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The Political Economy of Oil Production in Latin America*

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1 Introduction

The 1990s witnessed a period of significant increase in investments in the oil and gas sector in Latin America. In most countries private investment took the lead after the privatization and liberalization of the sector. For example, in Argentina, Bolivia, Brazil, Ecuador, and Venezuela, private oil investment and/or some form of privatization made possible significant additions in hydrocarbons production and/or reserves.

In contrast, in the last five years, there has been a new wave of resource nationalism in the region, with increases in the government-take and state control. Oil taxes have been significantly increased in Argentina, Bolivia, Ecuador, and Venezuela. In addition, in Bolivia and Venezuela there has been a partial nationalization of oil projects. In this paper, we argue that the recent trend is largely the outcome of the rise in the international price of oil. Furthermore, we show how the likelihood of expropriation increased after a period of successful investment in exploration and production.

Nevertheless, there has been significant divergence in the timing and direction in which the sector has evolved across the region. In contrast to most other countries in the region; in Brazil, Colombia, and Peru, the institutional framework and the property rights of private oil producers have been generally strengthened. In the paper we provide a political economy rationale for the divergent evolution.

The general pattern of development that we are witnessing in the oil sector is not new. Historically, the evolution of oil and gas production in Latin America has seen cycles of investment and expropriation. For example, in Venezuela large oil investments were made throughout the 1940s and 1950s; then starting in the late fifties a process of systematic increase in the government-take began. The fiscal-take on profits rose from levels around 50%, which prevailed in 1943-1958, to a maximum of 94% in 1974, the year before nationalization (Monaldi, 2002). In different periods, similar episodes have occurred in Argentina, Bolivia, Ecuador, Mexico, Peru, and other developing countries (Philip, 1989). Moreover, even in some developed countries, there have been significant incidents of government reneging on the fiscal and contractual conditions after considerable

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investments have been made. One recent example being the increase in royalty rates in Alberta, Canada.

This paper studies the cycles of investment and expropriation in the context of the Latin American oil sector. In particular, it provides an explanation for the state's difficulties in capturing the oil rents and rationalizes the tendency of governments to periodically renege on their prior agreements pursuing the quasi-rents. However, the paper does not try to propose the right fiscal and contractual structure. As it will be suggested, the right structure would have to be tailor made for each country.

Although the discussion on expropriation is typically an emerging market issue, it is important to emphasize that changes in the tax and contractual framework of the oil sector have not happened only in less developed or oil dependent countries. For example, in the United Kingdom there have been important tax modifications and most of them have coincided with oil price changes.[1] Besides the Corporate Income Tax, oil projects in the British North Sea pay a special tax called the Petroleum Revenue Tax (PRT). The PRT is a form of a tax on returns, which originally was set at a rate of 45%. However, when prices increased in the seventies, the rate was increased to 75%. In contrast, in the nineties when the North Sea began to deplete, the PRT was reduced to 50% for existing projects and eliminated for new projects.[2] However, the changes did not stop there. In 2002, when oil prices increased again, the British government established a 'Supplementary Charge' at a rate of 10%, effectively increasing the tax on upstream profits.[3] A comparable history can be written with regards to oil taxation in the United States and Canada.

The oil industry has some specific features that highly influence the way the institutional framework and the political economy of the sector evolve. Some of those features are shared with other sectors in different degrees, but the oil industry is one of the few in which their combined importance is significant. First, there are important rents generated in oil extraction (and to lesser extent in natural gas extraction). Second, oil and gas extraction require a major proportion of sunken investments. Third, a high proportion of oil reserves are concentrated in countries with weak institutions and high political risks. Fourth, there are high geological risks involved in oil exploration, whereas in the phases of field development and production these risks significantly decline. Fifth, oil products are massively consumed and therefore politically salient. Sixth, the oil price in the international markets is volatile and as a result oil rents are also quite volatile. The paper discusses how these characteristics of hydrocarbon exploitation interact with the institutional and contractual environment to explain the political economy of expropriation.

The characteristics of the oil sector, specially the presence of large rents and considerable sunk costs, combined with the lack of effective and progressive tax systems; generate

1 For a review of the tax regimes in the North Sea see Kretzschmar et al (2005)
2 In addition, the tax ring-fencing of oil projects was eliminated allowing the deduction of the costs of new projects from the taxes generated by the profits of mature oil projects. This resulted in a significant reduction of effective taxation.
3 It is important to mention, though, that in addition to these changes, there have been modifications in the way asset depreciation is considered for tax purposes. In general, these changes partially offset the tax increases.

episodes of contract renegotiation, particularly when the price of oil goes up significantly. The fact that contractual and fiscal systems do not appropriately take into account price contingencies, implies that when the oil price rises steeply, an increasing share of oil rents is retained by oil producers. Consequently, governments have powerful incentives for contract renegotiation or nationalization. Moreover, after large investments have been sunk, if the government reneges on the contract, the producer would still have incentives to continue operating as long as he can recover operational and non-sunk costs. As a result, high sunk costs industries like oil are tempting targets for expropriation.

The optimal contractual and fiscal system should effectively incorporate price contingencies, allowing governments to capture the oil rents. For example, the fiscal regime could incorporate rates that increase with the oil price. In fact some windfall taxes recently approved have done just that. However, there are significant difficulties in achieving an efficient and progressive tax system. Income taxes are more progressive than royalties, but they provide incentives to overspend and since the rate has to be higher than a royalty, they generate larger distortions. In addition, more progressive taxation systems require administrative capacities that many countries in the region lack. State-ownership could be a solution, but the national oil companies have often been inefficient and easy targets of revenue expropriation.

In addition, credible commitment to property rights is difficult in a context of powerful incentives for expropriation and weak institutional frameworks. An option that has been recently implemented to mitigate the time inconsistency problem is the creation of an independent regulatory agency which may help to provide some credibility without making the system excessively rigid.

The paper is organized as follows: Section 2 analyzes the economics of oil taxation and the basic characteristics of oil taxation in Latin America. It provides the theoretical foundations to understand the challenges faced by the fiscal and contractual frameworks. Taking into account the theoretical and practical problems involved in contract design; Section 3 presents the key characteristics of the oil sector and discusses how they shape the political economy of oil extraction in the region. Finally, Section 4 presents some concluding remarks.

2 The Challenges and Inconveniences of Oil Taxation

Resource exploitation is an important part of the economy in developing countries.[4] For that reason, governments implement alternative tax and contractual structures in order to capture as much as they can of the revenues generated by those activities. This is particularly true in oil exporting countries. Moreover, in most legal frameworks over the world (including all Latin American countries) hydrocarbon reservoirs are the property of the state.

[4] For the countries we are analyzing, according to the World Bank Fuel exports represented around 13% (unweighted average) of their GDP in 2004.

In the oil and gas industry, there exist important rents in the activity of hydrocarbon extraction. In particular, rents arise when the fields exploited are infra-marginal in the global context.[5] Rents also arise because the countries with the largest and less costly oil reserves restrict access to them. As a result of the existence of rents and the state ownership of the resource, states typically apply special taxes to the oil sector. In particular the most common instruments are royalties and special income taxes. Signing bonuses and variable rates also are used. In Table 1 we present a summary of the different types of instruments used in the Latin American exporting countries.

It shows that a common way of taxing the sector is the royalty. Only Mexico, where the state is the owner of the industry, and Trinidad and Tobago do not have this type of taxes.[6] Moreover, as shown, Argentina, Bolivia and Venezuela have increased them (or introduced them) recently. Royalties are a form of sale tax, as we will discuss later. Besides that, countries use either a higher rate of the income tax or a special profit tax to capture extra rents.

Besides the tax structure, there are different contractual regimes for private operators (in case there is not a state monopoly over production), which can be based on: concessions (were the producer has ownership rights over the oil field), service contracts (production for a fee), risk-service contracts (the fee is related to the price of oil and the increases in production), production sharing contracts (the state receives a share of production), or technical assistance contracts. These are important in terms of the risks taken by the Private or International Oil Company (IOC), as it will be discussed later. Finally, other relevant elements of the contractual regime are the duration of the concession or contract, the domestic price of production, the conditions to export, and the dispute resolution mechanisms (e.g. if it includes international arbitration, multilateral arbitration, or there are bilateral investment treaties). We will focus fundamentally on the taxation issues.

In addition to the capacity for revenue generation; given that taxes have significant impacts on economic activity, it is also important to understand those impacts in order to evaluate the tax structure of a particular country. In terms of the effects of taxes on the resource sector, a recent literature has focused on the market power of resource producers and how to induce efficiency in domestic resource markets. However, in countries like the ones in the region, the governments are 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.

5 This refers tp fields with total costs below the marginal producing field in the oil market.
6 The export tax in Argentina is similar to a royalty.

Table 1

Country		Royalty rate on production	Income tax rate in excess of other activities	Profit tax	Others	Participation of the State
Argentina		12% for the Local Government	No		Export Tax (since 2002)	
Bolivia	1990's	18% for new oilfields and 50% for old oilfields	No	25% y 12.5% for remittance to the outside. Additional 25% by extraordinary utilities	IEHD on the commercialization	No
	2004- Nationalization	18%	No		Direct tax on hydrocarbons = 32% Contribution to YPFB* = 32%	Yes
Colombia		20% for old oilfields	No	7%	Transports of Pipeline	Yes
		The law 756 change the royalty system. Variable 8% - 25% for new oilfields**				
Ecuador		Variable: 12.5% - 18.5% **,	Petroecuador = 100%	25%	"Tax holiday" for new oilfields in exploration phase	Yes
			Other oil companies = No			
México		No	5% additional	7,70%	Hydrocarbon rights and Advantages or utilization (They reach 60.8%)	Yes
Trinidad y Tobago			5% additional	50%	Additional Tax depend of oil price	
Venezuela	90's	1-16.66%	33%	PEG for oil fields in exploration phase	Superficial tax (100ut/km or more) Tax of own consumption (10%) Tax of general consumption (from 30% to 50%) Reduction of income tax, from 4% to 8% for new oil investment	Yes
	After the 2000 enabling law	Traditional oil fields = 30%	16% additional			
		Faja del Orinoco 20%				
		Operative agreements, depending of the contract				
	Of the present time	33% of the oil produced for any oil field.***	16% additional	No		

*YPFB: Bolivia's NOC (Yacimientos Petroliferos Fiscales de Bolvia)
**Rate Variable on flied conditions
*** In theory, if this tax structure does not allow profitability of the field, it can be reduce to 20% of the oil produced.

