Tax Effects upon Oil Field Development in Venezuela.

Osmel Manzano*

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Abstract

Important reforms have been made to the oil sector tax code in Venezuela. Given its diversity of oil resources, there was a concern that some resources were not being exploited because of the structure of the tax code. This paper uses traditional theoretical models to review these reforms. Then, a panel of 821 Venezuelan oil fields was used to estimate the effects of the reforms. The major conclusion reached is that reforms based on the development of marginal fields -fields that will not produce because of the tax structure- may overlook the distortions generated by the tax system in non-marginal fields, distortions that can be greater than is the case in marginal fields.

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One of the singular characteristics of the Venezuelan oil sector is its diverse resource base. Current reserves in Venezuela range from extra-heavy oil and what is called "*bitumen*"[1], to light crudes, comparable to the WTI or Brent crude. Consequently, the major concern in Venezuela is whether the current tax system allows for the development of this resource base, rather than whether each field is being developed to its maximum or not[2].

As a consequence, important changes have been made in recent years to the tax system in Venezuela. The economics and political economy of oil production in Venezuela is, of course, well-documented[3]; basically, the regulation framework has been the same since 1944, except for changes in tax rates. Petróleos de Venezuela (hereinafter PDVSA)[4] pays a 1/6 royalty and income tax at a rate of 67% (the royalty is tax deductible). In 1991, Operating Agreements ("*convenios operativos*") were introduced, and marginal fields that, under normal circumstances, were not going to be exploited by PDVSA, were instead given to private companies - companies that would produce the oil for a certain fee per barrel. Next, in 1993, associations for heavy and extra-heavy oil production were introduced (*"asociaciones estratégicas"*). One could describe these crudes in two ways: either as low-commercial-value crudes; or as those requiring a special "pre-refining" that would make them suitable for any refinery and, consequently, characterize them as high-production-cost crudes. Around 60% of the reserves discovered in Venezuela represent one or the other of these crudes; thus it was argued that, thanks to the existing tax structure, they would not be exploited, leading to a new regulation being approved both for their extraction and the production of off-shore gas[5]. In 1996, new areas were given over to private investors for exploration and exploitation. This was termed the "opening-up" of the oil sector (*"apertura",* and I am going to refer them as exploration at risk); however, although these areas were supposed to possess light and medium crudes, little or no exploration was actually carried out. Once again, it was argued that - thanks to the current tax system - there were few incentives to do

[1]Heavy Oil associated with other elements.

[2]The latter is probably the major concern in most other countries and, therefore, in most of the literature. See, for example, Lund [15], Kemp [10] and Kemp and Rose [12]. In these texts the main concern is that fields involving high developmental costs are not going to be exploited.

[3]A summary of the history of Venezuelan oil can be gotten in España and Manzano [3] and [4]. A good view of the different aspects and the different views that exists about these topics can be gotten with three papers: Espinasa [5], Mommer [18], and Rodriguez and Sachs [22].

[4]The oil company created in 1975, following the nationalization of the oil sector.

[5]Actually, the project for off-shore gas was the first approved by Congress.

so; once again, a new tax system was introduced in an attempt to remedy this.

This paper reviews the traditional Hotelling [7] model and introduces different taxes in order to analyze the effects of changes in the tax system upon oil exploitation. In this regard, recent literature has focused on the market power of resource producers and how to induce efficiency in domestic resource markets.[6] However, as explained before, in countries like Venezuela the government is more concerned with the development of the oil sector and the collection of revenue coming from the sector. Domestic markets are usually subsidized and only represent a relatively small fraction of the total production of oil. For that reason I will not focuss on this area.

Then, a panel of 821 Venezuelan oil fields is used top estimate the previous model and measure those effects. There are two different approaches to estimate those values. The first approach would use data from the situation before the taxes were introduced and data from the situation after and compare both cases. Alternatively, knowledge of the oil sector can be used to estimate the situations before and after a tax reform. In the Venezuelan case, the reforms are relatively recent given the characteristics of the oil industry.[7] Therefore the latter approach would be used.

This approach has already been used in the past to study the effects of taxes on oil field development.[8] However, in the previous literature producers are not allowed to adjust the amount of reserves developed and/or the production path over time in reaction to the taxes introduced. In this chapter, I will estimate the parameters needed to calibrate a model of the oil sector for the panel of 821 fields, and predict with that model the effects of the reforms. This approach allows for the agents to adjust to the presence and the changes of the tax code.

The primary conclusion is that tax reforms based solely upon the effects of the tax code on marginal fields overlooks the distortions that the tax system creates in non-marginal fields, which can be even greater[9].

The paper is organized as follows: Section 1 presents a review and extension to our case of the theory on the effects of taxes upon oil production. Then a discussion of the singular characteristics of the Venezuelan case is done in section 2. A model of the Venezuelan oil sector is done in section 3, followed by

[6] See Karp and Livernois [9], Rowse [23] and Semmler [25].

[7] The first reforms were introduced at the beginning of the 1990's.

[8] See for example Kemp [10] and [11], Kemp and Rose [12] and Lund [15]. For the Venezuelan case see Office of the Chief Economist [19] and Smith [26].

[9] It is importatn to clarify, that in this research it will be called marginal those fields that were not active under the past tax structure and will produce under the new tax code.

the evaluation of the tax reforms in section 4. Finally, section 5 presents some concluding remarks.

1. The Theory on Oil Production and Taxes.

In this section a review and extention to our particular case of the theory on the effects of taxes on oil production is done[10]. Subsection 1.1 reviews the Hotelling model. Next, the effects of the two main tax instruments used in Venezuela - income tax and the royalty - upon the amount of reserves developed and the entry conditions are analyzed, in subsections 1.2 and 1.3, respectively.

1.1. The Producer's Problem

The problems of the producer of a natural resource were developed by Hotelling [7] in its seminal work[11]. Basically, the producer maximizes:

$$\max_{\overline{R},q,T} V = \int_0^T \pi\left(q\right) e^{-rt} dt - C\left(\overline{R}\right) \tag{1.1}$$

$$\text{subject to} \quad \begin{aligned} \dot{R} &= -q \\ R(0) &= \overline{R} \\ R(T) &= 0 \end{aligned}$$

where π represents profits, q the extraction rate, r the discount rate, C the development and exploration cost and $\overline{R}$ reserves.

In this paper, Iam going to assume that:

$$\pi\left(q\right) = pq - c\left(q\right)$$

which implies that:

[10]Given the volatility exhibited by the price of oil, a branch of the literature has been shifting its attention towards the use of option value techniques (See, for example, Lund [15] and Zhang [27]. Also, Sansing [24] studies the risk sharing properties of alternative tax instruments). Instead, I choose Hotelling for two reasons: (1) I find important tax distortions with the Hotelling model and (2) the implications derived for option value models are less important in Venezuela because the oil exploration is not characterized by large sunk-fixed costs, as in the North Sea areas, for example.

[11]I am using Heaps and Helliwell's [6] formulation here.

1. There are two different types of costs involved in producing oil: (1) $C(\overline{R})$ or the cost, in money, of period 0 of the reserves. This is basically made up of exploration expenses, and may include such costs as connecting to the distribution infrastructure, etc.[12]. And (2) $c(q)$, which represents the costs of oil extraction *per se*, and includes labor costs, gas injection, etc.[13].

2. This problem assumes that oil companies are price takers, an assumption that is not so very removed from reality, at least not from the point of view of PDVSA.[14].

The producer will choose the extraction path (q and T) and the amount of reserves that maximizes the profit function subject to the constraint, which implies that the total amount extracted should be equal to the reserves at the beginning of the exploitation.

Clearly, we can solve this problem in two steps. Firstly, for the optimal path given $\overline{R}$, and then, for the optimal $\overline{R}$. In the first step, we must use the maximum principle to solve it, and the first order conditions would be:[15]:

$$\frac{\partial \pi}{\partial q} e^{-rt} = \lambda \tag{1.2}$$

where λ - the Lagrangian multiplier - can be interpreted as the shadow price, or user cost, of the reserves. This solution implies that the discounted marginal profit of all periods should be equal, which means that production follows a declining path - assuming that $c''(q) > 0$.

We then have the following Transversality Condition:

[12] $C(\overline{R})$ will be the present value of all the *past* expenditures in exploration and development of the field.

[13] There is an important branch of literature on the nature of $c(q)$. In particular, Pindyck [21], who assumes it depends on the amount of reserves present at the time of extraction, and also introduces the possibility of adding reserves through the lifetime of the field. However, one can safely say that the simple framework used in this research will be sufficient to ascertain the affects of the tax system on the development of different kind of fields.

Models like Pyndick [21] will help us to understand the affects of the tax system on the timing of extraction and the timing of field development, which, though non-trivial, are not the focus of this research.

[14] It is important to differentiate the fact that there are oil reserves in few countries from the fact that there are numerous oil companies exploiting those reverses. Here we are concerned with the behavior of those firms, which I can assume to be competitive firms.

[15] The complete solution to the problem is in the Appendix A.

$$q(T) = \underline{q} \tag{1.3}$$

where $\underline{q}$ represents the point where the marginal profit is equal to the average profit or, similarly, where average profits are maximized. In our particular case (where firms are price takers), this condition implies that $\underline{q}$ is the point where the average cost is equal to the marginal cost. Consequently, 1.2 and 1.3 imply that production will decline until it reaches $\underline{q}$.

Finally, once the optimal path is solved, we can solve for the optimal amount of reserves, getting:

$$\lambda^* = C'(\overline{R}) \tag{1.4}$$

The problem of the government will be to try to capture V. The fact that V exists and is positive is because the fields exploited are infra-marginal. Since the law specifies that the owner of the field is the state, the government assumes that those rents are its property. Consequently, it will introduce taxes in order to capture V.

Ideally, the first and best solution would be an auction for the field. However, many issues arise from this:

1. Political Economy Issues: Governments cannot commit to not changing taxes in the future - in particular, when prices are high - and, sometimes, to not possibly nationalizing the sector.

2. There may be liquidity constraints regarding the firms.

As a consequence, alternative instruments are used. The most common are royalties and income taxes.

1.2. Tax effects on reserves developed

A first alternative with which to check whether the current tax system affects, negatively, the development of certain kinds of fields is to check the effects of the tax system, by field, on the amount of reserves developed. One will do this in this subsection.

1.2.1. Royalty effects

The royalty is similar to a revenue tax; however, it is called a royalty because the government is the owner of the oil field and thus collects its royalty from the business.

The affect of Royalties is well-documented in Heaps and Heliwell [6]. Consequently, I am merely going to summarize the results already presented there and come straight to the point I am most interested in - namely, the effects of a royalty upon the discrimination between different fields. Using the same model I introduced in the previous section, if we introduce a royalty - such as that in the Venezuelan tax code (i.e., 1/6 of the production valued at market price) - the new maximization problem becomes:

$$\max_{\overline{R},q,T} V = \int_0^T \left[pq\left(\mathbf{1}-\boldsymbol{\rho}\right) - c\left(q\right)\right] e^{-rt} dt - C\left(\overline{R}\right) \tag{1.5}$$

$$\text{subject to} \quad \begin{aligned} &\dot{R} = -q \\ &R(0) = \overline{R} \\ &R(T) = 0 \end{aligned}$$

where ρ represents the royalty rate.

The solution for this problem implies that:

$$\left[p\left(1-\rho\right) - c'\left(q\right)\right] e^{-rt} = \lambda, and \tag{1.6}$$

$$\left[p\left(1-\rho\right) - c'\left(q_T\right)\right] e^{-rT} - C'\left(\overline{R}\right) = 0 \tag{1.7}$$

So, if we compare equation 1.4 with equation 1.7 it is clear that this differs from the first-best solution. If we rearrange 1.4 and 1.7:

$\left[p - c_o'\left(q_T\right)\right] e^{-rT} - C'\left(\overline{R}\right) = 0$, non-distortionary solution

$\left[p - c_o'\left(q_T\right)\right] e^{-rT} - C'\left(\overline{R}\right) = p\rho e^{-rT}$, is the new solution.

This means that less reserves are going to be developed. The reduction will depend on the shape of $C(\overline{R})$. and, if development costs increase sharply, the reduction in reserves will be less marked. This will be shown below.

Another consequence is the tilting of the production path - production is shifted from closer periods to further ones. The reason for this is that firms try to minimize the net present value of the tax burden, thus postponing production delaying tax payments. An alternative way of seeing it is that the shadow price of the reserves is reduced. As I mentioned before, all the previous results are already described in Heaps and Heliwell [6][16]

Besides the previous results, most of the literature on the topic has thus far focused on the tax burden[17]. I am going to refer to this tax burden as the Net Present Tax Rate (NPTR)., and we can check it for this case:

$$NPTR = \frac{\int_0^T pq\rho e^{-rt}dt}{\int_0^T \left[pq - c\left(q\right)\right] e^{-rt}dt - C\left(\overline{R}\right)} = \rho \frac{\int_0^T qe^{-rt}dt}{\int_0^T \left[q - \frac{c(q)}{p}\right] e^{-rt}dt - \frac{C\left(\overline{R}\right)}{p}} \qquad (1.8)$$

Looking at 1.8, we see a result widely reported in this area of the literature: i.e., that the tax rate is going to be higher for those crudes with lower value (p), higher production costs ($c_o\left(q\right)$) and higher development costs ($C\left(\overline{R}\right)$).

However, this analysis does not take into account the fact that producers will adjust when they face a tax; consequently, we cannot draw conclusions regarding just which fields are going to be more affected based solely upon the analysis of the $NPTR$.[18] For this reason, I derive the change in the amount of reserves developed from the change in the royalty rate[19]. From here I can calculate how that derivative changes with respect to the parameters that we?re interested in.

I get the following results[20]:

$$\underset{(a)}{\frac{\partial \frac{dR}{d\rho}}{\partial C''(\overline{R})} > 0} \quad \underset{(b)}{\frac{\partial \frac{dR}{d\rho}}{\partial c''(q_t)} > 0} \quad \underset{(c)}{\frac{\partial \frac{dR}{d\rho}}{\partial p} < 0} \quad \underset{(d)}{\begin{array}{ll} \frac{\partial \frac{dR}{d\rho}}{\partial c'(q_t)} = 0, & \forall\, t \neq T \\ \frac{\partial \frac{dR}{d\rho}}{\partial c'(q_T)} > 0 & t = T \end{array}} \qquad (1.9)$$

[16] In particular, Heaps and Heliwell [6] develop, in detail, the change in the optimal path.

[17] Kemp [10] and Kemp and Rose [12], for example. This is not a bad approach if you consider that most of that literature was written to consider the tax affects on oil field development in places like the North Sea, where adjusting is costly. A detailed explanation of the characteristics of oil exploitation in the North Sea can de found in Lund [15].

However, this is not the case in Venezuela, where the relatively easier conditions make it easier for the producer to adjust.

[18] The fact that producers do adjust to the presence of taxes is already mentioned in Livernois [14], where the effects of tax brackets on the production path are discussed.

Alternatively, Jacoby and Smith [8] also allow producers to adjust. In their case though, they parametrize a model for the offshore gas sector in the United States, and check the effects of taxes and price regulation.

[19] The derivation can be found in Appendix A

[20] There are some general conditions for 1.9.c and 1.9.d to be true. See Appendix A, for an explanation.

The results from 1.9.a and 1.9.b imply that reserves in fields where costs increase at the fastest rate - either in production or development - are going to be less affected by the royalty. A possible reason for this is that the royalty is going to be an "additional cost" and is going to be proportionally less relevant in cases where development costs or operating costs increase faster. Alternatively, and using a common description used in Public Finance literature, inelastic agents bear most of the burden, but then also alter less as a consequence of the tax imposed. Consequently, if we are interested in the amount of reserves not developed because of the tax structure, these agents are going to reduce their reserves less than the more elastic agents do. As I mentioned before, these results are similar to well known results from the standard literature in public finance concerning inelastic agents. In fact, the development costs result is already mentioned in Heaps and Heliwell[6].

The result in 1.9.c contravenes conventional wisdom. It means that the reduction in reserves developed in high value fields as a consequence of the royalty is larger than is the case with low value fields. The reason for this is that high value fields are going to lose more value relative to the costs of developing those crudes than are low value fields. Consequently, there will be a larger reduction in reserves.

Finally,1.9.d implies that the only channel through which the marginal cost affects the value of the derivative is through the marginal cost of q_T.. Consequently, the effect is small.

