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OUTLOOK ON VENEZUELA'S PETROLEUM POLICY

A STUDY

PREPARED FOR THE USE OF THE

SUBCOMMITTEE ON ENERGY

OF THE

JOINT ECONOMIC COMMITTEE
CONGRESS OF THE UNITED STATES

FEBRUARY 1980

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LETTERS OF TRANSMITTAL

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(CREATED PURSUANT TO SEC. 5(a) OF PUBLIC LAW 304, 79TH CONGRESS)
WASHINGTON, D.C. 20510

13 February 1980

Hon. Lloyd Bentsen
Chairman
Joint Economic Committee
Washington, DC

Dear Mr. Chairman:

I am pleased to transmit herewith a study prepared for the Subcommittee on Energy entitled "Outlook on Venezuela's Petroleum Policy." The study was prepared by Erik J. Sivesind, Environment and Natural Resources Division, Congressional Research Service.

As the major exporter of oil in the Western Hemisphere, Venezuela's role in providing the United States and other nations of the Free World with stable and constant levels of oil cannot be underestimated. Recent upheavels in the Middle East underscore the need to develop and strengthen ties with our Western Hemisphere neighbors. Despite its membership in OPEC, Venezuela has been a secure source of oil, and the United States must develop policies which will insure the continuation of this beacon of security.

The findings of this study, of course, are those of the author and do not necessarily coincide with the views of the members of the Subcommittee on Energy.

Sincerely,

Edward M. Kennedy
Chairman, Subcommittee on Energy

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Washington, D.C. 20540

Honorable Edward M. Kennedy, Chairman
Subcommittee on Energy
Joint Economic Committee
U.S. Congress
Washington, D.C. 20510

Dear Senator Kennedy:

I am pleased to transmit the accompanying study entitled "Outlook on Venezuela's Petroleum Policy", prepared at your request by the Congressional Research Service. The study presents information on the background of petroleum development in Venezuela, as well as an analysis of Venezuela's export potential and probable export policies as they will affect U.S. energy policies. It was prepared by Erik J. Sivesind, who was an analyst with our Environment and Natural Resources Division during its preparation, under the supervision of John W. Jimison, Head of the Energy and Minerals Section. Editorial assistance was provided by Diana J. Sloan. We are pleased to be able to contribute this effort to your ongoing consideration of this critical area of national concern, and stand ready to provide additional assistance as requested.

Sincerely,

Gilbert Gude

Gilbert Gude
Director

FOREWORD BY SENATOR EDWARD M. KENNEDY

The Congressional Research Service has prepared a valuable and timely study of Venezuelan petroleum policy. This study comes at a time when our Nation is in the process of rethinking its energy policy. In the months following the oil embargo of 1973, many Americans hoped that somehow this Nation could quickly eliminate its dependence upon foreign sources of petroleum. Indeed there has been a persistent tendency to see our energy problem as wholly a question of dependence on foreign oil. Our energy policy has largely consisted of a myopic pursuit of anything that could claim to reduce oil imports. In particular, this has led to a highly questionable enthusiasm for very high cost synthetic fuels.

Many are now coming to realize that our energy problem is not solely dependent upon foreign sources, but rather the fragile security of our sources in the Middle East. There is also a growing awareness that, even if it were possible, total self-sufficiency in energy production would not solve our security problem. Our security problems remain as long as our European and Asian allies remain vulnerable to major supply interruptions. Needless to say, the events in Iran over the past year have done much to stimulate fresh thinking on these issues.

In March of 1978, the Energy Subcommittee held hearings which examined the question of world oil supplies. In particular, the Subcommittee looked at the potential for the United States to diversify its sources of foreign oil supply. Since then, both the General Accounting Office and the Congressional Budget Office have issued reports dealing with these issues and pointing out the economic, national security, and foreign policy advantages that could come from a diversification of our sources of oil supply. Earlier this year the Energy Subcommittee published a report which Senator Church and I requested from the Congressional Research Service which examined Mexico's potential as a major producer of oil and gas.

Now the Congressional Research Service, with this study of Venezuela, has given us an opportunity to examine another aspect of the foreign oil question. In my view, a careful examination of our relationship with Venezuela and its oil resources will contribute significantly to our energy policy. For many years Venezuela was our most important supplier of foreign crude oil, and it is still one of our major sources. There are many valuable lessons to be learned from the record of this relationship. On its side, Venezuela has been one of our most steadfast allies. It has provided us with a reliable source of petroleum through two world wars and numerous world crisis. On our side the record is less consistent. In its early days the relationship was marred by corruption and exploitation. More recently the record is one of mistake and missed opportunity. In 1959 we imposed the Mandatory Oil Import Quota. The purpose was to protect domestic oil prices from the competition of low world market prices. The effect was to drive world prices even lower and to deprive Venezuela of an important market. In the face of this serious economic setback, it is hardly surprising that Venezuela played a key role in the formation of OPEC. Venezuela, however, has never joined with those nations that have used oil as a political weapon. During the Arab oil embargo of 1973-74, Venezuela continued to ship oil to the United States, and was perhaps rightly offended when it was not exempted from the retaliatory measures imposed by Congress on OPEC nations.

Past failures cannot be undone and missed opportunities cannot be retrieved, but the lessons they teach can give us a surer sense of direction for the future. As this report shows, Venezuela's oil production will remain extremely important for the world economy. Beyond its conventional oil resources, Venezuela has enormous reserves of heavy crude. It may well be that this heavy crude could be produced at today's prices. But we cannot expect Venezuela's energy policy to be conducted in our interests. Venezuela's interests are not, and will not, be ours. What we can do is understand that there is enormous poten-tail for cooperation in pursuing mutual objectives.

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OUTLOOK ON VENEZUELA'S PETROLEUM POLICY

by

Erik Sivesind
Analyst
Environment and National Resource Policy Division

PREFACE

Venezuela exports more oil than any other nation in the Western Hemisphere--1.9 mbd in 1978--34% of which goes directly to the United States. The sepectacular size of the recent petroleum discoveries in Mexico has caused a sensation in energy circles and diverted attention away from Venezuela. Yet even when Mexican production rates surpass those of Venezuela sometime in the early 1980's, Mexican exports will still lag far behind Venezuelan exports because of Mexico's higher domestic consumption. According to a recent CRS study, Mexican exports will not reach present Venezuelan levels of 1.9 mbd[1/] until 1987 or 1988 at the earliest.

For the past thirty years the Western Hemisphere has counted on a steady supply of oil from Venezuela and has not been disappointed. During the Embargo of 1973-74, Venezuelan supplies continued to flow freely. Despite its consistency and constancy, the U.S. lumped Venezuela in with all cartel members in a 1974 retaliatory move by Congress that imposed trade restrictions on all OPEC members. The restrictions have little economic importance, but as the president of the Venezuelan Senate remarked during a visit early this year by Vice President Mondale, they "sentimentally and morally hurt" Venezuela.[2/]

As interpreted by Venezuelan spokesmen, by failing to acknowledge and reward Venezuela's reliability as a source of energy, the U.S. has symbolically denied the essence of Venezuela's international identity: credit worthiness, foreign reserves, trade, political stability, third world influence and prestige, are all perceived by the foreigner as functions of Venezuela's steady oil production and supply.

1/ U.S. Congress. Joint Economic Committee and Senate Committee on Foreign Relations. Mexico's Oil and Gas Policy: An Analysis; by Congressional Research Service. Washington, U.S. Govt. Print. Off., December 1978. p.3

2/ Christian Science Monitor, editorial, April 2, 1979.

Likewise, the Venezuelans view their nation and its oil as inseparable entities--the country cannot develop economically and socially without the resource. Such an intimate and dependent relationship invariably carries strong emotional elements. The emotion is mixed: a Venezuelan feels fortunate for the natural wealth permeating the subsoil, but he is fearful of depending too heavily on that one natural attribute. That fear animates the emotional content of the Venezuelan perception of her petroleum resources, and contributes an important part to the dynamics of Venezuelan petroleum policy.

This emphasis on the emotional aspect of petroleum related issues in Venezuela is not an exercise in sympathetic abstraction. The democratic governments of Venezuela have made national control over oil resources an issue of national pride. Their success in spreading the doctrine of national sovereignty over petroleum to other oil producers, and in leading them by ideology and action into the formation of OPEC, has imbued Venezuelans with a deep sense of national pride. Any action that hints at a reduction in that control over its resources not only threatens the practical advantages of sovereignty, but also takes a slap at Venezuelan pride.

The quest for that control has not always been guided by the dispassionate application of economic principles. One of the most persistent and powerful Venezuelan advocates of state ownership and management of petroleum resources and also a former president, Romulo Betancourt, proudly acknowledges the emotional catalysts in that struggle for control: "I have not used impersonal academic tools to examine the oil question but rather my own passionately committed personal vision."3/

That personal vision has become a national reality and only because the academic arguments that warned of economic upheaval in the event of nationalization did not match the strength of the Venezuelans' collective commitment to their vision of national sovereignty. Should the Venezuelan leaders decide to reverse the direction of current policy by allowing greater foreign participation in the petroleum sector, they would predictably find themselves ensnared in a trap of their own making--they would be hindered at every step by a population seeing such a move as a capitulation to foreign interests and an insult to Venezuelan pride. Regardless of economic calculations of potential benefit, greater foreign participation would be viewed as an injury to the nation's self-concept.

The volatile emotional mixture of gratitude, fear, and pride that insinuates its way into the dynamics of Venezuelan petroleum policy cannot be quantified. Yet it is a major consideration in any policy approaches the U.S. might take in regard to Venezuelan petroleum activities.

3/ Betancourt, Romulo. Venezuela's Oil. London, George Allen & Unwin (1978) p. 256.

I. Background of Petroleum in Venezuela

Even before Gonzalo Fernandez de Oviedo y Valdes described Venezuelan oil as "nector from Cubagua," the local Indians had long used it as medicine and for the caulking of boats. Local folk medicine also appealed to regal tastes, and in 1539 the first documented oil export from Venezuela went to alleviate the gout of Charles V.

Though petroleum substances played a negligible role in the colonial Venezuelan economy [Intendancy of Venezuela], the crown retained a legal interest. Under Spanish mining law, based on Roman practice, the discoverer of a mine received a concession to exploit it as long as the crown received its royal fifth--or quinto--of the output. This law specifically referred only to metallic substances, until in 1783, Charles the III reaffirmed the crown's dominion over metallic mines and extended the law to cover non-metallic substances such as "earth liquids." These "Ordenanzas de mineria" applied to New Spain as well as Spain, and gained jurisdiction over the Intendency of Venezuela in a 1784 "cedula," or royal proclamation. Thus from early colonial days, ownership of the subsoil lay firmly in the hands of the state.

After independence, with the crown's property becoming part of the public domain, the 1783 mining ordinances continued in force and the president of Gran Colombia had exclusive authority to grant mining concessions. Venezuela seceeded from Gran Colombia in 1830 and promulgated its first minning code in 1854, which repealed the 1783 ordinances. However the new code retained the central feature of the 1783 ordinances: state ownership of the subsoil. A decree in January 1855 specifically subjected combustible materials to the provisions of the mining code.

The 1854 code and similar ones following it continued as the legal basis for petroleum concessions, until 1904. Depending on the strength of the central government, actual jurisdiction over mines shifted between the states and the national government--but always a public authority.

The new mining law of January 1904 came during the rule of the military dictator, Cipriano Castro. While the 1904 law increased the state's revenue participation, it also liberalized the terms of concession agreements and reaffirmed the president's right to grant and administer concessions without the consent of Congress.[4/]

In April 1914, the first important Venezulan oil field was discovered by Caribbean Petroleum Company, which had been taken over by Shell Oil Company in 1913. The first shipments of oil out of Venezuela took place in 1917, when 121,000 barrels were produced. Through the early 20's all major petroleum operations were under British and Dutch control, and by 1922 production had reached 2,235,000 barrels.*

U.S. interests only became significant producers in the mid-20's, with Gulf and Standard of Indiana competing side by side with Royal Dutch Shell in the prolific Bolivar Coastal fields. This area produced 106 million of the 137 million barrels produced in all of Venezuela in 1928. And those producers accounted for 98% of all production. By 1928, Venezuela had become the world's leading exporter and was second only to the United States in total production.

4/ The above legal information from: Lieuwen, Edwin. Petroleum in Venezuela. New York, Russell & Russel (1954) pp. 5-12.

* This information on production levels and following data on its effects on Venezuela, are from, Ibid. pp. 31-53. (Edwin Lieuwen)

Standard of New Jersey, later Exxon, and the future giant of the Venezuelan industry, spent over $20,000,000 in Western Venezuela alone and had produced no oil commercially by 1929.

With the three major foreign companies rapidly expanding during the 20's, labor migrated from rural areas to the oil fields, wages and prices rose, and agriculture declined. When the industry halted its expansion briefly in 1927 due to excess world supplies, thousands of workers were dismissed and local businesses were caught with large inventories they could not sell. When the companies resumed expansion plans in 1928, prosperity returned, but the country's growing dependence on petroleum had made itself felt.

The dollar value of Venezuelas' three traditional exports--coffee, cocoa, and hides--stayed constant during this boom period of the industry, but by 1925, petroleum passed coffee as the country's leading export. By 1929, it composed 76% of all exports.

Through 1942, various legal changes affected only the terms of the concessions and made minor adjustments to tax and royalty rates. In January 1943, Venezuela's first income tax law went into effect, which included a levy on the net profits of foreign companies. Two months later a new petroleum code passed Congress--the Hydrocarbon Law of 1943--which gave the government a much larger share of profits; in exchange the companies received a forty year extension on their concessions and previously granted concessions were placed under the terms and jurisdiction of the new law, which cleared any claims on the validity or legality of the older concessions.[5/]

5/ Martinez, Anibal R. Chronology of Venezuelan Oil. London, George Allen & Unwin Ltd. (1969) p. 80.

With passage of the new law, President Medina quickly began a massive sale of concessions that gave the oil companies rights to 5.97 million hectares of land in 1944 alone--more than in all of Venezuelan history. The 1943 code had been touted as the first truly nationalistic government effort in petroleum policy. However, Perez Alfonzo later discovered that the new code had been drafted in secret by Medina, his attorney general and several U.S. oil industry "experts". 6/

Despite Medina's claim that his policies had gained a fifty percent share for the government in oil company profits, his successor in a 1945 coup, announced that the income tax figures had been manipulated by Medina's regime to support his claim. Accordingly, they levied an extraordinary tax of $27 million on the oil companies to bring the figure to 50 percent in line with their own calculations. A measure known as the Additional Tax, decreed in 1948, firmly established the fifty-fifty split in profits by taking 50 percent of any sum by which a company's net profits exceeded the government's total revenue from that company's Venezuelan operations. This fifty-fifty principle became a milestone in the politics of world oil and initiated Venezuela in her role as a leader of other oil producing countries: Iran adopted the formula in 1949, Saudi Arabia in 1950, Kuwait in 1951, and Bahrain and Iraq in 1952. 7/

6/ Franklin Tugwell cites this in: The Politics of Oil in Venezuela. Stan ford, Stanford Univ. Press (1975), p. 43. Tugwell interviewed Perez Alfonzo in 1973 and saw documents and correspondence detailing the companies' role.

7/ Ibid., p. 45.

In addition to statutory changes in the tax structure, the civil-military junta announced in 1945 that no further concessions would be granted. For the oil companies, the spring of 1948 brought further bad news: a special commission had been appointed to study the establishment of a national petroleum company which would develop Venezuela's remaining oil reserves.

The first seeds of a nationally owned and operated petroleum industry were planted that spring, though they lay dormant for many years. The government of Romulo Gallegos, along with its reformist policies, was overthrown in 1948 by a military dictatorship. The new government retained some of the reforms in order to garner higher revenues, but went back to the practice of granting concessions.

After ten years of dictatorship, Venezuela in 1959 had become in the words of Romulo Betancourt, "a petroleum factory". Farmers had been drawn from the land by the hope of higher wages in the oil lands, and agriculture, the traditional base of society, had atrophied to the point that food had to be imported. Commerce and manufacturing depended on the spillover of funds from oil development for financing their activities, and two-thirds of the government's spending came from royalties, income taxes and other oil company payments.[8/] Venezuela existed off the proceeds of the oil companies operations--not the government's own activities or those of Venezuelan nationals. As the international oil industry went, so went Venezuela.

OPEC and Venezuela

Unemployment, a decimated and destitute rural sector, domestic capital shortage, and a large budget deficit were the legacies of the Perez Jimenez dictatorship. When the government led by Romulo Betancourt came to power

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8/ Tugwell, Politics in Venezuela, p. 49

in 1959, the problems inherited from the dictatorship constrained the new government's approach to petroleum policy. Oil revenues were needed desperately so nationalization was out of the question. But the government confronted a deteriorating international oil market and falling income.

Through 1957, prices for Venezuelan oil climbed steadily, and then began a decline that lasted until 1970.[9/] The downward pressure on prices was due to forces beyond the control of Venezuela: the emergence of low cost Middle East producers, falling transport rates after the reopening of the Suez Canal, Soviet efforts to expand its oil markets outside the Eastern Bloc, and the higher than average production costs of Venezuelan oil.[10/]

On February 6, 1959, Shell began a general reduction of the posted prices of Venezuelan oil. The Middle East was hit by larger reductions the next week. In early April, posted prices of Venezuelan crude oil, were lowered by all operating companies. Perez Alfonzo, Minister of Mines and Hydrocarbons, denounced the cuts. On an average production of 2.8 million barrels a day (mbd), the 27 cent/barrel price drop in 1959 meant a loss of $276 million a year to the companies operating in Venezuela, and of $105 million to the government.[11/]

9/ I.M.F. International Financial Statistics, various issues, cited in Tugwell, Politics of Oil, Appendix, Table D p. 183.

10/ Tugwell confirms the contention of the oil companies that Venezuelan oil was more expensive to produce. But the companies overstated their case. Tugwell notes that M.A. Adelman concluded that the companies had chosen an expensive mix of producing areas, leaving much lower cost crude in the ground.

11/ Tugwell, Politics of Oil, p. 54.

In reponse to this threat to the country's development, the government established the Coordinating Commission for the Conservation and Commerce of Hydrocarbons--just five days after the price cut. Its functions were to be: "studying and recommending the regulations on the commerce of hydrocarbons and of coordinating them with the conservation policy advised by the supreme interest of the nation."[12/]

Perez Alfonzo recognized that excess productive capacity existed in the major producing areas and believed that controlling production levels offered the only way of maintaining the price of oil. His hope was that the Commission would serve just that purpose in Venezuela and provide on example to other producing countries. The effectiveness of the Commission, as in any prorationing system, depended upon its ability to control other principal sources of supply to the market. Without the participation of the Middle East producers, the commission was hamstrung. As Perez Alfonzo later said, "the principal sucess of the Coordinating Commission was to serve as a stimulus for the creation of OPEC..."[13/]

Less than two weeks after forming the Commission, Venezuela attended the First Arab Petroleum Congress, called together in reaction to the price cuts. Invitations also went to the oil companies. A party at a sailing club gave the producing countries a chance to meet alone. There they reached the famous "gentleman's agreement" to set up channels for exchanging information about oil and to find measures to prevent any further price deterioration. The Venezuelans wanted to go further by creating an international producer's organization, but that idea got a tepid reception from the other countries. Only Abdullah Tariki, the Saudi Arabian representative gave full support to the Venezuelan proposal.

12/ Martinez, Chronology, p. 129.

13/ Perez Alfonzo, Juan Pablo. El Pentagono Petrolero. Caracas, Ed. Revista Politica (1967), p. 23.

In August of 1960, Standard Oil of New Jersey led a second unilateral price cut by the international oil companies. Another meeting of the major oil producers was called in Baghdad, and the understanding of the year before between Tariki and Perez Alfonzo, now bore fruit in the creation of OPEC.

U.S.-Venezuelan Oil Relations

With OPEC presently operating just as unilaterally as the oil companies had in the past, the U.S. can recall in a spirit of self-flagellation the missed opportunities of the early 60's to become a positive influence on the changes occuring in the world of oil. In early 1960, before OPEC, Perez Alfonzo addressed an international petroleum conference in Texas, and supported consumer country participation in a prorationing scheme. At that time and in later discussions with the U.S. government, he argued that both producers and consumers would benefit from a system which maintained prices and assured a steady flow of oil.

In addition to the prorationing effort, Perez Alfonzo sought a second policy objective: a comprehensive agreement with the U.S. and Canada "to regulate and stabilize oil trade within the hemisphere, thus assuring Venezuela a degree of control and predictability in her principal market area."[14/] His goal then was much like the present U.S. interest in focusing on a hemispheric approach to energy supply problems. However, in 1960, the main beneficiary of such a move seemed to be Venezuela; now the U.S. stands to gain the most from an integrated energy arrangement in the Western Hemisphere.

Venezuela can be expected to view such U.S. advances with an eye on the past. In, March 1959, President Eisenhower released Proclamation 3279,[15/]

14/ Tugwell, Politics of Oil, p. 60.

15/ U.S. Presidential Proclamation 3279, "Adjusting Imports of Petroleum and Products into the U.S.," Federal Register 24, No. 42, pp. 178-84.

establishing mandatory control of oil imports into the U.S., using the national security clause in the Trade Agreements Extensions Act, of 1955, as the justification. This allowed the president to limit imports he considered to be "in such quantities as to threaten to impair the national security."

Venezuela initially reacted favorably, believing first, that the restrictions on all imported oil would help to support prices, and second as Eisenhower said in his announcement, Venezuela and other Western Hemisphere nations would be included in future consultations leading to a more elaborate system. Perez Alfonzo envisaged this as a hemispheric extension of the existing U.S. prorationing system, with the Venezuelan and Canadian governments receiving their share of the production requirements of the United States. Instead, the U.S.alloted the quota to the importing companies, keeping the governments out of the system.

