



Montara Commission of Inquiry

17 June 2010

The Hon Martin Ferguson AM MP
Minister for Resources and Energy
Parliament House
CANBERRA ACT

Dear Minister

I hereby submit the Report of the Montara Commission of Inquiry in accordance with the Terms of Reference you announced on 5 November 2009.

Yours sincerely,

A handwritten signature in cursive script that reads 'David Borthwick'.

David Borthwick AO PSM
Commissioner



Report of the Montara Commission of Inquiry

**Commissioner
David Borthwick AO PSM**

June 2010

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ACRONYMS AND ABBREVIATIONS

2009 regulations	<i>Offshore Petroleum (Safety) Regulations 2009</i>
AIMS	Australian Institute of Marine Science
AFMA	Australian Fisheries Management Authority
ALERT	ALERT Disaster Control (Asia) Pte Ltd
APASA	Asia-Pacific Applied Science Associates
APPEA	Australian Petroleum Production & Exploration Association
AMSA	Australian Maritime Safety Authority
AMOSC	Australian Marine Oil Spill Centre
Atlas	Atlas Drilling (S) Pte Ltd
bbls	Barrels (1 barrel = approximately 159 litres)
BOP	Blowout Preventer
BOWD	Basis of Well Design
Coogee Resources	Coogee Resources (Ashmore Cartier) Pty Ltd
CST	Central Standard Time
DA	Designated Authority
DDR	Daily Drilling Report
DEWHA	Department of the Environment, Water, Heritage and the Arts (Commonwealth)
DFAT	Department of Foreign Affairs and Trade (Commonwealth)
DMP	Department of Mines and Petroleum (Western Australia)
DOR	Daily Operations Report
DPI	Department of Primary Industries (Victoria)
EEZ	Exclusive Economic Zone
EPBC Act	<i>Environment Protection and Biodiversity Conservation Act 1999</i>
ERG	Emergency Response Group
ESC	Environmental and Scientific Coordinator
FPSO	Floating Production, Storage and Offloading facility
GA	Geoscience Australia (Commonwealth)
GI	Gas Injection (one of five wells at the Montara Oilfield)

H1, H2, H3, H4 Wells	Production wells drilled in the Montara Oilfield by PTTEPAA
H1 ST1 RW1 Well	The Relief Well drilled by PTTEPAA
HAZID	Hazard Identification
HAZOP	Hazard and operability
IADC	International Association of Drilling Contractors
IAP	Incident Action Plan
ICG	Incident Coordination Group
IGA	Inter-Governmental Agreement
JA	Joint Authority
MLS	Mud Line Suspension system
MODU	Mobile Offshore Drilling Unit
MOE Regulations	<i>Petroleum (Submerged Lands) (Management of Environment) Regulations 1999</i>
MOSOF Regulations/ 1996 Regulations	<i>Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996</i>
National Plan	<i>National Plan to Combat Pollution of the Sea by Oil and other Noxious and Hazardous Substances</i>
NEBA	Net Environmental Benefit Analysis
NES	National Environmental Significance
NOPR	National Offshore Petroleum Regulator
NOPSA	National Offshore Petroleum Safety Authority
NT DoR	Northern Territory Department of Resources (formerly Department of Regional Development, Primary Industries, Fisheries and Resources (DRDPIFR))
OHS	Occupational Health and Safety
OIM	Offshore Installation Manager
OPA	<i>Offshore Petroleum Act 2006</i>
OPGGS Act	<i>Offshore Petroleum and Greenhouse Gas Storage Act 2006</i>
OSCP	Oil Spill Contingency Plan
PC	Productivity Commission
PCCC	Pressure containing anti-corrosion caps
psi	Pounds per square inch
PSLA	<i>Petroleum (Submerged Lands) Act 1967</i>

PTTEP	PTT Exploration and Production Public Company Limited
PTTEPAA	PTTEP Australasia (Ashmore Cartier) Pty Ltd
Relief Well	Montara H1 ST1 RW1 Well
RET	Department of Resources, Energy and Tourism (Commonwealth)
ROV	Remote Operated Vessel
RTTS Packer	Retrievable Pressure Testing, Chemical Treating and Cement Squeezing Packer
sg	Specific Gravity
SIMOP	Simultaneous operations
TOC	Top of Cement
WHP	Wellhead Platform
WOC	Wait On Cement
WOMP	Well Operations Management Plan
WST	Western Standard Time

EXECUTIVE SUMMARY

INTRODUCTION

Prior to 21 August 2009, Australia had not seen an oil spill of the magnitude of the uncontrolled release of oil and gas (the **Blowout**) from the Montara Wellhead Platform (**WHP**) in over 20 years. The volume of oil spilt from the Montara WHP makes the Blowout Australia's third largest oil spill after the *Kirki* oil tanker in 1991 and the *Princess Anne Marie* oil tanker in 1975. However, the Blowout is the worst of its kind in Australia's offshore petroleum industry history.

In the early hours of 21 August 2009, a small 'burp' of oil and gas was reported as having escaped from the H1 Well at the Montara WHP. The oil and gas had travelled a distance of over four kilometres from the reservoir beneath the sea bed. Whilst the initial 'burp' subsided, approximately two hours later the H1 Well kicked with such force that a column of oil, fluid and gas was expelled from the top of the well, through the hatch on the top deck of the WHP, hitting the underside of the *West Atlas* drilling rig and cascading into the sea.

For a period of just over 10 weeks, oil and gas continued to flow unabated into the Timor Sea, approximately 250 kilometres off the northwest coast of Australia. Patches of sheen or weathered oil could have affected at various times an area as large as 90,000 square kilometres.

Ensuring the integrity of oil and/or gas wells (that is, preventing blowouts) is a fundamental responsibility of companies involved in offshore petroleum exploration and production.

Blowouts offshore can have major and long lasting effects - including the loss of human life; the pollution of marine and shoreline ecosystems; and substantial commercial losses by the companies directly involved and third parties affected by the spill.

Although the likelihood of a major blowout occurring is relatively low, the consequences can be very grave. However, the likelihood is relatively low only because well integrity is (or should be) scrupulously observed by the industry and those who regulate it. At each stage, from exploratory drilling through to production, the systems and technologies in place are designed to be fail-safe, with considerable back-up capability built in to prevent blowouts. The systems and technologies are not new; they are well proven and they do work, if correctly applied.

Getting to the nub of what happened, and why it happened and what can be done to prevent a similar incident occurring in the future, is what this Inquiry has been tasked to find out.

Did the owner/operators exercise their responsibilities diligently? Was the oversight of their operations by regulators diligent? It is the task of this Inquiry to shed light on these questions, both with respect to the events leading up to the Blowout, and subsequent measures taken to stop the flow of hydrocarbons.

To find out answers to these questions the Inquiry invited submissions, issued notices¹ seeking documents from organisations within both industry and government, conducted a public hearing and released parts of its draft report² for comment, before finalising this report.

The Inquiry has concluded that PTTEP Australasia (Ashmore Cartier) Pty Ltd (**PTTEPAA**) did not observe sensible oilfield practices at the Montara Oilfield. Major shortcomings in the company's procedures were widespread and systemic, directly leading to the Blowout.

Well control practices approved by the delegate of the Designated Authority (**DA**), the Northern Territory Department of Resources (the **NT DoR**), most likely would have been sufficient to prevent the Blowout if PTTEPAA had adhered to them and to its own Well Construction Standards. However, the NT DoR was not a sufficiently diligent regulator: it should not have approved the Phase 1B Drilling Program for the Montara Oilfield in July 2009 as it did not reflect sensible oilfield practice; it also adopted a minimalist approach to its regulatory responsibilities. The way the regulator (the NT DoR) conducted its responsibilities gave it little chance of discovering PTTEPAA's poor practices. In this case, the regulatory dog did not bark.

¹ Pursuant to s 2(3A) of the *Royal Commission Act 1902*, as applied in relation to the Inquiry by Part 9.10A of the *Offshore Petroleum and Greenhouse Gas Storage Act 2006*.

² To parties that (a) were authorised to appear before the Inquiry; (b) whose interests may have been adversely affected by the preliminary findings contained in the draft section of the Inquiry's report; and/or (c) who the Inquiry considered may have been able to provide information or submissions that would be of assistance to the Inquiry relevant to preliminary findings contained in the draft section of the Inquiry's report.

THE CIRCUMSTANCES AND CAUSES OF THE BLOWOUT

The responsibility of companies

The **source** of the Blowout is largely uncontested. While the Inquiry received submissions advancing several theories, it is most likely that hydrocarbons entered the H1 Well through the 9 $\frac{5}{8}$ " cemented casing shoe and flowed up the inside of the 9 $\frac{5}{8}$ " casing. The Inquiry finds that the primary well control barrier – the 9 $\frac{5}{8}$ " cemented casing shoe – failed.

The Inquiry has been asked to determine what **caused** the Blowout. In this context, the Inquiry has found that at the time the H1 Well was suspended in March 2009, not one well control barrier complied with PTTEPAA's own Well Construction Standards (or, importantly, with sensible oilfield practice). Relevantly, the 9 $\frac{5}{8}$ " cemented casing shoe had not been pressure tested in accordance with the company's Well Construction Standards, despite major problems having been experienced with the cementing job. In particular, the cement in the casing shoe was likely to have been compromised as it had been substantially over-displaced by fluid, resulting in what is known as a 'wet shoe'. None of this was understood by senior PTTEPAA personnel at the time, even though the company's contemporaneous records, such as the Daily Drilling Report (**DDR**), clearly indicated what had happened. The multiple problems in undertaking the cement job – such as the failure of the top and bottom plugs to create a seal after 'bumping', the failure of the float valves and an unexpected rush of fluid – should have raised alarm bells. Those problems necessitated a careful evaluation of what happened, the instigation of pressure testing and, most likely, remedial action. No such careful evaluation was undertaken. The problems were not complicated or unsolvable, and the potential remedies were well known and not costly. This was a failure of 'sensible oilfield practice 101'.

Compounding the initial cementing problem was the fact that while two secondary well control barriers chosen by PTTEPAA – pressure containing anti-corrosion caps (**PCCCs**) – were programmed for installation, only one was ever installed. Further, the PCCC that was installed (the 9 $\frac{5}{8}$ " PCCC) was not tested and verified in situ as required by the Well Construction Standards. The manufacturer of the PCCCs (GE Oil & Gas) informed the Inquiry that while:

...the PCCC may contain pressure upon installation...it is not intended as a barrier against an uncontrolled release of hydrocarbons...[and] GE has not designed and is not aware of a test that could verify the internal pressure containing capability...

The Inquiry finds that PTTEPAA's use of PCCCs as secondary well control barriers did not constitute sensible oilfield practice, especially in light of the suspension and drilling programmes in which they were used.

Furthermore, key personnel working for PTTEPAA, both on the rig and onshore, were under the mistaken impression that the fluid left in the casing string was overbalanced to pore pressure and would therefore act as an additional barrier (even though the fluid was not monitored and overbalanced significantly to pore pressure as required by the Well Construction Standards in order to be regarded as a proper barrier).

In summary, as at April 2009 when the H1 Well had been suspended and the *West Atlas* rig had departed from the Montara WHP to undertake other work, not one well control barrier in the H1 Well had been satisfactorily tested and verified, and one barrier that should have been installed was missing. In other words, the H1 Well was suspended without regard to PTTEPAA's own Well Construction Standards or sensible oilfield practice.

When the *West Atlas* rig returned to the WHP in August 2009 it was discovered that the 13 $\frac{3}{8}$ " PCCC had never been installed. The absence of this PCCC had resulted in corrosion of the threads of the 13 $\frac{3}{8}$ " casing and this, in turn, led to the removal of the 9 $\frac{5}{8}$ " PCCC in order to clean the threads. This was viewed by PTTEPAA personnel as a mere change of sequence that simply involved bringing forward the time of the removal of the 9 $\frac{5}{8}$ " PCCC. PTTEPAA's Well Construction Manager, Mr Duncan, took a positive decision not to reinstall the 9 $\frac{5}{8}$ " PCCC. This meant that, according to PTTEPAA's operational forecast and drilling program, the H1 Well would have been exposed to the air without any secondary well control barrier in place for some 4 to 5 days, with sole reliance on an untested primary barrier (the cemented 9 $\frac{5}{8}$ " casing shoe) that had been the subject of significant problems during its installation.

After the 9 $\frac{5}{8}$ " PCCC had been removed, the H1 Well was left in an unprotected state (and relying on an untested primary barrier) while the rig proceeded to complete other planned activities as part of batch drilling operations at the Montara WHP. The Blowout in the H1 Well occurred 15 hours later.

In the petroleum industry, well integrity is ensured by always having built in redundancies (secondary barriers) to safeguard against a blowout. Unfortunately, in the H1 Well there were no tested and verified barriers in place at the time of the Blowout.

How did this parlous situation arise?

The absence of tested barriers was a proximate cause of the Blowout, yet this itself reflected systemic errors of a more deep seated kind within PTTEPAA. In that sense, the Inquiry considers the following systemic and interrelated factors indirectly contributed to the Blowout:

- a. PTTEPAA's Well Operations Management Plan (**WOMP**) for the H1 Well and Well Construction Standards (which form part of the WOMP) were themselves inadequate. For example, they did not adequately set out how PTTEPAA would address risks affecting well integrity that arose during drilling, suspension and re-entry of the Montara wells. The WOMP and Well Construction Standards were also of a generic kind and did not adequately address the well control consequences of a batch drilling operation, which involved the derrick spending significant time away from each well and therefore considerable work being undertaken 'offline' (which was not always captured in essential reporting formats, such as DDRs).
- b. These difficulties were compounded by the fact that senior PTTEPAA personnel had only limited experience of batch drilling and batch tieback operations and did not fully comprehend the implications of such operations.
- c. A number of aspects of PTTEPAA's Well Construction Standards were at best ambiguous and open to different interpretations. The fact that a number of PTTEPAA employees and contractors interpreted aspects of the Well Construction Standards differently illustrates the ambiguity and inappropriateness of the Well Construction Standards.
- d. Irrespective of the adequacy of PTTEPAA's Well Construction Standards, the company's personnel on the rig demonstrated a manifestly inadequate understanding of their contents and knowledge of what they required (for example, the requirement that all barriers be tested and verified in situ).
- e. PTTEPAA's senior personnel on the rig and onshore were also deficient in their decision-making and judgments in relation to a number of important matters. For example, they failed to comprehend the manifest problems in the cementing job for the cemented 9 $\frac{5}{8}$ " casing shoe. In particular, Mr Treasure (company Drilling Supervisor), Mr Wilson (company onshore Drilling Superintendent) and Mr Duncan (company onshore Well Construction Manager) failed to adequately comprehend that the cementing operation was seriously compromised and required testing and, most likely, remedial action. The magnitude of this failure reflected a failure of judgment and competence. The associated failure of *West Atlas* personnel (the rig

operator hereafter referred to as **Atlas**) to subsequently recognise the problems in the cementing job also reflects poorly on them. Halliburton (the cementing contractor) undertook the cementing job but this was at PTTEPAA's direction. It was PTTEPAA personnel that called the shots, and it is they who must bear primary responsibility for overlooking this failed task.

- f. PTTEPAA's records and communication management were defective, particularly the exchange of information between rig and shore, between night and day shifts, between offline and online operations and in relation to milestones such as the installation of secondary barriers. This meant that at crucial times critical matters were either not attended to or fell between the cracks (for example, the failure to install the 13 $\frac{3}{8}$ " PCCC).
- g. There was also a systemic failure of communication between PTTEPAA and Atlas personnel, particularly with the Offshore Installation Manager (the **OIM**) and between rig and onshore personnel of both companies. It is clear that on two critical procedures, the poor cementing job and the removal of the 9 $\frac{5}{8}$ " PCCC, Atlas personnel, both on-rig and onshore, were not involved in the actual decision-making. The decisions were all taken by key PTTEPAA personnel and PTTEPAA needs to bear primary responsibility. Atlas onshore personnel (Messrs Gouldin and Millar) nevertheless conceded during the public hearing that Atlas personnel should have subsequently picked up deficiencies, particularly in the cementing job.
- h. A further systemic issue concerns the relationship between PTTEPAA and the rig operator, Atlas. Matters relating to rig safety are ultimately the responsibility of the rig operator. However, it was clearly PTTEPAA that effectively called the shots in key areas of the drilling operations at Montara. In this instance, there were clearly ineffective exchanges of information between the two parties, with Atlas rig personnel either oblivious to key and flawed decisions being taken by PTTEPAA personnel or going along with them (particularly on matters pertaining to well integrity). The relationship between PTTEPAA and Atlas needed to be more formalised, with mutual explicit sign off on important decisions affecting safety, well integrity and the environment.
- i. A contributing factor to PTTEPAA's systemic errors extends to its onshore management and governance structure. The Inquiry heard that there is a direct line of reporting through the CEO to the parent company in Thailand. Under this management structure there was insufficient attention paid to putting in place mechanisms to assess and manage project risks, the

competence of key personnel, the adequacy of WOMPs, and the interaction with contractors. More attention needed to be paid to high level governance procedures and to how this translated into field operations and procedures. Moreover, PTTEPAA's dealings with this Inquiry, as indicated in Chapter 7, left a lot to be desired.

- j. Although PTTEPAA insisted in its oral and written submissions to this Inquiry that it did not cut corners or seek to minimise costs where this might compromise safety or well integrity, this claim does not bear scrutiny. The prevailing philosophy revealed by PTTEPAA's actions appears to have been to get the job done without delay. For example, PTTEPAA took a decision that it would be convenient from time to time to park the Blowout Preventer (**BOP**) on the H1 Well rather than to install the 13 $\frac{3}{8}$ " PCCC as required by the regulator; and when things went wrong, such as the difficulty with the cementing and the corrosion of the 13 $\frac{3}{8}$ " casing threads on the H1 Well leading to the removal of the 9 $\frac{5}{8}$ " PCCC, PTTEPAA pursued an expeditious but flawed response. The evidence before the Inquiry repeatedly showed that risks were not recognised when they should have been, and not assessed properly when recognised. Judgments were made to push on with the Phase 1B Drilling Program without a careful evaluation of the consequences. Furthermore, there was no internal audit or review process at critical milestones which, if instituted, may have raised questions about fundamental issues bearing on well integrity (such as whether the approach being adopted under the Phase 1B Drilling Program was in all respects in line with PTTEPAA's Well Construction Standards).
- k. The manifest failures within PTTEPAA extended to the interactions that the company had with the regulator, the NT DoR which, in the Inquiry's view, had become far too comfortable. The Inquiry is of the view that PTTEPAA engaged with the regulator as if it were a 'soft touch'.

In essence, the way that PTTEPAA operated the Montara Oilfield did not come within a 'bulls roar' of sensible oilfield practice. The Blowout was not a reflection of one unfortunate incident, or of bad luck. What happened with the H1 Well was an accident waiting to happen; the company's systems and processes were so deficient and its key personnel so lacking in basic competence, that the Blowout can properly be said to have been an event waiting to occur. Indeed, during the course of its public hearing, the Inquiry discovered that not one of the five Montara wells currently complies with the company's Well Construction Standards. Indeed, so poor has PTTEPAA's performance been on the Montara Oilfield, the Inquiry considers it is imperative that remedial action be instituted.

The Inquiry considers that the manner in which PTTEPAA approached the National Offshore Petroleum Authority (**NOPSA**), the NT DoR and the Inquiry itself provides further evidence of the company's poor governance. PTTEPAA did not seek to properly inform itself as to the circumstances and the causes of the Blowout. The information that it provided to the regulators was consequently incomplete and apt to mislead. Its dealings with this Inquiry followed a similar pattern.

The Inquiry recommends that the Minister for Resources and Energy review PTTEPAA's licence to operate at the Montara Oilfield. At this juncture the Inquiry has little confidence in PTTEPAA's capacity to apply principles of sensible oilfield practice.

However, the Inquiry notes that shortly prior to the finalisation of the Inquiry's report PTTEPAA provided the Inquiry with an Action Plan to prevent a recurrence of the Blowout. It is comprehensive and impressive. As a plan, it effectively addresses the shortcomings in PTTEPAA's operations identified by the Inquiry. The Action Plan is, however, only a plan; it needs to be given real substance and be fully and effectively implemented across all of PTTEPAA's operations.

ADEQUACY OF THE REGULATORY REGIME, INCLUDING COMPLIANCE AND ENFORCEMENT

The responsibility of the NT DoR

There are a number of regulators involved at various stages in the development of offshore petroleum fields but, in this instance, it was the NT DoR that was responsible for overlooking the requirements bearing on the integrity of the H1 Well, including the general requirement that good oilfield practice be followed.

The term 'good oilfield practice' is defined in very general terms by the legislation. However, the systems and procedures to be followed in undertaking drilling operations should be set out fully in a drilling company's WOMP (which includes the company's Well Construction Standards) and Drilling Programs which are approved by the regulator. In practice there are also requirements for detailed reporting to the regulator on well operations, particularly through DDRs.

At its most basic level, good oilfield practice requires putting in place systems and procedures so that a well is constructed, operated and monitored in a way that is generally accepted as preventing the unintended escape of hydrocarbons. This requires adequate primary and secondary containment barriers – as an integrated system – to secure the integrity of the well.

There has been a trend in recent years for the regulatory framework to move away from prescriptive regulation toward objective-based regulation, leaving it to the owner/operator to determine how good oilfield practice is to be applied (subject to the regulator's approval of the WOMP and associated documents).

As described in the Northern Territory's submission to the Inquiry:

The legislative regime places the onus [to maintain safety to minimise the risk of a major accident event] on operators and provides them with flexibility on how best to manage hazards and minimise risk.

As the Northern Territory goes on to describe:

It is an interesting feature of this regime that industry assumes the obligation to operate responsibly in consideration of the flexibility it is afforded.³

The Northern Territory has also contended that 'at all material times prior to the [Blowout], the Territory appropriately administered the licence area within which the Montara Wellhead Platform is located'. The Inquiry has no hesitation in rejecting this contention. However, the Inquiry finds that if PTTEPAA had observed its own Well Construction Standards and given effect to the various approvals given by the NT DoR, the Blowout is unlikely to have occurred. In particular, the cementing of the casing shoe and annulus would have been undertaken properly and the cement in the casing shoe track would have been verified by a pressure test. Moreover, the NT DoR should have been notified (i) when PTTEPAA discovered in August 2009 that the 13 $\frac{3}{8}$ " PCCC had not been installed; (ii) before the removal of the 9 $\frac{5}{8}$ " PCCC; and (iii) of the subsequent failure to reinstall the 9 $\frac{5}{8}$ " PCCC. This was not a mere change of sequence but a crucial decision affecting the integrity of the wellbore.

The NT DoR made a major error when it approved the Phase 1B Drilling Program in July 2009. The Phase 1B Drilling Program set out the sequence of events to batch drill the five Montara wells. This involved leaving the H1 Well open to the air with only one permanent barrier in place for not less than 36 hours, while other activity was being undertaken. The Inquiry finds that this approval was contrary to good oilfield practice, which should have required, as a minimum, two tested barriers to be in place. The NT DoR should have sought more information or clarification from PTTEPAA to satisfy itself that there were effective means of ensuring well integrity. The Victorian and Western Australian regulators have indicated to the Inquiry that it is unlikely that they would have approved the Phase 1B Drilling Program as proposed.

³ Northern Territory, Submission to the Inquiry. The submission paraphrases the Bills K and Agostini D 2009, *Offshore Petroleum Safety Regulation – Better Practice and Effectiveness of the National Offshore Petroleum Safety Authority*, Australian Government, June 2009, p. xi.

If a secondary tested barrier had been in place, such as a cement plug, an RTTS packer, or if the 9⁵/₈" PCCC had been removed through a BOP, the Blowout is unlikely to have occurred. The causes of the Blowout were unquestionably the repeated failures to ensure well integrity by PTTEPAA; however, the NT DoR did not do its job by ensuring that the company's WOMP or the Phase 1B Drilling Program complied with good oilfield practice. In short, the NT DoR did not take adequate steps to ensure that PTTEPAA actually complied with the requirement of good oilfield practice.

The Inquiry has been asked to draw lessons from this incident for the regulatory arrangements applying to the offshore petroleum sector. In this context, the Inquiry observes that there has been a move to objective-based, rather than prescriptive based, regulation of the offshore petroleum industry. Objective-based regulation requires that:

- a. owner/operators of petroleum fields have in place systems to assess and manage risks, including the consequences of something going wrong, which should be part of the overall WOMP approved by the regulator (PTTEPAA clearly did not have adequate processes to manage risk);
- b. approved WOMPs and associated documentation, including drilling programs, reflect good oilfield practice. The NT DoR did not appreciate that with a batch drilling operation the H1 Well and other wells would be exposed to air, if the Phase 1B Drilling Program had gone to plan, with reliance only on one primary barrier for some 36 hours or more; and
- c. the regulator has in place a robust approval, monitoring and enforcement regime to ensure that good oilfield practice is, in fact, being observed (for example, that an approved WOMP is being adhered to).

According to the Northern Territory's submission '[t]he audit of the relevant documentation confirmed that all approvals met the requirements under the relevant legislation'. Again, the Inquiry has no hesitation in rejecting this submission. As indicated above, particularly in relation to the approval of the Phase 1B Drilling Program, the NT DoR should not have given its approval on the basis of what was before it.

The Inquiry is of the view that nothing should detract from the primary responsibility of PTTEPAA to ensure well integrity. However, the Inquiry finds that the NT DoR's regulatory regime was totally inadequate, being little more than a 'tick and flick' exercise. In particular, the Inquiry does not agree with the Northern Territory's characterisation (before the Inquiry's public hearing) that the approach the NT DoR adopted followed 'contemporary regulatory practice'. The information provided to the Inquiry indicates that, in contrast to the approach adopted by the NT DoR, the Victorian regulator

undertakes a monitoring, inspection, audit and compliance regime. It also appears to assess WOMPs and drilling programs submitted to it for approval much more vigorously than the NT DoR. Furthermore, the Best Practice Guide (2007) for Administering Regulation produced by the Australian National Audit Office (ANAO) makes it clear that monitoring of compliance is an essential task of all regulators. It relevantly says (at p. 51):

Regulators have a responsibility to provide assurance to the Australian community that regulated entities are meeting mandated requirements. A systematic, risk-based program of compliance assessment activities provides a regulator with a cost-effective approach to monitoring compliance, enabling it to target available resources at the highest priority regulatory risks and to respond proactively to changing emerging risks.

The ANAO by way of example goes on to say (at p. 52):

Aligning activities with regulatory requirements to be assessed increases the likelihood that relevant, reliable evidence will be collected. For example, on-site inspections are well suited to gathering evidence of compliance with manufacturing standards. A desk audit of a procedures manual would not adequately confirm that a manufacturer was achieving production quality standards.

These conclusions apply to the regulation of the offshore petroleum industry. Indeed, while the movement toward a more objective-based regulatory regime is appropriate, it demands that more effort be devoted to validating the approval of the WOMP and then following that approval up with targeted monitoring, audit and compliance activities. The regulator needs to actively probe and inquire; it should not be passive; the regulator needs to ask questions of the owner/operator; it should keep owner/operators up to the mark to ensure that the requirements of the WOMP are in fact met; and the regulator needs to also make sure that the WOMP itself is adequate – reflecting good oilfield practice – in the first place.

Mention has already been made of multiple deficiencies in terms of PTTEPAA's own well construction management systems and to numerous specific failures. Yet the fact is that none of this was apparent to the NT DoR. It also appears unlikely that the NT DoR would have become aware of most of these deficiencies if this Inquiry had not uncovered them. The NT DoR regarded PTTEPAA as a good operator, although it is impossible to support that conclusion on any objective basis judging by the multiple oversights and failings in the development of the Montara Oilfield. The fact of the matter is that the NT DoR never placed itself in a position so that it could properly inform itself. This is not necessarily a call for onsite inspections – although that might well be justified in certain circumstances – rather, it is a call for regulators to inquire and examine to ensure that owner/operators are actually doing what they have been approved to do.

The relationship between the NT DoR and PTTEPAA had become far too comfortable. Indeed, one contributory factor to PTTEPAA's own lax standards was the minimalist approach to regulatory oversight by the NT DoR.

In this regard, the Inquiry considers that in assessing applications submitted to it by PTTEPAA, the NT DoR was not sufficiently diligent in ensuring that principles of good oilfield practice would be followed by PTTEPAA. By way of example, when PTTEPAA submitted an application to suspend the H1 Well utilising PCCCs rather than a cement plug, it received preliminary approval in 30 minutes. However, as the Inquiry heard from the manufacturers of the particular PCCC used, they were not intended to be used as barriers against a blowout. In this respect, the information that had been conveyed to the NT DoR was seriously deficient. However the NT DoR, which had no real prior experience with PCCCs, gave almost immediate approval for their use.

The approach taken by the NT DoR is in part reflective of a profound misunderstanding of what is required of a regulator under the modern-day objective (as opposed to prescriptive) approach to regulatory oversight. While it is the case that industry, under the current regime, has a greater level of responsibility for itself than exists under more prescriptive regimes, a regulator must still ensure that a company's procedures meet the statutory standard of good oilfield practice.

Under the oversight of the NT DoR there was, in reality, no means of discovering inadequacies in PTTEPAA's arrangements, since there was a 'no questions asked' approach and no effective monitoring or audit regime pursued by the regulator. The NT DoR needed to have a more active approach than checking the DDR and daily email updates.

The Inquiry formed the view that the resources and expertise that the NT DoR devoted to its task as delegate of the DA were inadequate (effectively only one person, who appeared to have a limited ability to fulfil this task). The Minister should consider removing this delegation from the NT DoR.

The adequacy of the overall regulatory approach

More generally, the Inquiry is of the view that while the move to objective-based regulation has been a desirable development overall, more attention should have been paid to enforcing requirements of the *Offshore Petroleum and Greenhouse Gas Storage Act 2006 (OPGGGS Act)* and the regulations as they relate to well integrity. WOMPs and associated documents need to be carefully scrutinised and amended if necessary. Owner/operators need to be kept up to the mark.

The Inquiry's examination of some overseas jurisdictions indicates that they pay much closer attention to well integrity issues and, to varying degrees, they issue detailed guidelines and/or set out minimum standards. The Inquiry does not support a return to a prescriptive approach. The Inquiry's examination of the level of prescription in at least one prominent jurisdiction suggests that it is unnecessarily complicated, obscure and may, of itself, lead to difficulties in interpretation by the regulator and owner/operators alike. Greater prescription can also, inter alia, unduly stifle innovation and new technologies. However, utilising the WOMP as the cornerstone of good oilfield practice demands the articulation and observance of some minimum requirements; these need not be excessively prescriptive or onerous. For example, when a well is suspended there should be a requirement, as a minimum, for two barriers to be in place, that have been properly tested and verified. If there is any departure from that, or variation from what has been approved, the operator should have to present a convincing case to the regulator that the departure or variation would enhance, or at least not detract from, well integrity. Indeed, especially where petroleum developments are in sensitive environmental areas, there is a strong justification for insisting on a minimum of three barriers being in place at all times.

In addition to imposing basic minimum standards in relation to barriers, the Inquiry recommends, inter alia, that the following legislative amendments be made:⁴

- a. the definition of 'good oilfield practice' be amended so that it is inclusionary rather than exhaustive;
- b. regulation 25 of the *Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004 (PSLA)* be amended;
- c. a power be provided to suspend the rights conferred by a petroleum production licence;
- d. the penalties applicable to well operations and safety breaches be reviewed; and
- e. NOPSA's prohibition powers be extended.

The Inquiry has been struck by the substantial divergence within Australia in regulatory practices, with all jurisdictions purporting to follow the objective, non-prescriptive approach to regulation. The Inquiry is of the view that the approach of the Victorian regulator is more searching and robust than that of the NT DoR. The NT DoR's approval of

⁴ See Chapter 3.

the Phase 1B Drilling Program of July 2009 which relied on a single barrier for an extended period of time is the clearest example. At the very least, the Victorian regulator would have asked probing questions to better understand what was involved in batch drilling, and would have required the company to have managed risks accordingly. Clearly, steps need to be taken - if the current DA arrangements are to continue in relation to Commonwealth offshore areas – to ensure a greater measure and consistency of regulatory oversight to properly give effect to the objective approach to regulation now in place.

The Inquiry is of the view – based on its examination of what has occurred with respect to the regulatory regime that applied at the Montara Oilfield – that, as a minimum, the proposal in the *Productivity Commission Research Report (Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector, April 2009)* to establish a National Offshore Petroleum Regulator (**NOPR**) should be pursued.

The Inquiry concurs with the view of other recent inquiries that responsibility for well integrity should be moved to the National Offshore Petroleum Safety Authority (**NOPSA**) (see below). Ensuring the integrity of the well is essential for ensuring safety and environmental outcomes. The Designated and Joint Authority (**JA**) arrangements currently in place pursue a mix of objectives: policy, promoting industry development and regulatory. The Inquiry is concerned that under these arrangements well integrity issues do not receive necessary priority, thereby prejudicing safety and environmental objectives. The regulatory framework as it applied to the Montara Oilfield may have been adequate if it had been adhered to by PTTEPAA, but it was not. The current regulatory framework does not build in a sufficient margin of safety and relies too much on the owner/operator doing the right thing. The regulatory regime was too trusting and that trust was not deserved.

Other facets of the regulatory regime are the approval for the Montara Oilfield development under the *Environment Protection Biodiversity Conservation Act 1999* (the **EPBC Act**) administered by the Department of the Environment, Water, Heritage and the Arts (**DEWHA**), and the occupational, health and safety regime applicable to offshore installations administered by NOPSA.

The EPBC Act approval was granted to PTTEPAA to develop the Montara Oilfield on 3 September 2003, subject to six conditions relating to the operation of the development. These conditions operate as the only civil penalty regime applicable to the titleholder under the EPBC Act (a matter which the Inquiry recommends be reviewed). One of the conditions placed on the development related to the preparation of an Oil Spill Contingency Plan (**OSCP**) detailing the strategy to mitigate the environmental effects of any hydrocarbon spills.

PTTEPAA submitted two environmental plans which covered the Montara, Skua, Swift and Swallow Fields to the NT DoR in accordance with the *Petroleum (Submerged Lands) (Management of the Environment) Regulations 1999* (the **MOE Regulations**). These plans were complementary to the overarching EPBC Act approval, essentially dealing with important rig/WHP specific environmental issues, such as waste management, liquid discharges, hazardous wastes and the like. This is important and useful but it does not bear on the risks arising from a large scale blowout.

The biggest environmental risk for offshore developments is the possibility of large blowouts due to a failure of well integrity. The adequacy of well integrity measures was not examined by DEWHA with respect to the Montara Oilfield development, and nor should it have been. Regulatory responsibility for oversighting well integrity rested with the NT DoR. It was reasonable for DEWHA to expect that well integrity issues would be properly addressed by the NT DoR.

The same conclusions may be drawn for NOPSA. During the Inquiry it was suggested that NOPSA's remit could and should have extended to well integrity issues, essentially on the basis that safety and operations on the *West Atlas* rig and WHP were integrated by virtue of the relevant Drilling Program. NOPSA did not examine issues relating to well integrity in the Montara Oilfield (or in other fields), leaving that to the DAs who have primary well control responsibility. This was a reasonable judgment given the respective regulatory roles assumed by NOPSA and the DAs.

NOPSA considers that primary responsibility for oversighting well integrity issues should, in future, be moved from the DAs (or NOPR) to it. The Inquiry agrees with this view, which has also been supported by the Productivity Commission Research Report, which in this context stated (at p. 175) that:

The legislated coverage of the National Offshore Petroleum Safety Authority should be extended to include the safety and integrity of offshore pipelines, subsea equipment and wells...

The proposal to extend NOPSA's role in this regard is not only supported by the Productivity Commission, but as NOPSA has pointed out in its submission the proposal is supported by three other reports over the last three years.⁵

⁵ These other reports are: Well Integrity Working Group report to the Upstream Petroleum and Geothermal Subcommittee of the Ministerial Council on Mineral and Petroleum Resources; Ognedal M, Griffiths D and Lake B 2008, *Review of the National Offshore Petroleum Safety Authority operational activities, February-March 2008: report of the independent review team*; and Bills K and Agostini D 2009, *Offshore Petroleum Safety Regulation: Better practice and the effectiveness of the National Offshore Petroleum Safety Authority*.

The proposals to form NOPR, and to give NOPSA primary responsibility for well integrity, would be a start to fixing up current systemic deficiencies.

The Inquiry recommends that a further step also be taken: it recommends that NOPSA's and NOPR's key roles be combined. This would mean establishing a single independent authority, with a properly functioning Board, which would be responsible for safety, well integrity and environment plans. Industry policy and resource development and promotion activities would reside in government departments and not with the regulatory agency. The regulatory agency could be empowered to provide information to assist departmental policy advice and decision-making (for example, on decisions to grant licences and any conditions that might be attached to them).

The current arrangements of having multiple DAs across jurisdictions is far from ideal and will become more fraught as offshore developments continue at pace over the next decade or so. Splitting regulatory responsibility between a NOPR and NOPSA risks divergent approaches and confusion, not least for the petroleum industry. The independent authority could absorb the regulatory roles of NOPR and NOPSA without compromising safety as a primary objective. There would be a single integrated regulatory agency for developments in offshore Commonwealth waters. The scale of developments at the moment, let alone in the future, demands a more integrated, rigorous and independent approach.

This approach will, of course, lead to other boundary issues such as the interface with arrangements in state waters or with onshore petroleum developments. Such interface issues need to be directly addressed under the auspices of the Ministerial Council on Mineral and Petroleum Resources.

ADEQUACY OF THE RESPONSE

The Blowout occurred at 7.23am (CST) on 21 August 2009, although this was preceded by a small unexpected release of hydrocarbons from the H1 Well at 5.30am. PTTEPAA and Atlas were unable to respond to this as the derrick (including the BOP) was over the H4 Well at the time of the Blowout. There was insufficient time to assess the situation and skid the derrick back over to the H1 Well to stop the Blowout (by, say, setting an RTTS packer in the H1 Well).

Actions by PTTEPAA

The action of PTTEPAA and Atlas in promptly evacuating 69 personnel from the *West Atlas*/Montara WHP was undoubtedly a correct decision given the risk of major injury and loss of life from ignition of the H1 Well.

PTTEPAA also immediately acted to initiate measures to investigate how to stop the flow of hydrocarbons. It contacted ALERT Well Control (Asia) Pte Ltd (**ALERT**), which is an international specialist in this field, and ALERT came from Singapore to Perth on 22 August 2009.

An issue the Inquiry has carefully considered is why it took so long – some ten weeks – to stop the flow of hydrocarbons. In this regard, the Inquiry finds that PTTEPAA did act with vigour and a sense of urgency. In particular, the Inquiry considers that:

- a. securing the *West Triton* rig (which left Singapore on 27 August 2009 and arrived on site on 11 September 2009) was a reasonable option, given the alternatives;
- b. PTTEPAA had explored a number of other options and the rigs were either not suitable or were in the midst of operations which would not have enabled them to be released (without other companies being commercially compromised); and
- c. the drilling of a relief well (the **Relief Well**), utilising the *West Triton* rig, began on 14 September 2009 and it took some five attempts to successfully intercept the H1 Well, this being done on 1 November 2009. The Inquiry is of the view that the Relief Well operation was always likely to take considerable time, in view of the technical challenges of drilling some 2.6 kilometres into the seabed to intercept a casing of 9 $\frac{5}{8}$ " (or 244mm) diameter, effectively through a trial and correction process.

If there was any failure by PTTEPAA in this area it was creating the impression, at least initially, that the well interception might take as little as four weeks once the *West Triton* rig arrived on site and commenced drilling activities. In the event, it took around seven weeks to stop the flow of hydrocarbons.

When ALERT assessed the situation, it proposed three options to assist in containing the Blowout: deluging the rig to lessen the consequences should a fire occur; surface capping of the H1 Well; and drilling a relief well. PTTEPAA also explored but did not pursue the possibility of intercepting and either crushing or capping the casing beneath the sea surface.

Of the options advanced by ALERT, the drilling of the Relief Well and the surface capping option were alternative approaches. The option pursued was drilling the Relief Well which took some ten weeks to stop the flow of hydrocarbons. The Inquiry accepts that

this was the preferable option, although an issue does arise as to whether the surface capping option should have been pursued in tandem with the Relief Well operation.

Actions by NOPSA

On 22 August 2009 NOPSA issued a prohibition notice which prohibited persons from being on the rig or being on support ships adjacent to the rig because such activity was considered to pose an undue threat to health and safety. These prohibition notices would only be lifted by NOPSA if it was satisfied that the risks to safety had been comprehensively assessed and that control measures were in place to reduce the risks to a level that was as low as reasonably practicable.

In the event, NOPSA had a number of significant safety concerns with the deluge option submitted to it by PTTEPAA. PTTEPAA decided not to proceed with the deluge option. PTTEPAA itself decided not to pursue the surface capping and subsea options because of safety and other concerns, without putting a case to NOPSA.

The Inquiry accepts that safety matters must be of foremost consideration. For the future, the Inquiry considers that NOPSA should work with the petroleum industry with a view to exploring well control options, so that it and the industry are better prepared to respond, acknowledging that each circumstance will need to be assessed on its merits. Nevertheless, the Inquiry is of the view that in this instance PTTEPAA and NOPSA acted defensibly having regard to the risks.

Actions by the Australian Maritime Safety Authority

The Australian Maritime Safety Authority (**AMSA**) was central to the response to the Blowout, assuming the role of Combat Agency under the *National Plan to Combat Pollution of the Sea by Oil and Other Noxious and Hazardous Substances* (the **National Plan**), and taking charge of the clean-up operations. AMSA was quick to enact the National Plan and to deploy considerable resources, including aircraft, vessels, equipment and other materials (such as dispersants, marker buoys to track oil, a 300 metre containment boom and a skimmer to recover oil).

It is apparent that the overall response objective of preventing oil from impacting on sensitive marine resources (in particular the marine parks of Ashmore Reef and Cartier Island, and the north-west coast of Western Australia) was largely achieved.

An issue raised by a number of submissions to the Inquiry was whether the use of oil dispersants by AMSA was appropriate. In this context, dispersants act to dissipate hydrocarbons on the surface to around the first five metres of the water column. Dispersants are often used if shorelines or shallow reefs are likely to be threatened.

However, dispersants are not typically used in open ocean situations where such sensitive resources are not at risk because they involve effectively putting more pollution in the water.

AMSA conducted a Net Environmental Benefit Analysis (**NEBA**) prior to the decision to apply dispersants and this analysis was regularly reviewed and updated throughout the response.

The Inquiry has concluded that the use of dispersants was appropriate, in view of modelling which indicated that the movement of untreated oil could have threatened sensitive environmental areas around Ashmore Reef and Cartier Island as well as the Western Australia coastline. AMSA acted expeditiously and had regard to the available information.

The information provided to the Inquiry indicates that the dispersant/oil mix could have had an adverse effect on coral spawn and fish larvae and other shallow subsurface species. These are points that were known and acknowledged at the time by AMSA. The effects of the dispersants and the oil may never be fully known. This underscores the point that this was a major spill of hydrocarbons and the environmental consequences should not have been downplayed. The fact is that the spill affected a vast and remote area with oil sightings at various times in an area of up to 90,000 square kilometres. In the absence of baseline data, it is likely to be very difficult to assess the ongoing consequences of the spill.

The Inquiry considers that AMSA responded exceptionally well to an incident that was beyond its first hand experience and in a remote and difficult location. AMSA should be commended. Nevertheless, there are lessons that can be drawn for the future, including:

- a. the need to better integrate Operational and Scientific (or environmental) Monitoring efforts, including ensuring that any Scientific Monitoring is adequate, peer reviewed and timely (see below under the DEWHA heading);
- b. the Commonwealth Government should put in place effective arrangements to ensure that petroleum companies, in the event of a spill, fully pay for AMSA's clean-up operations and all Operational and Scientific Monitoring and any associated remedial operations (consistent with the application of the 'polluter pays' principle);
- c. AMSA should ensure that environmental issues are fully comprehended in the National Plan;

- d. AMSA along with DEWHA (the latter taking primary responsibility) should prepare 'off the shelf' environmental monitoring programs which are scientifically peer reviewed and are tailored to accommodate the different situations that may arise in Commonwealth waters, so that they can be readily adapted and speedily implemented in the event of a blowout;
- e. AMSA, along with the Australian Marine Oil Spill Centre (**AMOSC**), should continue to explore and assess the state of readiness in terms of equipment and other resources in the event of another blowout (having regard to the likely expansion of the offshore petroleum industry in coming years); and
- f. funding arrangements under the National Plan should be reviewed to ensure that costs associated with preparedness and response are equitably shared between the shipping and the offshore petroleum industries.

PTTEPAA should be commended for not only fully meeting the costs incurred by AMSA in undertaking the clean-up program, but for providing AMSA with considerable operational and logistical assistance.

Actions by DEWHA

In response to the Blowout, DEWHA conducted wildlife response activities, negotiated a Scientific Monitoring program with PTTEPAA, and acted (from 15 September 2009) as the Environmental and Scientific Coordinator (**ESC**) with the task of providing AMSA with advice on environmental priorities and response options under the National Plan.

An issue the Inquiry carefully considered is why it took so long to put in place a Scientific Monitoring program.

DEWHA raised the need for this with PTTEPAA on 23 August 2009. However, there were no legislative provisions available to DEWHA to require PTTEPAA to undertake Scientific Monitoring and the cost of Scientific Monitoring was not recoverable under the National Plan. It needed to be undertaken on a voluntary basis, and there was certainly no funding, resources or equipment available to DEWHA to undertake Scientific Monitoring. A Scientific Monitoring program (the **Monitoring Plan**) was agreed on 9 October 2009 through a memorandum of understanding between DEWHA and PTTEPAA.

PTTEPAA is to be commended for agreeing to cooperate in the development of, and then undertaking, the Monitoring Plan, which it is now funding.

Nevertheless, settlement of the Monitoring Plan between DEWHA and PTTEPAA, and getting specialised input from bodies such as AMSA, the Australian Institute of Marine

Science (**AIMS**), CSIRO and the Western Australian and Northern Territory Governments, contributed to the delay. Notwithstanding PTTEPAA's goodwill, the Monitoring Plan required its cooperation and PTTEPAA was and remains in the driving seat in terms of undertaking and following through with the Scientific Monitoring aspect of the Monitoring Plan.

These arrangements, while representing a reasonable attempt in the circumstances, are far from ideal. The Monitoring Plan needed to be in place shortly after 21 August 2009; that it was not in place until October 2009 is unacceptable. DEWHA's response should not have been dependant on PTTEPAA's cooperation or willingness to fund the Monitoring Plan. In the future, there needs to be arrangements in place that require companies to fund Scientific Monitoring (and any remediation) programs and these need to be undertaken independently of companies, with peer review processes built into the development and evaluation of the plan. Scientific Monitoring – like AMSA's clean-up operations – should not be beholden to the cooperation of a titleholder/licensee.

In this context, the EPBC Act as it currently stands is deficient. The EPBC Act puts in place an environmental assessment and approval regime, with the onus being on the proponent to refer actions to the Minister that have, will have or are likely to have a significant impact on matters of national environmental significance (**NES**, which includes Commonwealth waters). In other words, the EPBC Act provides limited oversight of environmental matters because, when it was framed, it was done on the basis that state and territory legislation (such as that administered by Environment Protection Agencies) also applied.

In short, there is a major gap in the application of environmental legislation applying to Commonwealth waters. The environmental regulation needs to be equivalent to that which would apply if the oil spill had been on land or in state waters. This should include a capacity to issue fines for pollution on a no fault basis.

AMSA should have appointed DEWHA as the ESC earlier than 15 September 2009. As ESC, DEWHA felt it was in a better position to mobilise equipment and personnel to respond to affected wildlife and to provide advice to AMSA on environmental priorities and response options. Without detracting in any way from the role performed by DEWHA, this was new territory for them and they did not have the operational capacity to undertake response operations. In the circumstances, DEWHA did well, as did AMSA. However there are lessons to be learned from this incident by both bodies. In this regard, and as noted above, the environmental component of the National Plan needs to be built up.

ENVIRONMENTAL IMPACTS

It is unlikely that the full environmental consequences of the Blowout will ever be known. This reflects the vast and remote area affected by the spill; the absence of solid reliable baseline data on species and ecosystems; and the slow response in putting in place the Monitoring Plan.

The volume and extent of the spill

Mention was repeatedly made that the volume of oil that was released from the Montara Oilfield was around 400 barrels a day. There was also testimony from Mr Jacob, PTTEPAA's Chief Operating Officer, to the effect that the initial flow may have been as high as 1,000 to 1,500 barrels per day before dropping to around 400 barrels and possibly less. There are methods that could and should have been applied to get a more informed estimate of the amount of oil that was released, with a view to informing the public.

Estimates of the surface coverage of the hydrocarbons have ranged from 6,000 to 25,000 square kilometres. The evidence before the Inquiry indicated that hydrocarbons did enter Indonesian and Timor Leste waters to a significant degree. AMSA's best estimate of the total surface area within which oil or sheen was observed at one time or another during the spill was around 90,000 square kilometres. However, as indicated by AMSA in its submission to the Inquiry, most of the hydrocarbons remained 'within 35 kilometres of the platform with patches of sheen and weathered oil reported at various distances in different directions from the platform as currents, wind and temperature varied over the three month period'.

Effect on wildlife

Notwithstanding the water sampling that was undertaken, this needed to be better targeted and integrated with the Scientific Monitoring program (under the Monitoring Plan). To this end there also needed to be monitoring of oil/dispersant mix below the ocean's surface. This would have enabled a better understanding of the extent of the spread (since the effect of dispersants is to sink the hydrocarbons into the water column) and a better understanding of the impacts of the hydrocarbons, especially on subsurface ecosystems such as fish larvae and coral spawn.

It is unfortunate that an adequate water sampling regime was not implemented as many of the effects of the oil spill and dispersants are likely to be on subsurface species. The lack of adequate water sampling combined with the absence of good baseline data on most species and ecosystems means that the Scientific Monitoring arrangements under the Monitoring Plan will be of some, but limited, value.

The adequacy of the Monitoring Plan – both the operational and scientific components – has been lessened because:

- a. Operational and Scientific Monitoring needed to be undertaken in a more integrated way, while recognising the initial pressure of responding to the Blowout;
- b. significant delay in implementing Scientific Monitoring under the Monitoring Plan compromised the worth of some of the evaluations;
- c. inadequate water sampling that was undertaken compromised the ability to measure the movement of oil/dispersants and to form assessments on species and ecosystems that might be affected; and
- d. the need for DEWHA to reach an agreement on the Monitoring Plan with PTTEPAA caused significant delays and gives rise to questions about its overall efficacy.

The Inquiry considers that, even at this late stage, the Monitoring Plan could be peer reviewed by independent experts to establish whether there are likely to be net benefits from modifying it and to determine lessons for the future.

Mention has been made in submissions to this Inquiry of very limited impacts of the Blowout on wildlife. It is unlikely that this reporting depicts the extent of the impact on species. The area is vast and the aerial and other surveillance undertaken is unlikely to have revealed what really happened.

THE OFFSHORE PETROLEUM INDUSTRY'S RESPONSE

The offshore petroleum industry's response to the incident was via the AMOSC and a number of industry participants were invited by PTTEPAA to assess the proposed Relief Well operation.

Member companies, through AMOSC, 'provide(s) the coordination point for the provision of AMOSC and oil industry equipment and resources to the National Plan'.⁶

Sections of the petroleum industry were also consulted by PTTEPAA in terms of the availability of rigs to drill the Relief Well. There was also a peer review meeting with a number of petroleum companies to review the approach to intercepting the H1 Well to

⁶ AMOSC, Submission to the Inquiry, p. 4.

stem the flow of hydrocarbons. The Inquiry is of the view that members of the petroleum industry responded well in the circumstances, both through AMOSC and the peer review processes.

The Inquiry considers that the process of peer review in terms of WOMPs and wellhead integrity in particular would be an avenue worth exploring in terms of the future interfaces between the regulator(s) and the industry. The Inquiry received information that a number of companies utilise peer review processes as part of their quality control processes. This might be a useful practice to adopt; it need not compromise commercially confidential considerations.

Mention has been made during the course of the Inquiry as to whether equipment such as drilling rigs should be on standby so that they can be quickly deployed in the event of a future release of hydrocarbons. This would be a costly and ineffective response. The type of rig that would need to be deployed would depend on the particular situation and Australian offshore oil and gas fields are often remote and some distance apart. A better option would be for the responsible Minister to reasonably exercise current powers to second a suitable rig and other equipment from other owner/operators, with them being fully recompensed by the polluting company. There should also be a regulatory requirement for an owner/operator to make meaningful inquiries as to potential rig availability and to undertake contingency planning so that they can quickly respond in the event of a future incident.

A number of the Inquiry's recommendations for preventing another blowout will require careful consideration by industry. The Inquiry considers that, to date, industry has not participated in self-regulation in a proactive and cohesive manner.

ADEQUACY OF INFORMATION AND THE APPROACH TO THE INQUIRY

The Inquiry is of the view that the provision of information to the public and to affected stakeholders following the Blowout should not have been left, to such a large extent, in PTTEPAA's hands. This was a major incident of national and international significance. As such there needed to be a reliable and authoritative source of information capable of pulling all the threads together. For example:

- a. why was it that there was no authoritative information provided on either the volume of the oil being spilt or its coverage?
- b. why was it that the options to stop the Blowout were left entirely to PTTEPAA to explore and develop (although the Inquiry finds that they did this conscientiously and well in the circumstances), rather than for the responsible authority – the Commonwealth – assuring itself that all options

had exhaustively been pursued, with a view to taking action if that was appropriate and then informing the public?

For the future, the Commonwealth (preferably the regulator with expanded powers) needs to take charge, rather than leave matters to the owner/operators. That would have surely been the case if a major industrial incident occurred onshore. And to put the issue in perspective, no one would surely have proposed that with the grounding of the coal carrying ship in the Great Barrier Reef Marine Park in April 2010, key decisions be left to the ship owner as to how to resolve the situation. Yet in this situation PTTEPAA was essentially left to its own devices.

PTTEPAA made it clear subsequent to the Blowout that it would fully cooperate with the Inquiry, rather than provide commentary to the public prior to the Inquiry, especially in relation to the circumstances and causes of the Blowout. Thus PTTEPAA provided very little information directly to the public in relation to the circumstances and likely causes of the Blowout.

PTTEPAA's submission to the Inquiry of December 2009 was seriously deficient in terms of its depiction of what had occurred. Subsequent statutory declarations provided by PTTEPAA personnel shortly prior to the Inquiry's public hearing displayed no real appreciation of the issues that the Inquiry needed to address. In fact PTTEPAA's efforts in this regard were in important respects misleading and unhelpful to the Inquiry's task of determining the circumstances and causes of the Blowout. PTTEPAA had not gone back and evaluated contemporaneous information, such as DDRs or forward work programs, in order to properly inform itself on essential points (for example, the poor cementing job in March 2009 and removal of the 9 $\frac{5}{8}$ " PCCC in August 2009).

PTTEPAA seems to have been under the belief that it had little or no responsibility to positively assist the Inquiry to get to the nub of what really happened. PTTEPAA approached the Inquiry as a learning exercise. PTTEPAA's poor efforts to properly inform the Inquiry reflects badly on PTTEPAA's ethics and governance.

By its own admission, PTTEPAA made no substantive effort subsequent to the Blowout to truly find out what happened and why. It tried in its submissions to limit responsibility to PTTEPAA personnel on the rig. It failed in that endeavour, with senior onshore personnel being shown to be critically involved, or directly involved, in overlooking shonky procedures.

PTTEPAA's approach to this Inquiry stands in stark contrast to the way that Atlas approached the Inquiry. Atlas' submission to the Inquiry was informative; it undertook a thorough investigation of the circumstances and causes of the Blowout and provided that

to the Inquiry; and its senior people in their statutory declarations and testimony readily conceded where Atlas as a company should have performed better. Atlas through its representatives observed a high standard of ethics and corporate governance in the way they approached this Inquiry, which is to its credit.

In conclusion, whilst PTTEPAA's efforts in responding to the Blowout are commendable, this was overshadowed by:

- a. widespread and deep-seated poor practices that not only caused the Blowout, but made it little more than a matter of time before such an event occurred; and
- b. an approach to the Inquiry which reflected poorly on its ethics and governance.

These matters raise, in the Inquiry's view, an issue about the desirability of PTTEPAA's conduct of further drilling operations at the Montara Oilfield until the significant shortcomings in its operations have been satisfactorily addressed.

1. INTRODUCTION

The Inquiry

- 1.1. The Minister for Resources and Energy, the Hon Martin Ferguson AM MP, announced the Commission of Inquiry (the **Inquiry**) on 5 November 2009 with the following Terms of Reference.

