Energy Economics 68 (2017) 566–578

Contents lists available at ScienceDirect

Energy Economics

journal homepage: www.elsevier.com/locate/eneco

A model to assess the impact of employment policy and subsidized domestic fuel prices on national oil companies

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ARTICLE INFO

Article history:
Received 13 December 2016
Received in revised form 20 October 2017
Accepted 23 October 2017
Available online 28 October 2017

JEL classification:
C2
C6
H2
L2
Q3
Q4

Keywords:
National oil company
State ownership
Exploration
Recovery
Optimal control

ABSTRACT

National oil companies (NOCs) control international oil markets. Nevertheless, by the end of the 2000s, their share of the industry's total revenues was only 35% while controlling more than 70% of the oil reserves and 65% of the gas reserves. Conventional financial theory prescribes that the proper management of an enterprise should seek the maximization of the NOCs' profits. However, maximization of profits is not their only objective. Their targets often include non-commercial objectives, such as domestic fuel subsidies and employment. This paper develops a model to assess the impact of domestic fuel subsidies and employment on NOCs' performance, which clarifies the trade-offs among non-commercial objectives and NOCs' market value, production, and reinvestment. The model is applied and calibrated to the Colombian NOC to find the financial and operative effects of these non-commercial objectives for different scenarios.

1. Introduction

National oil companies (NOCs), that have the government as their major ownership, control most of the international oil reserves. In the early 1970s, NOCs controlled slightly more than 10% of the world's oil and gas reserves (Leis et al., 2012). By the end of 2000s, NOCs controlled 73% of oil reserves and 65% of gas reserves (Victor et al., 2011). The nature of the NOC's ownership alters its objectives, and directly influence the public policies and incentives faced by company's managers (Vickers and Yarrow, 1988).

Despite the importance of the effects of ownership, research on oil and gas companies is limited. In fact, the literature has compared the technical efficiency between NOCs and IOCs. Al-Obaidan and Scully (1992) state that NOCs generate between 61% and 65% of the IOCs' revenues with the same inputs. Victor (2007) finds that revenues from their main commercial objective are generated with more efficiency by IOCs than NOCs. This author attributes these inefficiencies to several factors, in particular, employment policy and subsidies for delivered products, among others. Wolf and Pollitt (2008) estimate a 3.6% increase in return on sales, a 35% drop in employment and an average of 15% increase in total production when an NOC becomes an IOC. Wolf (2009) finds that IOCs encourage superior performance compared to NOCs in terms of output efficiency and profitability. Eller et al. (2011) find that NOCs are less efficient than IOCs, which can be mainly explained by the differences in the firms' objectives. Likewise, Shleifer and Vishny (1994), Hartley and Medlock (2008), Eller et al. (2011) and Hartley et al. (2012) find empirical evidence that non-commercial objectives, such as domestic fuel subsidies and employment – which represent high levels of employment, unprofitable projects, or non-necessary expenditures – are major sources of reduced economic efficiency for many NOCs.

NOCs' commercial objective is very much like those of international oil companies (IOCs), seeking to generate wealth for their owners – the citizens. Nevertheless, governments include non-commercial

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https://doi.org/10.1016/j.eneco.2017.10.038
0140-9883/

objectives in NOCs missions. While IOCs seek to maximize shareholder value, NOCs often have a wider range of objectives, such as providing domestic fuel price subsidies, fostering domestic employment, wealth re-distribution, economic development, and energy security (Shleifer and Vishny, 1994; Hartley and Medlock, 2008; Eller et al., 2011; Hartley et al., 2012).

The different objectives between NOCs and IOCs are even deeper at the managerial level, due to their different ownership and/or shareholding. In IOCs, so far as they are publicly traded, ownership means – in principle – a direct claim on the profits generated by the firms commercial activities. Any fundamental changes in IOC's governance ultimately require the shareholders' majority approval, according with their by-laws. This structure poses well known problems related to managerial incentives, mainly studied through the principal-agent paradigm (Jensen and Meckling, 1976; Harris and Raviv, 1978). In practice, this agency problem is countered by the existence of a market for ownership rights, the threat of takeover, the threat of bankruptcy, and a managerial labor market (Jensen and Meckling, 1976; Harris and Raviv, 1978). A widespread incentive practice has been to align management's interests with those of stockholders, through partial compensation with stocks and stock options (Holmström, 1999).

There is also a principal–agent relationship between the government and IOC, in which the government (principal) could design an incentive contract that induces the IOC (agent) to undertake actions that will maximize the government's welfare through taxes and royalties (Pongsiri, 2004). Oil reserves are owned by the state, which may offer access to them while IOCs can offer access to capital, expertise in recovery and management skill (Marcel, 2006). Under concession licenses or contractual arrangements, the state has to offer economically attractive contract terms for the IOC to take the implicit risk of this industry (Pongsiri, 2004).

In the case of NOCs, ownership is closer to a representative form, where officials act in the name of the public at large. Thus, the governance arrangement is a two-stage principal–agent relationship: the manager (agent)–government (principal) relationship, and the government (agent)–citizen (principal) relationship. This places governments as intermediaries between NOCs and the citizens. Government, as a principal to the NOC's manager, is in the position to hire, fire or reward, according to some expected performance, but the relationship usually lacks most of the mechanisms and incentives listed in the case of IOCs (Villalonga, 2000). Besides, the State is the guarantor of the NOC's debt, which shields it from the effects of financial distress or bankruptcy (Laffont and Tirole, 1991). As a consequence, NOC's managers are likely to be monitored less strictly than their counterparts in IOCs (Hartley and Medlock, 2008). On the other hand, government, as the principal, may influence the allocation of final production, production decisions, employment, and reinvestments (exploration and recovery). Some of these decisions are clearly guided by the Government's dual role as the agent to the citizens. A given outcome may occur because Government might be tempted to prioritize non-commercial objectives with the purpose of increasing its own political benefits (Karl, 1997). Since government officials are but temporary administrators of the state, elected by the citizens, their incentive is to extract as much as possible from the NOC, within sustainable limits.

Direct comparisons among oil companies is a major challenge, given the substantial variations in geological characteristics, petrochemical properties of oil and gas, taxes and royalty systems, and logistic factors. In light of these difficulties, and taking cues from an operational model developed by Pindyck (1978), Hartley and Medlock (2008) introduce a dynamic optimization model of the operation and development of an NOC in which the authors propose a multiplicative production function that depends on the oil reserves, the productivity of labor, and past exploration. The authors consider the operational effects of increased non-commercial objectives, such as the political discount premium, the employment incentive and the domestic fuel subsidy, suggestion although the model proposed on this paper does not consider new recovery technologies such as enhanced oil recovery (EOR).

To address this deficiency, we develop an extension of Pindyck (1978), explicitly incorporating the effects of exploration and enhanced oil recovery (EOR). The model assesses the trade-off between decisions on employment and subsidized domestic fuel price and financial-operational performance measures such as market value, production and reinvestment (exploration and recovery). The developed methodology seems to be relevant when the ratio of oil reserves to production is less than 15 years, such as Argentina, Brazil, Colombia, Egypt, India, Indonesia, Mexico, Norway, Oman, United Kingdom and US (BP, 2017). This means that these countries cannot maintain their actual production in the long term unless they add new reserves. These new reserves may come from exploration and/or EOR.

The rest of this paper is structured as follows: Section 2 compares the operational and financial performance of NOCs and IOCs during the first decade of this century, therein seeking to elicit some stylized facts, such as differences of revenue per employee and revenue per produced barrel. Section 3 introduces a model to obtain the optimal production and reinvestment path for IOCs. Section 4 applies this model to evaluate the consequences of employment and domestic subsidized fuel price on the operational and financial performance of an NOC. Section 5 illustrates these implications in the Colombian NOC, Ecopetrol. Finally, Section 6 provides the main conclusions.