We can show these effects with a simple example. Let us assume $c(q) = a + bq + cq^2$ and $C(R) = dR^2$. Figure 1.1 shows us the result from 1.9.a. In the horizontal axis we have R, and in the vertical we measure $C'(R)$ and λ. The difference between $C1'(R)$ and $C2'(R)$ is that $d2 > d1$. λ and $\lambda\tau$ show us the value of λ (the Lagrange multiplier) both without and with royalty, respectively. It is clear from the graph that the distance between A and A' is greater than the distance between B and B'. Why is that? It is because $C2'(R)$ changes faster, and the adjustment can be produced with only small movements of R. In Figure 1.2, the difference between $\lambda 1$ and $\lambda 2$ is that $b2 > b1$. Again, the distance between A and A' is greater than the distance between B and B', showing the result from 1.9.b. Here, $c2'(q)$ changes faster and, once more, small movements - in this case of q, - will produce the adjustment. Clearly, a similar graph will show us the effects of 1.9.c and 1.9.d.

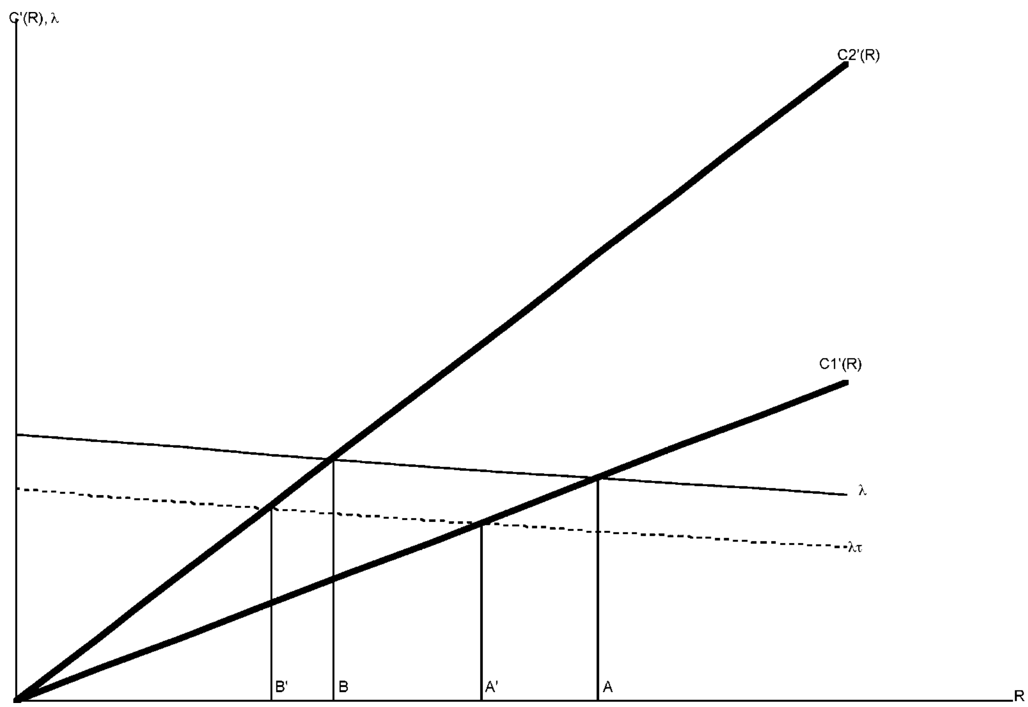

Figure 1.1: Effects of Royalty: Different Development Costs.

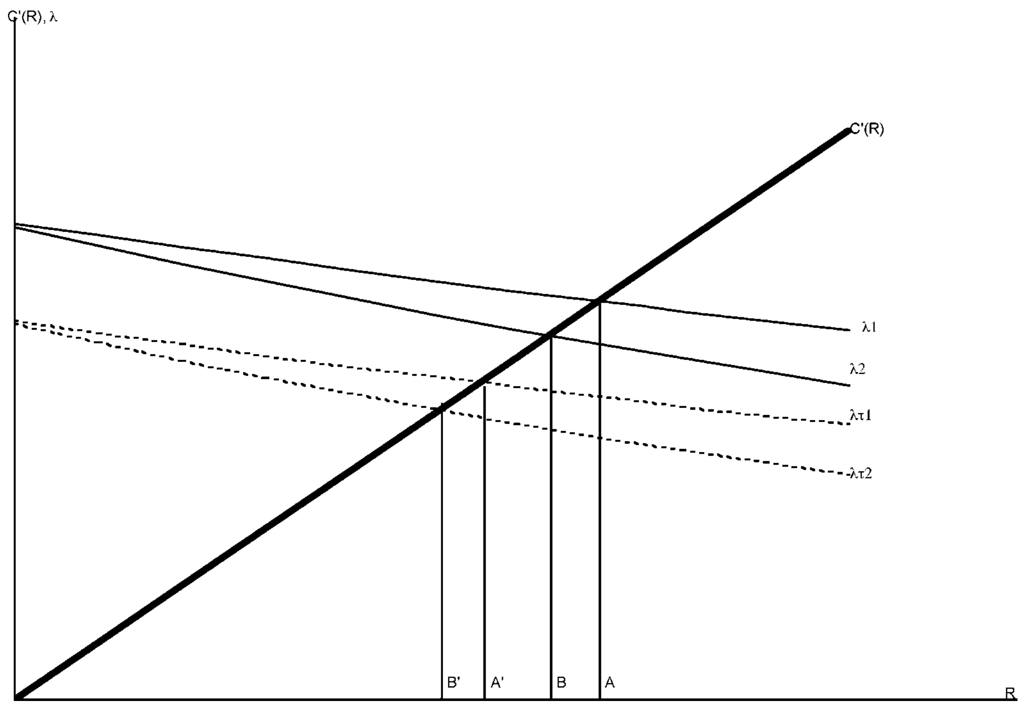

Figure 1.2: Effects of Royalty: Different Extraction Costs.

1.2.2. Income Tax effect

It is clear that if we have a tax system that allow us to deduct all expenses, the optimal solution will not be affected by that system [21]. However, most of the tax codes do not recognize, or allow for, the amortization of these $C\left(\overline{R}\right)$. Instead, they offer a tax credit for them. Therefore, the oil producer faces the following problem:

$$\max_{\overline{R},q,T} V = \int_0^T \left[\left(pq - c_o\left(q\right) \right) \left(\mathbf{1} - \boldsymbol{\tau} \right) \right] e^{-rt} dt - \left(\ \mathbf{1} - \boldsymbol{\tau} \cdot \mathbf{t}_c \right) C\left(\overline{R}\right) {}^{22,23} \qquad (1.10)$$

$$\text{subject to} \quad \begin{array}{l} \dot{R} = -q \\ R(0) = \overline{R} \\ R(T) = 0 \end{array}$$

where τ represents the tax rate, and t_c the tax credit given[24].

The solution for this problem implies that:

$$\left(1 - \tau\right)\left(p - c_o'\left(q\right)\right) e^{-rt} = \lambda, and \qquad (1.11)$$

$$\left(1 - \tau\right)\left[p - c_o'\left(q_T\right)\right] e^{-rT} - \left(1 - \tau \cdot t_c\right) C'\left(\overline{R}\right) = 0 \qquad (1.12)$$

[21]In this case 1.1 will be multiplied by $(1-\tau)$, and it will disappear once we set the first order conditions.

[22]The expression is the rearrangement of: $\int_0^T \left[\left(pq - c_o\left(q\right)\right)\right] e^{-rt} dt - C\left(\overline{R}\right) - \tau \cdot \left\{\int_0^T \left[\left(pq - c_o\left(q\right)\right)\right] e^{-rt} dt - C\left(\overline{R}\right) t_c\right\}$

[23]The reader will note that I have not included the royalty in the expression. I am trying to separate the affects of each tax instrument, and including it would change the expression to: $V = \int_0^T \left[\left(pq\left(1 - \rho\right) - c_o\left(q\right)\right)\left(1 - \tau\right)\right] e^{-rt} dt - \left(1 - \tau \cdot t_c\right) C\left(\overline{R}\right)$.The tax code in Venezuela allows for the deduction of the royalty from the income tax.

[24]This means that, for income tax purposes, you are allowed to deduct, as an expense, t_c of your investment in field development.

The reader familiar with the literature regarding investment and tax policy will see that the notation is slightly different from that used in such literature. For example, in that literature you might expect to find an expression like:

$\max_{\overline{R},q,T} V = \int_0^T \left[\left(pq - c_o\left(q\right)\right)\left(1 - \tau\right)\right] e^{-rt} dt - \left(1 - \Gamma\right) C\left(\overline{R}\right)$
where Γ represents the tax credit given for new capital added to the firm.

I used the formulation present in equation 1.10 in order to reflect the way that it is written according to Venezuelan law, as explained below.

Again, if we compare equation 1.4 with equation 1.12 it is clear that we are not in accordance with the first best solution. If we rearrange 1.4 and 1.12, we get:

$\frac{[p-c_o'(q_T)]e^{-rT}}{C'\left(\overline{R}\right)} = 1$, is the non-distortion solution, and

$\frac{[p-c_o'(q_T)]e^{-rT}}{C'\left(\overline{R}\right)} = \frac{1-\tau\cdot t_c}{1-\tau\cdot}$, is the new solution.

This means that, as long as $t_c < 1$, fewer reserves are going to be developed.

We can also repeat the traditional analysis for tax incidence, and get:

$$NPTR = \frac{\int_0^T \tau\left(pq - c_o\left(q\right)\right)e^{-rt}dt - \tau\cdot t_c C'\left(\overline{R}\right)}{\int_0^T \left[pq - c_o\left(q\right)\right]e^{-rt}dt - C\left(\overline{R}\right)} = \tau\left\{1 + \frac{C\left(\overline{R}\right)\left(1-\tau\cdot t_c\right)}{\int_0^T \left[pq - c_o\left(q\right)\right]e^{-rt}dt - C\left(\overline{R}\right)}\right\} \tag{1.13}$$

Note that the tax burden is higher than τ, because development costs are not allowed to be fully deducted.

The fields that will pay a higher tax rate are those that have a lower value, higher development costs and higher operating costs.

However, we have - once again - the same problem we had with royalties: this analysis does not take into account that producers will adjust when they face a tax. Consequently, we cannot draw conclusions regarding which fields are going to more affected solely as a result of analysis of the $NPTR$. For this reason, I am again going to derive the change to reserves with respect to the tax rate, and then derive it with respect to the parameters we are interested in [25].

I get the following results:

$$\underset{(a)}{\frac{\partial\frac{dR}{d\tau}}{\partial C''(\overline{R})} > 0} \quad \underset{(b)}{\frac{\partial\frac{dR}{d\tau}}{\partial c''(q_t)} > 0} \quad \underset{(c)}{\frac{\partial\frac{dR}{d\tau}}{\partial p} < 0} \quad \underset{(d)}{\frac{\partial\frac{dR}{d\tau}}{\partial c'(qt)} > 0} \tag{1.14}$$

We see that the results are similar to those in the royalty case.

The main difference here is that the marginal cost has a more direct affect. This is because the royalty is based only on the price, while the profit tax takes into account the cost of producing oil. Here, again, the result contravenes conventional wisdom in the sense that fields with lower marginal costs will reduce their level of reserves, as a consequence of the introduction of an income tax, more than do those with higher costs. The reason is that, in fields with lower

[25] Again, the reader is referred to the Appendix A.

costs, the government take with respect to development costs is going to be greater than is the case in fields with higher costs.

If we repeat the graphic example in section 1.2.1 we can see these results. A figure similar to Figure 1.1 will illustrate the result on 1.14.a, and a figure similar to Figure 1.2 will illustrate the last three results.

Is, then, the conventional wisdom as demonstrated in equations 1.8 and 1.13 erroneous?.

Not really. Firstly, the traditional approach says that the tax burden will be higher and this is true - inelastic actors bear the higher burden.

Secondly, in many cases, low value fields or fields where operational and/or development costs increase faster can be left undeveloped. In Figure 1.3 I provided an example of this situation, using the example in section 1.2.1 but changing the $C(R)$ function to $C(R) = dR$. The situation depicted in the Figure is that of 1.9 .c and 1.14.c. It is clear that, once you introduce a royalty or a tax, the low value field will not be developed. Similarly, we can construct examples mirroring the other conditions. However, in all these cases, the fall in reserves will be greater in the fields with high value, low cost or more slowly increasing development/operating costs. Consequently, it all depends on precisely what the focus of the study is - if it is on tax rates, the view in the traditional literature regarding which fields are more affected by the tax structure is valid[26]; alternatively, if it is based on the degree of reserves left undeveloped, this approach is more suited.

Finally, we would also like to consider which of both taxes have a greater impact on reserves developed. For that purpose, we would like to find the value of the difference between the change in reserves due to an increase in the tax rate and the change in reserves due to a change in the royalty rate. Following the standard approach in public finance, I calculate that difference when all the tax rates are equal to zero. The result is:[27]

$$sign\left(\frac{d\overline{R}}{d\tau} - \frac{d\overline{R}}{d\rho}\right)_{\rho=0,\ \tau=0,\ t_c=0} = sign\left[(p-1) - \frac{r}{q_T}\left(\int_0^T \frac{p}{c''(q_t)}dt - \int_0^T \frac{p - c'(q_t)}{c''(q_t)}dt\right)\right] \tag{1.15}$$

The expression is positive,[28] suggesting that reserves will fall more with the

[26] A common term used in this literature is that these taxes are “regressive” because low value fields pay the higher tax rates.

[27] This is based on the results presented in Appendix A.

[28] It is expected that $p > 1$, and it is clear that $p > p - c'(q_t)$.

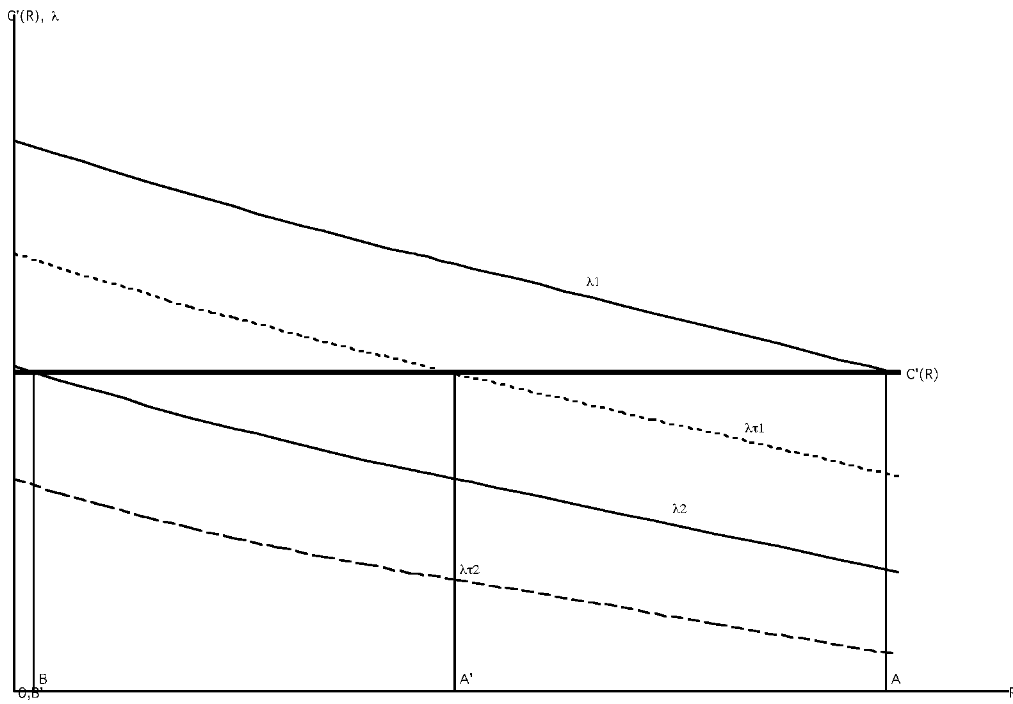

Figure 1.3: Effects of Taxes on Marginal Fields.

introduction of a royalty. However, equation 1.15 does not take into account that similar increases in the rates of both taxes will produce different amounts of revenues. For that reason I also calculate the value of the difference imposing equal tax collection with both taxes. The result is:

$$sign\left[\frac{d\overline{R}}{d\tau}\cdot\widetilde{\left(\frac{d\tau}{d\rho}\right)}-\frac{d\overline{R}}{d\rho}\right]_{\rho=0,\ \tau=0,\ t_c=0}=sign\left[(p-\Phi)-\frac{r\cdot p}{q_T}\left(\int_0^T\frac{1}{c''(q_t)}dt-\int_0^T\frac{\Upsilon_t}{c''(q_t)}dt\right)\right] \tag{1.16}$$

where $\widetilde{\left(\frac{d\tau}{d\rho}\right)}$ represents the change in tax that will raise the same revenue as a marginal change in royalty;[29] $\Phi=\frac{\int_0^T pqe^{-rt}dt}{\int_0^T[pq-c(q)]e^{-rt}dt}$ and $\Upsilon_t=\frac{p-c'(q_t)}{\frac{\int[pq-c(q)]e^{-rt}dt}{\int q_t e^{-rt}dt}}$.

