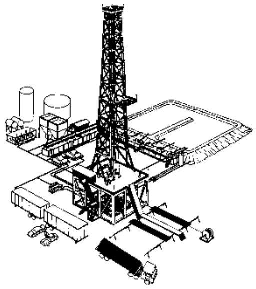

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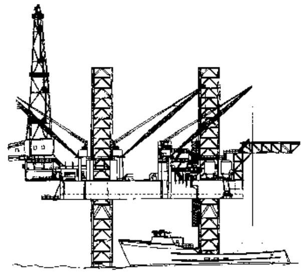

Expert Opinion of Ken Kaigler, P.E. Comparing Texpet E&P Practices in Ecuador to Contemporaneous Practices in the U.S. and Venezuela

in

Chevron Corporation and Texaco Petroleum Company

vs.

***Republic of Ecuador*,**

PCA Case No. 2009-23

Report Prepared for
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1.0 Texaco's History In Ecuador As Consortium Operator

I have read many documents in order (1) to understand Texaco's subsidiary's (Texpet's) methods of operations in Ecuador during the time period from 1964-1990 in its capacity as Operator of the Texaco / Gulf Consortium (Consortium) and (2) to compare them to my work experiences in Venezuela and the United States during that time period. These documents are listed in Section 7.0 and include, in particular, the article *Sacha Field-Ecuador, Oriente Basin* prepared by Texpet's Robert Canfield; a Texaco memorandum from U.V. Henderson, Jr. et al. to W.C. Benton, dated Nov. 14, 1990; the reports of Mr. John A. Connor, dated September 10, 2010 and June 3, 2013; the Fugro-McClelland Audit Report, dated October 1992; and the HBT Agra Audit Reports, dated October 1993 and March 1997. This section presents background information from those sources about Texpet's practices in Ecuador that is relevant to my opinion.

1. At the Sacha wellfield, early wells were drilled with 9 5/8-inch surface casing set to a depth between 240 feet and 2,400 feet.[1] Wells drilled later at Sacha (after Well 57) were drilled with 10 3/4-inch surface casing cemented to about 2,000 feet.[2] Production tubing installed in the Sacha wells was 2 7/8-inch or 3 1/2-inch.[3] The approximate depth of the Sacha wells was 10,000 feet.[4] This information regarding the Sacha wellfield comes from Mr. Canfield's article. It is the most thorough discussion of the details of Texpet's practices in Ecuador that I have identified. Based on my personal experience, as well as information in the Fugro-McClelland and HBT Agra Audit Reports and the Connor reports, I can extrapolate Texpet's likely practices throughout the Concession.

2. According to Texaco's Mr. Henderson: "Drilling was conducted using water-based mud containing bentonite, polymers, caustic soda, surfactants, and barite. The relative proportions of these ingredients varied depending upon the stage of the operation… The drilling fluids and cuttings were managed in unlined reserve pits. The aqueous portion of the drilling fluid is allowed to seep into the ground as much as possible and then the pit is closed by filling the pit."[5]

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[1] Robert Canfield, *Sacha Field-Ecuador, Oriente Basin*, 1991, p. 286. (Canfield, 1991).

[2] Canfield, 1991, p. 286.

[3] Canfield, 1991, p. 288.

[4] Canfield, 1991, p. 285 (the Sacha discovery well flowed oil through perforations in its casing between 9,816 feet and 9,885 feet).

[5] Texaco memorandum from U.V. Henderson, Jr. et al. to W.C. Benton, dated Nov. 14, 1990 (Henderson et al., 1990), p. 3; Fugro-McClelland, Final Environmental Field Audit For Practices 1964-1990 Petroecuador-Texaco Consortium Oriente, Ecuador, dated October 1992 (Fugro-McClelland, October 1992), p. 6-3 ("The practice for drill mud and cuttings was to dispose of those wastes in the reserve pit."); Fugro-McClelland, October 1992, p. 6-9 ("Prior to 1990, muds containing lithium sulphate and other heavy metals were disposed of in sump pits…Workover, completion wastes, salt solutions and oil/water emulsions have historically been disposed of into well site pits.").

3. Mr. Connor asserts: "Specifically, during the time period that Texpet served as operator of the Concession (1972 through June 1990), the use of earthen pits to contain oily waste liquids at well sites; the management of the produced water by means of treatment and discharge to surface streams; and the flaring of unused natural gas were consistent with applicable Ecuadorian regulations, as well as the prevailing practices in the oil industry at that time in the U.S. and worldwide."[6]

4. As Mr. Connor notes, the HBT Agra and Fugro-McClelland Audit Reports found in 1992 and 1993 "…the presence of open pits, oil-affected soils, and produced water discharges…"[7]

5. Mr. Connor also states: "In the former Petroecuador-Texaco Concession, drilling pits and workover pits were used at the individual well sites, while produced water pits were located at the production stations for centralized collection and management of produced water."[8]

6. Mr. Connor asserts: "In the decades of the 1960's, 1970's, and 1980's, the common practice for management of produced water in the U.S. as well as other countries around the world was treatment in a series of tanks or earthen ponds to remove oil, emulsions, and solids, followed by discharge to nearby surface water or the ground surface."[9]

