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<td>N-11000-FM0621/A88649</td>
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INVESTIGATION INTO THE UNCONTROLLED RELEASE OF HYDROCARBONS FROM THE MONTARA WELLHEAD PLATFORM ON THE 21 AUGUST 2009
EXPERT WITNESS REPORT

REVISION HISTORY

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<th>Reviewer</th>
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<tr>
<td>Colin Stuart</td>
<td>Managing &amp; Technical Director of Stuart Wright Pty Ltd</td>
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<td>17 February 2012</td>
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| Reviewed By:    |                                   |           |                    |
| Myo Kyaw Thu    | Well Engineer                     |           | 17 February 2012   |
| Linus Lim       | Well Engineer                     |           | 17 February 2012   |

| Approved By:    |                                   |           |                    |
| Colin Stuart    | Managing & Technical Director of Stuart Wright Pty Ltd |           | 17 February 2012   |

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1. Introduction

This is Volume 3 of 3 of the Report by the NOPSA engaged Expert Witness entitled

"INVESTIGATION INTO THE UNCONTROLLED RELEASE OF HYDROCARBONS FROM THE MONTARA WELLHEAD PLATFORM ON THE 21 AUGUST 2009 – EXPERT WITNESS REPORT”.

Volume 3 contains supporting information pertaining to the Expert Witness’s opinions and findings in relation to the nine questions raised by NOPSA on the investigation into the uncontrolled release of hydrocarbons from the Montara Jacket Platform on the 21 August 2009.

Part of the supporting information includes the Well Integrity condition of the H1-ST1 well at various critical stages of construction, suspension, and re-entry. The Expert witness has used the proprietary Stuart Wright Pte Ltd’s WAiT® (Well Assessment of Integrity Tool) to explain the condition of the H1-ST1 well at these different stages. The Well Integrity condition is shown in a visual chart format using the WAiT® process. There are two WAiT® charts in A0 size.

The SWPL WAiT® process is a comprehensive review platform used to drive a “forensic” assessment of the candidate wells’ integrity status, and can be applied to all stages of wells’ investigation and asset-wide risk assessment and management. The SW WAiT® process captures the subsurface environment data, well architecture (as-built condition), and as required, the production historical data of a well in an integrated view, and represents this data in the form of a WAiT® chart.

For the purpose of this investigation, the WAiT® process is used to assess the Well Integrity condition of the H1 and H1-ST1 Wells, represented in the form of two (2) charts as follows:

1. WAiT® #1 – An integrated assessment of the Well Integrity status for the Construction and Abandonment of H1 Well, and subsequent Well Integrity status for the Construction and Suspension of H1-ST1 Well.
2. WAIT® #2 – An integrated assessment of the Well Integrity status for the Re-entry of H1-ST1 Well to the Blowout Event.

Volume 3 also includes the “Timeline of relevant facts and events” focusing on the approvals PTTEPAA received from the NTDRDPIFR to undertake Montara Development activities from commencement of operations to the H1ST1 blowout event. In addition, where an activity is performed by PTTEPAA as Operator without prior approval from the NTDRDPIFR, or where it deviates from the approval given by the NTDRDPIFR, this is recorded in the Timeline. The Expert Witness has also recorded on the timeline comments specifically relating to points in time where Risk Assessments should have been performed using “Good Oilfield Practice”.

Finally, Volume 3 contains the Expert Witness’s response to specific queries from NOPSA raised during the course of the Expert Witness investigation period.
2. A Timeline of relevant events from 13 February 2007 to 21 August 2009

As requested by NOPSA, the Expert has incorporated a “Timeline of relevant events from 26 January 2009 to 21 August 2009” in this investigation report. In reviewing the timeline, the expert has expanded the timescale to a start date of 13 February 2007. This is to capture the planning and approval stage which is highly relevant to the expert witness on the outcome. The timeline review has considered the NOPSA document “Assumed Facts”; the PTTEPAA unapproved Deviation from NTDA Approvals/ from Internal MOC, and Risk Assessment Opportunities Identified by the Expert Witness.

The timeline review by stages is illustrated by a panel with 3 columns.

2. Column 2: PTTEPAA Unapproved Deviation from NTDA Approvals/Internal MOC.

The timeline is divided into 4 stages as follows:

1. Planning & Approval Stage
2. H1-ST1 Construction Stage
3. Suspension Stage
4. Re-entry Stage

During the preparation of Column 1 of the Timeline, the Expert has compared the information described in the NOPSA document “Assumed Facts” against the DDR, NT Approvals and PTTEPAA WCCCF. Any opinions and information obtained post Montara Blowout, described in the NOPSA document “Assumed Facts”, were not included in the Expert Witness’s time line.

While preparing Column 1 of the Timeline, the Expert identified unapproved deviations of the NT DA approvals by PTTEPAA as well as deviations from PTTEPAA internal change management (MOC), which can be found in Column 2 of the Timeline.
In order to identify any internal deviation on the part of PTTEPAA, the Expert has referenced Section 4.1.8 Change Management in the Construct Service or Abandon Well Process (DB-30291-NOPSA-401), one of three documents found in the PTTEPAA Well Construction Management System.

The activity “Change Management” is defined by PTTEPAA as a reoccurring activity run in parallel with core processes 4.1.1, 4.1.2, 4.1.3 and 4.1.4 (See Figure 1) in response to changes in the Statement of Requirements, Basis of Design or Well Programmes that were brought about by scope changes or unforeseen operational incidents. The tasks defined in the activities are as follows:

1. **Identify Requirement for Change and Justify**
   a. Complete Change Request complete with justification
   b. Maintain Change Register
   c. Following changes are subjected to change control:
      i. Changes that significantly increase risks or changes to well objectives, trajectory, pressures, etc.
      ii. Changes in material specifications or requirements including surplus materials or cancellation charges
      iii. Changes the cost by USD$0.5M
   d. Proposed changes should be carefully thought through and the change proposer should be prepared to substantiate the change including the gains to be made, the resources required and the impact of not making the change.

2. **Engineer Change**
   a. Engineer change in accordance with the Well Construction Standards
      i. Wherever possible, changes are engineered to the same level of details as the original design
   b. Carry out hazard analysis and risk mitigation in accordance with Risk Management Activity
   c. Prepare programme revision if engineer change

3. **Record and Disseminate Change**
   a. Update the Change Register and e-mail all persons details of the change
b. Record learning experience in Knowledge Database if applicable (Knowledge Management Activity)

Figure 1: PTTEP Management System Framework, Develop and Service Wells Process

Column 3 of the Timeline contains specific risk assessment opportunities which the expert has concluded would have been beneficial to PTTEPAA in identifying key risks, and enabled effective controls and mitigation to be implemented.

*Note: The PTTEPAA Well Construction Management System (as defined in Page 18 of the Safety Case Revision ("EV0000055"), a bridging document jointly prepared by ATLAS and the PTTEPAA Well Construction Department), was agreed to be the governing document: "During the WHP well construction, activities will be managed in accordance with PTTEP Australasia Well Construction Management System."

2.1 Legend

The figure below explains the symbols used in Timeline of relevant events.
Figure 2: Legend for Timeline of relevant events
2.2  Timeline - Planning & Approval Stage
### Assumed Facts - Montara Wellhead Platform @ H3-ST1 Planning and Approval Stage

<table>
<thead>
<tr>
<th>Date</th>
<th>Event Description</th>
<th>NOPSA Acceptance</th>
<th>PTTEPAA Unapproved Deviation from NTDA Approvals/Change Management</th>
<th>Risk Assessment Opportunities in the Expert’s Opinion</th>
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<tbody>
<tr>
<td>Feb/07</td>
<td>Submitted Operator Legislation for Montara, the FPSO and WHP, associated well equipment and secondary lines to NOPSA</td>
<td><em>NOPSA accepted CE as facility operator</em></td>
<td><em>00000000</em></td>
<td></td>
</tr>
<tr>
<td>Aug/07</td>
<td>SEADALL submitted <em>Safety Case Rev 1</em> for WIC in NOPSA</td>
<td></td>
<td><em>00000000</em></td>
<td></td>
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<tr>
<td>Aug/07</td>
<td>NOPSA accepted <em>Safety Case Rev 1</em> submitted by <strong>ALIAS</strong></td>
<td></td>
<td><em>00000000</em></td>
<td></td>
</tr>
<tr>
<td>Aug/07</td>
<td><strong>ALIAS</strong> accepted <em>Safety Case Rev 1</em> submitted by <strong>ALIAS</strong></td>
<td></td>
<td><em>00000000</em></td>
<td></td>
</tr>
<tr>
<td>Sep/07</td>
<td>Andrew Jacobs (A) of PTTEPAA informed NOPSA on the details of the contract they had in place with SEADALL</td>
<td></td>
<td><em>00000000</em></td>
<td></td>
</tr>
<tr>
<td>Oct/07</td>
<td>OR approved Well Construction Standards Version 1</td>
<td></td>
<td><em>00000000</em></td>
<td></td>
</tr>
<tr>
<td>Nov/07</td>
<td>A letter to NOPSA confirming that the Operator had satisfied the Montara FPSO and WHP facility for each of the construction, installation, operation, modification and decommissioning stages of the life of the field</td>
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<td><em>00000000</em></td>
<td></td>
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<td>Dec/07</td>
<td>CR submitted to NOPSA a <em>Safety Case for the construction &amp; installation of the proposed Montara Development</em></td>
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</tr>
<tr>
<td>Feb/08</td>
<td>NOPSA accepted Safety Case Submitted by <strong>ALIAS</strong></td>
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<tr>
<td>Feb/08</td>
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2.3 Timeline - H1-ST1 Construction Stage
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AUGUST 2009 - EXPERT WITNESS REPORT

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2.4 Timeline - Suspension Stage
INVESTIGATION INTO THE UNCONTROLLED RELEASE OF HYDROCARBONS FROM THE MONTARA WELLHEAD PLATFORM ON THE 21 AUGUST 2009 - EXPERT WITNESS REPORT

Assumed Facts - Montara Wellhead Platform @ H1-ST1 Stage 2 Suspension Stage

On 11 Mar 2009 formal approval for the M1 Well was granted for the suspension of Montara H1-ST1 well as described in the letter dated 5 Mar 2009 to TMR CS Mon & Drs BODEN & Ross.

PTEPAA issued "WCC1". PTEPAA WCC1 requiring all replace the cement plug with a 1.3” PCC. WCC1 attached on the WA & 13” PCC was installed on 12 Apr 2009.

WCC1 was approved the same day by PTEPAA WM.

PTEPAA WM issued a letter to Stoffel regarding approval to perform "M5 Stage 1 Suspension of Montara H1 ST1, PECTA. Not until all the 13” PCC.

PTEPAA approved the "M5 Stage 1 Suspension of Montara H1 ST1, PECTA. Not until all the 13” PCC.

PTEPAA approved the "M5 Stage 1 Suspension of Montara H1 ST1, PECTA. Not until all the 13” PCC.

PTEPAA advised NOPSA of the change of name from Gascoyne Resources (Mackay) Ltd to PTEPAA Mackay Northshore Carry Pty Ltd.

PTEPAA advised NOPSA of the change of name from Gascoyne Resources (Mackay) Ltd to PTEPAA Mackay Northshore Carry Pty Ltd.

According to PTEPAA, "WCC" well was any well on a well, or wells that could be undertaken concurrently with all other operations on the adjoing H1 and H1-ST1 wells.

PTEPAA Unapproved Deviation from NTDA Approvals/Change Management

Risk Assessment Opportunities In the Expert's Opinion

A request to suspend the well in 2 stages was submitted to the NT on 6 March 2009 and based on preliminary approval. PTEPAA proceeded to install the 13” PCC on 7 March 2009.

The WCC1 was issued on 11 March 2009 to replace the cement plug with the 13” PCC, was issued only after the well had been capped by the installation of the 10 3/4” PCC on 2 March 2009.

