

The Political Economy of Oil Contract Renegotiation in Venezuela¹

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I. Introduction

Since its beginnings in the 1910s, the history of the Venezuelan oil industry has witnessed three significant periods of contract renegotiation. In 1943 all existing oil concessions were transformed into new concessions based on a new law with tougher fiscal terms and more government control. In 1958-1974, the concessions approved in the forties and fifties, based on the 1943 Law, were the object of significant increases in the government-take through a systematic rise in the income tax rate applicable to the oil activity and the approval of additional surcharge taxes. These changes increased the government-take from about 50% in the forties and fifties to more than 65% in the sixties and a maximum of 94% in the seventies. In 1975 the oil industry was nationalized. Finally, after the successful re-opening of the oil industry in the nineties, in 2004-2007 the government once again forced the renegotiation of the oil contracts, increasing royalties and income taxes and transforming the contracts into mixed enterprises (joint-ventures) with government control (including a stake of 60% or more of the capital), implying a partial re-nationalization of the oil sector. This paper studies the conditions under which these re-negotiations were implemented and the driving forces behind them.

The paper argues that to a significant extent these renegotiations were the result of lack of progressivity in the tax structure, which made governments increase taxes in periods of increasing rents. However, the way the renegotiations were conducted during the 60s and 70s, as well as in 2004-2007 had a significant component of opportunistic expropriation, generating high uncertainty on property rights and investment decline, resulting in nationalization.

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. Governments naturally attempt to appropriate a significant share of those rents. Second, oil extraction requires a major proportion of sunken investments. Once the assets are deployed the government can change the rules of the game leaving little option to the investor but to acquiesce. Third, there are high geological risks involved in oil exploration, whereas in the phases of field development and production these risks significantly decline. As a result,

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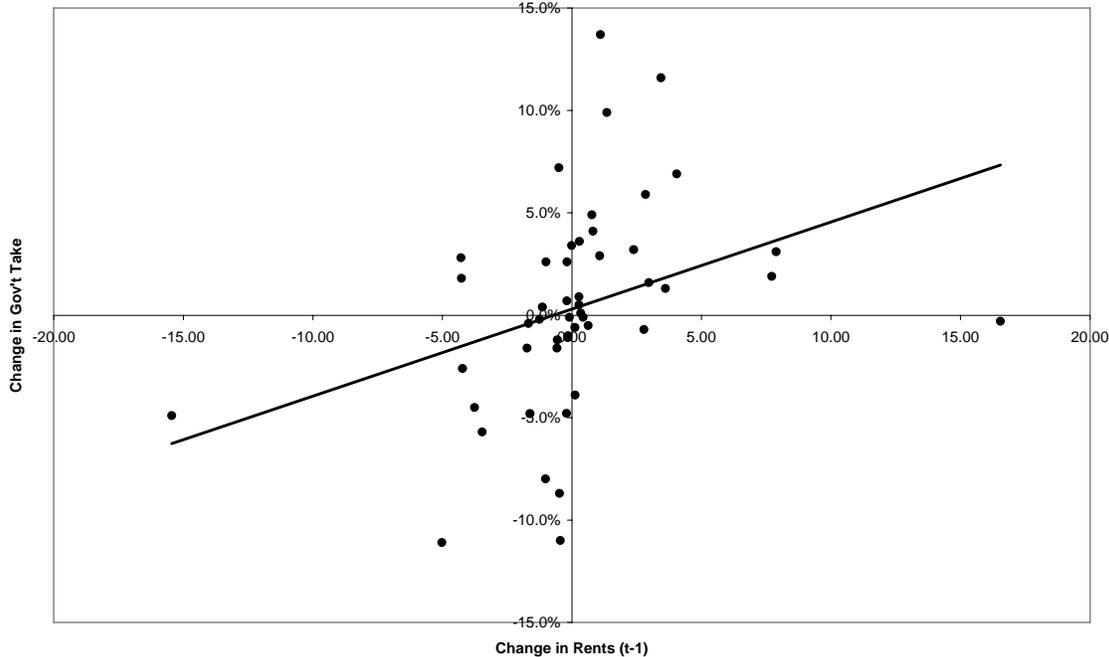
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contractual frameworks designed to promote investment in exploration have often been ill suited for the later phases if significant oil reserves have been developed. Fourth, the oil price in the international markets has been volatile, especially since the 1970s, and as a result oil rents have also been quite volatile. The volatility of rents provides a challenge for fiscal systems to capture the oil rents under different price scenarios. The way oil dependent countries manage the ensuing fiscal volatility can also affect the contractual framework. The paper discusses how these qualities of oil exploitation interact with the country's institutional environment to explain the political economy of contract renegotiation in Venezuela.

The above characteristics of the oil sector combined with the lack of effective and progressive tax systems and a weak institutional framework; have generated episodes of contract renegotiation, particularly whenever rents coming from the oil sector go 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 companies, i.e. frameworks are not progressive. Consequently, governments have had 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-cost industries, like oil extraction, have been tempting targets for quasi-rent appropriation.⁴

Figure 1



⁴ In addition, contract renegotiation has sometimes been, at least partially, driven by the corrupt approval of the original contracts and by the presumption of tax underpayment due to informational asymmetries in the context of poor regulatory institutions.

Figure 1 shows this point more dramatically. In the horizontal axis are the changes in the rent –price minus cost- per barrel in the period $t-1$. The vertical axis shows the changes in the government take in t . As can be seen in the graph the relationship is positive⁵. As will be shown, these changes were mostly due to discretionary actions by the government and not the result of automatic triggers from progressive taxation systems. Consequently, it seems that in Venezuela, most of the institutional changes and contract renegotiations have been generally associated with distributive issues. These results seem to suggest the need for a better design of revenue sharing between the government and oil firms and the inadequacy of the current structure.

In this paper we review three episodes of oil contractual renegotiation in Venezuela: 1943, 1958-1976, and 2004-2007. We show that those episodes had some common elements, like large sunken assets in place, a politically favorable environment for renegotiation, and the occurrence of increasing rents and successful reserve development in the context of non-progressive contracts, which generally did not incorporate the different prices contingencies in an effective manner.

The paper is structured as follows. Section II provides a brief theoretical framework to analyze oil contract renegotiation in the context of a weak institutional environment. Section III analyzes the original concessions of 1910-1935 and the renegotiation that occurred under the Law of 1943. Section IV evaluates the concessions approved in 1943-1957, under the framework provided by the 1943 Law and the significant changes in the investment bargain that occurred in 1958-1976, including nationalization. Section V, discusses the contracts signed under the oil reopening in the 1990s and the forced renegotiation that has occurred in 2004-2007. Section VI, provides some concluding thoughts.

II. The Political Economy of Tax and Contract Renegotiation in the Oil Industry

Some particular characteristics of the oil sector make it susceptible to contract renegotiation. There exist significant rents in oil exploitation. 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.⁶ In practice, significant rents are often kept by the producer. The problem arises, as explained below, from the fact that in general tax and contractual frameworks are not very progressive. As a result, when there is a considerable increase in the

⁵ The correlation coefficient is 0.35 and statistically significant from zero. Furthermore, in levels the correlation is 0.61. However, since the stochastic process of the oil price is still on debate, we rather present the first differences.

⁶ 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.

international oil price, there are incentives for the government to renege on deals made when the oil prices were lower.⁷

As will be described in the following sections, the core element of the Venezuelan oil tax structure, which is similar to most relevant oil producing countries, has been the royalty.⁸ The main problem of the royalty is that it is not well suited to capture rents. Suppose that you have oil that sells for \$10 per barrel and costs \$5 per barrel. Additionally, assume that the government wants to get 50% of the net income (profit). In this case out of the \$5 in profits, the government would take \$2.5. Given that the royalty is basically a gross revenue tax; the rate should be set at 25%. Consequently, for each increase of an additional dollar in oil prices, the government will take \$0.25. This implies that the marginal tax rate is actually lower than the average tax rate.⁹ As a result, a royalty based tax structure is not progressive.

The introduction of an income tax solves partially the problem. Oil production is a capital intensive industry. Moreover, it requires additional investments, to the traditional buildings and equipment, which are the investment in exploration and development. Consequently it is bound to have the same problems of all other capital intensive industries with the standard type of income taxation. In particular, it will be affected by how the issues of depreciation and the cost of capital are dealt with in the law.

Leaving aside the issue of depreciation, let us return to the previous example. Suppose that for the production of one barrel a year, an investment of \$10 is made and the opportunity cost of that capital is 10%. This will imply an additional cost of \$1 for each barrel. If the government wants 50% of net income, but capital costs are not considered in the income tax, the government would ask for \$2 out of the \$5 of “operational revenue”. Consequently it will set up an income tax rate of 40%. However, for each additional dollar of increase in oil prices, the government will take \$0.40. Therefore, again the marginal tax rate is actually lower than the average tax rate.

As we will point out throughout this chapter, this is a key issue impacting oil contract renegotiation in Venezuela. A fundamental question is: why there have not been effective attempts to establish more progressive tax systems that consider capital costs and try to capture the rents more efficiently? There are different arguments to explain this:

- 1) The institutional knowledge available at the time in which the original contracts were designed. As it will be pointed out, the terms on the Venezuelan contracts were not different to those in other similar countries. Consequently, even if Venezuela was not an innovator on oil contract design, it was neither a laggard.

⁷ 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.

⁸ Until 1943 it was actually the only mechanism –except for the land tax and other minor instruments- used to collect revenues. After 1943, the government started to collect an income tax. Nevertheless, it was just in 1958 that the income tax rate for the oil sector began being set at a higher level than the regular tax rate for the non-oil sectors.

⁹ Manzano (2000) and Manzano and Monaldi (2007) present a formalization of the arguments given by these examples.

- 2) The structure and timing of the contracts: Even when contracts did include capital costs and profit-sharing for the government, the contracts were designed based on a low-price scenario. Furthermore, as it will be shown, prices went up before the clauses set to increase the government-take kicked-in.
- 3) Principal-agent considerations: contracts that try to include capital costs in order to make taxes more progressive tend to have the problems associated with regulations on the rate of return.¹⁰ In particular, firms might try to invest more or make costs look higher in order to avoid taxes. Consequently, royalties are seen as a way to induce efficiency from the point of view of the government.^{11,12}
- 4) Fiscal income stability considerations: fiscal income from royalties is less volatile than the one coming from more progressive taxation schemes. As a result policy-makers that have trouble setting up fiscal stabilization mechanisms prefer royalties.¹³
- 5) Heterogeneous agents: More recently, one of the challenges of the Venezuelan tax system has been the existence of different types of oil fields. Consequently, the tax system has to deal not only with issues regarding the progressiveness related to the oil price, but also to the progressiveness related to field productivity. In this regard efficiency issues might imply that the tax schedule does not have to be “progressive” to rents.¹⁴

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).¹⁵ 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 other actors, may expropriate the quasi-rents by opportunistically changing the conditions of investment, including the taxes and regulations. The political benefits of opportunistic renegeing 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 (Monaldi, 2006; Manzano and Monaldi, 2007).

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

¹⁰ See Train (1987).

¹¹ Mommer (2002).

¹² A partial solution for this issue is to have a royalty with a sliding scale based on the oil price. This will have the “efficiency” aspect of the royalty combined with a progressive tax system. This type of royalties are being introduced in new contracts around the world, but were not common in the past.

¹³ See the work of Rigobon in this book for a comprehensive treatment of this issue.

¹⁴ Manzano (2000) argued that changes on the tax system based on “effective tax rates” might not be the same to changes that try to address efficiency. Therefore, with the “reopening” of the oil sector to private investors in the nineties, fields that got tax breaks because they had a higher “effective tax rate” might not have gotten such breaks if the concern was to reduce deadweight losses from the tax system

¹⁵ 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.

exploration is highly successful, the incentives for ex-post renegotiation by the government may be significant. Contracts typically do not incorporate mechanisms allowing the government to capture 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.¹⁶

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 investors to recover their sunken investments. If the political benefits of renegeing are high and the short-term costs low, only strong domestic institutions or effective external enforcement would provide credible property rights. In fact, throughout the history of oil and mineral investment in developing countries, external enforcement played a significant role. For example when there existed a cartel of oil multinationals that could coordinate punishment and the hegemonic powers enforced international property rights (Lipson, 1985). However, after the rise of the independent and state-owned oil companies, and the increase in the sovereignty of many developing producing areas, starting 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 exporting countries very powerful players. More recently, multilateral arbitration, investment treaties, and loans guaranteed by oil export receivables, have provided a limited degree of external enforcement (Monaldi, 2002). Still, in some 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).

The reputational costs of renegeing 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 beginning, or there was a long period of disinvestment (possibly due to previous expropriation), or the government does not have the necessary fiscal resources to invest. 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 renegeing 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 renegeing 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 renegeed on oil contracts.

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,

¹⁶ This phenomena was labeled as the “obsolescing bargain” by Vernon (1977)

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, when the oil prices fall and the government faces a fiscal crisis.

