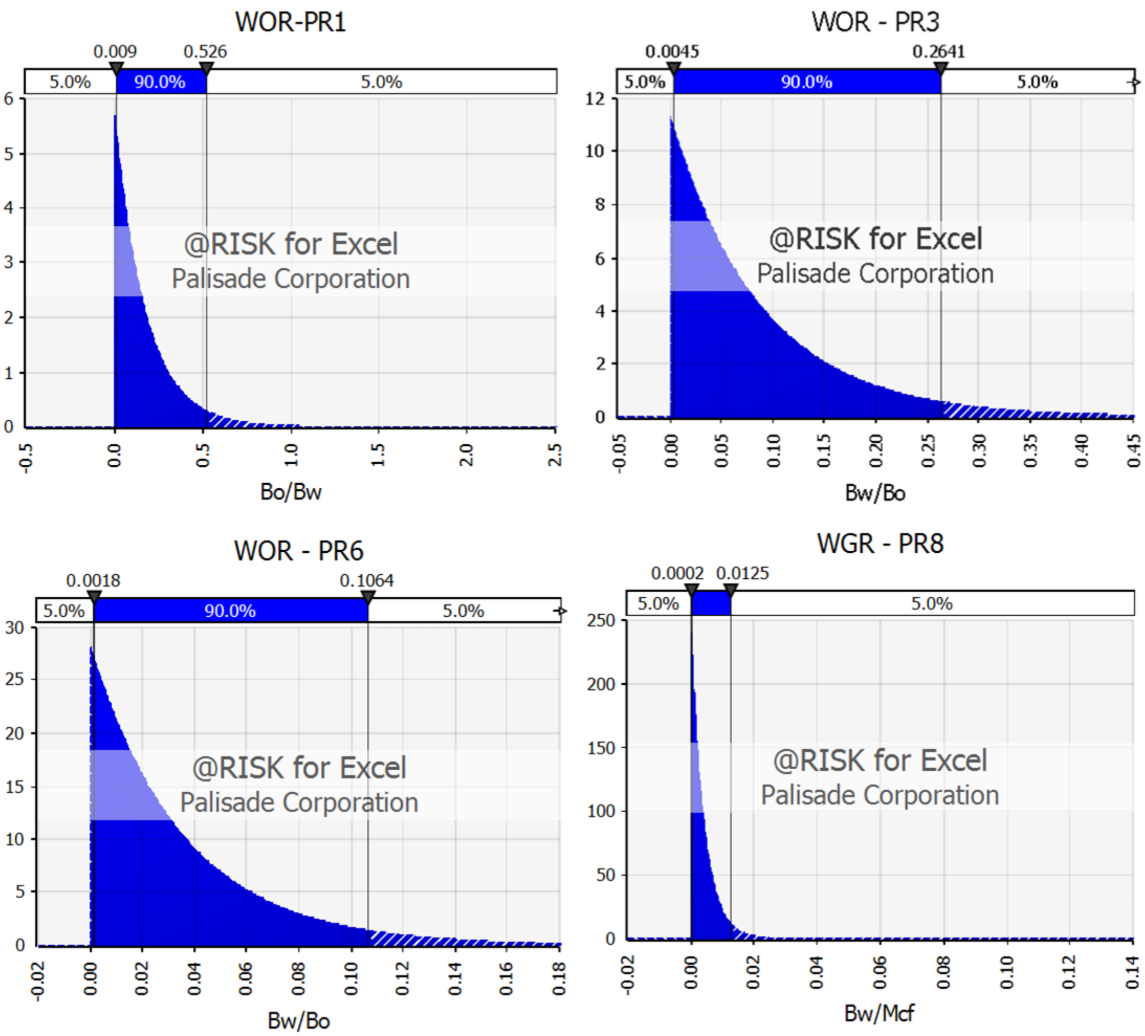

Figure 13—WOR and WGR distributions for PR1, PR3, PR6, and PR8.

Commodity pricing model

Oil and natural gas price forecasts are key factors in reserves estimations. With the high uncertainty associated to Eagle Ford shale production forecasts, it was necessary to use a price forecasting methodology capable of provide accurate and realistic ranges of future prices.

Olsen et al. (2005a) applied five price forecasting techniques–conventional, bootstrap, Inverted Hockey Stick (IHS), historical, and Sequential Gaussian Simulation (SGS)–to different industry and synthetic projects. The authors identified that conventional forecasting typically underestimates the volatility of future oil and natural gas prices, affecting the economic indicators necessary to evaluate projects. The other four techniques quantified uncertainty better than conventional forecasts, given that the resulting trends of future prices are based on historical price variability. Furthermore, Olsen et al. (2005b) also found that the IHS forecasts are more effective when assessing uncertainty of future prices and to evaluate the "potential upside and/or substantial downside risk" inherent to development projects of the oil and gas industry. We decided to use the IHS technique for reserves estimation.

IHS method and price forecasts

The IHS method, developed by Akilu et al. (2006), generates low and high price forecasts based on historical price data and the maximum positive and negative historical rates of change. Additionally, the IHS price forecasts include a period of rapid and sustained change in price at the beginning of the projection, where the impact on economic yardsticks is greatest. Listed below are the methodology steps we followed to generate the low and high forecasts:

1. We obtained monthly historical crude oil and natural gas spot price data from the EIA. In the case of the Eagle Ford shale, the applicable spot prices for crude oil

and natural gas are the West Texas Intermediate (WTI) spot price and the Henry Hub Gulf Coast spot price respectively.

2. Using Consumer Price Index (CPI) data, we adjusted historical prices to present-day prices.
3. We identified maximum (P_{max}) and minimum (P_{min}) historical commodity prices, using present-day data calculated in step 2. P_{max} for oil was US$ 142.43/bbl (June 2008) and for natural gas was US$ 15.68/Mmbtu (October 2005). P_{min} for oil was US$ 16.12/bbl (December 1998) and US$ 1.97/Mmbtu (April 2012) for natural gas.
4. We determined the maximum sustained rates of increasing and decreasing changes in prices. As seen in **Figure 14**, between January 2007 and June 2008 the price of oil increased from US$ 62.69/bbl to US$ 142.43/bbl. Following this period, the maximum decreasing happened until January 2009 when the price fell to US$ 45.98/bbl. **Figure 15** shows that from May 2005 to December 2005, the price of natural gas increased from US$ 6.95/Mmbtu to US$ 13.50/Mmbtu. The maximum decreasing happened from June 2008 to April 2009 when the price declined from US$ 13.50/Mmbtu to US$ 3.82/Mmbtu.
5. The IHS method states that current prices ($P_{current}$) of oil and natural gas are considered the "Month 0" price for both IHS low and high forecasts. As of April 2013, $P_{current}$ for oil and natural gas were US$ 92.94/bbl and US$ 3.81/Mmbtu, respectively.

6. The IHS method says that the high forecast is generated by adding 70% of the maximum increasing rate per month to the $P_{current}$ until a high limit price or $P_{ceiling}$ is reached. The following equation is used to calculate $P_{ceiling}$,

$$P_{ceiling} = P_{current} + (P_{max} - P_{current}) * 0.7 \tag{1}$$

For crude oil, the monthly rate of price increase was US$ 3.03 and the $P_{ceiling}$ was US$ 127.58/bbl. Likewise, the monthly increase rate for natural gas was US$ 0.67 and the $P_{ceiling}$ was US$ 12.12/Mmbtu.

7. Similarly, the low forecast was generating by subtracting 70% of the maximum decreasing rate per month from the $P_{current}$ until a low limit price or $P_{ceiling}$ is reached. The following equation is used to calculate P_{floor},

$$P_{floor} = P_{current} + (P_{min} - P_{current}) * 0.7 \tag{2}$$

For crude oil, the monthly decrease rate of price was US$ 11.38 and the $P_{ceiling}$ was US$ 39.17/bbl. Likewise, the monthly decrease rate for natural gas was US$ 0.62 and the $P_{ceiling}$ was US$ 2.52/Mmbtu.

Finally, the values of $P_{ceiling}$ and P_{floor} were held constant for the rest of the project life. Figure 14 and Figure 15 show the IHS forecasts for oil and natural gas prices respectively.

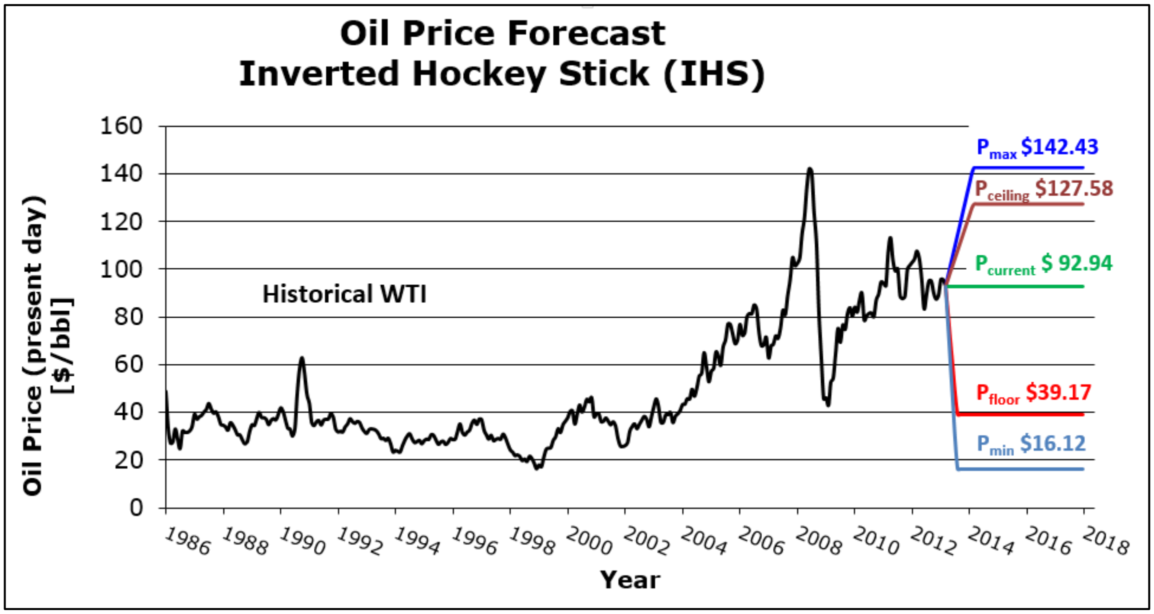

Figure 14—Oil price forecasts using IHS.

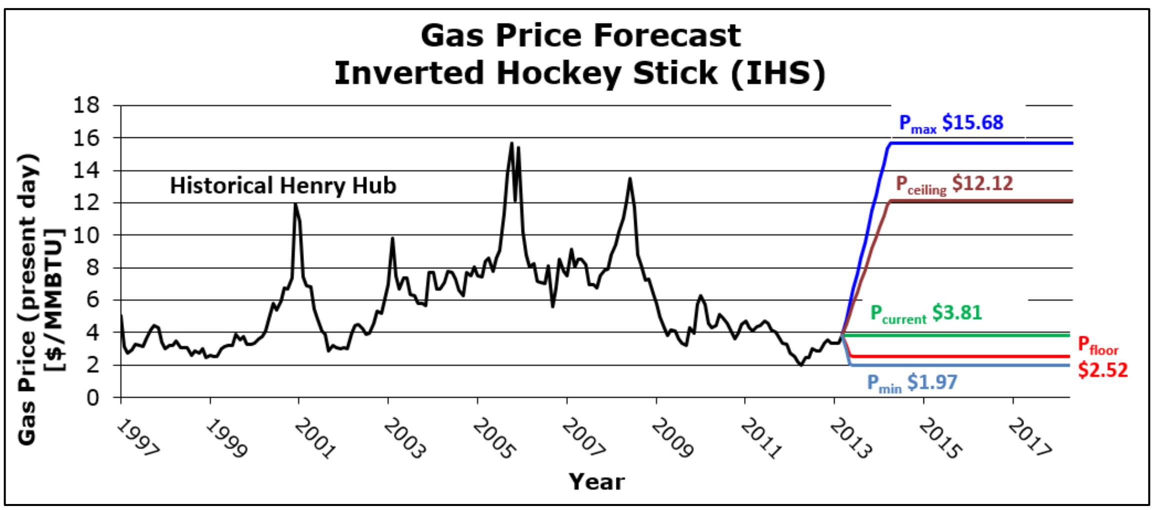

Figure 15—Natural gas price forecasts using IHS.

Price adjustments

Crude oil and natural gas spot prices work as pricing benchmarks based on hydrocarbon fluids of a given quality. For instance, WTI price is based on crude oil with API gravity of 38º to 40º and a sulfur content of 0.3% (Mian 2011). Price adjustments are applied depending on the quality of the oil and natural gas produced from a reservoir. It is important to determine the correct market price of the production fluids, given that any variation affects the revenue of the project.

After reviewing several corporate presentations from operators with development projects in the Eagle Ford shale, we found that it is necessary to apply some adjustments to the spot prices in order to obtain the adequate market price for condensate oil, volatile oil and natural gas produced in the Eagle Ford shale.

In the case of condensate and volatile oil, we identified that in some cases a price differential was applied to the WTI, ranging between US$ 1/bbl to US$ 9, while in others no adjustment was considered. **Figure 16** shows the uniform distribution included in the model to apply the price differential for condensate and volatile oil production volumes.

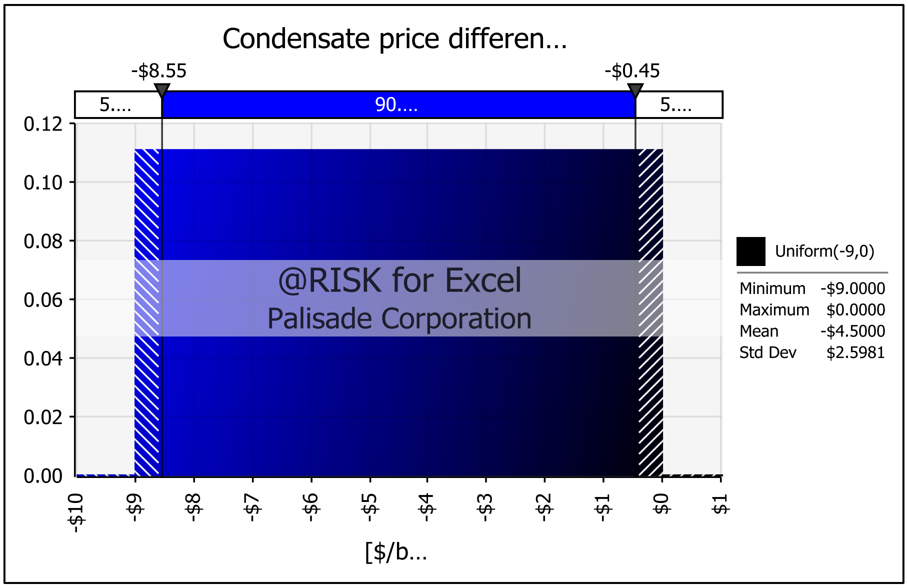

Figure 16—Condensate price differential distribution.

Two different kinds of price adjustment were needed for natural gas prices. First, a natural gas price differential was included to adjust the Henry Hub Gulf Coast price. Following the same type of distribution as the condensate and volatile oil differential, but ranging from US$ 0.40/Mmbtu to US$ 0.55/Mmbtu.

Additionally, a gas energy content factor was needed to transform the spot price from US$/Mmbtu to US$/Mcf. As it was done with condensate oil and natural gas price differentials, we designed distributions based on results from gas analysis samples from different sites of the Eagle Ford shale (API 2011; Braziel 2013). Uniform distributions with maximum and minimum values for all production regions are shown in **Figure 17.**

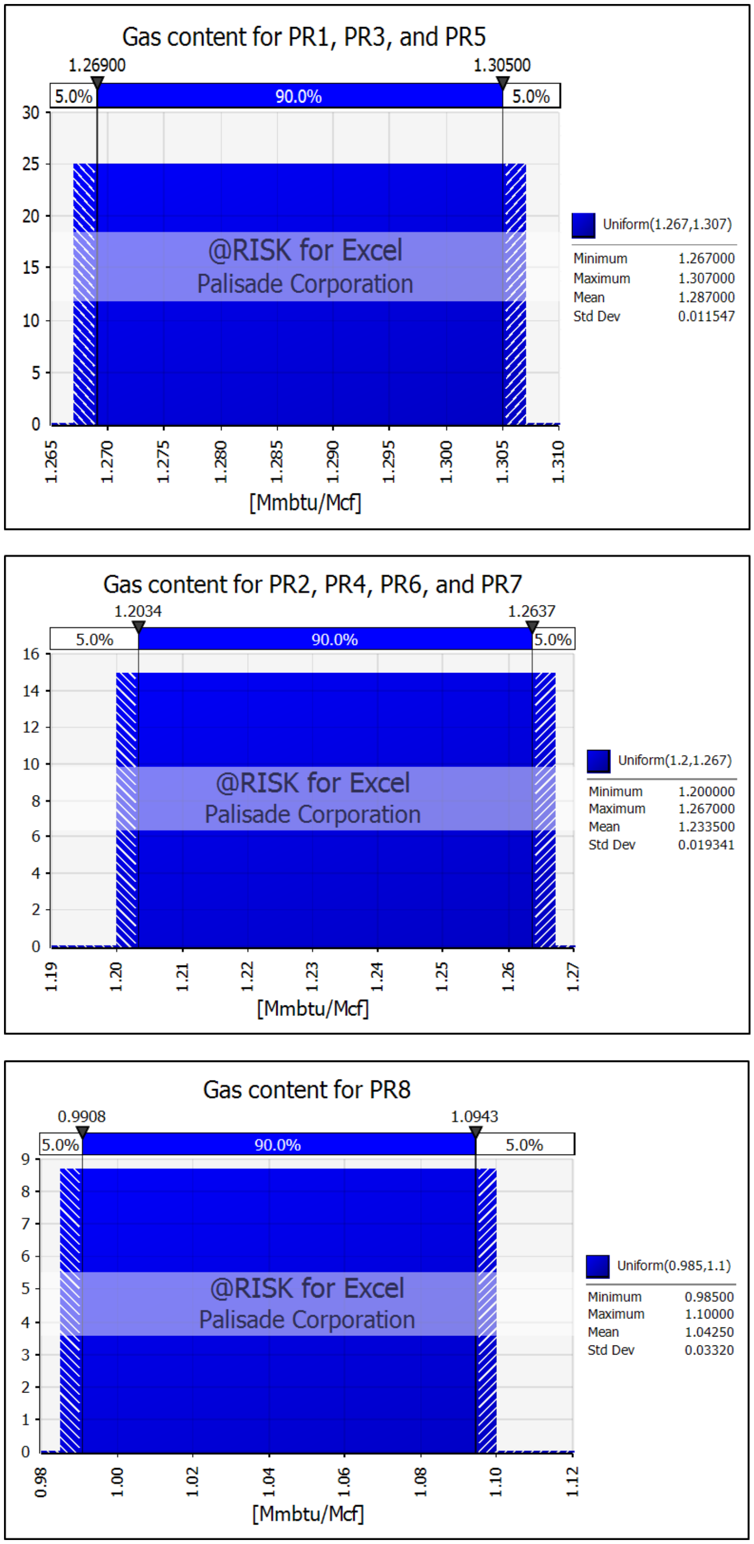

Figure 17—Gas content distributions for black oil (top), condensate and volatile oil (middle), and dry gas (bottom) production regions.

Taxes

Production taxes are one of the major components of the before-tax cash flow model. They are surcharges imposed by the state or local government to the owner of oil and gas interests. The most common types of production taxes are the ad valorem tax, which is a tax based on the fair market value production of minerals, and the severance tax, which is a tax imposed on the removal of nonrenewable sources such as hydrocarbon fluids. Additionally, regulatory fees charged on a dollar per unit basis can be applied to oil and natural gas production. These taxes are imposed by the state or local government on the owner of oil and gas interests (Mian 2011).

We included the following production taxes in the model according to the information published by the Office of the Texas Comptroller of Public accounts:

- Ad Valorem tax: 2.5% imposed on the market value of produced volumes
- Oil severance tax: 4.6% of market value of oil
- Gas severance tax: 7.5% of market value of natural gas
- Condensate severance tax: 4.6% of market value of condensate
- Oil regulatory fee: $ 0.00625 per barrel
- Natural gas regulatory fee: $ 0.000667 per thousand cubic feet.

Capital expenditures

Mian (2011) defines capital expenditures (CapEx) as large front-end costs, usually incurred at the beginning of a project, which will create future benefits during the project life. Examples of CapEx in oil and gas projects are geological and geophysical costs, drilling and completion costs, process facilities, wellheads and flow lines. CapEx may also occur during the project life such as drilling, completion, and tie-in costs of development wells, installing of artificial lift systems after a natural flow period, recompletion of existing wells, and facilities necessary for secondary or enhanced recovery.

We used information from corporate presentations of active operators in all production regions of the Eagle Ford shale, to build distributions to model the typical values of drilling, completion, and tie-in (D&C) costs, on a per-well basis, for development wells. We found that D&C costs for some regions were similar enough to be grouped and modeled in single distributions. Using the @Risk distribution fitting tool, we identified that triangular distribution offered the best fit for data available for PR1 to PR7, and all distributions were truncated with a lowest D&C cost per well of US$ 4,500,000. In the case of PR8, a normal distribution was used because development activity is limited given the low price trend for natural gas since 2010.

Average values of D&C costs per well for all the regions are shown in **Table 4**, and **Figure 18** shows the probability density function for all D&C distributions. Even though these distributions were created with data of corporate and investor presentations from companies, which are likely to content optimistic values of costs, we found high D&C costs for the whole Eagle Ford shale.

Table 4—D&C costs distributions

Production Region	**D&C Distribution**	**Avg. D&C [US$ Million/well]**
PR1/PR3	D&C1	$7,720,446
PR2/PR3	D&C2	$7,366,582
PR5	D&C4	$8,438,952
PR6/PR4	D&C5	$8,194,154
PR8	D&C6	$7,365,454

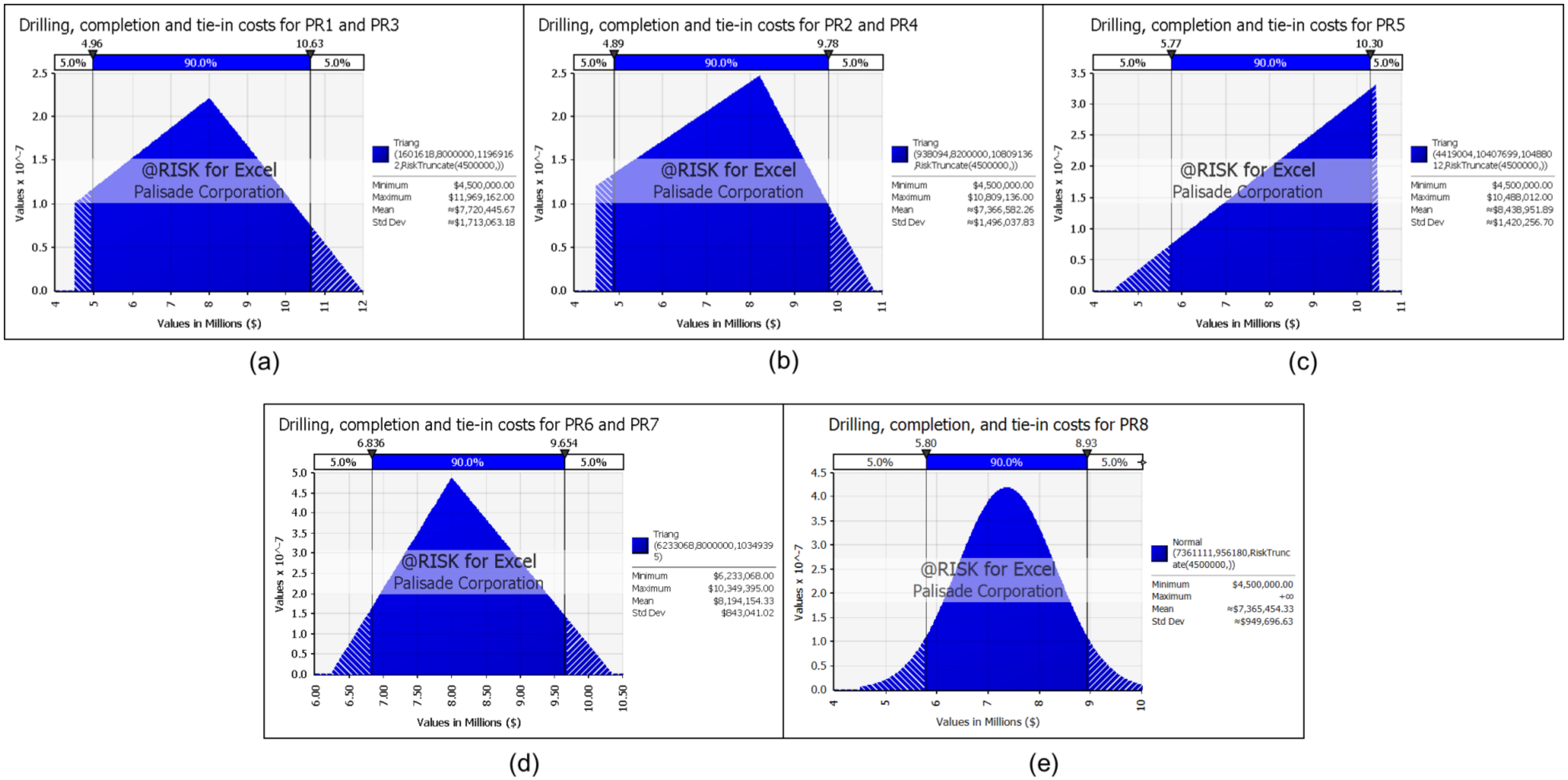

Figure 18—D&C costs distributions for all production regions

Operating expenses

Operating expenses (OpEx), or leasing operating expenditures (LOE), are periodic and necessary costs to sustain the normal and continuous operation and production of the field (Mian 2011). OpEx consist of a fixed cost portion and a variable cost per unit of production.

