Client	**NOPSA**
Document Title	**INVESTIGATION INTO THE UNCONTROLLED RELEASE OF HYDROCARBONS FROM THE MONTARA WELLHEAD PLATFORM ON THE 21 AUGUST 2009 – EXPERT WITNESS REPORT**
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I. Introduction

This is Volume 2 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".

This Volume (2) contains the specific response by the Expert Witness to the requirements as stated by NOPSA, contained in their engagement letter (NOPSA Ref: A184396); dated 26 September 2011, "EXPERT WITNESS REPORT REQUIREMENTS", and specifically the Scope of Work contained within the referenced letter.

II. Scope of Work and the List of 9 NOPSA issues (NOPSA Ref: A184396)

On 29 September 2011, the "National Offshore Petroleum Safety Authority" (NOPSA) of Australia appointed Mr. Colin Stuart, Managing and Technical Director of "Stuart Wright Pty Ltd" (SWPL) as Expert Witness in relation to NOPSA's investigation into the uncontrolled release of hydrocarbons from the Montara Jacket Platform on the 21 August 2009.

This Volume 2 report documents the response completed by the Expert Witness to the following scope of work:

A. Review ALL available evidence provided by NOPSA.
B. Provide a written report with opinions based upon the nine (9) issues listed below.
    1. **Failure to use the correct volume of tail cement**
    2. **Pumping the wrong volume of cement**
    3. **Over displacement of cement**
    4. **Failure to verify the casing shoe was a barrier**
    5. **Failing to pressure test the 9 5/8 inch cement casing shoe**
    6. **Failure to install the 13 3/8 inch MLS PCCC**
    7. **Corrosion of the threads on the 13 3/8 inch mud line hanger**
    8. **Removal of the 9 5/8 inch MLS PCCC**
    9. **Failure to reinstall the 9 5/8 inch MLS PCCC**

In summary, this Volume 2 report details the Expert Opinion on each of the NOPSA Defined 9 omissions stated above, whether the omissions would increase the risk of an uncontrolled release of hydrocarbons, the practicability of the steps suggested to reduce risks and what good oilfield practice would have been in a similar situation.

Finally the qualifications of the Expert Witness, Mr Colin Stuart, are attached in Appendix A found in Volume 3 of the Report.

III. Structure of this document

Sections 1 to 5 relating to NOPSA Issues 1 to 5

Section 1A of this document presents the results of a detailed assessment of key documents related to the Montara Project by the Expert Witness in relation to NOPSA issue 1. A list of these key documents is presented in section 1.A.I, together with the Expert Witness assessment of each, presented in section 1.A.II. Sections 1B to 1D present the Expert Witness's opinion in relation to NOPSA issue 1, in view of the assessed documents.

Sections 2 to 5 of this document presents the Expert Witness's opinion in relation to NOPSA issues 2 to 5, in view of the assessed documents. The Expert Witness observes that the key documents in relation to issue 1 are also directly related to issues 2 to 5. Therefore "part A" within each Issue 2 to 5 relates to the same documents assessed under Section 1.A.

Sections 6 to 9 relating to NOPSA Issues 6 to 9

Section 6A of this document presents the results of a detailed assessment of key documents related to the Montara Project by the Expert Witness in relation to NOPSA issue 6. A list of these key documents is presented in section 6.A.I, together with the Expert Witness assessment of each, presented in section 6.A.II. Sections 6B to 6D present the Expert Witness's opinion in relation to NOPSA issue 6, in view of the assessed documents.

Sections 7 to 9 of this document presents the Expert Witness opinion in relation to NOPSA issues 7 to 9, in view of the assessed documents. The Expert Witness observes that the key documents in relation to issue 6 are also directly related to issues 7 to 9. Therefore "part A" within each Issue 7 to 9 relates to the same documents assessed under Section 6.A.

1. Failure to use the correct volume of tail cement

1.A An assessment of ALL documentation provided by NOPSA relating to the failure to use the correct volume of tail cement when cementing the 9 5/8 inch casing shoe in H1-ST1 Well on 7 March 2009.

1.A.I List of ALL relevant Documentation

The Expert Witness has reviewed all available information provided by NOPSA, and identified the following documents as having direct importance to NOPSA issues 1 to 5. The list of documents is presented in Table 1 below. A detailed assessment of each document, including in particular the relevance of each document to the NOPSA issues 1 to 5 in presented in Section 1.A.II.

No	NOPSA provided Document Titles	Reference	Results of Expert Witness Assessment
Document Type: Operational			
[1]	PTTEP Australasia titled "Montara Platform, Forward Plan #17-Run and Cement 9 5/8" Version:2.0	EV0000033	Table 2
[2]	Workbook containing 6 worksheets including Coogee Resources	EV0000028	Table 3
[3]	PTTEP Australasia titled "Montara Platform, Forward Plan #17-Run and Cement 9 5/8" Version:1.0	EV0000029	Table 4
[4]	Excel spreadsheet in the name of PTTEP Australasia & Schlumberger- Montara H1 ST1 MWD Surveys	EV0000030	Table 5
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[8]	Submission - PTTEP Document Submission - Bundle Well survey reports#3	*DB-30291-NOPSA-394	Table 9
[9]	Submission - 09 - Actual TVD of formation tops for H1 ST1 , H4 and GI ST1	*DB-30291-NOPSA-359	Table 10
[10]	Submission - 12 - Montara Pressure Test Charts for H1 ST1	*DB-30291-NOPSA-360	Table 11
[11]	Submission - 13 - Montara H1 ST-1 244mm Casing Tally and Report#2	*DB-30291-NOPSA-361	Table 12
[12]	Submission - Halliburton Montara H1cement 244mm casing cementing report#2	*DB-30291-NOPSA-419	13
Document Type: Planning			

No	NOPSA provided Document Titles	Reference	Results of Expert Witness Assessment
[13]	Submission - Halliburton Montara H1 cement program Ver-3#2	*DB-30291-NOPSA-418	Table 14
[14]	Document-PTTEP Australasia-Well Construction Standards, Standard ID: D41-502433-FACCOM Version 3	EV0000096	Table 15
[15]	Coogee Resources-GI, H1 & H4 (Batch Drilled) Drilling Program Document No: TM-CR-MON-B-150-00001 Rev0 September 2008	EV0000011	Table 16
[16]	Coogee Resources-GI, H1 & H4 (Batch Drilled) Drilling Program Document Number: TM-CR-MON-B-150-00001 REV:2 January 2009	EV0000018	Table 17
[17]	Letter addressed to Jerry Whitfield from Ian Paton of Coogee Resources - GI, H1 & H4-AC/L7-Revised Drilling Program	EV0000013	Table 18
[18]	Transmittal addressed to Jerry Whitfield from Catherine Noonan of Coogee Resources - GI, H1 & H4-AC/L7-Revised Drilling Program	EV0000014	Table 19
[19]	Submission - Halliburton P-09-055BB Montara H1 9-58 Lead Cement Lab Report#2	*DB-30291-NOPSA-420	Table 20
[20]	Submission - Halliburton P-09-056C Montara H1 9-58 Tail Cement Lab Report#2	*DB-30291-NOPSA-421	Table 21
Document Type: MOC and Approvals			
[21] ii	Coogee Resources-Well Construction Change Control Form D65005A 001	EV0000015	Table 22
[22] ii	Coogee Resources-Cementing Program-Montara H1 No Topsides, Attachment to D65005A 001	EV0000016	Table 23
[23] ii	Well Control Change Form Montara- Well GI, H1, H4 Rev. 2, D65005A 003	EV0000801	Table 24
[24] i	Email from Chris Wilson to West Atlas Supervisor-Application for Approval to sidetrack Montara H1-AC-L7	EV0000020	Table 25
[25] ii	Email from Chris Wilson-Preliminary Copy of Change Control-Montara H1, H4, H2 & H3 & Coogee Resources, D65005A-005	EV0000021	Table 26
[26] i	Letter addressed to Jerry Whitfield from Ian Paton-PTTEP Australasia Pty Ltd on 6 March 2009	EV0000026	Table 27
[27] i	Letter addressed to Jerry Whitfield from Ian Paton-PTTEP Australasia Pty Ltd on 12 March 2009	EV0000038	Table 28
[28] i	Submission - PTTEP Document Submission - Regulatory Approvals#3	*DB-30291-NOPSA-404	Table 29
Notes: **i: Superscript depicting NT approvals for PETTPAA Suspension Activities** **ii: Superscript depicting PTTEPAA's Management of Change** ***Note: Document Reference Number Given by the Expert Witness**			

Table 1: List of Critical Documents – NOPSA Issue 1 to 5

1.A.II Assessment of Table 1 Documents

No	NOPSA provided Document Titles	Reference
Document Type: Operational		
[1]	PTTEP Australasia titled "Montara Platform, Forward Plan #17-Run and Cement 9 5/8" Version:2.0	EV0000033
Description and Relevance to NOPSA issue 1-5		
Document [1] is an instructional document which describes the Operational Procedures to run and cement the 9 5/8” (244mm) casing. It was jointly issued by ATLAS and PTTEPAA to the rig crew and offshore third party service contractors. This document has been used as a reference document by the Expert Witness.		
Consistency between Documents, and Consistency between Approvals		
There were two revisions of the “Forward Plan for Running and Cementing the 9 5/8” Casing”, identified by Documents [1] and [3]. Both documents have been found to contain the same information in relation to the operational procedures described as Steps 6 to 11 in the document, which is to cement the 9 5/8” (244mm) casing, in H1-ST1 well. The information presented in both Documents [1] and [3] are consistent.		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 2: Assessment of Document [1] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
	Document Type: Operational	
[2]	**Workbook containing 6 worksheets including Coogee Resources**	**EV0000028**
	Description and Relevance to NOPSA issue 1-5	

Document [2] contains the following key records directly related to the cementation of the 9 5/8" (244mm) casing for H1-ST1 well:

1. "*PTTEPAA Offshore Cementing Pre-job Calculations*": contains the volume of cement to pump, pumping schedule, and expected final circulating pressure before plug bump.
2. "*Expected 9 5/8" (244mm) Casing Pressure Test Graph*".
3. "*9 5/8" (244mm) Casing, Running and Cementing Report*", in Imperial and Metric units.

The following issues have been identified based on a detailed assessment of Document [2] "*PTTEPAA Offshore Cementing Pre-job Calculations*":

1. Discrepancy between data adopted by PTTEPAA for Cementing Pre Job Calculations and DDR recorded data.
2. Calculation errors:
   a. The rathole volume of 4.75bbl was not included, in determining the total tail slurry volume to be pumped. Total tail slurry volume including the rathole, as calculated within this report is 137.18bbl [Expert Witness Report Vol 3 Section 5.1].
   b. The application of a "25% open hole excess" assumption was not included, in determining the tail slurry volume that would occupy the rathole. It should be highlighted that the assumption of a 25% open hole excess had been assumed by PTTEPAA in the calculations of the remaining 12 1/4" (311mm) open hole sections [Expert Witness Report Vol 3 Section 5.1].
   c. An incorrect density of the Tuned Spacer and incorrect volume of Pre-Flush (drill water) was used, in determining the expected differential pressure just before plug bump in order to calculate the expected top of cement in the 9 5/8" (244mm) x 13 3/8" (340mm) annulus. [Expert Witness Report Vol 3 Section 5.3 and 5.4].

   For the purpose of verifying PTTEPAA's cementing calculations, the following **ASSUMPTIONS** have been made:

   - Based on the value stated within Document [13], Tuned Spacer density is 10.5ppg

- Based on value stated within Document [7], Pre Flush Volume is 5 bbl

d. Measured Depths (MD) instead of True Vertical Depths (TVD) were used for the calculation of fluid hydrostatic pressures, by PTTEPAA in determining the expected differential pressure just before plug bump, to calculate the expected top of cement.

e. Neither a specific datum depth nor a specific value for the reservoir pressure of the Montara Cycle IV, had been provided. There were two values of the reservoir pressure given: **1.04SG** [EV0000073] and **1.06SG** Document [7].

For the purposes of the calculations performed by the Expert Witness, the following **ASSUMPTIONS** have been made:

- The datum depth is at the total depth of the H1-ST1 well, at 2654m TVDRT
- Reservoir pressure ranges between 1.04SG to 1.06SG at the assumed datum depth.

f. Discrepancies between the Planned and Actual cement additive concentration have been identified and are captured in Table 30.

Consistency between Documents, and Consistency between Approvals

The following discrepancies between input data captured in the "*PTTEPAA Offshore Cementing Pre-job Calculations*", and in the PTTEPAA/ATLAS DDR were identified:

1. "**Previous Casing Shoe Depth**" at **1637.52m** as recorded in [2], is different from the DDR record [EV0000529] of **1636.8m**. For the purposes of the calculations performed by the Expert Witness, the **ASSUMED** "**Previous Casing Shoe Depth**" depth is 1636.8m.
2. "**Length of Lead in 17 ½" cased hole**" of **7m** as recorded in [2], is different from DDR record [EV0000529] of **7.2m**. For the purposes of the calculations performed by the Expert Witness, the **ASSUMED** "**Length of Lead in 17 ½" cased hole**" to be 7.2m.
3. Final pressure to "**Confirm float not holding**" of **1150 psi** as recorded in [2], is different from DDR records stated within Document [6] and [7] of **1300 psi**. For the purpose of verifying PTTEPAA's cementing calculations, EW have **ASSUMED** the Final pressure to "**Confirm float not holding**" to be 1300 psi.

Omissions of Data received (if any)

The density of Tuned Spacer pumped into the H1-ST1 well has not been provided in this document.

This assessment is used in response to issue:

Section 1.B, 2.B, 3.B, 4.B, and 5.B

Table 3: Assessment of Document [2] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: Operational		
[3]	PTTEP Australasia titled "Montara Platform, Forward Plan #17-Run and Cement 9 5/8" Version:1.0	EV0000029
Description and Relevance t NOPSA issue 1-5		
Document [3] is a previous revision of Document [1]. This document has been used as a reference document by the Expert Witness.		
Consistency between Documents, and Consistency between Approvals		
There were two revisions of the “Montara Forward Plan for Running and Cementing the 9 5/8” Casing”, identified by Documents [1] and [3]. Both documents have been found to contain the same information in relation to the operational procedures described as Steps 6 to 11 in the document, which is to cement the 9 5/8” (244mm) casing, in H1-ST1 well. The information presented in both Documents [1] and [3] are consistent.		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 4: Assessment of Document [3] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: Operational		
[4]	**Excel spreadsheet in the name of PTTEP Australasia & Schlumberger- Montara H1 ST1 MWD Surveys**	**EV0000030**
Description and Relevance to NOPSA issue 1-5		
Document [4] contains the MWD survey for H1-ST1 well. This document is believed to be the final approved well survey for the H1-ST1 well. Data extracted from Document [4] were used to perform conversions from Measured Depth to True Vertical Depth.		
Consistency between Documents, and Consistency between Approvals		
Document [8] contains the same MWD survey information for the H1 and H1-ST1 well. Data for H1-ST1 provided in Document [8] is consistent with Document [4].		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 5: Assessment of Document [4] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: Operational		
[5]	**Email from West Atlas Drilling Supervisor to Craig Duncan and Chris Wilson-Montara WHP Morning Reports**	**EV0000034**
Description and Relevance to NOPSA issue 1-5		
Document [5] is an email addressed to the PTTEPAA WCM and DSUP, sent by the WA Drilling Supervisor. It contains six (6) attachments detailing Operational Events on 7 March 2009, when Stage 1 Suspension activities were carried out. Of particular interest in the 6 attachments, is the "*Advantage Drilling Fluid Report-7-07/March/2009*", believed to be the final Drilling Fluid Report submitted by Baker Hughes, the drilling fluid service company, to PTTEPAA on the 7 March 2009. The following quote was found in the comments section of Document [5]: "*Pumped 15.1m3 of Tuned Spacer followed by 59m3 of 1.50sg lead slurry then 21.1m3 of 1.90sg tail slurry. Total returns seen at surface.*" For the purpose of determining the Top of Cement based on different pressure calculations in Expert Witness Report Vol 3 Section 5.2 to 5.12 where it is **ASSUMED** that no losses occurred during the cementation of the 9 5/8" (244mm) casing, in the H1-ST1 well.		
Consistency between Documents, and Consistency between Approvals		
There are no other NOPSA provided documents identified that contain similar information presented in Document [5].		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 6: Assessment of Document [5] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: Operational		
[6]	**Seadrill DDR Montara-H1-ST1 (07/03/09)**	**EV0000655**
Description and Relevance to NOPSA issue 1-5		
Document [6] is a Daily Drilling Report issued by ATLAS on 7 March 2009. Information provided in this document was used to verify calculations, used in the assessment of Document [2]. See Table 3		
Consistency between Documents, and Consistency between Approvals		
Data discrepancies have been identified and used in the assessment of Document [2]. See Table 3.		
Omissions of Data received (if any)		
The density of Tuned Spacer pumped into the H1-ST1 well has not been provided in this document.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 7: Assessment of Document [6] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: Operational		
[7]	**PTTEPAA DDR Montara-H1 ST-1 (07/03/09)**	**EV0000756**
Description and Relevance to NOPSA issue 1-5		
Document [7] is a Daily Drilling Report issued by PTTEPAA on 7 March 2009. Information provided in this document was used to verify calculations, used in the assessment of Document [2]. See Table 3.		
Consistency between Documents, and Consistency between Approvals		
Data discrepancies have been identified and used in the assessment of Document [2]. See Table 3.		
Omissions of Data received (if any)		
The density of Tuned Spacer pumped into the H1-ST1 well has not been provided in this document.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 8: Assessment of Document [7] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: Operational		
[8]	Submission - PTTEP Document Submission - Bundle Well survey reports#3	*DB-30291-NOPSA-394
Description and Relevance to NOPSA issue 1-5		
Document [8] contains the MWD survey for H1 and the H1-ST1 well, believed to be the final approved survey for the H1. Data extracted from Document [4] were used to perform conversions from Measured Depth to True Vertical Depth.		
Consistency between Documents, and Consistency between Approvals		
Document [4] is contains the same MWD survey information for the H1-ST1 well. Data for H1-ST1 provided in Document [8] is consistent with Document [4].		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 9: Assessment of Document [8] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: Operational		
[9]	**Submission - 09 - Actual TVD of formation tops for H1 ST1 , H4 and GI ST1**	**DB-30291-NOPSA-359**
Description and Relevance to NOPSA issue 1-5		
Document [9] contains the MDs, TVDs (referenced from the MSL and RT), Northings and Eastings of the respective formation tops, encountered by the H1-ST1 well during the Construction Stage. The depths of the hydrocarbon bearing formations such as "*Gibson*", "*Woolaston*", and "*Montara Cycle IV*", were used in the following applications: 1. Determine if the hydrocarbon bearing formations had been isolated by the 9 5/8" cementation job containing a lead and tail slurry. 2. Calculate reservoir pressure based on the **ASSUMED** range of 1.04SG to 1.06SG stated in Table 3.		
Consistency between Documents, and Consistency between Approvals		
Data within Document [9] are found to be consistent with Document [28].		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 10: Assessment of Document [9] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: Operational		
[10]	**Submission - 12 - Montara Pressure Test Charts for H1 ST1**	**DB-30291-NOPSA-360**
Description and Relevance to NOPSA issue 1-5		
Document [10] contains two pressure test charts of the actual H1-ST1 9 5/8" (244mm) cementing job execution. The description of these are as follows: The first chart contains the surface pump pressures, pump rates, total pumped volume, and surface circulating densities from the time when the bottom wiper plug was release. This chart also shows the surface pressure changes during the displacement of the lead and tail slurries, and the release of the top wiper plug. The second graph contains the surface pump pressures and total pumped/bled off volumes from the time the top wiper plug landed on the bottom plug, the 9 5/8" (244mm) casing pressure test to 4000psi and subsequent bleed off to 200psi before a rapid pressure increase to 1300 psi, the flowback of 7 bbls, and the re-displacement of 16.5 bbl of seawater, and finally when the well was shut in at the cement head for during the WOC period.		
Consistency between Documents, and Consistency between Approvals		
Document [10] has been found to be consistent with other NOPSA supplied documents.		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 11: Assessment of Document [10] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: Operational		
[11]	**Submission - 13 - Montara H1 ST-1 244mm Casing Tally and Report#2**	**DB-30291-NOPSA-361**
Description and Relevance to NOPSA issue 1-5		
Document [11] contains details relating to the order and geometric specifications of all H1-ST1 9 5/8" (244mm) casing joints, accessories (centralisers), and other downhole casing equipment as assembled, ran and installed in the H1-ST1 Well. Comments on the 9 5/8" (244mm) casing running operations were also recorded in document [11].		
Consistency between Documents, and Consistency between Approvals		
Document [11] is been found to be consistent with other NOPSA supplied documents.		
Omissions of Data received (if any)		
The average callipered inner diameter of the 9 5/8" (244mm) casing joints, actual placement of centralizers on the casing joints (where applicable), and the specifications of the casing shoe and float collar (i.e. manufacturer, and auto-fill type), have been identified as key omissions in this document.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 12: Assessment of Document [11] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: Operational		
[12]	**Submission - Halliburton Montara H1cement 244mm casing cementing report#2**	**DB-30291-NOPSA-419**
Description and Relevance to NOPSA issue 1-5		
Document [12] contains the 9 5/8" (244mm) post cementing job summary for the H1-ST well, prepared by Halliburton.		
Consistency between Documents, and Consistency between Approvals		
Discrepancies between the Planned and Actual cement additive concentrations have been identified and are captured in Table 30.		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 13: Assessment of Document [12] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: Planning		
[13]	**Montara H1-ST1 Halliburton Cement programme version 3**	*DB-30291-NOPSA-418
Description and Relevance to NOPSA issue 1-5		
Document [13] is the final version of Halliburton's Cementing Programme for Montara H1-ST1 well issued on 30 January 2009. The following data were referenced and used to verify calculations used in Expert Witness Report Vol 3 Section 5.2 to 5.13 as described in Table 3. 1. Tuned Spacer density of 10.5 ppg, 2. Concentration of cement additives used in the 9 5/8" (244mm) lead slurry 3. Concentration of cement additives used in the 9 5/8" (244mm) tail slurry		
Consistency between Documents, and Consistency between Approvals		
Discrepancies between the Planned and Actual cement additive concentrations have been identified and are captured in Table 30.		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 14: Assessment of Document [13] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: Planning		
[14]	**Document-PTTEP Australasia-Well Construction Standards, Standard ID: D41-502433-FACCOM Version 3**	**EV0000096**
Description and Relevance to NOPSA issue 1-5		