In summary, the oil sector is very susceptible to contract renegotiation due to the special characteristics it has. In particular these are: large rents without progressive taxation systems, high sunk-costs, geological uncertainties when contracts are awarded, reserves concentrated in countries with weak institutions, and volatile rents due to volatile prices. Given these characteristics, it should be expected that governments with oil and gas reserves are in a better position to renegotiate and increase the government-take and their control over the industry if:

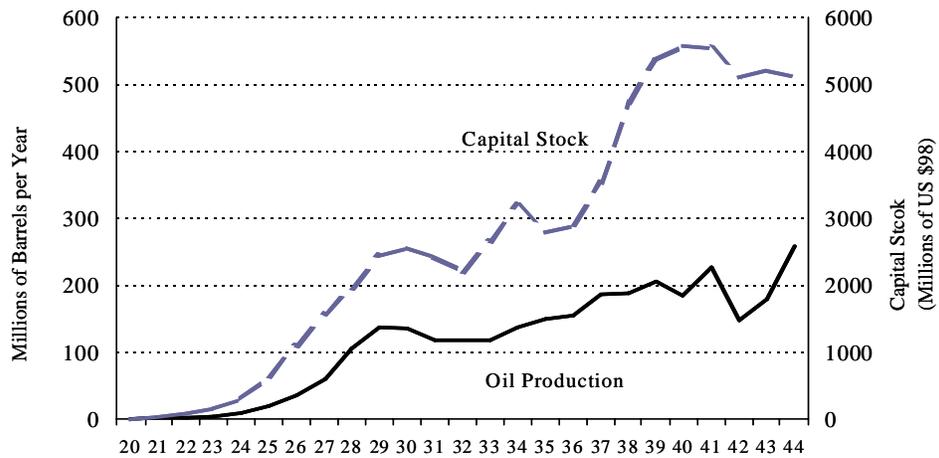
- 1) They have higher oil reserves and higher prospectivity (likelihood of finding oil and gas in exploration). IOCs would be interested in entering and staying in this type of country.
- 2) They have financial resources to finance the needed oil investment (due to high oil revenues or access to international financial markets). In contrast, when governments are in dire need of financial resources, IOCs are needed.¹⁷
- 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 and oil rents are large.

III. The early years of the oil industry and the rise of foreign investment: low taxes and external enforcement mechanisms (1909-1943)

Oil exploration and production began early in the twentieth century with the first significant concessions approved under the 1909 Mining Law. Production became economically significant in the 1920s. Oil became the country's largest export by 1927 and by the 1930s Venezuela was the largest oil exporter in the world. Production in 1929 reached 370 thousand barrels-per-day (BPD) (e.g. compared to around 120 thousand BPD in Mexico). That same year, oil fiscal revenues became the largest item in the government's budget and have always been since (Baptista, 1996).

Figure 2 Oil Production and Capital Stock: 1920-1944

¹⁷ Depending on the availability of domestic human resources, technology, and know-how, governments may have more incentives to attract IOCs.



Source: Baptista (1997) and own calculations.

Figure 2 shows the increasing trend of oil production in 1920-1943, with some volatility: the rapid initial growth, the slowdown produced by the world depression of the 1930s, and the short dip produced by World War II. The chart also shows the equally rapid increase in the capital stock of the oil industry, with similar slowdowns produced by the events mentioned above.¹⁸

Table 1. Taxes to Oil Production in each law (1909-1942)

	Royalty	Superficial Tax	Export Tax	Other Taxes
1909 Mining Law	1%	Bs. 0.5 / ha yearly.		Landowners' payment: one third of profits.
1910 Mining Law	3%	Bs 1 / ha yearly		Landowners' payment: one third of profits. Exploitation tax: Bs. 2 per ton or Bs. 1,000 per concession.
1915 Mining Law	8%	Between Bs. 0.01 and 0.02 / ha yearly.		
1918 Mining Law	8%	Between Bs. 0.05 and 0.1 / ha yearly and eventually between Bs. 2 and 5 / ha yearly.		
1920 Hydrocarbons Law	15%	Bs. 5 / ha yearly.		Initial superficial tax: Bs. 1,000 on receiving the concession. Minimum exploitation tax: Bs. 1,000 yearly
1921 Hydrocarbons Law	15%	Exploration: Bs. 0.05 / ha yearly. Exploitation: Bs. 5 / ha yearly.		Initial superficial tax: Bs. 1,000 on receiving the concession.
1922 Hydrocarbons Law	Between 7,5% and 10%	Exploration: Between Bs. 0.01 and 0.05 / ha yearly. Exploitation: Bs. 2 / ha the first three years. Bs. 4 / ha the next twenty seven years and Bs. 5 / ha the last ten years.		Initial superficial tax: Bs. 0.1 / ha for exploration contracts; Bs 2 / ha for exploitation contracts.

¹⁸ Changes in the real exchange rate also affect this measure of capital stock.

1925 Hydrocarbons Law*	Between 7,5% and 10%	Exploration: Between Bs. 0.01 and 0.05 / ha yearly. Exploitation: Bs. 2 / ha the first three years. Bs. 4 / ha the next twenty seven years and Bs. 5 / ha the last ten years	Bs. 2 per ton.**	Initial superficial tax: Bs. 0.1 / ha for exploration contracts; Bs 2 / ha for exploitation contracts.
1928 Hydrocarbons Law	Between 7,5% and 10%	Exploration: Between Bs. 0.01 and 0,05 / ha yearly. Exploitation: Bs. 4 / ha the first three years. Bs. 5 / ha the next twenty seven years and Bs. 8 / ha the last ten years.	Bs. 2 per ton.	Initial superficial tax: Bs. 0.1 / ha for exploration contracts; Bs 2 / ha for exploitation contracts.
1930 Hydrocarbons Law	15%	Exploration: Between Bs. 0.01 and 0.05 / ha yearly. Exploitation: Bs. 4 / ha the first three years. Bs. 5 / ha the next twenty seven years and Bs. 8 / ha the last ten years.	Bs. 2 per ton.	Initial superficial tax: Bs. 15 / ha for exploitation contracts.
1935 Hydrocarbons Law	15%	Exploration: Between Bs. 0.01 and 0.05 / ha yearly. Exploitation: Bs. 4 / ha the first three years. Bs. 5 / ha the next twenty seven years and Bs. 8 / ha the last ten years.	Bs. 2 per ton.	Initial superficial tax: Bs. 15 / ha for exploitation contracts.

* Includes the 1926 Buoy Law that set the tax on exports

** Reduced to Bs. 1 per ton soon after it's enactment, but increased again in 1928 (McBeth, 1983)

Since 1909 and until his death in 1935, Gen. Juan Vicente Gómez, autocratically ruled Venezuela. Gómez came into power, backed by U.S. support, after ousting his nationalistic predecessor (Gen. Cipriano Castro) who had systematically confronted the U.S. and European powers. Gómez was, therefore, particularly careful not to hurt important U.S. interests. During this period, even though the government, as it became aware of the tremendous geological potential of the country, aimed to increase the fiscal income from oil by systematically approving new laws with increasingly higher tax rates; it always backed down from renegeing on the original contracts made with foreign investors. Each new law only applied to the concessions approved afterwards.¹⁹ Contract sanctity was the basic principle defended by the U.S. and British diplomacy at the time, drawing from the prevailing doctrine of international contract law (Philip, 1982; MacBeth, 1983).

Oil exploration had started at the dawn of the century under high geological uncertainty. Very significant investments were made before oil began to be profitably extracted. In order to attract investment in these inhospitable initial conditions, the original legislation was very favorable to investors. The first significant oil concessions were approved under the Mining Laws of 1909 and 1910, which provided a very liberal regime, emphasizing “the security provided to the operators of the concession” and operational freedom “because the less obstacles the better.” The landowners, by decision of the Supreme Court in 1912, did not have any property rights over the mining concessions given in their land.

Table 1 presents a summary of the fiscal conditions under each law approved between 1909 and 1942. Over this period, the contracts were structured as *concessions* lasting 30 to 50 years (depending on the law), during which the concessionaire company had the right to explore, produce, and export oil from a certain area, generally subject to: 1) a *royalty*, i.e. a percentage

¹⁹ A couple of laws allowed for the older concessions to be voluntarily transformed into the new conditions if the companies considered them more favorable.

tax over gross revenue, which started at 1% and was successively increased to a maximum of 15%; 2) a *superficial tax*, in bolivars per hectare per year (with different amounts assigned for the exploration and production phases); 3) an *exploitation tax* in bolivars per ton of oil extracted (typically Bs. 2 per ton); 4) since 1926 an *export tax*, Bs. 2 per ton of exported crude; and 5) an *initial superficial tax* (similar to a signing bonus) according to the number of hectares assigned to the concession (typically Bs. 2 per hectare or a total of Bs. 1.000, whichever was higher). The specific concessions were governed by contracts that had to be in accordance with the parameters established by the law applicable at the time of the approval of each concession. No other taxes different from those established in the concession contracts could be levied ex-post, a principle that was systematically upheld by Venezuelan courts until 1942.

The Mining Law of 1909 established a royalty of 1% of gross revenue and a superficial tax of Bs. 0.5 per hectare of the concession area. The Mining Law of 1910, under which significant concessions were approved; increased the royalty to 3%, established a production tax of Bs. 2 per ton of mineral produced, and raised the superficial tax to Bs.1 per hectare. The mining laws of 1915 and 1918 increased the royalty to a range of 8%-15% depending on specific conditions (such as distance to the port and distance between oil wells, but generally the minimum rate was applicable), although it eliminated the production tax (per ton), and significantly reduced the superficial tax.

The first Petroleum Law of 1920 confirmed the state ownership over oil reserves and increased the royalty to 15% (25% in state-owned lands). The Law of 1922 reduced again the royalty to a range between 7.5% and 10% (but set at of Bs. 2 per ton the minimum to be paid). A Law in 1926 introduced a tax on crude oil exports of Bs. 2 per ton (which remained in place for the rest of this period). Finally, the last rate change in this period occurred in 1930 when the royalty was increased back to 15% and the production tax was eliminated.

The general tendency towards increasing oil taxes in this period is unmistakable. Espinasa (1995, p.10) summarizes it well: “as the state got conscience of the rent-generation potential of oil, there was an increasing tension between the nation, requesting a higher rent and the companies resisting it... The evolution of the legal framework... was reflected in the seven laws approved between 1920 and 1935, each one representing a gain in the oil rents appropriated by the state.”

However, it is important to emphasize again that during this period (1909-1942) the new - generally higher- tax rates did not apply to the concessions that had been approved before, only to those concessions approved during the prevalence of the specific law. As a result, by 1942 a significant proportion of the Venezuelan production was paying royalties as low as 1% to 3%. For example, according to McBeth (1983) the main concessions of Shell were approved under the 1910 law (which set a 3% royalty). As a result, Shell’s tax payments were proportionally significantly lower than its share in total oil production. As can be seen in Table 2 covering the period 1922-1935, total oil taxes as a percentage of the gross oil revenues were on average 8.4% and reached a maximum of 13.2% in 1935, well below the 15% royalty rate that prevailed during a significant part of this period. For the period 1936-1942, when we have data on total oil profits, the average total government take on the oil companies’ total profit

was 38.8%. As will be shown below, after the 1943 contract renegotiation, the government-take was significantly increased to levels above 50% of total oil profits.

Table 2

Year	Oil taxes (% of gross oil revenues)
1922	10,6%
1923	9,2%
1924	7,2%
1925	5,7%
1926	4,8%
1927	5,0%
1928	7,2%
1929	5,6%
1930	5,7%
1931	12,1%
1932	8,4%
1933	10,8%
1934	12,7%
1935	13,2%
1922-1935	8,4%

Source: McBeth (1983) and own calculations

If the government desired to obtain additional fiscal revenues from the oil industry, the oil legislation provided incentives to authorize additional concessions instead simply raising taxes. Since changes in the oil laws did not apply to previously signed concession contracts, in order to obtain higher fiscal revenues, after changing the tax rate in the law, new concessions had to be approved. As will be shown, the Hydrocarbons Law of 1943, which forced the renegotiation of all contracts, also changed this principle, opening the door for additional future renegotiations. After 1943, the easiest way to get additional revenues was by changing the tax rate.

The method of allocating concessions in this period was non-transparent and the source of significant corruption. Gen. Gómez often gave oil concessions to friends, relatives, and other well-connected intermediaries, who in turn sold them to the international companies, obtaining handsome profits, including in many cases a *private* royalty for the remaining of the concession. After the death of the dictator in 1935 this was one of the main sources of criticism against the legality of the concessions.

Two key questions arise from the analysis of this period:

- 1) Why were concessions given in such favorable terms for operators (especially at the beginning)? All concessions were characterized by: long contract periods; the impossibility of changing, adding or renegotiating taxes; and a fiscal structure that was highly regressive to profits. Moreover, the concessions approved before 1915 had to

pay royalties of just 1% to 3%, rates significantly lower than those approved later (with a 15% royalty rate).

- 2) Why did governments, before 1943, abide by the contracts and did not try to renegotiate them or expropriate the companies? Until 1943 the government and the domestic courts respected the sanctity of the contracts despite the strong incentives to change the terms.

To answer the first question it is important to remember that the first concessions were approved before significant oil discoveries had been made. Geological risks were very significant and large investments had to be made before any considerable level of exports could be reached. The country lacked any oil infrastructure and there were significant political risks. Venezuela had defaulted on its external debt in 1902 and was the object of a blockade by England, France, and Germany, that was only lifted after the U.S. intervention. The high risks intrinsic in these investments had to be compensated by potentially high returns and some institutional guarantees against expropriation. Contract credibility required sticking to the principle of contract sanctity, and specifically to the rule that no additional taxes, outside from those in the concession contract, could be levied.