The Venezuelans' attitude quickly changed with the news on April 30, 1959, that Eisenhower had exempted all imports arriving through overland means of transport. This lifted all restrictions on Canadian and Mexican oil exports, effectively discriminating against Venezuela. The Minister of Mines responded in a press conference at the Venezuelan Embassy in Washington, that his country "faced with anguish" the recent changes in import controls, and not just because of the privilege accorded Canada and Mexico, and the resulting discrimination against Venezuela. He reminded the U.S. that Venezuela had for many years been the major source of U.S. oil imports and that her production had always been available in times of peace and emergency. 16/ This made the discrimination

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16/ "Declaracion del Ministro de Minas," in press conference of May 6, 1959, in the Venezuelan Embassy, Washington: reprinted in Perez Alfonzo, El Pentagono, Documento No. 4, p. 176.

against her on the basis of national security especially distasteful and suggested to Venezuela the "implication that Venezuela is held in low regard and that her sources of petroleum are not considered, as once they were, essential to the security of the U.S." 17/

A tightened market for her imports also meant downward pressure on prices of Venezuelan oil. From the Venezuelans' perspective, the quota system amounted to a subsidization of the U.S. oil industry at the expense of the struggling exporting countries. In his book, El Pentagono Petrolero, Perez Alfonzo computed the cost to Venezuela in the first six years of the program: on total exports to the U.S. of 2,500 million barrels, the loss was $1,875 million, based on the refiners subsidy of 50 cents to one dollar per barrel, as reported in the Oil and Gas Journal. 18/

In 1967 after eight years of unsucessful effort to convince the U.S. to end its discrimination, feelings in Venezuela still ran high over this issue. Perez Alfonzo thought that the U.S. treatment of Canada "was the just treatment that the rich and powerful United States ought to have extended to all of her suppliers or, at least, for reasons of hemispheric solidarity, to those in the Americas that have been called 'sister'." 18/

17/ "Memorandum presented to the Dept. of State, April 24, 1959, in relation to the modification of the Program of Restrictions, which is known to be considered." Reprinted in: Perez Alfonzo, El Pentagono, Documents No. 6, p. 178-182.

18/ Ibid, p. 32.

President Betancourt complained to President Kennedy several times about the system and said that a preferential trade agreement would do more for Venezuela than any amount of Alliance for Progress aid.[19/]

After 1963, restrictions on fuel oil imports gradually eased, although those on crude oil were tightened by about ten percent in 1962. The threat of a major energy crisis in 1973 finally brought about the end of the import quota system. By that time, Venezuela had lost interest in a hemispheric strategy. As President Caldera said in 1973:

> "If the United States didn't have the intelligence to offer us a hemisphere preference... for so long, it now makes little difference to us... Now it is impossible to hide the fact that we have a very precious commodity... the need for which is increasing daily at an astonishing rate in every country." 20/

Venezuela is not likely to forget that the change of heart in the U.S. had nothing to do with a concern for Venezuela or for hemispheric solidarity.

In any case, the lifting of restrictions on oil imports was followed quickly by the 1974 trade restrictions which Congress imposed on all OPEC members, including Venezuela. Though financially unimportant, the U.S. move represented to the Venezuelaus a symbolic censure of the cartel members for the Embargo of 1973-74--in which Venezuela took no part. Even if the action against Venezuela could be defended on the grounds of the dislocating effects of the cartel price on the U.S. economy, the present U.S. energy policy ostensibly supports a price that covers the replacement cost of oil and thus eliminates the rationale behind the sanctions.

19/ Interview between Betancourt and Franklin Tugwell, Feb. 6, 1967.

20/ El Nacional, May 8, 1973, p. D1; quoted in Tugwell, Politics of Oil, p. 141.

Nationalization

Venezuela's Hydrocarbons Reversion Law of 1971 called for the state to take ownership of all company properties and their concessions when they expired in the early 1980's.

The deterioration of oil production facilities and the depletion of proven reserves motivated enactment of the Reversion Law. Legislative reform in 1970 had increased petroleum taxes from 52 percent to 60 percent and also gave Venezuela the right to set oil reference prices unilaterally and at any time. This ended a 1966 agreement for setting them every five years through negotiations with the companies. 21/ In the 1966 reforms, the companies had been able to ally themselves with local economic elites, since both were to be hit by tax increases. But the companies went their own way in working out a compromise agreement with the government, leaving their local supporters to fend for themselves. The companies won short-term gains in the 1966 compromise but consequently won the enmity of many former supporters. The 1970 tax increases caught the oil companies off their guard and without local political support.

Faced with these economic and political reverses, the oil companies' natural reaction to the increasingly inhospitable environment was to avoid further investments in the country and instead to extend the lifetime of their

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21/ Refrence prices are those on which taxes are computed. However, the 1966 agreement provided for taxes to be paid on income calculated at market prices rather than reference prices whenever the market price rose higher than the reference price. Tugwell, Politics of Oil, p. 113.

facilities and increase production only to the levels exploitable before the concessions expired. That lack of investment meant losses in future income for the government and ignited concern over the condition of the oil companies' properties upon devolution in 1983.

A less obvious problem, but more serious in terms of the Venezuelan government's long range responsibilities, was the companies' tendency to disregard conservation measures designed to maximize long term production from existing wells. Uncertain of their future once concessions ended in 1983 the companies wanted to extract as much oil as possible in the interim and

were freed from protective investments for future operations. Such rapid, unbridled pumping can cause water in an oil field pressurized by water to bypass large amounts of oil in the formations and reduce their productive life. Similarly, natural gas found in association with crude oil is often reinjected into the field to prolong its life, but the gas may be flared off in the absence of time and investment incentives.

The Hydrocarbons Reversion Law addressed these threats to the country's oil industry. It also cleared up uncertainty over the disposition of equipment on and off the concession sites. For example refining, transport and port facilities were often located off concession sites, and previous legislation failed to specify whether the state automatically acquired ownership of all properties, or just those on concession lands. Besides awarding the state ownership of all the companies' properties in 1983, the new law required government approval for any changes in industry operations and invested the state with the power to decide when and where to explore and drill new wells.

Though the law clarified the situation, the oil companies, already disturbed by the last tax hike and their newly revealed political vulnerability, found the extension of government control over company operations nearly intolerable. Senators Stevens of Alaska, Bellmon of Oklahoma, and Hansen of Wyoming introduced legislation in the U.S. Congress to prohibit imports of Venezuelan petroleum if the reversion bill passed. It did, July 30, 1971. Nothing came of the U.S. legislation.

The Venezulan Reversion Law made provisions to safeguard the condition of the concessionaires' physical assets, by requiring the companies to post a bond amounting to ten percent of the value of their installations, to guarantee that they would be turned over to the state in good shape. The companies could have expected to reclaim whatever amount of this they had paid at the time of reversion, but according to Tugwell, company officials conceded that they were treating the deposits as a loss for planning purposes.[22/] This implied that the companies did not plan to maintain their installations adequately enough to justify return of the deposits. Rather than acting as an incentive to maintain oil facilities, the bond measure became another cost of operating in Venezuela.

Production in 1970 averaged 3.7 mbd and increased to 3.8 mbd in the first quarter of 1971; just as the reversion measure was introduced as a bill in Congress, production fell off. Average production for 1971 dropped 4.3 percent, to 3.55 mbd and in 1972 it lost another 9.3 percent to 3.22 mbd. Costs had certainly risen with the tax hikes, and tanker rates fell

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22/ Tugwell, Politics of Oil., p. 121.

during part of 1971, so it is difficult to argue that the companies were cutting production simply to pressure the government. But the government had no doubts that the cuts were indeed reprisals for the Reversion Law.

With the new authority granted by the law to fix reference prices, the government sought to alleviate the budgetary squeeze caused by the production cutbacks. The Caldera administration announced that it was planning on a 2 percent production increase and a 6 cents per barrel boost in the reference price for the 1972 budget. Perez Alfonzo wanted a 40 cent increase per barrel and criticized the government for pushing production, arguing for a cut of half a million barrels per day. President Caldera compromised with a 32 cent per barrel increase and added an export-volume penalty system. The companies would be penalized for failure to reach the high production levels of 1970, assuring the government of a steady income despite fluctuating production levels.

Following the government's measures to prevent further income loss, the companies accelerated their production cutback. By February 1972, output had plummeted 13 per cent in two months, to a level of 3 mbd. With elections coming up in 1973, the government decided it would be inopportune to decrease expenditures and so the reference prices were raised again using a formula that paralleled changes in Middle Eastern taxes.

Then the fateful year itself arrived: 1973. World demand for oil surged after the outbreak of the war in the Middle East, and the Arab members of OPEC embargoed shipments to the U.S. In January, the average reference price in Venezuela was around \$3 per barrel. During the year, that figure increased six times and by the end of 1973 reached an average of \$14.08. All immediate budgetary problems had been swept away in that one year, and the government company relationship was drastically altered.

Newly elected Carlos Andres Perez, exuding an optimism engendered by the improved world oil market and a deluge of government income, abandoned the restraints that characterized his campaign. After the election, his first words ended the companies' faint hopes for improved conditions:

> The private companies are maintaining their exploratory activities at minimal levels, and we run the risk that our industry, owing to the failure to incorporate new techniques in the absence of appropriate investment and maintenance, will rapidly deteriorate, so that when the concessions are given up, we will find ourselves with outworn equipment and an obsolete technology. For these reasons, it appears impossible to wait until 1983 before the state assumes the full management of the petroleum industry. It would be prudent, as an alternative, that we proceed in the immediate future to nationalize--which ensures our sovereignty in the industry--and that we arrive at new formulas for the participation of the foreign companies in those areas where we need their technical resources, their financing, or their marketing ability. 23/

Exploratory activity, as shown in Table 1, did fall slightly from 1972 to 1973, but the overall trend from 1968 to 1974 is an upward one. Not until 1975, when nationalization became imminent, did explorations take a drastic fall. Yet the companies cannot take much credit for maintaining exploration activities at fairly constant levels after the Reversion Law, since the government had legal control over exploration. The government could not risk pushing the companies too far during years those of budgetary concern, but the companies acknowledged that they drilled more than they would have had they not feared greater government intervention in their operations. 24/

23/ Latin America, Christmas 1973, p. 409, reprinted in Tugwell, Politics of Oil, pp. 143-144.

24/ Decree 832, Dec 17, 1971 required the oil companies to submit for approval their plans for exploration, investment, and production each year, and any changes had to be approved in advance. Company officials indicated that their plans had been approved with few significant changes. Tugwell, Politics of Oil, p. 122.

EXPLORATORY ACTIVITY IN VENEZUALA 1968-75

Year	Exploratory Wells (a)	Field Parties (b)
1968	28	13
1969	34	17
1970	37	20
1971	44	24
1972	62	36
1973	59	29
1974	110	39
1975	34	40

a. By purpose at commencement of drillings and according to LAHEE classification, including wells A-2a, A-2b, A-2c & A-3.

b. Activity of geological and geophysical field parties, in party-months.

Source: Ministry of Energy and Mines, Memoria y Cuenta, 1978, VI-388.

Andres Perez's anxiety over the levels of exploration actually reflected government preoccupation with its proven reserves. Between 1971 and 1973, production had outstripped additions to reserves by 36 million cubic meters (226.4 million barrels). In 1961, Venezuela had a reserves to production ratio in years, of 15.8; in 1973 this had dropped to 11.3.[25/] The shortfall of additions to reserves in those three years in the early 70's indicated that the longer term decline in the reserve to production ratio was continuing, and must be stopped.

While the jump in prices in 1973-74 relieved fiscal pressures on the government and added substantially to reserves, the increase also gave the country the financial leeway and hence confidence, to carryout a nationalization of the industry at a greatly reduced risk to the nation's economic well-being. The Organic Law, which reserves for the state the production and marketing of hydrocarbons, was signed by Carlos Andres Perez on August 29, 1975, and took effect January 1, 1976.

25/ Ministry of Energy and Mines, Memoria y Cuenta 1978, VI-298.

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THE NATIONALIZED INDUSTRY

Petroleos de Venezuela

At the time of nationalization, the following 14 foreign concessionaires were operating in Venezuela:

Foreign Concessionaire	New Name	1975 Production MBD
Creole (Exxon Subsidiary)	Lagoven	997.8
Shell & Continental	Maraven	545.9
Mene Grande (Gulf, IPC., and Shell)	Meneven	373.3
Mobil	Llanoven	58.1
Texaco	Deltaven	72.7
Sun & Charter	Palmaven	126.0
Phillips	Roqueven	31.1
Arco	Bariven	23.1
Amoco	Amoven	26.8
Chevron	Boscaven	38.0
Talon	Taloven	3.1
Las Mercedes	Guariven	2.4
Mito Juan	Vistaven	3.9
	CVP 26/	42.9
	TOTAL	2,346.2

Petroleos de Venezuela, S.A. (PDVSA), was set up as a holding company to administer the operating companies. By the beginning of 1979, the number of operating

26/ CVP: Corporacion Venezolano de Petroleo, was founded in 1960 as the state oil company, to manage foreign concessions, and exploit non-concession land for petroleum. After nationalization it became one of the subsidiaries of Petroleos de Venezuela.

companies had been reduced to four through a progression of mergers. Corpoven (C.V.P. plus Bariven, Boscaven, Deltaven, Llanoven and Palmaven), Lagoven, Maraven and Meneven comprise the new litany of operating companies. In addition, Petroquimica de Venezuela (Pequiven), and the Instituto Technologico Venezolano de Petroleo (Intevep), a research branch, are subsidiaries of PDVSA.

Compensation

Following nationalization, offers of compensations were based on net book value. The Venezuelans totally rejected the idea of basing it on lucrum cesans, meaning the estimated value of the profits the companies would have realized had they been able to hold their concessions through 1983. Final compensation totaled $1.1 billion for the concessionaires and $22.7 million for the participating companies. Most of the compensation is being paid by 6 percent interest bearing Venezuelan government bonds.

As of May 1, 1979, $560 million of the compensation bonds are still being held by Venezuela in the Guarantee Fund.[27/] Deductions will be assessed against the fund for improperly maintained facilities and back tax claims for 1970. Negotiations are underway to resolve the claims against the foreign companies' bonds. Howard Kauffman, president of Exxon, recently injected a militant factor in the talks by telling President Luis Herrera Campins that the oil companies will not make any further investments in Venezuela until the compensation is fully paid.[28/]

27/ U.S. Dept. of State, Venezuelan Desk information, May 1, 1979.

28/ El Universal, March 13, 1979, p. 1-19.

The Ministry of Energy and Mines announced on March 30, that 90% of the income tax claims pending against the ex-concessionaires have been evaluated and that a ruling would be announced soon.[29/]

Foreign Participation --Private

Article 1 of the Organic Law, which nationalized the holdings of foreign oil companies, reserves to the state "all that which relates to the exploration of the national territory in prospecting for petroleum, asphalt, or other hydrocarbons, ...as well as the exploitation of deposits of the same; their manufacture or refining, and transportation; ....the domestic and foreign commerce of the exploited and refined substances, and whatever works are required for the handling thereof..."[30/]

That article would seem to exclude all forms of foreign involvement in the industry. However, Article 5 of the Organic Law provides for two exceptions. The text of the article follows:

> Article 5: The State shall exercise the activities set forth in Article 1 of this Law directly through the National Executive or by means of agencies of its own. It may also sign any operative agreements that may be necessary for a sound performance of its functions. By no means, however, shall such negotiations affect the substantial nature of the activities hereby attributed.
>
> In special cases, and whenever it suits the public interest, the National Executive or the said agencies may, in exercising any of the activities herein referred to, enter into partnership agreements with private entities; maintaining, however, such a share therein that will guarantee control by the State, and establishing a fixed duration for such agreements.
>
> Authorization from both Chambers of Congress meeting in joint session shall be required prior to signing any such agreements, under such terms as may be set therefor, and once the Chambers have been duly informed by the National Executive with respect to all matters pertaining thereto. 31/

29/ Platt's Oilgram News, April 2, 1979, p.3.

30/ The Organic Law which reserves for the State the production and marketing of hydrocarbons, August 29, 1975. Translated and reprinted in, Romulo Betancourt, Venezuela's Oil, pp. 211-231.

31/ Ibid.

The first exception, is that of "operative agreements" granted by PDVSA, which would include service contracts and technical assistance contracts. The second possiblity is "partnership agreements with private entities," requiring the approval of Congress. Although no such partnership agreements have been made, and none are planned at this time, the prospect has received support from one of the most nationalistic of all Venezuelans in petroleum affairs, Romulo Betancourt.

> "A situation could arise in which a partnership agreement could be favorable or even necessary to the national interest. I cannot believe that such an agreement might open another period of submissive surrender of the nation's wealth..."32/

Should Venezuela determine that foreign private participation is required, then the terms of the agreement and certain political resistance will be the only obstacles--though perhaps formidable ones.

The government took advantage of Article 5, after nationalization, by negotiating four year technical assistance service contracts with the former operating companies to assure continuity in the industry. The service fee fluctuates with the domestic Venezuelan wholesale import price level, but cannot escalate more than the average of sales prices of Venezuela's three largest types of crude oil. The service fee averaged a net 19 cents per barrel in 1976 after deducting a 47% income tax.33/

The present Energy and Mines Minister, Humberto Calderon Berti, said in March 1979, that these technology contracts with the former concessionaires will be cancelled when they expire at the end of 1979. He added that "if we renegotiate any of these contracts if will not be on a per barrel produced

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32/ Romulo Betancourt, "The Venezuelanization of Oil," Speech in Caracas, August 6, 1975; in: Betancourt, Venezuela's Oil, p. 45.

33/ DOE, Office of International Affairs, The Role of Foreign Governments in the Energy Industries, October 1977, p. 81.

basis," and will be "under conditions more favorable to the national interst."[33/] The Vice Minister of Energy and Mines, Mr. Moreno Leon, clarified those conditions later in the month, saying that companies providing technical assistance would have to abandon their confidentiality clause requirements and allow a free exchange of information throughout the Venezuelan industry.[34/] The Venezuelans see PDVSA's research institute, Intevep, as a means to reduce dependence on foreign expertise and plan to accelerate its development.[35/]

The human resources of the institute are rather limited, although they have increased rapidly since 1976. In May of 1976, Intevep employed fewer than 20 professional and technical workers. By the end of April 1977, 70 professional and technical personnel were involved in research projects. For the end of 1980, this total should reach 271.[36/]

Although the growth of the institute will continue, its capacity to take an offensive role in technological development will remain limited for several years. An examination of the work under way in May of 1977 reveals that 18 of the 25 projects in the Exploration and Production Division were defensive--that is, oriented toward the application of existing technology, generally through adaptation of information transferred from foreign sources.[37/]

33/ Platt's Oilgram New, March 20, 1979, p. 3.

34/ Journal of Commerce, March 30, 1979, p. 30.

35/ El Universal, March 13, 1979, p. 1-19.

36/ Romero, Evanan, Research and Development Center, Venezuelan National Oil Corporation, "Intevep: its Mission and Objectives." From the Oil Sands Symposium, in The Journal of Canadian Petroleum Technology, (July-Sept. 1977) pp. 88-89.

37/ Ibid. p. 91.

In fact, the institute states that its major effort during its first phase (1976-1980), has been to build a qualified staff through the use of technological assistance agreements with foreign companies, as well as with other governmental and private R & D institutions and companies.38/

This defensive approach and reliance on foreign technology continues because Intevep is still in the initial stages of setting up its research infrastructure. It has originated 72% of the total projects from within itself (1977), with the aim of building up its research capability--creating several laboratories, a data bank, and establishing regional centers. The institute also spent 33 percent of its 1977 budget to send 25 of its professionals abroad for training. This gradual accretion of an infrastructure is a prerequiste to attaining a degree of technological independence, but even Intevep's own second phase plan (1981-1985), does not forsee a significant offensive research capability until well into that period.39/

Given the nascent state of PDVSA's research capabilities, and the heavy foreign content in the skills and equipment being acquired, Intevep will remain tied to some foreign technological assistance at least through the second phase of its development. And even then, it will be a competitor of foreign technology, not a full replacement for it. Room in Venezuela should still exist for innovative technology, regardless of its source.

38/ *Ibid.*, p. 85.

39/ *Ibid.*, p. 85.

Foreign Government Participation

Since the late 1950's, Venezuela has sought an increase in government to government petroleum arrangements. The original intent was to bypass the international oil companies in marketing oil, as in Perez Alfonzo's efforts to convince the U.S. to award Venezuela and other exporting nations--not the oil companies--a share of imports in the U.S. oil import quota system. The same intent motivates present Venezuelan negotiations for oil sales directly to foreign governments. In some cases, it also serves to diversify Venezuela's markets, another goal of the government.

This effort has been accelerated by the oil companies themselves. When Imperial Oil of Canada failed to get permission from its parent, Exxon, to import directly from Venezuela, the Canadian government ordered Petro-Canada to negotiate directly with PDVSA.[40/] The Venezuelan Minister of Energy and Mines has said that sales to Petro-Canada may begin in 1980, after sales contracts with the international oil companies expire.[41/]

The British National Oil Corp. (BNOC) negotiated a trade with Venezuela of light British crude for heavy Venezuelan crude, in October of 1978. However, when BNOC suggested adding to the deal by letting British industry operate in Venezuela, they received the reply that outside industrial and engineering help will be considered only on the basis of merit and that no tie-in oil deals will be considered.[42/]

40/ Platt's Oilgram News, March 23, 1979, p. 3.

41/ Journal of Commerce, April 4, 1979.

42/ World Oil, October 1978, p. 25.

In addition to marketing deals, numerous technical cooperation agreements have been reached between Venezuela and foreign governments and agencies.

FRANCE: Two agreements for technical cooperation were signed in the fall of 1978, one with the French Petroleum Institute (IFP), dealing with treatment of crude types in the Orinoco Belt; the second with the French Center for Geological and Mineral Research for assistance in exploration and inventory of all types of minerals.43/

WEST GERMANY: Venezuela signed an agreement with the West Germans for a feasibility study of the technology needed in producing and processing crude oil from the Orinoco Belt. Germany will also do a study of Venezuela's potential for nuclear power development.44/

CANADA: Venezuela seems to be far more interested in technical assistance from Canada than from any other country. Part of the preference arises from the countries sharing similar technical problems in developing heavy oil and tar sand deposits, and from Canada's greater experience with those problems and her access to the most recent technologies. Perhaps equally important to Venezuela, is that Canada presents a more politically palatable source than the United States.

Consultations between the two government have been going on since 1973, with an emphasis on heavy oil and tar sands dominating the relationship

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43/ Venezuela Up to Date, Fall 1978, IXX, No. 3, Caracas.

44/ Petroleum Economist, Nov. 1978, p. 489.

since 1976. The Canadian participants have been representatives of the Ministry of Energy, Mines and Resources and Petro-Canada. Since April 1977, "Crown Corporation" organizations, as Venezuela calls them, have also taken part in discussions. These include Syncrude Oil Ltd., and Great Canadian Oil Sands.[45/]

In the first week of January 1979, officials of the Alberta Oil Sands Technical and Research Authority, (AOSTRA) visited PDVSA, and four joint projects were discussed and an agreement reached for an increased program of technical cooperation in heavy oil technology. The agreement also calls for regular formal meetings between AOSTRA and Intevep.[46/]

The two government agencies will exchange published data and present a joint paper at the First International Conference on the Future of Heavy Crude and Tar Sands, to be held in Edmunton, June 6, 1979.[47/]

At the time of these negotiations, then Minister of Energy and Mines, Valentin Hernandez Acosta, said that Venezuela is "very interested" in closer ties with Canada's oil industry, especially regarding heavy crude oil production.[48/] The technical advances in Canadian development of its tar sands and heavy oils and the applicability of that experience to Venezuela will be discussed in a later section.