7. Texaco's Mr. Henderson notes: "Current government regulations require a pit at each well for the purpose of receiving spent workover and stimulation fluids. In February, 1986, Texaco requested permission to close these pits. A formal response has not been received to date. These pits contain oil, produced water, workover brines, spent acid, and treatment solvents. Fluids are not generally recovered from these pits, since in many cases they are inaccessible."[10]

8. According to Fugro-McClelland: "Some of the pits contained siphons which allowed collected water to be released while retaining the crude oil. Contamination beyond the pits was observed at some areas. The contamination usually occurred as a result of pit overflow, berm failure or releases through the siphon."[11]

9. The volumes of produced water disposed by Texpet are estimated as follows:

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[6] Expert Opinion of John A. Connor, GSI, 2010, p. 7. (Connor, 2010).

[7] Connor, 2010, p. 7.

[8] Connor, 2010, p. 16.

[9] Connor, 2010, p. 23.

[10] Henderson et al., 1990, p. 4.

[11] Fugro-McClelland, October 1992, p. 6-10.

- 5.5 million barrels (bbl) annually (as of 1991) from the Sacha wellfield.[12]
- 8.15 million bbl annually (as of 1986) from the Sacha wellfield.[13]
- 197.324 million bbl cumulative from the Sacha wellfield.[14]
- Consortium average 2.3 million bbls/month 1980 through July 1990.[15]
- 375 million bbls during 1964-1990 (Consortium total).[16]

10. The volumes of crude oil produced by Texpet are estimated as follows:

- 337.930 million bbl cumulative from the Sacha wellfield (through 1987).[17]
- 22.475 million bbl/yr annual production from the Sacha wellfield (as of 1986).[18]
- 1,377,580,906 bbls cumulative oil production through 1990 (92% of Consortium wells).[19]

2.0 Opinion

From 1973-1990 Texpet, as Operator of the Consortium, drilled 344 wells in the Concession area[20] following practices which had been prohibited by environmental protection regulations and which were contrary to recommended oilfield practices and general drilling procedures employed in the United States during that same period of time. From my personal experiences in Louisiana, Texas and Venezuela, I can personally attest that Texpet's practices also deviated from the more environmentally protective methods used by the oil and gas industry at that time, not only in the United States, but also in Latin America.

3.0 Typical U.S. And Venezuelan Drilling Operations In The 1970s and 1980s

This section gives an overview of a typical petroleum exploration and production (E&P) operation during the 1970s and 1980s, concurrent with the two decades of Texaco's operations in Ecuador, based on my experiences in the United States and Venezuela.

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[12] Canfield, 1991, p. 288.

[13] Canfield, 1991, p. 303.

[14] Canfield, 1991, p. 303.

[15] Fugro-McClelland, October 1992, p. 6-36.

[16] HBT Agra, Draft Environmental Assessment of the PetroEcuador-Texaco Consortium Oil Fields 1964-1990, dated October 1993 (HBT Agra, 1993), p. 5-6.

[17] Canfield, 1991, p. 303.

[18] Canfield, 1991, p. 303.

[19] HBT Agra, Environmental Audit and Assessment of the PetroEcuador-Texaco Consortium Oil Fields Until June 30, 1990, dated March 19, 1997 (HBT Agra, 1997), Revised, Appendix A, Table A-1.

[20] Expert Opinion of John A. Connor, GSI, 2013, p. 7. (Connor 2013).

3.1 Exploratory Drilling

The operator usually assembled a rig and a camp at each drilling site. Typical camps included a drilling rig, drilling mud handling equipment, power generators and cementing equipment. The camp provided accommodations for the crew, dining facilities, sanitary facilities, communications equipment, vehicle maintenance and parking areas, fuel handling and storage areas, and provision for the collection, treatment and disposal of wastes.

Drilling an exploratory oil or gas well in the U.S. lasted about one to two months. Drilling rigs and support equipment were normally divided into modules to facilitate transportation. Pits were dug into the ground or steel tanks were moved to the drilling rig site to store, on a temporary basis, drilling fluids, drilling mud, cuttings and any oily wastes generated during the exploratory drilling.

When well drilling began, drilling mud was circulated from the mud pit, to the rig floor, down the drill pipe, through the bit, and back up the annulus around the drill pipe to the blow out preventer (BOP) equipment. Drilling mud was used to balance hydrostatic pressure and prevent collapse of the surrounding soil into the borehole. This drilling mud also served to cool and lubricate the drill bit and flush out drill cuttings from the bottom of the borehole. The cuttings were separated from the mud at the shale shaker, and then deposited into a reserve pit.

When necessary, casing was then run into completed sections of the well and cement pumped into the annulus between the casing and the well bore. To deepen the well a smaller bit was used to drill through the casing. The casing and cement provided support for the borehole and protected water and sand from infiltrating the crude oil and/or gas formations.