With respect to the uncontrolled release of hydrocarbons at the Montara Wellhead Platform that commenced on 21 August 2009, and subsequent events including the fire that commenced on 1 November 2009 (together the Uncontrolled Release) the Commission of Inquiry will:

1. Investigate and identify the circumstances and likely cause(s) of the Uncontrolled Release.
2. Review the adequacy and effectiveness of the regulatory regime applicable to operations at or in connection with the Montara oil field, including under the *Offshore Petroleum and Greenhouse Gas Storage Act 2006*, and including the adequacy and effectiveness of all safety, environment, operations and resource management plans, and other arrangements approved by a regulator and in force at relevant times.
3. Assess the performance of relevant persons⁷ in carrying out their obligations under the regulatory regime.
4. Review the adequacy and effectiveness of monitoring and enforcement by regulators of relevant persons⁷, under the regulatory regime.
5. Assess the adequacy of the response to the Uncontrolled Release by the current title-holder of AC/L7, the owner and/or operator of the Montara Wellhead Platform and the owner and/or operator of the West Atlas drilling rig.
6. Assess the adequacy of regulatory obligations applicable to the titleholder of AC/L7, the owner and/or operator of the Montara Wellhead Platform, and the owner and/or operator of the West Atlas drilling rig in relation to the response to the incident and make any recommendations necessary to improve the regulatory obligations that may be applicable to any future incidents.
7. Assess and report on the environmental impacts following the Uncontrolled Release using available data and evidence including the outcomes from monitoring activities already underway, review any proposed environmental monitoring plans, and make recommendations

⁷ For the purposes of paragraphs 3 and 4, 'relevant persons' are persons who have engaged at any time in petroleum-related operations at the Montara Wellhead Platform that may have contributed to the cause(s) of the Uncontrolled Release, including but not limited to: the titleholder or a former titleholder of AC/L7 permit, a present or former owner or operator of the Montara Wellhead Platform, a present or former owner or operator of a drilling rig, a drilling contractor or a supplier or installer of plant or equipment.

on whether any further measures are warranted to protect the environment from the consequences of the Uncontrolled Release.

8. Consider and comment on the offshore petroleum industry's response to the Uncontrolled Release.
 9. Consider and comment on the provision and accessibility of relevant information regarding the Uncontrolled Release to affected stakeholders and the public.
 10. Make recommendations to the Minister for Resources and Energy, and through the Minister for Resources and Energy, other relevant Commonwealth Ministers, regulators and industry, as appropriate, on any measures that might help to prevent similar incidents occurring in the future and any measures that might mitigate the safety, environmental, and resource impacts arising from such an incident. Measures may include improvements to industry practices or applicable regulatory regimes and their administration.
 11. Consider, assess and make recommendations in relation to any other matter the Commission of Inquiry considers relevant to or arising from the Uncontrolled Release and the prevention of similar events occurring in the future.
- 1.2. The Inquiry was established under Part 9.10A of the OPGGS Act. This meant that the Inquiry had nearly all the powers of a royal commission, including the power to require companies and individuals to provide relevant documents to the Inquiry and the power to summons witnesses and take sworn evidence.
- 1.3. Part 9.10A was added to the OPGGS Act as a result of amendments introduced into Parliament by Minister Ferguson in September 2009. The Inquiry considers that, in the light of what has transpired, the powers provided by the amendments were essential to the conduct of the Inquiry. In the absence of the Part 9.10A powers, the Inquiry would not have had access to the information that was necessary to understand what occurred on the Montara WHP in either March or August 2009 when critical events took place. Nor would the Inquiry have had access to other information on which its findings and recommendations also rely.
- 1.4. At the outset in November 2009 the Inquiry invited submissions from all interested parties through advertisements placed in the national press. During the course of the Inquiry around 40 submissions were received from companies, government agencies, organisations and individuals. To assist public understanding of the Inquiry and the issues before it, the Inquiry posted submissions on its website (www.montarainquiry.gov.au). Throughout the period from December 2009 to June 2010, the website was used to provide public access to information about the course of the Inquiry.

- 1.5. In addition to submissions, the Inquiry received most of the information which underlies this report from two sources. The Inquiry issued Notices to Produce Documents to 15 companies and government agencies which resulted in a considerable volume of relevant documents. Secondly, the Inquiry conducted its public hearing for 21 days over the period between 15 March and 16 April 2010. The Inquiry heard evidence from 15 witnesses in relation to information in statutory declarations they provided to the Inquiry. The transcripts of the public hearing were also made available through the Inquiry's website, where they attracted considerable interest both from within Australia and internationally.
- 1.6. The proceedings of the Inquiry have attracted increasing interest both because of the more recent incident involving the *Deepwater Horizon* rig in the Gulf of Mexico and because of the implications of the Blowout for the way in which offshore drilling is, or should be, regulated. The lessons to be learned by regulators and companies about prudent oilfield practice are, of course, the essential focus of an Inquiry of this kind. There is no relationship between the Inquiry and the normal regulatory processes which are tasked with establishing whether offences were committed and whether penalties should be enforced.
- 1.7. The Inquiry was scheduled to report to the Minister by the end of April 2010. At the Commissioner's request this was extended to 18 June 2010 because the time required to conduct the Inquiry's public hearing was longer than anticipated and because of the need to ensure that procedural fairness was afforded to persons and organisations that were mentioned adversely in the Inquiry's proposed findings.
- 1.8. It is timely that there should be some attention focused on the operation and regulation of the offshore petroleum industry given the expansion that is in prospect. The Blowout serves as an important reminder of the very real risks that come with the substantial economic benefits of petroleum developments, and the need for an effective regulatory and emergency response framework to ensure that sustainable development objectives can be achieved, whilst also ensuring well integrity and maintaining high standards of occupational health and safety (**OHS**) and environment protection.
- 1.9. Australia's energy sector brings significant economic benefits to the nation, both in terms of energy usage and by contributing 20 per cent of the country's total export value. Australia has a very large and diverse range of energy resources,

including approximately 38 per cent of the world's uranium resources, 9 per cent of coal resources and 2 per cent of natural gas resources.⁸

- 1.10. The upstream petroleum sector, consisting of exploration, development and production of oil and gas, is small by global standards and relative to Australia's large reserves of uranium and coal. The upstream petroleum sector is, however, an important component of the Australian economy, with oil and gas extraction representing around 2.5 per cent of GDP.⁹ The industry contributes significantly to regional and state economies and supports new investment, infrastructure development, employment, and a range of other socio-economic benefits.¹⁰
- 1.11. Australia has significant reserves of natural gas which are used domestically and exported. Australia has about 0.3 per cent of world oil reserves and is increasingly reliant on imports for its transport fuels. Australian oils tend to be light crude oils, which yield premium products including transport fuels, and are valued higher than heavier crudes, which yield fuel oils and bitumen.¹¹ Around 70 per cent of Australia's crude oil and condensate production occurs off the north-west coast, and more than half of Australia's production is exported given the proximity of this region to Asia.¹²
- 1.12. World production of oil fell in 2009 as a result of the drop in prices associated with the global financial crisis, but both production and prices are forecast by the Australian Bureau of Agricultural and Resource Economics (**ABARE**) to grow in the medium term.¹³ Australian oil production and exports are forecast to increase in the next few years as new oilfields commence operation, and then decline gradually in the medium term.¹⁴ Demand for oil is forecast to continue to grow, and the offshore petroleum industry is and will continue to be a significant contributor to Australia's economy. Given Australia's largely under-explored offshore areas and improvements in exploration and production technologies, there is the potential for growth in Australia's oil reserves in

⁸ Geoscience Australia (GA) and ABARE 2010, *Australian Energy Resource Assessment*, p. 2.

⁹ Australian Bureau of Statistics 2009, *Australian National Accounts: Input-Output Tables – Electronic Publication, 2005-06 Final*, Cat No. 5209.0.55.001.

¹⁰ DEWHA 2008, *North-west Marine Bioregional Plan, Bioregional Profile*, <www.environment.gov.au/coasts/mbp/publications/north-west/bioregional-profile.html>, p. 139.

¹¹ Wilkinson R 2006, *Speaking Oil and Gas*, p. 116.

¹² GA and ABARE, *Australian Energy Resource Assessment*, p. 47.

¹³ ABARE 2010, *Australian Commodities: March quarter 2010*, pp. 135-139.

¹⁴ ABARE 2010, *Australian Commodities: March quarter 2010*, p. 142.

existing fields, and for new oil discoveries in both existing fields and the poorly explored frontier basins.¹⁵



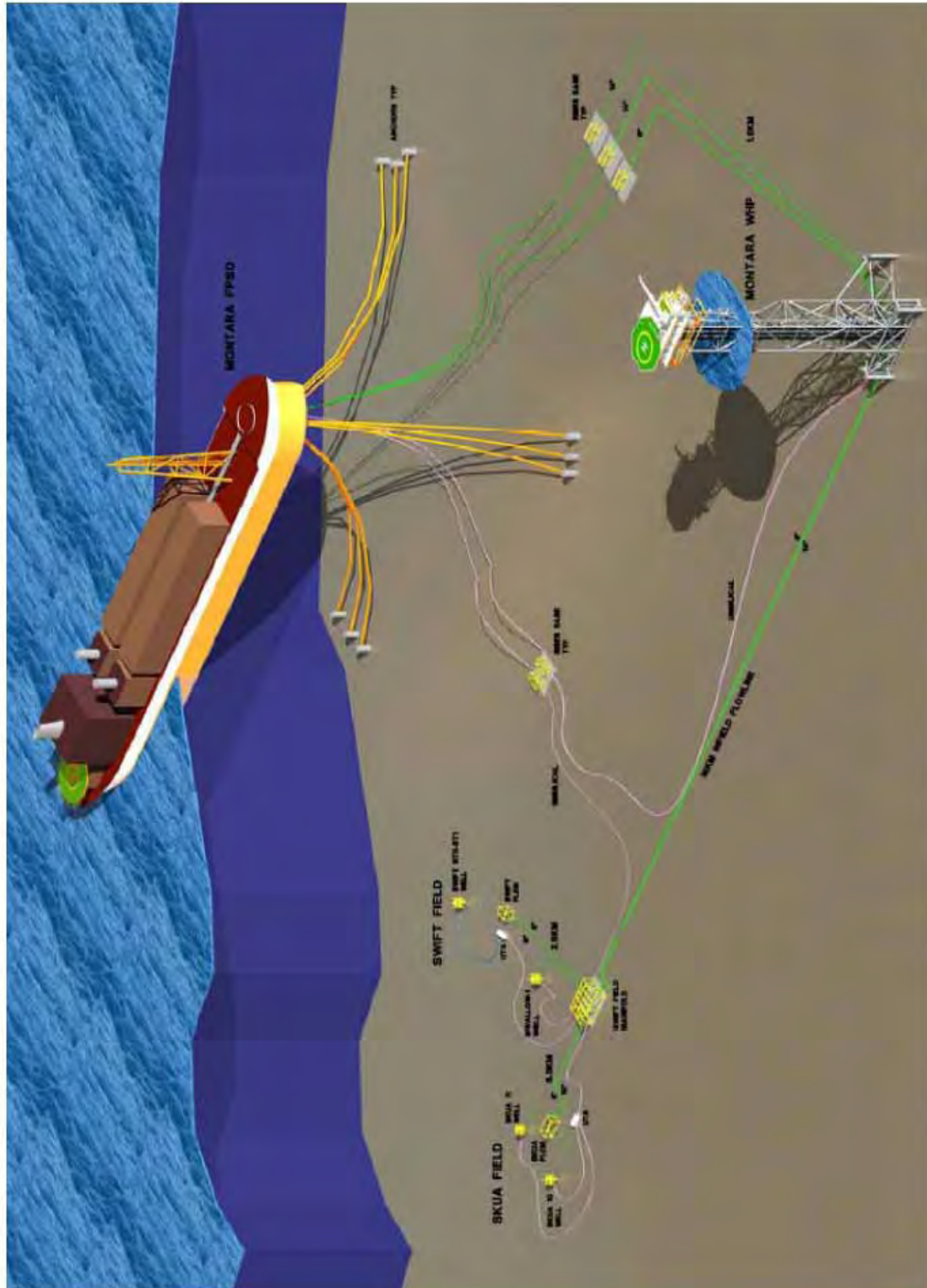
Source: www.amsa.gov.au

¹⁵ GA and ABARE, *Australian Energy Resource Assessment*, p. 74.

The Montara Development Project

- 1.13. The Montara Development Project is owned and operated by PTTEPAA, a subsidiary of the Thai company PTT Exploration and Production Public Company Limited (**PTTEP**). The Development is located in a remote area of the Timor Sea, approximately 250km north-west of the Western Australian coast, and almost 700km from Darwin. The location of the Montara WHP is shown above.
- 1.14. The Montara Development Project is located in the offshore area of the Territory of Ashmore and Cartier Islands, which is an area of Commonwealth waters, and is around 100km and 150km from Cartier Island and Ashmore Reef respectively. The Director of Energy, from the NT DoR (formerly the Department of Regional Development, Primary Industries, Fisheries and Resources) regulates well control in this area on behalf of the Commonwealth Government.
- 1.15. Geologically, the Montara Development Project is located in the Vulcan sub-basin of the Bonaparte basin, which contains significant oil and gas fields under various stages of operation, construction and consideration, including the Blacktip, Tern, and Petrel fields. Montara is located in the western section of the Bonaparte Basin, within the AC/L7 and AC/L8 Production Licence areas, in water depths ranging between 76 and 90 metres.
- 1.16. In September 2003, Coogee Resources (Ashmore Cartier) Pty Ltd (**Coogee Resources**) acquired the Newfield Australia group of companies, including the Retention Lease of the Montara Oilfield. Coogee Resources submitted a Montara Field Final Development Plan, with an application for a Production Licence for the AC/L7 field in October 2006, which was approved in March 2007. Coogee Resources received approval from the NT DoR to batch drill three development wells in the Montara Oilfield, and later received approval to batch drill two additional wells. In February 2009, Coogee Resources was acquired by a subsidiary of PTTEP and renamed PTTEP Australasia (Ashmore Cartier) Pty Ltd.
- 1.17. The Montara Oilfield includes four production wells (H1, H2, H3 and H4) and a gas injection (**GI**) well. In addition, there are two production wells in the Skua Oilfield and three production wells in the Swift/Swallow Oilfield. Facilities include a WHP at the Montara Oilfield, and are intended to include a Floating Production, Storage and Offloading (**FPSO**) facility for processing,¹⁶ as illustrated below.

¹⁶ PTTEPAA, Submission to the Inquiry, Term of Reference 1.



Source: Northern Territory Oil and Gas 2008¹⁷

¹⁷ Northern Territory Department of Resources 2009, *Northern Territory Oil and Gas 2008*, <http://www.nt.gov.au/d/Minerals_Energy/Content/File/pdf/2008_Petroleum_Annual_Summary.pdf>

- 1.18. PTTEPAA engaged Atlas, a Singapore based company, to drill the Montara wells, using the *West Atlas* jack-up drilling rig. The *West Atlas* commenced drilling the five wells between January and April 2009 and then returned in August 2009 in order to complete drilling and to tie-back the wells to the platform.

The Blowout

- 1.19. At approximately 7.30am (CST) on 21 August 2009, there was a blowout from the H1 Well. The Well leaked possibly between 400 and 1500 barrels of oil per day, and unknown amounts of gas, condensate and water, until the Relief Well operations were successful in ‘killing’ the well over ten weeks later.
- 1.20. Based on the estimate of 400 barrels per day, the volume of oil spilled from the Montara WHP makes the Blowout Australia’s third-largest oil spill. Only two oil spills from the tanker *Kirki* in 1991 and the *Princess Anne Marie* in 1975 were larger. The Blowout caused the worst oil spill in Australia’s offshore petroleum industry history. Previously, there had been six offshore blowouts in Australian waters between 1965 and 1984. These involved either no oil spill or spills of only negligible amounts.¹⁸
- 1.21. It is fortunate, in view of the highly flammable nature of the material released, that the impact of the Blowout was not more severe and did not include the loss of human lives. Disasters such as the explosion and fire on the *Piper Alpha* gas production platform in the North Sea in 1988, which claimed 167 lives, and the *Deepwater Horizon* rig in the Gulf of Mexico in 2010, which claimed 11 lives, remind us of the potentially catastrophic consequences of failures in equipment or procedures in the offshore petroleum industry.
- 1.22. The circumstances and likely causes of the Blowout are discussed in Chapter 3 of the Report.

Regulation

- 1.23. In Australia, the offshore petroleum industry is subject to a complex regulatory regime with powers and responsibilities shared between the Commonwealth and the state and Northern Territory governments. Regulation of the industry is based on a less prescriptive and more outcomes-based framework in which primary responsibility for safety and the management of hazards lies with operators, enabling them to have flexibility in how they minimise risks.

¹⁸ Advice from GA to RET, 24 August 2009, RET.0017.0001.0497.

- 1.24. There are a number of recent reviews of the regulatory framework and other related issues including a review by the Productivity Commission of the regulatory burden on the offshore petroleum sector.¹⁹ The Inquiry has had regard to these reviews and the potential regulatory changes that may follow from them. The regulatory framework is addressed in Chapter 4 of the report, which discusses the regulatory regime applying to well integrity and safety, and Chapter 6 which discusses the environmental regulatory framework and response.

Response

- 1.25. In the immediate aftermath of the Blowout, PTTEPAA and Atlas safely evacuated all 69 personnel from the Montara WHP. AMSA became the Combat Agency and commenced clean-up operations later on that day. NOPSAs issued prohibition notices to PTTEPAA and Atlas to ensure human safety was not put at undue risk on the Montara WHP and the *West Atlas* rig.
- 1.26. The Inquiry has heard that PTTEPAA considered a number of options for stopping the Blowout from the H1 Well before deciding to drill a Relief Well to intercept the H1 Well. The *West Triton* rig was engaged by PTTEPAA to undertake this drilling and then to 'kill' the H1 Well by pumping in heavy mud and plugging it with cement.
- 1.27. After several attempts, the leaking H1 Well was intercepted on 1 November 2009. This allowed the pumping of heavy mud to commence. Nevertheless, fire broke out on the Montara WHP and *West Atlas* rig. The fire continued to burn at high temperatures until the H1 Well was 'killed' with the further pumping of heavy mud on 3 November 2009. Further information on the arresting of the Blowout, including the response by regulators and the offshore petroleum industry, is provided in Chapter 5.
- 1.28. The environmental impacts from the Blowout are difficult to determine and are unlikely to ever be known. The location of the Montara WHP is remote and there is little baseline data about species and habitats. There was also a delay before the commencement of Scientific Monitoring of the environmental impacts of the oil spill. Chapter 6 discusses the spread of the pollution, the clean-up led by AMSA and the regulatory framework for environmental protection.

¹⁹ Productivity Commission 2009, *Review of the Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector*, Research Report.

Findings and Recommendations

- 1.29. Chapter 7 of the Report reviews additional aspects of the performance of PTTEPAA which, as the operator of the Montara WHP, is the company that has been central to the Inquiry's consideration of the Blowout and its consequences. Chapter 8 assembles the Inquiry's findings and recommendations against the various Terms of Reference addressed by the Inquiry.

2. PRELIMINARY MATTERS

2.1. Prior to presenting the Inquiry's findings and recommendations in relation to its Terms of Reference, a number of issues raised in the course of the Inquiry are addressed in this Chapter so that the Inquiry's approach in subsequent Chapters of this Report can be understood.

Sensible oilfield practice as a frame of reference

- 2.2. During the public hearing PTTEPAA objected to witnesses being questioned by reference to 'good oilfield practice', on the basis that this expression had a defined legal meaning under the OPGGS Act. It was noted that:
- a. the *defined* meaning of the expression might not be understood by witnesses; and, in any event,
 - b. confusion might arise as to whether evidence was given by reference to the *defined* or *ordinary* meaning of that expression.
- 2.3. Further, as the Inquiry was not tasked to make findings with respect to any civil or criminal liability of any person or entity, it was considered preferable to steer clear of the expression 'good oilfield practice' as a frame of reference when assessing the acts and omissions of those persons or entities.
- 2.4. Accordingly, witnesses were usually asked questions by reference to whether acts and omissions conformed, in their view, to 'sensible oilfield practice'. That is, they were asked to express views by reference to their understanding of the ordinary meaning of that expression.²⁰ Based on their experience, was the doing of an act sensible? Based on their experience, was the non-performance of an act sensible? This course was adopted as a prudent precaution, even though some PTTEPAA-related witnesses and documents (including its own Well Construction Standards) themselves used the expression 'good oilfield practice'.
- 2.5. In submissions put to the Inquiry after the public hearing, PTTEPAA then raised various further objections:
- a. PTTEPAA objected to use of the expression 'sensible oilfield practice' as a frame of reference in this Report on the basis, inter alia, that this expression was *not* in the OPGGS Act and its meaning was unclear;

²⁰ On some occasions witnesses were asked questions as to whether acts or omissions were 'reasonable'.

- b. PTTEPAA submitted that the Inquiry's questioning of witnesses by reference to 'sensible oilfield practice' was unfair, despite (i) not objecting to such questions at the time; and (ii) witnesses being readily able to answer questions by reference to that standard - including Mr Jacob who gave evidence on behalf of PTTEPAA; and
 - c. PTTEPAA also submitted that it was not open to the Inquiry 'on the sole basis of oral evidence' to make a finding as to whether PTTEPAA's practices were 'good' or 'sensible oilfield practices'.
- 2.6. The Inquiry rejects PTTEPAA's objections and submissions concerning use of 'sensible oilfield practice' as a frame of reference in this Report.
- 2.7. Indeed, it is surprising that, in the context of this public inquiry, PTTEPAA would assert that it is unsure what 'sensible oilfield practice' means - particularly when its own personnel (who had considerable experience in oilfield practice) had little or no difficulty understanding that expression, nor any difficulty expressing views as to whether various acts and omissions conformed to that standard.
- 2.8. Further, the very last documents the Inquiry received from PTTEPAA were inconsistent with its stated opposition to the Inquiry's use of the concepts of 'sensible oilfield practice' and 'good oilfield practice'. Those documents consisted of a written submission under the hand of PTTEPAA's CEO dated 25 May 2010, and an attached consultant's report. PTTEPAA sought to rely upon those documents to demonstrate the steps it proposed to take 'to ensure that in future PTTEPAA operates at the highest level of good oilfield practice'. Some of the identified steps referred explicitly to 'good oilfield practice', and the consultant's report relied upon by PTTEPAA contained many references to 'good oilfield practice'. Indeed, the consultant's report itself expressed views to the effect that various acts and omissions did, or did not, conform to 'good oilfield practice'. How the Inquiry was meant to assess the content of those documents without reference to the very standard invoked in them was not explained.
- 2.9. In any event, the Inquiry is satisfied that (i) the concept of 'sensible oilfield practice' is a useful frame of reference when assessing the acts and omissions of persons and entities in this Report; and (ii) the legislative concept of 'good oilfield practice' must necessarily be referred to when assessing features of the regulatory regime and the performance of regulators under that regime.
- 2.10. The Inquiry rejects PTTEPAA's suggestion that there is not a proper evidentiary basis to allow the Inquiry to express findings by reference to 'sensible oilfield practice'. A large amount of material was obtained in the course of the Inquiry's

public hearing in support of these findings, including from many PTTEPAA-related witnesses.

- 2.11. However, the Inquiry emphasises that any finding to the effect that particular acts and omissions of persons/entities did not conform to sensible oilfield practice should *not* be interpreted as a finding that the person/entity in question bears any civil or criminal liability under the legislative regime. The Terms of Reference do not contemplate findings being made by the Inquiry as to the existence of civil or criminal liability.

Whether adverse findings are prohibited by the Inquiry's Terms of Reference

- 2.12. Another related argument raised by PTTEPAA (on several occasions) was that the Inquiry's Terms of Reference did not permit adverse findings to be made against any individual or entity, including PTTEPAA.
- 2.13. On 8 February 2010 the Inquiry received a letter from PTTEPAA's solicitors which dealt, amongst other things, with the scope of paragraph 3 of the Inquiry's Terms of Reference. In the letter of 8 February 2010 PTTEPAA submitted that:
- a. Terms of Reference 2 and 3 were restricted to whether PTTEPAA complied with its duties to submit required plans, whether regulators appropriately assessed those plans, and whether regulators conducted sufficient audits of PTTEPAA's activities prior to the incident; and
 - b. discussions with the Minister's Office prior to the Terms of Reference being released indicated that the Inquiry was not meant to deal with PTTEPAA's actual compliance with its plans – 'as that would result in the Commission gathering evidence for use in a prosecution'.
- 2.14. The Solicitor Assisting the Inquiry responded as follows by letter dated 11 February 2010:
- This Inquiry proposes to give the terms of reference their ordinary and natural meaning. The Inquiry does not presently consider that [PTTEPAA]'s understanding of the scope of terms of reference 2 and 3 is consistent with the ordinary and natural meaning of these terms of reference. The Inquiry presently considers that whether or not [PTTEPAA] complied with its management system and plans is relevant to terms of reference 2 and 3, and probably terms of reference 1, 4 and 10 as well...
- 2.15. The Inquiry invited PTTEPAA to revisit the scope of the Terms of Reference, if it wished, at the public hearing. It did not do so.

2.16. However, subsequent to the public hearing PTTEPAA's solicitor sent an email to the Inquiry dated 22 April 2010. That email expressed surprise that the Inquiry might make adverse findings against particular individuals. In this regard, PTTEPAA referred to the following statement made by the Minister when he announced the Inquiry in a media release on 5 November 2009:

Consistent with well established practice such as for the Australian Transport Safety Bureau, the Commission of Inquiry will receive evidence on a no-blame basis.²¹

2.17. PTTEPAA's solicitor went on to state as follows:

If the Commissioner is to follow the intent the Minister advised the public he was to follow in conducting the Commission of Inquiry, we would anticipate that his report will not be making any adverse comments about any entity and, in particular, in relation to any individual and will be limited to factual matters so that future learnings may be taken from that.

2.18. The Solicitor Assisting the Inquiry responded to this submission by letter dated 22 April 2010. In that letter it was explained that, to the extent considered necessary or appropriate to properly address the Inquiry's Terms of Reference, adverse findings against entities and/or individuals may be expressed in the final report.

2.19. In this Report adverse findings have been expressed against entities and individuals. In this regard, the Inquiry notes as follows:

- a. the Minister's media release expressly referred to the basis upon which the Inquiry *would receive evidence*. In context, the Minister was referring to the fact that evidence given by witnesses could not be used against them to establish any civil or criminal liability;
- b. this view of the legislation underpinning the Inquiry is supported by the statements made by the Minister in a speech to the House of Representatives on 17 November 2009. In that speech the Minister referred to the Inquiry *receiving evidence* on a 'no-blame basis' and immediately then stated:

Independent of the Commission of Inquiry, the relevant regulatory processes will determine whether any non-compliance with the laws has occurred and whether any measures to seek penalties and other sanctions should be pursued.

²¹ Media release available at:
<<http://minister.ret.gov.au/TheHonMartinFergusonMP/Pages/MINISTERANNOUNCESDETAILSOFMONTARACOMMISSIONOFINQUIRY.aspx.html>>.

- c. the Minister must have known that the Inquiry's focus had to be fulfilment of its Terms of Reference in accordance with relevant provisions of the OPGGS Act and the *Royal Commissions Act 1902*. Those pieces of legislation do not prohibit the Inquiry from expressing adverse findings. Indeed, they oblige the Inquiry to do so to the extent necessary to fulfil its Terms of Reference; and
- d. the Minister must have known that Terms of Reference 1, 3 and 11, for instance, might well result in adverse findings being included in the Inquiry's Report.

2.20. Accordingly, the Inquiry considers that the Minister's media release of 5 November 2009 was not intended to (nor could it) prohibit the Inquiry from expressing adverse findings to the extent necessary or appropriate to properly address the Inquiry's Terms of Reference.

2.21. Ultimately, the Inquiry has considered it both necessary and appropriate to include adverse findings in its Report, so as to properly address the Terms of Reference.²² For instance:

- a. the Inquiry's findings and reasoning with respect to 'the circumstances and likely causes' of the Blowout could not have been adequately stated without adverse findings being expressed against PTTEPAA and its personnel;
- b. likewise, the Inquiry's findings and reasoning with respect to 'the performance of relevant persons in carrying out their obligations under the regulatory regime' could not have been adequately stated without adverse findings being expressed against PTTEPAA and its personnel; and
- c. the Inquiry could not have properly assessed and made a recommendation about another relevant matter without reaching and expressing adverse findings against PTTEPAA and its personnel: namely, the Inquiry's recommendation that the Minister review PTTEPAA's permit and licence (see Chapter 7).

2.22. This is particularly the case having regard to the following:

- a. PTTEPAA and Atlas contested a number of factual matters concerning the circumstances and likely causes of the Blowout;

²² The Inquiry has been careful to avoid expressing adverse findings in terms which assert the existence of any civil or criminal liability. The Inquiry has not made findings that particular sections of relevant legislation have been breached by any party. The Inquiry has not gathered a single piece of evidence for prosecutorial purposes.

- b. in its own submission to the Inquiry in December 2009, PTTEPAA explained the circumstances and likely causes of the Blowout in terms which were adverse to various on-rig personnel;
- c. subsequently, PTTEPAA and its personnel advanced a considerable amount of evidentiary material to the Inquiry concerning Terms of Reference 1 and 3. That material was largely exculpatory, particularly with respect to PTTEPAA's onshore personnel. At the same time, however, much of the material advanced by PTTEPAA and its personnel invited, in effect, adverse findings to be made against Atlas; and
- d. the information provided by PTTEPAA and its personnel was tested in the course of the Inquiry's public hearing, and found wanting in various respects. Indeed, the Inquiry has felt compelled to reject much of this material, for reasons which cannot be properly explained except in terms which involve adverse findings against PTTEPAA and its personnel. Mr Jacob's own evidence acknowledged this reality.

2.23. The Inquiry therefore rejects PTTEPAA's unduly narrow approach to the Terms of Reference. Had that approach been adopted, PTTEPAA and its personnel would have been spared the burden of adverse findings. However, the Inquiry, the Minister and the public at large (indeed, PTTEPAA itself) would have arrived at a very imperfect understanding of matters such as (i) the circumstances and likely causes of the Blowout; and (ii) the performance of relevant persons in carrying out their regulatory obligations.

Disclosure of names of persons against whom adverse findings have been made

2.24. The Inquiry considered whether titles rather than names should be used in this report, on the basis that use of names could involve damage to reputations and harm to employment prospects.

2.25. The Inquiry decided not to omit names of those involved in relevant events for a number of reasons:

- a. the 'default' position under the applicable legislation is that evidence given before the Inquiry was required to be given in public, unless a direction was given that (i) the evidence be taken in private; and/or (ii) particular evidence not be published;

- b. this 'default' position recognises that 'there is a public interest in openness of proceedings', notwithstanding possible damage to private interests;²³
- c. possible harm to private interests required that procedural fairness be observed (as occurred prior to finalisation of this Report),²⁴ but there is no general principle of fairness which requires that proceedings be conducted in all respects in such a way as to exclude or minimise damage to reputation or the possibility (or even probability) of adverse publicity;²⁵
- d. prior to giving evidence all witnesses produced Statutory Declarations which were made public, and all witnesses gave evidence in public hearing. No non-publication orders were sought or made in respect of the identity of witnesses during the public hearing of the Inquiry;
- e. even if titles rather than names were used in this Report, anyone minded to could ascertain identities by the simple expedient of referring to the transcript of proceedings (which has been publicly accessible since the evidence was given by witnesses);
- f. it could hardly be argued that the identity of someone like Mr Jacob, as a senior PTTEPAA representative, should be withheld from disclosure in this Report. Yet his evidence was based in part upon incorrect information provided to him by other PTTEPAA-related witnesses; and Mr Jacob's evidence also took account of earlier oral evidence given by all PTTEPAA-related witnesses. It is not apparent why Mr Jacob's name should appear in this Report, but not the names of other PTTEPAA-related witnesses;
- g. it could also hardly be argued that the names of public regulatory officials should be withheld as a matter of public or private interest.²⁶ It is not apparent why the names of public officials should appear, but not the names of private persons whose acts and omissions gave rise to well control issues;²⁷ and
- h. in criticising individuals, there is real difficulty in drawing any principled or clear line between those who should be named and those whose names should be withheld.

²³ See *ICAC v Chaffey* (1993) 30 NSWLR 21 per Gleeson CJ at pp. 30B-31D.

²⁴ Here, in disclosing the terms of preliminary findings to those who might be adversely affected, the Inquiry went beyond the requirements of procedural fairness.

²⁵ See *ICAC v Chaffey* at pp. 28D and 29D (and see again at p. 31D).

²⁶ The NT DoR did not seek non-disclosure of names of its officials.

²⁷ Atlas, Halliburton and their personnel did not seek non-disclosure of names.

2.26. Of particular significance is that, as noted in subparagraph (d) above, before the Inquiry's public hearing commenced all witnesses advanced material to the Inquiry which they knew (or ought to have known) would be canvassed publicly. Many witnesses also chose to put submissions to the Inquiry as to what findings should be made. It is not apparent why, given the Inquiry's rejection of some significant aspects of the evidence given by particular witnesses, they should now be referred to anonymously. Had their evidence been wholly accepted, it is doubtful any of those named would wish the use of titles rather than names.

Adverse findings against PTTEPAA

2.27. Any person who reads only parts of this Report, such as Chapter 3 dealing with the circumstances and likely causes of the Blowout, may take away an impression that it contains only adverse findings against PTTEPAA. This is not the case. Certainly, there are a large number of adverse findings against PTTEPAA in Chapters 3 and 7. However, there are also very positive findings about the performance of PTTEPAA in relation to its operational response to the Blowout - see for example Chapter 5. Moreover, towards the very end of the Inquiry PTTEPAA submitted an Action Plan to address matters of concern raised during the Inquiry. That Action Plan, although belated, is an impressive document which, if implemented, may go a long way to restoring confidence in PTTEPAA's ability and commitment to operate as a responsible licensee at the Montara Oilfield.

Use of imperial measurements in this Report

2.28. While the Inquiry has in its report referred to volumes in terms of barrels, the Inquiry notes that the Australian standard for the measurement of volume is the metric measurement of a litre.²⁸ Volume can also be measured in cubic metres, cubic centimetres and so on.

²⁸ See the *National Measurement Regulations 1999* (Cth).

3. THE CIRCUMSTANCES AND LIKELY CAUSES OF THE BLOWOUT

Introduction

- 3.1. This chapter is primarily concerned with paragraph 1 of the Inquiry's Terms of Reference, dealing with the circumstances and likely causes of the Blowout. The chapter also deals with aspects of paragraphs 2, 3, 4, 10 and 11 to the extent they overlap with paragraph 1 of the Terms of Reference. In particular, paragraph 2 of the Terms of Reference directs the Inquiry to investigate and report on the performance of relevant persons in carrying out their obligations under the regulatory regime;²⁹ and paragraphs 10 and 11 contemplates the making of recommendations relevant to, or arising from, the Blowout and the prevention of similar events in the future.³⁰
- 3.2. The likely causes of the Blowout can be divided into two broad categories: first, the direct and proximate causes of the Blowout; secondly, broader systemic factors which played a contributory role in the lead up to the Blowout. The Inquiry's main findings with respect to the circumstances and likely causes of the Blowout are set out in the shaded sections of this Chapter.
- 3.3. The following overview of facts leading up to the Blowout, and relevant aspects of the applicable regulatory regime, is intended to assist consideration of the circumstances and likely causes of the Blowout.

Overview of relevant facts

- 3.4. In November 2008, PTTEPAA sought and was granted approval by the NT DoR to batch drill three development wells in the Montara oilfield, one of those being the H1 Well. PTTEPAA later sought approval to batch drill two additional wells. Accordingly, there were five wells at Montara - H1, H2, H3, H4, and GI.
- 3.5. Between January and April 2009, the *West Atlas* rig (owned and operated by Atlas) was positioned over the Montara WHP, located in waters approximately 77 metres deep, for the purpose of enabling Atlas to drill the wells (as contractor) for PTTEPAA.

²⁹ The expression 'relevant persons' is defined to mean persons who have engaged at any time in petroleum-related operations at the Montara Wellhead Platform that may have contributed to the cause(s) of the Uncontrolled Release.

³⁰ Such recommendations appear at the end of this chapter, and in other chapters of the Report.

- 3.6. On 27 February 2009, while the derrick of the *West Atlas* rig was positioned over the H1 Well, PTTEPAA applied to the NT DoR to change the course of the H1 Well. The process of changing the course of a well is known as sidetracking. The reason PTTEPAA sought to sidetrack the H1 Well was to enable access to a cleaner section of the reservoir into which PTTEPAA had already drilled a 12¼" hole.
- 3.7. On 2 March 2009, the NT DoR granted approval to PTTEPAA to sidetrack the H1 Well. The H1 Well thereafter became known as the H1-ST1 Well but, for convenience, will continue to be referred to in this Report as the H1 Well.
- 3.8. Between 2 and 7 March 2009, PTTEPAA continued to drill the H1 Well to a measured depth of 3,796 metres, as measured from the rotary table on the *West Atlas* rig. The total direct vertical depth of the H1 Well from the rotary table was 2,654 metres.
- 3.9. On 6 and 12 March 2009, PTTEPAA sought approval from the NT DoR to suspend the H1 Well, with the foot of the 9⅝" casing in the reservoir, by installing PCCCs on the 9⅝" and 13⅝" casing strings (instead of setting a shallow-set cement plug within the 9⅝" casing string as originally planned).
- 3.10. The NT DoR granted PTTEPAA approval to suspend the well in this manner.
- 3.11. On 7 March 2009, PTTEPAA pumped an amount of cement into the 9⅝" casing shoe (the shoe being located within the bottom-most lengths of the casing). At that point, the casing was located inside the reservoir at a point three metres (10 feet) above the oil-water contact, thereby providing a pathway for hydrocarbons to enter the well through the casing shoe. The cementing procedure was intended to set the casing shoe in the wellbore, and thereby provide a primary barrier against a blowout.
- 3.12. Following pumping of the cement, pressure was held in the casing to 4,000psi. Upon release of the pressure, 16.5 barrels of fluid returned. The return of this fluid indicated that there was a problem with the float valves in the casing shoe. The 16.5 barrels of fluid were pumped back down the casing, and the top of the casing was then closed-in so as to maintain pressure in the casing whilst the cement set.
- 3.13. Following so-called wait on cement (**WOC**), and the absence of any unwarranted further backflow of fluids, a 9⅝" PCCC was installed on the H1 Well, followed by

a so-called trash cap. The derrick of the *West Atlas* rig was then moved (or skidded) from the H1 Well over to the H4 Well.

- 3.14. On 21 April 2009, the *West Atlas* rig departed from the Montara WHP in order to perform drilling operations in other fields. At that point, or perhaps even earlier in March, the H1 Well was 'suspended'. It was generally believed that a PCCC had also been installed, as required, on the 13 $\frac{3}{8}$ " casing in the H1 Well, but it is now known that this did not in fact occur.
- 3.15. On 19 August 2009, the *West Atlas* rig returned to the Montara WHP to allow PTTEPAA to (i) commence the tie-back of the casing strings of each of the five wells to the platform; and (ii) 'complete' the wells to the point of production.
- 3.16. At 4.30am on 20 August 2009, the derrick of the *West Atlas* rig moved over the H1 Well. At 6am on the same day, the 20" trash cap was removed from the H1 Well. It then became clear to personnel from PTTEPAA and Atlas that there was no PCCC installed as required on the 13 $\frac{3}{8}$ " casing of the H1 Well.
- 3.17. As a consequence of the non-installation of the 13 $\frac{3}{8}$ " PCCC, the threads at the top of the 13 $\frac{3}{8}$ " casing – known as the mud line suspension (**MLS**) threads – had rusted or corroded. In order to tie the 13 $\frac{3}{8}$ " casing back to the WHP on a long-term basis, PTTEPAA personnel on-rig and onshore decided that those threads should be cleaned.
- 3.18. At around 11.30am, the 9 $\frac{5}{8}$ " PCCC was then removed from the H1 Well in order to allow a tool to be run in to clean the MLS threads on the inside of the 13 $\frac{3}{8}$ " casing. The 9 $\frac{5}{8}$ " PCCC was not thereafter reinstalled.
- 3.19. At that time, it seems to have been generally considered that there were two barriers within the H1 Well to prevent a blowout of fluids from the reservoir: the cemented casing shoe; and a column of inhibited seawater within the 9 $\frac{5}{8}$ " casing, which was thought to have had a so-called 'kill weight' (being sufficient weight to counter the pressure in the reservoir).
- 3.20. Significant work on the H1 Well was placed in temporary abeyance at that point, pending the tie-back of casings on other wells.
- 3.21. At around 5pm on 20 August 2009, the derrick of the *West Atlas* rig was skidded to the GI Well, and work was carried out on that well between about 6.30pm and midnight on 20 August 2009.

- 3.22. At midnight on 20 August 2009, the derrick of the *West Atlas* rig was skidded to the H4 Well.
- 3.23. At about 5.30am on 21 August 2009, workers on the WHP observed a blowout of fluid coming from the H1 Well. The volume was estimated at between 40 and 60 barrels. Gas alarms on the *West Atlas* rig were triggered and emergency response procedures were activated.
- 3.24. The flow appeared to subside and the *West Atlas* rig's OIM, Mr Trueman, gave the all clear at around 5.55am.
- 3.25. At about 6am on 21 August 2009, a decision was made to skid the derrick from the H4 Well back to the H1 Well in order to set a mechanical pressure isolation device in the H1 Well to prevent further flow.
- 3.26. At around 7.23am on 21 August 2009, the H1 Well 'kicked' again, this time blowing a column of oil and gas to the underside of the rig floor. Emergency response procedures were once again activated, and over the next hour or so senior PTTEPAA and Atlas personnel on board the rig and WHP decided to evacuate the 69 personnel.
- 3.27. All of those personnel were then safely evacuated from the rig and the WHP.

Overview of basic features of the regulatory regime

- 3.28. Features of the applicable regulatory regime are explained in detail in Chapter 4. It suffices for present purposes to note the following:
 - a. well control was a direct statutory responsibility of PTTEPAA. It was required to approach management of well control in a manner which conformed to good oilfield practice;
 - b. good oilfield practice was defined to mean 'all those things which are generally accepted as good and safe' in petroleum recovery operations;
 - c. regulation of well control as a specific activity was performed by the NT DoR, by way of approval of various documents and programs;
 - d. regulation of general OHS on the WHP and the rig was performed by NOPSA;
 - e. each of PTTEPAA and Atlas had OHS responsibilities in relation to persons at *or near* their respective facilities. Thus, the OHS responsibilities of PTTEPAA and Atlas with respect to activities and personnel could intersect and overlap.

- 3.29. The Inquiry will now turn to consider the likely circumstances of the Blowout in more detail.

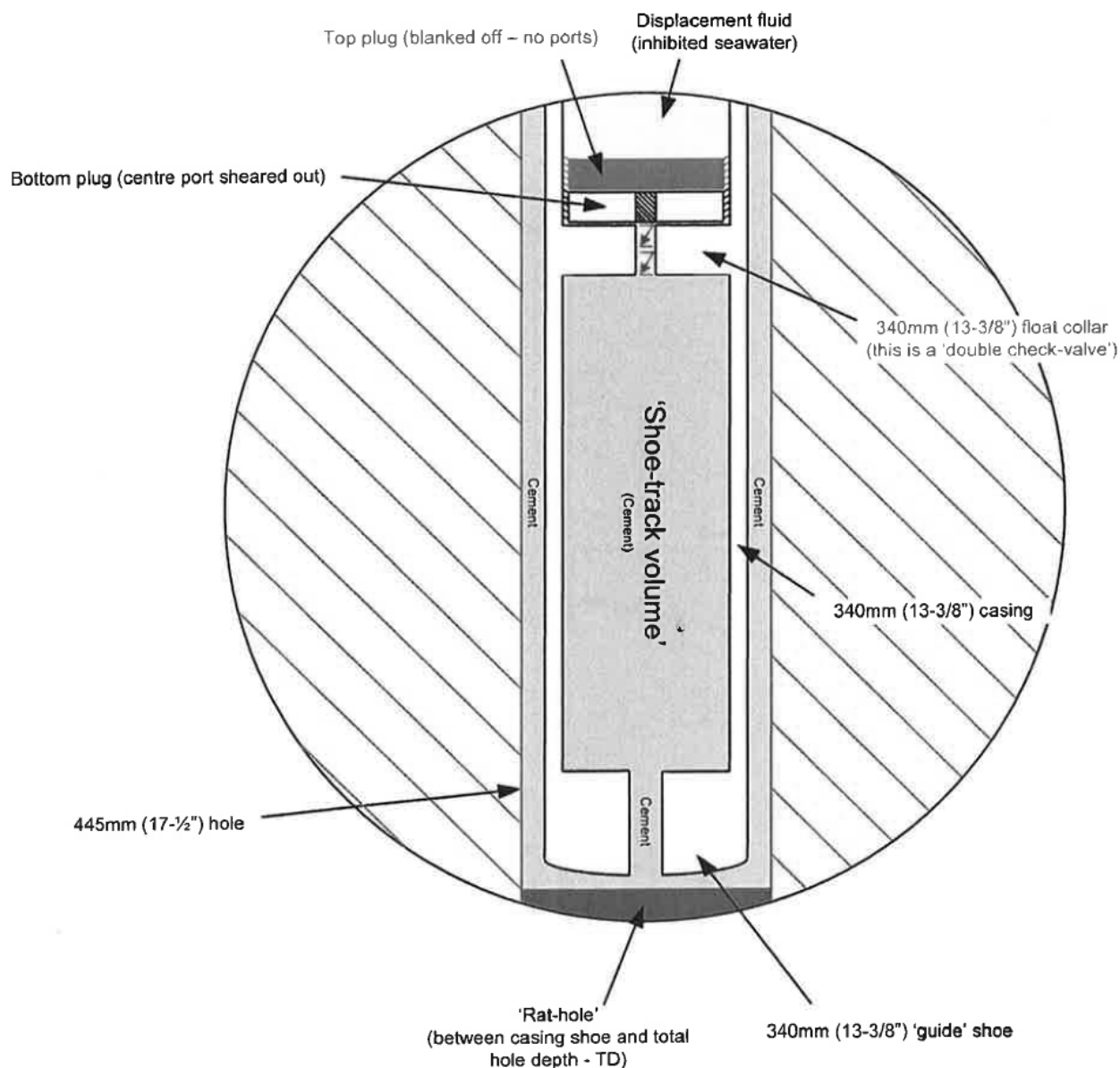
Over-displacement of cement within and around the 9 $\frac{5}{8}$ " casing shoe

- 3.30. In order to properly understand the problems which occurred with the cementing of the 9 $\frac{5}{8}$ " casing shoe, it is first necessary to explain what should occur in the course of cementing a casing shoe.

Procedures for cementing a casing shoe

- 3.31. To install a casing string into the wellbore (drilled hole) there are a number of components required. The bottom (lowermost) one to three joints of casing form what is known as a casing shoe, and this shoe contains a shoe track. The top of the shoe track consists of a float collar.
- 3.32. The space inside the shoe track should, in the course of the cementing of a casing shoe, be filled with cement; and the quantity of cement necessary to fill the shoe track is known as the 'shoe track volume'.
- 3.33. Reproduced below is a diagrammatic depiction of a casing shoe located in a vertical position inside a reservoir.³¹

³¹ PTTEPAA, Submission to the Inquiry. This diagram is taken from paragraph 24 concerning paragraph 1 of the Inquiry's Terms of Reference. It is noted that the casing shoe in the H1 Well was actually located in a horizontal, rather than a vertical, position.



- 3.34. The shoe track volume can vary depending on the number and length of the spacer joints which make up the shoe track. At the time of the cementing of the 9 $\frac{5}{8}$ " casing shoe in the H1 Well, the shoe track had a volume of approximately 6.5 barrels.
- 3.35. The float collar is located above the shoe track. The float collar incorporates a built-in landing point for top and bottom plugs, and two float valves. The two float valves in the H1 Well float collar were one-way valves that allowed the pumping of cement down beneath the float collar, but prevented its return.
- 3.36. Prior to cementing of a casing shoe, spacer fluid is pumped under pressure into the casing string, through the float collar and shoe track, out the end of the

casing shoe, and up the annulus surrounding the casing string. The purpose of this procedure is to clean the casing string of debris to enable proper setting of the cement.

- 3.37. After circulation of the spacer fluid, the cementing process begins. The first step is the launching of the bottom plug down into the casing string. The plug used in the H1 Well had a built-in membrane designed to rupture after the plug reached, and seated itself upon, the float collar.³²
- 3.38. Lead and tail cement are then pumped behind (that is, after) the bottom plug in pre-calculated volumes.
- 3.39. Thereafter, the top plug is placed into the casing string (that is, above the recently introduced cement). The top plug is a solid plug designed to seat itself upon, and lock into, the bottom plug. This so-called 'bumping of the plugs' is designed to occur at a pre-determined point, that is, at the point at which all of the cement has been pumped down the casing string and through the float collar (so that the shoe track is filled with cement).
- 3.40. The cement is actually forced down the casing string through the float collar by way of displacement fluid being introduced into the casing string, above the top plug, under pressure.
- 3.41. Two types of pumps are typically used in the cementing of a casing shoe: a cement pump and a rig pump. The cement unit is usually a small volume, very high, pressure pump with cement mixing capabilities. The rig pump is a high volume high pressure pump which enables volumes pumped to be measured and monitored. Each stroke of the rig pump is designed to deliver a given volume.³³
- 3.42. The cement pump is usually used to pump cement into the casing string above the bottom plug, whereas a rig pump is used to pump the displacement fluid into the casing string above the top plug. The rig pump introduces fluid from so-called mud tanks, the volume of which is monitored.
- 3.43. To enable a cementing operation to proceed properly, the volume of displacement fluid is carefully calculated so that, once the plugs bump, the

³² The rupturing of this membrane allows cement to be pumped through the bottom plug.

³³ Stroke counters are fitted to the pump, and stroke counter displays are located on the rig floor and within a mud logging unit.

whole of the shoe track volume beneath the float collar is filled with tail cement, as is the annulus at the end of the casing shoe and up the sides of the casing string to a predetermined height. The areas in which cement is located are depicted in grey on the diagram shown at paragraph 3.33 above.

- 3.44. If the plugs bump as predicted, a seal is created and the pressure within the casing string increases. At this point, if the cementing job proceeds normally, a pressure test would be carried out to ensure there are no leaks within the casing string. After completion of this pressure test, the pressure is bled off and, providing the float valves hold so as to prevent any unexpected return of cement from beneath the float collar, the cementing of the casing shoe may be considered to have integrity.

Problems which can occur in the course of cementing a casing shoe

- 3.45. During the hearing, the Inquiry heard that each of two problems (amongst others) can attend the cementing of a casing shoe: first, the plugs might not bump; and secondly, when pressure is bled off after the bumping of the plugs the float valves may fail, causing cement to return from beneath the float collar up into the casing string.
- 3.46. The Inquiry heard that there are fairly standard procedures for dealing with each of these problems.
- 3.47. If the plugs fail to bump, continued pumping of the displacement fluid will result in the fluid being introduced beneath the float collar, thereby displacing cement out of the shoe track. In order to avoid displacing all of the cement from the shoe track, the Inquiry understands that the rule of thumb is to pump the predetermined volume of displacement fluid and an additional amount of fluid equal to 50 per cent of the shoe track volume. The purpose of this procedure is to ensure that cement is left in the shoe track at the end of the cementing operation. Thereafter, barrier status would depend on testing and follow-up remedial action.
- 3.48. If the float valves fail, the standard procedure is to immediately close-in the system with sufficient pressure to stop further flows of cement from beneath the float collar. That pressure is held for a minimum of several hours WOC. If the pressure decreases whilst WOC, that is a strong indication of a leak path somewhere in the cement. After WOC, two things should happen: first, the

cemented casing shoe should be tested;³⁴ and secondly, consideration should be given to the taking of remedial action to ensure the cemented casing shoe can be relied upon as a barrier.³⁵

- 3.49. What is described above is not rocket science. Basic principles of ‘cause and effect’ are at play, and those principles should have been understood by those involved in cementing operations.

Additional contextual matters

- 3.50. Four further matters should be noted before turning to the cementing operations actually undertaken on 7 March 2009:
- a. first, as noted by PTTEPAA in its submission to the Inquiry, it can be extremely challenging to obtain a uniform cement job around a casing shoe when the casing string is located in a horizontal position. This is because of the tendency of the cement to flow on the low side of the casing string. The H1 Well was initially planned without as long a horizontal section, but when the well did not intersect good reservoir at a measured depth of 2,935m, it was sidetracked and drilled near horizontal to a measured depth of 3,796m. That is, the wellbore tracked near horizontally for around 700m;³⁶
 - b. secondly, whilst failure of floats in the course of cementing a casing shoe is a predictable contingency, it is still relatively uncommon. None of the Halliburton, Atlas or PTTEPAA personnel who gave evidence at the public hearing of the Inquiry had previously encountered a failure of float valves during the course of cementing a casing shoe located in a horizontal position within a reservoir;
 - c. thirdly, a failure of float valves is a significant problem which requires a thoughtful and considered response to the *particular* circumstances surrounding that failure; and

³⁴ There are various tests which may be carried out. At the very least, a pressure test should be carried out. This test may demonstrate that the cemented casing shoe has no integrity. Even if a pressure test is passed, this may simply indicate that the plugs have re-bumped, in which case other tests would need to be undertaken to verify cement integrity.

³⁵ There are a number of remedial actions which might be taken, depending on the circumstances. If doubts about the integrity of the cemented casing shoe are not resolved, a further primary barrier would need to be introduced (for example, by the laying of a bridge and the introduction of a plug above the bridge at the bottom of the casing string).

³⁶ See the Schlumberger Montara H1 ST1 End of Well Report (SCD.0001.0021.2100), which describes the H1 Well as tracking nearly horizontally (that is, from approximately 80° to approximately 90°) for around 700 metres.

d. fourthly, cementing problems are a significant cause of blowouts. The Inquiry received information to the effect that such problems accounted for approximately 50 per cent of blowouts in incidents analysed by the United States Minerals Management Service.³⁷ A 2001 Halliburton study of USA Gulf of Mexico cementing failures in 4000 wells showed that (i) approximately one in six casing shoes required remedial work after primary cementing (by way of a so-called 'squeeze job'); and (ii) intermediate casing shoes failed shoe tests 70 per cent more often than shallower casings because they were more likely to be over-displaced.³⁸

- 3.51. In light of these factors, it is clear that the float failure which occurred on 7 March 2009 should have been treated by those involved as a very significant event. Personnel involved should have (i) informed themselves properly of what had occurred; (ii) communicated about relevant events effectively; (iii) sought appropriate input to ensure they dealt with the situation properly; (iv) identified and assessed risks carefully; and (v) responded to the situation in a way which reduced those risks to the greatest extent practicable, including by way of a careful post-incident review.
- 3.52. As will become apparent, none of these things occurred in the aftermath of the float valve failure on 7 March 2009.

The cementing of the 9⁵/₈" casing shoe on 7 March 2009

- 3.53. It is apparent that, initially, things went according to plan. The plugs apparently bumped at the pre-calculated point. A pressure test of the casing string was then conducted.
- 3.54. Significantly, in order to pressure test the casing, 9.25 barrels of displacement fluid was introduced into the casing string and pumped to a pressure of approximately 4,000psi. The pressure was held for 10 minutes without incident.
- 3.55. However, when this pressure was bled off at the conclusion of the pressure test, 16.5 barrels of fluid were 'returned' from within the casing string. Significantly, of the 16.5 barrels of returned fluid, 9.25 barrels consisted of the displacement fluid which had been introduced into the casing string for the purposes of conducting the pressure test. The balance of the 16.5 barrels - that is, an

³⁷ Izon D, Danenberger E and Mayes M 2007, 'Absence of fatalities in blowouts encouraging in MMS study of OCS incidents 1992-2006', in *Drilling Contractor*, July/August 2007.