Alternatively, given the volatility exhibited by the price of oil, another branch of the literature has been shifting its attention towards the use of option value techniques. Instead, as in Manzano (2000), we choose a Hotelling model for two reasons: (1) there are important tax distortions with the Hotelling model; and (2) the implications derived from the option value models are less important for the subject of this paper. These implications are ultimately related to the effects of price volatility on investment decisions. These are interesting issues, but are less relevant to the study of the recent tax reforms in the Latin American oil sector.

The solution to the problem of the producer of natural resources is developed in the seminal work by Hotelling (1931). The producer maximizes a value function (V) with constraints:

$$\max_{\overline{R},q,T} V = \int_0^T \pi(q) e^{-rt} dt - C\left(\overline{R}\right) \tag{1}$$

$$s.t.\ \dot{R} = -q$$
$$R(0) = \overline{R}$$
$$R(T) = 0$$

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, we define the profit function to be: $\pi(q) = pq - c(q)$ which has two implications:

1. There are two different types of costs involved in producing oil: $C(\overline{R})$ or the monetary value at 0 of all past exploration and development costs, which may include such costs as connecting to the distribution infrastructure, etc. *c(q)* represents the costs of oil extraction and includes labor costs, gas injection, etc. [7]

2. This problem assumes that oil companies are price takers. An assumption that is not far from reality, at least not from the point of view of oil companies.[8]

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.

For the reasons explained above, the problem for the government will be to try to capture the entire value *V*. Consequently, it will introduce special taxes in order to obtain it. Ideally, the first best solution would be an auction of the field for a signing bonus payment (which would be the only payment received by the government). However several issues make this solution highly problematic. The political economy issue, discussed in this paper, is that the government cannot commit not to change the taxes in the future or not to expropriate the sector. Another issue may be that the auctions are not feasible due to liquidity and/or collateral constraints. As a consequence, alternative instruments are used. The most common are royalties and income taxes.[9] Consequently, distortions will arise.

In particular, it is worth noting in equation 1, that there are two margins that could be distorted. First, we see that there is an "extraction margin" that is the difference between the price and the extraction cost. The second one is the "development margin" which is the

7 There is an important branch of literature on the nature of c(q). In particular, Pindyck (1978), 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. Models like Pindyck(1978) will help us understand the effects of the tax system on the timing of extraction and the timing of field development. We will return to this point later.

8 It is important to differentiate the fact that there are only a few oil reserves from the fact that there are numerous oil companies exploiting these reserves. Here, we are concerned with the behavior of these many oil companies, which we assume to act competitively.

9 An alternative tax used for the oil sector is "resource-rent" tax, a form of tax on returns, used in Australia and Great Britain (the PRT). For a review and study of that type of tax see Emerson and Garnaut (1984), Garnaut and Ross (1975 an d 1979), and Zhang (1997).

difference between the net income from extraction and the development cost. Depending on how taxes affect these margins we will see effects on one or both decisions, extraction and development.

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 operator. When we introduce royalty payments to the original, the new maximization problem becomes:

$$\max_{\bar{R},q,T} V = \int_0^T \left[pq(1-\rho) - c(q)\right]e^{-rt}\,dt - C(\bar{R}) \tag{2}$$

$$s.t.\ \dot{R} = -q$$
$$R(0) = \bar{R}$$
$$R(T) = 0$$

where ρ represents the royalty rate. The effect of royalties is well-documented in Heaps and Helliwell (1985) and Manzano (2000). Consequently, we are merely going to summarize the results already presented there.

As clearly seen from equation 2, the royalty distorts both margins. Consequently, less oil reserves are going to be developed. 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 and delaying tax payments.

Beyond these results, most of the literature on the topic has thus far focused on the tax burden.[10] We are going to refer to this tax burden as the Net Present Tax Rate (NPTR), and we can check it for this case:

$$\begin{aligned} NPTR &= \frac{\int_0^T pq\rho e^{-rt}\,dt}{\int_0^T \left[pq - c(q)\right]e^{-rt}\,dt - C(\bar{R})} \\ &= \rho\,\frac{\int_0^T q e^{-rt}\,dt}{\int_0^T \left[q - \frac{c(q)}{p}\right]e^{-rt}\,dt - \frac{C(\bar{R})}{p}} \end{aligned} \tag{3}$$

Looking at (3), we see a result widely reported in this area of the literature: i.e., the tax rate is going to be higher for oil fields with lower value (*p*), higher production costs ($c_0(q)$) and higher development costs ($C(\bar{R})$).

10 Kemp (1987, 1989) and Kemp and Rose (1984), for example.

This analysis assumes that the level of production is exogenously given. However, firms are likely to adjust their production plan according to the tax scheme they face.[11] Following Manzano (2000), it is possible to derive the change in the amount of reserves developed from the change in the royalty rate,[12] from there, it is possible to compute the change in reserves development for the different parameters of interest:

$$\underbrace{\frac{\partial \frac{dR}{d\rho}}{\partial C''(\bar{R})} > 0}_{(a)} \quad \underbrace{\frac{\partial \frac{dR}{d\rho}}{\partial c''(q_t)} > 0}_{(b)} \quad \underbrace{\frac{\partial \frac{dR}{d\rho}}{\partial p} < 0}_{(c)} \quad \underbrace{\begin{array}{ll} \frac{\partial \frac{dR}{d\rho}}{\partial c'(q_t)} = 0, & \forall\, t \neq T \\ \frac{\partial \frac{dR}{d\rho}}{\partial c'(qr)} > 0 & t = T \end{array}}_{(d)} \tag{4}$$

The results from 4.a and 4.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. Consequently, if we are interested in the amount of reserves not developed because of the tax structure, inelastic agents are going to reduce reserves less than the more elastic agents do. These results are similar to the standard results found in most public finance textbooks concerning inelastic agents. Inelastic agents should bear most of the burden since they alter the least their behavior because of the tax.

The result in 4.c contravenes the conventional wisdom derived from the NPTR. It implies that the reduction in reserves developed in high value fields, as a consequence of the royalty, is larger than in the case of low value fields. The reason for this is that high value fields are going to lose a larger proportion of income relative to the costs of development. Consequently, there will be a larger reduction in reserves.

Finally, 4.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. It is clear that if we have a tax system that allows us to deduct all expenses, the optimal solution

11 Therefore, we cannot draw final conclusions regarding just which fields are going to be more affected based solely upon the analysis of the NPTR. This view is relatively valid in a context based on geology. The idea is that each oil field has a “maximum efficient recovery rate”. Therefore, we could think of an oil field as a project where once we do a fix investment, we then receive a stream of income, determined by geological characteristics. Nevertheless, Black and LaFrance (1998) argued that this not the case. They actually test data from oil fields and found that oil production actually follows what would be an economically driven model.

12 The fact that producers do adjust to the presence of taxes is already mentioned in Livernois (1991), where the effects of tax brackets on the production path are discussed. Alternatively, Jacoby and Smith (1985) 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.

will not be affected by that system.[13] However, most of the tax codes do not recognize, or allow for, the amortization of these development costs. Instead, they offer a tax credit for them. These means that the oil producer faces the following problem:

$$\max_{\overline{R},q,T} V = \int_0^T \left[\left(pq - c_0(q)\right)(1-\tau)\right] e^{-r\tau} dt - (1 - \tau \cdot t_c) C\left(\overline{R}\right) \tag{5}$$

$$s.t.\ \dot{R} = -q$$

$$R(0) = \overline{R}$$

$$R(T) = 0$$

where τ represents the tax rate, and τ_c the tax credit given,[14] implying that only the development margin is distorted. Therefore, as long as tc<1, fewer reserves are going to be developed. However, there should be no impact on the extraction path. We can also repeat the traditional analysis for tax incidence, and get:

$$NPTR = \frac{\int_0^T \tau(pq - c_o(q))e^{-rt}dt - \tau \cdot t_c C'(\overline{R})}{\int_0^T \left[pq - c_0(q)\right]e^{-rt}dt - C(\overline{R})} = \tau\left\{1 + \frac{C(\overline{R})(1-\tau \cdot t_c)}{\int_0^T \left[pq - c_o(q)\right]e^{-rt}dt - C(\overline{R})}\right\} \tag{6}$$

Note that the tax burden is higher than τ because development costs are not allowed to be fully deducted. The fields that pay a higher tax rate are those that have lower value, higher development costs and higher operating costs. As before, this is a simplistic approach to the problem because this analysis does not take into account that producers will adjust their production plans when facing taxes. We can derive the change in reserves with respect to the tax rate, and with respect to the parameters we are interested in.

$$\underbrace{\frac{\partial \frac{dR}{d\tau}}{\partial C''(\overline{R})} > 0}_{(a)} \quad \underbrace{\frac{\partial \frac{dR}{d\tau}}{\partial c''(q_t)} > 0}_{(b)} \quad \underbrace{\frac{\partial \frac{dR}{d\tau}}{\partial p} < 0}_{(c)} \quad \underbrace{\frac{\partial \frac{dR}{d\tau}}{\partial c'(q_t)} > 0}_{(d)} \tag{7}$$

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 effect than in the case of the royalty. This is because the royalty is based only on 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 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 for fields with lower costs, the ratio of tax to development cost is much larger.

13 In this case, the right-hand-side of equation 1 will be multiplied by (1-τ), and it will disappear once we set the first order conditions.