Document [14] provides the minimum standards applicable to all aspects to well design, construction, servicing and well abandonment activities.

It is stated in Page 9 of Document [14] that "*During drilling, completion, testing, intervention and other open hole operations the following barriers shall be maintained in the annulus – two proven barriers between hydrocarbon bearing permeable zones and the surface*".

For the purposes of answering NOPSA issues 1 to 5, the Expert Witness has extracted references of PTTEPAA definitions and minimum standards stated in Chapter 5 (Barriers) and Chapter 14 (Abandonment and Long Term Suspension) as follows:

Section 5 defines the following barrier verification methods of annulus cement, cement plug (not surface plugs) and all other barriers must be verified in-situ as follows:

For annulus cement:

1. "*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*"
2. "*The differential pressure must confirm that the TOC is a minimum of 50m above any hydrocarbon or over-pressure water zone*".

For cement plugs (NOT surface plugs):

1. *"Tagging with sufficient force to confirm the top of good cement"*
2. *"Tagging pressure must equal the equivalent of 3500KPa (500 psi)"*
3. *"Or Pressure testing to 7000 KPa (1000 psi) over leak off*"

For ALL other barrier(s):

1. *"Either pressure or inflow test"*

In addition to the barrier verification methods described above, **Section 5** also defines a "*Temporary suspension is where the MODU or well intervention vessel remains on location*". Since the WA MODU **did not remain on location** following suspension of H1-ST1 well, hence the well according to PTTEPAA well construction standards, could not have been in a Temporary Suspension state. Therefore it can be argued that barrier types listed during temporary suspension as defined in **Section 5** were **not applicable** to H1-ST1 well. **Section 14** defines a "*Long term suspension is when the MODU leaves the well site.*" It can be argued that according to the PTTEPAA well construction standards, the H1-ST1 well was in a **long term** suspension condition and therefore the barriers defined in **Section 14.1** were applicable.
Consistency between Documents, and Consistency between Approvals
There are no other NOPSA provided documents identified that contain similar information presented in Document [14].
Omissions of Data received (if any)
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.
This assessment is used in response to issue:
Section 1.B, 2.B, 3.B, 4.B, and 5.B

Table 15: Assessment of Document [14] in relation to Issue 1 to 5

<table>
<tr><th>No</th><th>NOPSA provided Document Titles</th><th>Reference</th></tr>
<tr><td colspan="3">Document Type: Planning</td></tr>
<tr><td>[15]</td><td>Coogee Resources-GI, H1 & H4 (Batch Drilled) Drilling Program Document No: TM-CR-MON-B-150-00001 Rev0 September 2008</td><td>EV0000011</td></tr>
<tr><td colspan="3">Description and Relevance to NOPSA issue 1-5</td></tr>
<tr><td colspan="3">Document [15] is the first of three revisions made to the drilling programme for wells GI, H1 and H4 planned in part of the Montara Development Project. It contains the objectives and programme requirements for drilling and completing the Montara Development Project for Campaign.</td></tr>
<tr><td colspan="3">Consistency between Documents, and Consistency between Approvals</td></tr>
<tr><td colspan="3">There were three revisions to the “GI, H1 & H4 (Batch Drilled) Drilling Program”, identified by Documents [15] and Document [16]. The changes between the three revisions are as follows:

“Revision 0 of this drill program assumed the Platform topsides would be in place and the wells would be batch drilled and completed.”

“Revision 1 of this drilling program is based on the Platform Topsides not being in place and the wells being sequentially drilled down to the 244mm (9 5/8”) casing shoe and suspended. The well surface and target locations, formation tops, and directional profile have not changed. The well design has been changed to include an MLS that will allow the wells to be suspended below the top of the jacket.” Revision 1 of Document [15] was not provided to the Expert Witness.

“Revision 2 of this drilling program is based on the Platform Topsides not being in place and West Atlas Conductor Deck Extension being used without the conductor tensioner. This allows the wells to be batch drilled. All three wells will be batch drilled to the 244mm (9 5/8”) casing shoe and suspended. The well surface and target locations, formation tops, and directional profile have not changed. “</td></tr>
<tr><td colspan="3">Omissions of Data received (if any)</td></tr>
<tr><td colspan="3">No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.</td></tr>
<tr><td colspan="3">This assessment is used in response to issue:</td></tr>
<tr><td colspan="3">Section 1.B, 2.B, 3.B, 4.B, and 5.B</td></tr>
</table>

Table 16: Assessment of Document [15] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: Planning		
[16]	**Coogee Resources-GI, H1 & H4 (Batch Drilled) Drilling Program Document Number: TM-CR-MON-B-150-00001 REV:2 January 2009**	**EV0000018**
Description and Relevance to NOPSA issue 1-5		

Document [16] is the third revision of Document [15], and contains the final program requirements for drilling and suspending Wells G1, H1 and H4 of the Montara Development Project. The two main revisions of the document, found on Page 5 of 75 are as follows:

1. Revision 1, 28 November 2008: Updated for no Topsides – Not Generally Issued
2. Revision 2, 6 January 2009: Updated for no Topsides & Batch Drilling – Issued for Use

Consistency between Documents, and Consistency between Approvals

Document [16] is the third revision of Document [15], titled Revision 2. The previous revision of Document [16], i.e. Revision 1, had not been provided to the Expert Witness. From the assessment of all documents supplied, the Expert Witness has reasons to believe that *Revision 1 was not submitted to the NT.

The revisions to the "GI, H1 & H4 (Batch Drilled) Drilling Program", identified by Documents [15] and Document [16] are as follows:

"Revision 0 of this drill program assumed the Platform topsides would be in place and the wells would be batch drilled and completed."

**"Revision 1 of this drilling program is based on the Platform Topsides not being in place and the wells being sequentially drilled down to the 244mm (9 5/8") casing shoe and suspended. The well surface and target locations, formation tops, and directional profile have not changed. The well design has been changed to include an MLS that will allow the wells to be suspended below the top of the jacket. "*

"Revision 2 of this drilling program is based on the Platform Topsides not being in place and West Atlas Conductor Deck Extension being used without the conductor tensioner. This allows the wells to be batch drilled. All three wells will be batch drilled to the 244mm (9 5/8") casing shoe and suspended. The well surface and target locations, formation tops, and directional profile have not changed. "

Omissions of Data received (if any)
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.
This assessment is used in response to issue:
Section 1.B, 2.B, 3.B, 4.B, and 5.B

Table 17: Assessment of Document [16] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: Planning		
[17]	**Letter addressed to Jerry Whitfield from Ian Paton of Coogee Resources - GI, H1 & H4-AC/L7-Revised Drilling Program**	**EV0000013**
Description and Relevance to NOPSA issue 1-5		
Document [17] is a cover letter, dated 7 November 2008, from PTTEPAA to the NT, informing the NT DoE of the revisions made to the Document [15] for the Montara wells. Attached with the letter is Document [16]. This document has been used as a reference document by EW, and has been determined to have no significant impact on the answer to the issue.		
Consistency between Documents, and Consistency between Approvals		
There are no other NOPSA provided documents identified that contain similar information presented in Document [17].		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 18: Assessment of Document [17] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: Planning		
[18]	**Transmittal addressed to Jerry Whitfield from Catherine Noonan of Coogee Resources - GI, H1 & H4-AC/L7-Revised Drilling Program**	**EV0000014**
Description and Relevance to e NOPSA issue 1-5		
Document [18] is a transmittal slip from PTTEPAA to the NT, documenting the acknowledgement receipt of Document [16]. The acknowledgement receipt was received by Mr Dominic Marozzi on 12 January 2009. This document has been used as a reference document by EW, and has been determined to have no significant impact on the answer to the issue.		
Consistency between Documents, and Consistency between Approvals		
There are no other NOPSA provided documents identified that contain similar information presented in Document [18].		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 19: Assessment of Document [18] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: Planning		
[19]	**Submission - Halliburton P-09-055BB Montara H1 9-58 Lead Cement Lab Report#2**	**DB-30291-NOPSA-420**
Description and Relevance to NOPSA issue 1-5		
Document [19], contains the laboratory results of the 9 5/8" (244mm) Lead cement for the H1 Well.		
Consistency between Documents, and Consistency between Approvals		
Discrepancies between the Planned and Actual cement additive concentrations have been identified and are captured in Table 30.		
Omissions of Data received (if any)		
Upon the assessment of ALL relevant documentation provided, it has been observed that the Cementing Programme went through several phases of change. These changes were driven in part by Topsides delay, in part by discovery of shallow gas sands in G1, in part due to improved Well Integrity by improved zonal isolation of the Cycle IV formation, and in part by cement design changes due to the unplanned drilling of H1-ST1. These many phases of change, in all likelihood, had an impact on the failure to use the correct volume of tail cement. The phases are described from Table 22 to Table 26.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 20: Assessment of Document [19] in relation to Issue 1 to 5

<table>
<tr><th>No</th><th>NOPSA provided Document Titles</th><th>Reference</th></tr>
<tr><td colspan="3">Document Type: Planning</td></tr>
<tr><td>[20]</td><td>Submission - Halliburton P-09-056C Montara H1 9-58 Tail Cement Lab Report#2</td><td>DB-30291-NOPSA-421</td></tr>
<tr><td colspan="3">Description and Relevance to NOPSA issue 1-5</td></tr>
<tr><td colspan="3">Document [20], contains the laboratory results of the 9 5/8” (244mm) Tail cement for the H1 Well.</td></tr>
<tr><td colspan="3">Consistency between Documents, and Consistency between Approvals</td></tr>
<tr><td colspan="3">Discrepancies between the Planned and Actual cement additive concentrations have been identified and are captured in Table 30.</td></tr>
<tr><td colspan="3">Omissions of Data received (if any)</td></tr>
<tr><td colspan="3">Upon the assessment of ALL relevant documentation provided, it has been observed that the Cementing Programme went through several phases of change. These changes were driven in part by Topsides delay, in part by discovery of shallow gas sands in G1, in part due to improved Well Integrity by improved zonal isolation of the Cycle IV formation, and in part by cement design changes due to the unplanned drilling of H1-ST1.

These many phases of change, in all likelihood, had an impact on the failure to use the correct volume of tail cement. The phases are described from Table 22 to Table 26.</td></tr>
<tr><td colspan="3">This assessment is used in response to issue:</td></tr>
<tr><td colspan="3">Section 1.B, 2.B, 3.B, 4.B, and 5.B</td></tr>
</table>

Table 21: Assessment of Document [20] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: MOC and Approvals		
[21]	**Coogee Resources-Well Construction Change Control Form D65005A 001**	**EV0000015**
Description and Relevance to NOPSA issue 1-5		
Document [21] dated 23 January 2009, contains the following changes to the tail cement program with the following details: *"Increase the top of the tail cement for the 244mm (9 5/8") casing from 2923mMDRT to 2823mMDRT. This will increase the vertical height of the cement by 39m increasing the vertical length of the top of cement to 69m above the reservoir".* The HSE impact of the proposed change is: *"Increased well control protection by increasing the TOC from 30mTVD above the reservoir to 69mTVD above the reservoir".*		
Consistency between Documents, and Consistency between Approvals		
Discrepancies between the Planned and Actual cement additive concentrations have been identified and are captured in Table 30.		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 22: Assessment of Document [21] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: MOC and Approvals		
Document Type: Planning		
[22]	**Coogee Resources-Cementing Program-Montara H1 No Topsides, Attachment to D65005A 001**	**EV0000016**
Description and Relevance to NOPSA issue 1-5		
Document [22] contains the changes to the 9 5/8" (244mm) tail cement recipe in accordance to the Document [21].		
Consistency between Documents, and Consistency between Approvals		
Discrepancies between the Planned and Actual cement additive concentrations have been identified and are captured in Table 30.		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 23: Assessment of Document [22] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
	Document Type: MOC and Approvals	
[23]	**Well Control Change Form Montara- Well GI, H1, H4 Rev. 2, D65005A 003**	**EV0000801**
	Description and Relevance to NOPSA issue 1-5	
	Document [23], dated 30 January 2009, contains the following changes to the H1 9 5/8" cement program with the following details: *"The suspension of the H1 and H4 wells will require the wells to be suspended at the MLS. No pressure containing caps will be installed and this leaves the annulus between the 311mm (12 ¼") hole and the 244mm (9 5/8") casing open at surface. A lead cemented has been added to the program that will fill the annulus from the top of the tail cement up into the 340mm (13 3/8") casing by 50m – effectively sealing off the casing annulus".* The HSE impact of the proposed change is: *"Secures the open hole annulus prior to well suspension".* Document [23] also contains a revised cementing program. In particular, the following information pertaining to Anti-Gas Migration additives in the lead and tail cement additive recipe is provided below: **Lead Cement** 1. *Halad 413L – 15 gal/10bbl* 2. *Gascon 469 – 1.2 gal/sk* **Tail Cement** 1. *Halad 413L – 20 gal/10bbl* 2. *Gascon 469 – 0.1 gal/sk*	
	Consistency between Documents, and Consistency between Approvals	
	Discrepancies between the Planned and Actual cement additive concentrations have been identified and are captured in Table 30.	
	Omissions of Data received (if any)	

No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.
This assessment is used in response to issue:
Section 1.B, 2.B, 3.B, 4.B, and 5.B

Table 24: Assessment of Document [23] in relation to Issue 1 to 5

<table>
<tr><th>No</th><th>NOPSA provided Document Titles</th><th>Reference</th></tr>
<tr><td colspan="3">Document Type: MOC and Approvals</td></tr>
<tr><td>[24]</td><td>Email from Chris Wilson to West Atlas Supervisor- Application for Approval to sidetrack Montara H1-AC-L7</td><td>EV0000020</td></tr>
<tr><td colspan="3">Description and Relevance to NOPSA issue 1-5</td></tr>
<tr><td colspan="3">Document [24], dated 2 March 2009, is NT’s approval for PTTEPAA’s application to sidetrack H1-ST1 well, in accordance to PTTEPAA’s submission via email and received by the NT on 27 February 2009.</td></tr>
<tr><td colspan="3">Consistency between Documents, and Consistency between Approvals</td></tr>
<tr><td colspan="3">There are no other NOPSA provided documents identified that contain similar information presented in Document [24].</td></tr>
<tr><td colspan="3">Omissions of Data received (if any)</td></tr>
<tr><td colspan="3">No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.</td></tr>
<tr><td colspan="3">This assessment is used in response to issue:</td></tr>
<tr><td colspan="3">Section 1.B, 2.B, 3.B, 4.B, and 5.B</td></tr>
</table>

Table 25: Assessment of Document [24] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: MOC and Approvals		
[25]	Email from Chris Wilson-Preliminary Copy of Change Control-Montara H1, H4, H2 & H3 & Coogee Resources, D65005A-005	EV0000021
Description and Relevance to NOPSA issue 1-5		
Document [25] dated 3 March 2009, comes with an "*unofficial change control form for the centralizers*" attached. A proposed change "*To include the running of 244mm (9 5/8") casing centralizers across small gas sand in the Gibson and Woolaston Formation*" was approved on the same day. The HSE Impact of the proposed change stated was "*improved well integrity by isolating the gas sand in the Gibson/Woolaston*".		
Consistency between Documents, and Consistency between Approvals		
There are no other NOPSA provided documents identified that contain similar information presented in Document [25].		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 26: Assessment of Document [25] in relation to Issue 1 to 5

