INVESTIGATION OF THE OIL LEAK INCIDENT IN THE FRADE OIL FIELD

FINAL REPORT

OFFICE OF THE SUPERINTENDENT OF OPERATIONAL & ENVIRONMENTAL SAFETY - SSM

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Executive Summary

Oil leak during the drilling of Brazilian Offshore Well No. 9-FR-50DP-RJS, Frade Field

An accident is the result of a combination of operational defects, inappropriate managerial decisions and degraded safety barriers, which are termed causal factors upon establishment of an investigative process to determine the sequence of events that culminated in the occurrence of damage. In the case of carrying out O&G exploration and production, the regulatory agency is to employ methods and processes that ensure the prevention of operational accidents and to adopt technologies and procedures associated with the prevention of accidents, with a view to preventing the alignment of causal factors that result in the materialization of a damaging event, as well as mitigating the environmental damages that may occur.

Internationally, entities that regulate E&P activities and adopt up-to-date operational safety management techniques, such as occurs with ANP in Brazil, believe that the operator of the concession is the party responsible for conducting ongoing evaluation of its activities and making decisions to keep the level of risk of its operations as low as possible. For this reason, the regulations in effect in these countries grant operating companies considerable decision-making autonomy in the context of best industry practices, albeit with increased responsibility.

Hence, oil industry players, especially those engaged in drilling activities should analyze the contents of this document in detail and adopt any and all measures aimed at minimizing the re-occurrence of a similar event.

This report presents the results of the investigation, carried out in full by the technical team of the Brazilian National Petroleum, Natural Gas and Biofuels Agency (ANP), of the blowout that occurred in November 2011 in the Frade Oilfield as a result of the drilling activities of Brazilian Well No. 9-FR-50DP-RJS, operated by the Concession-holder Chevron Brasil Upstream Frade Ltda.

The ANP team sought to identify the causal factors of the blowout, specifying the managerial decisions and other actions on Chevron's part that gave cause to and/or aggravated the accident in question. The information obtained during the investigation is based on facts uncovered and records seized at the head offices of Chevron Brazil, on board the FPSO Frade and the Sedco 706 drillship, the latter being the property of the company Transocean do Brasil Ltda., which was drilling the well at the moment of the accident. After getting hold of these documents during the investigation, the ANP was able to analyze in detail the facts that occurred and identify the causes that gave rise to the leak, as set out below.

Accordingly, this document intends to fully reveal the facts to Brazilian society at large based on a detailed description of the occurrences that culminated in the leakage of roughly 3,700 barrels of crude oil into the sea, at a distance of around 120 km from the coast of the State of Rio de Janeiro.

The elements appraised and described in this report demonstrate in detailed fashion that the accident could have been avoided had Chevron Brasil Upstream Frade Ltda. conducted its operations in full compliance with the regulations, in conformity with best oil industry practices and in line with its own procedures manual.

In brief, during the course of drilling Well No. 9-FR-50DP-RJS, when the Concession-holder Chevron Brasil Upstream Frade Ltda. reached the upper section of reservoir N560, which was over-pressured due to the injection of water carried out in the area by the Concession-holder itself, it caused the kick event that initiated the polluting incident.

Once the kick was registered on board, the blow-out preventer (BOP) was shut down. The BOP is basically a set of valves that prevent the influx of fluids from the wellhead to the surface. The walls of the well were submitted to pressures greater than their limit of resistance. A fragile region, where the Chevron project did not call for casing (open well section), right below the final dead block failed to withstand the pressure and broke, causing an underground blowout (when fluids flow from the formation of one zone to the other). From then on, the petroleum began flowing from reservoir N560, running through the well to a depth of about 700 meters from the seabed, from where it migrated through the fractured formation during the Concession-holder's operations.

As Chevron placed the final dead block not very deep (just 600 meters from the seabed), the fluid from the underground blowout migrated until it reached the seabed.

Chevron was not capable of detecting the *underground blowout, even though there were strong indications of its* existence, such as the behavior of the pressures during the shutting down of the BOP; the severe losses of mud that occurred during the first attempts to control the *kick; and the appearance of an oil sheen of unknown origin just hours after the shut-in of the well. Had Chevron immediately identified the underground blowout, the volume of oil released into the sea would have been significantly lower.*

The occurrence of these three causal factors – kick; open well fracture; and migration of the oil to the bottom of the sea – led to the leaking of oil that occurred in the Frade Oilfield. During the course of the investigation, it was determined that Chevron committed both project and operational errors that contributed decisively to the occurrence of the accident and aggravation thereof. The accident could have been avoided had the company adopted safer measures by following its own procedures manual and ANP regulations.

Although 62 (sixty-two) wells have been drilled in the Frade Oilfield, 19 (nineteen) of them passing through the reservoir over-pressured thereby, Chevron indicated that it lacked knowledge of the local geology and fluid-dynamics, even to the point of alleging that one of the causes of the event was the unpredictability of the local geological characteristics. Such lack of knowledge meant that the company mistakenly estimated a pressure of 3,700 psi (9.4 ppg) in its models, when the pressures were actually between 4,003 psi (10.16 ppg) and 4,176 psi (10.6 ppg). This report demonstrates in a clear and unequivocal manner that the company had available sufficient data and information to conclude that the risk classification of the operations, in the manner that they were carried out, was intolerable.

Upon preparation of a well project, given the high degree of uncertainty involved in geological studies, all data available has to be considered in order to guarantee the safety of the operations, in that it is not uncommon for there to be a certain margin for error in the reservoir simulations. Data drawn from all other wells drilled in the same region, known as correlation wells, are the most important sources of information on the formations that are drilled.

During the investigations conducted by the ANP, based on data gathered at the concession-holder's offices and on the rigs, it was identified that in preparing the project for well No. 9-FR-50DP-RJS, Chevron disregarded information that was vital to minimizing the risk of fracturing the formation during the drilling operation, which in fact occurred and wound up causing the blowout followed by the leak at the bottom of the sea. The company ignored the formation resistance tests of 3 (three) correlation wells drilled in the Frade Oilfield in 2001, 2008 and 2009 that resulted in pressure gradients of between 10.1 and 10.3 ppg.

Had Chevron properly used all of the data available to define the criterion for kick tolerance, it would have mandatorily altered the project for the well in question, adopting sufficient safeguards for efficient reduction of the risk (for example, by increasing the depth for setting the dead block or increasing the number of phases), which would obviously have increased the time of the operation and the cost of the well in favor of a safety operation. As the pressure gradient of the formation that fractured was 10.23 ppg, use of an unreliable project on Chevron's part that failed to consider essential premises heightened the operational risk in a totally intolerable manner and could only culminate in fracture of the formation, which in fact took place.

Another finding that demonstrates, in a clear and unequivocal manner, Chevron's fault in evaluating the risk of its operations is the fact that the company used a 0.3 ppg pore pressure uncertainty in the case in question, which would only be applicable to development wells, where the risks of a kick due to reservoir overpressure are lower.

It happens that Well No. 9-FR-50DP-RJS was classified by Chevron as "special", that is to say, it was designed by the company to investigate a region of the reservoir surrounded by geological doubts. Moreover, this well had been designed to penetrate reservoir N560 at a point where simulation of the reservoir indicated over-pressurization. Although it declared to the ANP that it would drilling a type "9" well, that is to say a special one, Chevron only employed a kick tolerance for a development project, when the facts demonstrated that it should have considered an appraisal project.

Had the company adopted due precautions and correctly classified the well in question, uncertainty regarding the pressure of the pores to be used in the kick tolerance criterion would have been between 0.5 ppg and 1.0 ppg, which once again would give rise to the mandatory requirement to alter the project, increasing the depth of setting the dead block, increasing the number of phases or adopting complementary measures to reduce the risks to more tolerable levels.

Furthermore, by setting the final dead block just 600 (six hundred) meters from the seabed (which would not have occurred if Chevron had correctly evaluated the premises and adopted due precautions), the company heightened the risk of causing a fracture up to the surface in the case of facing an over-pressure situation. Indeed, literature available on well control[1] alerts emphatically that, in the event of an underground blowout at a depth of more than 3,000 feet (914 meters), it is highly probable that the fracturing of formations will reach the surface, chiefly in cases involving the seabed, which have very recent geological ages.

Yet even after identifying the influx of hydrocarbons into the well and the loss of circulation for the adjacent formations (on November 7, 2011), Chevron took two days to perceive that an underground blowout had occurred. Even the fact that Petrobras had noted an orphan oil sheen between the Roncador and Frade concessions on November 8, 2011 was not sufficient for Chevron to recognize the factual incidental scenario. As a result, the specialists from *Wild Well Control Inc.* (WWCI), a firm that specializes in well control, were only contracted on November 10, 2011, which increased to 6 (six) days the time required to control the blowout (November 13, 2011), increasing the volume of oil seeping out to a significant degree.

The project employed by the concession-holder for Well No. 9-FR-50DP-RJS, associated with the operating conditions, contributed to a situation where Chevron by itself did not manage to control the well. Attempts at bull heading (pumping in fluids to make the flow of hydrocarbons return to the formation) were insufficient, since the well's final dead block was set just 600 m from the seabed, the open well section was extremely long (1,450 m), the column was taken by fluid from the reservoir (more than 24 hours of flow from the reservoir to the well), the fracture point of the formation was unknown and, finally, use was made of mud with density below the pressure gradient of reservoir N560. Under such conditions, for the most part caused by errors made by the concession-holder itself, the chances of traditional well-control procedures were remote.

The low degree of perception of risks in planning and appraising the operations demonstrates the insufficiency of a safety culture that would emphasize carrying out activities in a safer manner and contributed significantly to a sequence of events that culminated in the spillage of oil into the sea.

Investigation Team

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Terms and Definitions

ANP : Brazilian National Petroleum, Natural Gas and Biofuels Agency;

Ballooning: Loss of mud to the formation and, after reduction of well pressure, return of fluid to the rig, similar to a *kick;*

BAP: Production Adaptor Base - Equipment installed in the well head for connection of the BOP or Christmas tree;

bbl : Barrel of petroleum, equivalent to 158,9873 liters;

BHA : *Bottom Hole Assembly* – Configuration and components at the bottom end of the drill pipe;

Blowout: Uncontrolled outflow of invasive fluid to the surface, sea floor or other formation;

BOP: *Blowout Preventer – set of valves that prevent the influx of fluids from the wellhead to the surface*;

Bull heading: Conventional well control technique that consists of pumping in mud, through the drill pipe or annulus, to force the kick fluid back to the formation;

CBL: *Cement Bounding Log* – appraisal of the cementing carried out in the well;

Downlink: Automatic procedure in which a negative pressurizer emits pressure oscillations by means of mud to communicate to the directional tool in the BHA;

DWT: *Deadweight tonnage* – Measured in metric tons (gross weight);

ECD: *Equivalent Circulation Density* – Weight of mud equivalent exercised at the bottom of the well. It is a function of the weight of mud and the loss of load in the annulus during mud circulation;

EMW: *Equivalent Mud Weight* (measured in ppg);

Caliper tool*:* instrument used to measure the width of the well based on depth;

FIT: *Formation Integrity Test* – Pressure test of the formation and dead block;

Float valve: Safety valve that prevents the upflow of fluid through the drill pipe;

Flow check: test conducted to check whether the well is flowing even with the mud pumps disconnected. It is used to confirm a *kick;*

FPSO: Floating oil production, storage and offloading units;

gpm: Gallons per minute – drilling discharge;

Kick: undesired influx of fluid from the formation to the well;

KOP: Kick-off Point – Gain in angle of a directional well;

gpm: Discharge unit – gallons per minute;

Water depth: Vertical depth between the ocean floor and the surface of the sea;

LCM: *Loss Circulation Materials* – Material used to combat the loss of fluids during a drilling operation;

Kill line: High-pressure pipeline that links the BOP on the well head to the pumping equipment in the drill, used to inject drilling fluid in the well head during kick control*;*

Choke line: High-pressure pipeline linked to the BOP stack, used to make fluids circulate from the kick to the surface to control the well;

LOT : *Leak Off Test* – Test of resistance of the formation and from the dead block to the beginning of the fracture;

LWD : *Logging while drilling* – Tool used in the BHA to log the well during drilling;

MD: Measured depth along the well, from the rotary chain (wale) of the drill;

Mud Tank: tank used to store fluids circulating during drilling, manufacturing or storing drilling or completion fluids.

MW: *Mud Weight* – measured in ppg;

MWD: *Measurement while drilling* – Tool used in the BHA to appraise the geometric parameters of the well (depth, inclination and azimuth) and its physical properties during drilling;

Exploratory wells: Wells drilled for the main objective of producing petroleum;

Pioneer wells: Wells drill for the purpose of studying the formations they

perforate;

ppg: Pounds per gallon - unit for measuring density;

PWD Stethoscope: Tool that measures pressures during well drilling;

ROV: Remotely operated vehicles (underwater);

Dead block: Final and cemented portion of each casing;

Shut in: Shut-in of the well by means of the BOP;

Sidetrack: Sideways deviation of an already drilled well, generally for construction of a directional well;

SICP: Shut-in casing pressure (of the annulus);

SIDPP: Shut-in drill pipe pressure;

Space out: Procedure used to leave the drill pipe adequately positioned for possible shearing of the BOP;

spm: *Strokes per minute* – unit used to measure mud pump discharge;

TOC: *Top of cement*- Position found after a cementing operation;

Tractor: Equipment used to guide the tools that measure pressure and inside the drill pipe;

Trip Tank: Tank used to check on loss or gain of fluids during the maneuvering of the drill pipe. It is also used to check if the well is gaining mud during the *flow check and with this the* existence of a *kick;*

TVD: *Total vertical depth* – vertical depth from the rotary chain (wale) of the drill;

Underground blowout: Uncontrolled outflow of invasive fluid to another formation;

VLCC: *Very Large Crude Carrier*- Oil tanker with gross weight (deadweight tonnage) of between 200 and 300 thousand DWT;

Washout: Region of the well with expanded diameter, the result of washing in a section of an open well;

Xline *(cross line):* Vertical cut of a seismic survey, showing the respective cut plane; and

$AP_{annulus}$: Loss of load on the annulus.

1. Introduction

On November 7, 2011, during the drilling of Brazilian Well No. 9-FR-50DP-RJS by the Sedco 706 drillship operated by the firm Transocean, there was an incident where control over the well was lost. The incident is known in the oil industry as a kick (undesired influx of fluids from the formation to the well), followed by a blowout (uncontrolled outflow of invasive fluid to the surface, sea floor or other formation). Subsequently, there occurred migration of hydrocarbons through the formation, occasioning the seeping of petroleum onto the seabed, at a distance of around 120 km (one hundred and twenty kilometers) from the coast of the State of Rio de Janeiro, in the Campos Basin in Southeast Brazil. The drill was in the service of Chevron Brasil Upstream Frade Ltda., the operator of the Frade Oil Field Concession.

The ANP calculated that the volume of oil leaking into the sea reached a total of around 3,700 barrels, although there is still seepage of smaller volumes of petroleum into the sea as of the shut-in of this report.

1.1. The Frade Oil Field

Concession Contract No. 48000.0038969720 for the Frade Oil Field presently involves as concession-operators Chevron Brasil Upstream Frade Ltda., the operator of the concession, which has a 51.7% share in the consortium, Petróleo Brasileiro S/A (Petrobras) with 30% and Frade Japão Petróleo Ltda. with the remaining 18.3%.

The Frade Oil Field was discovered in December 1986 by Petrobras with the drilling of Brazilian Well No. 1-RJS-366. A subsequent appraisal well, No. 3-RJS-416, was drilled in 1989. In October of 1996 pioneer well No. 1-RJS-511 discovered an additional accumulation of petroleum southwest of the principal structure. As from institution of the concession system in Brazil, there were assignments of emerging rights from the exploration and production (E&P) contracts, up to the point where the current configuration of the consortium was reached. Production from the field began on June 20, 2009, with termination slated for the year 2025.

The Frade Oil Field is located in the Campos Basin, State of Rio de Janeiro, facing the Roncador Oil Field, which is under Petrobras concession. The distance to the shoreline of the Municipality of Campos dos Goytacazes is approximately 113 km. The water depth is around 1,100 meters and the current area of the Field is 154.1 km2.