³⁸ Harris K, Grayson G and Langlinais J 2001, *Obtaining Successful Shoe Tests in the Gulf of Mexico: Critical Cementing Factors*, SPE paper 71388.

amount of 7.25 barrels - is likely to have consisted of a combination of cement and leached hydrocarbons from the reservoir, which flowed into the casing string from beneath the float collar.³⁹

- 3.56. Rather than the system being closed in immediately, being the standard response described above, the whole of the 16.5 barrels was pumped back down the casing string. The necessary consequences of this were:
- a. 7.25 barrels of cement, infiltrated with leached hydrocarbons, were forced beneath the float collar; and
 - b. 9.25 barrels of displacement fluid, consisting of inhibited seawater, were forced beneath the float collar, thereby displacing a significant amount of cement from the casing shoe track and from the area outside the casing shoe. This displaced cement was replaced with inhibited seawater, resulting in a so-called 'wet shoe'.
- 3.57. The consequence of this over-displacement of cement can be readily comprehended by reference to the diagram reproduced in paragraph 3.33 above. Whereas the areas of grey should have consisted of cement, it is likely that most of those areas would have consisted of inhibited seawater. Channel paths are likely to have been thereby created, enabling fluids to move from the reservoir to the end of the casing shoe, up through the shoe track and float collar, and into the 9⁵/₈" casing string.
- 3.58. Ordinary common sense supplemented by a rudimentary knowledge of sensible oilfield practice concerning well control should have alerted those involved in the cementing operation to the existence of a major ongoing problem. However, the evidence indicates that not a single person involved in the operation, whether on the rig or onshore, understood that fact.
- 3.59. The procedure of holding sufficient pressure (approximately 1,350psi) to prevent further returns, and waiting on cement to set for several hours, was a procedure which, on any proper analysis, could not be regarded as curing the

³⁹ In his evidence and submission Mr Duncan (PTTEPAA's Well Construction Manager) made the point that the amount of fluid bled back in excess of reasonable expectation was 5.5 barrels rather than 7.25 barrels. Mr Wilson (PTTEPAA's Drilling Superintendent) in his submission suggested that only 4.75 barrels returned from beneath the float collar. Whilst the amount returned from beneath the float collar may have been less than 7.25 barrels, Mr Duncan accepted 'it does not change things'. Indeed, if only 5 barrels returned from beneath the float collar, the pumping back of 16.5 barrels would have resulted in 11.5 barrels of inhibited seawater being pumped beneath the float collar, that is, greater over-displacement than described above.

problem of over-displacement of cement from inside and around the casing shoe. That procedure merely preserved the status quo. When the pressure of 1,350psi was bled off, and no further unwarranted return of fluid was observed, the wet shoe remained in place. The absence of any further returns did not mean that the float valves had suddenly, somehow, commenced to operate properly. Nor did it mean that the bottom and top plugs had re-bumped and created an effective seal.

- 3.60. As things stood, there was every reason to suppose that the float valves had irretrievably failed, and no effective seal had been created between the bottom and top plugs. This is particularly the case because there was no spike in pressure such as one would expect if the plugs had re-bumped.
- 3.61. Accordingly, the problem created by the float valve failure was responded to in a manner which not only failed to solve the problem, but made it much worse. None of those involved in the operation had, or gained, any real appreciation of the ongoing risks. Without doubt, the cemented casing shoe should have been subjected to a timely pressure test (around 4,000psi) which, had it occurred, would likely have demonstrated the absence of integrity in the cemented casing shoe.⁴⁰
- 3.62. That test was not carried out. Further, so far as the Inquiry has been able to ascertain, the topic of the cemented casing shoe was not even discussed again (much less risk assessed) by any of those involved after 7 March 2009 - despite onshore supervisory personnel from both PTTEPAA and Atlas reading documents sent to them by on-rig personnel which described the cementing operation in detail. If those documents had been considered with a reasonable amount of care by those on-rig and onshore, the ongoing problem with the cemented shoe would have been (or should have been) detected.

Finding 1

A direct and proximate cause of the Blowout was the defective installation by PTTEPAA of a cemented shoe in the 9½” casing of the H1 Well on 7 March 2009. This cemented shoe was intended to operate as the primary barrier against a blowout.

⁴⁰ A pressure test might have only demonstrated the integrity of the casing string if the shoe was cemented with a thin layer of cement sufficient to withstand the pressure test. Although possible, the Inquiry considers this an unlikely result in the case of the H1 Well. If the pressure test had returned a ‘pass’ result, further investigations would have needed to be carried out.

Finding 2

The installation of the cemented shoe was defective in that, after failure of floats/valves located in the shoe apparatus, displacement fluid was pumped beneath the float collar which resulted in over-displacement of cement from the casing shoe track and in the area outside the casing shoe (called the annulus).

Finding 3

The pumping back of this displacement fluid was contrary to sensible oilfield practice,⁴¹ and led to a so-called 'wet shoe'. The result was that the cemented shoe lacked integrity as a barrier.

Evidence Presented to the Inquiry in relation to the Cement Operation

David Arthur Doeg (cement unit operator)

- 3.63. Mr Doeg was a cementer engaged by Halliburton through a labour hire company, Adecco Industry Pty Ltd. Halliburton was engaged by PTTEPAA to undertake cementing operations at the WHP. Mr Doeg received his instructions from the senior 'company man' on the rig, being Mr Treasure (PTTEPAA's Day Drilling Supervisor).
- 3.64. Mr Doeg told the Inquiry that when pressure was bled off the casing string following the pressure test, at around 2.41pm (CST), a sudden rush of fluid returned from the top of the casing string into displacement tanks on the cementing unit. Mr Doeg immediately thought that the float valves had failed. In an amended Statutory Declaration Mr Doeg described what then happened in the following terms:

57. At this point I shut the well in, meaning that I simply shut the valve at the surface so that nothing could flow back.

58. I had been involved in one other job when the float collar had failed. This was in about 2006. At that time we suspected the failure was caused by debris under the float collar, so we pumped the volume that had returned back down the well and re-seated the plug - meaning that we forced the wiper plugs back down onto the float collar.⁴²

...

61. I recall that I rang the Company Man [Mr Treasure] and discussed what had happened. I cannot remember the details of my conversation with the Company Man, but the end result was that I was given an instruction by the Company Man to try and re-seat the plugs.

⁴¹ As to the use of 'sensible oilfield practice' as a frame of reference, see Chapter 2.

⁴² Mr Doeg conceded in his oral evidence that this earlier experience of float collar failure bore little resemblance to the situation which occurred on 7 March 2009.

62. I do remember that I agreed with the Company Man that I would only pump back 16.5 bbls.

63. The Job Log shows that at 14:47 I pumped back 16.5 bbls to try and re-seat the plug. However it did not work. When I started to pump back in the pressure rose to 1300 psi, but then would not rise any further...

64. If everything was working well I would have expected we should have been able to pump about 9.25 barrels back in and get the pressure to climb back to 4000 psi.

65. I kept pumping until I had pumped 16.5 bbls as instructed.

66. It is a rule that you never pump in more than you get back so the instruction to pump back 16.5 bbls did not cause me any concern at the time. However, it has now been pointed out to me that the extra fluid used to get the casing to 4,000 psi was not taken into account.⁴³ I accept this and that pumping 16.5 barrels back in probably resulted in a wet shoe.

67. After I had pumped 16.5 barrels back I said to the drilling engineer words to the effect:

“Something’s not right here. I’m not sure what.”

68. By this I meant that the pressure had not climbed beyond 1,300 psi and therefore the plugs had not re-landed. I had not idea [sic] what might have been causing this as I had never experienced something like this before.

...

82. If the casing was re-tested after the wait on cement, then it should be an adequate primary tested barrier.

...

84. There was a pressure of 687 psi following the wait on cement, but as far as I am aware this is not unusual. It did not cause me any concerns.

...

88. I am not aware of any formal PTTEPAA or [Atlas] Drilling standards that applied to the work I was doing.⁴⁴ I carried out the work in accordance with my training and what I consider to be proper industry standards.

...

94. ...I agree that the fact that the plugs did not bump should have raised some concerns, although not necessarily the possibility that the shoe had been over displaced.

...

97. ...I believe that my training and experience were appropriate for the work being done...⁴⁵

3.65. It is clear from Mr Doeg’s account that he had a very imperfect understanding of the overall mechanics involved in the cementing of a casing shoe. First, the

⁴³ This is a reference to 9.25 barrels of inhibited water which was introduced into the casing string as displacement fluid in order to pressure test the casing string after the apparent bumping of the plugs.

⁴⁴ This deficiency is dealt with below.

⁴⁵ Statutory Declaration of Mr David Doeg, 19 March 2009, pp. 4-7, WIT.1804.0003.0001.

pumping back of 16.5 barrels caused him no concern at the time, despite the fact that it inevitably led to an over-displacement of cement from within and around the casing shoe. Secondly, the reduction of pressure from 1,350psi down to 687psi at the end of WOC also failed to generate any concerns on his part, notwithstanding that holding pressure or shutting in was meant to create a closed system.

- 3.66. Accordingly, Mr Doeg's statement that his training and experience were appropriate for the work being done very much directs attention to the nature of the services actually rendered by Halliburton to PTTEPAA in the course of cementing a shoe.
- 3.67. If Mr Doeg's role was confined essentially to that of a machinist, operating at all times under instruction and direction from PTTEPAA, Mr Doeg's training and experience might possibly be regarded as adequate to enable him to perform that limited role. If, however, Halliburton's role was not so limited, but extended to the provision of expert assistance (including by way of advice) to achieve the objective of a 'fit for purpose' cemented shoe, Mr Doeg's level of training and experience was clearly inadequate.
- 3.68. The oral evidence presented to the Inquiry in the course of its public hearing indicates, surprisingly, that Halliburton's role was in fact quite limited. This is certainly how Mr Doeg saw his role, and senior PTTEPAA executives (being Mr Duncan and Mr Jacob) agreed that PTTEPAA exercised overall control over, and responsibility for, cementing operations. Although PTTEPAA would have appreciated any advisory input from Halliburton in the course of cementing operations, the oral evidence was to the effect that Halliburton was not required or expected to 'value add' by doing more than complying with PTTEPAA's instructions and directions.⁴⁶ This oral evidence was not disputed by PTTEPAA at the public hearing of the Inquiry.
- 3.69. When the effect of this oral evidence was subsequently raised by the Inquiry with PTTEPAA, the company submitted, for the first time, that its contractual arrangements with Halliburton actually extended to the provision of shore-based operational, logistics and technical support, including engineering support to be provided by a Halliburton 'Cementing Technical Professional' (pursuant to page 16 of Service Order 6). PTTEPAA also referred to various clauses in its Masters Services Agreement with Halliburton which required Halliburton to adhere to stipulated standards in the performance of works and services (which,

⁴⁶ T1518 (Duncan) and T1792 (Jacob).

in turn, direct attention to the nature of the contracted works and services). PTTEPAA concluded its written submission as follows:

In summary, PTTEPAA did purchase expertise, skills and advisory services from Halliburton, in addition to machine operating services even though its ability to sue for breach of those service[s] may be contractually limited.

Halliburton failed to provide these services in that it failed to properly advise PTTEPAA of the issues it had identified with the cement shoe other than in the report which is...not sufficient to meet it[s] contractual duties to it.

Halliburton's cementer [Mr Doeg] acknowledged that part of his role involved raising with PTTEPAA circumstances where the cementing operation experienced a problem [T459:18]. He did this with respect to the apparent float failure but then failed to do so with respect to the volume of fluid he pumped back and the potential ramifications of having done so.⁴⁷

- 3.70. Halliburton made the following submissions to the Inquiry in response to the belated position adopted by PTTEPAA.⁴⁸
- a. it was never put to any Halliburton witnesses that any actions of Halliburton, or of its agents or employees, were in breach of any contractual obligation;⁴⁹
 - b. the oral evidence clearly supported a limited role on the part of Halliburton personnel on-rig. Mr Doeg's role was to report the facts, which he did in relation to the apparent float valve failure and the fluid pumped back. It was not his role to provide advice as to ramifications, nor was he asked to do so;
 - c. Service Order 6 refers to services generally in relation to technical issues to do with cement design and cement performance. Those services were properly provided prior to commencement of the cementing operation; and
 - d. insofar as PTTEPAA may have purchased any other expertise, skills and advisory services, they were dependent upon PTTEPAA accessing the services from Halliburton personnel onshore. Such onshore services were available to PTTEPAA, if requested, 24 hours a day. Onshore personnel from Halliburton were not contacted by PTTEPAA in relation to any of the issues which arose in the course of the cementing of the casing shoe on 7 March 2009.

⁴⁷ Response from PTTEPAA to the Inquiry, 18 May 2010, p. 6.

⁴⁸ Letter from Solicitor for Halliburton to Solicitor Assisting the Inquiry, 28 May 2010.

⁴⁹ Indeed, the Inquiry notes that no such submission was advanced until after the Inquiry's public hearing, and only then in response to preliminary findings issued by the Inquiry to PTTEPAA.

- 3.71. The Inquiry does not consider it necessary or appropriate to express a concluded view as to the precise nature of the services stipulated on page 16 of Service Order 6. However, the Inquiry accepts that, insofar as PTTEPAA may have purchased expertise, skills and advisory services (apart from machinist services), use of those services was dependent upon PTTEPAA accessing them from Halliburton personnel onshore in a timely manner. No-one from PTTEPAA sought to do so at any time in relation to the problems which arose in the course of the cementing operation on 7 March 2009. Thus, if PTTEPAA personnel were entitled to access expert advisory services from Halliburton, PTTEPAA was deficient in not ensuring that they did so.
- 3.72. The Inquiry considers that Mr Doeg's role was confined, in effect, to that of a machinist. In this regard, PTTEPAA's submission that Mr Doeg 'acknowledged that part of his role involved raising with PTTEPAA circumstances where the cementing operation experienced a problem' is somewhat incomplete. The actual evidence cited by PTTEPAA in support of this submission is as follows:
- Q. Do you understand that it's part of your role to indicate to the company man circumstances where you think that the cementing job may be defective?
- A. Yes.⁵⁰
- 3.73. Informing PTTEPAA of deficiencies which happen to come to mind is one thing. Being bound to independently assess and advise in an expert way is quite another thing.⁵¹
- 3.74. The Inquiry heard no evidence of any deficiencies on Mr Doeg's part with respect to the limited role played by him. Accordingly, the Inquiry considers that it would not be appropriate to level any criticism at Mr Doeg (or Halliburton), notwithstanding significant gaps in Mr Doeg's overall understanding of the mechanics of cementing a casing shoe.

The Halliburton cementing report

- 3.75. The Inquiry is reinforced in reaching this conclusion by the fact that Halliburton, through Mr Doeg, captured and presented all relevant information about the cementing operation in a post-job cementing report which was given to PTTEPAA's senior on-rig representative, Mr Treasure.⁵² This cementing report

⁵⁰ T459:18 (Doeg); see also PTTEPAA's response to the Inquiry, 18 May 2010, p. 6.

⁵¹ See, in this regard, the evidence at T464 (Doeg), T468 (Geste), T1519 (Duncan).

⁵² See Production Casing 7523 report prepared by David Doeg (Halliburton) for PTTEPAA, 7 March 2009, HAL.9002.0004.0294.

recorded sufficient information to indicate the existence of a major ongoing problem with the cemented shoe. Indeed, relevant information was recorded on the form in each of two places: first, in a 'job log' table; and secondly, in readily comprehensible graphic form.

- 3.76. The information recorded on the form does not have the character of fine print. It is not buried within a large amount of dense data. It appears prominently and in unambiguous terms.
- 3.77. Significantly, neither the job log table nor the graph records any testing of the cemented casing shoe after WOC. It should therefore have been apparent that no such test had been carried out.
- 3.78. Despite the fact that the Halliburton cementing report clearly showed that the casing shoe could not be regarded as having barrier integrity, the report was 'signed off' by Mr Treasure later in the evening on 7 March 2009, with a handwritten annotation 'good job well done'.
- 3.79. The extraordinariness of this state of affairs need not be laboured. It suffices to reproduce the following evidence given by Mr Treasure.

Q. To someone who's familiar with this document, it's not a matter of missing the words. I want to put to you that a person who would ordinarily see this document would know, without a second glance, that this was not a normal situation; correct?

A. Yes, sir.

Q. That there had been a problem experienced; correct?

A. Yes.

Q. And that that problem hadn't been resolved; correct?

A. Yes, sir.

Q. So in this document was all the information, I want to put to you, that anyone in your position needed to realise that a problem had occurred and had not been resolved; correct?

A. Correct.

Q. In the clearest of terms; correct?

A. It was obvious, yes.

Q. Well, it can't be any clearer. What else do you think Mr Doeg should have done to make it clearer to you?

A. There's nothing else he could do, is there?⁵³

⁵³ T497-T498 (Treasure).

Other reports from on-rig personnel to onshore personnel

- 3.80. What is perhaps even more extraordinary is that similar information was included in reports sent by on-rig personnel to their respective onshore supervisors within Atlas and PTTEPAA, without raising alarm bells on the part of anyone. For example:
- a. the most senior Atlas person on the rig, Mr Trueman (OIM), prepared and sent a report to his onshore supervisor, Mr Millar (Atlas' Rig Manager). This report was called a Daily Operations Report (**DOR**), but covered a 30 hour period;
 - b. the most senior PTTEPAA person on the rig, Mr Treasure (who occupied the position of Day Drilling Supervisor), reviewed and sent a report to (i) his onshore supervisor, Mr Wilson (PTTEPAA's Drilling Superintendent); and (ii) Mr Duncan (PTTEPAA's Well Construction Manager). This report was called a DDR; and
 - c. Mr Treasure also prepared and sent to Mr Wilson and Mr Duncan a PTTEPAA cementing report (which is to be distinguished from the Halliburton cementing report).

Mr Millar's evidence concerning the Atlas DOR of 7 March 2009

- 3.81. Mr Millar readily admitted in his oral evidence to not having given sufficient attention to the Atlas DOR of 7 March 2009. Had he done so, he accepted that he would have, or at least should have, discovered the existence of a wet shoe in the 9½" casing.
- 3.82. The Inquiry was impressed with the candour and forthrightness with which Mr Millar gave his evidence. He did not seek to diminish his level of responsibility in any way. He accepted he should have paid closer attention when reviewing documents relating to the cementing operation. The Inquiry notes that PTTEPAA's Mr Wilson admitted that if there was a problem identified with the operation, Mr Millar would, quite reasonably, have expected to receive a telephone call from Mr Wilson.⁵⁴ There was no such telephone call.

Mr Treasure's evidence concerning pumping back after float valve failure

- 3.83. Mr Treasure's general account of the actual cementing operations on 7 March 2009 accords generally with that of Mr Doeg. Mr Treasure's account is

⁵⁴ T1166 (Wilson).

also consistent with the broad thrust of information contained in various contemporaneous records relating to the cementing of the casing shoe.

- 3.84. However, Mr Treasure's account with respect to two inter-related issues has changed significantly over time: first, as to the content of his telephone conversations with Mr Wilson during the course of the cementing operation; and secondly, as to why he (Mr Treasure) instructed Mr Doeg to pump the whole of the 16.5 barrels back beneath the float collar.
- 3.85. When Mr Treasure was interviewed by NOPSA on 15 October 2009 he told NOPSA that after the return of 16.5 barrels, the system was closed in. He told NOPSA that he then phoned Mr Wilson, following which 'we pumped it up again within half a barrel of what we received back'. The clear implication was that this procedure was directed, or at least authorised, by Mr Wilson. Mr Treasure also told NOPSA that:
- ...we didn't pump anymore because...we didn't want to have the cement go outside the shoe. We didn't want to have a wet shoe, as they call it.
- 3.86. It is quite apparent from this statement to NOPSA that Mr Treasure had no understanding (both on 7 March 2009 and when interviewed by NOPSA) that the action he took actually resulted in, rather than avoided, a wet shoe.
- 3.87. NOPSA subsequently prepared a draft statement for Mr Treasure to sign. Mr Treasure provided his NOPSA interview and the draft NOPSA statement to Mr Duncan who specifically drew to Mr Treasure's attention the fact that his (Mr Treasure's) version of his telephone conversation with Mr Wilson differed from Mr Wilson's. On 10 March 2010 Mr Treasure signed a NOPSA statement which records the following:

32. The Halliburton cementer closed the bleed-off valve and the pressure built up again.

33. A short while later I telephoned Mr Wilson in Perth and told him that I thought the float had failed. He said something like, pump it back and hold it until the cement sample gets hard. I said that I suspected that the float had failed and did he want us to continue on with the program to install surface cement plugs. He said something like, do your flow checks after the cement samples have set and then install the cap... He didn't tell me to pressure test the 9 5/8 inch casing again.

34. After my telephone call to Mr Wilson I telephoned the Halliburton cementer, Mr Dave Doeg and told him to pump back what had been received less half a barrel...

...

37. I recall that the H1 ST1 Well 95/8 inch casing was not pressure tested again after the cement had set because I wasn't instructed to do so. I did

think about it but didn't suggest it to Mr Wilson or Mr Wishart because I believed there was a risk of creating a micro annulus outside the 9 5/8 inch casing, while the cement was going off.⁵⁵

3.88. On 10 March 2010 Mr Treasure caused his solicitor to send to the Inquiry a draft witness statement. That statement included the following assertions as to his dealings with Mr Wilson during the course of the cementing operation:

14. At that time I was talking to Chris Wilson on the telephone on the rig. Chris Wilson was located somewhere in Perth, but not in the office because it was a weekend. I was calling to tell him that the cementing operation was successful and that we had held the cement at 4000 psi for 10 minutes. It was important for him to know about that because this was a big cementing operation and everyone was at that point relieved that it had occurred successfully. However, while I was talking to him I was informed that the pressure had come back. I said to Chris something like "We just bled it off and the pressure has come back. What do you think we should do?" He said something like "Pump it back again and hold it at whatever pressure it stops at". What he meant by that was to pump back the quantity of the inhibited seawater which had been displaced when pressure had returned...So when Chris said something like "Pump it back again and hold it at whatever pressure it stops at" I understood him to mean to pump back what had come out within half a barrel and hold it at whatever pressure is showing when that amount is pumped back in. So that's what we did...

...

27. ...I say that I did not realise that pumping back 16.5 barrels of displaced fluid might leave a wet shoe. I just did not think of it. I was just equalling what came out - same out as in, and its [sic] what Chris Wilson told me to do.

28. ...I do not agree that the cement job had to be verified by CBL⁵⁶ or an annulus pressure test as this was not necessary. It would have been necessary to wait on cement for 24 hours before we could pressure test to 4000 psi again, and that just was not possible with the program that we had.

...

32. I agree...about over displacement leaving a wet shoe, but I say that Chris Wilson told me to pump back what had come out and hold it, and he got it wrong also, along with the Halliburton team...⁵⁷

3.89. According to this version, Mr Treasure was instructed by Mr Wilson to take action which inevitably resulted in a wet shoe.

⁵⁵ Statement of Mr Noel Treasure to NOPSA, 10 March 2010, pp. 8-9.

⁵⁶ CBL refers to a Cement Bond Logging test.

⁵⁷ Draft Witness Statement of Mr Noel Treasure, 10 March 2010, pp. 6-7, 13-14.

3.90. After Mr Treasure provided a copy of his draft Inquiry statement to Mr Duncan, the latter told Mr Treasure that he did not think it was factually accurate and that Mr Treasure could expect a very hard time in the witness box when he gave evidence. Indeed, Mr Duncan warned Mr Treasure that he could expect to be 'torn to pieces'.⁵⁸

3.91. On 15 March 2010, the very day that the public hearing of the Inquiry commenced, Mr Treasure signed a Statutory Declaration in final form which contained a significantly different version of his dealings with Mr Wilson on 7 March 2009. In that Statutory Declaration Mr Treasure stated:

19. Once we had reached 4000psi and I saw there were no leaks I left the rig floor, went up to the office and rang Mr Wilson in Perth to advise him the cement was in place and we were having a good pressure test.

20. A short while later someone called to tell me that as they were bleeding off the pressure the non-return valve in the float collar had 'let go', and there had been an unexpected flow back into the 9½" casing in the H1 Well. Dave Doeg had closed off the bleed-off valve and I was told the pressure built up again - which indicated to me cement had flowed back into the 9½" casing and confirming in my mind the valve had failed. This sometimes happens but it is not a common occurrence.

21. Somebody told me what the flow back was (as I recall about 16 bbls) and I said...something like 'pump back what was returned within half a barrel and hold it'. We then waited on cement. During that period I rang Mr Wilson back and informed him what had happened. I don't recall what he said but I believe he agreed that we should wait on cement.

22. At the time I...thought that by pumping back what had been displaced we would return to where we were before we bled off the pressure, and that upon setting, the shoe would provide an effective barrier...⁵⁹

3.92. In his oral evidence to the Inquiry, Mr Treasure confirmed that when he first learned of the float valve failure:

I thought we needed to pump it back...So I figured we needed to pump it back out – what we received in, we needed to pump back out again.⁶⁰

3.93. Mr Treasure also told the Inquiry that, to the best of his recollection, he rang Mr Wilson *after* he (Mr Treasure) gave the instruction to Mr Doeg to pump back the 16.5 barrels.⁶¹

⁵⁸ T1258 (Duncan).

⁵⁹ Statutory Declaration of Mr Noel Treasure, 15 March 2010, p. 3.

⁶⁰ T268 (Treasure).

⁶¹ T270 (Treasure).

3.94. Mr Treasure was an unsatisfactory witness. He confused reconstruction with recollection, and he tended to give his evidence with an eye keenly attuned to his own interests and the interests (as he saw them) of PTTEPAA. He admitted to the Inquiry that he had changed his 'story' many times and said that 'I was so mixed up with my story...I didn't know whether I was coming or going'.⁶² He also admitted to having constructed earlier accounts of his conversations with Mr Wilson even though he knew he had no recollection of those conversations.⁶³ At times, he revealed himself to be positively evasive.⁶⁴

Mr Wilson's evidence concerning his telephone conversations with Mr Treasure on 7 March 2009

3.95. Mr Wilson's account to this Inquiry was to the effect that he gave no instruction to Mr Treasure to pump back any volume of returned fluid. Mr Wilson stated in his Statutory Declaration as follows:

175. On 7 March 2009 [a Saturday] I was not near my computer most of the day so most of the communication with the rig was via telephone. At approximately 1330hrs I had one or two telephone conversations with Mr Treasure on the *West Atlas*, the substance of which was as follows:

(a) Mr Teasure [sic] informed me that:

(i) the cement job was complete and they had pressure tested the casing;
(ii) once the casing pressure test was complete they had bled-off the pressure and when they had nearly bled-off all the pressure they got a rush of fluid and shut the well in at the cement unit and it appeared that the float had failed.

(b) I asked Mr Treasure to apply or hold some pressure and wait on the cement to set.

...

180. I do not recall Mr Treasure telling me or me asking him how many barrels of fluid had been initially bled off or how many barrels he pumped back...⁶⁵

3.96. The concluding words in the above excerpt convey the suggestion that there may have been some discussion between Mr Wilson and Mr Treasure about barrels of fluid being pumped back. However, in his oral evidence Mr Wilson

⁶² T544 (Treasure).

⁶³ T545 (Treasure) and T549 (Treasure).

⁶⁴ See, for example, T577-578 (Treasure) and T579-584 (Treasure). At T577-578, Mr Treasure was questioned about earlier evidence he had given to the effect that he went off duty before expiry of WOC on 7 March 2009. When taken to a document signed by him on 7 March 2009 which showed otherwise, Mr Treasure initially sought to raise an issue about what was recorded in that document. Only when pressed did he accept the necessary effect of the document. At T579-584 Mr Treasure was questioned about earlier evidence he gave disputing the effect of a contemporaneous document. His answers were quite unsatisfactory.

⁶⁵ Statutory Declaration of Mr Chris Wilson, 9 March 2010, pp. 36-37.

said that he did not discuss with Mr Treasure pumping back any barrels of fluid. Rather, he told the Inquiry that he merely instructed Mr Treasure to 'pump it up a little bit',⁶⁶ by which he meant increasing and holding pressure to ensure no further returns. This particular evidence is problematic: first, it is not clear why Mr Wilson would have given such an instruction; secondly, had he given such an instruction it would almost certainly have been implemented by Mr Treasure, and there is no objective evidence of any increase in pumping pressure (the objective evidence is to contrary effect); and thirdly, it is not consistent with the following statements in PTTEPAA's submission to the Inquiry in December 2009:

108. Eight barrels of Mud were pumped into the [9 $\frac{5}{8}$ "'] casing to create the...4000psi required to pressure test the H1 Well, but sixteen and a half barrels were bled off. The excessive bleed off, which suggested that there may have been a back flow of hydrocarbons was discussed by the Drilling Superintendent [Mr Wilson] and the Drilling Supervisor [Mr Treasure] and the decision was made...to hold pressure on the casing after the cement job. To do this the fluid was re-inserted into the well to create more pressure in the well than the Pore Pressure and force the cement back through the float shoe.⁶⁷

- 3.97. What is significant, for present purposes, is that this statement closely matches the account given by Mr Treasure in his NOPSA statement and in his draft statement to this Inquiry (that is, Mr Wilson instructed Mr Treasure to pump back 16.5 barrels). Neither Mr Wilson nor Mr Duncan could adequately explain the inclusion of paragraph 108 (above) in PTTEPAA's submission to the Inquiry.

Did Mr Wilson give an instruction to pump back?

- 3.98. On the basis of telephone records produced to the Inquiry under summons, the Inquiry finds that Mr Treasure decided to pump back the whole of the 16.5 barrels without any input from Mr Wilson. When allowance is made for time differences between Darwin rig-time (CST) and Perth-time (WST), the telephone records show the first telephone call from the rig to Mr Wilson's mobile phone occurred at 3.01pm (CST) on 7 March 2009. Significantly, this call occurred *after* the 16.5 barrels of fluid were pumped back beneath the float collar.⁶⁸ In this regard the Inquiry notes as follows:

⁶⁶ T971 (Wilson).

⁶⁷ PTTEPAA, Submission to the Inquiry, Term of Reference 1, p. 45.

⁶⁸ See the graph depicted in the Production Casing 7523 report prepared by David Doeg (Halliburton) for PTTEPAA, HAL.9002.0004.0297. Times shown on this graph were automatically generated by the Halliburton cementing unit. The graph shows that the 16.5 barrels were pumped back between 14.47 and 14.59.

- a. in submissions to the Inquiry, Mr Treasure initially disputed the Inquiry's reliance on the Telstra records on the bases that (i) the allowance for time differences had been calculated wrongly; (ii) there was uncertainty as to the provenance of the phone number (08) 6311 2400, since all rig phones used the prefix (08) 6263; (iii) there was uncertainty as to the times recorded in the Halliburton cementing report, both as to their accuracy and whether times shown were Darwin time (CST) or Perth time (WST); and (iv) the Inquiry's analysis of the Telstra records made no sense when compared to the objective sequence of events;
- b. the Inquiry is satisfied that its analysis of the Telstra records is correct, namely (i) time differences have been correctly allowed for as confirmed by Telstra and PTTEPAA; (ii) the number (08) 6311 2400 was a centralised local Perth number used by PTTEPAA through which calls to and from the rig were diverted (as indicated by Mr Wilson and PTTEPAA); (iii) there is no reason to doubt the accuracy of the times shown in the Halliburton cementing report, nor the fact that those times were calibrated by reference to Darwin/rig time (CST) (as confirmed by Halliburton); and (iv) the Inquiry's analysis makes sense in the light of Mr Wilson's evidence that the pumping back of returned fluid occurred *before* Mr Wilson was informed of the float valve failure; and
- c. the Inquiry's analysis actually supports the version of events given by Mr Treasure in his final Statutory Declaration. Although the Inquiry's analysis is inconsistent with earlier versions given by him, Mr Treasure himself accepted in his final evidence that those earlier versions were false.

3.99. The Inquiry therefore considers that Mr Treasure's earlier accounts to the effect that he was instructed by Mr Wilson to pump back 16.5 barrels are false. These earlier accounts were given in (i) his NOPSAs interview, (ii) his NOPSAs statement, and (iii) his draft statement to the Inquiry. The falsity of those accounts is likely to have been influenced by a desire on Mr Treasure's part to spread responsibility for the wet shoe. The Inquiry is not able to conclusively determine whether that desire operated at a conscious or subconscious level. However, the Inquiry is strongly inclined to the view that Mr Treasure gave a deliberately false and misleading account of the nature and extent of his discussions with Mr Duncan in the lead-up to the public hearing of the Inquiry.⁶⁹

⁶⁹ Mr Treasure told the Inquiry that he discussed his proposed evidence with Mr Duncan on one occasion only, namely on 11 March 2010, which was after he prepared his draft Statutory Declaration. The terms of that telephone conversation are summarised in paragraph 3.90 above. However, in the light of various objective records and Mr Treasure's demeanor when giving evidence, the Inquiry has great difficulty accepting that (i) after Mr Treasure prepared his final Statutory Declaration, its contents were

What was Mr Wilson told on 7 March 2009?

- 3.100. The Inquiry considers it inherently unlikely that no mention was ever made of the volumes of fluid returned and pumped back in the telephone calls between Mr Treasure and Mr Wilson on 7 March 2009. In this regard, the Inquiry finds the following evidence persuasive:

THE COMMISSIONER:...

Q. Mr Treasure, when you said in your statement that you told Mr Wilson what happened, why wouldn't I be entitled to read into those terms what would be the ordinary explanation that you told him what had actually happened?

A. Well, Commissioner, I really can't remember what it was that I told him. It was a year ago. I've had a lot of conversations --

Q. I understand that you can't recall. You've been very clear on it. But you've also been clear in saying that you told him "what happened". Now, you mightn't recall, but the whole context, surely, of the conversation must have been about what happened, so what might that have been? Did you talk about the football?

A. No.

Q. Well, what --

A. I suppose that I would have told him about what happened.

THE COMMISSIONER: Precisely. Thank you.

MR HOWE: Q. So you accept that the likelihood is that you told him what you had understood had occurred with respect to the apparent failure of the float valves?

A. Yes, that's correct.

...

Q. You have told us that Mr Wilson had a role to supervise and manage what happened on the rig by reference to his dealings with you; that's right, isn't it?

A. That's correct.

Q. And you've told us that this was a significant cementing operation that Mr Wilson was aware of in advance; that's correct, isn't it?

A. That's correct, yes.

Q. And after the initial good test result, a significant event occurred in terms of the apparent failure of the float valves and a return of cement?

A. That's correct.

Q. Whatever other understanding you had, you understood that that was a significant event; that's right, isn't it?

A. That's correct.

never discussed at all in the many telephone calls which took place between Mr Duncan and Mr Treasure; and (ii) Mr Treasure had simply forgotten that other discussions had taken place (see summonsed Telstra records INQ.0004.0001.0015 and emails passing between Mr Treasure and Mr Duncan on 15 March 2009 (INQ.0005.0001.0001 – INQ.0005.0001.0026).

Q. And you were having a discussion with Mr Wilson, who was your supervisor and manager onshore at the time, about that event; that's right, isn't it?

A. That's correct.

Q. And it's likely, isn't it, that he was keenly interested in what had happened?

A. Yes, that's correct. He's always keen.

Q. Yes, and I suggest, therefore, that it's more likely than not that you and Mr Wilson had a conversation in which you conveyed to him what had happened in relation to the failure of the float valves and the pump-back of cement, because you wanted to keep him informed, and he wanted to be kept informed. Now, does that sound more likely than not?

A. That sounds more likely than not, yes.⁷⁰

3.101. Unfortunately, Mr Wilson failed to keep any record of any of these important telephone conversations with Mr Treasure on 7 March 2009. He routinely kept such records in a diary. The Inquiry cited diary entries for 6 and 8 March 2009, which dealt with matters of far less significance than the problems with cementing operations on 7 March. Mr Wilson could not explain the absence of any diary entries for 7 March 2009.

3.102. Having regard to the matters canvassed in the above passages from Mr Treasure's evidence, the Inquiry is satisfied that some discussion is likely to have taken place between Mr Treasure and Mr Wilson concerning volumes of fluid returned and pumped back.⁷¹

3.103. However, the Inquiry is also satisfied that Mr Treasure is unlikely to have conveyed to Mr Wilson a clear picture of exactly what had occurred. Mr Treasure was, at the time, labouring under a very flawed understanding of what had occurred. In his own mind he did not discriminate between the volume of returns at the top of the casing string (16.5 barrels) and the volume of returns from beneath the float collar (7.25 barrels).⁷² The Inquiry is satisfied,

⁷⁰ T282-284 (Treasure).

⁷¹ PTTEPAA submitted to the Inquiry that this finding ought not be made because it depended upon acceptance of Mr Treasure's evidence (whom the Inquiry regarded as an unsatisfactory witness). The evidence given by Mr Treasure on this aspect of the matter was really directed to what was objectively likely, having regard to the known circumstances then prevailing. It was not evidence based on Mr Treasure's recollection. The Inquiry considers that, given the objective circumstances described by Mr Treasure, it is likely that some discussion took place between Mr Treasure and Mr Wilson concerning volumes of fluid returned and pumped back.

⁷² T280 (Treasure). Such was the extent of Mr Treasure's incomprehension that (i) his consideration of the Halliburton cementing report on 7 March 2009; and (ii) his preparation of a PTTEPAA cementing report (mis-dated 6 March 2009), wholly failed to shed any additional light, in his mind, as to what had occurred.

therefore, that Mr Treasure did not properly convey to Mr Wilson what had occurred in the course of the cementing of the casing shoe.

- 3.104. However, the Inquiry is also satisfied that Mr Wilson did not take sufficient steps to gain a proper understanding of what had occurred when he spoke to Mr Treasure on numerous occasions on 7 March 2009. Mr Wilson was initially inclined to be somewhat defensive in relation to his dealings with Mr Treasure, but he eventually conceded that he should have elicited more information from Mr Treasure when they spoke on 7 March 2009. The summonsed telephone records indicate that discussions took place between Mr Wilson and Mr Treasure at 3.01pm, 3.11pm, 5.17pm, 5.27pm, 6.23pm and 6.54pm (CST).
- 3.105. The Inquiry is satisfied, therefore, that both Mr Treasure and Mr Wilson should have communicated with each other more effectively when they discussed the float valve failure on 7 March 2009. In reaching this conclusion the Inquiry recognises that some allowance must be made for the pressure under which Mr Treasure and Mr Wilson were operating in the immediate aftermath of the float valve failure on 7 March 2009.⁷³ However, it should have been clear to Mr Treasure and Mr Wilson that the event was untoward, that it demanded careful evaluation, and that remedial action was likely to be required.
- 3.106. Moreover, poor communication simply cannot explain their failure to properly consider various contemporaneous documents which they later reviewed, and which should have alerted them to the existence of a wet shoe. Had they read these documents with sufficient care they should have realized that the cemented casing shoe ought not be relied upon as a barrier.

Documents reviews undertaken by PTTEPAA personnel

- 3.107. As noted above, the Halliburton cementing report of 7 March 2009 was seen, endorsed, and signed by Mr Treasure that same day. This report was not seen by onshore PTTEPAA personnel until sometime after the Blowout. However, two other contemporaneous records were created, each of which should have led Mr Treasure and onshore personnel (being Mr Wilson and Mr Duncan) to understand that the cemented casing shoe had been left in a dangerous state as at 7 March 2009.

⁷³ The Inquiry heard evidence that the cement would have become very difficult to move within 30 minutes of float valve failure. However, this 30 minute period did not comprise the time limit for taking remedial action. That is, remedial action could have been taken after hardening of the cement.

3.108. The two reports were a DDR and a PTTEPAA cementing report.

The PTTEPAA DDR of 7 March 2009

3.109. A draft DDR was prepared by Mr Wishart (PTTEPAA's Night Drilling Supervisor) in the course of his shift from 6.00pm 7 March to 6.00am 8 March 2009. The draft DDR was based upon handwritten entries made on another contemporaneous document called an 'IADC report'.⁷⁴ The draft DDR which Mr Wishart prepared contained the following information:

1400 - 1500: switched back to Halliburton and pressure tested casing to [4,000psi] x 10 mins - ok. Bled off test pressure to [200psi] and observed pressure rapidly increase to [1200psi]. Note: Pumped [9.25bbls] and bled off [16.5bbls], suspected float valve failure. Pumped [16bbls] back into casing at [1350psi].⁷⁵

1500 - 1800: Waited on cement...

1800 - 1830: Open casing annulus to atmosphere and confirm no back flow...⁷⁶

3.110. Pausing here, it can be seen that this information, properly analysed, indicates that cement would have been over-displaced within and around the casing shoe. Mr Wishart did not appreciate the significance of this information at the time he prepared the draft DDR.

3.111. The IADC report to which Mr Wishart had regard did contain an entry 'Retest float good' between 1800 - 1830 hrs.⁷⁷ Mr Wishart understood that entry to be 'a reference to the opening of the cement head valve to confirm no backflow from the casing which indicated that the cement had set'.⁷⁸ Although Mr Wishart wrongly considered at the time that this procedure somehow confirmed that the cement had integrity,⁷⁹ he at least knew that the entry was incorrect to the extent that the procedure did not actually constitute a test of the floats.⁸⁰

⁷⁴ An IADC report is used as the basis for payments against the contract, so it is signed by the senior representatives of both PTTEPAA and Atlas.

⁷⁵ The information contained within square brackets consists of the equivalent imperial measures to those metric measures which actually appeared in Mr Wishart's draft report. Personnel involved in the offshore petroleum industry use both metric and imperial measures more or less interchangeably. This does not appear to have been the source of any confusion whatsoever on the part of any personnel involved in the cementing operation on 7 March 2009.

⁷⁶ PTTEPAA Daily Drilling Report, 7 March 2009, p. 2.

⁷⁷ IADC Report 7 March 2009.

⁷⁸ Statutory Declaration of Mr Lindsay Wishart, 10 March 2010, paragraph 177.

⁷⁹ T659 (Wishart).

⁸⁰ T700 (Wishart).

3.112. Mr Wishart also prepared a draft email update for Mr Treasure's consideration. The system in place at the time was that if the draft email update was approved by Mr Treasure, it would then be sent by Mr Treasure to Mr Wilson enclosing the final rig version of the DDR.⁸¹ In the draft email update Mr Wishart included three lines that read:

Tested casing to [4,000psi] - okay; bled off and encountered float failure.
WOC 3 hrs...
checked cement integrity - okay...

3.113. Mr Wishart gave evidence that the reference to 'checked cement integrity' was again a reference to 'the opening of the cement head valve to confirm no backflow from the casing which indicated that the cement had set'.⁸²

3.114. It is clear that Mr Wishart misunderstood the information recorded in the IADC report. The mere fact that, after a WOC period, no unwarranted backflow occurred, did not in reality confirm either of the following:

- a. that the float valves had regained integrity, or
- b. that the cement had integrity.

3.115. Accordingly, there was simply no proper basis for Mr Wishart to conclude, as he did, that 'despite the in service failure of the valve, the cementing of the 9 $\frac{5}{8}$ " shoe casing had been correctly completed'.⁸³

Mr Treasure's consideration of the DDR

3.116. Mr Wishart's errors in comprehension should have been detected by Mr Treasure, but they were not. He simply sent the email update and draft DDR as prepared by Mr Wishart to Mr Wilson and Mr Duncan, the two most senior personnel within PTTEPAA's Well Construction Department. The Inquiry is satisfied that Mr Treasure failed to properly comprehend the significance of the information before him. For instance, he told the Inquiry that he thought, at the time, that the whole of the 16.5 barrels consisted of cement from beneath the float collar, and he wrongly considered that an inflow test had been carried out after WOC (as to which, see below).

⁸¹ The rig version of the DDR might be changed by Mr Wilson before forwarding to the NT DoR.

⁸² Statutory Declaration of Mr Lindsay Wishart, 10 March 2010, paragraph 176.

⁸³ Ibid, paragraph 178.

Mr Wilson's consideration of the DDR

- 3.117. Mr Wilson should have given the DDR close attention, for the following reasons:
- a. the failure of float valves was a significant event, particularly in the context of cementing a casing shoe at considerable depth whilst the casing string was located in a horizontal position within the reservoir – an event which Mr Wilson had never encountered before;
 - b. it was part of Mr Wilson's job to check DDRs sent by the rig before forwarding them to the NT DoR as regulator; and
 - c. Mr Wilson also had responsibility for preparing and distributing (to a wide audience)⁸⁴ a morning update email summarising operations at the WHP and rig on 7 March 2009.
- 3.118. When Mr Wilson prepared his morning update email of 8 March 2009 he did not simply 'cut and paste' from Mr Treasure's email update. Rather, Mr Wilson described various activities in his own words, in terms which suggest he gave real attention to the information sent to him by Mr Treasure. Indeed, in Mr Wilson's morning update email he stated:
- When bleeding off the pressure after testing the casing the float appeared to let go. Held pressure on the casing and waited on cement...Checked floats on casing - ok.⁸⁵
- 3.119. Thus, whereas Mr Treasure had referred to 'checked cement integrity - okay', this was changed to 'checked floats on casing - okay'. Mr Wilson stated that the reason for this change was that he knew that the procedure which had been carried out did not involve any actual check on the integrity of the cement. Mr Wilson was clearly correct in that regard.
- 3.120. However, Mr Wilson thought that the absence of any further unwarranted return after pressure was bled off (following WOC) amounted to an inflow test of the floats.⁸⁶ Mr Wilson was wrong in that regard.⁸⁷ As Mr Duncan explained in his Statutory Declaration:

334. ...inflow test requires a differential pressure from the well bore to the casing. This condition only exists whilst the cement slurry is liquid and

⁸⁴ The audience included Mr Millar from Atlas, the NT DoR as regulator, and the CEO of PTTEPAA.

⁸⁵ Email with subject Montara Platform Wells Morning Update, 8 March 2010, PTT.9006.0001.0003.

⁸⁶ Early in his oral evidence Mr Wilson even asserted that the WOC procedure involved a form of pressure test (see T954).

⁸⁷ It is noteworthy that, in addition to Mr Wilson, Mr Wishart, Mr Treasure, and Mr O'Shea all had a flawed understanding of an inflow test.

therefore providing hydrostatic pressure. If the cement is set it generates no hydrostatic pressure and the inflow pressure is reduced to reservoir pressure. As the pressure due to the cement displacement fluid exceeded the reservoir pressure there was no differential pressure to generate any flow from the well.

335. As the floats had broken in service it did not test the floats at all.

336. ...The test that was performed...demonstrated no flow. It did not test the floats at all.⁸⁸

3.121. Thus, the absence of any flow following the so-called 'inflow test' simply showed the absence of further flow, and nothing else.⁸⁹ Mr Wilson's failure to appreciate this, and his failure to understand that the cementing operation had resulted in a wet shoe, suggests either or both of the following shortfalls in competency:

a. serious inattention; or

b. significant gaps in his level of knowledge and expertise.

3.122. Mr Wilson was reluctant to admit to any gaps in his level of knowledge and expertise. He gave the following explanation in his Statutory Declaration dated 9 March 2010:

185. Given my discussions with Mr Treasure on 7 March 2009 there was no need for me to and I did not scrutinise the volumes and pressures relevant to the cementing process recorded in the DDR. I reviewed the DDR to see if there was any obvious errors or issues. There were none.

...

194. Putting together the comments made in the DDR and Advantage Mud report [which referred to 'wait on cement retested float'] and telephone conversations with Mr Treasure, I concluded that the cementing had been completed properly and the well integrity was not a concern.⁹⁰

3.123. The Inquiry has little hesitation in rejecting the statements contained in paragraph 185 of Mr Wilson's Statutory Declaration. Mr Wilson's role was not simply to check the DDR for 'obvious errors or issues'. His job involved day-to-day supervision of rig activities to ensure safety of operations.

⁸⁸ Statutory Declaration of Mr Craig Duncan, 8 March 2010, p. 59.

⁸⁹ Mr Gouldin agreed with this proposition at T79-T80; T83, T88. So too did Mr Duncan at T1454. Eventually, Mr Wilson also accepted that (i) the bleeding off of pressure after WOC did not really establish that the floats were okay, and (ii) his reference to 'Check floats on casing - okay' involved a poor choice of words which may have misinformed readers of his morning update (T1184-T1185).

⁹⁰ Statutory Declaration of Mr Chris Wilson, 9 March 2010, pp. 38-39.

3.124. In any event, the over-displacement of the casing shoe cement should have been obvious to Mr Wilson. Indeed, on Mr Wilson's version of events – that is, there was no reference by Mr Treasure to pumping back, let alone any discussion of volumes pumped back – a cursory examination of the DDR should, at the least, have alerted him to the need to make further inquiries of Mr Treasure. In his oral evidence to the Inquiry Mr Wilson eventually conceded as much.⁹¹

Mr Wilson's consideration of the PTTEPAA cementing report sent by Mr Treasure

3.125. In Mr Wilson's Statutory Declaration he went on to acknowledge that on 11 March 2009 he received from Mr Treasure a completed cementing report dated 6 March 2009, but updated following completion of the cementing operation on 7 March 2009. The cementing report is a document specifically required by PTTEPAA's Well Construction Standards. Its very existence as a required form of reporting reflects the importance which attaches to a proper consideration of cementing operations.

3.126. In his Statutory Declaration Mr Wilson stated as follows in relation to this cementing report:

195. ...I looked very briefly at the report but did not scrutinised [sic] the figures. There was no need for me to scrutinise the figures, given the events of 7 March 2009 as I have described above. The report contains a pumping schedule. This schedule records fluid type, volume, pressure and comments on the cementing program. This schedule recorded that 16.5 bbls of fluid had been pumped back into the 9 5/8 inch casing after the float failed and that the final pressure prior to stopping pumping was 1350psi.⁹²

3.127. This is a selective summary of the material contained in the PTTEPAA cementing report. That report contains the following additional information not mentioned by Mr Wilson:

- a. 9.25 barrels of seawater were introduced into the casing string in order to pressure test the casing string at 4,000psi for 10 minutes; and
- b. after the WOC period the pressure had reduced from 1,350psi down to 687psi.

⁹¹ T972 (Wilson).

⁹² Statutory Declaration of Mr Chris Wilson, 9 March 2010, pp. 39.

3.128. Despite this information in the PTTEPAA cementing report, Mr Wilson went on to state as follows in his Statutory Declaration:

252. I was not made aware on 7 or 8 March 2009 and all relevant times after that, of:

(a) the pressure bleeding off whilst waiting on cement; and

(b) anything that indicated the possibility of fluid bypassing the top or bottom plugs.

253. If I had been aware of the above information, I would have requested that another pressure test of the casing be performed...

254. The absence of another pressure test meant that, with hindsight and knowing what I now know, the integrity of the H1 Well was not verified.

255. Although there was appropriate communications [sic] between Mr Treasure and me on 7 March 20079, **there was information that I consider, with the benefit of hindsight, could have been given to me so that I would be better able to make decisions about what needed to be done in the face of the apparent failure of the float valve. In hindsight, the additional information required was about the quantity of fluids that were pumped back into the casing and the variation in the pressures whilst waiting on cement to set.** [emphasis added]⁹³

3.129. The highlighted parts in the above excerpt are quite surprising. This is because all of the information which Mr Wilson specifically denied having received was in fact set out, with unmistakable clarity, in the DDR and the PTTEPAA cementing report.⁹⁴ In the course of his oral evidence Mr Wilson eventually admitted as much.⁹⁵

3.130. As Mr Jacob (PTTEPAA's Chief Operating Officer) subsequently noted in his evidence, it would only take 5-10 minutes consideration of the DDR and cementing report to understand that the cemented casing shoe lacked integrity and ought not be relied upon as a primary barrier against a blowout. It is apparent that Mr Wilson did not discern this at the time. Even after reflecting on the content of the DDR and cementing report in the course of preparing his Statutory Declaration, Mr Wilson was still unable to properly comprehend their content and import.

⁹³ Ibid, p. 53.

⁹⁴ The Inquiry notes that information about pressure bleeding off whilst waiting on cement did not appear in the DDR. However, there was sufficient information in the DDR to indicate over-displacement of cement within and around the casing shoe, which could only have occurred because the top and bottom plugs above the float collar had not sealed.

⁹⁵ The Inquiry considers that these paragraphs of Mr Wilson's Statutory Declaration are only accurate to the extent they refer to the information supplied *orally* by Mr Treasure on 7 March 2009.

3.131. Before leaving Mr Wilson's role in the cementing operation it should be noted that he gave evidence to the Inquiry to the effect that he positively considered whether the casing shoe should be subjected to a conventional post-WOC pressure test, but decided such a test was unnecessary.⁹⁶ That was a serious error on the part of Mr Wilson. A pressure test would only have taken about 20 minutes to perform.⁹⁷ Had a pressure test been carried out the Blowout would likely have been prevented.

Mr Duncan's consideration of the DDR and PTTEPAA cementing report

3.132. Unfortunately, the approach which was taken by Mr Duncan, PTTEPAA's Well Construction Manager (who supervised the work of Mr Wilson), was similar to that of Mr Wilson.

3.133. Mr Duncan received and read the DDR and PTTEPAA cementing report in March 2009 and again in the course of preparing his Statutory Declaration. The burden of his evidence-in-chief was to the effect that PTTEPAA personnel onshore had no reason to suspect that the cemented casing shoe was an inadequate barrier. When questioned by Counsel Assisting, Mr Duncan was initially reluctant to admit that he and Mr Wilson had all the information they needed to ascertain that the cemented casing shoe was a seriously defective barrier. He eventually made full admissions to this effect.

3.134. By way of contrast, after Mr Jacob heard the evidence canvassed at the Inquiry's public hearing he freely admitted that in March 2009 Mr Wilson and Mr Duncan did have all the information they needed to discern an ongoing problem with the cemented casing shoe.

Further examination of the role of Atlas personnel in connection with the cementing of the casing shoe

3.135. The Inquiry received evidence from a number of witnesses to the effect that Atlas' direct involvement in the cementing of the casing shoe on 7 March 2009 was very limited.

⁹⁶ T954 and T152-153 (Wilson).

⁹⁷ T1055 (Wilson).

3.136. For instance Mr O'Shea (PTTEPAA's Day Drilling Supervisor on the rig) told the Inquiry that:

Generally, you would never see an Atlas representative on the cementing unit.⁹⁸

3.137. Mr Jacob agreed with this evidence.⁹⁹ He stated that Atlas personnel would not get involved in the actual pumping or displacement of cement in the course of a cementing operation.¹⁰⁰

3.138. In Mr Gouldin's Statutory Declaration he dealt with the topic of Atlas' involvement in cementing operations as follows:

15. The design and calculations for the cementing of the casing shoe on a well are undertaken by the client operator [in this case PTTEPAA] in conjunction with its specialist cementing contractor, in this case Halliburton.

16. Facilitating the cementing activities requires [Atlas'] personnel to run the 9 5/8" casing into the well bore, following which they would set up the rig's circulation system at the top of the casing, circulating the drilling fluid to keep the casing clean and clear. Once that has been completed, the next action would be to set up the cementing contractor's circulation system.

17. From this point onwards, [Atlas] would not have any significant involvement in the cementing process...The actions taken by the cementing contractor are recorded in the rig's daily operations report for information, but [Atlas] does not record any of the detailed technical specifications.

18. Where, as happened on this occasion, there was an apparent failure of the non-return valves, the drilling supervisor [from PTTEPAA] and the cementing contractor on the rig would implement the contingency plan in the drilling program or, where there was no such contingency plan, consult with one another to decide on the action that should be taken.

19. [Atlas' OIM] would ordinarily be informed of the decision made by the drilling supervisor and the cementing contractor.¹⁰¹

3.139. The Inquiry accepts all of the above evidence as to the limited role performed by Atlas personnel, particularly the OIM, in relation to the cementing operation. It is clear that, under the formal and documented arrangements in place between PTTEPAA and Atlas, the latter was not expected to supervise

⁹⁸ T786 (O'Shea).

⁹⁹ T1793 (Jacob).

¹⁰⁰ T1794 (Jacob).

¹⁰¹ Statutory Declaration of Mr David Gouldin, 23 February 2010, p. 3.

PTTEPAA's cementing operations, and PTTEPAA did not in fact rely on Atlas to provide any level of expert supervisory oversight.

3.140. However, the Inquiry considers it likely that after the cementing operation Mr Trueman was informed (probably by Mr Kok¹⁰²) that the float valves had failed, that there had been a return of cement beneath the float collar, and that there had been pumping back to some extent of cement.

3.141. Indeed, this appears from a draft Proof of Evidence which Atlas obtained from the *West Atlas* OIM, Mr Trueman. Atlas and Mr Trueman were content to have this draft placed before the Inquiry. PTTEPAA, however, objected to the Inquiry receiving the draft Proof of Evidence given that PTTEPAA did not have the opportunity to cross-examine Mr Trueman on its contents. However, in relation to those parts of the draft Proof of Evidence which are adverse to the interests of Mr Trueman and Atlas, no unfairness arises if they are taken into account.

3.142. In Mr Trueman's draft Proof of Evidence he states, relevantly, as follows:

1. I remember that I was on board when we cemented although I was not involved in the job itself...What I know of the cement job has been told to me by Bart Kok, the [Atlas] day tool pusher, and by looking at Bart Kok's book.¹⁰³

...

4. From my discussions with Bart Kok, I am aware that the cement was pumped and pressure was held for 4 hours. This is standard procedure.

5. When they bled off the pressure, there was back flow. They pumped the cement back in and held pressure at 1,500 psi for 4 hours. That took until after the time that Bart Kok knocked off.

...

6. If it had leaked again, they would not have continued.

...