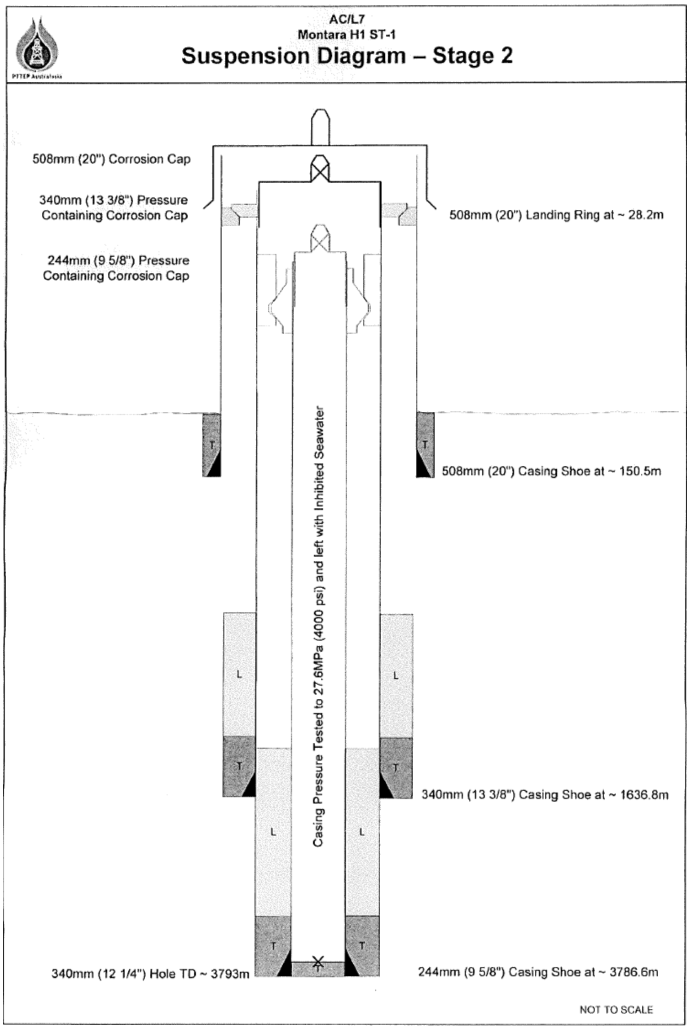
No	NOPSA provided Document Titles	Reference
Document Type: MOC and Approvals		
[26]	Letter addressed to Jerry Whitfield from Ian Paton-PTTEP Australasia Pty Ltd on 6 March 2009	EV0000026
Description and Relevance to NOPSA issue 1-5		
Document [26], dated 6 March 2009, is an application by PTTEPAA to the NT, requesting approval to suspend Montara H1-ST1 development well, AC/7 in accordance with Drilling Programme (TM-CR-MON-B-150-0001 Rev 2). The proposed programme seeks approval to suspend the well in two stages: 1st Stage: Cement and Pressure Test of the 9 5/8" (244mm) casing, Install 9-5/8" (244mm) PCCC with diagram provided. 2nd Stage: Recover 13 3/8" (340mm) casing above the MLS, Install a second (13 3/8" (340mm)) PCCC, Recover 20" (508mm) casing above MLS and Install a further suspension cap, with no diagram provided.		
Consistency between Documents, and Consistency between Approvals		
During the Re-entry of H1-ST1, on 20 August 2009, it was found that the 13 3/8" (340mm) PCCC was not installed as proposed in Document [26].		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 27: Assessment of Document [26] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
	Document Type: MOC and Approvals	
[27]	**Letter addressed to Jerry** Whitfield **from Ian Paton-PTTEP Australasia Pty Ltd on 12 March 2009**	EV0000038
	Description and Relevance to NOPSA issue 1-5	

Document [27], dated 12 March 2009, is an application by PTTEPAA to the NT, requesting approval to suspend Montara H4 and perform Stage 2 suspensions on GI-ST1 and Montara H1-ST1 development wells, AC/7 in accordance with Drilling Programme (TM-CR-MON-B-150-0001 Rev 2). The proposed programme seeks approval to perform 2nd Stage suspension of H1-ST1 as per attached suspension diagram.

2nd Stage: Recover 13 3/8" (340mm) casing above the MLS, Install a second PCCC, Recover 20" (508mm) casing above MLS and Install a further suspension cap.



Consistency between Documents, and Consistency between Approvals

During the Re-entry of H1-ST1, on 20 August 2009, where it was found that the 13 3/8" (340mm) PCCC was not installed as proposed in Document [27].
Omissions of Data received (if any)
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5. However it was not explicitly stated in the application that the Stage 2 suspension was to be performed as an offline activity.
This assessment is used in response to issue:
Section 1.B, 2.B, 3.B, 4.B, and 5.B

Table 28: Assessment of Document [27] in relation to Issue 1 to 5

No	NOPSA provided Document Titles	Reference
Document Type: MOC and Approval		
[28]	**Submission - PTTEP Document Submission - Regulatory Approvals#3**	**DB-30291-NOPSA-404**
Description and Relevance to NOPSA issue 1-5		
Document [28] contains, in addition to other approvals granted by the NT to PTTEPPAA for the development of the Montara Wells, PTTEPAA's request for approval to sidetrack the Montara-H1 Well, and the following was stated in the Document [28]: *"We have directionally drilled our 311mm hole to 90^0 and landed the well at the required target per the drilling program TM-CR-MON-B-150-00001 Rev 2. The 311mm hole section intersected the top of the reservoir as planned directly into the gas cap at 2935mMDRT. Drilling continued through the gas cap into an intra reservoir shale where we had built to 90^0 at 3445mMDRT (original planned section TD). Due to the lack of reservoir where the well was landed we decided to drill ahead remaining at 90^0 to find the reservoir. We penetrated a dirty sand +/- 3602mMDRT and initially thought this was water wet (later evaluated to be oil saturated poor reservoir). The well was then steered-upwards in an attempt to intersect oil in a cleaner reservoir and this was achieved at 3675mMDRT. Drilling continued upwards to intersect and confirm the TVD of the Gas Oil Contact and this was found at 3840mMDRT.* *We now propose to set a cement plug across the gas zone at the TD of the well and then set a kick-off plug further back in the well (+/-3180mMDRT). We will then kick-off the sidetrack from 3180m and re-land the TD in the good oil sands."*		
Consistency between Documents, and Consistency between Approvals		
There are no other NOPSA provided documents identified that contain similar information presented in Document [28].		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 1-5.		
This assessment is used in response to issue:		
Section 1.B, 2.B, 3.B, 4.B, and 5.B		

Table 29: Assessment of Document [28] in relation to Issue 1 to 5

1.B Whether the failure to use the correct volume of tail cement when cementing the 9 5/8 inch casing shoe in the Montara H1-ST1 Well increased the risk of an uncontrolled release of hydrocarbons?

Two (2) separate issues must be addressed in order to answer issue 1.B fully:

I. Whether the failure to use the correct volume of tail cement when cementing the 9 5/8 inch casing shoe in the Montara H1-ST1 Well increased the risk of an uncontrolled release of hydrocarbons **from the 9 5/8" (244mm) by 13 3/8" (340mm) annulus?**

II. Whether the failure to use the correct volume of tail cement when cementing the 9 5/8 inch casing shoe in the Montara H1-ST1 Well increased the risk of an uncontrolled release of hydrocarbons **from within the 9 5/8" (244mm) Casing through a "Wet Shoe"?**

1.B.I Whether the failure to use the correct volume of tail cement when cementing the 9 5/8 inch casing shoe in the Montara H1-ST1 Well increased the risk of an uncontrolled release of hydrocarbons from the 9 5/8" (244mm) by 13 3/8" (340mm) annulus?

The Expert's response to issue 1.B.I is:

Yes, the risk of an uncontrolled release of hydrocarbons from the 9 5/8" (244mm) by 13 3/8" (340mm) annulus **was increased**, with the use of an incorrect volume of tail cement.

Due to the failure to use the correct tail cement volume, the Montara Cycle IV reservoir which was exposed to the H1-ST1 Well, was not completely isolated by the tail cement.

From the Top of Cement verification calculation shown in Expert Witness Report Vol 3 Section 5.2 to 5.13, the remaining exposed section of the Montara Cycle IV reservoir was isolated by the lead cement instead, even if the subsequent cement over displacement had not occurred. It is a possibility that the lead cement design could have allowed gas migration from the Montara Cycle IV reservoir into the cement, thereby compromising its effectiveness as a well barrier to hydrocarbon flow. However, quantifying this risk is not possible for this investigation, due to the lack of information provided by Halliburton as stated in points 1 and 2 below:

1. The risk of gas migration from the Montara Cycle IV reservoir into the lead cement might have been increased due to an insufficient **transition time**, especially since this time was

not measured by Halliburton in the laboratory report in [19], thereby possibly compromising its effectiveness as a well barrier to hydrocarbon flow.

2. The risk of gas migration from the Montara Cycle IV reservoir into the lead cement might have been increased due to insufficient **CSGS development**, especially since this property was not measured by Halliburton in the laboratory report in [19], thereby compromising its effectiveness as a well barrier to hydrocarbon flow.

However, what can be objectively stated, since the H1-ST1 Well was horizontal, was that the relative contributions to hydrostatic control of the various components of the cement system against the reservoir pressure are significant as follows:

1. The tail slurry in its final position at plug bump contributes only **64 psi** to the effective **5060 psi** bottom hole pressure and does not completely isolate the Montara Cycle IV reservoir (Section 5.6 of Report Volume 3 "Pseudo Static Equivalent Annulus BHP while Circulating TAIL Slurry below Float Collar");
2. The lead slurry contributed **3163 psi** hydrostatic pressure (Section 5.6 of Report Volume 3 "Pseudo Static Equivalent Annulus BHP while Circulating TAIL Slurry below Float Collar");
3. The mud, spacer and pre-flush contributed **1834 psi** hydrostatic pressure (Section 5.6 of Report Volume 3 "Pseudo Static Equivalent Annulus BHP while Circulating TAIL Slurry below Float Collar").

Given the above, the significance of the tail cement volume, and cement recipes for the tail and lead cement can be illustrated clearly as follows:

1. The tail slurry should have been designed to reach its CSGS (500 lbs/ft^2) **PRIOR** to the lead slurry undergoing its CSGS development;
2. Some of the Montara Cycle IV reservoir was not isolated by the tail slurry, therefore this portion of the Montara Cycle IV reservoir would have seen a reduction in hydrostatic overbalance pressure, especially when the lead slurry started to lose its overbalance pressure as it undergoes CSGS development. For the reservoir not to flow, during this time, the lead slurry must have reached its CSGS of 500 lbs/ft^2, prior to the column above the Montara Cycle IV reservoir losing approximately 1000 psi due to the hydration process and overbalance reduction.

If the tail cement volume had covered the Montara Cycle IV reservoir **AND** achieved CSGS prior to the Lead cement by design, then the phenomena of hydrostatic overbalance reduction occurring in the lead slurry due to CSGS development would not have impacted the risk of gas migration from the Montara Cycle IV reservoir since the tail cement would have impeded the migration of gas.

The Expert Witness's elaboration to Issue I.B.I is as follows:

1. The top of Tail Cement in the 9 5/8" (244mm) x 12 ¼" (311mm) annulus would have been below the Top of Cycle IV reservoir by 190mMD/ 48mTVD as per Panel 8 of XLS-30291-NOPSA-001-WAiT© [Expert Witness Report Vol 3 Section 3.1.8], and therefore the Lead Slurry and not the Tail Slurry was across the entire Montara Cycle IV reservoir.
2. As described in Document [21], Table 22, it was PTTEPAA's intent to isolate the Montara Cycle IV reservoir in the H1 well with tail cement. However, there is no documentation provided to suggest that a change in the cementing programme to isolate the Montara Cycle IV reservoir in the H1-ST1 well with the lead cement was implemented. Since it was not planned for the Lead Slurry to isolate the Montara Cycle IV reservoir, the likely consequence of its final placement across the reservoir, could be such that the additives used to prevent gas flow while cementing, were not present in the Lead Slurry in the correct proportions, to resist gas flow from the exposed Montara Cycle IV reservoir.
    a. As described in Document [23], the planned Lead Slurry contained 1.20gal/sk of GASCON 469 and 15gal/10bblMF of HALAD 413L. The requirement for GASCON 469 and HALAD 413L in the Lead Slurry recipe was justified by the presence of "*a small gas sand in the Gibson and Woolaston Formation*", as documented in Document [25].
    b. The Expert Witness has identified a significant non compliance for the actual additive concentration of H1-ST1 9 5/8" (244mm) Lead and Tail cement slurries against planned additive concentration (Table 30). As such, it cannot be concluded if the actual lead slurry possesses the required CSGS (Critical Static Gel Strength) development ability and transition time properties to mitigate against risk of gas migration from the Montara Cycle IV reservoir. In particular, the retarder concentration actually pumped in the tail slurry could have affected the cement setting process thus increasing the risk of hydrocarbon flow, in the case of float failure.

3. The implications of the changed cement additive concentration coupled with the lack of coverage of the Montara Cycle IV reservoir by the tail slurry increased the risk of gas flow while cementing. API standard 65-2, section A.9, summary of API 65 workgroup studying Loss of Well Control (LWC) incidents states the following: "*In API 65 Group Meetings, annular flow statistics on offshore wells in U.S. federal waters were presented including MMS records on the occurrence of SCP and on the 34 LWC incidents that occurred during drilling operations and reported in the years 1992 through 2002. Of the 34 LWC incidents, 19 (56%) were caused by annular flows associated with the cementing process.*"
4. API Standard 65-2 section 5.7.8 "Static Gel Strength" describes the significance and impact of the hydration behavior of cement slurries. "Static Gel Strength (SGS) development is one of the many factors that contribute to decay of hydrostatic pressure. The cement slurry undergoes a chemical reaction between the water, additives and dry cement, driven by temperature, which causes a change of state from gelled fluid to a solid over a period of time. At some point the slurry reaches the CSGS where the cement column loses its ability to transmit hydrostatic pressure. Once the SGS reaches a value of 500 lbs/ft^2 (the CSGS), it is commonly accepted that at this value gas cannot move freely through the column. Therefore the exposure period whereby hydrocarbons (in particular gas) could flow through the cement is the time difference between full hydrostatic transmissibility and an SGS=500 lbs/ft^2 (the CSGS). This period of time when gel strength starts to develop, reducing hydrostatic transmissibility and SGS = 500lbs /ft^2, is known as CGSP, Critical Gel Strength period. One *method recommended by API 65 to evaluate the impact of the gel strength development on wellbore fluid influx is to calculate the CSGS and then to measure the CGSP*."
5. The cement recipe or laboratory testing by Halliburton for the 9 5/8" (244mm) casing cementation did not include a measurement of either CSGS or CSGP. Therefore the Expert Witness cannot comment on the effectiveness of this slurry to resist gas migration into the annulus during the transitional phase.

Figure 1 is the Expert Witness's illustration of the concept described in point 4.

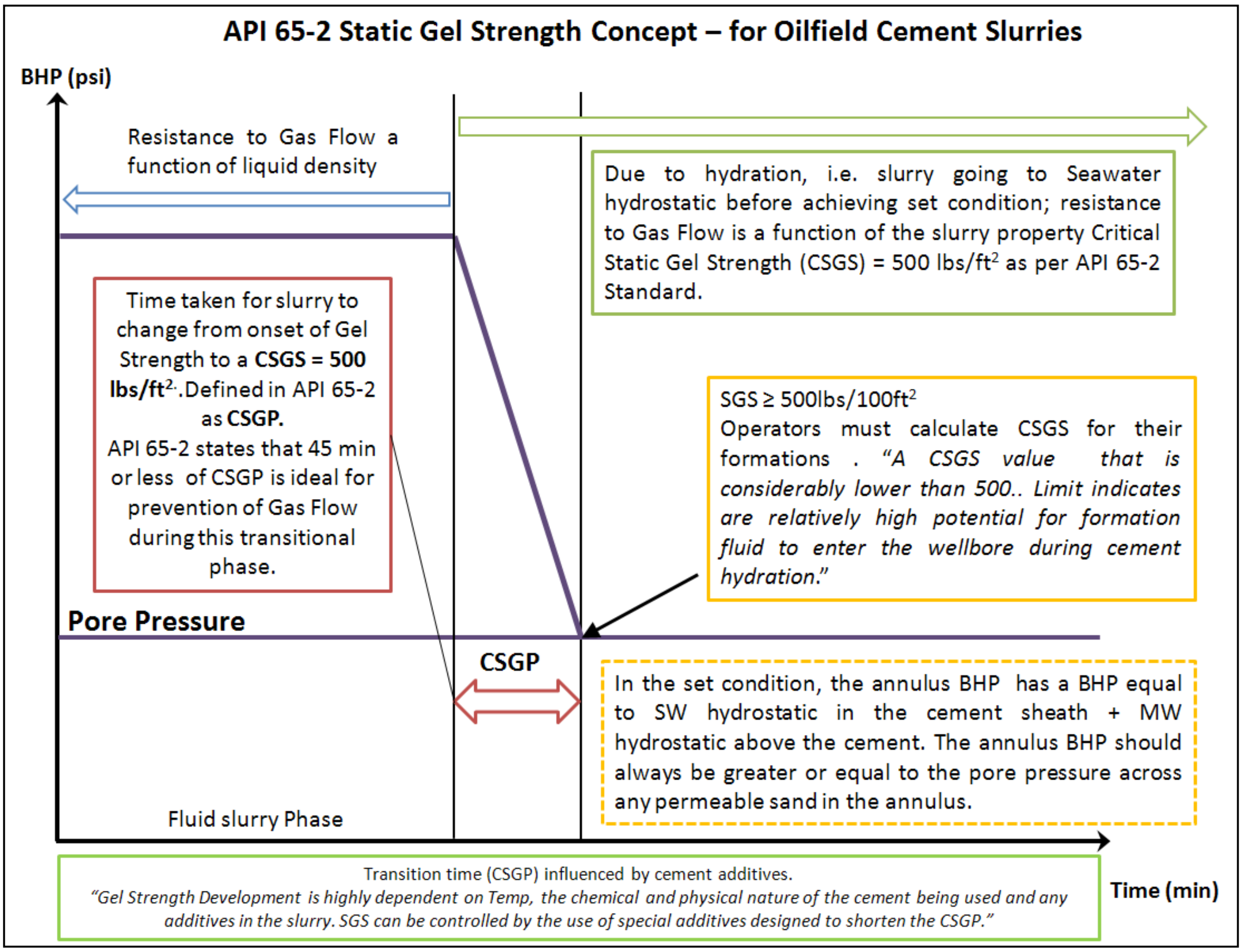


Figure 1: The Expert's interpretation of API 65-2 Static Gel Strength Concept for Oilfield Cement Slurries

Notes: The calculations supporting point 1 above can be found in Panel 8 of XLS-30291-NOPSA-001-WAiT© [Expert Witness Report Vol 3 Section 3.1.8]. The calculations in support of points 1 to 5 have not addressed the issue of the cement over-displacement; but rather given the physical volumes of cements pumped in the H1-ST1 well, whether they **would** have provided the required isolation against the hydrocarbon reservoirs, and achieving the required TOC depth if the cement had not been over-displaced. The issue of the cement over-displacement will be addressed in the Expert Witness's response to issue 3.