45/ Correspondence from Jesus Garcia-Coronado, Minister-Counsellor Petroleum Affairs, Embassy of Venezuela, Ottawa, Canada. April 9, 1979.

46/ Ibid, and Oilweek, February 12, 1979, p. 20.

47/ Oil and Gas Journal, "Newsletter," Feb. 19, 1979.

48/ Journal of Commerce, January 15, 1979.

UNITED STATES: The U.S. and Venezuelan governments do not have any formal technical cooperation agreements. However, a series of regular consultations was begun in November 1977 as a follow up of a meeting of Presidents Andres Perez and Carter in June of that same year. A team of DOE technical experts visited Venezuela in the summer of '78 and Venezuelan experts visited the United States in the summer of 1979. That trip has been delayed due to the change of administrations in Venezuela in March, and is now expected to take place sometime this summer (1979). Their itinerary will probably cover DOE headquarters in Washington, Bartlesville, Oklahoma petroleum research center, and DOE's main heavy oil research facility at the Laramie Energy Technology Center. Since the visit will only last for one week approximately, the Venezuelans' main concern will be to identify areas in which they would like to initiate exchanges of information.

The official U.S. approach to cooperation mirrors that demonstrated by Venezuela, and in that sense defers to the Venezuelan's wary outlook. Under Secretary of Energy, John O'Leary, remarked after his visit to Caracas in January that "the major objective" is to strengthen friendship and maintain high levels of information exchange on matters of petroleum research and development.[49/]

49/ Journal of Commerce, January 31, 1979.

II. Economic Setting

Venezuela does not face any immediate financial problems, yet recent trends in the economy give warning of trouble in the near future, if the trends do not even out or reverse. The most disturbing trend is the growth in external debt. At less than $3 billion in 1976, the public external debt ended, as of December 31, 1978, at $7.4 billion. Total public debt reached $11.66 billion, up 44.5% over 1977.[50/]

Last year's import bill grew more than 25% to $11.9 billion, while exports dropped 7.5% to $8.94 billion, for a trade deficit of nearly $3 billion. However, most of the import bill can be accounted for by the expanding requirements of the country's development program. More than 80% of total imports were intermediate and capital goods, many of which will be used to produce domestically what was once imported.[51/] As these imported goods become factors of production in the next couple of years and other develoment projects in steel, aluminum and cement come on stream, imports should taper off. Furthermore, the shortfall in petroleum output in 1978, to 2.165 mbd against a target of 2.2 mbd, has been eliminated thus far in 1979. Through April 25 production averaged 2.35 mbd, 450,000 b/d more than during the same period in 1978.[52/] Since petroleum exports accounted for 94.6% of total export earnings, this strengthening of production will have a healtly

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50/ Bank of America, Economics Policy Research #3015, Fernando Arias, "Country Update: Venezuela," (April 1979); and John Sweeney, "Venezuela Encounters Difficulties," Journal of Commerce, April 16, 1979, p. 1A.

51/ Bank of America, "Country Update..."

52/ Journal of Commerce, May 1, 1979, p. 32.

impact on the trade balance. Bank of America has estimated that with political development in Iran and the price hikes contributing to a more secure market for oil output, Venezuela will reap a revenue increase for 1979 of about $800 million; the Venezuelan Finance Ministry estimates additional revenues from price rises at $1.2 billion.[53/] The public sector's income will also get beefed up by the new tax law taking effect this year, which will add approximately $750 million. These additions were not included in projections for the 1979 budget.[54/]

Growth in imports, freight, insurance and travel jumped in 1978, as did the debit on the private transfer account. As a result, the current account deficit for 1978 was $6.1 billion, triple the size the 1977 deficit--which was the first since a negligible deficit in 1972. Private direct investments and public sector borrowing were insufficient to wipe out the 1978 deficit, causing a drop of $1.7 billion in international reserves.

Growth of the public debt became a focal point of the presidential campaign, and led President Herrera Campins to declare in his inaugural address: "I inherit a country mortgaged by debts."[55/] Yet given Venezuela's large financial resources, she should have no trouble servicing the debt in the

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53/ Bank of America, "Country Update... "; and Platt's Oilgram News 3/23/79 p.3.

54/ Journal of Commerce, November 20, 1978.

55/ Business International Corp., Business Latin America, March 14, 1979, p. 81.

short or medium term. The country's level of international reserves exceeds the total external debt,[56/] and the government holds as much as $3 billion abroad in other assets. In addition, some analysts believe that much of the current debt will be refinanced to take advantage of low interest rates and extended repayment schedules.[57/]

The deteriorating external accounts have prompted speculation of a possible devaluation sometime this year. Proponents of devaluation argue that it would increase non-oil exports, increase the bolivar revenues from oil sales and limit import growth. However, given Venezuela's oil dominated export structure, a devaluation may not increase exports to any significant extent since nearly 95 per cent of export revenues come from petroleum. And because import growth has largely been the result of a deliberate expansionary policy by the public sector, devaluation may be an unnecessarily risky means of achieving the same goal that a shift in government spending policy could accomplish.

The Finance Minister of the last administration summed up the case against devaluation:

> "Venezuela's current balance of payments, our income from oil, future development plans & annual budgeting hinge on parity with the dollar. Although revaluation might be good for us, devaluation would be irresponsible, stupid, and pointless."[58/]

56/ Reserves in gold valued at market prices.

57/ Bank of America, "Country Update.."

58/ Finance Minister Luis Jose Silva Luongo, in Journal of Commerce, November 6, 1978.

He said this in the midst of the presidential campaign, in which his party was fighting for reelection, and he admitted the bolivar's purchasing power had declined in West Germany, Holland and Japan. Yet only 25% of Veneuelan imports come from these nations, while U.S. products accounted for 38% in 1977.

The financial considerations described would not seem to support a devaluation under the present circumstances. Yet if the foreign debt increses still further in 1979, devaluation may become more attractive.

For the domestic economy as a whole, GDP increased by 6.4% in 1978, after a 7% growth in 1977. Further slight declines are expected in 1979 and '80. The slow down is projected for a number of reasons. Perhaps most important is the more conservative outlook of Venezuela's recently inaugurated president, Luis Herrera Campins. He campaigned against his predecessor's expansionist policies with the slogan "Enough Already" and promised a "government of austerity."[59/] The construction sector continued a decline in '78, mostly due to the completion of several government projects, and although private construction activity did grow, it accounted for only a small share of the total. From 1971 through 1976 agricultural production declined in real terms, and dropped 3.8 per cent in 1976. In 1977 it rebounded strongly with an increase in output of 8.4%.[60/]

59/ Miami Herald, December 5 and 30, 1978.

60/ Business International Corp., Latin America Forecasting Study, "Venezuela." (Sept. 1978), p. 14.

Agriculture continued to improve in '78, but at a decreased rate of expansion. Farm labor shortages and an inadequate infrastructure present the major problems, as the government has provided favorable credit terms, tax incentives and price supports in the agricultural sector since 1976. Manufacturing presents the most favorable outlook, with a growth rate of 9.4% in real terms over the past five years, and most projections calling for continued steady growth.[61/] Even so, this sector has been plagued with a high rate of labor turnover and absenteeism, as well as a shortage of management personnel and skilled labor.[62/] Complicating the labor picture, is the Venezuelan Workers Confederation (CTV), to which most of the country's 5,000 legally recognized unions belong. The CTV has strong ties to the Accion Democratica Party (AD), which was just ousted in the last national elections, and may now clamor for greater benefits. With AD now the opposition party, CTV does not have to worry about embarrasing its ally and may pursue a confrontation policy against the Christian Democrats (Copei). Negotiations will be heavy this year with some 1,600 contracts expiring. So far the relationship has been calm with AD leadership pledging the unions will be "vigilant but not obstructionist."[63/]

61/ Business International Corp., Latin American Forecasting Study, "Venezuela," (Sept. 1978), pp 21-22; and Bank of America, "Country Update." (April 1979).

62/ Some companies report a daily average absenteeism rate of 8-10%, which forces them to keep extra workers on the payroll permanently. Turnover averages 25-35% per year in large manufacturing firms, and much higher rates have been reported. Ibid., p. 28 (Business International)

63/ Business International Corp., Business Latin America., March 7, 1979, p. 80.

The major socioeconomic goals of the Herrera Campins administration will include the following:

(1) Improving income distribution and purchasing power because of harsh income inequities--the bottom 40 percent of the population receives 8% of total income, while the top 20 percent takes 65%.

(2) Industrial decentralization to take population and pollution pressure off of Caracas and Maracaibo and to stimulate infrastructure development.

(3) Continue the process of diversifying the economy to reduce its dependence upon the petroleum sector. The emphasis is on steel, aluminum and petrochemicals.

<u>Petroleum Dependence</u>

Although Venezuela has a far more diversified economy than most OPEC members, petroleum unquestionably dominates the economy and provides the bulk of government income. One important but incomplete measure of oil's role in the economy is its contribution to the gross national product. The accompanying table (Table #2) shows the petroleum sector's heavy contribution to the Venezuelan economy. Until 1974, petroleum's share in GNP varied between 16 and 23 percent, and then the price jumps of '74 swelled its contribution to nearly 40 percent, despite lower production levels after 1970. Since '74, oil's share in GNP has dropped gradually to around one-quarter in 1977, due to a combination of reduced petroleum production, and growth in other sectors of the economy. When 25 percent of a nation's economic production

TABLE 2

OIL CONTRIBUTION TO GROSS NATIONAL PRODUCT
(current prices; millions of bolivares)

Year	Gross National Petrolem Product*	GNP	Percentage Contribution from Petroleum
1968	8.015	41,284	19.4
1969	6.970	42.746	16.3
1970	8.787	48.402	18.2
1971	9.752	53.051	18.4
1972	10.816	58.472	18.5
1973	15.748	69.377	22.7
1974	42.486	108.442	39.2
1975	33.446	116.955	28.6
1976	35.933	113.447	26.9
1977	38.094	153.750	24.8

* Equals salaries of employees, plus direct and indirect taxes, plus net revenues of the industry, plus depreciation.

Source: M.E.M., Petroleo y otros datos estadisticos, (PODE), 1977, p. 3; from Banco Central de Venezuela figures.

arises from one source, the country becomes very vulnerable to fluctuations from that source--and very sensitive to the policies which affect its well being.[64/]

During the same period, petroleum greatly increased its contribution to government income, through fiscal and state-owned business channels. Table 3 (attached) shows that the petroleum sector gained a steadily larger participation in total government income, until reaching a peak of 93.3 percent in 1974, the year of the OPEC price increases. Through that year, absolute increases in national petroleum income generally meant a parallel increase of approximately the same amount in total government income--the two moved in tandem and on the same absolute scale, indicating the near total dependency of the government upon the performance of the petroleum sector.

However, the inundation of petroleum revenues in 1974 gave the nation the capital resources with which to extricate itself from its slavish

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64/ Some figures indicate a smaller participation in GNP by the petroleum sector. For instance some figures circulated in Venezuela have shown a 15% contribution in 1974 and 10% in 1977, yet most of the lower figures use constant 1968 bolivares, or constant 1968 prices which distort the contribution. The data in Table 2 seems the most complete and accurate acailable, but like all estimates for contribution to GNP, understated because the ripple effect is not calculated.

relationship with oil. Diversification of the economy through the strengthening of traditional sectors, and the creation of new, primarily state-owned enterprises has been the overriding concern of Venezuela since 1974. By 1977, petroleum's share in government income had fallen to 68.0 percent, and the 1979 budget calls for petroleum to provide 58 percent of its expenditure requirements.[65/] Since the expenditures of the central, state, and municipal governments surpass 50 percent of all national income,[66/] petroleum remains an indispensable part of the dynamics of economic growth in the country as a whole, not just of government income. Petroleum has given the government the power to become the dynamo for economic growth and diversification. The OPEC control over price has allowed her to lower production levels and thus extend the life of her oil reserves, future income and power from those reserves.

65/ Journal of Commerce, November 13, 1978.

66/ Ministry of Energy and Mines, Carta Semanal, No. 37, Sept. 16, 1978, p. 21.

NATIONAL PETROLEUM INCOME (millions bolivares; 4.2925/$)

TABLE 3

year	Fiscal[a]	per barrel produced	Business[b]	Total Petroleum	Total Government Income	Petroleum's Share
1969	5,526	4.2	———	5,526	9,676.8	57.1
1970	6,200	4.5	———	6,200	10,252.1	60.5
1971	7,546	5.7	———	7,546	12,122.6	62.3
1972	8,411	7.0	———	8,411	12,545.8	67.1
1973	13,389	10.6	———	13,389	16,432.8	81.5
1974	39,720	35.6	184	39,903	42,799.7	93.3
1975	29,858	33.8	84	29,942	41,000.9	73.1
1976	29,328	33.8	3,761	33,089	43,143.0	76.7
1977	26,991	32.0	7,805	34,796	51,178.8	68.0
1978	24,745	30.8	6,589	31,018	———	

[a] Includes: tax on income of both operators and providers of technological assistance; royalties and tax on exploitation of petroleum and gas; and foreign exchange tax through 1975.

[b] Through 1975, the only income generated for the state in this category came from the profits of the Corporacion Venezolano de Petroleo (CVP)—a negligible amount. Beginning with 1976, Petroleos de Venezuela (PDVSA) contributed through profits and other contributions.

Sources: Ministerio de Hacienda - Direccion Nacional de Presupuesto - Tesoreria Nacional; Ministerio de Energia y Minas - Direccion de Planificacion y Economia de Hidrocarburos, in M.E.M, Memoria y Cuenta Ano 1978, Vol. I pp. 76-78 and Vol. II, Cuadros No's 28, 29 and 58.

III. PETROLEUM RESERVES AND RESOURCES

Conventional Hydrocarbons

According to the latest estimate of the Ministry of Energy and Mines (MEM), Venezuela had proven reserves of conventional oil and condensate of 18.227 billion barrels, as of December 31, 1978. Proven reserves of both associated and unassociated natural gas were 42.137 trillion cubic feet. Associated gas constitutes 96 percent of total natural gas reserves.[67/] During Under-secretary of Energy John O'Leary's trip to Venezuela in January 1979, he was told that semi-proved (probable) reserves of crude oil are 15 billion barrels, and potential reserves 32 billion.[68/]

Unlike the rather extraordinary uncertainty surrounding 1977 and 1978 estimates of Mexico's large and sudden additions to reserves, Venezuela's reserves have been well established for many years, and only relatively small increments to the total have been added each year. Between 1961 and 1978 proven reseves of oil have stayed within a range of 13.8 billion barrels to 18.6.[69/] The downward fluctuations during the period were the result of rising production levels through 1970, and the only major upward trend got its boost from the price increases of 1974. Figure 1 (attached) shows for 1969-78 the reserves to production relationship and the jump in reserves coinciding with the higher world oil prices of 1974. Since

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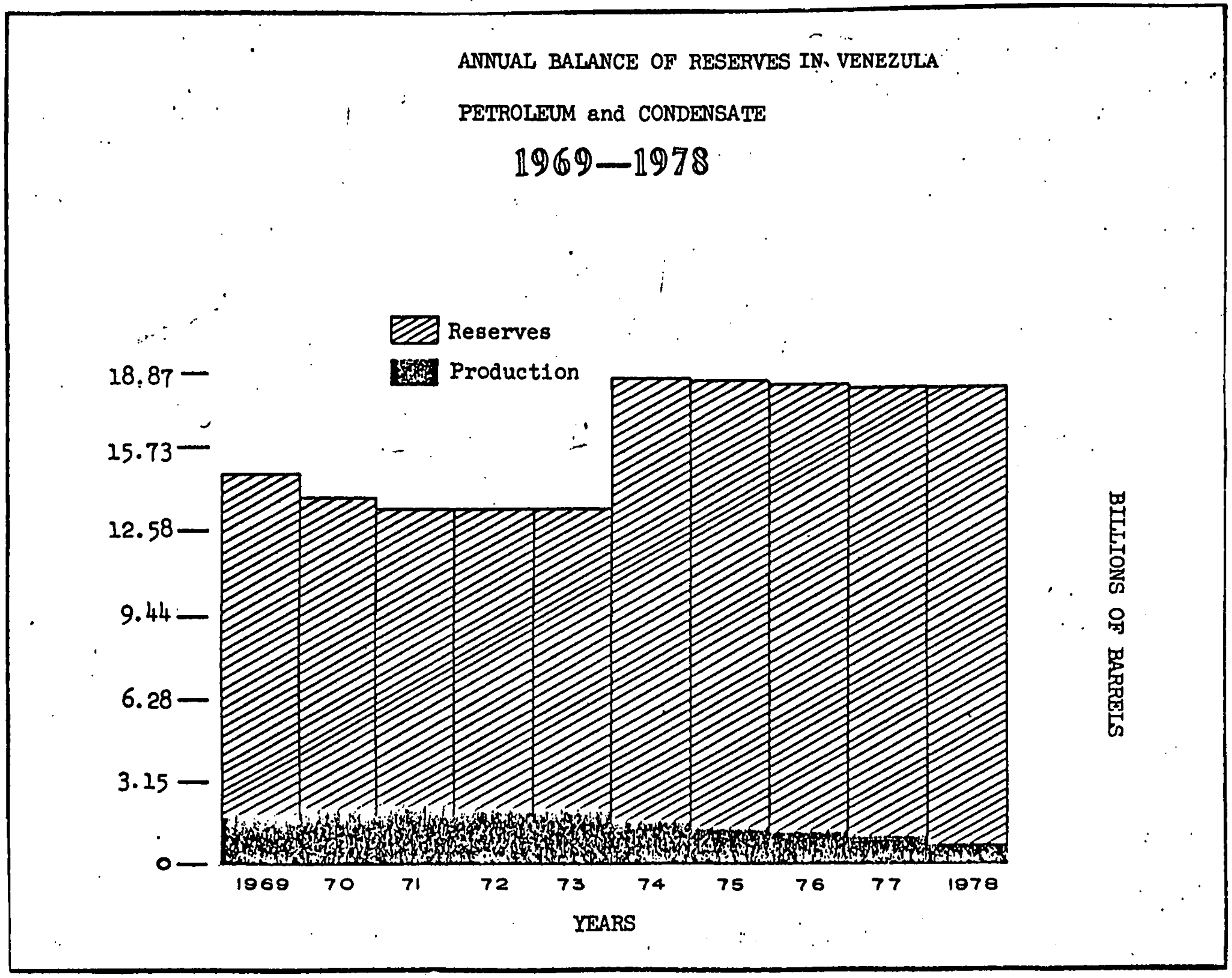
67/ Ministry of Energy and Mines, Memoria y Cuenta Ano 1978, Vol. II, p. VI-7 and 8.

68/ Counsellor for Petroleum Affairs, Embassy of Venezuela, Washington, D.C.; 5/9/79.

69/ MEM, Memoria..., Vol. II, p. VI-298.

FIGURE 1



Source: Ministry of Energy and Mines

that time, reserves have stayed within the range of 18.04 and 18.57 billion barrels. Thus the present figures represent an accumulation of several years experience and knowledge, primarily about old fields, thereby giving the present estimates a high degree of reliability--subject only to the inherent weaknesses of the methodology.

Besides the level of proven reserves, Venezuela keeps a close eye on the composition of her petroleum reserves. Output from traditional sources of lighter oils is declining steadily. Few favorable prospective onshore areas remain for the discovery of medium and light crude oil (greater than 22° API, according to Venezuela's classification, as of 1/1/77.)[70/] Because lighter oils bring a premium on the market, Venezuela follows a deliberate policy of protecting her light reserves through the following measures: (1) limiting production of crude greater than 22° API to no more than 70 percent of production (1979); (2) concentrating exploratory efforts on light crude prospects;[71/] (3) investigating new methods and using existing ones to produce super-heavy and heavy crudes; and (4) making basic changes in her refining pattern to increase its capacity to handle a heavier average crude feed.[72/]

70/ MEM, Carta Semenal, No. 17, April 29, 1978, p. 16; and Oil and Gas Journal, June 5, 1978, p. 70.

71/ According to Rafael Alfonzo Revard, Pres. PDVSA, in Petroleo Internacional, January 1979, p. 15. In 1978, Venezuela intensified a drilling program to evaluate the Createaceous zone in both the western and eastern parts of the country. Accumulations of light crude were found in the field of Urdaneta Oeste in Zulia State. In eastern Venezuela, efforts focused on the Cretaceous in the Quiriquire field and in development of the Acema-Casma and Onado areas. MEM, Memoria y Cuenta 1978, Vol. I, pp. 40-41.