The fact that the WCC1 was only issued after the operation has been considered to a deviation from PTEPAA’s Change Management Process.
INVESTIGATION INTO THE UNCONTROLLED RELEASE OF HYDROCARBONS FROM THE MONTARA WELLHEAD PLATFORM ON THE 21 AUGUST 2009 - EXPERT WITNESS REPORT

On 6 March 2009, PTTEP submitted an application to extend HS STI to conclude the Drilling Programme TM CA-605A & BC-605. PVU, however known as "REV1", submitted and approved on 21 November 2008. It was submitted that REV1 was issued for use on 5 January 2009 that is 4 minutes after the LT acknowledge receipt of this document on 11 January 2009.

Pg 44 of the review describes the installation of the 13 3/8" PICC for a BIG ACTIVITY.

On 12 March 2009, PTTEP submitted an application to perform Stage 2 suspension on HS STI in accordance to REV2.

It appears that Stage 2 suspension was put in place on 13 March 2009.

There has been no mention, in any of the applications submitted to the LT, to suggest that HS STI was suspended from an OFFLINE activity.

This has been observed to be a deviation from the HS STI approval.

The following deviations have been observed from the review of the relevant "Montara" Processes - 18 D Rig and Completion Program Document. Montara TM 6A & TM 7A (000-000) 11/24/2000, which is known as "18 DRilling Programme" for use on 31 May 2000:

1. No Drilling Activity was suspended for at least 30 min of flow back observed.
2. No "Drilling Activity" was observed.
3. No "Dryback" was performed.
4. No "Drilling Activity" was observed.
5. No "Dryback" was performed.
6. No "Drilling Activity" was observed.
7. No "Drilling Activity" was observed.
8. No "Drilling Activity" was observed.
9. No "Drilling Activity" was observed.
10. No "Drilling Activity" was observed.

A deviation Risk Assessment Process would have identified the "well" as an "active" risk and additional "well" restrictions would have been put in place to ensure the "well" was not pressurized.

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10. No "Drilling Activity" was observed.

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2.5 Timeline - Re-entry Stage
INVESTIGATION INTO THE UNCONTROLLED RELEASE OF HYDROCARBONS FROM THE MONTARA WELLHEAD PLATFORM ON THE 21 AUGUST 2009

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3. WAiT© Analysis

The Expert has used a Well Assessment integrity tool (WAiT©) by Stuart Wright Pte Ltd to analyze and illustrate the Well Integrity condition of H1-ST1 at key stages (represented in 2 Charts) of Well Construction & Suspension and Re-entry.

- WAiT© #1 – Well Integrity Status of H1/H1-ST1 from TD 12 ¾” to Stage 2 Suspension
- WAiT© #2 – Well Integrity Status of H1-ST1 from Re-Entry to Blowout

For WAiT© #1 there are 13 key operational stages, and for WAiT© #2 there are 5 key operational stages. Each key stage contains a separate montage describing the Well Integrity status based on the facts, and concludes with the Expert’s opinion as to the Well Integrity condition at that stage.

Each stage contains the following details:

1. TVD/MD depths
2. Montara Lithology
3. Date and Time of Events
4. Well Architecture
5. Well Trajectories
6. Surface Equipment Schematic
7. Legends and References
8. Schematic of Downhole Well Conditions
9. As Built well facts as defined by NOPSA document Assumed Facts and DDRs
10. Expert’s Opinion of Well Integrity Condition for:
   a. Primary Barriers
   b. Secondary Barriers
3.1 **WAiT® #1 – Well Integrity Status of H1/H1-ST1 from TD 12 ¼” to Stage 2 Suspension**

**WAiT® #1 includes:**

1. WI Status of H1 Well at 12-1/4" Hole Section TD
2. WI Status of H1 well at Plug & Abandonment
3. WI Status of H1-ST1 Well at 12-1/4" hole TD
4. WI Status of H1-ST1 Well, Running 9-5/8”Casing to TD
5. WI Status of H1-ST1 well at 9-5/8" casing plug bump with FCP 1375 psi
6. WI Status of H1-ST1 well during 9-5/8” casing Pressure Test
7. WI Status of H1-ST1 well after 9-5/8" casing Pressure test and bleed off
8. WI Status of H1-ST1 well at 9-5/8" Casing Float Failure
9. WI Status of H1-ST1 well at 9-5/8" Casing Float Failure and Backflow
10. WI Status of H1-ST1 Well, after overdisplacement of 16bbl of SW back into 9-5/8" casing
11. WI Status of H1-ST1 Well, Post Overdisplacement
12. WI Status of H1-ST1 at Stage-1 Suspension
13. WI Status of H1-ST1 at Stage 2 Suspension
3.1.1 WI Status of H1 Well at 12-1/4" Hole Section TD
INVESTIGATION INTO THE UNCONTROLLED RELEASE OF HYDROCARBONS FROM THE MONTARA WELLHEAD PLATFORM ON THE 21 AUGUST 2009 - EXPERT WITNESS REPORT

27-Feb-09

TVRD (m)

As Buoyant Wall Parts to H1 TD 12-1/2" Hole

H1 Integrity Analysis

Table 1 - Well Integrity Conditions

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Measurement</th>
<th>Status/Colour</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydraulic inflows</td>
<td>Drilling fluid: 5.2 kg/m3 sodium chloride to assist pressure monitoring at stage 1, 2 kg/m3 at top of interval</td>
<td>Green</td>
</tr>
<tr>
<td>Secondary barriers</td>
<td>Substage 1: 69.2° C 'dead' 32.5 kg/m3 NaCl &amp; 3.26 kg/m3 CaCl2, 278.8 kg/m3 NaCl &amp; 166.5 kg/m3 CaCl2</td>
<td>Green</td>
</tr>
</tbody>
</table>

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3.1.2 WI Status of H1 well at Plug & Abandonment
3.1.3 WI Status of H1-ST1 Well at 12-1/4" hole TD
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Plan View of H1 & H1-ST1

Vertical Section (m)

Vertical Section of H1 & H1-ST1

Primary Well Barrier(s) with respect to Arrested Multicycle TH Formation as per HPET becomes ineffective at REV 5.8 AUGUST 2008

Secondary Well Barrier(s) with respect to Progressed Multicycle TH Formation as per SECTION 5.6.5, NBP/TAS 3560/003 STANDARD, REV. 5.8 AUGUST 2008

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3.1.4 WI Status of H1-ST1 Well, Running 9-5/8" Casing to TD
3.1.5 WI Status of H1-ST1 well at 9-5/8" casing plug bump with FCP 1375 psi
INVESTIGATION INTO THE UNCONTROLLED RELEASE OF HYDROCARBONS FROM THE MONTARA WELLHEAD PLATFORM ON THE 21 AUGUST 2009 - EXPERT WITNESS REPORT

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WALT P1 - Well Integrity Status of HIH1-ST1 from TD 12 3/8 to Stage 2 Suspension

WI Status of H1-ST1 well at 9-5/8" casing plug bump with FCP 1375 psi (Panel 5 of 13)

Vertical Section of H1 & H1-ST1

Oil Water Contact: 2657.2m TVDRT

VIEW A-A

"As Built" Well Integrity Analysis

Panel 5 of 13

42. PTEP then instructed their cementing contractor, Halliburton, to cement the casing in place, as per the approved cementing programme. The Halliburton cementing contractor pumped the approved programmatized quantity and quality of cement into the 9 5/8 inch casing and then headed the H1-ST1 Well over to the West Atlas drillers.

43. Using the West Atlas drilling pumps the driller pumped the approved programmatized volume of inhibited seawater into the well to displace the cement to the bottom of the well. This placed cement in the annulus formed by the 9 5/8 inch casing and the 12 7/8 inch hole.

44. A rubber plug known as the "top plug", was previously installed in the 9 5/8 inch casing between the cement and inhibited seawater. On pumping the agreed volume of seawater the top plug reached the bottom of the casing and sealed against a float collar positioned two casing joints (approximately 20 metres) above the casing shoe.

45. This event, known as "bumping the plug", is in indication that the cement displacement has been carried out in accordance with the cementing programme. This procedure ensures that in addition to cement around the casing in the annulus between the 9 5/8 inch casing and the 12 7/8 inch hole, an amount of cement is left in the bottom two joints of the casing, known as the "shoe track". When the cement job is set it should form a barrier to the flow of hydrocarbons, both into the casing and up the annulus.

46. After the plug had been successfully "bumped" the West Atlas drillers handed the well back to the Halliburton cementing contractor. He then used the cementing equipment to presurize the casing internally to 4,000 psi for 10 minutes. This required 9.5 barrels of inhibited seawater to be pumped into the casing.
3.1.6 WI Status of H1-ST1 well during 9-5/8" casing Pressure Test
47. After the plug had been successfully "bumped" the West Atlas driller handed the well back to the Halliburton cementing contractor. He then used the cementing pump to pressure the casing internally to 4,000 psi for 10 minutes. This required 9.5 barrels of inhibited seawater to be pumped into the casing.
3.1.7 WI Status of H1-ST1 well after 9-5/8" casing Pressure test and bleed off
48. On completion of the pressure test, the Halliburton cementing contractor, under instruction from PTTIEPA, bled off the pressure in the casing by opening a valve on the cement unit. As expected this allowed the 9.5 barrels of inhibited seawater used to pressurize the casing to back-flow into the tank on the cement unit.
3.1.8 WI Status of H1-ST1 well at 9-5/8" Casing Float Failure
49. The pressure in the casing then fell to approximately 200 psi and the 9.5 barrels of inhibited seawater had back flowed into the cementing unit tanks. Then there was a sudden and unexpected increase in pressure and an additional 7 barrels of inhibited seawater flowed out of the casing before the Halliburton contractor was able to close the valve.
3.1.9 WI Status of H1-ST1 well at 9-5/8" Casing Float Failure and Backflow
3.1.10 WI Status of H1-ST1 Well, after overdisplacement of 16bbl of SW back into 9-5/8" casing
INVESTIGATION INTO THE UNCONTROLLED RELEASE OF HYDROCARBONS FROM THE MONTARA WELLHEAD PLATFORM ON THE 21 AUGUST 2009 - EXPERT WITNESS REPORT

WAIT 1 - Well Integrity Status of H1/ST1-3X from TD 12 ½” to Stage 2 Suspension

WI Status of H1-ST1 Well, after overdisplacement of 166bl of SW back into 9 5/8” casing (Panel 10 of 13)

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3.1.11WI Status of H1-ST1 Well, Post Overdisplacement
52. The valve on the cement unit was then closed to hold the pressure in the casing at 1200 psi whilst the cement set. Following ‘Wait on Cement’ (WOC), a 9 5/8 inch MLS PCCC was installed on the H1-ST1 Well.
3.1.12WI Status of H1-ST1 at Stage-1 Suspension
52. The valve on the cement unit was then closed to hold the pressure in the casing at 1200 psi whilst the cement set. Following “Wait on Cement” (WOC), a 9 5/8 inch MLS PCCC was installed on the H1-ST1 Well.
3.1.13 WI Status of H1-ST1 at Stage 2 Suspension
3.2  WAiT © #2 – Well Integrity Status of H1-ST1 from Re-Entry to Blowout

WAiT© #2 includes:

1. WI Status of H1-ST1 - Removal of 20" (508mm)Trash Cap
2. WI Status of H1-ST1 - Pressure Check Below 9 5/8" MLS PCCC
   a. H1-ST1 9 5/8" PCCC Pressure Test: Scenario 1
   b. H1-ST1 9 5/8" PCCC Pressure Test: Scenario 2
   c. H1-ST1 9 5/8" PCCC Pressure Test: Scenario 3
3. WI Status of H1-ST1 - Removal of 9 5/8" MLS PCCC
4. WI Status of H1-ST1 - Wellflow Observed
5. WI Status of H1-ST1 – Evacuation
3.2.1 WI Status of H1-ST1 - Removal of 20" (508mm) Trash Cap
INVESTIGATION INTO THE UNCONTROLLED RELEASE OF HYDROCARBONS FROM THE MONTARA WELLHEAD PLATFORM ON THE 21 AUGUST 2009 - EXPERT WITNESS REPORT

Presented by

INVESTIGATION INTO THE UNCONTROLLED RELEASE OF HYDROCARBONS FROM THE MONTARA WELLHEAD PLATFORM ON THE 21 AUGUST 2009

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3.2.2 WI Status of H1-ST1 - Pressure Check Below 9 5/8" MLS PCCC
3.2.2.1 H1-ST1 9 5/8\textquoteleft PCCC Pressure Check: Scenario 1
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WAIT® #2 – Well Integrity Status of H1-ST1 from Re-Entry to Blowout

Pressure Check under 5 1/2” MD PCC (Assuming E25 & 15 psi over FV)

On the basis that the H2L did not find any information in relation to the status of the drill pipe being filled with fluid or being empty during the pressure testing of the 5 1/2” MD PCC (as referenced from H1-ST1 WESTEN DRILLING Report on 28 Aug 2009), the following assumptions were made to determine the likely scenario where the pipe was empty and in a small pressure was read on the pressure gauge at the standpipe manifold.