Notice that after 1914-1917, when some big oil discoveries in the Lake of Maracaibo were made, fiscal conditions were significantly tightened. As the government became aware of the potential profits to be made in oil extraction, it offered concessions with higher taxes. Moreover, Venezuelan concessions followed the evolution of the Mexican oil concessions, which were initially given in even more favorable terms to investors. Still one might wonder why both in Mexico and Venezuela fiscal terms were so regressive.

Table 3

Concession Year	Marginal Tax Rate
1909	1%
1910	3%
1911	3%
1912	3%
1913	3%
1914	3%
1915	8%
1916	8%
1917	8%
1918	8%
1919	8%
1920	15%
1921	15%
1922	8%
1923	8%
1924	8%
1925	10%
1926	10%
1927	10%
1928	10%

1929	10%
1930	15%
1931	15%
1932	15%
1933	15%
1934	15%
1935	15%
1936	15%
1937	15%
1938	15%
1939	15%
1940	15%
1941	15%

As can be seen in Table 3, the Marginal tax rate (to an additional dollar in the price of oil) for concessions approved in 1909-1942 was quite low, especially for the initial years. If an operator was lucky enough to have concessions that were approved in 1909, he had to pay only 1% of the revenues arising from an increase in the price of oil. Of course he also typically made a riskier investment with less geological information. In contrast, the operator of a concession approved in the 1930s had to pay 15% on a dollar, when the oil price increased. The production tax charged in bolivars per ton produced, the export tax, and the superficial tax charged over hectares of land in use, did not capture any additional rent in the event of a price increase, and therefore did not have any effect over the marginal take.

These taxes, more so the superficial tax, were highly regressive to profits. The capacity of the production tax in capturing rents, having been set in bolivars, was also affected by inflation and the real exchange rate. A devaluation of the bolivar, implied that the companies paid a lower percentage of their profits in this type of tax. Moreover, we already discussed the lack of progressiveness of the royalty.. However, to a large extent the regressivity of the tax structure might be explained by the fact that at the time developing countries generally did not implement more sophisticated royalty structures (such as a sliding scale), and initially they did not have the administrative capacity to implement a more progressive tax such as the income tax.

Regarding the fact that the government respected the initial contractual terms the key explanatory factors we hypothesize are: 1) production in the country was concentrated in very few companies, members of the “Seven Sisters” cartel, which could credibly retaliate in concert in the event of contract renegeing; 2) the U.S. and Britain on occasion served as external enforcers in tandem with the companies from their countries; and 3) in the early period before there were significant sunken investments and successful exploration had added reserves, there were little incentives to expropriate (low benefits, high reputational costs); however, as significant production and reserves were in place, the incentives to renegotiate increased (Lipson, 1985; Philip, 1982; Monaldi, 2002).

In particular, reputational costs were made high by the rise of a relatively stable and effective international oil cartel.²⁰ In Venezuela, in the beginning, oil concessions were exploited by a variety of companies but by the end of the 1920's they were increasingly consolidated into two: Jersey Standard (later known as Exxon) through its affiliate Creole and Royal Dutch Shell. By 1937, 92% of the Venezuelan oil production was extracted by these two companies. The international cartel plus the dominant position of the two world largest companies made government renegeing potentially very costly. The companies and their governments successfully defended the principle that the state could only charge the taxes that were established in the concession contract (Monaldi, 2002).²¹

In sum, in the period 1920-1943, many of the characteristics we described in section 2 were not inducing a renegotiation to occur. Firstly, the industry was just starting; consequently, little investment had been sunk and the sector needed to be developed. Secondly, there were important geological uncertainties in the early years. Thirdly, prices were relatively low and stable.

However, taxation was not progressive, and in the latter part of the period some of the sector "characteristics" started to provide incentives for renegotiation. In this regard, the commitment against revenue expropriation seems to have been guaranteed by the prospect of high reputational costs and by external enforcement mechanisms (U.S. enforcement and the cartel of oil producers). Domestic legislation served to codify the external enforcement mechanism. As a result the large investments in exploration and development required for the take-off of the Venezuelan oil industry were made and Venezuela became the largest exporter of oil in the world.

The 1943 Hydrocarbons Law: The renegotiation of the oil original concessions

After Gómez death in 1935, his successors Gen. Eleazar López Contreras (1936-1941) and Gen. Isaías Medina Angarita (1941-1945) slowly opened the political system, making it more inclusive. The opposition, led by the left (the Communist Party and the social-democratic party, Acción Democrática) began to play a significant role. Oil was a key element in their political discourse. They demanded reviewing all oil concessions signed under Gómez. They asserted that many of those concessions were illegally assigned. Moreover, they pushed for the collection of back taxes, arguing that the companies had not appropriately paid them, and for an increase in the government-take on oil profits. Partly responding to those pressures, Medina's government, after extensive negotiations with the oil companies, and with the

20 The seven sisters (as the cartel was eventually known) were led by the three major companies Standard Oil of New Jersey (later Exxon), Royal Dutch/Shell, and Anglo-Persian (later BP). After the Achnacarry Accord of 1928 these companies agreed to maintain their share of production relatively constant in each country outside of the U.S. in which they operated. Marketing quotas were widely put into force and were specifically agreed throughout Latin America.

21 Philip (1982) and McBeth (1983) agree that, during the first two decades of production, foreign companies were able to enforce the oil contracts even without asking for the help of their home governments. They claim that the economic costs of renegeing were more significant than the threat of military or political intervention.

participation of the U.S. State Department, promulgated a new oil law and renegotiated all the concessions.

The Hydrocarbons Law of 1943 is a landmark in the history of Venezuela's oil institutional framework. The Venezuelan government took advantage of the Allies' desperate need for oil in World War II and the shadow of the Mexican nationalization, to renegotiate the terms of the oil concessions with the foreign companies. The U.S. government in this occasion pressured the companies to settle with Venezuela (Machado de Acedo, 1990). The objective of winning the War prevailed over safeguarding the property rights of the companies. The outcome of such negotiations was a law that increased the government's share in oil profits from around 40% to above 50% (see Figure 2). It was known as the "fifty-fifty" deal to split oil profits between the state and the companies. The opposition leaders from Acción Democrática called the Law a sell-out to the foreign multinationals since it validated everything that had happened in the past (Espinasa, 1995; Mommer, 1989; and Tugwell, 1975).

The 1943 Law unified under a common legal framework all the particular contractual concession-deals that had been made in the past. It established -for the first time- the requirement that oil companies would be subject to the Corporate Income Tax on top of any oil-specific taxes. The law creating the Income Tax had been approved a year earlier setting the rate at 12%. In addition, the Hydrocarbons Law established a 16.66% royalty tax over gross revenue (similar to the highest landlord royalty in Texas). The total government-take on profits was in line to the one paid by companies in the U.S. (Mommer, 1989).

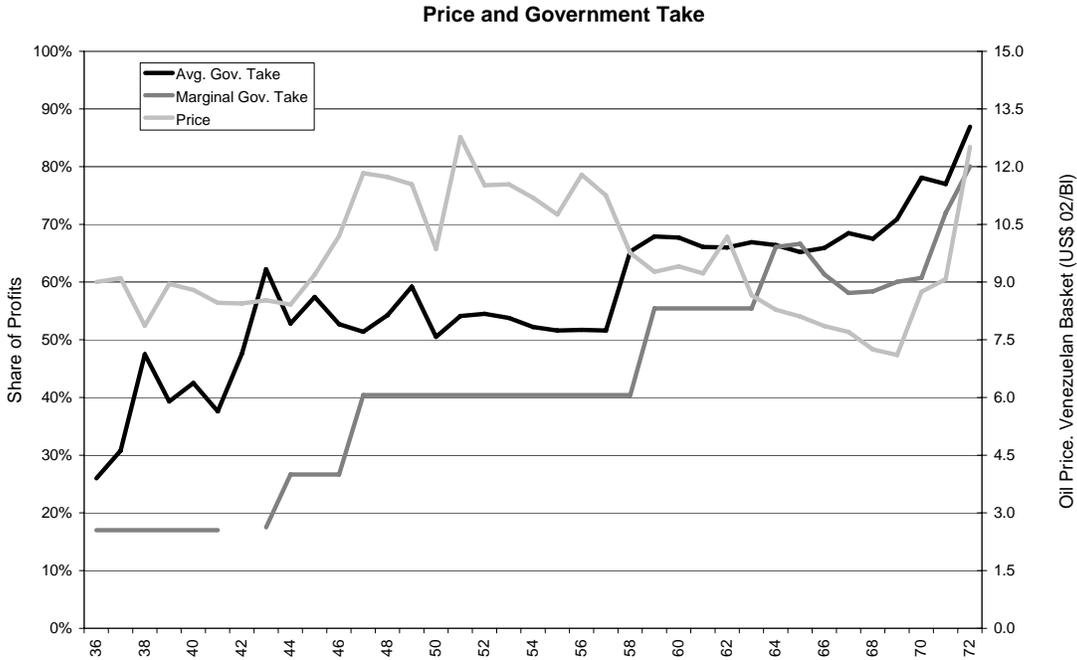
By recognizing the validity of this law, the oil companies were accepting the sovereign right of the Venezuelan state to charge taxes over the companies' profits and to change the income tax rate in the future. The oil companies realized that this would be a powerful instrument for future expropriation, so they opposed it fiercely. They insisted that their fiscal obligations should be contractually fixed.

In exchange for the full application of this tax increase, the 1943 Law gave the companies a long-term planning horizon and a transparent tax regime. It renovated all concessions for forty years, increasing the life of many concessions that were going to lapse soon, and provided for the renovation of concessions after twenty years (in 1963). It also gave the companies sounder legal rights over their concessions. This was an important compromise in favor of the companies since one of the objectives of politicians, in the government and the opposition, had been to act retroactively against the companies whose concessions were claimed to be legally tainted.²² The state also agreed to forgo indemnification from previous tax evasion. Moreover, in 1944 and 1945 the government of Medina approved substantial additional forty-year concessions (that covered more land than all the concessions given before) (Tugwell, 1975). The fact that new concessions, under these new terms, were signed in the forties and fifties with significant success, including important signing bonuses, seems to show that the 1943 law provided enough incentives for new investments.

22 After Gómez death the government initiated some legal actions against some companies asking for damage compensation for the illegal advantages they had obtained in their concession contracts. Some were settled out of court, but sometimes the Supreme Court of Venezuela ordered the companies to pay. For example in 1938 Mene Grande (Gulf) paid \$10 million (Tugwell, 1975).

After the increase of 1943, taxes during the period 1944-1958 remained relatively stable. The state's share over total oil profits stayed on average just above the fifty-fifty split benchmark accorded in 1943 (see Figure 3). Both the companies and the Venezuelan state benefited from an increase in the international price of oil in the mid forties and most of the fifties (see Figure 2). The oil price hike generated an increase in the companies' profits across the 1950s (before and after taxes given the relatively stable distribution). Similarly, oil fiscal revenues increased dramatically, 190% in real terms between 1950 and 1958.

Figure 3



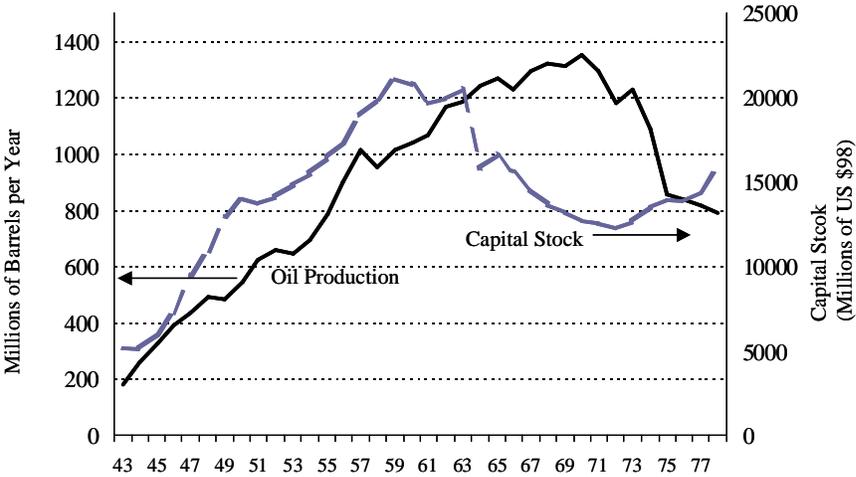
Source: PODE, Ministry of Energy and Mines, and own calculations

The 1943 bargain, originally provided the stability required for a very significant expansion of the oil sector. Additionally, there was “institutional stability”. Except for a brief three-year democratic interregnum (1945-1948), the oil companies confronted a military regime led by Gen. Pérez Jiménez (1948-1958). Pérez Jiménez was clearly aligned with U.S. interests and benefited from a hemispheric preference given to the Venezuelan oil exported to the U.S.²³ Furthermore, in 1956 and 1957 the government auctioned significant new oil concessions from which his government received signing bonuses totaling \$675 million (Tugwell, 1975; Mommer, 1998).

23 The short-lived democratic government instituted a special surcharge tax to guarantee the 50/50 distribution of profits agreed in 1943. If the total government take did not reach 50%, and additional tax would be levied to reach 50% Pérez Jiménez maintained the application of this surcharge tax (Tugwell, 1975).

As seen in Figure 4, between 1944 and 1958 the annual growth rate of the net capital stock of the oil industry was on average 14.3 %.²⁴ Production grew at an average 19.5 % annual rate in the same period. Espinasa (1995) summarizes the period: “clear and stable distributives rules and a long investment horizon, created the conditions for what can be called the golden age of oil activity in the country (1944-58), multiplying investment and production to respond to the demand expansion of the post-war period.”