2. Comparing national oil companies and international oil companies

Research on ownership effects in the oil and gas industry is hindered by the poor disclosure of NOCs. Many of them are not standardized. This means that information is scattered or varies depending on the source. Based on Hartley et al. (2012), we calculate basic statistics of the top 61 oil and gas companies, which represent approximate 80% of world oil production. In a more extended survey, Victor et al. (2011) reported that NOCs produced 61% of the world oil supply and 52% of the world gas supply in 2008, while holding more than 85% of world oil reserves and more than 65% of world gas reserves.

Al-Obaidan and Scully (1992), Victor (2007), Wolf and Pollitt (2008), Wolf (2009), Eller et al. (2011), and Hartley et al. (2012) propose the use of revenue per employee and revenue per produced barrel as a basic measure of economic efficiency. The average revenue is US$ 1440 per NOC employee versus US$ 1925 per IOC employee, as shown in Table 1. If we assume similar technology, cost structure, and workforce quality across companies, the inefficiencies in NOCs relative to IOCs may be explained by their employment policy (Victor, 2007; Hartley and Medlock, 2008; Eller et al., 2011; Hartley et al., 2012).

Table 1
Comparison between national oil companies (NOCs) and international oil companies (IOCs) for 2001–2009.
Data source: Energy Intelligence annual publication "Ranking the World's Oil Companies" published and completed by Hartley et al. (2012).

	NOC	IOC
Number of companies	23	38
Oil reserves (billion barrels)	733.51	112.70
Natural gas reserves (billion cubic meters)	2.67	1.26
Employees (million)	1.68	1.54
Revenue per employee (US$)	1440	1925
Refining capacity (thousand barrels/day)	22,102	29,283
Vertical integration (products/oil production)	1.13	1.69

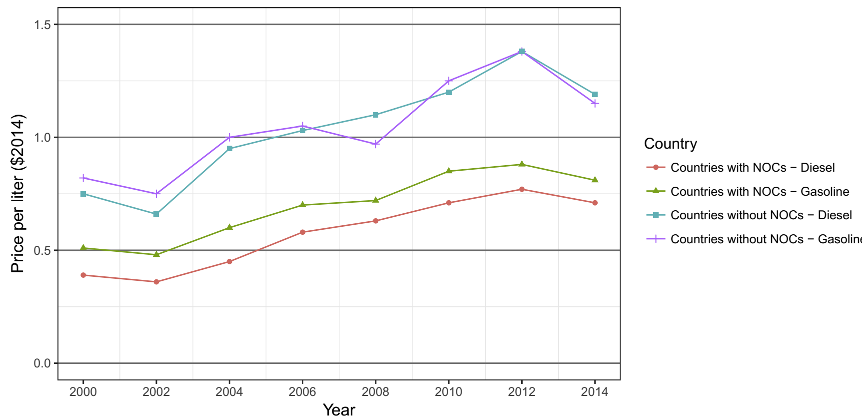

Fig. 1. Gasoline and diesel price of countries with NOCs or without NOCs.
Data source: The World Bank (2016).

As a second basic measure of economic efficiency, we use a proxy of revenue per produced barrel. Oil companies may sell their oil and gas production to international or domestic oil market. There is no evidence of significant differences between the international oil prices taken by NOCs vis-à-vis the IOCs (Bernard and Weiner, 1996). Nevertheless, the averages of domestic gasoline and diesel prices in countries with NOCs were significantly lower than those without NOCs, as shown in Fig. 1. Gasoline and diesel prices in countries with NOCs were on average 34% and 45% below those with only IOCs, respectively. These findings are aligned with the hypothesis of Eller et al. (2011) and Hartley et al. (2012) that governments, who are the principals in their relation with an NOC management, are more likely to redistribute income through subsidized domestic fuel prices. Cheon et al. (2013) note that major oil producing countries with weak institutional capacities tend to subsidize domestic fuel prices.

In general, NOC efficiency measures are affected by employment policies and domestic fuel subsidies, which may affect their production and reinvestment decisions. We propose a model including exploration and enhanced oil recovery that provides an operative and financial benchmark to assess the effects of these non-commercial objectives.

3. Production and reinvestment of international oil companies

An IOC can distribute its profits among shareholders through dividends and stock repurchases, once reinvestment decisions have been made. Such reinvestment is deployed mainly via exploration and recovery (Fig. 2), allocated to each item depending on the company's objectives, reserves, and time horizon.

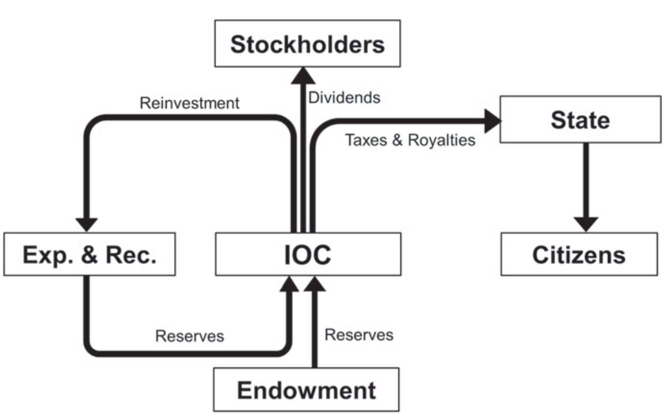

Fig. 2. Flow diagram for international oil company (IOC).

The general approach to investigating management's optimal reinvestment decisions, and their consequences, will follow the well-established principle of maximization of shareholder value. In what follows we simplify matters in the following ways: i) IOC managers maximize the net present value of the free cash flows going to equity, paid out only in the form of dividends. ii) The IOC finances all its activities exclusively from internally generated funds. It has no debt outstanding. iii) For ease of computation and further interpretation, the formulation is continuous-time.

Our proxy of the market value of equity is given by the net present value of free cash flow:

$$\max_{q,w,z} \int_0^\infty [p(t)\,q(t) - c(q(t))\,q(t) - c_F(t) - w(t) - z(t)]\,e^{-\delta t}dt, \tag{1}$$

where $q(t)$ represents the oil extraction rate, $w(t)$ denotes the exploration investment rate, $z(t)$ represents the enhanced oil recovery (EOR) investment rate, $p(t)$ is the oil price, $c(q(t))$ is the production cost per barrel, $c_F(t)$ represents all fixed costs that are independent of the production rate, and δ is a constant discount rate. We also assume that the IOC takes the oil price as given (price-taker).

Pindyck (1978) argues that the production cost per barrel is an inverse function of the remaining reserves; instead, we assume that the production cost per barrel depends on the production rate. Based on the break-even cost, Exploration and Production (E&P) companies first rely on low-cost oil wells and then high-cost oil wells. Therefore, the production cost per barrel is the weighted average of the production cost of each producing well. If the company wants to increase its production rate, they will need to drill and/or develop over higher cost oil wells. Therefore, we assume that the production cost per barrel is increasing in $q(t)$, so that $c_q > 0$[1].

Depending of the reserves/production ratio of E&P companies, there exist incentives to invest in exploration and/or EOR. Oil production in reservoirs might include three distinct phases, which are not necessarily sequential: primary, secondary, and enhanced oil recoveries (tertiary recoveries)[2].

The original oil in place (OOIP) is the total oil volume stored in reservoirs prior to production (Terry and Rogers, 2013), and the

[1] The c_q represents the first derivative with respect to q.