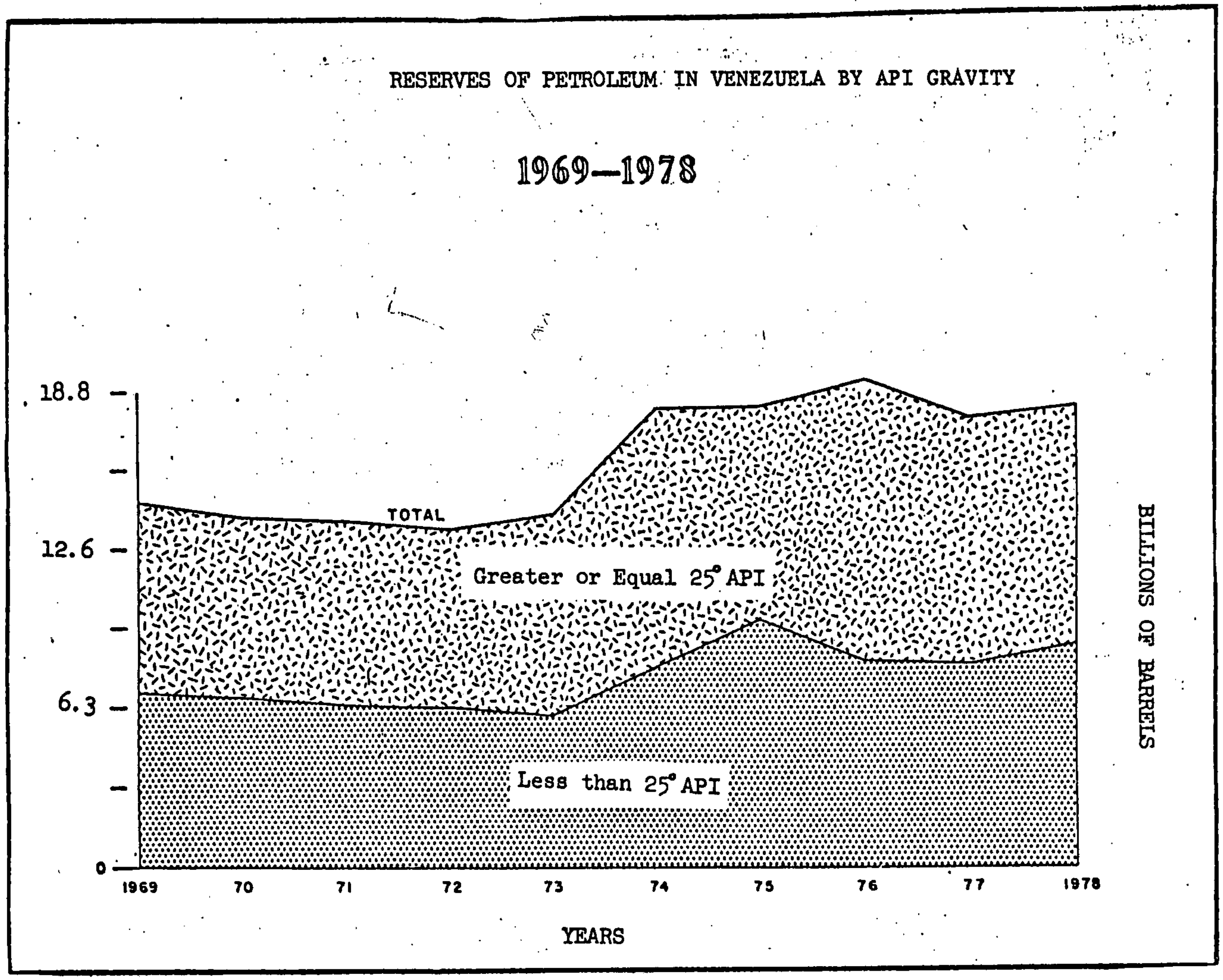
72/ Venezuelan refineries, originally designed to process a crude mix of about 27 API gravity, will be adapted to an average 20 gravity feed by 1985. Oil and Gas Journal, June, 5, 1978, p. 70.

Figure 2 shows that only one half of Venezuela's remaining proven reserves fall within the greater than 25° API category, and that share has remained steady since 1969. With production targets aiming at 70% crude of 25°, API or greater, and 30% below 25°, the relationship of 50-50 light and heavier reserves can remain steady only so long as 70% of additions to reserves come from light crude discoveries. That appears increasingly unlikely in the next few years; PDVSA does not even expect significant new production of light and medium crudes until at least the middle 1980's.73/

Venezuela's most prolific producing area is the Maracaibo basin, a 23,000 square mile, bowl shaped feature centered in Lake Maracaibo, at the western side of the country. Except for a small section extending into Colombia, the basin lies entirely within Venezuelan territory. The basin has contributed 60 percent of the cumulative production plus proved reserves of the entire north central Latin American region (Venezuela, Trinidad, Colombia). And nearly half of that 60 percent has come from the Bolivar Coastal field on the eastern rim of Lake Maracaibo. (See Map 1) That field consists of three contiguous accumulations of slightly different physical characteristics--Tia Juana, Lagunillas, and Bachaquero. The basin's sediments lie in the Tertiary and Cretaceous horizons and are up to six miles thick, with both limestones and sandstones found in the producing sections. Production has depended mostly on the sandstones, but the deeper limestones have recently added to the basin's productive capacity.

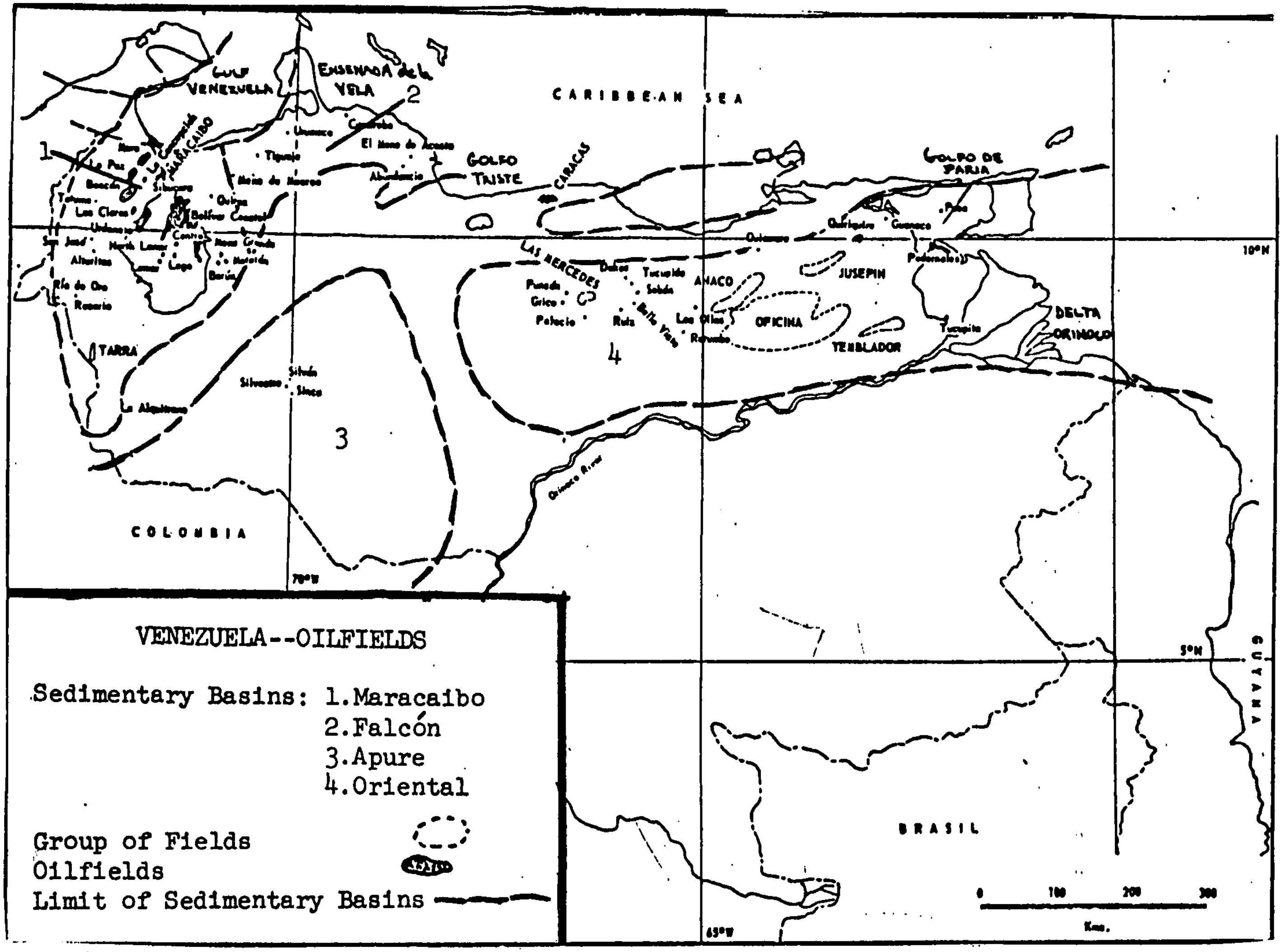
73/ Petroleo Internacional, September 1978, p. 17.

FIGURE 2



Source: Ministry of Energy and Mines

MAP 1


CARIBBEAN SEA
GULF VENEZUELA
ENSENADA de la VELA
GOLFO TRISTE
GOLFO DE PARIA
CARACAS
LAS MERCEDES
ANACO
OFICINA
JUSEPIN
TEMBLADOR
DELTA ORINOCO
TARRA
COLOMBIA
BRASIL
GUYANA
10°N
5°N
70°W
65°W
0 100 200 300
Km.
VENEZUELA--OILFIELDS
Sedimentary Basins: 1.Maracaibo
2.Falcón
3.Apure
4.Oriental
Group of Fields
Oilfields
Limit of Sedimentary Basins

The Oriental basin, also known as Maturin or Eastern Venezuela province, follows Maracaibo in importance and is nearly 3 times as large in area. Its sediments are mostly Tertiary, and the basin extends offshore to include the island and continental shelf of Trinidad.

Other Venezuelan basins include: Falcon, about 15,000 square miles onshore with a few small fields, with offshore extensions where some recent discoveries have been made at Ensenada de la Vela; Apure (or Barinas-Apure) a 25,000 square-mile basin separated from the Oriental by a structural arch; Gulf of Venezuela, an offshore, 6,000 square mile basin directly north of Lake Maracaibo; and the Venezuelan basin, which occupies the entire eastern Caribbean sea and has a 40,000 foot thick wedge of promising sediments along its southern margin in deep water.74/ Up to 1979, almost no drilling had been done in Venezuela's offshore regions, and no production comes from offshore.

For 1978, Venezuela's four producing basins held the following shares of total production:

Maracaibo	78%
Oriental	20%
Apure	1.6%
Falcon	0.03%

74/ SRI International, World Energy Study, Vol. 3, "Resource Analysis and Production Technology," 1978, pp. 188-89. For most of the information on sedimentary basins.

Reserves and Production Capability

Total recovery of oil in place in any one reservoir, depends upon the pressure in the reservoir, the viscosity of the oil, and the permeability of the reservoir rock. Maximum yield is obtained by releasing reservoir pressure in a controlled manner. Variations in viscosity and rock permeability then constrain the unaided and pumped flow into the well to from 5-80 percent of the in-place oil. This initial rate is known as primary recovery and averages 15-20 percent.

In general, the controlled release of reservoir pressure means that it is impossible to produce more than 10 percent of the recoverable reserves in any one year without reducing the total ultimate recovery. Some highly permeable fields can be produced more rapidly, and other require slower production ration. World experience indicates that a proven reserves to production rates of ten to one represents the maximum efficient production rate for a field.

However, a couple of considerations make that figure too high for Venezuela's situation. First, her fields are already highly developed. Most have reached their peak production levels and are on the downward side of their production curve. Nearly half of Venezuela's output comes from costly secondary recovery methods,[75/] indicating that those fields have either reached their production peak, or they hold heavy oils which cannot be produced without the initial use of advanced recovery techniques. Second, heavy

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75/ Wall Street Journal, November 29, 1978; and MEM, Memoria y Cuenta 1978, p. VI-207, places the figure for supplementary recovery at 43.45% of total production.

oils make up 50 percent of Venezuela's proven reserves. These viscous oils create many technical production problems, which tend to attenuate their development and result in a slower production rate relative to light, easy-flowing, higher API crudes.

Due to those considerations, a 15 to 1 reserves to production ratio. offers a more reasonable technical limit to production in Venezuela. The Ministry of Energy and Mines has reached the same conclusion-- though perhaps more from concern for conservation than from a technical basis-- in announcing an official policy of maintaining a reserves level of at least 15 years of production, applicable to each API gravity range.[76/]

Therefore, assuming a 15 to 1 ratio, proven reserves of 18.2 billion barrels could support a maximum annual production of 1.22 billion barrels or 3.34 mbd. Venezuela's present production capacity hovers around 2.44 mbd, and most production facilities this year ('79) have been operating at 96 percent of capacity, or 2.34 mbd (April 1979). Assuming Venezuela wanted to reach a capacity of 3.34 mbd, an enormous investment for that extra million barrels per day would be required.

Capacity Expansion

Additions to capacity can come from two basic sources in Venzuela: (1) existing oil fields, which contain 50 percent oil of less than 25° API, through the use of secondary or tertiary recovery techniques; and (2) new discoveries of light to medium crude. The second possibility will be discussed later.

As mentioned earlier, Venezuela has a deliberate policy aimed at conserving her lighter crude oils. Figure 3 (attached) shows the gradual drop in

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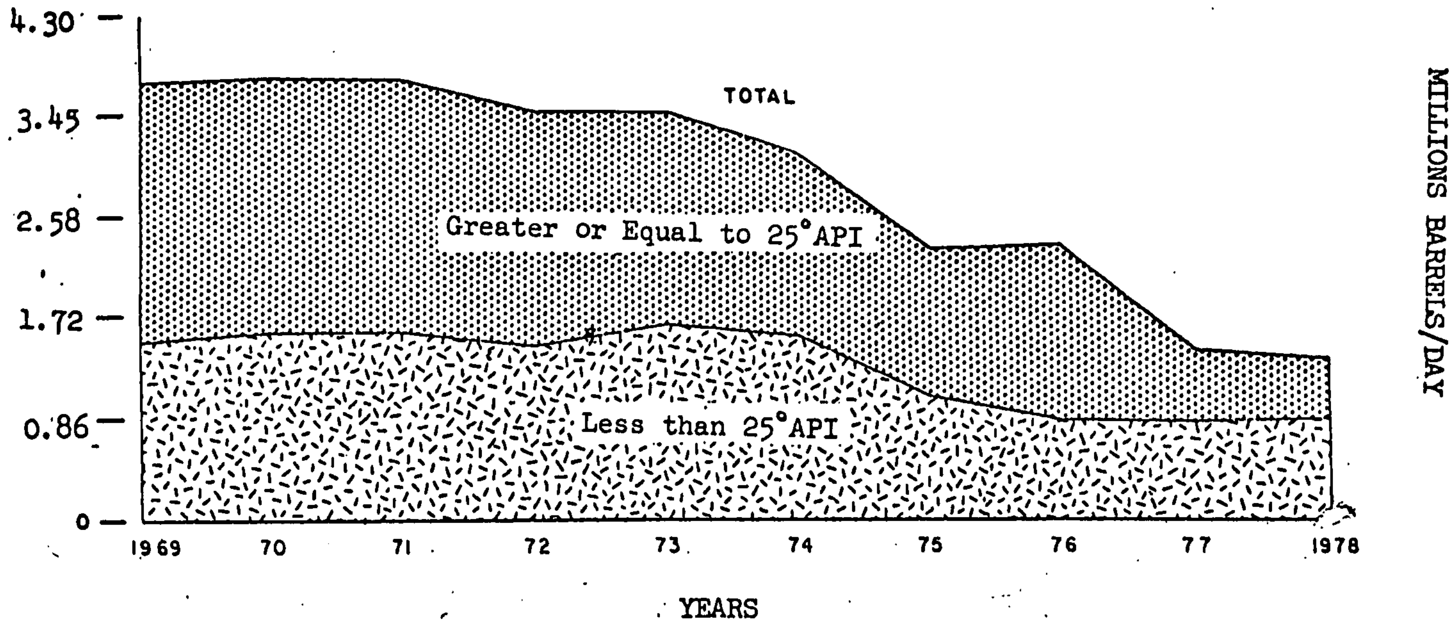
76/ MEM, Memoria y Cuenta 1978, Vol I, p. 51.

FIGURE 3

PETROLEUM PRODUCTION BY API GRAVITY

1969-1978



output of crude above 25^{o} API gravity up to 1976, and then with nationalization that year, government policy took effect, dramatically cutting the light crude share of production. This means that additions to capacity from existing fields must come predominantly from heavy crudes, first because Venezuela has no choice with 50 percent of her reserves below 25^{o} API, and second, because government policy demands it for the protection of the premium light crudes.

Expansion of heavy crude production capacity will be more expensive than would be the case for light conventional oil. Technical production costs from 3 heavy oil fields in the Oriental basin run about 250 percent above the costs in light Venezuelan fields.[77/] Those three fields produce 150,000 b/d and have been producing commercially for 20 years, so the cost data is not from a pilot project, but from fields using production techniques (cyclic steam injection) similar to what would be used in the rest of the country's heavy oil fields. The 250 percent figure may be a bit high for the country as a whole however, since all costs in eastern Venezuela receive an upward nudge from an infrastructure that remains inferior to that in the Maracaibo region, where other large heavy oil deposits exist. On the other hand, some fields may require more elaborate and hence, expensive production facilities than those required for cyclic steam injection.

Another financial burden of expanding heavy oil capacity, is that while production is usually more expensive than for light crude, the end

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77/ Petroleum Times, January 6, 1978, p. 19.

product is less valuable, giving a lower return on investment. And yet, because of that very burden, Venezuela has a great incentive to develop more cost-effective recovery techniques and oil upgrading processes which increase its market value. Without those developments production could stay at the present overall level, while total revenues dwindle as heavy oil and domestic consumption take over larger shares of production.

For instance, in 1978, PDVSA's profits dropped 35 pecent from 1977, even though exports stayed almost constant. This large cut hit the state company partly due to higher operating costs, but also because of the higher proportion of heavy crudes and heavy refined products sold. President of PDVSA, Rafael Alfonzo Ravard, said in March that the state oil company loses \$450 million a year as a result of having to sell 300,000 b/d of this oil at prices well below world levels.[78/]

Discovery of new sources of light to medium crude would facilitate capacity expansion--or maintenance-efforts, and prospects in the medium to long term appear quite promising. In the past 10 years most new additions to proven reserves in Venezuela have been made by revisions of previous estimates, as economic conditions change and new technologies develop. Since 1969, 76 percent of all additions have been in that category. Revisions for 1974 alone, account for 42 percent of all additions to reserves in the past 10 years. Physical extensions of existing fields makeup 13 percent of new reserves in the period and actual new discoveries only 12 percent. (see Table 4)

78/ Financial Times, Dec. 30, 1978; and Platt's Oilgram News, March 23, 1979, p. 3.

Table 4 NEW RESERVES (millions cubic meters)

Year	Discoveries	Extensions	Revisions	Total/Year
1969	6	60	23	89
1970	8	16	52	76
1971	72	44	46	162
1972	19	27	166	212
1973	26	32	126	178
1974	35	18	875	928
1975	21	25	63	109
1976	17	28	60	105
1977	18	10	73	101
1978*	14	17	124	155
Period Total:	236	277	1608	2115
in billions bbls:	(1.5)	(1.7)	(10.1)	(13.3)

*1978 figures subject to change
Source: Ministry of Energy and Mines, Memoria y Cuenta Ano 1978, adapted from table in Vol. II, p. VI-298.

If 1974's atypical figures are substracted from the ten year period, the nine year average of additions to reserves is 829 million barrels per year (132 million m^3) or some 26 million above the government's yearly production target of 803 million (2.2 mbd). Thus, Venezuela's overall petroleum resource base should remain steady over the next several years, if the historical rate of additions to reserves continues. The three-year-old state run industry appears capable of sustaining that rate, surpassing it by 145 million barrels in 1978.

Yet even with the resource base remaining steady, the preponderance of heavy oils will continue unless new discoveries of light crude are made. Since 1974, despite the incentive of higher market prices, new discoveries have declined in volume (See Table 4). The fall has continued even as Venezuela has raised expenditures for exploration after taking over the industry in 1976. In that first year after nationalization, $69 million went into exploratory activity; $115 million in 1977, and $196 million in 1978 (budgeted). For 1979, PDVSA plans to spend $254 million, including 50 wells in the Orinoco Belt, directed at the heavy oil deposits. 79/

The fact that more money has been spent and less oil found in comparing any one year to another, does not necessarily indicate a less successful exploratory program. Table 5 gives a summary some of the more important indicators of exploratory activity from 1969-78. Only a very slight increase in the number of completed wells has taken place since 1975, despite rapidly rising expenditures over the same time span. The large expansion of field parties partially explains this apparent oddity, and reflects an increase in seismic activity from 5,501 kms in 1977 to 12,179 kms. in '78--a 121 percent jump. 80/ The burgeoning importance of geophysical activity helps define the exploration strategy taken by the Venezuelans after nationalization.

79/ Dr. Edgard A. Leal, Director PDVSA, "Outlook for Venezuelan Petroleum Activity," at Salomon Brothers Petroleum Seminar, New York, April 12, 1979; Summary Report.

80/ MEM, Memoria--1978, Vol. I, p. 37.

Table 5 EXPLORATORY ACTIVITY IN VENEZUELA 1969-78

	Wells Completed[a]	Producers of Petroleum	Success Rate%	Field Parties[b]	Expenditures (million $ US)
1969	34	16	47%	29.0	
1970	37	14	38%	32.2	
1971	44	30	69%	33.3	
1972	62	31	50%	44.2	
1973	59	32	55%	37.6	
1974	110	89	81%	61.6	
1975	34	14	42%	49.0	
1976	39	22	57%	24.0	69
1977	43	32	75%	34.3	115
1978	45[c]	25	56%	46.2	196

a Exploratory wells according to objective at start of drilling; by LAHEE clasification, including A-2a (shallow deposits); A-2b (very deep drilling); A-2c (new pools); A-3 (new fields). Many more wells are started each year, but are either abandoned before completion, suspended due to equipment breakdown or the need for evaluation, and some have not reached their programmed depth by year-end, and thus are not included in "wells completed."

b Geological and geophysical field parties, in party-months (sum of monthly averages). 1976-1978, only seismographic work done.

c Does not include the three offshore wells completed in 1978.

Source: Ministry of Energy and Mines. Memoria y Cuenta 1978, Vol. II, pp. VI-284 & 388.

They are concentrating on geological and geophysical studies in their first years of running the industry, in order to acquire the data base necessary for exploratory drilling. In addition to the seismic work carried out in 1978, and indicated by work-parties in Table 2, PDVSA completed an aerial mapping survey of the superficial geologic features of every sedimentary basin in the country, covering 600,000 square kilometers. The eastern region of Lake Maracaibo, comprising an area of 30,000 sq. kms. was surveyed using a stereoscopic technique.[81/] Although an exact breakdown of the expenditures is not available, the amount spent on geophysical and geological work will not show any return on investment until drilling in later years actually makes proven discoveries.[82/] Therefore, it is incorrect to assume that the nationalized industry has been running an unsuccessful exploratory program based simply on the fact that new discoveries have fallen while expenditures have risen. The success of the Venezuelan program can be evaluated fairly only several years from now. Moreover, the upward revisions of earlier discoveries which have accounted for most of increase in reserves did not occur without large expenses for geophysical and geological work.

81/ Petroleo Internacional, February 1979, p. 66.

82/ For 1978, 11,063 kms. of seismic line surveys were programmed at a projected cost of 100 million bolivares, or $23.3 million U.S., while 12,171 kms. were actually surveyed. The 71 originally planned exploratory wells were to cost 666 million bvs. or $155.15 million. Ninety-two exploratory wells were either completed, abandoned, suspended, or were still being drilled during 1978, although an unknown number of these were started and programmed for 1977. Based on this one year, expenditures on seismic work and exploratory drilling broke down into a ratio of 1:7. However, other types of geophysical studies are not included under seismic work. Data from: Petroleo Internacional, January 1979, p.15; and MEM, Memoria--1978, Vol. II, chart p. VI-284.