Figure 4
Oil Production and Capital Stock: 1943-1978



Source: Baptista (1997), and own calculations.

In summary, in this period most of the conditions that could induce a contract renegotiation were present: important sunk investments, ex-post realization of low geological risks, and a tax structure that was not progressive. This was aided by a very special international juncture (WWII), which diminished the effectiveness of external enforcement (i.e. the threat of the costs imposed by the oil cartel and U.S. intervention). As a result, increasing taxes became an attractive strategy for the government. Nevertheless, because the law provided some stability to the sector, the new conditions still made investment attractive, and due to the good prospectivity of the country; IOCs did not leave the country and actually increased investments.

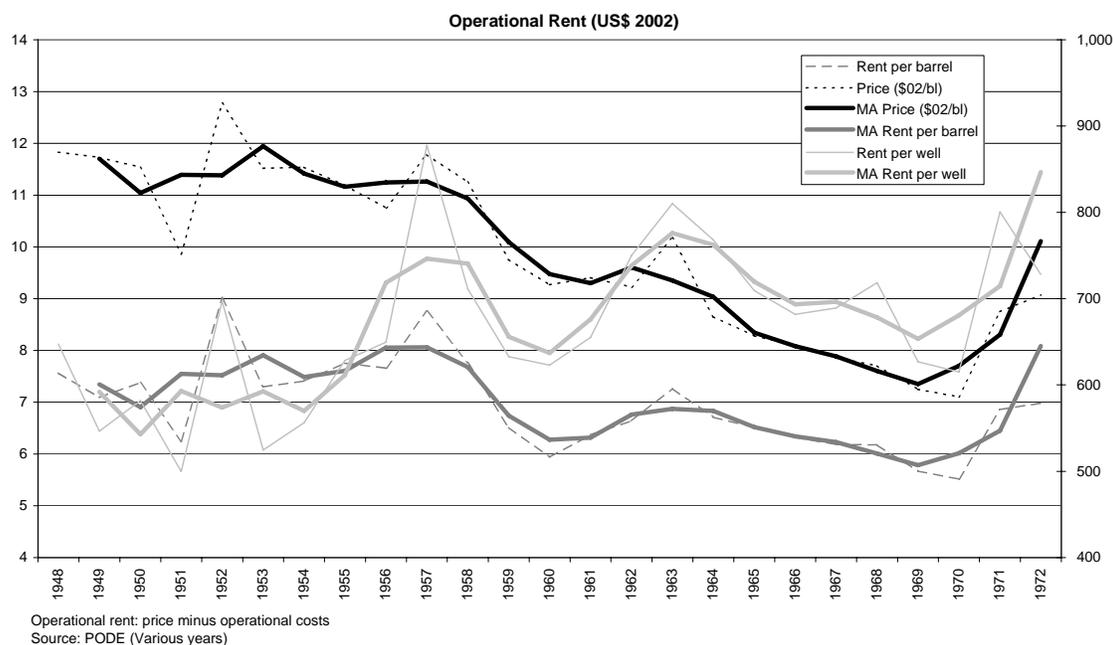
²⁴ Compared with an average annual rate of 3.2% in the previous 15 years (1929-1943) and a negative rate of -2.1% in the following 15 years (1958- 1972). These figures are calculated using the capital stock in constant bolivars of 1984. Source: Baptista (1997).

IV. Tax Renegotiation and Nationalization: 1958-1976

In 1958, after the failed three-year experience in 1945-48 and after ten years of dictatorship, Venezuela's democracy was finally established. Acción Democrática, the social democratic party led by Rómulo Betancourt, regained its majority support and won the first elections. The precarious democratic regime immediately faced non-democratic challenges from the left (guerrillas) and the right (military coup attempts). Fiscal resources were needed to satisfy the many demands repressed by the previous regime and confront the enemies of the democratic regime.²⁵

Furthermore, the market conditions were changing and the oil fiscal rules continued being not progressive. On the marginal dollar of economic profits –i.e. resulting from higher prices and/or lower costs- the government retained only 40.4%. This was mostly due to the low rate of the income tax, which was set at the same level of the non-oil activities. Additionally, independent oil companies, with no ties to the seven sisters obtained a considerable portion of those concessions, debilitating the cartel's grip in Venezuela and over the world.

Figure 5



Unfortunately, in 1957, the price of oil started to decline and continued to do so (in real terms) for the following decade (see Figure 5). The decline in prices in a period of high demand growth is widely attributed in the literature to the aforementioned oil cartel's loss of control over the oil market (Adelman, 1972; Yergin, 1992). To avoid the decline in fiscal expenditures brought about by the oil price decline, Venezuelan politicians decided once again to extract additional rents to the tempting target of the multinational oil companies.

²⁵ Ames' (1987) study of fiscal politics in Latin America, found evidence suggesting that at the beginning of a regime there is a tendency to increase fiscal spending to gather support and increase survival probabilities.

However, it is important to differentiate between price behavior and economic rents and also between rents per barrel and rents per well. As seen in Figure 3, although prices decreased 6.6% between 1950 and 1958²⁶, operational rents per barrel went up 4.5%²⁷ and rents per well increased 25%. This situation was driven by lower costs –around 20% lower- and higher productivity –production per well was also around 20% higher. Furthermore, as argued in Manzano (2007), the stock of capital per well was also decreasing.²⁸ Though this is not a measure of capital costs per barrel, it does suggest that the capital costs per barrel, or at least per well, were decreasing. Consequently, the total economic rent was indeed increasing.

This increase in rents was mostly due to technological advances and discoveries. As argued in Cuddington and Moss (1998), the fifties and sixties saw important advances in the evaluation hydrocarbon-bearing rock formations (e.g., well logging and testing). These technologies stem from advances in geochemistry, stratigraphy, and fluid system sciences. Also, important major new reserve discoveries were made in Venezuela.²⁹ These large fields implied lower average costs.

Against this backdrop, we have seen that the government share was either constant or decreasing. In fact, as we can see in Figure 2, after 1943 the government-take fell even though prices increased.³⁰ Only when the brief democratic government of 1945-1948 increased the income tax rate –to the whole economy- the government’s share increased. The figure shows the main reason behind this behavior: lack of progressivity. During this period, the marginal take was below the average take. Therefore, the system was not progressive in terms of higher economic profits.

Finally, it is important to mention the institutional setting. The 1943 Oil Law sowed the seeds for what later turned to be a dead-end distributive confrontation between the state and the companies. Quoting Karl (1997: 88): “The new law introduced a process of fiscal extraction through bargaining between the companies and the state. Once concessions were replaced by this new form of taxation, the granting of access to land that had proved so beneficial to both parties gradually was substituted for a zero-sum negotiating game over relative shares of profits from the industry...In the long run, it even created powerful incentives for state authorities to organize forms of cooperation among contending domestic social groups in order to enhance their bargaining power vis-à-vis the companies, who were especially vulnerable as nationalistic targets.” This Law eliminated the most important domestic legal restraint against expropriation, establishing sovereign taxation as opposed to contract provisions as the way to determine the state’s take on profits.

As a consequence, the prevailing tax and institutional structure gave incentives to the political leadership to increase the government-take. In fact, the most dramatic early episode of

26 Based on the moving averages

27 Operational rents: price minus operational costs

28 In 1956, prior to the auction of new concessions given by Perez Jimenez, the stock of capital per well was 13% lower than in 1948..

29 Between 1950 and 1958, 10 fields considered “giant fields” by the time were discovered (Oritupano, Dacion, Boca, La Paz, Agusay, Zapatos, Los Claros, Centro, Morichal and Lamar).

30 Prices increased 20% between 1943 and 1946, but the average government take fell from 60% to 50%.

confrontation occurred just before Betancourt took office. The civil-military junta, that governed the country after Pérez Jiménez was overthrown, unilaterally decreed an increase in oil income taxes. The government-take profits rose from 51% to 65% (see Figure 6). The Decreto Sanabria, as it was known, was the first time an increase in oil taxes was completely unilateral (not even discussed with the companies) and distinctive from the regular income tax paid by other non-oil sectors.³¹

The decree represented a radical break with the “fifty-fifty” rule that had been bargained in 1943. This rule had provided stability for more than a decade and had been adopted -after Venezuela- by other oil exporting countries in the Middle East. The Venezuelan tax increase opened the door for raising the government-take in these countries. It clearly marked the beginning of a more confrontational form of extraction of rents that would continue up to nationalization in 1976 (Tugwell, 1975; Mommer, 1982). As can be seen in Figure 3, the government-take in oil profits stayed just above 65% until 1967 when it resumed its upward trend, escalating to a maximum of 94% in 1974 and 1975, the two years before nationalization.

Later, AD established a policy of no more oil concessions, not renewing the 1943 concessions in 1963 (an option provided by the concession contracts negotiated in 1943); as a result, many concessions would contractually lapse in 1983. During the 60s, oil policy was not geared towards nationalization, but generally oriented towards defining alternative arrangements with the oil multinationals which gave the state more control -including partial state ownership of the industry- in order to eventually substitute the old concession system. Higher state control over the industry and higher participation in oil profits, with participation of private capital appears to have been the goal (Tugwell, 1975; Urbaneja, 1992).

During the administration of Betancourt, the companies in a situation of increased market competition started giving discounts below the “marker” oil prices. Since that policy of discounts implied smaller declared profits (and oil tax revenues), the government claimed that the policy was a tax evasion strategy.³² As a penalty, it imposed monetary sanctions to the use of discounts.

Under the next president’s administration -Raul Leoni- the Venezuelan government negotiated a deal with the companies according to which oil taxes were to be calculated not using actual selling prices, but “fiscal reference prices” (FRP). Under the agreement, the FRP were to be negotiated with the companies and set for five-year periods (1967-1971) slightly above the usual effective prices. In practice, this was equivalent to an additional excise tax (a tax on the price, similar to the royalty).

Table 4: Oil Taxes (1943-1975)

31 The decree produced an irate response from the foreign oil companies. The president of Jersey Standard (later Exxon) was forced to leave the country after vehemently publicly voicing his anger over the implementation of the policy. Partly in retaliation against the decree the US government eliminated the preferences given to Venezuelan oil, putting Canada at a relative advantage (Hellinger, 2000).

32 A significant proportion of the oil exported was sold to subsidiaries, thus government officials had good reasons to feel suspicious. According to Adelman (1995) in reality the companies were giving the discounts and it was not merely a tax evasion strategy.

Year	Royalty	Income Tax	Surcharge Tax (FRP)
1943	16,67%	12,00%	none
1946	16,67%	28,50%	none
1958	16,67%	46,50%	none
1966	16,67%	47,50%	10,64%
1970	16,67%	60,00%	7,95%
1971	16,67%	47,50%	8,00%
1972	16,67%	47,50%	20,08%
1974	16,67%	63,50%	36,37%
1975	16,67%	72,00%	27,02%

The government used the threat of increasing oil taxes as a negotiating tool. The administration was anxious to finance its recurrent fiscal deficit. The negotiated agreement on the FRP came after a partially successful government attempt to pass a legislative package increasing the income tax rates applicable to the oil industry and the rest of the economy. Among other objectives, the government package aimed to collect reparations for the oil taxes not collected in the past as a result of the price discounts given by the oil companies. The bill proposal also contemplated a special additional tax on capital assets (only applicable to the oil industry).³³ At the end, even though the administration did not obtain all that it had proposed, it was quite successful. In addition to the fiscal reference price agreement, the income tax was raised 3 percentage points, and the companies obtained what they thought was a guaranteed 5-year period of tax stability given by the FRP agreement (Tugwell, 1975; Urbaneja, 1992; Espinasa, 1995).³⁴ As a result of the tax “agreement,” the government share over operating profits increased from 65.9% in 1966 to 68.5% in 1967, and 71% in 1969.

The first administration of the center-right opposition party, COPEI, began in 1969 under the leadership of President Rafael Caldera. At the beginning, Caldera’s approach was to provide a variety of incentives and new investment opportunities for the oil companies to increase investment and production. As it turned out, this strategy did not provide the short-term fiscal resources that his government expected.

Caldera’s strategy to induce new investment was centered on an innovative framework for creating joint-ventures –service contracts- between the small state-owned company, CVP, and some foreign multinationals.³⁵ The opposition in Congress was reluctant to approve the

³³ The companies organized a common front with the domestic private sector to oppose the income tax increase. The government then attempted to split the opposition and negotiated separately with the oil companies. Simultaneously, the government threatened domestic capitalists, hinting that if an agreement with the oil companies could not be reached, domestic taxes would have to be increased even further.

³⁴ The companies agreed to pay Bs.700 million in reparations to settle the “discount” controversy (much less than were originally asked by the government). In exchange, the companies were given immunity against all tax reparations in the past, and the oil capital asset tax was not approved.

³⁵ The operational service contracts, as were denominated these joint ventures, were a way around the problem of providing foreign companies with secure (although limited) property rights over new investments, without reestablishing the old concession system. Concessions were not ideologically feasible anymore (would not get passed in Congress) and at that point did not guarantee any rights to investors. The foreign oil company would operate as a service contractor signing a private contract with CVP. Risks were shared and the state fiscal participation was contractually enforceable (in Venezuelan courts).

contracts arguing that they were “hidden” concessions. The politicized debate in Congress made the companies worry that the commitment to respect these contracts was not credible. After many negotiations, a few contracts were signed in 1971 and the signing bonuses totaled just \$21 million (Tugwell, 1975; Mommer, 1998).