[2] The American Petroleum Institute (API) defines primary recovery as recovered by natural flow or artificial lift. Secondary recovery is defined as recovered by any artificial flowing or pumping obtained by the injection of water or gases into the reservoir to increase reservoir energy (Riva Jr, 1974). Green and Willhite (1998) define the EOR recovery as thermal, gas injection, chemical, or other methods used to displace additional oil.

recovery factor (RF) is the percentage of the OOIP that can be produced, depending on the recovery phase[3]. Therefore, the oil reserves at time t, $R(t)$, are then given by Eq. (2).

$$R(t) = OOIP(t) * RF(t). \tag{2}$$

The model proposed by Pindyck (1978) contains three pooled components of reserve additions: new discovery, extensions and revisions. However, besides these pooled additions, we independently consider exploration and EOR, which means that our model considers two explicitly different ways to add reserves: by expanding the $OOIP(t)$ via exploration and by increasing the $RF(t)$ via EOR, as shown in Eqs. (3)–(5).

$$\dot{R}(t) = \dot{X}(t) + \dot{Y}(t) - q(t) \tag{3}$$

$$\dot{X}(t) = f(w, X) \tag{4}$$

$$\dot{Y}(t) = g(z, Z) \tag{5}$$

where $f(w,X)$ is the rate of addition to reserves by exploration, which depends on the exploration investment rate $w(t)$ and the cumulative exploration reserve additions $X(t)$, as Pindyck (1978) proposes. f is assumed to be non-decreasing and strictly concave in w ($f_w \geq 0$ and $f_{ww} < 0$) and monotonically decreasing in X ($f_X < 0$). g is the rate of addition to reserves by EOR, which depends on the recovery investment rate z, and the cumulative recovery investment Z, given an OOIP. We assume that $g(z,Z)$ is non-decreasing and strictly concave in z ($g_z \geq 0$ and $g_{zz} < 0$) and monotonically increasing in Z ($g_Z > 0$). Additionally, the control variables involved must be nonnegative, as shown in Eqs. (6)–(8).

$$q(t) \geq 0 \tag{6}$$

$$w(t) \geq 0 \tag{7}$$

$$z(t) \geq 0 \tag{8}$$

The Hamiltonian of the optimization problem is

$$H = [pq - cq - c_F - w - z]\, e^{-\delta t} + \lambda_1(f + g - q) + \lambda_2 \quad f + \lambda_3 g \tag{9}$$

The Hamiltonian is a nonlinear function of the all decision variables. The optimal production rate is found by differentiating the Hamiltonian with respect to q, as shown in Eq. (10).

$$(p - c - c_q q)\, e^{-\delta t} - \lambda_1 = 0 \tag{10}$$

The shadow price λ_1 represents the profitability of the marginal contribution of an oil barrel that will be produced in the future. The Karush–Kuhn–Tucker conditions force the optimal oil extraction rate to be either the maximum production capacity or zero, depending on whether the present value of the marginal income per barrel $(p - c - c_q q)e^{-\delta t}$ is greater or smaller than λ_1, respectively. In other words, if the profit of producing a barrel now is more than the profit of postponing extraction, the optimal production rate is its maximum capacity.

Differentiating the Hamiltonian with respect to w, we obtain the optimal exploration investment rate, as shown in Eq. (11).

$$\left[(p - c - c_q q) - \frac{1}{f_w}\right] e^{-\delta t} + \lambda_2 = 0 \tag{11}$$

where $\left(\frac{1}{f_w}\right)$ represents the cost of adding one barrel through exploration, known as the finding cost. The optimal exploration investment rate is positive when the marginal income, the price less both the production cost and the finding cost, is greater than the profit of postponing exploration investment.

In a similar manner, the optimal EOR investment rate is positive when the marginal income per barrel added by EOR is greater than the profit of postponing EOR investment, as shown in Eq. (12).

$$\left[(p - c - c_q q) - \frac{1}{g_z}\right] e^{-\delta t} + \lambda_3 = 0 \tag{12}$$

where $\left(\frac{1}{g_z}\right)$ represents the cost to add an oil barrel by EOR, analogous to the finding cost in exploration.

4. The effects of employment policy and subsidized domestic fuel price on NOC's performance

We contrast the production rate, exploration investment rate, and recovery investment rate of NOCs versus IOCs, assuming that both have the same endowment, capabilities and technology. The only difference is that NOCs face two non-commercial objectives: employment policy and domestic fuel subsides.

When an E&P company is totally owned by a State, the cash flows and reserve flows are assumed as shown in Fig. 3. Its profit can be split among the State (through dividends, taxes and royalties) and reinvestment (exploration and recovery investments), or directly subtracted from its revenues, and transferred to citizens via employment policy or fuel subsidies. The State uses part of those dividends, taxes and royalties to increase the social welfare of its citizens through government budget. In the following subsections, we present how non-commercial objectives are modeled.

4.1. Employment policy

In NOCs, government take the place of stockholders in the owner–manager relation in some oil-producing countries. Government frequently asks NOC management to hire more employees than the NOC would require to operate as an equivalent IOC, or to make unprofitable investments (Al-Obaidan and Scully, 1992; Hartley and Medlock, 2008; Hartley et al., 2012), thus causing the NOC costs to

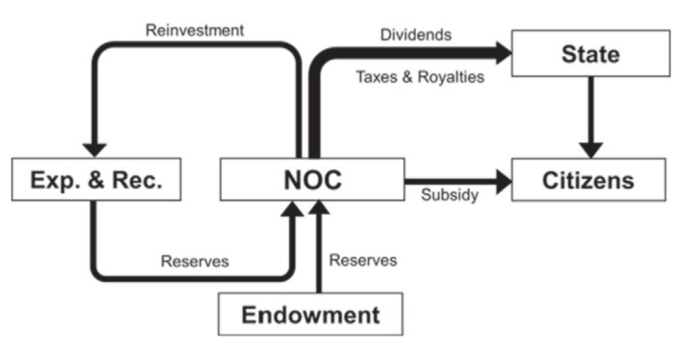

Fig. 3. The flow diagram for a national oil company (NOC).

[3] Ball (1988) reports that recovery factors (RFs) of the primary, secondary and tertiary recoveries might be in the ranges 12–15%, 15–20%, and 4–11%, respectively.

exceed the corresponding IOC costs. If at any time the NOC production cost per barrel exceeds the price, the optimal production policy would be to keep the oil underground.

The way employment levels will be modeled is as a load on top of the ideal cost per barrel and fixed cost:

$$c^{NOC}(q(t)) = c^{IOC}(q(t))\,(1+\rho) \tag{13}$$

$$c_F^{NOC}(t) = c_F^{IOC}(t)\,(1+\rho) \tag{14}$$

where ρ quantifies the size of the NOC employment load.

4.2. The subsidized domestic fuel price

Government might set or regulate the domestic fuel price p_d ($p_d < p$) to boost their political capital. In oil-producing countries, if politicians require that NOCs sell the domestic fuel at a subsidized price, the NOC frequently supplies all or part of domestic fossil demand $q_d(t)$. When the domestic demand surpass the NOC's production, we assume that the State imports fuel to supply the remaining demand.

If its production surpasses the domestic demand, the NOC sells its remaining production at the international price. In other words, the NOC revenue will be a composition of the international price plus the domestic price such that

$$revenue = p\ \max\left[q(t) - q_d(t), 0\right] + p_d\ \min\left[q(t), q_d(t)\right] \tag{15}$$

The domestic fuel subsidy θ is modeled by

$$p_d = p\,(1-\theta) \tag{16}$$

where θ quantifies the size of domestic fuel discount. In the next section, we estimate the financial and operational effects of those policies, using a numerical example that employs the data from the Colombian NOC, Ecopetrol.

5. Numerical example

To illustrate, through the building of scenarios, the effects of non-commercial objectives, we collected some basic information of the Colombian national oil company, Ecopetrol, which has a ratio of reserves to production of less than 7 years and has a 89-percentage government ownership share. We compiled the required information (Appendix B) and proceeded to fit functional forms for the production cost function, the exploration function, and the enhanced oil recovery function. However, this numerical example does not provide a complete realistic representation of the company. The production cost function, exploration function and recovery function themselves are over-simplifications. Our sole objective is to provide some insights about the operational and financial effects of employment and subsidized domestic fuel price scenarios starting from actual data.