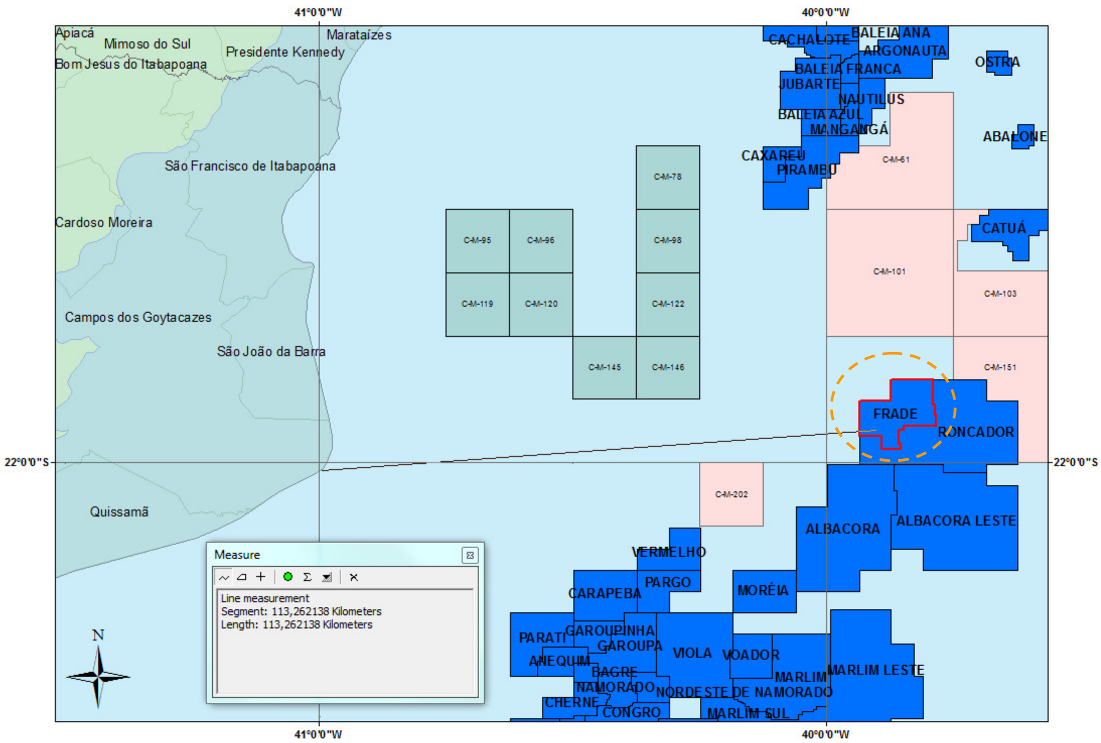

Figure 1 – Location of the Frade Oil Field

At present there are 62 wells drilled in the field, including pioneer, extension and adjacent pioneer (exploratory), production and injection (exploratory) wells, and special wells besides. On the date of the accident (November 7, 2011) there were 11 production wells (10 in operation), besides 4 water injection wells, with one of them, precisely the injector well for reservoir N560, was closed due to operational problems, just 3 days before commencement of drilling of Well No. 9-FR-50DP-RJS. Average daily production on the date in question was distributed as follows: 11,170 m3/day or 70,258 bbl/day of petroleum; 860 Mm3/day of gas; and 2,035 m3/day or 12,800 bbl/day of water. The petroleum produced was on average 20°API.

1.2. Well No. 9-FR-50DP-RJS

Well No. 9-FR-50DP-RJS is classified as "special", directional and shared (sidetrack of Well No. 9-FR-46D-RJS). The well in question was part of an investigative program to ascertain the best location for a future producer well, and drilling began at 10:30 AM on November 6, 2011, in water depth of 1,184 m. The objective was reservoir N545, passing through reservoirs N560 and N570. The final average depth forecast would have been 3,835.9 m (MD) (2,550.0 m TVD), which was not reached due to the accident.

Among all the wells already drilled in the area, Well No. 9-FR-50DP-RJS would pass through reservoir N560 at the closest point to the injector well for this reservoir, in a region presumably over-pressurized due to the injection of water carried out by Chevron itself.

1.3. Description of the maritime installations that operate in the Frade Oil Field

1.3.1. Sedco 706 drillship

The drillship that drilled Well No. 9-FR-50DP-RJS was the SEDCO 706 (Figure 2), operated by the company Transocean do Brasil Ltda. The drillship is a second generation unit of the semi-submersible type, with dynamic positioning.

Well No. 9-FR-50DP-RJS was the 43th well drilled by this drillship in Brazilian jurisdictional Waters. The unit was built in 1976, converted in 1994 and modernized in 2007. In can operate in water depths of up to 1,980 meters and has maximum drilling capacity of 6,600 meters.

Figure 2 - Sedco 706 drillship, operated by Transocean.

The blow-out preventer (BOP), the safety equipment installed in the well head, was made by the manufacturing firm Cameron. It is a "U" type BOP with internal dimension of **18 ¾"** and capacity to withstand maximum pressure of 10,000 psi. It has 4 slide valves: the upper one is a 5" blind shear, followed by a variable slide valve of **3 ½" a 5 ½",** beneath that is a 9 5/8" pipe slide valve and another variable slide valve of **3 ½" to 5 ½".**

1.3.2. FPSO Frade

The FPSO Frade vessel was developed for full processing of the oil, gas and water from the Frade Oil Field. Its construction was carried out based on the tanker vessel 273,567 DWT VLCC "Lu San", which was converted based on re-fabrication of the existing structures and through construction of modules above the floating line, besides addition of an internal system of anchoring by tower and other marine equipment. The FPSO vessel in question was classified by the American Bureau of Shipping as category A1 – Floating production, storage and offloading system, RFL (20) - 2028, Campos Basin, Brazil, *MAS, UWILD.

The arrangement below shows the general outlay of the FPSO. The vessel consists mainly of a crude oil storage tank, transfer connection (offloading) point, accommodations, heli-deck, services and utilities.

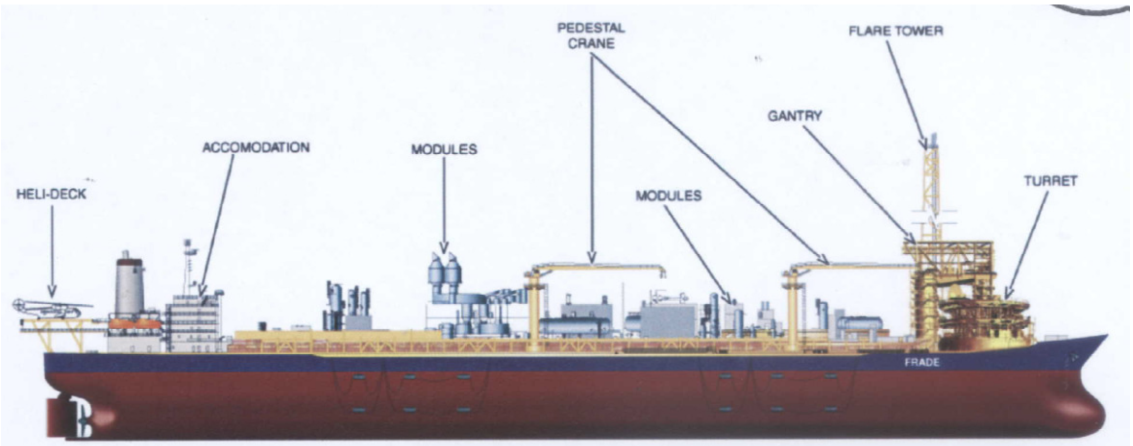

Figure 3 - FPSO Frade

The chief characteristics of the FPSO Frade are: total length of 337 meters; total breadth of 54.5 meters; hold depth of 27 meters; draft of 21.04 meters; deadweight of 273,567 t;

lightweight of 39,405 t; single-cast type hull; gross storage capacity of 100,000 barrels of crude; water storage capacity of 100,000 barrels.

The FPSO vessel in question was designed for 18 years of use and classified for uninterrupted service throughout this entire period. Field appraisals are conducted for the purpose of maintaining this classification.

1.4. Relevant information on the geological structures drilled by the well

A normal post-depositional fault divides the Frade Oil Field into two main isolated fault blocks (upper sector and lower sector). The faulting model, generated by movement of the underlying saline section, makes the existence of secondary faults natural. The field has 4 (four) vertically piled up reservoirs from the Oligocene and Miocene epochs, denominated N570, N560, N545/N547 and N540, containing poorly sectioned unconsolidated arcosic sandstone, with moderate porosity and high permeability.

Reservoir N560 is a narrow body that is around 2 km in length and 40 meters thick. At the time of the incident, the reservoir was producing through wells 7-FR-15HP-RJS (Chevron Nomenclature N5P1) and 7-FR-34HP-RJS (Chevron Nomenclature ODP3). The pressure of the reservoir was maintained by means of injection in Well No. 8-FR-29D-RJS (Chevron Nomenclature 8-FR-29D-RJS-N560), with injection pressure gradient of around 13.4 ppg. Water injection was suspended four days before the incident on February 3, 2011, due to operational problems in the injection system for this well, on the FPSO Frade.

Above reservoir N560 there are sealing rocks, Oligo-Myocene stratified clayish rocks that are 60 to 120 meters thick, separating reservoirs N560 and the already depleted

N570. The rocks located above reservoir N570 have faults and structures with fracture gradients that can reach minimum values of 10.3 ppg. Originally, the reservoirs of the Frade Oil Field featured a normal pore pressure gradient (8.6 ppg).

Figure 4 on the next page shows the interpretation, based on processed seismic data, of the geological behavior of the formations near N560. Then Figure 5 presents the interpretation of the top of the structure of reservoir N560, in a seismic section picked up in the course of an inspection at Chevron, indicating the point at which well 9-FR-50DP-RJS (MUP1-P-ST2) perforated this reservoir and the distance thereof to producer wells 7-FR-34HP-RJS (ODP3) and 7-FR-15HP-RJS (N5P1) and to injector well 8-**FR-29D-RJS (N5I1).**

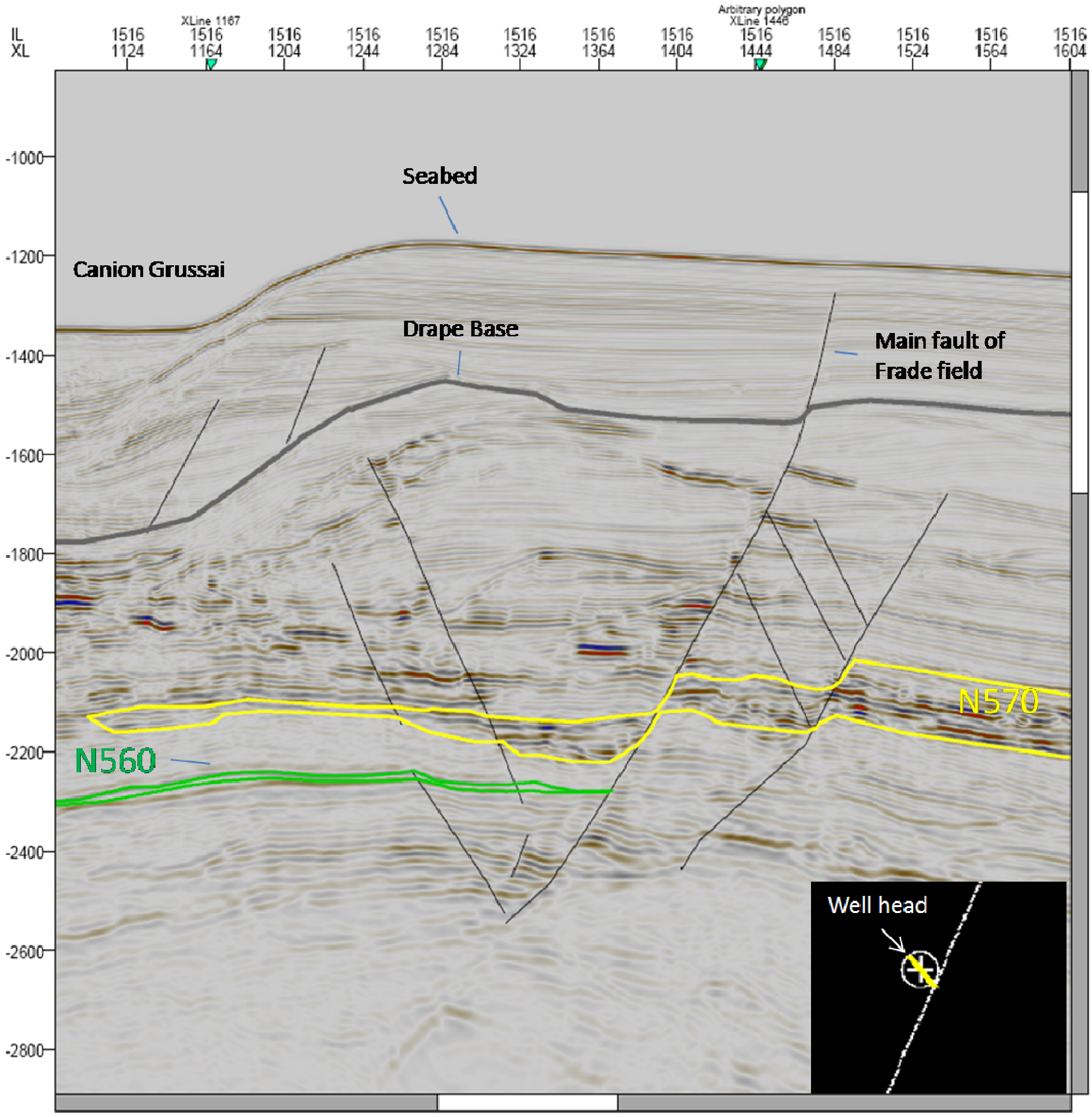

Figure 4 - Xline 1516 of the seismic survey of the region surrounding reservoir N560.

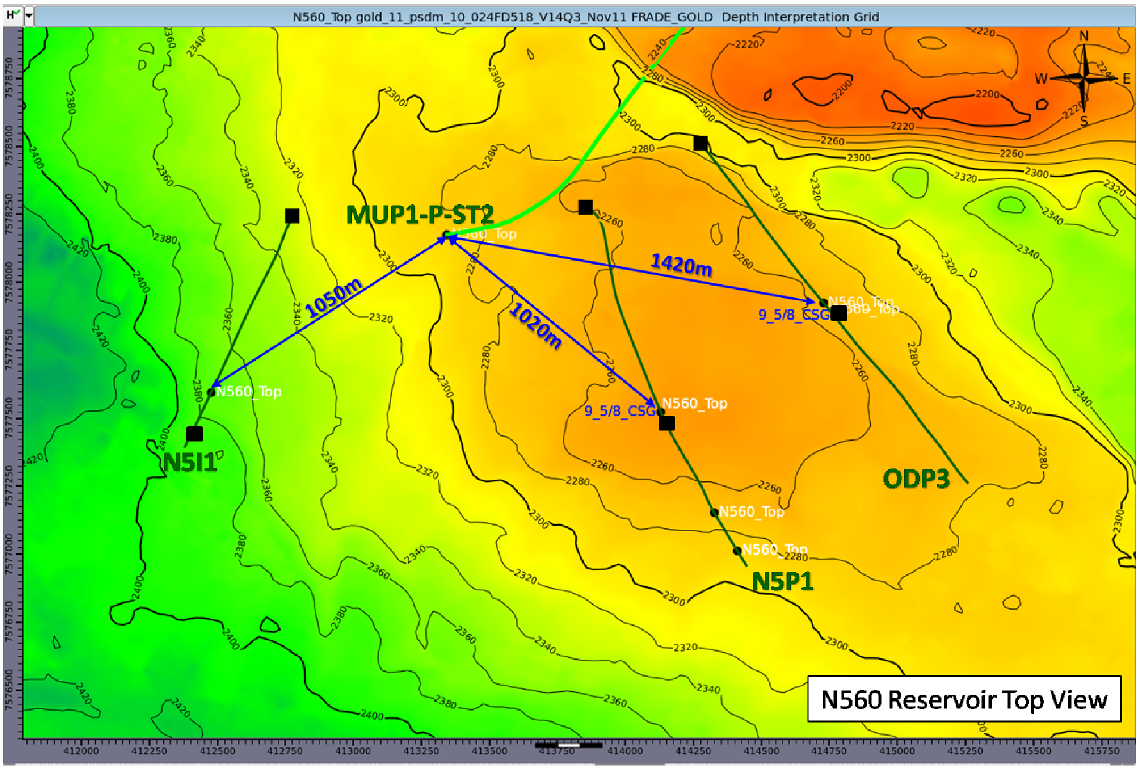

Figure 5 -View of the top of the structure of reservoir N-560, indicating the distance between the point at which Well No. 9-FR-50DP-RJS (MUP1-P-ST2) perforated this reservoir and production wells 7-FR-34HP-RJS (ODP3) and 7-FR-15HP-RJS (N5P1), besides injection

2. Description of the Incident

2.1. Chronology

The following is a description of the facts uncovered by the investigation as significant for understanding the factors that determined the occurrence of the incident of November 7, 2011 (the period covered is from August to November of 2011). The events have been divided into two sequences of events, as follows:

Period prior to the incident; and

Period after beginning of the incident.