- From DR-3006 NOPSA-46: “‘PTDR Document Submission – Regulatory Approvals’ the depth of top cycle IV annulus was given as 2500m TVD ST.
- From D386298: “Productive thickness of 5 wells being including Cheops-Response”, the seawater specific gravity was given as 1.04 SG. Using these values, the calculated hydrostatic pressure of the seawater from FV to top of cycle IV annulus was 290psi.
- An assumed drillpipe capacity of 9,800 psi, based on the OD of 5 1/2” from D386298, was assumed by NWS in this calculation; this was because no information was provided for the exact specification of the drill pipe used.
- Also given was a seawater viscosity of 1.7 cP.

This would give an underbalance pressure just below the bottom of the 5 1/2” MD PCC to be 73psi.

The DR attempts to determine the pressure that would correspond to the pressure gauge level on the standpipe manifold.

The above was used for this analysis which describes the inverse relationship of pressure and source of the drilling fluid. The volume considered in this analysis was the sum of the drill pipe volume, the annulus volume, the BOP volume, the Minor volume and the standpipe volume. In accordance with the NDC Class 2 Specifications, Chapter 9 Section 7.11.18.2.2.3.2.1 of fluid equipment classes 6 psi due to the difference in 16.35” for individual components, an effective capacity was used to represent the capacity of the combined components, which is 0.69 psi.

Bernoulli’s Law states:

\[ P_{1} + \frac{1}{2} \rho v^{2} + \rho gh = P_{2} \]

Orifice of pressure using the 5 1/2” sampling tool into the 5 1/2” MD PCC, a column of seawater is assumed to be displaced to a height “h” in the drill pipe, axially, above and seaward. This volume of displaced seawater would compress the initial volume of air retained in the annular space. The height “h” could be calculated using the equation below which describes the above location.

\[ P_{1} = \text{Underbalanced Pressure} \]
\[ h = \text{Annulus Height} \]
\[ \rho = \text{Effective Capacity} \]

With the height of seawater calculated, the pressure at the standpipe manifold gauge was calculated to be 29psi.

If 29psi is an indication of pipe used in a large scale intervention, then pressure would not have been detected.

If no pressure, the standing instructions in the re-entry procedures (Drilling Programme 18 (EW6786)) it was highlighted that any identification of pressure below the 5 1/2” PCC would be to report pressure and bleed off.
3.2.2.2 H1-ST1 9 5/8" PCCC Pressure Check: Scenario 2
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WAIT II - Well Integrity Status of H1-ST1 from Re-Entry to Blowout

| 20 August 2009, 1130 Hrs |

H1-ST1 9 5/8” PCCC Pressure Check: Scenario 2

Pressure Check under 9 5/8” MLS PCCC (Assuming Drill Pipe filled)

In view of the fact that the FW did not find any information in relation to the status of the drill pipe being filled with fluid or being empty during the pressure testing of the 9 5/8” MLS PCCC (as referenced from H1-ST1 Well DRD EV0008595 on the 20 Aug 2009), the following assumptions were made where the pipe was filled with seawater and a small pressure was read on the pressure gauge at the standpipe manifold.

- From DB-30291-NOPSA-404 "PITREP Document Submission - Regulatory Approval/FO", the depth of top cycle IV reservoir was given as 2585m TVD RT.
- From EV00000538-EV00005351 "Daily Drilling Report" the cycle IV reservoir pore pressure specific gravity was given as 1.06 SG.
- Using these values, the calculated hydrostatic pressure of the formation was 3888psi.
- From EV0000028 "Workbook containing 6 worksheets including Coreg Resources", the seawater specific gravity was given as 1.04 SG.
- Using these values, the calculated hydrostatic pressure of the seawater from H1 to top of cycle IV reservoir was 3814psi.

Therefore, the most likely trapped pressure below the 9 5/8” PCCC is 73 psi based on the Expert’s calculation.

With an additional column of seawater in the drill pipe, that would have further reduced the underbalanced pressure to 31.8psi, because of the additional hydrostatic pressure exerted by the seawater column in the drill pipe after the 9 5/8” PCCC retrieval tool was stung into the 9 5/8” PCCC.

If a 10k psi instrument gauge was being used (conjecture?) this pressure would not have been detected.

In any case, the standing instructions in the re-entry procedures: Drilling Programme 18 (EV0000051), it was highlighted that any identification of pressure below the 9 5/8” PCCC would be to “record pressure and bleed off”. 
3.2.2.3 H1-ST1 9 5/8" PCCC Pressure Check: Scenario 3
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**WAIT #2 – Well Integrity Status of H1-ST1 from Re-Entry to Blowout**

<table>
<thead>
<tr>
<th>H1-ST1 9 5/8&quot; PCCC Pressure Check: Scenario 3</th>
<th>20 August 2009, 11:30 Hrs</th>
</tr>
</thead>
</table>

**Pressure check under 9 5/8" MLS PCCC (Assuming 9 5/8" MLS PCCC threads to be corroded on the outside)**

The EW believes that a corroded external 9 5/8" MLS PCCC is a possible scenario due to a similar observation made on the 13 3/8" MLS threads (as referenced from H1-ST1 Well DDR EV0000555 on the 20 Aug 2009). This assumes that the exterior body of the 9 5/8" PCCC that is exposed to the marine environment is not corrosion resistant.

In view of this, when the 9 5/8" PCCC retrieval tool was run in and made up to the 9 5/8" PCCC in order to check for pressure below the 9 5/8" PCCC, a true hydraulic seal between the 9 5/8" PCCC and the elastomeric seal on the 9 5/8" retrieval tool may not have been achieved.

The consequence of this could have been that when the pressure relief valve was released through the recovery tool in the 9 5/8" PCCC, the compromised hydraulic seal between the recovery tool and the 9 5/8" PCCC initiated a leak path, thereby venting any small excess pressure into the atmosphere and preventing any observable pressure at the standpipe manifold pressure gauge.

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No additional text appears in the diagram or on the page beyond what is transcribed above.
3.2.3 WI Status of H1-ST1 - Removal of 9 5/8" MLS PCCC
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3.2.4 WI Status of H1-ST1 - Wellflow Observed
128. At about 5:38 am on Friday 21st August 2009 workers on the Montara WHP, engaged in tying back the H4 well, observed a quantity of liquid flowing from one of the Montara WHP wells. Initially they were not sure which well was flowing but they later identified it as the H1-ST1 Well.

134. About 3.35 am, the flow from the well subsided and the West Atlas OIM stood down all personnel from their master stations.

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3.2.5 WI Status of H1-ST1 – Evacuation
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138. About 7:23 am before skidding operations could commence the H1-ST1 Well started flowing again, with such force that a column of oil and gas was blowing into the underside of the West Atlas rig floor.
4. Additional Factors Considered by the Expert Witness after consideration of ALL documents, examination of “Assumed Facts” and after answering NOPSA’s Nine (9) Issues

In addition to answering the nine (9) issues raised by NOPSA to the examination on the uncontrolled release of hydrocarbon from the Montara Jacket Platform on 21 August 2009, the Expert Witness had identified in his opinion, additional critical factors in relation to the investigation.

These additional critical factors are as follows:

- Comments and Opinions on PTTEPAA’S P&A and Suspension requirement - drawing comparison between PTTEPAA, CFR and NORSOK D-10 P&A requirement.
- Comments and Opinions on PTTEPAA and ATLAS Drilling Risk Assessment Methods employed.
- No Surface Isolation Barriers to Annular Flow in H1-ST1 9 5/8” (244mm) x 13 3/8” (340mm) annulus.
- Impact of the Mud Line Suspension System deployed by PTTEPAA on Well Risk.

4.1 Expert Witness’s Comments and Opinion on PTTEPAA’s P&A and Suspension Requirements

In this section, the status of the H1 and H1-ST1 Wells are highlighted, prior to the tie-back operations on the 19 August 2009, to determine the appropriate standards that construction methods for Wells H1 and H1-ST1 were required to comply with:

1. Status of the H1 Well, as defined in the PTTEPAA Well Construction Standards, [“EV0000096”], prior to the tie-back operations on the 19 August 2009
2. Status of the H1-ST1 Well, as defined in the PTTEPAA Well Construction Standards, [“EV0000096”], prior to the tie-back operations on the 19 August 2009
3. Comparison between the PTTEPAA Well Construction Standards [“EV0000096”] against the CFR and NORSOK D-010 P&A and Suspension Requirements
Special Note¹: According to the document ‘Application for Approval to sidetrack Montara H1-AC-L7’, [“EV0000020”], the following was stated by the NT “Pursuant to Clause 17 (1) (a) of the Petroleum (Submerged Lands) Management of Well Operations) Regulations 2004, I hereby approve your application to sidetrack the well Montara – H1 in accordance with your submission sent by email and received by this office on 27 February 2009”. The H1 Well, according to PTTEPAA Well Construction Standards should have been permanently abandoned as described in Volume 1 of this report.

Special Note²: Since the MODU did not remain on location following suspension on the H1-ST1 Well on 7 March 2009, the well according to PTTEPAA well construction standards could not have been in a Temporary Suspension state, but rather in ‘Long Term Suspension’ as described in Volume 1 of this report.

Special Note³: Refer to section 4.1.1.

4.1.1 Comparison between PTTEPAA against CFR and NORSOK D-010 P&A and Suspension Requirements

4.1.1.1 Barrier Philosophy

With reference to section 4.5 of Volume 1 of this report, PTTEPAA’s barrier philosophy of maintaining two (2) proven barriers between hydrocarbon bearing zones and the surface is in accordance to the requirements of NORSOK D-010 and the CFR.

4.1.1.2 Barrier Acceptance Criteria

Barriers pertinent to those installed in the wellbores H1 and H1-ST1, and their respective acceptance criteria are discussed below.

Cement Plug in H1 Open Hole

PTTEPAA’s barrier verification acceptance criteria as stated in their Well Construction Standard [“EV0000096”] for cement plugs in the open hole, had met similar requirements of NORSOK D-010 and the CFR through the following means:
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- “Tagging with sufficient force to confirm the top of good cement
- Tagging pressure must equal the equivalent of 3500KPa (500 psi)
- Or Pressure Testing to 7000 KPa (1000 psi) over leak off”.

As stated by NORSOK D-010 in Clause 15.24, cement plugs in open hole at a minimum shall be verified by means of:
- “Tagging, or measure to confirm depth of firm plug”

As stated in 30 CFR 250.174, BSEE states that the Operator must test the first plug below the surface plug and all plugs in lost circulation areas that are in open hole. The plug must pass one of the following tests to verify plug integrity:

- “A pipe weight of at least 15,000 pounds on the plug; or
- A pump pressure of at least 1,000 pounds per square inch. Ensure that the pressure does not drop more than 10 percent in 15 minutes”.

9 5/8” (244mm) Casing Cement in H1-ST1

PTTEPAA’s barrier verification acceptance criteria as stated in their Well Construction Standard [EV0000096] for casing cement, had met similar requirements of NORSOK D-010 as follows:

- “Waiting until the surface cement (tail) samples are set, providing that the cement job proceeded normally and a clear pressure differential was observed prior to bumping the plug.
- The differential pressure must confirm that the TOC is a minimum of 50m above any hydrocarbon or over-pressured water zone”.