7. I was told, that night, it wasn't tested.

8. The decision to pump the cement back in would have been (1) made by the Company Man [being a reference to Mr Treasure]. However, I would have (2) endorsed that decision, otherwise you would have wound up with too much cement in the casing and not enough on the outside

...

¹⁰² The Atlas Toolpusher.

¹⁰³ The reference to 'Bart Kok's book' is unclear. It is probably a reference to notes kept by Mr Kok which formed part of the material for creation of the IADC report: see T600 (Treasure).

[However], I Would Not Have been asked [at the time] to endorse this operation.¹⁰⁴

- 3.143. This account must be considered in light of the fact that Mr Trueman prepared the Atlas DOR of 7 March 2009. As noted above, the DOR makes clear that:
- a. 9.25 barrels of displacement fluid were introduced into the 9 $\frac{5}{8}$ " casing string to bring the pressure up to 4,000psi, which pressure was held for 10 minutes without any loss of pressure;
 - b. when pressure was bled off 16.5 barrels returned and pressure increased within the casing string to 1,300psi;
 - c. the 16.5 barrels which returned consisted of the 9.25 barrels of displacement fluid which had been used to pressure up the casing string, and 7.25 barrels of cement (mixed with hydrocarbons) from beneath the float collar;¹⁰⁵ and
 - d. the whole of the 16.5 barrels was pumped back into the casing, without any increase in pressure (meaning that the plugs had not re-bumped).¹⁰⁶
- 3.144. Both Mr Millar and Mr Gouldin freely admitted that the DOR described an over-displacement of cement from within and around the casing shoe, that is, a wet shoe. However, Mr Trueman and Mr Millar failed to comprehend this fact, and so no action was taken by them, on behalf of Atlas, to address the casing shoe's lack of integrity.
- 3.145. The Inquiry considers that, although PTTEPAA must bear primary responsibility for the faulty installation of the cemented casing shoe, these failures on the part of Atlas personnel materially contributed to the Blowout. In this regard, the Inquiry notes and accepts the following evidence given by Mr Jacob:

¹⁰⁴ Proof of Evidence of Mr Phillip Trueman, pp. 1-3. The last sentence in this extract accords with other evidence heard by the Inquiry. The last sentence has also been included because it resolves an ambiguity which otherwise inheres in the penultimate sentence.

¹⁰⁵ Atlas submitted that the data in the report was capable of misinterpretation, particularly as to whether the volume of fluid returned was inclusive or exclusive of the original 9.25 barrels. The Inquiry notes that Mr Millar did not give evidence of having misinterpreted the data in this way. The Inquiry considers that any ambiguity in the DOR was not great. Any ambiguity should have been investigated and resolved. Indeed, a return of 16.5 barrels from beneath the float collar (if interpreted in that way) should have been regarded as a very large level of return, and the fact it was pumped back without impedance should have signified a defective cemented shoe. Accordingly, even if there was some ambiguity in the data in the DOR, it clearly indicated the existence of a defective shoe which required testing.

¹⁰⁶ Although the DOR did not record a loss of pressure during WOC (from 1350psi to 687psi), it indicated likely over-displacement and, at the very least, a cemented shoe which could not be relied upon as having integrity.

The obligation of the registered operator of any facility is to ensure that their facility is operated in a safe manner...there has been a lot of discussion around the well construction management systems, which originate through the well operations regulations [applicable to PTTEPAA as the titleholder of the Montara licence].

There's another set of regulatory laws in place here, which are the safety case laws...Atlas have their safety case [in respect of the rig] and we have our own safety case for the wellhead platform. It just appears to me that better application of those may have given an opportunity for some of these unfortunate events to have been caught.¹⁰⁷

...

...I still hold very strong views that the application of the safety case regime is an area that maybe should have caught this, and I don't think it did.¹⁰⁸

...

...under the occupational health and safety area, the rig operator has responsibility for safety of personnel on that rig, not only from the way in which they carry out [activities] but from physically being there in presence. That naturally involves being over a well. So there was an opportunity, within the obligations of the rig operator, for him to inform himself as to the barriers required, and, if he saw something was not being done, to question it.

As I say, I'm not trying to deflect anything; I'm just trying to ensure that the Commission understands that there is an obligation there on the part of the operator of any of the facilities...¹⁰⁹

- 3.146. The Inquiry did not understand this evidence to be disputed by Atlas witnesses. Indeed, Mr Gouldin (a very senior Atlas executive) accepted, with commendable frankness, that both Mr Trueman and Mr Millar should have identified the problem with the casing shoe and taken action with respect to it. Having said that, the fact remains that PTTEPAA took on primary responsibility for the cementing operation. PTTEPAA personnel on-rig and onshore should have specifically engaged with Mr Trueman and Mr Millar about the cementing operation.

Concluding comments on the role of Halliburton in the cementing operations

- 3.147. Before leaving this topic the Inquiry considers it appropriate to comment further upon the limited role performed by Halliburton in the course of the cementing operation on 7 March 2009. Halliburton holds itself out as having expertise in

¹⁰⁷ T1748 (Jacob).

¹⁰⁸ T1764 (Jacob).

¹⁰⁹ T1782 (Jacob).

cementing operations, and it is one of the two leading cementers in the offshore petroleum industry in the world.

- 3.148. The Inquiry considers that PTTEPAA should have purchased, in clear terms, advisory expertise of a supervisory kind from Halliburton, rather than just machinist expertise, with respect to the actual cementing operation. Further, PTTEPAA should have taken steps to ensure that its own personnel made contact with Halliburton personnel onshore when problems arose in the course of cementing the casing shoe on 7 March 2009, for example, by issuing a standard operating procedure to that effect.

Finding 4

The acts and omissions of PTTEPAA personnel, both on-rig and onshore, were directly responsible for the creation and non-detection of the defective cemented casing shoe.

Finding 5

Although Halliburton played a role in the actual cementing operation its role was, relevantly, confined to the performance of machinist services on the rig (rather than onshore advisory services). The Inquiry heard no evidence of any deficiency in Halliburton's performance of that role. PTTEPAA did not seek advisory input from Halliburton personnel onshore in relation to the problems which arose in the course of the cementing operation.

Finding 6

Atlas personnel were not relevantly involved in the actual installation of the cemented casing shoe.

Finding 7

However, the direct and proximate causes of the Blowout include failures on the part of personnel from both PTTEPAA and Atlas (on-rig and onshore) to recognise, in the aftermath of the cementing operation on 7 March 2009, that a wet shoe had been created. These failures occurred at each of two stages: first, during the course of preparation, by on-rig personnel, of contemporaneous documents which described the cementing operation; and secondly, upon review of those documents by onshore personnel from each organisation (which occurred soon after the cementing operation).

Finding 8

PTTEPAA bears a larger measure of responsibility for these failures than Atlas. This is because (i) under arrangements agreed between them, PTTEPAA took on primary responsibility for well control; and (ii) in its day-to-day operations PTTEPAA did not in fact rely upon Atlas for expert supervisory oversight of well control operations.

Non-testing of the cemented casing shoe after installation

3.149. This aspect of the matter is closely related to the failures by PTTEPAA and Atlas to identify any problem with the cemented casing shoe.

3.150. Within days of the Blowout Atlas commenced an investigation into its causes. The investigation included external input. Within a matter of weeks Atlas received a report from an external expert, Mr G Ross, who expressed the following views in relation to non-testing of the cemented casing shoe:

...it is without doubt that a pressure test should have been conducted on the shoetrack post cement setting up. The top cement plug was not re-bumped so this should have been very simple to conduct.

...

...On H1, a leak path had been created, due to leaking float equipment, with 16.5 bbls backflow measured...(not an insignificant volume and arguably recklessly high) this would push the top cement plug up approximately...(69m) above the float collar. To then re-inject this volume...is not sensible as it is likely to make worse any leak channel.

...

...In any case for the cement to be pushed back into place a second time is hardly ideal for a contamination free TOC [top of cement] and a barrier in the 13 $\frac{3}{8}$ " x 9 $\frac{5}{8}$ " annulus.

An appropriate level of pressure test on the casing shoetrack should have been performed post cement setting to establish if integrity was in place. Assuming the top plug was not re-bumped...it would have been possible to carry out a simple test against the shoetrack. To omit conducting such a test is not good oilfield practice to say the least and also contravenes the [PTTEPAA] barrier policy.

...

...this annulus barrier is supposed to be tested as per the [PTTEPAA] barrier policy and this can only be done by pressuring up on the annulus to a pressure higher than the 13 $\frac{3}{8}$ " LOT, to establish if a seal is present, or possibly you could obtain satisfaction via a CBL/VDL run and computing the bond index.¹¹⁰

3.151. By way of contrast, PTTEPAA carried out a very cursory and inadequate investigation of the causes of the Blowout. For nearly seven months after the Blowout PTTEPAA maintained that 'there was no reason to suspect at that time that the backflow had compromised the cement job'.¹¹¹

¹¹⁰ Memorandum from G Ross to D Gouldin, T Trendall, D Millar and R Pallesen, 24 September 2009.

¹¹¹ PTTEPAA, Submission to the Inquiry, paragraph 110.

3.152. Shortly prior to the commencement of the Inquiry's public hearing PTTEPAA informed the Inquiry that it had changed its mind about the need for a post-WOC pressure test. This change of mind was prompted, apparently, by its consideration of a detailed and comprehensive report produced to the Inquiry by Atlas. In submissions filed by PTTEPAA – only three working days prior to commencement of the Inquiry's public hearing – it stated:

...PTTEPAA has now come to the same conclusion [as Atlas] that pumping the 16.5bbls of fluid back into the well effectively pumped cement out of the shoe...When pumping back down, too much fluid was pumped into the well. This effectively invalidated the prior test of the cemented shoe being a tested barrier. The integrity of the casing shoe should have been retested. There were a number of [Atlas and PTTEPAA] people on the rig involved in that operation...who did not recognise this at the time. It is notable that, at the time, the Seadrill IADC Daily Drilling Report of 7 March 2009 records that after waiting on cement – “Retest float good”. The failure to retest the shoe integrity at that time is one of the root causes in this incident, however it was consistent with the [Atlas] Well Control Manual (...which does not require a pressure test of the casing after waiting on cement), the West Atlas SDI Operations manual (section 1.1.31 on cementing intermediate casing contemplates a failure of the float valves at step 15 of the procedure and does not require a pressure test of the casing after a suitable period of waiting on cement) and the PTTEPAA Well Construction Standards (section 5 states that “All other barriers may be pressure tested or inflow tested”).¹¹²

- 3.153. The belated admission at the start of the above excerpt is undermined by the misleading statements toward the end of the excerpt:
- a. first, no-one from Atlas was involved in any real way with the actual cementing operation;
 - b. secondly, the quote from the IADC DDR is so selective as to be misleading;
 - c. thirdly, the failure to retest the cemented casing shoe could not reasonably be regarded as supported by the identified passages in the Atlas Well Control Manual, the SDI Operations Manual, or the PTTEPAA Well Construction Standard. Indeed, the passage quoted from section 5 of PTTEPAA's Well Construction Standard is not even applicable because cementing of a casing shoe is separately, but inadequately, dealt with in that section (that is, annulus cement); and

¹¹² PTTEPAA Response to Seadrill's investigation report, 10 March 2010.

d. fourthly, as admitted by Messrs Duncan and Jacob, the cemented casing shoe was not subjected to either a pressure test or inflow test (of a kind recognised by sensible oilfield practice).

3.154. The plain fact of the matter is that the failure to carry out a pressure test was inexcusable. PTTEPAA's proffering of excuses right up to the commencement of the public hearing reflects very poorly upon it.

Apportioning responsibility for non-testing between PTTEPAA and Atlas

3.155. Although each of Atlas and PTTEPAA should have identified the need for a post-WOC pressure test (as a minimum), it is considered that PTTEPAA bears a higher measure of responsibility for these failures than Atlas. The formally agreed arrangements between PTTEPAA and Atlas recognised the primacy of PTTEPAA's role in relation to well construction and control. Similarly, the practical day-to-day interactions between PTTEPAA and Atlas were conducted on the basis that PTTEPAA took primary responsibility for well control.¹¹³

3.156. Nevertheless, as both Mr Gouldin and Mr Jacob noted, Atlas should have exercised more vigilance in relation to well control. Despite having no first-hand operational involvement in the cementing of the casing shoe, both Mr Trueman and Mr Millar were well placed, in terms of their roles and the information available to them, to identify the problem with the creation of the wet shoe, and to insist upon retesting and remedial action. Indeed, Mr Trueman as the OIM had ultimate over-arching responsibility for rig safety, and Mr Millar as the Rig Manager should have paid closer attention to the topic of well control.

3.157. Therefore, it would not be correct to describe Atlas' responsibility for the failure of the primary barrier as merely minor or purely incidental. Atlas had an important safety role which it failed to discharge. Atlas' role was, however, secondary compared to that of PTTEPAA.

Finding 9

The direct and proximate causes of the Blowout include failures on the part of personnel from both PTTEPAA and Atlas, on-rig and onshore, to ensure that a test of the cemented casing shoe was carried out (that is, a test after waiting on the cement to set).

¹¹³ In his oral evidence Mr Jacob frankly acknowledged the primacy of PTTEPAA's role in relation to well control.

Finding 10

These failures were contrary to sensible oilfield practice, and were also contrary to PTTEPAA's own Well Construction Standards.

Finding 11

It is likely that, if a test had been carried out, it would have confirmed the unreliability of the cemented casing shoe as a barrier. In any event, remedial action could and should have been taken, in which case the Blowout would not have occurred.

Finding 12

PTTEPAA bears a higher measure of responsibility for these failures than Atlas. This is because (i) under arrangements agreed between them, PTTEPAA took on primary responsibility for well control; and (ii) in its day-to-day operations PTTEPAA did not in fact rely upon Atlas for expert supervisory oversight of well control operations.

Use of the wrong volume of tail cement

- 3.158. PTTEPAA's Well Construction Standards required tail cement to be placed within the annulus outside 9 $\frac{5}{8}$ " casing string at a height of 100 metres above the top of reservoir. The purpose of this standard was to prevent the leach of reservoir fluids into the annulus. Instead of seeking to achieve this standard, PTTEPAA aimed for a lesser height of 69m above the top of reservoir.¹¹⁴
- 3.159. To achieve this height of 69m, 199bbbls of tail cement should have been used in the cementing of the casing shoe. However, only 132bbbls were used. The result was that tail cement in the annulus reached a height of only 61m **below** the top of reservoir. Accordingly, reservoir fluids may have leached from the formation into the annulus during the setting of the cement, thereby compromising the integrity of the cement as a barrier.
- 3.160. In its December 2009 submission to the Inquiry PTTEPAA asserted that:
- a. responsibility for the miscalculation rested only with personnel on the rig; and
 - b. in any event, the miscalculation did not play any role in the actual Blowout which occurred, because the Blowout came from within the 9 $\frac{5}{8}$ " casing rather than up the annulus surrounding that casing string.

¹¹⁴ Mr Wilson submitted that what PTTEPAA aimed for was within its standards because the requirement for cement to be more than 100m above the reservoir did not specify tail cement. However, Mr Duncan gave evidence that this standard should normally be understood as requiring tail cement rather than lead cement (T1412).

3.161. After hearing evidence adduced in the public hearing Mr Jacob changed his mind about each of these matters.

3.162. The Inquiry notes and accepts the following evidence given by Mr Jacob in relation to the first matter:

Q. Significantly, you will recall Mr Wilson's evidence that he was actually sent these calculations by Mr Treasure on 5 March, I think it was, who asked that Mr Wilson check the calculations; do you recall that?

A. I believe I do, yes. I'm not sure whether I read that in the transcript or whether I was here, but, yes.

Q. I take it that you learned that for the first time [in the hearing]?

A. To the best of my recollection, yes.

Q. You also learned that, quite contrary to Mr Treasure's express request, there was simply no response on Mr Wilson's part?

A. That's what I understood to be --

Q. And he simply couldn't explain the absence of any such response?

A. Yes.¹¹⁵

Q. But you will agree that that fact significantly implicates [PTTEPAA] personnel onshore in relation to the miscalculation of tail cement?

A. Yes, the fact that he was requested to make the check and didn't, yes.

Q. Indeed, I think you will also recall evidence from Mr Duncan to the effect that [PTTEPAA] personnel onshore could have done more to ensure that those on the rig properly understood what was required with respect to the change control process on 23 January; do you recall that?

A. Yes, I think one of the learnings that will be gained is that we need a far more robust process and checking process on cement calculations.

Q. I think he suggested that mere numbers had been used, without a sufficient explanation of the objective that was sought to be achieved; do you recall that evidence by Mr Duncan?

A. Yes.

Q. So, again, we have an acceptance of some level of responsibility on the part of [PTTEPAA] personnel onshore in relation to the miscalculation?

A. In that they weren't clear in what the ultimate requirement was.

Q. Yes. Again, something you learned for the first time?

A. It certainly became clear to me.

Q. So whereas your view was, prior to the commencement of these public hearings, that the miscalculation resulted from people on the rig not doing their job, you now know don't you that significantly both Mr Wilson and Mr Duncan were implicated, to some extent, in the miscalculation?

A. Yes, the process of giving the people on the rig the information was poor and it was unclear, and that resulted in miscalculations, yes, absolutely.¹¹⁶

¹¹⁵ T945 (Wilson); cf T1008 (Wilson).

¹¹⁶ T1627-1629 (Jacob).

3.163. Mr Jacob gave the following evidence concerning the possibility that the miscalculation materially contributed to the Blowout:

Q. I want to suggest to you, sir, that even if one might conclude that it's unlikely that the source of the actual flow was right up through the annulus, nonetheless what you have described here could have contributed to a source of flow from within the 9-5/8" casing, because what's described could have led to some wormholing or channelling of the cement outside the casing, which might have created leak paths from the reservoir to the bottom of the casing. Do you follow?

A. Yes - well, I'll put it in my words and see if it's the same. The cement outside the cement shoe and up the annulus of the 9-5/8" casing in the reservoir could have been compromised, and that would provide a path for hydrocarbons within the oil leg and the gas leg to go back down towards the 9-5/8" shoe. Yes, I think that's a possibility, yes.

Q. Those hydrocarbons will, in effect, seek to track to a lower pressure point, whether it's right up through the annulus cement or at some other point?

A. Yes, and because of that - well, that is part of the reason. It is more likely, I would suggest, that the lower pressure point, once the well was flowing, was certainly at the 9-5/8" casing shoe than above.¹¹⁷

3.164. Mr Gouldin and Mr Millar from Atlas also accepted that the use of the wrong volume of tail cement might have materially contributed to the Blowout.

3.165. The Inquiry accepts the evidence of Mr Jacob, Mr Millar and Mr Gouldin on this question.¹¹⁸

Finding 13

Another factor which may have directly and proximately contributed to the Blowout was the use by PTTEPAA of an incorrect volume of 'tail' cement in the course of the cementing of the shoe in the H1 Well on 7 March 2009. This may have led to the creation of channels or 'wormholes' in the cement surrounding the 9 5/8" casing string and casing shoe, thereby further compromising the integrity of the cemented casing shoe as a barrier. Whilst it is unlikely that this directly contributed to the Blowout, the possibility that it did so cannot be excluded.

¹¹⁷ T1714 (Jacob).

¹¹⁸ The Inquiry notes that Mr Wilson and Mr Duncan maintained in their oral evidence that the miscalculation could not have played any causal role in the Blowout. The Inquiry considers that Mr Wilson and Mr Duncan put the matter somewhat too highly in this regard. The Inquiry considers that the use of the wrong volume of tail cement cannot be completely discounted as a material contributing factor. However, the Inquiry accepts that reasonable minds may differ on this question.

Finding 14

Again, both on-rig and onshore personnel from PTTEPAA were involved in the creation of this defect.

Finding 15

The use of an incorrect volume of tail cement – even if it did not cause the Blowout – is further evidence of an unsatisfactory approach by PTTEPAA to issues affecting well integrity.

Non-Installation of a 13³/₈" PCCC on the H1 Well

- 3.166. It will be recalled that on 12 March 2009 PTTEPAA sought approval to install a 13³/₈" PCCC on the H1 Well. That application comprised so-called Phase 2 of a Change Control Process which envisaged replacement of a cement plug with two PCCCs – one located on the 9⁵/₈" casing string, and the other located on the 13³/₈" casing string.
- 3.167. Approval was given by the NT DoR regulator to install a 13³/₈" PCCC on 13 March 2009.
- 3.168. At the time that approval was given, the NT DoR could reasonably have expected that the 13³/₈" PCCC would be installed on the H1 Well in a timely fashion. However, this did not happen. Rather, installation of the 13³/₈" PCCC was deferred to enable the H1 Well to be used as a parking spot, from time to time, for the BOP. Mr Treasure was significantly involved in this practice.¹¹⁹ It is highly likely that Mr Trueman (the OIM) knew that this was happening.
- 3.169. Mr Wilson and Mr Duncan were also aware of the fact that installation of the 13³/₈" PCCC had been deferred. Mr Wilson accepted that he made the decision to defer installation, with the concurrence of Mr Duncan.¹²⁰ Mr Duncan agreed he was aware that installation of the 13³/₈" PCCC was deferred.¹²¹
- 3.170. It appears therefore that no-one within PTTEPAA or Atlas took any steps to insist upon timely installation of the 13³/₈" PCCC. Everyone appears to have

¹¹⁹ Mr Treasure told the Inquiry that he thought the practice was appropriate even though it left the annulus between the 9⁵/₈" casing and the 13³/₈" casing protected by only one barrier when the BOP was not in place. He also told the Inquiry that he participated in a discussion about the practice with the OIM and onshore personnel from PTTEPAA. As the senior licensee representative on the rig, the Inquiry considers it likely that Mr Treasure was involved in decisions about the location of the BOP from time to time.

¹²⁰ T1080 (Duncan).

¹²¹ T1297 (Duncan).

proceeded on the basis that the 13 $\frac{3}{8}$ " PCCC simply needed to be installed some time prior to the rig leaving the Montara WHP. Mr Wilson accepted that the NT DoR would have been misled into thinking that a 13 $\frac{3}{8}$ " PCCC had been installed soon after approval was obtained to do so.

- 3.171. On 17 April 2009 Mr Treasure sent an email to Messrs Wilson and Duncan which advised them, among other things, of the installation of the 13 $\frac{3}{8}$ " PCCC on the H1 Well. This email was sent a mere four days before the rig left the Montara WHP. Subsequent to receipt of Mr Treasure's email, a 'Suspension As-Built' drawing was prepared which showed that the H1 Well was suspended with the 13 $\frac{3}{8}$ " PCCC in place. This information was incorporated into the Phase 1B Drilling Program.
- 3.172. In fact, however, the 13 $\frac{3}{8}$ " PCCC was never installed. The Inquiry has received no explanation whatsoever, let alone a satisfactory explanation, for this omission.
- 3.173. It seems, however, that the following factors played a part in the failure to install the 13 $\frac{3}{8}$ " PCCC:
- a. non-recognition of the importance of timely installation of the 13 $\frac{3}{8}$ " PCCC. In this regard, the Inquiry finds that deferral of installation simply to enable the H1 Well to be used as a convenient parking spot for the BOP was quite contrary to sensible oilfield practice. Secondary barriers should be installed at the earliest practicable opportunity. The reason is obvious. Unless they are in place they cannot act as a secondary barrier to prevent a blowout;¹²²
 - b. decisions were taken by PTTEPAA personnel, on the rig and onshore, to manage the installation of the 13 $\frac{3}{8}$ " PCCC as an 'off-line' activity. This meant that the installation of the PCCC was relegated as a priority,¹²³ and there was an insufficiently rigorous system in place for monitoring, recording, and reporting of performance of off-line activities (as conceded by Mr Treasure, Mr Wilson and Mr Duncan). The Inquiry considers that important activities, such as the achievement of well control through installation of secondary barriers, should not be managed off-line;
 - c. because installation of the 13 $\frac{3}{8}$ " PCCC was managed off-line there was no rigorous system in place for capturing information about that activity. Rather, the Inquiry heard evidence to the effect that a whiteboard was used

¹²² The Inquiry notes that Mr Jacob in his evidence agreed that the 13 $\frac{3}{8}$ " PCCC should have been installed in a timely fashion (T1652-T1653).

¹²³ Mr Gouldin accepted this at T59.

on the rig to record performance of work. Not a single person could tell the Inquiry whether anyone had actually written on the whiteboard that the 13 $\frac{3}{8}$ " PCCC had been installed. However, the Inquiry is satisfied that use of a whiteboard is an inadequate records-management tool in respect of activities such as barrier installation. Various PTTEPAA personnel accepted this proposition in their oral evidence to the Inquiry; and

- d. on 16 April 2009 Mr O'Shea was rostered off duty on the rig and Mr Treasure took over as PTTEPAA's Day Drilling supervisor (the day of the supposed installation of the 13 $\frac{3}{8}$ " PCCC). The system of handover which was in place at that time was inadequate. It did not ensure the capture of critical information such as barrier installation. PTTEPAA accepts that the handover regime needs improvement.¹²⁴

3.174. PTTEPAA makes the point in its submissions to the Inquiry that, in all likelihood, one or more personnel from both PTTEPAA and Atlas must have been aware, at the time, of the non-installation of the 13 $\frac{3}{8}$ " PCCC. For instance, when the trash cap was installed on the 20" casing it should have been apparent that no 13 $\frac{3}{8}$ " PCCC was in place.¹²⁵ At the time, no-one in either PTTEPAA or Atlas was required to certify that the PCCC had been installed. Had such a requirement been in place it is likely that the absence of the 13 $\frac{3}{8}$ " PCCC would have been detected.

3.175. Indeed, the Inquiry considers that in relation to safety critical tasks, such as barrier installation, a process of mutual 'sign-off' or certification should take place between the licensee and the rig operator, which should include onshore personnel. This aspect of the matter is addressed further below.¹²⁶

¹²⁴ It is noteworthy that when Mr O'Shea handed over to Mr Treasure there was no reference in his handover notes to anything to do with the installation of the 13 $\frac{3}{8}$ " PCCC, let alone identification of who had installed it. Had a system been in place which required such matters to be addressed at the time of handover, it is likely that Mr O'Shea would have discovered the non-installation of the 13 $\frac{3}{8}$ " PCCC, and Mr Treasure would have then become aware of it.

¹²⁵ Atlas submitted that it did not necessarily follow that anyone from Atlas would have known that the PCCC *should* have been in place. This may be true. As the installation of the PCCC was to be managed off-line, the Atlas personnel involved in these activities (the Roughnecks and the Assistant Driller(s)) may well have been unfamiliar with which barriers were required to be installed. However, the Inquiry is satisfied that someone from Atlas (the OIM if no-one else) should have ensured that all barriers required to be installed were in fact installed.

¹²⁶ Both PTTEPAA and Atlas accepted the utility of joint sign-off at the Inquiry's public hearing. Indeed, PTTEPAA raised this as a useful procedure prior to the Inquiry's public hearing (but did not extend the requirement to include onshore personnel).

- 3.176. The failure to install the 13 $\frac{3}{8}$ " PCCC cannot be dismissed as an unfortunate, but immaterial, happenchance - as initially suggested by various witnesses.¹²⁷ The absence of a 13 $\frac{3}{8}$ " PCCC led to corrosion of the inner threads of the uppermost part of the 13 $\frac{3}{8}$ " casing string, which formed part of the mud-line suspension system (**MLS**).¹²⁸ When the H1 Well was re-entered on 20 August 2009 a decision was taken to clean these threads, which required removal of the 9 $\frac{5}{8}$ " PCCC.
- 3.177. Had the 13 $\frac{3}{8}$ " PCCC been installed as required, the 9 $\frac{5}{8}$ " PCCC would not have been removed at an earlier point in time. Further, a pressure test would have been carried out within a couple of hours of the scheduled removal of the 9 $\frac{5}{8}$ " PCCC. It is likely that a pressure test would have detected deficiencies in the cemented casing shoe at a point in time when, with a derrick located over the H1 Well, effective remedial action could have been taken to prevent a blowout.
- 3.178. Thus, in the scheme of things, the failure to install the 13 $\frac{3}{8}$ " PCCC materially contributed to a sequence of events which ultimately led to the Blowout. The Inquiry notes that PTTEPAA adopted a contrary position in submissions it put to the Inquiry prior to the public hearing. However, a number of senior PTTEPAA personnel gave oral evidence at the public hearing which accepted the causal role played by the failure to install the 13 $\frac{3}{8}$ " PCCC.

Finding 16

The direct and proximate causes of the Blowout include the failure to install a PCCC on the 13 $\frac{3}{8}$ " casing string of the H1 Well. This should have occurred in early/mid March 2009. This PCCC was intended to operate as a secondary barrier against a blowout.

Finding 17

The non-installation of a 13 $\frac{3}{8}$ " PCCC was contrary to sensible oilfield practice, and was also contrary to PTTEPAA's own Well Construction Standards.

¹²⁷ The majority of witnesses ultimately agreed that non-installation of the PCCC was significant: see, for example, T46 (Gouldin); T369 (Treasure); T844 (O'Shea); T968-969 (Wilson) and T1187 (Wilson); and T1290 (Duncan).

¹²⁸ It was predictable that if the 13 $\frac{3}{8}$ " PCCC was not installed, the threads would become corroded: see T46 (Gouldin).

Finding 18

If the 13³/₈" PCCC had been installed it would have operated as a secondary barrier against a blowout. Further, failure to install a 13³/₈" PCCC led to the removal of the 9⁵/₈" PCCC in August 2009, thereby leaving the H1 Well without any secondary barriers against a blowout.

Finding 19

The non-installation of the 13³/₈" PCCC should have been detected by on-rig personnel from both PTTEPAA and Atlas. However, PTTEPAA bears a larger measure of responsibility for this cause than Atlas. This is because (i) under arrangements agreed between them, PTTEPAA took on primary responsibility for well control; (ii) in its day-to-day operations PTTEPAA did not in fact rely upon Atlas for expert supervisory oversight of well control operations; and (iii) it was PTTEPAA-related personnel who mistakenly reported that the 13³/₈" PCCC had been installed.

Removal and non-reinstallation of the 9⁵/₈" PCCC

Additional background facts

- 3.179. As noted above, after re-entry into the H1 Well on 20 August 2009 it was discovered that the MLS threads inside the 13³/₈" casing string had corroded. This was drawn to the attention of Mr Duncan, who was onboard the platform/rig to review the setup for operations (Mr Duncan expected to depart the next day).
- 3.180. Once the trash cap was removed from the 20" casing it was immediately apparent that the 13³/₈" PCCC had not been installed – indeed, the installation of the 13³/₈" PCCC would have prevented the very corrosion which was detected at the MLS point of the 13³/₈" casing string.
- 3.181. Mr Duncan formed the view that the corrosion on the tieback threads on the 13³/₈" MLS hanger needed to be removed in order to ensure subsequent casing integrity after tieback. In order to clean the tieback threads on the 13³/₈" MLS hanger it was considered necessary to remove the 9⁵/₈" PCCC from the top of the 9⁵/₈" casing string. Mr O'Shea and Mr Duncan discussed this proposed course of action with Mr Wilson, who was onshore at the time. Mr Wilson agreed with Mr Duncan's decision. However, the Inquiry notes and accepts the following evidence given by Mr Gouldin:

Whenever you have a deviation or a discovery or a combination of these things, as took place here, there is every option just to stop at that point, review the situation and consider the alternative ways forward. Without oversimplifying the situation here, there were two choices - take the 9-5/8" cap out or leave it in. They were two very simple, opposite

solutions to the problem at that time. It wasn't necessary to clean those threads then. It was the easiest time to clean them, but it certainly wasn't necessary. So that's why I say it was a point where discussion of the alternatives could have taken place and the options at that time.¹²⁹

Inquiry's assessment of Mr Duncan's decision to remove the 9½" PCCC

- 3.182. At the time, Mr Duncan considered that removal of the 9½" PCCC involved a relatively insignificant change in timing and sequence. Mr Duncan told the Inquiry that his decision to remove the 9½" PCCC was influenced by the following factors:
- a. his view that the 9½" cemented casing shoe was a competent barrier which he assumed had been pressure tested after waiting on cement;
 - b. his view that the displacement fluid in the 9½" casing string was overbalanced to the reservoir and therefore could act as a pressure barrier; and
 - c. his view that if there had been any change in wellbore dynamics by way of flow from the reservoir, this would be evident and managed by checking for trapped pressure below the 9½" PCCC before its removal.
- 3.183. Each aspect of this reasoning was flawed:
- a. the cemented casing shoe was an improperly installed and untested barrier, and Mr Duncan should have been aware of these facts;
 - b. it was quite wrong of Mr Duncan to approach well control on the basis that the displacement fluid was overbalanced to the reservoir. In fact, the information available to Mr Duncan at the time – had he examined it – indicated that the displacement fluid was under-balanced to the reservoir.¹³⁰ In any event, the displacement fluid had not been monitored and maintained since suspension of the wells, and there was no basis whatsoever to suppose that, even if it was overbalanced to formation, it possessed a sufficient margin of safety as required by PTTEPAA's own Well Construction Standards and sensible oilfield practice; and

¹²⁹ T60 (Gouldin).

¹³⁰ See the Basis of Well Design – Montara H1 July 2008 (at PTT.9001.0014.0158-59); charts (such as those at HAL.9000.0001.0125-26, PTT.9000.0005.0293; PTT.9004.0001.0100); the Daily Drilling Reports for 21 and 22 February 2009 (see PTT.9001.0007.0301; PTT.90001.0007.0304); the Daily Drilling Reports for 5, 6, and 7 March 2009 (see PTT.9001.0007.0340, PTT.9001.0007.0343, and PTT.9001.0007.0346 respectively); the Advantage Drilling Fluids Report of 6 March 2009 (PTT.9004.0001.0120); the Daily Geological Report of 8 March 2009 at PTT.9002.0025.0209.

c. the 9 $\frac{5}{8}$ " PCCC had not been tested and verified post-installation and therefore checking for trapped pressure prior to its removal could not guarantee the absence of flow from the reservoir. Further, Mr Gouldin and other witnesses have told the Inquiry that it is possible that a low level of pressure beneath the PCCC may not have been detectable.

3.184. Further, Mr Duncan simply assumed that Mr Wilson would discuss the earlier-than-planned removal of the 9 $\frac{5}{8}$ " PCCC with the Rig Manager, Mr Millar. As it happened, Mr Millar was not informed of the removal.

3.185. Mr Duncan did discuss removal of the 9 $\frac{5}{8}$ " PCCC with Mr O'Shea, PTTEPAA's Day Drilling Supervisor who was on the rig at the time. Mr Duncan left it to Mr O'Shea to communicate the proposed change to Mr Trueman, the *West Atlas* OIM, 'and gain his agreement'.¹³¹ However, the Inquiry is satisfied that, in reality, no-one from PTTEPAA (Mr Duncan included) truly engaged with Mr Trueman, the Atlas OIM, in relation to the decision to remove the 9 $\frac{5}{8}$ " PCCC. The evidence before the Inquiry is to the effect that Mr Trueman was merely informed, after the fact, of the decision having been made - almost in passing, as it were.¹³²

Non-reinstallation of the 9 $\frac{5}{8}$ " PCCC

3.186. Significantly, at the time Mr Duncan made the decision to remove the 9 $\frac{5}{8}$ " PCCC he expected or assumed that it would be reinstalled. The Inquiry is satisfied that Mr O'Shea (PTTEPAA's Day Drilling Supervisor) should have arranged reinstallation (even without a specific instruction from Mr Duncan). However, Mr Duncan took no steps at all to ensure that his expectation was fulfilled. It would have only taken 15-30 minutes to reinstall the 9 $\frac{5}{8}$ " PCCC whilst the derrick of the rig was located over the H1 Well.

3.187. Mr Duncan told the Inquiry that sometime in the evening of 20 August 2009 he became aware that the 9 $\frac{5}{8}$ " PCCC had not been reinstalled after the cleaning operation. Mr Duncan said that he then made a positive decision not to insist upon re-installation of the 9 $\frac{5}{8}$ " PCCC because, although he thought it preferable, he did not want to give the impression to personnel on the rig that

¹³¹ Statutory Declaration of Mr Craig Duncan, 8 March 2010, paragraph 248.

¹³² Mr Trueman was given a copy of the forward plan by Mr O'Shea before removal. However, Mr O'Shea would not have raised the issue with Mr Trueman as something of any importance because he told the Inquiry that, at the time, he simply did not think the removal of the PCCC had any significance in terms of well control.

he was trying to teach them how to do their jobs.¹³³ Mr Duncan told the Inquiry that saving rig time also influenced his decision, but was not the primary factor.¹³⁴

3.188. Within ten or so hours of Mr Duncan's decision to allow the 9½" PCCC to remain off the H1 Well the Blowout occurred.

3.189. In these circumstances one would have expected that PTTEPAA would readily accept the causal significance of the removal and non-reinstallation of the 9½" PCCC. However, the Inquiry notes that:

a. in submissions filed with the Inquiry on 10 March 2010, just prior to the commencement of the Inquiry's public hearing, PTTEPAA stated on several occasions that the removal of the 9½" PCCC was merely a change of sequence or timing, rather than a matter of any substance. PTTEPAA also asserted that 'the cap was to be removed in any event a little later on in the Drilling Program'. Indeed, PTTEPAA went so far as to state as follows:

The removal of the 9½" PCCC was not a root cause. It was a planned operation conducted a few hours sooner than programmed...The 9½" PCCC was not re-installed before skidding the drilling package to the H4 well. However, re-installation of that cap was not required by the Drilling Program due to the nature of the tie-back operations.¹³⁵

b. apart from Mr Jacob, nearly every PTTEPAA-related witness adopted this same position (or a similar position) in their pre-hearing Statutory Declarations. Then, in the course of the public hearing, those PTTEPAA witnesses abandoned their position.

3.190. A proper examination of PTTEPAA's own '7 Day Operational Forecast' dated 19 August 2009¹³⁶ should have disabused PTTEPAA's witnesses of their profound misconception in relation to this aspect of the case. That 7 Day Operational Forecast shows that:

a. a BOP was not going to be installed on the H1 Well until, at the earliest, 26 August 2009;

¹³³ The Inquiry notes that other PTTEPAA personnel on the rig at the time, such as Mr O'Shea and Mr Wishart, did not raise for discussion the reinstallation of the 9½" PCCC. They did not consider it their place to do so. The Inquiry considers it unfortunate they did not pursue the matter, although their deference to Mr Duncan is, in all the circumstances, quite understandable.

¹³⁴ T1322-1323 (Duncan).

¹³⁵ PTTEPAA Response to Seadrill's investigation report, 10 March 2010, p. 20.

¹³⁶ See PTT.9002.0010.0038.

- b. the derrick was forecast to be skidded to the H1 Well at 4am (CST) on Monday 24 August 2009, followed by removal of the 13 $\frac{3}{8}$ " PCCC and tieback of the 13 $\frac{3}{8}$ " casing string;
- c. removal of the 9 $\frac{5}{8}$ " PCCC was forecast to occur at 4pm (CST) on 24 August 2009; and
- d. within three hours of the forecast removal of the 9 $\frac{5}{8}$ " PCCC a pressure test of the entire 9 $\frac{5}{8}$ " casing string was scheduled to take place.

3.191. Accordingly, if all of those events had taken place as planned, it is likely that the deficiencies in the cemented casing shoe would have been detected as a result of the forecast pressure test. At that point, the derrick would have been over the H1 Well and therefore urgent remedial steps could have been taken to prevent a blowout. Mr Gouldin emphasised the significance of this in his evidence.¹³⁷

3.192. As it happened, the removal of the 9 $\frac{5}{8}$ " PCCC was brought forward by four days and four hours, and that removal was not followed by any testing of the 9 $\frac{5}{8}$ " casing string. This had the effect of leaving the H1 Well wholly dependent upon the cemented casing shoe as the only barrier against a blowout – a barrier which had not been properly tested and verified.

3.193. It is unfortunate that PTTEPAA was content to rely upon the views of Mr Wilson and Mr Duncan in relation to this aspect of the matter. They were each personally implicated in the decision to remove the 9 $\frac{5}{8}$ " PCCC, and Mr Duncan made a positive decision against insisting upon its reinstallation. The Inquiry is satisfied that by virtue of their involvement they lost some objectivity in relation to this aspect of the matter, which affected the reliability of their initial positions. Had PTTEPAA carried out a proper investigation into the circumstances and likely causes of the Blowout (as to which see Chapter 7), it is likely that both Mr Wilson and Mr Duncan would have gained a better appreciation of their roles (assuming they were de-briefed on the outcome of that investigation, as one would expect). In that event, Mr Wilson and Mr Duncan would have been much better prepared prior to giving evidence.

3.194. As it was, Mr Duncan in particular was initially inclined to strain in favour of defending the non-reinstallation of the 9 $\frac{5}{8}$ " PCCC. At one stage he told the Inquiry, in effect, that 'if it's okay to take it off it's okay to leave it off'. That is an unreasonable proposition. Mr Duncan also initially sought to convince the

¹³⁷ T49 (Gouldin).

Inquiry that reliance upon only one barrier happens quite often and ought not be regarded as exceptional. The Inquiry has no hesitation in rejecting this aspect of his evidence. Indeed, every PTTEPAA-related witness eventually conceded that a secondary barrier should be installed (or reinstalled as the case may be) whenever it is reasonably practicable to do so.

- 3.195. Indeed, in their oral evidence Messrs Wilson, Duncan and Jacob all accepted the force of the following statement by the Western Australian regulator.¹³⁸

The cementing of casing is an inexact science especially when the casing shoe is set at 90 degrees to the vertical wellbore. There are cementing practices which are known to provide a satisfactory ‘barrier’ between the reservoir and the well bore, but there is never a guarantee that the result is 100% effective, and this is the reason for the application of the two physical barriers method which does not include the hydrostatic head or well bore fluid. It is simply a matter of probability – more barriers equals lower risk.¹³⁹

- 3.196. They also expressed their agreement with the following principles stated by the Victorian regulator:¹⁴⁰

Well integrity should be maintained at all time [sic] – whether the well is actively worked on or suspended temporary [sic] or temporary [sic] abandoned (long term suspension). That means that there must be well control in place at all times. In addition [to a cemented casing shoe], other barriers should be placed inside the well bore and in the annular spaces above the last cemented casing shoe...

...

It must be noted that well integrity does not rely solely on the primary barrier. It is unwise to rely only on cemented casing as the only barrier for well integrity even if the above tests have been conducted and are accepted as confirming the calculated integrity of the cemented casing. There must be appropriate secondary barriers in place for the well at all times, particularly when the well is being worked on whether it is active (live) or been killed [sic]. Well integrity needs to be considered as “a whole well approach” in that the well must be controlled at all time [sic].¹⁴¹

¹³⁸ For instance, Mr Jacob described this statement as ‘perfectly reasonable’ (T1696).

¹³⁹ Letter from WA DMP to Inquiry, 11 March 2010.

¹⁴⁰ See, for instance, T1697 (Jacob).

¹⁴¹ Letter from Vic DPI to the Inquiry, 5 March 2010.

3.197. The need for secondary barriers to be in place whenever practicable is not at the outer margins of sensible oilfield practice. It is a fundamental, non-negotiable requirement. In this regard the Inquiry notes the following evidence given by Mr Jacob:

Q. So far as you're aware, a proper risk assessment would have entailed a decision to reinstall the 9-5/8" [PCCC] at the earliest practicable opportunity; that's right, isn't it?

A. I would have expected that, yes.

Q. There can be no sensible justification for doing otherwise, can there?

A. Not that I'm aware of at the moment.

Q. Do you recall the evidence that to reinstall the 9-5/8" [PCCC] would have occupied as little as 15 minutes, perhaps half an hour?

A. With the derrick over the well, yes.

Q. Yes, which it was.

A. Yes.

Q. So does it seem extraordinary to you, looking back on the events which occurred on 20 August, that the 9-5/8" [PCCC] was left off the H1 well?

A. Yes.¹⁴²

...

Q. So had you inspected the seven-day forecast with any sort of reasonable care, it would have been immediately apparent, wouldn't it, that the decision to remove the 9-5/8" [PCCC] wasn't simply an insignificant matter of scheduling and timing; do you agree?

A. In that regard, yes.¹⁴³

3.198. It reflects poorly upon PTTEPAA that it took so long to properly appreciate the significance of removal and non-reinstallation of the 9 5/8" PCCC. Having said that, two further points should be noted:

- a. first, Mr Jacob is to be commended for the independence of mind he brought (albeit belatedly) to this issue. He was forthright and non-defensive in his evidence on this aspect of the matter; and
- b. secondly, the approved Phase 1B Drilling Program did contemplate that the H1 Well would be exposed to atmosphere between steps 196 and 321. That very fact influenced the decision to remove the 9 5/8" PCCC. Therefore, as discussed below, poor regulatory practice by the NT DoR can be regarded as having contributed to poor operational practices on the part of PTTEPAA.

¹⁴² T1660-1661 (Jacob).

¹⁴³ T1869-1870 (Jacob).

Atlas' knowledge of, or involvement in, the removal of the 9 $\frac{5}{8}$ " PCCC

- 3.199. As noted above, Mr Millar was not informed of the fact of removal of the 9 $\frac{5}{8}$ " PCCC. The fact he was not informed is reflective of the lack of significance which Mr Wilson, Mr Duncan and Mr Trueman attached to removal.
- 3.200. The evidence before the Inquiry is to the effect that Mr Trueman (the OIM) knew that the 9 $\frac{5}{8}$ " PCCC had been removed, and he did not think re-installation was required for safety reasons.¹⁴⁴ Set out below are relevant paragraphs from Mr Trueman's draft Proof of Evidence.¹⁴⁵

21. We had to take the 9 $\frac{5}{8}$ off to clean the thread of the 13 $\frac{3}{8}$ casing.
22. I knew that they had taken the 9 $\frac{5}{8}$ cap off and that we had only the cemented shoe and the fluid barrier.
23. That is the same situation as when you run the casing...having the 9 $\frac{5}{8}$ cap off is exactly the same as what we had when we had run the casing.
24. They would not have taken the cap off if it had any pressure whatsoever.
25. In 6 months' time (since we suspended the well), if there had been any leaking, there would have been pressure.
- ...
27. I don't know why the cap was not put back on. I would have thought it would be sensible to put the cap back on. At the least, it would have stopped things falling in from the welder. Putting the cap back on, in my view, would have been for the sake of nothing being dropped down the well while the welder was there. I would not have done it for the safety concerns of the well blow out.
- ...
31. The Company Man [Mr O'Shea] told me what had been decided to do. He brought the program to the rig floor office just as I was going to the pre-tell meeting. He gave the program to the driller and the tool pusher.
- ...
33. Later in the afternoon, I went down to the Platform and spoke to the welder. I remember that he didn't perform a straight cut...
34. Usually, I take a walk around the rig in the afternoon and ask what has been done in order to report to [Atlas]. I send a report every afternoon to

¹⁴⁴ Mr Gouldin accepted that the OIM should have raised a query about removal of the 9 $\frac{5}{8}$ " PCCC either with PTTEPAA personnel on the rig or with Atlas personnel onshore (T47 and T50).

¹⁴⁵ As noted above, Atlas waived privilege over the draft Proof of Evidence and Mr Trueman was content to have it placed before the Inquiry. PTTEPAA, however, objected to the Inquiry attaching any weight to it. Nevertheless, the extracted portions of the draft Proof of Evidence are entirely consistent with other evidence the Inquiry heard and, if anything, are adverse to rather than supportive of the interests of Mr Trueman and Atlas. Accordingly, the Inquiry considers that no real unfairness is occasioned to PTTEPAA by the fact that Mr Trueman was not available for cross-examination on these parts of his draft Proof of Evidence.

say what's been done that day since 6am - the "Afternoon Report" is sent at about 5pm.

...

64. I think it was [Mr Duncan's] decision to take the cap off then and there. At the time, I did not think it was a wrong decision - the well had been there for 6 months, it had been cemented, there was no pressure.

...

67. I did not have the opportunity to offer my opinion because I only found out about what they were doing as I was going to the pre-tell meeting.

68. I didn't realise that they hadn't put the 9 5/8" back on again until after the well kicked.

...

70. ...I think I took it for granted that it had gone back on.

72. If they do anything I think is unsafe, I won't let them do it. It all comes back to the fact that there was no pressure there after 6 months and there was cement in place.¹⁴⁶

3.201. From the above account, and other evidence heard by the Inquiry, it is apparent that Mr Trueman knew of the decision to remove the 9 5/8" PCCC before it was actually removed. He had an opportunity at that time, and certainly in the six hours before he went off-shift, to check whether the 9 5/8" PCCC had been reinstalled, and to insist upon its reinstallation. Rather than making any inquiry at all he appears to have simply assumed that the PCCC had been reinstalled. Having gone down to the platform and inspected the welder's cut it would have been a simple matter for him to check whether the 9 5/8" PCCC had been reinstalled. Likewise, as he walked around the rig in the afternoon he could have readily satisfied himself as to whether the 9 5/8" PCCC had been reinstalled.

3.202. The Inquiry considers it likely that Mr Trueman simply gave no real attention to the topic of reinstallation of the 9 5/8" PCCC because, as he says, he 'did not think it was a wrong decision' to remove the PCCC and he did not think re-installation was a matter of safety.

3.203. The Inquiry has also considered the terms of Mr Trueman's 'afternoon report' which he sent to various onshore personnel at 7.39pm on 20 August 2009. That report states as follows:

Operations: Rig up over well H1, prepare to Pick up HWDP, pick up 2 stds HWDP and stand in the Derrick, Prepare the 20" csg. Make [sic] up 9 5/8" corrosion cap pulling tool, Run and recover 9 5/8" corrosion cap from H1, Run 9 5/8" thread cleaning tool into the 9 5/8" Csg and clean the threads, Pull

¹⁴⁶ See PRF.6010.0001.0003.

[sic] cleaning tool and lay out same. Rig up and run 20" tie in string and tie in to well H1, rough cut the 20" 0.5nt above the mezzanine Deck and lay out the landing Jt.¹⁴⁷

- 3.204. It is quite unlikely that this afternoon report would in fact have been read by Mr Millar before the Blowout the next morning. However the significance of the afternoon report, for present purposes, is that its terms suggest that Mr Trueman knew (or ought to have known) that the 9 $\frac{5}{8}$ " PCCC had not been reinstalled on the 9 $\frac{5}{8}$ " casing string - noting that there is no reference whatsoever to re-installation.
- 3.205. The upshot, in the Inquiry's view, is that Atlas (through Mr Trueman) is implicated in a meaningful way in the non-reinstallation of the 9 $\frac{5}{8}$ " PCCC. If Mr Trueman had done his job properly, he would have ascertained that the 9 $\frac{5}{8}$ " PCCC had not been reinstalled, whereupon he should have insisted that this take place. Had that occurred, it is likely that the Blowout would have been prevented.
- 3.206. Having said that, the Inquiry nevertheless considers that PTTEPAA bears the largest level of responsibility given Mr Duncan's seniority and the facts that (i) he personally decided to remove the 9 $\frac{5}{8}$ " PCCC and (ii) he personally decided not to insist upon its reinstallation.¹⁴⁸

Additional matter concerning significance of removal of 9 $\frac{5}{8}$ " PCCC

- 3.207. Finally, before leaving this aspect of the matter it should be noted that removal of the 9 $\frac{5}{8}$ " PCCC may have causally contributed to the Blowout apart from the simple fact of it not being in place and therefore not operating as a barrier.
- 3.208. This was a matter originally raised in Atlas' investigation report. In its December submissions to the Inquiry Atlas stated:

...it is possible that the inhibited seawater in the 9 $\frac{5}{8}$ inch well casing above the cement together with the 9-5/8 inch PCCC held the pressure balance within the 9 $\frac{5}{8}$ inch casing whilst the H1 was suspended between March 2009 and August 2009.

...

¹⁴⁷ See SEA.002.009.4412.

¹⁴⁸ See T1656-1657 (Jacob) as to the special responsibility which Mr Duncan bore by virtue of his seniority, expertise, and perceived authority.

The removal of the 9⁵/₈ inch PCCC may have been sufficient to alter the balance within the 9⁵/₈ inch well casing allowing any hydrocarbons to start moving to the surface.¹⁴⁹

3.209. Mr Gouldin gave oral evidence to the Inquiry to the effect that removal of the 9⁵/₈" PCCC may have operated to alter the wellbore dynamics, so as to have a triggering or accelerant effect on the Blowout. Mr Jacob gave evidence to similar effect:

Q. Do you recall some reference in the Atlas report to the possibility that the very fact of the removal of the 9-5/8" PCC might have altered the dynamics in the wellbore?

A. Yes, I believe that was in there, yes.

Q. Do you have any views to offer in that regard?

A. Giving consideration to all the evidence as an engineer, it occurs to me that that is a possibility. It's an easy statement to make. The problem is backing it up with evidence as to what difference it made, and that's the bit where I haven't, in my mind, been able to definitively understand what difference it made. But I can accept that its removal could well have changed one of the variables in the situation, yes.

Q. Does the fact that the sustained blowout was preceded by what some people have called a burp have any significance at all, in your mind, for present purposes?

A. ...one possibility that it indicates to me is that there were some hydrocarbons in the horizontal section of the well. Some time during the period between March and August, they arrived there and they were held in potentially a high spot on the horizontal section.

The removal of the 9-5/8" cap, if there was a just balanced situation, may be enough to allow the movement of that. At the time the cap was removed there was also some additional height of water, which would have increased the pressure at the horizontal section slightly, and then that would have been removed, so there would have been a change in parameters, and that could have allowed that accumulation of hydrocarbon to just move outside of that high area and flow up into the vertical section. If it was hydrocarbons, oil and gas, the gas would expand, and that could result in the burp. Then, having done that, it would have lightened the column and have definitely – well, I say "definitely" – I would assume it put it into an underbalanced situation, which would have then allowed that.

But, as I say, there would need to be some detailed modelling to see whether those time frames made sense between the burp – I'm not qualified to answer that, but it would make sense to me as a viable option.¹⁵⁰

¹⁴⁹ Atlas, Submission to the Inquiry. Mr Jacob made clear that this aspect of his evidence was supposition which would need to be the subject of detailed modelling.

¹⁵⁰ T1764-1765 (Jacob).

- 3.210. The Inquiry considers that removal of the 9 $\frac{5}{8}$ " PCCC could have altered the wellbore dynamics.¹⁵¹ We will probably never know whether this in fact occurred in the H1 Well. However, the evidence given by Mr Gouldin and Mr Jacob recognises that one can never be sure of what is happening down a wellbore, and this warrants a precautionary approach to well control.
- 3.211. Accordingly, the Inquiry rejects the evidence given by Mr Duncan that, in the circumstances which prevailed, 'there was no compelling reason to re-install the 244mm (9 $\frac{5}{8}$ ") corrosion cap'.¹⁵² That evidence completely reverses the default position: namely, unless there is a compelling reason to leave a well unprotected by a secondary barrier, such a barrier should be in place at all times.

Finding 20

The direct and proximate causes of the Blowout include removal, and non-reinstallation, of a PCCC on the 9 $\frac{5}{8}$ " casing string of the H1 Well around midday on 20 August 2009. This PCCC was intended to operate as a secondary barrier against a blowout.

Finding 21

The absence of a 9 $\frac{5}{8}$ " PCCC from midday 20 August 2009 was contrary to sensible oilfield practice, and was also contrary to PTTEPAA's own Well Construction Standards.

Finding 22

The Blowout occurred approximately 15 hours after removal of the 9 $\frac{5}{8}$ " PCCC. If the 9 $\frac{5}{8}$ " PCCC had remained in place, or been re-installed, the Blowout would not have occurred.

Finding 23

Personnel from PTTEPAA were responsible for the decision to remove, and not re-install, the 9 $\frac{5}{8}$ " PCCC. However, Atlas' OIM did not take any steps to ensure that the 9 $\frac{5}{8}$ " PCCC was re-installed, despite being aware of its removal.

Finding 24

In respect of these failures the largest share of responsibility must be borne by PTTEPAA rather than Atlas. Under arrangements agreed between them, PTTEPAA took on primary responsibility for well control, and in its day-to-day operations it did not in fact rely upon Atlas for expert supervisory oversight of well control operations.

¹⁵¹ Mr Duncan's evidence to contrary effect is rejected.

¹⁵² Statutory Declaration of Mr Craig Duncan, 8 March 2010, paragraph 251.

3.212. The Inquiry will now turn to consider other contextual, secondary and/or systemic factors which may have contributed to the Blowout.

The absence of a proper risk assessment on the part of PTTEPAA prior to the decision to use PCCCs

3.213. This issue is not directed to the particular decision to remove and not reinstall the 9½” PCCC on 20 August 2009 (dealt with above). Rather, this topic directs attention to PTTEPAA’s decision to replace cement plugs on wells at the Montara Oilfield with PCCCs. Use of PCCCs as secondary barriers was an unusual initiative. Mr Gouldin, Mr O’Shea, Mr Horne and Mr Wilson said that they had not previously come across PCCCs as well control barriers.