We found that it was particularly difficult to model OpEx for the Eagle Ford shale development projects, given the lack of information available. However, enough information was found to set low and high reasonable limits for OpEx and to be modeled using Log-Normal distributions, usually used in oil and gas projects (Capen 2001). Fixed OpEx were considered on a monthly per-well basis, using a Log-Normal distribution with a mean value of US$ 3,111, standard deviation of US$ 1,258, maximum value of US$ 6,500, and minimum value of US$ 1,450, as shown in **Figure 19.**

Variable OpEx for black, condensate, and volatile oil were modeled on dollar per barrel produced basis, using a Log-Normal distribution with a mean value of US$ 5.18, standard deviation of US$ 2.53, maximum value of US$ 12, and minimum value of US$ 1.75, as shown in **Figure 20.** A similar model was used for natural gas OpEx, with a Log-Normal distribution with a mean value of US$ 5.18, standard deviation of US$ 2.53, maximum value of US$ 12, and minimum value of US$ 1.75, as shown in **Figure 21.**

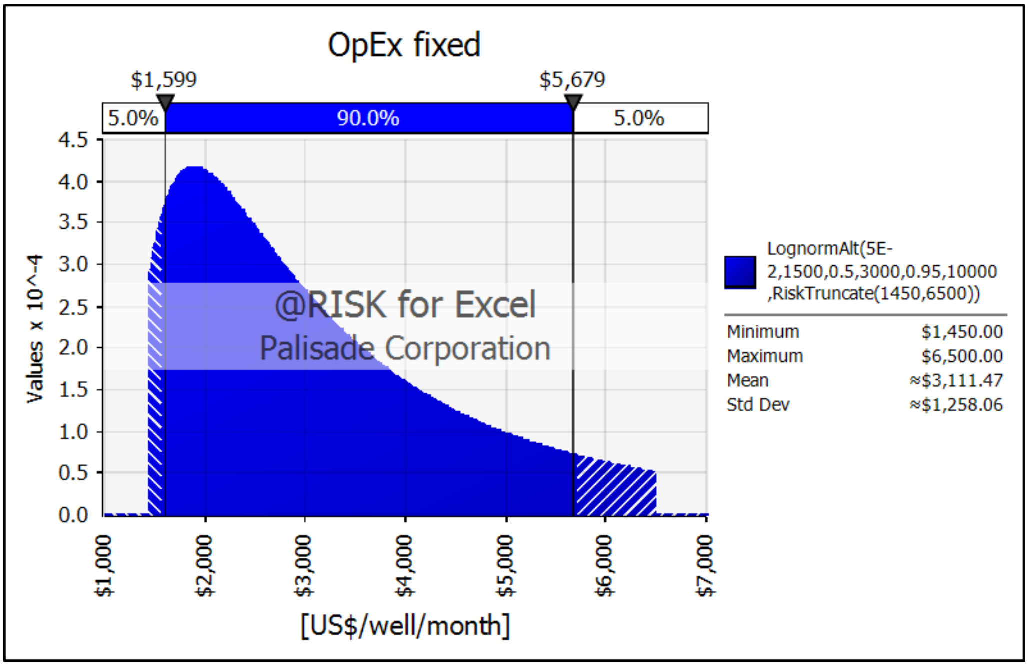

Figure 19—Log-Normal distribution for fixed OpEx.

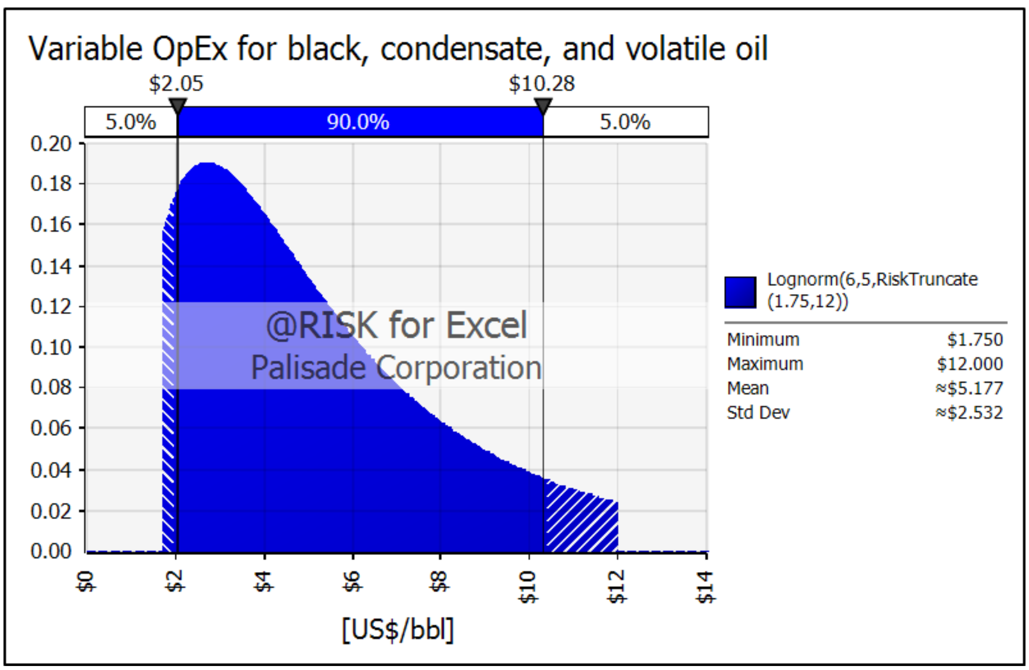

Figure 20—Log-Normal distribution for variable OpEx for black, condensate and black oil production.

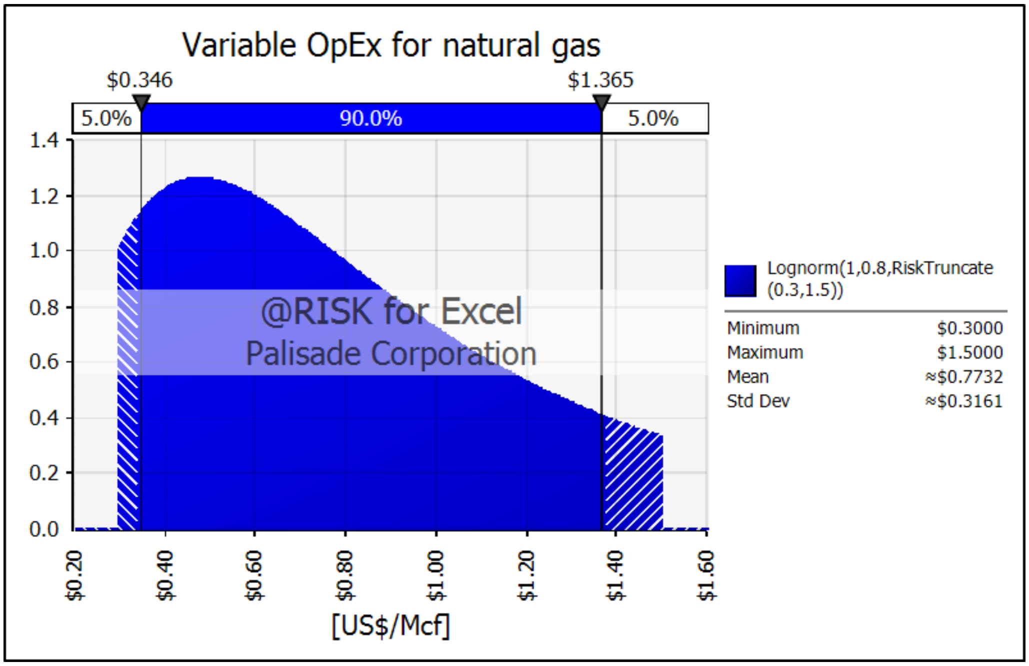

Figure 21—Log-Normal distribution for variable OpEx for natural gas production.

Additionally, a negative correlation between fixed OpEx and variable OpEx was established, using a correlation coefficient of -0.7, so when the model chooses a high value of fixed OpEx the corresponding variable OpEx value is low, and vice versa. For PR1 to PR7 the correlation was set with variable OpEx for oil, and for PR8 the variable OpEx for gas was used. Finally, a deterministic value for production water disposal of US$ 1.50/Bw was included.

Leasing considerations

In the U.S., private operators must sign a contract or lease with landowners to acquire rights for exploration and production of hydrocarbons in a property. Important aspects of the terms of a lease are the percentages of royalty and working interest (WI). WI is defined as the percentage of ownership that grants its owner the right to execute exploration and production in a determined property, and it also establishes the percentage of the costs that must be assumed by the WI owner (Schlumberger 2013). We used deterministic values of 100% of WI and 25% for Royalty in all calculations.

In this chapter, we have described the before-tax cash flow model designed to estimate reserves in the Eagle Ford shale, acknowledging all the challenges that the complexity and heterogeneity of the play imposes. In the following chapter we present the different scenarios for development projects considered and the corresponding results of estimation of reserves.

CHAPTER IV

EAGLE FORD RESERVES ESTIMATION

In the previous chapter, we described the before-tax cash flow model designed to estimate reserves in the Eagle Ford shale, including all the necessary considerations and assumptions to handle the high complexity and heterogeneity of the play. This chapter discusses the different scenarios under which the reserves estimation was performed, obtained results, and most important findings.

Definition of the scenarios for evaluation

The methodology proposed by Gong (2013), discussed in the previous chapter, handles the uncertainty associated with the production of hydrocarbons in the Eagle Ford shale and generates accurate forecasts of production. One important aspect of this methodology was the division of the Eagle Ford shale into 8 different production regions. Each of them has a specific PDCA model to forecast hydrocarbons production.

Given this, we decided to consider three scenarios to perform the reserves estimation, running 10.000 iterations in every case in each of the production regions. We considered a project life of 20 years following in all cases, following the same considerations used by Gong (2013) in his work and evaluations of the Eagle Ford shale.

The three scenarios are described as follows:

1. Single well scenario: The estimation of reserves was performed considering one development well in each region.
2. 100-well scenario: In this scenario, we estimated reserves from the production of a group of 100 wells. Here, we considered that during the first 25 months of the project life, two wells were drilled, completed, and put into production each month.
3. Full-well scenario. In this scenario, we estimated reserves from production of two different groups of wells: (1) existing wells in each region as of December 2012, and (2) future wells drilled during the first five years of the project life. We assumed that the number of wells to be drilled during each of the first five years will be the same number of wells drilled in each region during 2012.
4. **Table 5** shows the total number of wells considered in this scenario for each of the production regions.

Table 5—Number of wells considered in each region for Full-well scenario

Production Region	Existing wells as of December 2012	Wells drilled in 2012	Wells drilled in next five years	Wells per month
PR1	102	47	235	4
PR2	839	407	2035	35
PR3	913	542	2710	45
PR4	428	193	965	16
PR5	1020	542	2710	45
PR6	561	309	1545	26
PR7	310	146	730	12
PR8	229	73	365	6

In order to evaluate the effect of commodity price change on reserves estimates, we run six different simulations in each of the described scenarios with the following price models:

- Base case: This model assumes flat spot prices of US$ 95/bbl for WTI crude oil and US$ 4.50/Mmbtu for Henry Hub natural gas price for the complete project life. Additionally, we used the average values of all the input distributions presented in Chapter II.
- Base case M: This model uses the same prices as in Base case and all probabilistic input distributions to obtain results of sensitivity analysis.
- High oil-High gas (HH): This model uses the IHS high price forecasts for oil and natural gas.
- Low oil-Low gas (LL): This model uses the IHS low price forecasts for oil and natural gas.
- High oil-Low gas (HL): This model assumes the IHS high forecast for oil price and IHS low forecast for natural gas price.
- Low oil-High gas (LH): This model uses the IHS low forecast for oil price and IHS high forecast for natural gas price.

  Table 6 shows the long-term crude oil and natural gas prices for each of the price models.

Table 6—Summary of long-term commodity prices for each of the price models

Price Model	WTI crude oil price [US$/bbl]	Henry Hub natural gas price [US$/Mmbtu]
Base case	95.00	4.50
Base case M	95.00	4.50
High oil-High gas (HH)	127.58	12.12
Low oil-Low gas (LL)	39.17	2.52
High oil-Low gas (HL)	127.58	2.52
Low oil-High gas (LH)	39.17	12.12
High IHS 35% (HH35)	110.26	7.97
Low IHS 35% (LL35)	54.53	3.17

Additionally, we used IHS to generate two additional price models, one high and one low price forecast for oil and natural gas using a truncation factor of 35%. The long term commodity prices for this additional high price model, denoted with HH35, are US$ 110.26/bbl for oil and US$ 7.97/Mmbtu for natural gas. While the low price forecast, denoted with LL35, has long-term prices of US$ 54.53/bbl for oil and US$ 3.17/Mmbtu for natural gas. These two price models were used generate the graphs, included in this Chapter, that show the behavior of different economic yardsticks with the change in oil and natural gas prices.

We used the net present value discounted at a rate of 10% (PV10) as economic criteria to classify production volumes as reserves. The corresponding forecasted production volumes were classified as reserves when the PV10 value was greater than zero in the single well and 100-well scenarios. For the Full-well scenario, we used the same criteria for the forecasted production volumes corresponding to the new wells drilled. The production from the existing wells is classified as reserves until it reaches the Economic Limit (SPE et al. 2007).

Single well scenario results

Even though development projects in the oil and gas industry do not consist of drilling, completion, and production from one well, it is important to evaluate the productivity and commerciality on a single well basis in the different production regions of the Eagle Ford shale, and the effect of the change in crude oil and natural gas prices. A summary of oil and natural gas TRR20 for a single well in each of the production regions of the Eagle Ford shale is shown in **Table 7**. These values were calculated using the PDCA with 10.000 iterations and without any economic consideration. Results were consistent with the work of Gong (2013).

Table 7—Oil and natural gas TRR20 for a single well for all production regions

Production Region	Gas Resources (BCF)				Oil Resources (STB)			
	Mean	P10	P50	P90	Mean	P10	P50	P90
PR1	0.33	0.77	0.20	0.04	104,246	212,444	73,201	23,587
PR2	3.71	8.41	2.46	0.47	178,660	389,666	126,285	27,278
PR3	0.83	1.80	0.56	0.14	256,910	500,637	199,774	71,737
PR4	3.01	6.58	2.00	0.48	133,969	286,562	94,074	28,353
PR5	0.76	1.62	0.55	0.16	250,624	467,071	205,296	83,562
PR6	2.87	6.47	1.70	0.52	461,614	951,435	321,752	137,031
PR7	4.89	11.76	2.76	0.56	277,694	676,813	155,283	28,646
PR8	3.26	6.36	2.46	0.84	-	-	-	-

Figure 22 shows the resulting distributions of oil reserves for PR1, PR3, and PR5 calculated using the Base M price model. In the case of PR1, the frequency values are too low to form a clear distribution shape, being the frequency value of zero the only one noticeable. This means that the productivity in PR1 is not good enough to yield positive values of PV10. By contrast, reserves distributions for PR3 and PR5 show higher frequencies for values greater than zero, which has the highest frequency in both cases. PR3 and PR5 have mean values of 158.734 STB and 149.278 STB, respectively, while PR1 has significant lower value of 32.374 STB.

Additionally, **Figure 23** shows the corresponding sensitivity analysis of reserves in the black oil production regions. These figures, known as Tornado charts, are calculated by @Risk measuring the effect of each of the input distributions, such as D&C and OpEx costs for our model, has on the average value for oil reserves. The input distributions are ranked from the highest to lowest effect and each bar shows the value of increment and reduction caused. We can see that D&C costs have the greatest effect on all three cases of reserves distributions.

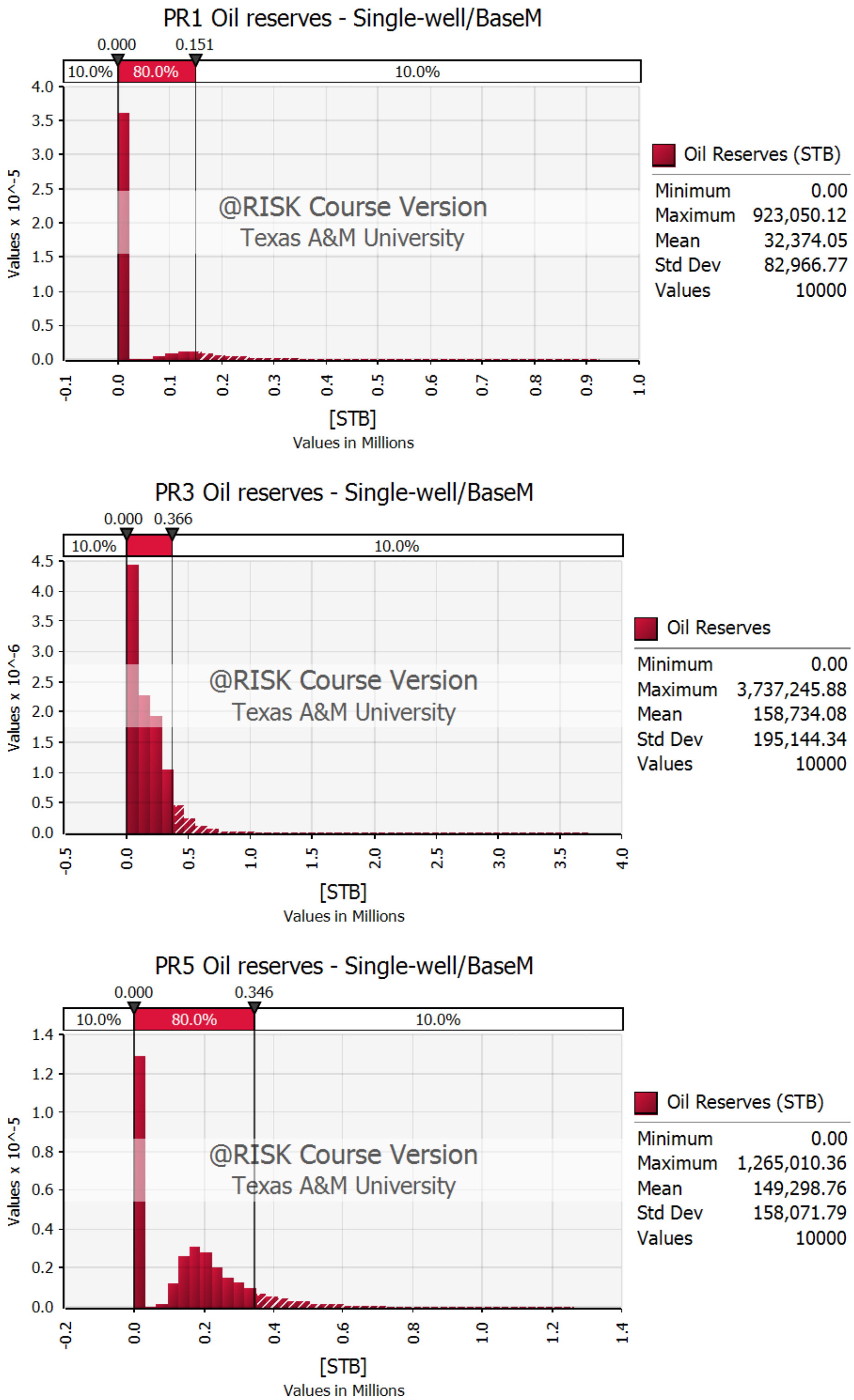

Figure 22—Resulting oil reserves distributions for a single well in black oil production regions with Base case M prices.

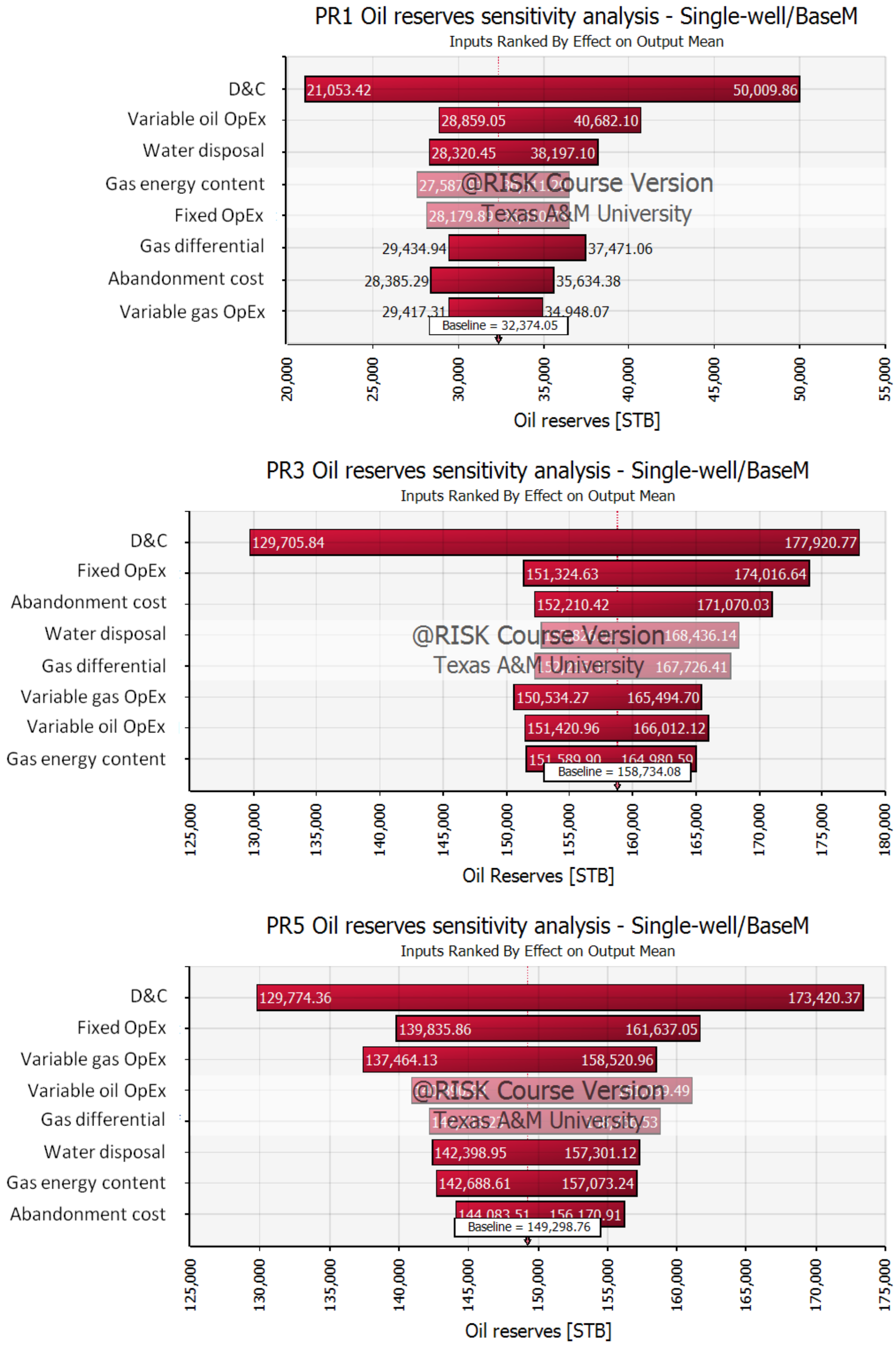

Figure 23—Sensitivity analysis for oil reserves distributions for a single well in black oil production regions with Base case M prices.

Although we used a probabilistic methodology to calculate the price forecasts, IHS does not generate a full distribution of future prices. This is why @Risk Tornado charts cannot measure the effect of price on reserves results. Olsen et al. (2005b) compared the IHS results with price distributions generated with other methods based on historical data. They found that results obtained of project evaluations using the IHS high and low forecasts, represented a probability interval of 83% of the results yielded with the price distributions of other methods. IHS offers a rapid and accurate way to determine the range of results without the need to have numerous price forecasts.

Figure 24 shows the oil reserves for a single well in PR3 with the Base M, HH, and LL models. We found that in the three cases, the highest frequency corresponds to zero reserves; however distribution shape is different in each case. In the case of Base M and LL prices the shape resembles an exponential distribution, with an improvement for higher prices; while in LL case the shape is hardly appreciable. We see that higher prices increase the chance to have reserves. The mean of each distribution also reflects this effect with higher values for HH and Base M, 176.261 STB and 158.734 STB respectively, than the LL case with a mean of 82.982 STB, representing a reduction of approximately 50%. We found a different situation for the P10 reserves, with very little variation in value for the three cases. We consider that this is caused by the project life of 20 years used for the evaluation, in which the real economic limit for the best productivity cases is not reached.

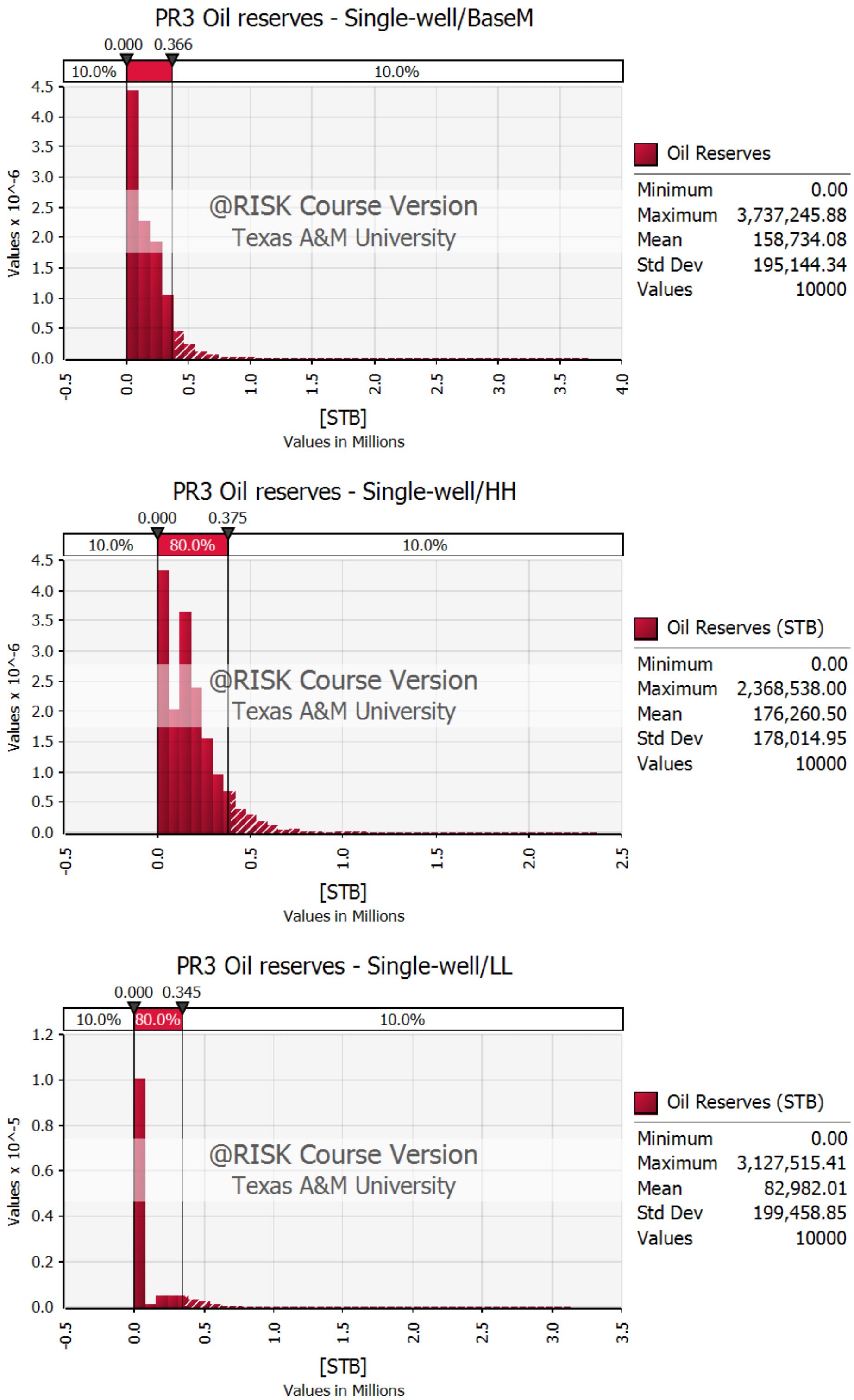

Figure 24—Comparison of oil reserves for a single well in PR3 with different price models.