The expression does not have a clear sign, but we can sign the expression for certain values of the parameters. First, as long as $pq-c(q)>1$, $(p-\Phi)>0$. Therefore, only in rare cases when the field has extremely low quality or high cost would the royalty affect the reserves less than the income tax.

On the second expression on the right-hand-side of 1.16, the expression represents the subtraction of two summations. The first one is a simple sum of $\frac{1}{c''(q_t)}$ and the other is weighted by Υ_t. Υ_t represents a ratio of the marginal profit of the barrel produced in t, compared to an average profit, but not the average profit of the reserves, but rather the average profit of the net present value of the reserves.[30] As production follows a declining path, this ratio would be increasing through time. Therefore the process will put more weight in those periods where $\frac{1}{c''(q_t)}$ is higher. Nevertheless, $\Upsilon_t<1$ in the first periods and will not necessarily reach a value greater than one. In spite of that, the expression in the parenthesis of the second term on the right-hand-side of 1.16 should be expected to be negative and have a positive effect on the sign. However, it is expected that $\frac{r\cdot p}{q_T}\to 0$. Therefore, this term will change the sign of the whole right-hand-side only when $c''(q_t)\to 0$.

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[29] This is done by imposing the condition $\int_0^T\rho\cdot pqe^{-rt}dt=\tau\int_0^T[pq-c(q)]e^{-rt}dt$, and using the implicit function theorem to find $\left(\frac{d\tau}{d\rho}\right)_{\rho=0,\ \tau=0,\ t_c=0}$.

[30] The average profit per barrel developed is equal to $\frac{\int_0^T[pq-c(q)]e^{-rt}dt}{\overline{R}}<\frac{\int_0^T[pq-c(q)]e^{-rt}dt}{\int_0^T q_t e^{-rt}dt}$.

We can conclude then, that in general the income tax will affect the amount of reserves developed less than the royalty. The royalty will have less effect on the amount of reserves developed when it is easier for producers to shift production between periods. In other words, there are two margins that can be affected by taxes: the production path and the development of reserve.. Income taxation only affects one of them, the amount of reserves developed. The royalty affects both. If producers can adjust easily the production path, they would be able to adjust less on the other margin.

1.3. Tax effects on entry conditions

The next step is then, to explore the effects of the tax system on the entry of oil firms into different kinds of fields. This will be carried out in this subsection.

One of the problems faced when carrying out this analysis is the need to assume certain functional forms in order to complete it properly. Consequently, I am going to rely more on graphs - and the changes in relative positions in those graphs - in this section, rather than focus on absolute magnitudes in projects left undeveloped.

This subsection is divided as follows: Subsection 1.3.1 will explain the alterations made to our original model in Section 1.1 , and then subsections 1.3.2 and 1.3.3 will explain the effects of the royalties and income tax.

1.3.1. New "dimensions" added.

The first step is to divide the space into dimensions representing the differences between the projects that we are interested in. I chose three properties relevant to the Venezuelan situation: namely, the quality of crude, the degree of difficulty in extracting, and the degree in difficulty in finding the crude in the area.

As a consequence, our problem in 1.1 becomes:

$$\max_{\overline{R},q,T} V = \int_0^T \pi\left(q, \boldsymbol{\Theta}, \boldsymbol{\mu}_1\right) e^{-rt} dt - C\left(\overline{R}, \boldsymbol{\mu}_2\right) \tag{1.17}$$

$$\text{subject to} \quad \begin{aligned} \dot{R} &= -q \\ R(0) &= \overline{R} \\ R(T) &= 0 \end{aligned}$$

where the new variable Θ will represent the oil quality[31], and μ_1 and μ_2 will represent the ease of extracting oil and the ease of finding it respectively[32].

For this purpose we assume that:

$$\pi(q, \Theta) = \Theta \cdot p \cdot q - c(q, \mu_1) \tag{1.18}$$
$$\text{for } \frac{\partial c}{\partial \mu_1} < 0$$

implying that higher the Θ, better the quality and, therefore, higher the price. On the other hand, higher $\mu_{1,}$ results in more easy oil extraction, and therefore lower the cost.

We also assume that:

$$C\left(\overline{R}, \mu\right) = F + f\left(\overline{R}, \mu_2\right) \tag{1.19}$$
$$\text{for } \frac{\partial C}{\partial \mu_2} < 0$$

implying that higher μ_2, results in more easy oil finding, and therefore cheaper development cost.

This representation in equation 1.19 divides the cost of developing reserves into fixed cost (F) and variable cost ($f\left(\overline{R}, \mu_2\right)$), which is not so far from reality. There are some development costs that can be considered fixed - that do not depend on the amount of reserves developed - such as seismic exploration, maintenance of the exploration infrastructure, etc. And there are others that are going to depend on the degree of reserves developed -such as the number of exploratory wells drilled. Equivalently, it can be said that there exists a production function for reserves with fixed and variable costs, where μ_2 represents the level of increases in the amount of reserves developed per unit of "input" (wells) used[33].

[31]The effects of taxation on quality selection in the production of natural resources is discussed in Krautkraemer [13]. however, he focused on minerals where he consequences are different for geological reasons.

[32]I switched to "easiness" as this approach is more suitable for graphic illustration, as seen later in this section.

[33]A practical interpretation for μ_2 can be the size of the field. It is well known that fields can be of different sizes - it is easier to find marginal reserves in big fields than it is in smaller fields.

The objective is then, to find the combinations of Θ, $\mu_1$and μ_2 that produce zero profit, assuming that there are fixed costs of development. In other words, we substitute 1.18 and 1.19 in 1.17 and want to find the combinations of Θ, $\mu_1$and μ_2 that makes the next equality hold:

$$\int_0^{T^*} [\Theta \cdot p \cdot q^* - c(q^*, \mu_1)]\, e^{-rt} dt - F - f\left(\overline{R}^*, \mu_2\right) = 0 \qquad (1.20)$$

for q^*, $\overline{R}^*$ and T^* being the values that solve 1.17.

This gives us a plane on the space of Θ, $\mu_1$and μ_2 that will divide it between profitable and not profitable fields. For the sake of simplicity, I will focus only on Θ and μ_2.

This is illustrated in Figure 1.4. In this figure, the Y axis measures the easiness finding oil space,and the X axis measures the quality. As shown in equation 1.20 there is a negative relationship between Θ and μ: if we lower oil quality, we need to increase the easiness finding oil to maintain zero profits. This is shown by the thick line, which represents the level curve for 1.20. In the figure, the projects to the right of, and above, the curve will operate. They have either higher quality or easier to find reserves than do projects that make zero profits and will thus produce positive profits. On the other hand, projects to the left of, or below, the curve will not produce. They have either lower quality or harder to find reserves than do projects that make zero profits, and would thus make negative profits if they were to operate. By the envelope condition, we can calculate the slope of the curve:

$$\frac{\partial \mu_2}{\partial \Theta} = \frac{\int_0^{T^*} p \cdot q^* e^{-rt} dt}{f_{u_2}\left(\overline{R}^*, \mu_2\right)} < 0, \qquad (1.21)$$

since $f_{u_2}\left(\overline{R}^*, \mu_2\right) < 0$

With this framework we introduce taxes and check to see how the Zero-Profit-Condition (hereinafter, ZPC) shifts. The ideal tax will avoid these shifts. This can be done with a "pure" profits tax[34] and any other tax will shift the curve.

An alternative is a *lump-sum* tax. It will change 1.20 to:

$$\int_0^{T^*} [\Theta \cdot p \cdot q^* - c(q^*, \mu_1)]\, e^{-rt} dt - F - f\left(\overline{R}^*, \mu_2\right) - \text{"}lump - sum\text{"} = 0 \qquad (1.22)$$

[34]A tax of the form $(1 - \tau_{pure}) \cdot V$.

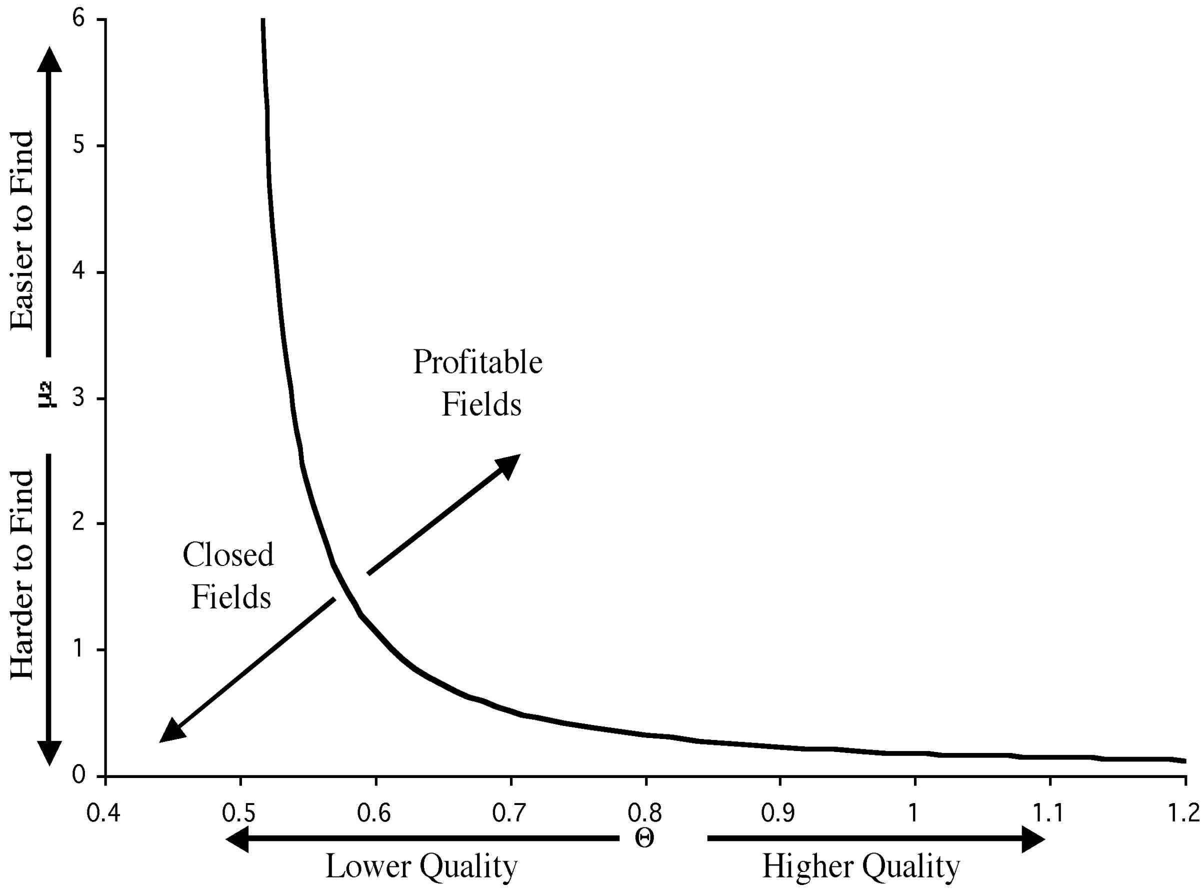

Figure 1.4: Zero Profit Condition for Field Development

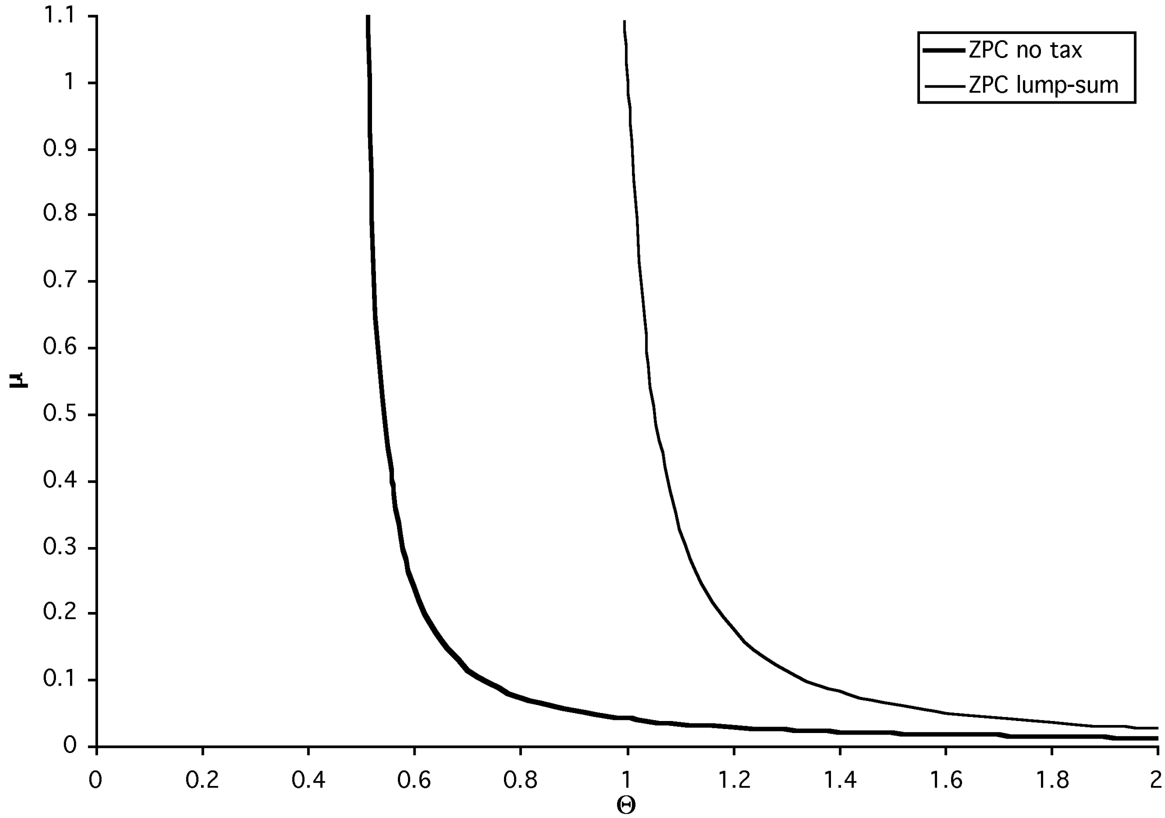

Figure 1.5: Zero Profit Condition: Introducing a lump-sum tax

We see that this tax shifts the curve upwards, but without changing the slope of it, represented in 1.21. In Figure 1.5, I show the zero-profit conditions with and without a lump-sum tax[35]. This implies that fields of lower quality and where oil is harder to find will be left out. However, there will be no bias against any of them in the process because the slope of both curves is the same.

Similar conclusions can be reached by repeating the analysis for the other two combinations of fields characteristics defined here.

[35]The amount of the tax chosen is equal to the amount of economic profit generated by a field of $\mu = 1$ and $\Theta = 1$. This means that:

$$\text{“}lump - sum\text{''} = \int_0^{T^*} \left[p \cdot q^* - c(q^*)\right] e^{-rt} dt - F - f\left(\overline{R}^*\right)$$

for q^*, T^*, $\overline{R}^*$ being the solution for 1.17 with a profit function like 1.18 with $\mu = 1$ and $\Theta = 1$.

1.3.2. Royalty effects

Basically, 1.18 changes to:

$$\pi(q, \Theta) = (1 - \rho)\, \Theta \cdot p \cdot q - c(q, \mu_1) \tag{1.23}$$

where ρ is again the royalty rate.