The information that comprises the chronology or timetable of the incident was gathered based on records and information seized from the Sedco 706 drillship, the FPSO Frade vessel and the offices of Chevron in Rio de Janeiro, during the ANP inspection activities.

***Table I** – Chronology of the incident.*

Period prior to the incident		
Date	**Time**	**Occurrence**
08/03/2011	-	Beginning of drilling of well 9-FR-46D-RJS.
08/07/2011	-	Conclusion of descent of 13 3/8" casing and cementing with return to seabed. The drillship left the location and returned on September 16, 2011.
10/09/2011	01h30	Beginning of descent of the BOP.
10/12/2011	07h00	Top of cement (TOC) position verified at 1,818 m (MD).
10/13/2011	04h30	Cementing of dead block drilled and another 6 meters of formation, between 1,830 and 1,850 meters (MD), with a 8 1/2" drill bit.
10/13/2011	07h00	Leak off test (LOT) conducted and value of 10.6 ppg arrived at.
10/13/2011	20h30	After penetrating the hard region at 2,111 meters (MD) and after carrying out the connection of a new section at 2,123 m (MD), it was not possible to re-establish circulation. Sixty-one (61) bbl were lost to the formation during the attempt at recirculation and 40 bbl de LCM *(Loss Circulation Materials) were added. In the following days, around* 100 bbl/day were lost to the formation, up to the termination of drilling of this first well.

Period prior to the incident		
Date	**Time**	**Occurrence**
10/22/2011		Procedures were begun to abandon well 9-FR-46D-RJS, with placement of cement covers Nos. 1, 2 and 3.
10/22/2011	23h00	A loss of 28 bbl followed by a gain of 8 bbl was noted. The flow check identified a gain of 7 bbl in 5 min. The well was shut down at 11:20 PM and ballooning was identified.
10/23/2011	-	Cement covers Nos. 4 and 5 were installed, designed for top of cement (TOC) at 2,040 m (MD) and kick-off point (KOP) cover between 2,040 and 1,784 m (MD).
10/24/2011	11h00	It was identified that the top of cement (TOC) for the KOP was at 1,958 m (MD). (TOC slated for 1,784m (MD)).
10/24/2011	13h00	Drilling begun on well 9-FR-49D-RJS, the first sidetrack of well 9-FR-46D-RJS from 1,850 to 1,859 m (MD), without cementing being performed down to the slated TOC of 1,784 m (MD).
10/25/2011	-	Re-entry down to 1,859m (MD), when obstruction was encountered in the well. The drill pipe down to 1,845 m (MD) was withdrawn and the column was slowly lowered, managing to arrive at 1,880 m (MD). Even so, it was ascertained that they were in the wrong sidetrack, thus returning to 1,850 m and seeking the desired sidetrack. Drilling was done down to 2.519 m (MD). After connection of the next section, circulation of drilling mud was not achieved, with the column being worked above the problem region and mud circulation being normalized. A total of 56 bbl of mud was lost in the previous 24 hours.
10/26/2011	-	Drilling of well 9-FR-49D-RJS continued, with loss of around 240 bbl of mud per day. The losses were battled by means of 40 or 50 bbl of LCM *(Loss Circulation Materials),* on which occasions they were identified. Losses of mud to the formation were also observed during well abandonment, to the tune of roughly 50 bbl.
11/06/2011	10h30	Beginning of drilling of well 9-FR-50DP-RJS, the second sidetrack of well 9-FR-46D-RJS. Loss of 40 bbl in 24 hours.

Period after beginning of the incident		
Time	**Date**	**Occurrence**
11/07/2011	13h30	First observation of kick: observation of gain of 4 bbl during drilling of the 8 1/2" sine-shaped section of the well. (3,329 m (MD), after 272 m drilled in this well). After the pumps were shut down and the flow test conducted, a gain of 14 bbl was noted in 4 min. The well was shut down in the preventer annulus of the BOP. Mud density was 9.5 ppg.
11/07/2011	14h30	Attempt to circle the kick by means of the sounder method. A total of 115 bbl were pumped but only 3 bbl were received back (loss of 112 bbl – Indications of fracture of the formation).
11/08/2011	10h00	Petrobras (operator of the nearby Roncador Oil Field) observed an oil sheen of unknown origin.
11/08/2011	15h30	After 3 unsuccessful attempts to kill the well by using the sounder method, the weight of the mud was raised to 10.1 ppg.
11/08/2011	17h30	Decision was made to initiate bull heading procedures in the well.
11/08/2011	19h00	Bull heading began at 30 spm (thirty strokes per minute). There was a total of 2 bull heading operations lasting two and a half hours each attempt and loss of 850 bbl to the formation in a period of 24 hours.
11/09/2011	03h30	The third bull heading procedure was carried out, completing the planned operation. Pressures were monitored.
11/09/2011	10h00	During circulation of the kill line to the choke line, traces of oil were encountered in the mud tank, indicating that the well was not yet dead.
11/09/2011	14h00	By means of its ROV, Chevron identified a flow of oil at the bottom of the ocean, near Well No. 9-FR-50DP-RJS.
11/09/2011	18h30	The well was opened and monitored in the trip tank. Loss of one hundred twenty barrels (120 bbl) in Just one (1) hour was noted.
11/10/2011	-	Monitoring of the well continued, completing the well with drilling fluid (loss to the formation). A total of ninety-seven barrels (97 bbl) was lost in a 24-hour period.
11/10/2011	Wee hours of the morning	Wild Well Control (WWCI), a firm specializing in well control, is contacted by Chevron.

Period after beginning of the incident		
Time	**Date**	**Occurrence**
11/11/2011	0h00 to 24h00	Round-the-clock monitoring of the well continued, completing the well with drilling fluid (loss to the formation). Loss of 84 bbl in a period of 24 hours.
11/12/2011	-	Round-the-clock monitoring of the well continued, completing the well with drilling fluid (loss to the formation). Loss of 79 bbl in a period of 24 hours.
11/12/2011	morning	Team dispatched by Wild Well Control arrives at the offices of Chevron.
11/13/2011	01h30	End of run of the first logging of temperature and pressure carried out to ascertain the fracture point of the well.
11/13/2011	18h30	Dynamic kill procedure initiated an hour and a half after arrival of the WWCI team at the drill (which occurred at 5:00 PM).
11/14/2011	-	A new logging was taken of the pressure and temperature after the dynamic kill procedure, indicating that the influx from reservoir N560 to the well was controlled.
11/16/2011	01h00	Completion of the annulus with 10.1 ppg mud continued, as did completion of the column with 13.9 ppg mud. Schlumberger identified the level of fluid in the drill pipe at 382 m (in the previous appraisal it was identified at 428 m).
11/17/2011	-	Chevron pumped the cement of the first cover and waited for it to take hold.
11/19/2011	15h00	Descent of the Welltec tractor with Schlumberger caliper and temperature tool down to 3,155 m (MD). Once again the temperature log shows indications that the well was dead.

Appraisal of the quality and technical procedures of definitive abandonment of well 9-FR-50DP-RJS, which was only concluded on February 12, 2012, is the object of an independent Administrative Proceeding, which is not part of the scope of the investigation of the accident.

2.2. Description of the Causal Factors

The flow chart (or “tree”) of flaws, illustrated in Figure 6 below, was drawn up by the investigation team based on the path percolated by the fluid in the structures existing between reservoir N560 and the seabed. Accordingly, we note the following paths and interfaces for the flow of oil: point of penetration of the drill bit in N560; unlined portion of well 9-FR-50DP-RJS; fracture point on the wall of the well; structures adjacent to the fracture and/or side of the 13 3/8" cementing; surface geological formations and seabed.

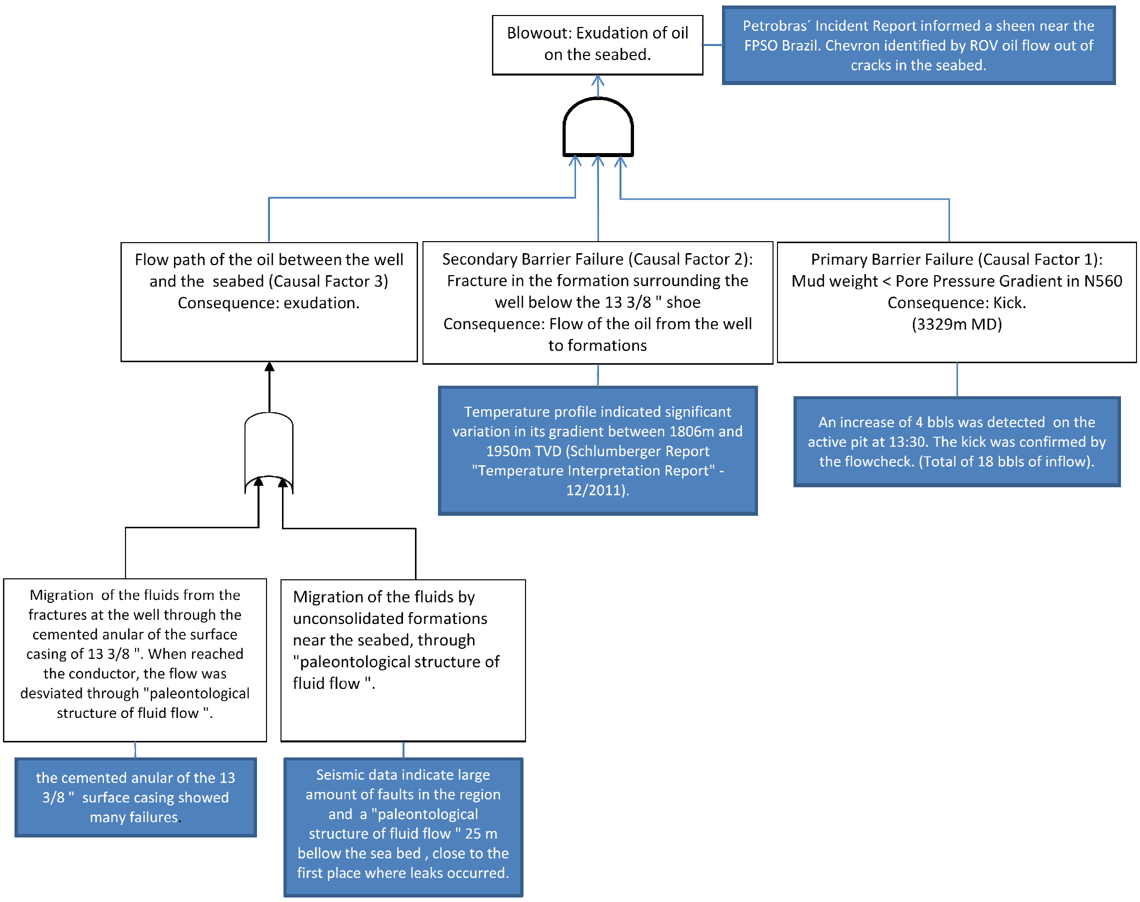

Figure 6 – Flow chart of flaws leading to seepage of oil to the seabed.

The physical limits of the investigation were defined by the region between the reservoir N560, inclusive, and the seabed, at the spots where the seepage took place.

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The line of the investigation was based on the faults of the primary and secondary barriers and on the aggravation of the incident, related to the migration of the fluid from the formations adjacent to the fracture to the seabed, as can be seen in Figure 7 below.

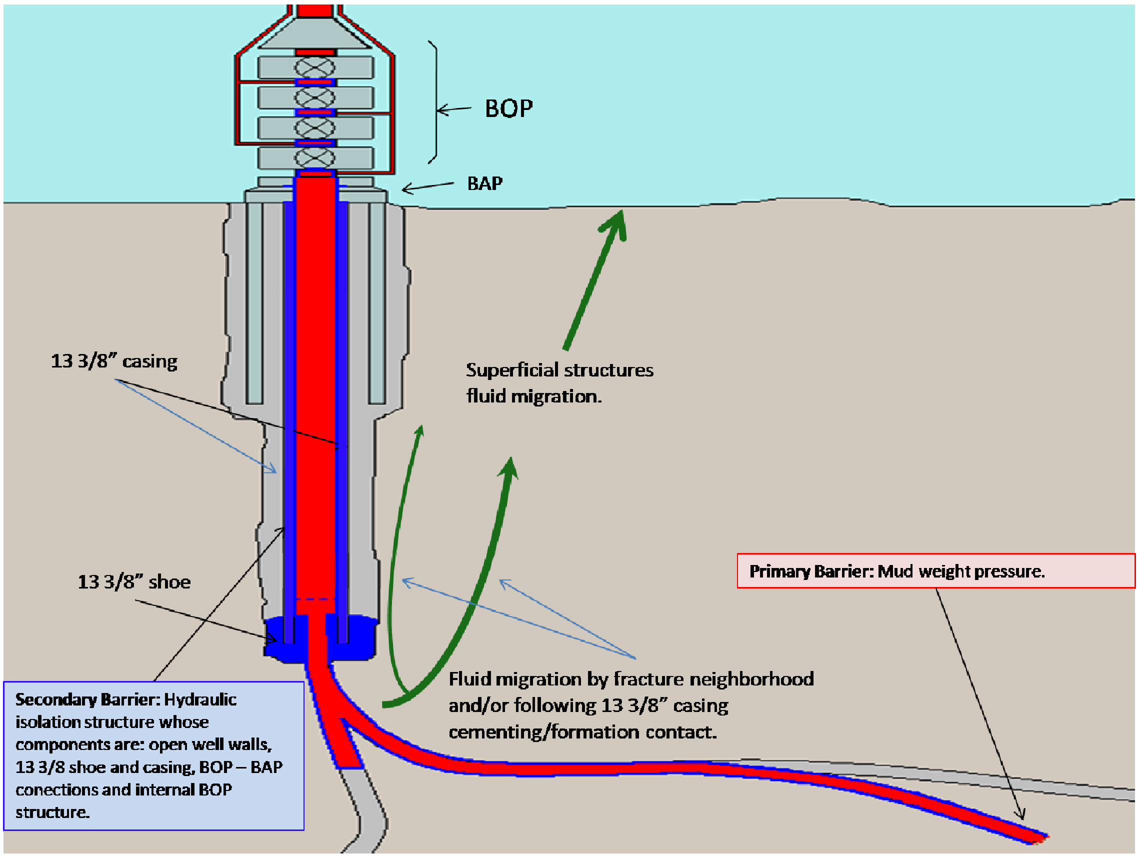

Figure 7 – Well safety barriers and migration through the geological formations.

During the drilling of well 9-FR-50DP-RJS, when the drill bit reached reservoir N560, pore pressure gradient that was greater than the equivalent mud weight was encountered. At that point, the first barrier, formed by the hydrostatic of the weight of the drilling mud broke down, permitting the formation fluids to penetrate the well (kick), this being the first causal factor of the accident.

The above statement was confirmed around 1:30 PM on November 7, 2011, when a gain of 4 barrels was identified in the active mud tank. The pumps were shut down and a flow check was conducted. It was then noted that there was a gain of another 14 barrels in the trip tank in just 4 minutes, as illustrated in Figure 8 which follows, a fact that confirmed the kick and led to the shutdown of the BOP.