14 This means that, for income tax purposes, you are allowed to deduct, as an expense, tc% of your investment in field development.

From this analysis it is relatively evident that an income tax appears to be better than a royalty, given that it distorts only one margin. Moreover, as tax systems move to include capital expenditures more appropriately - trough depreciation provisions, allowing for some form of capitalization that can be deducted later, etc. - they might generate fewer distortions. Another alternative to generate fewer distortions is making the government a partner, so that the government-take (the "tax") is collected trough the government participation in the oil project. For this reason, recent contracts in the oil sector have introduced alternative forms of government participation, partially reducing the distortions. Some of these provisions include: a government share in profits, or a tax on the repatriation of dividends, among others. In Table 1 we saw some of these mechanisms in the region.

Nevertheless, these instruments end up being a form of "rate of return regulation." The theory of regulation shows that a problem arises with the rate of return regulation, which is that it could induce overinvestment by the firms.[15] So giving the government a share on profits and/or taxes on dividends may have similar effects. Moreover, there is also literature on the perverse incentives that taxes with brackets may have on investment decisions by firms on the resource sector.[16]

Alternatively, this could be viewed as a problem of asymmetric information. The oil sector is characterized by relatively good information on oil quality, prices, reservoir depth, etc. Nevertheless, there is less information on the required investment to develop a field. This would be the equivalent of the labor economics literature on effort. For this reason, some governments may have decided to use more extensively the royalty.[17]

The main problem with the royalty is that it performs quite poorly to capture rents. As oil prices go up a set royalty rate captures less rent than a set income tax rate. Royalty rates are typically lower than income tax rates. If a government wants a specific share of the profits, leaving aside behavioral changes, it needs a higher income tax rate than a royalty rate. Because of that, when prices go up, the share of the government in the increased price is lower with a royalty.[18] Therefore, an important amount of rents remain with the producer and these rents are pro-cyclical.

Table 2 shows this. It presents a reference oil price per barrel (the WTI) and the average portion appropriated by the government, measured by the fiscal-take per-barrel as a share of the reference price. In the table it is evident that as the oil price increased, the average fiscal share decreased or remained stable, i.e. the tax systems are not progressive.[19]

15 Train(1983)
16 Livernois (1991)
17 See for example Mommer (2002). Though not formally, the author argues that the use of royalty could solve the principal-agent problem between the government and the oil firm derived from the asymmetric information on costs.
18 For example, with prices per barrel of $20 and costs per barrel of $10 a royalty of 25% (0.25 x 20 = 5) is equivalent to an income tax of 50% ((20-10) x 0.5 = 5). If the price of oil increases to $40 a royalty of 25% captures now $10 per barrel whereas an income tax of 50% captures $15 per barrel.
19 The Bolivian case is a textbook example of Rate of Return Regulation. Firms over invested and their liability was reduced.

Table 2
Fiscal take per barrel (% of international price)

Country	1996-1998	1999-2001	2002-2004
WTI	**19.0**	**25.1**	**32.9**
Bolivia	37%	24%	15%
Colombia	22%	21%	22%
Ecuador	66%	46%	51%
México	42%	38%	52%
Venezuela	51%	47%	53%
Trinidad y Tobago	37%	16%	23%
Argentina		20%	24%

Source: Authors' calculations based on official figures. The authors thank Sebastian Scheimberg for his help with the Argentine figures.

This could help explain the recent wave of tax increases. Most Latin American countries signed new agreements for exploration and development in the nineties. During the nineties, the average price of the WTI was US$19.96 per barrel. Therefore, most contracts were signed in a different price context. Most of them did not include provisions for higher prices. Those that were based on some form of rate of return regulation, came out of the period of highest investment, therefore, the tax burden was still reduced.

For that reason, we have seen an increase in the royalty rate in Argentina, Bolivia and Venezuela. In addition, in Ecuador and Venezuela windfall taxes have been recently approved. Moreover, given the theoretical framework discussed above, in most cases we are dealing with "inelastic fields". In other words in most cases we are talking about fields with low value, or where there was an accompanying sunken investment that is the binding constraint.[20] Given this, it is expected that firms will not change their behavior considerably once taxes are increased. It might have an effect on "entry" of new investment, but production will react very little.

An interesting fact is that during the nineties, in those countries where there was no privatization of the National Oil Company (NOC), but only a selective opening to private investment; in order to attract private investors, the better fiscal conditions were given precisely to this "inelastic fields". NOCs like PDVSA or Petroecuador kept for them the higher-returns fields, i.e. bigger fields and/or light crude fields. In some cases it was argued that the tax regime existing at the time was not competitive. However, as explained before, these reforms were mostly driven by lack of capital to increase production in the sector.

What happened is that in those countries production shifted towards crude coming from these contracts with private investors. This shift has two effects. One is that this might not be the optimal mix of production. The optimal production mix would require producing

20 For example, in the case of Bolivia and Ecuador there are pipelines that accompanied the investment in exploration and development.

first the higher quality and/or lower cost types of oil, and then move towards the lower quality and/or higher cost fields. Secondly, countries have become more fiscal dependant of these new fields. Consequently, countries were in a context of higher prices with relatively low taxes coming from the hydrocarbon sector. If most of the privately operated fields were perceived as “inelastic”, there were incentives to change tax rates as it happened in some countries in the region.

There is an important agency problem in oil exploitation. The source of the problem is that the government does not have good information on the investments and costs required for oil extraction.[21] A way to solve the informational problem is for the state to exploit the resources by itself. This could explain why in many countries governments own National Oil Companies (NOCs) that operate with a monopoly of the sector or in parallel to IOCs. However the main problem with this is the distributive conflict between governments and NOC’s in terms of resource allocation between giving resources to the government and fulfilling their investment plans.[22] As it will be explained later, the NOCs are in many cases more vulnerable to expropriation of revenues by the state through different mechanisms. Examples include PDVSA which executes directly significant social investments (before paying taxes), Petroecuador which has difficulties fulfilling its investment plans because the government’s Treasury directly receives payments for the oil exports, and PEMEX whose exports have been extensively used as collateral for the issuing government debt.

A final point is the relationship between taxes and economic volatility. In general, price volatility is expected to have a negative impact on investment, in particular in the case of projects such as oil exploitation. There is an important amount of literature using real option valuation techniques to evaluate these issues in the oil sector.[23] However, given that tax instruments do not take into account this volatility –i.e. they are not contingent- this adds a second element of volatility. Firms might include the uncertainty of tax changes in their evaluation of different projects. In a recent study by Moles et al. (2005) for the North Sea, the authors found that including tax volatility into the model, the valuation of the assets involved in this activity could be reduced up to 20%. This could lead to less investment in the sector.

In summary, the instruments used in the region for the taxation of the hydrocarbon sector tend to have the problem of leaving rents with the producing firms. These rents are pro-cyclical and give incentives to the governments to enter into an “expropriation” cycle. This tax volatility compounds the effects of oil price volatility and leads to less investment in the sector of what would be the optimal level.

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[21] It is important to recognize that after the oil crises of the late seventies and early eighties, the amount of information coming out of the oil sector has been increasing. Governments know oil quality, reservoir depth, pressure, etc. However, there is still an amount of private information from the part of the oil firm, which is not available to the government. As argued before, this is closer to the literature on workers’ effort in the field of labor economics.

22 For example, in Venezuela in the nineties, the average investment just in the production phase of the oil industry averaged around 3.4% of GDP. During the same period the fiscal deficit averaged around 1% -not including the cost of the financial crisis. Therefore, for the government these resources have alternative uses.

23 See Kretzschmar et al (2005) for a review of the literature.

3 The Political Economy of Taxation and Contracting in the Latin American Oil Industry

Economic and political economy factors help us explain the patterns of development that exist in the oil industry. We first start by presenting the main characteristics of the oil industry that make it particularly susceptible to changes in the tax and contractual conditions. Second, having argued that tax systems are relatively infective in capturing the rents, particularly when prices go up, and typically generate significant distortions; in this section we analyze the political economy of oil taxation and contracting in the region.

3.1 A primer on the oil industry's characteristics and the sources of expropriation

There exist significant rents in oil exploitation. For example, the cost per-barrel in the region (and the world) typically varies from as low as $1 to as high as $15. As a result, rents skyrocketed as the price of oil rose to levels above $70 dollars per barrel in recent times. In theory all rents can be captured by the state -which typically has sovereign control and property rights over oil reservoirs- without affecting long-term production.[24] In practice, as argued above, significant rents are often kept by the producer. The problem arises from the fact that tax and contractual frameworks are typically not very progressive. As a result, when there is a large increase in the international oil price, there are incentives for the government to renege on deals made when the oil prices were lower.[25] In addition, some rents are typically captured by other groups including the oil workers, local actors, and domestic consumers.

There exists a time inconsistency problem in oil investment. A large proportion of the investments in oil production are sunk-costs, i.e. assets that are immobilized even before revenues start being collected. For example: seismic studies, exploration and production wells, and pipelines, are sunken investments. Once deployed, the ex-post value of these assets in alternative uses is very low; as a result there exist significant quasi-rents that can be appropriated (Klein, Crawford, and Alchian, 1978; Williamson, 1996).[26] The operator would do better by continuing to operate as long as he can recover operational and non-sunken assets, even if he cannot recover the sunk costs. As a result, the government, or

24 A definition of rent is the excess revenue above the opportunity cost of the reproducible factors of production (i.e. labor and capital). Mineral rents can be the result of the natural lower costs of extraction or higher quality of certain mineral reservoirs, compared to the marginal producer; these are known as differential rents. In addition, rents can arise from monopolistic restrictions to access the mineral reservoirs or from output restrictions by cartels.

25 In this case the increase in government-take may be only capturing the additional rents provided by the increase in oil prices and not expropriating the quasi-rents (see below). Still, the prospect of contractual changes increases the risk for investors.