Cement Additives	Montara H1 Cementing Program Rev3 [13]		PTTEPAA H1 Cement Program [23]		H1 Cement Slurry Lab Test Reports [19], [20]		CR Cementing Calculations & Reporting Form Revision 2 [2]		Post Montara H1-ST1 Cementing Reports [2], [12]		Properties
	Planned Cement Additive Concentration						Actual Cement Additive Concentration				
	Lead	Tail	Lead	Tail	Lead	Tail	Lead	Tail	Lead	Tail	
Yield (ft^3/sx)	2.42	1.16	2.42	1.16	2.41	1.16	2.41	1.16	2.41	1.16	
Mix Water[i] (gal/sk)	12.72	4.78	12.72	4.78	12.68	4.78	12.68	4.76	12.69	4.68	
NF-6[i] (gal/10bblMF)	0.25	0.25	0.25	0.25	0.25	0.25	0.26	0.25	0.06[ii]	0.12[ii]	Defoamer
Gascon 469[i] (gal/sk)	1.20	0.10	1.20	0.10	1.20	0.10	1.20	0.10	1.46[iii]	0.19[iii]	**Extender and anti-gas migration**
SCR-100L[i] (gal/10bblMF)	4.00	4.00	4.00	4.00	3.00	6.00	3.01[iv]	5.04[iv]	3.49[iv]	7.30[iv]	Retarder
Halad-413L[i] (gal/10bblMF)	15.00	20.00	15.00	20.00	15.00	20.00	14.99	19.98	16.96[v]	24.33[v]	**Dispersant, retarder and anti-gas migration**

Note[i]: Different units pertaining to the concentration of the additives had been used in various documents listed above. For the purpose of consistency, EW has converted and applied similar units to the respective additives.

Note[ii]: The concentration of **NF-6** as reportedly pumped into H1-ST1 via the "Montara H1-ST1 Casing, Running and Cementing Report" [2] and [12] is a distinct variant from the Program Requirements stated in [13] and [23], and the concentration of the slurries as tested in the Laboratory [19] and [20].

Note[iii]: The concentration of **Gascon 469** as reportedly pumped into H1-ST1 via the "Montara H1-ST1 Casing, Running and Cementing Report" [2] and [12] is a distinct variant from the Program Requirements stated in [13] and [23], and the concentration of the slurries as tested in the Laboratory [19] and [20].

Note[iv]: The concentration of **SCR-100L** as reportedly pumped into H1-ST1 via the "Montara H1-ST1 Casing, Running and Cementing Report" [2], [12] and the "Coogee Resources Cementing Calculations and Reporting Form Revision 2" [2], is a distinct variant from the Program Requirements stated in [13] and [23], and the concentration of the slurries as tested in the Laboratory [19] and [20].

Note[v]: The concentration of **Halad-413L** as reportedly pumped into H1-ST1 via the "Montara H1-ST1 Casing, Running and Cementing Report" [2] and [12] is a distinct variant from the Program Requirements stated in [13] and [23], and the concentration of the slurries as tested in the Laboratory [19] and [20].

Table 30: Comparison between Program(s) and Actual Cement Additive Concentrations

1.B.II Whether the failure to use the correct volume of tail cement when cementing the 9 5/8 inch casing shoe in the Montara H1-ST1 Well increased the risk of an uncontrolled release of hydrocarbons from within the 9 5/8" (244mm) Casing through a "Wet Shoe"?

The Expert's response to issue 1.B.II is:

No, the failure to use the correct volume of tail cement when cementing the 9 5/8 inch casing shoe in the Montara H1-ST1 Well **had no effect** on the risk of an uncontrolled release of hydrocarbons from within the 9 5/8" (244mm) Casing through a "Wet Shoe".

The Expert Witness's elaboration to Issue I.B.II is as follows:

The hydrostatic pressure exerted by the cement columns (Tail and Lead Slurry) in the annuli create the BHP overbalance against the Montara Cycle IV reservoir and consequently affect the risk of hydrocarbon flow up the annulus. At the end of cement displacement, in the dynamic slurry condition, an adequate overbalance of 1064psi (5060psi -3996psi), Figure 2, End of Phase 5, existed to the Montara Cycle IV reservoir.

The hydrostatic pressure exerted by the cement column in the annulus has no bearing on the hydrocarbon flow potential through the casing. Prevention of uncontrolled flow via the casing is normally provided by the BPVs in the casing shoe, and if they fail, the hydrostatic column of fluid in the casing. At the time of pumping the tail slurry, PTTEPAA would have assumed the BPVs to have been functional. The displacing fluid in this case was a seawater column and not an overbalance fluid.

The volume of tail could only have influenced the risk of uncontrolled hydrocarbon flow through the casing if the volume of tail and the lead slurries did not generate sufficient hydrostatic pressure to create an overbalance to the reservoir and there were intentionally no back pressure valves in the casing shoe, and a deliberately underbalanced displacing fluid, none of which was the case.

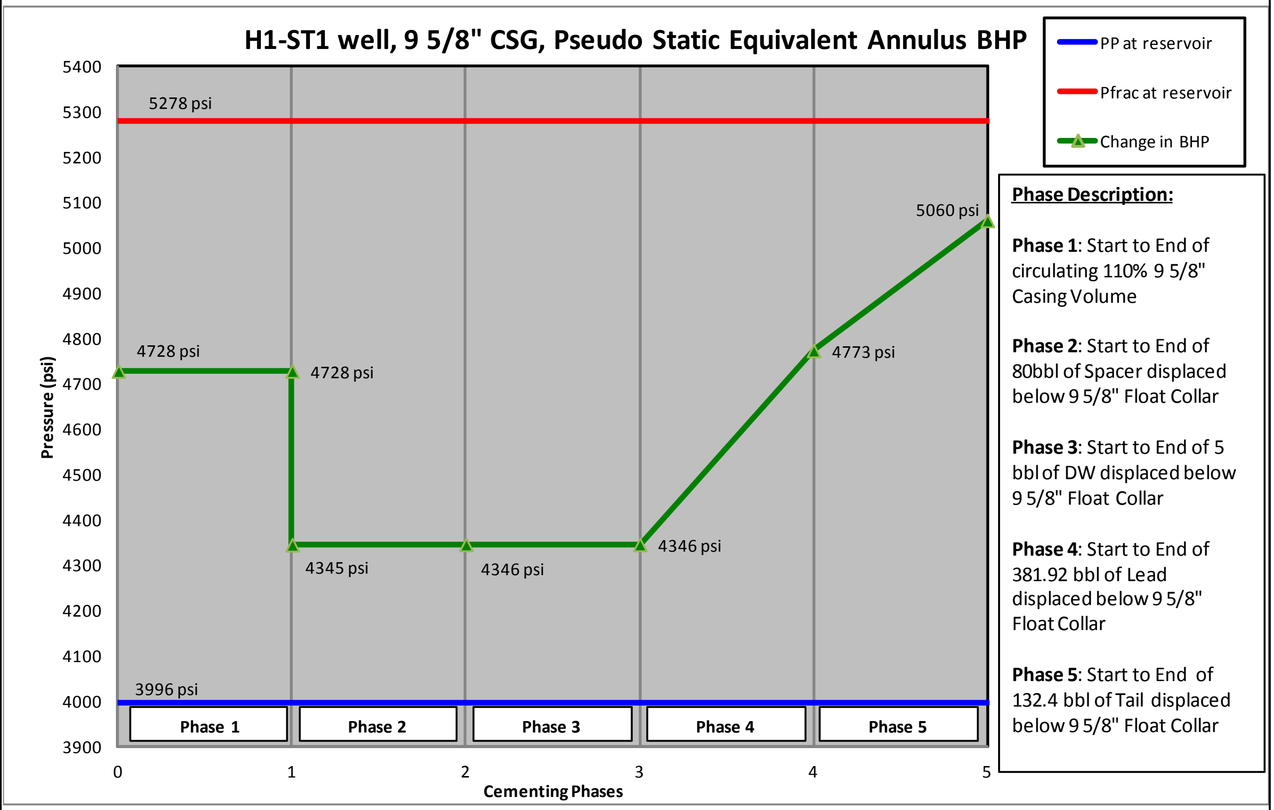


Chart Description

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.

Figure 2 : H1-ST1 well, 9 5/8" (244mm) CSG, Pseudo Static Equivalent Annulus BHP

1.C What other practicable steps could have been undertaken by PTTEP to prevent the use of an incorrect volume of tail cement?

PTTEPAA could have had in place a Technical Authority procedure whereby cementing calculations are checked by a Senior Engineer, which would have avoided pumping insufficient tail cement to cover the Montara Cycle IV reservoir.

Consideration could be given to request for contracted cementing service companies to follow minimum standards set out in API 65-2 "*Isolating Potential Flow Zones During Well Construction*" or demonstrate how their proprietary methods are an improvement, in particular with reference to SGS development and prevention of gas flow during cement transitional time.

1.D What would good oilfield practice have been in this situation?

A Technical Authority Procedure would be in place, whereby cementing calculations would have been checked by a Senior Engineer which would have avoided pumping insufficient tail cement to cover the reservoir.

This cement recipe would have been designed for the specific wellbore conditions and checked by a Senior Engineer, in particular with reference to eliminating the risk of annular flow. Complete coverage of the Montara Cycle IV reservoir by tail cement would have been ensured, and the transition time to CSGS development for cement would be as short as possible. Especially since two potential shallow gas flow zones (*Gibson and Woolaston Formation*) were identified and the 9 5/8" (244mm) casing was deployed in a horizontal wellbore where the risk of gas by-passing the cement is increased.

Any changes made to the Cementing Programme, due to deviation from the original Drilling Programme (i.e. sidetrack), should have been the subject of a documented Risk Assessment.

2. Pumping the wrong volume of cement

2.A An assessment of ALL documentation provided by NOPSA relating to the risks to the well integrity caused by pumping the wrong volume of cement into the 9 5/8 inch casing shoe in the Montara H1-ST1 Well.

The Expert Witness has reviewed all available information provided by NOPSA, and identified the documents as described in Section 1.A.I that have direct importance to NOPSA issue 2. The list of documents is presented in Table 1. A detailed assessment of each document, including their particular relevance to the NOPSA issue 2 has been presented in Section 1.A.II.

2.B Whether the failure to pump the correct volume of cement into the 9 5/8 inch casing in the Montara H1-ST1 Well increased the risk of an uncontrolled release of hydrocarbons?

Two (2) separate issues must be established in order to answer 2.B fully:

I. Whether the failure to pump the correct volume of cement into the 9 5/8" casing in the Montara H1-ST1 had resulted in a failure to isolate ALL hydrocarbon reservoirs exposed to the H1-ST1 Well **irrespective of the type of cement isolating these hydrocarbon reservoirs**, thereby increasing the risk of an uncontrolled release of hydrocarbons **OR**

II. Whether the failure to pump the correct volume of cement into the 9 5/8" (244mm) casing in the Montara H1-ST1 had resulted in a failure of the tail cement to **completely isolate** the Montara Cycle IV reservoir, thereby increasing the risk of an uncontrolled release of hydrocarbons.

The Expert's response to issue 2.B.I is:

No, there was **no increased** risk of an uncontrolled release of hydrocarbons in the Montara H1-ST1 Well due to the **physical volume** of cement pumped for the following reasons:

1. The Montara Cycle IV Reservoir would have been isolated by cementation in the H1-ST1 Well. In particular, 190m MD/48 m TVD and 671m MD/ 24m TVD of the Montara Cycle IV Reservoir would have been isolated by the lead and tail cements respectively.
2. The Gibson and Woolaston formations would have been isolated by the lead cement.
3. The top of lead cement would have been 550m MD/ 543m TVD into the 13 3/8" Casing Shoe, therefore achieving a top of cement objective of at least 50m into the previous 13 3/8" casing shoe.

Notes: The calculations and illustration supporting points 1, 2 and 3 above can be found in Panel 8 of XLS-30291-NOPSA-001-WAiT© [Expert Witness Report Vol 3 Section 3.1.8]. The calculations in support of points 1, 2 and 3 have not addressed the issue of cement over-displacement; but rather given the physical volumes of cements pumped in the H1-ST1 well, whether they **would** have provided the required isolation against the hydrocarbon reservoirs, and achieving the required TOC depth if the cement had not been over-displaced. The issue of the cement over-displacement will be addressed in NOPSA issue 3.

The Expert's response to issue 2.B.II is:

Yes, the risk of an uncontrolled release of hydrocarbons **did increase** due to the relative proportions of lead and tail cement volumes pumped into the 9 5/8 inch casing in the Montara H1-ST1 Well. As per the answer to issue 1.B, PTTEPAA did not pump the correct volume of tail cement to completely cover the Montara Cycle IV reservoir. The objective of the lead cement volume was to achieve a Top of Cement that was at least 50m inside the previous 13 3/8" (340mm) casing shoe, which was and would have been achieved irrespective of whether the over-displacement had occurred.

As a result of the tail cement volume not completely covering the Montara Cycle IV reservoir, the lead cement would have covered the upper 190m MD/48 m TVD of the Montara Cycle IV reservoir and the gas bearing Gibson/Woolaston formation, though the lead cement's design is questionable with regard to its effectiveness in preventing gas migration from the Montara Cycle IV Reservoir as elaborated in Section 1.B.I. A visual elaboration of the above statement is found in Panel 8 of XLS-30291-NOPSA-001-WAiT© [Expert Witness Report Vol 3 Section 3.1.8].

Notes: The calculations and illustration supporting the statements above can be found in Panel 8 of XLS-30291-NOPSA-001-WAiT© [Expert Witness Report Vol 3 Section 3.1.8]. The calculations in support of the statements above have not addressed the issue of cement over-displacement; but rather given the physical volumes of cements pumped in the H1-ST1 well, whether they **would** have provided the required isolation against the hydrocarbon reservoirs, and achieving the required TOC depth if the cement had not been over-displaced. The issue of the cement over-displacement will be addressed in NOPSA issue 3.

2.C What other practicable steps could have been undertaken by PTTEP to prevent pumping the wrong volume of cement.

PTTEPAA could have had in place a Technical Authority procedure whereby cementing calculations are checked by a Senior Engineer, which would have avoided pumping insufficient tail cement to cover the Montara Cycle IV reservoir.

Consideration could be given to request for contracted cementing service companies to follow minimum standards set out in API 65-2 “Isolating Potential Flow Zones During Well Construction” or demonstrate how their proprietary methods are an improvement, in particular with reference to SGS development and prevention of gas flow during cement transitional time.

2.D What would good oilfield practice have been in this situation?

A Technical Authority Procedure would be in place, whereby cementing calculations would have been checked by a Senior Engineer which would have avoided pumping insufficient tail cement to cover the reservoir.

This cement recipe would have been designed for the specific wellbore conditions and checked by a Senior Engineer, in particular with reference to eliminating the risk of annular flow. Complete coverage of the Montara Cycle IV reservoir by tail cement would have been ensured, and the transition time to CSGS development for cement would be as short as possible. Especially since two potential shallow gas flow zones (Gibson and Woolaston Formation) were identified and the 9 5/8” (244mm) casing was deployed in a horizontal wellbore where the risk of gas by-passing the cement is increased.

Any changes made to the Cementing Programme, due to deviation from the original Drilling Programme (i.e. sidetrack), should have been the subject of a documented Risk Assessment.

3. Over displacement of cement

3.A An assessment of ALL documentation provided by NOPSA relating to the over displacement of cement within and around the 9 5/8 inch shoe of the Montara H1-ST1 Well.

The Expert Witness has reviewed all available information provided by NOPSA, and identified the documents as described in Section 1.A.I that have direct importance to NOPSA issue 3. The list of documents is presented in Table 1. A detailed assessment of each document, including their particular relevance to the NOPSA issue 3 has been presented in Section 1.A.II.

3.B Whether the over displacement of cement within and around the 9 5/8 inch casing shoe of the Montara H1-ST1 Well, resulting in the creation of what is termed a 'wet cement shoe', increased the risk of an uncontrolled release of hydrocarbons.

The Expert's response to issue 3.B is:

Yes, the over displacement of cement within and around the 9 5/8 inch casing shoe of the Montara H1-ST1 Well, resulting in the creation of what is termed a 'wet cement shoe', **did increase** the risk of an uncontrolled release of hydrocarbons.

The Expert Witness's elaboration in support of the answer is as follows:

It is an established fact that the H1-ST1 well, received and returned 9 bbl due to fluid compression, after the 4000psi pressure test on the 9 5/8" casing was bled down to 200psi, before seeing a rapid increase of surface pressure to 1300psi, followed by an unexpected gain of 7bbl. This gain of 7bbl and observation of a rapid increase of surface pressure to 1300psi was indicative that the Back Pressure Valves in the float shoe and float collar had failed.

The subsequent re-displacement of 16bbl of inhibited seawater into the H1-ST1 had **over displaced** the well by 9bbl. Given that the Casing Shoe Track had a volume of 6.61bbl, there is no doubt that the remaining 2.39bbl of seawater would be displaced into the rathole and the 9 5/8" x 12 ¼" annular space.

With a lack of cement inside the shoe track and for a short distance around the H1-ST1 9 5/8" casing shoe, as illustrated in WAiT© Panel 10 of XLS-30291-NOPSA-001-WAiT© [Expert Witness Report Vol 3 Section 3.1.10], a hydraulic communication path between the Montara Cycle IV reservoir and the H1-ST1 Well back up to the Montara WHP surface existed and remained so, despite the holding of pressure at the cement unit.

The over displacement of cement **within** and subsequently **around the 9 5/8 inch casing shoe** of the Montara H1-ST1 Well, resulting in the creation of a compromised 'wet cement shoe' barrier, did increase the risk of an uncontrolled release of hydrocarbons.

3.C What other practicable steps could have been undertaken by PTTEP to prevent the over displacement of cement?