5.1. Model calibration

Estimation of the production cost may be complex when we include reserves, decline rate, learning rate, production life etc. (Luo and Zhao, 2012), but our aim is only to capture the stylized fact that the production cost rises as the production rate increases. As we noted earlier, companies prioritize the production wells by operating costs. Possible causes of increased production costs are low-production wells, distance from the central processing facility (CPF), heavier oil, and a higher water/oil ratio (WOR), among others. In the Ecopetrol case, the production cost per barrel is the sum of the lifting cost[4], transportation cost and diluent cost (naphtha) (Ecopetrol, 2016):

$$c(q(t)) = c_L(q(t)) + c_T(t) + c_D(t) \tag{17}$$

$$c_L(q(t)) = \rho_0 e^{\rho_1 q(t)} \tag{18}$$

where $c_L(q(t))$ is the lifting cost, $c_T(t)$ is the transportation cost per barrel, and $c_D(t)$ is the diluent cost per barrel. Using the lifting cost of Ecopetrol during the period from 2005 to 2015 (Appendix D), we estimate the coefficients of the functional form of the lifting cost:

$$\begin{array}{lll} \ln(c_L(q(t))) = & 1.34 & +0.0014q(t) \\ & (2.65) & (3.85) \\ \text{Observations} = 11 & R^2 = 0.4968 & F(1,9) = 7.01 \end{array} \tag{19}$$

The flow of reserves by exploration, $f(w,X)$, denote additions to reserves by primary-secondary recovery. The exploration function proposed by Pindyck (1978) is the following:

$$f(w,X) = \alpha_0 w^{\alpha_1} e^{-\alpha_2 X}, \alpha_0, \alpha_1, \alpha_2 > 0 \tag{20}$$

Using the Colombian data for exploration investment and oil discovery during the period from 1978 to 2006 (Appendix C), we obtain significant coefficients of Pindyck's functional form for the exploration function, as shown in Eq. (21).

$$\begin{array}{lll} \ln(f(w,X)) = & 0.974\ \ln(w) & -0.000491\ X \\ & (8.95) & (-3.05) \\ \text{Observations} = 26 & R^2 = 0.9226 & F(2,24) = 138.76 \end{array} \tag{21}$$

where w represents the annual exploration investment (exploration drilling cost, the geological cost and the geophysical cost) in millions of US dollars, and X is the cumulative exploration discoveries in millions of barrels (Wright and Gallun, 2008).

Given the non-availability of Colombian CO_2-*EOR* data, we use two CO_2-*EOR* models: the Kinder Morgan - San Andres Model and the Kinder Morgan – Morrow Model, as shown in Appendices E and F. As in Van't Veld and Phillips (2010), we use an analog method to predict oil additions and CO_2 expenses based on these two CO_2-*EOR* models. Scaling with Colombian OOIP, we propose a functional form for the EOR function, as shown in Eq. (22).

$$g(z(t),Z) = \beta_0 e^{\beta_1 z(t) - \beta_2 z(t)^2} Z^{\beta_3}, \beta_0, \beta_1, \beta_2, \beta_3 > 0 \tag{22}$$

where $z(t)$ represents the annual CO_2 expenses in millions of dollars and Z represents the cumulative CO_2 expenses. Finally, we obtain the significant coefficients of the proposed functional form, as shown in Eq. (23).

$$\begin{array}{lllll} \ln(g(z),Z)) = & -12.23 & +0.000319z & -0.00000000107z^2 & +1.5718\ln(Z) \\ & (-3.89) & (9.29) & (-12.76) & (5.70) \\ & \text{Observations} = 40 & R^2 = 0.5191 & & \end{array} \tag{23}$$

The following subsections show the optimal production and reinvestment using parameters adjusted from Ecopetrol's data and an oil price equal to US$ 60 per barrel. We discuss four scenarios: a base scenario where the company follows the optimal policy of an IOC, a scenario with employment factor of 1.2, a scenario with a 20-percent

[4] The lifting costs are the sum of operating expenses, administration and the maintenance of wells, equipment and facilities (EIA, 2011).

discount on domestic fuel, and a scenario that combines employment factor of 1.2 and a 20-percent price subsidy.

5.2. The behavior of optimal production, exploration and recovery

We assume the base scenario condition as being close to the actual data of Ecopetrol, in which the company sells domestic fossil fuel at the international price and its employment factor is close to 1. In 2015, the company's reserves were 1849 million barrels, its annual production rate was 260 million barrels, and its maximum production capacity was approximately 800,000 barrels per day. Another important assumption is a constant oil price: $60 per barrel. To differentiate between value effects due to price volatility and those stemming from policy, such as employment and subsidized fuel, we work under fixed-price scenarios[5].

All scenarios assume that there are restrictions in the company's capacity to raise outside capital. Starting from this baseline, our model produces an optimal schedule for investments in exploration, recovery and production rates for the next twenty years[6] as shown in Fig. 4. If past investment-discovery patterns are any guide for the future, the company might be able to produce at almost the maximum rate for the next twenty years. For this to be the case, the optimization model tells that the company would require intensive investments in exploration and recovery after the sixth year. The investment profile of the baseline suggests that, unless the company optimally schedule its investments between exploration and recovery in the coming years, its present rate of production will sharply decline over the next five to six years.

Given the baseline conditions, there is no economic incentive to invest in exploration or recovery during the first 6 years of production, because it is more profitable to exploit existing reserves than to add new ones via exploration or recovery. Furthermore, the model output, as shown in Fig. 4, point to the need for US$ 18.3 billion in investments in exploration from the seventh until the eleventh year. From this effort, Ecopetrol might expect to add over 1000 million barrels to its initial reserves. As may be observed from Fig. 4, the evolution of the reserves is such that, during much of this period, the extraction rate essentially matches the discovery rate. Of course, this is a stylized steady-state-like situation, which idealizes the actual impacts of geological risk. Nevertheless, the important message that it conveys is that, for this to occur, significant exploration investment is required. After the eleventh year, our optimization model stops any further exploration investment because of increasing finding costs associated with the cumulative effects of past investments.

Recovery investments come lumped into two separate clusters, with a two-year hiatus, from the eleventh to the sixteenth year. In contrast to exploration, which might have a faster effect on reserves, the effects of recovery investment continue adding to reserves for some years after the investment period; however, this requires significant initial investments. During the relevant time intervals, the required investments amount to nearly US$ 49.3 billion. With this investment schedule for recovery alone, Ecopetrol might expect to increase reserves by as much as 2831 million barrels. As a result of the proposed optimal investment schedule, the proxy for the market value of Ecopetrol, as given by Eq. (1), is approximately US$ 28.2 billion.

[5] The results presented here do not imply recommendations to the company. Any result about investment or extraction patterns may be interpreted as the best decision paths if the decision maker believes that, in the long term, oil prices will most likely remain around the present price.

[6] This choice of horizon is arbitrary, and it may have the consequence of not capturing entirely the effects of a particular decision adopted late in the time line, especially in the case of EOR.

5.3. The effects of employment policy

Employment is interpreted as any above an equivalent IOC-expected expenditures, such as a greater number of employees, unprofitable projects or other non-required regular expenditures, that may increase the production costs per barrel and the fixed costs of the company. Fig. 5 shows the main results produced by the model in the case where the company operates under an employment factor of 1.2, which is modeled as a 20-percent increase in all costs above the baseline. Under this particular case, the optimal schedule of exploration investments starts delayed two years with respect to the baseline. Investments in exploration are then the almost exclusive alternative to improve reserves and are sustainable only through a series of moderately sized disbursements spread over thirteen years - up to the twentieth year - that amount to approximately US$ 30.7 billion. Investments in recovery are reduced to negligible amounts. They are suppressed because these investments require relatively high initial disbursements.

The associated optimal production rate schedule corresponds to a monotonically decreasing series, starting from a maximum production rate of 800,000 barrels per day. This is consistent with the investment schedule. This allows for the systematic extraction of oil reserves initially in place and a subsequent long tail of "just-in-time" investments that lead to decreased production levels until a stable minimum is attained. Up to the model's horizon, it forecasts added reserves of approximately 1470 million barrels.

It is necessary to be cautious in interpreting these results, as they smooth out actual geological risks; therefore, if the model's results are to be of any guidance, predicted investments can only be seen as a ballpark reference. Assuming a constant domestic fuel demand of 330 MBOPD (BP, 2015), under this scenario, our model estimates that the Colombian government will need to import fuel after the thirteenth year, as shown in Fig. 5. Another result of the proposed exploration investment schedule is that Ecopetrol's market value proxy is estimated at approximately US$ 18.7 billion, which represents a 34% discount over the base scenario.