26 A definition of quasi-rent is the difference between the ex-ante and ex-post opportunity cost of the production factor. In contrast to rents, if the quasi-rents are extracted to the producer, long run production would be affected. The operator would continue operating in the short run as long as he can recover operational and non-sunk costs, but he would not redeploy sunken assets, i.e. he would not invest.

other actors, may expropriate the quasi-rents by opportunistically changing the conditions of investment, for example the taxes, the regulations, or the domestic price of oil. The political benefits of opportunistic reneging are high. In the short term the government can extract significant fiscal resources or transfer them to the domestic consumers of energy, without a significant impact on oil production. The expropriation of revenues from state-owned enterprises can also be a significant problem, depending, among other variables, on their governance structure (Monaldi, 2002 and 2005).

In addition to the existence of appropriable quasi-rents, hydrocarbon production is risky because world oil reserves are concentrated in underdeveloped countries with weak institutions and high political risks. As a result, governments have trouble committing to allow private investors -or state-owned enterprises- to recover their sunken investments. If the political benefits of reneging are high and the short-term costs low, only strong domestic institutions or external enforcement would provide credible property rights. In fact, throughout the history of oil and mineral investment in developing countries, external enforcement played a more significant role than domestic enforcement. For example when there existed a cartel of oil multinationals that could coordinate punishment and the hegemonic powers enforced international property rights (Lipson, 1985). More recently, multilateral arbitration, investment treaties, and loans guaranteed by oil export receivables, have provided some degree of external enforcement (Monaldi, 2002). Still in a few cases (e.g. Brasil, Chile, Norway), domestic political and regulatory institutions have provided credible commitment to foreign investors in high sunk cost sectors (Levy and Spiller, 1996).[27]

The reputational costs of reneging on sunken investments are high when the governments are eager to attract new foreign investment (particularly in the same sector). Thus, expropriation is less likely when a new cycle of investment is being initiated, either because production is starting, or there has been a long period of disinvestment (possibly due to previous expropriation), or the government does not have the necessary fiscal resources. In contrast after long periods of high investment and rising revenues (and reserves), or when the government has plentiful financial resources; the likelihood of expropriation increases.

The incentives for governmental reneging also depend on the discount rate of politicians. In the presence of weak institutional frameworks, episodes of economic and political instability induce high discount rates, which make the reputational costs of reneging less relevant. The short term benefits of expropriating the oil industry combined with the occurrence high discount rates, have made the oil industry a very tempting target in the past. For example, as a result of the Argentinean economic crisis of 2000-2002, the government reneged on oil contracts.

27 Levy and Spiller (1996) identify three conditions required for institutional commitment: 1) the existence of substantive legal restrictions to government reneging, 2) the existence of higher level procedural restrictions to changing the legal restrictions, and 3) the existence of credible institutional mechanisms to enforce the first two types of restrictions (e.g. independent judiciary). The case of Chile in electricity is presented as one example of credible commitment supported by domestic institutions.

The existence of high geological risks in the exploration phase provides incentives for governments to offer attractive deals in order to attract private investment. However, when exploration is highly successful, the incentives for ex-post renegotiation by the government may be significant. Contracts typically do not incorporate clauses that allow the government to capture all the large rents that arise after significant new discoveries. As a result, even in the initial phase of production, there has been a tendency to observe changes in the fiscal and contractual conditions after the discovery of major hydrocarbon reserves which significantly increase the net present value of the project.[28] Similarly, as has been argued, because fiscal and contractual frameworks are typically not progressive to increases in oil prices; in periods of high oil prices there has been a tendency to renegotiate taxes up (Monaldi, 2005).

The massive consumption of oil and gas products (including gasoline and residential gas) has made their domestic pricing a charged political issue. Politicians are therefore pressured to avoid significant increases in domestic energy prices. As a result, in some exporting countries, domestic prices have been regulated below the opportunity cost of exports, especially during periods of international price hikes. In contrast, since the demand of oil products is highly inelastic, in some countries consumption taxes have been a favorite tool to obtain fiscal revenues.

Volatile oil prices generate volatile oil rents. We have already argued that fiscal systems have a hard time capturing oil rents in different price scenarios; as a result, price volatility is particularly problematic. In addition, in the particular case of oil dependant exporters, volatility may create macroeconomic and fiscal instability, unless stabilization mechanisms are effectively implemented, which has been typically not the case. As a result, oil dependent governments might be tempted to renege on oil companies, particularly the state-owned, when the oil prices fall and the government faces a fiscal crisis. A high discount rate of government officials, partly induced by the high volatility of oil income, could make the reputational costs of reneging less relevant during a fiscal crisis. A fiscal crisis produced by a non-oil shock could also make the oil industry a tempting target.

3.2 Actors and Incentives

In general, governments have incentives to attract oil investments because they benefit from the development of oil projects and oil production in their territory. The economic activity generated and the tax collected, provide authorities with both fiscal resources and political support from constituents. However, as explained before, once investments have been deployed and production is ongoing, governments might have incentives to renege on previous oil deals. In particular they might have incentives to increase the government-take or regulate the domestic price of production.

The governments' incentives depend also on the extent to which the country is a *net exporter* or a *net importer* of oil. In case the country is a significant net exporter, one key issue is if oil revenues can represent a significant source of fiscal income. In such case,

28 This phenomena was labeled as the "obsolescing bargain" by Vernon (1977)

there are powerful incentives to maximize generation and appropriation of rents from oil exports. Depending, among other things, on the discount rate of politicians', the level of the country's oil reserves, and future market expectations; this rent maximization could imply a strategy focused on short-term fiscal revenue extraction or more concerned towards increasing long term production.[29] Net exporters are typically more reluctant to privatize *national oil companies* (NOCs), because NOCs can be more easily used than private companies as cash-cows or piggy-banks. In addition, since they capture mineral rents, the oil NOCs are typically less deficit prone and debt-ridden compared to other state-owned companies, making the rationale for privatizing them politically less compelling.[30] Moreover, given that oil taxation inevitably introduces distortions; for significant exporters state-ownership might appear as a less distortionary alternative than having high marginal taxes on private operators, particularly when the oil price is high.

In case their governments are willing to offer foreign investors access to their oil reserves, net exporters with substantial oil reserves would tend to have the upper hand in their negotiation with *international oil companies* (IOCs), given that these companies have few alternative options to increase their reserves. They typically open first the projects with lower rent generation. When the price of oil in the international market goes significantly up, net exporters are in the best position to negotiate. Moreover, IOCs with existing sunken assets in the country would be in particularly weak bargaining position, if the governments attempts to change existing conditions. As a result, resource nationalism and increases in tax rates are typical in net exporters during periods when the price of oil rises significantly.

In contrast, in the case of *net oil importers* the incentives are skewed towards increasing investment and production. Rent extraction from upstream activities becomes less relevant. Given that production is domestically consumed, rents are not generated in the international markets; rather they are extracted from political constituents. Moreover, oil imports are potentially very costly when oil prices are high, generating high political and/or fiscal costs, and external account problems. As a result, net importers typically provide more attractive terms for oil exploration and extraction (although this can be partly a result of the lack of attractive geological prospects). Still, there can be situations in which the governments of net importers renege on oil deals, e.g. an oil price, an external shock, and a high political discount rate. For example, the domestic price of natural gas or oil products can be regulated down, or the existing exports heavily taxed or forbidden, in order to benefit domestic consumers and obtain constituent support.

In addition, net oil importers typically offer fewer subsidies to the domestic consumption of energy. They do not have external oil rents to cover for these subsidies. Instead, they have to finance subsidies with cross-subsidies, other taxes or inflation. In addition, net importers in the face of fiscal deficits or the need for large investments in oil, are typically more willing to privatize their NOCs. Since in this case NOCs do not obtain external rents, they can more easily generate net losses.

29 In addition if the country is a relevant player in the international oil market the government has to decide if it wants to belong to OPEC or not, and in case it belongs if it respects the cartel production quotas.

30 A counterexample is YPF, the NOC of Argentina, which incurred in significant deficits before being privatized. However, Argentina was not a significant oil exporter.

In general governments with oil and gas reserves are in a better negotiating position to increase government-take and control if:

1) They have higher oil reserves and higher prospectivity (likelihood of finding oil and gas in exploration). IOCs would be interested in entering and staying in this type of country.
2) They have financial resources to finance the needed oil investment (due to high oil revenues or access to international financial markets). In contrast, when governments are in dire need of financial resources, IOCs are needed.[31]
3) At the end of an asset deployment cycle, after a successful investment period, when there are significant sunken assets and little new investment is required.
4) When the price of oil and gas in the international market is quite high.

The NOCs' managers may have different incentives from their governments. For example, they typically prefer to keep resources in the company, rather than pay taxes. The managers' incentives depend largely on the institutional and governance structure regulating the NOC. For example, if the company is highly politicized, it could become a clientelistic vehicle of the ruling party. Using rents and quasi-rents to over-employ and over-pay party supporters.

The political costs, for the government, of expropriating revenues from the NOC will depend on how autonomous and institutionalized the company is; and how discretional the fiscal regime is. If the Ministry of Finance or the Executive can discretionally decide the government-take over oil revenues, or fully control the budget of the NOC, the costs of expropriation are low. In general, extracting revenues from the NOC is typically less costly than doing it to a private company. The cases of Petroecuador, PEMEX, and PDVSA today are clear examples. However, there have been cases of financially autonomous NOCs were systematic expropriation has been avoided (e.g. PDVSA in the nineties, Petrobras). One mechanism to reduce the likelihood of expropriation of a NOC has been the existence of private shareholders and a listed stock (e.g. Petrobras, Statoil).

Beside states and NOCs, the IOCs are the other key player in the oil business in Latin America. There are only a few relatively small domestic oil companies in the region.[32] The IOCs maximize global profits, typically with longer horizons than those of the developing countries governments'. They provide capital, know-how, technology, and human capital in exchange for oil profits. In the era of the *seven sisters* cartel of multinational oil companies they were able to coordinate to impose high costs on reneging governments. However, after the rise of the independent oil companies and the increase in the sovereignty of many developing producing areas in the 1960s, the capacity of external enforcement greatly diminished. The ensuing massive nationalizations of the 1970s dramatically changed the structure of the oil market making the NOCs of exporting countries very powerful players.