1. Document [16], Drilling Programme Revision 2 states the following: "*fill each joint of casing with mud whilst running in the hole*". It is evident that the Drilling Programme intended Conventional Shoe and Float equipment for use in the H1-ST1 Well instead of a self filling Shoe and Float equipment.
    a. However, DDR ["EV0000551"] states that at 21:00H "*note: once washing down was commenced the self filling shoe and float lost the self filling function*", and later at 23:30H "…. *filling each joint*."
    b. There was no documentation provided that described the self filling shoe and float equipment in the H1-ST1 Well or stated the request for approval to use a self filling shoe and float equipment. It is the Expert Witness's opinion that PTTEPAA should have had clear procedures in the Drilling Programme describing the type, functionality and testing of the self filling shoe equipment, including contingency procedures should the self filling shoe equipment fail.
    c. Failure of the self filling shoe equipment under the circumstances described by PTTEPAA would normally have triggered the activation mechanism of the float equipment being deployed. This action would have removed any doubt that the activation mechanism would not interfere with the functionality of the shoe and float back pressure valves. In addition, under these circumstances, filling of the casing manually would have to be carefully measured on a trip sheet. No such trip sheet existed in the documentation provided.
2. According to events as stated in Document [7], 9.5 bbl was pumped into the H1-ST1 well to pressure test the 9 5/8" (3244mm) casing to 4000 psi. Following a 10 minute pressure test, 9.5bbl of seawater were bled back from the H1-ST1 well. The bleed off pressure reached 200psi before it rapidly increased to 1300psi, and a further 7 bbl of seawater were received in the surface tanks. This was an indication that the back pressure valves in the float shoe and float collars had failed.
    a. At this point in time, the practicable steps that could have been undertaken by PTTEPAA to prevent an over displacement of cement would have been to:

i. Shut in the well using the cement manifold where pressure readings could have been recorded to monitor the well, at the differential pressure required to prevent the back flow of cement into the 9 5/8" casing; Or

ii. Displace the 50% (approximately half the shoe track volume) of the 7 bbl back into the well and then shut the well in using the cement manifold.

3.D What would good oilfield practice have been in this situation?

A Contingency Casing running and Cementing Procedure should be in place to give guidance for offshore personnel on the following:

1. Test procedure of casing shoe equipment in particular “self filling” equipment
2. Response to apparent failure of self filling equipment
3. Mandated response to back flow after plug bump
4. Maintain accurate records of hole fill via trip sheets
5. Define under what circumstances casing should be pulled back out of the hole to inspect/replace float equipment
6. Displace the cement plugs with a over balanced drilling mud, not seawater.

4. Failure to verify the casing shoe was a barrier

4.A An assessment of ALL documentation provided by NOPSA relating to the failure to verify the 9 5/8 inch casing shoe as a barrier in the Montara H1-ST1 Well.

The Expert Witness has reviewed all available information provided by NOPSA, and identified the documents as described in Section 1.A.I that have direct importance to NOPSA issue 4. The list of documents is presented in Table 1. A detailed assessment of each document, including their particular relevance to the NOPSA issue 4 has been presented in Section 1.A.II.

4.B Whether the failure to verify the 9 5/8 inch casing shoe was a barrier in the Montara H1-ST1 Well increased the risk of an uncontrolled release of hydrocarbons.

The Expert's response to issue 4.B is:

Yes, the failure to verify that the 9 5/8 inch casing shoe was a barrier in the Montara H1-ST1 Well **did increase** the risk of an uncontrolled release of hydrocarbons.

The Expert Witness's' elaboration in support of the answer is as follows:

If the floats had held in a normal situation, following bleed off of the bump/test pressure, this would have been a consequential negative test of the 9 5/8" shoe track equivalent to 1300 psi, due to the seawater column inside the 9 5/8" casing. However, since the floats did fail at the time of bleeding off the 4000 psi test pressure, no negative pressure test of the casing shoe floats was possible.

It should also be highlighted that a positive pressure test on the 9 5/8" casing shoe would not have been possible, after the top wiper plug had bumped to the time the cement had set after the WOC period, as the top wiper plug would have isolated the seawater column above from the 9 5/8" casing shoe below.

The practicable steps PTTEPAA could have taken given the situation, in order to verify that the 9 5/8" casing shoe was a barrier were to:

1. Conduct a negative pressure test against the Montara Cycle IV reservoir after the WOC period OR
2. Run in hole and displace to an overbalance fluid OR
3. Create a new barrier by setting a bridge plug to the casing shoe OR
4. Run in hole, drill out the floats and re-cement the shoe track with drill pipe

4.C What other practicable steps could have been undertaken by PTTEP to prevent the failure to verify the casing shoe was a barrier?

PTTEPAA, in this circumstance following the WOC period, could have run a test packer in the well to establish a drawdown across the 9 5/8" casing shoe and verify that the cement plug, although displaced out of the shoe, had set across the Montara Cycle IV reservoir and was a barrier.

If this test showed that the casing shoe was no longer a barrier to the Montara Cycle IV reservoir, PTTEPAA could have drilled out the floats, and run a stinger to the bottom of the 9 5/8" casing and re-cemented the shoe, OR set a bridge plug (mechanical barrier) above the float collar, and tested it positively at least.

4.D What would good oilfield practice have been in this situation?

Under a failed casing shoe scenario, good oilfield practice would have been to:

1. Run a test packer in the well to establish a drawdown across the shoe and verify the cement plug, although displaced out of the shoe, had set across the Montara Cycle IV reservoir and was a barrier.
2. If the test in point 1, showed that the casing shoe was no longer a barrier to the Montara Cycle IV reservoir, then a stinger would have been run to the bottom of the 9 5/8" casing and the shoe re-cemented[i].
3. To negatively test the re-cemented shoe once the cement had set.
4. A mechanical bridge plug would have been set above the re-cemented shoe track.

Note[i]: If pumping into the shoe was not possible, then the float collar/plug and shoe track would have to have been drilled out, and subsequently re-cemented, as follows:

1. Displace the hole to an overbalanced fluid which may have required PTTEPAA to strip in hole well if an underbalance did exist.
2. Drill out the shoe track and re-cement the shoe
3. Re test the shoe

5. Failure to pressure test the 9 5/8 inch cement casing shoe

5.A An assessment of ALL documentation provided by NOPSA relating to the failure to pressure test the 9 5/8 inch cement casing shoe in the Montara H1-ST1 Well after 7 March 2009.

The Expert Witness has reviewed all available information provided by NOPSA, and identified the documents as described in Section 1.A.I that have direct importance to NOPSA issue 5. The list of documents is presented in Table 1. A detailed assessment of each document, including their particular relevance to the NOPSA issue 5 has been presented in Section 1.A.II.

5.B Whether the failure to pressure test the 9 5/8 inch cement casing shoe after 7 March 2009 in the Montara H1-ST1 Well increased the risk of an uncontrolled release of hydrocarbons?

The Expert's response to issue 5.B is:

Yes, the failure to pressure test the 9 5/8 inch cement casing shoe after 7 March 2009 in the Montara H1-ST1 Well **did increase** the risk of an uncontrolled release of hydrocarbons.

The Expert Witness's' elaboration in support of the answer is identical to 4.B as follows:

"If the floats had held in a normal situation, following bleed off of the bump/test pressure, this would have been a consequential negative test of the 9 5/8" shoe track equivalent to 1300 psi, due to the seawater column inside the 9 5/8" casing. However, since the floats did fail at the time of bleeding off the 4000 psi test pressure, no negative pressure test of the casing shoe was possible.

It should also be highlighted that a positive pressure test on the 9 5/8" casing shoe would not have been possible, after the top wiper plug had bumped to the time the cement had set after the WOC period, as the top wiper plug would have isolated the seawater column above from the 9 5/8" casing shoe below.

The practicable steps PTTEPAA could have taken given the situation, in order to verify that the 9 5/8" casing shoe was a barrier were to:

5. *Conduct a negative pressure test against the Montara Cycle IV reservoir after the WOC period OR*
6. *Run in hole and displace to an overbalance fluid OR*
7. *Create a new barrier by setting a bridge plug to the casing shoe OR*
8. *Run in hole, drill out the floats and re-cement the shoe track with drill pipe."*

The H1-ST1 well of course did not flow in an uncontrolled fashion after the 7bbl of backflow, since the well was shut in against the cement unit and pressure was held. After three (3) hours, the valve on the cement unit was opened, and it was discovered that the pressure had dissipated in the wellbore to 687psi.

The fact that the pressure had reduced, clearly indicated a pressure leak off into the Montara Cycle IV reservoir. This value of 687 psi cannot be taken as an equivalent test value, since according to the Document [2], it would appear that this would be the value rig personnel observed following the valve opening at the cement unit. If this was indeed the case, it is not known whether the value of 687 psi during the WOC period, had been steady for any period of time, or if the pressure could equally have continued to bleed off ultimately to zero.

Issue 5 seeks to identify whether the risk of uncontrolled flow was increased. When the 7 barrels of back flow occurred, there were no competent barriers to the Montara Cycle IV reservoir, until the cement was displaced back, and the valve on the cement unit closed. If the valve on the cement unit had leaked, especially after the cement had set, the only barrier against flow to the Montara Cycle IV reservoir was the underbalanced seawater column in the 9 5/8" casing (Panel 11 of XLS-30291-NOPSA-001-WAiT©, Expert Witness Report Vol 3 Section 3.1.11), therefore there was a serious risk of uncontrolled flow to surface at this stage.

5.C What other practicable steps could have been undertaken by PTTEP to prevent the failure to pressure test the 9 5/8 inch cement casing shoe?

PTTEPAA, in this circumstance following the WOC period, could have run a test packer in the well to establish a drawdown across the shoe and verify the cement plug. If this test showed that the casing shoe was no longer a barrier to the Montara Cycle IV reservoir, PTTEPAA would have run a stinger to the bottom of the 9 5/8" casing and re-cemented the shoe.

In addition to the practical steps above, PTTEPAA should have had the following corporate governance and standards in place. This would have ensured minimum acceptance criteria would have to be established prior to suspending the well:

1. Management insistence on compliance with standards and procedures through regular audits
2. A comprehensive Risk Assessment process. This would have identified the wet shoe on a horizontal production casing inside the hydrocarbon reservoir as a High Risk event.
3. A Well Integrity Management System. This would clearly identify minimum acceptance criteria for well barriers and would have **prevented the acceptance of no barrier on H1-ST1**.
4. A rigorous MOC system which has a zero tolerance for accepting change to approved programmes without detailed and documented risk assessment.

5.D What would good oilfield practice have been in this situation?

The acceptance by PTTEPAA of the failed shoe track as a barrier, when it clearly was not, is exceptional and extremely difficult to understand given today's emphasis in the oil industry on **Risk Assessment**, **Management of Change** and **Well Integrity**.

Many of the reviewed documents (as discussed in Table 1), showed the emphasis on reducing time in operations. Several PTTEPAA MOC documents justified the change on reduced time and cost but do not address the risk impact of the change. The MOC form does prompt the author to identify HSE impact, but this would appear to be inviting from the examples given, only positive impacts due to the changes, rather than the identification of any additional/new risk as a result of the new changes. In addition, the consequences of any additional/new risks as a result of the changes were also not given any consideration.

Under a failed casing shoe scenario, good oilfield practice would have been to:

1. Run a test packer in the well to establish a drawdown across the shoe and verify the cement plug, although displaced out of the shoe, had set across the Montara Cycle IV reservoir and was a barrier.
2. If the test in point 1, showed that the casing shoe was no longer a barrier to the Montara Cycle IV reservoir, then a stinger would have been run to the bottom of the 9 5/8" casing and the shoe re-cemented[i] with a kill weight fluid circulated into the wellbore and not a Seawater column
3. To negatively test the re-cemented shoe once the cement had set.
4. A mechanical bridge plug would have been set above the re-cemented shoe track.
5. Install a kill string in the well with an RTTS packer and back pressure valve. This would have enable PTTEPAA to circulate the well to a kill weight fluid during re-entry, in the event they found pressure below the RTTS BPV.

Note[i]: If pumping into the shoe was not possible, then the float collar/plug and shoe track would have to have been drilled out, and subsequently re-cemented.

In addition to the practical steps above, PTTEPAA should have had the following corporate governance and standards in place. This would have ensured minimum acceptance criteria to be established prior to suspending the H1-ST1 well:

1. Management insistence on compliance with standards and procedures through regular audits
2. A comprehensive Risk Assessment process. This would have identified the wet shoe on a horizontal production casing inside the hydrocarbon reservoir as a High Risk event.
3. A Well Integrity Management System. This would clearly identify minimum acceptance criteria for well barriers and would have prevented the acceptance of no barrier on H1-ST1.
4. A rigorous MOC system which has a zero tolerance for accepting change to approved programmes without detailed and documented risk assessment.

6. Failure to install the 13 3/8 inch MLS PCCC

6.A An assessment of ALL documentation provided by NOPSA relating to the failure to install the 13 3/8 inch MLS PCCC on the Montara H1-ST1 Well between 7 March 2009 and 21 April 2009.

6.A.I List of ALL relevant Documentation

The Expert Witness has reviewed all available information provided by NOPSA, and identified the following documents as having direct importance to NOPSA issues 6 to 9. The list of documents is presented in Table 31 below. A detailed assessment of each document, including in particular the relevance of each document to the NOPSA issues 6 to 9 in presented in Section 6.A.II.

No	NOPSA provided Document Titles	NOPSA Reference	Results of Expert Witness Assessment
Document Type: Planning			
[1]	PTTEPAA Management Standard: Well Construction Management Framework Standard ID	EV0000050	Table 32: Assessment
[2]	Document-PTTEP Australasia-Well Construction Standards, Standard ID: D41-502433-FACCOM Version 3	EV0000096	Table 33
[3]	Montara Phase 1B-Drilling & Completion Program	EV0000799	Table 34
[4]	Montara - Well GI, H1, H4 (Batch Drilled) Drilling Programme Rev. 2	EV0000614	Table 35
Document Type: MOC and Approvals			
[5]	Well Control Change Form, Montara-Well H1-001, D65005A-001	EV0000800	Table 36
[6]	Coogee Resources--Well Construction Change Control Form-Montara H1 & H4- Change Control D65005A 003	EV0000801	Table 37
[7]	Email from Chris Wilson-Preliminary Copy of Change Control-Montara H1, H4, H2 & H3 & Coogee Resources, D65005A-005	EV0000021	Table 38
[8]	Well Control Change Form, Montara- HI-006, D65005A-006	EV0000802	Table 39
[9]	Letter addressed to Jerry Whitfield from Ian Paton-PTTEP Australasia Pty Ltd	EV0000026	Table 40
[10]	Email from Dominic Marozzi to Ian Paton from Jerry Whitfield-Application for Approval to Suspend Montara H1ST1 Development Well AC/L7 [i]	EV0000036	Table 41

[11]	DDR Montara-H1-ST1 (07/03/09)	EV0000552	Table 42
[12]	Email from Dominic Marozzi to Ian Paton from Jerry Whitfield-Application for Approval to Suspend Montara H1ST1 Development Well AC/L7 [i]	EV0000036	Table 43
[13]	Letter addressed to Mr Jerry Whitfield frim Ian Paton, PTTEP Australasia Pty Ltd- [i]	EV0000038	Table 44
[14]	Email addressed to Ian Paton from Jerry Whitfield-Approval to Suspend Montara H4 & perform Stage 2 [i]	EV0000040	Table 45
Document Type: Operational			
[15]	DDR Montara-H2 (16/04/09)	EV0000676	Table 46
[16]	DDR Montara-H2 (16/04/09)	EV0000569	Table 46
Note: **i: Superscript depicting NT approvals for PETTPAA Suspension Activities** **ii: Superscript depicting PTTEPAA's internal Management of Change**			

Table 31: List of Critical Documents – NOPSA Issue 6 to 9

6.A.II Expert Witness Assessment of ALL Documentation

<table>
<tr><th>No</th><th>NOPSA provided Document Titles</th><th>Reference</th></tr>
<tr><td colspan="3">Document Type: Planning</td></tr>
<tr><td>[1]</td><td>PTTEPAA Management Standard: Well Construction Management Framework Standard ID</td><td>EV0000050</td></tr>
<tr><td colspan="3">Description and Relevance to NOPSA issue 6-9</td></tr>
<tr><td colspan="3">Document [1] is a PTTEPAA Standard that describes the process by which PTTEPAA will manage the project and describes the business fundamentals for leadership, policies, objectives, governing legislation, organization, resources, documentation, risk assessment, auditing, and Well Construction responsibilities.

The Risk Assessment and Management Section 3.4 of [1] states that PTTEPAA uses a “defined process to systematically identify the inherent risks involved in performing various activities”. This “defined process” is not contained within the Well Construction Management Framework Standard nor in any of the PTTEPAA documents submitted.</td></tr>
<tr><td colspan="3">Consistency between Documents, and Consistency between Approvals</td></tr>
<tr><td colspan="3">There are no other NOPSA provided documents identified that contain similar information presented in Document [1].</td></tr>
<tr><td colspan="3">Omissions of Data received (if any)</td></tr>
<tr><td colspan="3">From an assessment of Document [1], the Expert Witness does not consider that the Risk Management Framework as stated in Section 3.4 of Document [1] had been applied.

In addition, Section 3.4 of Document [1] states that the PTTEPAA Management Framework Section 6 explains how risk is assessed and control strategies are put in place. However, Section 6 is missing from the Well Construction Management Framework and therefore the process of how risk is assessed and how controls are put in place to manage the risk is not explained within any of the PTTEPAA documents received from NOPSA.</td></tr>
<tr><td colspan="3">This assessment is used in response to issue:</td></tr>
<tr><td colspan="3">Section 6.B, 7.B, 8.B, and 9.B</td></tr>
</table>

Table 32: Assessment of Document [1] in relation to Issue 6 to 9

No	NOPSA provided Document Titles	Reference
Document Type: Planning		
[2]	**Document-PTTEP Australasia-Well Construction Standards, Standard ID: D41-502433-FACCOM Version 3**	**EV0000096**
Description and Relevance to NOPSA issue 6-9		

Document [2] provides the minimum PTTEPAA standards applicable to all aspects of well design, construction, servicing and well abandonment activities. In particular, barriers, well control, well abandonment and long term suspension have minimum standards as defined by PTTEPAA in this document.

Barriers during Temporary Suspension are defined in **Section 5** of the document. Temporary suspension is defined as "*where the MODU or well intervention vessel remains on location*". Since the MODU did not remain on location following the completion of H1-ST1 Well, Stage 1 suspension, the well according to PTTEPAA Well Construction Standards could not have been in a Temporary Suspension state. Therefore it could be argued that barriers during temporary suspension as defined in **Section 5**, did not apply.

Section 14 of Document [2] defines **Long Term Suspension** as "*when the MODU leaves the well site*". Hence, according to the PTTEPAA Well Construction Standards, the H1-ST1 well, was considered to be under Long Term Suspension and therefore the barriers defined in **Section 14.1** should have applied.