Table 8, **Table 9**, and **Table 10** show the mean, P10, P50, and P90 values for oil and natural gas reserves, as well as the PV10 results, for a single well in PR1, PR3, and PR5. In the case of PR1, all price models have P10 reserves, with the exception of LL price model. However, results of P50 and P90 reserves have value of zero indicating that only the combination of best production forecasts with high price models can achieve commerciality.

PR3 and PR5 have better results than PR1. In these two cases, P10 reserves are present in all price models. With the exception of the LL and LH price models, P50 reserves are present in PR3 and PR5. This shows an improvement in the productivity of wells and that the crude oil price has a significant effect on commerciality of the well. Even with the improved hydrocarbon production for these two production regions no P90 values were found. Here again, the 20-year project life constitute and additional hurdle for the P50 and P10 reserves.

Table 8—Oil and natural gas reserves of a single well in PR1

Price Model	Gas Reserves (BCF)				Oil Reserves (STB)				PV10 (US$ Million)			
	Mean	P10	P50	P90	Mean	P10	P50	P90	Mean	P10	P50	P90
Base	0.10	0.44	-	-	29,120	154,873	-	-	(3.21)	1.10	(4.20)	(6.66)
Base M	0.10	0.44	-	-	35,374	151,159	-	-	(3.09)	1.80	(3.88)	(7.48)
HH	0.15	0.51	-	-	45,053	153,814	-	-	(1.32)	5.45	(2.69)	(7.02)
LL	0.03	-	-	-	9,589	-	-	-	(5.41)	(2.29)	(5.59)	(8.58)
HL	0.12	0.47	-	-	37,480	15,068	-	-	(2.39)	3.12	(3.30)	(7.28)
LH	0.08	-	-	-	21,623	-	-	-	(4.23)	(0.15)	(4.75)	(7.98)

Table 9—Oil and natural gas reserves of a single well in PR3

Price Model	Gas Reserves (BCF)				Oil Reserves (STB)				PV10 (US$ Million)			
	Mean	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**
Base	0.50	1.25	0.32	-	159,696	368,921	149,836	-	3.28	12.65	1.44	(4.46)
Base M	0.51	1.26	0.32	-	160,672	370,038	144,166	-	3.33	12.98	1.54	(4.94)
HH	0.56	1.26	0.44	-	176,260	375,926	176,256	-	8.63	23.44	5.46	(3.40)
LL	0.27	1.02	-	-	82,982	344,785	-	-	(2.41)	2.30	(2.99)	(6.88)
HL	0.52	1.26	0.41	-	169,803	374,181	148,294	-	5.44	17.51	3.03	(4.30)
LH	0.43	1.28	-	-	132,830	370,933	-	-	0.55	8.05	(0.76)	(5.80)

Table 10—Oil and natural gas reserves of a single well in PR5

Price Model	Gas Reserves (BCF)				Oil Reserves (STB)				PV10 (US$ Million)			
	Mean	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**
Base	0.44	1.12	0.31	-	149,401	345,706	152,475	-	2.61	11.44	1.02	(4.37)
Base M	0.44	1.14	0.30	-	149,299	345,791	147,562	-	2.73	12.00	1.26	(4.65)
HH	0.50	1.12	0.39	-	171,103	343,592	154,898	-	7.49	20.68	5.04	(3.06)
LL	0.20	0.87	-	-	65,540	324,740	-	-	(2.90)	1.72	(3.45)	(6.88)
HL	0.47	1.11	-	-	160,534	339,017	155,238	-	4.62	15.44	2.86	(4.00)
LH	0.36	1.13	-	-	114,824	343,926	-	-	(0.15)	7.00	(1.33)	(5.82)

We selected PV10 as the economic tool to measure the commerciality of the different scenarios and development projects in the Eagle Ford shale. However, PV10 is not the only economic yardstick used to measure and evaluate projects in the oil and gas industry. Internal rate of return (IRR) and Present worth index (PWI) are other two important ways to evaluate development projects and to make investment decisions. IRR is the rate of discount that makes the NPV of a project equal to zero; whereas PWI is defined as the ratio of the NPV to the total capital investment, or CapEx, of the project (Mian 2011).

Results of PV10, IRR, and PWI, as a function of the price model, are displayed in **Figure 25**, **Figure 26**, and **Figure 27** for the three black oil production regions. For all three economic measures, a positive trend of change is seen as natural gas and oil prices increase, with better results for PR3 and PR5 than PR1. Nevertheless, we found negative results in P50 and P90 values of the three measures even with the highest commodity prices. This reflects the effect that production variability has in the economic evaluation.

These graphs also show the change in the probability interval of the results. For PV10 and PWI cases, we found that the increase in prices generated wider ranges of results in all three production regions. In the case of IRR the same effect is appreciable, however not as clear as for PV10 and PWI.

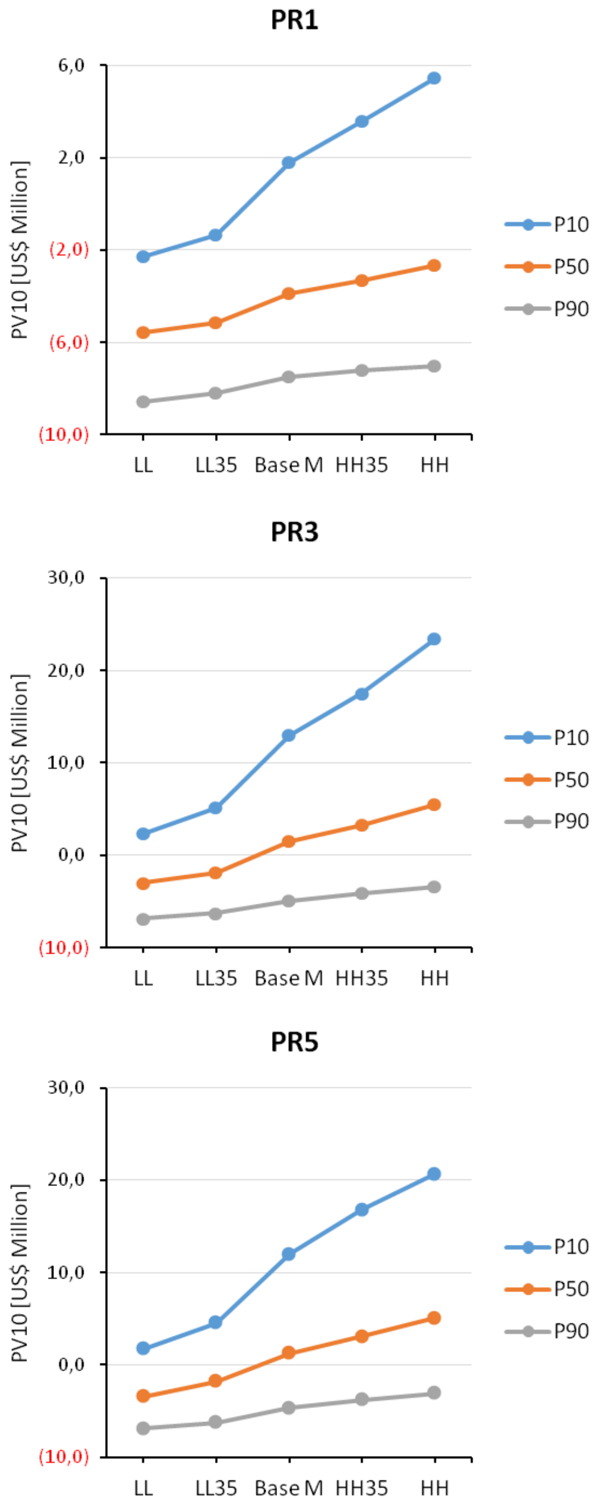

Figure 25—P10, P50, and P90 values of PV10, as function of price, for a single well in PR1, PR3, and PR5.

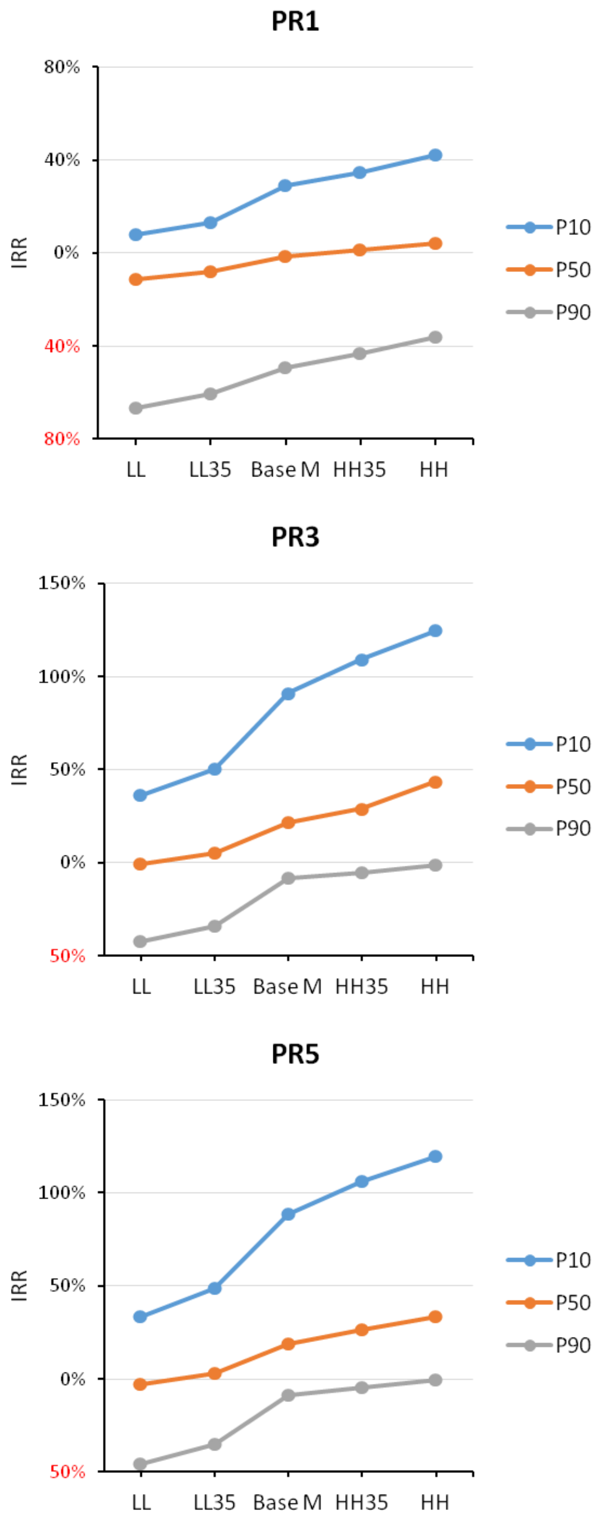

Figure 26—P10, P50, and P90 values of IRR, as function of price, for a single well in PR1, PR3, and PR5.

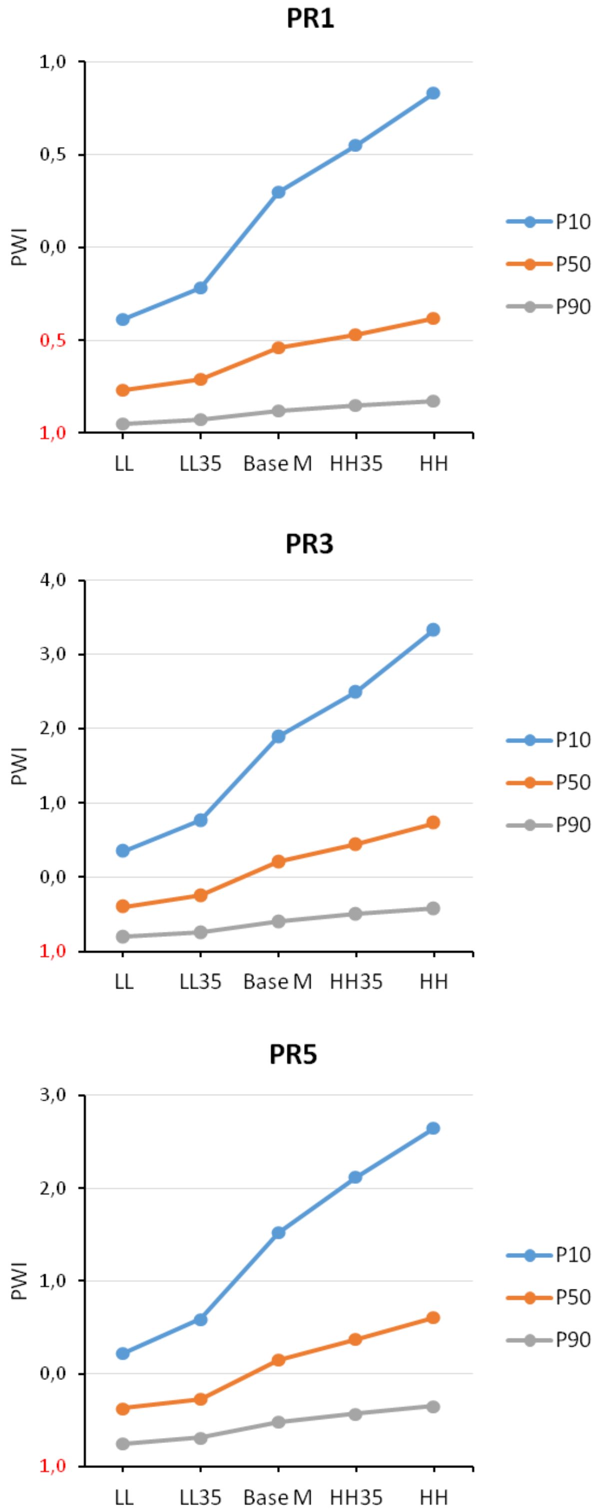

Figure 27—P10, P50, and P90 values of PWI, as function of price, for a single well in PR1, PR3, and PR5.

Figure 28 shows the oil reserves distributions of a single well in the condensate and volatile oil production regions. PR2 and PR4 distributions have mean values of 114.434 STB and 75.783 STB, respectively; while PR6 and PR7 distributions show better results, with mean values of 328.661 STB and 186.317 STB. The oil reserves distribution for PR6 is the only case in which the highest frequency corresponds to a value greater than zero, reflecting the best productivity of a single well in the Eagle Ford shale. **Figure 29** shows that for PR2, PR4, PR6, and PR7, D&C costs have the greatest effect on the resulting oil reserves distributions.

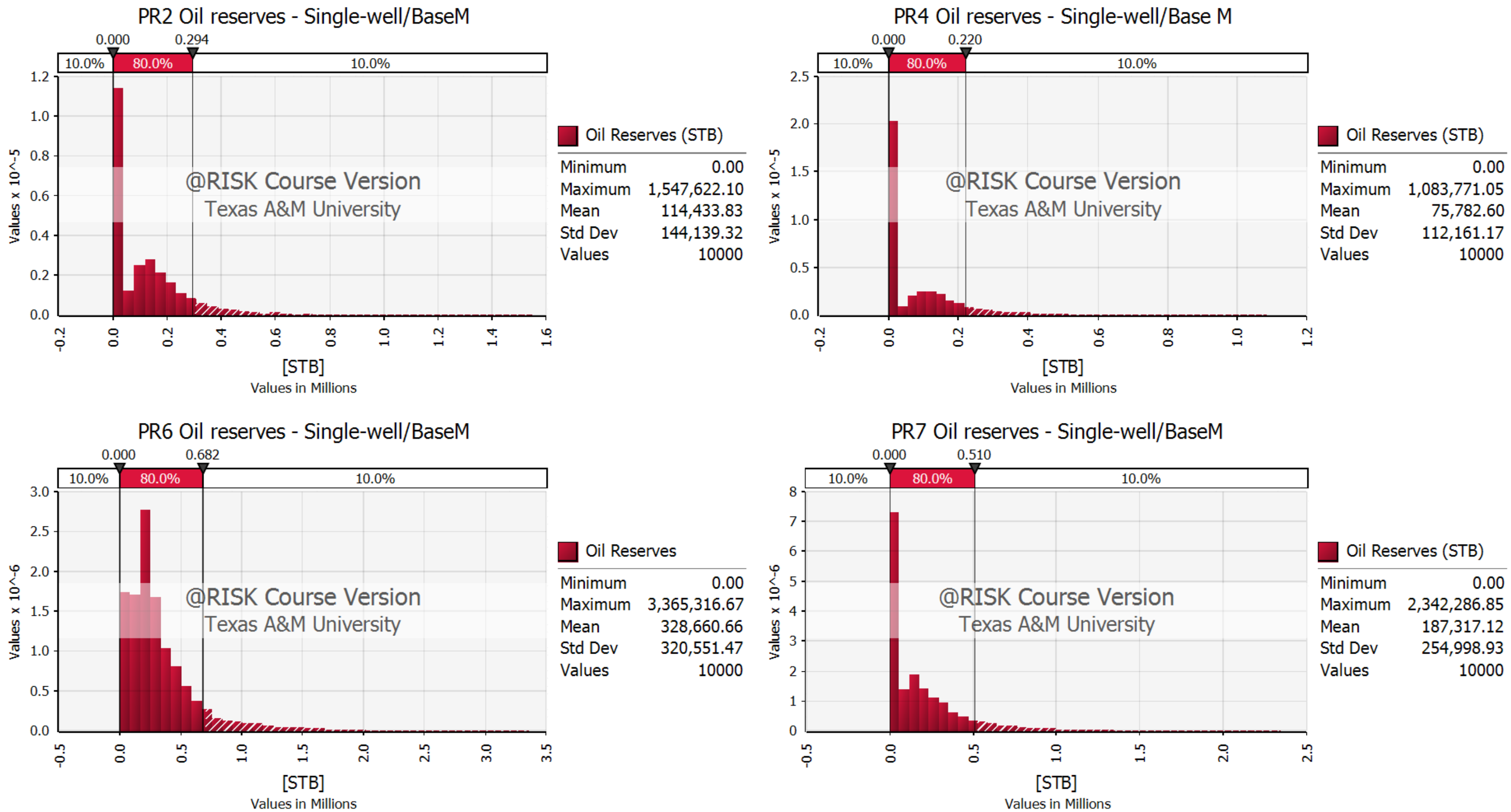

Figure 28—Oil reserves distributions for a single well in the condensate and volatile oil production regions.

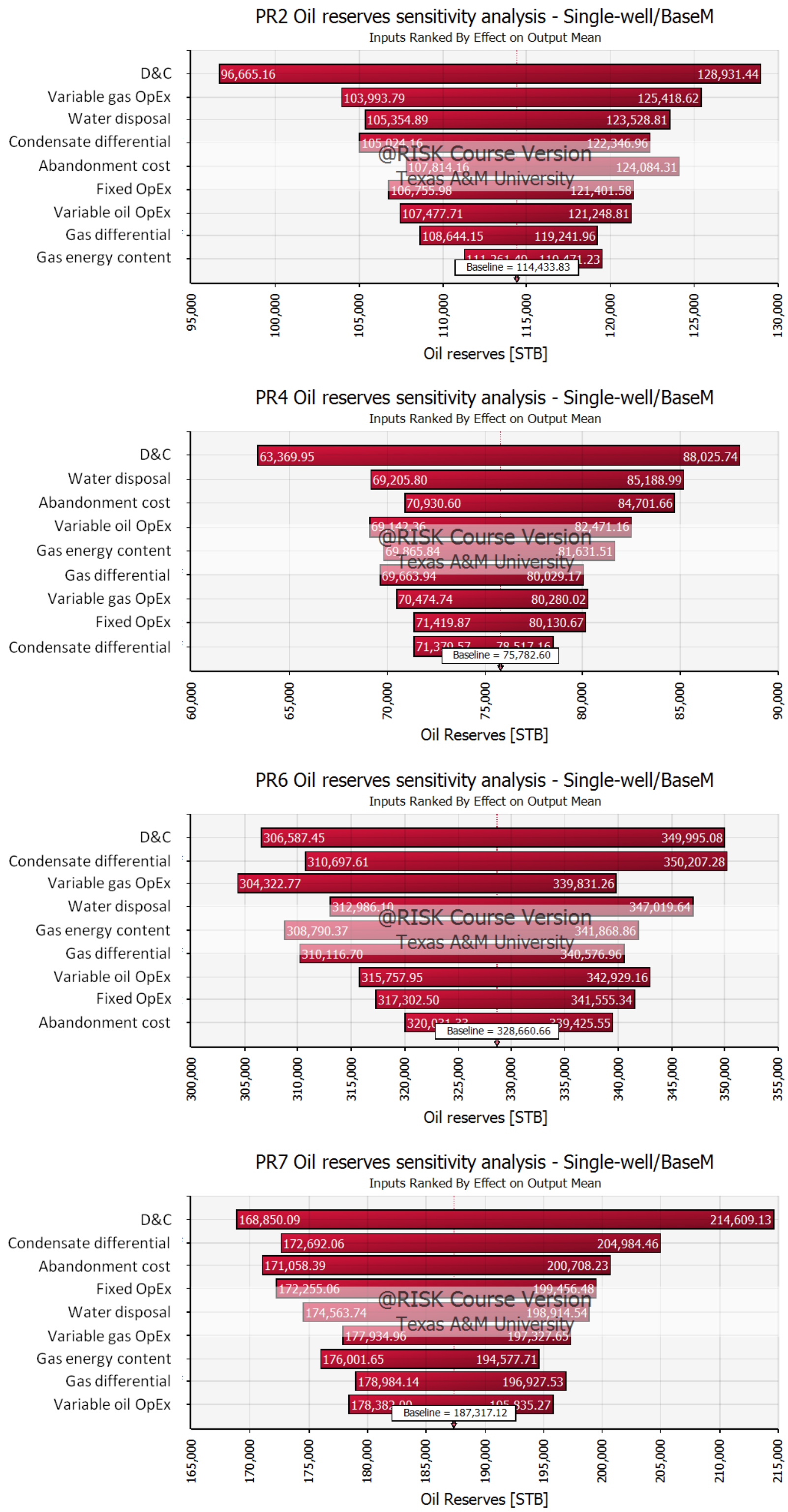

Figure 29—Sensitivity analysis for oil reserves distributions for a single well in the condensate and volatile oil production regions.

Table 11 has mean, P10, P50, and P90 results of oil and natural gas resources and reserves for a single well in PR4 and PR7. PR4 has P10 reserves in all price models and P50 values with HH and LH, which indicates the effect of high gas price. In the case of PR2 and PR7, **Table 12** and **Table 14** show that all cases yielded P10 and P50 reserves, with the exception of LL price model. Finally, PR6 has the best results among the condensate and volatile oil production regions. Results in **Table 13** show that PR6 yielded P10 and P50 reserves in all cases. Additionally, PR6 was the only production region with a P90 reserves value obtained with the HH price model.

Table 11—Oil and natural gas reserves of a single well in PR2

Price Model	Gas Reserves (BCF)				Oil Reserves (STB)				PV10 (US$ Million)			
	Mean	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**
Base	2.33	5.99	1.56	-	115,634	296,512	87,756	-	4.01	16.48	1.29	(5.26)
Base M	2.29	6.06	1.47	-	114,434	293,848	82,440	-	3.98	16.67	1.34	(5.36)
HH	2.62	6.21	2.06	-	128,420	296,486	95,089	-	16.54	44.19	10.31	(3.40)
LL	1.34	5.44	-	-	64,666	269,536	-	-	(2.30)	3.20	(3.21)	(6.91)
HL	2.13	5.78	0.99	-	108,861	286,143	74,565	-	2.90	14.25	0.51	(5.62)
LH	2.52	6.04	1.77	-	122,705	293,258	92,699	-	10.98	32.44	5.90	(4.34)

Table 12—Oil and natural gas reserves of a single well in PR4

Price Model	Gas Reserves (BCF)				Oil Reserves (STB)				PV10 (US$ Million)			
	Mean	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**
Base	1.67	4.74	-	-	76,199	215,805	-	-	1.49	10.88	(0.82)	(5.37)
Base M	1.66	4.86	-	-	75,783	219,857	-	-	1.44	11.36	(0.69)	(5.78)
HH	2.00	4.64	1.35	-	91,280	213,455	68,961	-	11.10	32.06	5.94	(3.56)
LL	0.76	3.15	-	-	33,053	143,077	-	-	(3.52)	0.99	(4.26)	(7.32)
HL	1.50	4.63	-	-	71,579	212,227	-	-	0.51	9.16	(1.33)	(6.02)
LH	1.95	4.76	1.43	-	86,218	214,388	62,272	-	7.36	24.63	3.05	(3.66)

Table 13—Oil and natural gas reserves of a single well in PR6

Price Model	Gas Reserves (BCF)				Oil Reserves (STB)				PV10 (US$ Million)			
	Mean	P10	P50	P90	Mean	P10	P50	P90	Mean	P10	P50	P90
Base	2.00	4.67	1.21	-	337,317	713,799	242,788	-	13.52	34.57	8.11	(0.93)
Base M	1.94	4.52	1.20	-	328,661	681,641	240,789	-	13.16	32.99	8.09	(1.33)
HH	2.06	4.62	1.21	0.33	347,475	720,383	241,220	116,273	26.70	63.77	16.36	1.87
LL	1.63	4.68	0.62	-	268,244	702,936	183,147	-	2.02	10.35	0.39	(4.52)
HL	2.00	4.63	1.19	-	336,464	708,024	239,074	-	15.97	39.53	9.65	(0.70)
LH	1.95	4.76	1.43	-	338,881	714,611	240,343	-	16.06	40.35	9.80	(0.44)

Table 14—Oil and natural gas reserves of a single well in PR7

Price Model	Gas Reserves (BCF)				Oil Reserves (STB)				PV10 (US$ Million)			
	Mean	P10	P50	P90	Mean	P10	P50	P90	Mean	P10	P50	P90
Base	2.97	7.91	1.70	-	177,997	473,317	104,663	-	7.36	27.63	1.87	(6.15)
Base M	3.11	8.33	1.81	-	187,317	509,857	111,188	-	7.98	29.35	2.44	(6.20)
HH	3.35	8.33	1.97	-	199,343	512,850	113,585	-	24.54	69.46	12.25	(3.98)
LL	2.21	7.89	-	-	135,133	476,336	-	-	(1.52)	6.96	(0.35)	(7.47)
HL	2.92	8.04	1.38	-	180,326	493,312	107,033	-	6.79	27.11	1.26	(6.44)
LH	3.24	8.18	1.97	-	189,397	496,770	108,294	-	15.91	47.90	7.24	(5.03)

Figure 30, **Figure 31**, and **Figure 32** display the results obtained for the economic measures PV10, IRR, and PWI under the different price models. As we found for the black oil production regions, there is an improvement in the values and an increase in the P90-P10 range as prices increase for the three yardsticks. PR6 and PR7 returned better numbers than PR2 and PR4, reflecting the better productivity of the western regions.