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31 Depending on the availability of domestic human resources, technology, and know-how, governments may have more incentives to attract IOCs.

32 Argentina has had the more relevant domestic private companies. The largest, Perez Companc was bought by Petrobras.

3.3 The Latin American Oil and Gas Sector

Latin American countries differ in many of the endowment and institutional dimensions, described above, which shape the governments' incentives. Accordingly, their oil sectors have had relatively different trajectories. Still there have been some common trends in the evolution of the oil sector in the region (that can be also partially attributed to the features discussed above). In particular, in the past two decades there have been extensive changes in the institutional framework of the oil and gas sector throughout the region.

Proven Conventional Oil Reserves (billion barrels)			
	1986	1996	2006
Argentina	2.2	2.6	2.0
Bolivia	0.0	0.0	0.0
Brazil	2.4	6.7	12.2
Colombia	1.7	2.8	1.5
Ecuador	1.2	3.5	4.7
Mexico	54.9	48.5	12.9
Peru	0.5	0.8	1.1
Venezuela	55.5	72.7	80.0
Total	**118.5**	**137.4**	**114.3**

Source: BP Statistical Review of Energy, 2007

As can be seen in the enclosed tables, the countries in the region vary dramatically in terms of their oil reserves. Venezuela's reserves are by far the largest and have been growing in the last two decades. Mexico's reserves are the second largest, but have been revised significantly down.[33] Brazil has the third largest reserves, which have been increasing, but still are not that significant relative to its consumption and population. Very recent discoveries promise to make Brazil a future exporter. Ecuador ranks fourth, with increasing reserves, which are relatively significant in per capita terms and relative to domestic consumption.

In terms of natural gas reserves, Venezuela ranks first but 90% is gas associated to oil, which is generally used for re-injection for oil production. Bolivia has the second largest gas reserves, which are non-associated, and therefore more amenable for exporting them and using them for residential and industrial use. Argentina and Mexico are next in natural gas reserves. Brazil and Peru have made important recent discoveries. The rest of the countries in the region, with the exception of Guatemala, have negligible levels of oil and gas reserves.

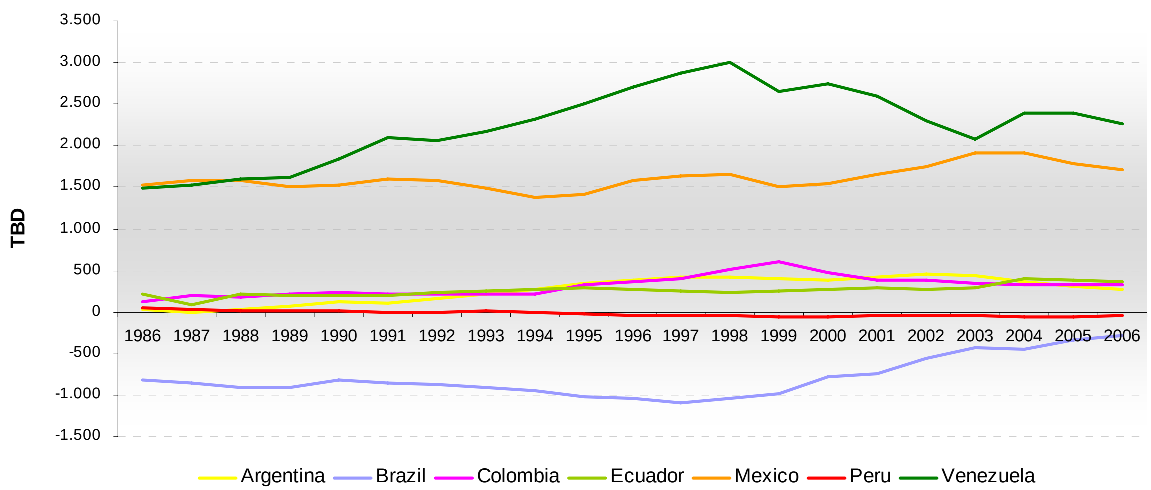
33 PEMEX reserves were reduced after having been audited according to the SEC rules. The reserve certification was required due to the use of the oil receivables from PEMEX exports as debt collateral.

Proven Natural Gas Reserves (trillion cubic meters)			
	1986	1996	2006
Argentina	0.7	0.6	0.4
Bolivia	0.1	0.1	0.7
Brazil	0.1	0.2	0.4
Colombia	0.1	0.2	0.1
Ecuador	0.0	0.0	0.0
Mexico	2.2	1.9	0.4
Peru	0.0	0.2	0.3
Venezuela	2.6	4.1	4.3
Total	**5.8**	**7.2**	**6.7**

Source: BP Statistical Review of Energy 2007

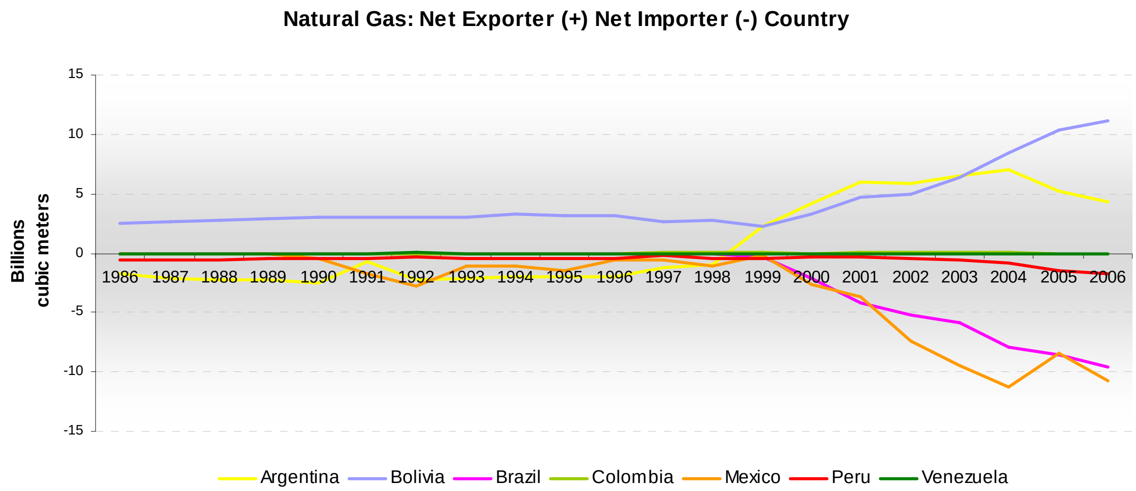
As shown in the graph below, the largest net oil exporters are Venezuela and México. Ecuador is next with increasing exports of around 400 thousand BD. However, Ecuador's oil exports in per capita terms are the second largest in the region behind Venezuela's. Colombia and Argentina have become relevant net exporters in the last two decades. However, in both countries production has been declining in the last few years. Brazil and Peru have been net importers of oil. Brazil has been able to significantly decrease its dependence on imported oil and become self-sufficient. Peru has not had much success in increasing production.

Oil: Net Exporter (+) Net Importer (-) Country



Source: BP Statistical Review of Energy 2007

Argentina and Bolivia are the region's natural gas net exporters. Venezuela despite its huge reserves consumes its gas production domestically, mainly as an input for oil extraction. Other countries, in particular Brazil and Mexico, are significant net importers of natural gas.



Source: BP Statistical Review of Energy 2007

In terms of institutional variables there is also significant variation in the region, for example, in terms of state and private participation in oil and gas production. In one extreme is Mexico where oil production has been a state monopoly for 70 years and only recently there has been a timid opening to the private sector using natural gas service contracts. Next come Brazil, Colombia, Ecuador, and Venezuela which have a dominant state owned company. However, in Brazil, Petrobras was partly privatized and although the state maintains control through special voting power shares, the majority of the stock is in private hands. In 2006, Colombia followed Brazil's path, with the privatization of a minority portion of Ecopetrol stock. In contrast, in Ecuador and Venezuela, the NOCs have not sold stocks in the market. Still, in both countries private operators became increasingly relevant in the last decade getting to produce over 40% of the total oil extracted. On the other extreme are the cases of full privatization in the nineties in Argentina, Bolivia (through "capitalization"), and Peru. However, in Bolivia, in the last two years, there has been a dramatic reversal of privatization, with the recent nationalization of the natural gas industry and the oil refining facilities.

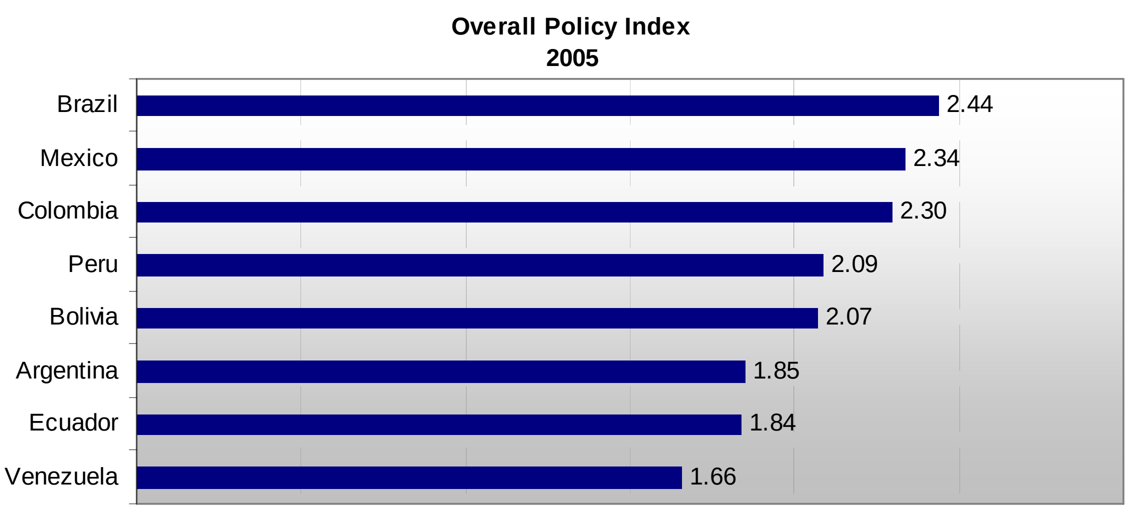
The trend towards privatization and opening to private investment in the 1990s was partially the result of the market reforms induced by the fiscal crises of the 1980s in the region. Moreover, the decline in oil prices implied that there were less rents to finance oil investments. However, there were no privatizations in the net exporters, like Ecuador, Mexico, and Venezuela, where the state had a significant fiscal and financial (e.g. used for debt emissions) dependence on the national oil company. In contrast, in net importers (Brazil and Peru) or small per capita exporters (Argentina), some with deficit ridden oil companies, privatization prevailed.