The governments' exploratory programs for both 1978 and 1979 as described in official publications, place the search for light and medium crudes at the very top of their priority list.83/ The efforts toward that end concentrate on two possiblilities: (1) deep drilling in known oil-bearing and producing regions, and (2) offshore Venezuela. In 1978, over 50% of all wells programmed had targeted depths of over 14,000 feet, although only 8 of the 45 exploratory wells were designated for discovery of deep pools (A-2b), and 4 of them were completed as oil producers, 1 as a gas producer, 1 as an extension, and 2 were dry--an encouraging outcome.84/ Deep drilling has aimed primarily at the Createaceous horizons in both eastern and western Venezuela.85/ Light crude discoveries have been made at Urdanete Oeste in Zulia State (1978), and another strike of 35° oil at 17,300 ft. in the same state (Perija district) was announced in March 1979. Drilling of the Cretaceous under the Quiriquire field in Monagas state, eastern Venezuela,

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83/ MEM, Montly Bulletin, January 1978, Vol, XIII, No 1. p. 1; and MEM, Memoria... 1978, Vol. I, p. 44; from : Official Memorandum No. 74, January 18, 1979 to PDVSA from MEM.

84/ MEM, Memoria... 1978, Vol. II, p. VI-6; and MEM, Montly Bulletin, Jan. 1978, Vol. XIII, No. 1, p. 2.

85/ See Oil and Gas Journal, "Innovations Speed Maracaibo Drilling," June 5, 1978, pp. 79-85: Cretaceous prospects in the Maracaibo region lay below 15,000 ft. and penetration rates are slowed by high pressure Eocene and Paleocene intervals. Four distinct areas of Lake Maracaibo have Cretaceous prospects of 27 -30 gravity oil. Deep-drilling penetration rates have been improving thanks to innovations by Lagoven, but the effort is expensive and slows the effort to add to reserves and production capacity.

also began in 1978. Known deep deposits of light and medium crude at Acema-Casma and Onado just began undergoing deep drilling last year.86/ This deep drilling approach is only in its infancy, and its success or failure remains to be seen. All that can be said with certainty, is that much more drilling can and will be done, and that a potential for discoveries of light and medium crudes exists and awaits quantification. The Venezuelans may be encouraged by Mexico's recent experience. Many of Mexico's major discoveries of the last two years lie at deep depths beneath previously explored and developed oil bearing areas.

Venezuela's continental shelf offers the most enticing source for new finds of light and medium crudes. The offshore area represents almost exclusively virgin territory to the exploratory drill. Only one region, the La Vela Embayment or "Ensenada," has been explored to any extent, and commercial discoveries amounting to 300 million barrels of proven reserves were made there in the early seventies, by the Corporacion Venezolana de Petroleo (CVP).87/ The area has not been developed yet, and is among the three offshore areas that underwent exploratory drilling in 1978--the very first year of Venezuela's offshore drilling program.

The other two areas are the Gulf of Triste and the Orinoco Delta. (See Map 2) From the beginning of 1978 through 1980, PDVSA plans to drill a series

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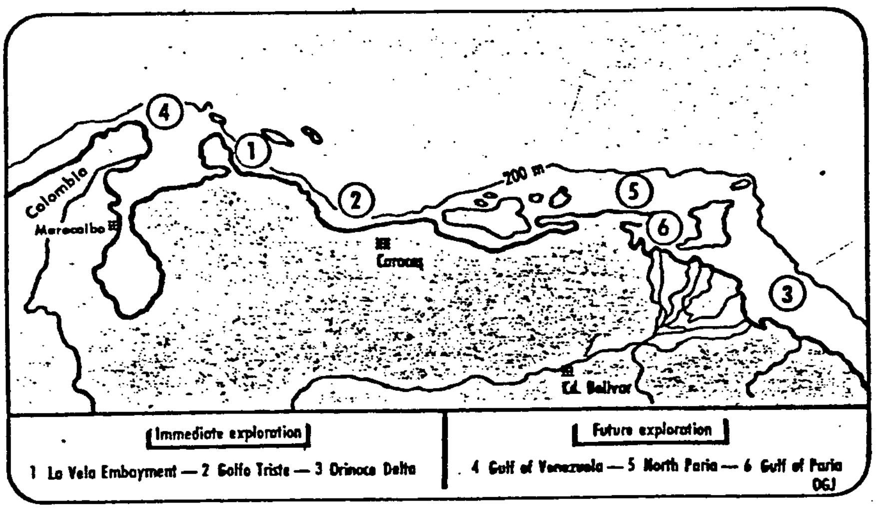
86/ Platt's Oilgram News, March 19, 1979, p. 5; and MEM, Memoria... 1978, Vol. I, pp. 40-41.

87/ Petroleo Internacional, August 1978, p. 10.

MAP 2

Present and future targets off Venezuela



SOURCE: Oil & Gas Journel, June 5, 1978, p. 72

of 45 wells in those three offshore areas at water depths between 200 and 500 feet, and expects to be producing 50,000 b/d by 1981.[88/] For 1979 and 1980, investments in offshore exploration will reach $175 million (U.S.), and PDVSA is projecting expenditures of $3 billion on the effort in the decade beginning in 1981.[89/]

During 1978, three offshore wells were completed--all dry. At the beginning of 1979, nine offshore wells remained to be drilled in the program slated for the first two years. As of March 3, 1979, one of these was abandoned dry in the La Vela Embayment, another was still being drilled; one rig was undergoing repairs at 10,000 feet in the Golfo Triste; and the Orinoco I was still drilling in the offshore delta region.[90/]

Despite the lack of sucess with the first few offshore wells, the surface has, quite literally, barely been scratched. PDVSA officially places the amount of probable light to medium crude in offshore areas at 10 billion barrels--[91/] another 12.5 years of production at present levels. This estimate relies solely on geologic studies, and means no more than estimates for the Baltimore Canyon do, until the reserves are proven. But the Venezuelans have made a very conservative estimate in their official stance.

88/ Petroleo Internacional, August 1978, p. 10 and January 1979, p. 14.

89/ Ibid. p. 14.

90/ MEM, Carta Semenal, Vol. XXII No. 9, March 3, 1979, pp. 6-10; The Guaro 1 wildcat in the Orinoco Delta was plugged at 17,300 ft. early this year, and the Orinoco 1 spudded 15 miles away. Oil and Gas Journal, Feb. 19, 1979, p. 84.

91/ Petroleo Internacional, September 1978, p. 18.

An earlier government report placed offshore probable reserves at 18 billion barrels,[92/] while other geologists' estimates range between 26 and 64 billion barrels of probable reserves.[93/] Dr. Bernardo Grossling believes that ten to fifteen years will be needed to drill the prospective offshore areas before their real potential can be gauged. Their value may well be proved long before 15 years have passed, but an absence of discoveries over the next several years does not necessarily mean an absence of oil, and that the search will be stopped. The Venezuelans have indicated their belief in the great potential of the continental shelf and a commitment to its thorough exploration through their announced intention of pouring $3 billion into offshore areas in the decade beginning in 1981.

That commitment may wax or wane as results come in, but offshore will remain a priority area for exploration during the next several years, at least, and continue to be perceived by Venezuelan policy makers as an important source for production in the coming years. The proven reserves in the La Vela Embayment may well reach production of 50,000 b/d by 1981, since discoveries have already been made there and due to the proximity of the huge refinery complex on the Paraguana peninsula. However, because of the long lead times needed to build production facilities in most of the other promising offshore areas, major volumes from them could not come on stream until the mid-80's at the earliest.

92/ MEM, Carta Semanal, No. 17, April 29, 1978, p.

93/ The Oil and Gas Journal, June 5, 1978, p. 71; Dr. Bernardo Grossling of the U.S.G.S., believes 20 to 60 billion is the most likely range, but that there is a potential for up to 100 billion barrels.

Therefore, up through 1985 approximately, any significant additions to production capacity must come from either heavy oil resources, or deep drilling for light crudes in known producing areas. As described above, the heavy oil approach will be costly and time-consuming, and will also put a strain on the present refining pattern of the country, which was designed for a lighter mix of crudes. Although the government's refinery development plan will absorb $1.87 billion between 1978 and 1983, most of the major changes will be completed toward the far end of that period.[94] Until that time, heavy crude additions to production, and hence to refining input, will yield additional heavier refined products incompatible with domestic demand, and less valuable on the international market. Therefore, during the transition period of the refining industry, production capacity increases may be somewhat delayed.

Short-term additions to production capacity would be fraught with difficulty, though the situation should improve by the mid-80's as the refining pattern adjusts to a mix of heavier crudes and when and if light crude discoveries come on stream. Yet even with a favorable resource outlook, the Venezuelans' ability to achieve a net increase in productive capacity will be put to a hard test. For while proven reserves have remained steady

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94/ Actual refining capaicty is 1,480,000 b/d, but the refining structure restricts utilization of installed capacity to 66%. Few downstream processing units are available to decontaminate, crack and hydrotreat heavier stocks--the type in abundance--while easier to handle light crudes are on the wane. Without the major revamping and addition of downstream processing units, Venezuela might become a net importer of gasoline in the next 3-4 years. More than half of the investments will go to the three refineries, El Palito, Cardon, and Amuay, third largest in the world. El Palito's capacity for gasoline production will increase 52,000 b/d; El Cardon's by 15,000 b/d, plus a 21,000 b/d increase in its catalytic cracking unit. The Amuay unit will have an extra 63,000 b/d capacity for gasoline and distillates and its average feedstock of 24.3 degrees API will drop to 21.7 degrees. No light crudes will be handled there, which now account for 17.7% of its feed. -- MEM, Monthly Bulletin, January 1978, Vol. XIII, No. 1, pp. 12-14; Memoria....1978, Vol. I, pp. 53-56; Business International Corp., Business Latin America, February 15, 1978 p. 51; and Oil and Gas Journal, June 5, 1978, pp. 86-88.

over several years, actual productive capacity has dropped steadily, so any net increase must fill that gap before adding to capacity.

	Production Capacity (mbd/day)
1965	4.0
1970	4.0
1975	3.2
1977	2.49
1978	2.44

Source: CRS, Project Interdependence: U.S. and World Energy Outlook Through 1990, Nov. 1977, p. 78; and M.E.M., Memoria----1978, Vol. I, p. 46.

According to a 1978 article in Petroleum Times, the natural decline in production from Venezuela's fields is about 43 million barrels per year,[95/] slightly less than the total drop in productive capacity from 1977 to 1978. Although the number of development wells drilled in '78 reached 515 compared to 304 in 1977, including 494 producers against 296 in 1977, capacity still could not keep up with the natural decline of the old fields in Venezuela.[96/] In 1979, PDVSA plans to drill 829 development wells, another huge increase and nearly 3 times as many as were drilled in 1977.[97/] Thus, the drop in capacity should cease, but whether capacity can be increased within the next few years is more doubtful.

95/ Petroleum Times, January 6, 1978, p. 19.

96/ MEM, Memoria----1978, Vol. II, chart, p. VI-389.

97/ MEM, Carta Semenal, No. 9, March 3, 1979, p. 12.

of 45 wells in those three offshore areas at water depths between 200 and 500 feet, and expects to be producing 50,000 b/d by 1981.[88/] For 1979 and 1980, investments in offshore exploration will reach $175 million (U.S.), and PDVSA is projecting expenditures of $3 billion on the effort in the decade beginning in 1981.[89/]

During 1978, three offshore wells were completed--all dry. At the beginning of 1979, nine offshore wells remained to be drilled in the program slated for the first two years. As of March 3, 1979, one of these was abandoned dry in the La Vela Embayment, another was still being drilled; one rig was undergoing repairs at 10,000 feet in the Golfo Triste; and the Orinoco I was still drilling in the offshore delta region.[90/]

Despite the lack of sucess with the first few offshore wells, the surface has, quite literally, barely been scratched. PDVSA officially places the amount of probable light to medium crude in offshore areas at 10 billion barrels--[91/] another 12.5 years of production at present levels. This estimate relies solely on geologic studies, and means no more than estimates for the Baltimore Canyon do, until the reserves are proven. But the Venezuelans have made a very conservative estimate in their official stance.

88/ Petroleo Internacional, August 1978, p. 10 and January 1979, p. 14.

89/ Ibid. p. 14.

90/ MEM, Carta Semenal, Vol. XXII No. 9, March 3, 1979, pp. 6-10; The Guaro 1 wildcat in the Orinoco Delta was plugged at 17,300 ft. early this year, and the Orinoco 1 spudded 15 miles away. Oil and Gas Journal, Feb. 19, 1979, p. 84.

91/ Petroleo Internacional, September 1978, p. 18.

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An earlier government report placed offshore probable reserves at 18 billion barrels,[92/] while other geologists' estimates range between 26 and 64 billion barrels of probable reserves.[93/] Dr. Bernardo Grossling believes that ten to fifteen years will be needed to drill the prospective offshore areas before their real potential can be gauged. Their value may well be proved long before 15 years have passed, but an absence of discoveries over the next several years does not necessarily mean an absence of oil, and that the search will be stopped. The Venezuelans have indicated their belief in the great potential of the continental shelf and a commitment to its thorough exploration through their announced intention of pouring $3 billion into offshore areas in the decade beginning in 1981.

That commitment may wax or wane as results come in, but offshore will remain a priority area for exploration during the next several years, at least, and continue to be perceived by Venezuelan policy makers as an important source for production in the coming years. The proven reserves in the La Vela Embayment may well reach production of 50,000 b/d by 1981, since discoveries have already been made there and due to the proximity of the huge refinery complex on the Paraguana peninsula. However, because of the long lead times needed to build production facilities in most of the other promising offshore areas, major volumes from them could not come on stream until the mid-80's at the earliest.

92/ MEM, Carta Semanal, No. 17, April 29, 1978, p.

93/ The Oil and Gas Journal, June 5, 1978, p. 71; Dr. Bernardo Grossling of the U.S.G.S., believes 20 to 60 billion is the most likely range, but that there is a potential for up to 100 billion barrels.

Therefore, up through 1985 approximately, any significant additions to production capacity must come from either heavy oil resources, or deep drilling for light crudes in known producing areas. As described above, the heavy oil approach will be costly and time-consuming, and will also put a strain on the present refining pattern of the country, which was designed for a lighter mix of crudes. Although the government's refinery development plan will absorb $1.87 billion between 1978 and 1983, most of the major changes will be completed toward the far end of that period.[94/] Until that time, heavy crude additions to production, and hence to refining input, will yield additional heavier refined products incompatible with domestic demand, and less valuable on the international market. Therefore, during the transition period of the refining industry, production capacity increases may be somewhat delayed.

Short-term additions to production capacity would be fraught with difficulty, though the situation should improve by the mid-80's as the refining pattern adjusts to a mix of heavier crudes and when and if light crude discoveries come on stream. Yet even with a favorable resource outlook, the Venezuelans' ability to achieve a net increase in productive capacity will be put to a hard test. For while proven reserves have remained steady

94/ Actual refining capaicty is 1,480,000 b/d, but the refining structure restricts utilization of installed capacity to 66%. Few downstream processing units are available to decontaminate, crack and hydrotreat heavier stocks--the type in abundance--while easier to handle light crudes are on the wane. Without the major revamping and addition of downstream processing units, Venezuela might become a net importer of gasoline in the next 3-4 years. More than half of the investments will go to the three refineries, El Palito, Cardon, and Amuay, third largest in the world. El Palito's capacity for gasoline production will increase 52,000 b/d; El Cardon's by 15,000 b/d, plus a 21,000 b/d increase in its catalytic cracking unit. The Amuay unit will have an extra 63,000 b/d capacity for gasoline and distillates and its average feedstock of 24.3 degrees API will drop to 21.7 degrees. No light crudes will be handled there, which now account for 17.7% of its feed. -- MEM, Monthly Bulletin, January 1978, Vol. XIII, No. 1, pp. 12-14; Memoria....1978, Vol. I, pp. 53-56; Business International Corp., Business Latin America, February 15, 1978 p. 51; and Oil and Gas Journal, June 5, 1978, pp. 86-88.

over several years, actual productive capacity has dropped steadily, so any net increase must fill that gap before adding to capacity.

	Production Capacity (mbd/day)
1965	4.0
1970	4.0
1975	3.2
1977	2.49
1978	2.44

Source: CRS, Project Interdependence: U.S. and World Energy Outlook Through 1990, Nov. 1977, p. 78; and M.E.M., Memoria----1978, Vol. I, p. 46.

According to a 1978 article in Petroleum Times, the natural decline in production from Venezuela's fields is about 43 million barrels per year,[95/] slightly less than the total drop in productive capacity from 1977 to 1978. Although the number of development wells drilled in '78 reached 515 compared to 304 in 1977, including 494 producers against 296 in 1977, capacity still could not keep up with the natural decline of the old fields in Venezuela.[96/] In 1979, PDVSA plans to drill 829 development wells, another huge increase and nearly 3 times as many as were drilled in 1977.[97/] Thus, the drop in capacity should cease, but whether capacity can be increased within the next few years is more doubtful.

95/ Petroleum Times, January 6, 1978, p. 19.

96/ MEM, Memoria----1978, Vol. II, chart, p. VI-389.

97/ MEM, Carta Semenal, No. 9, March 3, 1979, p. 12.

The Venezuela government believes that it can achieve a net increase however, and has announced plans to increase production capacity by nearly 400,000 b/d, to a total of 2.8 mbd. The government also stipulates that production should not exceed 85 percent of the potential, which would be 2.3 mbd if the 2.8 level should be reached. President Luis Herrera Campins recently gave his support to the increase which was planned under former president, Carlos Andres Perez. President Campins said that his government "will have the strength necessary to add to the potential production [capacity] in accord with the amount of reserves and to accommodate a development strategy consonant with the best interests of the Venezuelan people."[98/] The government is well aware that capacity has fallen and admits that it has not been caused by conservation, as often claimed in the past, but by a decline in potential. Although the present government has not given any timetable for the planned increase, the Finance Minister under Perez, Luis Jose Silva Luongo, estimated it would take approximately five years -- so 1983-84.[99/] Privately, some members of the present government, and the international oil industry, believe the increase to 2.8 mbd is too ambitious and that a steady production capacity or a slight decline is more likely.

If capacity expansion efforts do not succeed, and capacity remains at 2.44 mbd, then Venezuela will be producing at 90 percent of capacity in order to maintain production of 2.2 mbd. That represents a high level of production which over an extended period will strain production facilities. Although industry people involved in Venezuela tend to feel that

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98/ Charles A. Krause, "Venezuela Hints at Plan to Increase Output of Oil," Washington Post, March 13, 1979.

99/ Journal of Commerce, November 20, 1978.

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a ninety percent level is sustainable, government officials believe that ten percent is too narrow a margin and that production will eventually drop below the ninety percent level, and hence below 2.2 mbd. Although the government hopes to avoid any drop by adding to capacity, a small decline should not cause any major economic problems given the larger than expected revenues to be earned this year which will help to correct the balance of payments difficulties experienced in 1978. An improved financial situation in 1980 coupled to the likelihood of even higher oil prices will give the government enough leeway to accept a slight decline in the volume of production without suffering a loss of revenues or a deteriorating balance of payments situation. The more conservative administration of Herrera Campins will also require less income than that of its free-spending predecessor, and will adjust government expenditures to reflect its more fiscally conservative approach.

Based on the above analysis of Venezuela's resources, their composition, the refining structure, and drilling programs, CRS estimates that production capacity will not go above present levels through the mid-1980's, at which time, increases become more likely with the more flexible refining pattern, possible offshore finds of light crude, and the added incentive of higher world oil prices.

Orinoco Heavy Oil Belt

Of course, the greatest long-term source for additions to productive capacity is the heavy oil of the Orinoco Belt. Until recent drillings and evaluations of the past few years demonstrated that the hydrocarbons in place are fluid and never bituminous, the area had been known inaccurately as the Tar Belt. Although estimates of the volume of heavy oil in the Belt vary widely, everyone agrees that the potential is immense. The spread of present estimates goes from 1 trillion to 7 trillion barrels of heavy oil in place, with the Venezuelan government placing the figure at 2 trillion. 101/

Until 1976-1977, the government's estimate, and that of many others, put the total at 700 billion barrels. Because of recent reevaluations of the data and additional exploratory work, the size of the resource has been greatly expanded (See maps 3 and 4 attached). According to Francisco Gutierrez, an engineer with long experience in the Orinoco, three factors led to the upward revision.

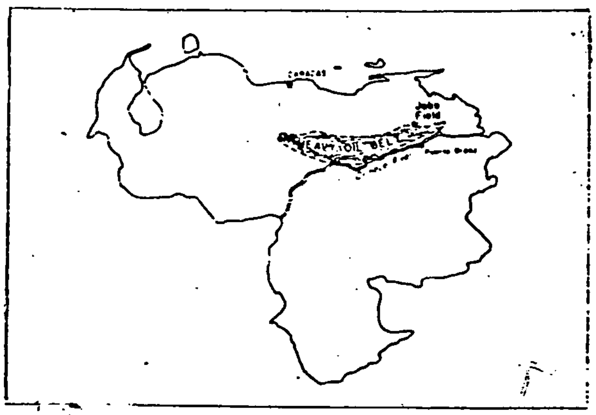
1) The original southern limit of oil-bearing sediments had been set 20 to 30 kms. north of the Orinoco River. Recent drilling has discovered petroliferous sands over 100 feet thick right up to the edge of the river, with the exception of one small zone north of San Felix.

2) Earlier evaluation of the petroliferous sands put their average thickness between 40 and 60 feet. The present average is greater than 100 feet.

101/ A recent Delphic consensus of petroleum geologists has placed total ultimate recoverable world oil resources at 2 trillion barrels.