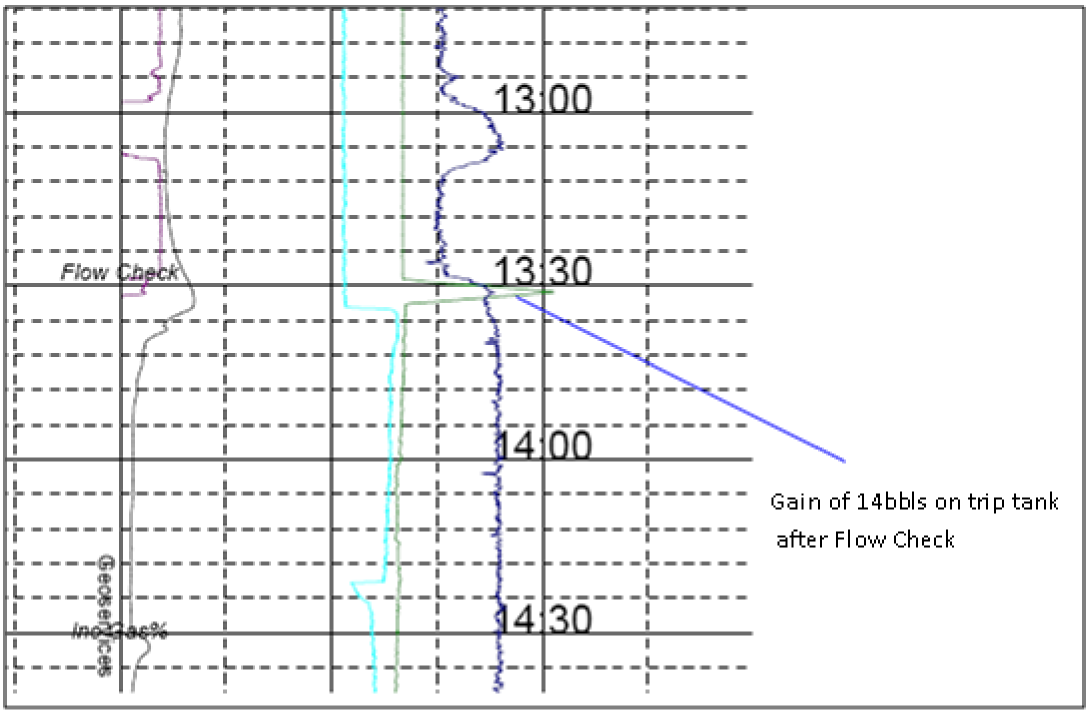

Figure 8 – Evidence of the mud-logger chart at the moment of the flow check.

The second causal factor was the breakdown of the secondary barrier, in this case constituted by the walls of the open well, dead block of 13 3/8" and casing of 13 3/8", which permitted the fluid from reservoir N560 to migrate from well 9-FR-50DP-RJS to the formations adjacent to it.

The above statement was confirmed by the measurement of the temperature log carried out along the well, through the running of a tool inside the drill pipe on November 13, 2011, as described in detail in item 3.2.2. It can be confirmed that the section between 1,830 and 1,960 m (TVD), in the region of open well right beneath the 13 3/8" dead

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block, was the one with the highest temperature gradient. This evidence demonstrates the occurrence of an underground blowout in this section.

The third causal factor is the patch taken by the fluids from the point of fracture to the seabed. Two hypotheses are pointed to, and they are not mutually exclusive: a) flow through flaws in the 13 3/8" cement casing to a region near the conductor guide and from there through unconsolidated structures; and/or b) flow through fractures caused by the Chevron operation that connect the well to flaws in the adjacent geological structures that were activated by the pressurization of the well.

3. Analysis of the Causal Factors

3.1. Causal Factor 1 - Occurrence of the kick

The drilling of Well No. 9-FR-50DP-RJS was begun on November 6, 2011, with 9.2 ppg density mud, being thickened to 9.5 ppg for the drilling of reservoir N-560. The sidetrack (deviation of well 9-FR-49DP-RJS) was carried out from 2,664 to 2,687 m (MD), with the drilling of the sine wave section thereafter, employing an 8 1/2" drill bit. The last dead block was that of the 13 3/8" casing, located at 1,834 m (MD) or 1,806 m (TVD). The absorption or leak-off test (LOT), used to determine the resistance or pressure of a formation fracture, was conducted at 1,850 m (MD) on October 13, 2011, when the drilling of well 9-FR-46DP-RJS had a fraction gradient of 10.57 ppg.

On November 7, 2011, continuing drilling in the sine wave section, the top and base of reservoir N570 [2,968 m (MD) and 3,027 m (MD), respectively] were penetrated. Chevron's forecast was that it had been depleted between -600 and -300 psi.

When reservoir N560 (top slated at 3,319 m MD) was being perforated, a 4 bbl kick was detected on the drillship. According to Chevron's modeling, this section of the reservoir was slated to have formation pressure of from -100 psi (depleted) to +300 psi (mud weight equivalent to 9.4 ppg). Thereupon, a flow check was conducted and a gain of approximately 14 barrels in 4 minutes was detected, thus confirming the kick. The well was then shut down in the upper annulus of the BOP. The shut-in pressures in the annulus (SICP) and drill pipe (SIDPP) were monitored in order to calculate circulation of the kick, and the shut-in pressure was monitored by the pressure sensor installed in the BOP.

Analysis of the documentation gathered during the course of the inspections indicated that at approximately 1:21 PM on November 7, 2011, the downlink of the directional tool was begun, giving rise to a variation in the discharge of the circulation mud and, consequently, of the ECD

(Equivalent Circulation Density) during drilling. The on-board logs indicate that during execution of this downlink, there was a rise in the level of the active mud tank, indicating the occurrence of a kick, as illustrated in Figure 9 below:

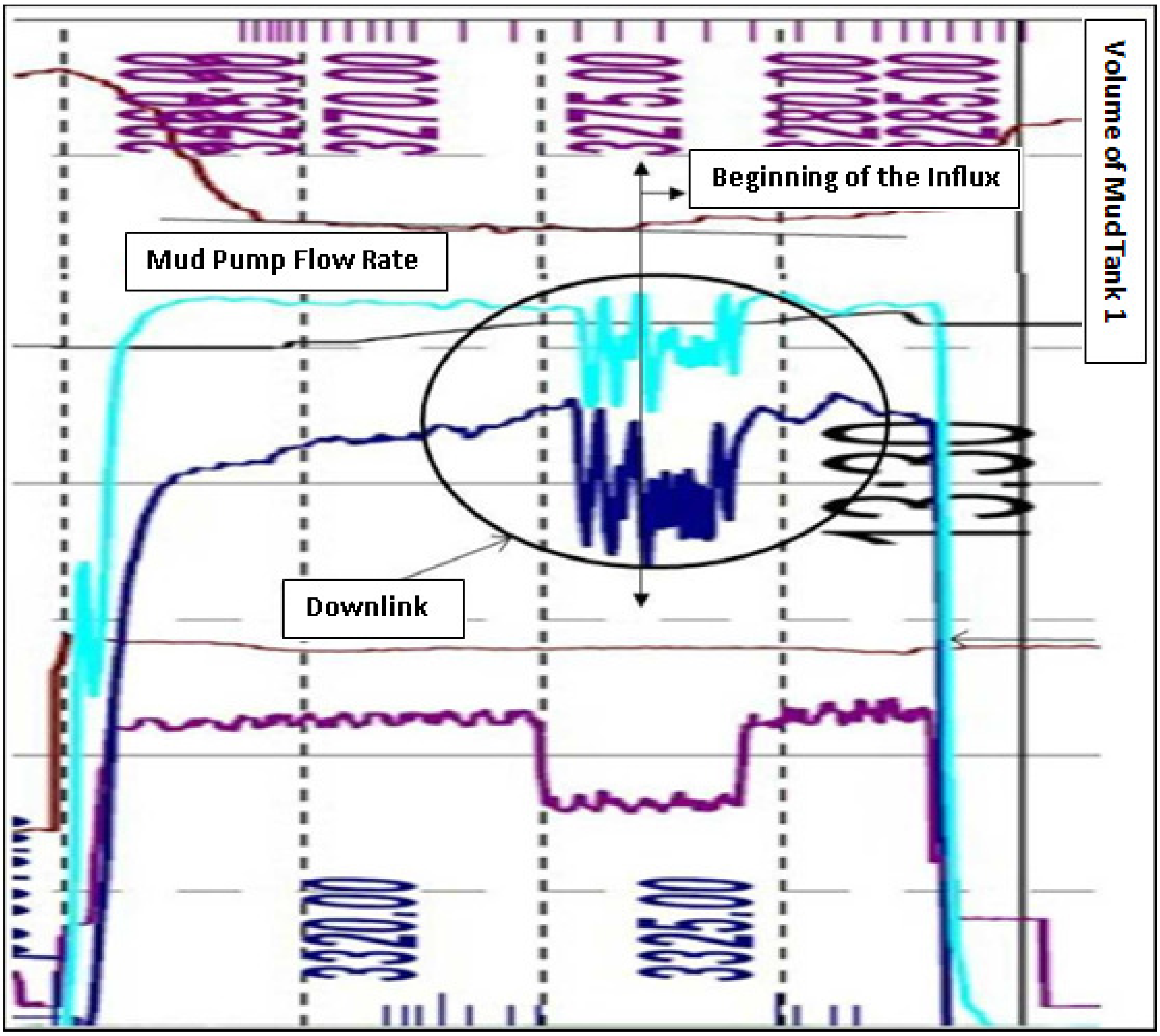

Figure 9 - Mud-logger tracking data illustrating that, after the beginning of the downlink, there is a rise in the active tank volume (indicative of a kick).

Once a rise of 4 bbl in the active mud tank was detected by the sounder (drillship), well shut-in procedures were begun, through positioning of the drill pipe in the BOP (space-out). Then, the mud pumps were turned off and the flow was directed to the trip tank in order to conduct the flow check. A gain of 14 bbl was noted, bringing the total influx gain to 18 bbl. The well was closed by the upper annulus, using what is termed a hard shut-in procedure in the oil industry.

The drill pipe was equipped with a float valve and the shut-in pressures were monitored. Table II below shows the tracking of the shut-in pressures.

***Table II** – Shut-in pressures of the annulus (SICP) and drill pipe (SIDPP).*

Time	SIDPP (psi)	SICP (psi)
1:35 PM	177	150
1:40 PM	190	150
1:45 PM	190	140
1:50 PM	180	130
1:55 PM	165	130
2:00 PM	144	130
2:05 PM	147	130
2:10 PM	112	130
2:15 PM	81	120
2:20 PM	103	120
2:25 PM	87	90
2:30 PM	Bleed to 0 psi	90
2:35 PM	0	90

The loggings of these shut-in pressures show atypical behavior, in which the SICP is lower than the SIDPP. This matter will be dealt with in item 3.2.1.

At 2:40 PM, the first circulation attempt was made using the sounder method, which did not work out, since virtually no return was observed. 110 barrels of mud were pumped at a discharge rate of 30 spm (3 bbl/min), with initial circulation pressure of 360 psi, resulting in a return of 5 bbl. Upon opening of 1/8 of the choke line valve, the annulus pressure dropped from 90 psi to 20 psi, remaining constant for any alteration in the opening or shut-in of this valve. An attempt was made to reduce the discharge of the pump, based on expectations of obtaining return to the surface, but this likewise proved to be unsuccessful.

On November 8, 2011, an additional 3 (three) attempts were made to achieve circulation through the sounder method, but all were unsuccessful. At 3:30 AM, the drilling team began to increase the weight of the mud to 10.1 ppg and to prepare the high viscosity (Hi Vis) pills and LCM (Loss Circulation Material), in order to combat the loss of circulation. At 5:30 PM, the decision was made to carry out a bull heading operation, with mud weight of 10.1 ppg. The procedure to kill the well through bull heading was begun at 7:00 PM on the 8th and finalized at 3:30 AM in the morning of the following day, November 9, 2011.

According to the daily drilling bulletin for November 9, 2011, at 10:00 AM 128 bbl of 10.1 ppg density drilling fluid was circulated through the choke line and returned through the kill line, with traces of oil being identified, which would be a strong indication that the bull heading operation was also unsuccessful.

Previously, at 10:00 AM on November 8, 2011, an orphan oil sheen was identified by Petrobras between the Frade and Roncador oil fields. **Nevertheless, despite the evident signals that were cropping up, the seepage on the seabed was only confirmed by Chevron at 2:00 PM on the next day, November 9, 2011, by means of footing filmed by the ROV submarine,** with the accident taking shape as an underground blowout.

On November 10, 2011, the company Wild Well Control Inc. (WWCI), which has a service agreement signed with Chevron entitled the Well Control Emergency Response

Plan, was contracted to control the underground blowout. This document establishes that the underground blowout should be treated as a level 3 response situation, **requiring the immediate consultation and mobilization of WWCI by Chevron, evidently behind schedule due to its inability to recognize the scenario.** Right away, then, planning was begun to kill the well using dynamic kill techniques, and WWCI's technicians were mobilized to come to Brazil to supervise the underground blowout control operations.

On November 12, 2011, a run was made with tools inside the drill pipe to check on the temperature and pressure profiles, with the formation fracture point being identified at approximately 1,860 m (TVD). WWCI's technicians arrived in Brazil on this same Day. The well temperature logging operation was completed in the early morning of November 13, 2011.

The dynamic kill procedures were begun on November 13, 2011, with 13.9 ppg weight mud being pumped through the drill pipe, while the level of mud being maintained at 10.1 ppg in the annulus, thus obtaining a mud weight equivalent of 10.7 ppg at the bottom of the well, this being the mud weight established by Chevron. Previously, the bull heading operation had been carried out with mud weight of 10.1 ppg.

The runs with tools to log the temperature performed as from November 13, 2011 indicated the success of the dynamic kill procedure in killing off the well.

Accordingly, it is now possible to summarize the facts arising from the first Causal Factor:

1) There was an influx to the well (kick) - Gains in the active mud tank and in the flow check;

2) The initial influx occurred during the carrying out of the downlink, which caused a temporary reduction in the ECD (Equivalent Circulation Density) that sufficed for the latter to be lower than the pressure of the reservoir, causing an influx to the well (kick);

3) The shutdown of the mud pumps exposed the pressure of the reservoir to just the hydrostatic pressure of the mud, and the flow check result evidenced that this was below the pressure of the reservoir;

4) The intensity of the influx (difference between the pressure of the reservoir and the hydrostatic pressure of the mud) caused the fracture of a formation adjacent to the well almost immediately upon the shut-in of the BOP, establishing an outlet route for the fluids of reservoir N560, causing loss of drilling fluid circulation to the rig and making any and all procedures attempting to circulate the influx to kill the well through the sounder method ineffective;

5) Thus, an underground blowout situation was confirmed;

6) According to the Well Control Emergency Response Plan, an underground blowout is to be treated as a level 3 response event and requires immediate consultation and mobilization of WWCI by Chevron. The incident began on November 7, 2011, but WWCI was only contacted on November 10, 2011, indicating that Chevron delayed perceiving that it was faced with an underground blowout situation; and

7) The influx of fluid to the interior portion of the well (kick) came from formation N-560, indicating that the pressure of the reservoir was higher than that predicted by Chevron's modeling. At this point, the portion of the open

well after the 13 3/8" dead block had an extension of 1,485 m (MD), passing through the top and base of the depleted reservoir N-570.

3.1.1. Estimate of reservoir pressure

The reservoir modeling carried out by Chevron erroneously indicated a worse scenario of over-pressure of 300 psi above the normal reservoir pressure, equivalent to the pressure gradient of 9.4 ppg. Relying just on the modeling, naturally riddled with uncertainties, Chevron decided to drill with mud of 9.5 ppg, which caused the influx from the reservoir to the well, since the pressure of the pores was obviously higher than the weight of the mud.

The following are descriptions of the three methodologies used during investigation of the accident to evaluate the reservoir pressure.

Method 1: Pressure trapped in the drill pipe.

Upon the event of a kick, the shut-in pressures of the column (SIDPP), or of the annulus (SICP) plus the volume of the influx, are sufficient to calculate the pressure of the reservoir. Even so, owing to the fracturing of the formation right after shut-in of the well, the information from the SIDPP and SICP were compromised. At the time of well shut-in, the SIDPP showed a maximum reading of 190 psi, falling down over time, probably due to the fracture of a formation below the dead block, estimated at 1,860 m (TVD). Accordingly, a flow of fluids was established from reservoir N560 to this fracture point, putting the well in a dynamic drainage condition.

Taking the maximum pressure in the SIDPP as a reference for the minimum pressure of the reservoir:

$$\text{Reservoir pressure} = \text{Hydrostatic pressure} + \text{SIDPP}$$

$$= \text{MW} \times 0.171 \times \text{TVD} + \text{SIDPP}$$

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Where,

MW = Mud weight (ppg)

TVD = Total vertical depth of the influx (m)

SIDPP = Shut-in pressure of the drill pipe (psi)

Hence:

Reservoir pressure = 9.5 x 0.171 x 2,306 + 190 = 3,936 psi

Transforming this into equivalent mud weight (EMW), we would have:

EMW = Reservoir pressure/(TVD x 0.171) = 3,936/(2,306 x 0.171) = 9.98 ppg.