Even if PTTEPAA had considered the well to be Temporarily Suspended, as defined in **Section 5**, the barriers defined under Temporary Suspensions were not installed. Specifically there was no installation of a BOP, retrievable packer, wireline plug or SSSV. For a fluid column to be a well barrier, **Section 5** states the following: "*fluid with a hydrostatic head greater than the formation pressure, provided that the liquid level and density could be monitored and maintained".*

Section 5 of [2] also states that "*a single temporary barrier may be used for temporary suspension, provided that petro physical logs and other data confirmed beyond doubt that no hydrocarbon zones or over pressured water zones are present either the wellbore or annuli*". Even if PTTEPAA had incorrectly defined the suspension as a Temporary Suspension, the condition of the well did not comply with the above statement. I.e. hydrocarbon zones were present in the wellbore via the

"wet shoe" and exposed reservoir. [Expert Witness Report Vol 3 Section 3.1.13] **The well construction standards do not state that a Temporary Abandonment cap/ PCCC is a recognized barrier at any well stage and therefore according to Document [2], could not have been considered an equivalent replacement for the downhole cement plugs in the suspension plan.**
Consistency between Documents, and Consistency between Approvals
There are no other NOPSA provided documents identified that contain similar information presented in Document [2].
Omissions of Data received (if any)
No identifiable omission of data is observed within this document relating to NOPSA issues 6 to 9.
This assessment is used in response to issue:
Section 6.B, 7.B, 8.B, and 9.B

Table 33: Assessment of Document [2] in relation to Issue 6 to 9

No	NOPSA provided Document Titles	Reference
	Document Type: Planning	
[3]	**Montara Phase 1B-Drilling & Completion Program**	**EV0000799**
	Description and Relevance to NOPSA issue 6-9	

Document [3] describes the drilling and completion program for wells GI-ST1, H1-HT1, H2, H3-ST1 and H4 which have been batched drilled and suspended at the 9 5/8” (244mm) casing shoe. It contains the planned sequence of operations for each of the above five (5) wells to be re-entered, tied back, drilled and completed.

Of particular interest are the specific references made, regarding the recovery of the supposedly installed 13 3/8” PCCC, at the time of Stage 2 suspension. Specifically in **Section 7** which contains the following information:

1. Hazard Register
2. Montara H1-ST1 Datum Adjustment Worksheet
3. AC/L7 Montara H1-ST1 Suspension Diagram – As Built
4. Vetco Operating and Service Procedure Vetco OPS-03001 (Mudline Suspension System Tieback)

Note: As per point 3, Document [3] contains references for the recovery of the installed 13 3/8” TA cap at the time of suspension of H1-ST1, specifically the 13 3/8” TA cap on pages (Section 7 Montara H1-ST1 Datum adjustment worksheet, Pg 38 Tie back procedure of the 13 3/8” Casing Montara H1-ST1, Section 7 AC/L7 H1-ST1 Suspension Diagram As Built).

These references clearly indicate that PTTEPAA believed that the 13 3/8” TA cap had been installed as per the programme, and in fact recorded in the H2 DDR#14, 16 April 2009 [“EV0000569”].

Document [3] also contains the “*VETCO GRAY MUDLINE SUSPENSION SYSTEMS OPERATING AND SERVICE PROCEDURE 03001*” where a 13 3/8” Corrosion Cap (Part no. 14303-1*) is identified as non-pressure containing.

Consistency between Documents, and Consistency between Approvals

The “**Hazard Register”** found in **Section 7 Pg 198** of the document lists the PTTEPAA identified Hazards, with their corresponding Consequence and Prevention/ Mitigation as follows:

"Hazard - Gas below the TA Cap

Consequence - Gas to surface without BOP's in place

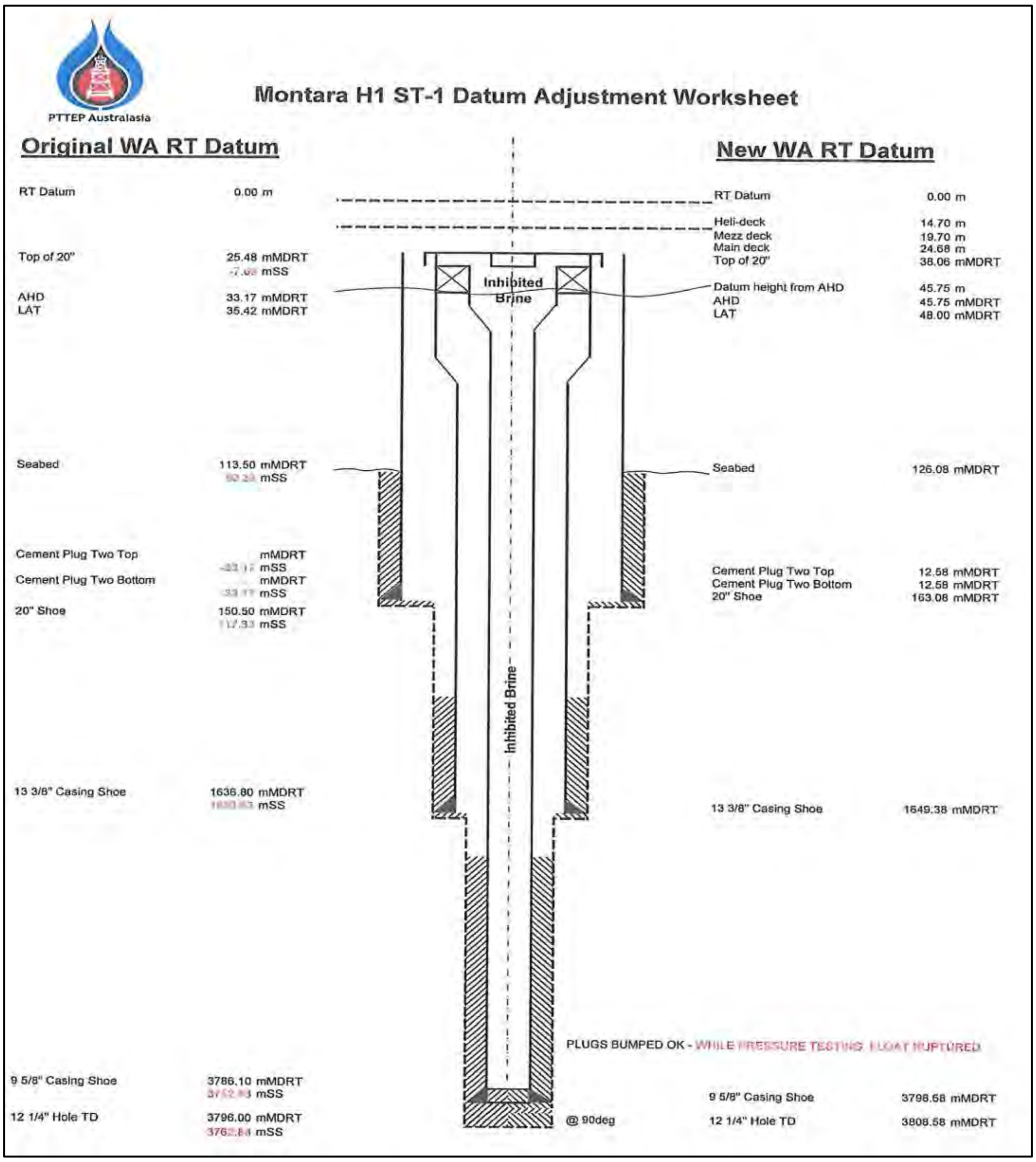
Prevention/ Mitigation - Sting into the cap and record any pressure. ***Bleed-off any pressure below the cap before removing the cap"***.

In addition, as stated in **Section 5.16** of the tie-back 340mm (13 3/8") Casing – Montara H1 ST1, and subsequently in **Section 5.17** of the tie-back 244mm (9 5/8") Casing – Montara H1 ST1, the following procedures were stated:

1. *"Run in hole with the corrosion cap running tool"*
2. *"Make up the TDS before engaging the running tool onto the corrosion cap (this will allow for any pressure below the corrosion cap to be observed on the standpipe and then bled off through the choke manifold)"*
3. *"Engage the corrosion cap and check for any pressure below the corrosion cap. Note any pressure on the IADC and the DDC.* ***Bleed off any pressure via the choke manifold****."*

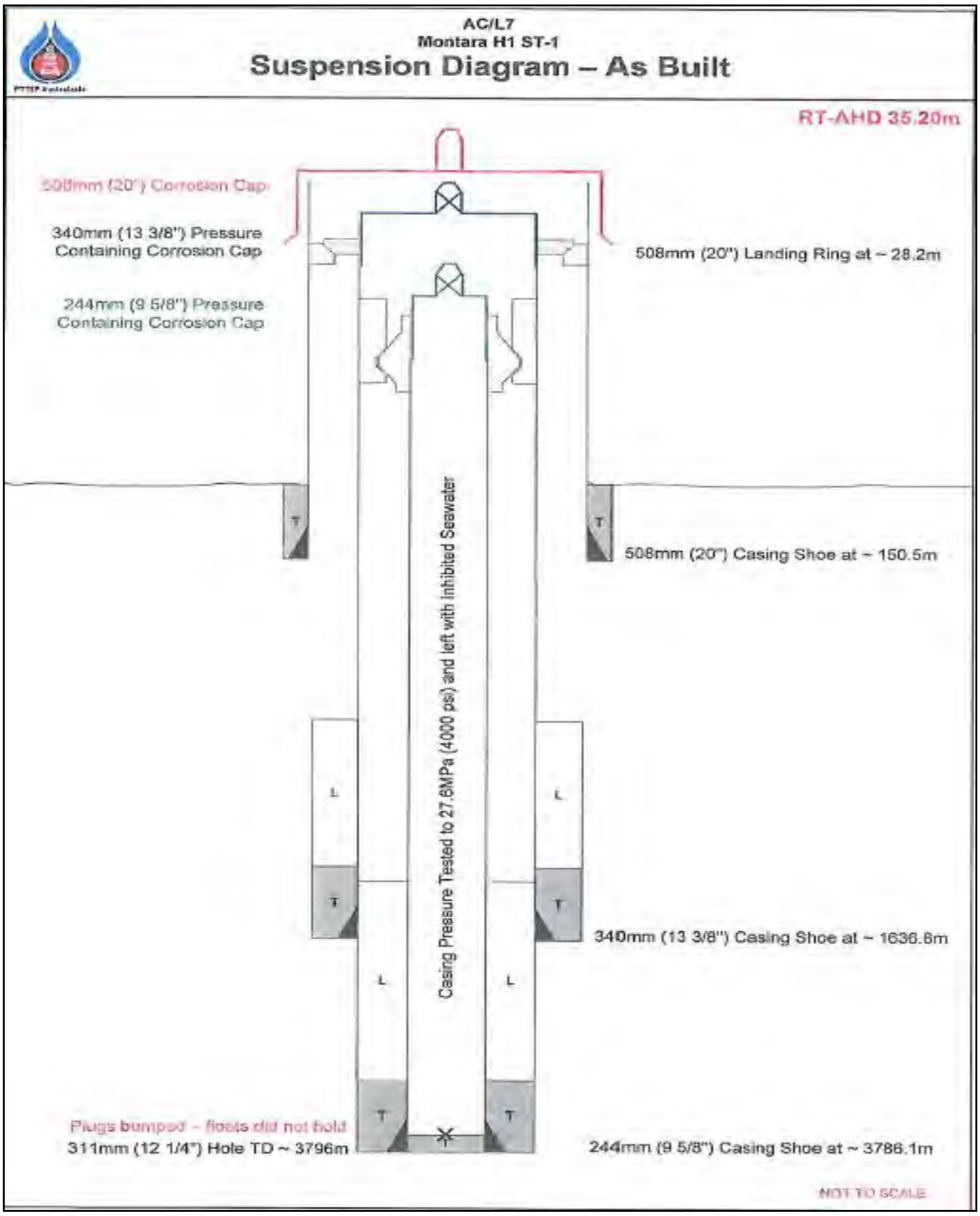
The "**Montara H1-ST1 Datum Adjustment Worksheet**" (Page number was not provided in the Program) contained several errors as follows with regards to well barriers:

1. The 13 3/8" (340mm) MLS Hanger has pressure isolation as shown in the figure, though the rating of the packer seal is neither defined in the drawing nor mentioned anywhere in the program.
2. The 20"(508mm) and 9 5/8"(244mm) PCCC were not shown in the figure, when they had been installed physically on H1-ST1, 16 April 2009, prior to the issue of Document [3] in June 2009.
3. The rat-hole and shoe track as shown in the diagram had been isolated with cement, when in fact 9 bbl of seawater had been over displaced after the floats had failed, leading to seawater residing in the shoe track, rathole and annulus space, and not cement.



The "**AC/L7 Montara H1-ST1 Suspension Diagram – As Built**" (Page number was not provided in the Program) shown below, contains several errors with regards to well barriers:

1. The 13 3/8" Pressure Containing Corrosion Cap is shown as a barrier in the Suspension Diagram, when in actual fact it had not been installed.
2. The rat-hole and shoe track had been isolated with cement, when in fact 9.0 bbl of seawater had been over displaced after the floats had failed, leading to seawater residing in the shoe track, rathole and annulus space.



The "Vetco Operating and Service Procedure Vetco OPS-03001 (Mudline Suspension System Tieback)" (Page number not provided in Document [3]) has been identified as a reference for the MLS.

1. With Reference to the “Vetco OPS-03001” document, the 13-3/8” (340mm) PCCC was not designed to be pressure rated (see below).
2. This is an inconsistency with the information stated in [“EV0000802”], a WCCCF which states that “*A 13 3/8” pressure containing suspension cap will also be installed on the 13 3/8” MLS.*”

VetcoGray

MUDLINE SUSPENSION SYSTEM TIEBACK
MLC 30 X 20 X 13-3/8 X 9-5/8 X 7 (OPTIONAL)

Corrosion Caps

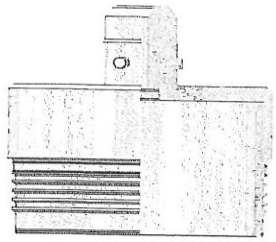
CORROSION CAP DATA	
SIZE	20"
PART NUMBER	143028-1*
SERVICE	Standard
MAXIMUM OD	21.280"
PRESSURE RATING	N/A
THREAD TYPE	LEFT HAND - 1 TPI
NUMBER OF TURNS TO MAKE-UP	3 TO 3-1/2
RECOMMENDED MAKE-UP TORQUE	1500 TO 2500 FT-LBS

SIZE	13-3/8"
PART NUMBER	143030-1*
SERVICE	H_2S
MAXIMUM OD	14.78"
PRESSURE RATING	N/A
THREAD TYPE	LEFT HAND - 2 TPI
NUMBER OF TURNS TO MAKE-UP	7 TO 8
RECOMMENDED MAKE-UP TORQUE	1500 TO 2500 FT-LBS

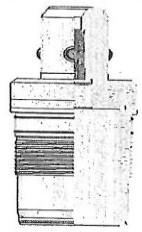
SIZE	9-5/8"
PART NUMBER	143032-1*
SERVICE	H_2S
MAXIMUM OD	11.28"
PRESSURE RATING	10,000 PSI
THREAD TYPE	LEFT HAND - 2 TPI
NUMBER OF TURNS TO MAKE-UP	7 TO 8
RECOMMENDED MAKE-UP TORQUE	1500 TO 2500 FT-LBS

SIZE	7"
PART NUMBER	143033-1*
SERVICE	H_2S
MAXIMUM OD	7.84"
PRESSURE RATING	10,000 PSI
THREAD TYPE	LEFT HAND - 2 TPI
NUMBER OF TURNS TO MAKE-UP	6 TO 7
RECOMMENDED MAKE-UP TORQUE	1500 TO 2500 FT-LBS

Mudline corrosion caps provide protection for hanger threads, seal areas, and offer pressure containment when the check valve is installed in stem. The corrosion cap makes up into the left hand running threads in the hanger and has elastomer seals above and below the threads. The corrosion cap running tool opens the check valve preventing pressure lock when installing the corrosion cap in the casing hanger.



Corrosion Cap - Non-Pressure Containing



Corrosion Cap - Pressure Containing

OSP03000, NC 6 OF 29 17 DECEMBER 2008

GE imagination at work

Omissions of Data received (if any)

It should be highlighted that the "*VETCO GRAY MUDLINE SUSPENSION SYSTEMS OPERATING AND SERVICE PROCEDURE 03001*" should not be taken as the definitive "Final Approved Assembly Drawing" for either of the PCCC's.

For the purpose of representing the surface suspension system (including the MLS and PCCCs), information provided in this section have been **ASSUMED** to be representative of the physical surface suspension system installed for the H1-ST1 well.

This assessment is used in response to issue:

Section 6.B, 7.B, 8.B, and 9.B

Table 34: Assessment of Document [3] in relation to Issue 6 to 9

No	NOPSA provided Document Titles	Reference
Document Type: Planning		
[4]	**Montara - Well GI, H1, H4 (Batch Drilled) Drilling Programme Rev. 2**	**EV0000614**
Description and Relevance to the NOPSA issue 6		
Document [4] is the original Montara H1-ST1 Suspension Plan and it is stated that the well will be suspended with the cemented Shoe track and a surface cement plug. In the "*Assumed Facts – Montara Wellhead Platform*" received by the Expert Witness from NOPSA on 29 September 2011, a statement appeared on Page 2, item 19 that states the following: "*On 12 January 2009, Mr Marozzi, Senior Petroleum Operations office, Minerals and Energy Group, [NT] Dept of Regional Development, Primary Industry, Fisheries and Resources, acknowledged receipt of the Montara GI, H1, H4 (Batch Drilled) Drilling Programme Revision 2*".		
Consistency between Documents, and Consistency between Approvals		
There are no other NOPSA provided documents identified that contain similar information presented in Document [4].		
Omissions of Data received (if any)		
The Expert Witness has have not seen any formal approval by the NT of this document.		
This assessment is used in response to issue:		
Section 6.B, 7.B, 8.B, and 9.B		

Table 35: Assessment of Document [4] in relation to Issue 6 to 9

MOC and Approval Documentation in relation to Well Suspension Planning for H1-ST1

Upon the assessment of ALL relevant documentation provided, it has been observed that the Suspension Programme as originally defined in Document [4], went through several phases of change. These changes were driven in part by Topsides delay, in part by the discovery of shallow gas sands in G1, in part by cement design changes, and in part due to the availability of suspension caps and cost savings. During the course of these changes, the 13 3/8" suspension cap was mistakenly identified in PTTEPAA's documents to be 1) pressure containing, and, 2) the 9 5/8" PCCC was mistakenly identified as annulus sealing.

These many phases of change, in all likelihood, together with the decision by PTTEPAA to conduct the phase 2 suspension offline, had an impact on the failure to install the 13 3/8" PCCC. The phases are described below from 1st Event/Change to 11th Event/Change.