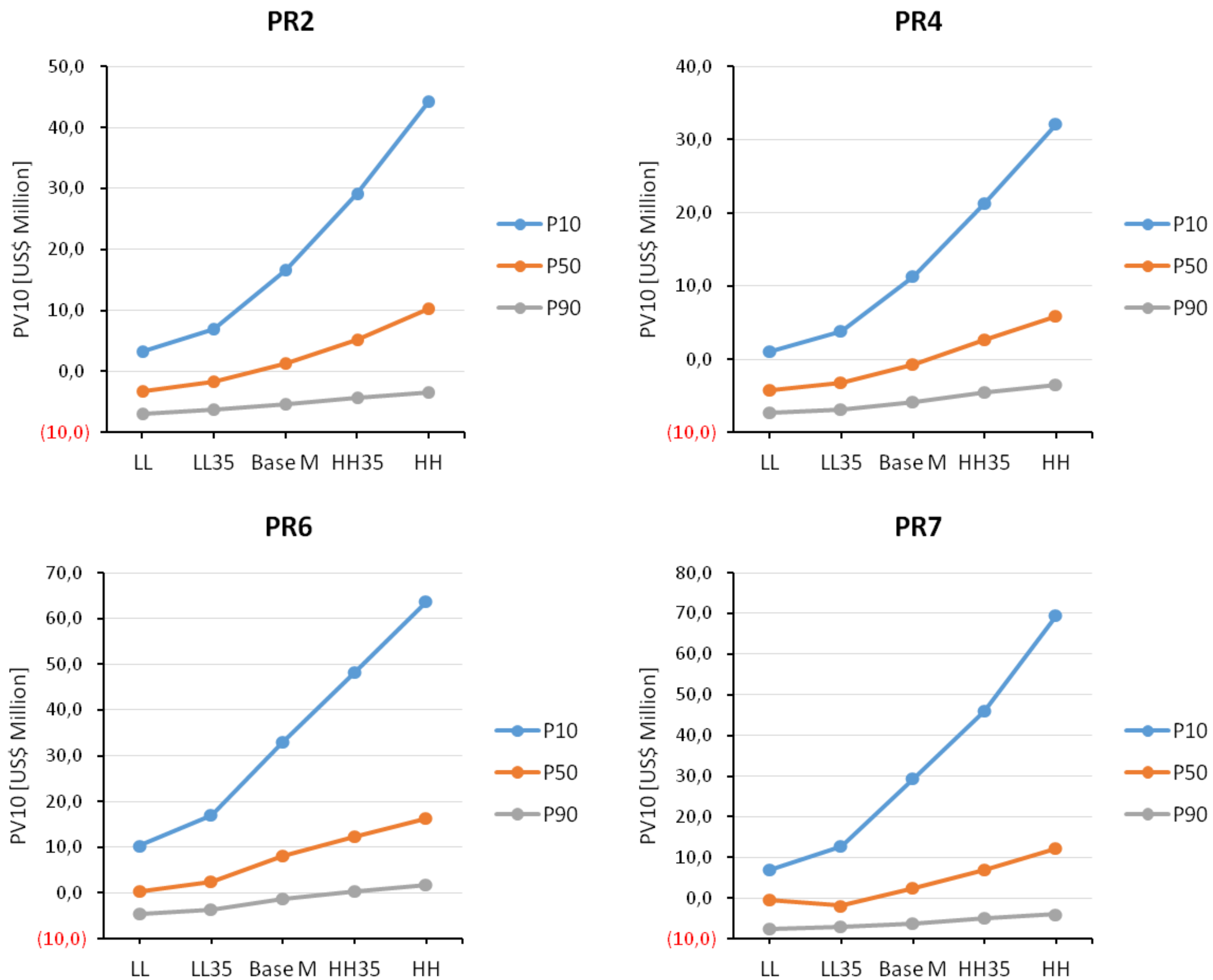

Figure 30—P10, P50, and P90 values of PV10, as function of price, for a single well in PR2, PR4, PR6, and PR7.

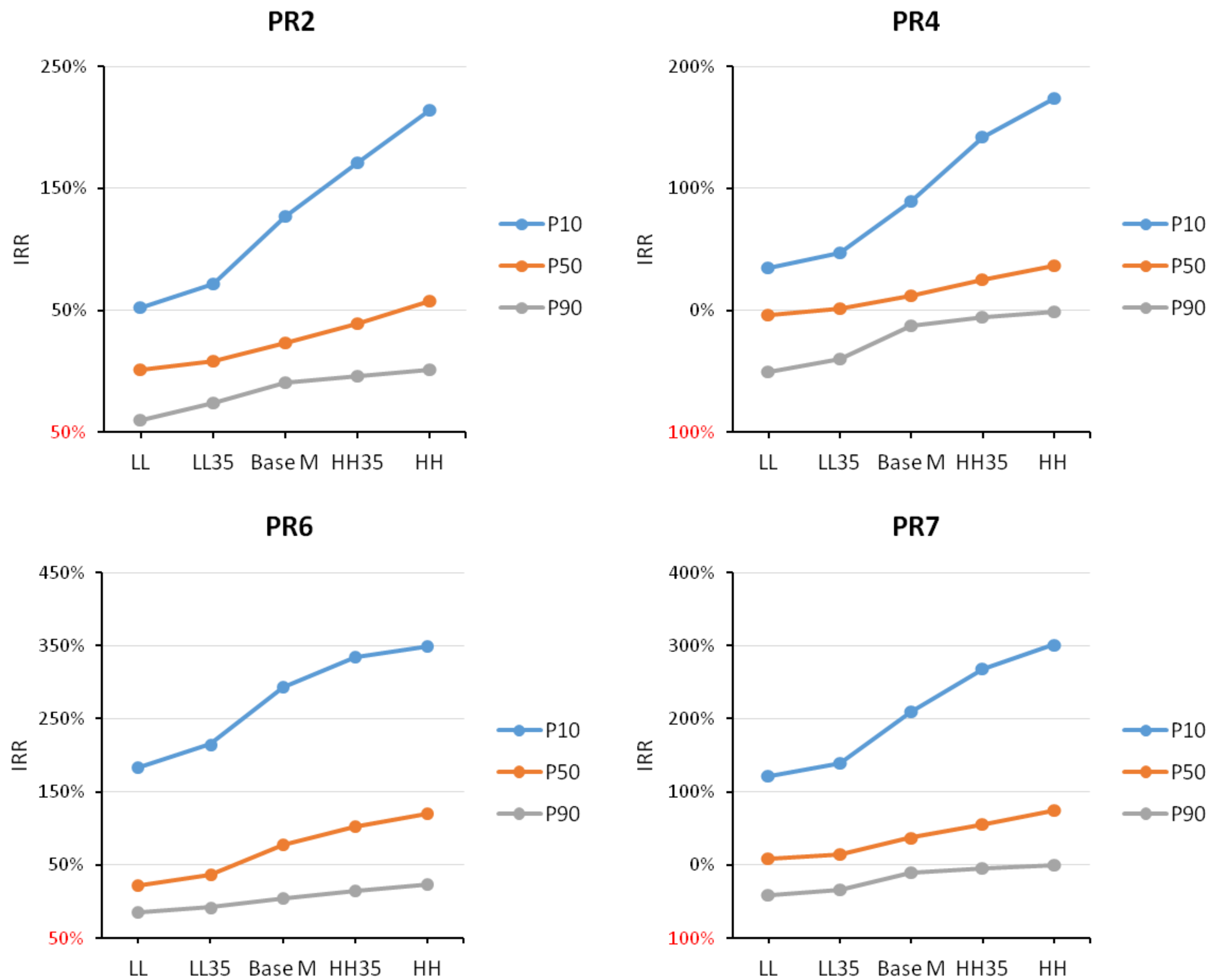

Figure 31—P10, P50, and P90 values of IRR, as function of price, for a single well in PR2, PR4, PR6, and PR7.

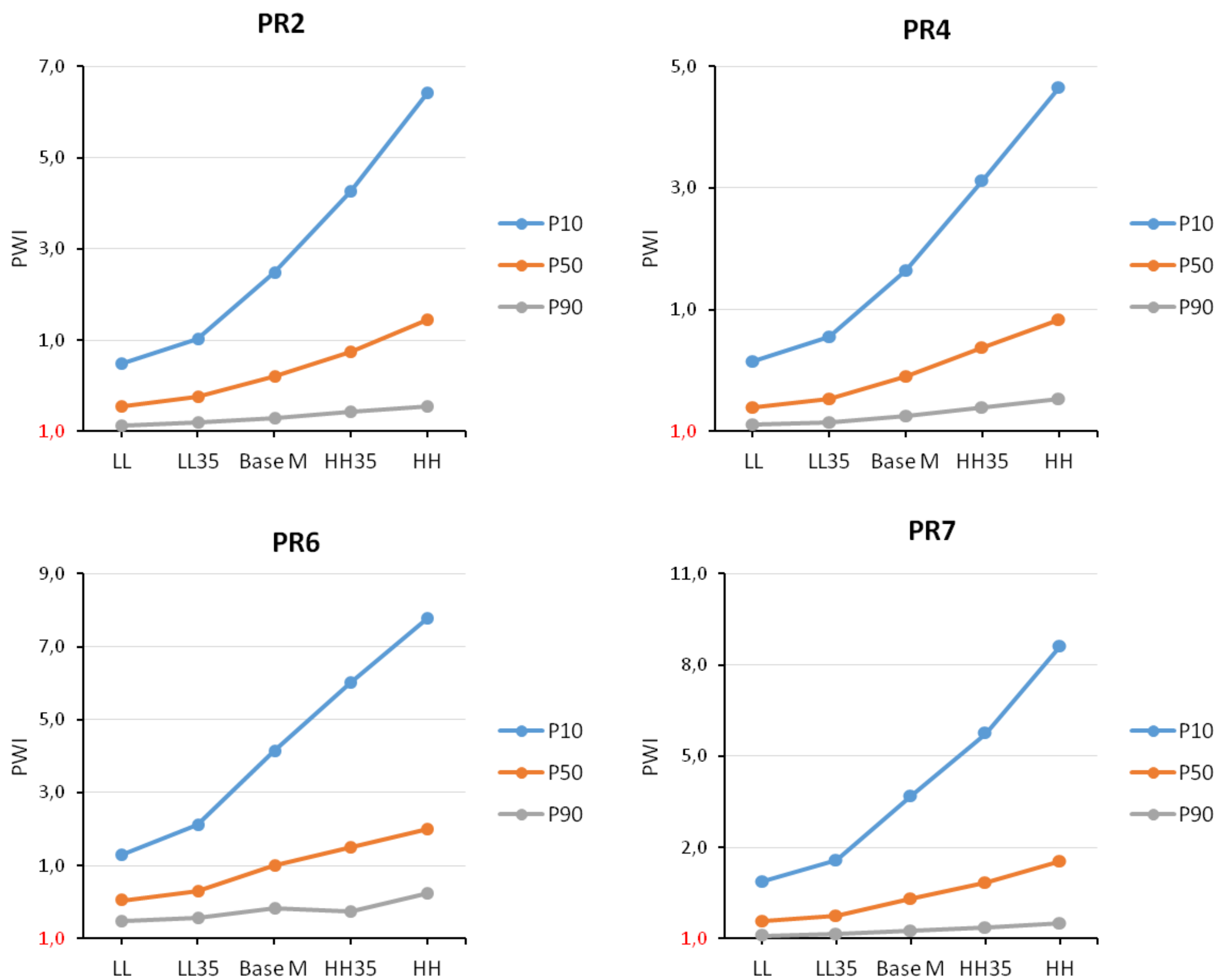

Figure 32—P10, P50, and P90 values of PWI, as function of price, for a single well in PR2, PR4, PR6, and PR7.

In the case of PR8, where there is no hydrocarbon liquids production, the evaluation of a single well returns the worst results of all production regions. **Figure 33** shows the distribution of natural gas reserves and the sensitivity analysis results. As we found for PR1, a distribution shape is not clearly seen and the only visible frequency volume corresponds to zero reserves.

Results of reserves and PV10 shown in **Table 15** are predominantly negative, with the exception of mean, P10, and P50 values for HH and HL price models, in which natural gas price is significantly high. **Figure 34** shows the resulting natural gas reserves distributions with LL and HH price models. We found that even with the highest price forecast, the value of zero reserves still had the highest frequency. Plots of PV10, IRR, and PWI displayed in **Figure 35** show the same trend of increase as in the other production regions. However, even with the highest natural gas prices the results were not completely successful.

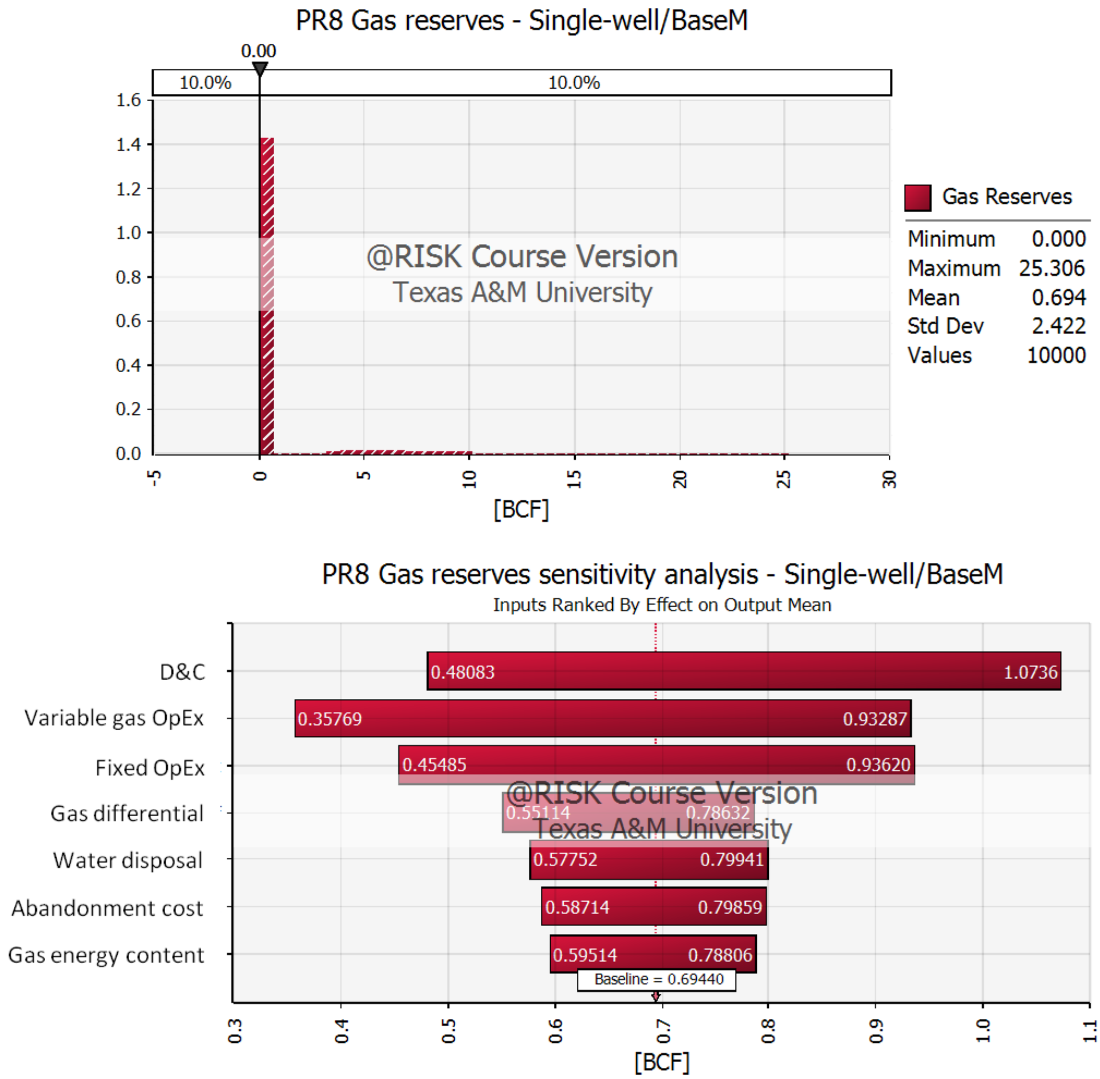

Figure 33—Gas reserves distribution (top) and sensitivity analysis (bottom) for a single well in PR8.

Table 15—Natural gas reserves of a single well in PR8

Price Model	Gas Reserves (BCF)				PV10 (US$ Million)			
	Mean	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**
Base	0.73	-	-	-	(3.75)	(0.20)	(4.52)	(6.43)
Base M	0.69	-	-	-	(3.80)	(0.11)	(4.54)	(6.82)
HH	2.02	4.58	1.75	-	5.07	16.86	2.38	(4.32)
LL	0.13	-	-	-	(6.03)	(4.12)	(6.27)	(7.80)
HL	0.13	-	-	-	(6.03)	(4.12)	(6.27)	(7.80)
LH	2.02	4.58	1.75	-	5.07	16.86	2.38	(4.32)

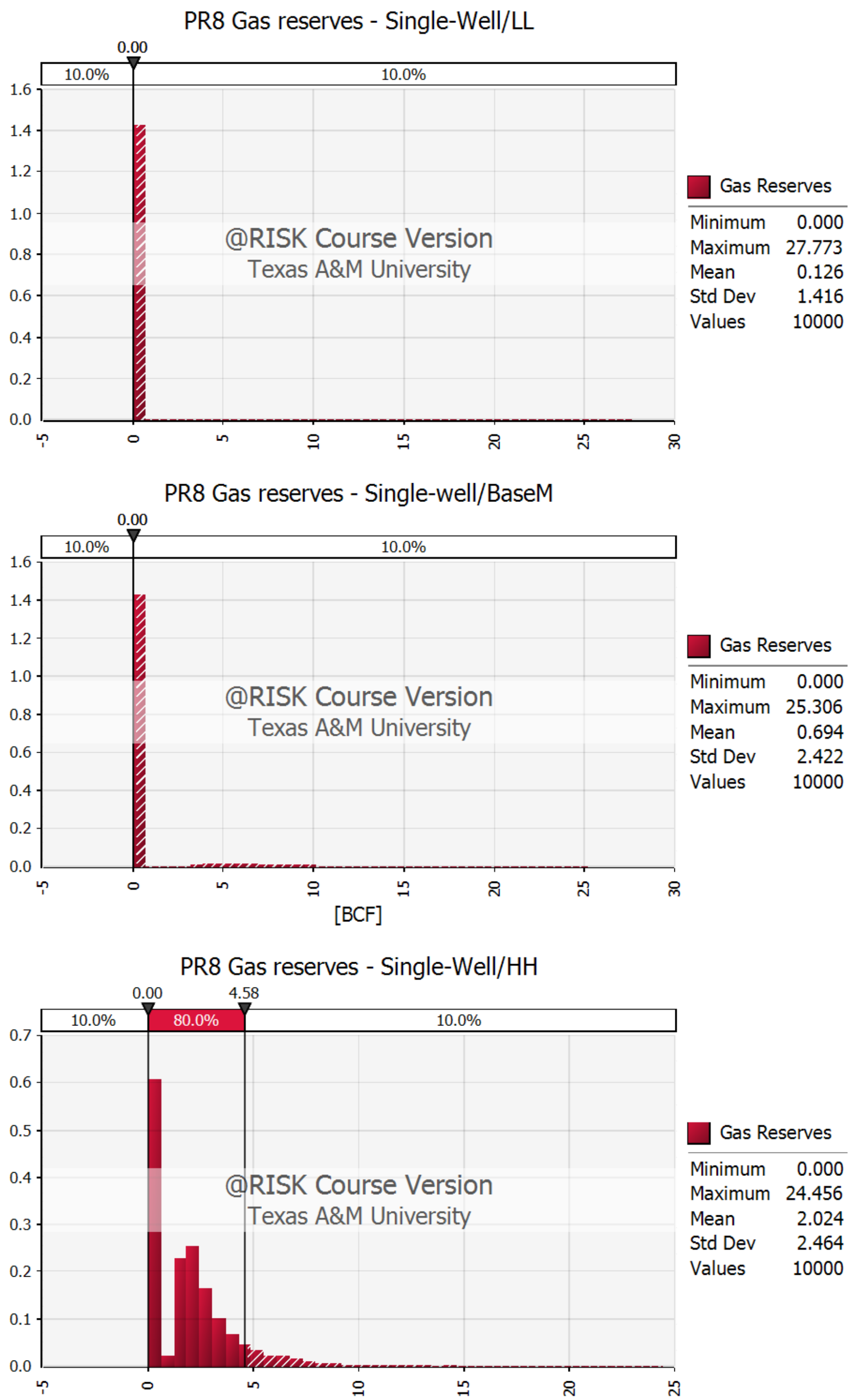

Figure 34—Comparison of oil reserves for a single well in PR8 with different price models.

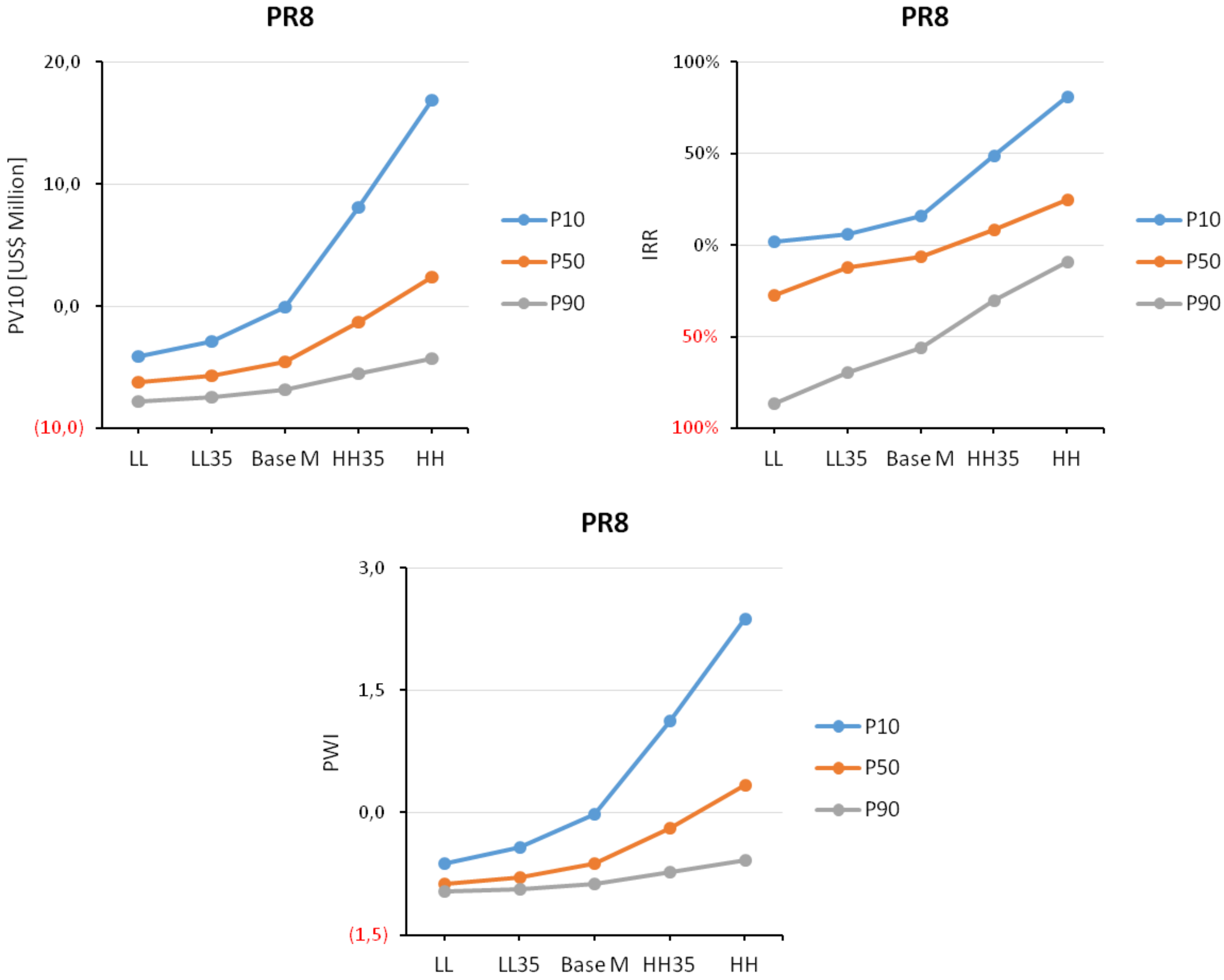

Figure 35—P10, P50, and P90 values of PV10, IRR, and PWI, as function of price, for a single well in PR8.

Another two important measures used in project evaluations in the oil and gas industry are F&D and Average OpEx (Avg OpEx) costs. We calculated these two economic yardsticks in every scenario and case, expressing them in US$/Boe for PR1 to PR7 and in US$/Mcfe for PR8. **Table 16** shows the resulting distributions of F&D Avg OpEx costs for all production regions. Among the liquid-rich producing regions, PR6 has the lowest values of these two parameters and PR1 has the highest costs. In the case of PR8, values of F&D and Avg OpEx costs are considerably high, which is consistent with the results of reserves previously discussed for the dry gas production region.