It is clear that not only the ZPC shifts, but also that the slope changes to:

$$\frac{\partial \mu_2}{\partial \Theta} = (1 - \rho) \frac{\int_0^{T^*} p \cdot q^* e^{-rt} dt}{f_{u_2}\left(\overline{R}^*, \mu_2\right)} \tag{1.24}$$

We see that if $\frac{\partial \overline{R}^*}{\partial \rho} = 0$ and $\frac{\partial q^*}{\partial \rho} = 0$, then $\frac{\partial \mu_2}{\partial \Theta \partial \rho} > 0$. However, as seen in section 1.2, this is not true. Therefore, the effect of the royalty on the slope of the curve depends on the functional forms of the cost functions[36]. To illustrate the effects of the royalty in concrete applications, I am going to assume functional forms[37].

The new ZPC is shown in Figure 1.6. Given that the royalty will shift the ZPC, I show two solutions, the *lump-sum* tax (which is "slope-neutral") and the other with the royalty[38].

The ZPC seems to rotate counterclockwise. Consequently, compared to a lump-sum tax, a royalty leaves out fields of high quality but where oil is harder to find, and allows the operation of fields of low value but where oil is easier to find. The reason is that this is a tax that does not take into account the costs of producing the oil, favoring fields that are low cost and easier to find.

This result has important welfare implications. The total surplus V, represents a producer's surplus, and therefore welfare surplus. The original ZPC represents an "iso-surplus" line, in other words combinations of μ_2 and Θ that has the same amount of welfare. Any point above it has a higher welfare. The line that represents the lump-sum tax is also another iso-surplus. In the ZPC

[36] Without going trough all the mathematical procedure, the key parameters that does not allow me to conclude that $\frac{\partial \mu_2}{\partial \Theta \partial \rho} > 0$ for all cases are $\frac{\partial f}{\partial \mu_2 \partial \bar{R}^*}$ and $\frac{\partial T^8}{\partial \rho}$. The sufficient conditions needed are $\frac{\partial f}{\partial \mu_2 \partial \bar{R}^*} \leq 0$ and $\frac{\partial T^8}{\partial \rho} \leq 0$. We now that the latter is true in most but not all cases.

[37] The functional form and parameters are going to be those of Medina [16]. This is the most recent estimation of costs functions for the Venezuelan oil sector, based on an specification developed by Deacon [2].

[38] The reader will note that both lines cross at $\mu = 1$ and $\Theta = 1$. The royalty rate was chosen so as to give, at that point, the same amount of taxes as the *lump sum* tax.

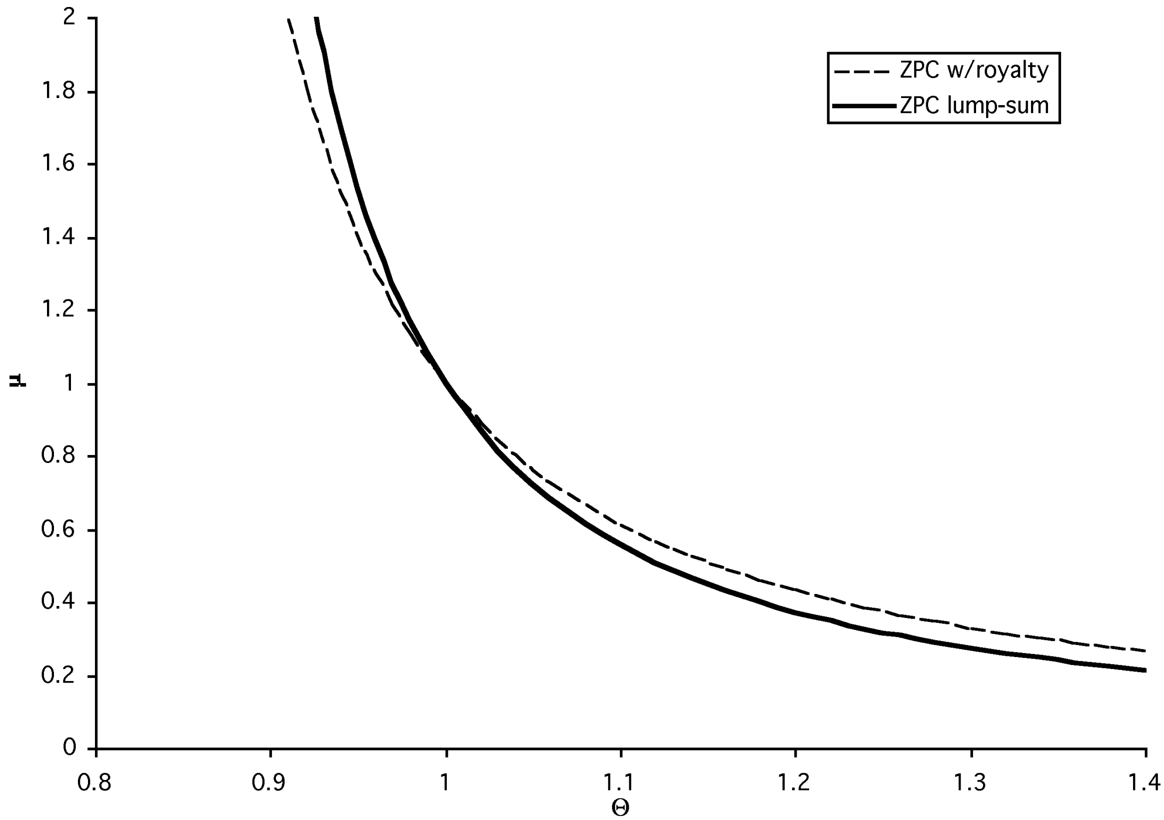

Figure 1.6: Zero Profit Condition, Effect of the Royalty

without tax the welfare level was zero, in the ZPC for the lump-sum tax the welfare level is the amount of the tax. The fact that ZPC with royalty crosses the ZPC for the lump-sum tax will imply that the tax system is shifting the composition of producing fields towards fields were less welfare is generated. In other words the fields that with the introduction of a royalty (substituting a lump-sum tax) produce will generate less welfare than the fields that close.

Repeating this analysis on the plane defined by μ_1 and Θ yields similar conclusions. The royalty shifts the ZPC, rotating. The rotation favors fields of lower value against fields that are harder to extract. On the other hand, the royalty has no effects on the plane defined by μ_1 and μ_2.

1.3.3. Income tax effect

In this case, 1.17 becomes:

$$\max_{\overline{R},q,T} V = \int_0^T \left[\left(\Theta \cdot p \cdot q - c_o\left(q, \mu_1\right)\right)\left(1-\tau\right)\right] e^{-rt} dt - \left(1 - \tau \cdot t_c\right) C\left(\overline{R}, \mu_2\right) \quad (1.25)$$

where again τ is the tax rate and t_c is the investment tax credit.

Similarly to the case in the previous sections, this tax will not only shift the ZPC but also change its slope to:

$$\frac{\partial \mu_2}{\partial \Theta} = \frac{(1-\tau)}{(1-\tau \cdot t_c)} \frac{\int_0^{T^*} p \cdot q^* e^{-rt} dt}{f_{u_2}\left(\overline{R}^*, \mu_2\right)} \quad (1.26)$$

As before, the effect of the tax will depend on the functional forms of the cost functions[39].

Similar to Figure 1.6, I show in Figure 1.7 the Zero-Profits-Conditions[40]. As with the royalty, the income tax discriminates against fields where oil is harder to find. On the Θ, μ_1 plane, the income tax will not have an effect. Finally on the μ_2, μ_1 plane, the slope will change to:

[39] Again, the key parameters that does not allow me to conclude that $\frac{\partial \mu_2}{\partial \Theta \partial \tau} > 0$ for all cases are $\frac{\partial f}{\partial \mu_2 \partial \bar{R}^*}$ and $\frac{\partial T^8}{\partial \tau}$. The sufficient conditions needed are $\frac{\partial f}{\partial \mu_2 \partial \bar{R}^*} \leq 0$ and $\frac{\partial T^8}{\partial \tau} \leq 0$. Here the latter is always true.

[40] As in the previous section, both lines cross at $\mu = 1$ and $\Theta = 1$. The income tax rate was chosen so as to give, at that point, the same amount of taxes as the *lump sum* tax.

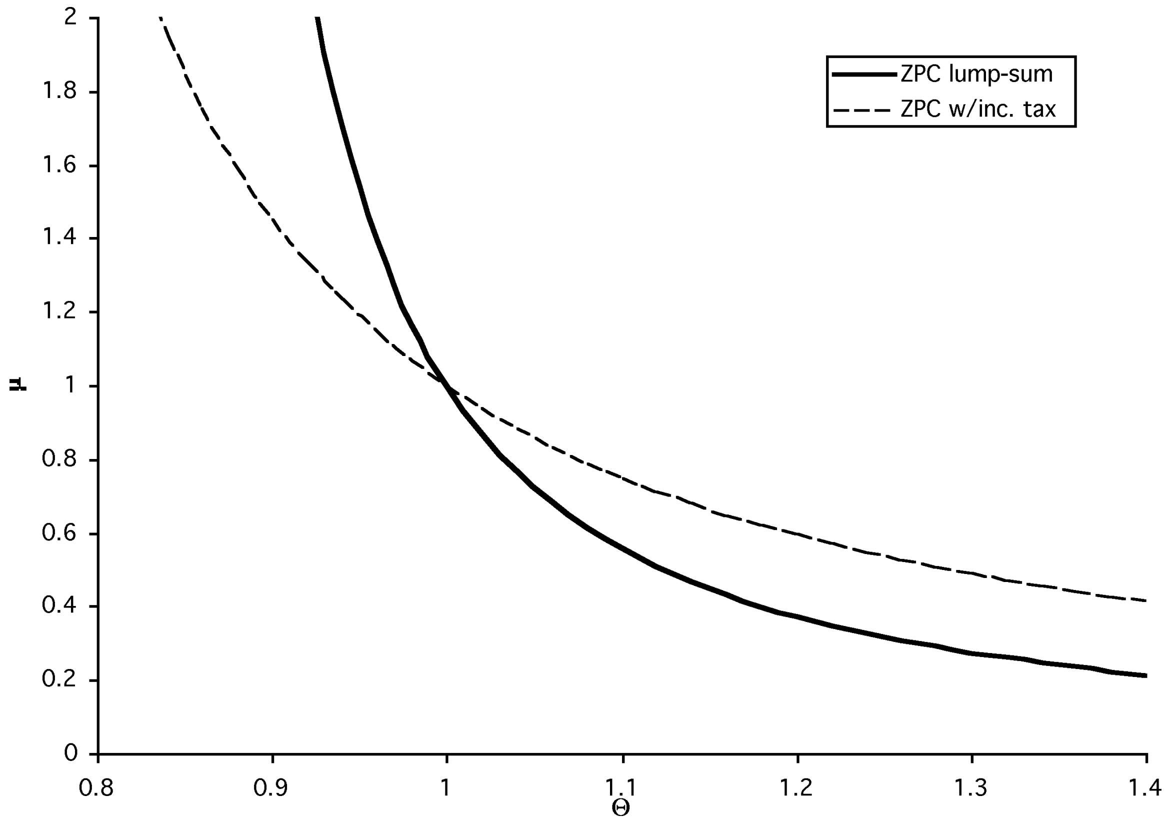

Figure 1.7: Zero Profit condition, Effect of the Income Tax

$$\frac{\partial \mu_2}{\partial \mu_1} = -\frac{(1-\tau)}{(1-\tau \cdot t_c)} \frac{\int_0^{T^*} c_{\mu_1}(q^*, \mu_1) e^{-rt} dt}{f_{u_2}\left(\overline{R}^*, \mu_2\right)} \tag{1.27}$$

Intuitively, this shift is usually biased towards fields that are harder to extracts. This is due to the fact that extraction expenses are fully deductible from the income tax. It is clear from 1.27 that if $t_c = 1$ (i.e. fully deductibility of investment on field development) the first fraction will disappears leaving the expression as the slope without taxes.

2. The Venezuelan Case

The previous section developed the basic framework on oil exploitation and taxation. In this section the particulars of the Venezuelan tax system and its effects are described and discussed. Subsection 2.1 introduces the departures of the Venezuelan tax code from the theoretical analysis of the previous section and the changes introduced to the original tax system. Subsection 2.2 uses the framework developed in the section 1 to discuss the expected effects of the Venezuelan reforms upon oil exploitation.

2.1. Venezuela's Oil Tax Regime

In this part of the paper I am going to analyze the particulars of oil exploitation in Venezuela. Firstly, I am going to describe the common rules that the tax system possesses and the ways in which it departs from the theoretical model in section 1. Next, I will describe the particular rules pertaining to different kinds of oil activity.

2.1.1. Common Rules

In this sub-section, I will analyze the effects of the common rules - in particular, those referring to development costs.

1. First, there is a tax credit on the investment in field development. This credit works in the following way: each year, firms are allowed to deduct 12% of their investment as an expense for income tax purpose. This is equivalent to the t_c of section 1.2.1; consequently, no further analysis is needed.

2. Secondly, there is another allowance for development costs. In the case of Venezuela, they are recognized in a particular way as, each year, you are allowed to deduct a portion of them from your taxes - a portion equal to the proportion of the reserves of the field used that year. It is important to mention that this deduction is called *depreciation allowance* according to the tax code, but that, as I will show, it will have effects upon oil production, even if the project exhibits no depreciation at all[41]. Consequently, I prefer to call it the *development costs allowance* and thus avoid introducing depreciation considerations that will simply complicate things.

Development Cost Allowance: For the reasons mentioned above, let us assume that there is no depreciation. The problem will then change to:

$$\max_{\overline{R},q,T} V = \int_0^T \left[(pq - c_o(q))(1-\tau) + \tau q \frac{C(\overline{R})}{\overline{R}} \right] e^{-rt} dt - C(\overline{R})^{42,43} \qquad (2.1)$$

Clearly, this is a much harder problem to solve; however, two clear distortions are apparent. First of all, the lack of consideration regarding the value of money in time will make the $\int_0^T \tau q \frac{1}{R} e^{-rt} dt < \tau$. Consequently, this kind of deduction is not equivalent to expensing. Secondly, you are being allowed to deduct in each

[41] Formally, this provision in the law allows not only for expenses in $C(\overline{R})$ but also for the investments made to produce oil.

It is easy to see that the investment carried out in $C(\overline{R})$ is different to investment in the production infrastructure.

Once you have discovered the reserves, you enter in the producing phase of the project. And given the property of the field in Venezuela, the expenses incurred in exploration cannot be recovered by means of selling the field after the firm discovers the reserves. These expenses do not have any depreciation or cost attached to them throughout the exploitation of the field.

On the other hand, investment in production will exhibit the standard depreciation costs.

Clearly, in the latter case, the way depreciation is being allowed to be deducted will have important consequences regarding the allocation of capital in the production of oil.

Since the focus of this research is the amount of reserves developed, I can assume that there is no depreciation in the capital invested in oil production.

[42] The term in the square brackets is a re-arrangement of the expression representing the net income of the firm: $pq - c_o(q) - \tau \left(pq - c_o(q) - q\frac{C(\overline{R})}{\overline{R}} \right)$.

[43] The correct expression would actually be: $V = \int_0^T \left[(pq - c_o(q))(1-\tau) + \tau q \frac{\beta C(\overline{R})}{\overline{R}} \right] e^{-rt} dt - C\left(\overline{R}\right)$, for $\beta < 1$, because development costs are incurred in different periods and you are not allowed to capitalize them.

period not the true value of the barrel of reserve being used in that period, but the average value. This also creates a distortion, depending upon the shape of the development costs.