3.214. It was Mr Duncan who made the decision to use PCCCs as barriers at the Montara Oilfield. Use of PCCCs as barriers on specific wells during suspension was, of course, subject to approval by the NT DoR as the relevant regulator, and such approval was in fact given.

3.215. The Inquiry received evidence that Mr Duncan undertook a rudimentary level of risk analysis before arriving at his decision to seek approval to use PCCCs. The only contemporaneous record of any risk assessment was a couple of lines in a Change Control Form which simply (and mistakenly) referred to them as providing ‘improved well integrity’.¹⁵³ Mr Duncan seems to have simply satisfied himself that, at a functional level, PCCCs can fulfil the role of a secondary barrier,¹⁵⁴ and he noted that their use entailed cost savings of US\$50,000. The Inquiry notes, however, that this aspect of Mr Duncan’s risk assessment is contrary to the position adopted by the manufacturer. According to the manufacturer, its PCCCs are not designed to operate as barriers against a blowout, and are only meant to be used on a well that has been plugged and secured (as explicitly stated in the Operating and Service Manual).

3.216. The Inquiry is satisfied that in reaching the decision to use PCCCs as barriers Mr Duncan gave inadequate consideration to other relevant matters:

- a. unlike other secondary barriers, a PCCC has to be removed prior to tieback of the casing string. Accordingly, Mr Duncan gave little or no attention to how wells would be controlled, by way of secondary barriers, after removal of the PCCCs and prior to the installation of the BOP;

¹⁵³ T1057-1058 (Duncan).

¹⁵⁴ T1283 (Duncan).

- b. Mr Duncan did not satisfy himself properly of the content of the PCCC manufacturer's instructions. Had he done so, he would have ascertained that those instructions simply did not deal at all with post-installation testing of PCCCs (see below). The whole issue of post-installation testing appears to have escaped any real attention prior to the decision to use PCCCs; and
- c. the method of installation was specific and contemplated the use of equipment which was not available on the rig.

3.217. The Inquiry notes that Mr Jacob accepted the specific deficiencies in (a), (b), and (c) above,¹⁵⁵ but did not seem to be aware that PCCCs were never designed by the manufacturer to operate as barriers against blowouts. Had a proper risk assessment been carried out at the time, including as to post-installation testing (see below), it seems likely that PCCCs would not have been used – because, for instance, there was no tool then in existence which the manufacturer endorsed as a reliable mechanism for testing.¹⁵⁶

Finding 25

A factor which is likely to have indirectly contributed to the Blowout is that a sufficiently detailed risk assessment was not undertaken by PTTEPAA in relation to the general topic of use of PCCCs as secondary barriers against a blowout, particularly in the context of batched tie-back operations which were to occur at Montara.

Finding 26

The absence of such a risk assessment meant, for instance, that (i) PTTEPAA personnel wrongly thought that the PCCCs in question were designed to operate as barriers against a blowout; (ii) PTTEPAA personnel wrongly thought that the PCCCs were able to be tested and verified post-installation in accordance with the manufacturer's instructions; and (iii) PTTEPAA personnel did not properly appreciate one significant advantage which other types of barriers have over PCCCs in the context of batched tie-back operations: namely, other barriers can remain in place during and after tie-back, whereas PCCCs must be removed prior to tie-back of a casing string.

¹⁵⁵ T1640 (Jacob).

¹⁵⁶ PTTEPAA advised the Inquiry after the public hearing that the WA Department of Mines and Petroleum (DMP) had, it thought, approved the use of PCCCs as secondary barriers by another operator. DMP confirmed this occurred, and without any risk assessment having been carried out by DMP. DMP advised the Inquiry that the onus was on the licensee to conduct a risk assessment 'associated with re-entry works'. The Inquiry does not consider this to be a satisfactory approach by DMP. First, regulatory authorities should be engaging with operators to ensure proper risk assessments are actually carried out; secondly, it is not good enough to defer any risk assessment until the point of re-entry.

Finding 27

Had the use of PCCCs been properly risk assessed a decision would probably have been reached to rely upon some other form of secondary barrier such as a cement plug. In that event, it is unlikely the Blowout would have occurred.

Non-testing of the 9 $\frac{5}{8}$ " PCCC post-installation

- 3.218. PTTEPAA's own Well Construction Standards, as well as sensible oilfield practice, required that each barrier be tested in situ to ensure integrity.¹⁵⁷ In the case of PCCCs, this would involve a timely post-installation check to guard against, for instance, damage of the o-rings during the course of installation. Unless such a test is carried out there can be no assurance that the PCCC is, in fact, functioning properly. In this regard, the Inquiry notes:
- a. PTTEPAA personnel onshore did not give any instruction to the personnel on the rig to test the PCCCs after installation. Had such an instruction been given, the following matters may have come to light;
 - b. PCCCs are principally designed to prevent fluid and debris entering a casing string from above, and to control corrosion, rather than to operate as verifiable barriers against blowouts;¹⁵⁸
 - c. at the time the PCCC was installed in the H1 Well, there was no accepted method for testing the integrity of that PCCC post-installation; and
 - d. indeed, the manufacturer has informed the Inquiry that, from its point of view, there is still no test which can confirm the integrity of its PCCCs as barriers against blowouts, because its PCCCs are simply not designed to operate in that way (even though they are pressure containing).¹⁵⁹
- 3.219. After the Inquiry's public hearing PTTEPAA advised the Inquiry that it has developed a Hydraulic Actuation Tool which now permits the testing of 13 $\frac{3}{8}$ " PCCCs. PTTEPAA informed the Inquiry that this tool involves removal of the probe from the manufacturer's running and retrieval tool, and replacement with a hydraulically deployed probe, which:

...will allow for the installation of the tool without opening the poppet valve. Once the running tool is engaged, a chain tong is used to turn it slightly to use the pins on the top of the PCCC neck to long the tool into position using the J slots. PTTEPAA has introduced a ½" test port in the

¹⁵⁷ Messrs Gouldin, Wilson, Duncan and Jacob accepted that PCCC's should be tested in situ.

¹⁵⁸ See T47 (Gouldin) and information provided by the manufacturer.

¹⁵⁹ The manufacturer stated that it has not designed, and is not aware of, any test that could verify the internal pressure containing capability of its PCCCs after installation.

side of the tool to connect a pressure test line attachment to the running tool. A low pressure test of the running tool O rings can be done at that time...

The hydraulically actuated probe can then be utilised to open the poppet valve, allowing communication with the fluids below the PCCC. This will allow PTTEPAA to measure any pressure below the PCCC.¹⁶⁰

3.220. PTTEPAA also informed the Inquiry that:

PTTEPAA has advised [the manufacturer] of the modification to the running tool and how it works. [The manufacturer] has not raised any concerns over the proposed modification or its purpose.¹⁶¹

3.221. Mr Wilson and Mr Duncan informed the Inquiry after the public hearing that they disagreed with the manufacturer's position that PCCCs should not be used as barriers against blowouts, because they carried a pressure rating and were described as pressure containing. Mr Wilson did not express any specific knowledge of a testing tool developed by PTTEPAA, but he did refer to the manufacturer having informed PTTEPAA, prior to his departure from the company, that it was possible to pump through the PCCC with the running tool installed. Mr Duncan considered that it was possible to pressure test beneath a PCCC, providing (i) care was taken not to pump through the check valve too quickly; and (ii) after the casing string was filled with fluid, the test pump should slowly increase pressure to test the PCCC seals.¹⁶²

3.222. The Inquiry is not in a position to reach a concluded view as to whether PCCCs can be properly tested in situ in order to verify their integrity as a barrier. However, what is significant for present purposes is that the method and tool described by PTTEPAA were only developed since the Blowout (indeed, after the Inquiry's public hearing). The PCCC used in the H1 Well should have been tested soon after installation, and it wasn't.

3.223. The absence of any test of the 9 $\frac{5}{8}$ " PCCC has possible relevance in this case because all PTTEPAA-related witnesses who gave evidence to the Inquiry attached significance to the fact that, prior to removal, there was no detectable pressure beneath the 9 $\frac{5}{8}$ " PCCC. The possibility that the PCCC may not have been working properly might account for the absence of any detectable pressure.

¹⁶⁰ Letter from Solicitors for PTTEPAA to the Solicitor Assisting the Inquiry dated 26 May 2010.

¹⁶¹ Ibid.

¹⁶² Mr Duncan accepted that erosion of the steel was a valid concern, hence the need to pump through at a low rate.

- 3.224. The absence of any test of the 9 $\frac{5}{8}$ " PCCC installed on the H1 Well is also relevant to the subject matter of this Inquiry because the same omission occurred in respect of every other PCCC installed on all of the other wells at the Montara WHP. This is indicative of a serious laxity in the approach adopted by PTTEPAA (and to a lesser extent Atlas) in relation to the management of well integrity.

Finding 28

The PCCC used in the H1 Well should have been tested by PTTEPAA soon after installation. However, no instruction was given by PTTEPAA to carry out such a test.

Finding 29

Had such an instruction been given it may have come to light that (i) the manufacturer did not endorse any post-installation test for barrier integrity; and (ii) at that point in time there was no method or equipment available to reliably test the PCCC after installation. That may have prompted a review of the use of PCCCs as barriers.

Finding 30

Further, as noted above, in the absence of any such test it is possible that the 9 $\frac{5}{8}$ " PCCC on the H1 Well was not working properly after installation, which might explain the absence of any detectable pressure beneath the PCCC prior to its removal.

Misconceptions as to the status of the 9 $\frac{5}{8}$ " casing fluid

Introduction

- 3.225. The Inquiry is satisfied that every PTTEPAA witness who was actually involved in events leading up to the Blowout seriously misunderstood the status of the fluid in the 9 $\frac{5}{8}$ " casing string.
- 3.226. Each such PTTEPAA witness considered that the fluid was 'overbalanced' as compared to the pressure of the reservoir. Accordingly, they each considered that the casing fluid would operate as a barrier against a blowout, notwithstanding that:
- a. the fluid's density had not been monitored and maintained in accordance with PTTEPAA's own Well Construction Standards, and as required by sensible oilfield practice;
 - b. the fluid had not been verified as actually having a hydrostatic overbalance at any time between March/April 2009 and the date of the Blowout; and
 - c. it was generally understood that even if the casing fluid happened to be overbalanced, it would only be by a small margin, that is, personnel understood that the density of the fluid did not satisfy the requirement for a

safety margin over the reservoir pressure. That safety margin was at least 143psi according to PTTEPAA's own Well Construction Standards.¹⁶³

- 3.227. The upshot was that PTTEPAA witnesses drew an unwarranted level of comfort from the presence of fluid in the casing string, which both reflected and influenced a lax approach to well control in the lead up to the Blowout.

General explanation of fluids as barriers

- 3.228. Before turning to the actual evidence given by PTTEPAA witnesses, some brief background matters should be noted:
- a. hydrostatic pressure is the pressure exerted by a fluid at rest. In the context of well construction, it is the pressure exerted by the fluid in the reservoir and the casing string (respectively) at a particular vertical depth;
 - b. calculation of hydrostatic pressure requires consideration of vertical depth, fluid density, and gravity. At any point in the well, gravity and vertical depth can be considered constant. Accordingly, as density is the only variable, it is common to refer to hydrostatic pressure in terms of density (measured as specific gravity or 'sg');
 - c. if the hydrostatic pressure of casing fluid is greater than the formation/reservoir pressure, the fluid is said to be overbalanced to formation;
 - d. if the formation pressure is greater than the hydrostatic pressure of casing fluid, then the fluid is said to be underbalanced. In that event, it cannot be considered to operate as a barrier. Indeed, absent other primary or secondary barriers, an underbalanced situation within a wellbore would lead to an influx of reservoir fluids into a well;
 - e. accordingly, to enable a fluid within a wellbore to operate as a barrier it must be overbalanced to formation. However, sensible oilfield practice recognises that casing fluid ought only be relied upon as a barrier if (i) it is overbalanced by an acceptable safety margin; and (ii) that level of hydrostatic overbalance, with a safety margin, is tested and verified;
 - f. because the properties of fluids used in well construction operations can change over time, they should only be relied upon as a barrier if the requisite level of overbalance is monitored, measured, and maintained over time.

¹⁶³ Mr O'Shea suggested in his oral evidence that fluid in a *horizontal* casing string might require a significantly higher safety margin.

In effect, this requires that the fluid be connected to a fluid circulatory system, and remain connected to that system, when operating as a barrier; and

- g. prior to commencement of drilling operations, PTTEPAA undertook an analysis of the pressure of the Montara reservoir (variously called 'formation pressure' or 'pore pressure'). Various geological data were analysed to arrive at an estimate of the reservoir pressure. This estimate was factored into a document known as the Basis of Well Design (**BOWD**), the purpose of which is aptly described by its title. In the BOWD applicable to the H1 Well the pore pressure of the reservoir was described as 'normal - 1.04sg throughout entire well'. DDRs for the H1 Well described the pore pressure of the formation variously between 1.04sg - 1.06sg. These records were based on mud logging records maintained during the course of drilling operations.¹⁶⁴

Evidence of PTTEPAA witnesses concerning casing fluid in H1 Well

- 3.229. All of the relevant PTTEPAA witnesses - Mr Wishart, Mr O'Shea, Mr Wilson, and Mr Duncan - reasoned as follows in relation to the casing fluid in the H1 Well:
 - a. the pore pressure of the H1 Well was listed in the BOWD as 'normal - 1.04sg';
 - b. the word 'normal' was considered to be of more importance than the numerical pressure value;
 - c. 'normal pressure' is equivalent to that of seawater, which was asserted to be 1.03sg;
 - d. the fracture pressure in the H1 Well was estimated in the BOWD as 1.40sg near the reservoir; and
 - e. the above pore and fracture pressure figures meant that the H1 Well would be overbalanced to formation if the well was filled with seawater.

Assessment of this reasoning process

- 3.230. This line of reasoning gives rise to self-evident logical problems:
 - a. according to the BOWD, the density of the reservoir exceeded that of seawater. Put simply, a specific gravity of 1.04sg is higher than 1.03sg;

¹⁶⁴ These mud logging records, whilst useful, are not as reliable as actual pressure measurements known as RFT (repeat formation test) measures or MDT (modular dynamic tool) measures. The pore pressure estimated and described in the BOWD took account of RFT data.

- b. this result is not overcome by ascribing more importance to the reservoir being 'normally pressured' as opposed to 'over pressured';
- c. further, according to the Victorian regulator, seawater is taken to have a density of between 1.02sg - 1.03sg, a proposition with which Mr Jacob did not disagree. Indeed, the undisputed evidence before the Inquiry is that the inhibited seawater which was introduced into the 9 $\frac{5}{8}$ " casing string on 7 March 2009 was recorded as having a specific gravity of 1.02sg,¹⁶⁵
- d. therefore, the geologist's reference to the reservoir pressure being 'normal' should not have been interpreted as meaning that a column of seawater in the 9 $\frac{5}{8}$ " casing string would be overbalanced to formation.

3.231. After Mr Duncan gave his evidence he produced a handwritten calculation which allegedly showed that at the point the casing shoe was located inside the reservoir, the pore pressure of the reservoir was 1.0136sg. The Inquiry notes as follows in relation to this calculation:

- a. the calculation is based on the gas-oil contact pressure, and it is correct only for the single point at the end of the casing shoe;
- b. when designing and implementing a well control regime, it is standard practice to use the water zone pressure gradient to determine the pore pressure of a reservoir such as Montara; and
- c. in any event, Mr Duncan's figures showed that the casing fluid would need a density of 1.052sg to achieve a satisfactory safety margin.¹⁶⁶

3.232. The Inquiry notes and accepts the following evidence given by Mr Jacob in relation to the status of the casing fluid in the H1 Well prior to the Blowout:

- a. the casing fluid failed to meet each and every criterion specified in PTTEPAA's own Well Construction Standards applicable to the barrier status of fluids;¹⁶⁷
- b. the density of the casing fluid could have been lowered in the period between March and August 2009 as a result of a leakage of gas from the formation;¹⁶⁸

¹⁶⁵ See the Advantage Drilling Fluids Report dated 6 March 2009; see also Mr Treasure's evidence concerning this report.

¹⁶⁶ This is the figure one arrives at if the alleged formation pressure of 1.0136 sg is overbalanced by a safety margin of 143 psi. Mr O'Shea gave evidence that when casing is located *horizontally*, an ever higher safety margin than 143 psi would be appropriate (T831:29-38).

¹⁶⁷ T1664 (Jacob).

- c. there should have been more expansive treatment of the topic of casing fluids as barriers in PTTEPAA's Well Construction Standards;¹⁶⁹ and
 - d. the use of seawater as a barrier against a normally pressured reservoir 'doesn't make any sense'. Inhibited seawater should never be relied upon as a barrier against a normally pressured reservoir.¹⁷⁰
- 3.233. PTTEPAA personnel should not have approached the geologist's assessment in the BOWD document by attaching emphasis to the word 'normal' and ignoring the reference to '1.04 sg'. PTTEPAA personnel should not have proceeded on the basis that the seawater in the casing provided hydrostatic overbalance.¹⁷¹
- a. the presence of seawater in the 9 $\frac{5}{8}$ " casing string gave a level of comfort to PTTEPAA personnel which was unwarranted;¹⁷²
 - b. reliance upon inhibited seawater as affording any sort of barrier protection was 'not within safe oilfield practice';¹⁷³ and
 - c. when planning and implementing well control over the H1 Well PTTEPAA personnel should have operated on the basis that the casing fluid was actually under-balanced to formation, having regard to the contemporaneous material available to PTTEPAA at the time.¹⁷⁴

Movement in PTTEPAA's position on the question of the status of the casing fluid

- 3.234. On 22 December 2009 PTTEPAA lodged written submissions with the Inquiry. Those submissions stated that the seawater in the casing fluid was a barrier:
- ...which provided hydrostatic pressure greater than the pore pressure.¹⁷⁵
- 3.235. This proposition was repeated in the Statutory Declarations made by Mr Wishart, Mr O'Shea, Mr Wilson and Mr Duncan.

¹⁶⁸ T1665 (Jacob).

¹⁶⁹ T1668 (Jacob).

¹⁷⁰ T1668-1669 (Jacob).

¹⁷¹ T1719 (Jacob).

¹⁷² T1727 (Jacob); T1737 (Jacob).

¹⁷³ T1735 (Jacob).

¹⁷⁴ T1770 (Jacob); T1773 (Jacob). This is starkly illustrated by the fact that when PTTEPAA designed the Relief Well, it did not seek to rely on Mr Duncan's calculation of the reservoir pore pressure. Rather, it designed the Relief Well on the basis that the pore pressure of the reservoir was 1.04sg.

¹⁷⁵ PTEPAA, Submission to the Inquiry, paragraph 98.

- 3.236. Further, only a matter of days prior to commencement of the Inquiry's public hearing, PTTEPAA filed written submissions in response to the Atlas Report,¹⁷⁶ wherein the following statements were made by PTTEPAA:

The inhibited seawater column inside the 9 $\frac{5}{8}$ " casing is also a well control barrier when its pressure exceeds the reservoir pressure (Section 5 'Barriers', 'Barriers during Temporary Suspension', PTTEPAA Well Construction Standards and section 2.3.1 of the [Atlas] Well Control Manual). PTTEPAA has verified that the pressure of the inhibited seawater column exceeded the reservoir pressure but PTTEPAA still has no explanation as to why the flow of hydrocarbons in the 9 $\frac{5}{8}$ " casing was not stopped by the hydrostatic head created by the inhibited seawater.

...

The cement displacement fluid was compliant with Section 2.3.1 of the [Atlas] Well Control Manual whenever the 244mm [9 $\frac{5}{8}$ "] PCCC was removed.¹⁷⁷

- 3.237. Section 2.3.1 of the Atlas Well Control Manual, referred to in PTTEPAA's written submissions quoted above, provided as follows:

To maintain hydrostatic well control, the fluid in the well bore must be of sufficient density to contain formation pressure.

All well operations conducted from the Company's installations are designed, planned and conducted to maintain, wherever possible, hydrostatic or primary well control. To this end, all installations will have a system for the regular monitoring and recording, of drilling or completion fluid properties. The monitoring system must also include the sampling and reporting frequency when circulation of fluid is not in progress...¹⁷⁸

- 3.238. The Inquiry notes that, contrary to PTTEPAA's submission, the displacement fluid in the 9 $\frac{5}{8}$ " casing of the H1 Well did not come close to satisfying section 2.3.1 of the Atlas Well Control Manual.
- 3.239. In any event, what is significant for present purposes is that up to the time the public hearing commenced, PTTEPAA was contending that its personnel were entitled to rely upon the casing fluid as a verified, compliant barrier. This accords with various answers Mr Jacob gave to NOPSAs when he was interviewed in mid February 2010.

¹⁷⁶ Seadrill Investigation Report Blowout on Montara Platform – Fri 21 Aug 2009 (the Atlas Report).

¹⁷⁷ PTTEPAA's response to the Atlas Report, 10 March 2010.

¹⁷⁸ Atlas Well Control Manual, 26 June 2006, p. 24, SEA.009.001.0766.

3.240. Then, halfway through the Inquiry's public hearing, PTTEPAA informed the Inquiry as follows:

[PTTEPAA]'s position is that it [the casing fluid] has never been relied upon as a verified barrier. It is potentially a barrier within the terms of the standards, and there is a difference between a verified barrier and a barrier.

It was considered, when the cap was taken off, to show that there was no movement of the fluids in there, but it was not actually the barrier that was relied upon at that time. The barrier relied upon when the cap was taken off was the cemented shoe.¹⁷⁹

3.241. These statements are worthy of close attention. First, PTTEPAA had at earlier points in time asserted reliance upon the casing fluid as a compliant barrier; secondly, the statements quoted in the preceding paragraph were made following evidence being adduced which showed that the casing fluid should never have been relied upon as a compliant barrier; and thirdly, contrary to the statement made by PTTEPAA to the Inquiry, Mr Duncan and other PTTEPAA personnel did not merely rely upon the absence of movement of fluids within the casing string on 20 August 2009. The Inquiry heard much evidence to the effect that when the 9 $\frac{5}{8}$ " PCCC was removed, PTTEPAA personnel thought that the casing fluid could be relied upon as an effective practical barrier against a blowout.

3.242. It is difficult to avoid a conclusion that PTTEPAA seriously overreached in relation to the status of the casing fluid, and gave ground on that issue only when required by the weight of evidence.

Conclusions concerning PTTEPAA's approach to status of casing fluid

3.243. There was widespread misunderstanding on the part of PTTEPAA personnel as to the barrier status of the displacement fluid contained within the 9 $\frac{5}{8}$ " casing in the H1 Well.¹⁸⁰ In the lead up to the Blowout, on-rig and onshore personnel from PTTEPAA considered that the fluid could be relied upon as an effective barrier against a blowout. Their approach to that question was contrary, in fundamental respects, to sensible oilfield practice with respect to well control. It was also contrary to PTTEPAA's own Well Construction Standards. The significance of PTTEPAA's flawed approach to the status of the casing fluid is starkly captured in the following evidence of Mr Wilson:

¹⁷⁹ T869:33-42.

¹⁸⁰ This displacement fluid was introduced in March 2009 and remained in place up to the point of the Blowout.

I can't say specifically that it did play a role, but I can say if I knew that the fluid in there was underbalanced, we certainly wouldn't have taken the cap off.¹⁸¹

3.244. Mr Duncan gave evidence on this question in these terms:

Q. Do you think that there might have been a general level of confusion along the exact lines you have just articulated, namely, that because this was thought to have some level of overbalance, it could be relied upon to have a kill weight density and therefore act as a barrier?

A. That's possible, yes.

Q. Because a number of the statements, the actual statutory declarations, that have been filed with the Commission, do refer to the author of the declaration describing the casing fluid as a barrier, and I want to suggest to you that that betrays, if you like, a misconception; do you agree with that?

A. Yes.

Q. And do you accept the possibility that that misconception might have influenced some of the way in which the management of the H1 well was approached?

A. Certainly in August, yes.

Q. Why do you qualify your answer by reference to August but, in respect of August, express the view in fairly emphatic terms?

A. Because I was trying to work out when it would be most likely to be confusing, and August was the time, in my opinion.

Q. Do you accept the possibility that you yourself might have succumbed to that misconception in the way you approached events on 20 August?

A. Strictly speaking, in our standards, yes, I was aware it couldn't be considered a barrier, but I knew it was an indicator as to what was going on down-hole. Yes, there's an element of acceptance there. I thought, and still think, it was overbalanced to formation; it didn't meet the strict criteria of being a barrier, so, yes, in August, that's possible.¹⁸²

...

Q. So is it correct that, as at 20 August last year, your decision not to insist upon reinstallation of the 9-5/8" [PCCC] was influenced, at least to some extent, by your understanding that the casing fluid would create a pressure barrier against a blowout?

A. It was influenced, in that I knew that the fluid was overbalanced to the reservoir and that it was an indicator as to what I thought was happening down-hole. If there had been any movement in that fluid, we would have done something differently, for sure.¹⁸³

¹⁸¹ T1136 (Wilson).

¹⁸² T1305-1306 (Duncan).

¹⁸³ T1510 (Duncan).

- 3.245. There can be little doubt, therefore, that misconceptions as to the status of the casing fluid did indirectly influence PTTEPAA's approach to well control.

Finding 31

An indirect and systemic factor which contributed to the Blowout was widespread misunderstanding on the part of PTTEPAA personnel as to the barrier status of the displacement fluid contained within the 9 $\frac{5}{8}$ " casing in the H1 Well.¹⁸⁴ Misconceptions as to the status of the casing fluid influenced PTTEPAA's approach to well control.

Finding 32

Both on-rig and onshore personnel from PTTEPAA wrongly considered that the fluid could be relied upon as an effective barrier against a blowout.

Finding 33

Their approach to that question was contrary, in fundamental respects, to sensible oilfield practice with respect to well control. It was also contrary to PTTEPAA's own Well Construction Standards.

Too much weight given by PTTEPAA and Atlas to absence of detectable signs of flow; and inadequate monitoring of the well after removal of the 9 $\frac{5}{8}$ " PCCC

- 3.246. These two factors could perhaps be separated, but it is convenient to deal with them together.
- 3.247. Every PTTEPAA-related witness involved in the removal of the 9 $\frac{5}{8}$ " PCCC attached significant weight to the fact that, at the time of the removal of the 9 $\frac{5}{8}$ " PCCC, no signs of flow from the H1 Well were detected. As noted above, weight was attached to the absence of detectable pressure beneath the 9 $\frac{5}{8}$ " PCCC immediately prior to its removal. Visual inspection of the casing fluid was then undertaken for a short time, on a somewhat ad hoc basis.
- 3.248. The Inquiry is satisfied that those involved in the removal of the 9 $\frac{5}{8}$ " PCCC attached too much weight to the absence of any signs of well flow. PTTEPAA personnel proceeded on the basis that if the H1 Well was flowing, even to a small extent, observable signs of flow should have been apparent. The general approach of these witnesses is summarised in the following portions of Mr Duncan's Statutory Declaration:

¹⁸⁴ This displacement fluid was introduced in March 2009 and remained in place up to the point of the Blowout.

238 ...The well had at that time been suspended for 5½ months and there was no evidence of anything to be concerned about from an imminent well safety perspective...

246 ...if there had been any change in the fluid status since cement placement on 7 March 2009, this would be evident and managed by checking for trapped pressure below the 244mm (9⅝”) PCCC before its removal.

...

251. Based on the well status of the H1 Well, the planned exposure to atmosphere whilst the tie backs were undertaken, and the absence of any physical evidence of a change in fluid status, there was no compelling reason to re-install the 244mm (9⅝”) corrosion cap.¹⁸⁵

- 3.249. The Inquiry considers that the process of reasoning described by Mr Duncan and other PTTEPAA-related witnesses confounds a proper approach to barriers and well control. The absence of any observable signs of well flow cannot justify removal and non-reinstallation of a secondary barrier against a blowout. Sensible oilfield practice recognises that one can never be sure, at any point in time, of exactly what is happening, or may imminently happen, within a wellbore. A flow may be incremental or sudden; the rate of flow may be slow, fast, or varied; a flow may occur to a certain point within a casing string and proceed no further until blowout and so on. The number of variables and uncertainties affecting whether, when, and how a blowout might occur are such that it is sensible and prudent to have proven primary and secondary barriers in place at all times.
- 3.250. Even Mr Jacob was inclined to attach too much significance, in the scheme of things, to the absence of any observable signs of flow when the 9⅝” PCCC was removed – although he frankly conceded that the level of monitoring after removal of the PCCC was ‘totally inadequate’.¹⁸⁶ By way of contrast, Mr Gouldin considered it quite plausible that the H1 Well could have been flowing to some extent prior to removal of the 9⅝” PCCC, even though no signs of pressure were detected.¹⁸⁷

¹⁸⁵ Statutory Declaration of Mr Craig Duncan, 8 March 2010, p. 47. Mr Duncan told the Inquiry: ‘I was of the opinion that the fluids in the casing would always indicate, transmit to surface, if there was anything untoward down-hole’ (T1306).

¹⁸⁶ See T1665-T1666 (Jacob).

¹⁸⁷ See T50 - T51 (Gouldin) as to the distance between the PCCC and the pressure gauges, and the possibility of release of pressure when the removal tool was connected to the PCCC. Mr O’Shea gave similar evidence (T854 and T862). Mr Millar agreed that the pressure sensors on the choke manifold or in the drillers console may not have been able to detect pressure beneath the PCCC (T681).

3.251. The crucial point, for present purposes, is that well control should be managed on the basis that there may be little or no adequate forewarning of a blowout. For instance, Mr Duncan eventually conceded that the casing fluid might not necessarily show evidence of flow:

Q. So might there have been a leakage of oil, for instance, from the reservoir, in that direction, and then also a leakage of inhibited seawater from the casing string into the reservoir, so, in effect, you have an exchange?

A. That's possible.

Q. And that wouldn't be apparent in terms of visibly eyeballing the level of the casing fluid at the top, some distance of 3,700 metres away?

A. Agreed.

Q. So you can, in fact, have an exchange of fluids between the bottom of the casing string and the reservoir in circumstances which won't necessarily be apparent by eyeballing the fluid level at the top?

A. Yes.

Q. Which is a very good reason, I suggest, not to rely on that sort of casual eyeballing as any sort of proper system of well management.

A. I agree.¹⁸⁸

3.252. Hence the need to have effective primary and secondary barriers in place. The Inquiry did not understand there to be any disagreement between Mr Jacob and Mr Gouldin on this point.

Atlas' approach to the absence of physical signs of flow

3.253. Atlas, through Mr Trueman, also drew an unwarranted level of comfort from the absence of any physical signs of flow around the time of removal of the 9½" PCCC. In Mr Trueman's draft Proof of Evidence he stated, relevantly, as follows:

19. When they took the trash cap off we learned that the 13 3/8 cap was not in place.

20. This did not ring any alarm bells with me. There were no bubbles, nothing to suggest that the well was leaking.

...

24. They would not have taken the cap off if it had any pressure whatsoever.

25. In 6 months' [sic] time (since we suspended the well), if there had been any leaking, there would have been pressure.

...

45. I didn't see any risk. If we'd gone to take that cap off and there'd been pressure, there is no way we would have taken the pressure cap off.

¹⁸⁸ T1367 (Duncan).

...

50. As to whether there might have been a slow upward flow of fluid before the kick, the [PTTEPAA] Night Company Man, Brian [Robinson] went and looked into the well and said there was no movement at all, no flow.¹⁸⁹

- 3.254. Accordingly, it appears that Atlas' senior representative on the rig also placed too much weight on the absence of physical signs of flow.

Finding 34

In the lead up to the Blowout, both on-rig and onshore personnel from PTTEPAA attached too much weight to the absence of observable signs of flow from the reservoir. There is reliable evidence to the effect that Atlas personnel succumbed to the same mistake.

Finding 35

Similarly, personnel from both PTTEPAA and Atlas failed to ensure that the dynamics of the casing fluid were properly monitored after removal of the 9 $\frac{5}{8}$ " PCCC.

Deficiencies in PTTEPAA's well control documents

- 3.255. During the course of the public hearing a large number of deficiencies were identified in relation to PTTEPAA's well control documents. The Inquiry is satisfied that these deficiencies are likely to have materially contributed, albeit in an indirect way, to the Blowout. The Inquiry notes that PTTEPAA has accepted a need to re-write its well control documents, and has engaged an external consultant to conduct the review.

Phase 1B Drilling Program and batched tie-back

- 3.256. The Phase 1B Drilling Program issued in June 2009¹⁹⁰ was seriously deficient in terms of management of well control in the course of batched tieback operations. It made provision for removal of secondary barriers in the H1 Well (and, the Inquiry notes, in the GI Well) in circumstances where the H1 Well would be left exposed to atmosphere for an unsatisfactory length of time.
- 3.257. The estimates of that length of time have varied from eight-ten hours to three days. Doing the best it can, the Inquiry considers that if the Phase 1B Drilling Program had been implemented it would have resulted in the H1 Well being exposed to atmosphere for up to 48 hours after removal of the 9 $\frac{5}{8}$ " PCCC.

¹⁸⁹ Proof of evidence of Mr Trueman, undated, pp. 5-11, PRF.6010.0001.0003.

¹⁹⁰ Montara Phase 1B Drilling and Completion Program, June 2009, PTT.9000.0002.0005.

For approximately 36 of these 48 hours the derrick would not have been over the H1 Well.¹⁹¹

- 3.258. Whatever the precise period of time, the Inquiry is satisfied it was too long. Exposing the H1 Well to atmosphere between steps 197-320 in the Phase 1B Drilling Program was not a matter of necessity - it was a program predicated upon considerations of efficiency, rather than safety.
- 3.259. The failure of the Phase 1B Drilling Program to make adequate provision for well control during batched tie-back operations is an example of PTTEPAA succumbing to the allure of time and cost savings.¹⁹²

Other deficiencies in well control documents

- 3.260. Other deficiencies with respect to PTTEPAA's well control documents included:
- a. the Drilling Program in force at the time of the cementing of the casing shoe in March 2009 did not adequately describe the objectives sought to be achieved with respect to annulus cement. Had the Drilling Program been more instructive, it is likely that personnel on the rig would have used the correct volume of tail cement, thereby avoiding the creation of wormholes or channels whilst the cement set;
 - b. that same Drilling Program did not deal with the need for a repeat pressure test if the plugs did not bump or de-dumped. In this regard, it is noteworthy that an earlier version of the Drilling Program (Revision 0) explicitly required a repeat pressure test after the cement had set if the plugs did not bump (see pages 47-48 of PTT.9000.0003.0148). When Revision 0 of the Drilling Program was replaced by Revision 2 in January 2009, the new program was silent on the need for a repeat pressure test if the plugs did not achieve and maintain a proper seal;
 - c. Drilling Program Revision 2 did not deal in any way with a known and predictable contingency, being a failure of float valves during the course of a

¹⁹¹ The removal of the 9½" PCCC from the H1 Well was step 196 in the Drilling Program, and a BOP was stipulated for installation on top of the H1 Well in step 321 of the Drilling Program. Tieback of each casing string is likely to have occupied approximately 12 hours. The actual work undertaken on the H1, G1 and H4 Wells in August 2009 supports this assessment.

¹⁹² The Inquiry notes that PTTEPAA's stated management position was that time and cost savings should not be pursued at the expense of safety. However, PTTEPAA did not do anywhere near enough to ensure that this stated position was carried out by its personnel. This is an issue that should have been identified during an audit process.

cementing operation. The Inquiry notes that Mr Duncan and Mr Jacob accepted that the document was deficient in this respect;¹⁹³

- d. the Phase 1B Drilling Program Revision 0 published in June 2009 wrongly asserted that a 13 $\frac{3}{8}$ " PCCC had been installed on the H1 Well;¹⁹⁴
- e. neither Drilling Program Revision 2 nor the Instructions to Drillers published by PTTEPAA adequately reflected the manufacturer's instructions concerning installation of PCCCs;
- f. the Drilling Program in place at the time of cementing the casing shoe did not properly identify the relevance of other documents to well control, for example, the Atlas SDI Operations Manual;
- g. neither Drilling Program Revision 2 nor the Instructions to Drillers referred to the need for, or manner of, a post-installation test of PCCCs;
- h. PTTEPAA reporting documents, such as the cementing report, could be improved to assist personnel who complete or review the documents to identify problems. In this regard, the Inquiry notes the following evidence given by Mr Jacob:

...that's why, going forward, looking at a cementing form that clearly identifies all the requirements and picks up all of the separate elements so that it's obvious to the innocent person that one plus one equals five is not the right answer.¹⁹⁵

- 3.261. PTTEPAA's WOMP adopted a very broad and non-specific approach to identification and management of risks. In significant respects, the WOMP was non-instructive. The WOMP required users to wend their way through a series of cross-referenced documents, most of which were also pitched at a high level of generality. The WOMP did not provide a cohesive user-friendly framework for identification and management of well construction risks.

Deficiencies in PTTEPAA's Well Construction Standards

- 3.262. PTTEPAA's Well Construction Standards were clearly deficient in a number of respects. For instance:

¹⁹³ See T1455 (Duncan); T1635 - T1636 (Jacob); T1716 - T1717 (Jacob).

¹⁹⁴ The Inquiry accepts that PTTEPAA personnel onshore cannot be criticised for this error, as they were wrongly advised by personnel on the rig that the 13 $\frac{3}{8}$ " PCCC had been installed.

¹⁹⁵ T1674 (Jacob).

- a. they did not explicitly state the need for a safety margin if displacement fluid was to be relied upon as a barrier;¹⁹⁶
- b. they were ambiguous as to the circumstances in which reliance upon only one barrier might occur, and did not make clear that secondary barriers must be in place except in very limited exceptional circumstances;
- c. the parts of the Well Construction Standards dealing with cementing did not properly discriminate between lead and tail cement, or whether Top of Cement (**TOC**) referred to cement in the outside annulus or within the casing;
- d. they did not deal specifically with drilling and suspension of wells at a platform prior to topsides installation;
- e. they did not deal in any way with well control during batched tieback of casing strings on different wells.

3.263. As to the second of the deficiencies identified in the preceding paragraph, it is clear this deficiency exerted considerable influence over Mr O’Shea, Mr Wilson and Mr Duncan, each of whom gave evidence to the effect that they were content to remove, and not reinstall, the 9⁵/₈” PCCC on 20 August 2009 because they thought doing so was compliant with PTTEPAA’s Well Construction Standards. In their oral evidence, all of these witnesses initially sought to maintain that the Well Construction Standards and customary oilfield practice allowed for exposure of wells to atmosphere while other tasks were carried out, but eventually accepted that a secondary barrier must be in place whenever practicable to do so.

3.264. It is unfortunate that Mr Duncan, as Well Construction Manager, had responsibility for ensuring contractors understood and applied the Well Construction Standards – given that his own understanding of them was deficient in some significant respects.

3.265. In relation to deficiencies in the Well Construction Standards, the Inquiry agrees with the following evidence given by Mr Jacob:

Q. Indeed, you accept, don’t you, sir, that in fact the well construction standards were really devised by reference to a significantly different set of circumstances?

A. Yes.

¹⁹⁶ T1669; T1735 (Jacob).

Q. And they should have been revised prior to the Montara oilfield development?

A. There should have been a review undertaken...

...

Q. Likewise, in relation, for instance, to the batch drilling regime... and the batch tie-backing and so on, you will agree with me, sir, that when it was decided to embark upon those regimes, there should have been a review of the well construction standards to ensure that they adequately dealt with those regimes?

A. Yes, there should have been a HAZID review at that time, which would have identified whether or not they were applicable or whether additional things should have been put in place. Yes, I agree with that.

Q. You will agree, sir, that the Commission heard quite a lot of evidence to the effect that the absence of any such review has led to a considerable degree of both confusion and divergence of opinion as to the meaning of the well construction standards and what they required in respect of the H1 well; that's right, isn't it?

A. Yes, very much so. There was definitely confusion over the meaning of them in that regard, yes.¹⁹⁷

- 3.266. It might be said that PTTEPAA ought not be criticised for deficiencies in documents approved by the NT DoR.¹⁹⁸ The Inquiry rejects this proposition. The mere fact of approval of an activity under regulation 17 of the applicable regulations¹⁹⁹ does not operate to permit a titleholder to undertake the activity in question regardless of the risks involved. The granting of approval under regulation 17 has the effect of removing a prohibition that would otherwise apply to a well activity. This is made clear by the terms of regulation 25, which prohibit the commencement or continuation of well activities which are unsafe in the prevailing circumstances, regardless of whether undertaking the activity is the subject of approval under regulation 17.
- 3.267. Thus, the Inquiry is satisfied that titleholders cannot ignore known risks in undertaking a particular well activity (such as removing a secondary barrier) simply because that well activity is the subject of prior regulatory approval under regulation 17. Were it otherwise, the operation of s 569 of the OPGGS Act would be confounded. That section requires that all petroleum recovery operations undertaken by a titleholder should be conducted in accordance with good oilfield practice.

¹⁹⁷ T1638-1639 (Jacob).

¹⁹⁸ It should be acknowledged that at no stage has PTTEPAA raised this argument.

¹⁹⁹ The *Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004*.

3.268. Finally, the mere fact that an approved program does not require a particular action to be taken does not mean that a titleholder has authority to refrain from taking that action. Thus, the fact that Drilling Program Revision 2 did not require a post-WOC test if the plugs did not bump does not mean that PTTEPAA was authorised to omit such a step.

Finding 36

There were a large number of significant deficiencies in various PTTEPAA documents dealing with well control – such as the WOMP, the Well Construction Standards, the two Drilling Programs in force in March and August 2009, and instructions given to drillers. These deficiencies were, in aggregate, an important systemic factor which indirectly contributed to the Blowout.

Other deficiencies in PTTEPAA’s management systems for recording and communicating information

- 3.269. The Inquiry considers that information capture and communication within PTTEPAA could have been improved:
- a. between night and day staff on the rig. For example, there was confusion between personnel as to whether any, and if so what, test had been undertaken in relation to the cemented shoe;
 - b. between rostered-on and rostered-off staff. For example, when Mr Treasure left the rig he did not inform Mr O’Shea of what had occurred in the course of cementing the casing shoe. Mr O’Shea naturally thought that the cemented casing shoe was a tested and verified barrier;
 - c. between onshore and offshore personnel. For example, very poor communications occurred between Mr Treasure and Mr Wilson in relation to the cementing of the casing shoe; Mr Wilson kept no records of these communications; the problems with the cementing of the casing shoe were not discussed, much less reviewed, the next day; notes were not kept of morning teleconferences between onshore and offshore personnel; there was no system in place whereby the Halliburton reports were sent from the rig to onshore;²⁰⁰ and Mr Duncan and Mr Wilson did not even have onshore IT access to electronic versions of the day-to-day instructions to drillers;²⁰¹ and

²⁰⁰ T1420 (Duncan).

²⁰¹ T1430; T1439-1440 (Duncan).

d. between onshore personnel. For example, Mr Wilson did not have a very good understanding of the risk assessment undertaken by Mr Duncan prior to the decision to use PCCCs.

3.270. Mr Jacob accepted the need for systems improvements in all of these areas.

3.271. Mr Jacob also accepted that:

a. use of a whiteboard was a ‘completely deficient’ system of managing information concerning milestones such as installation of secondary barriers,²⁰² and

b. there was insufficient capture and communication of information concerning activities managed by PTTEPAA ‘off-line’.²⁰³

3.272. The Inquiry does not intend to create a model system for the identification, recording and communication of risk-relevant information by participants in the offshore petroleum industry. Expertise in records management and communications systems is readily available to participants on a fee-for-service basis. However, it is apparent that PTTEPAA must undertake a significant overhaul of its systems for managing information.

Finding 37

There were a number of significant deficiencies in PTTEPAA’s management systems for recording and communicating information within the company – between personnel working day and night shifts, between personnel at the time of hitch handover (usually on 21 day cycles), between on-rig and onshore personnel, and between onshore personnel. These deficiencies were, in aggregate, an important systemic factor which indirectly contributed to the Blowout.

Deficiencies in the formal and informal arrangements concerning well control

3.273. ‘Simultaneous operations’ (**SIMOPS**) consist of those offshore operations which are undertaken jointly or which affect the safety interests of facility operators – in this case PTTEPAA in respect of the WHP, and Atlas in respect of the rig.

3.274. Given that (i) for all intents and purposes the WHP and the rig were co-located at the Montara Oilfield; (ii) the very nature of proposed drilling operations required considerable intersection and co-ordination between PTTEPAA and Atlas; and (iii) issues to do with well control were of fundamental importance to

²⁰² T1653 (Jacob).

²⁰³ T1653-1654 (Jacob).

both entities, it was incumbent upon PTTEPAA and Atlas to develop clear protocols with respect to well control operations. Two things are apparent: first, SIMOPS Plans, instituted by way of Safety Case Revisions, were not produced until July and August 2009;²⁰⁴ secondly, the respective roles and responsibilities of PTTEPAA and Atlas, particularly with respect to well control, were not adequately defined, documented or implemented by them before or after the SIMOPS Plans were produced. These deficiencies, taken together, constitute one of the most significant indirect causes of the Blowout.

3.275. At the time of the cementing operation on 7 March 2009 SIMOPS Plans were not in place. Mr Wilson told the Inquiry that he didn't think the cementing operation fell within the rubric of a SIMOP - it was purely a PTTEPAA well control operation.²⁰⁵ Both PTTEPAA and Atlas endorsed this characterisation in their submissions to the Inquiry. Whether one characterises well control activities as a SIMOP or not, the fact of the matter is that there was an unsatisfactory level of engagement between PTTEPPA and Atlas during the course of the cementing operations, even though well integrity is of critical importance to both entities. The Safety Case Revision in place as at March 2009 described PTTEPAA as having responsibility for 'day to day direction of work associated with the well' and then described Atlas as having responsibility for managing safety on the rig 'during routine operations'. The potential for confusion in this division of responsibility is readily apparent, as is marginalising of the safety role of Atlas in relation to well control matters.²⁰⁶

3.276. The somewhat confusing SIMOPS regime eventually put in place was explained by Mr Jacob in these terms:

A. There are three documents regarding SIMOPS. There is the individual safety case revisions for the wellhead platform and the West Atlas, and then there was the SIMOPS plan which was written by [PTTEPAA]. The wellhead platform revision and SIMOPS plan are [PTTEPAA] documents. The West Atlas revision would have been developed jointly, because the HAZID was held jointly, but it would have been submitted by [Atlas] as the operator of the rig.²⁰⁷

3.277. The Inquiry is satisfied that in the lead up to the Blowout there existed a high degree of tension, if not misunderstanding, in relation to intersecting levels of

²⁰⁴ Statutory Declaration of Mr Chris Wilson, 9 March 2010, paragraph 35; T1125-T1126 (Wilson).

²⁰⁵ T1125 (Wilson).

²⁰⁶ PTTEPAA submitted to the Inquiry that Atlas, in order to comply with its safety duties as an operator of the rig, should have engaged with PTTEPAA in relation to cementing. However, that position was not properly reflected in the arrangements PTTEPAA agreed with Atlas at the time.

²⁰⁷ T1897 (Jacob).

responsibility for well control operations as between PTTEPAA and Atlas. In submissions filed after the public hearing, PTTEPAA suggested that (i) there was no confusion on its part with respect to these roles; and (ii) it was only Atlas that succumbed to any confusion about these roles. The Inquiry was not convinced by these submissions from PTTEPAA. Onshore and on-rig personnel from PTTEPAA did not properly engage with Atlas about safety-related issues (such as the float valve failure in March 2009 and removal of the 9⁵/₈" PCCC in August 2009) precisely because they did not properly appreciate the intersecting levels of responsibility with respect to well control.

- 3.278. As noted above, both PTTEPAA and Atlas agreed that Atlas' OIM had a non-delegable overarching responsibility for rig safety. At the same time, however, PTTEPAA and Atlas agreed that PTTEPAA would have the primary role in relation to well control, such that PTTEPAA's documented standards and systems would govern those operations.²⁰⁸
- 3.279. The Inquiry considers that framework documents for managing risk should have required PTTEPAA and Atlas personnel to properly engage/consult with one another in relation to all safety critical activities. It is not enough to simply state that this should occur. Rather, provision should have been made for obligatory mutual signoff with respect to the performance of safety critical activities by both agencies. In this regard, the Inquiry notes and agrees with the following evidence given by Mr Jacob:

Q. So would it be fair to say that...this requirement for a mutual certification might be a systems improvement?

A. Yes, and I'm not trying to diminish our responsibilities, but it is a mechanism by which to engage the facility operator, in this case Atlas, with systems that are paramount to the safety of personnel.

...

Q. Would you agree, sir, that having listened to the evidence, most of the [PTTEPAA] people on the rig at the time approached the performance by them of specific activities on 7 March and 20 August referable to well control largely on the basis that if the OIM had had a role, it wasn't one of any great practical significance to them?

A. I believe that's what they indicated, yes. That's not my view.

Q. There was an absence of any real engagement with the OIM in relation to the cementing of the casing shoe; that's right, isn't it?

A. Yes, from [PTTEPAA] personnel offshore, yes.

²⁰⁸ See, for example, Mr Jacob's evidence (T1897). Both Mr Gouldin and Mr Jacob agreed that the OIM's safety role was not intended to absolve personnel with a well control function from the necessity of exercising sound professional judgment and following sensible oilfield practice.

Q. And there was an absence of any real engagement with the OIM in relation to the decision to remove the 9-5/8" [PCCC] and not reinstall it on 20 August?

A. In that he wasn't involved in the discussion, yes, but I believe he was advised of it. I don't believe the current practice is good in that regard,...and I believe it needs highlighting that there is a responsibility and a mechanism to improve it, generally for the industry...²⁰⁹

3.280. In relation to the need for mutual signoffs, Mr Jacob gave the following additional (persuasive) evidence:

...the intent being that it would draw in both parties' legal responsibilities and give both parties an audit trail to say that they had carried out their works properly.

...it would heighten people's awareness of the activity and therefore their verification that that activity had actually been undertaken.

...

If they are required to sign the document, then it is an opportunity for both parties to independently verify the information.²¹⁰

3.281. The Inquiry also considers that (i) the Hazard Identification (**HAZID**) workshops which were conducted between PTTEPAA and Atlas to identify and manage risks at Montara; and (ii) the Safety Case Revisions/SIMOPS Plans which were produced by both entities, were pitched at far too great a level of generality. For instance, the workshops and documents did not deal in any specific way with management of barriers. Moreover, the SIMOPS documents were replete with delphic 'motherhood' statements, such as the following:

Safety management in the field is primarily the responsibility of the Vessel Masters/Superintendents, FPSO OIM, Rig OIM and WHP Person In Charge (PIC). The prioritisation of all activities in the Montara field is the responsibility of the PTTEPAA Project Manager. However, control of the individual activities during the field development remains with the relevant supervisors.

...

All parties in the Montara field development shall have clear structuring of HSE interfaces to ensure that there is no confusion as to: approval authority; roles and responsibilities of personnel; organisational structures, management of HSE; operating procedures; reporting structures; and SIMOPS.

3.282. General statements of this kind are well and good, but they do little to guard against the sort of marginalising of the OIM's role as occurred at the Montara

²⁰⁹ T1898-T1899 (Jacob). See also Mr Jacob's evidence at T1747-T1749; T1764; T1782; T1798-1800; T1858; T1898.

²¹⁰ T1858-T1859 (Jacob).

Oilfield in relation to well control.²¹¹ Nevertheless, the OIM should have had regard to the oversight of safety matters on the rig/platform. It was incumbent on the OIM and Atlas shore-based staff to insist that proper standards were in fact being observed. To the extent that the OIM was marginalised, this occurred as a result of choice and/or apathy on the part of Atlas, which is totally unacceptable.²¹² Testimony from Atlas (Messrs Millar and Gouldin) indicated in several places that the performance of the OIM fell short of what they would have expected.

- 3.283. Before leaving this aspect, it is noteworthy that one of the reasons Mr Duncan was on the *West Atlas* on 20 August 2009 was to actually ensure that the SIMOPS operation was implemented properly and was working effectively.²¹³ Yet he decided that removal and non-reinstallation of the 9 $\frac{5}{8}$ " PCCC was not something which he needed to raise with onshore Atlas personnel.

Finding 38

There were considerable deficiencies in the formal and informal arrangements which PTTEPAA and Atlas adopted for managing risks arising out of operations affecting the safety interests of both entities.

Finding 39

The respective roles and responsibilities of PTTEPAA and Atlas, particularly with respect to well control, were not adequately defined, documented or implemented.

Finding 40

These deficiencies, taken together, constitute one of the most significant indirect causes of the Blowout.

²¹¹ In its submissions to the Inquiry PTTEPAA suggested that there was no marginalisation of the OIM's role. The Inquiry rejects this proposition. PTTEPAA did not engage with the OIM in a way which properly reflected his overarching safety role.

²¹² Mr Gouldin essentially agreed with this (T66 and T96).

²¹³ T1127 (Duncan).

Deficiencies in PTTEPAA's logistics management

- 3.284. Mr Wilson, Mr Duncan, and Mr Jacob accepted that PTTEPAA's logistics management was deficient because no-one identified or appreciated that the 13 $\frac{3}{8}$ " PCCC which was meant to be installed on the H1 Well was in fact shipped back to Darwin after the wells at Montara were suspended.²¹⁴
- 3.285. Another possible deficiency which may have played a causal role in the Blowout was the absence of an adaptor to enable the BOP to be connected to the 20" casing on the H1 Well. The Inquiry understands from PTTEPAA's own submissions that well equipment of this kind is free-issued by PTTEPAA to Atlas during the course of well operations. Mr O'Shea gave evidence that PTTEPAA bore responsibility for this sort of equipment.²¹⁵ If such an adaptor had been available, it may have enabled a BOP to be installed on the 20" casing (after that casing was tied back), which would then have allowed the 9 $\frac{5}{8}$ " PCCC to be removed through a BOP and the threads of the 13 $\frac{3}{8}$ " casing to be cleaned through a BOP, thereby maintaining secondary well control at all times. A number of witnesses agreed that the 9 $\frac{5}{8}$ " PCCC should have been removed through a BOP; and the 13 $\frac{3}{8}$ " MLS threads should have been cleaned through a BOP. Mr Duncan denied that this was a practicable strategy.²¹⁶ Mr Duncan said that there would still be a gap between the annulus of the 13 $\frac{3}{8}$ " and 20" casing strings, and that gap would not provide any pressure integrity at all.
- 3.286. The Inquiry also notes that there was no equipment on the rig to install PCCCs in the manner contemplated by the manufacturer (that is, so as to enable an accurate measure of torque). This meant that PCCCs were installed in a 'rough and ready' manner.²¹⁷

Finding 41

There were some deficiencies in PTTEPAA's logistics management. Of most significance was the fact that no-one identified or appreciated that the 13 $\frac{3}{8}$ " PCCC which was meant to be installed on the H1 Well was in fact shipped back to Darwin after the wells at the Montara Oilfield were suspended.

²¹⁴ See, for instance, T995-1000 (Wilson); T1324 (Duncan); and T1643 (Jacob).

²¹⁵ T890 (O'Shea).

²¹⁶ T1470 (Duncan).

²¹⁷ T1490 (Duncan).

Absence of robust supervision and compliance monitoring within PTTEPAA

3.287. The system of supervision in place within PTTEPAA at the time could hardly be described as robust. The prevailing supervisory culture was that subordinates could be relied upon to do everything required of them, and supervisors did not need to be concerned about the possibility of subordinates losing sight of proper processes in the pursuit of efficiency dividends. In considering this issue the following evidence given by Mr Duncan provides very relevant background:

Q. Sir, Mr Wilson has given evidence that there is a very natural tendency on the part of the people out on the rig to want to get the job done as quickly as possible; do you accept that?

A. Yes.

Q. It is a known phenomenon, isn't it?

A. Yes, I'm not denying that.

Q. It is just like breathing air - that's what they do; that's right, isn't it?

A. Yes.

Q. In fact, I think there is almost, if you like, a known phenomenon of wanting to go from pre-spud to production as quickly as possible, and that's a general phenomenon on the rig; people get sort of implicated in it and they make a positive effort to acquit themselves favourably in that regard - that's right, isn't it?

A. That's fair.²¹⁸

3.288. The Inquiry is satisfied that there was a corporate culture within PTTEPAA that attached a high premium to the achievement of time/cost savings, with little or no emphasis given to quality assurance on a day-to-day basis, particularly with respect to well control. Mr Horne, an Atlas driller, gave evidence of PTTEPAA cutting corners on a regular basis around March/April last year. The Inquiry was left in no doubt, after hearing Mr Duncan's evidence, that he had an eye keenly attuned to the achievement of efficiency dividends, but a blind-spot in relation to compliance monitoring and enforcement. The Inquiry received a lot of evidence about steps being taken which saved time and money but which were not properly risk assessed by PTTEPAA: for example, using PCCCs as barriers; undertaking activities off-line; batched tie-back operations; deferring the installation of the 13 $\frac{3}{8}$ " PCCC; and not testing cement plugs or PCCCs after installation. The Inquiry also heard evidence about PTTEPAA's dealings with a contractor in 2007 which caused the contractor to withdraw its services by virtue of significant concerns it held that PTTEPAA's pursuit of cost savings had significantly increased the risk profile of the 'completions' project.