Table 16—Summary of F&D and Average OpEx costs for all production regions in the single-well scenario

Production Region	**F&D (US$/Boe)**				**Average OpEx (US$/Boe)**			
	Mean	**P90**	**P50**	**P10**	**Mean**	**P90**	**P50**	**P10**
PR1	200.58	354.25	91.91	28.23	15.54	24.26	13.70	8.86
PR2	78.58	82.37	17.98	5.37	9.22	13.10	8.75	5.50
PR3	96.43	103.74	34.30	12.49	11.02	15.41	10.24	6.86
PR4	42.09	85.71	22.44	6.93	10.42	14.97	9.96	6.23
PR5	52.29	98.71	37.49	15.33	10.55	14.46	10.06	6.93
PR6	25.01	49.03	18.36	5.63	8.71	12.41	8.30	5.40
PR7	106.38	86.85	17.31	4.33	10.87	15.87	10.08	6.35
	(US$/Mcfe)				**(US$/Mcfe)**			
PR8	13.10	13.38	4.29	1.58	1.45	2.06	1.40	0.93

PR100-well scenario results

In this section we present results obtained from the evaluation of a development project with 100 wells in the each of the production regions. We assumed that there was independency between production forecasts of the wells. **Figure 36** shows the resulting oil reserves distributions in each of the black oil production regions. In the case of PR1, we do not see a proper distribution shape, where the only visible frequency column corresponds to zero reserves and its value is close to one. Results yielded for PR3 and PR5 reflect the higher productivity of these two production regions. Both cases have clear distribution shapes and also visible frequency for zero reserves, although outside the range of 80% chance.

Figure 37 displays the corresponding sensitivity analysis results black oil production regions. In the three cases, D&C costs have the highest effect on oil reserves. For PR1 the second input distribution with more effect on reserves is abandonment cost, while for PR3 and PR5 the second ranked is variable oil OpEx, reflecting better productivity in the central and western black oil regions.

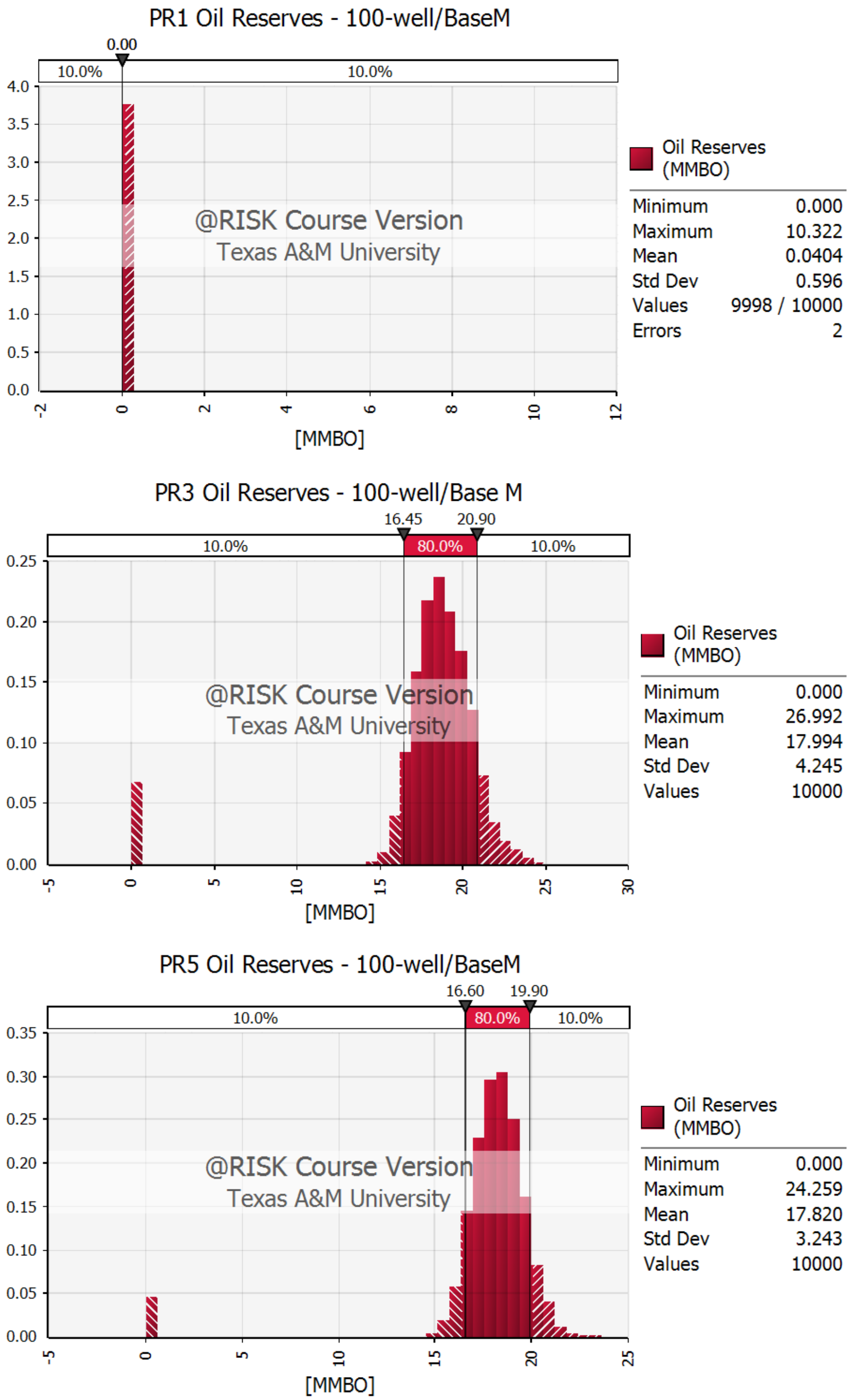

Figure 36—Resulting Oil reserves distributions for 100 wells in black oil production regions with Base case M prices.

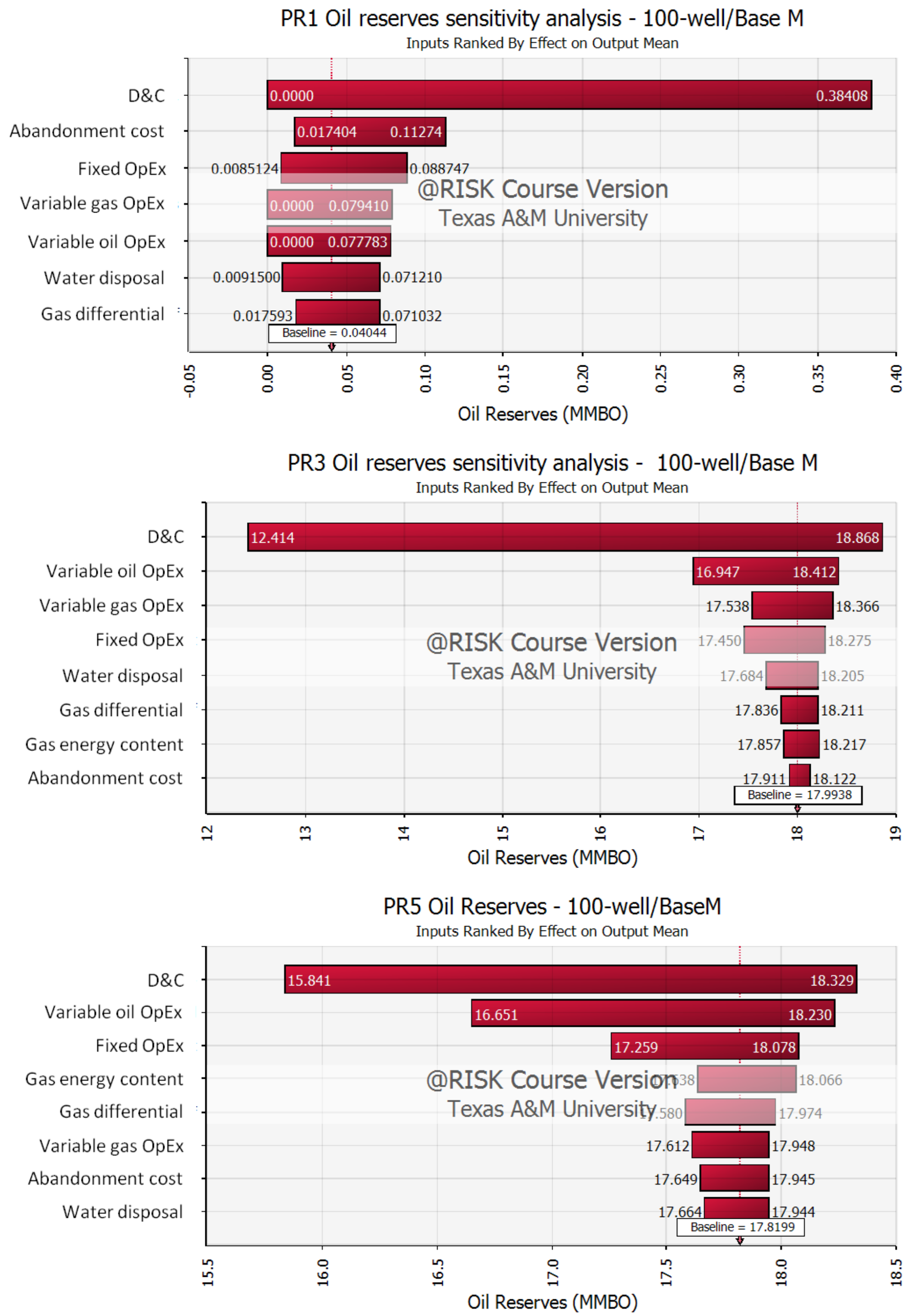

Figure 37—Sensitivity analysis for oil reserves distributions for 100 wells in black oil production regions with Base case M prices.

A summary of natural gas and oil reserves with their corresponding PV10 for PR1, PR3, and PR5 are respectively shown in **Table 17**, **Table 18**, and **Table 19**. We found different effects of prices and productivity for these production regions. In the case of PR1, we saw that, regardless of the price, results in most cases were of zero reserves even for the mean of the distribution. By contrast, the results obtained for PR3 and PR5 with Base case M, HH, and HL price models had all P10, P50, and P90 reserves values. PR3 had better results than PR5 in all cases.

Table 17—Oil and natural gas reserves of 100 wells in PR1

Price Model	Gas Reserves (BCF)				Oil Reserves (MMBO)				PV10 (US$ Million)			
	Mean	P10	P50	P90	Mean	P10	P50	P90	Mean	P10	P50	P90
Base	-	-	-	-	-	-	-	-	(294.13)	(251.58)	(295.41)	(334.52)
Base M	0.12	-	-	-	0.04	-	-	-	(296.49)	(100.64)	(297.09)	(490.48)
HH	5.51	22.43	-	-	1.95	7.87	-	-	(109.26)	87.00	(109.41)	(304.92)
LL	-	-	-	-	-	-	-	-	(527.15)	(335.28)	(528.68)	(718.28)
HL	2.47	19.24	-	-	0.88	7.02	-	-	(188.05)	6.74	(187.31)	(389.50)
LH	-	-	-	-	-	-	-	-	(4.23)	(0.15)	(4.75)	(7.98)

Table 18—Oil and natural gas reserves of 100 wells in PR3

Price Model	Gas Reserves (BCF)				Oil Reserves (MMBO)				PV10 (US$ Million)			
	Mean	P10	P50	P90	Mean	P10	P50	P90	Mean	P10	P50	P90
Base	54.70	62.63	54.25	47.38	18.76	20.87	18.67	16.77	271.93	366.77	267.45	183.02
Base M	52.56	62.64	54.34	46.22	17.99	20.90	18.65	16.45	274.90	486.72	274.85	59.85
HH	54.86	62.88	54.40	47.36	18.79	20.95	18.68	16.80	784.05	1,023.06	782.81	545.07
LL	0.20	-	-	-	0.07	-	-	-	(311.08)	(113.96)	(310.04)	(510.66)
HL	54.83	62.83	54.40	47.46	18.79	20.95	18.70	16.77	518.33	735.54	518.54	294.91
LH	22.69	60.46	-	-	7.72	20.28	-	-	(44.74)	154.11	(41.97)	(248.55)

Table 19—Oil and natural gas reserves of 100 wells in PR5

Price Model	Gas Reserves (BCF)				Oil Reserves (MMBO)				PV10 (US$ Million)			
	Mean	P10	P50	P90	Mean	P10	P50	P90	Mean	P10	P50	P90
Base	50.66	56.65	50.45	44.89	18.25	19.88	18.20	16.69	218.24	292.95	216.61	145.31
Base M	49.52	56.77	50.58	44.43	17.82	19.90	18.25	16.60	219.90	405.27	205.36	56.59
HH	50.68	56.78	50.52	44.81	18.25	19.88	18.22	16.66	722.99	929.57	711.41	534.44
LL	0.02	-	-	-	0.01	-	-	-	(366.99)	(189.83)	(382.15)	(512.62)
HL	50.70	56.88	50.47	44.86	18.26	19.89	18.22	16.67	468.98	456.21	284.92	294.09
LH	10.94	52.20	-	-	3.92	18.75	-	-	(110.95)	69.95	(125.67)	(265.01)

Figure 38 shows the resulting oil distributions for 100 wells in PR5 with the Base Case M, HH, and LL price models. We can see a significant difference in the distribution shape in all three models. With the lowest price model is clear that most cases resulted in zero reserves. The distribution has a maximum value of 21.857 MMBO which corresponds to a case in which most wells had a high productivity. In the case of Base case M and HH prices, the distributions appear to be different but they have similarities in shape and also in their P90-P10 range. The main difference lies in the fact that with the high prices forecast all 10.000 iterations resulted in reserves; whereas with Base case M prices there were a reduced number of cases that could not achieve a positive PV10.

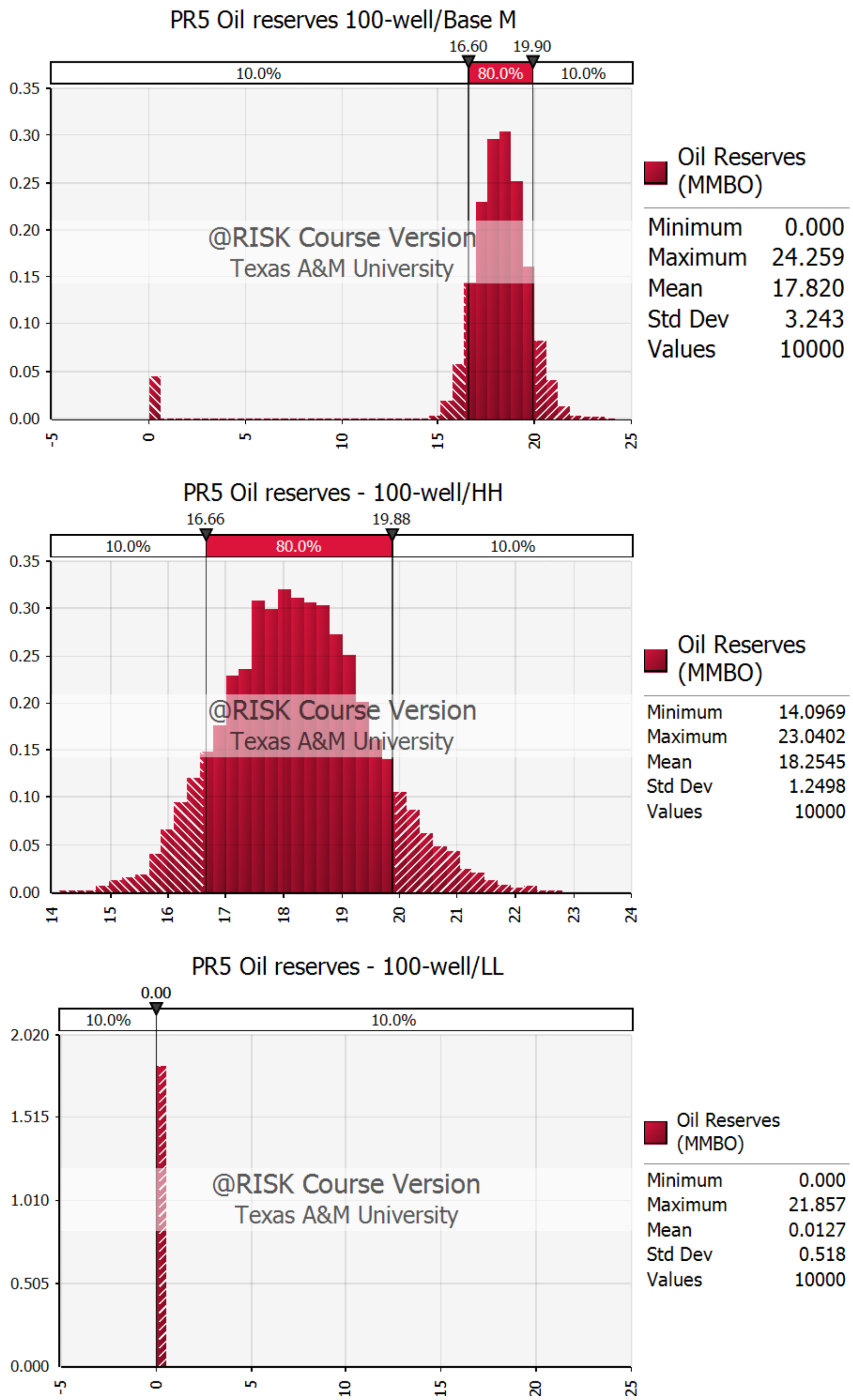

Figure 38—Comparison of oil reserves distributions for 100 wells in PR5 with different price models.

Plots for change in PV10, IRR, and PWI as a function of price are shown in **Figure 39**, **Figure 40**, and **Figure 41**. In the case of PV10, we found that results improved as prices increased but the P10-P90 range remained nearly constant for all price models. IRR and PWI results also improved with the increase of prices but with a clear and significant growth of the P10-P90 range value. We consider this is caused by the probabilistic aggregation of production from the group of 100 wells. As we assumed independency between the wells, there is a significant reduction in the range of reserves results especially because within the 20 years of production the economic limit is not reached, in which the extended production life of the well as a result of higher prices is not measurable.

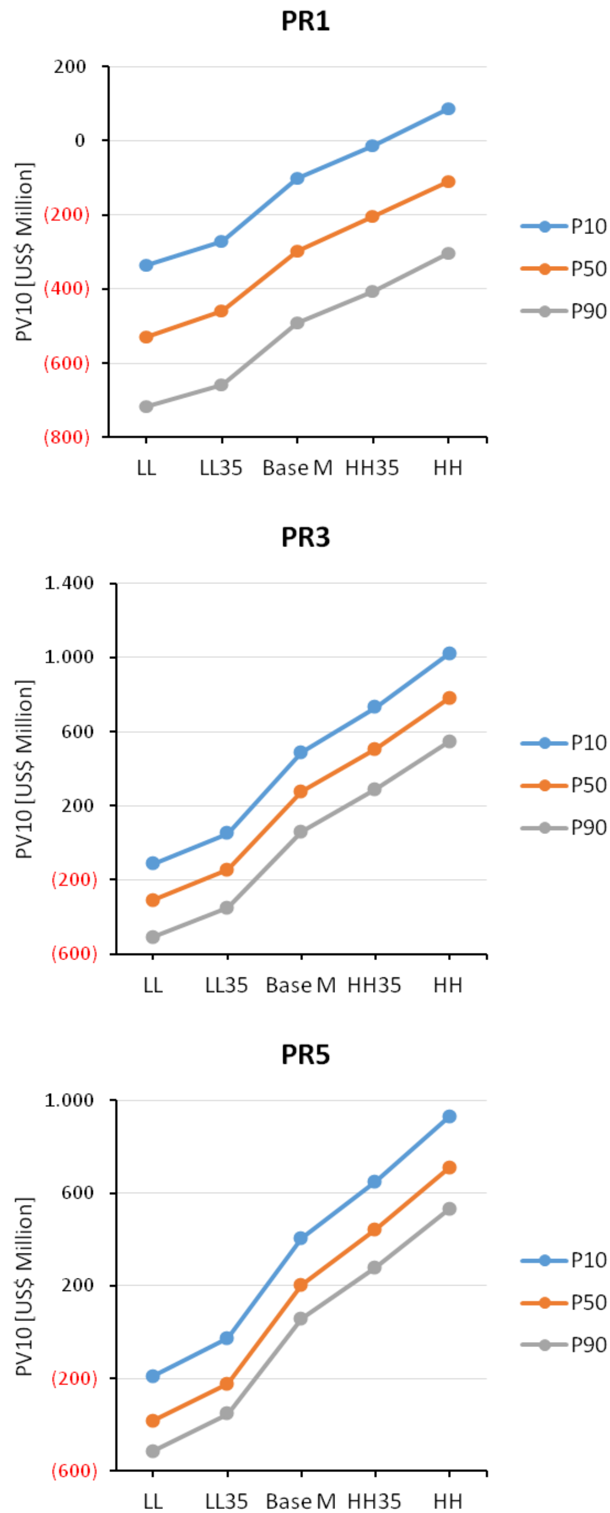

Figure 39—P10, P50, and P90 values of PV10, as function of price, for 100 wells in PR1, PR3, and PR5.

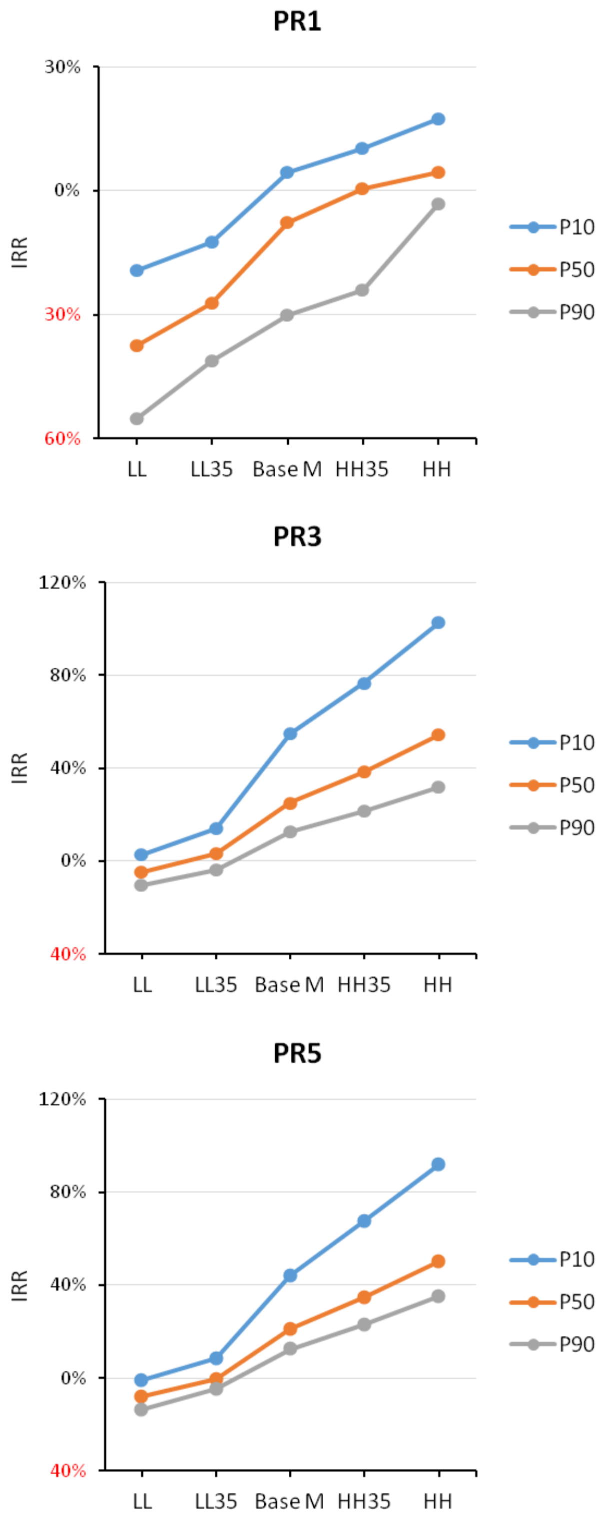

Figure 40—P10, P50, and P90 values of IRR, as function of price, for 100 wells in PR1, PR3, and PR5.

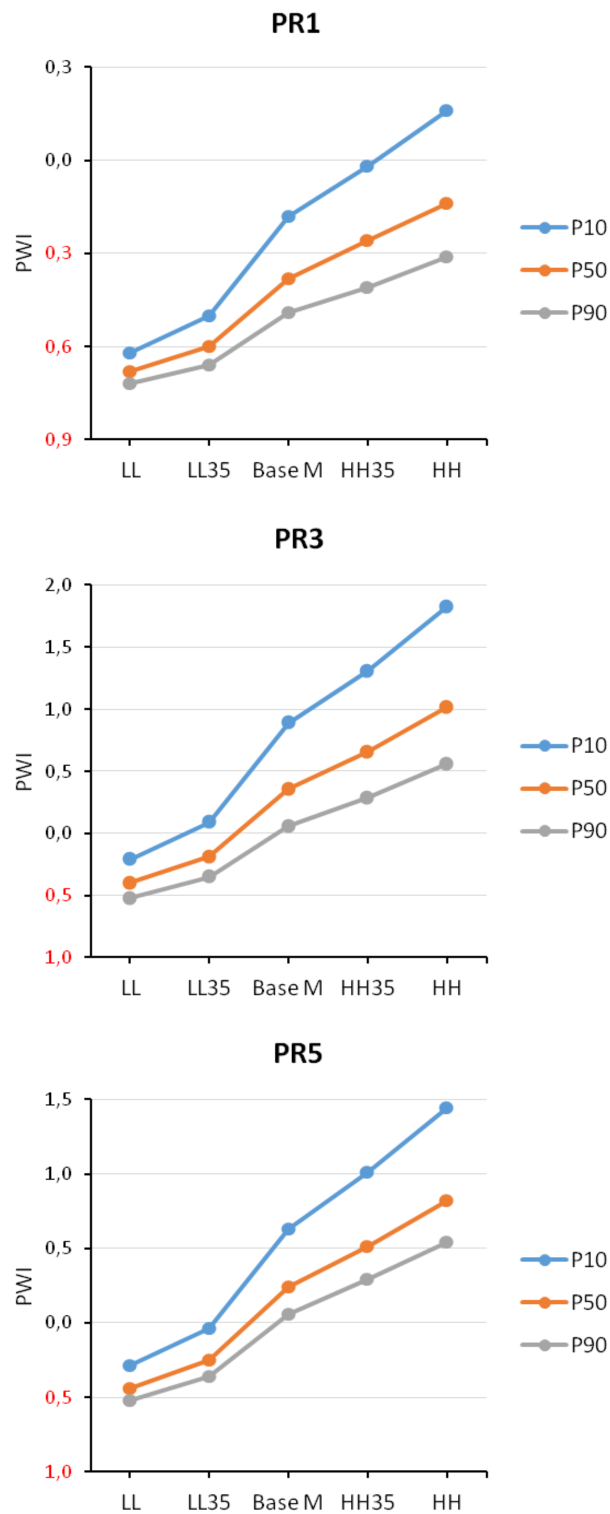

Figure 41—P10, P50, and P90 values of PWI, as function of price, for 100 wells in PR1, PR3, and PR5.