Method 2 – Kick tolerance criterion

Another approach for calculation of the minimum reservoir pressure would be through consideration of the kick tolerance criterion, based on the premise that the influx of 18 bbl at the bottom of the well was sufficient for the fracture of the formation at 1,860 m (TVD). As the likely rupture point was below the LOT point, this cannot be used as the fracture gradient. To appraise the fracture gradient at 1,860 m (TVD), the maximum pressure of the BOP upon shut-in of the well (2,200 psi) was used. The vertical depth from the BOP to the rupture point was estimated at 649 m (TVD).

Accordingly, the pressure at this fracture point would be as follows:

Pressure at the rupture point = Shut-in pressure of the BOP + Hydrostatic pressure of the BOP at the fracture point

Pressure at the rupture point = 2,200 + mud weight x 0.171x TVD of the BOP at the fracture point

Pressure at the rupture point = 2,200 + mud weight x 0.171x TVD of the BOP at the fracture point

Pressure at the rupture point = 2,200 + 9.5 x 0.171 x 649

Pressure at the rupture point = 3,254 psi or

Pressure at the rupture point = 3,254/(0,171 x 1,860) = 10.23 ppg

Calculation of the kick tolerance for breakage of the formation at 1,860 m (TVD) for an influx of 18 bbl of oil, with a gradient of 0.4 psi/ft, and using mud with density of 9.5 ppg, is illustrated by Figure 10 on the next page of this report:

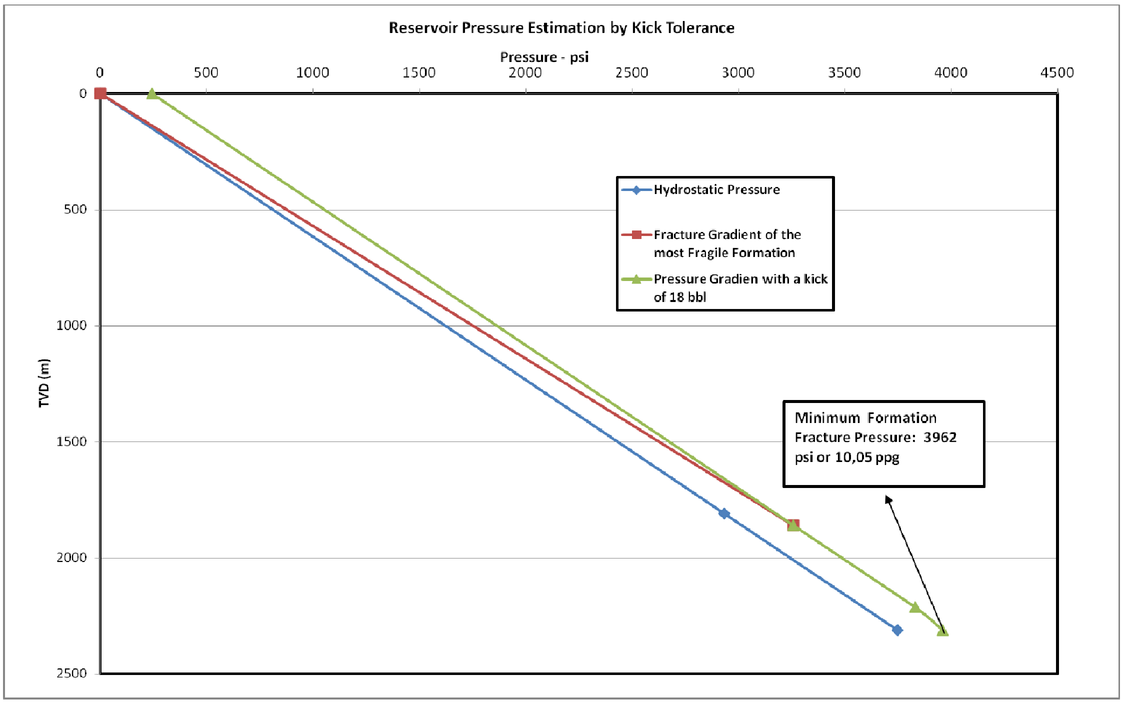

Figure 10 - Graph of kick tolerance criterion for calculation of reservoir pressure.

Therefore, **reservoir pressure of 3,962 psi or 10.05 ppg would be necessary to have a formation fracture right after the shut-in of the BOP, for an influx of 18 bbl of oil.** This also constitutes an estimate of the minimum reservoir pressure.

Method 3 – Reduction of the ECD during the downlink

The third approach to estimate the reservoir pressure through the reduction of the Equivalent Circulation Density (ECD) when the downlink was carried out

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(communication from the directional tool at the bottom of the well to the surface). In Figure 9, which we saw earlier, we can perceive the initial increase in the level of the active mud tank. The estimated ECD for a discharge of 538 gpm (drilling discharge of this section) would be 10.6 ppg. This amount was obtained from the Daily Drilling Bulletin and reflects the range of ECD of the PWD Stethoscope tool, with the highest value being adopted as reference in this calculation.

In the downlink, the average of minimum discharges was estimated at 417 gpm, which reduced the ECD at the bottom of the well and caused the influx. Therefore, the minimum reservoir pressure would be that relating to an ECD for a mud discharge of 417 gpm.

The ECD is estimated through the following equation:

ECD= MW + APannulus/(0.171 x TVD)

Where:

ECD – Equivalent circulation density

MW - Mud weight (ppg)

APannulus – Loss of load on the annulus (psi)

TVD – Total vertical depth to the drilling point (m)

Through this formula above, we calculate that the loss of load in the annulus for the ECD of 10.6 ppg (discharge of 538 gpm mud pumps), TVD of 2,304 m and mud weight of 9.5 ppg is 432 psi.

In the downlink, when the discharge of the mud pumps for well circulation oscillates, arriving at minimum values near 417 gpm, the new loss of load to the annulus for this discharge is calculated in the following manner:

APannulus@417 gpm = APannulus@538 gpm x (4172/5382)

That is to say,

APannulus@417 gpm = 432 x (4172/5382) = 259 psi.

Accordingly, the ECD when carrying out the downlink would be:

ECD = MW + APannulus@417 gpm/(0.171 x TVD)

ECD = 9.5 + 259/(0.171 x 2,304) = 10.16 ppg

Thus, **the lowest pressure forecast for the reservoir would be 10.16 ppg,** or, for the TVD of 2,304 m, 4,003 psi.

Therefore, based on the pressures of the well shut-in and reductions of the ECD that occurred during the downlink, it can be stated that the reservoir pressure would be between 10.16 ppg and 10.6 ppg.

3.1.2. Elevation of reservoir pressure above normal

The cause pointed out by the investigation team for the over-pressuring of reservoir N560, in the section that was perforated by well 9-FR-50DP-RJS, to values between 10.16 ppg and 10.6 ppg, was the injection of water carried out by injector well 8-FR-29D-RJS.

The injection of water by well 8-FR-29D-RJS began on July 12, 2010. On November 3, 2011, owing to operational problems, the injection was interrupted.

It should be pointed out that such shutdown of the injection system was not Chevron's intention, and that the only mention made by the operator in this sense that was encountered during the investigations, was the guidance passed on to the team on board the Sedco 706 drillship to inform the FPSO Frade to suspend the injection into N560 in the event a kick occurred. Such a determination, an extremely ineffective one as the interruption of the injection only came about after commencement of the undesirable event, was made when the injector well was already shut down for three days, demonstrating a flaw in managing the operations.

The tracking of the injector well pressure is shown in the following graph:

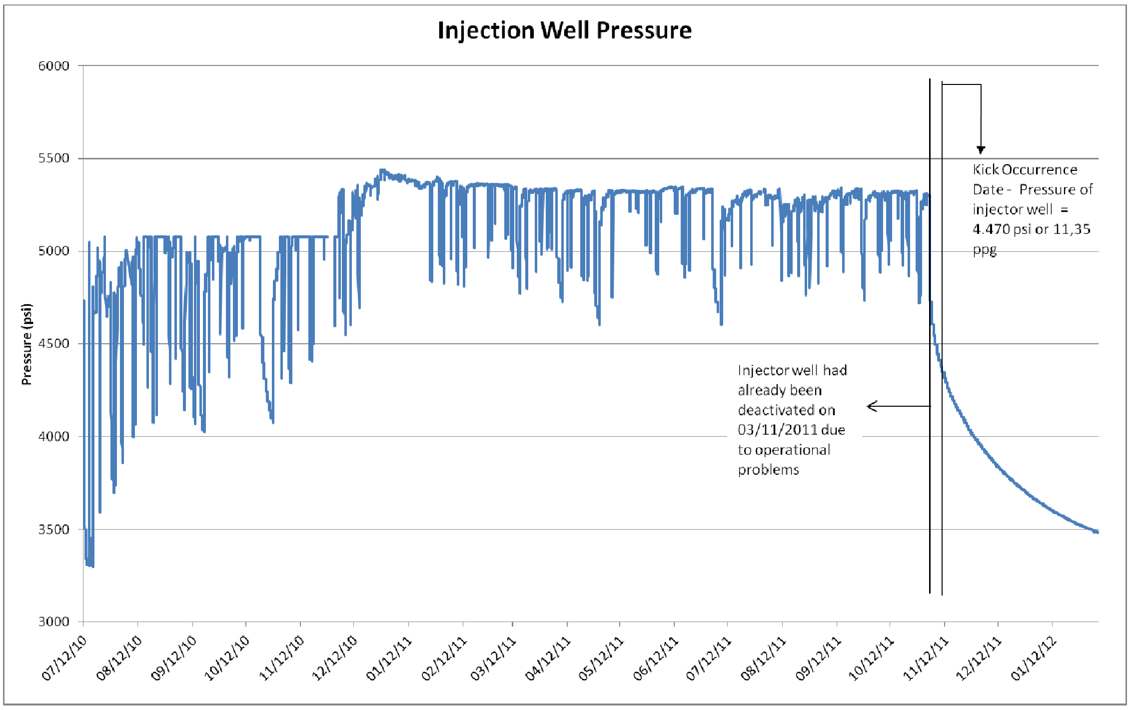

Figure 11 - Pressure of injector well 8-FR-29D-RJS over the course of time.

The injector well in question was operated with an average pressure of around 5,300 psi (13.4 ppg), although when the kick occurred on November 7, 2011, the injector well's pressure was at 4,470 psi (11.35 ppg), due to the interruption of the injection of water.

The reservoir modeling carried out by Chevron showed a maximum of 3,700 psi (9.4 ppg) at the point where the drilling would occur, with the injector well at its normal operating pressure. Nonetheless, the calculations for the forecast of the reservoir pressure as per item 6.1.1 indicated amounts of between 4,003 psi (10.16 ppg) and 4,176 psi (10.6 ppg), much higher than forecast by the model. It should be added that, **upon entry into reservoir N560, the injector well had already been deactivated for 4 days, due to operational problems, meaning that, in the event the injection had still been going on, the pressure in the region of the kick would be even greater and further from that forecast by the model.** After commencement of the injection by well 8-FR-29D-RJS, reservoir N560 had been perforated by three wells: 9-FR-41D-

RJS, 9-FR-31D-RJS and 8-FR-48D-RJS, as shown in the map on the following page (Figure 12).

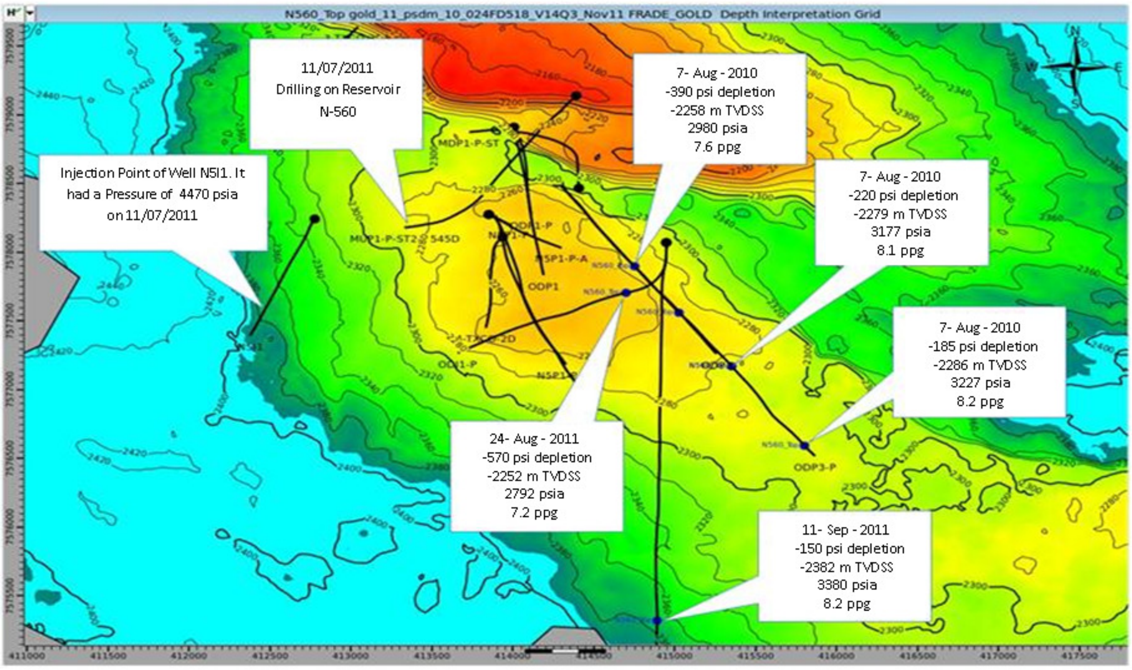

Figure 12 – Map indicating the wells that reached reservoir N-560 after the beginning of injection.

Of all the wells drilled after the injection of water (well 8-FR-29D-RJS), well 9-FR-50DP-RJS, the one which caused the accident, was the one that penetrated reservoir N560 at the closest point to the injector and the last one, when the injection tended to be more effective.

Accordingly, it is evident that one of the causes of the kick was the lack of knowledge of the geology and fluid-dynamics of the reservoir on the part of Chevron, **whose injector well artificially elevated the pressure of the section of the reservoir perforated by well 9-FR-50DP-RJS to between 4,003 psi and 4,176 psi.**

3.2. Causal Factor 2 – Blowout – Fracture of the Formation

The second Causal Factor was the set of conditions that made the kick evolve into a blowout. Two hypotheses raised for the occurrence of the blowout are evident through the analysis of the facts, that the specific case was an underground blowout, as will be discussed in this section.

Prior to the drilling of well 9-FR-50DP-RJS, wells 9-FR-46D-RJS and 9-FR-49D-RJS were drilled. All the wells used the same casing structure down to the last 13 3/8" dead block, set at 1,834 m (MD), as can be seen in Figure 13 below. From this dead block on down, the differential of the wells were the trajectory and the objectives defined.