Applying pressure to the companies to increase production was also disappointing since production was close to full capacity and could only be increased by a meager 3%. The government search of revenues to close the fiscal deficit then evolved into the old policy of maximizing short-term rents from the oil companies. In 1970, Congress passed a law allowing the executive to unilaterally set the fiscal reference price. In practice this meant that each year the executive could single-handedly increase taxes by as much as 14%. Initially, Caldera’s administration did not favor this move because it would hinder its attempt to create the new joint-ventures with the oil companies. This enlarged executive discretion for increasing taxes would destroy any credible commitment to the new agreements. However, once the opposition majority approved it into law, the executive used it immediately to increase the government-take in oil profits from 71% to 78.1%. In a very short time, the government received around US\$200 million in additional fiscal revenues.

Furthermore, many concessions would end in 1983 and the alternative of joint-ventures with the state-owned company did not seem to credibly protect property rights in the future (as the failure of Caldera’s joint-ventures suggested). Knowing that, the government decided to take preemptive actions to limit the oil companies’ policy of taking all non-essential movable equipment out of the country. As a result, Congress passed the Law of Reversion. A complete account of all the companies’ assets was made and they were forced to deposit 10% of the total value as a surety to guarantee the reversion of those assets to the state when the concessions ran out. This decision escalated the conflict between the companies and the government. They further decreased production and the executive established high monetary sanctions against production cuts. At this point Caldera abandoned all attempts to look for ways to induce the companies to invest and became openly confrontational. The government decided to compensate the decline in total oil revenues, due to a 9% fall in production, with an increase in the government’s fiscal take, which reached 87% in 1972.

In 1973, the Arab-Israeli war generated a dramatic increase in oil prices. In January the average export price of Venezuelan oil was \$3 by December it had risen to more than \$10. The government received a windfall of more than \$500 million. Oil fiscal revenues increased 30% in real terms. During the next decade the price of oil climbed above \$30 and the Venezuelan government received more revenues from oil than in all its previous history.

In 1974 power returned to AD under the leadership of President Pérez. Although nationalization was not part of his campaign platform it quickly became the consensus solution to the dead-end in which the state/oil industry relationship had fell into. In the rest of the developing world a wave of nationalizations was beginning, so it was a focal point policy.

Nationalization, in fact, was a relatively conflict-less policy decision. The companies focused more on shaping the nature of the relationship they would have with the Venezuelan oil industry after nationalization and secondarily on the amount of compensation they would receive, rather than on challenging the nationalization decision itself. They were, nevertheless,

relatively well compensated with payments of US\$1.02 billion and with generous oil distribution and technical support contracts (that represented in effect an additional under-the-table compensation) for the first few years (Martz, 1977).³⁶ The Nationalization Law was passed in 1975 to take effect in January 1976. A state oil monopoly company, *Petróleos de Venezuela (PDVSA)*, was created as a holding of all the previous private companies, including two small companies owned by domestic capitalists.³⁷

Before proceeding to the summary of this period, there are two issues that remain unaddressed. First, there is a difference between a contract renegotiation and outright expropriation by nationalization and this period ended with the later. However, as we already argued that the nationalization was a relatively conflict-less decision given that, by the time it happened, all parties recognized that the prevalent framework was not viable. In addition, as we explained before originally there was no apparent intent on nationalizing the industry. Therefore, the relevant fact is that contract renegotiation led to a point in which most IOCs concluded that they should stop investing and prepare to leave the country.

There exist some degree of controversy about when did the conflict deteriorate to the point of making the nationalization irreversible. Some authors have argued that the process was triggered right in 1958, by the combination of the tax hike and the “no new concessions” policy which limited the firm’s horizons (Tugwell, 1975; Espinasa, 1995; Monaldi, 2002 and 2006).³⁸ Other authors, have argued that the tipping point could have been the laws passed in 1970 and 1971 –the law that unilaterally set the FRP and the Law of Reversion-, rather than the *Decreto Sanabria* of 1958 (Manzano, 2007) Nevertheless, none of them argue that the original goal of the government with the *Decreto Sanabria* was to nationalize the industry.

A second issue that is not clear is whether a more progressive tax structure would have prevented this conflict. It is evident from the discussion that the amount of revenues received by the government was the central element of the dispute. Still, there were other significant arguments raised by key policy makers of the time, which we still have not mentioned. In particular, Juan Pablo Perez Alfonso, AD’s leading oil expert, was concerned about resource preservation. For Perez Alfonso, oil was scarce, and more so in Venezuela. Consequently, oil should be preserved for future generations. However, as we already mentioned, the Leoni and particularly Caldera administrations, wanted oil firms to increase production, which was in contradiction with the preservation principle. Therefore, there is still some controversy regarding the role played by ideology versus the pure distributive conflict..

36 The accounting value of the capital stock at the time was around \$12 billion but most concessions would legally have expired in six years with all capital reverting to the government free of charge.

37 Former multinational oil executives interviewed argue that nationalization was at that point almost promoted by the oil multinationals. Their goal was to obtain lucrative distribution agreements that they thought would be more stable.

38 After its peak in 1959 the net capital stock declined systematically for almost twenty years until the downward tendency was finally sharply reverted in 1977-78, after nationalization (see Figure 3). Espinasa (1995) and Monaldi (2002 and 2006) argued that the combination of regulatory and fiscal changes in the political context of the time contributed to push the companies out of Venezuela and to the more competitive oil fields of the Middle East.. Production did not fall until 1971, but as argued by Monaldi this is typical of a high sunk-cost sectors in which there is a significant lag between investment decline and production decline. In such a case, quasi-rents may be expropriated and still production could continue going upwards for a while.

In summary, this period was characterized by some of the key driving factors identified in our theoretical section: large sunken investments in place, low geological risks with high prospectivity, compounded by a non-progressive tax system in a context of increasing rents. Before 1973, even though prices tended to decline, rents tended to increase due to a significant fall in costs-per barrel. A key institutional factor in this period is the precedent of the 1943 law. The acceptance of this law by the IOCs reduced the reputational costs for reneging on contracts. Furthermore, the external enforcement mechanisms provided by the IOCs cartel and the U.S. government were weakened by the appearance of independent producers and the rise of resource sovereignty. Thus, even though to an extent contract renegotiation was the result of lack of progressivity in the context of increasing rents, at some point in this period the conflict seems to have turned into opportunistic expropriation.

V. Reopening and Renationalization: 1990-2007

Fifteen years after full nationalization of the oil sector, in 1991-92, the process of reopening the oil sector to foreign investment (“la apertura petrolera”) timidly began with the proposal to offer to foreign oil companies the operation of a few marginal oil fields (operational service agreements, OSA, first round). At the same time the negotiations were initiated to create joint-ventures with foreign companies to develop the extra-heavy crude reservoirs in the Orinoco Belt. In 1994-98, under the tenure of the leading advocate of this strategy, PDVSA’s CEO Luis Giusti, the process was given a definite impulse and the contracts that support the majority of the projects were signed.

The institutional framework used to re-open the Venezuelan oil sector to foreign investment was fragmented and complex. In part, it was done in such a way because the government wanted to implement it without paying the political costs inherent in making significant changes to major laws. The administrations that designed and implemented the new investment regime, those of presidents Pérez (1989-93), Velázquez (1993-94), and specially Caldera (1994-99) did not have a majority in Congress, thus they tried to maximize what could be done without going through a difficult legislative process. PDVSA and the government stretched to its limits the “narrow space” given to private investment by article 5 of the Oil Nationalization Law. Article 5 only allowed foreign participation in oil production in the case of joint ventures “controlled” by PDVSA, the deals also requiring Congressional approval. In order to attract foreign investors, PDVSA obtained some favorable interpretations of the Law by the Supreme Court (Mommer, 2002; Monaldi, 2002).

The framework implemented was not based on legislation, as had been the case during the concession system that prevailed in the past. Instead, a contractual framework was put into place, in which PDVSA -and not the state- was the legal entity that signed the deals with investors. Under this framework, if the government or the legislature using their sovereign authority changes the rules that governed the investment in a way that has a significant negative impact on the foreign investor and which was not valid under the contract, PDVSA could be, under some provisions, contractually required to compensate the investor. In case the state-owned oil company did not abide by the contract, the foreign investor could request international arbitration (Mommer, 2002). Under the contract PDVSA resigned to any

immunity that it might had as a state-owned enterprise.³⁹ If Venezuelan courts were not willing to enforce an arbitration decision, foreign courts may be able to enforce it. Arbitration would be costly and would probably take years to implement, but it provides some potential source of compensation for the companies.

To some extent, the new contractual framework offered PDVSA as a *shield*, and PDVSA's foreign assets as a "hostage," to protect investors against renegeing by state authorities. PDVSA contractually guaranteed that the original bargain with the state will not be significantly modified in the future. If the government did not abide by the deal, PDVSA is contractually required to provide some compensation to the foreign investors.⁴⁰ The government of Venezuela had the right to change legislation, rules, and regulations, affecting the oil sector, and it could not be legally challenged for doing so according to its sovereign laws. However, the investor could get around the issue of sovereignty by instead taking legal action against PDVSA, a multinational company with assets and business in the U.S. and Europe. More than 20% of PDVSA's consolidated assets were outside of Venezuela, e.g. its U.S. refining subsidiary, CITGO was worth above \$10 billion in 2006, according to our own estimates (Mommer, 1998 and 2002; Monaldi, 2002).

There were three types of contracts. In the appendix we present a detailed description of them. Firstly, there were the Operational Service Agreements (OSA), which started in 1991, with the first round of auctions, and continued with a second round in 1992, and a third in 1997. In theory these were mature fields with low production. The idea was that the IOCs invested to maintain or increase production in these fields and were pay a fee per barrel. Nevertheless, the III round auction was clearly different from the first two, and the contracts resembled more a risk service contract. The original expectation was that oil fields that were producing a mere 70 thousand BD in 1991 wound up producing more than 500 thousand BD by 2004. These expectations were more than fulfilled; in fact at its peak in 2005 the total production in OSA fields' reached 600 thousand BD. Table 5 below, describes the fields and reserves allocated in the three auctioning rounds of OSA fields. As can be seen, the third round was by far the most important in terms of the amount of reserves allocated.

Table 5
Operational Service Agreements (OSA) Oil Field Auction Rounds
1991-1997

39 In all the new contracts PDVSA explicitly waived its sovereign immunity. The clear waiving of immunity is important since any business owned by the Venezuelan government is considered an agency of the Venezuelan state and entitled to immunity from US Courts according to the US Foreign Immunities Act, unless such immunity is explicitly waived. The immunity granted by that Law would have precluded attachment of PDVSA's assets to enforce a judgment. (Moody's PDVSA report April, 1999).

40 Under this structure, PDVSA's management provided the first line of defense against expropriation. PDVSA's financial and operational autonomy would have made it costly for governments to force the company to violate its contracts. PDVSA's management used to be interested in honoring the contracts. Otherwise, the company could risk suffering significant reputational costs. In contrast to the sovereign Venezuelan state, PDVSA, was an independent multinational company, governed by contract law, with investments, joint ventures, and long-term contracts in foreign countries. The institutional costs of expropriation arising from the resistance to contract renegeing from PDVSA's autonomous management, was before president Chavez took control in 2003, a limit to political renegotiation.

Round	# oil fields offered	# oil fields allocated	Proven oil reserves allocated (million barrels)
First (1991)	9	3	175
Second (1992)	14	13	1,55
Third (1997)	20	18	20,51

Source: PDVSA.

Originally, OSAs were supposed to cover only a few marginal oil fields that required significant new investments in secondary recovery to increase production and which at the prevailing tax rates paid by PDVSA in the nineties, a 16.67% royalty and a 67% income tax, would not have been profitable for PDVSA to maintain in operation. In order to make them fiscally viable, in all the OSAs the operator paid only the non-oil income tax rate of 34%, and PDVSA took charge of the royalties (which were in some cases reduced).⁴¹ However, this type of contract was used more widely, not just for marginal fields. In the third round, and in a couple of ad-hoc contracts, more productive oil fields with larger areas were also allocated as OSAs. Under those contracts, operators had more liberty to explore and extract in the blocks assigned than in those of the first two rounds.

Later the government launched the extra-heavy oil Association Agreements (AA), to pursue four large extraction and upgrading projects (1993-1997). The mechanism used was the creation of joint-ventures between PDVSA and IOCs. Four Association Agreements were approved in extra-heavy oil upgrading:

- 1) CERRO NEGRO Project, in association with ExxonMobil (with a 41.67% stake) and BP (16.67%) (originally Veba Oel). PDVSA 41.67%.
- 2) HAMACA (AMERIVEN) Project, in association with Chevron (30%), and Conoco (40%). PDVSA 30%.
- 3) PETROZUATA with Conoco (with a 50.1% controlling stake).
- 4) SINCOR with Total (France) 47% and Statoil 15% (Norway).

The projects added up to a total investment of some US\$15 billion in ten years, with a production of 650 thousand BD by the year 2006.