There are also clear divergent paths in the recent trends of reform of the regulatory and tax regimes. In the last five years, Argentina, Bolivia, Venezuela, and Ecuador, have reneged on oil contracts and increased the government-take on oil and gas private production. In these countries, private investors were partially the victims of their own success. The large private investments in the previous decade resulted in increased reserves and production.

As a result, the large sunk investments, and the recent increase in the international price of oil and gas, provided a perfect opportunity for the governments to renegotiate the contracts.

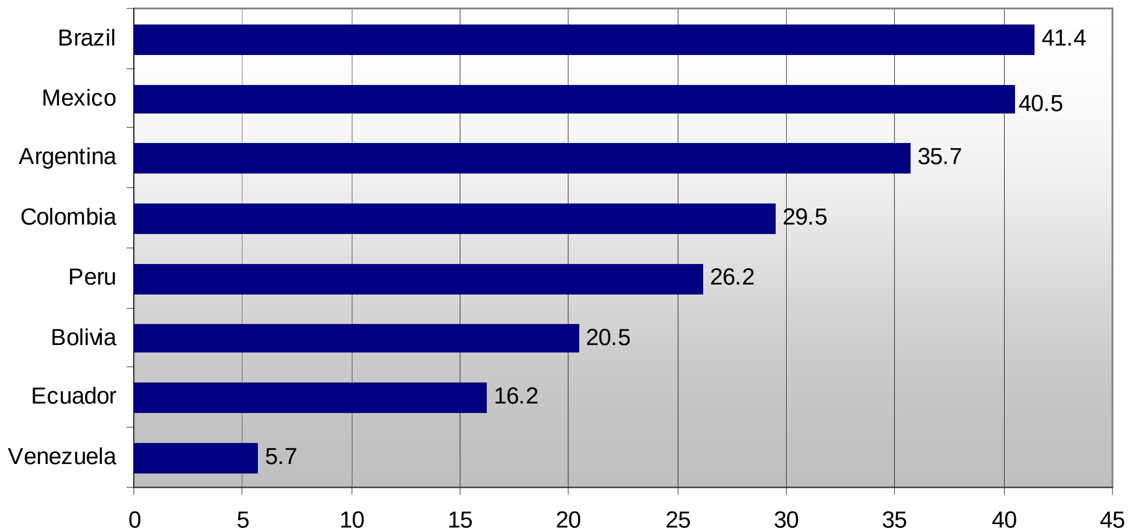
In contrast, in the last few years, Brazil, Colombia, and Peru, have strengthened the credibility of their regulatory framework and moved generally in the direction of promoting private participation. Brazil and Peru have been net importers eager to obtain more oil and gas investment. In Colombia, the decline in reserves and production, promised to transform the country into a net importer in the next decade if radical actions to promote investment were not taken.

It is important to notice that the countries in which the governments have changed the rules of the game with respect to the oil tax and contractual frameworks, generally also have relatively low ratings in different subjective measures of institutional strength and rule of law that are not based on the energy sector, such as the ones compiled by the World Bank and the Inter-American Development Bank. In contrast, Brazil and Colombia the countries were the oil sector institutional framework has been strengthened have relatively good ratings in these measures. The oil and gas sector regulations are in fact framed in the larger set of domestic political institutions. For example, a country with the current institutional endowment of Venezuela would have difficulty committing by using domestic institutional guarantees. Still Bolivia, one of the leading resource nationalists, had a relatively good standing in this measures. Moreover, in countries like Argentina, Ecuador, or Venezuela, despite the institutional weaknesses that have been present, contracts were respected during the nineties and reneged later on, showing that the timing of reneging cannot be attributed just to the relative strength of domestic institutions. Moreover, as explained before changes in oil tax and contracts have been common elsewhere, even in developed and highly institutionalized countries, such as Britain, Canada, and the U.S., when the triggering conditions have occurred.



Source: IDB, 2006

Rule of Law (Percentile Rank)
2006



Source: World Bank, 2007

3.4 Country Cases

In this sub-section the country cases of the region's relevant producers are briefly discussed, analyzing the political economy factors that affected the institutional and economic evolution of the oil and gas sector.

Venezuela

The case of Venezuela exemplifies the dynamics of investment and expropriation cycles. The periods of contract renegotiation have coincided with the end of successful cycles of investment, and nationalizations have occurred during periods of oil boom. The country has generally behaved as a typical significant net exporter with short term horizons, maximizing short term rents and heavily subsidizing the domestic oil products market.

Venezuela is the second largest producer, the largest exporter, and has by far the largest hydrocarbon reserves in the region.[34] It is also the only founding member of OPEC in the region. Oil has been for decades the main source of fiscal revenues (at around 50%) and exports (above 80%). After decades of high investment, in the 1960s and 1970s oil taxation of the IOCs was significantly increased and oil concessions were not renewed. As a result, oil investment declined throughout the 1958-1976 period. In contrast, oil production capacity kept increasing until the early seventies, and then abruptly fell, but with a significant lag. The oil industry was eventually nationalized in 1976. After nationalization, PDVSA, the NOC, increased investments dramatically, taking advantage of the high oil

34 If the non-conventional hydrocarbons of the Orinoco Belt are included, Venezuela could claim to have the largest crude reserves in the world. Total reserves would be above 300 billion barrels.

prices that prevailed. The governance of the NOC was designed to minimize political interference and rent extraction from it (Monaldi, 2005).

By the early 1990s large new investments were needed to increase production. PDVSA significantly increased capital expenditures.[35] Still, the fiscal difficulties of the government induced the opening of the oil sector to private operators using a special contractual framework that provided some credibility against government reneging, by using PDVSA and its foreign assets as a guarantee. The projects offered to private investors were the ones with lower rent generation, mature or abandoned oil fields (high cost), extra-heavy crude that requires expensive upgrading (high costs), and exploration. Consequently the contracts with private operators generally set lower implicit tax rates (Monaldi, 2005).[36]

In the late 1990s, private investment substantially increased, adding 1.2 million BD of production by 2005. In contrast, after 1998, the government increasingly extracted more resources from PDVSA. Still, until late 2004, the revolutionary government of President Hugo Chavez honored the private contracts despite having changed the constitution and the oil law to increase government control over the oil sector. The externally enforceable contractual framework, the institutional autonomy of PDVSA, and the fact that significant private oil investments were being deployed in 1997-2003, provided protection for the investors' property rights.

In the case of Venezuela, the evolution of the government-take in the sector reflects the "composition effect," i.e. the relative increase in privately operated production with a lower implicit tax, and the reliance on royalties. PDVSA's production declined in 1998-2003, while the privately operated production increased until 2005. Consequently, the share of private production increased. Moreover, as explained above, the government-take on the private sector production was lower than the one applied to PDVSA. In general, looking back at Table 2, it can be seen that even though the oil fiscal take per barrel increased in absolute terms from 1996-1998 to 1999-2001,[37] the share of the government in total oil revenue actually decreased. As explained before, systems based on royalties, which are not progressive, tend to have this effect.

In 2002-2003, the attempt of the government to eliminate the autonomy of PDVSA resulted in a massive oil strike that dramatically diminished oil investments and production. The government fired half of the oil workforce and most of the management, taking complete political control over the company. Moreover, by 2004 the private oil investment cycle had concluded, and the higher oil price provided incentives and opportunities for renegotiating the oil contracts. As a result, in the last two years the contractual framework of the oil opening has been significantly changed, considerably increasing the government-take and control over private investments. By 2007 the government had "nationalized" the oil

35 In the 1980s, Venezuela's production was limited by OPEC quotas, making investments in exploration and production relatively unnecessary. In addition, after the debt crisis the government began discretionally extracting revenues from PDVSA. After the elimination of OPEC quotas in the late 1980s, PDVSA was able to increase production using its spare production capacity.

36 For example, the extra-heavy oil projects of the Orinoco Belt had a 1% royalty and a 34% income tax, compared to the 16.66% royalty and 67% income tax rate charged to PDVSA at the time.

37 From around US$ 9.70 to US$ 10.30 per barrel.

industry, taking majority control of all privately operated projects, without providing market compensation. The weakening of the domestic institutional framework has resulted in a new cycle of expropriation. It is also important to notice that Venezuela, the largest net exporter relative to its domestic market, has been the country with the highest subsidy of domestic oil product prices.[38] In sum, the case of Venezuela, shows that contract renegotiation and expropriation has occurred during periods of increasing rents, and after high investment has been sunk.

Mexico

The case of Mexico exemplifies the use of the NOC as a fiscal, financial, and political tool, in a net exporting country. If the regulatory framework is not reformed, the country would probably face declining production and reserves in the future.