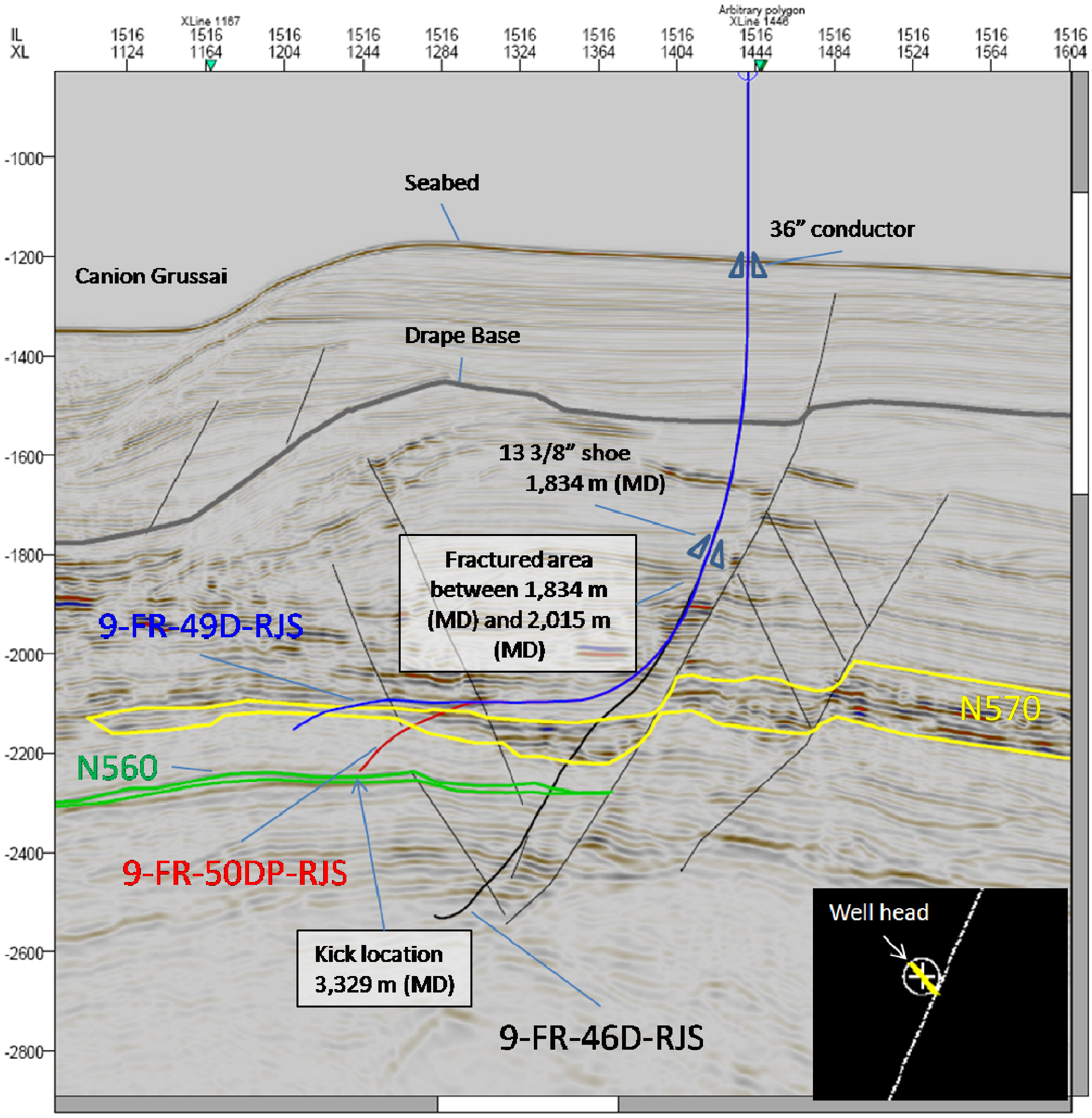

Figure 13 - Scheme for drilling special wells showing where in the last sidetrack (9-FR-50DP-RJS) there occurred the kick in Xline 1516 of the seismic survey of the region.

The drilling of well 9-FR-46D-RJS began on August 3, 2011 and the 13 3/8" casing dead block was set and cemented on August 7, 2011. The well was abandoned and the drillship demobilized, returning to the location on October 11, 2011.

On October 12, 2011, the leak off test (LOT) was conducted after the drilling of 6 meters of open well between depths of 1,844 and 1,850m (MD). The result of this test indicated that the pressure gradient of the formation fracture at the depth of 1,850 m (MD) would be 10.57 ppg.

After penetrating a hard region at 2,111 m (MD) and making a connection at 2,123 m (MD), on October 13, it was not possible to establish mud circulation. The procedure employed to re-establish circulation caused a loss of 61 barrels of mud to the formation and, to combat this loss, 40 bbl of LCM **(Loss Circulation Materials) were added.**

After this date, during the course of the drilling work, significant losses of mud to the formation occurred. Such losses were again combated by means of LCM, in order to cover any fractures encountered. Such losses, which reached as high as 280 barrels on October 27, continued at an average of 100 barrels per day, until the drilling of this first well was complete.

The abandonment of well 9-FR-46D-RJS, as planned, consisted of 5 cement covers, followed by a special cement cover of 16.5 ppg, which would remain in the depths of the well at the point where the kick off point would be carried out (KOP – Gain of angle for a directional well) for well 9-FR-49D-RJS.

After the placement of the third abandonment cover, a loss of 28 barrels, followed by a gain of 8 barrels of mud, was identified. The drillship shut down the well after a flow check indicated a gain of another 7 barrels. The occurrence of ballooning was identified, when the formation, after taking in a volume of drilling mud, returned part of this fluid to the well, giving the impression that a kick took place.

The cement cover designed for carrying out the kick-off point (KOP) was set on October 23, 2011. The top of this cover was programmed to stay at 1,784 meters (MD), about 50 meters above the base of the dead block. **The top of cement (TOC) at this depth would guarantee complete isolation of the first well and increased resistance in the region where the KOP would be carried out.**

Nevertheless, on October 24, 2011, at round 11 in the morning, during the test of the cement bond, **it was ascertained that the TOC was 175 meters below the point where it was designed to be,** at a depth of 1,959 m (MD). **Even having identified the absence of the cement cover in the region of the KOP, Chevron stuck to its schedule, beginning the drilling of the first sidetrack two hours after identifying the position of the TOC, without appraising the risks of the change.**

As a consequence, the configuration of the open well had a forked profile, as illustrated in green in Figure 14 below.

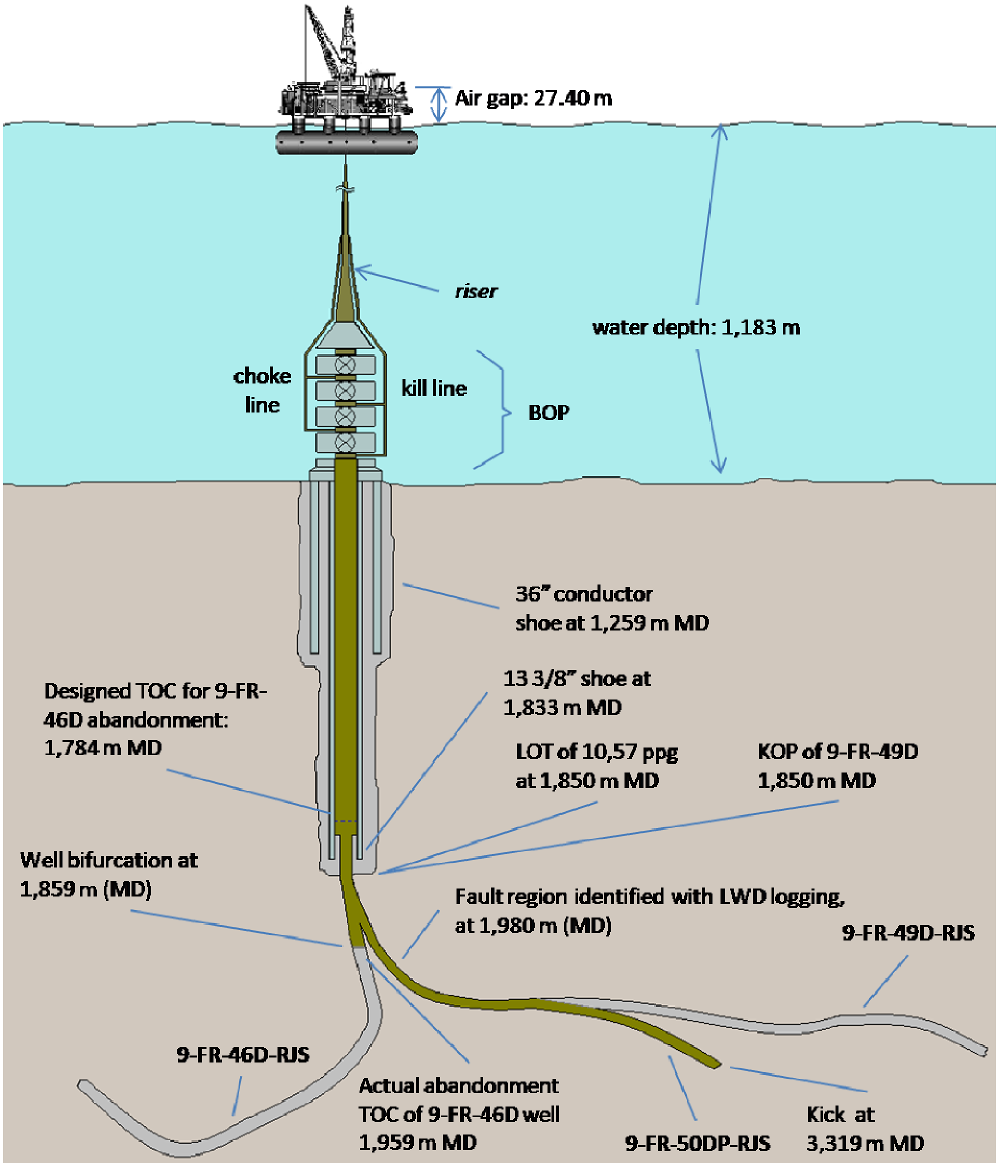

Figure 14 - Schematic illustration of the well profile

In the open well section, which was between the TOC and the 13 3/8" dead block, a discontinuity in the depth of 1,860 m (MD) was identified, with depth of 3 meters, encountered only in well 9-FR-46D-RJS. Figure 15 on the next page presents the logging while drilling (LWD) of wells 9-FR-46D-RJS and 9-FR-49D-RJS, comparing the region where the anomaly in the first well was identified.

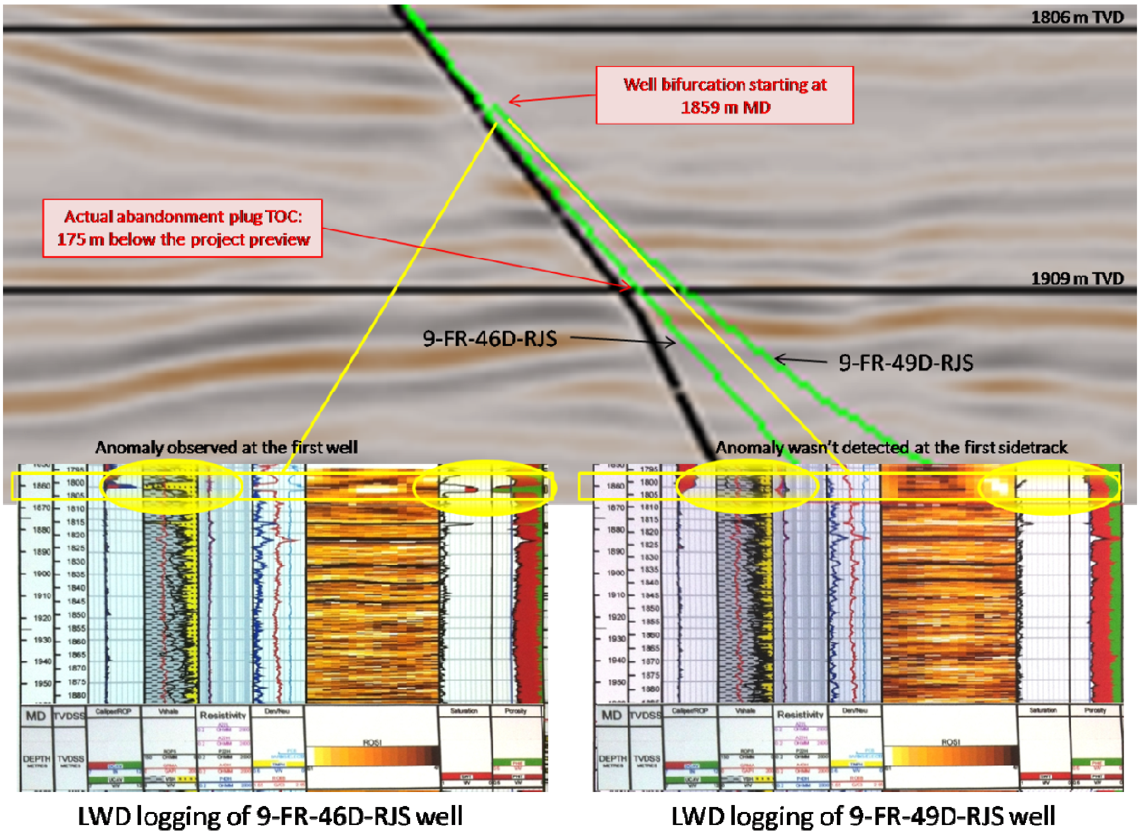

Figure 15 – Logging while drilling (LWD) of wells 9-FR-46D-RJS and 9-FR-49D-RJS.

Knowledge of the existence of this fork on the part of the Concession-holder was evidenced in the daily bulletin of the drillship (sounder) for October 25, 2011, which was gathered by the ANP on the Sedco 706 drillship during the course of the investigation. This document shows that during the descent of the drill pipe, the BHA encountered an obstruction at 1,859 m (MD) (depth of the fork) and, in a second attempt, the tool descended to a depth of 1,880 m (MD), and the readings indicated that the tool was in the wrong sidetrack. Only on the third attempt was it possible to reach the correct sidetrack, in 9FR-49D-RJS. **Obviously, the existence of the fork was already making operations in the well difficult.**

The formations right below the dead block of the surface casing are unconsolidated formations and present the lowest fracture gradients in the course of the drilling. **The**

continuation of the drilling of well 9FR-49D-RJS, without correction of the cementing of the 175 m of interval of open well in well 9-FR-46D-RJS, exposed two distinct sections to fracture in the event of a kick incident, making the operation as a whole riskier. By not having formally evaluated the risks of the change, Chevron conducted its operations in a manner that was clearly contrary to Brazilian regulations, heightening the risk of the drilling of the well that gave rise to the accident.

3.2.1. Identification of the underground blowout

During the shut-in of the well, according to the pressure sensor loggings in the BOP of the Sedco 706 drillship, there was a sudden rise in pressure up to around 2,200 psi, followed by a drastic drop in pressure, returning to 2,100 psi, equivalent to the pressure encountered prior to the shut-in of the BOP. The graph of the loggings is shown below in Figure 16.

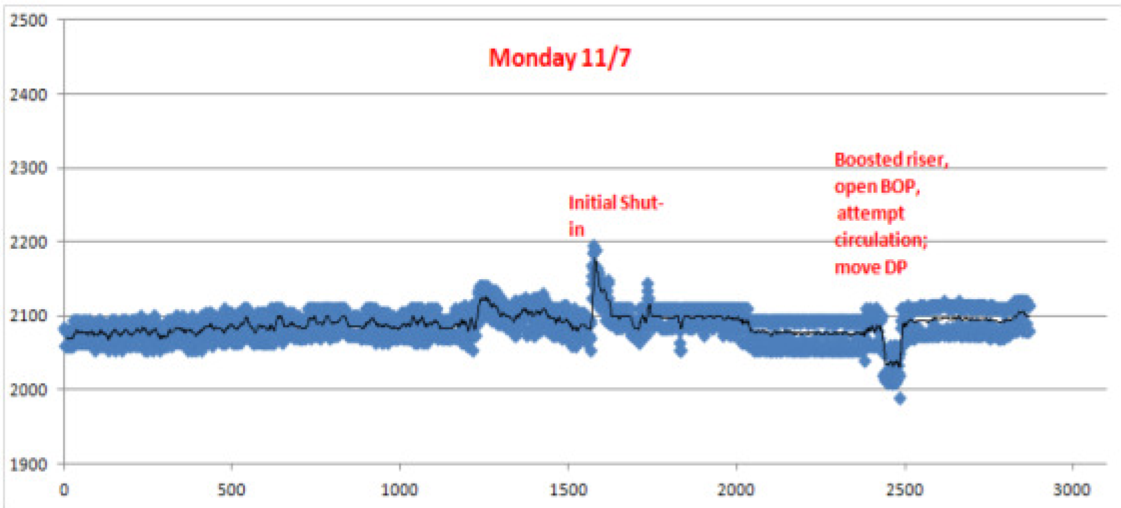

Figure 16 – Monitoring of pressure in the BOP annulus.

In the annotations of pressure loggings for the shut-in of the annulus (SICP) and drill pipe (SIDPP), which were carried out after the shut-in of the BOP, significant reductions in the pressure of the annulus, which was reduced 150 psi to 90 psi, providing indications that a fracture had occurred inside the well.

Moreover, as we saw earlier in Table II, the loggings of these shut-in pressures show atypical behavior, in which the SICP is lower than the SIDPP. Specialized literature on the subject indicates that the principal cause of this behavior is the occurrence of an underground blowout1.

These observations also indicate that the pressures near the fracture point were already close to the formation's resistance limit, in that no great rise in pressure was noted before the sudden drop, both in the annulus and in the BOP pressure gauges. Hydrostatic pressure calculations pointed to a 10.23 fracture gradient at 1,860 m (TVD), 50 m below the dead block (the point where it is estimated that the fracture occurred), as per item 3.1.1.

Besides the behavior of the pressure during the well shut-in, the existence of an underground blowout was also identifiable due to the huge volumes of mud loss to the formation after the kick. Added to this statement is the evidence from the Daily Drilling Bulletin that at 6:30 PM on November 9, 2011 the opening of the BOP was carried out. The variations in mud were monitored by means of the trip tank and loss of 120 bbl of mud to the formation in 1 hour was noted.