Results of oil reserves distributions for 100 wells, with Base case M prices, in the condensate and volatile oil production regions are shown in **Figure 42**. With the exception of PR4, in which the zero reserves value has the highest probability, all other production regions yielded distributions with P10, P50, and P90 reserves. As we found in the single-well scenario, PR6 is the region with best productivity and reserves results. PR6 distribution has a minimum value of 24,305 MMBO, meaning that all 10,000 iterations were successful, and significantly P90-P10 range higher values of 37.72 MMBO and 29.93 MMBO in comparison with the other production regions.

Sensitivity analysis results also reflected the best productivity of PR6. D&C costs have the greatest impact in PR2, PR4, and PR6. By contrast, in PR6 D&C costs are second ranked after variable natural gas OpEx, showing that the better productivity of this region makes more important OpEx costs than the CapEx.

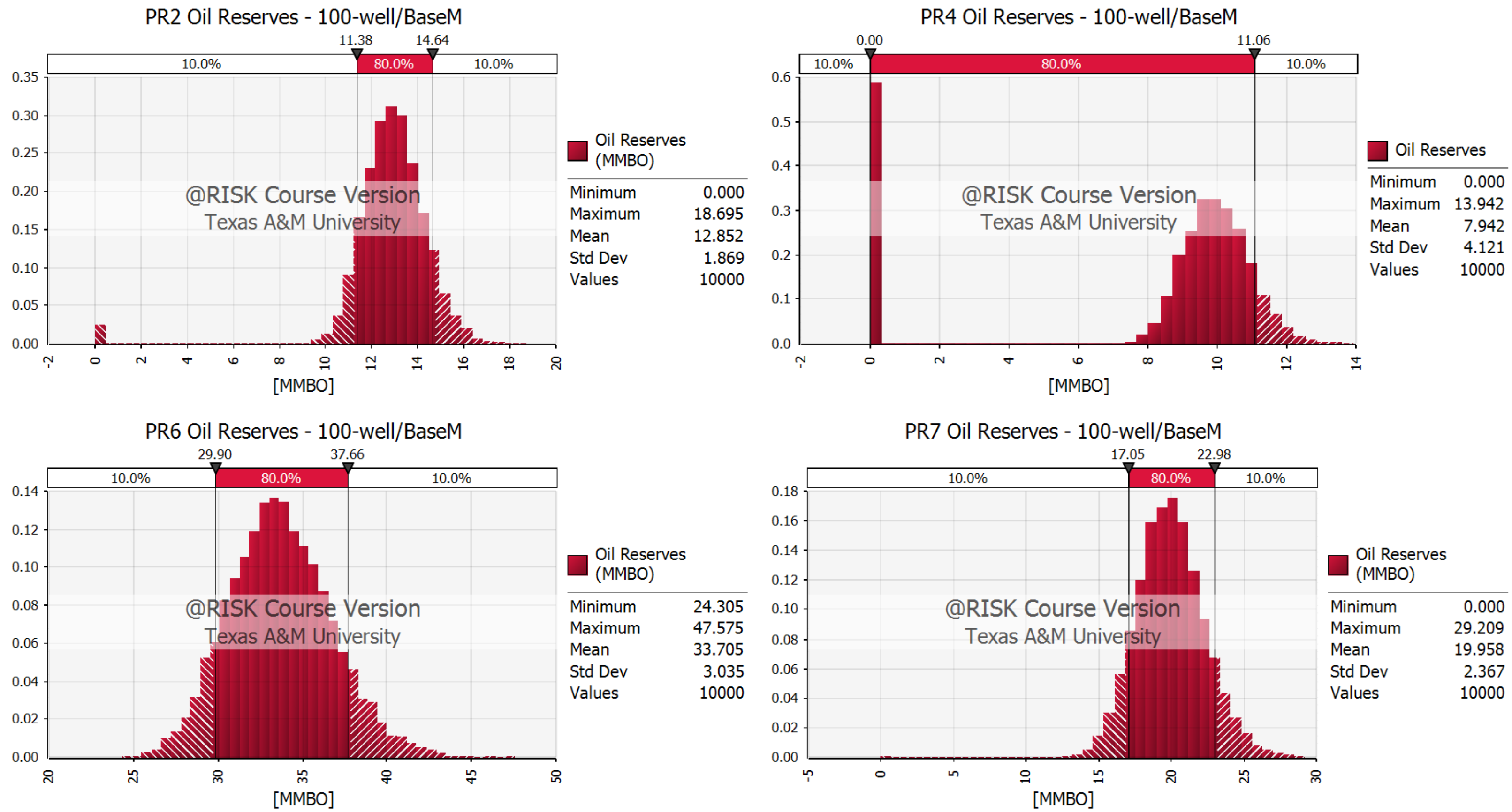

Figure 42—Oil reserves distributions for 100 wells in the condensate and volatile oil production regions.

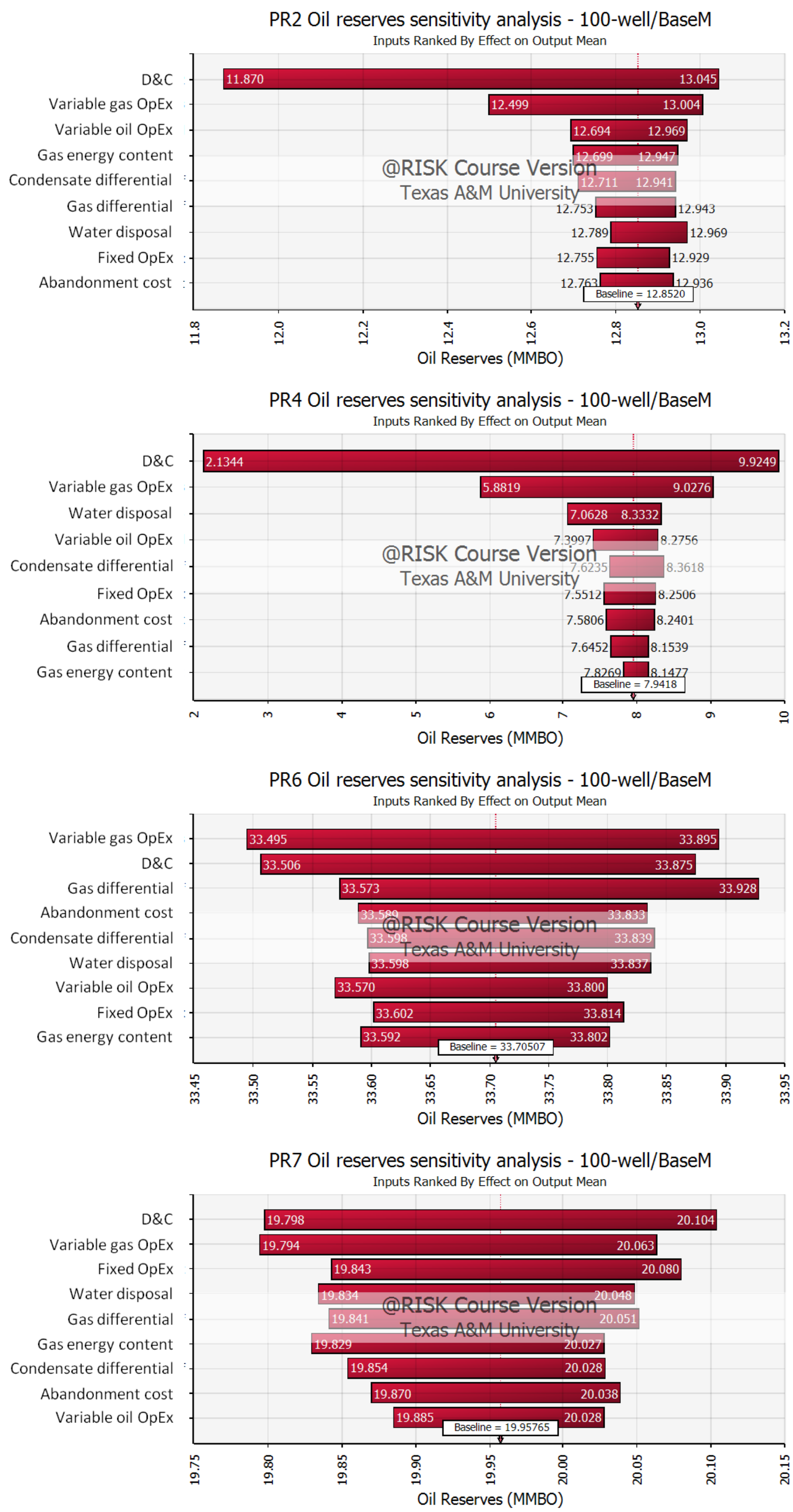

Figure 43—Sensitivity analysis for oil reserves distributions of 100 wells in the condensate and volatile oil production regions.

Table 20, **Table 21**, **Table 22**, and **Table 23** show the summary of oil and natural gas reserves, as well as resulting PV10 values, for 100 wells in PR2, PR4, PR6, and PR7. Here we see that results for PR2, PR6, and PR7 show that commerciality is achievable in all cases except with the LL price model. In the case of PR4, P90 values of PV10 are negative with Base case M, LL, and HL prices. We consider important to point out that in all four production regions, results obtained with the LH price model have positive PV10 values. Furthermore, with the exception of PR6, PV10 results of LH evaluations were better than those obtained with HL prices.

Table 20—Oil and natural gas reserves of 100 wells in PR2

Price Model	Gas Reserves (BCF)				Oil Reserves (MMBO)				PV10 (US$ Million)			
	Mean	P10	P50	P90	Mean	P10	P50	P90	Mean	P10	P50	P90
Base	250.03	282.26	248.52	217.17	12.99	14.66	12.93	11.40	333.57	440.14	330.99	230.98
Base M	247.36	284.51	248.59	216.34	12.85	14.64	12.94	11.38	334.17	539.45	333.62	128.86
HH	250.70	286.52	249.34	217.15	13.00	14.63	12.95	11.44	1,548.14	1,859.87	1,543.08	1,245.16
LL	2.61	-	-	-	0.13	-	-	-	(298.73)	(108.35)	(298.59)	(483.10)
HL	243.83	285.44	248.71	214.02	12.67	14.67	12.95	11.27	285.11	490.85	284.92	79.90
LH	250.46	285.78	248.92	216.78	12.99	14.62	12.95	11.40	967.57	1,239.67	962.92	695.35

Table 21—Oil and natural gas reserves of 100 wells in PR4

Price Model	Gas Reserves (BCF)				Oil Reserves (MMBO)				PV10 (US$ Million)			
	Mean	P10	P50	P90	Mean	P10	P50	P90	Mean	P10	P50	P90
Base	201.19	232.36	202.57	176.25	9.74	11.10	9.84	8.68	129.62	213.61	127.52	48.36
Base M	164.51	232.03	198.82	-	7.94	11.06	9.65	-	128.96	328.45	125.33	(65.26)
HH	203.33	231.85	202.33	176.03	9.86	11.09	9.82	8.67	1,134.60	1,415.26	1,127.51	867.28
LL	-	-	-	-	-	-	-	-	(378.39)	(192.65)	(380.94)	(556.47)
HL	137.66	229.94	191.42	-	6.68	11.03	9.39	-	67.37	262.97	66.82	(124.81)
LH	203.91	234.05	202.11	176.38	9.87	11.12	9.82	8.66	690.30	947.87	681.85	443.96

Table 22—Oil and natural gas reserves of 100 wells in PR6

Price Model	Gas Reserves (BCF)				Oil Reserves (MMBO)				PV10 (US$ Million)			
	Mean	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**
Base	192.18	222.31	190.94	163.77	33.74	37.72	33.60	29.91	1,104.30	1,291.21	1,096.58	923.51
Base M	191.83	220.76	190.68	163.81	33.71	37.66	33.57	29.90	1,100.45	1,334.94	1,093.64	872.20
HH	191.97	222.19	190.47	163.76	33.71	37.72	33.55	29.93	2,417.33	2,785.06	2,404.34	2,060.67
LL	53.54	209.29	-	-	9.30	36.12	-	-	(78.30)	75.97	(77.03)	(234.43)
HL	192.33	222.75	190.79	163.95	33.77	37.77	33.61	29.93	1,464.84	1,726.81	1,460.67	1,204.74
LH	192.59	222.08	191.23	164.59	33.80	37.74	33.69	30.04	883.46	1,118.33	880.49	650.77

Table 23—Oil and natural gas reserves of 100 wells in PR7

Price Model	Gas Reserves (BCF)				Oil Reserves (MMBO)				PV10 (US$ Million)			
	Mean	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**
Base	324.54	376.26	322.70	275.23	19.98	23.01	19.87	17.05	651.59	826.44	646.48	483.29
Base M	324.33	374.69	322.52	275.64	19.96	22.98	19.88	17.05	650.10	891.97	647.61	412.81
HH	324.53	376.17	322.83	275.35	19.98	23.07	19.88	17.07	2,295.34	2,738.34	2,279.81	1,870.13
LL	5.83	-	-	-	0.36	-	-	-	(271.44)	(100.61)	(269.02)	(447.61)
HL	323.99	376.36	321.83	274.92	19.93	23.03	19.83	17.00	638.31	889.80	635.17	396.14
LH	325.02	376.59	323.10	275.83	19.99	23.04	19.88	17.04	1,379.25	1,715.82	1,369.82	1,058.35

PV10, IRR, and PWI results as a function of the price model are shown in **Figure 44**, **Figure 45**, and **Figure 46.** We see the same effect on PV10 results as in black oil production regions, with no significant change in the P10-P90 range value as prices increased. IRR and PWI values show a consistent behavior of higher results and more variability as natural gas and oil prices increased.

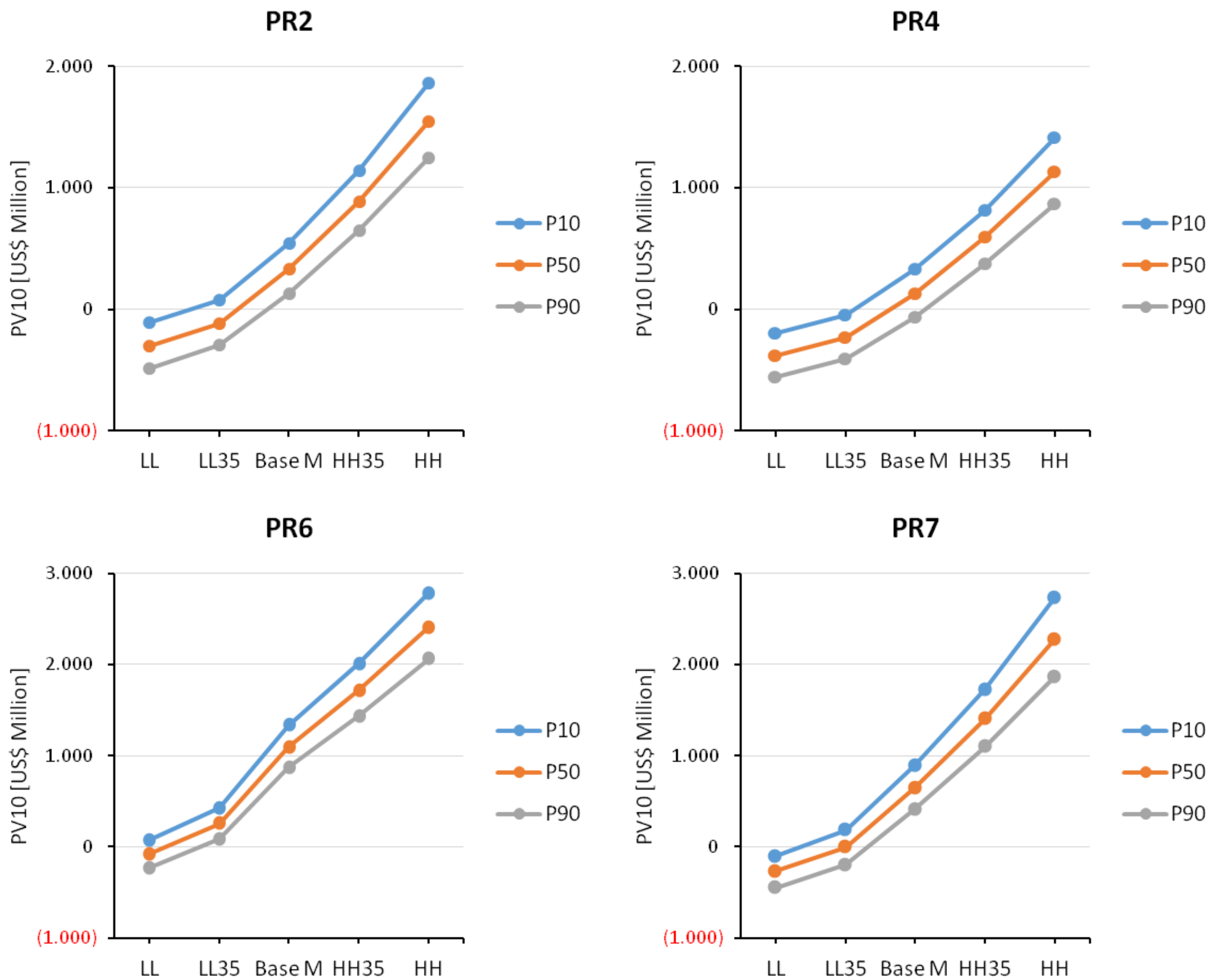

Figure 44—P10, P50, and P90 values of PV10, as function of price, of 100 wells in PR2, PR4, PR6, and PR7.

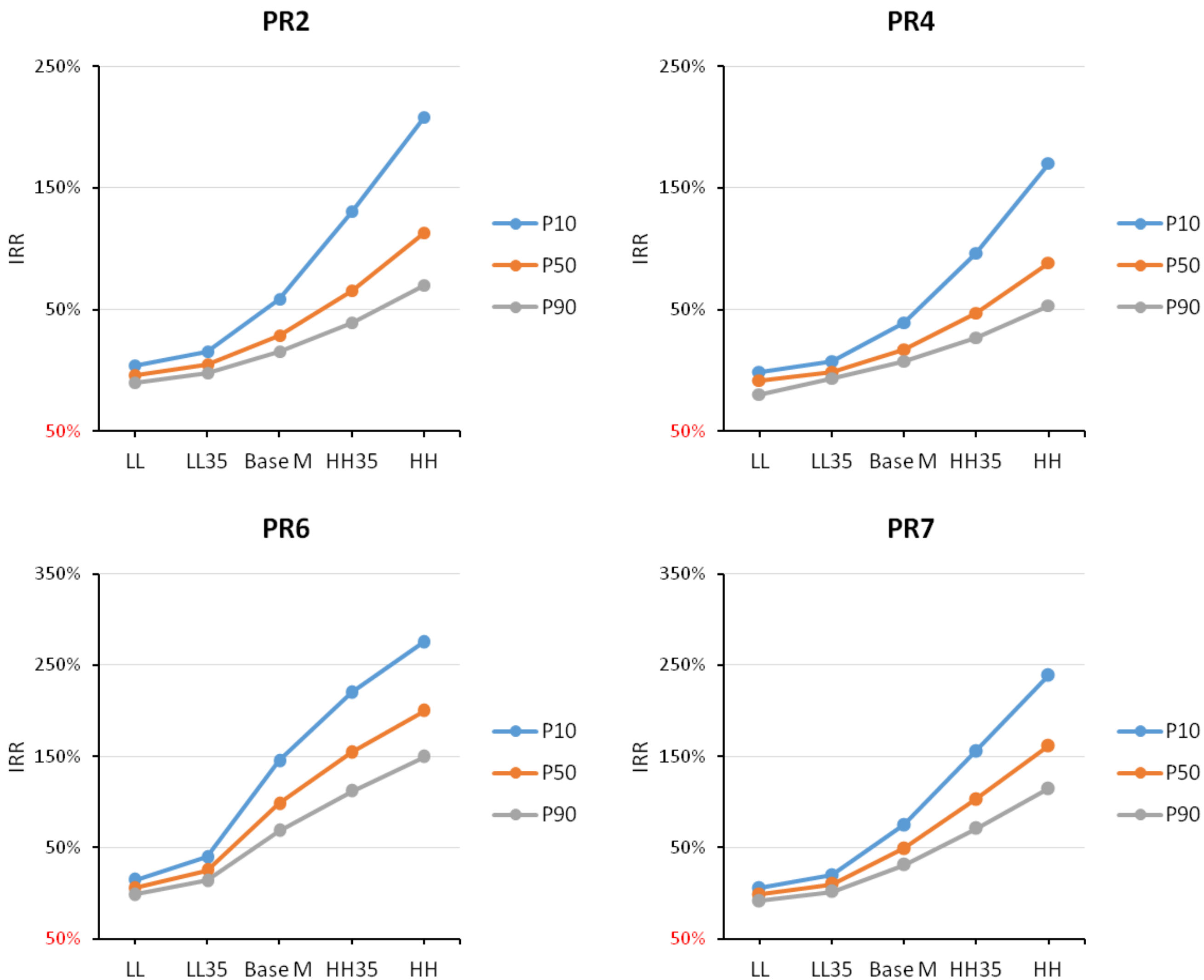

Figure 45—P10, P50, and P90 values of IRR, as function of price, of 100 wells in PR2, PR4, PR6, and PR7.

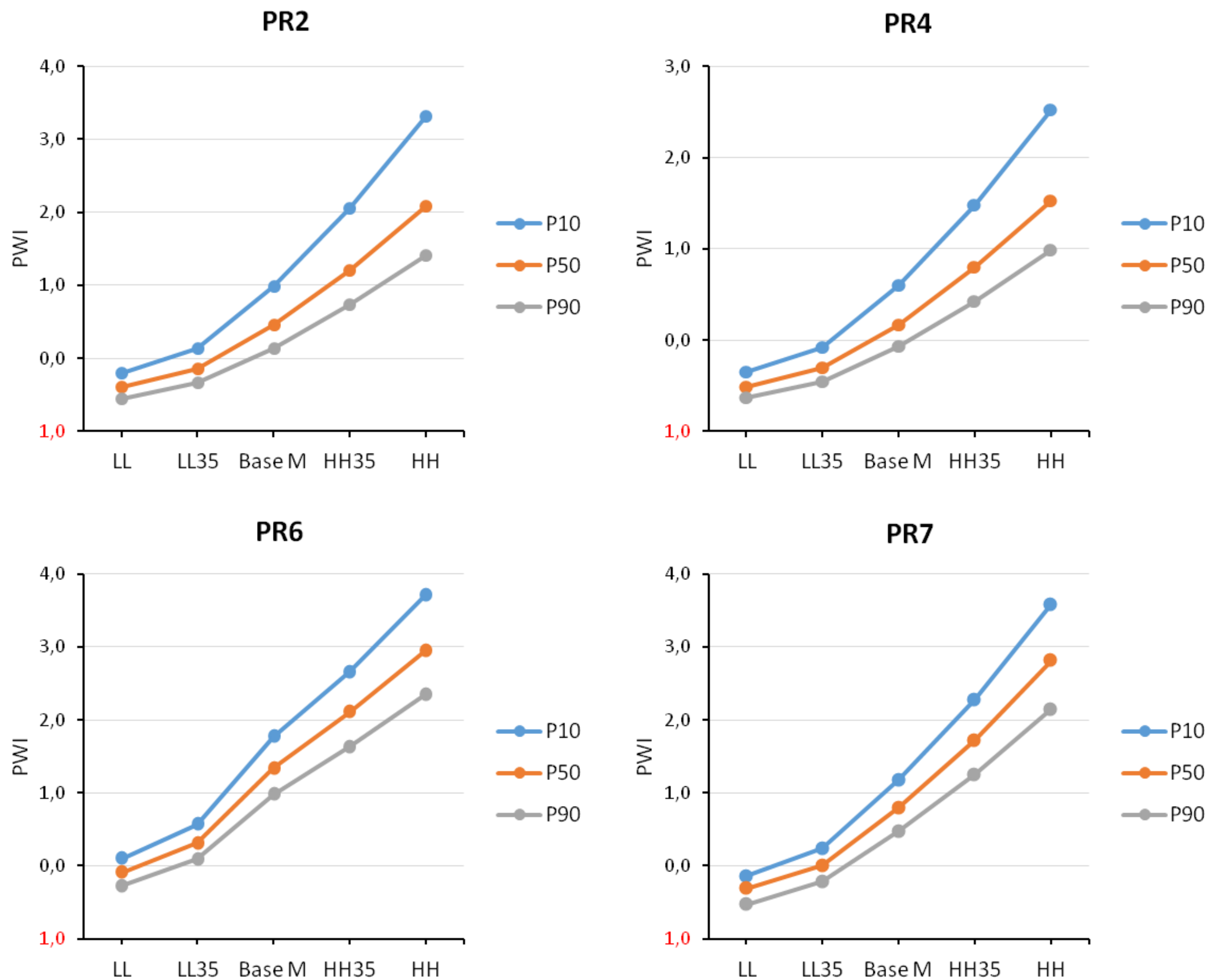

Figure 46—P10, P50, and P90 values of PWI, as function of price, of 100 wells in PR2, PR4, PR6, and PR7.

In the case of PR8, the dry gas production region, the results obtained do not show any significant improvement with the increased number of wells. **Figure 47** shows the results of natural gas reserves, for 100 wells with Base case M prices, and the corresponding sensitivity analysis. We see that most cases returned zero reserves for this production region and that D&C costs had the highest effect on the results.