As stated in NORSOK D-010, Clause 15.22, casing cement at a minimum shall be verified by means of:

- “Casing through hydrocarbon bearing formations: For cemented casing strings which are not drilled out, the height above a point of potential inflow/leakage point/permeable formation with hydrocarbons, shall be 200m, or to previous casing shoe, whichever is less.”
• The verification requirements for having obtained the minimum cement height shall be described, which can be:
  a. Verification by logs (cement bond, temperature, LWD sonic), or
  b. Estimation on the basis of records from the cement operation (volumes pumped, returns during cementing, etc)
  c. The strength development of the cement slurry shall be verified through observation of representative surface samples from the mixing cured under a representative temperature and pressure”.

Fluid Column within 9 5/8” (244mm) Casing in H1-ST1

According to page 37 of PTTEPAA’s Well Construction Standard [“EV0000096”], a fluid column is not considered as a barrier for either long term suspension or abandonment. However, inter alia, NORSOK D-010 states that the fluid column can be accepted as a barrier provided the following minimum requirements are met:

• “The hydrostatic pressure shall at all times be equal to the estimated or measured pore/reservoir pressure, plus a defined safety margin.
• Stable fluid level shall be verified.
• Critical fluid properties, including density shall be within specifications”.

9 5/8” (244mm) and 13 3/8” (340mm) Corrosion Caps in H1/H1-ST1

PTTEPAA’s barrier verification acceptance criteria for corrosion caps, classified as “All Other Barriers” in page 13 of the Well Construction Standard [“EV0000096”], has ONLY PARTIALLY met the minimum requirements of NORSOK D-010 as follows:

• “By either pressure testing or inflow testing”

No acceptance criteria have been provided in the NORSOK D-010 Standard, Rev 3, 2004 for Corrosion Caps. However, as stated in section 4.2.3.3 of the NORSOK D-010, Well barrier acceptance criteria are technical and operational requirements that need to be fulfilled in order to qualify the well barrier or WBE for its intended use. Corrosion Caps can only qualify as a well barrier provided they are designed, selected and/or constructed such that:
1. “it can withstand the maximum anticipated differential pressure it may become exposed to;

2. it can be leak tested and function tested or verified by other methods;

3. no single failure of well barrier or WBE leads to uncontrolled outflow from the borehole/ well to the external environment;

4. re-establishment of a lost well barrier or another alternative well barrier can be done;

5. it can operate competently and withstand the environment for which it may be exposed to over time;

6. its physical location and integrity status of the well barrier is known at all times when such monitoring is possible”.
4.2 Expert Witness’s Comment and Opinion on PTTEPAA and Atlas Drilling Risk Assessment Methods

In the sections 4.2.1 to 4.2.3 that follows, a comparison of the Risk Assessment Methods as applied by both PTTEPAA and Atlas Drilling for the Montara Field Development are compared against known industry Risk Assessment standards like the ISO. Also highlighted are key deficiencies found within the Risk Assessment and Management defined process as applied by PTTEPAA for their Well Construction Management System, which can be seen as a root cause to the Montara H1-ST1 Well blowout event.

4.2.1 PTTEPAA Risk Assessment Methods for Facilities Construction and Installation, SIMOPS, and WHP Hookup and Pre-Commissioning

As elaborated in section 5.7.1 of the Volume 1 Report, the Coogee Resources HSEMS [“EV0000010”] follows a continuous improvement cycle, which links the specific elements of the HSEMS to the management system model approach provided in AS/NZS 4804:2001.

The Expert Witness has identified that the AS/NZS 4804:2001 share common management systems principles with International (ISO) environmental management systems Standards such as “AS/NZS ISO 14001:1996, Environmental management systems— Specification with guidance for use and quality systems”, and Standards like “AS/NZS ISO 9001:2000, Quality systems management— Requirements”.

4.2.2 PTTEPAA Risk Assessment Methods for Well Construction Management System

As elaborated in section 5.7.2 of Volume 1 Report, the risk assessment and management Section 3.4 of [“EV0000050”] states that PTTEPAA uses a “defined process to systematically identify the inherent risks involved in performing various activities”. However, it should be highlighted that the “defined process” is not contained within the Well Construction Management Framework Standard [“EV0000050”] nor has it been located in any of the PTTEPAA documents submitted. Therefore no-one involved in the Montara well
construction project could have followed the “defined process to systematically identify the inherent risks involved in performing various activities”, since so far as the Expert can tell, it did not exist.

4.2.3 Atlas Drilling Risk Assessment Methods for Routine and Emergency Operations on Facility

As elaborated in section 5.7.3 of Volume 1 Report, the HAZID Risk Management technique is an endorsed method of the ISO/FDIS 31000:2009 standard’s definition and approach to Risk Assessment.
4.3 No Surface Isolation Barriers to Flow in H1-ST1 9 5/8” (244mm) x 13 3/8” (340mm) annulus

The H1-ST1 9 5/8” (244mm) by 13 3/8” (340mm) PCCC did not contain a pressure containing seal which is a standard barrier on casings at surface. It is speculated that this was left out at suspension by PTTEPAA since they would, after the tie-back of the 13 3/8” (340mm) casing to the production deck, install the final annular seal on the casing hanger. However, the time period that the H1-ST1 well contained no surface barrier on the annulus, exposed the well to annular flow risk, which would be considered unacceptable in any risk analysis under “Good Oilfield Practice”. Therefore the following summary points apply to the annular flow risk potential during the suspension period of the H1-ST1 Well, and as illustrated on the WAiT© Chart in section 3.1.13 “WI Status of H1-ST1 at Stage 2 Suspension”.

1. Lack of surface annular isolation (no containment) to Montara Cycle IV reservoir at time of suspension
   a. 9 5/8” (244mm) suspension casing hanger had no annulus seal
   b. Long term gas migration issue
   c. Risk of environmental spill

2. Insufficient tail volume coverage of reservoir
   a. The cement design and subsequent WCCCF [“EV0000800”] showed that PTTEPAA had intended the Tail slurry to cover the Montara Cycle IV reservoir. However, the physical volumes of cement pumped into the 9 5/8” (244mm) H1-ST1 Casing did not isolate the Montara Cycle IV reservoir.

3. Impact of the original hole H1 on H1-ST1 well integrity
   a. The WAiT© Chart in section 3.1.2 “WI Status of H1 well at Plug & Abandonment” shows that after the drilling out of the kick off plug, only 61m of cement plug #3 remained to isolate the entire volume of the H1 drilled reservoir from the H1-ST1 12 ¾” (311mm) x 9 5/8” (244mm) annulus. The significance of this is the tendency of gas to migrate into an annulus during cement hydration, due to loss of hydrostatic pressure. Since there is no evidence that the slurry had a short transition time, we can presume it did not. If this was the case, then the 61m of
remaining plug #3 (set at a hole angle of 82° inclination and exposed to drilling fluid) was likely in the Expert’s opinion, not to have remained an intact barrier by the time of the 9 5/8” (244mm) casing cementation. The significance of this is that there were additional reasons why the tail volume of cement was critical in height and gas flow inhibition properties.

4.3.1 Risk of Annular Flow

The WAiT© Chart in section 3.1.13 “WI Status of H1-ST1 at Stage 2 Suspension” shows the Well Integrity Status at the time of suspension. In terms of surface barriers, it is an essential feature of all wells that the wellhead cavity between casings (the annular space) is sealed by a tested barrier. This barrier is a seal (either elastomeric or metal to metal or often both), which is either an integral part of each casing hanger, or can be installed immediately following cementation as a separate item. In the case of the H1-ST1 well, no such annular seal was installed on the MLS 9 5/8” (244mm) casing hanger, nor was a seal installed post cementation. PTTEPAA had in fact planned not to install an annular seal and were relying, according to MOC statements, on the intention to pump sufficient cement on the 9 5/8” (244mm) casing to have a TOC well inside the 13 3/8” (340mm) shoe.

Above the TOC, a fluid hydrostatic barrier did exist, but it is a known phenomena that drilling fluid left in annuli often will degrade in density to the base fluid over time, thereby losing its effectiveness as a barrier. The prevalence of SCP in the vast majority of wells is partially attributable to this fluid degradation problem. This meant that should the cement barrier fail at any time or have developed a channel during cementation, then effectively there was no secondary barrier to an uncontrolled reservoir flow from the annulus. This exposure existed from the end of H1-ST1 9 5/8” (244mm) cementing operation to the time of the blowout. The hydrocarbon source could have been the Montara Cycle IV sands or the identified gas sands in the Gibson and Woolaston formations.

Since PTTEPAA was conducting a highly unusual mudline suspension, by suspending the well at the mezzanine deck, the well had a short distance to the production deck; it is possible that the temporary MLS design could not have accommodated a casing hanger seal. If this
was the case, this should have eliminated the MLS option in a full risk assessment, unless a removable temporary seal, to facilitate the tie-back was installed at the time of suspension.
4.4 Impact of the Mud Line Suspension System on Well Risk

A MLS is designed to facilitate the temporary or permanent (subsea producer) suspension of a well below the seabed where a drilling rig has to move off location, leaving no/minimal obstruction above the seabed. The MLS is essentially a casing hanger system with integral seals to isolate the annuli, within which all casing strings are contained, suspended and terminated at the MLS.

Each of the casing hangers within the MLS contains a connection thread(s) which allow each casing string to be reconnected to the surface following return of the drilling rig. Therefore a well can be pre-drilled and suspended prior to a jacket/top side being installed, under certain water depth restrictions.

Normally, when the well is suspended in the MLS, below the seabed, PCCCs are a required part of the suspension barriers. Below the PCCCs the suspension barriers will include cement plugs and mechanical barrier devices, the number and type of which will depend on whether the well has been perforated into hydrocarbons, and the configuration of the casings.

When the drilling rig returns to the well location for a well re-entry, good oil field practice would dictate that a surface tested barrier i.e. riser and BOPs, would be installed on the well prior to checking for pressure and the subsequent removal of the PCCCs. The PCCCs have back pressure valves (BPV) contained within the body, the function of which is to allow a check of pressure below the PCCC under the above stated control conditions, i.e. riser and BOPs installed, prior to the actual removal of the PCCCs. In this manner, the integrity of the barriers set within the wellbore below the PCCC, is established. Should any pressure be detected below the BPV, this would indicate barrier integrity failure in the wellbore below the PCCC.

Good oilfield practice would be to conduct a thorough Risk Assessment prior to a well re-entry which would have identified the risk of trapped gas presence below the PCCCs due to well barriers integrity failure.
PTTEPAA did in fact identify the risk of “gas below the TA cap” (PCCC) in (Volume 2, Table 34, Assessment of Document [3] Montara Phase 1B-Drilling & Completion Program).

The consequence of gas below the TA cap was correctly identified by PTTEPAA as “Gas to surface without BOPs in place” (Section 7 of Document [3], Pg 198).

However, the PTTEPAA’s mitigation (Section 7 of Document [3], Pg 198) to detected pressure below the PCCC, was to “bleed off any pressure below the cap before removing the cap”.

In the circumstances of well H1-ST1, at this state of suspension it was a fact that no approved wellbore barriers existed to the hydrocarbon reservoir (Refer to section 3.2.2 “WI Status of H1-ST1 - Pressure Check Below 9 5/8” MLS PCCC”).

Therefore, given that there were no wellbore barriers to the hydrocarbon reservoir below the PCCC, a proper risk assessment would have resulted in the conclusion, that any pressure detected below the PCCC would likely indicate communication with the reservoir.

PTTEPAA’s planned control measure, “bleed off any pressure” to the evidence of gas below the PCCC was in fact not a control but a risk escalation factor by potentially increasing the drawdown to the hydrocarbon bearing reservoir by the volume of the trapped pressure.

In the re-entry (Section 7 of Document [3], Pg 198) procedure, PTTEPAA in addition identified “gas below the cement plug” as a hazard with the consequences of well kick and well control problem, the prevention/mitigation to this hazard was as follows:

“BOPs will be installed prior to drilling out the cement plugs. Kill weight brine will be used to drill out the cement plug. After drilling out each plug the well will be flow checked and then circulate clean”.