The BOPs were left on the H1-ST1 well after the 9 5/8" PCCC was installed, on the 7 March 2009. This action prevented the installation of 13 3/8" PCCC since the BOP was effectively connected to the 13 3/8" casing by the wellhead and would have to be removed to allow the 13 3/8" PCCC to be installed. In effect, the BOP, given the condition of the H1-ST1 well, was the secondary barrier, and the only tested barrier on the well, since the 9 5/8" PCCC was not pressure tested.

From the assessment of the documents, the following location of the BOP has been established:

1. The BOP was first removed on **8 March 2009** from H1-ST1 and skidded for H4.
2. The BOP was re-installed onto H1-ST1 for storage on **20 March 2009**.
3. Finally, the BOP was removed from H1-ST1 and transferred to H3-ST1 on **3 April 2009**.

The available time windows for the 13 3/8" PCCC to have been installed on the H1-ST1 well were between 9 March 2009 to 19 of March 2009 and any time after 3 April 2009. Document [16] states that the 13 3/8" PCCC was installed on 16 April 2009 as an **OFFLINE** activity. From all documents reviewed, the NT had not approved the H1-ST1 well, "**Stage 2 Suspension**" as an OFFLINE activity.

No	NOPSA provided Document Titles	Reference
Document Type: MOC and Approval		
[5]	Well Control Change Form, Montara-Well H1-001, D65005A-001	**EV0000800**
Description and Relevance to NOPSA issue 6 to 9		
1st Event/Change: As stated in Document [5], dated 23 January 2009, a proposed change was submitted stating "*Increased the length of Tail cement for the 244mm Casing to increase the TVD height of the cement above the top of the Cycle IV formation (reservoir)*". The HSE Impact of proposed change was "*Increased well control protection by increasing the TOC from 30mTVD above the reservoir to 69m TVD above the reservoir*".		
Consistency between Documents, and Consistency between Approvals		
There are no other NOPSA provided documents identified that contain similar information presented in Document [5].		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 6 to 9.		
This assessment is used in response to issue:		
Section 6.B, 7.B, 8.B, and 9.B		

Table 36: Assessment of Document [5] in relation to Issue 6 to 9

<table>
<tr><th>No</th><th>NOPSA provided Document Titles</th><th>Reference</th></tr>
<tr><td colspan="3">Document Type: MOC and Approval</td></tr>
<tr><td>[6]</td><td>Coogee Resources--Well Construction Change Control Form- Montara H1 & H4- Change Control D65005A 003</td><td>EV0000801</td></tr>
<tr><td colspan="3">Description and Relevance to the NOPSA issue 6</td></tr>
<tr><td colspan="3"> 2nd Event/Change: As stated in Document [6], dated 30 January 2009, a proposed change was submitted stating the following: “The suspension of the H1 and H4 wells will require the wells to be suspended at the MLS. No pressure containing caps will be installed and this leaves the annulus between the 311mm (12 ¼”) hole and the 244mm (9 5/8”) casing open at surface. A lead cement has been added to the program that will fill the annulus from the top of the tail cement up into the 340mm (13 3/8”) casing by 50m – effectively sealing off the open hole annulus”. The HSE Impact of proposed change was to “secure the open hole annulus prior to well suspension”. </td></tr>
<tr><td colspan="3">Consistency between Documents, and Consistency between Approvals</td></tr>
<tr><td colspan="3">There are no other NOPSA provided documents identified that contain similar information presented in Document [6].</td></tr>
<tr><td colspan="3">Omissions of Data received (if any)</td></tr>
<tr><td colspan="3">No identifiable omission of data is observed within this document relating to NOPSA issues 6 to 9, other than the fact that the 13 3/8” PCCC was not pressure containing as advised to NT.</td></tr>
<tr><td colspan="3">This assessment is used in response to issue:</td></tr>
<tr><td colspan="3">Section 6.B, 7.B, 8.B, and 9.B</td></tr>
</table>

Table 37: Assessment of Document [6] in relation to Issue 6 to 9

No	NOPSA provided Document Titles	Reference
Document Type: MOC and Approval		
[7]	**Email from Chris Wilson-Preliminary Copy of Change Control-Montara H1, H4, H2 & H3 & Coogee Resources, D65005A-005**	**EV0000021**
Description and Relevance to NOPSA issue 6 to 9		
3rd Event/Change: As stated in [7], dated 3 March 2009, an "*unofficial change control form for the centralizers*" was submitted, as an attachment to an email. A proposed change "*To include the running of 244mm (9 5/8") casing centralizers across a small gas sand in the Gibson and Woolaston Formation*" was approved on the same day. The HSE Impact of the proposed change stated was "*improved well integrity by isolating the gas sand in the Gibson/Woolaston*".		
Consistency between Documents, and Consistency between Approvals		
There are no other NOPSA provided documents identified that contain similar information presented in Document [7].		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 6 to 9.		
This assessment is used in response to issue:		
Section 6.B, 7.B, 8.B, and 9.B		

Table 38: Assessment of Document [7] in relation to Issue 6 to 9

<table>
<tr><th>No</th><th>NOPSA provided Document Titles</th><th>Reference</th></tr>
<tr><td colspan="3">Document Type: MOC and Approval</td></tr>
<tr><td>[8]</td><td>Well Control Change Form, Montara- HI-006, D65005A-006</td><td>EV0000802</td></tr>
<tr><td colspan="3">Description and Relevance to NOPSA issue 6 to 9</td></tr>
<tr><td colspan="3"> 4th Event/Change: As stated in document [8], dated 11 March 2009, a proposed change was submitted to “change to suspension plan for Montara H1”.
The details of the proposed change is “Due to the availability of pressure containing suspension caps, the cement plug will now be replaced with a 9 5/8” pressure containing suspension cap installed on the 9 5/8” MLS. A 13 3/8” pressure containing suspension cap will also be installed on the 13 3/8” MLS.”
The HSE Impact of proposed change was “improved well integrity during suspension and re-entry operations”. </td></tr>
<tr><td colspan="3">Consistency between Documents, and Consistency between Approvals</td></tr>
<tr><td colspan="3">There are no other NOPSA provided documents identified that contain similar information presented in Document [8].</td></tr>
<tr><td colspan="3">Omissions of Data received (if any)</td></tr>
<tr><td colspan="3">No identifiable omission of data is observed within this document relating to NOPSA issues 6 to 9.</td></tr>
<tr><td colspan="3">This assessment is used in response to issue:</td></tr>
<tr><td colspan="3">Section 6.B, 7.B, 8.B, and 9.B</td></tr>
</table>

Table 39: Assessment of Document [8] in relation to Issue 6 to 9

No	NOPSA provided Document Titles	Reference
Document Type: MOC and Approval		
[9]	**Letter addressed to Jerry Whitfield from Ian Paton-PTTEP Australasia Pty Ltd**	**EV0000026**
Description and Relevance to NOPSA issue 6 to 9		
5th Event/Change: Letter request dated 6 March by PTTEPAA to the NT, requesting approval to suspend Montara H1-ST1 development well, AC/7 in accordance with Drilling Programme (TM-CR-MON-B-150-0001 Rev 2). The proposed programme seeks approval to suspend the well in two stages: 1st Stage: Cement and Pressure Test of the 9 5/8" (244mm) casing, Install 9-5/8" (244mm) PCCC with diagram provided. 2nd Stage: Recover 13 3/8" (340mm) casing above the MLS, Install a second 13 3/8" *Pressure Containing* PCCC, Recover 20" (508mm) casing above MLS and install a further suspension cap, with no diagram provided.		
Consistency between Documents, and Consistency between Approvals		
During the Re-entry of H1-ST1, on 20 August 2009, it was found that the 13 3/8" PCCC was not installed as proposed in Document [9].		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 6 to 9.		
This assessment is used in response to issue:		
Section 6.B, 7.B, 8.B, and 9.B		

Table 40: Assessment of Document [9] in relation to Issue 6 to 9

No	NOPSA provided Document Titles	Reference
Document Type: MOC and Approval		
[10]	**Email from Dominic Marozzi to Ian Paton from Jerry** Whitfield-**Application for Approval to Suspend Montara H1ST1 Development Well AC/L7**	**EV0000036**
Description and Relevance to NOPSA issue 6 to 9		
6th Event/Change: Preliminary Approval by Dominic Marozzi on 6 March 09, for the PTTEPAA letter request document [10] submitted to the NT on 6 March 09.		
Consistency between Documents, and Consistency between Approvals		
During the Re-entry of H1-ST1, on 20 August 2009, where it was found that the 13 3/8" PCCC was not installed as proposed in Document [10].		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 6 to 9.		
This assessment is used in response to issue:		
Section 6.B, 7.B, 8.B, and 9.B		

Table 41: Assessment of Document [10] in relation to Issue 6 to 9

No	NOPSA provided Document Titles	Reference
Document Type: MOC and Approval		
[11]	**DDR Montara-H1-ST1 (07/03/09)**	**EV0000552**
Description and Relevance to NOPSA issue 6 to 9		
7th Event/Change: Document [11] is a Daily Drilling Report issued by ATLAS on 7 March 2009.		
Consistency between Documents, and Consistency between Approvals		
There are no other NOPSA provided documents identified that contain similar information presented in Document [11].		
Omissions of Data received (if any)		
The execution of H1-ST1 Stage 1 Suspension was not recorded in the Seadrill DDR dated (07/03/09).		
This assessment is used in response to issue:		
Section 6.B, 7.B, 8.B, and 9.B		

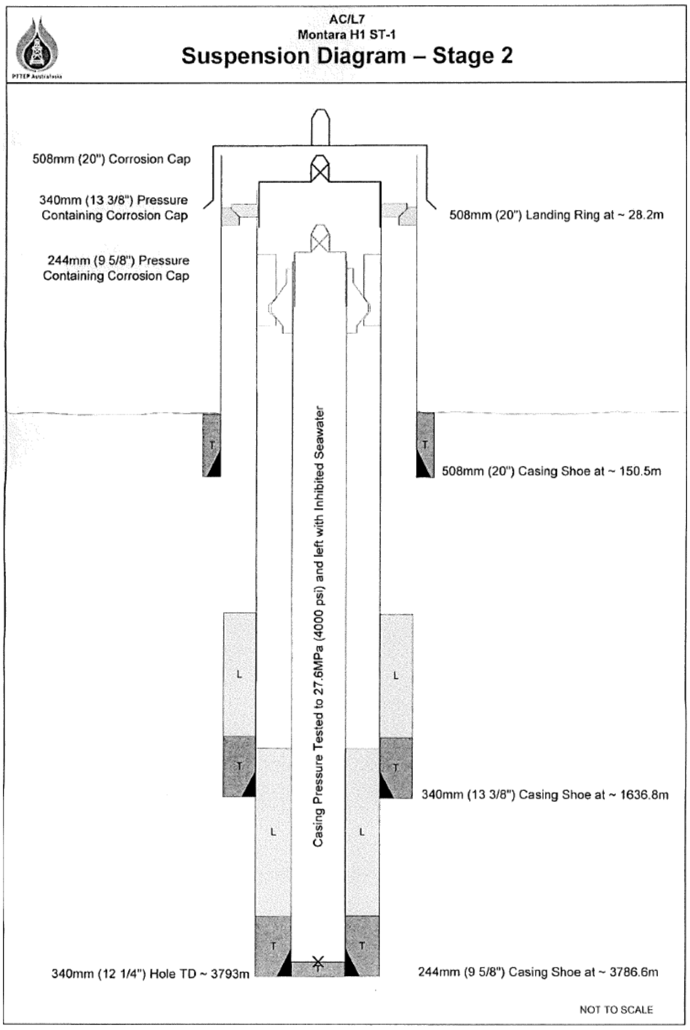
Table 42: Assessment of Document [11] in relation to Issue 6 to 9

No	NOPSA provided Document Titles	Reference
Document Type: MOC and Approval		
[12]	**Email from Dominic Marozzi to Ian Paton from Jerry** Whitfield**-Application for Approval to Suspend Montara H1ST1 Development Well AC/L7**	**EV0000036**
Description and Relevance to NOPSA issue 6 to 9		
8th Event/Change: Authorized approval of letter requesting for the NT approval to carry out H1-ST1 Stage 1 Suspension from Jerry Whitfield (NT DoE) dated 9 March 09. Note: Approval was received 2 days after H1-ST1 Well Stage 1 suspension was executed by PTTEPAA on 7 March 2009.		
Consistency between Documents, and Consistency between Approvals		
There are no other NOPSA provided documents identified that contain similar information presented in Document [12].		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 6 to 9.		
This assessment is used in response to issue:		
Section 6.B, 7.B, 8.B, and 9.B		

Table 43: Assessment of Document [12] in relation to Issue 6 to 9

No	NOPSA provided Document Titles	Reference
	Document Type: MOC and Approval	
[13]	Letter addressed to Mr Jerry Whitfield from Ian Paton, PTTEP Australasia Pty Ltd	EV0000038
	Description and Relevance to NOPSA issue 6 to 9	

9th Event/Change: Letter request dated 12 March by PTTEPAA to NT requesting approval to suspend Montara H4 and perform Stage 2 suspensions on Montara GI –ST1 and Montara H1-ST1 development wells, AC/7, using the rig.



Note: Stage 2 was executed on 16 April 2009 as an OFFLINE activity. The NT authority had been informed from [4] that the installation of the 20" trash cap would be installed offline but this programme was issued on 6 January 2009 several months before the suspension method was changed to include 9 5/8" (244mm) and 13 3/8" (340mm) PCCC's. Document [13], paragraph 3 states the following:

"Once Montara H4 is suspended, ***the rig*** *will then commence the stage 2 suspension for H1-ST1, as*

per the attached suspension diagram".   From documents it is the opinion of the Expert Witness that approval was not given by NT to perform the H1-ST1 well Stage 2 suspension, which included the 13 3/8" (340mm) suspension cap, as **an OFFLINE activity**.
Consistency between Documents, and Consistency between Approvals
During the Re-entry of the H1-ST1 Well, on 20 August 2009, where it was found that the 13 3/8" PCCC was not installed as proposed in Document [13].
Omissions of Data received (if any)
No identifiable omission of data is observed within this document relating to NOPSA issues 6 to 9.
This assessment is used in response to issue:
Section 6.B, 7.B, 8.B, and 9.B

Table 44: Assessment of Document [13] in relation to Issue 6 to 9

No	NOPSA provided Document Titles	Reference
Document Type: MOC and Approval		
[14]	**Email addressed to Ian Paton from Jerry** Whitfield-**Approval to Suspend Montara H4 & perform Stage 2**	**EV0000040**
Description and Relevance to NOPSA issue 6 to 9		
10th Event/Change: Authorized approval of letter requesting for approval to carry out H1-ST1 Stage 2 suspension from Jerry Whitfield (NT DA) dated 13 March 09.		
Consistency between Documents, and Consistency between Approvals		
During the Re-entry of H1-ST1 Well, on 20 August 2009, where it was found that the 13 3/8” PCCC was not installed as proposed in Document [14].		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 6 to 9.		
This assessment is used in response to issue:		
Section 6.B, 7.B, 8.B, and 9.B		

Table 45: **Assessment of Document [14] in relation to Issue 6 to 9**

No	NOPSA provided Document Titles	Reference
Document Type: Operational		
[15]	**Seadrill DDR Montara-H2 (16/04/09)**	**EV0000676**
[16]	**PTTEPAA DDR Montara-H2 (16/04/09)**	**EV0000569**
Description and Relevance to the NOPSA issue 6		
11th Event/Change: In the PTTEPAA DDR, dated 16 April 2009, states the following: *"Corrosion caps fitted to 340mm MLS and trash caps fitted to 508mm conductors on H1 and H3-ST1"*.		
Consistency between Documents, and Consistency between Approvals		
The installation of the 13 3/8" (340mm) Corrosion Cap had not been documented in the SEADRILL DDR (16/04/09), document [15], contrary to records shown in the PETTPAA DDR (16/04/09) [16].		
Omissions of Data received (if any)		
No identifiable omission of data is observed within this document relating to NOPSA issues 6 to 9.		
This assessment is used in response to issue:		
Section 6.B, 7.B, 8.B, and 9.B		

Table 46: Assessment of Document [15] & [16] in relation to Issue 6 to 9

6.B Whether the failure to install the 13 3/8 inch MLS PCCC on the Montara H1-ST1 Well increased the risk of an uncontrolled release of hydrocarbons?

The Expert's response issue 6.B is:

Yes, the failure to install the 13 3/8 inch MLS PCCC on the Montara H1-ST1 Well **did increase** the risk of an uncontrolled release of hydrocarbons.

The Expert Witness's elaboration in support of the answer is as follows:

During the 13 3/8" PCCC installation at the "Suspension Stage 2" on the H1-ST1 Well, the Well Integrity condition of the suspended well should have been known and all facts should have clearly indicated to PTTEPAA that the Well Integrity status of H1-ST1 well, was as follows:

1. The H1-ST1 9 5/8" shoe track had failed floats, and due to over displacement of seawater was in direct communication with the Montara Cycle IV reservoir Panel 13 of XLS-30291-NOPSA-001-WAiT© [Expert Witness Report Vol 3 Section 3.1.13], indicating that the H1-ST1 9 5/8" casing shoe was a compromised barrier.
2. The well had a compromised hydrostatic barrier (non-compliance with PTTEPAA's Well Construction Standard **[2] section 5**) with an estimated **75psi** under balance to the Top of the Montara Cycle IV reservoir pressure Panel 13 of XLS-30291-NOPSA-001-WAiT© [Expert Witness Report Vol 3 Section 3.1.13].
3. The H1-ST1 9 5/8" PCCC was not an approved well barrier according to PTTEPAA's own Well Construction Standard [2] **section 5.**
4. The well did **have a** H1-ST1 9 5/8" PCCC but was not tested after installation, and therefore cannot be verified as a competent barrier against flow from the Montara Cycle IV reservoir, and was not an approved barrier according to PTTEPAA's own management standards
5. The H1-ST1 well had no surface annular i**solation betwe**en the 9 5/8" and 13 3/8" casings to hydrocarbon bearing zones, and was relying on the unverified barrier of the 9 5/8" casing cement.
6. The 13 3/8" PCCC that had been selected by PTTEPAA was not pressure containing, despite informing NT that it was, nor did it provide any annular pressure isolation, due to no casing hanger pack-off, in contradiction to some schematic suggestions within PTTEPAA documents.

7. The well in this condition had zero barriers to hydrocarbons from the Montara Cycle IV reservoir, according to PTTEPAA procedures and barrier philosophy as per **[2] Section 5, on the inside of the casing, and only a single primary barrier (cement) on the annulus, with no cement bond log evaluation.**

If the correct 13 3/8" (340mm) PCCC (i.e. pressure containing and providing annular pressure isolation) was installed on H1-ST1 well, then the H1-ST1 well would in fact have had a secondary barrier to uncontrolled hydrocarbon flow above the 9 5/8" (244mm) PCCC, and a secondary barrier to the cement column in the annulus. The 13 3/8" (340mm) PCCC would have become the only competent barrier (provided the 13 3/8" PCCC can be tested and verified) in the event the 9 5/8" (244mm) PCCC leaked.