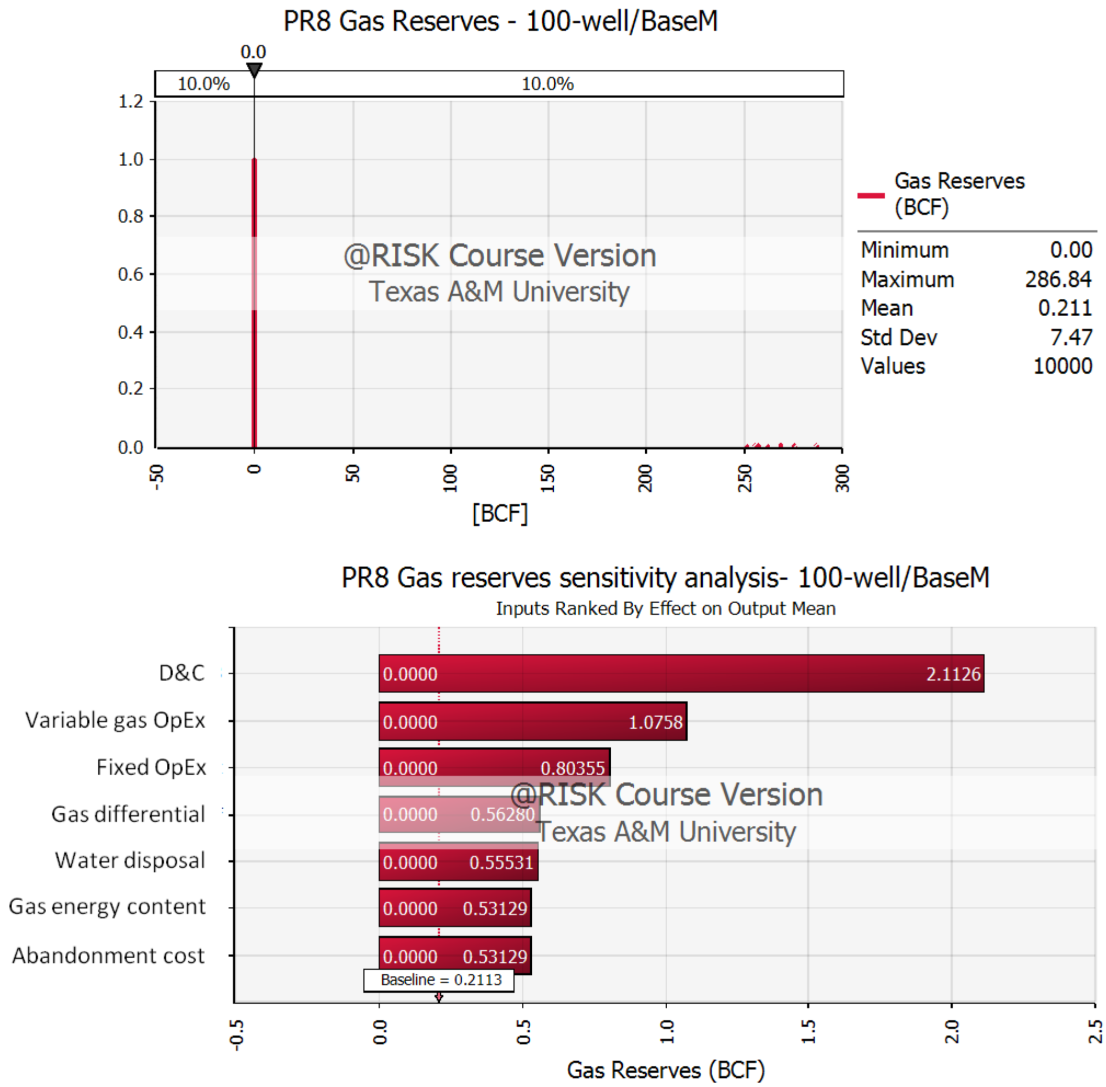

Figure 47—Gas reserves distribution (top) and sensitivity analysis (bottom) for 100 wells in PR8.

Results of natural gas reserves and PV10 values for PR8, summarized in **Table 24**, show that production volumes can be classified as reserves only with HH and LH price models. **Figure 48** shows results of PV10, IRR, and PWI as a function of price. We see again that only with the highest forecast of price the results of the three measures are good enough to consider the project as commercial.

Table 24—Oil and natural gas reserves of 100 wells in PR8

Price Model	Gas Reserves (BCF)				PV10 (US$ Million)			
	Mean	P10	P50	P90	Mean	P10	P50	P90
Base	-	-	-	-	(290.55)	(255.45)	(292.04)	(323.73)
Base M	0.21	-	-	-	(290.51)	(166.03)	(288.51)	(416.38)
HH	227.41	255.67	226.27	201.13	595.66	780.86	592.58	413.32
LL	-	-	-	-	(482.30)	(350.96)	(504.15)	(622.91)
HL	-	-	-	-	(482.30)	(350.96)	(504.15)	(622.91)
LH	227.41	255.67	226.27	201.13	595.66	780.86	592.58	413.32

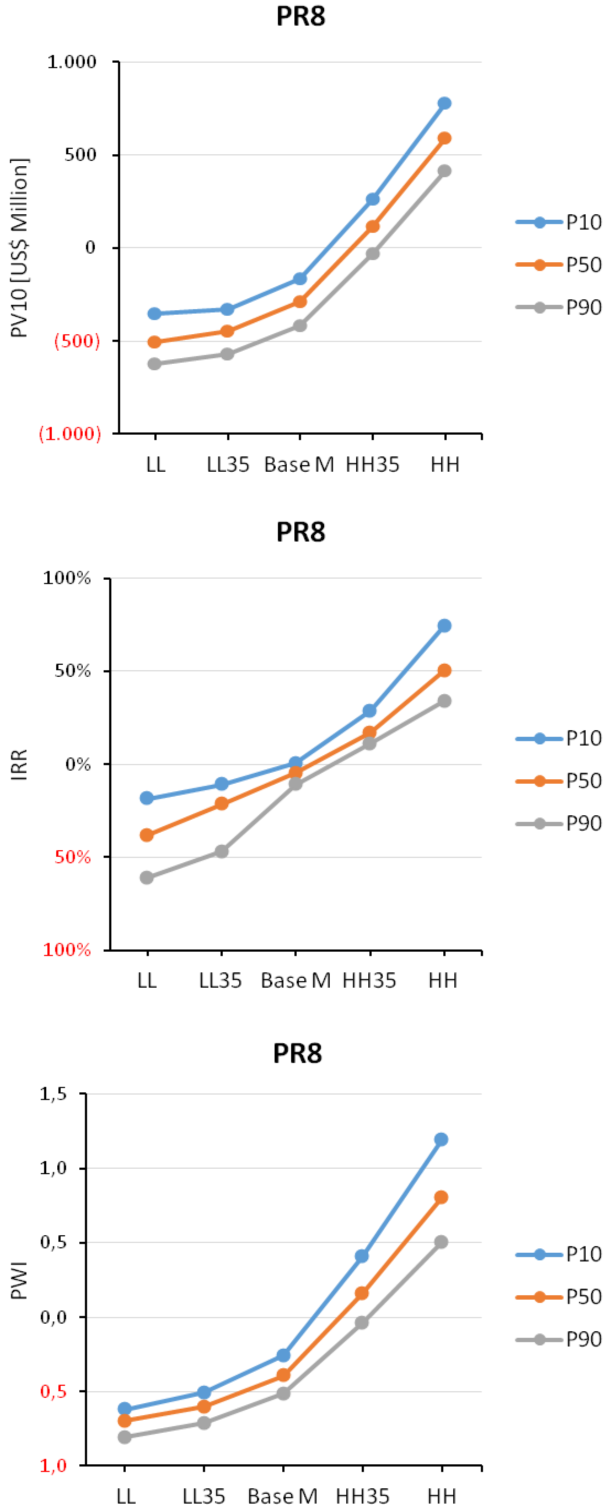

Figure 48—P10, P50, and P90 values of PV10, IRR, and PWI, as function of price, for 100 wells in PR8.

If we compare PR1 and PR8 with the other production regions, we can see that hydrocarbon liquids productivity is a key driver to obtain successful results for development projects in the Eagle Ford shale.

Table 25 shows results of F&D and Avg OpEx costs for all production regions. We can see a significant reduction in the P90-P10 range value, compared to single-well results shown in Table 16 at the end of the previous section. For instance, PR1 had a P90-P10 range of 354.25-48.59 US$/Boe in the single-well scenario. The resulting range in the 100-well scenario was 95.07-48.59 US$/Boe. In the case of PR6, the single-well P90-P10 range was 49.03-5.63 US$/Boe, whereas in the 100-well case was 15.12-10.36 US$/Boe.

Table 25—Summary of F&D and Average OpEx costs for all production regions in the 100-well scenario

Production Region	F&D (US$/Boe)				Avg Opex (US$/Boe)			
	Mean	**P90**	**P50**	**P10**	**Mean**	**P90**	**P50**	**P10**
PR1	71.45	95.07	70.71	48.59	13.19	16.40	13.07	10.14
PR2	13.60	17.69	13.51	9.54	8.03	11.14	7.76	5.41
PR3	27.77	36.92	27.50	18.91	9.35	12.29	9.08	6.90
PR4	17.00	22.18	16.92	11.88	9.02	12.32	8.76	6.16
PR5	31.71	38.92	32.23	23.49	9.46	12.42	9.18	7.08
PR6	12.64	15.12	12.52	10.36	7.76	10.48	7.55	5.33
PR7	11.22	13.54	11.09	9.05	9.24	12.82	8.92	5.97
	(US$/Mcfe)				**(US$/Mcfe)**			
PR8	3.26	3.94	3.24	2.61	1.39	1.97	1.31	0.95

Full-well scenario results

In this final section of Chapter IV, we present the results obtained in the Full-well scenario for each of the production regions of the Eagle Ford shale, and also the aggregation of reserves and other important components of the evaluation to the play level. In general, the results obtained for the Full-well scenario are very similar in structure as the 100-well scenario results, although with considerable differences in numeric values given the increased number of wells in each region.

Resulting oil reserves distributions for PR1, PR3, and PR5 are presented in **Figure 49**. In the three cases a distribution shape is visible but there are significant differences between PR1 and the other two production regions. In the 100-well case we concluded that productivity and commerciality of development projects in PR1 is very difficult to achieve, even with the highest price model. This conclusion remains the same in this case, with the difference that as of December of 2012 a total of 102 were in production in PR1. We classified the production volumes from existing wells in all production regions as reserves, based on the assumption that these wells have been evaluated and their commerciality was determined. The resulting oil reserves distribution for PR1 corresponds mainly to the existing wells production volumes.

In the case of PR3 and PR5, the oil reserves distributions obtained reflect the higher productivity for these two areas of the Eagle Ford. P90-P10 ranges of oil reserves for these two areas were 627-605 MMBO for PR3 and 668-598 MMBO for PR5. **Figure 50** shows that for the three black oil regions, D&C costs and variable oil OpEx had the highest effect on reserves. While fixed OpEx was the third ranked input for PR3 and PR5, it was abandonment cost for PR1. Complete results of natural gas, oil reserves, and PV10 for PR1, PR3, and PR5 are presented in **Table 26**, **Table 27**, and **Table 28**.

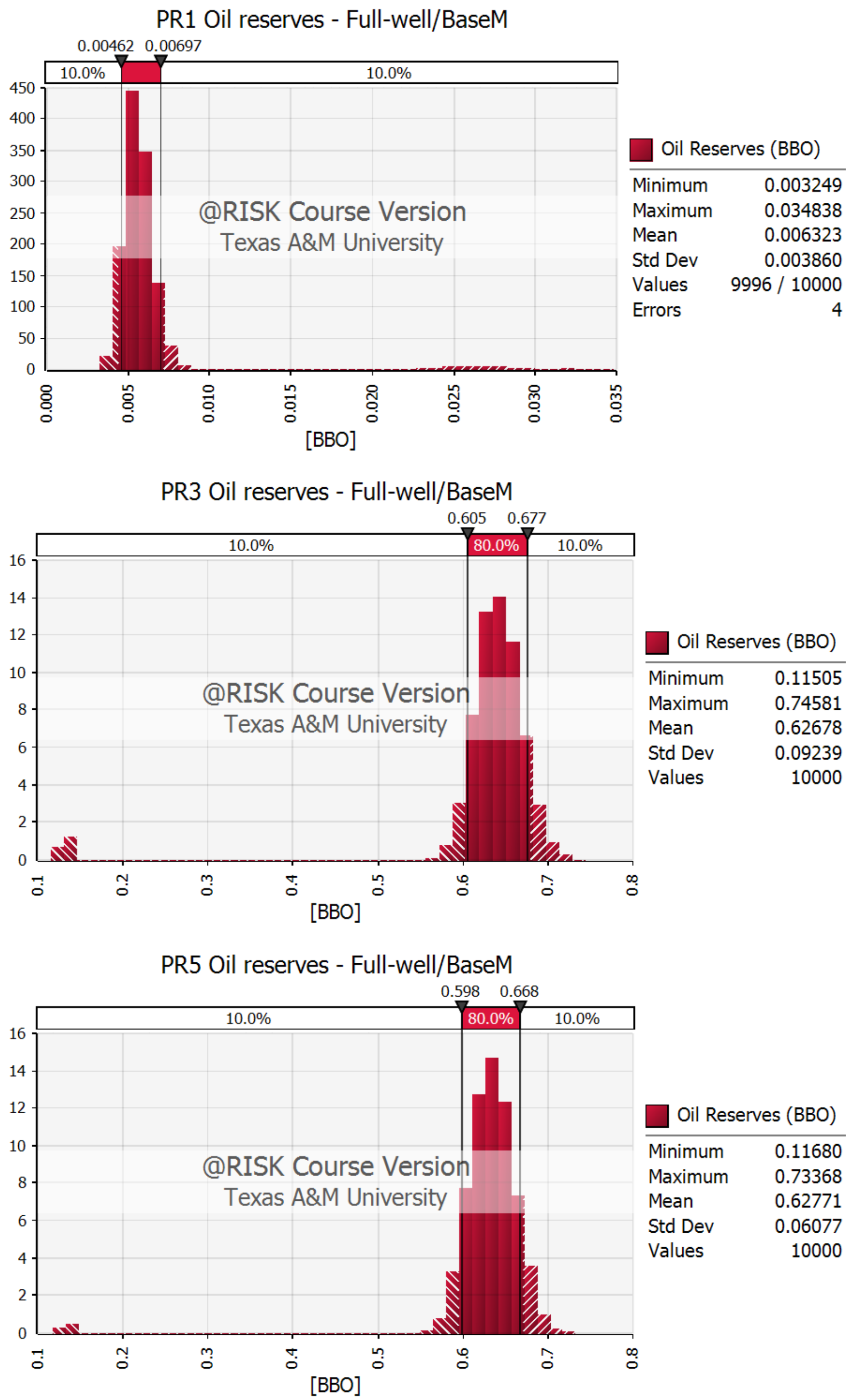

Figure 49—Resulting oil reserves distributions for Full-well scenario in black oil production regions with Base case M prices.

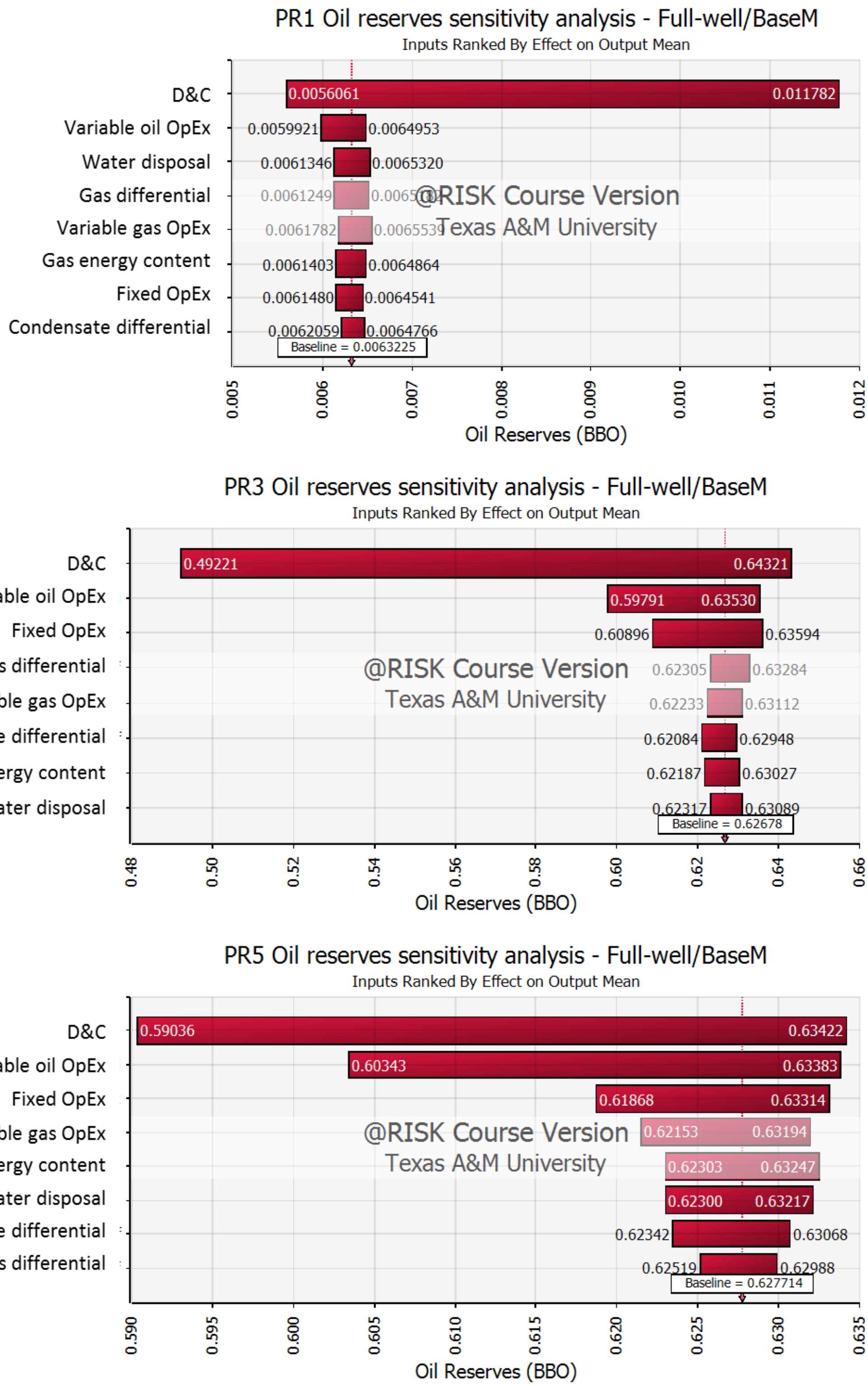

Figure 50—Sensitivity analysis for oil reserves distributions for Full-well in black oil production regions with Base case M prices.

Table 26—Oil and natural gas reserves for Full-well scenario in PR1

Price Model	Gas Reserves (TCF)				Oil Reserves (BBO)				PV10 (US$ Billion)			
	Mean	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**
Base	0.021	0.026	0.021	0.016	0.006	0.007	0.006	0.005	(0.343)	(0.156)	(0.351)	(0.516)
Base M	0.023	0.027	0.021	0.016	0.006	0.007	0.006	0.005	(0.348)	0.144	(0.349)	(0.835)
HH	0.040	0.081	0.023	0.017	0.012	0.026	0.006	0.005	0.301	0.833	0.298	(0.229)
LL	0.019	0.025	0.019	0.012	0.005	0.007	0.005	0.004	(1.071)	(0.594)	(1.079)	(1.533)
HL	0.030	0.072	0.021	0.017	0.009	0.024	0.006	0.005	(0.045)	0.460	(0.052)	(0.545)
LH	0.021	0.026	0.021	0.017	0.006	0.007	0.006	0.005	(0.713)	(0.229)	(0.714)	(1.189)

Table 27—Oil and natural gas reserves for Full-well scenario in PR3

Price Model	Gas Reserves (TCF)				Oil Reserves (BBO)				PV10 (US$ Billion)			
	Mean	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**
Base	1.962	2.092	1.959	1.836	0.642	0.675	0.642	0.610	14.388	15.878	14.367	12.920
Base M	1.917	2.094	1.956	1.820	0.627	0.677	0.641	0.605	14.503	19.718	14.567	9.124
HH	1.962	2.094	1.958	1.835	0.642	0.676	0.641	0.609	31.740	37.263	31.805	26.256
LL	0.503	0.539	0.501	0.467	0.137	0.145	0.137	0.129	(5.105)	0.013	(5.056)	(10.217)
HL	1.963	2.094	1.959	1.837	0.642	0.676	0.641	0.610	22.357	27.717	22.422	17.016
LH	1.068	2.041	0.524	0.472	0.333	0.662	0.142	0.130	4.248	9.467	4.272	(1.007)

Table 28—Oil and natural gas reserves for Full-well scenario in PR5

Price Model	Gas Reserves (TCF)				Oil Reserves (BBO)				PV10 (US$ Billion)			
	Mean	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**
Base	1.848	1.984	1.845	1.721	0.633	0.667	0.632	0.599	13.408	15.020	13.371	11.872
Base M	1.836	1.984	1.850	1.718	0.628	0.668	0.633	0.598	13.454	18.220	13.080	9.247
HH	1.850	1.983	1.846	1.722	0.633	0.667	0.633	0.599	30.724	35.825	30.454	26.066
LL	0.496	0.536	0.496	0.458	0.141	0.150	0.141	0.132	(6.350)	(1.690)	(6.798)	(10.173)
HL	1.849	1.981	1.845	1.720	0.633	0.667	0.632	0.599	21.453	26.350	21.095	17.137
LH	0.759	1.861	0.504	0.462	0.236	0.636	0.143	0.133	2.855	7.620	2.411	(1.107)

Results of PV10 as a function of price models are shown in **Figure 51**. Given that this scenario considered production of existing wells and the corresponding cash flows, no calculations on IRR and PWI were made.

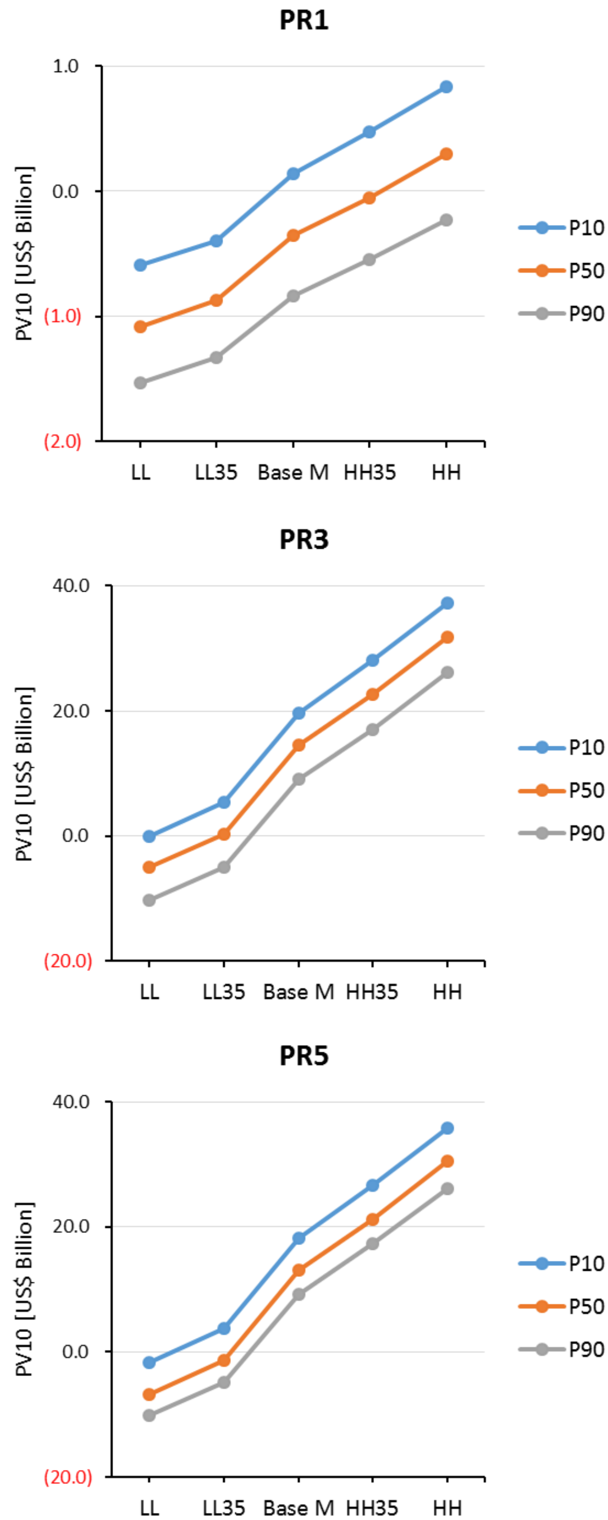

Figure 51—P10, P50, and P90 values of PV10, as function of price, for PR1, PR3, and PR5 in the Full-well scenario.

Oil reserves distributions for PR2, PR4, PR6, and PR7 for the Full-well scenario and Base case M prices are presented in **Figure 52**. Reserves distribution for PR6 and PR7 are symmetric with shapes close to normal distributions. PR2 and PR4 have a different shape that is caused by their lower productivity and the production from existing wells. PR4 seems to have a bimodal shape but that is far from true. The probability columns seen to the left of the graph correspond to reserves from existing wells. For cases with better production from new wells, or with higher prices, the distribution shape would tend to be like the distribution of PR6.

Figure 53 shows the sensitivity analysis for the resulting oil reserves in the condensate and volatile oil regions. As we found in most of the evaluations made in this work, D&C costs had the greatest impact on reserves for PR2 and PR4. However, in the case of PR6 and PR7 the sensitivity analysis returned very different results. Gas price differential was the model input with the highest effect on oil reserves for PR8, while D&C cost was displaced to the third place after gas variable OpEx. Condensate price differential had the highest effect on PR7 reserves results, with D&C costs in the fifth place.

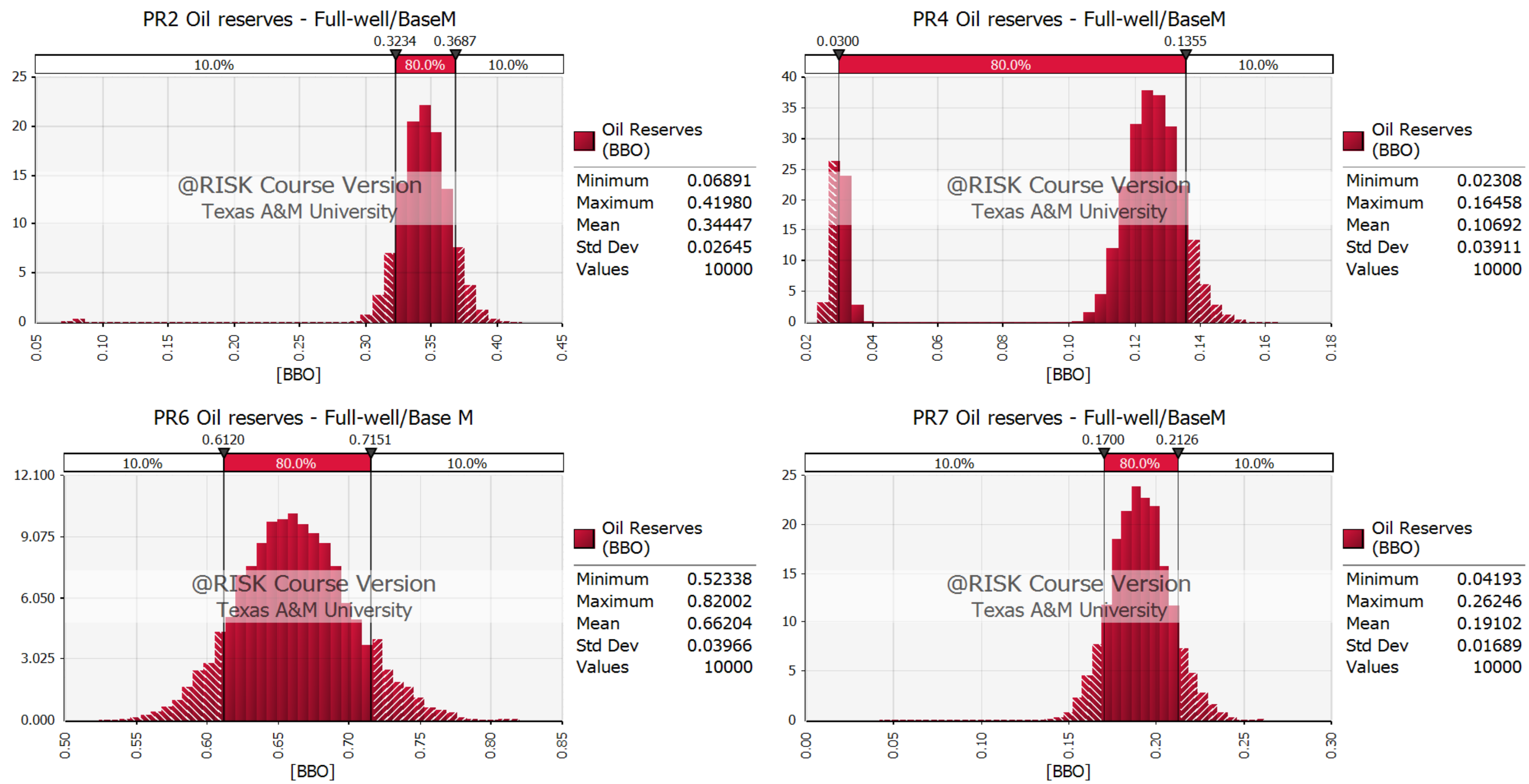

Figure 52—Resulting oil reserves distributions for Full-well scenario in condensate and volatile oil production regions with Base case M prices.