In fact, the intention to set a surface cement plug in the suspension program was reversed as part of PTTEPAA WCCF [“EV0000802”].
The seawater fluid column barrier within the 9 5/8” (244mm) casing could not be considered a barrier as per PTTEPAA’s own barrier policy (Volume 2, Table 33, Assessment of Document [3] PTTEP Australasia-Well Construction Standards) under the conditions of “Long Term Suspension”.

Furthermore, the seawater column in fact gave a -73 psi drawdown to the top of the Montara Cycle IV reservoir (WAiT© Chart in section 3.1.13 “WI Status of H1-ST1 at Stage 2 Suspension”), as calculated based on the documentation provided. The only barrier(s) in the H1-ST1 well to uncontrolled flow from the Montara Cycle IV reservoir from the time of bleeding off the pressure after the failed floats, was in fact the 9 5/8” (244mm) PCCC. There were no cement plugs inside the 9 5/8” (244mm) casing.

API 65-2 “Isolating Potential Flow Zones During Well Construction” states:

“The barrier design should incorporate the following elements:

1. ability to withstand the maximum anticipated wellbore pressure,
2. ability to be tested for function and leaks,
3. failure of a single barrier will not result in uncontrolled flow from the well,
4. the operating environment is within the design specifications of the barrier element.”

It could be argued reasonably that the 9 5/8” (244mm) PCCC did not meet the API 65-2 definition of a barrier. In addition the 9 5/8” (244mm) PCCC, though rated for 10,000psi, was not tested after installation, to confirm if it had pressure integrity. Although not easy to accomplish, in normal circumstances with a tested casing below, such a test is possible. In PTTEPAA’s case, pressure testing the well below the PCCC in order to test the threads and BPV integrity, would likely have been impossible due to the failed shoe track (Wet Shoe), and this may the reason why it was not attempted. The result however was that a device not considered a barrier nor tested and verified, was installed on the H1-ST1 well, with no other accepted barrier between this device and the Montara Cycle IV reservoir.

Given all of the above, the correct approach to the potential hazard gas below the 9 5/8” (240mm) PCCC, would have been to assume the 9 5/8” (240mm) PCCC was in effect
equivalent to a cement barrier from a Risk Perspective, and the PTTEPAA’s planned prevention/mitigation for “gas below cement plug” should have been applied in this case.

Under these circumstances, a kill weight fluid would be available on the rig and BOPs would have been installed prior to stinging into the TA cap. In terms of options under such conditions to the evidence of “gas below the TA cap”, PTTEPAA could have made available contingency milling equipment, to remove the TA cap in controlled conditions, and also considered the use of a rotating BOP to facilitate this operation under pressure. The Expert Witness has experience in re-entry contingency planning under this exact scenario.

DDR [“EV0000555”], dated 20 August 2009, describes the actions by PTTEPAA and SEADRILL offshore staff, during the operation to remove the 9 5/8” (240mm) PCCC. The document states that the 9 5/8” (240mm) PCCC retrieval tool was stung into the PCCC, and no pressure detected on the Standpipe manifold. This statement of zero pressure may be correct, however, subsequent events leading to the blowout of H1-ST1 would indicate that either:

1. The statement of zero pressure was incorrect due to equipment/instrument error or other reasons.
2. There was pressure below the 9 5/8” (240mm) PCCC, but it was undetectable at surface, by the crew.

For point 2 to be correct, several scenarios could support this:

1. The drill pipe on which the 9 5/8” (244mm) PCCC was run to the mezzanine deck, and was not filled with fluid; OR
2. There was a seal leak on the recovery tool; OR
3. The seawater column above the 9 5/8” (244mm) PCCC retrieval tool provided additional hydrostatic pressure to the H1-ST1 wellbore thus obscuring a small under balance pressure at surface.

The explanation for these plausible scenarios and their effect on a surface pressure gauge is explained in (WAiT© Charts in section 3.2.2.1 “H1-ST1 9 5/8" PCCC Pressure Check: Scenario 1” to section 3.2.2.3 “H1-ST1 9 5/8" PCCC Pressure Check: Scenario 3”).
Summarizing Section 4.4, given the fact of the blowout caused by the well being under-balanced to the reservoir, it is entirely plausible that there was pressure below the 9 5/8” (244mm) PCCC, which was not detected at surface.

In all probability the seal leak on the recovery tool was the cause of any pressure below the PCCC being released to the atmosphere via the 20” (508mm) cut off casing undetected (section 3.2.2 “WI Status of H1-ST1 - Pressure Check Below 9 5/8” MLS PCCC”). As indicated in (section 3.2.2 “WI Status of H1-ST1 - Pressure Check Below 9 5/8” MLS PCCC”), the amount of under balance to the reservoir at the time of potential release of any pressure and recovery of the 9 5/8” (240mm) PCCC, was extremely small (73 psi).

Nonetheless, the well at this stage could have been feeding incremental but small volumes of hydrocarbon (oil) into the wellbore via the open 9 5/8” (244mm) shoe. It would have taken some time, for sufficient volume of hydrocarbon, to enter the wellbore and travel along the horizontal section above the shoe, before a significant flow and or gas bubble was detected, at surface. This duration is a function of rate of influx, reservoir properties, hydrocarbon fluid properties, and bubble point none of which information is really known.

In reality, the DDR [“EV0000612”] states that first detected signs of flow from the well occurred at 0538 am on 21 August 2009 (17.5 hours after the 9 5/8” (244mm) PCCC was removed).

It should also be pointed out that during this entire time, no monitoring of the fluid level in H1-ST1 well was stated by PTTEPAA to be in force and in fact the full attention of the rig crew was on the next well to which the rig had skidded at 0500 pm on 20 August 2009. It is likely in our opinion that the well was flowing small volumes of seawater over the 20” (508mm) stub for some time prior to it being detected by which time gas had evolved (at approximately 2,400m of depth) due to the bubble point being reached, from the oil column travelling up the wellbore, causing an increase in the upward velocity of hydrocarbons. It was gas emissions (“burp”) from the well (PTTEP DDR H4 #22 [“EV0000612”]) that was first detected but this means that the oil column influx was already close to surface.
5. Cementing Calculation

The expert has provided a series of cementing calculations and graphs used in the analysis of the H1-ST1 9 5/8” (244mm) cementing operation, and a verification of PTTEPAA’s Pre Cementing Calculations as per Coogee Resources Cementing Calculations and Reporting Form Revision 2 [“EV0000028”]. In addition, bottom hole pressure calculations at key stages of the Well Construction, are provided in support of the information presented in “WAIT © #1 – Well Integrity Status of H1/H1-ST1 from TD 12 3/4” to Stage 2 Suspension”, and “WAIT © #2 – Well Integrity Status of H1-ST1 from Re-Entry to Blowout”.

The Expert’s verification of PTTEPAA’s Pre Cementing Calculations is provided as follows:

1. Expert Witness Verification of Pre Cementing Calculations as per Coogee Resources Cementing Calculations and Reporting Form Revision 2 (EV0000028)

The 9 5/8” (244mm) H1-ST1 Casing Cement calculations are provided as follows:

1. Pseudo Static Equivalent Annulus BHP while Circulating 110% Casing Volume
2. Pseudo Static Equivalent Annulus BHP while Circulating 80bbl Spacer below Float Collar
3. Pseudo Static Equivalent Annulus BHP while Circulating 5bbl DW below Float Collar
4. Pseudo Static Equivalent Annulus BHP while Circulating LEAD Slurry below Float Collar
5. Pseudo Static Equivalent Annulus BHP while Circulating TAIL Slurry below Float Collar
6. Pseudo Static Equivalent Annulus BHP while Pressure Test to 4000psi after Plug Bump
7. Pseudo Static Equivalent Annulus BHP after Casing Pressure Test - 9 bbl Bleed Off
8. Pseudo Static Equivalent Annulus BHP Post Casing Pressure Test – Pressure spike to 1300psi observed.
9. Pseudo Static Equivalent Annulus BHP Post Pressure Spike to 1300psi
10. Pseudo Static Equivalent Annulus BHP Post 16bbl Overdisplacement
11. Pseudo Static Equivalent Annulus BHP, Post Overdisplacement, Wait on Cement Period
12. Pseudo Static Equivalent Annulus BHP after Installation of 9 5/8” PCCC
Pseudo static equivalent pressure is a term used to describe the calculation of bottom hole pressure performed by the Expert Witness at specific points in time. Use of the term pseudo merely illustrates that the value of BHP thus calculated is an estimate and not a direct measurement, or extract from any NOPSA provided documentation.

Also provided are two (2) graphs depicting bottom hole pressure changes against the Montara Cycle IV Pore Pressure, and Fracture Gradient Boundaries for the above twelve (12) 9 5/8” (244mm) H1-ST1 cementing phases:

1. Pseudo Static Equivalent Annulus BHP (Phase 1 to 5)
2. Pseudo Static Equivalent Annulus BHP (Phase 6 to 12)
5.1 Expert Witness Verification of Pre Cementing Calculations as per Coogee Resources Cementing Calculations and Reporting Form Revision 2 (EV0000028)

### EW Verified Input Data from ODR

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Texts in BLACK: EW verified input data as per EV0000028.
Texts in Red: For further details, refer to Table 3 in Vol 2 of the the Expert Witness Report.
Texts in Note: EW calculated data.
5.2 Pseudo Static Equivalent Annulus BHP while Circulating 110% Casing Volume
5.3 Pseudo Static Equivalent Annulus BHP while Circulating 80bbl Spacer below Float Collar

This worksheet presents the calculation of static Bottom Holes Pressure (BHP) at the FINAL WELL DEPTH after displacing 80 bbl of 10.5 ppg spacer through the 9 5/8\" (244mm) Float Collar.

This worksheet is the second (2nd) of twelve (12) worksheets, and provides an appreciation of how the BHP varies through different stages of the H1-ST1 9 5/8\" (244mm) cementing operations in the annulus due to the displacement of different fluid columns.

This worksheet also shows that, despite the introduction of a spacer (10.5 ppg), it is still possible to achieve a calculated and measured BHP of 1300 psi with no injection into the annulus. This is based on the assumption that the spacer is not effectively circulated. The information provided is intended for educational purposes and should not be used for operational purposes without further verification.
5.4 Pseudo Static Equivalent Annulus BHP while Circulating 5bbl DW below Float Collar

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5.5 Pseudo Static Equivalent Annulus BHP while Circulating LEAD Slurry below Float Collar

![Diagram of wellhead and flow schematic]

- **H1-ST1 well, 9 5/8" Casing**, Pseudo Static Equivalent Annulus BHP while Circulating LEAD Slurry below Float Collar

**Tables and Calculations**

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**Diagram Notes**

- **M质感 Static Equivalent Annulus BHP**
- **Differential BHP**
- **Hydrostatic Pressure**

**Flow Diagram**

- **Wellhead Housing**
- **Casing**
- **Annulus**
- **Cement**

**Legend**

- **Black**
- **Red**
- **Blue**
- **Green**

**Calculation Worksheet Description**

This worksheet presents the calculation of total Bottom Hole Pressure (BHP) at the **HIL** depth after circulating 219,960 bbl of lead slurry through the 9 5/8" (244mm) Float Collar. This worksheet is the fourth (4th) of twelve (12) worksheets, and provides an appreciation of how the BHPs are calculated throughout the different stages of the H1-ST1 9 5/8" (244mm) cementing operations in the sequence, due to the displacement of different fluids. This worksheet also shows a marked increase in BHP as a direct result of heavier and larger volume of lead cement being disposed into the annulus of the H1-ST1 well.
5.6 Pseudo Static Equivalent Annulus BHP while Circulating TAIL Slurry below Float Collar

![Diagram showing the pseudo static equivalent annulus BHP while circulating TAIL slurry below the float collar.]

This diagram illustrates the calculations and measurements related to the pseudo static equivalent annulus BHP while circulating TAIL slurry below the float collar. The calculations involve the flow of fluid through the annulus, considering the presence of the TAIL slurry and the effect on the hydrostatic pressure gradient. The diagram also includes the calculation of the pseudo static equivalent annulus BHP, which is crucial for understanding the flow dynamics and ensuring safe operating conditions.