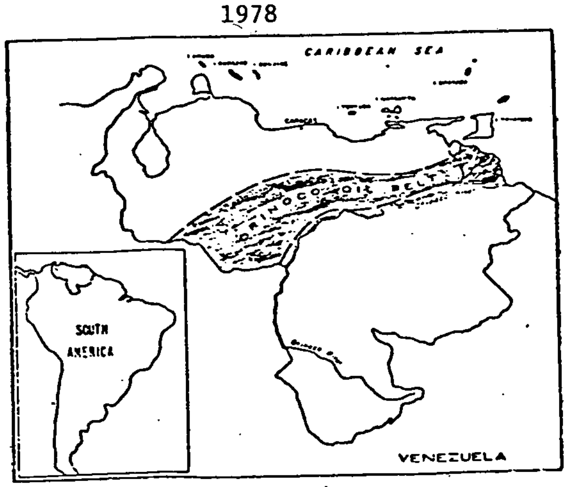
MAPS 3 and 4

1976 and earlier



Source: Journal of Canadian Petroleum Technology

1978



Source: Petroleum Times

3) Previous information indicated that the gravity of the crude diminished toward the south, and to such low values that it could only be considered bitumen. However, actual exploration has not revealed any hydrocarbons below 8 degrees API, and some horizons under evaluation in the southern region contain crude with gravities above 14 degrees API. 102/

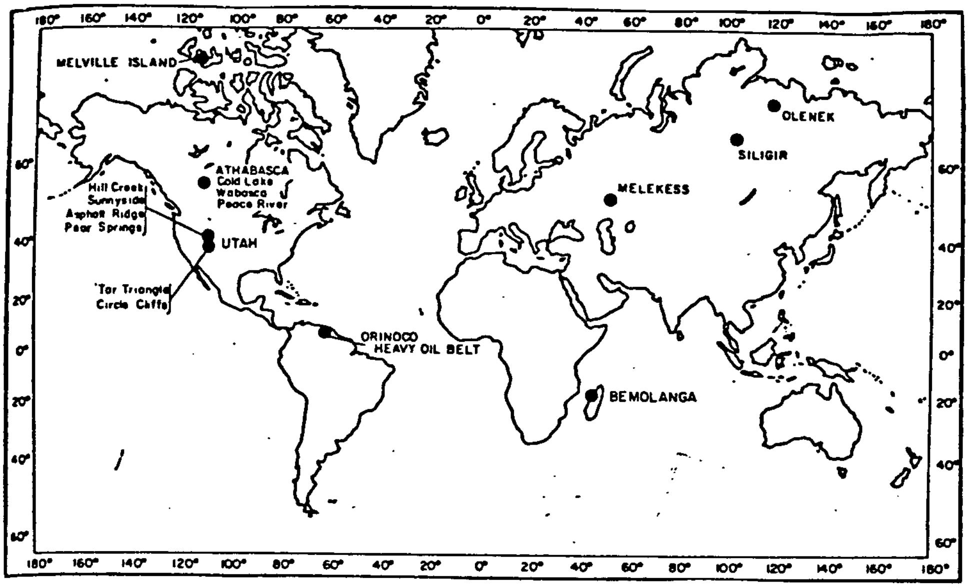
If so much oil exists is a known area, the obvious question is: Why not produce it? Any reasonable answer to that question requires the consideration of many factors, which must be evaluated separately and then analyzed in relation to each other. These factors include: 1) physical characteristics of the resources and their geologic setting; 2) production or recovery technologies; 3) crude oil upgrading technologies; 4) investment levels; and 5) world energy strategy.

Physical and Geologic Characteristics

The world contains 16 very large tar and heavy oil deposits (6-20 degrees API), amounting to approximately 3,100 billion barrels of oil/tar in place. The Orinoco accounts for 65% of this total and Canada another 29 percent (See map 5 and table 6 attached). Besides being abnormally large, these accumulations also share unusual geologic settings. They are found in traps that feature various degress of stratigraphic control in combination with structure, in non-marine or deltaic sediments, and usually are

102/ "Los Retos del la Faja del Orinoco," Petroleo Internacional, August 1978, pp. 39-40; and Francisco J. Gutierrez, The Orinoco Oil Belt, report to Ministerio de Minas e Hidrocarburos, June 30, 1976, pp. 17-18.

Location of Very Large Heavy Oil Deposits of the World



Comparative Characteristics of Heavy Oil Deposits
of the World

	VOLUME IN PLACE BILLION BARRELS	AGE AND TYPE OF RESERVOIR	SEDIMENTARY ENVIRONMENT	TYPE OF TRAP	AGE OF SOURCE BEDS	TIME OF MAIN GENERATION AND MIGRATION	MIGRATION DISTANCE (MILES)	BASINAL SETTING
VENEZUELA ORINOCO HEAVY OIL BELT	2000	OLIGOCENE AND EARLY CRETACEOUS SANDS	DELTAIC	STRATIGRAPHIC AND FAULTS	OLIGOCENE	MIOCENE TO PRESENT	60-120	FORELAND
W. CANADA ATHABASCA	625	EARLY CRETACEOUS SANDS	DELTAIC	STRUCTURAL-STRATIGRAPHIC	EARLY CRETACEOUS	LATE CRETACEOUS	240	FORELAND
COLD LAKE	164		-	-	-		135	-
WABASCA	53	-	-	-	-	-	90	-
PEACE RIVER	50	-	-	-	-	-	50	-
CANADIAN ARCTIC MELVILLE ISLAND	0.1	TRIASSIC SANDS	DELTAIC	STRATIGRAPHIC	TRIASSIC? JURASSIC?	LATE JURASSIC?	60	RIFT (SUCCESSOR)
USSR MELEKESS	123	PERMIAN SANDS DOLOMITES	DELTAIC TO NON MARINE	STRUCTURAL-STRATIGRAPHIC	DEVONIAN CARBONIFEROUS	?	100+	FORELAND
SILIGIR	13	CAMBRIAN CARBONATES	?	?	CAMBRIAN	?	?	?
OLENEK	8	PERMIAN SANDS	?	?	CAMBRIAN	?	?	FORELAND
USA TAR TRIANGLE	16	PERMIAN SANDS	DELTAIC	STRUCTURAL-STRATIGRAPHIC	PERMIAN	LATE CRETACEOUS	100+	FRAGMENTED FORELAND
CIRCLE CLIFFS	1	-		-	-	-	-	-
SUNNYSIDE	4	EOCENE SANDS	DELTAIC	STRATIGRAPHIC	EOCENE	LATE TERTIARY	25	INTERMOUNTAIN LACUSTRINE
P.R. SPRINGS	4	-	-	-	-		25	
HILL CREEK	1	-	-	-	-	-	10	-
ASPHALT RIDGE	6	-	-	-	-	-	10	-
MALAGASY BEMOLANGA	2	LIASSIC SANDS	DELTAIC	STRUCTURAL STRATIGRAPHIC	JURASSIC	EARLY CRETACEOUS	?	RIFT

SOURCE: G.J. Demaisson, "Tar Sands and Supergiant-Oilfields," The American Association of Petroleum Geolocists Bulletin, Vol. 61, No. 11 (November 1977) 1951. (Volume adjusted for Venezuela) unrelated to local source beds -- they have "migrated" to the deposit location.[103/]

The most recent theories on the origin of heavy oils, hold that they are the residue from medium gravity crudes which have been broken down through water washing and bacterial degradation. Water washing removes the more water-soluble, light hydrocarbons, and biodegradation eats away the normal paraffins, resulting in greater density and higher sulfer content. Degradation begins by the formation of a tar mat at the oil-water contact, and gradually extends throughout the accumulation. The degradation process helps to explain why some regions, which have undergone deep invasions of meteoric water, including the Officina Formation in the Belt, contain lighter crudes at the top of the formation and heavier crudes at the bottom.

Detailed structural characteristics of the Orinoco Belt are not well documented, but geologists note a similarity in setting with the Officina fields directly to the north. In addition, the Belt is not isolated but grades into prolific producible oil fields toward the north. The Belt consists of a regional wedge-out against the southern edge of the basin as well as four broad, fault controlled, structurally high areas which contain the thickest oil columns and largest reserves. These areas are:

103/ G.J. Demaison, "Tar Sands and Supergiant Oil Fields," AAPG Bulletin, Vol. 61, No. 11 (November 1977), p. 1952. Demaison notes that 85% of oil reserves in giant fields are restricted to structural traps --yet if tar/heavy oil deposits are included, it appears that half of the oil found in giant accumulations is controlled stratigraphically, in various degrees. He argues that this information should warn petroleum geologists against concentrating so much on structural features in searching for giant accumulations of oil.

Gorrin-Machete, Altamira-Suata, Hamaca-Santa Clara, and Cerro Negro.[104/] (See figure 4 attached).

Since drilling results show a very complex and variable picture with regard to the stratigraphy and subsoil characteristics in the region, one of Venezuela's most pressing tasks has been to undertake an intensive geologic interpretation of the region so that reliable maps of priority areas can be made. This geologic variety within the Belt means that exploratory and development work must tailor itself to the specific location.

A high percentage of the crude oils are found in unconsolidated sands at depths varying between 600 and 3,500 feet, and a small amount mingles with consolidated sands at depths below 3,500 feet. The porosity of the formations range between 12 and 35 percent, the gravity from 8 to 14 degress API, and viscosity from 1,500 to 4,500 centipoise (cp).

Francisco Gutierrez of the Ministry of Energy and Mines, and other experts, point to the importance of viscosity as an indicator of potential mobility, and hence producibility of the oil. Thus viscosity is a more meaningful gauge of the production constraints posed by the crude itself, than is the gravity.[105/]

The sulfur content of the Orinoco crudes varies from two to five percent by weight, and that of vanadium plus nickel from 200 to 500 parts per million. These contaminants cause two types of problems: 1) air pollution from sulfur oxides; and 2) damage to equipment and industrial processes from the corrosive characteristics of some of the contaminants, and metal poisoning of the catalysts used in processing.

104/ G.J. Demaison, "Tar Sands...," pp. 1953-55.

105/ Petroleum Times, January 6, 1978. p. 17; and R.B. Peterson, "Oil Sands Resources and Recovery Technology," Ninth World Energy Conference Transactions, Vol. IV, p. 315.

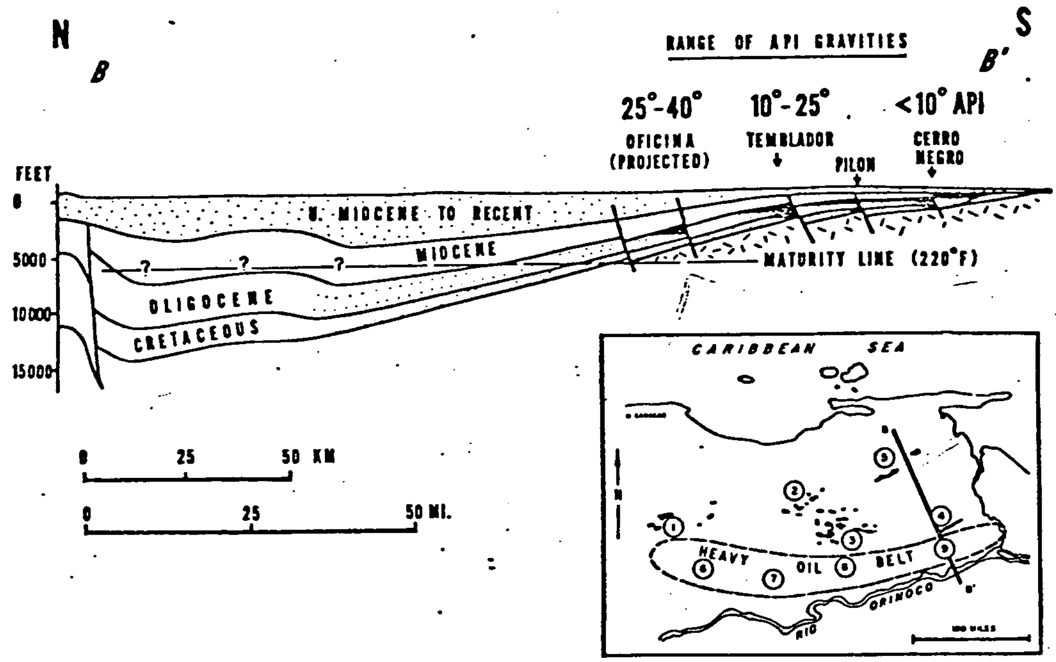


FIG.4—Schematic cross section of Eastern Venezuelan basin. Conventional oil fields are present at (1) Greater Mercedes, (2) Greater Anaco, (3) Greater Oficina, (4) Temblador and Tucupita, (5) Guarico. Largest reserves within Orinoco heavy-oil belt are at (6) Gorrin-Machete, (7) Altamira-Suata, (8) Hamaca-Santa Clara, (9) Cerro Negro-Morichal-Jobo.

SOURCE: G.J. Demaison, "Tar Sands and Supergiant Oil Fields," The American Association of Petroleum Geologists Bulletin (AAPG), Vol. 61, No. 11 (November 1977) p. 1956.

Production Technology

The geologic and physical characteristics of the heavy oil create a plethora of technical problems during the production stage. The most basic problem involves the mobility of the oil, a factor of the viscosity and reservoir characteristics, which in turn determines the rate of flow into the well, and total recovery levels. The difficulty is compounded because most of the heavy oil is found in unconsolidated sand. As a result, total recovery of heavy oil rarely exceeds 8 percent of the oil in place, when using only reservoir energy and mechanical pumping.[106/]

The most simple and direct method of raising production rates is to reduce the viscosity of the oil in the area surrounding a producing well. Most of the enhanced recovery techniques aimed at lowering viscosity can be grouped under the heading of "thermal recovery" -- the application of heat to the oil.[107/] For many years, Venezuela has been a pioneer in thermal techniques. In 1976, Venezuela had over 70 active thermal recovery projects profitably producing heavy oil.[108/]

Most of these secondary recovery projects have typically produced from 15 to 18 percent of the oil in place. But the government believes that in many cases thermal recovery merely accelerates extraction of oil producible by primary means, without noticeably increasing the final re-

106/ Petroleo Internacional, August 1978, p. 40.

107/ Other methods to reduce viscosity employ natural gas, diluents, solvents and acqueous emulsifying agents. With the exception of the latter, these methods are generally ineffective in heavy oil sands. Heat, however, dramatically reduces oil viscosity and can promote chemical changes. For example, at a reservoir temperature of 15 degrees C, Athabasca crude has a viscosity of one million cp; at 120 degrees C it is less than 100 cp; and at 230 degrees C it goes down to about 5 cp.

108/ The Oil and Gas Journal, April 5, 1976, p. 133.

covery factor.[109/] That is of pressing concern to a country where half of proven reserves come from heavy oil deposits. But the Orinoco is not even included in reserve figures -- if the 15 percent secondary recovery factor could be increased to 20 percent, additional ultimate production from that extra 5 percent in the Orinoco Belt alone would amount to 100 billion barrels (assuming 2 trillion barrels in place). That represents a very large reward for the careful development and application of appropriate recovery techniques to the Orinoco heavy oil.

The following provides a summary of thermal recovery methods either being used or tested in Venezuela, and the results obtained thus far.

Steam Injection -- This is the most widely used thermal recovery process, and is applied in two different ways discussed below. Steam has long been recognized as an effective medium for conveying energy because of its high latent heat capacity and its great mobility. Being in gaseous form, steam contacts a large volume of oil in the reservoir, heating and displacing the oil, which can then be driven through the reservoir by whatever pressure gradients exist.

1) Steam soak, also known as steam stimulation, steam cycle, intermittent steam injection, and huff'n puff: steam is injected into a reservoir for a few days or weeks (huff phase). The injection well is then closed in for a few days or weeks, depending upon the optimum soaking period of the reservoir, and is then reopened as a producer (puff phase.).

Almost all thermal recovery work in Venezuela has been done as some form of steam soak, with by far the majority of projects in Zulia state,

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109/ Ibid., p. 138.

and several in Monagas. Most successful applications have been in shallow heavy oil reservoirs ranging in depth from 300 to 3,000 feet and containing oil of 14 degrees to 20 degrees API, with viscosity levels generally under 1,000 cp. Steam soak affects only a limited area around the injection well however, and while it may give high production rates from a well, the ultimate oil recovery is low -- around 15 percent, and sometimes even lower.

Steam soak has not been very successful where the reservoir and crude properties differ appreciably from the ranges given above. This is the case in the northern portion of the Orinoco Belt where reservoir depth is between 3,600 and 4,000 feet, viscosity up to 2,000 cp. and gravity varies between 8.5 and 13 degrees API.[110/]

However, a successful steam soak project has been carried out on the Jobo Field, located on the northeastern edge of the Belt. The project has apparently demonstrated the applicability of steam soak under extreme conditions of reservoir depth, crude viscosity, and gravity, thanks to innovations in well completion techniques and special procedures used in mixing and handling the insulating fluid.[111/] Project wells have shown production rate increases of from 2 to 5-fold bringing all the wells up to commercially viable levels of production.[112/]

110/ J.R. Ballard, E.E. Lanfrauchi and P.A. Vanagas, "Thermal Recovery in the Venezuelan Heavy Oil Belt," The Journal of Canadian Petroleum Technology, (April - June 1977), pp. 26-27.

111/ Well completion techniques include pre-stretched casings and two-staged cemeting with thermally resistant cement mixtures -- these have solved the problems of cement, casing, liner and bottomhole

112/ Ballard et. al., "Thermal Recovery...," p. 27.

2) Steam drive, also known as steam flooding and continuous steam injection: steam is continuously injected through one well, or a set of wells, while oil production takes place through a different well or set of wells. This is a displacement type process and results in the sweeping of a large fraction of the reservoir. Ultimate oil recovery by steam drive processes have been estimated at about 35%, provided it is applied under favorable conditions of oil mobility and in a field with an overburden thick enough to confine the high injection pressures used.[113/]

Venezuela has steam drive projects in the Mene Grande, Tia Juana, Bachaquero and Lagunillas fields in Zulia state. Maraven, an affiliate of PDVSA, operates these heavy oil fields on the eastern shores of Lake Maracaibo. In 1977, the M-6 steam drive project, largest in the world, came on-stream, with 19 gas fired boilers for steam production, 19 injection wells, and 131 production wells. A large area in the southern part of the East Tia Juana field is the site of the M-6 project. This location attracted the project because primary and steam soak reserves had almost been exhausted, which will allow for a good test of the net additions to total recovery from steam drive application. The sands in the field are unconsolidated, as are the majority of Orinoco sands, and porosity and permeability are excellent. The gravity of the crude hovers around 12 degrees API, and viscosity varies between 1,000 and 9,000 cp., according to depth.

113/ A.W. Iyoho, "Selecting Enhanced OIl Recovery Processes." World Oil (November 1978) p. 62; and S.M. Farouq Ali, "In-place Recovery of Bitumen from Tar Sands, Earth and Mineral Sciences, Vol. 44, No. 9, June 1975, p. 67.

By extrapolating the results of a smaller preliminary pilot project in the field consisting of 24 wells, as well as results from other fields and laboratory and numerical models, Maraven projects the following recovery rates over the 20 year life of the project: 114/

	Millions Barrels	Per Cent Oil in Place
Oil in place at start of production	575.0	100
Primary recovery	105.2	18.3
Primary recovery including steam soak	136.9	23.8
Steam drive recovery (projected)	120.1	20.9
ULTIMATE RECOVERY	257.0	44.7

If completely proven commercially, this process applied only to Maraven's existing oil fields would generate an additional 4.8 billion barrels of reserves, assuming a total recovery rate of 32 percent. 115/ The same rate applied to the Orinoco would yield a recovery of 640 billion barrels -- in December 1977, total proven world oil reserves were estimated at 646 billion barrels. If the 3 trillion barrel figure for Orinoco heavy oil is used, and many international oil companies do use it, the total recovery with a 32 percent rate would be 960 billion barrels.

114/ Dr. Alberto Quiros Corradi, President of Maraven S.A., "Secondary Recovery of Heavy Oils: A Commercial Project and a National Strategy," OPEC Review, Vol. II, No. 4 (Sept. 1978) pp. 77-87. And: Armando J. Herrera, "The M-6 Steam Drive Project Design and Implementation," The Journal of Canadian Petroleum Technology, (July-September 1977) pp. 62-71.

115/ Quiros Corradi, "Secondary Recovery of Heavy Oils...," p. 78.

Another large steam drive project has been proposed for the Jobo field, to cover 620 acres, with 40 injection wells originally planned. Preliminary calculation for this project place total recovery at 30.2 percent of the oil in place from two separate reservoirs in the field. An important conclusion of these initial calculations is that the reservoir containing 13.5 degree API oil achieved a total recovery rate 4 percent higher than that for the reservoir with 9 degree API oil, as might be expected -- yet the difference is accounted for by a higher primary recovery factor for the lighter crude, since the steam drive phase actually yielded a slightly higher percentage recovery for the heavier crude than for the 13.5 degree crude.[116/]

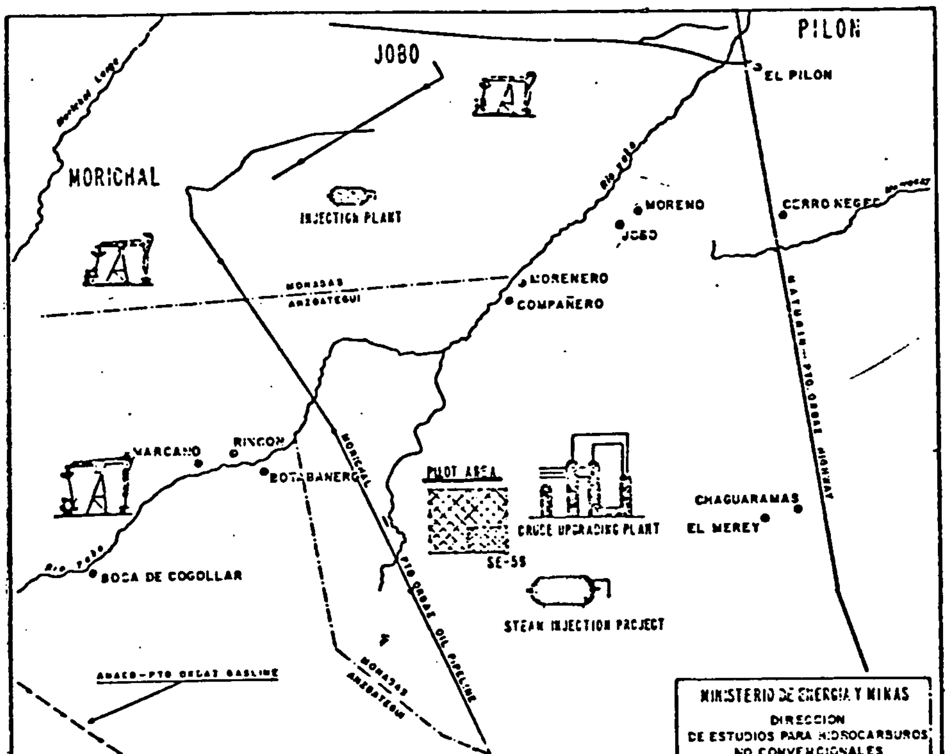
Unquestionably the most important pilot project underway is the one at Cerro Negro, just south of the Morichal and Jobo fields. After detailed studies of the geology and the acquifer of the area, which began in 1974-75, 8 wells were drilled last year and another 20 should be completed in 1979, for a production start up in October.[117/] The small size of this steam drive pilot project would not seem to merit much importance, but it has been chosen as the site of the first integrated production and oil upgrading plant for the Belt (see map 6 attachment). The second stage of the project calls for 96 wells, of which 60 will be producers, to be drilled in a grid pattern to define the areas of maximum oil concentration. After experience with the field's producing characteristics has yielded an optimum production program, the next stage will be the building of upgrading plants on the field to improve the quality of the crude.