²¹⁸ T1369 (Duncan).

3.289. In this regard, the Inquiry notes that Mr Jacob gave evidence to the effect that he found it hard to credit that PTTEPAA personnel might pursue time and cost savings to the detriment of proper procedures. He thought that the Project Manager and CEO would share his view. Indeed, he stated:

...I don't think anybody in the organisation would credit that things would be done to the detriment of safety for the benefit of cost.²¹⁹

3.290. This evidence led to the following questions and answers:

Q. I'm suggesting to you that the very fact that you are giving that evidence identifies a problem, namely, senior management did not properly recognise the plain fact of ordinary human nature and a known phenomenon, namely, when you have lots of people applying themselves to achieving time and financial efficiencies, they can lose sight of the need to properly attend to processes.

A. On the basis that there weren't systems in place to ensure that the barriers, et cetera, were identified as being in place and verified and that, yes, I can accept that.

...

Q. Yes, but one failing, I am suggesting, is a cultural or attitudinal notion that seems to have pervaded senior management within [PTTEPAA] to the effect that you just give people a job to do and let them go about doing that as efficiently as possible, and you need not worry, after that, whether they are in fact doing everything they need to, because you almost can't credit the alternative?

A. I think that's expanding it beyond the realms. I think in this particular case, as I said, I can agree that that's the way it appears, but extrapolating that into a general statement is taking it a bit too far.

Q. Let's just analyse that quickly. There seems to have been a complete absence of effective quality assurance with respect to the installation of barriers in every single well.

A. Yes, based on the evidence we have heard, I agree.

Q. I want to suggest that a common denominator that explains all of that is a view by senior management that they really didn't need to closely monitor what was happening, because senior management just couldn't credit the possibility that corners might be cut in the pursuit of time and cost savings.

A. That's certainly one element of it, I would suggest, yes.²²⁰

²¹⁹ T1784 (Jacob).

²²⁰ T1784-1786 (Jacob).

3.291. PTTEPAA's supervisory systems were not really directed toward achieving effective quality assurance. Later in his evidence Mr Jacob frankly accepted that the supervisory deficiencies infected the entire organisation:

Q. So there is a widespread corporate cultural problem that involves reposing too much reliance upon those in the field and too little reliance upon a close consideration of information provided by them; do you agree?

A. I would rather say too much reliance on personnel below each of those people, be it offshore or onshore. I don't think it is restricted to offshore.

Q. Was the project manager a direct report to the CEO?

A. Yes.

Q. So, in all likelihood, we can go that one step further, too, can't we, sir, namely, that the CEO didn't properly inform himself of the nature and extent of the project manager's supervision of the affairs of the well construction department?

A. It would appear so, yes.²²¹

...

Q. Will you accept, sir, that the nature of the evidence canvassed in the course of this Inquiry indicates deficiencies right up the line to and including the CEO of [PTTEPAA]?

A. Yes, based on the line of questioning you have been following, yes.²²²

3.292. In addition to the deficiencies in PTTEPAA's day-to-day supervisory arrangements, Mr Jacob also accepted that PTTEPAA should have conducted a compliance audit when the following facts came to light:

- a. failure of the float valves during the course of the cementing of the casing shoe on 7 March 2009;
- b. de-bumping of the plugs during the course of that same cementing operation;
- c. the plugs not bumping on another well at Montara; and
- d. the detection of bubbles in the GI Well.

3.293. Mr Jacob accepted that, in combination, these factors constituted an incontrovertible case for PTTEPAA pausing, in a timely fashion, and carrying out a considered review as to what had taken place out on Montara with respect to well control.²²³ It should be noted that PTTEPAA did have an audit planned to take place in August/September 2009 which did not take place due to the

²²¹ T1893 (Jacob).

²²² T1896 (Jacob).

²²³ T1671-1672 (Jacob).

Blowout. The Inquiry considers that such an audit should have been planned to take place earlier given the events that occurred. Mr Wilson accepted that there was a place for audits and that, had an audit been carried out, it might have picked up problems with well control.

Finding 42

PTTEPAA did not have effective internal systems in place to achieve a high level of quality assurance with respect to well control operations. In particular, systems were not in place to ensure (i) vigilant day-to-day supervision of subordinate personnel; (ii) monitoring of well operations through internal audits.

Finding 43

These deficiencies contributed to the development and non-detection of inadequate well control practices.

Shortfalls of expertise within PTTEPAA

- 3.294. The Inquiry heard evidence to the effect that the PTTEPAA personnel involved in the cementing operation on 7 March 2009 had limited prior experience of cementing a casing shoe whilst the casing string was located horizontally inside a reservoir at such a vertical and measured depth.²²⁴ Indeed, Mr Doeg told the Inquiry that it is unusual to set a casing shoe right into a reservoir.²²⁵ In any event, none of the personnel involved had ever previously encountered failure of floats during the course of such a cementing operation.²²⁶
- 3.295. Indeed, although failure of float valves was a known and predictable phenomenon, it was not a common event and PTTEPAA personnel did not, separately or collectively, have very much experience in dealing with float failure of any kind.
- 3.296. The Inquiry also heard evidence to the effect that PTTEPAA personnel had only limited experience of prior involvement in batched drilling and batched tieback

²²⁴ See for example T607-608 (Wishart). Mr Wilson gave evidence to the effect that he had been involved in cementing casing shoes located horizontally within a reservoir 'quite a few times' (T988).

²²⁵ T452 (Doeg).

²²⁶ For example, Mr Doeg and Mr Wishart had over 40 years of experience between them, but each had experienced float valve failure in a casing shoe on only one previous occasion. Mr Wilson had never previously experienced float valve failure (T992-993).

operations.²²⁷ Indeed, PTTEPAA personnel had not previously used PCCCs as secondary barriers in the context of batched drilling and batched tieback.

- 3.297. The Inquiry also heard evidence from Mr Wilson that Montara was the first experience of onshore management with off-line work: 'It was a platform campaign, the first time we'd done that'.²²⁸
- 3.298. The Inquiry is satisfied that there were a number of significant shortfalls in the level of expertise of PTTEPAA personnel with respect to well control at the Montara Oilfield. None of the PTTEPAA personnel on the rig or within PTTEPAA's onshore Well Construction Department recognised:
- a. the creation of a wet shoe on 7 March 2009;
 - b. the need for a post WOC pressure test of the casing shoe on 7 March 2009;
 - c. the significance of loss of pressure within the 9 $\frac{5}{8}$ " casing string whilst pressure was held during the WOC period;
 - d. the use of the wrong volume of tail cement during the cementing of the casing shoe on 7 March 2009;
 - e. the importance of timely installation of the 13 $\frac{3}{8}$ " PCCC on the H1 Well following regulatory approval for that action;
 - f. the need for testing of PCCCs following installation on the H1, GI, H2, H3, and H4 Wells at Montara;
 - g. the need for a more detailed investigation of problems associated with the cementing of the casing shoe in the GI Well;
 - h. the significance of the removal and non-reinstallation of the 9 $\frac{5}{8}$ " PCCC on the H1 Well on 20 August 2009;
 - i. the fact that the displacement fluid in the 9 $\frac{5}{8}$ " casing string should have been regarded, for well control purposes, as underbalanced to formation and therefore should not have been relied upon as affording any barrier protection whatsoever;
 - j. the need for more systematic and long term visual monitoring of the casing fluid in the H1 Well following removal of the 9 $\frac{5}{8}$ " PCCC on 20 August 2009;

²²⁷ Mr Wilson told the Inquiry that PTTEPAA had only performed a batch drilling operation on one earlier occasion, in a sub-sea situation.

²²⁸ T958 (Wilson).

- k. the possibility of a blowout occurring without any observable forewarning;
and
 - l. the requirements of PTTEPAA's own Well Construction Standards and sensible oilfield practice in terms of achieving well control.
- 3.299. Some of these deficiencies gain added significance in light of the fact that various PTTEPAA personnel reviewed the circumstances surrounding the Blowout, including by way of reappraisal of various contemporaneous documents, but still failed to gain a proper understanding of what had occurred and why.
- 3.300. This is particularly true of Mr Wilson and Mr Duncan. As noted above, Mr Jacob accepted that it should have been apparent to each of them when they reviewed the DDR, the PTTEPAA cementing report, and the 7 Day Operational Forecast that they were seriously implicated in events which caused the Blowout. However, even with the benefit of careful reflection and hindsight they failed to recognise the significance of their own involvement in those events. This speaks tellingly of deficiencies in their knowledge and expertise.
- 3.301. The same holds true for Mr Treasure. He was very reluctant to admit that on 7 March 2009 he was operating at the very outer reaches of his level of expertise. However, the Inquiry has no hesitation in finding that he simply did not possess sufficient expertise and knowledge to understand, and properly respond to, the risks presented by the failure of the float valves on 7 March 2009. The Inquiry rejects his evidence to contrary effect.²²⁹
- 3.302. The Inquiry notes that apart from an earlier two week period, Mr Treasure had never performed the role of Day Drilling Supervisor on a rig (being the most senior licensee representative on a rig) prior to commencing in this role at Montara in March 2008.²³⁰ Similarly, Mr Wilson had never before performed the role of Onshore Drilling Superintendent.
- 3.303. Mr Jacob frankly accepted that PTTEPAA's recruitment processes could be improved to ensure better identification of shortfalls in expertise, which could then be addressed by provision of appropriate training, particularly in relation

²²⁹ T277 and T299 (Treasure).

²³⁰ In a submission to the Inquiry Mr Treasure pointed out that he had held drilling supervisory positions for well over 10 years, albeit not as the most senior licensee representative on a rig. He strenuously defended his experience, knowledge, and expertise. However, the Inquiry notes that Mr Jacob, after hearing Mr Treasure's evidence, accepted that there were deficiencies in his level of expertise.

to well control. Mr Jacob accepted that rigorous skills auditing and targeted training are particularly important because many of the personnel involved in offshore petroleum operations are contracted-in, with relatively short lead-in times.²³¹

3.304. Mr Jacob went on to explain that dealing with a situation such as float valve failure should be within the fingertip resources of people who are going to be involved in cementing operations. He stated:

Yes, and that should be either via the induction process, which should take them through the well construction standards, which, as we've already said, should probably be included in that program, and/or via some additional course...²³²

3.305. Before leaving this aspect of the matter it should be noted that Atlas personnel also failed to identify deficiencies in the cementing of the casing shoe, and it is likely that this was influenced by some shortfalls in their level of knowledge and expertise. It may be that Atlas' systems for acquiring and maintaining appropriate levels of expertise require review.

3.306. At this point, the Inquiry is compelled to say that none of the points listed in 3.298 above should have been difficult to comprehend and then rectify. The Inquiry was able, from original source documents, to discover the shortcomings in PTTEPAA's processes and procedures largely without the benefit of submissions, sworn evidence and material such as the Atlas Report. It is sufficient to say that this was possible without having the expertise or experience of PTTEPAA/Atlas personnel. This underscores the magnitude of the companies' shortcomings.

Finding 44

Had key personnel from both PTTEPAA and Atlas (on-rig and onshore) possessed a greater level of knowledge and expertise in relation to cementing operations, it is likely they would have detected (i) the problem with the cemented casing shoe, thereby enabling remedial steps to be taken; and (ii) many other deficiencies in PTTEPAA's approach to well control at the Montara Oilfield.

²³¹ T1675-1677 (Jacob).

²³² T1678 (Jacob).

Finding 45

PTTEPAA did not have effective internal systems in place to acquire and maintain an appropriate level of knowledge and expertise on the part of its personnel. Atlas' systems for acquiring and maintaining appropriate levels of expertise may also require review.

Shortfalls in governance structures within PTTEPAA

- 3.307. In February 2009 the titleholder in respect of Montara was Coogee Resources. That company and all of its subsidiaries were acquired by PTTEP Australasia Browse Basin Pty Ltd, a subsidiary of PTT Exploration and Production Public Co Ltd on 4 February 2009 (a parent company based in Thailand). Soon thereafter, on 11 February 2009, Coogee Resources changed its name to PTTEP Australasia (Ashmore Cartier) Pty Ltd.²³³
- 3.308. After the acquisition the former CEO of Coogee Resources was replaced by another CEO, who came from the PTTEPAA parent company in Thailand. After the acquisition, the Coogee Resources Project Manager was also replaced by a new Project Manager.
- 3.309. Prior to February 2009 Coogee Resources was managed ultimately by a Board, to which various committees reported, including a Risk Management Committee, a Major Projects Committee, and an Audit Committee.²³⁴ The Major Projects Committee reviewed the major projects that the company was undertaking and reported to the full Board in relation to those projects. The Major Projects Committee met with the Project Manager and obtained updates from him to enable it to report to the Board. The Major Projects Committee met on a monthly basis, and its meetings were minuted.²³⁵
- 3.310. After the acquisition in February 2009 this governance structure was replaced by a so-called 'line management' structure, and decision-making in respect of significant matters moved from Australia to Bangkok.²³⁶ The 'line management' structure depended upon individuals reporting to a single person up the chain of command to, eventually, the CEO. In this regard, the Inquiry notes the following evidence given by Mr Jacob:

Q. Is this an aspect that PTT Exploration and Production, your parent company, might look at - the overall governance of its operations in

²³³ See T1760-1761 (Jacob). See also letter from PTTEPAA to NOPSA dated 26 February 2009, NOP.9000.0011.0321.

²³⁴ See T1929 (Jacob).

²³⁵ See T1930 and T1941 (Jacob).

²³⁶ T1931 (Jacob).

Australia, while fitting in with its overall need to get a level playing field in terms of evaluation of projects across its worldwide operations?

A. There has been some recent discussion about the way in which Australasia is managed over the last few months, and I think that this line of questioning opens up another avenue to look at. We've been concentrating on, as I say, integrating into PTTEP where there are benefits to the Australasian business and obviously to the entire group. I think this will serve to highlight the advantage, if you like, of local management.

Q. With the best will in the world, it's a different matter for line management to assess risks and compliance with regulatory requirements and having a board committee looking at those things, and it's a bit of a stretch to say that a board operating in Bangkok will necessarily have the familiarity with those sorts of things.

A. Yes, I agree. They do have an internal audit group in Bangkok, which would be fulfilling that role, but I think it would be better done locally, yes.²³⁷

...

Q. Is it the case that [PTTEPAA] was really being managed, in an ultimate sense, by the parent company?

A. Yes.

Q. Is that the reason why, for instance, you told the Commissioner that [PTTEPAA]'s CEO had a boss in Bangkok?

A. Yes, that's his reporting line.

Q. When you refer to a line of management, do you say that that line of management actually operated up to the CEO of [PTTEPAA] and, through the CEO, up to management of the parent company?

A. Yes.²³⁸

- 3.311. Mr Jacob also gave evidence to the effect that there was inadequate oversight within PTTEPAA of its Well Construction Department. PTTEPAA has devised a comprehensive Action Plan to address this deficiency.

Finding 46

PTTEPAA's internal governance structures post-acquisition were somewhat deficient: first, there was less committee oversight of important decisions which is likely to have reduced the level of quality assurance; secondly, there was an attenuation in the lines of accountability when decision-making was located offshore in Bangkok.

Finding 47

Had more rigorous internal governance structures been in place it is possible that risks associated with the operations at Montara may have been identified and addressed.

²³⁷ T1935-T1936 (Jacob).

²³⁸ T1942 (Jacob).

Deficiencies in the regulatory role performed by the NT DoR

- 3.312. So far as the role of the NT DoR as DA is concerned, many significant deficiencies in the performance of that role came to light in the course of the Inquiry's public hearing. These are considered in detail in Chapter 4.
- 3.313. Some of these deficiencies are unlikely to have played a *causal* role in the Blowout, but they are clearly relevant to the Inquiry's Terms of Reference dealing with the general adequacy of (i) the regulatory regime, and (ii) the NT DoR's regulatory performance.
- 3.314. However, the Inquiry considers that, on balance, some deficiencies in the NT DoR's regulatory role did play a *causal* role in the lead up to the Blowout, albeit that this role was indirect and non-proximate. In this regard, the Inquiry notes:
- a. immediately prior to, and at the time of, the Blowout the NT DoR could reasonably have expected that the H1 Well was protected by one primary barrier and at least one secondary barrier (being the 9 $\frac{5}{8}$ " PCCC);
 - b. it was not the role of the NT DoR to micro-manage day-to-day well operations at Montara. Nevertheless, it was given information which, if properly analysed, should have alerted it to a deficiency in the cemented casing shoe;
 - c. the NT DoR was entitled to expect, at the very least, that the integrity of the cemented casing shoe would be tested prior to exposing the H1 Well to atmosphere for any length of time;
 - d. indeed, the Phase 1B Drilling Program approved by the NT DoR required the performance of a casing string pressure test within a *very* short space of time after the scheduled removal of the 9 $\frac{5}{8}$ " PCCC (see page 40, steps 196-204 of the Phase 1B Drilling Program);
 - e. therefore, the NT DoR was entitled to expect that any deficiencies in the integrity of the cemented casing shoe would be identified and remedied before exposing the H1 Well to atmosphere for any length of time;
 - f. the NT DoR did not know that the 9 $\frac{5}{8}$ " PCCC had been removed and left off the H1 Well. It should have been informed of this proposal;
 - g. if PTTEPAA had kept to the approved Phase 1B Drilling Program, the Blowout would not have occurred.
- 3.315. In light of the above, the NT DoR is not implicated *directly* in the causes of the Blowout. However, the fact remains that the NT DoR should never have

approved the Phase 1B Drilling Program in the first place. At the very least, the NT DoR should have insisted on the installation of another secondary barrier in the H1 Well in the period between (i) scheduled removal of the 9 $\frac{5}{8}$ " PCCC; and (ii) installation of a BOP over the well.

- 3.316. In approving the Phase 1B Drilling Program the NT DoR reinforced fundamental misconceptions held by personnel in PTTEPAA's Well Construction Department, that is, it is okay to leave a well exposed to atmosphere for an indeterminate period of time while undertaking operations on other wells. The Inquiry is satisfied that deficiencies in the regulatory role performed by the NT DoR contributed to the development and non-detection of poor well control attitudes and practices on the part of PTTEPAA.

Finding 48

Deficiencies in the performance of the NT DoR's role as regulator did not contribute *directly* to the Blowout. However, they did contribute to the development and non-detection of poor well control attitudes and practices on the part of PTTEPAA.

Finding 49

Deficiencies in the NT DoR's role as regulator included (i) failure to undertake a proper assessment of the use of PCCCs in a batched drilling context in March 2009, when it approved PTTEPAA's use of PCCCs as secondary barriers on the H1 Well; (ii) failure to insist upon proper well control when it formally approved PTTEPAA's Phase 1B Drilling Program in July 2009 (noting that this Drilling Program contemplated that the H1 Well would be exposed to atmosphere for a somewhat indeterminate, but unsatisfactory, length of time whilst PTTEPAA undertook batched tie-back operations on other wells); and (iii) failure to adequately monitor PTTEPAA's compliance with good oilfield practice with respect to well control.

Deficiencies in the applicable regulatory regime

- 3.317. Responsibility for regulating the safety of well control operations was divided between the NT DoR (as delegate) and NOPSA. The NT DoR's role was an industry-wide regulatory role, which included approval of environmental plans and drilling operations. The NT DoR had the primary regulatory responsibility to address well integrity issues (which inevitably affects safety matters). Nevertheless, the safety of personnel was not the focus of the regulatory role performed by delegates. On the other hand, NOPSA's role was specifically targeted to achievement of OHS on offshore facilities (which included the WHP owned by PTTEPAA and the rig owned by Atlas). This division of regulatory responsibility between DAs and NOPSA may have resulted in:

- a. areas of overlapping responsibility, as well as gaps in regulatory oversight on the part of the NT DoR;
- b. confusion on the part of PTTEPAA and Atlas with respect to their own roles and responsibilities in relation to well control. As noted above, the respective roles and responsibilities of PTTEPAA and Atlas in relation to well control were not adequately identified, documented or implemented by them. This was one of the most significant indirect causes of the Blowout.

Finding 50

Deficiencies in the applicable regulatory regime may have led to (i) gaps and shortfalls in regulatory oversight by the NT DoR; and (ii) confusion on the part of PTTEPAA and Atlas concerning their respective roles and responsibilities in relation to well control.

Finding 51

In any event, regulation of well control by a single regulator, with comprehensive oversight of general industry practice and responsibility for all aspects of offshore operations, is likely to lead to higher standards of well control on the part of industry participants.

Recommendations

Introduction

- 3.318. In making its recommendations, the Inquiry has not considered the best means to achieve the outcomes stated. A variety of means may be available, such as:
- a. amendment of principal legislation or regulations;²³⁹
 - b. attachment of conditions to licences granted under the OPGGS Act;
 - c. the issue of guidance to regulators as to recommended regulatory practice;²⁴⁰
 - d. the issue of guidelines by regulators to industry stakeholders as to matters such as (i) recommended best practice on particular topics; and (ii) the policy expectations of regulators in relation to the exercise of their powers;²⁴¹

²³⁹ For instance, the regulations in force under the OPGGS Act could stipulate a set of minimum requirements which must be satisfied before approval could be given to WOMPs.

²⁴⁰ For instance, guidelines could be issued to licensees and regulators as to the expected minimum content of WOMPs.

²⁴¹ For instance, delegates of the Minister under the OPGGS Act could issue guidelines to licensees as to regulatory expectations concerning the content of WOMPs, including minimum well control standards which should be in place.

- e. adoption of recommendations by peak industry groups; and
- f. adoption of recommendations by licensees, rig operators, and other participants in the offshore petroleum industry.

3.319. In formulating the Inquiry's recommendations a principal objective has been to ensure that well control (and safety as it relates to well control) is recognised by all stakeholders as a matter of paramount importance. It should not be approached in an unfocussed way, or 'lost' in either the generality or detail of OHS regimes. Of course, it needs to be linked to those regimes in a real and effective way, but it is a topic deserving of special and detailed treatment.

3.320. In the recommendations that follow, the Inquiry is not proposing a substantial departure from the current objective-based (as opposed to a prescriptive) approach to regulation of the offshore petroleum industry in Australia. In some limited areas, however, minimum standards do need to be set (for example, minimum well control barrier requirements that are verified and tested in situ). The Inquiry is not specifying the form of such well control barriers; that needs to be properly analysed and risk assessed. The Inquiry is seeking to set out some yardsticks of good oilfield practice that licensees, rig operators, contractors and regulators need to apply with due diligence.

General recommendations regarding the well integrity framework

Recommendation 1

The Minister should appoint a senior policy adviser to investigate and report on the best means to implement the recommendations contained in this Chapter.

Recommendation 2

WOMPs submitted by licensees to the regulator(s) should continue to be the primary framework document for achieving well integrity.

Recommendation 3

WOMPs should be comprehensive and freestanding, rather than an overarching document cross-referencing many other documents (although the Inquiry also recommends a freestanding well control manual; this should be a guide to rig and onshore personnel on good oilfield practice).

Recommendation 4

The concept of 'good oilfield practice' should be supplemented by the requirement to incorporate into WOMPs non-exhaustive minimum compliance standards in relation to well control: for example, stipulations as to when BOPs and/or well control systems must be in place and when they can be removed and minimum barrier requirements (a number of other factors that should be stipulated are outlined in other recommendations below).

Recommendation 5

Well construction and management plans should include provision(s) for reviewing the integrity of barriers at safety-critical times or milestones, such as (i) prior to suspension involving departure of the rig from the platform; (ii) prior to re-entry of a well after suspension; (iii) prior to removal of any barrier.

Recommendation 6

Well construction and management plans, and drilling programs, should include provision for testing and verifying the integrity of all barriers as soon as practicable after installation.

Recommendation 7

Well construction and management plans should include provision for an independent compliance review of well integrity (i) in the event of stipulated triggers; and (ii) at least once in the period between perceived achievement of well integrity and production. The independent compliance review should be undertaken by an expert who is not involved in the day-to-day drilling operations. Reviews should be completed in sufficient time to enable results to be implemented in a meaningful manner.

Recommendation 8

Wellbore gas bubbling should be regarded as a trigger for independent review of well integrity. Industry and regulators should identify and document other triggers.

Recommendation 9

If a risk assessment or compliance review is triggered by the happening of a pre-determined event, specific consideration should be given to whether a 'hold point' should be introduced such that work must cease until the problem is resolved (and the subject of appropriate certification).

Recommendation 10

A separate, identifiable barrier manual should be agreed upon and used by licensees, rig operators, and cementing contractors.²⁴² These manuals should set out best industry practice in relation to achieving and maintaining well integrity. They should describe barrier types, barrier standards, general principles of well integrity, testing and verification methods and technologies, standard operating procedures (including procedures for the capture and communication of relevant information within and between relevant stakeholder entities). Barrier manuals should address blowout control during drilling, completion, re-entry, tie-back of casing strings and so on. Barrier manuals should be the subject of expert external review, and should be regularly updated.

Recommendation 11

Memoranda of Agreement should be entered into between operators in relation to provision of emergency assistance in the event of blowouts.

General recommendations regarding well integrity practices

Recommendation 12

Pre-drilling assessments should include a risk assessment of the worst-case blowout scenario.

Recommendation 13

Problems which arise in the course of installing barriers must be the subject of consultation between licensees, rig operators, and contractors (if used). A proper risk assessment should then be carried out and remedial steps (including further testing/verification) should be agreed upon, and documented in writing before the performance of remedial work whenever practicable. Joint written certification as to resolution of the problem should take place before resumption of drilling operations. Senior onshore representatives of stakeholder entities should be involved in that certification process.

Recommendation 14

Licensees should be subject to an express obligation to inform regulators of problems which arise in the course of installing barriers, even if they consider that well integrity is not thereby compromised. The information should be provided by way of special report, rather than included in a standard reporting document (such as a DDR). The information provided should include risk assessment details.

Recommendation 15

As soon as a risk of barrier failure arises, no other activities should take place in the well other than those directed to removal of the risk.

²⁴² Dealing with well control in general terms, and as simply one of a large number of issues, is apt to discount the special importance it warrants.

Recommendation 16

The use/type of barriers (including any change requests relating thereto) must be the subject of consultation between licensees and rig operators prior to installation. A proper risk assessment should be carried out, agreed upon, and documented in writing before installation. Joint written certification as to the appropriateness of the use of particular barriers should take place before installation. Senior onshore representatives of stakeholder entities should be involved in that certification process.

Recommendation 17

The successful installation of every barrier should be the subject of written verification within and between licensees and rig operators; and should be the subject of explicit reporting to the relevant regulator(s).

Recommendation 18

Removal of a barrier must be the subject of consultation between licensees and rig operators prior to removal. A proper risk assessment should be carried out and agreed upon, and documented in writing before removal. Joint written certification as to the appropriateness of removal should take place before removal. Senior onshore representatives of stakeholder entities should be involved in that certification process.

Recommendation 19

Licensees should be subject to an express obligation to inform regulators of the proposed removal of a barrier, even if they consider that well integrity is not thereby compromised. The information should be provided by way of special report, rather than included in a standard reporting document (such as a DDR). The information provided should include risk assessment details. Removal of a barrier should not take place without prior written approval of the relevant regulator(s).

Recommendation 20

If a dispute arises between a licensee and a rig operator in relation to a well control issue, and is not resolved between them, the matter must be raised with the relevant regulator before discretionary operations proceed.

Recommendation 21

Perceived time and cost savings relating to any matters impacting upon well control should be subjected to rigorous safety assessment.

Recommendation 22

Wells drilled into hydrocarbon zones should be treated as live wells, with the potential to blowout unless a documented risk assessment establishes otherwise.

Recommendation 23

Use of single strings of intermediate casing to penetrate hydrocarbon bearing zones should be carefully risk assessed. Multiple strings of intermediate casing have the advantage of isolating lost circulation zones and sealing off anomalous pressure zones. If intermediate casing is set in a hydrocarbon zone it should be treated as production casing.

General recommendations regarding well control barriers

(a) *Minimum barrier requirements*

Recommendation 24

A *minimum* of two barriers should be in place at all times (including during batched operations) whenever it is reasonably practicable to do so.

Recommendation 25

Reliance upon one barrier against a blowout must not take place except with the prior written approval of the relevant regulator and then only in a true emergency situation (see below).

Recommendation 26

Regulatory approval to rely on only one barrier should not be given unless (i) a proper risk assessment is carried out; (ii) exceptional circumstances exist; and (iii) risks involved are reduced to 'as low as reasonably practicable'. The default position must be that well integrity must be assured.

Recommendation 27

Licensees and rig operators should install an additional barrier whenever (i) there is any real doubt as to the integrity of any barrier; (ii) whenever the risk of flow from a reservoir increases materially in the course of operations; and (iii) where the consequences of a blowout are grave (for example, for reef systems or shorelines).

Recommendation 28

The industry standard of two barriers should be replaced with the concept of 'two or more barriers' as a minimum standard. A *minimum* standard when operations proceed normally should never be regarded as a *sufficient* standard in other circumstances.

(b) *Cementing*

Recommendation 29

Industry, regulators, and training/research institutions should develop standards that address best practices for cementing operations (including liaising, as appropriate, with overseas regulators) with a view to overcoming problems which can effect the integrity of cemented casing shoes, annulus and cement plugs.

Recommendation 30

Tracking and analysis of cementing problems/failures should occur to assess industry trends, principal causes, remedial techniques and so on.

Recommendation 31

It is recommended that industry, regulators, and training/research institutions liaise with one another with a view to developing better techniques for testing and verifying the integrity of cemented casing shoes as barriers (particularly in atypical situations such as where the casing shoe is located within a reservoir in a horizontal or high angle position at great depth).

Recommendation 32

Cement integrity should be evaluated wherever practicable by way of cement evaluation tests, rather than relying on pre-operational calculations of cement and displacement fluid volumes.

Recommendation 33

It should be standard industry practice to re-test a cemented casing shoe (that is, after WOC) whenever the plugs do not bump or the float valves apparently fail. Standard industry practice should require consideration of other tests in addition to a repeat pressure test.

Recommendation 34

Any indication of a compromised cemented shoe which cannot be resolved with a high measure of confidence should result in the installation of additional well control barrier(s).

Recommendation 35

Volumes of cement used in connection with barrier installation should be calculated with the assistance of a pro-forma which records all relevant baseline data, which should be verified by onshore personnel.

General recommendations regarding barrier installation and removal**Recommendation 36**

If performance of barrier installation is outsourced by a licensee, the contractor (for example, the cementing company) should be engaged on terms which clearly require the provision of expert advisory services by the contractor with respect to barrier integrity.

Recommendation 37

Consideration should be given to ways to ensure that contractors who are involved in barrier installation (such as cementing companies) have a direct interest in the performance of works to a proper standard. In particular, consideration should be given to (i) preventing contractors from avoiding the economic consequences of negligent installation of barriers; and/or (ii) imposing specific legislative standards of workmanship on contractors with respect to well control (similar to those which presently apply to licensees).

Recommendation 38

Horizontal or high angle penetration of a reservoir should be avoided *wherever practicable* until such time as the apparent problems associated with the cementing of a casing shoe in these situations are satisfactorily overcome. If a casing string does penetrate a well horizontally or at a high angle, standard practice should be to install two secondary barriers in addition to the cemented casing shoe.

Recommendation 39

The BOP and rig should not move from a well until barrier integrity has been verified.

Recommendation 40

Barriers should not be installed or removed off-line. The derrick should be located over a well at the time of removal and installation of any barrier. This will enable more decisive action to be taken in the event a problem arises.

Recommendation 41

Secondary barriers (including PCCCs) should only be installed, tested, and removed with a BOP in place unless a documented risk assessment indicates that well control can be maintained at all times.

Recommendation 42

PCCCs should be installed in a timely manner (for example, to prevent corrosion in the MLS apparatus). Non-installation in order to park a BOP is not acceptable.

Recommendation 43

Wells should be re-entered with a BOP in place unless a documented risk assessment indicates that well control can be maintained at all times.

Recommendation 44

Any equipment (including PCCCs) used as, or to install, a barrier should be manufactured for that purpose and be generally recognised as fit for purpose. If equipment is designed in-house by a licensee or rig operator it should not be approved for use unless and until it is subjected to expert external analysis.

Recommendation 45

Manufacturers should be consulted about how to address non-routine operational problems affecting their well control equipment.

Recommendation 46

Drilling programs dealing with barrier installation should incorporate relevant aspects of manufacturer's instructions.

Recommendation 47

Any pro-formas used by licensees, rig operators and contractors for recording information about installation of barriers should explicitly provide for 'exception reporting', that is, the form should include provision for recording any unforeseen or untoward events which occur in the course of installation.

Recommendation 48

Careful consideration must be given to equipment compatibility as part of well construction design.

General recommendations regarding batch drilling**Recommendation 49**

Batched drilling operations should only be undertaken after careful assessment of the special risks which such operations give rise to; well control must be maintained during the course of batched drilling operations.

Recommendation 50

Where multiple wells are drilled, operations and occurrences at one well must be carefully assessed for any implications with respect to well control at other wells.

Recommendation 51

The mere fact that the rig is over the platform should not be regarded by licensees or regulators as sufficient justification for reliance on only one barrier. The default position should be that producible wells are shut-in when a rig is moved on and off a platform, or when a drilling unit is moved between wells on a platform.

General recommendations regarding communications and logistics**Recommendation 52**

Relevant personnel from licensees and rig operators should meet face to face to agree on, and document, well control issues/arrangements prior to commencement of drilling operations. Well control should be regarded as a so-called SIMOP to signify its critical importance to both licensees and rig operators, and to ensure that they each take responsibility for achievement and maintenance of well control.

Recommendation 53

Prior to commencement of drilling operations, senior representatives of the licensee and rig operator should exchange certificates to the effect that their respective key personnel and contractors have been informed in writing of agreed well control arrangements.

Recommendation 54

Information relevant to well control must be captured and communicated *within* and *between* licensees and rig operators (and relevant third party contractors), in a manner which ensures it comes to the attention of relevant personnel. In particular, protocols should be developed to ensure that changes in shift and hitch do not operate as communication barriers.

Recommendation 55

All communications between on-rig and onshore personnel relating to well control should be documented in a timely manner.

Recommendation 56

Logistics management of well control equipment should be conducted in such a way as to operate as a check against deficient well control practices, for example, use of serial numbers to track availability, testing, and deployment of well control equipment.

General recommendations regarding professional standards and training

Recommendation 57

Decision-making about well control issues should be professionalised. Industry participants must recognise that decision-makers owe independent duties to the public, not just their employer or principal, in relation to well control. Risk management in the context of well control needs to be understood as an ethical/professional duty. Self-regulation contemplates self-regulation by the industry, not just by individual licensees and operators.²⁴³

Recommendation 58

Existing well control training programs should be reviewed by the industry, regulators and training providers, with a focus on well control accidents that have occurred (in Australia and overseas).

Recommendation 59

A specific focus on well control training should be mandatory for key personnel involved in well control operations (including both on-rig personnel and onshore personnel in supervisory capacities).

²⁴³ Most trades and occupations have undergone a process of professionalisation. Part of that process has included recognition of irreducible standards of practice. The offshore petroleum industry still operates largely on a project basis, without an overarching set of professional practice and operating standards.

Recommendation 60

Licensees and rig operators (and third party contractors involved in well control operations) should specifically assess, and document, the nature and extent of knowledge/skills of relevant personnel in relation to well control (including familiarity of personnel with agency-specific requirements and procedures). Training needs and opportunities should be identified. This process should take place on engagement and at appropriate intervals.

Recommendation 61

Licensees, rig operators, and relevant third party contractors should develop well control competency standards for their key personnel. Wherever possible, the competencies of key personnel should be benchmarked against their roles and responsibilities.

Recommendation 62

Licensees, rig operators and relevant third party contractors should develop well control competency standards for key personnel in other entities involved in well control operations.

Recommendation 63

Achievement and maintenance of well control should be written into the job responsibilities of key personnel, at every level up to and including CEOs. That is, a functional line of accountability for well control must exist up to, and including, CEOs.

Recommendation 64

Supervision/oversight of well control operations (within licensees, rig operators and by regulators) must occur without assuming adherence to good oilfield practice. The opposite assumption should prevail: namely adherence to good oilfield practice may well be compromised by the pursuit of time and cost savings.

Recommendation 65

Licensees and rig operators should be astute in ensuring that corporate systems and culture encourage rather than discourage raising of well control issues. For instance, do performance bonuses or rewards actually encourage or discourage reporting of issues? Is there a system in place to enable anonymous reporting of well control concerns? What whistleblower protections are in place?

Specific recommendation concerning PTTEPAA

- 3.321. It is apparent from the Inquiry's findings set out in this chapter that PTTEPAA was deficient in a large number of significant respects in the lead up to the Blowout in the H1 well.
- 3.322. However, well control problems were not confined to the H1 Well. As set out in Chapter 7, PTTEPAA was also seriously deficient in its approach to well control with respect to *all* the other wells at Montara.

- 3.323. These deficiencies reflect poorly upon PTTEPAA's performance as a titleholder. Their significance is compounded by serious inadequacies in the manner in which PTTEPAA engaged with regulatory authorities and this Inquiry after the Blowout. As noted in Chapter 7 of this Report:
- a. PTTEPAA failed to properly investigate the circumstances and likely causes of the Blowout;
 - b. as a result, PTTEPAA supplied a good deal of palpably false and misleading information to NOPSA and to this Inquiry;
 - c. PTTEPAA also chose to withhold relevant information from NOPSA and the NT DoR;
 - d. for nearly the whole of this Inquiry, PTTEPAA adopted a self-justifying and deflative position;
 - e. PTTEPAA only really acknowledged the nature and extent of its deficiencies in managing well control at Montara toward the very end of the Inquiry's public hearing - that is, after compulsory powers were exercised to test (and find wanting) the blame-avoidant position which PTTEPAA had, to that point, steadfastly adopted.
- 3.324. In light of the matters stated in the three preceding paragraphs, as noted in Chapter 7 the Inquiry recommends that the Minister review PTTEPAA's permit and licence to operate at Montara. The Inquiry emphasises that it is not recommending actual cancellation of PTTEPAA's licence. Indeed, the Inquiry recommends that when the Minister reviews PTTEPAA's licence, he assess the extent to which PTTEPAA has actually implemented a detailed and very worthwhile Action Plan which it has put in place to address matters of concern raised during the Inquiry. The Inquiry considers that if this Action Plan is conscientiously implemented it may go a long way to restoring confidence in PTTEPAA's ability and commitment to operate as a responsible licensee at Montara. This topic is explained in detail in Chapter 7.
- 3.325. Other recommendations in relation to the regulatory regime are to be found in Chapter 4.

4. THE REGULATORY REGIME: WELL INTEGRITY AND SAFETY²⁴⁴

Introduction

- 4.1. To quote from Messrs Bills and Agostini in their report on Offshore Petroleum Safety Regulation of June 2009:
- In a complex, high hazard industry such as offshore oil and gas, society expects a robust regulatory regime in which operators maintain safety to minimise the risk of a major accident event and regulators provide assurance that this is being done.²⁴⁵
- 4.2. The fact that the Blowout occurred within the current regulatory regime suggests the Inquiry needs to consider matters such as the following:
- a. was there a sufficient means of discovering the inadequacies in PTTEPAA's operations identified in Chapter 3? and
 - b. if not, was this because the relevant regulator failed to follow good regulatory practice and, if so, what factors contributed to this and how can they be avoided in the future?
- 4.3. There are a number of regulators involved at various stages in the development of offshore petroleum fields but, in this instance, it was the NT DoR which was responsible for overseeing the requirements bearing on the integrity of the H1 Well, including the general requirement that good oilfield practice be followed.
- 4.4. On 15 April 2010 Counsel Assisting the Inquiry questioned the Executive Director of the Minerals and Energy Division of the NT DoR (Mr Trier) about the following assessment of Mr Marozzi's²⁴⁶ evidence that had been publicly offered by Mr Danenberger:²⁴⁷

²⁴⁴ The regulatory regime relating to environmental matters is dealt with in Chapter 6.

²⁴⁵ Bills and Agostini, *Offshore Petroleum Safety Regulation*, p. xi.

²⁴⁶ Mr Marozzi was an officer of the NT DoR.

²⁴⁷ Mr Elmer (Bud) Danenberger III was employed as an engineer in the United States' Department of the Interior's offshore oil and gas program for 38 years serving as a staff engineer in the Gulf of Mexico regional office; Chief of the Technical Advisory Section at the headquarters office of the US Geological Survey; District Supervisor for Minerals Management Service (MMS) field offices in Santa Maria, California, and Hyannis, Massachusetts; and as Chief of the Engineering and Operations Division at MMS headquarters. Prior to retirement, he served as Chief of Offshore Regulatory Programs with responsibilities for safety and pollution-prevention research, engineering support, operating regulations, and inspection and enforcement programs. On 10 October, 2009, he was inducted into the Offshore Energy Center Hall of Fame as a Technology Pioneer. His assessment of Mr Marozzi's evidence

To this outside observer it was not a good day for the Northern Territory Department of Resources. While it is premature to speculate on the Commission's conclusions and the follow up actions by the Australian Government, today's testimony has not helped the NT cause. [Mr Marozzi's] attitude seems to be that if it's good enough for the operator, it's good enough for the regulator, and it's not a good time to be giving that impression. While, operator responsibility should be a fundamental tenant [sic] of any regulatory regime the regulator needs to verify the effectiveness of the management and operational systems. This can be accomplished through some combination of audits, inspections, program and plan reviews, performance measures, and other means. However, the regulator cannot be passive in any type of regime - performance-based, prescriptive or hybrid.

4.5. The following exchange took place:

Q. Having sat through Mr Marozzi's evidence and the other evidence that you have heard in the Inquiry, you would agree with that assessment, wouldn't you?

A. Yes, I agree.

Q. That would be fairly sobering evidence, I take it, for you to hear, given your role within the department?

A. I am not trying to be smart. That's an understatement.²⁴⁸

4.6. This frank concession by a senior manager from the NT DoR captures the upshot of the evidence uncovered by the Inquiry during its public hearing about the way the NT DoR fulfilled its regulatory role. This evidence, and other information considered by the Inquiry, has led it to conclude that changes are required to the regulatory regime in order to minimise the risk of a further major event.

4.7. The Inquiry's findings and recommendations relating to the adequacy and effectiveness of the current regulatory regime are set out at the end of this Chapter. In order to fully understand the basis upon which the Inquiry has made such findings and recommendations, it is necessary to:

- a. first outline the relevant aspects of the regulatory regime;
- b. consider the evidence presented to the Inquiry in relation to the effectiveness of the regulatory regime; and then

was offered on his website Bud's Offshore Energy (see <http://budsoffshoreenergy.wordpress.com/2010/04/13/montara-hearings-day-18/>).

²⁴⁸ T2319–2320 (Trier).

- c. consider the broader policy and other factors that also, in the Inquiry's view, suggest that significant changes to the regulation of the offshore petroleum industry are necessary.

Relevant Aspects of the Regulatory Regime

The history of and background to the regulatory regime

- 4.8. The Offshore Constitutional Settlement in 1979 contained an agreement between the Commonwealth, the states and the Northern Territory in relation to jurisdiction over the territorial sea (which extended to 12 nautical miles from Australia's territorial sea baseline).
- 4.9. Under that agreement, the Commonwealth agreed to pass legislation to vest in each state proprietary rights and title in respect of the seabed of the adjacent territorial sea, with certain reservations for national purposes such as Defence. The states' and the NT's powers were to be limited to three nautical miles. These rights were then enshrined in Commonwealth law — under the *Coastal Waters (State Title) Act 1980* (Cth) and the *Coastal Waters (State Powers) Act 1980* (Cth). The Northern Territory was given the same title and powers under the *Coastal Waters (Northern Territory Title) Act 1980* (Cth) and the *Coastal Waters (Northern Territory Powers) Act 1980* (Cth).
- 4.10. The Offshore Constitutional Settlement reinforced the terms of the Offshore Petroleum Agreement 1967 in that the states would continue to regulate petroleum in the area within three nautical miles of the low water mark or historic boundaries, and the Commonwealth outside that area, but with a statutory 'Joint Authority' (JA) to be responsible in respect of each state's adjacent waters. Special conditions were agreed with Western Australia (WA). This agreement formed the basis for the current regulatory framework, namely:
 - a. state and territory petroleum legislation applies in coastal waters and is administered by state and territory authorities; and
 - b. Commonwealth legislation alone applies in Commonwealth waters. However, the Commonwealth Government shares joint regulatory authority with the relevant state or territory in the adjacent areas of Commonwealth waters.
- 4.11. The width of Australian jurisdiction offshore, in international terms, varied over the years in accordance with variations to the width that was accepted internationally. Under s 7 of the *Seas and Submerged Lands Act 1973* (Cth) the Governor-General was given power, consistent with the Convention on the

Territorial Sea and the Contiguous Zone 1958, to declare the outer limits of the whole or any part of the territorial sea. In 1990, the outer limit of the territorial sea was declared to be extended to 12 nautical miles, but this did not extend the jurisdiction of the states and the Northern Territory beyond the three nautical mile limit previously agreed under the Offshore Constitutional Settlement. In 1994, Australia established an exclusive economic zone (**EEZ**) of 200 miles around its coast, adopting the provisions of the United Nations Convention on the Law of the Sea of 10 December 1982.

- 4.12. The PSLA was originally enacted to give effect to the Offshore Petroleum Agreement 1967. Each of the states and the Northern Territory passed their own legislation giving effect to the Offshore Constitutional Settlement.
- 4.13. Following the Offshore Constitutional Settlement, the joint regulatory authority for each adjacent area has consisted of a DA and a JA. The DA is the relevant state or Northern Territory Minister. The JA comprises the state or Northern Territory Minister and the responsible Commonwealth Minister. In practice, the terms often describe the government officials to whom the powers of the DA or the JA are delegated by the respective Ministers.
- 4.14. As agreed in the Offshore Constitutional Settlement, the DA is responsible for the day-to-day administration of petroleum activities, while the JA is concerned with significant decisions arising under the legislation. Examples of significant decisions are:
 - a. determining areas to be open for applications for exploration permits;
 - b. granting and renewing exploration permits and production licences; and
 - c. determining permit or licence conditions governing the level of work or expenditure required.
- 4.15. In the event of disagreement within a JA, the view of the Commonwealth Minister prevails.
- 4.16. In its submission to the Inquiry, the Department of Resources, Energy and Tourism (**RET**) described, in the Inquiry's view accurately, the structure of the regulatory framework governing the upstream petroleum sector in the following way:

The unique structure of the regulatory framework governing the upstream petroleum sector stems from Australia's federal system of government such that powers are shared between the Commonwealth and the state and NT governments. Inevitably, this structure gives rise to various

challenges. The regulatory regime is co-operative and relies on the states and NT performing their various responsibilities and discharging their obligations. The inherent nature of such a co-operative regime lends itself to circumstances where there may be inconsistencies as between the states and NT, particularly in terms of approaches, procedures and resourcing available to discharge their obligations with respect to the regulation of the offshore petroleum industry.²⁴⁹

The current regulatory regime

- 4.17. The PSLA was subjected to a long and thorough review and the result was the subject of consultations with industry, discussion papers and workshops for approximately five years. In 2006 the *Offshore Petroleum Act 2006* (Cth) (**OPA**) was passed by Parliament but was not brought into force for another two years as further issues relating to it were discussed and the OPGGS Act amended to deal with matters arising from these discussions.²⁵⁰
- 4.18. The PSLA was repealed and replaced by the OPA, effective from 1 July 2008. Shortly thereafter, further amendments were made and the name of the legislation was changed to the OPGGS Act. The OPGGS Act gained assent on 21 November 2008.
- 4.19. Under the OPGGS Act, the term ‘adjacent waters’ was replaced by ‘offshore area’. A table (in s 8 of the OPGGS Act) sets out the offshore areas of each state and territory, which are, generally, the waters that are beyond the outer limits of the coastal waters of the adjacent state or the Northern Territory and within the outer limits of the continental shelf (that is, three nautical miles from the baselines to 200 nautical miles (the EEZ) and beyond that for those areas where Australia has a recognised outer continental shelf).
- 4.20. The objects of the OPGGS Act include the provision of an effective regulatory framework for petroleum exploration and recovery (s 3).
- 4.21. There are nine subordinate regulations to the OPGGS Act. At the time of the Blowout the following contained provisions of relevance to the Inquiry:
- a. *Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996* (Cth),²⁵¹

²⁴⁹ RET, Submission to the Inquiry, paragraph 2.34.

²⁵⁰ White M 2009, *Australian Offshore Laws*, p. 46.

²⁵¹ The *Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996* (Cth), together with the *Petroleum (Submerged Lands) (Occupational Health and Safety) Regulations*

- b. *Petroleum (Submerged Lands) (Management of Environment Regulations) 1999 (Cth)*;²⁵² and
- c. *Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004 (Cth)*.

The Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cth)

- 4.22. The following provisions of the OPGGS Act are of particular relevance to the Inquiry.
- 4.23. Section 4 provides an outline of the OPGGS Act and summarises the division of responsibility for administration of the OPGGS Act between JAs and DAs.
- 4.24. Section 7 contains definitions, including of:
 - a. 'coastal waters';
 - b. 'Designated Authority' (as per s 70);
 - c. 'Joint Authority' (as per s 56);
 - d. 'Offshore area' (as per s 8, and including the Territory of Ashmore and Cartier Islands);
 - e. 'responsible Commonwealth Minister'; and
 - f. 'responsible Northern Territory Minister' (being, generally, the Minister of the Northern Territory who is authorised under a law of the Northern Territory to perform the functions of a DA under the OPGGS Act).

The JA and DA

- 4.25. Subsections 56(8) and (9) of the OPGGS Act provide that the responsible Commonwealth Minister (alone) is the JA for each of the external territories, and for the offshore areas of each of those territories. This includes the Territory of Ashmore and Cartier Islands where the Montara WHP is located. The JA for this area is to be known as the 'Territory of Ashmore and Cartier Islands Offshore Petroleum Joint Authority'.

1993 (Cth) and the Petroleum (Submerged Lands) (Diving Safety) Regulations 2002 (Cth), have been consolidated into, and repealed by, the Offshore Petroleum (Safety) Regulations 2009 (Cth) which commenced on 1 January 2010.

²⁵² The *Petroleum (Submerged Lands) (Management of Environment Regulations) 1999 (Cth)* have recently been amended to include greenhouse gas and have been renamed the *Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009 (Cth)*.

- 4.26. Similarly, subsections 70(8) and (9) provide that the responsible Commonwealth Minister (alone) is the DA for each of the external territories, and for the offshore areas of each of those territories, including the Territory of Ashmore and Cartier Islands.
- 4.27. Section 68(1) of the OPGGS Act allows the JA for an external territory to delegate to a person by written instrument any or all of the functions or powers of the JA under the OPGGS Act or the regulations.
- 4.28. Section 72(1) allows a DA to delegate by written instrument any or all of the functions or powers of the DA under the OPGGS Act or the regulations to either:
- a. an APS employee who is an SES employee or acting SES employee; or
 - b. an employee of a state or the NT.
- 4.29. The Minister for Resources and Energy, the Hon Martin Ferguson AM MP, is the 'responsible Commonwealth Minister' for the purposes of the OPGGS Act and is therefore both the JA and the DA for the external Territory of Ashmore and Cartier Islands and its offshore area.
- 4.30. On 25 August 2008 the Minister revoked all existing delegations and:
- a. in his capacity as the JA for the offshore area of the external Territory of Ashmore and Cartier Islands, pursuant to s 49 of the OPA, delegated all his functions and powers to the person who, from time to time, holds, occupies or performs the office of General Manager, Offshore Resources Branch, Resources Division, RET (JA Delegation). This is currently Mr Martin Squire, General Manager, Offshore Resources Branch, RET; and
 - b. in his capacity as the DA for the offshore area of the external Territory of Ashmore and Cartier Islands, pursuant to s 52 of the OPA delegated to the person who, from time to time, holds, occupies or performs the duties of the office of:
 - i. Director of Energy, Department of Regional Development, Primary Industry, Fisheries and Resources of the Northern Territory (now known as the Department of Resources) (NT DoR), the functions and powers of the DA under the OPA and the Regulations specified in Item 1 of the Schedule to that instrument.²⁵³ This is currently Mr Jerry Whitfield,

²⁵³ Item 1 refers to all the functions and powers of the DA under: the OPA; *Petroleum (Submerged Lands) Regulations 1985*; *Petroleum (Submerged Lands) (Management of Environment) Regulations 1999*; *Petroleum (Submerged Lands) (Pipelines) Regulations 2001*; *Petroleum (Submerged Lands) (Diving*

Director of Energy within the Mineral and Energy Titles Division of the NT DoR. **This delegation made the Director of Energy of the NT DoR, and the staff that assisted him fulfil his role, responsible for overseeing the regulation of matters relating to well integrity at the H1 Well;**

- ii. Registrar of the NT DoR, appointed under the Petroleum Act of the Northern Territory, the functions and powers of the DA under the OPA and the Regulations specified in Item 2 of the Schedule to that instrument.²⁵⁴ This is currently Ms Debby James, Manager Petroleum Titles, NT DoR;
- iii. Director of Geological Survey, NT DoR, the functions and powers of the DA under the OPGGS Act and the Regulations specified in Item 3 of the Schedule to that instrument.²⁵⁵ This is currently Mr Ian Scrimgeour, Director, Northern Territory Geological Survey; and
- iv. Chief of Division, Petroleum and Marine Division, Geoscience Australia (**GA**) of the Commonwealth of Australia, the functions and powers of the DA under the OPGGS Act and the Regulations specified in Item 4 of the Schedule to that instrument.²⁵⁶ This is currently Dr Clinton Foster.

4.31. Accordingly, by way of summary, for the purposes of the Territory of Ashmore and Cartier Islands:

- a. the Commonwealth Minister alone is both the JA and the DA; but
- b. all of the Minister's functions and powers as the JA are delegated to Mr Squire; and
- c. all of the Minister's functions and powers as the DA, other than those in Item 4 of the Schedule (which were delegated to the Chief of Division, Petroleum and Marine Division, GA), have been delegated to officers of the NT DoR.

Safety) Regulations 2002; Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004; and Petroleum (Submerged Lands) (Data Management) Regulations 2004.

²⁵⁴ Item 2 refers to all the functions and powers of the DA prescribed in Chapter 3 of the OPA.

²⁵⁵ Item 3 refers to ss 419, 421, 422, 423, 424 and Schedule 5 of the OPA; the *Petroleum (Submerged Lands) (Data Management) Regulations 2004*; and Regulations 2A, 2B and 2C of the *Petroleum (Submerged Lands) Regulations 1985*.

²⁵⁶ Item 4 refers to ss 422 and 423 of the OPA; and Parts 1 and 6 of the *Petroleum (Submerged Lands) (Data Management) Regulations 2004*.

Petroleum production licences

- 4.32. It is an offence to recover petroleum without a petroleum production licence unless otherwise authorised or required by or under the OPGGS Act (s 160).
- 4.33. Section 162 provides that the JA may grant a petroleum production licence subject to whatever condition the JA thinks appropriate.
- 4.34. By virtue of s 165 of the OPGGS Act the AC/L7 production licence granted to PTTEPAA (then Coogee Resources) on 20 March 2007 remains in force indefinitely unless it is cancelled.
- 4.35. Section 266 provides for suspension of rights conferred by a petroleum exploration permit or petroleum retention lease. It states:

Suspension of rights

(1) If the Joint Authority is satisfied that it is necessary to do so in the national interest, the Joint Authority must, by written notice given to a petroleum exploration permittee or petroleum retention lessee, suspend, either:

- (a) for a specified period; or
 - (b) indefinitely;
- any or all of the rights conferred by the permit or lease.

Note: See also section 780 (compensation for acquisition of property).

- 4.36. However, there does not appear to be a power to suspend a petroleum production licence.
- 4.37. Section 274 sets out the grounds for cancellation of a petroleum production licence. They include where:
- a. the registered holder has not complied with a direction given to the holder by the DA or the JA under Chapter 2, Chapter 6, Part 7.1 of the OPGGS Act; or
 - b. has not complied with a provision of Chapter 2, Chapter 4, Chapter 6, or Part 7.1 of the regulations.²⁵⁷

²⁵⁷ By virtue of s 17(r) of the *Acts Interpretation Act 1901* (Cth) 'The Regulations' should be interpreted as regulations made under the Act. The effect of the transitional provisions in Schedule 6 of the Act is that this will include the regulations made under the *Petroleum (Submerged Lands) and Offshore Petroleum (Submerged Lands) Act 1967* (Cth), including the *Petroleum (Submerged Lands) (Management of Well Operation) Regulations 2004* (Cth).