The calculations are based on the following parameters:
- **Flow Rate:** The rate at which the fluid is circulated.
- **Differential Pressure:** The difference in pressure between the annulus and the TAIL slurry.
- **Hydraulic Gradient:** The pressure gradient in the annulus.
- **Total Pressure:** The sum of the hydrostatic and frictional pressures.

The diagram provides a visual representation of these calculations, helping to visualize the flow conditions and the impact of the TAIL slurry on the annulus pressure.

This information is critical for ensuring the safe and effective operation of the wellhead platform, particularly in the context of the uncontrolled release of hydrocarbons that occurred on the 21 August 2009.

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INVESTIGATION INTO THE UNCONTROLLED RELEASE OF HYDROCARBONS FROM THE MONTARA WELLHEAD PLATFORM ON THE 21 AUGUST 2009
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5.7 Pseudo Static Equivalent Annulus BHP while Pressure Test to 4000psi after Plug Bump
5.8 **Pseudo Static Equivalent Annulus BHP after Casing Pressure Test - 9 bbl**

**Bleed Off**

---

**Figure Description**

- **Table Casing String**
- **Casing Loading**
- **Flow Diagram**

---

**Caption**

- **Before Casing Pressure Test**
- **After Casing Pressure Test**

**Notes and Assumptions**

- **Test in DEBE**
- **Refers to Table in Vol 2 of the Expert Witness Report to NOPSA**
- **Assumptions**

**Calculation Worksheet Description**

This worksheet presents the calculation of static bottomhole pressure (BHP) at the final well, 17 FT after the bleed down of the 4000 psi Positive Casing Pressure Test.

This worksheet is the seventh (7th) of twenty-two (22) worksheets, and provides an appreciation of how the bleed down of the 4000 psi Positive Casing Pressure Test had no effects on the 9 5/8" Casing annulus BHP of the final well, 17 FT, as a result of the Top Plug settlement due to displacement fluid from the cement annulus.
5.9 Pseudo Static Equivalent Annulus BHP Post Casing Pressure Test – Pressure Spike to 1300psi Observed

The Rob has secured efs-form access for the 5 5/8" outer hubs, based on the calculations used to achieve the required netting differential pressure of 1200 psi as stated in NOPSA’s 'required forms'.

This worksheet is the eighth (8th) of twelve (12) worksheets, and shows that the observation of an increased 1300 psi at surface, had no effect on the rate or the 5 5/8" (141mm) pseudo BHP at the wellbore depth.
5.10 Pseudo Static Equivalent Annulus BHP Post Pressure Spike to 1300psi

### Table

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<td></td>
<td></td>
</tr>
</tbody>
</table>

### Notes and Assumptions

- Data in BOLD = DR verified input data as per 12/30/03.
- Data in italic = Refer to Table 2 in V.2 of the Expert Witness Response to NOPSA Issue 1 to 5- Montara ST-1.
- Data in italic = Refer to Table 2 in V.2 of the Expert Witness Response to NOPSA Issue 1 to 5- Montara ST-1.
- All values have been assumed for these calculations as reported in the Oil and Gas Report dated 27/10/09 "HONORS".
- The BHP has assumed a 9% hole environ for the 11 1/2" Open hole, based on the calculations used to achieve the reported cementing differential pressure of 1300 psi as stipulated in NOPSA "Required Fields".

### Cement Calculations

<table>
<thead>
<tr>
<th>Well</th>
<th>MD Height to annulus (ft)</th>
<th>MD ID (psi)</th>
<th>Num PDC (1)</th>
<th>Num PDC (2)</th>
<th>Num PDC (3)</th>
<th>Num PDC (4)</th>
</tr>
</thead>
<tbody>
<tr>
<td>11192</td>
<td>100.00</td>
<td>500.00</td>
<td>200.00</td>
<td>100.00</td>
<td>50.00</td>
<td>25.00</td>
</tr>
</tbody>
</table>

### Generating Calculation Worksheet Description

This worksheet presents the calculations of static bottom hole pressure (BHP) at the final WELD position following a relief of relieved fluid backflow was observed surface 11 1/2" ID annulus was a result of blooding off the 1300 psi casing test pressure - AS EXPECTED, and it will result in the existence of a differential pressure between the 11 1/2" annulus and casing due to differences in fluid densities - AS EXPECTED.
5.11 Pseudo Static Equivalent Annulus BHP Post 16bbl Overdisplacement

<table>
<thead>
<tr>
<th>Tool Data</th>
<th>EW Verified Schematic</th>
<th>EW Calculated Schematic</th>
<th>EW Calculated Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pseudo Static Equivalent Annulus BHP Post 16bbl Overdisplacement</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**H1-ST1 well, 9 5/8" CSG, Pseudo Static Equivalent Annulus BHP Post 16bbl Overdisplacement**

This worksheet presents the calculation of static Bottom Hole Pressure (BHP). At the final WELL DEPTH, after 24 hours of isolation, 16 bbls was displaced back into the H1-ST1 well as a result of the 16 bbl backflow. This backflow at 24 hours was visible, but the pressure was maintained at the same level as before the backflow. The final pressure was within the allowable limits of the well. This worksheet is part of the investigation into the uncontrolled release of hydrocarbons from the Montara Wellhead Platform on the 21 August 2009.
5.12 Pseudo Static Equivalent Annulus BHP, Post Overdisplacement, Wait on Cement Period

This worksheet presents the calculation of static Bottom Hole Pressure (BHP) at the FINAL WELL DEPTH after the Waiting on Cement (WOC) period, in which time the tail and lead had solidified into a cement sheath, thereby preventing a transmission of fluid hydrostatic pressure in the annulus. This worksheet is the element (1.14) of twelve (12) worksheets, and shows that as a result of the cement hardening process, the only means of hydraulic pressure transmission to the Montara Field is seawater columns within the internal 9 5/8” cement sheath.
### 5.13 Pseudo Static Equivalent Annulus BHP after Installation of 9 5/8" PCCC

#### Data

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>hole</td>
<td>5.88</td>
</tr>
<tr>
<td>casing 1</td>
<td>15.25</td>
</tr>
<tr>
<td>casing 2</td>
<td>9.75</td>
</tr>
<tr>
<td>casing 3</td>
<td>7.15</td>
</tr>
<tr>
<td>casing 4</td>
<td>6.15</td>
</tr>
<tr>
<td>cement</td>
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</tr>
<tr>
<td>length</td>
<td>2.00</td>
</tr>
<tr>
<td>depth</td>
<td>12.15</td>
</tr>
<tr>
<td>Total</td>
<td>75.00</td>
</tr>
</tbody>
</table>

#### Calculations

<table>
<thead>
<tr>
<th>Calculation</th>
<th>Equation</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Weighted Volume</td>
<td>Vw</td>
<td>35.00</td>
</tr>
<tr>
<td>Swell</td>
<td>Swell %</td>
<td>3.00</td>
</tr>
<tr>
<td>Total Swell</td>
<td>Total Swell</td>
<td>3.00</td>
</tr>
<tr>
<td>Swell Factor</td>
<td>Swell Factor</td>
<td>0.80</td>
</tr>
<tr>
<td>Final Swell</td>
<td>Final Swell</td>
<td>3.00</td>
</tr>
<tr>
<td>Pseudo Static Equivalent Annulus BHP</td>
<td>Pseudo Static Equivalent Annulus BHP</td>
<td>5.00</td>
</tr>
</tbody>
</table>

### Notes and Assumptions

- Pressure in the BHA is calculated using the following formulas:
  - Pseudo Static Equivalent Annulus BHP = (Swell Factor x Total Swell) + Pseudo Static Equivalent Annulus BHP
  - Pseudo Static Equivalent Annulus BHP = (Swell Factor x Total Swell) + Pseudo Static Equivalent Annulus BHP
  - Pseudo Static Equivalent Annulus BHP = (Swell Factor x Total Swell) + Pseudo Static Equivalent Annulus BHP

---

**Disclaimer:**

This worksheet presents the calculation of static Bottom Hole Pressure (BHP) at the final BHA depth after the installation of the 9 5/8" PCCC onto the H1-ST1 Well in accordance with PTFPA's Stage 1 Suspension Plan. This worksheet is for illustrative purposes only and should not be used for operational purposes. The BHP values are subject to change based on operational conditions and should be verified by qualified personnel before being applied in the field.
5.14 Pseudo Static Equivalent Annulus BHP (Phase 1 to 5)

Chart Description

This chart presents the calculated Bottom Hole Pressures (BHP) at the FINAL WELL DEPTH in the annulus, exerted by the hydrostatic pressure(s) of the fluid column(s) during the different phases of the H1-ST1 9 5/8” (244mm) Cementing Operation.

This chart is the first of two charts, and provides an appreciation of how the BHPs is maintained within the Pore Pressure (PP) and Fracture Gradient (FG) boundary from the start of Phase 1 to the end of Phase 5.

The results of calculated BHPs show that from a Well Control perspective, PTTEPAA had used the correct densities and volumes of the Lead and Tail Slurries for the purpose of cementing the H1-ST1 9 5/8” Casing.
5.15 Pseudo Static Equivalent Annulus BHP (Phase 6 to 12)

This chart presents the calculated Bottom Hole Pressures (BHP) at the FINAL WELL DEPTH, exerted by the hydrostatic pressure(s) of the fluid column(s) during the different phases of the H1-ST1 9 5/8” (244mm) Cementing Operation.

The calculated BHP from Phase 6 to Phase 11, show from a Well Control perspective, that PTTEPA had used the correct densities and volumes of the Lead and Tail Slurries for the purpose of cementing the H1-ST1 9 5/8” Casing.

This chart further highlights that the 4000 psi Positive Pressure Test conducted after the Top Plug bump, and subsequent bleed off to 200 psi, had no effect on the 9 5/8” (244mm) annulus BHP at the FINAL WELL DEPTH, as a result of the Top Plug isolating the Displacement Fluid from the cement slurries.

However, after Phase 11, the creation of a ‘Wet Shoe’ due to a 9 bbl overdisplacement (beyond the shoe track volume), resulted in a direct communication between the Montara Cycle IV Reservoir at the FINAL WELL DEPTH with the H1-ST1 Well through the 9 5/8” Casing to surface. A bleed off to zero psi at surface, after the Wait on Cement (WOC) resulted in the BHP being under balance as compared to the Montara Cycle IV Reservoir Pressure.

Despite the small 75 psi underbalance at the FINAL WELL DEPTH after Phase 11, H1-ST1 Well was subsequently brought back to a balance state after the installation of the 9 5/8” PCC in Phase 12, with (in the Expert Witness’s Opinion) a calculated 75 psi pressure trapped under the 9 5/8” PCC. This pressure would have taken some time to build and is a function of the reservoir mechanical (permeability) and fluid properties. It is entirely possible that in the time period between the bleed off to zero, after Waiting of Cement, and the installation of the PCC (L5H) that no noticeable flow occurred at surface.
6. Technical Queries from NOPSA

A technical query was sent by NOPSA in an email on the 24 December 2011 to the Expert Witness. This section covers the Expert Witness’s response to the technical queries raised. Subsequently, a teleconference call on the 19 February 2012 between NOPSA and the Expert Witness was conducted to further address this issue.
6.1 NOPSA’s Technical Queries Email

From: Colin Stuart
Sent: Saturday, December 24, 2011 7:23 AM
To: Damien Cronin
Cc: Sean Fos; Elvin Heng
Subject: RE: Montara Investigation Action Items [SEC=UNCLASSIFIED]

Hello Damien,

Thank you for your note. We will check the respective questions and get back to you in a couple of days. We are still on track at this stage having made a good start. We are using a lot of the techniques developed for our BOEMRE investigation project which will provide a great deal of illumination on the incident, and have already made some key findings.

A very happy Xmas and New year to you and family also.