Mexico is the largest oil producer in the region and second largest country in terms exports and reserves. However, reserves dramatically declined in the last decade. Mexico became a significant oil exporter in the early part of the XX century. Oil was nationalized in 1938 and until the 1970s Mexico ceased to be a relevant net oil exporter.[39] Important reserve additions in the 1970s allowed a significant increase in production and exports, financed by the high oil prices. The proportion of oil in total exports (about 10% in 2004) is not nearly as relevant as in Venezuela (85%), Ecuador (50%), or even Colombia (30%). This is in sharp contrast with the 1970s when oil exports represented more than 70% of the total. Nevertheless, oil fiscal revenue is still very relevant for the Mexican government (above a third of the total). Only in Venezuela and Ecuador, oil fiscal dependence is higher.

The Mexican NOC, PEMEX, does not have financial autonomy from the government and it was generally used as a clientelistic tool of the ruling party (PRI). It has also been systematically used as a vehicle to guarantee government debt.[40] The budget of PEMEX is part of the government's budget approved by Congress; as a result, macroeconomic considerations have generally prevailed in its design (Campodónico, 2004). The excessive fiscal dependence of the Mexican government on PEMEX has required a government-take of more than 60% of oil profits, during the last decade, significantly higher than in Venezuela or Ecuador.

The lack of financial autonomy has limited PEMEX's own investment capacity, inducing the company to become highly indebted and to use an out of budget mechanism of deferred payment of projects (PIDIREGAS) to finance the expansion of production.[41] Oil production was sustained until recently, by the very large oil field of Cantarell which has lately started to fall. As a result oil production decline is expected to continue in the next few years. The

38 Domestic subsidies (with respect to the opportunity cost of exporting) exceeded US$ 10 billion in 2006.
39 The decline in Mexico's oil export capacity can be largely attributed to geological factors. Although, initially Mexico was punished by the IOCs for nationalizing the oil industry, the decline in production can be traced to lack of exploratory success. In the 1970s oil offshore discoveries increased the Mexican oil reserves allowing the country to become a net exporter again (Haber et al., 2003).
40 PEMEX debt has increased from $21 billion in 1998 to more than $50 billion in 2005. www.pemex.com
41 PIDIREGAS is an out of budget mechanism that allows the company to contract projects to private contractors and pay them, once finished, suing the new assets to guarantee loans (Campodónico, 2004)

Mexican oil and gas sector urgently need an increase in investments to avert the dramatic decline in reserves and sustain the falling export volume.

PEMEX has traditionally been one of the more inefficient oil NOCs. The use of the company as a clientelistic tool has implied the appropriation of oil rents by the labor unions and the PRI.[42] Still, due to its favorable endowment, PEMEX has been able to provide significant rents to the state, and Mexico has been significant net exporter with less fiscal difficulties than Argentina, Venezuela or Ecuador. As a result, it has been able to postpone privatization or opening to oil private investment (Palacios, 2003).[43] In sum, the institutional framework based on a state monopoly with little autonomy has allowed the government to capture the increasing rents but the expropriation of revenues has left the NOC with high debt and little investment capacity.

Ecuador

Ecuador has had one of the most volatile oil policies in the region, partly a refection of the high political volatility in the country. However, as was the case with other net exporters, which were able to increase investments and production in the nineties, the recent tendency points towards contract renegotiation, higher taxes, and expropriation.

Ecuador is the third largest exporter in the region, and has the fourth largest oil reserves. More than a third of the fiscal revenues, and close to half of the exports, has been generated by oil. More than half of oil production is operated by the NOC, Petroecuador, but an increasing proportion has been extracted by private companies.

As PEMEX, Petroecuador, has very limited financial autonomy. The government collects the oil revenues and gives Petroecuador back very limited resources for reinvestment. As a result, the company has had persistent difficulties fulfilling its investment plans. Due to the NOC financial difficulties and the decline in oil prices, in the 1990s progressively more attractive conditions were given to private investors. Production sharing contracts were established in 1993 and join-ventures in 1999. The reforms of the 1990s were successful in attracting an increased flow of investments. In the early 1990s annual foreign investment in oil was below US$ 200 million, by the early 2000s it had surpassed US$ 1 billion (Campodónico, 2004).[44]

In the case of Ecuador, the evolution of the government-take in the sector also reflects the "composition effect". Petroecuador did little investment in the last few years. As a result, its production declined. In contrast, the private sector production has been increasing.

42 PEMEX employed in 2002 three times as many workers as PDVSA in relation to production. The labor unions have obtained significant rents through contracting assignments.

43 Until now, the only, timid attempt to open the hydrocarbon sector has been the multiple service contracts in natural gas exploitation. This mechanism still represents a very minor source of investments. As shown before, Mexico is a significant net importer of natural gas; this condition and the existence of relevant gas reserves would probably provide incentives for further reform in this sector.

44 In 2003, again due to the NOC financial difficulties, additional reforms to favor private investors and reduce the role of Petroecuador were decreed by President Lucio Guitierrez, but never formally passed by Congress. After Gutierrez was thrown out of office, a new cycle of resource nationalism began.

Consequently, the share of private production on total production has risen. As explained in Table 1, the implicit tax rate on private production is lower. Because of that, as shown in Table 2, in spite of the increase on oil prices, the share of government revenue on oil revenue was relatively constant.

In the last few years, legal reforms increasing government-take have been approved and the government reneged on an oil contract with Occidental Petroleum. In particular, the election of President Rafael Correa, on a resource-nationalism platform, prompted increases in government control and the approval of a windfall tax. As in Venezuela, in the case of Ecuador the successful attraction of private investment in the nineties, combined with the recent increase in the price of oil, has provided the incentives and opportunities to renege on the original deals.[45] As in Mexico, the governance structure of the NOC has induced excessive expropriation of revenues and lack of state investment in the oil sector.

Colombia

Due to its declining production and reserves, Colombia has defied the trend of net exporters in the region, strengthening the regulatory framework, providing more attractive conditions for foreign investors, and partially privatizing the NOC.

Colombia is a net exporter, but its production, exports, and reserves have been declining in the last few years. Oil became a relevant source of exports and fiscal revenues in the late 1980s and 1990s, accounting for more than 20% of the total fiscal revenues and close to a third of exports. Ecopetrol, the NOC, produces directly and in association more than half of the oil extracted.

As in most countries in the region, conditions for private investments were improved in the 1990s. In 1999, a system of variable royalties made private investment in marginal fields more attractive. However, in Colombia as in Peru, despite the attraction of new private investments, there was little success in the addition of new oil reserves. At the prospect off becoming a net importer in the near future, in the last three years the Colombian government has implemented some additional reforms to induce more investment. The reforms were aimed at improving regulatory credibility, providing a more flexible tax regime, and making Ecopetrol, more accountable and financially autonomous.[46]

In contrast, to Venezuela, Ecuador, and Bolivia, the investment cycle of the 1990s did not generate an increase in production and reserves, or the consequent incentives for expropriation. In fact, in case the new reforms fail to significantly increase investment and the successful addition of reserves, Colombia could become a net importer in the next decade.

Argentina

45 In addition, the political instability that has plagued the country has generated an environment of significant legal uncertainty.

46 One key reform has been the creation, as in Brazil, of an independent regulatory agency to supervise the oil and gas sector. Another recent reform has been the partial privatization of Ecopetrol.

Argentina's success in obtaining investment in the nineties bred the conditions for contract renegotiation as a result of the dramatic economic crisis of 2002.

Argentina has the fifth largest proven oil reserves in the region, but until the 1990s it was barely self-sufficient. It implemented one of the most radical privatization, liberalization, and opening programs starting in 1989, having very significant success in attracting foreign investment in oil and gas, as well as significantly increasing production. Foreign investments in the oil sector exceeded US$27 billion in 1992-2002, more than 35% of total foreign investment in the country. As a result, the country became a net exporter of both oil and natural gas.[47]

In 2002, after the economic crisis exploded, the government implemented some emergency measures including a new oil export tax of 20% and domestic prices have been re-regulated. The success of the liberalization of the nineties and the fact that the country became a net exporter, has allowed the current administration to significantly worsen the conditions for foreign investors.

Brazil

The case of Brazil is an example of a net importer successfully trying to become self-sufficient. The institutional framework has provided credibility to investors and prevented the expropriation of the NOC.

Despite being the region's third largest producer, Brazil has been until recently a net importer of oil. However, in the last decade, it has been very successful in reducing its import dependence. In 1995-97 the oil sector was opened to private investment, eliminating the constitutionally sanctioned monopoly of the NOC, Petrobras. To provide regulatory credibility to private investors, an independent regulatory agency overseeing the oil sector was created. In addition, Petrobras has been partially privatized. Although the state maintains control of voting shares, the majority of its capital is now in private hands.

The institutional autonomy and accountability of Petrobras contributed to a dramatic increase in its levels of investment and production, directly, in joint-ventures with IOCs, and through project finance mechanisms. In the 1992-2002 period Petrobras investment exceeded US$46 billion. In addition, the country has made five auctioning rounds of oil areas for private investment.[48] As a result, Brazil has significantly reduced its dependence of foreign oil and gas, and it has become close to a self-sufficient country.

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47 The reforms of oil sector were part of the market oriented reforms of the Menem administration. The tax and contractual regime for private investment in oil became the most liberal in the region. Domestic oil product prices were deregulated. In addition, YPF the deficit ridden NOC, was privatized in 1993. YPF was highly inefficient, and in contrast to PEMEX and Petroecuador not a net exporter, making it propitious target for privatization. Eventually, the Spanish company Repsol obtained majority control over YPF. After the 2002 crisis, the Brazilian NOC, Petrobras, bought the private Argentinean oil company Perez Companc.

48 The country has been less successful in attracting interest in the recent auctioning rounds than in the projects in partnership with Petrobras.

The reform of Petrobras and the Brazilian oil sector, contrasts sharply with the lack of reform in PEMEX and Peroecuador, and the politicization of PDVSA, the net oil exporters that rival the Brazilian NOC. The fact that Brazil and Petrobras are net importers has provided incentives to increase oil investments in order to reduce import dependency, and to maintain domestic prices closer to international prices (compared to the net exporters in the region). The recent large discoveries of offshore oil reserves promise to make Brazil a net exporter in the future, possibly changing the political economy of the sector.