Given the lower profitability of extra-heavy crude oil extraction and upgrading (relative to rest of the oil sector), Congress approved an exception to the Income Tax Law to make these projects lucrative. The AA projects were taxed at the regular non-oil income tax rate (34%)

⁴¹ An illustration of the importance of PDVSA's role as a buffer is provided by the way in which royalty tax was set. Many of these oil fields were only profitable at the lowest (1%) royalty rate (Mommer, 1998). The Ministry could set the royalty rate in the range of 1% to 16.6%. Given that in the case of oil produced by contractor, the royalty could be set at the government's discretion, it was impossible to commit with foreign investors to such a low rate (1%) for the 20-year contract period. The OSA arrangement solved this commitment problem by making PDVSA the responsible party for paying all royalties. This is particularly important given that changing the royalty is one of the most common methods of revenue expropriation. According to Andrea MacDonald, Treasurer of Exxon Exploration Corp.: "the most frequent cases of breach of contract involve something like arbitrarily raising the royalty rate from 5% to 10%, which may not destroy the viability of the project but may indeed reduce the internal rate of return substantially" (MacDonald, 1998).

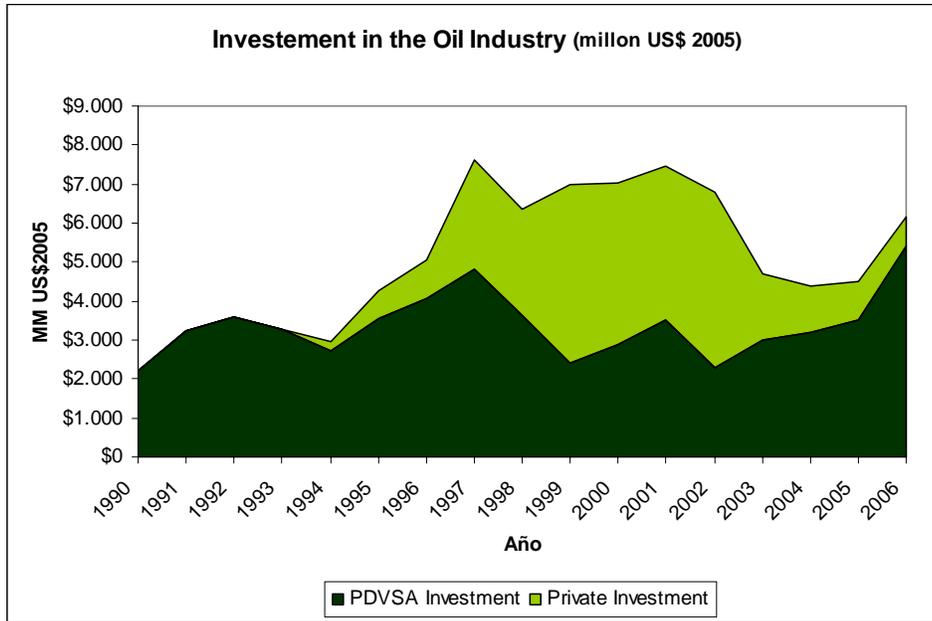
and not the special oil income rate (of 67% until 2001, and 50% since then). This modification of the Law was approved by Congress. The royalty was contractually determined; it was set at 1% for the first 10 years and the regular 16.67% thereafter. There was a provision allowing increasing the royalty earlier if a certain internal rate of return (IRR) was reached.

The final type of contracts introduced were the Risk Exploration Agreements (RE), in eight areas, which were auctioned in 1996 for the right to explore and extract oil. The fiscal structure was based on a royalty of 1% to 16.67% depending on the IRR of the project, a bidding contractual government-share of up to 50% of profits (PEG), and an income tax of 67% (the royalty and the PEG are subtracted from the profit). The marginal government take was set at 67% initially and increased to 86% after the IRR threshold. Of these contracts, only three resulted in a commercial discovery of hydrocarbons. The government did not create the joint-ventures prescribed in the contract, and postponed any decision until the renationalization of 2007.

As seen from the previous description all these new contracts implied changes in the tax structure. It is important to mention that the selection of fields assigned to private investors might not have been what theoretically should be the optimal strategy. The areas given were considered “marginal” areas because either they had higher costs, or lower value, or required higher investment needs, given that they had not been explored at the time. As argued in Manzano (2000), these are not the areas where the highest dead-weight losses arise from an optimal taxation point-of-view. Consequently, the areas where the highest welfare gains could have been obtained were not given to private investors, and the “export basket” of Venezuela shifted towards oil where the government-take was lower and less progressive.

In order to understand why the government implemented the reopening the way it did it is important to recall three conditioning factors. 1) Just fifteen years before it the reopening was implemented, foreign investors had been nationalized, after almost two decades of redistributive conflicts with the Venezuelan state. 2) The price of oil in the nineties was between \$10 and \$30 in current dollars; at those levels it was tougher to attract foreign investors. 3) Over this period, the Venezuelan state was confronting a tough fiscal situation with recurrent deficits and a banking crisis that required a bailout of more than 6% of GDP, putting pressure on the resources available to PDVSA to carry out investment. These factors made the governments very eager to obtain the new investments and the companies more hesitant on assuming risks in Venezuela. As a result, under these conditions the credibility of the framework was crucially important to attract foreign investors. This situation explains the contractual structure that basically “imported” foreign institutions into Venezuela.

Figure 6



In terms of investment and production, the oil reopening was a significant success. As can be seen in the Figure 6, private investment more than compensated the decline in PDVSA's investment during a period in which the company and the state did not have resources to spare. The total private investment in 1994-2006 exceeded US\$25 billion. By 2004, private oil companies were operating close to half of Venezuela's crude oil production. At its peak in 2004, OSA contracts reached a total production of close to 600 thousand BD. Similarly, Orinoco AA contracts reached 650 thousand BD in 2006. In contrast in the period 1998-2006 PDVSA's own production had a declining path.

Renegotiation 2004-2007

This process was reverted starting in 2004. In the presidential campaign of 1998, Chávez argued that all the oil opening contracts were illegal and Alí Rodríguez, his top oil advisor, had been among the most prominent critics of the contracts signed in the nineties. However, in his first six years in the presidency, the government did not alter the fiscal conditions in the contracts. In fact, as seen in the figure above most of the investment and the increase in production in these projects occurred during Chavez presidency. Moreover, when the president used his special legislative authority to sign the 2001 Hydrocarbons Law, changing the fiscal conditions by increasing the royalty to 30% (from 16.67%), setting the oil income tax rate at 50%, and establishing that the only form of private participation in oil production was as minority shareholders in joint-ventures controlled by PDVSA; the government announced that these changes did not apply to the existing contracts of the oil reopening ("there will not be retroactive application of the law" government officials emphasized).

However, late in 2004 the first forced renegotiation decision was made. The Orinoco Belt Extra-Heavy Oil projects (AA) royalty was increased from 1% to 16.67%. This was still not a major contractual change in three of the four projects, in the sense that the contracts anticipated the royalty increase to happen either after ten years had elapsed or an IRR

threshold had been reached, and the threshold was close to being reached in the three projects that had started earlier. Still Exxon Mobil threatened to go to international arbitration to establish the principle that the contract fiscal rules could not be changed unilaterally, but they did not do it at this point. This change in the royalty happened after the projects had only 3 to 6 years in operation (in contracts of 30-35 years of duration).

In 2005 the government initiated a full blown campaign to increase taxes to the OSA and AA projects. The tax authority SENIAT imposed the OSA companies with tax reparations for the previous three years totaling \$400 million. Then, the government announced that the OSA projects should have paid the income tax rate of 50%, set in 2001 (instead of 34%), and that starting in 2005 they would have to pay this higher rate. The Ministry of Petroleum announced that the Orinoco AA had been producing oil above the levels authorized by Congress when the contracts were approved, and that as a result the companies would have to pay the 30% royalty (instead of 16.67%) on the excess production. The Ministry also announced that the fees paid by PDVSA to OSAs would be paid in bolivars, instead of dollars as established in the contracts.

Later in 2006, the Ministry of Petroleum announced that the OSA contracts were illegal under the legal framework that prevailed when they were approved and that they had not been approved by Congress as they should have been. The Ministry also argued that under the contracts the oil was too costly for PDVSA and that they were paying lower taxes than they should, using a variety of accounting tricks. As a result the government announced that by 2006 the OSA contracts had to “migrate” into new contracts as joint ventures with a 60% majority for PDVSA, as prescribed by the 2001 Hydrocarbons Law.

The forced renegotiation of the OSA contracts was implemented during 2006. All the companies, except Exxon-Mobil which sold its minority stake to Repsol, accepted to start the renegotiation of the contracts. Some smaller companies renegotiated just compensation, returning their fields to PDVSA, but most stayed as minority shareholders of the new “mixed-enterprises.” However, in the case of two of the most productive OSA projects one owned by ENI (Italy) and the other by Total (France), the operators decided not to sign the migration. Eventually, Total (who also has a large Orinoco AA project) settled with the government for \$250 million. ENI decided to go to international arbitration.⁴² The fiscal rules for these new mixed enterprises were set as, a 33.33% royalty (contractually established) and a 50% income tax rate. PDVSA has between 60% and 80% of the shares in these new companies. Also in 2006 the government approved (Decree 1510) an exploitation tax (a royalty) of 33.33% applicable to all oil projects. This tax applies subtracting any other royalty paid by the project, so in practice all oil projects pay now a 33.33% royalty.

Finally, in late 2006 the government announced the forced migration of the Orinoco AA projects and the Revenue-Sharing Exploration projects (RE) to the mixed enterprise format. In 2007 the government took control over all these projects (“nationalization” was the term used). Of the four AA projects, in three the main private partner decided to leave and request international arbitration to set the compensation (Conoco in Petrozuata and Ameriven, and Exxon in Cerro Negro). Chevron (30%) and BP (16.6%), the minority partners in Ameriven

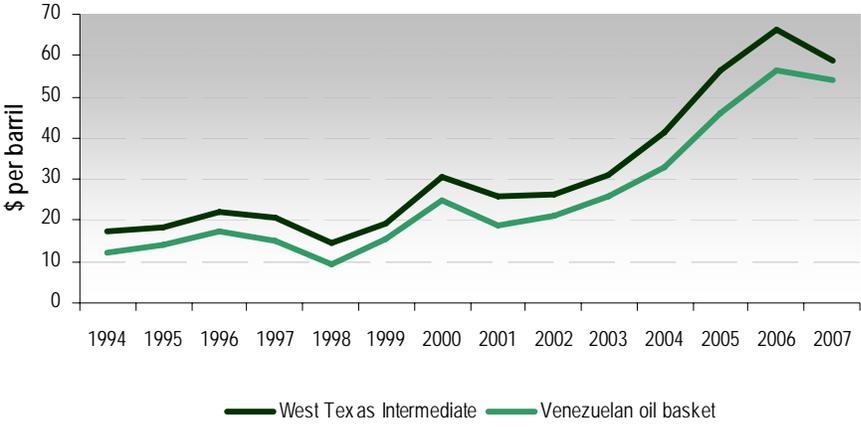
⁴² A settlement has not yet occurred as off February 2008.

and Cerro Negro respectively, decided to stay, and will keep the same share they had. Finally in the fourth project, the two partners Total and Statoil accepted a proportional reduction in their participation (from 62% to 40%) under the new conditions. PDVSA, which previously owned and average of 40% of the capital and did not operate the projects, now has an average participation of 78.3% and operates all the projects. The former AA projects, now mixed enterprises, also pay a royalty of 33.3% and an income tax of 50%, for a marginal take of 67%.

In the case of the RE projects, only three had declared commercial success from exploration and were waiting for PDVSA to proceed. Here three companies Conoco, Exxon and PetroCanada decided to leave and Conoco and Exxon have said they will take the international arbitration route. These three projects will also pay a 33.3% royalty and 50% income tax for a marginal government take of 67%.

Figure 7

Oil Price (1994-2007)



Three main questions arise from this recent episode of contract renegotiation. 1) Was it mainly the result of lack of progressivity in the fiscal framework of the contracts? 2) To what extent it could be considered opportunistic expropriation? 3) Why did the contractual framework using PDVSA as a hostage and international arbitration as a method of dispute resolution, not deter forced renegotiation? And, what prevented the changes from occurring before 2005?

Since the renegotiation of the contracts occurred after a significant increase in the price of oil (see Figure 7) one of the possible inducing factors would be the lack of progressivity of the fiscal framework of the contracts. This is clearly the case of the Orinoco Belt projects and to a lesser extent of the III Round OSA projects (before the higher IRR triggers enter into effect). However, in the case of the Revenue-Sharing Exploration (RE) and I and II Round OSA contracts the marginal take of the government/PDVSA was quite high. However, it is important to notice that the increased stake of PDVSA, as shareholder, in all this projects (a partial nationalization) provides the government with a higher marginal take, given that they

have a marginal take of 100% in the portion they own. Of course, PDVSA has from now on to provide its share of capital expenditures and costs, and it had to pay some form of compensation for the additional stake, but in marginal terms, the nationalization gives the government the upside of an oil price increase.

As can be seen in Table 6 the marginal take in the Orinoco AA extra-heavy oil projects was just 34.7% before 2005, as a result the operators were keeping about two thirds of the additional rent produced by the oil price increase. By 2005, once the royalty was increased, the marginal take became 45%, still relatively low at the prevailing price levels. With the application in 2006 of a royalty of 33.3% (Decree 1510) the marginal take was increased to 56% and with the migration into mixed enterprises in 2007 the marginal take is now 67%. Moreover, since now the state increased its stake from an average of 40% to 78% it obtains a marginal take of 100% in this additional stake of 38%. Taking this into consideration the marginal take would become 92.7% (compared to 60.82%, including only original stake and before the renegotiation).