Regards, Colin

Colin Stuart B.Eng FIMechE
Technical & Managing Director
Stuart Wright Pte Ltd
101 Thomson Road
No. 21- 01/02 United Square
Singapore 307591

Main Line: +65 6303 9988
Direct Line: +65 6303 9977
Fax: +65 6303 9989
E Mail: colin.stuart@stuartwright.com.sg
Web: www.stuartwright.com.sg

From: Damien Cronin [mailto:damiencronin@nopsa.gov.au]
Sent: Fri 12/23/2011 4:54 PM
To: Colin Stuart
Subject: Montara Investigation Action Items [SEC=UNCLASSIFIED]

Colin,

We have been reviewing our task list items for the Montara Investigation and would like to check the following with you:

1 - What should PTTEPAA and Atlas Drilling do with a deviation in drilling program — what is the process?

Based on the information provided to you (procedures, correspondence, records) and your knowledge of the regulatory requirements what would be required of PTTEPAA if they needed to deviate from there drilling program.

What would be required if anything from Atlas Drilling.

2 - Compliance with approval for stages of drilling program

As part of your report can you review the approvals received from the NTDA and cross check the compliance with these approvals in practice.

3 - Check that the expert witness will include in his report pictures of a 9 5/8” and 13 3/8” PCCC

Can you include pictures of 9 5/8” and 13 3/8” PCCC’s so the CDPP can see what they actually look like in reality. If they are the ‘Vetco Gray’ models, all the better.

4 - Check if the Expert Witness was given the schematic of Vetco Gray PCCC’s

Can you confirm that you were given a copy of the manufacturers data for the Vetco Gray PCCC’s used on the West Atlas. I believe you were provided with the manufacturers specification sheet.
5. Identify whether the Expert Witness was given a copy of the Schlumberger MWD document (exhibit 118)
Can you confirm that you were provided with a copy of the measurement while drilling report produced by Schlumberger.

6. BOP on H1ST1 Well – Check DDR’s to identify whether BOP in place on H1ST1 well
During your review of the DDR’s and other documentation, can you confirm whether the BOP was ever fitted to the H1 or H1ST1 well and if it was, when?

7. Need to verify if work was done under preliminary approval rather than authorised approval by NT DA
During your review of the documents provided can you identify whether work was done under preliminary approval and followed up with full written approval or not as the case may be.

If I can clarify any of the questions above please let me know.

Are you still on target to finish the report at the end of January 2012.

Hope you have a great Christmas and New Year.

Regards

Damien

Damien Cronin
Investigation Manager
National Offshore Petroleum Safety Authority (NOPSA)
Level 11, 58 Mounts Bay Road
Perth WA 6000
GPO Box 2568 Perth WA 6001
Ph: (08) 6188 8785  Fax: (08) 6188 8737
Email: damien.cronin@nopsa.gov.au
Web: www.nopsa.gov.au

Please Note: NOPSA’s head office has relocated. Visit www.nopsa.gov.au for more information.

Important: This message may contain confidential or legally privileged information. If you think it was sent to you by mistake, please immediately inform the sender, delete it from your system and do not disclose, copy or use the information contained in it. NOPSA does not guarantee that any message is secure, error-free or free of viruses or other unwanted or unexpected inclusions.
### 6.2 Response to Montara Investigation Action Items - 23 December 2011

(TQ_30291_ NOPSA_001)

<table>
<thead>
<tr>
<th>CDPP Question</th>
<th>NOPSA Comments</th>
<th>SWPL Answer</th>
</tr>
</thead>
<tbody>
<tr>
<td>What should PTTEPAA and Atlas Drilling do with a deviation in drilling program— what is the process?</td>
<td>Based on the information provided to you (procedures, correspondence, records) and your knowledge of the regulatory requirements what would be required of PTTEPAA if they needed to deviate from their drilling program. What would be required if anything from Atlas Drilling.</td>
<td>The general process is such that a MOC (Management of Change) document would have to be produced normally by the operator and co-signed by both operator and drilling contractor. The MOC states the deviation requested, needs to explain why the deviation is required, and state that a risk assessment has been conducted and that the risks resulting from the MOC are/can be managed. The inclusion of the drilling contractor authorised signature depends on what has been agreed in any bridging document or possibly stated in the safety case for the drilling rig itself. Specific to PTTEPAA and Atlas Drilling, a bridging document (&quot;EV0000055 Seadrill-West Atlas safety case revision-Document No. HSE SCR WA 070002 Montara SIMOPS Addendum&quot;) had been jointly prepared between Atlas Drilling and the PTTEPAA Well Construction department. Part of its preparation includes details on the finalisation, dissemination, implementation and ongoing hazard identification, of risk management and change control. As stated in the Safety Case Revision, the PTTEPAA Well Construction Management System is the agreed system used to plan and execute well construction activities at the Montara WHP as for any other drilling activities. The document PTTEPAA Well Construction Management Framework states that for any change management, the following task should be followed:</td>
</tr>
</tbody>
</table>


1. **Identify Requirement for Change and Justify**
   - Complete Change Request complete with justification
   - Maintain Change Register

2. **Engineer Change**
   - Engineer change in accordance with the Well Construction Standards
   - Carry out hazard analysis and risk mitigation in accordance with Risk Management Activity
   - Prepare programme revision if engineer change

3. **Record and Disseminate Change**
   - Update the Change Register and e-mail all persons details of the change
   - Record learning experience in Knowledge Database if applicable (Knowledge Management Activity)

<table>
<thead>
<tr>
<th>Compliance with approval for stages of drilling program</th>
<th>As part of your report can you review the approvals received from the NTDA and cross check the compliance with these approvals in practice.</th>
<th>This question we find is too open ended. Can NOPSA be more specific?</th>
</tr>
</thead>
</table>
| Check that the expert witness will include in his report pictures of a 9 5/8” and 13 3/8” PCCC | Can you include pictures of 9 5/8” and 13 3/8” PCCC’s so the CDPP can see what they actually look like in reality. If they are the ‘Vetco Gray’ models, all the better. | 1. We have 2D cross-sectioned drawings (not drawn to scale) from the "Vetco Operating and Service Procedure (Vecto Doc no: OSP03001)".  
2. It should be highlighted that the "Vetco Operating and Service Procedure (Vecto Doc no: OSP03001)" should not be taken as the definitive “final approved Assembly Drawings”. |
| Check if the Expert Witness was given the schematic of Vetco | Can you confirm that you were given a copy of the manufacturers data for the | 1. No manufacturer’s specification data of PCCC used on West Atlas was provided to SWPL. |
Gray PCCC's

Vetco Gray PCCC's used on the West Atlas. I believe you were provided with the manufacturers specification sheet.

2. Only a document termed "Vetco Operating and Service Procedure Vetco OPS-03001 (Mudline Suspension System Tieback)" were found as a reference document to the PPTEP Montara Phase 1B (Drilling & Completion Program, Rev-0 Jun 2009).

3. NOTE: With Reference to Vetco OPS-03001, the 13-3/8” Corrosion Cap was not designed to be pressure rated. (see below). Thus, it needs to be verified if this specification of corrosion cap (13-3/8"

<table>
<thead>
<tr>
<th>SIZE</th>
<th>PART NUMBER</th>
<th>SERVICE</th>
<th>MAXIMUM OD</th>
<th>PRESSURE RATING</th>
<th>THREAD TYPE</th>
<th>NUMBER OF TURNS TO MAKE-UP</th>
<th>RECOMMENDED MAKE-UP TORQUE</th>
</tr>
</thead>
<tbody>
<tr>
<td>13-3/8&quot;</td>
<td>143030-1*</td>
<td>H₂S</td>
<td>14.78&quot;</td>
<td>N/A</td>
<td>LEFT HAND - 2 TPI</td>
<td>7 TO 8</td>
<td>1500 TO 2500 FT-LBS</td>
</tr>
</tbody>
</table>

Identify whether the Expert Witness was given a copy of the Schlumberger MWD document (exhibit 118)

Can you confirm that you were provided with a copy of the measurement while drilling report produced by Schlumberger.

1. Only the Schlumberger MWD survey for H1-ST1 was provided.

2. SWPL will also require the final approved MWD survey for H1.

BOP on H1ST1 Well – Check DDR’s to identify whether BOP in place on H1ST1 well

During your review of the DDR’s and other documentation, can you confirm whether the BOP was ever fitted to the H1 or H1ST1 well and if it was, when?

1. BOP was fitted on both H1 and H1ST1 while drilling the 12-1/4” hole sections.

2. H1 Well
   - BOP was installed on H1 well after 13-3/8” casing cement was set and prepared for drilling the 12-14” hole section. (DDR H1 Report #8 dated 19th Feb
3. H1-ST1 well (commenced on 1 Mar 09)

- Continuation from H1 and BOP was installed on H1-ST1 until 9-5/8” casing was cemented (7th Mar 2009).
- Nipple-down BOP on 8th Mar 09 from H1-ST1 and skidded for H4.  (DDR H1-ST1 Report #8, dated 8th Mar 2009).
- Installed back BOP onto H1-ST1 for storage on 20 Mar 09.  (DDR H4 Report #21, dated 20th Mar 2009).
- Removed BOP from H1-ST1 and transferred to H3-ST1 on 3 Apr 09.  (DDR H3 ST1 Report #8, dated 3rd Apr 2009).

| Need to verify if work was done under preliminary approval rather than authorised approval by NT DA | During your review of the documents provided can you identify whether work was done under preliminary approval and followed up with full written approval or not as the case may be. | 1. **Work (1st stage suspension) was done under preliminary approval rather than authorized approval by NT DA.**

**Supporting Facts:**

2. **1st stage suspension (cementing & installing 9-5/8” PCCC).**

   - Application for approval by PTTEP 6th Mar 09 (Ref No: EV0000026)
   - Preliminary Approval by Dominic Marozzi on 6th Mar 09 (Ref No: EV0000036)
   - Execution of 1st stage suspension by PTTEP on 7th Mar 09 (Ref No: EV0000552)
   - Authorized approval from Jerry Whitfield on 9th Mar 09 (Ref No: EV0000036)

3. **2nd stage suspension (installation of 13 3/8” Corrosion Cap and 20” Trash Cap).**

   - Application for approval by PTTEP 12th Mar 09 (Ref
No: EV0000038)
- Authorized approval from Jerry Whitfield (NTDA) dated 13th Mar 09 (Ref No: EV0000040)
- Execution of 2nd stage suspension (NOTE: Only 20” trash cap installed but not 13 3/8” Corrosion Cap) by PTTEP on 16th Apr 09 (Ref No: EV0000569)

Table 1: Technical Queries dated 23 December 2011
6.3 Response to Montara Investigation Action Items -19 January 2012

(TQ_30291_ NOPSA_002)

<table>
<thead>
<tr>
<th>CDPP Question</th>
<th>NOPSA Comments</th>
<th>SWPL Answer</th>
</tr>
</thead>
<tbody>
<tr>
<td>What should PTTEPAA and Atlas Drilling do with a deviation in drilling program– what is the process?</td>
<td>Based on the information provided to you (procedures, correspondence, records) and your knowledge of the regulatory requirements what would be required of PTTEPAA if they needed to deviate from there drilling program. What would be required if anything from Atlas Drilling.</td>
<td>As per the teleconference call (dated 19 February 2012) between NOPSA and SWPL, SWPL's response to this question had been accepted by NOPSA. No further actions will be required. For reference, the document &quot;TQ_30291_ NOPSA_001 Response to Montara Investigation Action Items (111223)&quot; can be referred.</td>
</tr>
<tr>
<td>Compliance with approval for stages of drilling program</td>
<td>As part of your report can you review the approvals received from the NTDA and cross check the compliance with these approvals in practice.</td>
<td>As per the teleconference call (dated 19 February 2012) between NOPSA and SWPL, NOPSA explained that the CDPP were interested in the Expert’s view on whether PTTEPAA had in actual fact, executed all Wells' activities in accordance to what had been approved by the NT, and whether there was diligence and consistencies applied during the process. In answering CDPP’s question 2, SWPL will include in the final report submission, deviations/non-compliances to the approvals received from the NT, as well as deviations from PTTEPAA’s own internal MOC as per section 2 in Volume 3 of the Expert’s Report.</td>
</tr>
<tr>
<td>Check that the expert witness will include in his report pictures of a 9 5/8” and 13 3/8” PCCC</td>
<td>Can you include pictures of 9 5/8” and 13 3/8” PCCC's so the CDPP can see what they actually look like in reality. If they are the ‘Vetco Gray’ models, all the better.</td>
<td>As per the teleconference call (dated 19 February 2012) between NOPSA and SWPL, SWPL will include in the report if available, pictures of the 9 5/8” and 13 3/8” PCCC.</td>
</tr>
<tr>
<td>Check if the Expert</td>
<td>Can you confirm that you were</td>
<td>As per the teleconference call (dated 19 February 2012) between NOPSA and SWPL, SWPL will include in the report if available, pictures of the 9 5/8” and 13 3/8” PCCC.</td>
</tr>
</tbody>
</table>