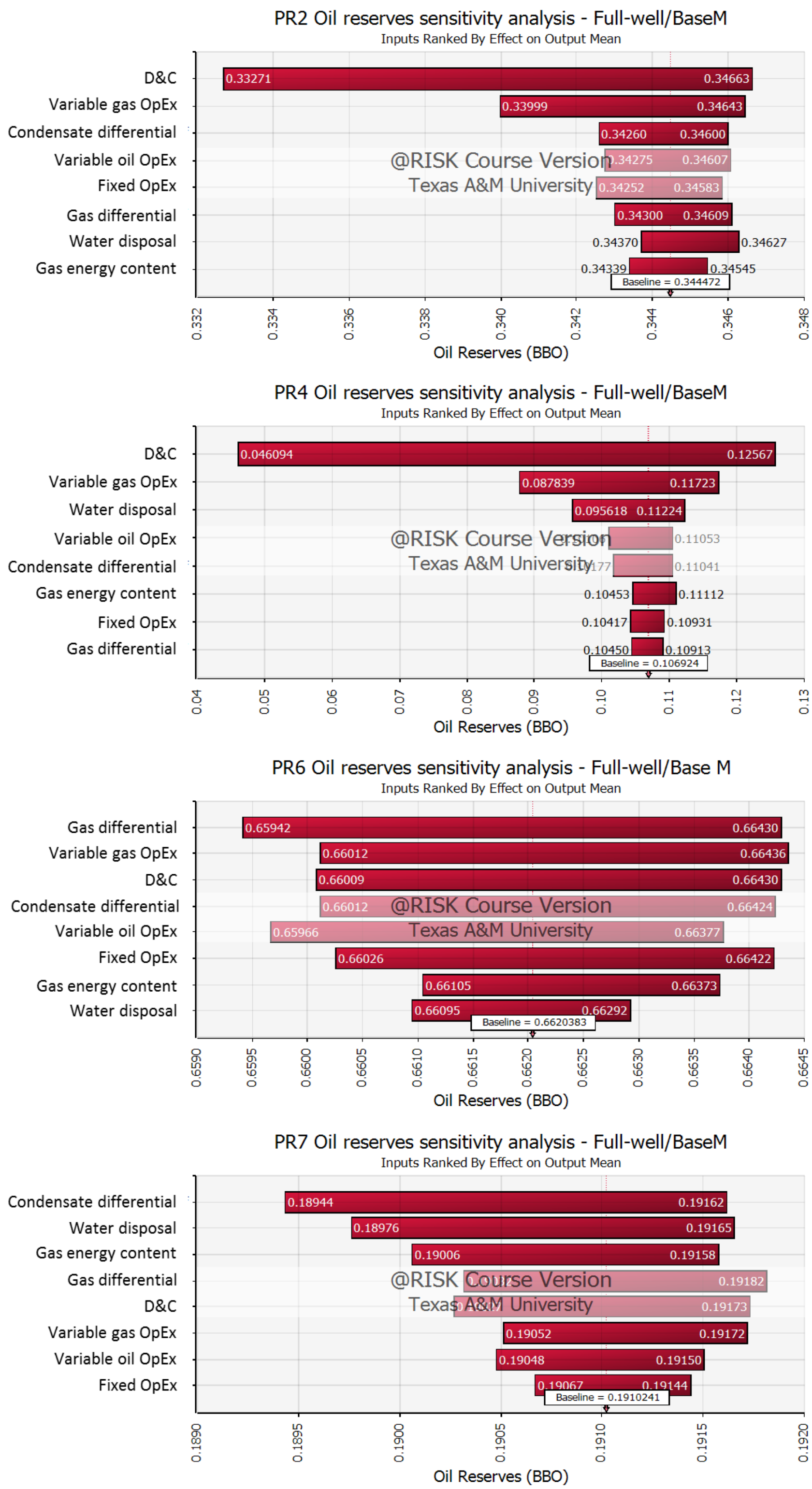

Figure 53—Sensitivity analysis for oil reserves distributions for Full-well in condensate and volatile oil production regions with Base case M prices.

Table 29, **Table 30**, **Table 31**, and **Table 32** have complete results of natural gas reserves, oil reserves, and PV10 values for PR2, PR4, PR6, and PR7. In all four cases, results of LL price model were the only forecast to produce negative values of PV10.

Table 29—Oil and natural gas reserves for Full-well scenario in PR2

Price Model	Gas Reserves (TCF)				Oil Reserves (BBO)				PV10 (US$ Billion)			
	Mean	P10	P50	P90	Mean	P10	P50	P90	Mean	P10	P50	P90
Base	6.931	7.419	6.923	6.440	0.346	0.368	0.346	0.324	13.360	14.820	13.346	11.904
Base M	6.906	7.427	6.922	6.441	0.344	0.369	0.345	0.323	13.345	17.405	13.377	9.308
HH	6.932	7.425	6.924	6.452	0.346	0.368	0.345	0.324	45.944	51.134	45.870	40.807
LL	1.938	2.065	1.911	1.764	0.085	0.090	0.083	0.077	(3.331)	0.591	(3.343)	(7.187)
HL	6.838	7.419	6.921	6.420	0.341	0.368	0.346	0.322	11.592	15.740	11.561	7.609
LH	6.934	7.425	6.928	6.455	0.346	0.368	0.345	0.324	30.960	35.666	30.923	26.295

Table 30—Oil and natural gas reserves for Full-well scenario in PR4

Price Model	Gas Reserves (TCF)				Oil Reserves (BBO)				PV10 (US$ Billion)			
	Mean	P10	P50	P90	Mean	P10	P50	P90	Mean	P10	P50	P90
Base	2.698	2.949	2.690	2.454	0.125	0.136	0.125	0.115	3.776	4.505	3.763	3.060
Base M	2.320	2.938	2.649	0.737	0.107	0.135	0.123	0.030	3.758	5.667	3.744	1.854
HH	2.698	2.948	2.691	2.461	0.125	0.136	0.125	0.115	16.675	19.150	16.630	14.256
LL	0.751	0.835	0.752	0.672	0.031	0.034	0.031	0.028	(2.613)	(0.842)	(2.616)	(4.375)
HL	2.089	2.925	2.594	0.717	0.096	0.135	0.121	0.029	2.887	4.783	2.891	0.982
LH	2.698	2.953	2.691	2.455	0.125	0.136	0.125	0.115	11.167	13.486	11.123	8.876

Table 31—Oil and natural gas reserves for Full-well scenario in PR6

Price Model	Gas Reserves (TCF)				Oil Reserves (BBO)				PV10 (US$ Billion)			
	Mean	P10	P50	P90	Mean	P10	P50	P90	Mean	P10	P50	P90
Base	3.938	4.340	3.926	3.547	0.662	0.714	0.661	0.612	24.949	27.427	24.910	22.524
Base M	3.938	4.335	3.929	3.552	0.662	0.715	0.661	0.612	24.936	28.437	24.904	21.441
HH	3.943	4.343	3.928	3.560	0.663	0.716	0.661	0.613	50.799	56.082	50.698	45.740
LL	1.758	4.111	1.033	0.901	0.276	0.685	0.147	0.131	2.254	4.901	2.300	(0.456)
HL	3.937	4.337	3.926	3.550	0.662	0.714	0.661	0.612	31.403	35.230	31.372	27.583
LH	3.938	4.339	3.923	3.560	0.662	0.714	0.661	0.612	21.620	25.219	21.585	18.017

Table 32—Oil and natural gas reserves for Full-well scenario in PR7

Price Model	Gas Reserves (TCF)				Oil Reserves (BBO)				PV10 (US$ Billion)			
	Mean	P10	P50	P90	Mean	P10	P50	P90	Mean	P10	P50	P90
Base	3.248	3.629	3.236	2.875	0.191	0.212	0.191	0.170	8.082	9.355	8.060	6.823
Base M	3.249	3.630	3.238	2.881	0.191	0.213	0.191	0.170	8.092	10.068	8.112	6.114
HH	3.243	3.629	3.228	2.876	0.191	0.212	0.190	0.170	23.957	27.203	23.901	20.771
LL	0.937	1.044	0.907	0.788	0.048	0.053	0.046	0.040	(0.646)	0.825	(0.579)	(2.210)
HL	3.251	3.635	3.241	2.885	0.191	0.213	0.190	0.170	7.781	9.752	7.781	5.831
LH	3.251	3.640	3.235	2.886	0.191	0.213	0.191	0.170	15.568	18.140	15.516	13.030

Results of P10, P50, and P90 values of PV10 for the condensate and volatile oil production regions are shown in **Figure 54**. In the four regions, we see that the P10-P90 ranges are narrow and do not show major variability with the increase of prices. As we mentioned before, this is caused by the probabilistic aggregation of production used within each of the production region. Additionally, the effect of prices when production is approaching the economic limit is not seen within the 20 years period of evaluation.

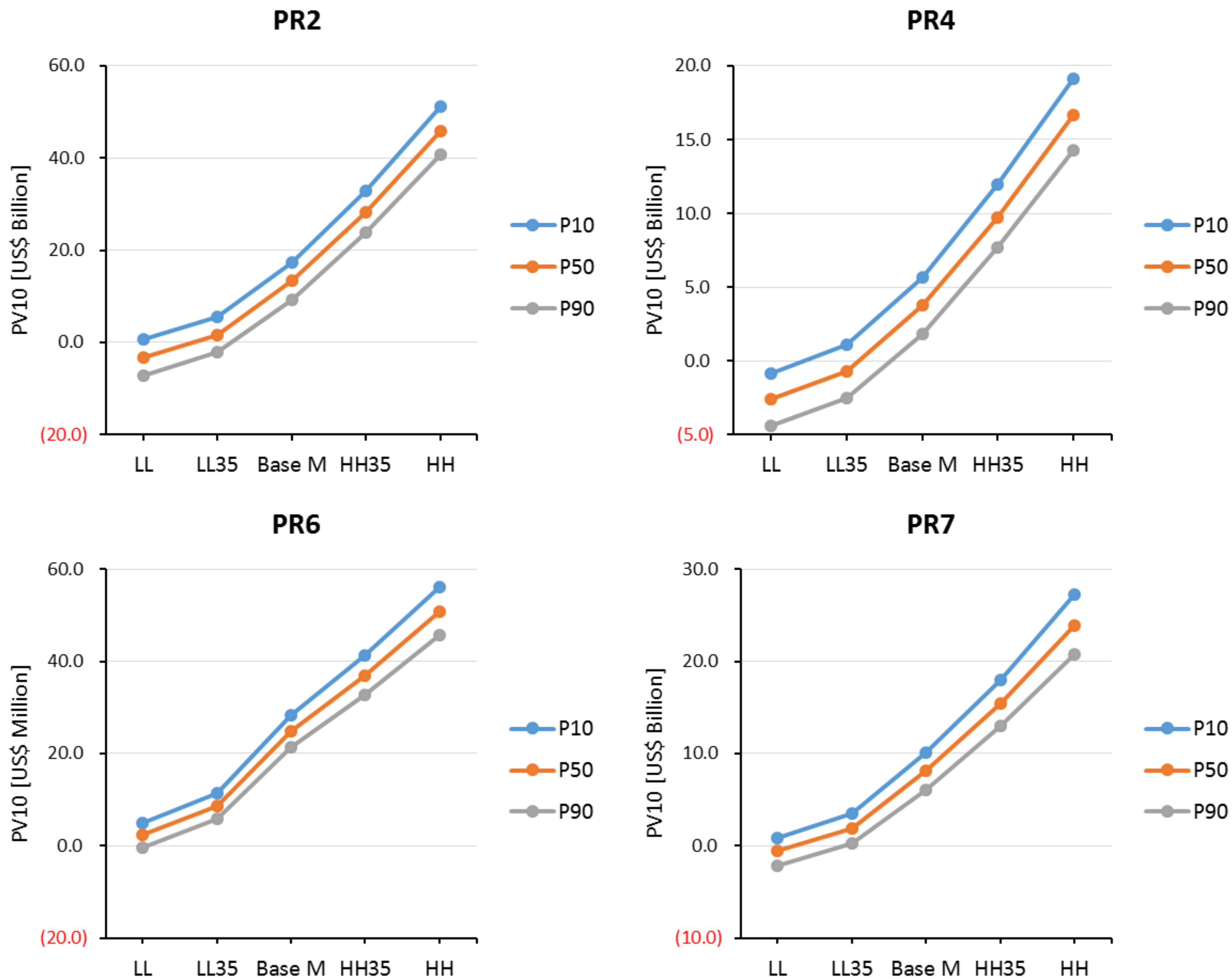

Figure 54—P10, P50, and P90 values of PV10, as function of price, for PR2, PR4, PR6, and PR7 in the Full-well scenario

PR8 results are similar to PR1, where the resulting natural gas reserves distribution in mainly formed by the production volumes of existing wells, shown in **Figure 55**, for which no considerations of CapEx were made. This is also reflected by the sensitivity analysis results, showing D&C costs with the second lowest effect on reserves. **Figure 56** shows the results of PV10 with the different price models for PR8.

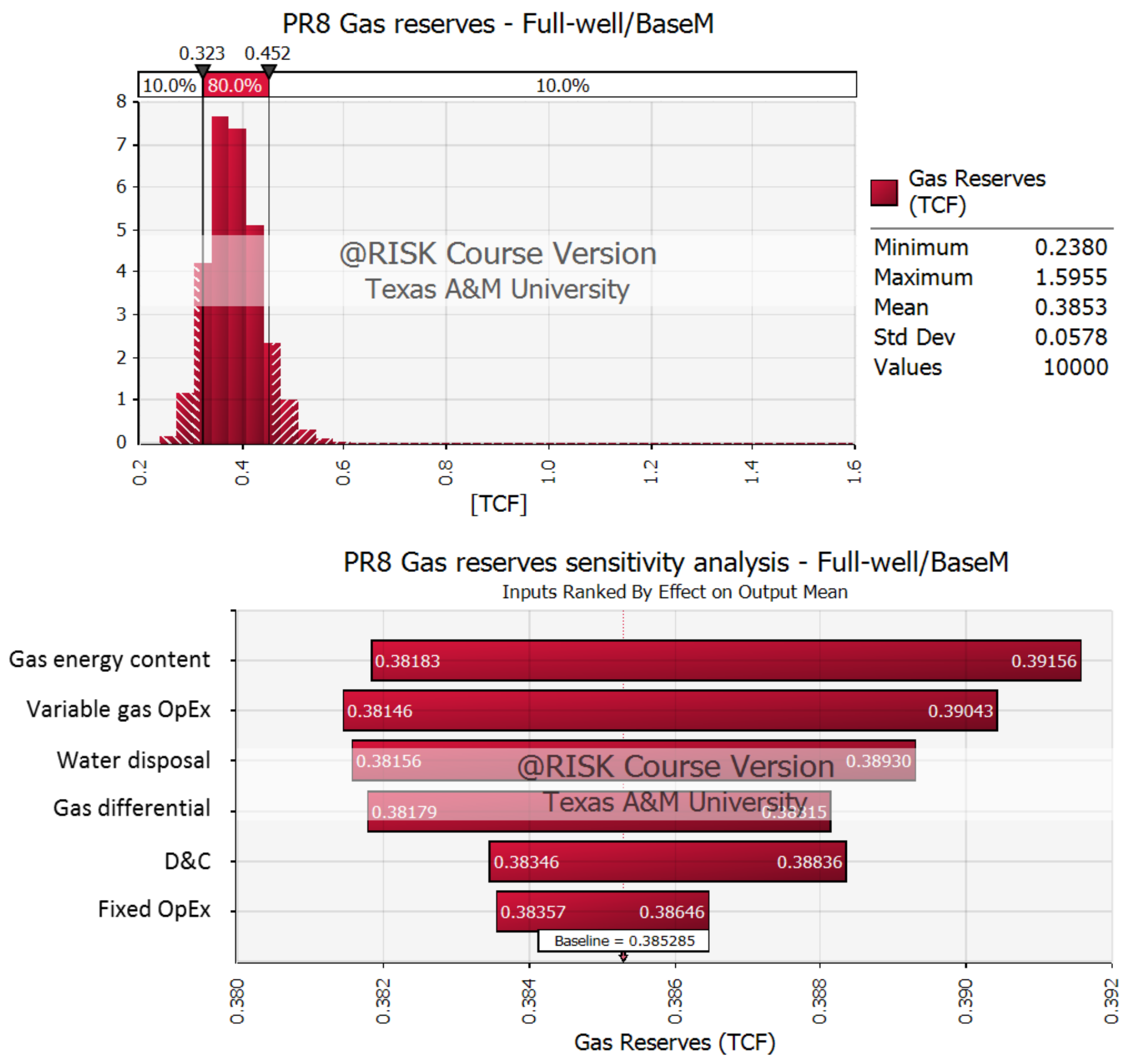

Figure 55—Gas reserves distribution (top) and sensitivity analysis (bottom) for a single well in PR8.

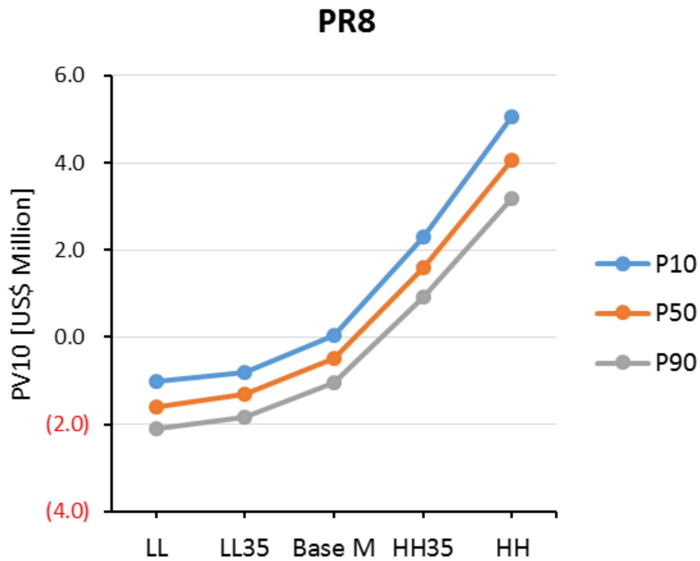

Figure 56—P10, P50, and P90 values of PV10, as function of price, for Full-well in PR8.

Results of F&D and Avg OpEx costs for each of the production regions in the Full-well scenario are summarized in **Table 33**. We see that results for Full-well and 100-well scenarios are very similar in value.

Table 33—Summary of F&D and Average OpEx costs for all production regions in the Full-well scenario

Production Region	**F&D (US$/Boe)**				**Avg Opex (US$/Boe)**			
	Mean	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**
PR1	70.60	97.00	69.50	45.40	14.83	18.66	14.63	11.34
PR2	13.66	17.50	13.70	9.71	8.21	11.39	7.92	5.58
PR3	27.94	36.70	27.81	19.39	9.44	12.22	9.20	7.07
PR4	17.11	21.90	17.13	12.10	8.31	11.57	8.05	5.35
PR5	31.90	38.52	32.71	23.84	9.88	12.68	9.66	7.48
PR6	12.63	14.67	12.55	10.70	7.91	10.55	7.72	5.49
PR7	11.27	13.29	11.16	9.42	9.24	12.76	8.92	6.04
	(US$/Mcfe)				**(US$/Mcfe)**			
PR8	3.30	4.00	3.27	2.64	1.46	2.02	1.40	1.04

As established in PRMS, we used probabilistic aggregation in the 100-well and Full-well scenarios to estimate reserves within each of the production regions. However, given that we have used a different production forecast model in every region, the aggregation of reserves between production regions was calculated arithmetically. **Table 34** shows the results of reserves distributions of the Eagle Ford shale, under all the assumptions we have applied and for the proposed price models. In general, we see that the best estimation corresponds to the HH price results, whereas results of LL prices have the smallest reserves distribution. PV10 results, shown in **Table 35**, have the same characteristic.

Table 34—Summary of oil and natural gas reserves for the Eagle Ford shale in Full-well scenario

Price Model	Gas Reserves (TCF)				Oil Reserves (BBO)			
	Mean	P10	P50	P90	Mean	P10	P50	P90
Base	21.030	22.892	20.981	19.210	2.605	2.781	2.602	2.434
Base M	20.575	22.886	20.946	17.488	2.565	2.783	2.600	2.344
HH	21.875	23.883	21.796	19.972	2.612	2.801	2.602	2.435
LL	6.699	9.585	5.935	5.173	0.722	1.163	0.590	0.541
HL	20.254	22.893	20.823	17.257	2.574	2.797	2.598	2.347
LH	19.878	23.663	19.024	17.354	1.899	2.737	1.612	1.489

Table 35—Summary of PV10 results for the Eagle Ford shale in Full-well scenario

Price Model	PV10 (US$ Billion)			
	Mean	P10	P50	P90
Base	77.123	86.568	76.961	67.882
Base M	77.240	99.705	76.942	55.206
HH	204.230	232.537	203.718	176.839
LL	(18.407)	2.195	(18.779)	(38.238)
HL	95.884	119.023	95.461	73.525
LH	89.795	114.416	89.178	66.086

Finally, we present in **Table 36** the results for Total CapEx and Total OpEx for each of the production regions in the Eagle Ford shale, as well as an arithmetic aggregation to the play level. We would like to point out that these values are strictly related to the different assumptions we made for the Full-well scenario.

Table 36—Total CapEx and Total OpEx for each production regions and the Eagle Ford shale in Full-well scenario

Price Model	Total CapEx (US$ Billion)				Total OpEx (US$ Billion)			
	Mean	**P10**	**P50**	**P90**	**Mean**	**P10**	**P50**	**P90**
PR1	1.954	2.549	1.957	1.346	0.493	0.617	0.487	0.375
PR2	15.085	19.143	15.224	10.742	12.208	16.979	11.744	8.218
PR3	21.061	27.473	21.027	14.708	9.031	11.832	8.756	6.704
PR4	7.194	9.113	7.249	5.145	5.241	7.181	5.052	3.554
PR5	22.998	27.627	23.622	17.257	9.078	11.813	8.831	6.799
PR6	12.763	14.564	12.705	11.046	10.309	13.936	10.032	7.061
PR7	6.036	6.888	6.004	5.218	6.758	9.459	6.501	4.351
PR8	3.301	4.004	3.265	2.638	1.465	2.023	1.397	1.035
EFS Total	**90.393**	**111.361**	**91.053**	**68.100**	**54.582**	**73.840**	**52.800**	**38.097**

In this Chapter, we presented the results of the estimation of reserves for each of the production regions of the Eagle Ford shale, for three different scenarios and with the different assumptions we made and explained. In the following chapter we present the conclusions of this work.

CHAPTER V

CONCLUSIONS

Based on the described approach and selected assumptions, we can make the following conclusions:

- Single-well scenario results showed that it is very difficult to obtain complete distributions of reserves from a single well in all production regions. This is caused mainly by high variability in production forecasts, the 20-year project life, and the economic hurdle imposed by other model parameters such as D&C costs, OpEx, and price differentials.
- Results of 100-well and Full-well scenarios show that there is a significant improvement in results when considering a production from multiple wells in every production region. With the exception of PR1 and PR8, complete distributions of reserves were obtained in most cases for all production regions when considering moderate to high price forecasts.
- We obtained the poorest results in all three scenarios from the evaluations of PR1 and PR8, in which not even with the IHS high price forecasts complete distributions of reserves were obtained. This shows that high productivity of hydrocarbon liquids in certain areas of the Eagle Ford shale is one of the determining factors in the success of development projects.
- PR6 is the best productivity region in the Eagle Ford shale. In all three scenarios of evaluation, the results obtained were significantly better than in the rest of

production regions, even when calculated with IHS low price forecasts. Furthermore, OpEx costs and price differentials had higher effect on reserves distributions than D&C costs, which are the second highest in the Eagle Ford play.

- In general, we found that the probabilistic components that have the highest effect on reserves are D&C costs, fixed and variable OpEx. Price differentials for natural gas, condensate, and volatile oil were particularly important for PR6 and PR7.
- Based on the assumptions made in the Full-well scenario and the price intervals calculated with IHS, we obtained the following P10-P50-P90 natural gas and oil reserves for the Eagle Ford shale:
  - 22.886-20.946-17.488 TCF and 2.783-2.600-2.344 BBO with the Base M price model.
  - 23.883-21.796-19.972 TCF and 2.801-2.602-2.435 BBO with the HH price model.
  - 9.585-5.935-5.173 TCF and 1.163-0.590-0.541 BBO with LL price model.
- We consider important to mention that this results are not static and that they should be reviewed as more information and development data becomes available. PDCA forecasts and D&C technology improvement, as well as costs optimization, can have a significant impact on reserves estimations for the Eagle Ford shale.

- Additionally, further integration and development of PDCA and the probabilistic before-tax cash flow model is recommended to generate more accurate results and to evaluate longer production periods that will add reserves into the economic limit; however, economic yardsticks results may not change significantly due to the time value of money.
- The methodology to perform evaluations with probabilistic components enables better project development and investment decisions and can be applied to other shale plays in studying large development well programs and general regional economic impacts.

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