5.4. The effects of subsidized domestic fuel price

Domestic fossil fuel subsidies mean a discount on the domestic fuel price relative to the international fuel price. Domestic fuel subsidies lead to increases in domestic demand that are roughly proportional to the level of discount (Cooper, 2003). In what follows, it will suffice to assume the following stylized linear domestic demand function (Kalymon, 1975; Brown and Phillips, 1984):

$$q_d(p_d) = 420 - 1.5\ p_d \tag{24}$$

where q_d is the Colombian domestic demand and p_d is the domestic fuel price in dollars per barrel. Without any fuel discount, we assume a constant demand of 330 MBOPD (BP, 2015).

Fig. 6 shows the optimal schedule for investment in exploration, recovery and annual production rate in the case where there is a fuel discount equivalent to 20% with respect to the international price. Under the domestic fuel discount, the optimal schedule of exploration investments totals approximately US$ 20.5 billion. The model forecasts added reserves by exploration of approximately 1059 million barrels. In contrast to the baseline, where recovery investments come combined in two separate periods, the optimal schedule of recovery investments occurs in a single four-year period that requires disbursements for a total of US$ 47.9 billion. With this schedule of recovery investments, added reserves are expected to be 1849 million barrels.

As in the base scenario, the optimal production schedule is to extract, as quickly as possible, the initial reserves. The model also forecasts that the government will need to import fuel to supply the

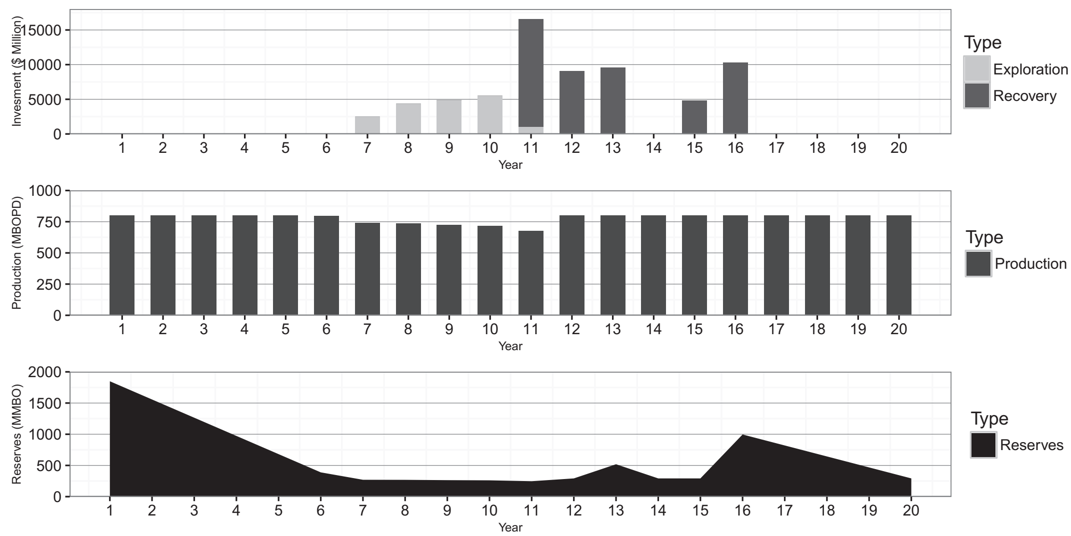

Fig. 4. Optimal exploration investment, recovery investment, production rate and reserves for the next 20 years.

domestic demand for a number of years, from the eleventh year up to the fourteenth year. This proposed investment schedule yields an expected market value of US$ 18.6 billion, representing a reduction of 34% with respect to the baseline.

5.5. The effect of combining employment and subsidized domestic fuel price

Under a combined scenario of employment factor 1.2 and a 20-percent subsidy, the optimal schedules for investments in exploration and recovery, and for the production rates, are shown in Fig. 7.

Under this extreme scenario, the only viable path is exploration with an optimal schedule of investments showing two modest peaks requiring a total of US$ 12 billion. Under this scenario, the model estimates additions of approximately 717 million barrels. As in the 1.2 factor of employment case, recovery investments are absent during the entire period of analysis. Self-sufficiency sputters to a permanent halt after year twelve, and the company's proxy market value is US$ 11.3 billion, which represents a 60% reduction with respect to the baseline.

6. Conclusions

The objective of this paper is to advance the understanding of the operational and financial effects of non-commercial objectives in NOCs. The model that we propose to achieve this end, maximizes the present value of future free cash flows for an ideal oil company, assumed to follow past patterns of investment-discovery and investment-recovery, especially of the EOR type.

Following the general arguments in the principal-agent paradigm, governments who represent NOCs' owners (citizens) might be tempted to seek political benefits by over-emphasizing non-commercial objectives in the NOC's mission. Seeking to reveal the specific consequences of such policies on investment and production in a medium-sized oil producer, we develop a model to assess their impact, through stylized representations of employment levels and subsidized domestic fuel prices.

Within this frame, we extend previous analyses to include two distinct modes in which the oil company may seek to increase its reserves. These two modes are exploration and enhanced oil recovery (EOR). The tension between exploration and recovery is the result of local conditions that lead to an NOC being constrained by

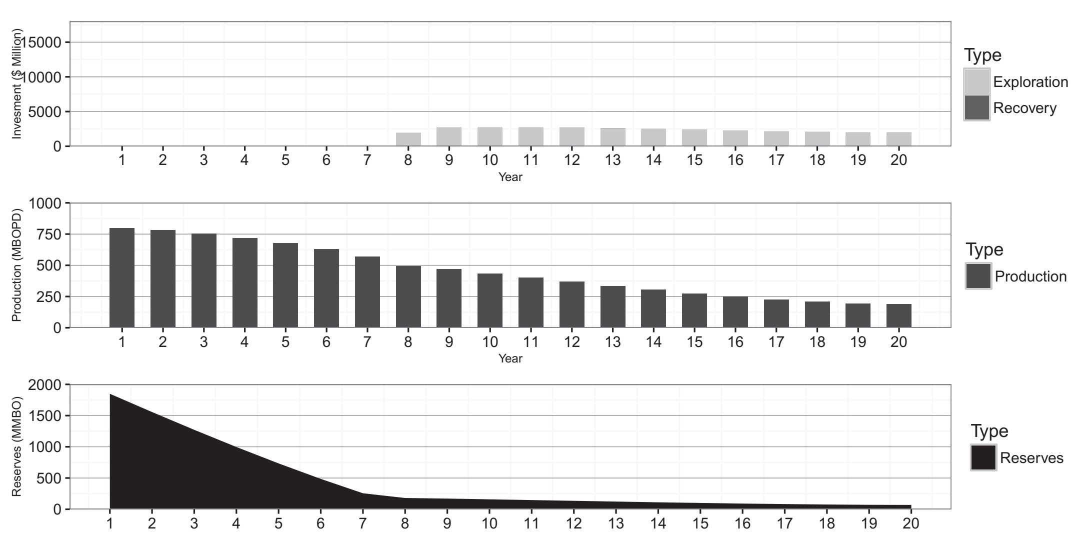

Fig. 5. Optimal exploration investment, recovery investment, production rate and reserves with employment factor 1.2.