17 FEBRUARY 2012

RPT-30291-NOPSA-001 VOLUME 3 REV0
| Witness was given the schematic of Vetco Gray PCCC's | given a copy of the manufacturers data for the Vetco Gray PCCC's used on the West Atlas. I believe you were provided with the manufacturers specification sheet. | February 2012) between NOPSA and SWPL, NOPSA has responded that the document "Vetco Operating and Service Procedure Vetco OPS-03001 (Mudline Suspension System Tieback)", attached to the PPTPEP Montara Phase 1B (Drilling & Completion Program, Rev-0 Jun 2009), is the only available document to NOPSA regarding the PCCCs' specifications and engineering schematics. For reference, the document "TQ_30291_NOPSA_001 Response to Montara Investigation Action Items (111223)" can be referred. |
| Identify whether the Expert Witness was given a copy of the Schlumberger MWD document (exhibit 118) | Can you confirm that you were provided with a copy of the measurement while drilling report produced by Schlumberger. | As per the teleconference call (dated 19 February 2012) between NOPSA and SWPL, SWPL acknowledged that we have a copy of the H1-ST1 Schlumberger MWD document (exhibit 118). However, SWPL maintains that we have not received a similar H1 MWD document, but is not a critical document required for the study. |
| BOP on H1ST1 Well – Check DDR’s to identify whether BOP in place on H1ST1 well | During your review of the DDR’s and other documentation, can you confirm whether the BOP was ever fitted to the H1 or H1ST1 well and if it was, when? | As per the teleconference call (dated 19 February 2012) between NOPSA and SWPL, SWPL’s response to this question had been accepted by NOPSA. No further actions will be required. For reference, the document "TQ_30291_NOPSA_001 Response to Montara Investigation Action Items (111223)" can be referred. |
| Need to verify if work was done under preliminary approval rather than authorised approval by NT DA | During your review of the documents provided can you identify whether work was done under preliminary approval and followed up with full written approval or not as the case may be. | As per the teleconference call (dated 19 February 2012) between NOPSA and SWPL, SWPL’s response to this question had been accepted by NOPSA. No further actions will be required. For reference, the document "TQ_30291_NOPSA_001 Response to Montara Investigation Action Items (111223)" can be referred. |

Table 2: Technical Queries dated 19 January 2012
7. Picture of Pressure Containing Corrosion Cap

The figure below is an illustration of examples PCCCs, in response to NOPSA’s request via the TQ “Montara Investigation Action Items -19 January 2012 (TQ_30291_ NOPSA_002)”.

![Figure 3: Picture of Example PCCCs in response to NOPSA's request](image_url)
8. Appendix

Appendix A: Qualifications of Mr Colin Stuart
Appendix B: Document List Register
Appendix A: Qualifications of Mr Colin Stuart B.Eng FI MechE

1 of 5: Bachelor of Engineer B.Eng, Awarded Liverpool University 1979

2 of 5: Fellow of the Institute of Mechanical Engineers FI MechE, Awarded July 1997

3 of 5: 25 Year member of Society of Petroleum Engineers S.P.E

4 of 5: Managing & Technical Director of Stuart Wright Pte Ltd Singapore, Leading Energy Industry Consultants, Established 2006

5 of 5: Curriculum Vitae Attached
CURRICULUM VITAE

Name: Colin Stuart, B.Eng. FIMechE
Gender: Male
Company: Stuart Wright Pte Ltd
Job Position: Managing and Technical Director (Founder)

PROFILE:

Well Control Engineering: Well Control kick support/remediation/engineering and root cause analysis. Have worked on remote support or in client offices or on site as situation demands.

Well Design, ERD optimization, casing design, drill string analysis, cement job planning, well control, and smart completions.

Drilling operations has included well design verification, daily operations supervision, performance monitoring and improvement.

Management of one well to multi-well drilling operations, offshore drilling supervision, created and managed 90 man well engineering department for major drilling contractor.

Experience in Petroleum Engineering has included PanOil Pan Gas well test analysis package user, well test job planning, completions design, completions procurement, subsea well planning and operations, rig site testing and completions supervision, reservoir equity studies.

Training has included basic and advanced drilling engineering; basic and advanced petroleum engineering, risk management; HPHT well planning and well control.

Computing skills have included being a trainer for DSP Well Engineering software, Word/Excel/PPT etc. Skilled Wellplan and Stresscheck/Wellcat user. Published Author: SPE Paper Summaries including:
- “20,000 PSI Dual Well Control Systems”
- “A 20 K Well Planning and Operations Experience”
- “Training Well Engineers in the Outsourced Era”
- “Contracting in the Outsourced Era”

SPE Forum Co-Chair 2004 “Completions 2007 and Beyond” Fellow of the Institute of Mechanical Engineers

Teaching: Casing Design Theory and Computer apps. Hydraulics Theory and computer apps. Introduction to Well Engineering/well planning; HPHT well design; HPHT rig crew training; HPHT rig capability audits.

LANGUAGES

Native language is English

AVAILABILITY

Available for entire project duration.

QUALIFICATIONS:

B.Eng (Mechanical), 1979, Liverpool University
Chartered Engineer, FIMECHE Fellow of the Institute of Mechanical Engineers

TRAINING:

Reservoir Engineering, Amoco, 1985
Advanced Drilling Engineering OGS, 1982
Production Optimisation, Amoco, 1984
Drilling Engineering, Preston Moore, 1980
UKCS Well Control Certificate, 1979 and repeated every two years
Negotiation skills, 2000
EMPLOYMENT HISTORY:

October 2006 to present

MANAGING AND TECHNICAL DIRECTOR - Stuart Wright Pte Ltd (Singapore)
- Established a Well Design and Risk Management company in Singapore, focusing on „upfront conceptual through to detailed well design services” for SE Asia, and supporting clients in either high risk drilling or well related production High Risk operations.
- Employment/company development is focused on recruitment and training of local Mechanical/Marine/Chemical Engineering graduates in Oil & Gas well design and Risk Management support roles. Training incorporates a practical experience period offshore on a partner drilling rig. Well designs are mapped through proprietary Business Process Mapping technique, which facilitate an extremely fast learning curve for graduates.
- Specialising in well control support/Risk management & Training/complex well design including HPHT, and well recovery operations, training, and rig capability auditing, also secondment of personnel in ops engineer roles.

October 2005 to September 2006

WELL DESIGN ENGINEER - John Wright Co (Singapore)
- Working for John Wright well control, Singapore, designing intersection well projects, primarily for Shell in Brunei. Projects include working on the design of the novel Conductor Connector well concept, for first trial execution in November 2006, and a relief/abandonment well by intersection.
- Planned and executed the abandonment using the relief well method from concept to execution including operations management of rig and all third parties.

2002- October 2005

SENIOR ASSET ENGINEER BRUNEI/DEPUTY PROJECT LEADER - Shell (Brunei)
- Working on front end well design for Champion West Phase 2. ERD wells with „Smart” completions. Integral part of subsurface and drilling teams. Drilled 5 complex snake/ERD wells in multiple stacked reservoirs with digital hydraulics smart completions c/w selective drawdown capability along 3.5 km horizontals.
- Skilled in Stresscheck/Wellplan/Wellcat/Peak Probabilistic software. Developed deterministic well cost software for Brunei Shell & resource planning system.
- Conducted well design and received budget approvals for phase 3 Champion West ERD Oil wells, plus high Pressure Gas wells. Special tasks included lead role in a serious well control incident recovery exercise, and the recovery of a slumped splitter wellhead, resulting in the saving of a $20 mm smart completion oil producer.

2000 – 2002

WELL ENGINEERING TEAM LEADER – Woodside Energy Ltd (Australia)
- Well Engineering Team Leader for the Sunrise Gas project. A $1,000 MM drilling project for which I had conceptual design and budget responsibility.
- ERD well designs plus subsea clusters.
- Design and conceptual to detailed level planning. Supervised a team of 7 engineers including drilling/completion/costing.

1998 – 2000

INTERNATIONAL DRILLING CONSULTANT – Kelly Down Consultants (Australia)
- Worked on Various Assignments planning and site supervision in the UK/ New Caledonia./Papua New Guinea/New Zealand and Australia.
- Well design/ equipment and rig procurement. Programme preparation and drilling superintendent duties. Also wrote and supervised well tests on several wild cat wells.

1998

ASSISTANT GENERAL MANAGER AND CONSULTANT WELL ENGINEERING MANAGER –Techdrill North Sea (UK)
- Assisted in establishing well engineering services for a well engineering computer software company, DSP-1 well planning software expert user. Licensed DSP-1 user.
- Contract and sales negotiations for Techdrill North Sea

1994 - 1998

WELL ENGINEERING MANAGER – Santa Fe Ltd (UK)
- Established and managed the UK Well Engineering Group, providing integrated well construction services, comprising 90 staff after 4 years. Turnover £4 MM per annum.
- Project Management and incentive drilling. Customers included BP/Shell/Amoco/B.Gas/Amerada Hess

1990 – 1993

**DRILLING SUPERINTENDENT - Ranger Oil Ltd (UK)**
- Planned and managed Southern Northern Sea development drilling programme on the Anglia Field. Template drilling and platform tiebacks.
- Senior Drilling Engineer providing technical support for an HPHT 20 K PSI offshore well including Superintendent cover.
- Superintendent for Subsea development of Anglia West Field. Set up and managed remote base in Gt Yarmouth. Totally responsible for all aspects of supply and operations base management.

1990

**DRILLING OPERATIONS ENGINEER (Consultant) - BP (Southern North Sea)**
- Well planning and daily support for development drilling operations on Amethyst Field. Multiwell deviated gas development.

1989 – 1990

**DRILLING OPERATIONS ENGINEER (Consultant) - Shell Expro (Southern North Sea)**
- Planning for eight well workover operations on Sean Field, Southern North Sea.

1989

**PETROLEUM ENGINEER (Consultant) - British Gas**
- On site Petroleum Engineer supervising slant rig completion and production well testing.

1987 – 1988

**PETROLEUM ENGINEER/WELL OPERATIONS ENGINEER (Staff) - Amoco UK (Yarmouth, UK)**
- Planned and supervised offshore platform well testing, completions, coiled tubing nitrogen operations and production logging. Supervised several offshore DST’s on exploration jackups.

1983 – 1987

**DRILLING ENGINEER (Staff) - Amoco UK (London, UK)**
- Appraised new discoveries, prepared development recommendations.
- Appraised and evaluated Gas Condensate Fields in North Sea resulting in full field development of Everest Fields.

1981 – 1983

**DRILLING ENGINEER (Staff) - Sohio Alaska Petroleum Co. (Canada)**
- Development Drilling Engineer planning and working in rotation on N. Slope running a seven rig drilling programme as on-site engineer.


**DRILLING ENGINEER (Staff) - BP Petroleum (Aberdeen, Scotland)**
- Development drilling and well workover programmes for Forties Field, including on site engineering supervision.

1980

**DRILLING ENGINEER (Staff) – BP (Norway)**
- Offshore semi-submersible exploration programme.
- Supported operations onshore and worked rig-site as Offshore Engineer.

1979 – 1980

**DRILLING ENGINEER IN TRAINING (Staff) - BP Petroleum (Aberdeen, Scotland)**
- Spent six months training in roughneck position on Forties drilling rigs.
- Received training in drilling engineering techniques during onshore assignments.
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