Where indications of hydrocarbons in a zone were found, casing was run into the well and cemented. Well tests were conducted to establish flow rates, formation pressure, and the relative concentration of fluids, such as water, oil and/or gas, within the formation.

3.2 Development Drilling

Where commercial reserves of crude oil were found through exploratory drilling, the oilfield went into the development drilling phase. Development drilling required more time and facilities. Roads, camps, produced water pits, production facilities and pipelines had to be built. Production facilities were required to separate, store and transport produced fluids. Formation gas may have been burned, used locally at the site, or transmitted through a gas sales line. The produced water may have been discharged back underground through saltwater injection wells, evaporated in pits or injected back into a non-producing well (water flooded) to maintain reservoir pressure. The size and type of the facilities depended on the location of the oil reservoir, the volume and type of produced fluids, and the availability of pipelines and tanker trucks.

Operators used a wire line unit or a workover rig for down-hole well servicing. Steel tanks were used to contain workover waste. In some areas a self-contained base camp was established to support routine development, production and maintenance operations. As in the case of exploratory drilling, the camp provided accommodations for the crew, dining facilities, sanitary facilities, communications equipment, vehicle maintenance and parking areas, fuel handling and storage areas, and provision for the collection, treatment and disposal of wastes. However, for development drilling and the handling of production, operators built more permanent structures.

From the production facilities an operator transported the oil and gas to other locations by transmission pipelines or tanker trucks. The transmission destinations included refineries for conversion to downstream products or ports from which the crude oil was exported to foreign market by tankers.

4.0 Oilfield Practice In The United States And Venezuela Prior To And During The Time Of Texpet's Operations In Ecuador

In his 2010 expert report, John A. Connor asserts that "Texpet operations in Ecuador from 1972 to 1990 were consistent with applicable regulations and prevailing practices for environmental management for oilfield operations at that time."[21] The Connor expert report also states that "In the decades of the 1960's, 1970's, and 1980's, the common practice for management of produced water in the U.S. as well as other countries around the world was treatment in a series of tanks or earthen ponds to remove oil, emulsions, and solids, followed by discharge to nearby surface water or the ground surface."[22]

These statements are contrary to my personal experience in the U.S., even earlier during the 1950's and 1960's when I worked as a floor hand[23] and roustabout[24] in South Texas for Humble Oil from 1950-52, and as a Production Engineer[25] for British American Oil Producing Company in Louisiana and Texas from 1957-1964. They are also contrary to my personal experience with a major oil company in Venezuela in the mid-1950s. My experience in dealing with oilfield

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[21] Connor, 2010, p. 5.

[22] Connor, 2010, p. 23.

[23] A floor hand is a worker on a drilling or workover rig, subordinate to the driller, whose primary work station is on the rig floor. On rotary drilling rigs, there are at least two and usually three or more rotary helpers on each crew. Some of the duties I performed as a floor hand included: moving the rig to a new location and assisting in setting up and testing the equipment; adding chemicals to the mud in the circulating pits; measuring the drill pipe on the pipe racks; helping move and rig-up the drilling rig; helping pull and set rotary clips and operate the drill pipe tongs when making connections during drilling operations and handling stands during tripping operations; helping measure casing and/or tubing on the pipe rack; helping pick up pipe and operate the back-up tongs when running casing or tubing; removing BOP's; installing Christmas trees (*i.e.*, the control valves, pressure gauges, and chokes assembled at the top of a well to control the flow of oil and gas after the well has been drilled and completed); and taking the rig down to move it to another location.

[24] A roustabout is a worker who assists the foreman in the general work around a producing oilwell, usually on the property of the oil company. Some my duties as a roustabout included cleaning up around the well locations; installing and repairing flow lines; and performing general maintenance on equipment.

[25] A production engineer is responsible for preparing drilling plans and authorizations for expenditure, including arranging for drilling rigs and other equipment and supplies that may be needed to drill and complete the well. Some of my duties as a production engineer included: preparing the necessary programs, equipment and materials for the drilling of the well; supervising the well site operations on site during drilling, completion and workover; reporting on all operations to the main office.

waste handling practices in the U.S. and in South America, which are detailed in the subsequent sections, may be summarized as follows:

- Wherever possible, we collected, temporarily stored and reused drilling mud on the next well to be drilled or during a future workover, rather than permanently disposing of it in a reserve pit or at the ground surface.

- "Evaporation pits" were used for produced water only in warm, relatively arid areas where the temperature and relative absence of humidity allowed for evaporation (*e.g.*, South Texas and North Louisiana). However, if an oil and water emulsion were observed in the pits it was first treated in a "gun barrel" (oil-water separator) and a "jug heater" to break down oil and water emulsions. As a matter of practice, we did not allow an oil layer to accumulate on the produced water pits, contrary to Texpet's operations in the Concession.[26]

- In no event were significant volumes of produced water (greater than approximately 15 bbls) disposed of, or even temporarily stored, in unlined pits. Instead, produced water was either pumped into a disposal well (5,000 to 6,000 ft. deep and connected to a saltwater formation) or re-injected into the oil-producing formation as water flood for pressure maintenance. Even in instances when small volumes of produced water were temporarily stored, unlined pits would be used only if the soil was compacted and the weather dry and hot (like in Texas and North Louisiana). If the soil was soft and/or the weather rainy (like in South Louisiana), lined pits would be used.