116/ J.R. Ballard, et. al., "Thermal Recovery ...," p. 27.

117/ D.O.E.

FIGURE 5

CERRO NEGRO PILOT PROJECT



SITUATION MAP OF THE
CERRO NEGRO PILOT PROJECT

In-situ Combustion -- Also known as fireflooding, this method calls for injecting air into the reservoir, igniting the crude oil, and then the injected air moves the burning front through the reservoir. The heat breaks the oil down into coke and lighter oils and the coke actually burns, while the lighter oils move ahead of the combustion front. Three variations of this method can be used:

1) Forward combustion in which air is injected into one well, and the crude is ignited creating a burning front which moves radially away from the injection well and drives oil, water and gas to surrounding production wells. Approximately 15 percent of the in place oil is consumed to generate heat in this process.

2) Wet combustion, also referred to as quenched combustion, and COFCAW (combination forward combustion and water injection), is a modified form of forward combustion incorporating the injection of cold water with the air. This recovers the large quantity of heat between the injection well and the advancing front and transports that heat farther downstream as steam, thus initiating a steamflood.

3) Reverse combustion differs from forward combustion in that the oil is ignited in the production well rather than the injection well. A short-term forward burn is started at the eventual production well by injecting air through it. Air flow is then switched to adjacent wells and maintained there. This process is suitable for very viscous oil that would not move through the cold zone of a forward combustion process. Some laboratory studies have shown that such high temperatures are encountered in reverse combustion, that cracking of the oil occurs, and that 25 degrees API oil of 15 cp viscosity can be produced in situ from 8 degree

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API heavy oil.[118/] Field tests have been discouraging, however.

Venezuela has plans to test all of these methods in the Belt, in productive zones below 1,000 meters.[119/] Some experience with in-situ combustion has already been gained through projects J-6 and K-7 in the East Tia Tuana field, and several in the Melones, Miga and Morichal fields in eastern Venezuela. All of these have been at depths greater than 3,000 feet, and at least the ones in eastern Venezuela, at quite low oil viscosities of 50 to 100 cp at 133 degrees F.[120/] Further work on more viscous oils remains to be done.

A wet combustion project is ongoing in the Melones area, with one injection well and four producing wells, aimed at testing the procedure on the Oficina Formation at 4,300 feet, with crude of 10 to 12 degrees API and viscosity of 1,836 cp at 140 degrees F.[121/] CVP and Intevep are carrying out this pilot project and valuable information should be obtained from it, especially since the general characteristics of the pay zone and the crude fall within the broad range of characteristics found in the Belt as a whole.

However, one of the greatest difficulties faced by Venezuela in determining development policy for the Orinoco Belt, is that results from one test can not be generalized and applied to the entire Belt -- this is true whether referring to production techniques or upgrading processes. For example, the technical discussion in this section has focused only on the the depth of the reservoir being considered, and the gravity and viscosity

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118/ S.M. Farouq Ali, "In-place Recovery ...", p. 67.

119/ Petroleo Internacional, August 1978, p. 42.

120/ Oil and Gas Journal, April 5, 1976, p. 134-35 and Petroleo Internacional, September 1978. p. 31.

121/ E.A. Negron Perez, Ing., "Realizan Obra Piloto de Combustion Humeda," Petroleo Internacional, August 1978, pp. 22-26.

of the crude. These are crucial factors in an assessment of possible production techniques, but they are only a fraction of the reservoir and crude properties which must be evaluated. The size of the Belt and the variety within it, dictate the need for caution in assuming that success or failure in one area will apply with the same results elsewhere. The attached table (#7) gives an idea of the complexity involved in choosing an appropriate enhanced recovery process (including fluid injection methods also under consideration in Venezuela). To complicate the decision-making even further, two processes will sometimes appear equally suitable in a given set of conditions, in which case an economic study must be done to determine which is cheaper or which will recover more oil.[121/]

This helps to explain the need for a great number of pilot tests which help establish parameters of success by identifiying real operating problems, average well productivity, well life, oil recovery and operating costs. The following excerpt points to the necessity of an accurate description of the reservoir, even before beginning a pilot project.

> "Critical to the success or failure of any recovery technique is the nature of the reservoir in which it is applied. This is particularly true in applying thermal recovery processes to heavy oil sand deposits. The reservoir system must be at sufficient depth to permit relatively high pressure operations without surface breakout while shallow enough to avoid significant well bore heat losses. In addition there must be sufficient vertical and lateral reservoir continuity, oil zone thickness and oil saturation to ensure the thermal energy is not dissipated heating rock. The effectiveness of the thermal recovery technique may also be decreased if there is significant water or gas in addition to oil which can act as a thief zone.
>
> Accordingly, a prerequisite to selecting or implementing a recovery Technique is an adequate description of the reservoir. The uncertainities

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121/ A.W. Iyoho, "Selecting Enhanced Oil Recovery Processes," World Oil, (November 1978), p. 63.

—Screening guide summary for enhanced-recovery processes

	Recovery process	Range of values of parameters for which particular process is preferred												
		μ_o cp	° API	ϕ %	k md	h ft.	kh/μ md-ft/cp	Bbls. per acre-ft.	S_o at start % P.V.	Depth, ft.	Well spacing, acres	Res. temp., °F	Rock type	Estimated sweep efficiency, %, P.V.
Thermal recovery methods	**STEAM INJECTION** Continuous drive	200→1000	10→20 8 >40	≧30	>1000	30→400	>50	>500	>50	2500→5000	≦10		sandstone or carbonate	
	Cyclic (huff'n'puff)	1000→4000	10→40	≧30		>50		>1000	>50				sandstone or carbonate	
	FIRE FLOODING Forward combustion	<1000	10→40	≧20	>300	5→50	>20	>600	>50	200→4500	≦40		sandstone	
	Reverse combustion	no upper limit	<10	≧20		10→120			>50				sandstone	
	Wet combustion-COFCAW	<1000	<45	≧25		>10		>500	>50	>500			sandstone	
Improved fluid-injection methods	**IMMISCIBLE DISPLACEMENT** Polymer flooding	depends on μ of polymer solution	20→40		≧50				>25			≦250	sandstone	>50
	Surfactant flooding	≦20	≧25		≧50				>25			≦250	sandstone preferred	>50
	Other chemicals	Manufacturers usually give some indication of conditions which favor specific application												
	MISCIBLE DISPLACEMENT CO_2 injection	<10	30→45		>10				>25	>2500			sandstone or carbonate	
	LPG injection	<10	25→45		>10				>25					
	HP or enriched gas flooding	requires high $C_1 \rightarrow C_3$ content in reservoir oil			>10				>25				sandstone or carbonate	
	Microemulsion and micellar flooding	<20	>30	≧20	≧50	≧10			>25			≦250	sandstone preferred	>50

h Net pay thickness (feet)
k Average absolute permeability (md)
S_o Oil saturation
ϕ Average reservoir porosity
μ_o Oil viscosity at formation temperature (cp)
cp Centipoise

md Millidarcy
P.V. Pore volume
> Greater than
≧ Greater than or equal to
< Less than
≦ Less than or equal to

SOURCE: A.W. Iyoho, "Selecting Enhanced Oil Recovery Processes," WORLD OIL, (November 1978) p. 63.

inherent in obtaining accurate reservoir descriptions introduce a significant element of risk as the outset of any venture whether experimental or commercial. In addition, because of variations in reservoir characteristics, approaches to heavy oil recovery which are successfully used in one deposit may not necessarily be applicable in another without significant modification. In fact, the technology appropriate to one area or sand member within a given heavy oil deposit may not be suitable for another area or sand member within the same deposit." 122/

The field pilot process consumes a great deal of time and money. The evaluation of pilot tests takes years and is the critical factor governing the pace at which technology can be developed.

For instance, the Cerro Negro pilot is scheduled to start up in October 1979, although at least one industry source believes it will not be until 1980. Then it will take two to three years to gather and analyze the data, at which point a commercial project can be given a fuller definition and detailed construction plans finalized. Only after that can construction of a commercial plant begin. Construction could not start before 1984 and it will take a minimum of four years to complete the plant. 123/ In the meantime, an upgrading technology must be selected for the commercial facility. An optimistic date for operation of the first commercial production - upgrading facility, of 125,000 b/d capacity, would be 1988.

Private industry sources believe that manpower and infrastructure constraints will delay start-up to well beyond 1988. The technology involved requires the émployment of many highly skilled personnel, who are

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122/ R.B. Peterson, "Oil Sands Resources and Recovery Technology," p. 317-18.

123/ A plant of similar size at Cold Lake, Alberta, Canada will take just under six years to build, according to estimates of Imperial Oil, Ltd.

in short supply on a worldwide basis. One estimate of manpower needs for a 125,000 b/d plant in Venzeuela is 30,000 man years -- or 6,000 workers over a 5 year period. If labor in Venezuela, which has suffered from chronic instability problems, and especially if skilled labor is in tight supply, then the construction stage will be stretched even longer. Coupling these constraints to the cautious approach taken thus far by Venezuela, a 1988 start-up date, while technically feasible, appears unlikely. And their caution is not born of timidity but of genuine uncertainties which plague the decision-making process -- they do not want to commit themselves to a proven technology which may soon prove obsolete, nor do they want to prematurely accept an unproven yet potentially more efficient new technology. The long lead time from design through construction to operation imposes an inherent risk in making a decision too hastily.[124/]

UPGRADING TECHNOLOGIES

The uncertainties involved in the long lead times apply to upgrading technologies even more strongly than to production processes. Much more experience has been accumulated on production than upgrading of this heavy crude, particularly in an in-situ environment. Between 1974 and 1978, Venezuela has employed the services of more than twelve private firms and research institution worldwide, in the analysis of upgrading methods for Orinoco heavy oil.[125/]

124/ Much of this section, particularly on lead times, labor requirements and commercial considerations come from discussions and correspondence with representatives of Esso Resources Ltd., Canada; Exxon Corporation; and the article by R.B. Peterson, "Oil Sands Resources and Recovery Technology." The figures used apply to a hypothetical plant and are not based on specific studies of the circumstances in the Orinoco -- the value of the figures is as indicators of the magnitude of the problems which will be encountered in Venezuela.

125/ MEM, Memoria y Cuenta 1978, Vol. II, p. III-C-2.

The need for upgrading arises because conventional distillation of this heavy crude into its natural components would yield very small amounts of naphthas, very little diesel and very high quantities of residuals. Some of the Orinoco crudes are so heavy and viscous that they would require the addition of diesel to satisfy the specifications for residual. With light crudes on the decline, the government does not want to draw down supplies by using it as a diluent for Orinoco crude. In addition, placing the oil on the world market in the form of residual fuel with high levels of sulfur and metal, would bring low prices and could not contribute to Venezuela's growing demand for light products -- particularly gasoline.

For these reasons the government has decided that most of the crude from the Belt must be upgraded to a lighter synthetic crude, of higher commercial value and greater marketing flexibility. They have adopted the concept of in-situ upgrading for several reasons. If it is upgraded on-site, the lowered viscosity and elimination of contaminants greatly eases transportation of the crude. Otherwise, dilutents from external sources would have to be brought into reduce viscosity before pumping it to a refinery. One of the original government guidelines for development of the Orinoco stipulated that the region remain self-sufficient in energy terms. In-situ upgrading can help satisfy that requirement because the steam needed in the production process can be generated by the lowest value product coming from the upgrading of the crude.

The most basic deficiency of heavy crudes is that they are low in hydrogen while high in carbon content. To convert a low API (low in hydrogen) crude into a higher API fraction requires either the addition of hydrogen or the removal of carbon. The attached figure (#6) shows the relationship between hydrogen/carbon content and API gravity. Several proven technologies exist already which can handle heavy crude upgrading yet most present problems of varying severity when used on Orinoco crude. (Most testing has been done with Jobo crude; some on Boscan crude from the Bachaquero field in the Maracaibo region).

Addition of hydrogen can be accomplished by using hydrocracking processes, which operate at high temperatures (800 to 1,400 degrees F), high pressures (1,000 to 4,000 psig), and employ hydrogenating catalysts. According to Mr. Gutierrez* of M.E.M, the hydrocracking of Orinoco crudes is handicapped by the deactivation of the catalysts due to the high metal content of the crude. Use of the process would require that reactors be designed to allow on-stream catalyst replacement. Gutierrez and Augustin Gonzalez, head of the refining division of MEM, assert that further advances in catalyst replacement techniques and reactor containment efficiencies are needed before this process could be adopted. MEM is still investigating the hydrocracking option, however. [126/]

MEM believes that "the removal of carbon molecules is simpler than hydrocracking, as it results in a naturally occuring process when the petroleum fractions are heated to decomposition temperatures and cracked to form lighter components." [127/] The commercial techniques used to remove

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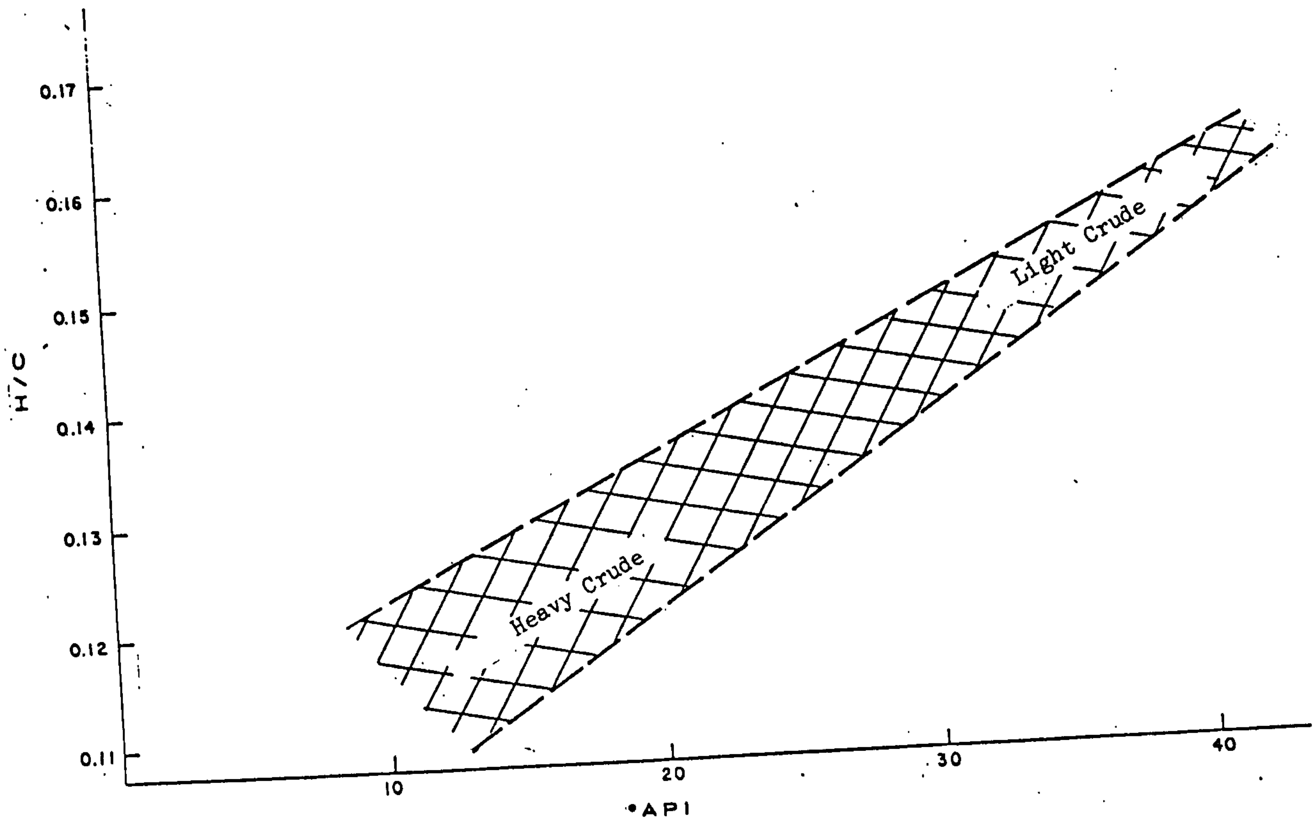
126/ Petroleum Times, January 6, 1978, p. 18; and Petroleo Internacional August 1978, pp. 43-44.

127/ Petroleum Times, January 6, 1978, p. 18.

* No longer at MEM, resigned in 1978.

FIGURE 6

HYDROGEN/CARBON CONTENT AND API GRAVITY



carbon from the crude are called coking processes. They produce an upgraded crude with a high content of volatile material and leave coke as a byproduct. Most of the sulfur and metal contaminants concentrate in the coke, thereby facilitating the cleaning of the crude. However, because the Orinoco crudes are so heavy with carbon, large quantities of low quality coke, unfit for steel production, would be produced. If commercial uses for the coke are not found then it would present a major disposal problem.

The most promising upgrading technology appears to be "Flexicoking", a process developed between 1969 and 1972 by Exxon Research and Engineering Company. Other "carbon rejection" routes have been chosen by Great Canadian Oil Sands, Ltd. which uses delayed coking, and by Syncrude, Canada, Ltd. which uses fluid coking. These coking processes result in lower hydrogen consumption than the alternative hydrogen addition approach. However, it is expensive and environmentally difficult to use the high ash, high sulfur coke produced by these coking processes. Flexicoking improves on these methods, and is based on fluid coking technology with the addition of coke gasification processes. Instead of a low value coke byproduct, flexicoking produces a clean, low sulfur, low BTU fuel gas from the coke as it is made. This fuel can then be used to fire boilers for steam generation during production, and for process furnaces, displacing hydrogen rich fuel oil and gas. Thus, total hydrogen consumption can be reduced even further than in standard coking technologies.[128/]

128/ Exxon Research and Engineering Company, "Flexicoking for Improved Utilization of Hydrocarbon Resources," May 1978, p. 6.

Other advantages of flexicoking include: 1) Insensitivity to feed stock qualities except feed concarbon which determines the amount of coke produced; this is an important feature for application in the Orinoco, where a wide range of heavy oils are encountered. 2) The sulfur and nitrogen content of the upgraded crude is low and can be varied depending upon the severity of the naphtha and gas oil hydrotreating. 3) More than 90 percent of the feed sulfur is recovered as 99 percent pure sulfur. 4) The purge coke from Venezuelan crude offers the opportunity to recover the vanadium trapped within it. 5) When combined with conventional hydrotreating processes, flexicoking yields an upgraded crude free of contaminants, low in viscosity, and residuum free which can be sold directly as low sulfur fuel or readily transported to existing refineries for further conversion and upgrading.[129/] The flexibility provided in quality of crude feed and product yield seem to merit the name Exxon has given this technology.

Although flexicoking is a very new technology, one commercial operation in Japan has been running successfully since start up in late 1976. According to Exxon, it has met or exceeded all design targets, and successfully demonstrated an ability to process a wide range of feed stocks. The 21,000 b/d capacity unit, has handled feeds of up to 7.2 wt. percent sulfur, 33 wt. per cent concarbon, and 660 wppm metals[130/] -- all above the normal

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129/ Ibid., p. 6 and; Exxon Research and Engineering Co., "Flexicoking for Heavy Crude Upgrading," by B.B. Fuque and G.C. Lahn, presented at International Petroleum Exposition, Tulsa, Oklahoma (May 1976), pp. 7-8.

130/ Exxon Research and Engineering Co., "Fluid Coking/Flexicoking, A Flexible Process for Upgrading Heavy Crudes," by D.E. Blaser, R.A. Busch, and T.A. Cavanaugh (October 26, 1978) pp. 5-6.

ranges for Orinoco crude. The attached table lists the probable output volumes and properties from a 125,000 b/d flexicoking unit plus hydrotreating of Jobo raw crude. (See appendix I for a more detailed description of the process, and a diagram of the units in a complete upgrading facility.)

At this time, flexicoking appears to have a clear lead over other possible upgrading processes for Orinoco crude. Venezuela has already ordered a 52,000 b/d flexicoking unit from Exxon for installation in their Amuay refinery. This will give the Venezuelans an opportunity to examine the technology at first hand and to test its capabilities -- as well as to increase their output of gasoline at Amuay. Both industry sources and Venezuelan government officials agree that flexicoking has attracted more interest than other options. However, other processes are still under evaluation and new technologies may appear before flexicoking is finally settled upon. Phillips Petroleum Company may have come upon a suitable technology which focuses upon removing the asphalts from the crude. They have apparently overcome problems with metal removal, and Venezuela has sent crude samples to Phillip's laboratories in Oklahoma for testing.[131/] As the various technologies improve and mature, all of them may find application in the Orinoco Belt under different operating conditions and product requirements.

131/ Conservation with Dr. Fleix Rossi-Guerrero, Counsellor for Petroleum Affairs, Venezuelan Embassy, Washington, D.C.