Bolivia

Bolivia represents the prototypical case of a country that is successful in attracting investments, increasing production and reserves of natural gas, under a non-progressive tax framework designed in a period of low commodity prices. As a result, after the international price of gas rose, and large investments in gas infrastructure were sunk, there were powerful incentives for contract renegotiation and nationalization.

Bolivia has no relevant oil reserves and a very small oil production. However, in the last decade it became the largest net exporter of natural gas, with the second largest proven reserves in the region. In 1996-97 the country made innovative privatization process of the NOC, YPFB, capitalizing the country's pension funds and attracting private IOCs into natural gas exploration and production, by making the tax and contractual framework more attractive. As a result, Bolivia was extremely successful in increasing foreign investment, production, exports, and reserves in the natural gas sector. In the period 1993-2002 foreign direct investment in hydrocarbons reached US$2.5 billion, representing 40% of total FDI in the country (Campodónico, 2004). Proven natural gas reserves increased sevenfold and net exports fourfold.

In the Bolivian case it is important to notice that the origin of the government-take was different prior to 1999 than afterwards. Before the natural gas exports to Brazil began, a large proportion of the government-take was originated on the domestic market. As a result, local political pressures imposed little adjustment on the dollar value of domestic taxes. Nevertheless, after 1999 most of the revenues come from the gas exports (see Figure above).

In this case, the system had some provisions that reduced its progressiveness. For example, windfall taxes were set at the dividend level. Consequently, firms chose to indebt themselves with their headquarters and revenues were sent back trough that channel. Also, it had provisions that allowed for the recovery of capital expenditures. Consequently, when prices were higher, firms were deducting these expenditures in their tax returns.

In the last two years the increase in international prices and the existence of high sunken investments provided incentives and opportunities, first for a significant increase in the government-take, and later for the outright nationalization of the natural gas industry. The royalty was increased from 18% to 50%, and the government got majority control of all oil and gas projects. Again, as in the case of Venezuela, Argentina, and Ecuador foreign investors have been victims of their own success by generating an increasing stream of export revenues that in the short term is not be affected by an increase in government revenue extraction.

Peru

In Peru, despite significant increases in oil investment during the last decade, there was little success in increasing oil production, furthering its status as net importer. Peru has gone the farthest in privatization and liberalization route. In addition it has been one of the countries, with Brazil and Colombia, which has done the most to increase regulatory credibility, by establishing contracts with conditions of tax stability. However, in natural gas, the discovery of the large field of Camisea has opened a new perspective as a potential exporter. As a result, there have been recent announcements suggesting an increase in the government-take on this project.

3.5 Reviewing the Latin American experiences in the context of the political and economic issues in the sector

Given the theoretical framework described before, it is important to compare the different cases presented in this section. In all cases there are issues regarding taxation as well as the political economy of the sector. As we pointed out in the introduction, in this paper, we do not attempt to propose and optimal tax and contractual framework. In fact, one of the main findings of the paper is that there are particular issues in each country case that require frameworks with different characteristics.

Venezuela is the result of the combination of both issues: the political economy problems of the sector and the taxation issues. On the latter, we argued that tax breaks were given precisely to the areas where the dead weight losses were lower, skewing the fiscal contribution towards fields with smaller rents and lower fiscal contribution. Additionally, the system lacked progressivity. Therefore, once oil prices increased, the marginal tax rate was equal or lower than the average rate and there were limited contractual provisions for increasing the government-take. However, Venezuela also has had the ingredients of opportunistic expropriation. There was a NOC that had cash flow problems due to the pressure for more fiscal contribution in the context of low oil prices. Regulatory changes were made to bring IOCs to the country to develop new oil production in joint-ventures with the NOC. Once the investment was already sunk, the government forced the renegotiation of the contracts to increase the government-take. Furthermore, it also forcefully acquired a controlling stake in the joint-ventures. It is difficult to answer the question on whether a more progressive and efficient tax regime would have prevented the forced regulatory changes from happening. It is hard to figure out which factor was more important: the regressive tax system or the incentives to expropriate.

Mexico is a case where the NOC has been used as a fiscal, financial, and political tool, in a net exporting country. Therefore, there have been not enough incentives to change the regulatory framework until a major crisis hits the country, for example the prospect of the country becoming a net importing country, or an external shock that requires taking action.

In this regard, as this paper was being finished, it seems this could be already the case. Oil production is declining and consumption is growing, increasing the probability that Mexico becomes a net importer. In this context, the current government has introduced legislation in Congress to allow some form of private participation in the sector.

Argentina, Bolivia and Ecuador seem to be closer to the typical case of political expropriation cycles. The three countries had some experience producing and exporting hydrocarbons. Due to the debt crises and the structural adjustment programs, they lacked the resources to invest in the sector. This problem was more evident in the case of Bolivia and Ecuador because in both countries investment was needed not only to develop reserves, but also to develop needed transportation infrastructure. Consequently, important regulatory changes were made to attract IOCs to invest in the country, and in the case of Bolivia and Argentina the NOCs were fully privatized. Nevertheless, once the investments were made, the governments changed revenue sharing rules and reneged on contracts – including, in the case or Argentina, contracts on the price of domestic supply. Even though, there were also problems of lack of progressivity in the contracts of Bolivia and Ecuador, it seems that the regulatory changes were mostly a result of the incentives to expropriate. Furthermore, both Argentina and Bolivia created new NOCs.

Brazil, Colombia and Peru are clear cases of countries that either were or are becoming net importing countries. Therefore, these countries made reforms to attract IOCs and privatized or opened their NOCs to private capital. Furthermore, parallel to an improvement in the general credibility of property rights, the three countries established a new institutional arrangement for the sector aimed at attracting new investments. The issue of taxation has been discussed in these nations in the light of the recent increase in oil prices. However, it seems that the renewed importance of property rights in these cases, as well as the pressure to generate more oil production, has so far allowed for stability of the revenue sharing rules. There have been only either reforms that allow for price-contingent royalties, but that apply only to new projects; or voluntary renegotiations with private investors. In the case of Brazil the new oil discoveries could represent a challenge for maintaining the credible regulatory framework, as incentives for expropriation rise in the future. Similarly, renegotiation pressures could eventually increase in the case of Camisea in Peru.

4 Concluding Remarks

In the wake of the recent wave of nationalizations and tax hikes in the Latin American hydrocarbons sector, this paper has discussed some of the key factors that may help understand these phenomena. A key source behind these changes arises from the distributive conflicts between the governments and the producing firms. These conflicts occur, to a large extent, because the tax systems used in the region have not taken into account fundamental contingencies; in particular price changes. As a result, when there have been significant increases in oil prices, an increasing portion of oil rents have been retained by the producers. Therefore, powerful incentives for renegotiation, government reneging on contracts, or nationalization, arise.

The optimal contract should be one that includes more appropriately price contingencies. The policy maker may consider tax and royalty rates that vary according to the price. However, the implementation of such a scheme will not be easy. On the one hand, taxes based on net revenues –like the income tax- will generate incentives to overspend or over invest. Furthermore, given that, for an expected amount of revenue, the tax rate should be bigger than a royalty, the distortions generated would be greater. On the other hand, taxes based on sales –like the royalty- will give incentives to shift production to other periods. However, there would be fewer distortions, because royalty rates would be lower.

On top of these incentive problems, there exist problems of agency, i.e. firms not revealing their true costs and investment needs. Consequently, for the fiscal system to work, in addition to including price contingencies, the contracts should incorporate: a tax structure customized for each field and cost regulations. These incentive problems are, to some extent, behind the reluctance of governments in the region to implement progressive tax frameworks.[49] It has been argued that all these requirements might imply an administrative capacity that most of the countries in the region lack. Therefore, for implementation reasons simpler systems, e.g. royalty based, are preferred, even though they have the problem that they increase the probability of future renegotiation.

As we mentioned, an alternative to the agency problem is for the state to control all or a significant part of the oil production. Nevertheless, we also mentioned the significant resources needed for the sector in a context of fiscal imbalances. Additionally, there exist the traditional agency problems between the state and the bureaucracy in charge of managing the NOC. Moreover, in the past, state-owned enterprises have typically been easier targets for quasi-rent expropriation, via regulatory and tax appropriation, prices set below opportunity-cost in the domestic markets, and the political use of clientelistic overpaid and oversized bureaucracies.

More generally, both in the case of NOCs and IOCs, besides the issue of designing a tax system that is progressive to prices increases, there is also the problem of credible commitment, i.e. the presence of powerful incentives for ex-post renegotiation, particularly in net exporters in which large investments have been sunk. Even if the tax structures are progressive and capture fully the rents, the quasi-rents could be a tempting expropriation target. As a result, the credibility of the institutional framework is crucial to develop the potential of the oil sector.

To provide credibility some countries have used external enforcement mechanisms such as international arbitration, bilateral investment treaties, and multilateral agency enforcement; to guarantee the stability of tax rules. However, these credibility devices have often been

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49 From the perspective of the oil companies, the lack of progressive tax systems has also potential disadvantages. First, because it provides incentives for governmental renegotiation and makes contracts obsolete. Second, because contracts signed under high price levels become uneconomical when the price goes down. However, due to the high sunk costs companies might be willing to continue operating. However, informally, some company executives explain that they prefer non-progressive tax systems signed at low prices because, when the price goes up, in the time lag before contracts are renegotiated they can make some handsome profits.

ineffective to deter renegotiation at high prices, and when they are effective, if combined with non-progressive taxes, limit the adaptability to price contingencies.

To provide credible commitment, some adaptability in the fiscal conditions, and a level playing field between NOCs and IOCs, some countries, like Brazil and Colombia, have created autonomous regulatory agencies to oversee the oil industry. This solution however requires a relatively stable and credible set of political institutions that support it. Otherwise, like it occurred in Bolivia, Ecuador, and Venezuela, all the restraints against expropriation can be easily removed.

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