- Pits used to temporarily store drilling mud, water, cuttings, etc. were pumped out and backfilled at the conclusion of drilling activities, and were not allowed to remain permanently open.

- We used steel tanks, rather than earthen pits, to contain fluids during workover operations.

- It was my understanding that it was universally recognized in the industry at this time that discharging highly saline produced water onto the ground or into the surface water would cause an adverse impact on agricultural and grazing land and on local marine life. Additionally, our practices for saltwater disposal were motivated by our recognition of the potential for adverse impacts on drinking water and local inhabitants from improper disposal.

4.1 Humble Oil And Refining Co. South Texas (1950 -1952)

I was employed by Humble Oil & Refining on Company rig No. 16. (See Exhibit A.) as a floor hand on a Humble drilling rig.

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[26] Henderson et al., 1990, p. 2 and Fugro-McClelland, October 1992, Figures 6-1 through 6-7.

The following sections describe the oilfield work process and waste management activities we used at that time.

4.1.1 Development Drilling

In South Texas the ground was firm, the temperature was hot and dry, and there was little rain. These conditions allowed for greater evaporation of impounded produced water and less chance of its seepage and resulting contamination to the deeper drinking water reservoir. We disposed of no more than 10-15 bbls. of produced water per day in evaporation pits.

The rig used an earthen circulating mud pit. We used fresh water pits for storage of fresh water needed for the steam boilers.

The rig pumps sucked up the drilling mud from the back end of the circulating pit, pumped the mud to the rig floor, through the kelly, down the drill string and through the bit, back up the annulus through the bell nipple, and finally to the shale shaker. The mud flowed through the shale shaker screen and down into the front of the pit. The cuttings removed by the shale shaker were carried on top of the screen to a slide and then deposited into the reserve pit for temporary storage. See Exhibit B, for a typical circulating system.

My experience with Humble included drilling and completing 8,000-9,000 ft. development wells. The rig drilled a 14 3/4 inch (in.) hole to 2,000-2,200 ft., and ran 10 3/4 in. surface casing to total depth. We then mixed cement and pumped it down the casing and up the annulus, between the casing and the well bore, and then from the bottom of the casing to the surface. Finally, we installed and pressure tested a Blow Out Preventer (BOP) system and bell nipple. See Exhibit C.

We then drilled a 9 7/8 in. hole to a depth of 8,000 or 9,000 ft. with chemically-treated gel mud. After the hole had been drilled, we ran an open-hole electric log and evaluated the well zones. Productive sands (those containing crude oil) generally ranged from 8,500 ft. to 7,000 ft.; saltwater sands from 6,500-4,000 ft.; and fresh water sands from 100-600 ft.

After a positive well evaluation, we ran a 7 in. casing string to total depth and cemented the annulus between the casing and the well bore, up to about 6,000 ft. We then ran a cased-hole electric log and perforated a predetermined zone. We also ran a production packer and 2 3/8 in. production tubing in the hole. Then, we removed the BOPs and installed a production tree. Finally, we swabbed in and tested the well. See Exhibit D, for a typical completion.

The drilling mud from the circulating and reserve pits was picked up and hauled to a central storage to be used for the next well drilled or for workovers. We left the mud in the circulating pits for only 30 to 40 days, depending on the depth of the well. The fresh water pits, circulating pits, and reserve pits were all suctioned, backfilled and compacted. Our workover rigs used steel pits (tanks) instead of unlined, excavated earthen pits to dispose of the acids, solvents, produced fluids, etc. associated with workovers on existing wells.

The final restoration of the well location was determined by the lease with the land owner, who generally wanted it to be cleaned up and available for commercial use. Most of the land area was being used for ranch or farm land; consequently no open pits were left at the location.

4.1.2 Production Facilities

The formation fluids from the production wells flowed to the separator at the central tank battery. The crude oil flowed to the heat-treater or storage tanks. See Exhibit E, for typical production facilities. The formation fluid from the well also contained gas and produced saline water, which we managed as follows:

Produced gas:

The gas was either used for gas lift (See Exhibit D, Page 2), re-injected back into the formation (for pressure maintenance), or piped into the sales line. Small amounts of gas may have been flared and burned if there were no pipelines available.

Produced water:

In a dry climate with relatively impermeable soils, if there was only a small amount of produced water, say up to 10-15 bbls., it was discharged into a saltwater pit and allowed to evaporate. Larger volumes of saltwater were always either pumped back into the producing formations (for water flood) or into a (5,000-6,000 ft. deep) saltwater disposal well. See Exhibit F for formations needing gas or water injection.