Table 6: Marginal Government Take by Type of Contract (1991-2007)

Contract type	Before IRR trigger			After IRR trigger		After 2006	Plus Govt. Stake
	Before 2005	Plus Govt. Stake	2005-2006		Plus Govt. Stake		
Orinoco AA	34,70%	60,82%	56,00%	45,00%	78,00%	66,70%	92,67%
OSA Rounds I and II	100,00%	100,00%	100,00%	100,00%	100,00%	66,70%	90,01%
OSA Round III	45,00%	45,00%	56,00%	86,80%	86,80%	66,70%	90,01%
Exploration (RE)	67,00%	78,55%	72,30%	86,10%	90,97%	66,70%	92,67%

In the case of the OSA contracts Rounds I and II the marginal take of the government was close to 100% since in those contracts the payment to the service contractor was based on a per-barrel cost fee, not in a share of profits. Here the marginal take actually has decreased to 67%. However, PDVSA passed from having a stake of 0% to an average stake of close to 70%, therefore the marginal take from that proportion will still be 100%. Taking into account the government's take in the new mixed-enterprises, the marginal take on this production will be now about 90%.

In the case of the OSA Round III, it gets more complex. As explained before, these are similar to profit-sharing contracts in which the government take depends on the IRR. Before the IRR reached 0% the marginal take was 45%, between IRR of 0% and 60% increased proportionally with the IRR and the time elapsed from 45% to 87%, and after the IRR surpassed 60% the marginal take stayed at 87%. We do not now for certain at which level of IRR all these projects were, but our understanding is that the majority were somewhere between 0% and 60%. Therefore the average marginal take will probably rise with the new contracts, but in the long run it would have been higher with the old contracts. However, again if we add the PDVSA shareholding stake the marginal take rises to about 90%.

Finally, in the case of the RE contracts they were highly progressive. Most of the companies that won in the auction process offered 50% the highest possible "Government Take on Profits" (PEG) parameter. Only three of those projects offered a PEG lower than 50%. The marginal take at the beginning of those projects would have been 67% and after the first

billion in gross revenues the marginal would have increased with the return on assets (ROA) until it reached a maximum of 86%. It is important to note that the marginal take for these projects was actually reduced in 2007, with the migration to mixed enterprises. However, it is also true that PDVSA took a stock participation of 60% or more in the three projects, when the original contracts set the maximum at 35%. Again, the compensation for this increased participation, at book value with some discounts, represents an additional appropriation. Taking into account the higher PDVSA stake in the projects the resulting marginal take raises to 92.7% (compared to 78.6% before the renegotiation, with the maximum stake allowed by the old contract of 35%).

From this analysis we can conclude that in the case of the Orinoco Belt AA projects and to some extent the OSA III Round projects, the lack of progressivity of the fiscal framework created the conditions for renegotiation of the fiscal terms in the context of a very significant increase in oil prices, such as the one we have seen in the last four years. Since these two types of contract concentrated more than 80% of the privately operated production, it is understandable for the government to propose a renegotiation of the whole fiscal framework of the sector.

In the case of the OSA Rounds I and II contracts, the marginal take actually has been reduced, so the justification of lack of progressivity does not work. However, there is an important issue with these contracts. As explained before, and in more detail in Manzano (2000), it is expected that what the government pays includes the capital cost. However, tax codes tend not to include capital costs or if so, they do it imperfectly. This is also true in the Venezuela tax code for the oil sector. Consequently, at least from the point of view of taxes, these fields had a higher cost when the rules of the OSA contracts were applied than if the regular rules for PDVSA were applied.

Expectedly, the government claimed that in those contracts the cost per barrel for PDVSA was higher than the cost in their own operated projects. Nevertheless, it is important to remember that these oil fields were among the least productive in the country and private investment was able to massively increase production. Now the government as an operator may be able, at least in the short run, to have a higher average take per barrel, but it will also take more production risks and, as shown above, the marginal take will decrease because now the private partners share on oil profits.

In the case of the exploration contracts RE, the marginal take will clearly decline, so there is no justification for renegotiation on progressivity grounds. As explained these projects have not entered into production and the government is taking operational control and a larger stake, without market value compensation. Now the government will face more production and price risks. Paradoxically, with the contract renegotiation, the private partners will face a lower marginal take, and the total marginal take, including the government stake, will just go up slightly. Still renegotiation may be justified as an effort to put all oil projects on the same institutional framework.

Granting the importance of lack of progressivity as a driver in the renegotiation of AA and OSA III Round contracts, it is important to acknowledge that the way the forced renegotiation was implemented and the conditions in which the government acquired ownership of the

assets, has a significant component of opportunistic expropriation. Instead of just renegotiating the fiscal framework for the future, the government asked for back taxes from the previous three years. Moreover, in the forced renegotiation of a government majority stake in all the contracts, the firms were offered well below the market (or net present value) price of the projects, even calculated using the new harsher tax structure. For example Wood Mackenzie, an oil consultant group, concluded that in the OSA contract renegotiation investors were compensated for less than half of the remaining value of the project, when the government acquired a 60%-100% stake in 2006. Eurasia Group, a political risk consultancy, reports that Total and BP received, as compensation for their OSA project of Jusepin (with a production of 35.000 BD), US\$ 250 million, less than half of the estimated market value of the project (at \$580 million). ENI filed for arbitration with ICSID in November 2006, when the government refused to pay market value (estimated at US\$1 billion) on another OSA (Dación, with a 60.000 thousand barrel production).

In the case of the AA the magnitude of the assets expropriated is more dramatic. When the state seized the Cerro Negro AA project, ExxonMobil was reportedly offered book value (with some discounts and a significant proportion not paid in cash) for its 41.6% stake, instead of the market value of an estimated US\$2.3 billion (Wood Mackenzie).⁴³ As a result, the company filed for arbitration at the ICSID in September 2007. Similarly, ConocoPhillips has filed for arbitration to obtain compensation for its stake in two AA projects (50.1% of Petrozuata and 40% of Ameriven) with a market estimate value of US\$7.2 billion (Wood Mackenzie). In February 2008, PDVSA reached an agreement with Total and Statoil over Sincor, to pay these companies US\$1.1 billion for their stake, which was valued at twice that amount by UBS. Moreover, the payment will be done partly in incremental production from the project. This is in line with what the government has consistently offered: book value compensation and not fully in cash.

It is important to mention that in the AA contracts there is an explicit clause detailing the price that should be paid for a stake in the project. Before operation the value of the project was to be determined by the sum of the capital provided by all the partners plus the interest obtained but not paid. After the initiation of operation the value should be calculated using the net present value of the discounted cash flow after taxes for the remainder of the project. The rules for calculation are detailed in the contract, e.g. interest based on treasuries, etc. This type of clause seems to offer a powerful tool to the firms that filed for international arbitration.

Chevron and BP remained with the same stake and simply accepted the new terms of the mixed-enterprise (with a PDVSA majority). Even though under the new contracts they have to face a significantly higher government take and have significantly less prerogatives (including losing the possibility of international arbitration), they will receive almost no compensation for the renegotiation. Finally, in the case of the RE projects Conoco, Exxon and Petrocanada did not accept the terms of the new contracts and are filing for arbitration.

From the previous analysis a set of questions arise: why did the institutional framework not deter expropriation? Why did expropriation not happen before, if it seems so attractive for the

43 The payment offered by PDVSA has not been officially revealed, but some estimates put it at less than half the market value (private communication).

state? Why did most companies acquiesce? And why did a few file for arbitration? The answer to the first question seems to be that the institutional framework in place generated significant costs to contract renegeing, but not enough to compensate for the benefits that resulted after the dramatic increase in oil prices. The contracts were respected during the first six years of Chavez for three main reasons. 1) The price of oil was much lower in 1999-2002. 2) The AA projects were not completed until 2002, therefore all the investments had not been sunk, and expropriation was less attractive. 3) Until the oil strike of 2002-2003, in which the executive took full discretionary control of PDVSA, the company remained autonomous and much less willing to execute an expropriatory renegotiation due to the reputational costs implied in this strategy. Moreover, in 2003 the government needed the IOCs to help it get back production up after the dramatic fall that occurred during and after the oil strike. As soon as these three factors changed, the government started the renegotiation, in late 2004. Moreover, as the price of oil went up the conditions proposed got harsher and the government got the upper-hand in the negotiations. The companies were now in a very weak negotiating position to use the institutional framework to deter expropriation.

It is important to notice that only three companies: Exxon, Conoco, and Eni have decided to use the dispute resolution and enforcement mechanisms provided by the contracts. All the other companies accepted the harsh renegotiation terms offered by the government. The explanation for that outcome we believe is two-fold: 1) from the standpoint of the project, once most investments have been sunken, the return, from the proportionally significantly lower investments and operational costs that will be spent in the future, is quite high. Even under the considerably higher government-take in the AA projects, the additional new investment in the future should be highly profitable, particularly at the current high oil price levels. Notice that the new 67% marginal take, still gives them 33 cents for each additional dollar in the price of oil. 2) Venezuela is one of the very few countries with very high oil reserves that is currently open to foreign investors, as a result the IOCs do not have many other attractive alternatives to obtain oil reserves and are compelled not to exit Venezuela (when the costs of reentry are probably high). Especially given that they expect to be offered new deals in the future. Our interpretation is that the three companies that left did it because: 1) they wanted to send an international signal that they would not acquiesce to a compensation of less than half the market value or their projects; 2) they did not believe that under the current government they would be offered attractive new deals in the future; and 3) taking the previous two points into consideration they believe what they will obtain by arbitration will be attractive enough and enforceable.

The future reputational costs of the way in which the renegotiation was done, in terms of decline in future investments and the damage to PDVSA's commercial standing, are more difficult to assess. A recent survey of oil executives by the Fraser Institute puts Venezuela in the worst relative position (just above Bolivia) in terms of the oil industry's Regulatory Climate Index, Tax Regime Index, and Fiscal Terms Index (Angevine and Cameron, 2007).⁴⁴

⁴⁴ The survey covered 54 oil producing regimes all over the world. 82% of those surveyed answered that the Regulatory Uncertainties in Venezuela "will cause them not to invest" or "is a strong deterrent for investment." 24% answered that the new Tax Regime in Venezuela "will cause them not to invest" and 35% answered that it "is a strong deterrent for investment." Similarly 42% answered that the Fiscal Terms "will cause them not to invest." (Angevine and Cameron, 2007).

However, the short-term horizons of government officials, typical of oil dependent countries, imply that reputational costs, even if they materialize, might not be sufficient deterrent when the short-term benefits are high enough, e.g. because of the high oil prices, and the short-term costs, e.g. production decline, are low.

In summary, during this cycle of reopening and renationalization we saw once again conditions inducing for renegotiation: important sunken investments in place, high prospectivity, and a dramatic increase in oil rents due to the increase in oil prices, all in a context in which some contracts did not have a progressive tax structure. However, there are two novel characteristics in this period. Firstly, in this occasion the institutional weaknesses which generated a commitment problem were supposed to be mitigated by the use of foreign institutions. Nevertheless, and it is still early to have a definite conclusion, it seems that the short-term costs were not very significant, given that, when the rules changed, most companies decided not to use the external enforcement mechanisms. It seems that for majority of the companies, at the stage in which the projects were, and under the prevalent market conditions, it was preferable not to invoke the clauses that protected investors –potentially losing a lucrative operation- and instead accept the stringer fiscal rules and below market compensation. This result shows how in this type of sector in certain situations sophisticated contractual agreements designed to protect private investors might not have enough teeth. However, in case Exxon and Conoco obtain a favorable arbitration decision for something close to the reported market value of their projects, adding to up to US\$7-9 billion; PDVSA and the Venezuelan government would bear some significant costs, which could set a significant precedent for the external enforcement of investment commitments in the oil industry.

Secondly, in some of the contracts, the tax structure was indeed progressive, but progressivity was triggered only after certain thresholds of profitability were reached. However, oil prices increased before those thresholds were reached and the conflict ensued. The tax structure did not effectively consider the possibility of a rapid and dramatic increase in prices, such as the one that actually happened. We cannot prove the counterfactual argument that if tax rules included some progressivity based on prices, these renegotiations would have not happened. Nevertheless, it is evident that the lack of them was a strong argument for them to occur.

It is important to emphasize that the new tax regime based on a 33.3% royalty is even less progressive than all the previous tax regimes. In fact if the price of oil rises further, the government would not be capturing as much as it should, of the additional rents. A marginal government take of 67% at an oil price of US\$120 is too low given that the additional dollar at price levels like those is way above the range of prices that makes investment profitable. As we showed, even some of the reopening contracts had higher marginal takes. On the other hand the regressiveness of the tax regime and the high level of the royalty imply that if the price of oil declines the government-take would be extremely high, making investments unattractive. According to a study by Cambridge Energy Research Associates (2007) the new tax regime generates a government-take of 94% at an oil price level of \$55 per-barrel (for the WTI), at a price of \$25 the operator would lose money (the government will get all the profits), and at a price level of \$80 the government-take would be at 87%. The break-even price for new investments with the new Venezuelan tax regime is estimated at \$44 per barrel (for the WTI). The new regime contrasts for example with the one set in 2007 in Ecuador,

based on wind-fall tax, where the marginal government-take for oil prices above \$70 is 99%, but the marginal take at low prices is 44%.⁴⁵

VI. Concluding Remarks

In general, the literature on the Venezuelan oil sector has focused on ideological explanations and, consequently, attributes most the historical episodes to the ideological debates and the winners and losers of such debate. Even though ideology might have been important in framing the policy options, in this paper we have argued that the distributive conflict and the lack of an effective tax system, which allow the government to effectively collect rents, should not be overlooked. In addition, the incentives intrinsic to the oil sector make the industry a tempting target for expropriation, as a result commitment is difficult to enforce under certain circumstances, such as periods of high oil prices, after high sunken investments have been made, and the government is not urged to attract investment.