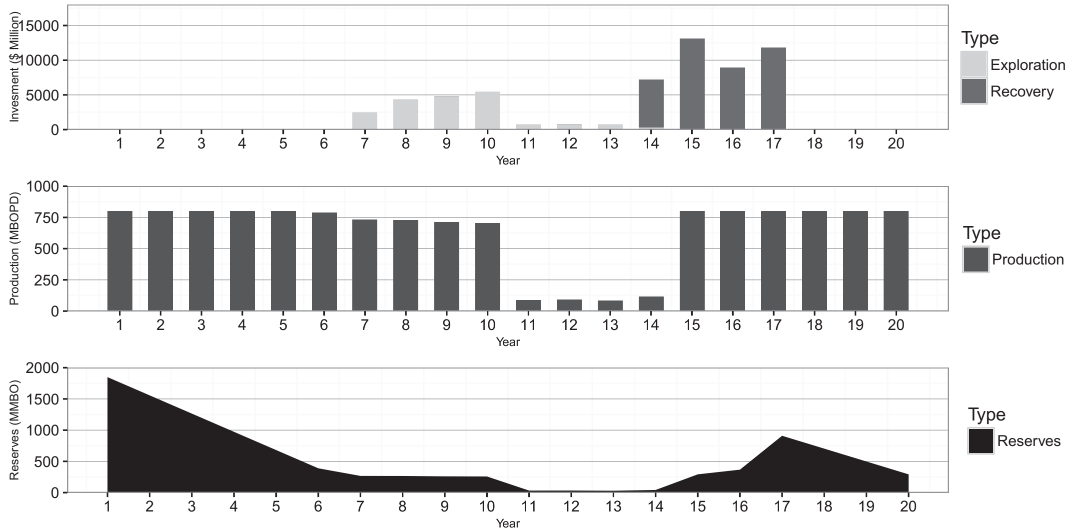

Fig. 6. Optimal exploration investment, recovery investment, production rate and reserves with 20% price subsidies.

budgetary pressures and with a limited perspective of future reserve growth. The main interest in adding EOR is that it presents a complementary risk profile to that of exploration - the risky exploration game (Marcel, 2006). Exploration may be carried out gradually, with the invested amounts spread over wide time periods. Nevertheless, the associated risk is relatively high, since the invested funds may not lead to significant discoveries. On the other hand, EOR usually requires high upfront amounts to be disbursed in a relatively short time span, but is less risky. The introduction of this second mode of investment is particularly relevant for NOCs that are cash- and reserve-constrained, because the added flexibility allows for a more efficient use of the available funds.

Our model starts from a baseline scenario, which is characterized by a twenty-year projection of the optimal investments in both exploration and recovery, the expected consequential yearly production rates, and its reserve evolution. The projections presented use as input the fitted historical data from Ecopetrol, the Colombian NOC, which allows for a more realistic view of how the model operates. In addition to the baseline, we build two separate scenarios: one for a level of employment 20% above the baseline and another for a 20% domestic fuel discount. Through these devices, we uncover a hierarchy of investment priorities, where investments in exploration come before investments in recovery. Only if prices are sufficiently high, can the (policy-constrained) value of the firm be maximized through significant investments in recovery. This hierarchy is summarized in Fig. 8.

This hierarchy follows from the different time lapses between investment and the resulting oil paybacks, combined with the quite different initial disbursements associated with each of these reserve addition modes. Initial investments in recovery are much higher than those in exploration, and the physical characteristics of the former imply a somewhat larger time delay between money spent and production results.

As expected, optimal investment is especially sensitive to low prices, in particular for the case where there are significant levels of employment. This sensitivity to price and scenario also extends to expected reserve additions, as shown in Fig. 9.

Our model leads to results of two distinguishable types. Chronologically, it favors initial investment in exploration, which, after a few years, yields to investment in recovery. But this sequence is the case

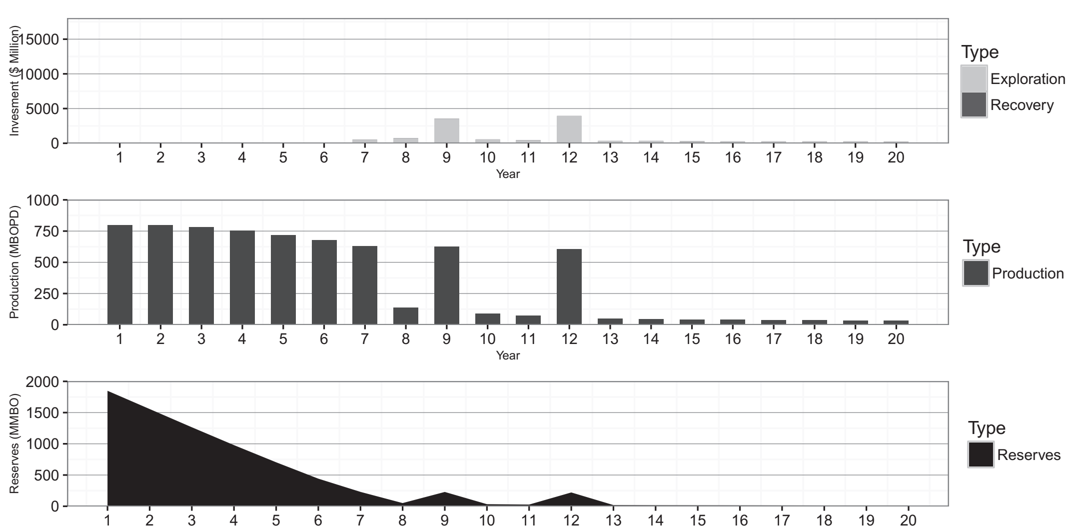

Fig. 7. Optimal exploration investment, recovery investment, production rate and reserves with employment factor of 1.2 and 20% price subsidies.

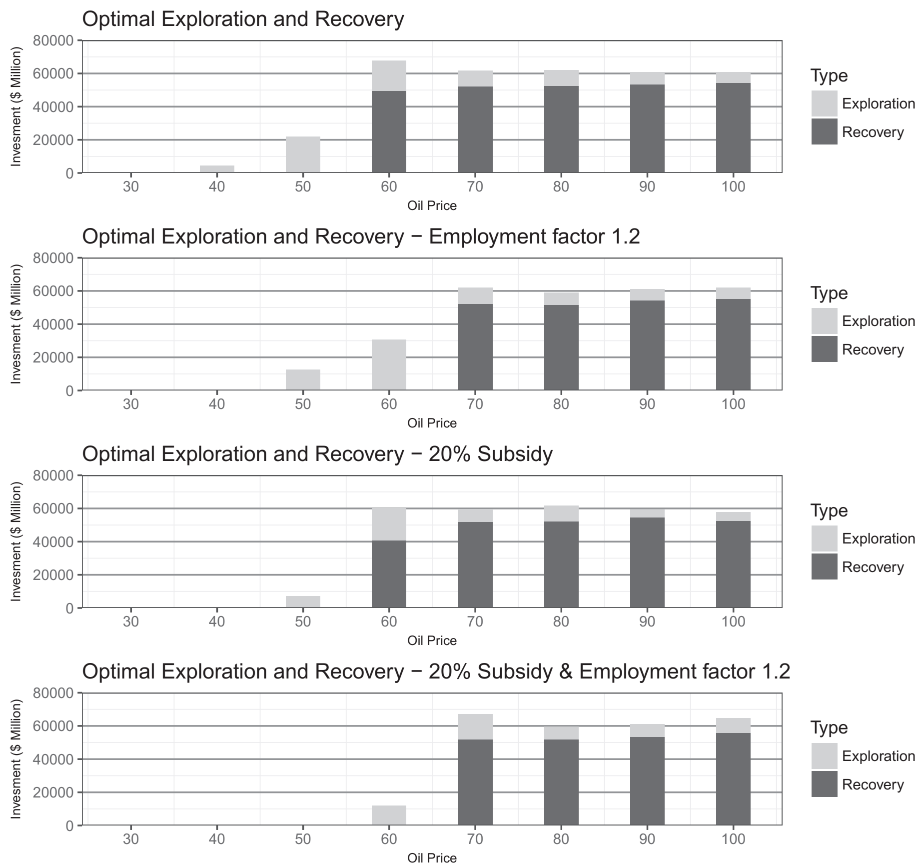

Fig. 8. Optimal exploration investment and recovery investment for different oil prices.