- 4.38. In exercising the power to cancel a production licence the JA must take into account any action taken by the registered holder:
- a. to remove the ground of cancellation; or
 - b. to prevent the occurrence of similar grounds.

Requirements to be complied with by titleholders

- 4.39. Chapter 6 of the OPGGS Act imposes requirements that must be complied with by titleholders in relation to, amongst other things, work practices and insurance. The maximum penalty for failing to comply with such a requirement is 100 penalty units for each offence.²⁵⁸
- 4.40. Section 569 requires the registered holder of a petroleum production licence to, amongst other things, ensure that they do the following things in their licence area:²⁵⁹
- a. carry out all petroleum exploration and recovery operations in a proper and workmanlike manner and in accordance with good oilfield practice; and
 - b. control the flow, and prevent the waste or escape, in the licence area, of petroleum or water.
- 4.41. It is an offence for the registered holder to engage in conduct which breaches the requirement to do these things but a defence is available if all reasonable steps were taken to comply (s 569(6) and (7)).
- 4.42. The holder of a petroleum production licence must also maintain, as directed by the DA from time to time, insurance against expenses, liabilities or specified things arising in connection with, or as a result of, the carrying out of work, or doing of any other thing, under the licence, including insurance against expenses of complying with directions relating to the clean-up or other remediation of the effects of the escape of petroleum (s 571). Information in relation to the NT DoR's regulation of this requirement is set out below.
- 4.43. Section 574 gives the DA power to give the registered holder of a petroleum production licence, by written notice, a direction as to any matter in relation to which regulations may be made under the OPGGS Act.²⁶⁰

²⁵⁸ See ss 569(6), 570(5) and 572(4). This is currently \$11,000 – see s 4AA of the *Crimes Act 1914* (Cth).

²⁵⁹ Subject to any new authorisation given or requirement made (see s 569(2)).

- 4.44. It is an offence of strict liability for a person who is subject to a direction under s 574 to engage in conduct that breaches the direction (s 576).
- 4.45. A direction given under s 574 may be expressed to apply to:
- a. employees or agents of, or persons acting on behalf of, the registered holder;
 - b. persons performing work or services for the registered holder;
 - c. any person(s) in the offshore area for any reasons touching, concerning, arising out of, or connected with, exploring the seabed or subsoil of the offshore area for petroleum or exploiting the petroleum that occurs as a natural resource of that seabed or subsoil; or
 - d. any person(s) who is on, above, below or within the vicinity of a vessel, aircraft structure or installation, or equipment or other property which is in the offshore area for reason of that kind.
- 4.46. A direction to a person that results in the acquisition of property would enliven s 780 of the OPGGS Act, which states:
- (1) If the operation of this Act or the regulations would result in an acquisition of property from a person otherwise than on just terms, the Commonwealth is liable to pay a reasonable amount of compensation to the person.
 - (2) If the Commonwealth and the person do not agree on the amount of the compensation, the person may institute proceedings in the Federal Court for the recovery from the Commonwealth of such reasonable amount of compensation as the court determines.
 - (3) In this section:
acquisition of property has the same meaning as in paragraph 51(xxxi) of the Constitution
just terms has the same meaning as in paragraph 51(xxxi) of the Constitution.
- 4.47. The DA must not give a direction under s 574, of a standing or permanent nature, except with the approval of the JA, but the validity of a direction given is not affected by breach of this requirement (s 574(5)).
- 4.48. If a person who is subject to a direction engages in conduct which breaches that direction the DA may do any or all of the things required by the direction, and

²⁶⁰ Section 782 of the OPGGS Act is the main provision setting out matters in relation to which regulations may be made. It includes the clean-up or other remediation of the effects of the escape of petroleum or a greenhouse gas substance. This power to give directions is dealt with further in Chapter 6.

the costs or expenses incurred by the DA become a debt due to the Commonwealth by the person subject to the direction that is recoverable in a court of competent jurisdiction (s 577). It is a defence to an action to recover such a debt, as well as a defence to a prosecution for breaching a direction, if the defendant proves that it took all reasonable steps to comply with the direction (ss 577(5) and 578).

- 4.49. The DA may also, by written notice, give the registered holder of a petroleum production licence a direction to provide, to the satisfaction of the DA, for the conservation and protection of the natural resources in the licence area on or before the first date on which the licence can be terminated under the OPGGS Act (s 586(2)). It is an offence for a registered holder to omit to do an act if the omission breaches such a direction (s 586(5)).
- 4.50. The holder of a petroleum production licence is also required to maintain in good repair all structures, equipment and other property in its title area that is used in connection with its operations authorised by their licence (s 572).

Petroleum project inspectors

- 4.51. The DA may, by writing, appoint any person who is an employee of the Commonwealth, state or territory or an authority of the Commonwealth, state or territory to be a petroleum project inspector (s 600). A petroleum project inspector has powers:
- a. of inspection of petroleum operations;
 - b. to test any equipment that the petroleum project inspector has reasonable grounds to believe has been, is being, or is to be used in the offshore area in connection with petroleum operations; and
 - c. to take extracts from or make copies of documents in any structure, aircraft or building in an offshore area relating to petroleum operations.²⁶¹

Occupational health and safety

- 4.52. Clause 9 of schedule 3 of the OPGGS Act requires the operator of a facility to take all reasonably practicable steps to ensure that:
- a. the facility is safe and without risk to the health of any person at or near the facility; and

²⁶¹ The relevant petroleum operations are listed in s 601(2)(b) of the OPGGS Act.

- b. all work and other activities carried out on the facility are carried out in a manner that is safe and without risk to the health of any person at or near the facility.

4.53. This includes:

- a. taking all reasonably practicable steps to provide and maintain a physical environment at the facility that is safe and without risk to health;
- b. taking all reasonably practicable steps to ensure that any plant, equipment, materials and substances at the facility are safe and without risk to health; and
- c. taking all reasonably practicable steps to implement and maintain systems of work at the facility that are safe and without risk to health.

4.54. Clause 10 imposes similar requirements in relation to a person who is in control of any part of a facility, or any particular work carried out at a facility and clause 11 creates similar duties for an employer in relation to employees at a facility.

The role of NOPSA²⁶²

4.55. Part 6.9 of the OPGGS Act deals with NOPSA.²⁶³

4.56. It states that NOPSA has functions in relation to the OHS of persons engaged in offshore petroleum operations and offshore greenhouse gas storage operations (s 642). NOPSA's functions include:

- a. the promotion of the OHS of persons engaged in offshore petroleum operations (s 646(c));
- b. developing and implementing effective monitoring and enforcement strategies to secure compliance by persons with their OHS obligations under the OPGGS Act and regulations (s 646(d));
- c. investigating accidents, occurrences and circumstances that affect, or have the potential to affect, the OHS of persons engaged in offshore petroleum operations (s 646(e)(i)) and to report to the responsible Minister on those investigations (s 646(e)(ii)); and

²⁶² NOPSA's primary role in relation to matters that have been examined by this Inquiry was in relation to the response to the Uncontrolled Release. This is examined in Chapter 5 of this report.

²⁶³ NOPSA was established under amendments to the *Petroleum (Submerged Lands) Act 1967* (Cth) by the *Petroleum (Submerged Lands) Amendment Act 2003* (Cth).

- d. to advise persons, either on its own initiative or on request, on OHS matters relating to offshore petroleum operations (s 646(f)).
- 4.57. NOPSA's functions apply in the offshore areas and can also apply in 'designated coastal waters' (which are the coastal waters) where state or Northern Territory legislation confers powers on it (s 643, 644 and 646).
- 4.58. NOPSA administers the OHS laws listed in s 638 of the OPGGS Act. At the time of the Blowout this included the *Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996* (Cth), the *Petroleum (Submerged Lands) (Occupational Health and Safety) Regulations 1993* (Cth); the *Petroleum (Submerged Lands) (Pipelines) Regulations 2001* (Cth) and Schedule 3 of the OPGGS Act.²⁶⁴
- 4.59. Schedule 3 of the OPGGS Act sets up a scheme to regulate OHS matters at or near offshore facilities. One of the key components of this scheme is the imposition of duties relating to health and safety on operators of facilities and other people or organisations who may be involved in activities on offshore facilities. The maximum penalties for failing to comply with such duties are 30,²⁶⁵ 50,²⁶⁶ 100,²⁶⁷ 200,²⁶⁸ 250²⁶⁹ to 1,000²⁷⁰ penalty units and imprisonment for 6 months.²⁷¹
- 4.60. Recent amendments to Schedule 3 introduced:
- a. the application of absolute liability²⁷² to the requirement that operators of facilities must take all reasonably practicable steps to ensure that:
 - i. the facility is safe and without risk to anyone at or near the facility; and
 - ii. work and other activities carried out on the facility are done in a safe manner without risk to the health of anyone at or near the facility;²⁷³ and

²⁶⁴ On 1 January 2010 the *Offshore Petroleum (Safety) Regulations 2009* (Cth) replaced the *Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996* (Cth).

²⁶⁵ See for example clause 83(4). This is currently \$3,300.

²⁶⁶ See for example clause 54. This is currently \$5,500.

²⁶⁷ See for example clauses 78(9), 79(4), 82(9). This is currently \$11,000.

²⁶⁸ See for example clauses 12(3), 13(2), 13A(3), 14(2), 15(2). This is currently \$22,000.

²⁶⁹ See for example clauses 82(4), 88(2). This is currently \$27,500.

²⁷⁰ See for example clauses 9(4), 10(4), 11(5). This is currently \$110,000.

²⁷¹ Clause 86(1) – which relates to deliberately interfering with safety or protective equipment.

²⁷² Which removes the defence of honest and reasonable mistake of fact.

²⁷³ See for example clause 9(4A).

- b. obligations on petroleum and greenhouse gas titleholders in relation to the design of facilities, requiring the relevant titleholder to take all reasonably practicable steps to ensure that the facility is designed to be safe and without risk to health, when it is properly used.

4.61. An OHS inspector appointed by NOPSA has the powers conferred by Part 4, Schedule 3 of the OPGGS Act.

4.62. NOPSA OHS inspectors are empowered under Schedule 3 to:

- a. conduct inspections:
 - i. to ascertain whether the listed OHS laws are being complied with (sch 3, cl 49(1)(a));
 - ii. concerning a contravention of a listed OHS law (sch 3, cl 49(1)(b)); or
 - iii. concerning an accident or dangerous occurrence that happened at a facility (sch 3, cl 49(1)(c));
- b. enter offshore facilities for the purposes of inspections, conduct inspections, interview people, seize evidence and take certain other actions to ensure compliance with listed OHS laws (sch 3, cl 50 – 79); and
- c. issue prohibition notices and improvement notices. Prohibition notices are governed by clause 77 which relevantly provides:

Issue of prohibition notice

(1) If, having conducted an inspection, an OHS inspector is satisfied on reasonable grounds that it is reasonably necessary to issue a prohibition notice to the operator of a facility in order to remove an immediate threat to the health or safety of any person, the OHS inspector may issue such a notice, in writing, to the operator.

(2) The notice must be issued to the operator by giving it to the operator's representative at the facility.

(3) The notice must:

(a) specify the activity in respect of which, in the OHS inspector's opinion, the threat to health or safety has arisen, and set out the reasons for that opinion; and

(b) either:

(i) direct the operator to ensure that the activity is not engaged in; or

(ii) direct the operator to ensure that the activity is not engaged in a specified manner.

(4) A specified manner may relate to any one or more of the following:

(a) any workplace, or part of a workplace, at which the activity is not to be engaged in;

- (b) any plant or substance that is not to be used in connection with the activity;
- (c) any procedure that is not to be followed in connection with the activity.

Offence

- (5) A person commits an offence if:
 - (a) the person is subject to a notice under subclause (1); and
 - (b) the person omits to do an act; and
 - (c) the omission breaches the notice.

Penalty: 250 penalty units.²⁷⁴

OHS inspector to inform operator if action is not adequate

- (6) If an OHS inspector is satisfied that action taken by the operator to remove the threat to health and safety is not adequate, the OHS inspector must inform the operator accordingly.

When notice ceases to have effect

- (7) The notice ceases to have effect when an OHS inspector notifies the operator that the OHS inspector is satisfied that the operator has taken adequate action to remove the threat to health or safety.

Powers of OHS inspector

- (8) In making a decision under subclause (6), an OHS inspector may exercise such of the powers of an OHS inspector conducting an inspection as the OHS inspector considers necessary for the purposes of making the decision.

Notice may specify what is adequate action

- (9) The notice may specify action that may be taken to satisfy an OHS inspector that adequate action has been taken to remove the threat to health and safety.

Duties of operator's representative

- (10) The operator's representative at the facility must:
 - (a) give a copy of the notice to each health and safety representative (if any) for any designated work group having group members performing work that is affected by the notice; and
 - (b) cause a copy of the notice to be displayed at a prominent place at or near each workplace at which that work is performed.

Notification of owner

- (11) If the notice relates to any workplace, plant, substance or thing that is owned by a person other than the operator, the OHS inspector must, upon issuing the notice, give a copy of the notice to that person.

Transitional provisions

- 4.63. The transitional provisions relating to the OPGGS Act are set out in Schedule 6. It contains a number of provisions which preserve the validity of action taken under the PSLA, notwithstanding the repeal of that Act. Any act or thing done

²⁷⁴ Currently \$27,500.

before the commencement of the OPGGS Act under, or for the purposes of, a particular provision of the PSLA has effect as if it had been done under, or for the purposes of, the corresponding provision of the OPGGS Act. This includes the appointment and actions of JAs and DAs.

The move away from a prescriptive regime

- 4.64. Regulation of the Australian offshore petroleum industry remained very prescriptive until changes were implemented to offshore petroleum health and safety regulation in the United Kingdom (**UK**). Such changes in the UK were precipitated by the disaster at the *Piper Alpha* oil production platform in the North Sea in 1988, where an explosion and fire claimed the lives of 167 people, including two rescue personnel. Only 59 people survived.
- 4.65. The report of the Inquiry held by the Hon Lord Cullen into the disaster, *The Public Inquiry into the Piper Alpha Disaster* (the **Cullen Report**), found that the accident was caused by an explosion of a gas condensate leakage which had built up beneath the drilling platform. It also found that prior to the accident, a sector-wide set of regulations applied to all platforms, which were enforced by governmental inspection. However, this policy did not allow for the customisation of safety regulations to a particular type of platform. One of the major failures of the UK regulatory system identified in the Cullen Report was that it did not adopt a policy of risk-based analysis requiring offshore operators to identify operational hazards with a view to demonstrating (or not) that their operations could be conducted safely. Although the occurrence of such potentially hazardous events as the *Piper Alpha* accident had been envisaged, the Cullen Report found that the operator of the platform was not required to assess the risks systematically.
- 4.66. The Cullen Report included 106 recommendations for improving the control of major hazards offshore, all of which were accepted by the UK Government. Fundamentally, the Cullen Report recommended that the regulation of the offshore petroleum industry move from a prescriptive to an objective-based safety case regime. Rather than specifying detailed standards of every aspect of an offshore facility, the new approach required facility operators to provide a safety case for their facility, which identified all the hazards and risks, and set out how these risks had been reduced to a level as low as reasonably practicable.²⁷⁵

²⁷⁵ NOPSA, 2008-09 NOPSA Annual Report, <http://www.nopsa.gov.au/document/NOPSA_Annual_Report_2008_09.pdf>, p. 16.

- 4.67. Such a regime aims to ensure that those who create risks are responsible for managing them, and that improvements in safety, culture and performance come from within the operating company, rather than being imposed externally by regulators. The move away from prescriptive legislation also provides companies with flexibility to utilise emerging technologies in their business undertakings and to manage risk.²⁷⁶
- 4.68. In response to the Cullen Report, the Commonwealth Government established the Consultative Committee on Safety in the Offshore Petroleum Industry, which recommended in 1991 that the key outcomes of the Cullen Report be implemented in Australia, in particular that the safety case regime be adopted and new performance-based regulations replace the prescriptive regulations contained in the PSLA.²⁷⁷
- 4.69. The Australian regime is now largely a performance-based regime, in which the operator of an offshore facility is responsible for its safe operation and holds the principal duty of care. Such a regime envisages that the regulatory role will primarily be fulfilled by:
- a. NOPSA assessing and challenging operators' safety cases, and seeking, through an oversight role, to ensure that the health and safety risks are properly controlled by the operator;²⁷⁸ and
 - b. DAs assessing Well Operation Management Plans and applications to conduct well activities in order to ensure that well operations will be conducted in accordance with sound engineering principles and good oilfield practices before approval to conduct them is granted.
- 4.70. Such regulatory oversight and control is currently primarily exercised pursuant to the *Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004* (Cth) and the *Offshore Petroleum (Safety) Regulations 2009* (Cth).

²⁷⁶ Ibid.

²⁷⁷ Department of Industry, Science and Resources, *Australian Offshore Petroleum Safety Case Review: Future Arrangements for the Regulation of Offshore Petroleum Safety*, <http://www.nopsa.gov.au/downloads/Future_Arrangements_for_regulating_Offshore_Petroleum_Safety.pdf>, p. 17.

²⁷⁸ NOPSA, *2008-09 NOPSA Annual Report*, p. 16.

The Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004

- 4.71. Notwithstanding the repeal of the PSLA on 1 July 2008, the *Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004* (Cth) (the **Management of Well Operations Regulations**) remain in force under the transitional provisions in clause 4 of schedule 6 to the OPGGS Act.²⁷⁹
- 4.72. Prior to the introduction of the Management of Well Operations Regulations there was a specific list of minimum engineering standards that had to be met on a well. That list was entitled *Specific Requirements as to Offshore Petroleum Exploration and Production*. It was commonly referred to as ‘the Schedule’ or ‘the Specific Requirements’.²⁸⁰ The Specific Requirements contained prescriptive standards in relation to such things as:
- a. pressure testing after cementing of the casing shoe – including a requirement that there be a satisfactory result before operations to complete a well commence;
 - b. notifying the DA if there was any reason to suspect a faulty cementing operation; and
 - c. the use of cement plugs (as opposed to devices such as PCCCs) as barriers when suspending a well.
- 4.73. These minimum prescriptive standards appear to have mirrored standards applied in the United States. Such minimum prescriptive standards are also still used in a number of countries which have a significant offshore petroleum industry. The United States, Canada and Norway are examples.
- 4.74. An essential part of the flexibility the Management of Well Operations Regulations sought to introduce is the development of a WOMP that specifies acceptable methods of conducting well operations in accordance with sound engineering principles and good oilfield practice. A WOMP must be accepted by the DA.
- 4.75. The object of the Management of Well Operations Regulations is to ensure that for petroleum exploration, appraisal and production:
- a. the design of downhole activities is in accordance with good oilfield practice;

²⁷⁹ It is therefore back captured in accordance with s 36 of the *Legislative Instruments Act 2003*.

²⁸⁰ The Specific Requirements were originally developed pursuant to the provisions of s 101 of the PSLA. Section 101 established the power of a DA to issue directions with a status equivalent to regulations in relation to all matters about which regulations may be made.

- b. downhole activities are carried out in accordance with an accepted WOMP; and
 - c. risks are identified and managed in accordance with sound engineering principles and good oilfield practice.²⁸¹
- 4.76. The regulations are objective-based. This allows for well activity arrangements to be changed in response to technologies and other circumstances while adhering to the key legislative principles.
- 4.77. A WOMP must:
- a. comply with the OPGGS Act and the Regulations;
 - b. be appropriate for the nature and scale of the well activity; and
 - c. show that the risks identified by the titleholder in relation to the well activity will be managed in accordance with sound engineering principles, standards, specifications and good oilfield practice (regulation 6).
- 4.78. It must also include the following:²⁸²
- a. information about the conduct of the well activity;
 - b. an explanation of:
 - i. the philosophy of, and criteria for, the design, construction, operational activity and management of the well;
 - ii. the possible production activities of the well; and
 - iii. how the well activity, and all associated operational work, will be carried out in accordance with good oilfield practice;
 - c. performance objectives against which the performance of the well activity is to be measured;
 - d. measurement criteria that define the performance objectives;
 - e. an explanation of how the titleholder will deal with:
 - i. a well integrity hazard;²⁸³

²⁸¹ See regulation 3 of the Management of Well Operations Regulations.

²⁸² Unless the DA has given permission, in writing, not to include such information.

²⁸³ Regulation 4 defines 'well integrity hazard' to mean an event that may compromise the well integrity of a well; and would, if it occurred, have the consequence of a significant threat to the safety of

- ii. a significant increase in an existing risk in relation to the well; and
 - iii. the possibility of continuing an activity for the purpose of dealing with the well integrity hazard or the risk;
- f. details of when and how the titleholder will notify the DA, and give reports and information, about:
- i. the well activity;
 - ii. well integrity hazards;
 - iii. significant increases in existing risks in relation to the well; and
 - iv. other matters relevant to the conduct of the well activity; and
- g. an explanation of the way in which the titleholder will keep information required by the WOMP (regulation 6(2)).

4.79. A titleholder can ask the DA to accept variations to the WOMP and the DA can require, subject to objection rights set out in regulations 13 and 14, the titleholder to vary the WOMP.

4.80. Unless a WOMP is withdrawn or replaced it remains in force for five years from the date of acceptance.

4.81. Regulation 17 assumes great significance in relation to the subject of the Inquiry. It provides:

17 Approval

(1) A titleholder must not commence any of the following well activities, that lead to the physical change of a wellbore, without the approval of the Designated Authority:

- (a) well drilling;
- (b) testing;
- (c) well completion;
- (d) abandonment or suspension of a well;
- (e) well intervention.

Note Other well activities that do not alter the well configuration, such as wireline activities, require only notification to the Designated Authority.

(2) Sub regulation (1) applies whether or not:

- (a) the titleholder has a current accepted well operations management plan relating to the activity; or

individuals; or an event that may involve a risk of significant damage to the environment or the well reservoir of a well.

(b) a new well integrity hazard exists that requires the titleholder to vary the titleholder's accepted well operations management plan.

(3) An application for approval to commence a well activity must include:

(a) a description of the well activity; and

(b) the titleholder's proposed timetable for carrying out the well activity.

Note there is no compulsory application form for this regulation.

4.82. Regulation 18 states:

18 Reasons for withdrawal of acceptance

The Designated Authority may withdraw its acceptance of a titleholder's accepted well operations management plan if:

(a) the titleholder has not complied with the Act, these Regulations, or a direction given under section 101 of the Act; or

(b) the titleholder has not complied with the accepted well operations management plan; or

(c) the Designated Authority is satisfied for any other reason that its acceptance of the well operations management plan should be withdrawn.

4.83. A titleholder must not undertake an activity relating to a petroleum well (such as production drilling or maintenance of a well) unless the titleholder has a WOMP for that activity that is accepted and current (regulation 22).

4.84. Regulation 24 creates an offence of strict liability where a titleholder does not carry out well activities for a well in accordance with its accepted WOMP or any requirements set out in the regulations.

4.85. Regulation 25 also assumes potential significance in relation to the subject of this Inquiry. It states:

25 Impact of well integrity hazard or increased risk not identified in well operations management plan

(1) A titleholder must not commence a well activity if:

(a) either:

(i) a well integrity hazard has been identified in relation to the well; or

(ii) there has been a significant increase in an existing risk in relation to the well; and

(b) the titleholder has not controlled the well integrity hazard or the risk.

Penalty: 50 penalty units.²⁸⁴

(2) A titleholder must not continue a well activity if:

²⁸⁴ Currently \$5,500.

- (a) either:
 - (i) a well integrity hazard has been identified in relation to the well; or
 - (ii) there has been a significant increase in an existing risk in relation to the well; and
- (b) the titleholder has not controlled the well integrity hazard or the risk.

Penalty: 50 penalty units.

- (3) It is a defence to a prosecution under sub regulation (1) or (2) if the defendant had a reasonable excuse.

Note A defendant bears an evidential burden in relation to the matter in sub regulation (3) (see subsection 13.3 (3) of the *Criminal Code*).

4.86. On 7 November 2008 Coogee Resources wrote to the NT DoR (Mr Whitfield) seeking, amongst other things, acceptance of its WOMP for the H1 Well.

4.87. The WOMP stated:

This WOMP describes the Coogee Resources (Ashmore Cartier) Pty Ltd ('Coogee Resources') management system which ensures that the risks associated with the activities relating to the drilling, completion, and suspension of the Montara H1 development well are managed in accordance with good oil field design and engineering practices.

4.88. The WOMP purported to meet the requirement to 'show that the risks identified by the titleholder in relation to the well activity will be managed in accordance with sound engineering principles, standards, specifications and good oilfield practice' by referring to all sections of Coogee Resources' Well Construction Standards.

4.89. In doing so, the Inquiry considers that these Well Construction Standards were incorporated into and formed part of Coogee Resources' (and subsequently PTTEPAA's) WOMP.

The Offshore Petroleum (Safety) Regulations 2009 (Cth)

4.90. These regulations commenced on 1 January 2010. They replace:

- a. *the Petroleum (Submerged Lands) (Occupational Health and Safety) Regulations 1993 (Cth)*;
- b. *the Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996 (Cth)*; and
- c. *the Petroleum (Submerged Lands) (Diving Safety) Regulations 2002 (Cth)*.

- 4.91. The primary objectives of the regulations relevant to the Inquiry are to ensure that:
- a. offshore petroleum facilities are designed, constructed, installed, operated, modified and decommissioned in Commonwealth waters only in accordance with safety cases that have been accepted by the Safety Authority;
 - b. safety cases for offshore petroleum facilities make provision for the following matters in relation to the health and safety of persons at or near the facilities:
 - i. the identification of hazards, and assessment of risks;
 - ii. the implementation of measures to eliminate the hazards, or otherwise control the risks;
 - iii. a comprehensive and integrated system for management of the hazards and risks;
 - iv. monitoring, audit, review and continuous improvement; and
 - c. the risks to the health and safety of persons at offshore petroleum facilities are reduced to a level that is as low as reasonably practicable (regulation 1.4).

4.92. At the time of the Blowout, the *Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996* (Cth) (the **MOSOF** or **1996 Regulations**) were in force. Both Part 3 of those regulations and Chapter 2, Part 2 of the regulations that replaced them (the **2009 Regulations**) set out the requirements for safety cases for an offshore facility. Both then and now a safety case²⁸⁵ needed to, amongst other things:

- a. be comprehensive and integrated;
- b. provide for all activities that will, or are likely to, take place at, or in connection with, the facility;
- c. provide for the continual and systematic identification of hazards to health and safety of persons at or near the facility;
- d. provide for inspection, testing and maintenance of the equipment and hardware that are the physical control measures for those risks; and

²⁸⁵ Which was referred to as a 'safety management system' under the 1996 Regulations.

- e. provide for any other matter that is necessary to ensure that the safety management system meets the requirements and objects of these Regulations.
- 4.93. The safety case was also, at the time of the Blowout, required to:
- a. provide for the operator of the facility to establish and maintain a documented system of coordinating and controlling the safe performance of all work activities of members of the workforce (regulation 14 of the 1996 Regulations); and
 - b. describe the means by which the operator would ensure the adequacy of the design, construction, installation, maintenance or modification of the facility after the relevant stage or stages in the life of the facility for which the safety case has been submitted. In particular the design, construction, installation, maintenance or modification had to provide for an adequate means of maintaining the structural integrity of the facility (regulation 16 of the 1996 Regulations).
- 4.94. At the time of the Blowout, the safety case also needed to describe a response plan designed to address possible emergencies, the risk of which were identified in the safety assessment for the facility (regulation 24 of the 1996 Regulations).
- 4.95. A safety case had to be submitted to NOPSA for approval (regulations 28-31 of the 1996 Regulations). This remains the case under the 2009 Regulations (Division 2).
- 4.96. Under both the 1996 and 2009 Regulations, offences are created for engaging in conduct in a manner that is contrary to the safety case in force for the facility (part 6 of the 1996 Regulations, Part 5 of Chapter 2 of the 2009 Regulations). The current penalty for failing to do so is 80 penalty units.²⁸⁶ Further offences are created for other breaches of OHS by an operator, employer and/or persons on an offshore petroleum facility. The maximum penalties for such offences are either 10 or 20 penalty units.²⁸⁷
- 4.97. Regulation 50 of the 1996 Regulations prohibited work on an offshore facility if there had been a significant new risk to health and safety or a significant increase in an existing risk to health and safety arising from the construction,

²⁸⁶ Currently \$8,800 - see regulations 2.43-2.45 of the 2009 Regulations.

²⁸⁷ Currently \$1,100 - \$2,200 - see regulations 3.1- 3.6 of the 2009 Regulations.

installation, operation, or modification of the facility, and the new risk or increased risk was not provided for:

- a. in a safety case in force for the facility; or
- b. in a revised safety case submitted to and accepted by NOPSA.

4.98. The same requirement is imposed by regulation 2.46 of the 2009 Regulations, but it imposes an additional requirement that if the titleholder knows about the new risk or increased risk they must notify the operator and NOPSA as soon as practicable.

The current legislative powers are largely sufficient

4.99. As described in the Northern Territory's submission to the Inquiry:

The legislative regime places the onus [to maintain safety to minimise the risk of a major accident event] on operators and provides them with flexibility on how best to manage hazards and minimise risk.²⁸⁸

4.100. With one exception,²⁸⁹ the Inquiry did not receive any submissions or hear any evidence that suggested that the current legislative regime did not provide regulators with sufficient powers and control mechanisms to effectively regulate matters relating to well integrity and/or safety. The Inquiry did, however, uncover significant evidence to suggest that the NT DoR failed to effectively utilise the significant powers and control mechanisms that were available to it in order to regulate PTTEPAA's activities. Its failings in this regard are set out below. Whilst such failings cannot be said to have directly caused the Blowout,²⁹⁰ they strongly suggest that steps should be taken to ensure that such poor regulatory practice is not repeated in order to reduce the risk of a recurrence of such an event.

4.101. The Inquiry therefore suggests that the recommendations it makes about suitable ways of achieving well integrity in Chapter 3 be included, as appropriate, in a guidance manual that is issued for the assistance of industry and regulators. Depending on what, if any, changes are made to the current regulatory regime and when they occur, the production of such a manual could be organised by RET, NOPSA or NOPR.²⁹¹ Ideally it would be updated by a

²⁸⁸ Northern Territory, Submission to the Inquiry, p. 11.

²⁸⁹ Relating to the extension of NOPSA's prohibition powers discussed below.

²⁹⁰ See Chapter 3.

²⁹¹ See paragraphs 4.219ff.

person(s) with suitable expertise every few years to incorporate changes in technology and views about how to best ensure well integrity.

- 4.102. The Inquiry is conscious that such a guidance manual could be perceived as ‘prescription by stealth’ and therefore counter-productive. However, for the reasons set out below the Inquiry considers that such a manual would make a positive contribution to minimising the risk of a recurrence. Any such manual should make it clear that it was not intended to be more than a list of basic well integrity issues that should never be overlooked, rather than a prescriptive or exhaustive list of requirements to be met. If a comprehensive risk assessment demonstrated that there was a better way of achieving well integrity then this would not be precluded. Such a manual should not absolve either industry or regulators of the responsibility to continue to carefully assess matters relating to well integrity.

Suggested legislative amendments

Impose basic minimum standards in relation to blowout preventing barriers

- 4.103. The Inquiry is of the view that while the move to objective-based regulation has been a desirable development overall, more attention needs to be paid to ensuring basic well integrity principles are met. In the Inquiry’s view this objective is of pre-eminent importance to the offshore petroleum industry. The Blowout and the recent incident in the Gulf of Mexico provide timely reminders of the consequences - including loss of life, serious injury and substantial damage to the environment, as well as to commercial and economic interests - that can flow from a failure to ensure well integrity. In this regard the Inquiry cannot think of anything more important to focus on than ensuring that there are appropriate and verified barriers, or well control systems, in place to prevent a blowout at all times.
- 4.104. This is something to which regulators should be highly attuned.
- 4.105. However, the evidence heard by the Inquiry in relation to the NT DoR’s performance suggests that it cannot be assumed that this will necessarily be the case. A number of factors, such as a lack of resources, developing too close a relationship with the operators being regulated, and/or a lack of sufficient experience, diligence or competence, can all prevent this occurring.
- 4.106. In relation to the last factor, the Inquiry received evidence from the Northern Territory to the effect that it was very hard for regulators to attract suitable officers to monitor operators’ activities because of the significant

disparity between the salaries paid to those working in the private sector of the offshore petroleum industry and public servants who regulate it. Given the lack of proper understanding of, and/or attention to, basic well integrity issues demonstrated by a number of PTTEPAA personnel, it seems that increasing the pay of regulators would not necessarily guarantee an appropriate focus on, and understanding of, well integrity issues.

- 4.107. In light of such factors, the Inquiry considers that some, relatively minor, amendments to the legislative regime would be desirable in order to reduce the risk of basic requirements of well integrity being overlooked.
- 4.108. The Inquiry's examination of the level of prescription in some overseas jurisdictions suggests that it is unnecessarily complicated, obscure and may, of itself, lead to difficulties in interpretation by the regulator and owner/operators alike. The argument against greater prescription has been that it can, amongst other things, unduly stifle innovation and new technologies as well as lead to 'box ticking' rather than careful consideration of the best way of achieving well integrity. There is force in such an argument. The Inquiry certainly does not favour any major move back to a regime which specifies detailed standards for every aspect of an offshore facility.
- 4.109. However, the current regulatory regime has effectively eliminated all levels of prescription in relation to well integrity, defaulting to an undefined standard of 'good oilfield practice'. This has left regulators with an ambiguous standard to rely on when assessing applications submitted by operators. The Inquiry considers that this ambiguity is likely to have contributed to very basic requirements of well integrity being overlooked by both PTTEPAA and the NT DoR. This suggests that the pendulum may have swung too far away from prescriptive standards.
- 4.110. A balance between prescriptive standards and technical innovation and flexibility must be achieved. In attempting to strike an appropriate balance, a steady eye must be kept on the ultimate goal of health, safety and environmental protection.
- 4.111. The Inquiry considers that whilst utilising the Management of Well Operations Regulations and, in particular the WOMP, as the cornerstone of good oilfield practice is sound in theory, its effectiveness would be significantly increased in practice if it was made clear that:
 - a. a WOMP must demonstrate, through an operator's well construction standards or otherwise, that the operator will at all times when production is

not occurring maintain a minimum of two suitable properly tested and verified barriers to protect against a blowout. Indeed, especially where petroleum developments are in a sensitive environmental area, or there are any unresolved well integrity issues, there is a strong justification for insisting on a minimum of three such barriers being in place;

- b. any application for drilling or suspension activities submitted to the DA for approval should provide for such barriers to be in place when production is not occurring;
- c. each WOMP and application for drilling or suspension activities submitted to the DA for approval must also provide for a appropriately senior representative from the operator to:
 - i. certify in writing, at the time of installation, that each proposed barrier has been installed, tested and verified in accordance with appropriate standards and/or good oilfield practice, and also obtain such certification from an appropriately senior representative of the owner of the drilling rig; and
 - ii. submit such certification to the DA within 24 hours of each barrier being installed;
- d. if there is any departure from such a practice in relation to the barriers to be installed in order to prevent a blowout, or variation from what has been approved, the operator should have to present a convincing case to the regulator that the departure or variation would enhance, or at least not detract from, well integrity. If it does not, it should not be approved. In this regard, the Inquiry has heard that, in certain circumstances, DAs have allowed the use of one verified and tested barrier for short periods of time (such as while a BOP is being installed). The Inquiry would strongly recommend against any such practice, except in a truly unavoidable situation. Reliance on a single barrier, even if tested and verified, is not a fail safe procedure. A secondary barrier should always be installed. This might include connection to a system which is monitored and maintained and therefore able to achieve well control. The additional costs or the time lost as a result of installing a second or third barrier are miniscule compared with the consequences of a blowout.

4.112. It appears that such minimum requirements could easily be added to the Management of Well Operations Regulations or other regulations governing what needed to be submitted to and approved by the DA.

4.113. An alternative way of doing this would be to make any future delegation of the Minister's functions and powers to the DA subject to conditions that seek to ensure that the delegate did not exercise his or her delegated powers of approval in a manner that was inconsistent with such minimum requirements. However, the Minister's power to do this does not seem clear cut. Whilst s 34AB(a) of the *Acts Interpretation Act 1901* (Cth) arguably supports the imposition of such conditions, the power to do so would be put beyond doubt by inserting a provision in Part 1.3 of the OPGGS Act specifying that a person exercising powers or functions as a DA must comply with any directions of the Minister.²⁹²

Amend regulations 17 and 25 of the Management of Well Operations Regulations

- 4.114. As outlined above, regulation 25 of the Management of Well Operations Regulations provides that a titleholder must not commence a well activity or continue a well activity if either:
- a. a well integrity hazard has been identified in relation to the well; or
 - b. there has been a significant increase in an existing risk in relation to the well; and
 - c. the titleholder has not controlled the well integrity hazard or the risk.
- 4.115. This regulation appears to require either a subjective awareness of a well integrity hazard, or the objective presence of a significant increase in an existing risk. A titleholder who did not take adequate steps to inform itself of well integrity hazards, or was wilfully blind to them, would therefore arguably fall outside the prohibition imposed by the regulation. Such a possibility seems to be contrary to the objects of these regulations which include ensuring that 'risks are **identified** and managed in accordance with sound engineering principles and good oilfield practice' [emphasis added].²⁹³ The Inquiry considers that this objective would be more likely to be achieved if regulation 25(1)(a)(i) and (2)(a)(i) (or any equivalent regulation that is enacted) was reworded as follows:

a well integrity hazard exists in relation to the well.

²⁹² A similar provision is contained in s 78(11) of the *Public Service Act 1999* (Cth).

²⁹³ Regulation 3(c). It also appears to be out of step with the recent legislative amendments which impose absolute liability (and therefore remove the defence of honest and reasonable mistake) in relation to certain duties imposed on titleholders to take all reasonable steps to ensure that offshore facilities are safe (see paragraph 4.60 above).

- 4.116. The Inquiry considers that the amendments to legislation referred to above would increase both regulators' and operators' focus on basic, crucially important, well integrity matters, and thereby significantly reduce the risk of a blowout occurring in the future.
- 4.117. The Inquiry also notes that regulation 17 of the Management of Well Operations Regulations permits the commencement of well activities that lead to the physical change of a wellbore upon verbal approval of the DA. The Inquiry did not receive any information to suggest that such verbal approvals regularly occur. However, in light of:
- a. the significant room for misunderstanding and/or doubt in relation to whether formal approval has been granted verbally;
 - b. the significant consequences that can flow from well activities that should not be approved; and
 - c. the fact that approving something in writing may encourage a greater sense of responsibility, and therefore closer scrutiny, on the part of a regulator,
- the Inquiry considers that written approval from the DA should be required before such activities can take place, other than in a true emergency situation.

Revise the definition of 'good oilfield practice'

- 4.118. As noted above, s 569 of the OPGGS Act requires the registered holder of a petroleum production licence to, amongst other things, ensure that they carry out all petroleum exploration and recovery operations in a proper and workmanlike manner and in accordance with good oilfield practice. The obligation to act in accordance with good oilfield practice is also imposed on other operators in the offshore petroleum and greenhouse gas storage industries by ss 569 and 570 of the OPGGS Act. Section 190(5) of the OPGGS Act provides that a JA should not issue a direction under s 190 if it 'would require action to be taken that is contrary to good oilfield practice'. The phrase 'good oilfield practice' is defined in s 7 of the OPGGS Act. It relevantly states:
- good oilfield practice** means all those things that are generally accepted as good and safe in:
- (a) the carrying on of exploration for petroleum; or
 - (b) petroleum recovery operations.
- 4.119. The Inquiry considers that this definition should be amended so as to replace 'means' with 'includes', so that it is an inclusive rather than exclusive definition. As the phrase is currently defined it cannot be satisfied unless things are generally accepted as good and safe. Many new and improved ways of

operating may fail to meet this definition until they obtain general acceptance. The Inquiry therefore considers that such a narrow definition may discourage innovation. This is one of the main vices that the move away from a prescriptive regime sought to avoid. Of course, any regulator who was called upon to approve certain activities of an operator that had not yet been generally accepted as good and safe should require the operator to comprehensively demonstrate, through a detailed risk assessment or otherwise, that its proposed method was at least as safe as those generally accepted by the industry, before approval to operate in that way was granted.

Suspension decisions

4.120. As noted in paragraphs 4.35-4.36 above, whilst there is a power to suspend the rights conferred by a petroleum exploration permit or petroleum retention lease there only appears to be a power to cancel a petroleum production licence or suspend its conditions, rather than suspend the rights conferred by it. The Inquiry considers that there may be circumstances where such a legislative power of suspension could prove to be extremely useful. A situation where there were doubts about a licence holder's ability to safely drill until certain shortcomings had been rectified may be one example. Given the very significant consequences that can flow from unsafe or inappropriate petroleum production, and that the power to cancel a licence is likely to be exercised sparingly, the Inquiry considers that the absence of a clear and direct power to suspend a petroleum production licence is unfortunate. The Inquiry considers that this apparent lacuna could be rectified by inserting a provision such as the following in Part 2.11 of the OPGGS Act:

- (1) If the Joint Authority is satisfied that it is appropriate to do so in the public interest, the Joint Authority may, by written notice, given to a petroleum production licensee, suspend either:
 - (a) for a specified period; or
 - (b) indefinitely;any or all of the rights conferred by the permit or lease.
- (2) If any rights are suspended under subsection (1), any conditions that must be complied with in the exercise of those rights are also suspended unless specifically continued.

Review the penalties applicable to well operations and safety breaches

4.121. The Inquiry heard evidence to suggest that the daily cost of running a drilling rig is in the order of \$500,000 - \$1,000,000. The cost of equipment and materials used on a rig can also be significant. This is something that PTTEPAA (and presumably other operators) are very aware of. For example:

- a. the Well Construction Change Control Form prepared by Mr Wilson on 30 January 2009 for Mr Duncan's approval stated that the cost impact of his proposal (to increase the level of lead cement in the annulus by 50 metres) was 'US \$120,000 for the additional cement and cementing chemicals'; and
- b. the Well Construction Change Control Form prepared by Mr Wilson on 11 March 2009 for Mr Duncan's approval stated that utilising a 9½' PCCC instead of a cement plug would lead to 'saving of US\$50,000 in rig time (time taken to set plug versus time taken to set suspension cap + cost of suspension cap' [sic]).

4.122. In the context of such amounts, the maximum penalties that can be imposed pursuant to provisions such as (i) regulations 22, 24 and 25 of the Management of Well Operations Regulations; (ii) and 2.43 - 3.6 of the 2009 Regulations; and (iii) ss 569(6), 570(6) and 572(4) and schedule 3 of the OPGGS Act, could be viewed by many in the industry as inconsequential. By way of contrast, under the United States' *Clean Water Act*, the US Environmental Protection Agency can seek civil penalties of up to \$4,300 per barrel in a federal court against any party whose negligence results in an oil spill in US federal waters. A ruthless Australian operator might take the view that the benefit of cutting corners in relation to certain well activities would dramatically exceed the cost of paying any fine in the event it was caught and prosecuted. There is a power to cancel a licence in the event of a failure to comply with such legislative requirements.²⁹⁴ However, in the Inquiry's view, this leaves a vast gulf between relatively inconsequential fines and a very dramatic sanction that is likely to only be exercised sparingly.

4.123. The Inquiry therefore recommends that the Government review whether it would be appropriate to introduce a rigorous civil penalty regime²⁹⁵ and/or substantially increase some or all of the maximum penalties that can be imposed for breaches of legislative requirements relating to well integrity and safety.

Extend NOPSA's prohibition powers

4.124. As described in paragraph 4.62.c above, NOPSA has the power to issue prohibition notices. However, it is currently a precondition to the exercise of

²⁹⁴ See paragraphs 4.37 and 4.38 above.

²⁹⁵ An example of the type of civil penalty regime that might be implemented can be found in Schedule 2 of the *Occupational Health and Safety Act 1991* (Cth).

such a power that an ‘inspection’ has taken place and that there is an immediate threat to the health or safety of a person.²⁹⁶

- 4.125. In its submission to the Inquiry, NOPSA suggested that its prohibition powers are currently too limited and should be extended to enable it to ‘prohibit entry to facilities where (a NOPSA inspector) perceives an immediate risk to health or safety of a person *may* occur at a facility’.²⁹⁷
- 4.126. As the intense fire on the Montara WHP and recent catastrophe in the Gulf of Mexico illustrate so starkly, the offshore petroleum industry must be considered to be one where OHS risks can have extremely severe consequences. In such an industry, it is also possible that by the time it can be said that there is an immediate threat of a blowout (or other risk to the OHS of workers), it may be too late to prevent that risk from eventuating. The use of prohibition notices on offshore petroleum facilities is also complicated by their isolation, which makes frequent inspections and monitoring difficult.
- 4.127. In light of such matters the Inquiry agrees that it would be appropriate for NOPSA to be able to issue a prohibition notice where a NOPSA Occupational Health and Safety Inspector believes, on reasonable grounds, that an activity is occurring or may occur at a facility involving an immediate threat to the health or safety of a person.
- 4.128. Examples of possible models for such an extended power can be found in the Commonwealth’s *Rail Safety Bill* (clause 105), in Victoria’s safety-related legislation such as s 19B of the *Equipment (Public Safety) Act 1994*, s 112 of the *Occupational Health and Safety Act 2009* and s 228ZZJ of the *Transport Act 1993*.²⁹⁸

What constitutes good regulatory practice in relation to the offshore petroleum industry?

- 4.129. The Inquiry considers the current regulatory regime imposes responsibilities on both titleholders and the DA responsible for regulating them. Titleholders must plan and conduct their drilling processes in a way that systematically assesses and manages risks, including the consequences of something going wrong. The DA must have in place a robust approval, monitoring and enforcement regime

²⁹⁶ Which may include an investigation or inquiry.

²⁹⁷ NOPSA, Submission to the Inquiry, p. 13.

²⁹⁸ Ibid.

to ensure that titleholders are indeed following good oilfield practices. If either of these things does not occur, then avoidance of potentially catastrophic consequences may be left to chance.

- 4.130. While the movement toward a more objective-based regulatory regime is appropriate, it demands that more effort be devoted to carefully ensuring that what is proposed by an operator is not approved unless it is consistent with good oilfield practice and such approval is followed up with targeted monitoring, audit and compliance activities. The regulator needs to actively probe and inquire; it should not be passive; the regulator needs to ask questions of the owner/operator and be prepared to engage in a technical debate with an operator about what truly is 'good oilfield practice'.
- 4.131. As noted in a submission provided to the Inquiry by WWF-Australia:²⁹⁹
- A technical debate can be challenging for agency staff when faced with late, rushed applications and highly paid oil and gas staff and consultants contending their application is worthy of approval.
- 4.132. However a regulator must be prepared to do this and, if not completely satisfied that good oilfield practice will be followed by the operator, make the decision to refuse to approve the application. The potential consequences of a failure to follow good oilfield practice are far too severe to do otherwise.
- 4.133. Whether applications to conduct drilling operations demonstrate good oilfield practice should be carefully assessed by officers with sound knowledge of petroleum operations. Sufficient information to make a considered decision in relation to such matters must be demanded from operators and then carefully scrutinised by a regulator. The Inquiry recommends that, in future, this information should normally include such things as:
- a. manufacturer's instructions relating to any significant pieces of equipment to be used in a wellbore in order to contribute to well security;
 - b. a description of the extent to which equipment and/or methods proposed by an operator in order to achieve well security are standard practice in the industry;

²⁹⁹ On 2 June 2010.

- c. information relating to:
 - i. the potential problems that could arise in relation to each major piece of equipment and/or method proposed by an operator in order to achieve well security; and
 - ii. how such risks will be alleviated by the operator;
- d. a detailed risk assessment comparing the ‘pros and cons’ of each major piece of equipment and/or method proposed by an operator in order to achieve well security as opposed to what is standard practice in the industry; and
- e. a detailed description of how, and at what stage, each barrier operating against a blowout is to be:
 - i. installed;
 - ii. removed; and
 - iii. tested and verified.

4.134. The evidence received by the Inquiry was that the NT DoR did not require the operator to provide the information referred to in the preceding paragraph, and so could not properly scrutinise and evaluate the applications for approval for the installation of PCCCs, or the Phase 1B Drilling Program.

Evidence relating to the effectiveness of the regulatory regime received by the Inquiry

4.135. The NT DoR initially submitted to the Inquiry that:

At all material times prior to the uncontrolled release, the Territory appropriately administered the licence area within which the Montara wellhead platform is located (under Production Licence for Petroleum AC/L7), in the role of delegate of the responsible Commonwealth Minister as Designated Authority for the Territory of Ashmore and Cartier Islands offshore area.³⁰⁰

4.136. The evidence heard during the Inquiry’s public hearing did not justify this submission.

³⁰⁰ Northern Territory, Submission to the Inquiry, paragraph 5.

4.137. The Inquiry heard evidence from the following officers from the NT DoR:

Dominic Marozzi A Senior Energy Engineer (formerly Senior Petroleum Operations Officer) within the Minerals and Energy Division

Jeremy Whitfield The Director of Energy within the Minerals and Energy Division

Alister Trier The Executive Director of the Minerals and Energy Division

4.138. Mr Whitfield was, at all times he held the position of Director of Energy,³⁰¹ the delegate of the DA for the offshore area for the Territory of Ashmore and Cartier Islands. Therefore, he was responsible for approving PTTEPAA's:

- a. Environmental Plans;
- b. WOMPs;
- c. drilling programs; and
- d. applications for approval to sidetrack and suspend development and production wells.

4.139. Mr Marozzi was the departmental officer with the direct responsibility for assessment of such applications. Both Mr Marozzi and Mr Whitfield agreed that Mr Marozzi was the only person within the NT DoR who was considered, within the Department, to have the technical skills and expertise to:

- a. properly assess such applications; and
- b. determine whether an operator's drilling activities complied with what had been approved.

4.140. Although holding the position of delegate, Mr Whitfield did not have the technical skills or experience to properly consider such matters. He therefore came to, in effect, largely adopt the role of 'rubber-stamping' recommendations made by Mr Marozzi.

³⁰¹ He gave evidence that for some short periods of time during 2008 and 2009 Mr Holland acted in this position.

- 4.141. The Inquiry considers that it is generally undesirable for a delegate of the DA to be so lacking in skills or experience in relation to offshore drilling activities that he or she can have little meaningful role in assessing an application submitted for approval. If this is the case, as it was with Mr Whitfield, then the delegate needs to be particularly careful to ensure that applications have been rigorously assessed by others and that there can be a high degree of confidence in any recommendation made.
- 4.142. Mr Marozzi's assessment of such applications, and Mr Whitfield's approval of his recommendations relating to them, did not satisfy the requirements specified in the preceding paragraph.
- 4.143. The Inquiry is conscious that regulation in a small jurisdiction such as the Northern Territory can be problematic. For example, hiring suitable staff that enables specialisation and/or back up capacity may prove problematic. Such difficulties may explain some of the shortcomings in the NT DoR's performance as a regulator although, more tellingly, the Inquiry is of the view that the NT DoR did not have a sufficient understanding of basic good regulatory practice in applying the OPGGS Act. In light of the risk of far reaching and/or catastrophic consequences that can arise from an incident at an offshore petroleum facility, the continuation of such shortcomings cannot be tolerated. The Inquiry's recommendations at the end of this Chapter seek to ensure that they will not be repeated.

The PTTEPAA applications submitted to the NT DoR

- 4.144. In the course of the public hearing, the Inquiry's attention focused on three applications PTTEPAA submitted to Mr Whitfield for approval pursuant to regulation 17 of the Management of Well Operations Regulations:
- a. the application to suspend the Montara GI Well submitted on 17 February 2009;
 - b. the applications to suspend the H1 Well (Stages 1 and 2) submitted on 6 and 12 March 2009; and
 - c. the application for approval to drill and complete the Montara GI, H1, H2, H3 and H4 Wells (the Montara Phase 1B Drilling Program submitted on 7 July 2009 and approved on 13 July 2009).
- 4.145. The evidence uncovered in the course of the public hearing revealed considerable and disturbing shortcomings in the way these applications were assessed by the NT DoR - both in the procedure that was adopted and the

decisions that were actually made. Such evidence indicated that these shortcomings were systemic rather than isolated incidents.

- 4.146. The Inquiry is mindful that whilst practical responsibility for assessing such applications came to fall on Mr Marozzi, Mr Whitfield remained ultimately responsible, as delegate, for ensuring that they were appropriately assessed.
- 4.147. Senior Managers within the NT DoR also had a responsibility to try and ensure that the Department was adequately resourced (both financially and otherwise) to ensure that applications were properly assessed.³⁰² The Inquiry returns to this subject below.

Procedural shortcomings

Information management

- 4.148. The approval process relating to the GI Well is illustrative of the deficiencies in the approaches of Mr Marozzi and Mr Whitfield. When asked about his understanding of what the phrase ‘good oilfield practice’ constituted, Mr Marozzi stated that it was ‘what industry generally accepts’.³⁰³ The Inquiry noted, with considerable alarm, that the application to suspend the GI Well was, on Mr Marozzi’s own evidence, the first time he had ever heard of PCCCs being used as the only secondary barrier operating against a blowout in suspending a well. Despite this, Mr Marozzi recommended approval for suspension without any information in relation to such things as:
- a. how the PCCCs would be installed;
 - b. how the PCCCs would be removed;³⁰⁴
 - c. whether the PCCCs would be tested or verified in situ;
 - d. manufacturer’s instructions; and
 - e. a detailed risk identification or risk assessment of the comparative merits of PCCCs as opposed to the cement plugs that PTTEPAA had initially proposed as secondary barriers against a blowout.

³⁰² In this regard the Inquiry notes that Mr Trier has only held the position of Executive Director of the Minerals and Energy Division of the Department of Resources since 13 July 2009.

³⁰³ T1979 (Marozzi).

³⁰⁴ As noted in Chapter 3, the Inquiry considers that the removal of a PCCC other than through a BOP (or with a production tree connected) creates an unacceptable risk to well integrity unless at least two other verified and tested barriers operating against a blowout remain in place at all times.

4.149. If information had been sought in relation to these things, it seems likely that some of the problems with PCCCs identified in Chapter 3 of this Report might have become apparent. The Inquiry notes that upon making basic enquiries with the manufacturer of the PCCCs used in the H1 Well it received the following information:

The 'Mudline corrosion cap' (also described as a PCCC) is offered to protect the mudline tie-back threads from corrosion (See attached Project Related procedure, PRP 8701). The PCCC may contain pressure upon installation, **but it is not intended as a barrier against an uncontrolled release of hydrocarbons**, as previously stated. GE has not designed and is not aware of a test that could verify the internal pressure containing capability of a Mudline corrosion cap upon installation. [emphasis added]

4.150. Further, Mr Marozzi conceded that he had not reviewed whether any of the applications referred to above were compliant with PTTEPAA's own Well Construction Standards which were incorporated into PTTEPAA's WOMP.

4.151. The only documents³⁰⁵ the NT DoR could provide to the Inquiry in relation to its consideration of the application to suspend the well were:

- a. a one page schematic diagram which did no more than indicate which barriers would be inserted in each part of the well;
- b. correspondence seeking approval to suspend on the basis of the schematic diagram (this correspondence did not provide any information beyond what was contained in the diagram); and
- c. the following memorandum prepared by Mr Marozzi for Mr Whitfield's signature.

³⁰⁵ Mr Marozzi gave evidence that he had had a telephone conversation with Mr Wilson from PTTEPAA in which the benefits of PCCCs were discussed but could not provide any file note or other record of what information was provided.



DEPARTMENT OF REGIONAL DEVELOPMENT,
PRIMARY INDUSTRY, FISHERIES AND
RESOURCES

www.nt.gov.au/drdpifr

MEMORANDUM

TO: Director of Energy

THROUGH: Assistant Director Minerals & Energy Titles
Petroleum Operations Team Leader *18/2/09*

FROM: Senior Petroleum Operations Officer

DATE: 17 February 2009

SUBJECT: Approval to Suspend Montara GI ST-1 in AC/L7

FILE No: WH2008/0005, C09.017.dm

Title: AC/L7 **Company:** Coogee Resources Pty Ltd

Request/Issue: Coogee has applied for approval to suspend its development well Montara GI ST-1 in AC/L7.

Legislation: Regulation 17(1) (d) of the *Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004*.

Time frame: The application to suspend was submitted on 17 February 2009. Suspension operations are scheduled to commence in the next day.

Stakeholder issues: None to report.

Departmental issues: None to report.

Assessment: Coogee's application has been assessed and is found to satisfy the applicable legislative requirements.

Recommendation: It is recommended that you approve the suspension of Montara GI ST-1 by signing the attached correspondence.