We analyze three periods of contract renegotiation in Venezuela: 1943, 1958-1974, and 2004-2007. In all of them, it is relatively evident that the tax structure in place lacked an effective form of progressivity leaving the government with a small share of an upside in the oil business. However, the last two contract renegotiation periods have also been generally associated with some form of opportunistic expropriation and nationalization.

The governments took advantage of the stronger negotiating position provided by high oil prices and favorable geopolitical conditions to expropriate revenues and assets. The way contract renegotiation was executed, particularly in the last two episodes, generating uncertainty over property rights and leading to state-ownership, which has its own problems, has had negative consequences over investment and growth.

Venezuela has not been alone in changing the terms of oil deals whenever oil rents increase. Elsewhere we have shown how it has been a trend in the Latin American region and even in developed countries around the world (Manzano and Monaldi, 2007). For example, in the recent cycle of high oil prices countries as diverse as the United Kingdom, Canada, Russia, China and Algeria have toughened the fiscal terms (CERA, 2007). This shows that the problems of lack of progressivity and credible commitment are widespread. However, the way the contracts have been renegotiated across the world has lead to different outcomes, sometimes generating high regulatory uncertainty and creating unattractive fiscal terms at lower oil prices. In other cases, like Venezuela in 1943, renegotiation has not affected the future investments in the sector.

The country has witnessed cycles of investment and expropriation caused by the lack of an appropriate institutional framework that is able to manage the changing environment allowing the state to capture the rents without impeding the development of the full potential of the oil industry. As we have argued elsewhere, state-ownership of the oil industry has not been free

⁴⁵ In Ecuador the new tax regime generates a government-take of 59% at an oil price level of \$55 per-barrel (for the WTI), 72% at a price of \$25, and 75% at a price level of \$80. As the price increases above \$80 the government-take rises (CERA, 2007).

of episodes of revenue expropriation by the government; in fact the problem sometimes gets worse than with private operation (Monaldi, 2002; and Manzano, 2007). Therefore, the search for an institutional framework that solves the lack of progressivity and the political economy issues has to continue.

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Appendix: The Contracts of the Oil Reopening

Operational Service Agreements (OSA)

OSA contracts were the first type to be implemented. Typically mature oil fields with low production were auctioned. The blocks allocated had proven reserves, therefore geological risks were relatively low, but still there was uncertainty over the ability of profitably increase production, which introduced some risks. In the first two auctioning rounds, the agreements may be classified as *service contracts*, in which the operator got reimbursed for capital investment and in addition received an operational fee per barrel (which covered operational costs and generated the profit). The operational fee formula provided incentives for increasing production and as result the operator shared some production risk, but the price risks and the upside were largely obtained by PDVSA and the government. In contrast, in the case of the third round auction, the contracts were clearly *risk-service contracts*, more akin to a *profit-sharing* or *production-sharing* contract. In this case the companies received a fee that was based on the market value of the additional oil produced. The fee varied inversely with the internal rate of return of the project introducing some degree of progressivity. Therefore, the operator kept a larger share of the risks and rewards.

I and II Round OSA Contracts

In these two rounds, the oil fields were auctioned in base of a combination of two parameters: 1) the lowest *operational fee per barrel* (*Opfee*) offered, and 2) the highest minimum 3-year initial work program guaranteed. PDVSA paid the operator a total fee composed by the sum of two different values: 1) the *capital fee*, to reimburse investments and interests on non-recovered capital expenses, and 2) the *operational fee per-barrel*, which covered the operational costs plus a profit.⁴⁶ The fees had the following characteristics: 1) the fees were set and paid in US dollars to eliminate exchange-rate risks; 2) the operational fee was indexed using the US energy CPI index; 3) the contracts established a *maximum total fee* (*Maxfee*), set for each field taking into account the type of crude extracted, and designed to allow PDVSA to cover the royalty it had to pay to the government plus some margin. This *Maxfee* was thus adjusted using a basket of marker crudes. If the total fee in a year exceeded the *Maxfee* the operator had a credit for next year. The existence of the *Maxfee* implied that the contractor faced risks if the price of oil declined significantly (as it did in 1998). 4) The formulas of the total fee, particularly in the II round, provided incentives to increase production. 5) For tax purposes, the companies declared the operational fee as taxable income and subtracted the applicable costs, applying a 34% income tax rate.

46 Legally the private companies were not “selling” the oil to PDVSA, they were contractors that received a service-fee. The reasons for this peculiar interpretation are twofold: 1) a creative interpretation of the legislation allowed to obtain foreign investment without changing any law (in particular the Nationalization Law). Operational contracts did not require Congress approval. In contrast, if the companies produced the oil and sold it, a joint-venture with PDVSA and legislative approval would have been required (under art. 5); 2) under this arrangement the foreign investor was shielded by PDVSA from the application of special oil taxation (the royalty, the special rate of the income tax, the surface tax, etc). A foreign investor classified as a contractor was equivalent under the law to a company that provides any other service to PDVSA. The foreign investor was thus subject only to regular taxes (maximum 34% income tax as any other business) and PDVSA alone paid the oil taxes.

The contracts' duration was 20 years, which could be extended to 30 years. Under OSAs, all contractual disputes could be settled through private arbitration. In the first round any disputes could be settled by private arbitration in Venezuela. In the second round contracts were still subject to private arbitration in Venezuela, but they specified the use of the International Chamber of Commerce (ICC) rules. This is contrast to the III round in which international arbitration was established.

In terms of fiscal progressivity these contracts were highly progressive. The marginal government take (including what was kept by PDVSA) on an increase in the price of oil was very high, close to 100%, since the total fee did not increase with the price of oil. The price of oil mainly served as a cap on the fee when the price went down. Still the government in 2006 argued that the cost per barrel to PDVSA in these contracts was too high, between \$12 and \$14 per barrel (probably the result of cost adjustments using the U.S. inflation and real exchange-rate appreciation). However, this figure implies that, using an estimated actual cost per barrel for the operator of \$4 to \$7, the operator was obtaining a pre-tax profit of about \$7-10 per barrel and a net profit of about \$5-6, a profit per barrel well below the one obtained in other contracts.

III Round OSA Contracts

In the third round implemented in 1997, the parameter to auction the fields was an initial signature bonus in a closed bid. The auction was a success, with investors offering higher bids than most analysts had expected. PDVSA collected payments for US\$2.2 billion (equivalent to about 20% of oil fiscal revenues in that year and more than 2% of total GDP). Analysts were surprised by the high bids offered. For example, Repsol offered \$300 million for an oil field that most analysts had valued at around \$150 million. Almost all oil fields offered were allocated for significantly higher amounts than originally expected by industry analysts (El Universal, 6/4/1997).

In this case, the amount paid to the operator was determined based on the net incremental value of production (NIV) and the internal rate of return of the project (IRR). In practice this implied that the contract was similar to a profit-sharing contract. The NIV was essentially the value of oil produced minus costs, royalties and an administrative fee. The operator take on the NIV varied with the IRR according to the following criteria:

100% of NIV when $IRR < 0\%$

K% (65%-52.5%) of NIV when $0\% < IRR < 60\%$

30% when $IRR > 60\%$

where $K = y + Tq(x-y)$

$y = (1 - (1+r)*IRR)$ where $r = \text{royalty rate} = 0.1667$

$x = 0.75 - 0.75*IRR$

$Tq = \text{an adjustment variable based on the time elapsed}$

The operator still had to pay income tax at a 34% rate and PDVSA paid the royalty (16.67%). The marginal government take in these contracts was progressive with respect to the IRR. Before the IRR of the project reached 0% the marginal take was 45% and after the IRR reached above 60% the marginal take reached a maximum of 87%. For IRRs higher than 0% and lower than 60% the marginal take increased from 45% to 87% in direct relation to the IRR and the time elapsed.

In the third round “definitive and irrevocable” international arbitration in the city of New York was specified, using the International Chamber of Commerce rules. “The decisions of the arbitrage tribunal must be obeyed and are binding for both parts” and “the enforcement of the sentence can be processed by any court with competency in the case without reviewing the substance of the case.” “The parts renounce to any appeal to the arbitration decision,” and PDVSA “abdicates any legal immunity of jurisdiction” that it may have as a state-owned company or “any immunity against executive embargo of its assets” (Third round OSA contracts, 1997).

Extra-Heavy Oil Strategic Association Agreements (AA)

In order to develop the Orinoco Oil Belt, the largest reservoir of extra-heavy oil in the world; significant investments had to be made (US\$12-15 billion). The low quality characteristics of this crude (very low gravity of around 8-9 API grades, high viscosity, and high sulfur content) required a costly upgrading process that made it less profitable than the typical oil production in the country. In order to upgrade this crude into marketable heavy or synthetic (medium gravity) oil, specialized highly capital-intensive oil upgrading refinery plants had to be constructed in Venezuela. Therefore, the proportion of sunken costs in this type of project was significantly higher than in other oil projects and capital recovery takes a longer period. Each project required investments of between \$2 to 4 billion. All were 30-35 year contracts.

In order to develop these projects the government decided in the early 90s to create joint ventures with foreign companies that could provide capital, know-how, and technology. These joint ventures were approved using the option provided by article 5 of the Nationalization Law, which permitted joint ventures with foreign investors under the following conditions: 1) The state has to be guaranteed “control” in the joint venture (but it did not precisely define control or how it should be achieved); 2) The association needs to have a determined duration (cannot be unlimited); 3) Congress has to approve the basic legal framework for the associations (Congreso de la República, 1975). The Venezuelan Congress accepted a lax interpretation of the meaning of “control” (and the Supreme Court upheld that interpretation). It required PDVSA’s approval, in a control committee, for “important” decisions. The “regular” decisions had to be approved by a simple majority in accordance to the proportion of shares. The marginal take in these contracts was relatively low at 34.7% before the IRR trigger and moved up to 45% afterwards.⁴⁷

These contracts included an interesting clause on tax stability. If the projects faced an act by a state entity or the government having a significant negative effect on its financial results (or those of its private shareholders), and such act represented “discriminatory” treatment not applicable to all companies in the country; the private investors would be compensated by PDVSA. Such discriminatory acts included a change in the income tax, the dividend declaration, or the possibility of maintaining the money obtained from the sale of oil in foreign currency. The compensation would occur in the same fiscal year and would be the maximum between 25% of the negative economic impact or a calculation based on a scale of the oil price. However, it established that the compensation would not apply in case the price of oil (Brent) reached above \$25 (adjusted for inflation).

International arbitration in the city of New York using the ICC rules was the method for settlement of disputes in AA (as in III Round OSA). Again, any competent tribunal could execute the arbitrage’s decision, without reviewing its substance. The dispute can be taken to ultimate arbitrage at the International Center for Settlement of Investment Disputes (a World Bank sponsored institution).

⁴⁷ The AA projects are constitutionally (art. 9) exonerated from local or regional taxes, since they (as opposed to OSA) are considered oil projects. They are also exonerated from the Value Added Tax in the pre-operational stage. If for any reason this situation changes, PDVSA would have to compensate foreign investors.

Revenue Sharing Risk Exploration Agreements (RE)

Revenue Sharing Risk Exploration Agreements (RE) are the third type of arrangement used in the oil opening. These contracts are the less relevant in terms of economic impact because none of them has gotten yet into the production phase. However, it is interesting to analyze why they were also renegotiated. Under RE some areas were auctioned for exploration by the foreign companies. In case exploration was successful and commercial, extraction of oil would be done in a joint-venture with PDVSA (which could choose to have participation between 1% and 35% of the stock). In 1996, ten exploration areas were auctioned, of which eight were allocated to 14 companies (some in multiple association).⁴⁸ Here the bidding parameter was not a present cash payment but the share of state participation in profits (PEG) offered by investors.⁴⁹ The auction process was very successful. Analysts were surprised by the fact that five of the winners of the auctioned areas offered the highest possible state-share on oil profits. In order to decide some tied bids, an additional bonus cash payment was offered. The bonuses added to a total of US\$ 245 million. As in the case of AA, RE contracts had to be approved by Congress under the conditions for private investment provided by article 5 of the Oil Nationalization Law. The duration of these contracts was 39 years, and they offered an extension in case there was a curtailment in production due to a government decision. This type of contract offered some guarantees to foreign investors similar the others reviewed above (to AA and OSA III round agreements).⁵⁰

48 Twenty-nine offers from 44 investors associated in twenty-three consortia were received (OCE-PDVSA, 1998a).

49 PEG. Participacion del Estado en las Ganancias (PEG).

50 1) The companies were exempted from local and regional taxes. 2) A contract clause provided for compensatory damages in case there was a discriminatory act by the government (not of general applicability). 3) The contracts provide final and binding international arbitration in the city of New York, using ICC rules (p. 61, RE contract, PDVSA 1996) . Again, PDVSA irrevocably agreed not to invoke “immunity from jurisdiction of any court or from attachment in aid of execution of any other legalprocess...with respect to itself or its assets.” (RE contracts, 1996).