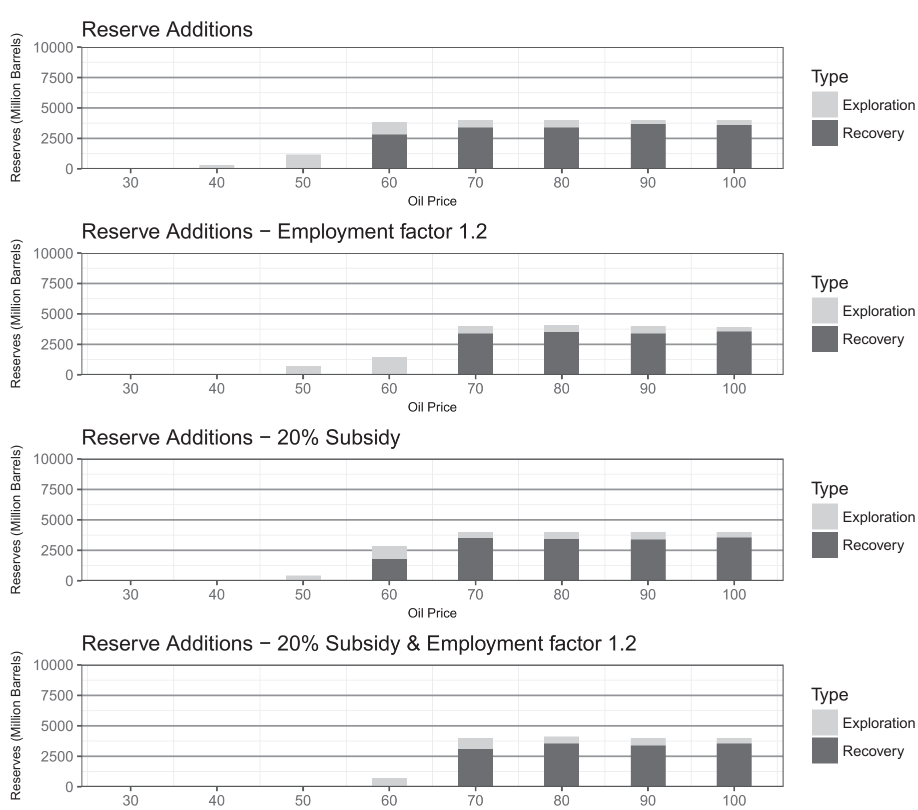

Fig. 9. Reserve additions for different oil prices.

only if enough funds are available to cover for both tasks. As such funds grow scarce, exploration is left as the only mode of investment that makes financial sense.

The second type of results concerns the sensibility to price of the chosen investment strategy. For low prices, exploration dominates as the main investment strategy. This is due to its lower upfront disbursements and higher time flexibility. As prices are higher, the amounts available for reserve expansion are larger, and EOR dominates the investment schedule.

An important limitation of our model is that its main input is the aggregate over all the different fields in the land, thus effectively making projections that ignore a great variety of geologic uncertainties. Clearly, the consequence of this limitation is that the model "averages out" geological risk, this is why its output for the optimal investment schedules must be viewed as a lower bound projection.

Appendix A. The production, exploration, and recovery model

$$\max_{q,w,z} \int_0^\infty [(p(t)q(t) - c(q(t))q(t) - c_F(t) - w(t) - z(t)]\, e^{-\delta t} dt \tag{A.1}$$

Subject to

$$\dot{R}(t) = \dot{X}(t) + \dot{Y}(t) - q(t) \tag{A.2}$$

$$\dot{X}(t) = f(w(t), X) \tag{A.3}$$

$$\dot{Y}(t) = g(z(t), Z) \tag{A.4}$$

$$q(t) \geq 0,\ w(t) \geq 0,\ z(t) \geq 0 \tag{A.5}$$

The Hamiltonian:

$$H = [pq - cq - c_F - w - z]\, e^{-\delta t} + \lambda_1(f + g - q) + \lambda_2 f + \lambda_3 g \tag{A.6}$$

Optimal rate of production, exploration investment and recovery investment:

$$H_q = (p - c - c_q q)e^{-\delta t} - \lambda_1 = 0 \tag{A.7}$$

$$\lambda_1 = (p - c - c_q q)e^{-\delta t} \tag{A.8}$$

$$H_w = -e^{-\delta t} + \lambda_1 f_w + \lambda_2 f_w = 0 \tag{A.9}$$

$$\left[(p - c - c_q q) - \frac{1}{f_w}\right] e^{-\delta t} + \lambda_2 = 0 \tag{A.10}$$

$$\lambda_2 = \left[\frac{1}{f_w} - (p - c - c_q q)\right] e^{-\delta t} \tag{A.11}$$

$$H_z = -e^{-\delta t} + \lambda_1 g_z + \lambda_3 g_z = 0 \tag{A.12}$$

$$\left[(p - c - c_q q) - \frac{1}{g_z}\right] e^{-\delta t} + \lambda_3 = 0 \tag{A.13}$$

$$\lambda_3 = \left[\frac{1}{g_z} - (p - c - c_q q)\right] e^{-\delta t} \tag{A.14}$$

$$H_R = 0 = -\dot{\lambda_1} \tag{A.15}$$

$$\dot{\lambda_1} = 0 \tag{A.16}$$

$$\dot{\lambda_1} = (\dot{p} - 2c_q\dot{q} - c_{qq}\dot{q}q)\, e^{-\delta t} - \delta(p - c - c_q q)e^{-\delta t} = 0 \tag{A.17}$$

$$\dot{p} = \delta(p - c - c_q q) + 2c_q\dot{q} + c_{qq}\dot{q}q \tag{A.18}$$

$$H_X = \lambda_1 f_X + \lambda_2 f_X = -\dot{\lambda_2} \tag{A.19}$$

$$-\dot{\lambda_2} = (p - c - c_q q)f_X e^{-\delta t} + \left[\frac{1}{f_w} - (p - c - c_q q)\right] f_X e^{-\delta t} \tag{A.20}$$

$$\dot{\lambda_2} = -\frac{f_X}{f_w} e^{-\delta t} \tag{A.21}$$

$$\dot{\lambda_2} = \left[\frac{-(f_{ww}\dot{w} + f_{wX}\dot{X})}{f_w^2} - (\dot{p} - 2c_q\dot{q} - c_{qq}\dot{q}q) - \frac{\delta}{f_w} + \delta(p - c - c_q q)\right] e^{-\delta t} \tag{A.22}$$

$$\dot{\lambda_2} = \left[-\frac{(f_{ww}\dot{w} + f_{wX}\dot{X})}{f_w^2} - \frac{\delta}{f_w}\right] e^{-\delta t} = -\frac{f_X}{f_w} e^{-\delta t} \tag{A.23}$$

$$\frac{f_{ww}}{f_w}\dot{w} = f_X - \delta - \frac{f_{wX}}{f_w}\dot{X} \tag{A.24}$$

$$\dot{w} = \left[\frac{f_X - \delta - \frac{f_{wX}}{f_w}\dot{X}}{\frac{f_{ww}}{f_w}}\right] \tag{A.25}$$

$$H_Y = 0 = -\dot{\lambda_3} \tag{A.26}$$

$$\dot{\lambda_3} = 0 \tag{A.27}$$

$$\dot{\lambda_3} = \left[-\frac{(g_{zz}\dot{Z} + g_{zZ}z)}{g_z^2} - (\dot{p} - 2c_q\dot{q} - c_{qq}\dot{q}q) - \frac{\delta}{g_z} + \delta(p - c - c_q q)\right] e^{-\delta t} \tag{A.28}$$

$$-\frac{(g_{zz}\dot{Z} + g_{zZ}z)}{g_z^2} - \frac{\delta}{g_z} = 0 \tag{A.29}$$

$$\frac{g_{zz}}{g_z}\dot{Z} = -\delta - \frac{g_{zZ}z}{g_z} \tag{A.30}$$

$$\dot{Z} = \left[\frac{-\delta - \frac{g_{zZ}}{g_z}}{\frac{g_{zz}}{g_z}}\right] \tag{A.31}$$

Appendix B. Ecopetrol information

Table B.2
Variables, their values, and sources of the numerical case.