In the first attempt to circulate the kick, through the sounder method, only 3 barrels returned through the choke line, after injection of 115 barrels of mud through the drill pipe. In the second attempt, of the 20 barrels pumped, only 2 returned.

There was still a gain of 20 barrels after reopening of the annulus at 10:30 PM. Even so, when an attempt was made to circulate at 1.3 bpm through the pipe, with return through the choke line at 530 psi, no mud returned.

The attempts to circulate the kick continued through the night of November 8 and, although some return was obtained, it came back with traces of oil, with significant losses occurring. It is believed that the difficulties encountered during the first attempts to circulate the kick, when losses of mud were noted, associated with the presence of oil upon return, **should have been considered by Chevron yet another strong indication of an underground blowout**.

Such recognition would have led to the use of advanced well control procedures, ones that are more consistent with the situation that loomed. Indeed, Chevron itself – out of its belief that such situations are excessively complex – has an agreement with Wild Well Control (Well Control Emergency Response Plan), for the latter to be put into action in underground blowout situations.

Out of its failure to recognize that it was facing an underground blowout situation, Chevron elected to try to use the bull heading technique to control the well. Bull heading is a technique that consists of pumping mud through the drill pipe or annulus to force the fluid from the kick back to the formation.

Best engineering practices, which are reflected in Chevron's own well control manual, indicate that bull heading should be used with caution, on account of the risks of fracturing of a section of open well. Its applicability is oriented to cases in which there is tremendous risk of permitting the rise of the fluid from the kick during circulation, such as presence of H2S, or when excessive volume of gas makes the risk of explosion on board intolerable, or further when the drill pipe is not in the well.

Furthermore, recommendations for the use of the method indicate that Bull heading should be applied immediately after shut-in of the well; **that it is not indicated when the last dead block is shallow; that application thereof in lengthy extensions of open well should be appraised with great care, considering the risk of fracturing and the possibility of underground blowout. There is n**o evidence that Chevron conducted such appraisals.

Therefore, the characteristics of the kick in well 9-FR-50DP-RJS were not in line with the situations in which bull heading is recommended, since that there was a lengthy extension of open well (1,450 m) and the 13 3/8" dead block was set 600 meters from the seabed (a shallow dead block, considering that the region features deep waters).

After three **bull heading** attempts, besides verifying that there was continual loss of mud (110 bph) with the annulus of the BOP open, the well had still not been killed, as was to be expected in the scenario that prevailed. In order to contain the ongoing loss of mud to the formation, the well was kept shut-in and its volume was being completed through the choke line.

As the situation was one of an underground blowout, it was probable that none of the convention well control techniques would be capable of eliminate the influx from N560. Nonetheless, as all the evidence pointed precisely to this scenario, the company should have immediately used auxiliary investigation methods, such as logging the well temperature.

The inability of Chevron to identify the underground blowout based on the indications presented meant that it used the bull heading procedure in an ineffective manner, which delayed mobilization of the WWCI team and resulted in at least two more days of leakage.

3.2.2. Location of the fracture

Determination of the section of the well where fracture of the formation occurred was carried out by descending a tool via cable through the drill pipe to measure the profile of the temperature and pressure.

The run to appraise the temperature and pressure profile through the well began on November 12, 2011 (5 days after occurrence of the kick), at 8:00 PM. At 11:30 PM on that same night the run reached the planned depth of 2,230 meters (MD). Logging of the well was concluded the next day, November 13, 2011.

The run to take the temperature did not reach the depth equivalent to reservoir N570, making it impossible to check on the occurrence of flow of oil between formations N560 and N570.

The temperature gradient inside the well was above the geothermic gradient, meaning that fluid was flowing from formation N560 to the upper regions of the well. As from 1,960 m (TVD) up to 1,830 m (TVD), a rise in the temperature gradient was noted, as illustrated in Figure 17 below, providing indications of the outflow of fluids from the well to adjacent formations. As from 1,830 m (TVD), there was gradual reduction of the temperature gradient to amounts just a little above the geothermic gradient. However, temperatures were encountered that were lower than the geothermic temperature, which is compatible with the descent of cooler fluid through the annulus.

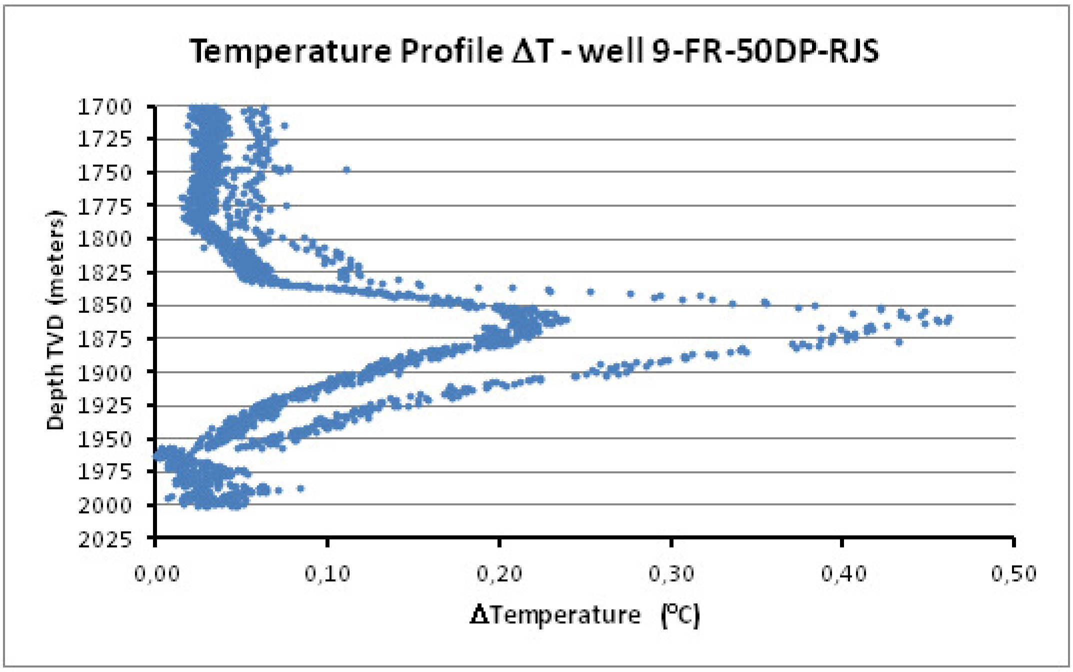

Figure 17 - Data on difference in temperature down the well, evidencing the region for outflow of fluids from the well to the adjacent formations.

Accordingly, it can be stated that **the fracture occurred in a region between 1,960 m (TVD) and 1,830 m (TVD).** The point of greatest heat exchange, located at approximately 1,860 m (TVD), is pointed to as the probable point of formation fracture.

3.3. Causal Factor 3 - Path of the Flow of Fluids between the Fracture and the Seabed

Once the fracture of the formation occurred at roughly 1,860 m (TVD), the fluid could have gone through fractures caused by over-pressure resulting from the kick, induced fractures connected to natural faults and/or faults due to cementing of the casings.

Best oil industry practices[1] indicate that when an underground blowout occurs through shallow formations (under 3,000 feet - approximately 914 meters), it is highly likely

[1] Grace, Robert D. - *Blowout and Well Control Handbook. Cap. 8: Underground Blowout.*

that such formations will fracture to the surface, mainly in cases of seabed, where the geological formations are more recent.

There is also the possibility of flaws in the cementing having facilitated migration of the fluid. By means of a CBL (cement bond log) that was conducted on January 17, 2012, it was identified that in the cemented interval between the 13 3/8" dead block and the conductor (guide) dead block, just 5 small sections of around 8 meters in thickness were encountered with conditions to bring about hydraulic insulation, as shown in Figure 18, which follows on the next page.

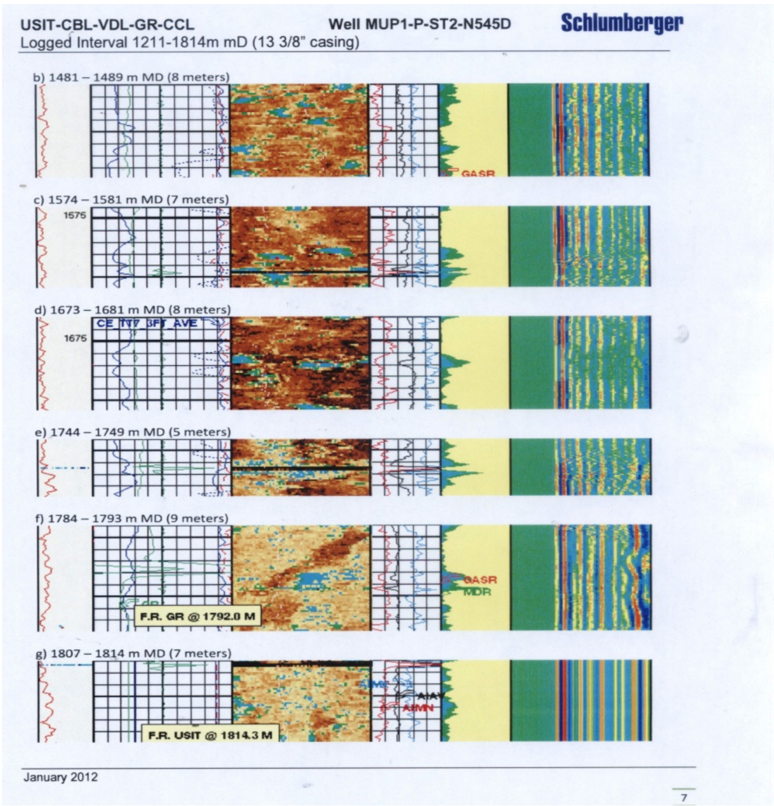

Figure 18 - Log of the spots where hydraulic insulation may have been achieved through cementing.

As the shallow formations in the region are fragile, there are major chances that such spots for potential hydraulic insulation were by-passed by the fluid through the opening of fractures in the formation. Such behavior would explain the proximity between the spot of the first seepage and the well head, as illustrated in Figure 19 below.

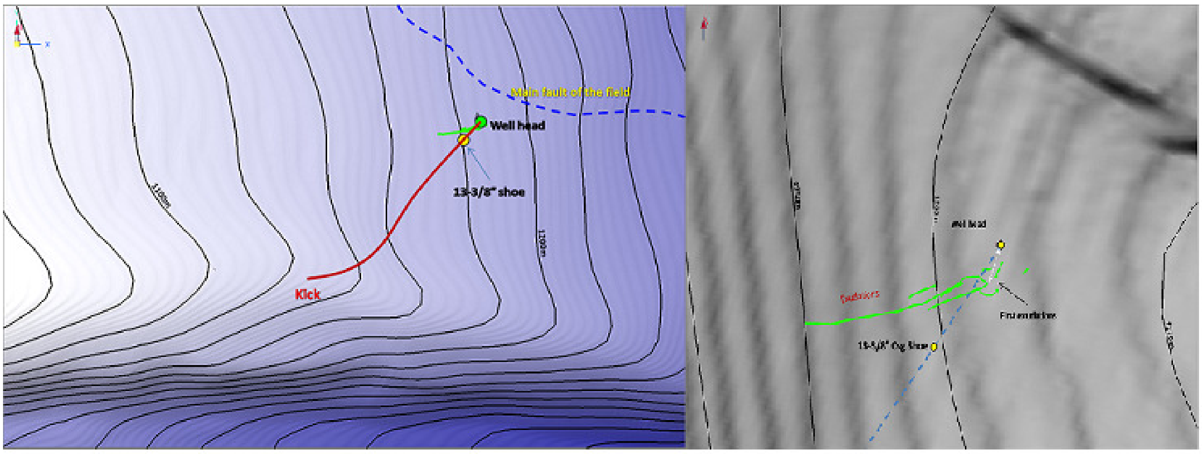

Figure 19 - Bathymetric charts of the ocean bed, showing the place of the seepage.

Accordingly, we can consider that **the root cause of migration of the oil from the fracture to the seabed was the fact that Chevron set the last dead block at 600 meters,** that is to say, 300 meters less than what is recommended by international literature on the subject to avoid fracturing up to the surface, in the case of an underground blowout.

4. Well Project

There are no published standards at either a national or international level for projects for construction of oil wells. The world-wide standards that do exist apply to the manufacture and specification of the components, such as, for example, casings, production pipes and well heads. The concession-holders responsible for construction of oil wells should have operating manuals and procedures that indicate how the entire process for development of the project is to take place, according to best engineering practices and in line with the currently effective regulations, based on risk, in the case of Brazil.

The project for drilling a well should contain all the information required for carrying it out in a safe manner. At the very least, the following aspects should be dealt with: requisites relating to knowledge of local geology, completion, trajectory, well stability, drilling fluids, casing program, cementing program, BHA, drill bits and drill pipe, hydraulics for drilling and cleaning the well and the specifications of the BOP and drillship to be employed.

As established in the Brazilian regulations, throughout the entire process of developing a well project, management of risks should be conducted on an ongoing basis, in order to guarantee that the drilling takes place at a tolerable level of risks. Nevertheless, the accident that took place last year reveals serious faults in the perception of risks and management of uncertainties during project development, for which Chevron bears the full responsibility.

Below is a list of the documents used by Chevron in the development of the project for well 9-FR-50DP-RJS.

- **Well Constructions - Basis of Design.** Approved on January 3, 2005 and updated on February 21, 2006 – This document deals with the premises use as bases for construction of the wells of the Frade Project.
- **Fluids Program - Frade Block** – Issued by the firm MI-SWACO, which was contracted by Chevron for the supply and control of the drilling fluids.
- MUP1-P-ST2-N545D Pilot 8 V" Hole Section - Well Plan and Objectives Document (WellPOD) of November 4, 2011 – This document contains information on the objectives of the well, mud logging instructions and MWD/LWD instructions.
- Technical proposal submitted by Schlumberger on November 4, 2011 containing the directional plan for the well, the geometry of the well, the appraisal program (MWD), Design of the BHA, Estimated interference of the drill pipe, appraisal of the torque & drag and anti-collision analysis.
- Appraisal of tolerance to a kick.
- Standard operating procedure CBBU_DC_001_001 SOP of July 27, 2010.
- Program for drilling well MUP1-P-ST2 of November 5, 2011.
- Chevron Drilling Well Control Guide, revised in March 2006.

In drilling well 9-FR-50DP-RJS, which began on November 6, 2011, Chevron failed to carry out an analysis in conformity with Brazilian regulations, even ignoring its own risk management procedures (Risk and Uncertainty Management Standard - RUMS of July 26, 2011, and the Single Well CPDEP Roadmap).

Mention of the management of risks was limited to the documents MUP1-P-ST2-N545D Pilot 8 V" Hole Section - Well Plan and Objectives Document (WellPOD) of November 4, 2011, item 1.8, in which it was stated that there would be low risk of losses to the depleted reservoir N570, and that in reservoir N560 there would be an estimated over-pressure of up to 300 psi (risk of influx), besides the Integrated Hazard Identification Study (IHAZID) of July 2008, a generic study for the entire block of the Frade Oil Field.

Chevron should have conducted a structured, well grounded and formal risk study appraisal for the drilling of well 9-FR-50DP-RJS. By not conducting such a study, Chevron failed to consider the drilling specifications in which the accident occurred.

The second point to be observed would be the criteria employed for setting the dead blocks. The last dead block set was that for the 13 3/8" surface casing. The cementing was carried out at the setting point to the surface of the seabed, and the BOP was set on this casing.

The well project developed by Chevron called for the last dead block to be set at a depth of just 600m from the seabed. At this depth, the formations are not consolidated, and it is highly likely that a fracture near the dead block in the event of a kick and underground blowout will begin a process that will conduct the fluids to the seabed, as in fact occurred.

It should further be added that the dead block was set near the principal fault of the Frade Oil Field, and this was drilled in some sections, as evidenced in Figures 20 and 21 which follow. The risks of setting the dead block in the region of the fault were likewise not evaluated by Chevron.