4.2 Drilling Operations In Venezuela (VARCO) (1952-1956)

From 1952-56 I worked as a Production Engineer for the Venezuelan Atlantic Refining Company (VARCO). VARCO was a major oil and gas producer in Venezuela, operating three major oilfields. In each of these fields the ground was soft, and there was both a dry season and a wet season. VARCO conducted its exploratory drilling during the dry season. An outside contractor would be hired to do the drilling. The contractor set up a camp in the area in which the drilling was to be done. The drilling rig used an earthen mud circulating pit and reserve pit, similar to the ones I worked on in South Texas. At the completion of drilling activities the waste mud, produced water and excess crude oil were all pumped from the pits back into the well borehole. After pumping, VARCO backfilled the empty pits with clean fill and compacted the fill. The fluid from a well workover was picked up and temporarily stored for either reuse or disposal into an injection well.

4.2.1 Exploratory Drilling

VARCO drilled exploratory wells to 9,000 ft. To accomplish this task, we drilled a 12 1/4 in. hole to a depth of 2,000 ft. and ran an open-hole log to evaluate the surface hole. A 9 5/8 in. surface casing would be run to total depth and cemented to the surface. The BOPs would be installed on the 9 5/8 in. casing head and then pressure tested. An 8 1/2 in. hole was drilled to 9,000 ft. and an open-hole electric log was run to evaluate the well.

If the well tested dry (no sign of hydrocarbons), we pumped the mud in the circulating and reserve pits back into the well and set a cement plug in the 9 5/8 in. casing. The BOPs were removed and a “dry hole tree” was installed on the 9 5/8 in. casing. The well was kept for use as a disposal or injection well. VARCO backfilled the pumped-out earthen pits and compacted the fill.

If the open-hole electric log indicated the presence of hydrocarbons, a string of 5 1/2 in. casing was run to a depth below the lowest section indicating presence of hydrocarbons, and cemented up to a point above those sections exhibiting the presence of hydrocarbons. The BOPs were removed and a flange installed on the casing head. The drilling rig was rigged down and moved off the location.

A workover rig, steel circulating pit, testing equipment and storage tanks were moved in to test the well. The workover rig BOPs were installed on the 5 1/2 in. casing head and pressure tested.

A cased-hole electric log was run in the 5 1/2 in. casing through the zones that indicated the presence of hydrocarbons. The lowermost zone was perforated, and a test tool and tubing was picked up and run into the well. The mud in the tubing was swabbed until the well flowed. Then we tested the well, with gas flared and burnt and produced oil stored in the tanks. After a zone had been tested (taking 1-3 days), the oil in the test tanks (from 50-100 bbls) was pumped back into that same zone and a cement plug set in the 5 1/2 in. casing above the perforations.

After each zone had been tested and plugged, we pumped the mud in the circulating and reserve pit down the annulus, between the 9 5/8 in. casing and the 5 ½ in. casing back into the saltwater zone. The BOPs were removed, and the rig moved off the location. Finally, VARCO pumped out, backfilled and compacted the earthen pits.

4.2.2 Development Drilling

VARCO also used a company-owned rig to drill some of their development wells in the producing fields. In Venezuela, the company rig used steel circulating mud pits (steel tanks). Unlike the exploration drilling that was limited to the dry season, development drilling was done year round. During the rainy season the ground was often soft and there was too much rain to maintain earthen circulating mud pits. The steel pits also had covers to keep out the rain to prevent overflow and thus minimize seepage. The rigs did use earthen reserve pits for temporary storage of surplus mud and cuttings. After the well completion the fluid in the reserve pit would be either hauled off to temporary storage for reuse or disposal in an injection well. The remaining cuttings would be covered with soil and packed.

The development wells in Venezuela were drilled in the same manner as I had experienced in south Texas. 10 3/4 in. casing was set at 2,000 ft. The well was drilled to 8,000-9,000 ft., logged and evaluated; 7 in. casing was run to total depth and cemented. After the well had been drilled and the 7 in. casing run and cemented, the drilling rig was moved off and a completion rig with steel circulating tanks was move in to complete the well. After the completion, VARCO pumped out, backfilled, and compacted the reserve pit.

The wells flowed to the central tank battery (See Exhibit E). The crude oil was pumped through a pipeline to a deep water seaport where it was sent by oil tanker to the U.S.A. Most of the gas was used for gas lifting or injected back into the formation for pressure control. Some of the gas was used to generate electricity for the VARCO camp and the local towns of Tucupido and

Saban. VARCO treated the produced water and either injected it back into the formation for pressure control (water flooding) or disposed of it into a saltwater injection well. Levees were built around the production facilities to prevent or control any accidental release of oil or saltwater. Any accidental discharge was vacuumed up and pumped back into the production tanks.

Because of the close presence of local inhabitants and the rainy weather, VARCO did not use open earthen pits at the production facilities or the wells. The produced water was collected in covered steel storage tanks and then disposed of by means of saltwater injection wells or a water flood system. When an oil well produced too high a percentage of saltwater (ratio of produced water to crude oil) and therefore became uneconomical to produce, it was converted to a saltwater injection well. The saltwater was pumped from the production facilities, through the flow line back to the well, and then back down into the saltwater formation.