Given that the down-hole barriers to the hydrocarbons in the Montara Cycle IV reservoir were compromised, it was essential to have had a secondary backup to the 9 5/8" (244mm) PCCC; since the well was now exposed to the risk of uncontrolled flow due to a **single point failure**, i.e. the 9 5/8" (244mm) PCCC.

It is in the Expert's opinion that an installed and verifiable 13 3/8" (340mm) PCCC would have reduced the risk of an uncontrolled release of hydrocarbon from the well in its' suspended state.

6.C What other practicable steps could have been undertaken by PTTEP to prevent the failure to install the 13 3/8 inch MLS PCCC?

Given that the failure to install the 13 3/8" PCCC was a gross human error, seriously compounded by the misreporting that it had been installed, practicable steps to prevent this failure can only relate to human and organization factors as follows:

1. The 13 3/8" (340mm) PCCC should have been installed as a rig activity (after BOP removal) instead of an offline activity, as per the NT's approval. In this way, the evidence of the 13 3/8" (340mm) PCCC installation and the correct torque applied for the installation would have been captured in the rig's data reporting system.
2. Given that the 13 3/8" (340mm) PCCC was supposedly run as an offline activity with no objective evidence being captured by the rig's data reporting system, PTTEPAA could have insisted on '**evidence based reporting'** for such a critical item i.e. photographs of the installed 13 3/8" (340mm) PCCC. The use of photographs of equipment is common practice on drilling units today.
3. PTTEPAA could have conducted a cross reference check on equipment on board against the inventory to confirm that the 13 3/8" (340mm) PCCC had been installed.
4. The establishment of Well Integrity on H1-ST1 prior to suspension would have been the **top priority** for the management team, given the condition of the failed floats, the cement over-displacement and a borderline or underbalance fluid column to a hydrocarbon reservoir.
5. A Risk Assessment on the final suspension plan would have been conducted in light of events on H1ST-1, quite possibly with third party participation.

6.D What would good oilfield practice have been in this situation?

The following typical good oilfield practices would apply:

1. The rig would have installed the 13 3/8" PCCC as per the NT approval after the removal of the BOP,
2. PTTEPAA would have produced a depth record of the 13 3/8" PCCC installation;
3. PTTEPAA would have conducted a cross reference check on equipment on board against the inventory to confirm that that 13 3/8" PCCC had been installed.
4. The establishment of Well Integrity on H1-ST1 prior to suspension would have been the **top priority** for the management team, given the condition of the failed floats, the cement over-displacement and a borderline or underbalance fluid column to a hydrocarbon reservoir.
5. A Risk Assessment on the final suspension plan would have been conducted in light of events on H1ST-1, quite possibly with third party participation.
6. Well suspensions should have been carried out by a drilling rig with safety barriers installed i.e. BOP, and not as an offline activity, where hydrocarbons or overpressure have been exposed.

7. Corrosion of the threads on the 13 3/8 inch mudline hanger

7.A An assessment of ALL documentation provided by NOPSA relating to the corrosion of the threads on the 13 3/8 inch mudline hanger of the Montara H1-ST1 Well.

The Expert Witness has reviewed all available information provided by NOPSA, and identified the documents as described in Section 6.A.I that have direct importance to NOPSA issue 7. The list of documents is presented in List of Critical Documents – NOPSA Issue 6 to 9 Table 31. A detailed assessment of each document, including their particular relevance to the NOPSA issue 7 has been presented in Section 6.A.II.

7.B Whether the failure to install a PCCC on the 13 3/8 inch mudline hanger of the Montara H1-ST1 Well was one of the direct causes of the blowout, in that it led to the corrosion of the threads on the 13 3/8 inch mudline hanger.

The Expert's response to issue 7.B is:

No, the failure to install a PCCC on the 13 3/8 inch mudline hanger of the Montara H1-ST1 Well was **not a direct** but was an **indirect cause** of the blowout, in that it led to the corrosion of the threads on the 13 3/8 inch mudline hanger, and subsequent removal of the 9 5/8" PCCC.

The Expert Witness's' elaboration in support of the answer is as follows:

The corrosion of the 13 3/8" MLS threads did not cause the blowout, although it is noteworthy to highlight that the threads corrosion would not have occurred if the 13 3/8" (340mm) PCCC was installed. The well did not directly blowout due to the failure to install 13 3/8" PCCC, but due to actions by PTTEPAA staff on discovering the absence of the 13 3/8" PCCC.

The reaction of the PTTEPAA personnel to the corrosion of the threads, was the **direct** cause of the blowout, by their decision to remove the only competent barrier to hydrocarbon flow from the Montara Cycle IV reservoir. This single barrier was the 9 5/8" (244mm) PCCC, and in the Expert's opinion, PTTEPAA's likely failed to detect pressure in the wellbore below the 9 5/8" (244mm) PCCC, which was highly to have existed, due to the under balance condition of the seawater column to the Montara Cycle IV reservoir.

What is evident is that the H1-ST1 Well had a blowout, and therefore the well must have been in an under balanced condition at the time it started to flow XLS-30291-NOPSA-002-WAiT© [Expert Witness Report Vol 3 Section 3.2]. In the Expert's opinion, actions on the well during the H1-ST1 re-entry operation on the 20/21 August 2009, changed the bottom hole pressure condition of the well. The bottom hole pressure could only have been reduced by the removal of the PCCC, therefore there must have been pressure beneath the 9 5/8" PCCC which was not detected when the running tool was stabbed into it. Hence, **the removal of the <u>9 5/8" PCCC</u> was a direct cause of the blowout.**

7.C What other practicable steps could have been undertaken by PTTEP to prevent the corrosion of the threads on the 13 3/8 inch mudline hanger?

The answer to issue 7.C is similar to issue 6.C as follows:

Given that the failure to install the 13 3/8" PCCC was a gross human error, seriously compounded by the misreporting that it had been installed, practicable steps to prevent this failure can only relate to human and organization factors as follows:

1. *The 13 3/8" (340mm) PCCC should have been installed as a rig activity (after BOP removal) instead of an offline activity, as per the NT's approval. In this way, the evidence of the 13 3/8" (340mm) PCCC installation and the correct torque applied for the installation would have been captured in the rig's data reporting system.*
2. *Given that the 13 3/8" (340mm) PCCC was supposedly run as an offline activity with no objective evidence being captured by the rig's data reporting system, PTTEPAA could have insisted on '**evidence based reporting'** for such a critical item i.e. photographs of the installed 13 3/8" (340mm) PCCC. The use of photographs of equipment is common practice on drilling units today.*
3. *PTTEPAA could have conducted a cross reference check on equipment on board against the inventory to confirm that the 13 3/8" (340mm) PCCC had been installed.*
4. *The establishment of Well Integrity on H1-ST1 prior to suspension would have been the **top priority** for the management team, given the condition of the failed floats, the cement over-displacement and a borderline or underbalance fluid column to a hydrocarbon reservoir.*
5. *A Risk Assessment on the final suspension plan would have been conducted in light of events on H1ST-1, quite possibly with third party participation.*

7.D What would good oilfield practice have been in this situation?

The answer to issue 7.D is similar to issue 6.D as follows:

The following typical oilfield practices could apply:

1. *The rig would have installed the 13 3/8" PCCC as per the NT approval after the removal of the BOP,*
2. *PTTEPAA would have produced a depth record of the 13 3/8" PCCC installation;*
3. *PTTEPAA would have conducted a cross reference check on equipment on board against the inventory to confirm that that 13 3/8" PCCC had been installed.*
4. *The establishment of Well Integrity on H1-ST1 prior to suspension would have been the **top priority** for the management team, given the condition of the failed floats, the cement over-displacement and a borderline or underbalance fluid column to a hydrocarbon reservoir.*
5. *A Risk Assessment on the final suspension plan would have been conducted in light of events on H1ST-1, quite possibly with third party participation.*
6. *Well suspensions should have been carried out by a drilling rig with safety barriers installed i.e. BOP, and not as an offline activity, where hydrocarbons or overpressure have been exposed.*

8. Removal of the 9 5/8 inch MLS PCCC

8.A An assessment of ALL documentation provided by NOPSA relating to the removal of the 9 5/8 inch MLS PCCC onto the Montara H1-ST1 Well on 20 August 2009 or 21 August 2009.

The Expert Witness has reviewed all available information provided by NOPSA, and identified the documents as described in Section 6.A.I that have direct importance to NOPSA issue 8. The list of documents is presented in List of Critical Documents – NOPSA Issue 6 to 9Table 31. A detailed assessment of each document, including their particular relevance to the NOPSA issue 8 has been presented in Section 6.A.II.

8.B Whether the removal of the 9 5/8 inch MLS PCCC from the Montara H1-ST1 Well increased the risk of an uncontrolled release of hydrocarbons?

The Expert's response to issue 8.B is:

Yes, the removal of the 9 5/8 inch MLS PCCC from the Montara H1-ST1 Well **did increase** the risk of an uncontrolled release of hydrocarbons.

The Expert Witness's' elaboration in support of the answer is as follows:

What is evident is that the H1-ST1 Well had a blowout, and therefore the well must have been in an under balanced condition at the time it started to flow XLS-30291-NOPSA-002-WAiT© [Expert Witness Report Vol 3 Section 3.2]. In the Expert's opinion, actions on the well during the H1-ST1 re-entry operation on the 20/21 August 2009, changed the bottom hole pressure condition of the well. The bottom hole pressure could only have been reduced by the removal of the PCCC, therefore the well was in an under balanced condition with the 9 5/8" PCCC installed. Consequently, it was likely that there was pressure beneath the 9 5/8" PCCC which was not detected when the running tool was stabbed into it. **Hence, the removal of the 9 5/8" PCCC was a direct cause of the blowout.**

8.C What other practicable steps could have been undertaken by PTTEP to reduce the risk, as low as reasonably practicable (ALARP), arising from the removal of the 9 5/8 inch MLS PCCC?

Since PTTEPAA staff had planned to remove the only barrier (although unverified) in the H1-ST1 Well, they should have installed new barriers prior to removing the 9 5/8" PCCC barrier as follows:

1. Install BOPs prior to the removal of 9 5/8" PCCC on the well.
2. Fill the riser above the 9 5/8" PCCC, close the annular around the PCCC stinger string, and monitor the well for pressure or flow under controlled conditions, not relying on human observations remote from the rig floor at the mezzanine deck. This method would have eliminated the riser of pressure leaking past the recovery tool seal and over the 20" casing string to the atmosphere.
3. Install a kill string after the removal of the 9 5/8" PCCC at a depth to enable the circulation of a kill weight fluid to restore an overbalance to the Montara Cycle IV reservoir.
4. Monitor and record fluid level in the 9 5/8" casing on a 24 hour basis.

8.D What would good oilfield practice have been in this situation?

Since PTTEPAA staff had planned to remove the only barrier (although unverified) in the H1-ST1 Well, they should have installed new barriers prior to removing the 9 5/8” PCCC barrier as follows:

1. Install BOPs prior to the removal of 9 5/8” PCCC on the well.
2. Fill the riser above the PCCC, close the annular around the PCCC stinger string, and monitor the well for pressure or flow under controlled conditions, not relying on human observations remote from the rig floor at the mezzanine deck. This method would have eliminated the riser of pressure leaking past the recovery tool seal and over the 20” casing string to the atmosphere.
3. Install a kill string after the removal of the 9 5/8” PCCC at a depth to enable the circulation of a kill weight fluid to restore an overbalance to the Montara Cycle IV reservoir.
4. Monitor and record fluid level in the 9 5/8” casing on a 24 hour basis.

9. Failure to reinstall the 9 5/8 inch MLS PCCC

9.A An assessment of ALL documentation provided by NOPSA relating to the failure to reinstall the 9 5/8 inch MLS PCCC onto the Montara H1-ST1 Well on 20 August 2009 or 21 August 2009.

The Expert Witness has reviewed all available information provided by NOPSA, and identified the documents as described in Section 6.A.I that have direct importance to NOPSA issue 9. The list of documents is presented in List of Critical Documents – NOPSA Issue 6 to 9Table 31. A detailed assessment of each document, including their particular relevance to the NOPSA issue 9 has been presented in Section 6.A.II.

9.B Whether the failure to re-install the 9 5/8 inch MLS PCCC onto the Montara H1-ST1 Well increased the risk of an uncontrolled release of hydrocarbons?

The Expert's response to issue 9.B is:

Yes, the failure to re-install the 9 5/8 inch MLS PCCC onto the Montara H1-ST1 Well **did increase** the risk of an uncontrolled release of hydrocarbons

The Expert Witness's' elaboration in support of the answer is as follows:

What is evident is that the H1-ST1 Well had a blowout, and therefore the well must have been in an under balanced condition at the time it started to flow XLS-30291-NOPSA-002-WAiT© [Expert Witness Report Vol 3 Section 3.2]. In the Expert's opinion, actions on the well during the H1-ST1 re-entry operation on the 20/21 August 2009, changed the bottom hole pressure condition of the well. The bottom hole pressure could only have been reduced by the removal of the PCCC, therefore the well was in an under balanced condition with the 9 5/8" PCCC installed. Consequently, there must have been pressure beneath the 9 5/8" PCCC which was not detected when the running tool was stabbed into it. Hence, the removal of the 9 5/8" PCCC was a direct cause of the blowout.

The re-installation of the 9 5/8" MLS PCCC would have **restored** the required surface barrier to effect a surface pressure in addition to the wellbore fluid hydrostatic to maintain balance between the H1-ST1 Well and the Montara Cycle IV reservoir. If the 9 5/8" PCCC had been re-installed on the well, the well could not have blown out while it remained in position.

9.C What other practicable steps could have been undertaken by PTTEP to reduce the risk, ALARP, arising from the failure to reinstall the 9 5/8 inch MLS PCCC?

Since PTTEPAA staff **did not recognize there were any risks** involved in the failure to re-install the 9 5/8" PCCC, it is not clear what they could have done to reduce risks. The well at this stage with no barriers and an underbalance fluid column was inevitably going to blowout since:

1. The well was underbalanced and opened to the hydrocarbon bearing Montara Cycle IV reservoir.
2. The rig has skidded to another well.
3. No surface barriers were left installed on the H1-ST1 well.
4. Theoretically, PTTEPAA could have installed the 13 3/8" PCCC. However, it was earlier demonstrated that the 13 3/8" PCCC was not pressure rated.
5. If PTTEPAA had conducted a full risk assessment on the H1-ST1 Well at the time of suspension and understood the high risk nature of the well, they could have realized that BOPs must be installed and remain on H1-ST1 Well until a time when a kill fluid could have been introduced into the well upon indications of a Well Control event.

However, BOPs should have been installed on the well prior to skidding the rig, to maintain Well Integrity, with a 24 hour watch on liquid levels.

9.D What would good oilfield practice have been in this situation?

1. The immediate re-installation of the single surface barrier and then the installation of secondary barrier(s), ie the BOP's with the rig fully connected to the well, until a proper risk assessment could be carried out.

In addition:

2. Management insistence on compliance with standards and procedures through regular audits
3. A comprehensive Risk Assessment process. This would have identified the wet shoe on a horizontal production casing inside the hydrocarbon reservoir as a High Risk event.
4. A Well Integrity Management System. This would clearly identify minimum acceptance criteria for well barriers and would have prevented the acceptance of no barrier on H1-ST1.
5. A rigorous MOC system which has a zero tolerance for accepting change to approved programmes without detailed and documented risk assessment.

10. References, Codes, Standards, Regulation and Statutory Requirements

A listing of required References, Codes, Standards, Regulation and Statutory Requirements applicable to this report are stated hereafter.

No.	Title of References, Codes and Standards
a	ISO/FDIS 31000:2009 Risk management — Principles and guidelines on implementation, © International Organization for Standardization
b	PSA Norway, 03 March 2010, "Accident investigations are opportunities for learning", Petroleum Safety Authority Norway, Retrieved from the world wide web on 20th Dec 2011 from: http://www.ptil.no/news/accident-investigations-are-opportunities-for-learning-article6884-79.html
c	A Guide to the Project Management Body of Knowledge (PMBOK) - Chapter 11 - Project Risk Management; Project Management Institute, USA 2002 20 (New edition in 2005) - American National Standard ANSI/PMI 99-001-2004
d	International Association of Drilling Contractors (IADC) - IADC HSE Case Guidelines Appendix 2 Issue 3.2.1 – 1 May 2009
e	Norsk Sokkels Konkuranseposisjon (NORSOK) – Standards developed by the Norwegian Technology Centre
f	Det Norske Veritas (DNV)
g	"Well Integrity in Drilling and Well Operations", NORSOK Standard D-010. Rev 3, August 2004, Standards Norway
h	API Standard 65-2, Second Edition, Isolating Potential Flow Zones During Well Construction December 2010

i	Tinsley, J.M., Miller, E.C., Sabins, F.L. and Sutton, D.L., "Study of Factors Causing Annular Gas Flow Following Primary Cementing," paper SPE 8257 published in JPT, August 1980, pp.1427-1437
j	API TR 10TR3, First Edition, Temperatures for API Cement Operating Thickening Time Tests - 1993 Report from the API Task Group on Cementing Temperature Schedules, 01-May-1999
k	API Recommended Practice 10B-2 (ISO 10426-2), First Edition, Recommended Practice for Testing Well Cements, July 2005
l	API Recommended Practice 10B-3 (ISO 10426-3), First Edition, Recommended Practice on Testing of Deepwater Well Cement Formulations, July 2004
m	API Recommended Practice 10B-4 (ISO 10426-4), First Edition, Recommended Practice on Preparation and Testing of Foamed Cement Slurries at Atmospheric Pressure, December 2004
n	API Recommended Practice 10B-6 (ISO 10426-5), First Edition, *Recommended Practice on Determining the Static Gel Strength of Cement Formulations,* AUGUST 2010
o	API TR 10TR1, Second Edition, Cement Sheath Evaluation, September 2008
q	Soanes, Catherine, and Angus Stevenson, Concise Oxford English dictionary. New York: Oxford University Press, 2004
s	AS/NZS 4804:2001, Occupational health and safety management systems – General guidelines on principles, systems and supporting techniques, November 2001
t	AS/NZS ISO 14001:1996, Environmental management systems— Specification with guidance for use, November 1996

u	AS/NZS ISO 9001:2000, Quality management systems – Requirements, December 2000

Table 47: Codes and Standards Applicable for Expert Witness's Investigation

No	Title of Regulations and Statutory Requirements
a	Electronic Code of Federal Regulations, Dec 23 2011, Title 30: Mineral Resources, Chapter II: Bureau of Safety and Environmental Enforcement, Department of the Interior, PART 250--OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF
b	The authority of the Minister for Resources and Energy Australia, Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996, Part 3.

Table 48: Regulations and Statutory Requirements Applicable for Expert Witness's Investigation