Getting the standard first order conditions for q and $\overline{R}$, we arrive at[44]:

$$\left[(p - c_o'(q))(1-\tau) + \tau\frac{C(\overline{R})}{\overline{R}}\right] e^{-rt} = \lambda \tag{2.2}$$

$$\lambda = C'(\overline{R})\left[1 - \tau\frac{\int qe^{-rt}dt}{R}\left(1 - \frac{\frac{C(R)}{R}}{C'(\overline{R})}\right)\right] \tag{2.3}$$

therefore, for increasing marginal costs of reserves, τ is multiplied by a term that is less than one[45]. This kind of allowance is thus not equivalent to expensing. In other words, if the term that multiplies τ were equal to one, the tax measure will be equivalent to expensing and, consequently, the income tax will not distort the amount of reserves being developed. However, since it is actually less than one, distortions will arise. In principle, we could say that these distortions will be similar to those presented in section 1.2.1; nevertheless, in this new problem the shape of $C(R)$ will also matter for the value of the term multiplying τ. Putting 2.2 and 2.3 together, we get:

$$\left[\underbrace{(p - c_o'(q))}_{A} + \underbrace{\frac{\tau}{(1-\tau)}\frac{C(\overline{R})}{\overline{R}}}_{B}\right] e^{-rt} = C'(\overline{R})\underbrace{\frac{\left[1 - \tau\frac{\int qe^{-rt}dt}{R}\left(1 - \frac{\frac{C(R)}{R}}{C'(\overline{R})}\right)\right]}{(1-\tau)}}_{C}$$

To understand the effects of this kind of taxation let us separate them. Assuming, for a moment, that $B = 0$, we see that $C > 1$. As a consequence, less reserves are going to be developed than would be the case without income tax. B is like a "positive" royalty, that will have the affect of speeding the extraction process. It should be expected that, since it is like a "positive" royalty, it can off-set some of the negative effects of the "incomplete" expensing, but easy algebraic manipulation demonstrates that it will not be enough.

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[44]See Appendix A for a solution of the problem.

[45]Remember that $\overline{R} = \int qdt$, and that $\int qdt > \int qe^{-rt}dt$. With respect to the second term, increasing marginal costs of reserves implies that $C'(\overline{R}) > \frac{C(\overline{R})}{\overline{R}}$.

Additional Rules: Finally, one should mention a couple of distortions that, though not mentioned before, are nonetheless important. The reason for not mentioning them in the theoretical framework is that the way they are written in Venezuelan law does not allow us to analyze them in the simple Hotelling model.

1. The deduction of 12% of investment in field development cannot be greater than 2% of the before tax net income of the year in which the investment is made. When firms hit this last limit - i.e., 12% of investment>2% of the before tax net income - they are allowed to carry forward the remaining portion of the 12% of investment for up to three years. This method of deduction can only be used by operating firms (since the carry forward is limited); consequently, it generates a new form of discrimination between newer and older firms. Also, if we allow for field development after the field is in operation (as Pyndick [21] does), it will further distort the timing of the development. However, this is a different model, and one we will not consider here.

2. The same can be said about losses. The analysis in section 1.2.1 was carried out under the assumption that the rules apply everywhere, even if the firm makes losses. However, the tax system does not allow for losses. Rather, you can carry them forward for up to three years for deduction against taxable income in future periods.

   This will be important for two reasons: (1) Firms tend to have losses in the first years, and not all of them would be deducted; and (2) If Venezuela continues to experience the high inflation of recent years then, even if firms can deduct losses in the future, the deductions will represent less than the real value of the losses.

2.1.2. Particular Rules

PDVSA Traditional Areas: As I mentioned in the introduction, PDVSA pays 1/6 royalty and 66.7% income tax.

Heavy Oil Associations: The changes in the tax code pertaining to these kinds of projects were that the tax rate was set at 34%, and the royalty was changed into a variable royalty ranging from 1-16.67%, depending on the profitability of the project. As mentioned earlier, the reason for the changes to the tax rules for these projects was that these were low value fields.

Operating Agreements: Here, as said in the introduction, a firm operates a "mature" field on behalf of PDVSA and receives a fee per barrel. In this case, the company producing for PDVSA pays the tax rate that applies to all non-oil companies (30%). PDVSA pays its standard tax rate and the royalty for production of the field; however, the way these agreements are designed completely changes the problem in 1.4. Since the rules within these agreements are extremely complicated, and since this will not allow us to introduce them into our simple model, I am going to state the optimal designs for such contracts and then explain the differences in Venezuela.

Ideally, what one does is to make contractors bid for a schedule of fees $f(q_t)q_t$ for the operation of the field. Consequently, the problem for them would be:

$$\max_{f(q_t)} V = (1-\tau_c)\left[\int_0^T \left(f(q_t)q_t - c_o\left(q_t\right)\right)e^{-rt}dt - C\left(\overline{R}\right)\right] \tag{2.4}$$

where τ_c is the tax rate for the contractors (35% in Venezuela).

For PDVSA, the problem would be:

$$\max_{\overline{R},q,T} V = (1-\tau_{PDVSA})\int_0^T \left(pq_t\left((1-\rho)\right) - f(q_t)q_t\right)e^{-rt}dt \tag{2.5}$$

where τ_{PDVSA} is the tax rate for PDVSA.

Competitive bidding would imply that:

$$\int_0^T f(q_t)q_t e^{-rt}dt = \int_0^T c_o\left(q_t\right)e^{-rt}dt + C\left(\overline{R}\right) \tag{2.6}$$

Which means that the problem for PDVSA would change to:

$$\max_{\overline{R},q,T} V = (1-\tau_{PDVSA})\left[\int_0^T \left[pq\left(1-\rho\right) - c\left(q\right)\right]e^{-rt}dt - C\left(\overline{R}\right)\right] \tag{2.7}$$

Consequently, we can see that the problem is similar to that in equation 1.5, and that the income tax distortion is removed[46].

[46]In this "perfect" contract, you will get an effective $t_c = 1$. However, given the departures, described below, in the actual law, it is less clear that this will be the case.

The situation in Venezuela is different to that presented here. The schedule $f(q_t)q_t$ is preset before the bidding, and what the agents bid is a bond payable at the beginning of operations. Clearly, if the preset schedule differs from that which the contractors would themselves have chosen, distortions will arise. The actual system is a very complicated formula that changes the amount of $C\left(\overline{R}\right)$ permitted to be deducted depending on the profitability of the project. In addition, it does so in brackets. Thus we cannot analyze it in this simple model. Nevertheless, we can safely say that the system would imply that PDVSA will maximize a function different to 2.7 if the distortion of the tax rate wasn?t completely eliminated.

Exploration at Risk: Here, as described before, a firm carries out the complete operation - right from the initial exploration of the field - but these areas are supposed to be areas of high quality crude. The tax system pertaining to these areas is more complex: (1) there is a variable royalty; (2) the tax rate is still 67%; and (3) an auction was called in which companies bidded upon the Government participation rate in the post-tax "economic" profits - i.e., including developmental costs. This was called the PEG rate[47]. However, the PEG was set to a maximum of 50%. Therefore, if two or more companies bid 50%, a second auction was made but firms bidded upon an up-front payment. In such a case, the winning firm would pay the 50% PEG and the up-front payment. The changes that such a regime introduces to the problem in 1.1 are:

$$\begin{array}{c}\text{if winning PEG}<50\% \\ \max_{\overline{R},q,T,PEG} V=\left[(1-\tau)\int_0^T\left[pq\,(1-\rho)-c_o\,(q)\right]e^{-rt}dt-C\left(\overline{R}\right)\right](1-PEG) \\ \text{if winningPEG }=50\% \\ \max_{\overline{R},q,T,PEG,BOND} V=\left[(1-\tau)\int_0^T\left[pq\,(1-\rho)-c_o\,(q)\right]e^{-rt}dt-C\left(\overline{R}\right)\right](1-0.5)-BOND\end{array} \tag{2.8}$$

Clearly, none of the new fiscal parameters would affect the decision made regarding the amount of reserves developed; however, the size of the PEG rates actually offered, and the amount collected in up-front payments, clearly reflects the fact that the previous tax system, besides the distortions described here, failed to capture the rent it was supposed to capture.

[47]PEG are the Spanish initials of Government Take on Profits.

As in the Operation Agreements, the actual setting is different, because the amount of $C\left(\overline{R}\right)$ that are allowed to be deducted changes with the profitability of the project, and it does so in brackets. Consequently, there is going to be a departure from the solution to the problem in 2.8.

Another important factor is that it exhibits variable royalty levels, too. The reason for this is simple: in these fields we can see that $C\left(\overline{R}\right) = f\left(\overline{R}\right) + E$, where E stands for fixed costs of exploration, which are going to be independent of the amount of reserves found. It is clear from equation 2.8 that, the higher the royalty, the lower the threshold of E that would be necessary to make the project viable. The reason the royalty was chosen in preference to the tax rate is related to risks and properties that are beyond the scope of analysis our model allows. It is clear, however, that the reduction of the royalty will have the effects presented in section 1.2.1.

2.2. Expected effects of the Tax Rules

We summarize the tax system in place in Venezuela and its recent changes in Table 2.1.[48]

As mentioned earlier, the changes to the tax code were introduced because the fields were different to PDVSA's fields. In Table I summarize those differnces[49].

In this section, then, I am going to used the framework developed in Sections 1.2 and 1.3 in order to provide a brief discussion on the consequences of these changes, using the PDVSA's tax rules as the base case.

2.2.1. Heavy Oils

In these areas there was a reduction in the different tax rates. In terms of the amount of reserves left undeveloped, neither of the results from Section 1.2.1 or Section 1.2.1 supports the reform. Clearly, the amount of reserves lost in PDVSA′s projects because of the tax structure is more than is the case in these fields.

[48]See Office of the Chief Economist of Petróleos de Venezuela [20] for a detailed description of the tax treatments.

[49]See Office of the Chief Economist of Petróleos de Venezuela [20] for a detailed description of the differences between areas.

Table 2.1: Summary of Tax Changes

<table>
<tr><th rowspan="2">Area</th><th colspan="2">Tax system</th></tr>
<tr><th>Old</th><th>Changes Introduced</th></tr>
<tr><td>PDVSA</td><td rowspan="4">Income Tax = 66.7%
Royalty = 1/6
Investment Credit = 12%
Depreciation = q· C($\bar{R}$)/$\bar{R}$</td><td>No Change</td></tr>
<tr><td>Heavy Oils</td><td>Income Tax = 35%
Royalty = 1%-1/6</td></tr>
<tr><td>Operating Agreements</td><td>Investment Credit = 100%</td></tr>
<tr><td>Exploration at Risk</td><td>Royalty = 1%-1/6
“After-Tax” Tax by bidding::
$PEG\% \cdot \pi$, if $PEG^b < 50\%$ [a,b,c]
$50\% \cdot \pi - BOND$,[d]
if $PEG^b > 50\%$</td></tr>
</table>

[a] PEG: Government participation in after-tax profits.
[b] π : after tax profits
[c] PEG^b : PEG bided.
[d] $BOND$: Up-front bond payment bided as explained in the text.

Table 2.2: Summary of Field Characteristics

Area	Characteristics
PDVSA	Average Quality Average Extraction Costs Average Development Costs
Heavy Oils	Lower Quality Average Extraction Costs Average Development Costs
Operating Agreements	Average Quality Higher Extraction Costs Higher Development Costs
Exploration at Risk	Average or Higher Quality Average Extraction Costs Average Marginal Dev. Costs Higher Fixed Dev. Costs

Alternatively, it might be that the concern here was more related to the problem in Figure 1.3 - that these fields may not be developed at all because of the tax structure. However, the results from Sections 1.3.2 and 1.3.3 are against the argument that these taxes affect low value fields more negatively than does a neutral tax.

2.2.2. Operating Agreements

It remains unclear just why these fields were selected for these forms of taxation. In the "Statement of Proposal" - which is necessary for any change of law in Venezuela - it states that the fields selected for this regime were:

> "1. Not priority fields for PDVSA′s subsidiaries because of its profitability and the capital availability for the subsidiary.
> 2. Inactive or almost depleted.
> [...]
> 6. Possessing minimum infrastructure for production, and requiring minimum investment to operate them..."[50]

If we can infer from these motives that these were fields with a low $C''(R)$, it becomes clear that more reserves were being left undeveloped in these areas than were in PDVSA′s areas.

Nevertheless, if $C'''(R) > 0$, it is less clear that the tax system generates more distortions in these fields than it does in PDVSA′s areas, in terms of reserves developed. With $C'''(R) > 0$, we can no longer expect that these fields have a low $C''(R)$, since these are areas that have already developed some reserves. Moreover, if these fields also have higher operational costs and those costs increase faster, as the statement on profitability seems to suggest, there are even fewer arguments for this tax change.

If one of the arguments for putting these areas into a better tax system is that oil is harder to find there[51], it becomes clear that the conclusion in Section 1.3.3 may support it in terms of entry considerations. There, it is shown that in some cases the income tax discriminates against those areas with harder to find oil. However, this will depend on the value of the cost function and, consequently,

[50] PDVSA [20]. There were other motivations that I have omitted, clearly included in order to assist with the political selling of the new tax. For example: "Fields should be in economically depressed areas of the country".

[51] Because most of the reserves have been depleted.

a careful estimation of this function is needed before one can conclude that a tax reform is needed. In addition, calculations based on the assumption that producers do not adjust may overestimate the effects of the tax rate.

Finally, some of these agreements exhibit a lower royalty, justified by the fact that these contractors may find different kinds of "sub-fields" with different qualities of oil. Nevertheless, the discussion carried out regarding the Heavy Oil Areas dismisses that argument and, therefore, the tax change.

2.2.3. Exploration at Risk

The introduction of a new "after-tax" tax and the up-front bond payment are supposed to have no effects on the first order conditions of the producer's problem[52]. Consequently, no further consideration is needed.

These changes will move - upwards - the level curve for the zero profit condition. Nonetheless, it was supposed that these fields were so profitable that they would still exist on the right hand side of the curve after the shift. Given that only one field was not awarded, it would seem that, generally, this assumption was accurate.

The important change to consider here is the reduction in the royalty. In particular, it is not clear if the bigger exploration effort needed in these areas is going to be in the form of a fixed cost or whether these are just areas in which oil is harder to find.

If the latter is the case, the change in the law addressed a clear distortion created by the tax system. The royalty rate discriminates against areas in which oil is harder to find, as explained in Section 1.3.2, and the reduction of the rate for these areas reduces the extent of that discrimination.

If the former is the case, though, the reforms will bias the entry of projects in these areas toward projects that are harder to find compared to the entry of projects in the traditional areas. In this case, projects have an "extra" *lump sum* payment. In terms of the analysis in 1.3, this means that the level curve for the zero profit condition, *before* tax, for this project is going to be higher. If the government's objective is to leave this field in the same *after* tax situation as the other areas, a reduction in the royalty will not achieve this. The result of the shift of the after tax ZPC curve will be a bias toward areas in which oil is harder to find - because these are the areas in which the royalty creates the

[52] I say this because, as I explained in Section 2.1, the design actually departed from the neutral design.

largest distortions.

3. Estimating and Calibrating a Model of the Venezuelan Oil Sector

In the previous sections I used the conceptual framework developed by Hotelling [7] to analyze the impact of the tax code on the oil sector. Under that framework, I introduced the taxes present in the Venezuelan tax code and its recent reform. It allowed me to predict where, theoretically, the tax code generates the most distortions and whether the reforms were targeting those areas. However, it did not allow me to measure those distortions or the effects of the reform.

In this section I will estimate a model for the Venezuelan oil sector that I will use in the next section to evaluate the reforms. I will use the model of the producer of a natural resource developed by Hotelling [7] described in equation 1.1 and summarized below. Basically, the producer maximizes:

$$\max_{\overline{R},q,T} V = \int_0^T \pi\left(q,\Theta,\mu\right)e^{-rt}dt - C\left(\overline{R}\right) \tag{3.1}$$

$$\text{subject to} \quad \begin{aligned} \dot{R} &= -q \\ R(0) &= \overline{R} \\ R(T) &= 0 \end{aligned}$$

$$\begin{aligned} \text{being} \quad \pi(q,\Theta) &= \Theta \cdot p \cdot q - c(q,\mu_1), \\ &\text{for } \tfrac{\partial c}{\partial \mu_1} < 0 \\ \text{and} \quad C\left(\overline{R}\right) &= F + f\left(\overline{R\mu_2}\right), \\ &\text{for } \tfrac{\partial C}{\partial \mu_2} < 0 \end{aligned}$$

where p represents the oil price, q the extraction rate, and r the discount rate. In this formulation I am assuming that there are two costs involved in oil production: $c(q)$ represents the costs of oil extraction, C the development and exploration cost associated with $\overline{R}$ reserves.