There were local Venezuelan families living in the area where VARCO was drilling and producing oil and gas. Many of the men worked for VARCO on the rigs and production facilities. The neighboring inhabitants did a lot of farming and ranching in the immediate area. They did not have a potable water supply system and had to get their drinking water and also water their livestock from a system of small lakes and rivers in the area. VARCO was therefore very careful not to pollute their water supply, as the VARCO workers knew that discharge of produced water into surface water would have polluted their potable water supply. Water was very scarce during the dry season and had to be protected as a resource.

4.3 British American Oil Producing Company (1957-1964)

With British American Oil I worked in Louisiana and Texas in production, drilling, and well workovers. I worked in both the swampy areas of South Louisiana and the drier areas of North Louisiana and East Texas. All of the drilling was done with rigs using steel mud circulation pits and earthen reserve pits. Shallow wells were drilled to 7,000-9,000 ft. and deeper wells to 16,000-18,000 ft.

The mud from the shallow wells was either vacuumed up and reused, or pumped into disposal wells. The mud from the deeper wells was chemically treated and weighted with barite. After a well had been completed its drilling mud was picked up and pumped into storage tanks for reuse. The fluid from the workover operations was either picked up and stored for reuse or disposed of in a disposal well.

Because of the surrounding agricultural and ranching land uses we all recognized that it was very important that the well locations and production facilities not discharge any oil or saltwater waste onto the land or into adjoining waterways. We were very strict about avoiding pollution. Produced crude oil was collected in tanks and either hauled off with tanker trucks or pumped through pipelines. If a gas pipeline was available the gas was sold. If not, it was used for gas lift, injected back into the formation or flared as a last alternative.

In the swampy areas of South Louisiana the ground was so soft that a board platform had to be built to hold the rig and associated equipment. A levee was built around the work location to collect any rain water runoff that might have been contaminated by rig activities. The collected rain water was hauled off to a disposal site. We did not use evaporation pits in these locations because the air was too humid and there was too much rainfall for evaporation to be effective. From what I have read, I believe the Concession environment, being in a rainforest, is even more humid and has even higher average precipitation than what I experienced in South Louisiana.[27]

5.0 Comparison Of Texpet Operations (1973-1990) With Normal Venezuelan Practices (1952-1956)

The 2010 Connor expert report identifies Venezuelan regulations established in 1998 for closure of oilfield pits[28], and in 1992 for disposal of produced water.[29] His conclusion, with which I strongly disagree, is that prior to the 1990s oilfield wastes had been managed throughout Latin America in the same manner as Texpet had done as Operator in the Concession area. I worked as a Production Engineer working in Venezuela during the 1952-1956 period, where I supervised drilling, completion and workover operations and cleaning up the location after completion of operations, occurred two decades before Texaco's Ecuadorian operations commenced. My personal experience, which is described in detail below, is completely contrary to Mr. Connor's report. I can state from personal experience that the major U.S. oil company by whom I was employed, VARCO, used the following practices for the disposal of Venezuelan oilfield wastes:

- On exploration wells, waste drilling mud was pumped into the annulus of the borehole for disposal back into the formation at a depth consistent with the presence of natural saline formation water.

- On development wells, waste drilling mud was either hauled off for temporary storage and reuse or pumped immediately into a disposal well.

- On exploration wells, crude oil from well testing was pumped back into the well tubing to await future production. This practice mitigated potential impacts from crude oil.

- On both types of wells, produced water was either injected into a disposal well (drilled to an appropriate depth) or disposed of in a reinjection well to increase crude oil production through water flooding.

Most importantly, these practices to handle waste were conducted out of reasonable sensitivity to the potential adverse impacts from oilfield waste disposal on local inhabitants and resources, as well as a desire to maximize production.

The Venezuelans living in the region of the drilling operations relied on surface water resources (rivers and lakes) for their drinking water supply; therefore, VARCO, which operated the oilfield, took steps to prevent disposal of produced water or drilling mud into surface water or

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[27] See HBT Agra, 1993, p. 2-1; HBT Agra, 1997, p. 2-1.

[28] Connor, 2010, p. 20.

[29] Connor, 2010, p. 24.

where it could infiltrate ground water. VARCO used disposal wells, depleted oil injection wells, water flood and/or pressure maintenance wells to dispose of the produced water.

5.1 Drilling Mud Waste From Drilling And Completion Operations

Although I don't have all of the historical information from Texpet's drilling and mud reports to make precise calculations as to the amount of drilling fluid waste generated by its drilling operations, I can make certain assumptions and calculate estimated minimum amounts of drilling mud waste Texpet would have left at each location. I can conservatively assume that a 14 ¾ inch hole was drilled to 2,000 ft. and 10 ¾ in. casing was run and cemented to the surface, based on the descriptions of drilling practices at the Sacha wellfield as documented in Canfield, 1991.[30] Then I assume that a 9 7/8 in. hole would be drilled to a depth of 10,000 ft. and 7 in. casing run to total depth and cemented back up to 6,000 ft.