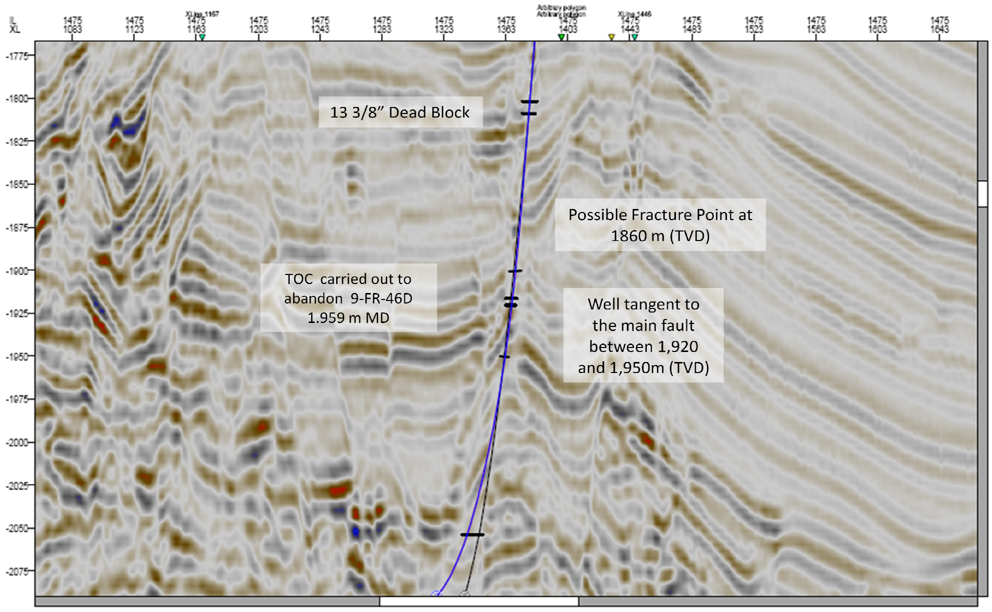

Figure 20 - Blow-up of Xline 1475 of the seismic survey of the region, perpendicular to the principal Frade fault.

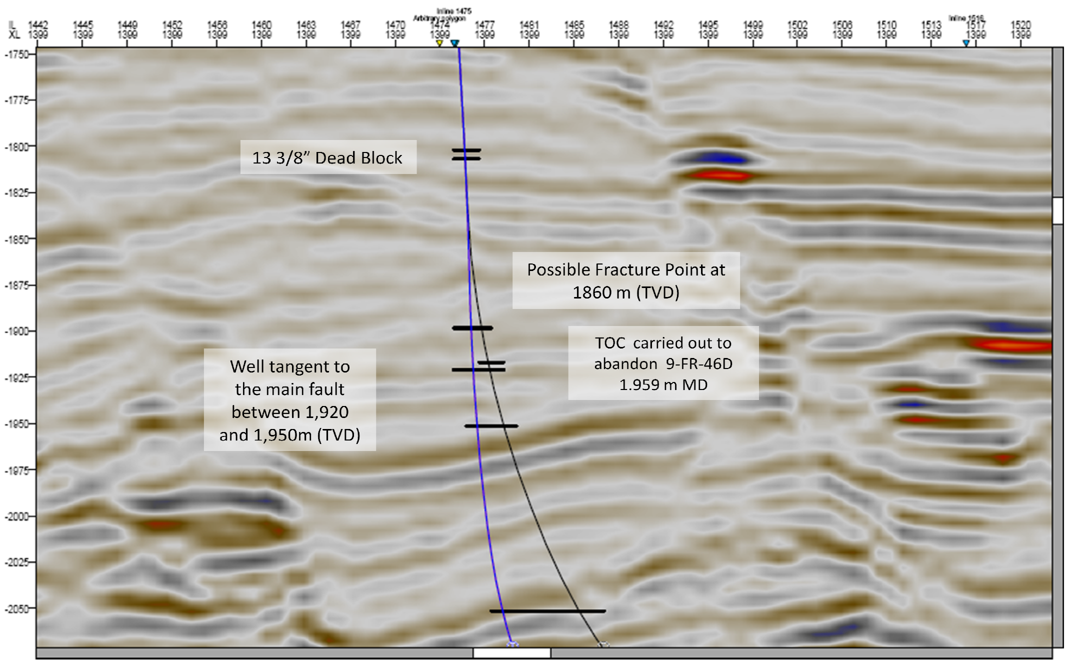

Figure 21 - Blow-up of Xline 1399 of the seismic survey of the region, facing the principal Frade fault.

With the last dead block set at 600 m from the seabed, the Chevron well project called for the drilling of three reservoirs: N570, N560 and N545. Out of all these reservoirs, it was known, as pointed out in the Drilling Program for Well MUP1-P-ST2 (9-FR-50DP-RJS), that reservoir N560 could be artificially over-pressurized, due to the injection of water.

The depths for setting the dead blocks and the mud weight to be used for each drilling phase are determined based on the projections for pore and fracture gradient pressures. Since they deal with predictions, they should be used with sufficient margin of safety to keep the risk within tolerable limits.

One of the criteria used by Chevron to evaluate the adequacy of the setting of the last dead block was the kick tolerance criterion, with use of the following premises for well 9-FR-50DP-RJS:

- Mud weight: 9.5 ppg
- Pore pressure uncertainty: 0.3 ppg
- Maximum mud weight equivalent (Fracture gradient): 10.6 ppg to 1817 m (TVD)
- Kick intensity: 0.3 ppg
- Invasive fluid: gas (0.1 psi/ft or 0.328 psi/m)
- Acceptance criterion: volume of influx for fracture of the formation > 25 bbl.

Based on this set of data, the well could receive an influx of 27.9 bbl of gas, without fracturing the formation at the fragile spot, located at 1,817 m (TVD). Such result caught the attention of this Agency, because the kick tolerance criterion showed a result quite close to the 25 bbl acceptance criterion and the parameters used did not contain considerations regarding the margin of safety and uncertainties conducive with the drilling situation, which would be that of penetration of a section of reservoir forecast to be over-pressurized.

Nonetheless, during the kick and blowout events, the reservoir pressure was higher than the forecast, the fracture gradient was lower than forecast and was at a greater depth and the invasive fluid was petroleum.

The discrepancies between the criteria adopted by Chevron and the factual situation were sufficient for the cracking of the formation after the kick, with influx of 18 bbl. Although the invasive fluid and the volume of influx had served to attenuate the kick tolerance criterion, the pressure of reservoir N560 and the formation fracture gradient, located at around 1,850 m (TVD), encountered during the drilling were of such magnitude that they caused the fracture of the unprotected formation, owing to the shallow depth of the dead block set, thus permitting the flow of fluids from reservoir N560 to the surface of the sea.

Analysis of the criteria of the kick tolerance and the above-cited documents indicate that a fracture gradient of 10.57 ppg, obtained from the leak off test (LOT) of well 9-FR-46DP-RJS was used. Even so, the results of the leak off test (LOT) of correlation wells 4-TXCO-2D-RJS (10.3 ppg) and formation integrity test (FIT) of wells 7-FR-2HP-RJS (10.1 ppg) and 7-FR-21HP-RJS (10.15 ppg) were not taken into consideration by Chevron.

The heterogeneity of the reservoir and the setting of the dead block just 600 m from the seabed should have been elements sufficing for the use of more restrictive values. The section of the formation that fractured had an estimated pressure gradient of 10.23 ppg (see item 3.1.1), indicating that the data of the correlation wells should never have been disregarded.

If Chevron had used the LOT data from well 4-TXCO-2D-RJS (10.3 ppg) and FIT data from wells 7-FR-2HP-RJS (10.1 ppg) and 7-FR-21HP-RJS (10.15 ppg), in light of the geological uncertainties and the setting of the last dead block at 600 m from the seabed, the result of the kick tolerance criterion would have indicated the need to alter the depth for setting this dead block and the number of phases, or to adopt such other measures as would be required to make the risks in this well project tolerable.

Another point to be noted is the 0.3 ppg pore pressure uncertainty used. This fact is indicative that Chevron considered this a development project well, contrary to best engineering practices, demonstrating the company's low perception of risks and failing to comply with its own approved manuals, as evidenced in Figure 22 below, extracted from the Chevron well control manual.

Table 5.7.1

Pore Pressure Uncertainty in ppg	Application
Up to 0.5 ppg	Development projects
Between 0.5 ppg and 1.0 ppg	Appraisal projects
Greater than 1.0 ppg	Exploration projects

Figure 22 - Table extracted from the Chevron Drilling Well Control Guide.

Development projects consist of wells with a high degree of knowledge of the geology and fluid-dynamics of the reservoir, so that the possibilities of a kick are reduced.

The fact that 9-FR-50DP-RJS (i) was a pilot well, and a special one at that, investigative in nature; (ii) was the one closest to the injector well; and (iii) the results of the reservoir simulation point to a tendency to over-pressurization in this section, constitute more than sufficient elements for Chevron to try drilling this well with the necessary care and consider it, at a minimum, as an appraisal project.

Had it used the poor pressure uncertainty in the range of appraisal projects, which would be from 0.5 ppg to 1.0 ppg, besides the value of 9.4 ppg as the worse case scenario for the poor pressure of reservoir N560, the intensity of the kick to be used as tolerance criterion would be between 0.4 ppg and 0.9 ppg, which would make the result of the kick tolerance between 22 bbl and 0 bbl.

Once again, had Chevron used this data, the result of the kick tolerance criterion would indicate the need to alter the depth of setting the dead block and the number of phases or adopting such other measures as would be required to make the risks tolerable.

The fact that the company ignored the data from the correlation wells, associated with the error in classification of the well as regards pore pressure uncertainty, led to adoption of a kick tolerance criterion that was absolutely unacceptable for this project, which caused the accident.

5. Conclusions

Based on the analyses set out in this document, the investigation team for the accident involving well 9-FR-50DP-RJS, which occurred on November 7, 2011 in the Frade Oil Field, has concluded that:

- **Chevron was not capable of correctly interpreting the local geology and fluid dynamics,** even though no less than 62 wells had already been drilled in the block in question (Frade Oil Field). With this, it caused the kick, the initial event that culminated in the seeping of oil into the sea;

- The mistake on Chevron's part in interpreting the geology and fluid dynamics, chiefly as relates to the effects of the water injection it carried out in the Frade Oil Field, led to an incorrect estimate in the model for pressure of reservoir N560 in the region where the kick occurred. The pressure mistakenly forecast by the company was 3,700 psi (9.4 ppg), whereas according to the ANP's calculations, it was actually between 4,003 psi (10.16 ppg) and 4,176 psi (10.6 ppg);

- **Chevron itself artificially raised the pressure of the section of reservoir N560 where the kick occurred** to levels between 4,003 psi and 4,176 psi, through injector well 8-FR-29D-RJS, **thus creating conditions for the accident to happen;**

- In drawing up the project for well 9-FR-50DP-RJS, Chevron disregarded the data resulting from the tests of well 4-TXCO-2D-RJS, drilled on May 15, 2001, which indicated a leak off test (LOT) of 10.3 ppg, as well as the formation integrity tests (FIT's) of the surface casings of wells 7-FR-2HP-RJS and 7-FR-21HP-RJS, drilled in 2008 and 2009, which indicated 10.19 ppg and 10.1 ppg, respectively. The estimate of the pressure gradient in the formation that fractured, causing the blowout, indicated 10.23 ppg, as per item 3.1.1., proving that such data from the correlation wells should never have been disregarded;

- **If Chevron had used the data available from the correlation wells, the project that was used for well 9-FR-50DP-RJS would have proven to be unfeasible**. It would have been necessary for the dead block to be set at a greater depth, for the number of phases to be increased and/or other measures taken to make the risks acceptable, which should have been adopted in order for the project to gain acceptance;

- The fact that well 9-FR-50DP-RJS was a pilot well, and a special one to boot, that it was investigative in nature, that it was the nearest one to the injector well after commencement of the injection of water and that the results of the reservoir simulation carried out prior to drilling indicated artificial over-pressuring in this section, should all have been sufficient elements for Chevron to consider the well as an appraisal project. Accordingly, the values of the pore pressure uncertainty to be used in the kick tolerance criterion should be between 0.5 ppg and 1 ppg. To calculate the kick tolerance, Chevron actually used a pore pressure uncertainty of a mere 0.3 ppg, which would only be applicable to a development project, in which the risks of a kick due to over-pressure of the reservoir are reduced;

- **If Chevron had used pore pressure uncertainty data compatible with an appraisal project,** which was the case of well 9-FR-50DP-RJS, classified by the company itself as "special", **the result of the kick tolerance criterion would indicate the need to alter the depth for setting the dead block and the number of phases or adopt such other measures as would be required to make the risks acceptable;**

- **Chevron did not engage in change management with respect to the well project**, when it was detected that the top of the last cement cover for abandonment of well 9-FR-46DP-RJS was 175 m below what was called for. Accordingly, the region right below the 13 3/8" dead block, where the gain in angle (KOP – kick-off point) of the first sidetrack was to have been carried out, was not cemented. The regions immediately below the dead block are generally the most fragile during drilling. **Continuation of the operation without engaging in a serious change management process (management of change - MOC) evidences the company's low perception of risks and is not in line with ANP regulations, and further is contrary to best oil industry practices;**

- **There was seepage of oil to the surface of the sea because the fracture of the well occurred 700 meters from the seabed.** International literature on the subject recognizes that when an underground blowout occurs in a region of up to 3,000 feet (914 meters) below the seabed, it is highly probable that the fracturing of formations will reach the surface, since shallower geological formations have very recent geological ages. Therefore, **setting the last dead block at just 600 m from the seabed, the case of well 9-FR-50DP-RJS, and the consequent exposures of the formations between 600 m and 914 m, heightens the risks of seepage of oil to the surface of the sea;**

- The kick and blowout were not controlled by the bull heading technique applied by Chevron in its attempts to kill the well, as this is clearly inadequate for the operational situation that was taking shape, since the well had its last dead block set a mere 600 m from the seabed, the section of open well was excessively lengthy (1.450 m), the well pipe was already filling up with fluid from the reservoir (upflow from the reservoir to the well was already going on for over 24 hours), the fracture point of the formation was unknown to Chevron and the mud that was used had density that was lower than the pressure gradient of the reservoir N560;

- Chevron took 2 (two) days to perceive that it was faced with an underground blowout situation. Indications of atypical shut-in pressures [the shut-in pressure of the drill pipe – SIDPP was higher than the shut-in casing pressure (of the annulus) – SICP], the occurrence of severe circulation losses during attempts at circulation using the sounder method and the fact that on November 8, 2011 Petrobras identified an orphan oil sheen between the Frade and Roncador blocks constitute sufficient elements for Chevron to have identified an underground blowout;

- Chevron only identified the occurrence of the underground blowout on November 9, 2011, when the seepage was spotted by the ROV. With this, the specialists from the firm Wild Well Control Inc. (WWCI) were only called in on November 10, 2011. The underground blowout should have been treated as a level 3 response, requiring immediate consultation and mobilization of WWCI by Chevron;

- Chevron took 6 (six) days to kill the well, which increased the time of leakage and, consequently, the volume of the seepage; and

- In drilling well 9-FR-50DP-RJS, which began on November 6, 2011, Chevron failed to conduct a risk analysis in conformity with Brazilian regulations and even ignored its own risk management procedures (Risk and Uncertainty Management Standard and Single Well CPDEP Roadmap). **By not appropriately evaluating the risks of the project, Chevron failed to consider the specific aspects of drilling well 9-FR-50DP-RJS, evidencing deficiencies in its culture of safety, failures in conducting the operations and accentuated weakness in managing risks on the part of the company in this project.**

Accordingly, there is no doubt that if Chevron had correctly managed the geological uncertainties (working with a margin of safety), considering the data from the correlation wells (4-TXCO-2D-RJS, 7-FR-2HP-RJS and 7-FR-21HP-RJS) and using the correct pore pressure uncertainty for an appraisal project upon evaluating the depth at which to set the dead block based on the kick tolerance criteria, the accident could have been avoided.

Moreover, weaknesses and oversights occurred in the management of risks and uncertainties associated with the operations, the project for well 9-FR-50DP-RJS, the geology and fluid dynamics of the region to be drilled, which was quite close to injector well 8-FR-29D-RJS. If the company had operated according to the regulations, granting priority to the safety of operations and basic preventive procedures, such as: (i) descent of a casing to more consolidated formations; (ii) suspension of water injection until the pressure of the region to be reached by the well to be drilled was at acceptable levels; or even (iii) reappraisal of the well's trajectory, so as to protect the passage through reservoir N560 in a safer position from the standpoint of distribution of pressures, it could have impeded any occurrence that damaged the environment or put the security of workers at risk.

Finally, if Chevron had immediately identified that it was facing an underground blowout situation and started executing dynamic kill procedures, which are clearly indicated for the scenario that was taking shape, mobilization of the resources and specialists could have come about faster, minimizing the volume that wound up leaking into the sea.