Θ, μ_1 and μ_2 will represent dimensions among which the oil fields differentiate. Θ is the oil quality, and μ_1 and μ_2 are the ease of extracting oil and the ease of finding it respectively. The higher the Θ, the better the quality and, therefore, the higher the price. On the other hand, the higher the μ_1 , the easier to extract oil and, therefore, the lower the extraction cost, and the higher the μ_2, the easier to find and, therefore, the cheaper to develop.

The producer chooses the extraction path (q and T) and the amount of reserves that maximizes the profit function subject to the constraint, which implies that the total amount extracted should be equal to the reserves at the beginning of the exploitation.

My task will be to estimate the cost functions, given the information on the path of production and costs.

3.1. The Data Set

For the estimation I am using a panel of 821 fields provided by the Exploration and Production Division from PDVSA. This panel contains the expected production for the next 20 years and their operational costs. These data are supposedly constructed by assuming that these are optimal production paths, given a constant price and no taxes. This information is given to a planning department, which then adds overhead expenses and makes a decision on whether to open the fields or not. The drawback to this panel is that the only information it provides on reserves is the reserves at the beginning of the period. In this regard the panel represents 33% of the total proven reserves in Venezuela.

Table 3.1 shows some of the summary statistics for the panel.[53] The correlation between production and costs is 0.7368 and the correlation between degrees API and total production is -0.0524. The reader will notice that the number of observations is less than 20 per field. Not all fields produce for the entire 20 years in the panel. The average length of production time per field is 17 years. Finally, Figure 3.1 shows the distribution of production and extraction costs.

Table 3.1: Data Set Characteristics: Summary Statistics

	N	Mean	Std. Dev.	Min.	Median	Max.
Production ('000,000 Barrels)	14001	1.9493	4.8391	0.0037	0.6332	132.6045
Costs ('000,000 US$ 1999)	14001	8.5072	15.6457	0.0044	3.2951	237.6725
Total Prod. ('000,000 Barrels)	821	33.2433	73.6320	0.2447	12.3126	966.6277
Degrees API	821	28.3079	9.1515	8.5000	30.4000	54.2000

[53]For confidentiality reasons I cannot disclose the source of my data.

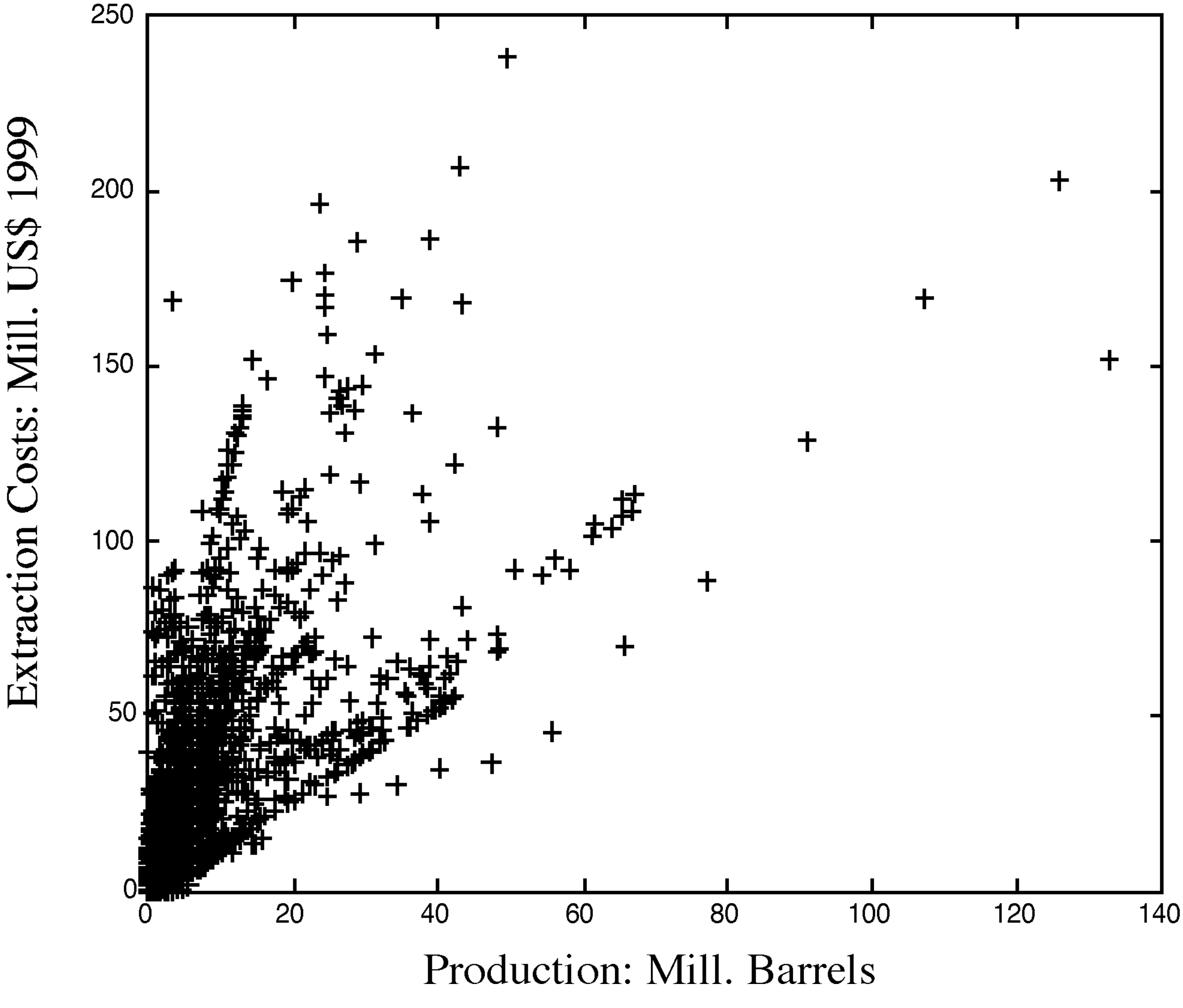

Figure 3.1: Production and Extraction Costs

With these fields, I can construct parameters for an extraction cost function. However, to carry out a calibration of the model developed in the previous section, I also need a development cost function. For that purpose I am going to include an estimation done by Medina [17] and [16].

Development Costs Used: Since I am using the estimation by Medina, I will first explain his estimation this subsection. He used aggregate data to estimate the optimal time path of oil production in Venezuela, and then check the effects of different taxes on that path.[54] He estimates the following functions:

$$R_t = \Gamma \cdot \left(1 - e^{-\beta \cdot W_t}\right) \tag{3.2}$$

and

$$C\left(w_t\right) = \varepsilon + \gamma \cdot w_t + \delta \cdot w_t^2 \tag{3.3}$$

where R_t represents the total amount of reserves discovered at time t, W_t represents the total number of wells drilled *up to* time t and w_t represents the total amount of wells drilled *at* time t (i.e. $W_T = \sum_0^T w_t$).

Basically, equation 3.2 is a negative growth function, in which we have Γ barrels of oil on the ground at the beginning of the exploitation, and the marginal well at t gets the $\beta\%$ of the reserves that are left in the ground at t. Then, equation 3.3 represents the cost function of the wells drilled, which is a quadratic cost function of the amount of wells drilled at time t. Figure 3.2 shows what equation 3.2 would look like and the shape of the development costs function as a consequence of 3.2 and 3.3. These functions are based on a model developed previously by Pindyck [21] and parametrized by Deacon [2].

Using the totals from the Venezuelan oil sector since 1960, the results of Medina's estimation were (t-statistics in parentheses):

$$R_t = \underset{\Gamma^M}{\underset{\text{(not estimated)}}{420 * 10^9}} \left(1 - e^{\underset{\beta^M}{\underset{(-72.7539)}{-8.4369 * 10^{-6}}} W_t} \right) \tag{3.4}$$

and

[54] The information used by Medina is of public domain. However, when I do the same estimation, the results are the same.

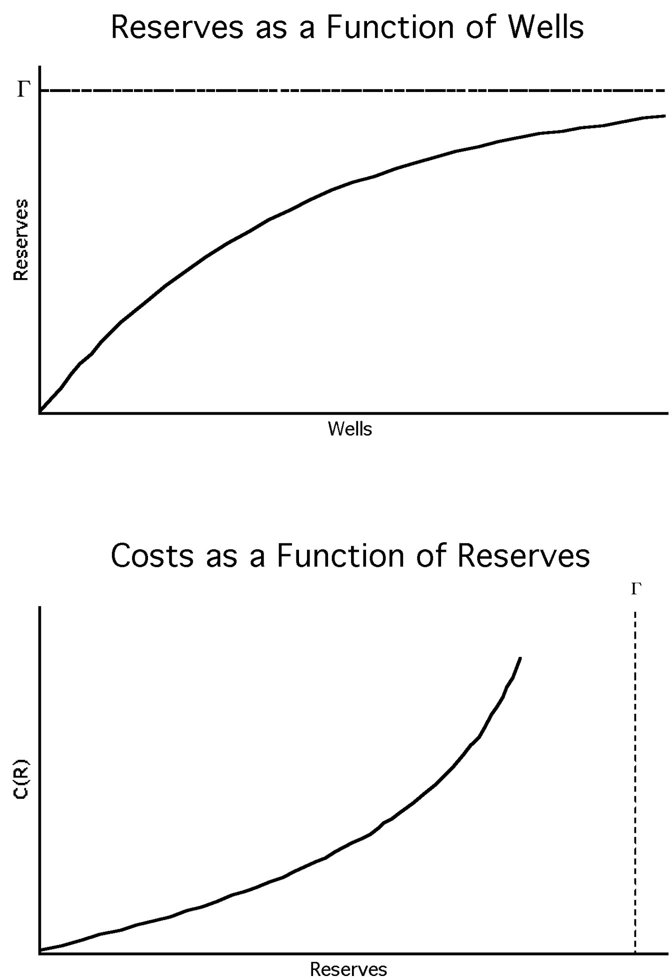

Figure 3.2: Development Cost, Functional Form Chosen

$$
\begin{array}{cccccccccc}
C(w_t)\cdot 10^{-6} & = & \underset{\substack{(4.8746)\\ \varepsilon^M}}{845.13} & + & \underset{(4.0514)}{1.4854} & \underset{\gamma^M}{\mathrm{w}_t} & + & \underset{(2.6268)}{0.7574} & \mathrm{w}_t\cdot \mathrm{D} & + & \underset{\substack{(1.3100)\\ \delta^M}}{0.0039} & \mathrm{w}_t^2
\end{array} \tag{3.5}
$$

for $D = 1$, after 1983.[55]

In equation 3.4, the results imply that Medina chose not to estimate Γ, but, rather, to use the estimates provided by the geology department of PDVSA and estimate β from there. In equation 3.5 the results imply, firstly, that the quadratic term is not significant and, secondly, that there is a time break in the cost function. The reason for this time break is that, originally, Deacon [2] uses the total amount of feet drilled. However, as this information was not available for a long period of time for Venezuela, Medina uses the number of wells. Nevertheless, it is known that the average depth of the wells drilled increased significantly after 1983, when a major exploration campaign commenced. As a consequence, Medina introduces the change of the slope in the estimation of 3.5.

I used Medina's parameters scaled to the fact that his model is designed for the aggregate and mine for individual areas. For the scaling, I used the fact that these areas represent 39 billion barrels out of a total of 119 billion barrels of reserves that Venezuela possesses. I assumed that the fields were of equal size. This then implies that, if 821 fields represent 39 billion barrels, there will be a total of 2505 fields. Consequently, if we divide the total resource base by 2505, each field will have a resource base of 168 million barrels.

In addition, for the scaling of β, I assumed that the marginal cost of the first barrel of oil in the aggregate is equal to the marginal cost of the first barrel of oil in each area. Finally, the fixed cost of 3.5 was divided by the number of fields, and a net present value of it for 40 years (the average life of a field) was used as a fixed cost for the purposes of our estimation.

Table 3.2 summarizes the parameters used. The main drawback is that I am not able to estimate the field's differences for the extraction cost (μ_2).

3.2. Estimating the Extraction Costs

For the cost function in 3.1, I use the following specification:

[55] All monetary values are in US$, 1999.

Table 3.2: Parameters Used from Medina [17]

Reserves	$\Gamma =$	$167.6578 * 10^6$
	$\beta =$	0.0210
Costs	$\varepsilon =$	$5.57 * 10^6$
	$\gamma =$	$2.2551 * 10^6$
	$\delta =$	0

$$c(q) = a + b \cdot q + c \cdot q^2 \tag{3.6}$$

This specification has the advantage that is simple but at the same time has the convexity properties needed for the Hotelling model. I still need to describe where I am going to introduce the difference in costs (μ_1) among fields. This will be solved with the estimation.

There is a problem, however, with carrying out a simple least square regression. In oil production, not only are costs a function of quantity but quantity is a function of costs. Returning to Figure 3.1, it is clear from the graph that fields with lower costs will also be the fields in which production is higher. This is partly the result of a maximizing process, and generates a simultaneous equation problem. In Figure 3.1 it is clear that each field has a convex extraction cost function, however if a simple Ordinary Least Square Estimation is done, since it has to fit all points, it will return a concave function. In other words, it will cause the estimation of c in 3.6 to be negative[56]. A solution would be to estimate the equation 3.6 individually for each field. However, this will imply that with twenty observations I will be estimating three parameters and one variance, and in some fields we may have fewer observations.

3.2.1. Identification Strategy

To solve the problem I will use the Hotelling model in 3.1 . I will assume that the model is true and parametrize it. Then I will use the implications drawn from this assumption, to identify the cost function.

The first order conditions for the problem in 3.1 imply that:

[56]The OLS result for c is -0.01363.

$$\frac{\partial \pi_{it}}{\partial q_{it}} e^{-rt} = \lambda_i \tag{3.7}$$

which given the parametrization chosen implies that:

$$q_{it} = \frac{\Theta_i p - b - \lambda_i e^{rt}}{2c} \tag{3.8}$$

In this expression, besides the parameters of the cost function, λ is unknown. Nevertheless, I have the total production for each field for the years in the sample, and integrating 3.8:

$$\int_0^T q_{it} dt = T_i \cdot \frac{(\Theta_i p - b)}{2c} + \frac{\lambda_i}{2c} \cdot \frac{e^{rT} - 1}{r} \tag{3.9}$$

Consequently, I substitute 3.9 on 3.8, that expression on 3.6, and then use Non-Linear Least Squares to estimate the resulting expression.[57]

3.2.2. Results

Table 3.3 shows the results of the estimation. Column (1) shows the estimation assuming no individual effects. The coefficients are of the expected sign and significant.

The next three columns show the results with different individual effects. Both specifications in (2) and (3) in the table reject the restricted model in (1), while the specification in (4) cannot reject it. I am going to choose column (3) for three reasons:

1. In Figure 3.1 it seems that the difference is on the slope of the cost functions and not on the intercept.

2. Theoretically, it is also more plausible to have different marginal costs than different fixed costs. Basically, fields are produced with the same technology. The differences are going to be caused by differences in the

[57] p will be the price for the Venezuelan basket. By the time the panel was done the expected price of the Venezuelan basket was US$ 13.96. Given that crudes usually are priced in absolute spreads over a reference value, this will imply that I can price other crudes based on the following formula: $p_i = 8.9192 + 0.1991 * Degrees\ API$. For the purposes of our estimation this will imply that $\Theta_i p = p_i$

characteristics of the field that are going to affect the extraction pattern.[58] This is associated with the marginal cost.

3. Finally, if we do a Haussman Test on the value of the coefficient of q_t^2, comparing the specifications in (2) and (3), the test rejects (2).

Table 3.3: Results from the Non-Linear Estimation
Dependent Variable: Extraction Costs
(t-statistics in parentheses)

	No Individual Effects	Individual Effects		
		on constant	on q_t	on q_t^2
	(1)	(2)	(3)	(4)
constant	6.7168		5.6541	4.7590
	(50.7843)		(58.9174)	(26.8220)
q_t	0.4034	-2.5676		16.8179
	(5.5477)	(-6.6856)		(208.2524)
q_t^2	0.2534	0.1196	0.2318	
	(134.0390)	(5.2872)	(181.3357)	
N	14001	14001	14001	14001
MSE	3.1481e+06	1.0987e+06	1.5434e+06	2.2170e+06
F-test for I.E.		1.87	1.04	0.42

Choosing the specification in Column (2) implies that, for our purposes, $\frac{1}{\mu_1} = b$. With the parameters, we can check the distribution of fields in the space of θ and b. For that purpose, Table 3.4 shows some statistics concerning the distribution of θ, and Figure 3.3 shows us the fields in that space.