When the casings are cemented, the mud in the annulus is displaced with cement and sent to the reserve pit. The mud displaced from the annulus in the surface casing would be 198 bbls. The mud displaced in the 9 7/8 inch by 7 inch annulus would be 179 bbls. Because there is no indication that the circulating pits were pumped clean, a minimum of 200 bbls. of drilling mud would also be left in the circulating pits when the rig moved off location. Therefore, a total of at least 577 bbls. of surplus mud waste from the well drilling activities would be left on each location.

I don't know exactly what type of completion fluid Texpet left in the well after completion. If drilling mud were left in the 7 in. casing then approximately 40 bbls would be displaced by the completion string into the completion fluid reserve pit. However, if the well was completed with a completion fluid then all of the mud in the 7 in. casing, 415 bbls., would have been displaced into the reserve pit. I would estimate that a minimum 600 bbls and a maximum of 1,000 bbls. of drilling mud would have been left on each well location, disposed in the reserve pit along with the cuttings and yield testing wastes, at the conclusion of the drilling and completion operations that were performed before a particular well could be used to produce oil.

I can reasonably assume that at least a 100 bbl. workover circulating fluid pit was left full of mud or saltwater waste after each subsequent workover that might have been performed during the life of the production well. Workovers could include changing pumps, adjusting the well to remove crude oil from a different stratum in the formation, maintaining production tubing, etc.

5.2 Drilling Cuttings Produced While Drilling

The amount of formation cuttings from a 14 3/4 in. surface hole would be (0.211 bbls./ft. X 2000 ft) = 204 bbls. Cuttings from the 9 7/8 in. hole would be (0.094 /ft. X 8000 ft) =752 bbls., with an estimated total of over 900 bbls. of formation cuttings produced from an approximate 10,000 foot deep well. These cuttings would be disposed in the reserve pit

[30] See Canfield, 1991, pp. 286, 288.

6.0 History Of Saltwater Problems And Injection

The American Petroleum Institute (API) issued its *API Recommended Onshore Production Operating Practices For The Protection of The Environment* in 1974[31] addressing environmental concerns related to oilfield production, produced water, oil discharge prevention and cleanup, spill reporting, spill control and containment and cleanup of petroleum production contaminants.

Other literature as well confirms my personal experience that for many years — well before 1973 — the industry considered saltwater production and pollution to be a problem:

- Water discharge Requirements Kern County 1958;[32]
- Oil Field salt water pollution, Oil & Gas Journal 1962;[33]
- Article from Civil Engineer about disposal of inland brines in Kansas;[34]

The history of the Louisiana Conservation Department, reveals that Louisiana passed a regulation as early as 1924 prohibiting pollution from oilfield production.[35]

6.1 Louisiana Open Pit Regulations

The Louisiana Department of Conservation's Handbook for the Oil and Gas Industry Division 29-B, Section XV, Pollution Control was revised in 1982 to include rules for:

- wells which re-inject fluids;
- existing pits, new pits, reserve pits;
- pit classification and operation requirements, burn pits and well test pits;
- closure requirements, monitoring pit closure, pit closure techniques and onsite disposal;
- land treatment;
- offsite disposal, disposal of reserve pit fluids by subsurface injection;
- saltwater disposal wells;

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[31] API Recommended Onshore Production Operating Practices For The Protection of The Environment, 1974.

[32] Kern County, California, Waste Discharge Requirements, 1958.

[33] Robert J. Enright, *Oilfield pollution ... and what's being done about it*, The Oil and Gas Journal, 1963.

[34] Ogden Jones, *Subsurface Disposal of Inland Oil-Field Brines Conserves Fresh Water Supply*, Vol. 17, No. 2, Civil Engineering.

[35] Louisiana Department of Natural Resources, Office of Conservation, History

- enhanced recovery injection; and

- off-site storage and treatment and/or setting the requirements for disposal of produced water, prohibiting the contamination of ground water, closing of existing pits not being used, classification of pits, standards and operational requirements for the disposal of nonhazardous oilfield waste.[36]

Even though my work in Louisiana predated these rules, in my experience industry operating there was already following some of the rules, such as disposal of all drilling mud and cuttings, closing and back-filling pits, preventing contamination of ground water, and injecting produced water into disposal wells or pressure maintenance wells. Thus, Texpet's practices in Ecuador were less environmentally protective than the practices employed by industry in Louisiana prior to 1982 and those required in Louisiana as of 1982.

6.2 Texas Open Pit Regulations

Saltwater re-injection in Texas began in 1930.[37]

The Texas Oil and Gas Statewide Rule book, effective June 1, 1964 "*OPEN PIT STORAGE PROHIBITED*" (order No. 20-884 dated July 31, 1939), ordered closure of all open pits or non-temporary earthen storage facilities.[38]

In the first half of the twentieth century Texas allowed disposal of produced water in earthen evaporation pits. However in the 1950's the State recognized this practice as a potential ground water problem and the Texas Railroad Commission (RRC) began prohibiting such pits and discharges on an area wide basis starting in 1955. In 1969 the RRC flatly prohibited such pits statewide.[39]

In my experience in Texas, industry followed these requirements and in some cases exceeded them. Thus, Texpet's practices in Ecuador were less environmentally protective than industry practice and the regulations in Texas. Nowhere did we ever leave open pits on the well locations. The land owners were very strict as to the conditions that we left the location. If we had a produced water pit at the production facilities it would be monitored so as to detect and prevent any water contamination to surrounding area.