Variable	Value	Unit	Source
Reserves (proven reserves, 1P)	1849	MMBO	Ecopetrol, (2015)
Original oil in place (OOIP)	42,053	MMBO	Ecopetrol, (2015)
Cumulative exploration reserve additions	5079	MMBO	Own calculation. Data source: Ecopetrol, (2015)
Corporative taxes	35	%	Ecopetrol, (2015)
Royalties	0	%	Assumption
Discount rate (weighted average cost of capital)	12	%	Ministry of Mines and Energy, Colombia (2014)
Domestic fuel Demand	330	MBOPD	BP (2015)
Price domestic fuel elasticity	−0.5		Kalymon (1975) and Brown and Phillips (1984)
Maximum daily production capacity	800	MBOPD	Ecopetrol (2014)
CO_2 supply cost (power plant)	$0.50 + 0.025*oil price	$/Mcf	Van't Veld and Phillips (2010)
Formation volume factor for CO_2	0.44	rb/Mcf	Assumption
Oil formation volume factor	1.1	rb/stb	Assumption

Appendix C. Colombian oil exploration

Table C.3
The Colombian exploration history between 1978 and 2006. Finding costs per barrel is a ratio between discovery reserves and exploration investment (Wright and Gallun, 2008).

Year	Reserve discoveries (MMBO)	Cumulative discovery reserves (MMBO)	Exploration investments (million US$ 2013)	Finding costs ($US/BO 2013)
1978	0.0	1668.4	203.4	
1979	95.8	1764.2	368.1	3.80
1980	168.7	1932.9	418.9	2.48
1981	26.1	1959.0	610.7	23.40
1982	130.8	2089.8	619.1	4.73
1983	80.6	2170.4	226.5	2.81
1984	540.6	2711.0	231.7	0.43
1985	57.7	2768.7	436.3	7.56
1986	44.8	2813.5	237.5	5.30
1987	157.0	2970.5	290.8	1.85
1988	200.9	3171.4	401.5	2.00
1989	42.6	3214.0	331.9	7.79
1990	46.5	3260.5	301.7	6.49
1991	57.0	3317.5	271.9	4.77
1992	1484.7	4802.2	566.7	0.38
1993	13.8	4816.0	500.4	36.26
1994	5.0	4821.0	302.2	60.44
1995	14.7	4835.7	436.7	29.71
1996	0.0	4835.7	415.0	
1997	0.0	4835.7	506.7	
1998	92.9	4928.6	511.7	5.51
1999	4.1	4932.7	216.1	52.72
2000	13.2	4945.9	145.4	11.02
2001	27.0	4972.9	359.6	13.32
2002	33.6	5006.5	260.1	7.74
2003	6.6	5013.1	233.1	35.31
2004	23.7	5036.8	262.1	11.06
2005	19.0	5055.8	305.2	16.06
2006	23.2	5079.0	397.6	17.14

Appendix D. Lifting cost

Table D.4
Lifting cost, production and reserves of Ecopetrol (2016).

Year	Lifting cost (US$)	Lifting cost (US$ 2015)	Production (MBOEPD)	Reserves (MMBO)
2005	3.26	3.96	376	1610
2006	5.23	6.15	385	1558
2007	7.24	8.28	399	1486
2008	8.33	9.17	447	1387
2009	8.27	9.14	521	1878
2010	9.83	10.68	616	1714
2011	10.43	10.99	754	1857
2012	11.93	12.32	754	1877
2013	11.57	11.77	788	1972
2014	11.29	11.30	755	2084
2015	7.40	7.40	761	1879

Appendix E. CO_2-EOR's models: Kinder Morgan - San Andres

Table E.5
Kinder Morgan - San Andres. The Kinder Morgan - San Andres model is based on the CO_2 project of Wasson-Denver San Andres (DSA) in the Permian Basin of West Texas (Kinder Morgan Inc.). The DSA project is one of the largest CO_2 projects in the world and has been injecting CO_2 since 1983 (Cook, 2012).

Year	Cumulative injected CO_2 (%HCPV)	Cumulative produced CO_2 (%HCPV)	Cumulative injected water (%HCPV)	Purchased CO_2 (millions US$)	Cumulative purchased CO_2 (millions US$)	Cumulative EOR recovery (%HCPV)	EOR recovery (MBO)
1	14.0	1.1	0.0	33,361.09	33,651.09	0.2	92.52
2	24.8	5.2	3.2	17,412.03	51,063.12	2.1	799.01
3	35.5	10.8	8.6	13,189.35	64,252.47	4.2	878.91
4	43.8	15.2	14.2	10,296.03	74,548.50	6.1	777.98
5	53.7	21.6	20.3	9097.00	83,645.50	8.0	803.21
6	60.5	27.3	27.5	2971.51	86,617.02	9.6	664.44
7	63.7	29.7	40.3	2137.40	88,754.42	11.1	668.64
8	64.8	30.6	53.2	234.59	88,989.01	12.2	462.58
9	65.7	31.6	68.3	52.13	89,041.15	13.2	395.30
10	66.5	32.3	81.5	0.00	89,041.15	13.8	264.93
11	67.2	33.0	94.8	52.13	89,093.28	14.3	201.85
12	67.9	33.7	110.1	26.07	89,119.34	14.7	176.62
13	68.5	34.3	123.5	26.07	89,145.41	15.1	168.21
14	69.2	35.1	138.8	0.00	89,145.41	15.7	239.70
15	69.9	35.7	152.1	0.00	89,145.41	16.1	172.42
16	70.6	36.4	167.5	26.07	89,171.48	16.5	159.80
17	71.1	36.9	180.9	0.00	89,171.48	16.7	113.54
18	71.7	37.5	196.3	26.07	89,197.54	17.0	117.75
19	72.3	38.1	209.7	26.07	89,223.61	17.2	88.31
20	72.9	38.6	225.2	0.00	89,223.61	17.5	92.52

Appendix F. CO_2-EOR's models: Kinder Morgan - Morrow

Table F.6
Kinder Morgan - Morrow Model: The Kinder Morgan - Morrow Model is based on the CO_2 project of Postle-Morrow (PM) in the Oklahoma panhandle (Kinder Morgan, 2002). In addition, Cook (2012) projected the analog model of Kinder Morgan Morrow to 2.98 HCPV.

Year	Cumulative injected CO_2 (%HCPV)	Cumulative produced CO_2 (%HCPV)	Cumulative injected water (%HCPV)	Purchased CO_2 (millions US$)	Cumulative purchased CO_2 (millions US$)	Cumulative EOR recovery (%HCPV)	EOR recovery (MBO)
1	7.0	0.3	7.0	17,359.90	17,359.90	0.4	147.19
2	15.2	1.8	14.9	17,464.16	34,824.05	1.5	479.40
3	22.3	4.2	21.7	12,433.44	47,257.49	3.0	630.80
4	30.6	7.8	29.4	12,172.78	59,430.27	5.0	828.44
5	37.9	11.2	36.1	10,035.38	69,465.65	6.6	698.08
6	43.8	15.0	46.2	5630.24	75,095.88	8.3	689.67
7	46.7	17.9	57.3	0.00	75,095.88	9.5	504.64
8	49.7	20.9	70.3	0.00	75,095.88	10.6	492.02
9	52.0	23.2	82.0	26.07	75,121.95	11.5	370.07
10	54.4	25.6	95.6	0.00	75,121.95	12.4	353.25
11	55.9	27.1	106.1	0.00	75,121.95	12.9	227.09
12	57.7	28.9	120.4	0.00	75,121.95	13.5	256.52
13	59.0	30.3	135.0	0.00	75,121.95	14.0	206.06
14	60.0	31.2	148.0	0.00	75,121.95	14.3	138.77
15	60.8	32.0	163.2	52.13	75,174.08	14.6	117.75
16	61.4	32.6	176.6	52.13	75,226.21	14.8	84.11
17	61.9	33.1	192.1	78.20	75,304.41	15.0	71.49
18	62.3	33.4	205.8	78.20	75,382.61	15.1	46.26
19	62.6	33.6	221.4	104.26	75,486.87	15.2	42.05
20	62.8	33.8	235.2	52.13	75,539.00	15.3	29.44

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