One of the striking characteristics of the table and the figure is the concentration of points around the value of $b = -0.7$. Therefore, I checked my sample composition. In Table 3.5 I show the total production of oil in my sample and

[58]In other words, these differences try to capture what in the industry jargon is referred to as *flow rates*.

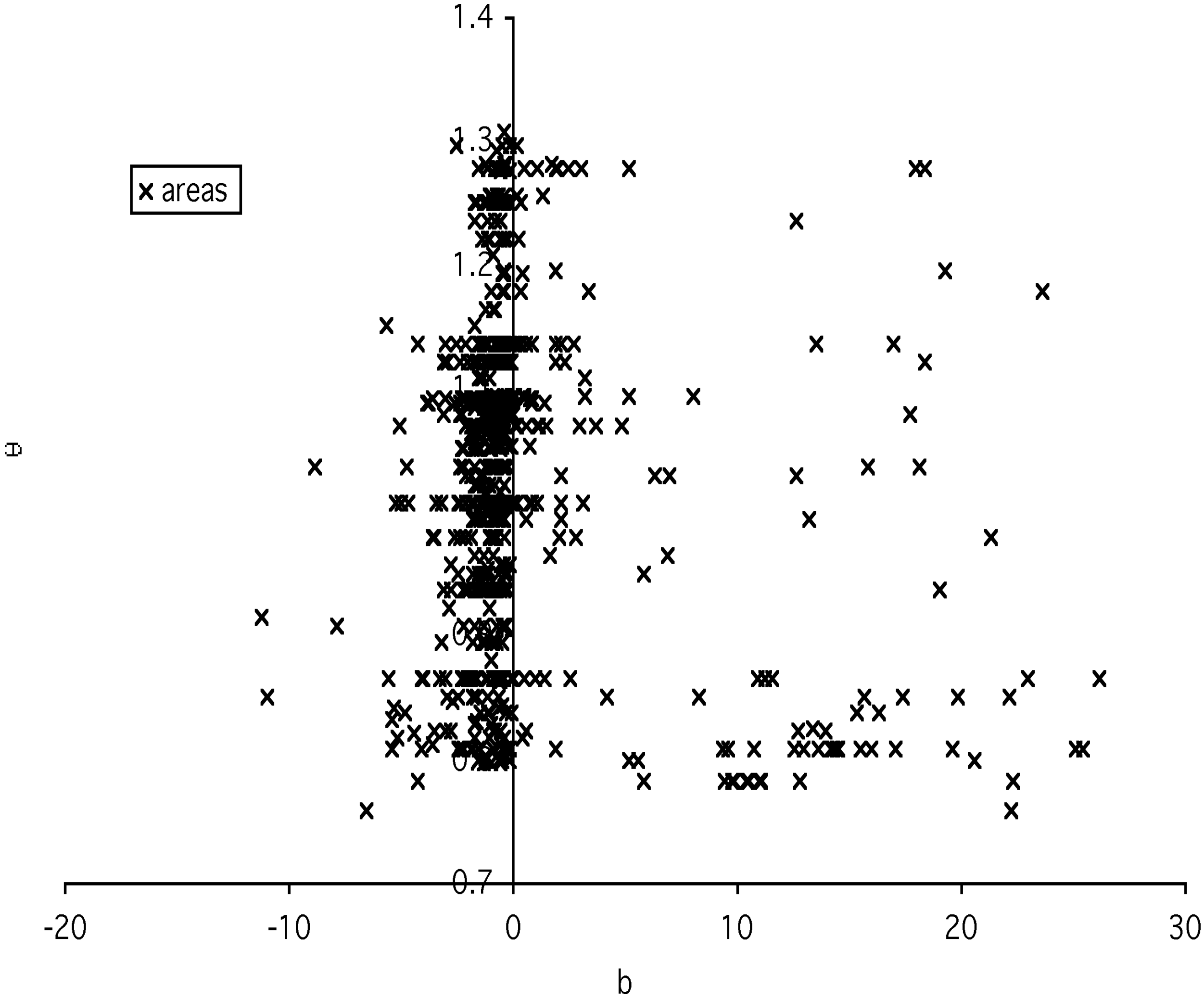

Figure 3.3: Distribution of Fields

Table 3.4: Summary of the Parameters Estimated

Distribution of Fields' Dimensions		
	θ	$\frac{1}{\mu_1} = b$
Mean	1.0412	0.2911
Std. Dev.	0.1303	4.6415
Min.	0.7591	-11.2014
10th Percent.	0.8374	-2.0980
25th Percent.	0.9656	-1.3031
Median	1.0710	-0.7091
75th Percent.	1.1223	-0.3795
90th Percent.	1.2220	2.1469
Max.	1.4100	26.1748
Correlation θ, b	-0.2110	

Table 3.5: Sample Selection

Expected Reserves	
Crude	%Sample/Country
Light/Condensated	78.0
Medium	57.4
Heavy	38.8
Extra-Heavy	0.3

compared it to the expected reserves calculated by PDVSA for the whole country, classified by oil quality. The table clearly demostrates that my sample is not a representative sample of the total fields in the country. Therefore, sample bias may explain the concentration of fields around a type of cost. This will prevent me from proposing an optimal tax structure for the sector, since it is important to know the composition of fields.

4. Evaluating the Tax Changes

In the following subsections I will use the panel to construct the parameters needed to evaluate the tax reform. As was mentioned previously, these tax changes were sectorial reforms, therefore different areas got different breaks. The panel used does not provide the information on the tax treatment of each area. As I mentioned before this was done under the assumption of no taxes. However, I can divide the areas using the results of my estimation together with the description of the areas given in the reasons for the reform. Then, I can calculate the effects of the reform.

4.1. Assigning Areas to Tax Codes

In this subsection I will divide my sample between different tax arrangements. The common characteristic of all these areas is that they are "closed" under the current tax system. Therefore, I will use the zero-profit condition to divide producing fields from closed fields.

4.1.1. Dividing Between Established Fields and Closed Fields

As explained in the previous sections, the idea here is to find the combinations of Θ and b that produce zero profits, given that there are fixed costs of development. In other words, we want to find the combinations of Θ and b that make the next equality hold:

$$\int_0^{T^*} \left[\Theta \cdot p \cdot q^* - c(q^*, b)\right] e^{-rt} dt - F - f\left(\overline{R}^*\right) = 0 \tag{4.1}$$

for q^*, $\overline{R}^*$ and T^* being the values that solve 3.1.

This would give us a plane on the space of Θ and b that will divide it between profitable and non-profitable fields. Figure 4.1 shows an example of this. The vertical axis represents the differences in quality: higher Θ, higher quality. On the other hand the horizontal axis represents the differences in extraction costs. The higher the b, the higher extraction costs.[59]

ZPC plots the level curve for those projects that are going to result in zero profits. In this case the relationship is positive. The higher the extraction costs, the higher the quality should be in order to keep the project without losses. Projects above the line will produce, while projects below it will not.

[59]The reader will notice that the slope in these graphs is different to those in Section 1.3. The reason is that in that case, the further away we move on the horizontal axis the *lower* the cost. That representation was chosen for expositional purposes, while this one is closer to our estimation.

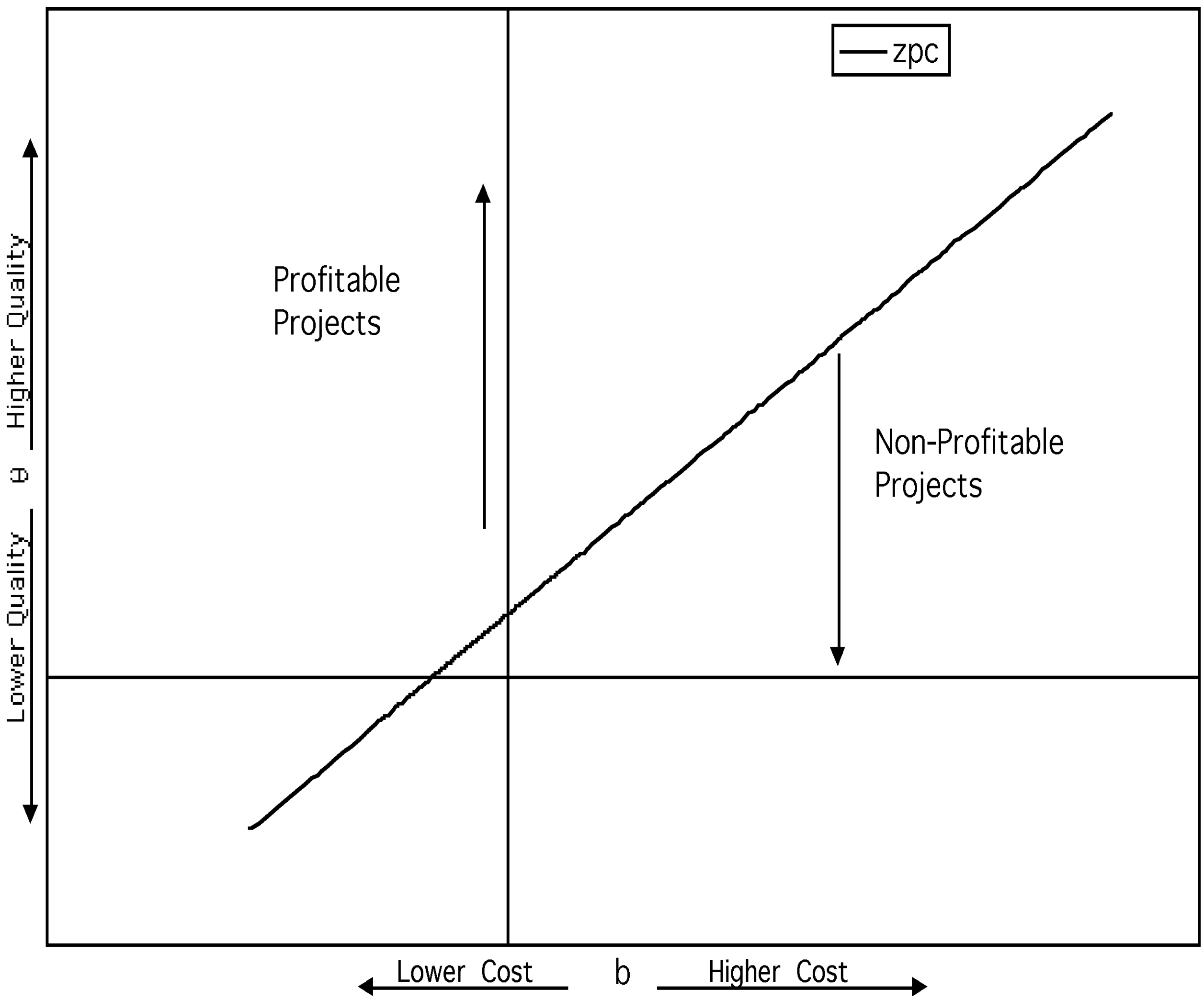

Figure 4.1: Zero-Profit Condition, Level Curve

In Figure 4.2 I illustrate the zero-profit conditions derived from my estimation. There I show four different curves: one without taxes ("ZPC"), one with royalty ("ZPC Royalty"), one with income taxes ("ZPC Inc Tax") and one with both taxes ("ZPC Inc Tax+Roy").

Thus we see that fifty-six (56) fields will not produce, even without the taxes.[60] Once the traditional taxes in Venezuela were introduced, 9 additional fields would be closed.[61]

4.1.2. Dividing Among Closed Fields

To divide the areas among closed fields I will use the description employed to grant them the special tax arrangement as summarized in Table 2.2.

Heavy Oils Areas: As shown in Table 2.2 on page 34, these areas are of low value. Consequently, of the areas that are not produced, I will consider Heavy Oils those whose θ is less than 0.9418 (i.e., areas with crudes of 20 or less degrees API). These represent 4 of the closed areas.

Operating Agreements: Here I put all the other areas that are not produced under the current tax system. This means that there are 5 areas.

Exploration at Risk: As I mentioned earlier, these areas may be interpreted in different ways. I have chosen to assume that they have a higher fixed cost of development than do the other areas. This assumption implies that their ZPC is different too. To determine the areas assigned to this group I did the following:

1. Calculate a new ZPC with an additional fixed cost of development of US$ 92 millions[62], with income tax and royalty.

[60] It is important to remember that the information I received from PDVSA were geologically optimal paths that did not take into account overhead costs and other fixed costs.

[61] This low number also seems to add to the evidence that the panel represented here is a biased panel of fields. The reader can see that in Figure 4.2 there is almost a "hole" between the fields that actually produce with the taxes and the fields that do not produce at all.

This seems to suggest that the panel represented here includes primarily PDVSA fields (i.e., no or few heavy oils, operational agreements, and exploration at risk areas).

[62] This magnitude comes from the following numbers: The expected initial exploration effort for the eight areas was expected to cost US$ 485 million and the sum of the "lump-sum" bonds bid on the eight areas was of US$ 250 millions.

I added up these numbers and divided by eight.

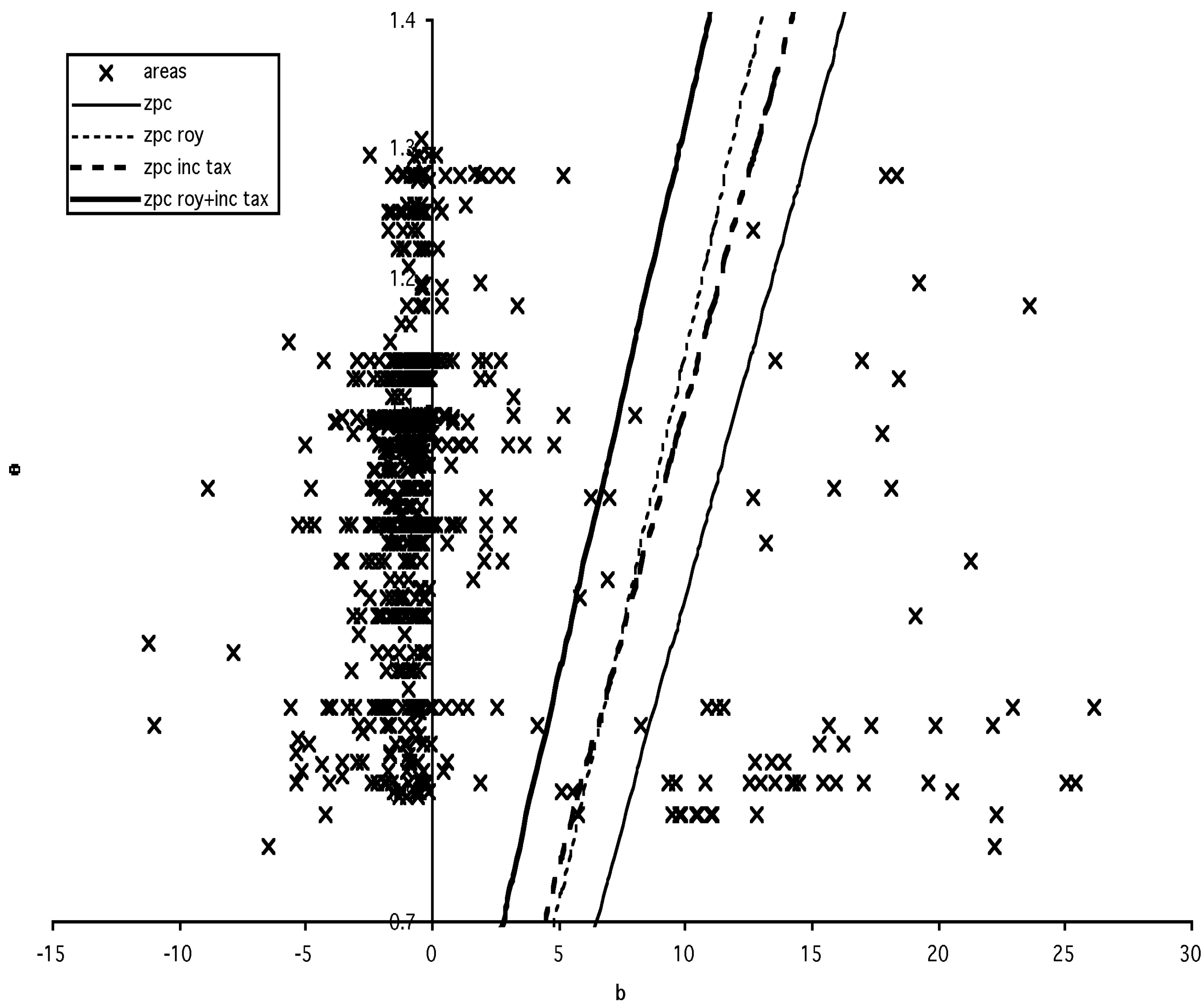

Figure 4.2: Fields and Entry Conditions

2. Calculate a new ZPC with the same fix cost, but without royalty.[63]

3. Take those areas that were not produced under (1) and are produced under (2). Total: 32 areas. It is important to recall that these areas were not previously counted as closed ones under the current tax system. The inclusion of these areas means that 41 areas are closed due to the current tax system.