7.0 Information Reviewed In Preparation For Report

Robert Canfield, *Sacha Field-Ecuador, Oriente Basin*, 1991;

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[36] Louisiana Department of Conservation Regulations, 29B Pollution, Louisiana Handbook for the Oil and Gas Industry, 1989

[37] EPA, History of the UIC Program – Injection Well Time Line

[38] Texas Oil and Gas Statewide Rule Book.

[39] John James Tintera and Leslie Savage, Effect of Oil and Gas Production on Groundwater, Texas Water Development Board, Report 365, Chp. 15, 2006.

Texaco memorandum from U.V. Henderson, Jr. et al. to W.C. Benton dated Nov. 14, 1990

Produced Water Correspondence by Texaco;

John A. Connor Report dated September 2010;

John A. Connor Report dated June 2013;

Amazon Defense Coalition, Summary of Overwhelming Evidence Against Chevron in Ecuador Trial;

Douglas Beltman, Chevron's Negligently Substandard Oilfield Waste Disposal Practices in Ecuador;

PETEX Primer of Oilwell Drilling 1970;

PETEX/IADC Rotary Drilling Circulating Systems 1981;

Introduction to Rotary Drilling, PETEX 1982;

Salt water disposal permits Kern County California 1958;

Robert J. Enright, *Oilfield pollution ... and what's being done about it*, The Oil and Gas Journal, 1963;

Ogden Jones, *Subsurface Disposal of Inland Oil-Field Brines Conserves Fresh Water Supply*, Vol. 17, No. 2, Civil Engineering, 1947;

History of Louisiana Production;

EPA, History of the UIC Program - Injection Well Time Line;

Louisiana Handbook for the Oil and Gas Industry Revised State wide Orders;

Fugro McClelland Audit Report, dated October 1992;

HBT Agra Audit Report, dated October 1993;

Section from Texas Oil and Gas Statewide Rule Book dated June 1964;

John James Tintera and Leslie Savage, Effect of Oil and Gas Production on Groundwater, Texas Water Development Board, Report 365, Chp. 15;

API, Recommended Onshore Production Operating Practices for Protection of The Environment, 1974;

Texas Regulations, 1975;

Texas Regulations, 1980;

Texas Regulations, 1981.

Attached to this report is a copy of the references identified above.

8.0 Supporting Exhibits

A. Typical land drilling rig;

B. Circulating system;

C. Blow Out Preventers (BOP);

D. Casing and single completion;

E. Production facilities flow diagram;

F. Producing formations;

G. Move in and rig up.

Attached to this report is a copy of the exhibits identified above.

9.0 Qualifications

9.1 Experience

I have over 37 years working on land, inland waters and offshore locations performing and supervising production, drilling, completion and workover operations for major oil and drilling contracting companies engaged in oil and gas exploration and development. I also have over 25 years as a consultant in oilfield operations and litigation. (See Attached C. V.).

While performing engineering duties in respect to drilling, completion, workover and production equipment and operations, I was always instructed by company management to take into consideration the safety and environmental aspects of the drilling, and I tried to insure that pollution was kept to a minimum.

As an expert witness, I have worked on over 800 oilfield related accident cases which had been caused by hazardous working conditions, faulty equipment or unsafe operation of equipment. I have testified in Louisiana federal and state courts and Texas state courts 50 times and in depositions over 190 times.

My opinions are based on technical and other specialized knowledge gained through my education, training and many years of "hands on" experience working on and supervising land drilling and workover rigs on behalf of the operator or the drilling contractor.

9.2 Training

In order to increase my knowledge and maintain my skills, I have continued an ongoing training and education program by attending special schools and training programs specializing in the recognition of hazardous oilfield working conditions, faulty equipment and unsafe operation of equipment.

9.3 Education

I received a Bachelor of Science degree in Petroleum and Natural Gas Engineering from Texas A & I University in 1952. I have continued my education by attending special schools and seminars presented by the Society of Petroleum Engineers (SPE), the International Association of Drilling Contractors (IADC), the American Petroleum Institute (API), Mineral Management Service (MMS), the United States Coast Guard (USCG) and the United States Occupational Safety and Health Administration (OSHA).

10.0 Disclaimer

The statements and opinions asserted in this report reflect my analysis of Texpet's methods of operation in the Concession area of Ecuador based upon my review of available information and materials for purposes of this arbitration. My report may be amended or supplemented if and when additional information becomes available to me, such as statements from other witnesses, and/or any relevant documents subsequently produced by any other involved entity, including any report or materials produced. I further reserve my right to create or have created for me additional drawings, photographs, video-recordings, animations or other demonstrative materials that depict information contained in this report or in any amendment or supplementation thereto.