TABLE 8

RAW CRUDE/PRODUCT QUALITY SUMMARY

Properties	Job Raw Crude	Upgraded Crude
Specific Gravity	1.0057	0.8565
Sulfur - Wt. %	4.1	0.31
Nitrogen - Wt. %	0.48	0.18
Conradson Carbon - Wt. %	15.7	1
Viscosity at 100°F - Centistokes	18500	10
Distillation		
C_4 - vol %	-	3
C_5 to 430°FVT - vol %	3	21
430 to 650°FVT - vol %	11	27
650 to 975°FVT - vol %	26	49
975°FVT+ - vol %	60	-

INPUT/OUTPUT SUMMARY

	Input	Output
Raw Crude - kB/CD	125	-
Natural Gas - GBTU/CD(kFOEB)	17(2.8)	-
Upgraded Crude - kB/CD	-	105
High BTU Gas - GBTU/CD(kFOEB)	-	48.2(8.9)
Low BTU Gas - GBTU/CD(kFOEB)		69.2(11.4)
Coke By-product - ST/CD(kFOEB)	-	216(0.9)
Sulfur By-product - ST/CD	-	800

$k = 10^3$; $M = 10^6$; $G = 10^9$

FOEB = Fuel Oil Equivalent Barrel (6.05 MBTG)

B/CD = 42 gallon barrels/calendar day

SOURCE: Exxon Research and Engineering Company

COST

The investments required to build an integrated production - upgrading facility in the Orinoco are difficult to estimate. Private industry sources estimate a flexicoking-type upgrading unit of 125,000 b/d capacity (raw crude) would require an investment of $500 million dollars, including 20 percent for project contingency.[132/] However, this calculation assumes "instant" first quarter 1978 construction and start up at a Gulf Coast location. Inflation through first quarter 1979 has increased that cost by future projects in the Orinoco will experience a greater cost increase from inflation, as the rate in Venezuela has been at 15-18% per year according to unofficial sources and construction could not begin until the mid-80's. Building a facility in a remote location such as the Orinoco will also add to the cost of construction and probably operating costs because of the need to import labor, and provide extensive training for both locally available tradesmen and potential operators. Higher transportation costs will also add to the total. Unusual site preparation problems were not included in the estimate nor were the costs of developing the local infrastructure. The cost of an upgrading plant to be built sometime in the mid to late 80's in the relatively remote region of eastern Venezuela, clearly will be substantially greater than the $500 million estimated for a 1978 Gulf Coast location. Simply for the sake of comparison and not to suggest any projections for an Orinoco plant, an upgrading a flexicoking plant using flexicoking and hydrotreating, with an output of 141,000

132/ Project contingency reflects the degree of definition of a project and is intended to cover the upper possible range of costs after more careful definition.

b/d upgraded capacity in Cold Lake, Alberta, Canada has been estimated to cost $1.5 billion, escalated to represent a 1985 completion date. 133/

Of course the upgrading unit is only a part of the integrated complex. The investments in production and ancillary facilities and the kind of indirect costs mentioned above for training and infrastructure improvements must also be included. CRS has only discovered one very rough estimate of the investment required for an integrated production - upgrading plant of 125,000 b/d upgraded crude capacity, with a Venezuelan start up date in 1988 -- $4 billion in 1986 dollars. And that figure does not include infrastructure costs. This estimate, by the way, approaches the $4.7 billion (Canadian) cost projections for the Cold Lake oil sands project, which will have a flexicoking capacity slightly greater than those planned for the Orinoco. 134/

One useful way of judging the opportunity costs of a $4 billion investment in the oil industry for a productive capacity of 125,000 b/d, is to compare it with the costs of producing oil from other sources. The $4 billion comes to a cost of $30,000 per barrel a day of capacity. According to Exxon, costs per barrel a day of capacity in Saudi Arabia average between 1 and $2,000; even the range in the North Sea is only from 7 to $10,000 per barrel a day of capacity. Because these latter figures are derived from historical costs and the $4 billion is a projection in 1986 dollars,

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133/ Costs include direct material and erection costs, indirect costs such as contractor fees, engineering, contractor field labor overheads and a 20% project contingency, for the following processess and facilities: primary distillation; hydrotreating; hydrogen synthesis; gas treating; and upgrader steam generation. From: The Cold Lake Project, A Report to the Energy Resources Conservation Board, by Imperial Oil Ltd., May 1978; Section 11, Question 6, Table 1, p. 5.

134/ Ibid. The Cold Lake project will begin construction in 1981 if all government approvals are obtained this year (1979). Esso will have to drill 1,400 wells initially, with 2,000 in production when the project is mature, and 8,000 would be drilled over the 25 year life of the project. Steam stimulation will be used for production.

the two sets of figures cannot be interpreted as strict cost comparisons, yet the large gap does indicate the magnitude of the development costs of the Orinoco heavy oil. To the degree they invest in the Orinoco, the Venezuelans would have to forego investments in offshore areas and remaining onshore structures which have a potential for a much higher return given the much lower investments required.

This helps to explain Venezuelan caution and their present emphasis on exploration for light to medium crude sources in structures underlying present producing fields, and in offshore areas. The line of reasoning which suggests that the longer the Venezuelans wait to produce from the Orinoco the more attractive the huge investments will appear, is certainly true, assuming higher world oil prices and possibly the reduced costs of a more mature technology. This reasoning however, tends to ignore that investments in other sources of petroleum will also appear more attractive as world oil prices rise further. The most important consideration is not at what point does Orinoco heavy oil development become commercially viable, but at what point it becomes a more attractive investment than other sources of petroleum--or for that matter, other industries which can provide foreign exchange for the government, or help meet pressing social and economic development needs.[135/]

135/ A firm of New York petroleum consultants is just now completing a study for the Venezuelan government on the opportunity costs of investment in the Orinoco Heavy Oil Belt.

Energy Strategy

Venezuelan energy strategists view the Orinoco as the nation's ace in the hole--a black and valuable ace. They do not want to risk that ace gambling it on a premature technology or a market where it is undervalued; they do want to hold it close to the vest for their own purposes in the world oil game. As a result, they prefer to develop the Orinoco at a steady, deliberate pace, and without foreign equity participation. Energy Minister Humbert Calderon Berti just recently announced that the Belt would not be opened to foreign investment,[136/] thus settling, at least temporarily, the question of whether the international oil companies with their technical expertise and capital resources might not be able to speed up development of the Belt.

The strategy breaks the oil game into two time periods: one before the peak of conventional world oil production, and the other, after the peak. Alberto Quiros Corradi, President of Maraven, S.A., and a leading strategist in the state oil industry, believes that even if only 5 billion barrels of conventional oil from new structures and offshore are added to proven reserves, it will be sufficient to carry Venezuelan conventional production past the peak of world oil production.[137/] Once that peak is scaled and the

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136/ Platt's Oilgram News, March 20, 1979, p. 3. This issue quotes Calderon Berti as saying the Belt will be opened up to foreign investment; the following issue on March 21, correct this to "will not be opened up."

137/ Dr. Alberto Quiros Corradi "Secondary Recovery of Heavy Oils: A Commercial Project and a National Strategy," OPEC Review, Vol. II, No. 4 (Sept. 1978) p. 83.

decent begins, all exporters will have great market power--much like the present situation in the world oil market where incremental supplies are unavailable. Prices will rise until demand balances with supplies. It is in that market that the Venezuelans hope to play their ace and offer supplies from the Orinoco. They actually see their heavy oil not as a competitor with conventional oil, but with coal conversion products, which will still be more expensive than upgraded Orinoco heavy crude. Upgrading costs, not including extraction, are estimated at between $5 and $10 per barrel.[138/]

In the time frame of the 1980's, Orinoco oil will not be a significant contributor to Venezuelan production. At the very earliest, one plant of 125,000 b/d capacity may be on stream at Cerro Negro by 1988. Lagoven, S.A. the PDVSA affilate handling the Cerro Negro project, and the leading company in the Orinoco, hopes to add another plant in 1991, and a third in 1995-96.[139/] The PDVSA affilates have been assigned geographic areas in the Belt, but Lagoven is two to three years ahead of the other companies in its work in the Orinoco, thus a second plant before 1990 from any of the other affiliates is unlikely. Therefore, productive capacity in Venezuela, based on the above analysis of Orinoco development and

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138/ J.P. Smith, "Can Heavy Oils End Fuel Crisis?" Washington Post, p. C5, quotes an Exxon study at $5.23 per barrel. Other Exxon spokesmen emphasize that the study assumed 1978 production and upgrading and did not include many of the indirect costs which would be faced in the Orinoco. Quiros Corradi in the OPEC Review article, estimates $8 to $10 per barrel for upgrading Orinoco crude.

139/ D.O.E., from information transmitted to Under Secretary John O'Leary during his visit to Caracas, in January 1979.

earlier conclusions regarding additions to capacity from both light and heavy oils, will not show any increases through the mid-1980's. Capacity may even show a slight decline before and after that time if new discoveries from deep structures and offshore do not appear. In any case, productive capacity through the 1980's must depend upon conventional sources as the Orinoco will not make a significant impact until the 1990's.

IV. VENEZUELAN EXPORTS

Direct exports of crude oil, refined products, and natural gas liquids totaled 1,896,244 b/d in 1978. Compared to 1977, this represented a drop of 89,008 b/d, or 4.4 percent. From 1974, exports of crude oil and products decreased at an interannual rate of 7.5%, going from 2.800 mbd to 1.896 mbd. The Ministry of Energy and Mines has explained the decrease as the result of the conservation policy of the state, manifested through lower crude production, increased internal consumption, which limited the surplus available for export, and an excess world supply during the first semester of 1978.[140/] However, as mentioned previously, the new administration has muted the conservation policy excuse and acknowledged that reduced crude production has now become a problem of falling productive capacity. In 1979, production and exports have increased, productive capacity has held steady, and the expectation of this study as discussed earlier, is that capacity will maintain present levels or decline slightly through the mid 80's, after which the level will depend largely upon the outcome of the search for new sources of light and medium crude oil. World supplies now appear likely to remain tight for an indefinite time, so the major constraint upon Venezuelan exports will be internal demand for petroleum.

In the period 1974 to 1978, internal demand went from 248,832 b/d to 300,721 b/d, for an average annual rate of increase of 4.8 percent. Of that demand, the needs of the industrial and domestic use sector ate up 82 percent, the petroleum sector 10 percent and deliveries to maritime transports 7%.

140/ MEM, Memoria... 1978, Vol. I p. 60.

In the industrial and domestic use sector, motor gasolines represented approximately 60 percent of demand, with an annual rate of growth of 11.4%. Of the gasolines, those of medium and high octanes (77-84 and above 84 octane) presented annual growth rates of 14.7% and 19.0% respectively, while low octane decreased from 19,086 b/d in 1974 to 9,857 b/d in 1978. Total growth in demand for gasoline jumped from 96,000 b/d in 1974 to 148,000 b/d in 1978, for an increase of 54 percent.[141/] The high growth rates for petroleum consumption, and particularly for gasolines, derives partially from the fact that prices are controlled by the state at artificially low levels. According to Alfonzo Ravard, President of PDVSA, those low prices cost Venezuela the equivalent of $95 million a year, and he hopes to increase prices.[142/] Indeed, everyone in government stresses the need to raise gasoline prices, yet actually doing so would create a very sensitive political problem, which no one seams willing to bear. Prices have been low for so long that they have become an institution in Venezuela; raising

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141/ El Universal, Dec. 28, 1978, p. 1-10.

142/ Petroleum Economist, October 1978, p. 435. According to DOE, International Petroleum Annual, Venezuela's pump price of regular gasoline was equivalent to 13.2 U.S. cents per gallon, at 31 July, 1977. From 1969 to 1976, the general price index went from 101.6 (base year 1968) to 167.5; energy and fuels went from 99.6 to 103. Banco Central de Venezuela, Informe Economico, Caracas 1977, p. A-29.

them represents a kind of admission that something is defective in the very heart of the economy--the petroleum sector, and the most vital element in Venezuela's indentity.

While the government expects to reformulate its pricing policy later this year, in the meantime, it hopes to raise the conservation consciouness of the populace. As Humberto Calderon Berti said in January: "The country's people must be made aware of their wastefulness... The uncontrolled increase in internal consumption, most of which comes from the private vehicle part, is harming the nation environmentally and financially and diverting needed funds which should be employed to advance industrialization."143/

Yet even the Ministry of Energy has little expectation of any changes merely through exhorting the public. At the I Seminar on the Economics of Energy, held in Mexico City during the summer of 1978, the Venezuelan presentation noted that a psychology peculiar to mining nations has been slowly taking root in their country: "the great problem of Venezuela consists in that her riches have not been earned [i.e. natural wealth], and they are a constant incitement to wastfulness."144/

More concrete plans such as a price hike, the manufacture and assembly of smaller automobile engines, a rapid transit system in Caracas, and improved traffic control will have an impact on fuel consumption, and the government is pushing all of these measures.

143/ Journal of Commerce, January 2, 1979.

144/ MEM, Carta Semenal, No. 37, Sept. 16, 1978, point I, p. 19. Quote from Arturo Uslar Pietri.

Despite large investments in the refining industry, $1.86 billion between 1977 and 1983, and conservation efforts, MEM expects gasoline demand to outstrip the country's gasoline refining capacity during the first few years of the eighties.[145/] Although this problem should be alleviated toward the end of the investment period, the growing demand for gasoline plus the heavy crude composition of reserves, will put an enhanced premium on light and medium crudes, making the export mix increasingly heavy. This shift has been taking place over the past five years. The percentage participation of heavy crudes in exports increased from 27.5% in 1974 to 33.7% in 1978, while exports of light and medium crudes dropped from 39.7% to 32.7% over the same time.[146]

Demand Projection

Table 9 projects petroleum demand in Venezuela from 1980 through 1990. The only figures given by the Ministry of Energy and Mines are for the first and last year of the period; CRS calculated demand in the interim years by using the average annual rate of increase indicated by the ten year growth: 8.0% for gasoline; 0.2% for distillates; 2.5% for fuel oils; and 5.0% for total petroleum demand. As a result, these figures should be used with caution when referring to a specific year, since the numbers would show a smooth growth curve, while in reality fluctuations from the curve probably will occur from year to year.

145/ MEM, Monthly Bulletin, Vol. XIII, No. 1, Janurary 1978, p. 12. Some sources contend this has already occured, although government statistics do not confirm this.

146/ MEM, Memoria y Cuenta 1978, Vol. I, pp. 64-65.

PROJECTED PETROLEUM DEMAND

IN VENEZUELA
(1980-1990)
('000's b/d)

	1980	'81	'82	'83	'84	'85	'86	'87	'88	'89	1900
GASOLINES	174.0	187.9	203.0	219.2	236.7	255.7	276.1	298.3	322.2	348.0	375.8
DISTILLATES	102.0	102.2	102.4	102.6	102.8	103.0	103.3	103.5	103.7	103.9	104.1
FUELS OILS	83.0	85.0	87.2	89.4	91.6	93.9	96.3	98.7	101.1	103.7	106.3
TOTALS*	359.0	376.9	395.8	415.6	436.4	458.2	481.1	505.2	530.4	556.9	584.8

SOURCE: Ministry of Energy and Mines, Direccion de Plainficacion Energetica de la Direccion General Sectorial de Energia: study presented at I Seminar on Economics of Energy (Efficiency and Energy Savings), Mexican Petroleum Institute, August 21-25, 1978. Quoted in M.E.M., Carta Semenal, No. 38, September 23, 1978, p. 16. Only projections for 1980 and 1990 were given. Figures in this chart were calculated using the average annual rate of increase indicated by the ten year growth.

* Totals may not add due to rounding of all figures

The average annual rates of growth reflected by MEM's projections for 1980 and 1990, coincide closely with the historical trends of the past five years in Venezuela. The projections allow for a slightly greater average annual rate of growth for all petroleum products, 5 percent, than the 4.8 percent of the 1974 to 1978 period. They do forsee a slow-down in demand for gasoline however, from over 11% to 8%, a drop whose actual length will depend mostly on the height of any price increase. The projections also consider contributions to energy supplies from a growing hydroelectric capability, which will not peak until the mid to late 1990's. Almost all additions to electrical generating capacity will be met by hydro until that source reaches its full potential, so natural gas and petroleum will be freed from supplying additional fuel for electricity until the mid-1990's, at which point nuclear power may also contribute to electrical power supplies. Coal may also become a fuel source in the mid-90's. Development of Venezuelan coal resources is just beginning and its first uses will be to supply the growing steel industry in the Orinoco region, although it must be blended with imported high grade coking coal for this purpose.

147/ MEM, Memoria... 1978, Vol. II, pp. VC-18-23; series of graphs showing different scenarios for meeting electrical demand under different rates of growth, from 1976 to 2,000.

148/ Ibid., and Karl Brandi, "Venezuela Looks to the Future with Coal," World Coal, Vol. IV, No. 8, (August 1978) pp. 66-68.

To get a general idea of the export levels Venezuela will maintain over the next several years, CRS has made the following assumptions, based largely on the previous analysis in this study: 1) productive capacity will not vary significantly from present levels through the mid- 1980's; 2) Orinoco production will not contribute to production until the late 1980's at the earliest, 149/ and 3) the government will hold to within ten percent of the 2.2 mbd production ceiling. 150/

Keeping in mind the uncertainties of the projections in Table 9, one can estimate that Venezuelan exports by 1985 will have dropped to approximately 1.742 mbd, from present levels of 1.896. The post 1985 period, through 1990, will depend to a large degree upon the outcome of Venezuela's exploration program. To the extent it is successful, productive capacity may be increased above the present 2.44 mbd; without new discoveries, capacity may decline as an increasing number of Venezuelan fields begin to require the application of secondary and tertiary recovery methods. The uncertainty inherent in projecting new commercial oil discoveries, tied to the effects of unknown price levels in that time period, make any projections past 1985 much more guesses than reasonable estimates.

149/ Excluding the 150,000 b/d of commercial production from northern fields on the edge of the Belt, such as Jobo and Morichal, which have been producing for over twenty years.

150/ The ten percent fluctuation is written into Venezuelan supply agreements to allow buyers to ease out of ten percent of their commitment in a flush market, or to receive ten percent above their contract level in a tight market.

Conclusions for U.S.--Venezulelan Energy Relations

The natural inclination of U.S. energy policy toward Venezuela is to encourage her to increase production levels, thus adding to world oil supplies and helping to alleviate the squeeze of a tight market. Interest has been drawn to Venezuela because of a band of heavy petroleum girdling the eastern half of the country from northeast to southwest, which contains by itself exploitable resources possibly equal to or exceeding the present levels of proven world reserves. The U.S. interest is especialy pronounced because the petroleum lies within the Western Hemisphere, and under the control of a traditional supplier of U.S. energy needs.

The sheer immensity of this resource gives it the potential to be a very long term source of world energy supplies and therefore a resource of strategic importance to the entire world. The oil in the Orinoco has already acquired an international aspect through the several agreements for technical cooperation and assistance that have been set up between Venezuela and many of the Western nations, including Japan. This environment of world wide attention and involvement in Venezuela's heavy oil tends to dampen U.S. influence, as does, it can be argued, past U.S. petroleum policy toward Venezuela. However, geographic proximity makes the U.S. a natural market for Venezuelan oil, and the Venezuelans prefer selling to North America rather than more distant markets where transportation costs cut into profit margins. If the proper quality of oil is available, the U.S. also prefers to buy from Venezuela since that helps spread U.S. foreign petroleum dependence among several countries and reduces reliance on Middle Eastern sources.

Thus, mutual interests in energy policy do exist between Venezuela and the U.S., but Venezuela clearly is in a stronger position. Venezuela can more easily forego the slightly higher profits involved in selling to the U.S., than the U.S. can forego buying oil. In addition, Venezuelan energy policy includes making efforts to diversify its markets and reduce its dependence on U.S. purchases. That process has been hampered in the past because Venezuelan crude oil is generally of poorer quality than crudes available from Middle Eastern and North African sources, and her refined products are weighted toward residual fuel oils for which the U.S. is the major outlet. However, development of the Venezuelan industry will increase marketing flexibility as the refining structure begins to turn out lighter and more desirable end products in the mid '80's. And in the 1990's, when the Orinoco begins significant production, its synthetic crude will be of high quality and readily marketable. Venezuela's other potentially large natural market, Brazil, will be requiring ever larger supplies of petroleum, because Brazil's own oil exploration has been disappointing and its economy expanding. The synthetic crude of the Orinoco could be a major source for Brazil, which would also help to satisfy Venezuelan efforts to diversify her markets. In the meantime, the U.S. will be facing a still tighter world oil supply situation in which sellers may have even more power than they have today. Thus, the U.S. could be cast in the role of a supplicant for Venezuelan supplies with little to offer her in exchange.

One of the hopes expressed in Washington has been that the U.S. will be able to bargain for higher production levels and a share of the added petroleum by offering U.S. technology and venture capital to the Venezuelans. Technology and capital are the two most important physical inputs required to develop the Orinoco heavy oil; but Venezuela's need for U.S. assistance with those two inputs depends upon the rate at which development takes place. Proponents of these inducements assume that Venezuela wants to speed development of the Orinoco, and only lacks sufficient quantities of these two imputs. This study has pointed out several factors which will attenuate development of the Orinoco, not least of which is a Venezuelan energy strategy which views the synthetic crude of the Orinoco as a competitor of coal conversion products, not conventional oil, and thus a product whose value will only be realized after the peak of conventional world oil production. The Venezuelans believe the peak will come in the 1990's if not sooner, so any production before that time will not be accorded its real value, and any investments will not receive as attractive a return as they would after that time.

Of course, this strategy depends upon the Venezuelans' ability to do without significant Orinoco production before the 1990's. As noted previously, the present rate of development will not yield any major production until the early 90's, with the first 125,000 b/d plant coming on stream in 1988, at the very earliest. Quicker development would require the infusion of foreign capital and more lenient terms on technical assistance agreements. But Venezuela's gradual approach to development of the Orinoco appears to be well-founded. Recent rates of additions to reserves, growing levels of exploration for conventional light oils, increased supplementary recovery work and promising offshore prospects of between 20 and 60 billion barrels of potential reserves indicate that Venezuela can maintain production of conventional oil at levels near the current target of 2.2 mbd, through the mid 80's. After that time, conventional production levels will depend largely upon the outcome of deep onshore drilling and offshore exploration efforts. Since present technology appears capable of producing and upgrading Orinoco crude at prices near or below present world oil prices, the Venezuelans know that they can fall back on an accelerated development strategy should conventional production begin to falter in the mid to late 80's. Naturally they would prefer to evaluate alternative technologies and allow them to mature before making any irrevocable financial commitments--and only time and field testing bring maturity to a technology. Thus, the longer development is delayed, the higher the value of the crude, the more certain the technical aspects of development and the more rewarding the return on investments.

As emphasized in an earlier section, higher world oil prices not only enhance the attractiveness of investment in the Orinoco, but also in conventional petroleum. As long as conventional resources hold out and prospects for new discoveries remain encouraging, Orinoco development will continue to be less alluring than investment in conventional sources. Thus U.S. capital for the Orinoco is not needed or wanted now, though perhaps it will be in the mid to late 80's, depending on the status of conventional Venezuelan production, and the degree of political resistance to U.S. participation arising from past Washington energy policy toward Venezuela. Long-term trading agreements offer the hope of satisfying both the North American desire for more petroleum and the Venezuelan need for access to capital, without introducing the political problems of U.S. equity participation.151/

151/ Dr. Lawrence Goldmuntz has elaborated on long term trade agreements with Venezuela in "Western Hemisphere Oil--Choices for U.S. Energy Policy" Presented at the Carnegie - Endowment for International Peace Face-to Face Dinner Discussion, February 26, 1979, pp. 8-9. A long term agreement can be used as an assurance of future income when applying for loans, thus easing Venezuelan access to the capital markets. Dr. Alberto Quiros Corradi of Maraven, SA., an affiliate of PDVSA, and other Venezuelan industry officials have also advocated these long term agreements.

Given the long lifetime of Venezuela's heavy oil resources, U.S. policy must consider its strategic importance and weigh the benefits of pushing for quick development of the Orinoco to shore up near term supply problems, against a more cautious approach consonant with present Venezuelan interests--and perhaps more consonant with long-term U.S. and Western Hemisphere energy needs.

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