4.2. Results

In this section I will present the impact of the reform on the different areas. The values shown in Table 2.1 on page 33, are the ones I will use in the calibration.

In Table 4.1, I show the results of the reform based on the arguments given for it, reserves developed and areas closed. The reader will note that I show the amount of reserves developed in each area as a fraction of the total resource base. As I explained before, since the panel I use has a small number of areas I found this number more representative.

Table 4.1: Evaluating the Tax Reform: Target Variables

Variable	Area: PDVSA	Heavy Oil	Expl. at Risk	Op. Agr.
With no Tax				
Reserves Used $\left(\frac{\sum \overline{R}}{\sum \Gamma}\right)$	0.9110	0.5253	0.8652	0.6759
Areas Producing	724	4	32	5
Under the current tax arrangement				
Reserves Used $\left(\frac{\sum \overline{R}}{\sum \Gamma}\right)$	0.6937	0	0	0
Areas Producing	724	0	0	0
Under the tax changes proposed				
Reserves Used $\left(\frac{\sum \overline{R}}{\sum \Gamma}\right)$	0.6840	0.3381	0.6004	0.5096
Reserves Used $\left(\frac{\sum \overline{R}_{new\ tax}}{\sum \overline{R}_{no\ tax}}\right)$	0.7508	0.6463	0.6939	0.7540
Areas Producing	724	3	32	4

[63] As I will explain in the next subsection, this was the reform proposed for these fields.

The table first presents the situation as it would be with no taxes. We see that the total number of areas that are available for production would produce under this scenario. Next, under the current tax arrangement, we see that only PDVSA areas produce. Then we see the improvements brought about by the new tax changes, as a result of which 38 of the 41 areas are recovered. Also, the amount of reserves recovered is important. The new tax arrangements recovered between 30% and 60% of the resource base in the closed areas. Alternatively, we can say the reform recovered between 65% and 75% of the economically feasible reserves.

Table 4.2 focuses upon welfare variables. I show the total producer surplus generated by each area, the total tax collected and the social surplus of the marginal barrel. These are shown for each area under the different scenarios.

On the first set of results, I show the total surplus in each area that would be produced if there were no taxes. Obviously, under this assumption, the marginal surplus would be zero in all fields (Social λ = Private $\lambda = C'\left(\overline{R}\right)$). It is clear that we cannot compare absolute magnitudes here, because of the overwhelming difference in the number of areas in favor of PDVSA Areas. For this reason, I will focus my discussion on the marginal surplus.

In the next set of results, I calculate the same variables again, this time under the current tax system. Because, under this assumption, there is no production in areas other than PDVSA areas, these areas have no surplus. Consequently, the surplus of the marginal barrel is the surplus of the first barrel produced. Note that, even though we do have production in PDVSA areas, the surplus of the marginal barrel in these areas is higher than in almost all other areas. This is because the other areas have lower value, higher costs, etc. As a consequence, the best strategy is to increase production in PDVSA areas rather than in the other areas.

The next step is to introduce the recent reforms. Because the PDVSA areas have not experienced a change in their tax structure, we see no change for them. I find that an extra-surplus is generated in all the "new" areas. Also more taxes are collected since the new areas will not produce under the old tax code.

As I mentioned, the social value of the barrels produced is much higher in PDVSA areas than in other areas. This raises the question of how should an optimal tax reform be constructed. Given that I do not have a good representation of the fields universe, I cannot answer that question. However, I can determine

Table 4.2: Evaluating the Tax Reform: Welfare Variables

Variables	PDVSA	Heavy Oil	Expl. at Risk	Op. Agr.
	Areas			
With no tax				
Surplus ($\cdot 10^9$)	871.64	0.42	23.00	1.12
Marg. Surplus	0	0	0	0
Under the current tax agreement				
Surplus ($\cdot 10^9$)	766.68	0	0	0
Tax ($\cdot 10^9$)	628.58	0	0	0
Marg. Surplus	9.1880	3.1342	9.8058	4.5217
Under the tax changes proposed				
Surplus ($\cdot 10^9$)	766.68	0.32	19.45	0.92
Tax ($\cdot 10^9$)	628.58	0.24	17.71	0.81
Marg. Surplus	9.1880	1.1308	4.2782	1.7098

Surplus: $V = \int_0^T \pi(q, \Theta, \mu) e^{-rt} dt - C\left(\overline{R}\right)$.

Tax: Net present value of all taxes collected.

Marg. Surplus: Social $\lambda - C'\left(\overline{R}\right)$.

what would be the effects of a general reform. In other words, what the effects of the reforms on PDVSA areas would be. The results are given in Table 4.3.

Table 4.3 presents the same variables I show in Tables 4.1 and 4.2. Clearly, if the reform is applied to PDVSA areas, no improvement will be made in terms of the number of areas producing.

In terms of reserves, it is obvious that the total fraction of reserves produced in PDVSA areas –if these areas were operating under the various new tax systems– would be greater than would be the case in the non-PDVSA areas. Nevertheless, the marginal recovery of reserves in PDVSA areas, thanks to the tax changes, is lower than the marginal recovery in the non-PDVSA areas. It cannot be concluded that the total gain in reserves in PDVSA areas would be smaller. It will depend on the total composition of the fields.

In terms of welfare, again we have gains. The interesting result here is that the marginal surplus after the tax reforms in PDVSA areas continues to be

Table 4.3: Evaluating the Tax Reform: General Tax Reform

Variable	Effects on PDVSA areas if we applied the reform to...			
	None	Hvy. Oil	Exp. Risk	Op. Ag.
Reserves (%Γ)	0.6840	0.8497	0.7255	0.8862
Change	-	0.1651	0.0415	.2022
Areas Producing	724	724	724	724
Change	-	-	-	-
Surplus ($\cdot 10^9$)	766.68	857.66	789.72	866.64
Change ($\cdot 10^9$)	-	90.98	23.04	99.96
Marg. Surplus	9.1880	4.9280	9.0438	1.8108
Tax ($\cdot 10^9$)	628.58	418.26	706.66	646.57
Change ($\cdot 10^9$)	-	-210.32	78.08	17.99

bigger than the surplus in the new areas. This means that the surplus per barrel generated by the reform in PDVSA Areas is bigger.

Finally, I have calculated the level of government revenue created under all these scenarios. It is clear that, as a result of all the changes, the government gains more revenue, except in the case of introducing the heavy oils tax agreement in PDVSA Areas. This is another way of measuring tax distortions. The fact that more tax revenue can be generated under the "easing" of the tax rules means that the sector is at a point were the marginal change in the tax rate would be more than off-set by the marginal change in production.

5. Conclusions

This paper has shown that a comprehensive tax reform of the oil sector should consider not simply whether projects are being developed under the current tax system but, rather, the effects of the tax structure on the whole oil sector and the distortions it creates.

The recent reforms in the Venezuelan oil tax system have pointed towards the development of marginal areas. The argument behind these reforms was that these areas either had the highest burden or were not being developed at all. However, it may be the case that these areas are also the ones that the tax system distorts the least. As a consequence, there would be areas where the tax system generates more distortions and thus a tax reform should be focused on those areas.

Estimating a model of the Venezuelan Oil sector, I found the reforms were beneficial in the sense that they would reduce death-weight losses, increase reserves developed and also increase government revenue. On the other hand, I estimated the effects of a general reform, applying to established areas a similar reform to that applied to marginal areas. In this case, I found that the general reform would also produce efficiency gains and increase reserves developed, but most importantly, would increase tax collection coming from established areas. This result implies that these areas are overtaxed and a reduction of the tax rates would increase tax revenue. Therefore, a general, more comprehensive tax reform would be welfare improving.

Appendix

A. Deduction of Mathematical Results

A.1. Results from Section 1.1

We set up the Hamiltonian for 1.1, and get:[64]

$$H = \pi(q)e^{-rt} + \lambda(t) \cdot (-q) \tag{A.1}$$

One of the characteristics of this problem is that the Lagrangian multipliers are constant, implying the solution in 1.2.

This problem has a Fixed-Endpoint. Therefore, if we solve for the transversality condition:

$$[H]_{t=T} = 0 \tag{A.2}$$

we get:

[64]For a complete treatment on the solution to this kind of problem see Chiang [1].

$\pi(q\,(T))e^{-rT} - \lambda q = 0$
but we know that $\lambda = \pi'(q\,(T))e^{-rT}$. Consequently, we can rewrite the transversality condition as 1.3.

Finally, to solve for the amount of reserves developed, we know that we can rewrite our problem as:

$$V^* = \int_0^T \left[H\left(t, R^*, q^*, \lambda^*\right) + R^*(t)\dot{\lambda}^*\right] dt - \lambda^*(T)R^*(T) + \lambda^*(0)\overline{R} - C(\overline{R}) \quad \text{(A.3)}$$

where the * implies that we have substituted the optimal path in the expression and, again, H represents the Hamiltonian. Therefore, maximizing it with respect to $\overline{R}$, we get 1.4 . This also proves that λ can be interpreted as a shadow price.

A.2. Results from Section 1.2.1

From 1.7 it is clear that:

$$\frac{d\overline{R}}{d\rho} = \frac{1}{C''(\overline{R})}\frac{d\lambda}{\rho} \quad \text{(A.4)}$$

From the transversality condition 1.3, we get that $\frac{dq_T}{d\rho} = 0$[65]. Therefore, for T the first order condition in 1.6 will imply:

$$\frac{d\lambda}{d\rho} = -pe^{-rT} - \left[p\,(1-\rho) - c'(q_T)\right] re^{-rT}\frac{dT}{d\rho} \quad \text{(A.5)}$$

The restrictions on the problem in 1.5 will imply that:

$$\frac{dR}{d\rho} = q_T\frac{dT}{d\rho} + \int_0^T \frac{dq_t}{d\rho}dt \quad \text{(A.6)}$$

Finally, for any t different from T the first order condition in 1.6 will imply:

$$\frac{d\lambda}{d\rho} = \left[-p - c''(q_t)\frac{dq_t}{d\rho}\right] e^{-rT} \quad \text{(A.7)}$$

Putting together A.4, A.5, A.6 and A.7, we get an expression like:

[65] Again, remember that firms are price takers, and thus that the condition is given by the equality of the marginal costs to the average costs. This condition is not affected by the royalty.

$$\frac{d\overline{R}}{d\rho} = -p\frac{\Psi\int_0^T \frac{1}{c''(q_t)}dt + 1}{C''(\overline{R})e^{rT} + C''(\overline{R})\Psi\int_0^T \frac{e^{rt}}{c''(q_t)}dt + \Psi} \tag{A.8}$$

for $\Psi = r\frac{[(1-\rho)p - c'(q_T)]}{q_T}$

We can then get the results in 1.9 from the derivation of A.8 with respect to the parameters we are interested in.

However, for 1.9.c and 1.9.d we need some conditions in order to ensure the proper sign of the derivative. If I rewrite A.8 as:

$$\frac{d\overline{R}}{d\rho} = -p\frac{N}{D} \tag{A.9}$$

for $N = \Psi\int_0^T \frac{1}{c''(q_t)}dt + 1$, and $D = C''(\overline{R})e^{rT} + C''(\overline{R})\Psi\int_0^T \frac{e^{rt}}{c''(q_t)}dt + \Psi$. We find that:

$$\begin{aligned} \frac{d\frac{dR}{d\rho}}{dp} &= -\frac{N}{D} - \frac{p}{D^2}\Psi_p\left[C''(\overline{R})\int_0^T \frac{e^{rT}-e^{rt}}{c''(q_t)}dt - 1\right] \\ \frac{d\frac{dR}{d\rho}}{dc'(q_T)} &= -\frac{p}{D^2}\Psi_{c'(q_T)}\left[C''(\overline{R})\int_0^T \frac{e^{rT}-e^{rt}}{c''(q_t)}dt - 1\right] \end{aligned} \tag{A.10}$$

for $\Psi_p = \frac{\partial\Psi}{\partial p} > 0$, and $\Psi_{c'(q_T)} = \frac{\partial\Psi}{\partial c'(q_T)} < 0$.

These results are relatively intuitive. Remember that one of the consequences of the royalty is the shift of production through time. These results indicate that, if it is too costly to do so, relative to the cost of changing reserves ($c''(q_t)$ too high and $C''(\overline{R})$ too low), it would be better to change reserves.

However, it should be noted that the numerator of the expression inside the integral is always greater than one, except for $t = T$. Therefore, this means that $C''(\overline{R})$ should be very low in order for the expression in the square brackets to be negative. It can safely be said that, in general, this expression is going to be positive.

A.3. Results from Section 1.2.1

Somewhat similar to A.4, we find that:

$$\frac{d\overline{R}}{d\tau} = \frac{1}{(1-\tau\cdot t_c)}\left[\frac{1}{C''(\overline{R})}\frac{d\lambda}{\tau} + t_c C'\left(\overline{R}\right)\right] \tag{A.11}$$

Using the same reasoning applied in A.5, we find that for T:

$$\frac{d\lambda}{d\tau} = -\left[p - c'(q_T)\right] e^{-rT} - (1-\tau)\left[p - c'(q_T)\right] re^{-rT}\frac{dT}{d\tau} \tag{A.12}$$

Again, the restrictions on the problem in 1.10 will imply that:

$$\frac{d\overline{R}}{d\tau} = q_T\frac{dT}{d\tau} + \int_0^T \frac{dq_t}{d\tau}dt \tag{A.13}$$

Finally, for any t different from T, the first order condition in 1.11 will imply:

$$\frac{d\lambda}{d\tau} = \left\{-\left[p - c'(q_t)\right] - (1-\tau)\, c''(q_t)\frac{dq_t}{d\tau}\right\} e^{-rt} \tag{A.14}$$

Putting together A.11, A.12, A.13 and A.14 we find that:

$$\frac{d\overline{R}}{d\tau} = -\frac{1}{C''(R)\Psi + \frac{r(1-\tau)}{q_T}}\left[1 + \frac{r\,(1-\tau)}{q_T}\int_0^T \frac{p - c'(q_t)}{c''(q_t)}dt\right] + \frac{t_c C'\left(\overline{R}\right)}{(1-\tau\cdot t_c)} \tag{A.15}$$

for $\Psi = (1-\tau\cdot t_c)\left[\frac{1}{[p-c'(q_T)]e^{-rT}} + \frac{r}{q_T}\int_0^T \frac{1}{c''(q_t)}e^{rt}dt\right]$

Taking derivatives of A.15 with respect to the parameters we are interested in, we get the results in 1.14.

A.4. Results from Section 2.1

In this case, the Hamiltonian would be:

$$H = \left[(pq - c_o(q))\,(1-\tau) + \tau q\frac{C(\overline{R})}{\overline{R}}\right] e^{-rt} + \lambda(t)\cdot(-q) \tag{A.16}$$

Again, the Lagrangian multipliers are constant, implying the solution in 2.2. If we rewrite A.3 for this problem, we get:

$$V^* = \int_0^T \left[H\left(t, R^*, q^*, \lambda^*, \overline{R}\right) + R^*(t)\dot{\lambda}^*\right] dt - \lambda^*(T)R^*(T) + \lambda^*(0)\overline{R} - C(\overline{R}), \tag{A.17}$$

because now profits are a function of $\overline{R}$. Therefore, the first order condition with respect to $\overline{R}$ would change to:

$$\tau\frac{\int qe^{-rt}dt}{R}\left[C'(R) - \frac{C(R)}{R}\right] + \lambda - C'(\overline{R}) = 0 \tag{A.18}$$

or, differently, 2.3.

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