Action officer:

Dominic Marozzi

18 February 2009

SIGNED/NOT SIGNED



Jerry Whitfield
Director of Energy

19 February 2009

4.152. The format, content and level of detail provided in this memorandum was virtually identical to all memoranda used to obtain Mr Whitfield's approval of applications submitted to him. Mr Whitfield gave evidence that such paperwork was typical of the process he and Mr Marozzi followed in assessing and approving applications submitted to him as delegate of the DA.

4.153. Mr Marozzi was questioned by Counsel Assisting in relation to what he had intended to signify in including the phrase 'the application has been assessed and is found to satisfy the applicable legislative requirements' in this memorandum. His evidence suggested that to him it meant little more than the formal requirements for seeking approval for a well operation had been met. He certainly did not take steps to check whether the application was consistent with the operator's statutory obligation to comply with its WOMP (and the Well Construction Standards incorporated into it).

4.154. The Inquiry considers that this is a completely inadequate form of regulatory assessment. This point is illustrated by the following exchange between Counsel Assisting and Mr Whitfield in relation to The Australian National Audit Office Better Practice Guide entitled *Administering Regulation*:

Q. Do you see that it says:

'The quality of operational decisions and decision to invoke statutory powers is determined, in large part, by the quality of the information available to managers and key decision makers'.

A. Yes.

Q. Now, do you agree with that statement?

A. Yes.

Q. Do you see under the heading 'Comprehensive', it suggests that:

'...all relevant information required to make a balanced, informed and defensible decision [should be] collected and made available to decision makers'.

Do you see that?

A. Yes.

Q. Do you agree with that?

A. Yes.

Q. Further on, it says:

'An effective information management system provides the right information to the right people (that is, decision makers) at the right time'.

Do you see that?

A. Yes.

Q. And do you agree with that?

A. Yes.

Q. Now, none of those things occurred in relation to your approvals of the stage 1 and stage 2 suspensions in March last year; that's right, isn't it?

A. That's correct.

Q. And none of those things occurred in relation to your approval of the suspension of the GI well in February last year; that's right, isn't it?

A. Yes.

Q. None of those things occurred in relation to your approval of the 1B drilling program in July last year; that's right, isn't it?

A. Yes.

Q. Do you accept that there (has been) a complete failure of information management in fulfilling your role as delegate in assessing those applications?

A. Yes.³⁰⁶

- 4.155. Mr Whitfield acknowledged that the assessment of the applications could properly be characterised as a 'tick and flick' exercise. The Inquiry agrees.
- 4.156. The Inquiry considers that the failure of the NT DoR to obtain sufficient information upon which to properly assess applications, and the apparent lack of any vigorous or critical analysis of whether they in fact complied with good oilfield practice, constituted a significant failure to fulfil good contemporary regulatory practice. It meant that there were insufficient means of discovering inadequacies in PTTEPAA's operations. This is not acceptable given that the NT DoR was entrusted with responsibility for regulating such a potentially hazardous industry.

The failure to take steps to ensure the operator had appropriate insurance

- 4.157. The expenses and liabilities arising from a blowout could quite foreseeably exceed the financial capacity of an operator to meet them. Many people and organisations could be affected by such an event over a long period of time. The Inquiry therefore took an interest in what steps the NT DoR had taken, pursuant to s 571 of the OPGGS Act,³⁰⁷ to ensure that PTTEPAA and other operators had appropriate insurance to cover expenses and liabilities. Once again, the evidence that emerged suggested that the NT DoR was content to rely on operators in order to ensure that the public was adequately protected from potential risks. Basic questioning, probing or testing (that could easily have taken place) was not considered necessary or appropriate. This attitude is reflected in the following evidence of Mr Marozzi.³⁰⁸

³⁰⁶ T2277–2279 (Whitfield).

³⁰⁷ See paragraph 4.42 above.

³⁰⁸ T1990-1993 (Marozzi).

Q. What steps does the department take to ensure that operators have appropriate insurance in place?

A. When the operator first submits its - we seek evidence of the level of insurance. If the figure is of a reasonably high level that suggests there's adequate insurance, we certainly look at that; we consider that. But generally we take the position that the operator is in the best position to ensure that its insurance is adequate for the activity it's undertaking.

Q. So do I understand, by your last answer, that, in your view, you can really leave it up to the operator to ensure they have appropriate insurance in place?

A. If the figure is deemed as inadequate, we would have a conversation with the operator, but generally we leave it to the operator.

Q. Are you the primary person within the Department of Resources who is responsible for ensuring the requirements in relation to maintaining insurance are met by operators?

A. The primary officer in terms of collecting it, yes, sure, I guess so.

Q. In fulfilling that role, you look primarily at the level of liability that is covered, in other words, how much the insurance policy is for; is that right?

A. That's right.

...

Q. What I want to ask you is your understanding of what is covered by the insurance class that [PTTEPAA] and other operators have in place. Do you see that in the two documents I have given you there are two types of insurance class?

A. Yes.

Q. Is that the sort of insurance that you would typically see operators have?

A. Yes.

Q. Do you know exactly what is covered and what is not covered by those types of insurance classes?

A. On a general level I do, on a broad level.

Q. But do you know on a specific level what they cover?

A. No, I don't know that information.

Q. Would you know, for example, whether either of those insurance classes would cover the cost of water sampling or environmental monitoring in the event of an uncontrolled release of hydrocarbons?

A. I'd be guessing as to which of the two covered that.

Q. Would you be guessing as to whether either of them covered it?

A. Yes.

Q. Would you be guessing as to whether either of those insurance classes covered the costs of reimbursing fishermen who might be affected by any uncontrolled release of hydrocarbons?

A. Well, I would expect that would be covered under 'third party'.

Q. Do you know?

A. I wouldn't be absolutely certain, no.

Q. And do you know whether either of those insurance classes would cover tourist operators whose operations might be affected by an uncontrolled release of hydrocarbons?

A. Again, I would suspect it would be covered under 'third party', but I wouldn't be certain.

Q. Do you think you should take steps to inform yourself as to exactly what is and is not covered by an operator's insurance before ticking off that aspect of the regulatory process, Mr Marozzi?

A. Well, it wouldn't hurt.

Q. I suggest that it is more than 'wouldn't hurt'. It would be a very sensible thing to do, wouldn't it?

A. See, the regulations don't require us to be auditors of the operators' insurance cover, but, yes, we can always do things better.

Q. You understand that the consequences of an uncontrolled release of hydrocarbons can be severe, don't you?

A. Sure.

Q. And they can be far reaching, can't they?

A. Sure.

Q. And they can have significant impacts on a significant number of people; that's right, isn't it?

A. Yes, that's right.

Q. And those ramifications can be long lasting as well, can't they?

A. Can be, yes.

Q. It's a very undesirable situation, I suggest, to have the possibility that some of those consequences aren't going to be covered for by insurance; that's right, isn't it?

A. That's fair comment, yes.

Q. Whilst [PTTEPAA] in this instance has agreed to fund the clean-up costs or remedial action of the uncontrolled release, that can't necessarily be guaranteed in relation to all uncontrolled releases, can it?

A. Fair comment, yes.

Q. It's conceivable that the costs of remediating an uncontrolled release might exceed the financial capacity of an operator to meet those costs, isn't it?

A. It might do, yes.

Q. The costs of remedial action could run into the many millions, or, in fact, billions of dollars conceivably, couldn't they?

A. They could do, yes.

Q. In those circumstances, I suggest that it's extremely important to satisfy yourself that the operator has insurance in place to cover all those eventualities before the relevant approvals are granted; do you agree?

A. Generally, yes. However, as I pointed out, the regulations don't require that. But fair comment.

- 4.158. Mr Marozzi's suggestion that, because legislation did not specifically require the DA to 'audit' operator's insurance, this was not something that needed to be

done is symptomatic of the NT DoR's failure to take adequate steps to verify that operators were operating responsibly.

Preliminary/urgent approvals

- 4.159. The Inquiry also has some concerns about evidence it heard of a practice that appears to have developed within the NT DoR to grant urgent 'preliminary' or 'verbal' approval to undertake certain drilling or suspension activities, and then grant formal approval at some time later.
- 4.160. Mr Marozzi gave evidence of a practice having developed of him 'telling' either Mr Whitfield or Mr Holland (who sometimes held the position of Director of Energy and therefore delegate of the DA) of his intention to grant preliminary approval, and then doing so unless he was told not to.
- 4.161. In the Inquiry's view, such a practice raises a number of unsatisfactory possibilities, including:
- a. preliminary approval being granted without a proper consideration of the merits of the application, which then places considerable pressure on the regulator to formally approve an application, even if further consideration suggested this may not be appropriate;
 - b. operators coming to expect very quick answers to important questions such as whether their proposals to suspend wells are satisfactory. This risk is heightened by the fact that the 'daily cost' of operating a rig is very significant,³⁰⁹ and
 - c. approval being conveyed to operators without a proper engagement of the authorised decision-maker.
- 4.162. The Inquiry received information from the Victorian regulator (the Department of Primary Industries or **DPI**) that it discouraged companies from requesting urgent approval.
- 4.163. The Inquiry considers that all regulators should strongly discourage operators from requesting urgent approval unless this is absolutely necessary. Regulators should make it clear that operators cannot expect that applications which do

³⁰⁹ The Inquiry's concern that this could arise is heightened by evidence that emerged in the course of Counsel Assisting's examination of Mr Wilson (PTTEPAA's drilling supervisor) that PTTEPAA could have been in a position to seek approval for the Stage 1 suspension on 5 March 2009 but did not do so until 2:37pm on Friday 6 March 2009.

not provide sufficient information on which to base a decision, or sufficient time in which to assess the information, will be approved. If this is done the chances of an operator either taking the regulator's approval for granted, or approval being wrongly granted should be significantly reduced.

Competence issues

- 4.164. As Mr Whitfield was content to rely almost solely on Mr Marozzi's technical skills and experience in relation to well integrity matters, an issue arises as to whether such trust and confidence may have been misplaced. The Inquiry finds that it was.
- 4.165. One example of Mr Marozzi's apparent lack of a sound understanding of well integrity issues was his view that a formation integrity test or a leak off test was the conventional way of establishing the integrity of the cement in a casing shoe, whereas a formation integrity test only tests the strength of the formation and a leak off test determines the fracture pressure of the formation.
- 4.166. Another example was his evidence that it 'failed to dawn' on him that recommending approval of suspension of the H1 Well for a number of months, without the primary barrier (the cemented casing shoe) being tested and verified until re-entry, was not appropriate.
- 4.167. The most damning indictment of his lack of understanding of basic well integrity matters was his concession that notwithstanding that:
- a. shortly after the Blowout the NT DoR had been told that neither of the secondary barriers (the 9 $\frac{5}{8}$ " or 13 $\frac{3}{8}$ " PCCC) were installed at the time of the Blowout; and
 - b. there was sufficient information contained in the DDR relating to the cementing of the 9 $\frac{5}{8}$ " casing shoe to reveal that it was unlikely to constitute an effective primary barrier.
- 4.168. Mr Marozzi was unable to 'join the dots'. The following passages from his evidence on this issue are illustrative:
- Q. I suggest that's a fairly damning indictment on your level of understanding, Mr Marozzi, having made those statements, in light of the evidence that I have taken you to. What do you say about that?
- A. At the time, that was my level of understanding, so, yes, my understanding was limited, I agree.
- ...

Q. I suggest that it's not rocket science, Mr Marozzi, to put those two pieces of information together and come to the view that it's very likely that those things were the contributing cause of the blowout; do you agree?

A. Fair enough, yes.

Q. I again suggest that it would have taken very little effort to have confirmed that the primary barrier against a blowout was not an effective one, and that's where the hydrocarbons had, in all likelihood, entered the wellbore; do you agree with that?

A. Fair comment.

Q. It would have taken less than a couple of minutes to have established that on a careful analysis of the information that was available to you; that's right, isn't it?

A. Possibly, yes.

Q. Yet when this submission³¹⁰ was provided to the Inquiry, the position, in your mind, was still that you weren't aware what had caused the blowout?

A. Yes, wasn't aware exactly what led to the uncontrolled release, that's right.

...

Q. Then the last sentence of your statutory declaration is: 'in my view neither of the above matters was, or led to, the direct cause of the Uncontrolled Release'.

A. That's what it says, yes.

Q. Do you accept that that's a completely and utterly false statement that you have made in paragraph 68 – and I'm not suggesting you deliberately made it falsely, but it's just not right, is it?

A. Correct, it's not right.

Q. And it's just not right at the most basic of levels, I suggest to you?

A. Fair comment.

Q. Do you have any explanation to the Commissioner about why that was something you wished to end your statutory declaration with?

A. Well, it reflects my understanding of the situation, that I could not put the different pieces of the jigsaw together about why did the cement fail, why the change of order, why a cap wasn't there. We didn't have those answers at the time.

Q. Did I understand your last answer to be, Mr Marozzi, that at the time you provided your statement to the Commission - namely, on 2 March this year, a little over a month ago - you still hadn't put the pieces of the jigsaw together in your mind about what caused the blowout; is that right?

A. I couldn't see how they affected each other, yes,

³¹⁰ Northern Territory, Submission to the Inquiry.

Q. Do you accept that that betrays a fundamental lack of knowledge and understanding on your part in relation to well integrity matters, Mr Marozzi?

A. It betrayed a lack of understanding of what really happened here.

Q. And that lack of understanding about what had happened suggests a lack of understanding of basic well control principles; do you agree?

A. It can be argued that way, yes.

- 4.169. This lack of understanding stands in stark and significant contrast to the good understanding of matters relating to well integrity the NOPSAs investigators demonstrated in the course of questioning people involved in events leading up to the Blowout. This is a further reason for the Inquiry's recommendations in relation to the NT DoR and NOPSAs at the end of this Chapter.

The decisions made by the NT DoR

The approval to suspend the H1 and GI Wells in March 2009

- 4.170. Mr Marozzi and Mr Whitfield accepted that the approval, in March 2009, of the Stage 1 suspension of the Montara H1 Well in accordance with the following application and accompanying suspension diagram did not represent good regulatory practice.
- 4.171. The application for Stage 1 suspension of the GI Well was made on the same basis.
- 4.172. Leaving aside the problems with PCCs referred to in Chapter 3, these suspensions were approved notwithstanding that for an unspecified period of time there would only be one barrier in the annulus.



PTTEP Australasia (Ashmore Cartier) Pty Ltd
ABN 27 004 210 164
A Company of PTTEP Group

Our Reference: RECORDS#137489_1
Your Reference:

6 March 2009

Mr Jerry Whitfield
Director of Energy
Northern Territory Department of Regional Development Primary Industry Fisheries and Resources
5th Floor, Centrepoint Building
48-50 Smith Street Mall
DARWIN NT 0800

Dear Jerry

Application for approval to suspend Montara H1 ST-1 development well, AC/L7

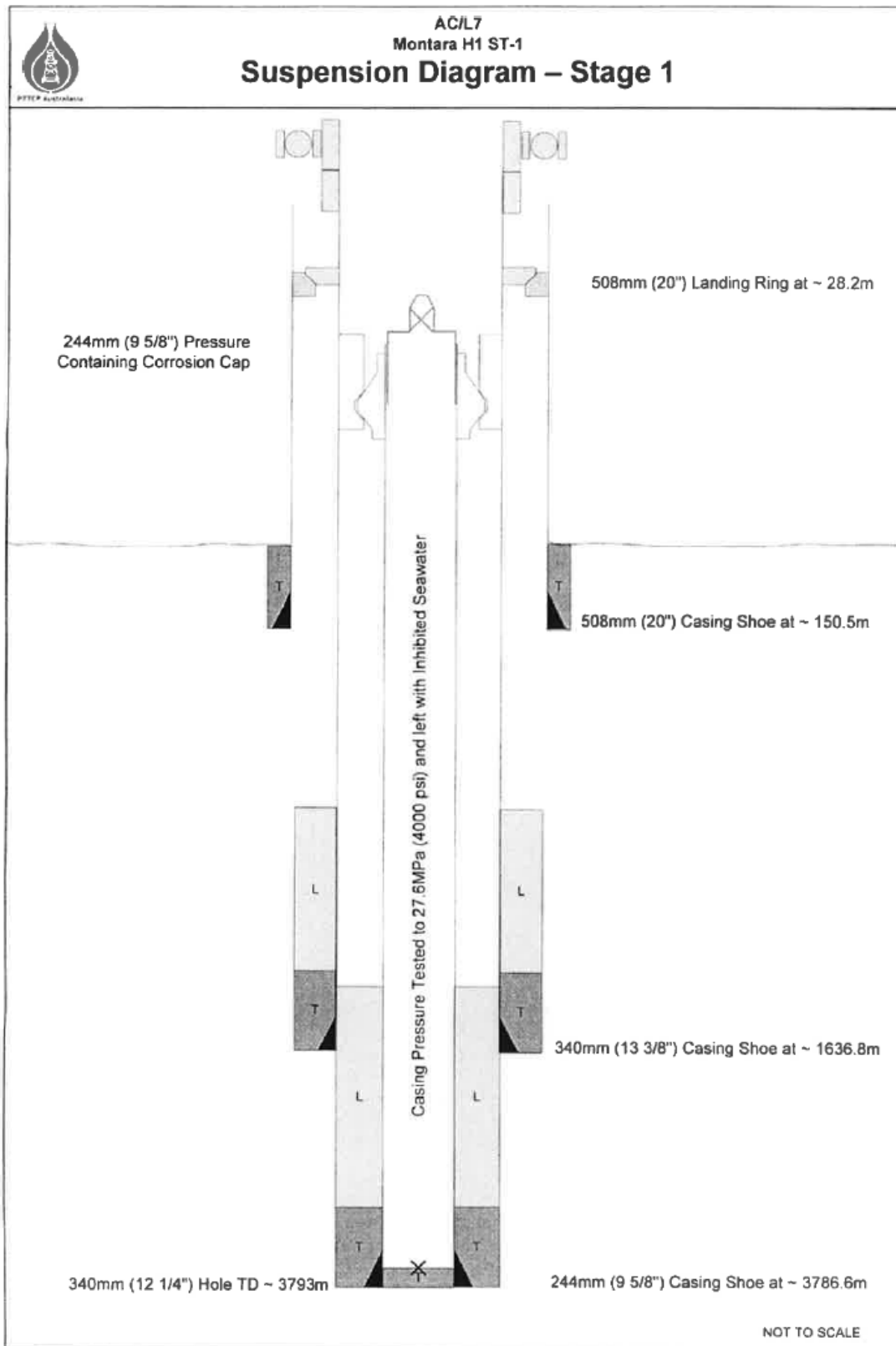
We refer to our earlier email of today's date.

PTTEP (Ashmore Cartier) Pty Ltd ("PTTEP") hereby applies pursuant to regulation 17 of the *Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004* for the approval of the Designated Authority to commence suspension of the Montara H1 ST-1 development well in accordance with the Drilling programme (TM-CR-MON-B-150-0001 REV 2) submitted and approved on 21 November 2008.

The well will be suspended in two stages. Stage 1 will involve the cementing and pressure testing of the 244mm casing followed by the installation of a pressure containing suspension cap. Stage 2 will involve the recovery of the 340mm casing above the MLS and the installation of a second pressure containing suspension cap followed by the recovery of the 508mm casing above the MLS and the installation of a further suspension cap. Schematics for Stage 1 and Stage 2 of the suspension are attached.

Yours sincerely

Ian Paton



The Phase 1B Drilling Program - July 2009

- 4.173. The Inquiry also finds that the NT DoR erred when it approved PTTEPAA's Phase 1B Drilling Program in July 2009. The Phase 1B Drilling Program set out the sequence of events to batch drill the five Montara wells. This involved leaving the H1 Well open to the air with only one permanent barrier in place for not less than 36 hours, while other discretionary activity was being undertaken. The Inquiry strongly recommends against relying on one barrier in such circumstances. In the Inquiry's view, there must always be an ability to exert well control against unforeseen events. Relying on the cement in the casing shoe and annulus does not provide adequate surety. Sensible oilfield practice requires, as a minimum, two tested barriers be in place at all times prior to production. The Inquiry has already noted³¹¹ that if two tested barriers had been in place at all times (such as – in addition to the primary barrier – a cement plug, an RTTS packer, or operations that ensured any PCCC was removed through a BOP), it is unlikely that the Blowout would have occurred.
- 4.174. Mr Marozzi also frankly conceded that he should not have recommended approval of a program that led to such a consequence.
- 4.175. Information provided to the Inquiry by both the Victorian DPI and Western Australian Department of Mines and Petroleum (**DMP**) suggests they would not have approved a drilling program that left a well with only one barrier in such circumstances. DMP went further, stating:
- there is such a range of pre-existing problems...associated with the drilling programme and the suspensions (as noted in Section 2 of the Montara Phase 1B Drilling and Completion Plan) that we would have raised alarm bells long before it got to the Phase 1B stage. We would have been concerned and acted during the previous drilling campaign; In the event we were unaware of the previous history and were only party to the Phase 1B submission, the problems evident in Section 2 of the...submission would have led us to express serious concerns about the adequacy of the site management and the programme as a whole. The problems which we consider to be 'show stoppers' are evident long before the reader gets to Section 5 of the report.³¹²
- 4.176. The fact that the NT DoR approved this drilling program is of significant concern to the Inquiry. It should not have done so.

³¹¹ See Chapter 3.

³¹² Letter from the DMP to the Inquiry, 18 May 2010.

The failure to properly monitor operator's activities

- 4.177. Also of concern to the Inquiry is evidence that emerged from Mr Marozzi and Mr Whitfield of the absence of any real attempt to monitor PTTEPAA's compliance with approved programs and good oilfield practice (other than Mr Marozzi's consideration of daily email updates and what he admitted was likely to have been reasonably cursory examination of DDRs submitted by operators).
- 4.178. The Inquiry considers that good regulatory practice should incorporate compliance monitoring. This could include such things as:
- a. in relation to well integrity:
 - i. a targeted, thorough comparison of DDRs (and/or other such updates) with an operator's WOMP and drilling programs;
 - ii. in conjunction with (i) above, requiring operators to include as part of the DDR all off-line activity and internal emails relating to significant operational matters;
 - iii. attending meetings pertinent to well integrity, including HAZID study meetings, hazard and operability (**HAZOP**) study meetings, test well on paper meetings and/or operators' pre-spud meetings;
 - iv. analysis of a proposed drilling program against a company's well control standards;
 - v. periodic review of operators' well control standards;
 - vi. in appropriate circumstances, the appointment of Petroleum Project Inspectors to conduct inspections of a drilling facility; and/or
 - vii. 'audit' type review of well control practices;³¹³ and
 - b. in relation to environmental regulation:
 - i. a targeted, thorough comparison of DDRs (and/or other such updates) with an operator's approved environmental plans;
 - ii. attendance at HAZID and other meetings directed to environmental compliance issues;

³¹³ This is not necessarily a call for onsite inspections – although that might well be justified in certain circumstances. Site visits during drilling may play a useful role in the exchange of operational information between the operator and regulator, and help the regulator identify risks that need to be carefully monitored.

- iii. review and audit of minutes of 'on rig' environmental meetings; and
 - iv. a targeted campaign of on-site inspections when rigs are at dock to assess the adequacy and efficacy of environmental equipment and the presence on-rig of procedural documentation.
- 4.179. An effective regulator should inquire, probe and examine in order to ensure that owner/operators are actually doing what they have been approved to do, and are otherwise up to the mark.
- 4.180. The Inquiry received information from the Western Australian regulator that its staff attend meetings pertinent to well integrity and environmental compliance issues (including HAZID and HAZOP study meetings, test well on paper meetings and/or operators' pre-spud meetings) in order to engage with the operators, contractors and subcontractors at all levels in relation to the drilling operations onshore and offshore. However, NOPSA submitted to the Inquiry that attendance at such meetings would:
- a. create a real risk of 'regulatory capture', including a risk that participation by the regulator in the development of operators' proposals would preclude objective independent assessment of those proposals by that regulator;
 - b. dilute one of the fundamental tenets of the offshore OHS regulatory regime (that those who create risks from work activity are responsible for protecting workers and the public from the consequences); and
 - c. consume limited regulatory resources.
- 4.181. The Inquiry considers that:
- a. the risks identified by NOPSA could be significantly reduced by appropriate administrative action by the regulator. Such action could include such things as:
 - i. making it clear to their staff (through their code of conduct, or other administrative processes) that dealings with operators should be professional and at 'arms length' and should not involve socialising with, or accepting hospitality from, operators that might create an apprehension that they were developing a relationship that was 'too cosy'; and
 - ii. making it clear to operators (through formal written correspondence) that any attendance by the regulator at a meeting at which drilling activities were discussed could in no way be taken as a suggestion that such activities were, or would be, approved by the regulator and that any

application to conduct such activities would need to be subsequently thoroughly assessed;³¹⁴

- b. engagement is an important aspect of gaining an understanding of the operator that may alert a regulator to possible non compliance with approved programs and/or failures to comply with good oilfield practice, both in the past and in the future. Having observed the key players involved in matters relating to the Blowout give evidence at the public hearing, the Inquiry is firmly of the view that observing personnel from operators discussing their operations, and testing their understanding of what constitutes good oilfield practice, is likely to identify risks and matters to focus on that would not readily emerge from an assessment of written programs or other information submitted by an operator;
- c. obtaining a better understanding of operators and their activities should not only enable the regulator to identify failures to comply with good oilfield practice that might otherwise have been missed, but also enables regulators to focus their resources on the operators and/or activities that appear to have the greatest risk profile – and therefore use their limited resources effectively; and
- d. the risks identified by NOPSAs are outweighed by the potential benefits of attending operational meetings in a targeted and appropriate way.

4.182. Mention has already been made of multiple deficiencies in terms of PTTEPAA's own well construction management systems and to numerous specific failures to conduct its operations in accordance with sensible oilfield practice. Yet the fact is that none of this was apparent to the NT DoR. It also appears unlikely that the NT DoR would have become aware of most of these deficiencies if this Inquiry had not uncovered them. The NT DoR regarded PTTEPAA as a good operator, although having regard to the evidence heard by the Inquiry it is impossible to support that conclusion on any objective basis, judging by the multiple oversights and failings in the development of the Montara Oilfield. For the reasons discussed above, the NT DoR did not place itself in a position so that it could properly inform itself.³¹⁵

³¹⁴ This would be assisted by implementation of the Inquiry's recommendation that regulation 17 of the Management of Well Operations Regulations be amended so as to require written approval from the DA before such activities could take place was implemented.

³¹⁵ The Inquiry notes that the Rig Manager of the *West Atlas* rig considered that PTTEPAA was a competent operator, as a result of his visits to the rig and extensive communications with PTTEPAA's on shore Well Construction Manager and Drilling Superintendent (T218-219 (Millar)). Be that as it may, the assessment of a contractor may not be as penetrating as a regulator. In the Inquiry's view this also

4.183. In the Inquiry's view the relationship between the NT DoR and PTTEPAA had become far too comfortable. This seems to have been implicitly acknowledged by Mr Marozzi who in an internal email of 4 September 2009 said:

...maybe we do get a little lax here but only because we have such an open and ongoing relationship with all of the key players at [PTTEPAA].

4.184. Indeed, one contributing factor to PTTEPAA's own poor practices was the minimalist approach to regulatory oversight by the NT DoR.

Resourcing issues

4.185. The evidence from the NT DoR witnesses satisfies the Inquiry that the Department is not adequately resourced to undertake effective compliance monitoring. For example, Mr Marozzi gave evidence that he did not have time to conduct any real monitoring of compliance by operators other than considering DDRs and e-mail updates submitted to him by operators. He did not even have time to properly consider these. If the NT DoR was to undertake the type of compliance monitoring referred to above it seems that significant additional resources would be required.

4.186. In its submission to the Inquiry RET stated:

Notwithstanding this objective,³¹⁶ the Commonwealth is not able to dictate nor determine the manner in which individual states or the NT approach their obligations or the amount of resources they dedicate to administering and managing the regulatory regime in their particular jurisdiction. Nor has it ever purported to do so (although, as discussed below, it has been active in the preparation and promotion of various protocols and guidelines). As a result, it is inevitable that differences may have emerged over time. That is, there will be differences between the manner in which each State and the NT discharges its obligations as DA (or delegated DA) and undertakes the day to day administration and management of offshore petroleum environment and resource management activities in their respective offshore areas, including, for present purposes, by the NT government officials referred to in paragraph 2.21(2) above in respect of the offshore area of the external Territory of Ashmore and Cartier Islands.

underscores the importance of a regulator thoroughly assessing the activities of an operator rather than relying on general impressions or cursory examinations of information.

³¹⁶ Set out in s 5(2)(e) of the OPGGS Act which provides that 'the Commonwealth, the States and the Northern Territory have agreed that...[they] should try to maintain, as far as practicable, common principles, rules and practices in regulating and controlling the exploration for, and exploitation of, offshore petroleum beyond the baseline of Australia's territorial sea'.

It has never been the Commonwealth's approach to stipulate the manner in which a DA or a delegated DA will carry out its functions or exercise its powers. The Commonwealth has approached the NT Department as the delegated DA for the offshore area of the external Territory of Ashmore and Cartier Islands in the same way that it has approached all other DAs.³¹⁷

- 4.187. The Inquiry considers it is worth noting that in recent years the Northern Territory has received significantly more funds (collected from the offshore petroleum industry operating off the Northern Territory coastline) than it has spent regulating such activities. This is demonstrated by the following table.

	2004/05 (\$000s)	2005/06 (\$000s)	2006/07 (\$000s)	2007/08 (\$000s)	2008/09 (\$000s)	1/7/2009 to 19/1/2010 (\$000s)
Tenement fees (NT)	331	410	182	579	290	340
Tenement fees (Ashmore and Cartier)	680	689	757	409	1,075	309
Tenement fees (Total)	1,011	1,099	939	988	1,365	649
Dealing fees	1,525	1,510	830	14,377	676	76
Total fees	2,536	2,609	1,769	15,365	2,041	725
Budget allocation	No data	642	980	980	980	980 (full year)

Source: Data taken from Witness Statement of Mr Alister Trier, 26 Jan 2010

- 4.188. Tenement fees are made up of application fees for petroleum licences, and related fees. The Northern Territory collects these amounts and places them in a bank account in the name of the Commonwealth. The Commonwealth then remits the funds to the Northern Territory.
- 4.189. It can be seen that tenement fees collected by, and subsequently remitted to, the Northern Territory remained fairly steady from 2004/05 to 2007/08.

³¹⁷ RET, Submission to the Inquiry, paragraphs 2.39-2.40.

The 2008/09 financial year showed an increase (a result of an increase in tenement fees collected for the Ashmore and Cartier area). Amounts collected this financial year up until 19 January 2010 show that the total amount for this financial year is likely to be in line with previous years.

- 4.190. In addition to the tenement fees, the Northern Territory collects and retains fees levied on transfers and dealings relating to petroleum licences (dealing fees). The fee is 1.5 per cent of the value of the transfer, or an amount prescribed by the regulations, whichever is higher. The amounts collected by the Northern Territory in the form of dealing fees have varied each year since 2004/05. This is particularly the case in 2007/08, when a large spike in the amount collected occurred.
- 4.191. The 'Budget allocation' is the allocation of funds for the administration of petroleum activity from the Northern Territory budget for that financial year. This amount is applied to the payment of salaries of officers directly involved in petroleum regulation activities (or where an officer's time is split with other activities, an amount is allocated for that portion of the officer's salary that relates to the amount of time spent regulating petroleum activities).
- 4.192. The average amount collected by the Northern Territory per year between 2004/05 and 2008/09 is approximately \$2,238,000 (disregarding the unusually high amount in 2007/08). The average amount budgeted by the Northern Territory annually on petroleum regulation activities from 2005/06 to 2008/09 is \$895,500 (noting that no data was provided for 2004/05).
- 4.193. As noted above, the Inquiry is conscious that regulation in a small jurisdiction such as the Northern Territory can be problematic and economies of scale will generally not be possible. Therefore the 'unit cost' of regulating an activity can be greater than in a bigger jurisdiction. However, when dealing with an activity like offshore petroleum exploration (which carries a risk of far reaching and/or catastrophic consequences) smaller regulators must either devote sufficient resources to enable them to 'punch above their weight' or hand responsibility to a larger, better resourced regulator who can make use of such things as economies of scale. The Northern Territory's submission to the Inquiry, and the evidence given by Messrs Whitfield and Trier, leaves the Inquiry with a sense of pessimism in relation to whether the Northern Territory will provide the NT DoR with sufficient resources to enable it to 'punch above its weight' and effectively regulate operators in its offshore area in the manner described above. That aside, poor regulatory practices that it followed are further reasons for a move to a national regulator as recommended below.

NOPSA's role in relation to the Montara WHP

Regulation of well integrity

4.194. There has been some criticism that NOPSA has interpreted its own legislation too narrowly in terms of the regulation of well integrity. For example, the Western Australian Department of Transport stated in its submission to the Inquiry that:

NOPSA has claimed limitations in addressing integrity issues despite these being an integral part of safety assurance...³¹⁸

- 4.195. NOPSA and the NT DoR have entered into a Memorandum of Understanding which sets out their common intentions to ensure delivery of a consistent and comprehensive safety regulatory regime in offshore waters. It provides that:
- a. both parties agree to consider the interests of the other party in carrying out their responsibilities offshore and consult the other party in relation to any decision or action that may impact upon the responsibilities of the other party (clause 4.2);
 - b. the NT DoR will, as soon as reasonably practicable, notify NOPSA of any incident that may have safety implications (clause 5.5); and
 - c. in relation to drilling:
 - i. the NT DoR is responsible for reviews and approvals/acceptances of, amongst other things:
 - A. drilling programs;
 - B. WOMPs;
 - C. operations management plans;
 - D. suspensions/abandonment; and
 - E. audits of reservoir, drilling and well data;
 - ii. NOPSA is responsible for reviews and approvals/acceptances of, amongst other things:
 - A. safety cases and safety case revisions; and
 - B. audits against safety cases; and

³¹⁸ Western Australian Department of Transport, Submission to the Inquiry, p. 6.

iii. 'collaboration will be required when reviewing aspects of drilling operations relevant to both the DA (reservoir, well or environment issues) and NOPSA (safety issues). NOPSA would review the safety issues associated with shallow gas, sea bed soil mechanics, well integrity, casing design, kick tolerance, well control and new or changed reservoir situations. Joint audits and investigations may also take place' (Schedule 1).

4.196. Both the NT DoR and NOPSA appear to have had a clear understanding that in practice the regulation of matters relating to well integrity at the Montara Oilfield was the NT DoR's responsibility.³¹⁹

4.197. NOPSA described its understanding of the regulation of well integrity in the following way in its submission to the Inquiry:

In the case of the Montara development located in the Ashmore and Cartier Area, the titleholder must submit well designs, reports and other information to the delegate of the Designated Authority (DA) under the requirements of the *Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004*...These regulations and directions are intended to ensure that titleholders manage the design and execution of well activities so as to minimise the risk of realisation of well integrity hazards...Well integrity failures, arising from inadequate design or execution of the well plan and which were reflected in the titleholders documented submissions and reports, could have been detected by the DA through thorough examination of that documentation.³²⁰

4.198. In light of clause 5.5 of its Memorandum of Understanding with the NT DoR, NOPSA could have expected that the NT DoR would notify them of any well design issues or activities revealed in PTTEPAA's WOMP, drilling programs and/or suspension applications.

4.199. In giving evidence Mr Whitfield accepted that as delegate of the DA he was responsible for ensuring well integrity in the area he was responsible for.³²¹

4.200. Given the focuses of the Management of Well Operations Regulations (which the NT DoR regulated and which do not include any provisions for referral of a WOMP to NOPSA by the DA for consideration or acceptance); Part 6.9 of the OPGGS Act; the 2009 Regulations; and schedule 3 of the OPGGS Act (which

³¹⁹ The NT DoR did not take issue with this characterisation when responding to the Inquiry's draft report.

³²⁰ NOPSA, Submission to the Inquiry, p. 3.

³²¹ T2234:5-8 (Whitfield).

NOPSA regulated), as well as the contents of drilling programs, WOMPs and safety cases, the Inquiry considers such an approach to the potential dual regulation of wells and pipelines was understandable.

- 4.201. However, the room for doubt about intersecting regulatory responsibility for matters relating to well integrity, environmental and/or safety matters would be removed by the establishment of a single national regulator as recommended in this Chapter.
- 4.202. NOPSA's focus is currently on the OHS of people engaged in offshore petroleum operations. In contrast to the NT DoR, which does not conduct on-site inspections, NOPSA's compliance and monitoring regime involves inspections of facilities against commitments made in operators' safety cases. As the Montara WHP had no accommodation facilities and had not commenced production, NOPSA had not inspected it prior to the Blowout. NOPSA had, however, inspected the *West Atlas* drilling rig four times since approving the safety case in August 2007, and had not identified any issues of relevance to OHS.³²² The Inquiry did not receive any information to suggest that such inspections had not been adequate.
- 4.203. The Inquiry also notes that NOPSA swiftly and, in the Inquiry's view, effectively commenced an investigation pursuant to schedule 3 of the OPGGS Act following the Blowout.

RET's role in relation to the Montara WHP

- 4.204. The Inquiry also notes that despite its lack of a formal regulatory role in relation to well integrity, safety or environmental aspects of the offshore petroleum industry, RET has taken a number of positive steps aimed at ensuring that the industry is appropriately regulated. For example it:
 - a. developed and published guidelines for Offshore Well Operations to provide assistance to the industry in fulfilling its regulatory responsibilities under the Management of Well Operations Regulations;
 - b. conducted a number of audits of how effectively DAs were fulfilling aspects of the powers and functions that had been delegated to them; and
 - c. took steps to commence an investigation of the Blowout when the NT DoR indicated that it did not consider it had the resources to do so.

³²² NOPSA, Submission to the Inquiry, pp. 12-13.

Recent reviews of the regulatory regime

4.205. There have been a number of recent reviews of the regulation of the offshore petroleum sector. Two key reports, with recommendations yet to be implemented, are outlined below.

The Productivity Commission Research Report

- 4.206. The Productivity Commission Research Report of April 2009 entitled *Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector* (the **PC Report**) was commissioned to assess Australia's framework for upstream petroleum regulation. It focussed on removing unnecessary burdens on the sector.
- 4.207. The PC Report notes the complexity of the regulatory framework, as well as the duplication, overlap and inconsistent administration of the various laws and regulations. In order to remove or at least minimise these problems, it recommends, among other things, the establishment of an independent statutory NOPR which would be responsible for resource management, pipelines and environmental regulation. It recommends that NOPR have responsibility for exploration permits, production and pipeline licensing; the administration and approval of production well construction and drilling, and pipeline consents; and environmental approvals and compliance.³²³
- 4.208. The Productivity Commission considered the benefits of the creation of NOPR included:³²⁴
- a. the separation of policy formulation and advice from regulation - thereby improving governance and ensuring best practice regulation by avoiding real and perceived conflicts between regulation and policy formulation, advice and resource maximisation;
 - b. the removal of the current iterative approval processes, some of which require multiple approvals across various regulators, including between the JA and the DA;
 - c. the reduction of delays as a result of the removal of these duplicative approval processes;

³²³ Productivity Commission, *Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector*, p. 292.

³²⁴ *Ibid*, pp. 253-54, 288-92.

- d. the removal of administrative inconsistencies between the state and territory agencies administering Commonwealth legislation in Commonwealth waters - thereby improving clarity and certainty for proponents operating across jurisdictions;
- e. addressing the issues of inadequate resourcing of regulators, given the potential for improved economies of scale;
- f. increased scope for mobilising resources for major projects; and
- g. avoiding the potential for resources being diverted from compliance activities to meet upswings in approval activities.

4.209. The PC Report recommended that NOPSA be maintained as a separate independent statutory regulator, maintaining its exclusive focus on OHS. This would avoid potential conflicts in regulatory objectives which may occur if NOPSA were combined with NOPR. However, the PC Report also noted that combining the two could achieve administrative efficiencies and improved communication, and there could be structural separation of the functions within the one agency if they were to be combined.³²⁵

4.210. The PC Report also made a recommendation that the regulation of well integrity be moved to NOPSA, as it is a key component of the safety of petroleum operations, and the current shared responsibility for the safety integrity of wells between NOPSA and the DAs creates unnecessary duplication. The Productivity Commission considered NOPSA was best placed to regulate the integrity of wells given its OHS role. The Productivity Commission also thought that NOPSA may have more relevant expertise to review well integrity than some of the DAs.³²⁶

4.211. This proposal has been supported by NOPSA, which recommended in its submission to the Inquiry that arrangements be put into place to bring the integrity of wells into NOPSA's regulatory responsibility. It suggested that a more focussed and better resourced administration for regulating the integrity of wells would have reduced the likelihood of the Blowout occurring.³²⁷

³²⁵ Ibid, pp. 251-52.

³²⁶ Ibid, pp. 173-75.

³²⁷ NOPSA, Submission to the Inquiry, pp. 9-11.

The Offshore Petroleum Safety Regulation Report into the effectiveness of NOPSA

- 4.212. The June 2009 report by Messrs Kym Bills and David Agostini entitled *Offshore Petroleum Safety Regulation: Better practice and the effectiveness of the National Offshore Petroleum Safety Authority* was undertaken with reference to the pipeline rupture and explosion on Varanus Island in June 2008. It made a number of recommendations dealing with legislative clarity, separation of policy and regulation, appropriate resourcing, competency of regulators and interaction with proponents with a particular focus on poor-performing companies.
- 4.213. Bills and Agostini acknowledged the complexity of the regulatory framework. They found the regime to be ‘a confusing mishmash of jurisdictional, legal, process and regulatory interfaces upon which is overlaid poor relationships among regulators’.³²⁸
- 4.214. In agreement with the views expressed in the PC Report, Bills and Agostini recommended that legislation be enacted to repose overall facility integrity within NOPSA’s responsibilities.³²⁹
- 4.215. Bills and Agostini supported the objective-based nature of regulation in the offshore petroleum industry.³³⁰ In the case of safety regulation, this is the safety case regime, in which the operator provides a safety case identifying risks and how they are managed to the regulator, which then becomes the basis for compliance. Safety cases are drafted to suit the facility and the activities to be conducted at that facility.
- 4.216. In relation to environmental regulation, Bills and Agostini recommended that environmental requirements for oil and gas projects not be imposed subsequent to consideration of safety approvals.³³¹

The Inquiry’s recommended changes to the regulatory regime

Combine NOPR and NOPSA

- 4.217. The Inquiry recommends that the NOPR and NOPSA roles be combined, creating a single independent authority (NOPR), with a properly functioning Board,

³²⁸ Bills and Agostini, *Offshore Petroleum Safety Regulation*, p. xi.

³²⁹ *Ibid*, p. 17.

³³⁰ *Ibid*, p. 19.

³³¹ *Ibid*, p. 76.

responsible for well integrity, safety and environmental regulation. Industry policy, resource development and promotion activities would reside in departments and not with the regulatory agency. The regulatory agency could be empowered and, in the Inquiry's view, should be encouraged, to provide information to assist departmental policy advice and decision-making (for example, decisions to grant licences and any conditions that might be attached to them).

- 4.218. The current arrangements of having multiple DAs across jurisdictions is far from ideal and will, in the Inquiry's view, become more fraught as offshore developments continue at pace over the next decade or so. The Inquiry considers that splitting regulatory responsibility between a NOPR and NOPSA risks divergent approaches and confusion. The independent authority could have joint regulatory roles without compromising safety as a primary objective. There would be a single integrated regulatory agency for developments in Commonwealth waters. In the Inquiry's view the scale of developments at the moment, let alone in the future, demands a more integrated, rigorous and independent approach.
- 4.219. Although the PC Report suggested that NOPSA should maintain its independence to continue its exclusive focus on OHS, and to avoid conflicts in regulatory objectives,³³² the Inquiry considers that the advantages of having a single offshore petroleum regulator outweigh the disadvantages.
- 4.220. Bringing the full gamut of safety regulation, including well integrity, into NOPR would serve to ensure all elements of regulation of offshore petroleum are considered together, ensuring consistency and a further reduction in regulatory duplication and overlap. A good example of the duplication and overlap that can arise under the current regime is the fact that NOPSA and RET (on behalf of the NT DoR) have both commenced major investigations of activities relating to the Blowout that will almost inevitably cover very similar issues. This does not seem to be an efficient use of resources.
- 4.221. To ensure that safety considerations are not compromised by other concerns, the consideration of safety issues within NOPR could be kept structurally separate from other areas. Alternatively, and more practically, the NOPSA legislation could be amended to give primacy to the safety objective (to the extent that there are competing objectives). For the most part, the Inquiry does

³³² Productivity Commission, *Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector*, pp. 251-52.

not believe these differing objectives necessarily compete with one another and notes that one of the greatest risks to the safety of people on an offshore facility is posed by poor well integrity practices.

- 4.222. As noted in the PC Report, such a consolidation would also lead to significant administrative savings and efficiencies, including by simplifying the approvals process by having a 'one-stop-shop' for all regulation, without the need to refer safety cases to NOPSA.³³³ The evidence given by the NT DoR witnesses confirmed the Inquiry's view that having a greater pool of resources to allocate amongst various tasks (including a number of officers with a range of relevant skills and experience who can share work and consult with each other) is likely to improve both decision-making and compliance monitoring and otherwise largely remove the difficulties associated with being a small regulator.
- 4.223. The Inquiry sees no reason why the vast bulk of regulation of the industry cannot take place in a different place from where the operator or facility is located. The Inquiry notes that a single regulator could, if it was considered preferable, have offices located in different states or territories. Even under the current system such co-location is not guaranteed.³³⁴ It seems likely that the economies of scale that can be achieved by setting up a single regulator, as opposed to a number of different regulators, would significantly exceed any travel or other costs that may be greater than under the current system.
- 4.224. Communication between regulators where overlap occurs has been problematic in offshore petroleum regulation despite a number of Memoranda of Understanding between regulators. Combining NOPSA's functions into NOPR should help to ensure that this communication occurs and continues to do so in the long run.
- 4.225. The Inquiry also received significant information suggesting that under the current system, different DAs took different approaches to certain activities of operators and/or how they would be regulated. Such inconsistency can lead to confusion and inefficiencies on the part of operators and encourage a drift to the lowest common denominator. The Inquiry considers that such matters are not conducive to good oilfield practice.
- 4.226. Currently, the regulatory arrangements (including JA and DA arrangements) are embedded in Commonwealth, state or territory departments, which gives rise

³³³ Ibid, pp. 251-52.

³³⁴ For example the NT DoR office was located in Darwin and PTTEPAA was located in Perth.

to a real possibility of conflicts of interest between policy interests (such as promoting offshore petroleum developments) and the administration of the regulatory regime in the public interest. Sound practice in this case should definitely involve a separation of policy and regulatory roles.³³⁵ The possibility of such conflict could be more easily avoided by transferring responsibility for all safety regulation to NOPR, leaving other Commonwealth, state and/or territory departments to promote offshore petroleum developments. As was noted in a report submitted to the Inquiry by WWF-Australia:

the difficulty of making unpopular permit denial decisions or permit decisions that cause rig delays or increased costs is compounded when the same agency making permit decisions is also responsible for ensuring ample oil and gas revenues are generated to fund public needs.

- 4.227. The Inquiry considers that it is important to ensure that any future institutional reforms avoid any unnecessary conflicts in regulatory objectives within agencies. To avoid these potential conflicts, it is appropriate to separate the allocation and management of resource titles (for example, the granting of petroleum exploration permits, licences and retention leases) from the regulation of safety, the environment and day-to-day reservoir operations, including those affecting well integrity. The allocation and management of resource titles, which are Ministerial decisions, often involve significant policy input as well as consideration of resource management issues (for example, assessment of exploration work program bids, field development options, commercial viability of fields, extent of field locations and boundaries, and so on).
- 4.228. The modern prevailing approach to safety regulation is to separate the regulation of resource management (that is, industry promotion and titles management) from safety. For example, following the *Piper Alpha* tragedy,³³⁶ the UK safety regulatory responsibilities were so separated. Similarly in 2004 Norway separated the Petroleum Safety Authority from the National Petroleum Directorate. Following the blowout in the Gulf of Mexico in April 2010 the US administration has announced such a separation within its Minerals Management Service.

³³⁵ As noted by the Productivity Commission: 'Separating policy advice and formulation from regulation is being emphasised in current regulatory reforms in many OECD countries with key benefits including: improved credibility, stability and consistency of regulatory decisions [and] creation of independent regulators acting at arms-length from Ministers'. (*Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector, Research Report*, p. 271).

³³⁶ See paragraphs 4.64 - 4.66 above.

- 4.229. Both the PC Report and Bills and Agostini Report recommended that policy and regulation be separated.³³⁷
- 4.230. The Inquiry recommends this as well.
- 4.231. A single regulator will also address the concerns expressed by Bills and Agostini regarding consideration of environmental requirements subsequent to safety assessments. Combining the regulation of safety and environmental matters into a single regulator would ensure that these issues are considered holistically and that conflicts between environmental and safety outcomes are recognised and considered together. This should help ensure that amendments to improve environmental concerns do not have an adverse impact on human safety and vice versa.
- 4.232. The PC Report notes that Canada has a single offshore regulator which undertakes all regulatory functions, including the regulation of OHS.³³⁸
- 4.233. Such an approach will, of course, lead to other boundary issues such as the interface with arrangements in state waters or with onshore petroleum developments. Such interface issues need to be directly addressed under the auspices of the Ministerial Council on Minerals and Petroleum Resources.

Alternatively, give NOPSA responsibility for well integrity

- 4.234. If NOPSA is not brought within NOPR, the Inquiry recommends that primary responsibility for overseeing well integrity issues should be moved from the DAs to NOPSA. This has been recommended not only by the PC Report and by Bills and Agostini in their report on the effectiveness of NOPSA, but also by two other recent independent reports over the last three years.³³⁹ Steps in such a direction have already been taken by the introduction of the *Offshore Petroleum and Greenhouse Gas Storage Legislation Amendment (Miscellaneous Measures) Bill 2010 (Cth)* (the **Bill**), which is presently before the Senate. The Bill introduces amendments to the OPGGS Act to augment the functions of NOPSA to include regulatory oversight of non-OHS structural integrity for offshore

³³⁷ Productivity Commission, *Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector*, pp. 271-272; Bills and Agostini, *Offshore Petroleum Safety Regulation*, p. 83.

³³⁸ Productivity Commission, *Review of Regulatory Burden on the Upstream Petroleum Sector*, pp. 239-40.

³³⁹ These other reports are: Well Integrity Working Group report to the Upstream Petroleum and Geothermal Subcommittee of the Ministerial Council on Mineral and Petroleum Resources; Ognedal M, Griffiths D and Lake B 2008, *Review of the National Offshore Petroleum Safety Authority operational activities, February-March 2008: report of the independent review team*.

facilities, wells and well-related equipment. If the Bill is passed in its current form,³⁴⁰ NOPSA will immediately assume an oversight role in relation to the structural integrity aspects of offshore facilities.³⁴¹

- 4.235. There are a number of factors justifying the regulation of well integrity by NOPSA:
- a. the Inquiry is concerned that there are conflicts of interest in the current arrangements, whereby the DA is responsible for both resource maximisation and industry development policies, as well as for the regulation of well integrity. Removing well integrity from the responsibilities of the DA would ensure that these issues are considered as a high priority, given the key contribution of well integrity to safety on an offshore petroleum facility; and
 - b. the PC Report also notes the unnecessary duplication which currently occurs as a result of the shared responsibility for the safety/ integrity of wells between NOPSA and the DAs.
- 4.236. NOPSA also considers that at least some DAs are not currently adequately resourced to undertake their roles. NOPSA suggests that the Blowout would have been less likely to occur under a more focussed and better resourced administration of well integrity.³⁴²
- 4.237. In order to bring well integrity into NOPSA's responsibility, NOPSA proposes that the titleholder should be made responsible for the safe design of wells under the relevant Acts, extending NOPSA's function to the regulation of well integrity, and providing NOPSA with adequate funding and the regulatory mechanisms to assess and monitor well integrity.³⁴³
- 4.238. The Inquiry supports this proposal, and considers it worthwhile even if the creation of NOPR goes ahead without integrating NOPSA. Well integrity is still a safety issue and should be regulated by NOPSA on an integrated basis with safety cases for facilities. If this occurs, it will be essential for NOPSA and NOPR

³⁴⁰ On 23 April 2010, the Senate Economics Legislation Committee recommended that the Senate pass the Bill in its current form.

³⁴¹ It should be noted, however, that regulations will provide a more detailed delineation of NOPSA's new functions between NOPSA and DAs relating to resource security and resource management, which may also have a structural integrity aspect (see Explanatory Memorandum, *Offshore Petroleum and Greenhouse Gas Storage Legislation Amendment (Miscellaneous Measures) Bill 2010* (Cth), p. 3).

³⁴² NOPSA, Submission to the Inquiry, pp. 10-11.

³⁴³ NOPSA, Submission to the Inquiry, p. 11.

to have a very close working arrangement to ensure that regulatory decisions are taken with full information. This last point, however, underscores the undesirability of having the roles separated. The WOMPs need to be considered on an integrated basis by a single regulator.

Confer power on NOPSA to ensure consistency of OHS legislation

4.239. The PC Report noted that as significant changes have been made to Australia's offshore petroleum regulatory regime, state and territory legislation has not kept pace, and there has been a growing gap between them. The PC Report found that this impacted on the regulation of OHS, stating:

The complex interface issues facing some projects in offshore waters across Commonwealth waters, coastal waters, State and Territory internal waters and islands in terms of occupational health and safety is confusing and adds to the risk of poor regulation of safety and potentially adds to unnecessary regulatory burdens.³⁴⁴

4.240. The Inquiry did not receive submissions or evidence in relation to this specific issue. However, it did receive significant evidence of inconsistent approaches to certain matters being taken by different regulators. The Inquiry considers that this is generally undesirable, especially in relation to operations which span both Commonwealth and coastal waters. As noted above the Inquiry also formed the view that a large, well-resourced regulator is much more likely to be effective than a series of smaller regulatory bodies.

4.241. The Inquiry therefore supports the PC Report recommendation that:

States and Territories...consider conferring powers on the National Offshore Petroleum Safety Authority to regulate occupational health and safety matters for all State and Territory waters seaward of the low tide mark, including islands within those waters'.³⁴⁵

If the Inquiry's recommendation that the NOPR and NOPSA roles be combined were to be adopted, the Inquiry supports conferring such powers on this authority.

³⁴⁴ Productivity Commission, *Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector*, p. 179.

³⁴⁵ Ibid.

Finding 52

Some of the more significant findings of the Inquiry in relation to the subject matter of this Chapter can be summarised as follows:

- a) the existing legislative regime is largely sufficient to allow effective monitoring and enforcement by regulators of offshore petroleum-related operations – the inadequacies identified by the Inquiry relate primarily to the implementation of this legislation. However, the Inquiry has identified some relatively minor amendments to applicable legislation which it considers would reduce the risk of an event such as the Blowout occurring again;
- b) in assessing PTTEPAA’s applications for suspension and/or drilling activities, the NT DoR conducted little more than a ‘tick and flick’ exercise;
- c) the NT DoR was not otherwise sufficiently diligent in ensuring that principles of good oilfield practice were followed by PTTEPAA;
- d) the NT DoR’s regulation of offshore petroleum-related operations was deficient insofar as there were insufficient means of discovering inadequacies in PTTEPAA’s operations bearing upon well integrity;
- e) the NT DoR should either not have approved a number of applications for suspension and drilling programs that PTTEPAA submitted to it, or should have sought additional information to satisfy itself that risks were being adequately addressed. This includes the Phase 1B Drilling Program that PTTEPAA was following at the time of the Blowout.³⁴⁶
 - i) in particular, while it is incumbent on owner/operators to fully assess risks and to provide all relevant information to the regulator, regulatory authorities should not assume that they will do so. A regulator also needs to ask searching questions and to take steps to satisfy itself that good oilfield practices are being followed; and
- f) the NT DoR fell well short of what good contemporary regulatory practice required in relation to the regulation of matters bearing upon well integrity in the offshore area it was responsible for.

Recommendation 66

The Inquiry supports the objective (rather than prescriptive) approach to regulation now followed in Australia. However, the pendulum has swung too far away from prescriptive standards. In some areas relating to well integrity there needs to be minimum standards.

³⁴⁶ The Montara Phase 1B Drilling Program submitted on 7 July 2009 and approved on 13 July 2009.

Recommendation 67

To better ensure that 'risks' are identified and managed in accordance with sound engineering principles and good oilfield practice, it is recommended that regulation 25(1)(a)(i) and (2)(a)(i) of the Management of Well Operations Regulations, be reworded as follows: 'A titleholder must not commence / continue a well activity if...a well integrity hazard exists in relation to the well'.

Recommendation 68

The definition of 'good oilfield practice' in the OPGGS Act is unduly narrow. The current definition is incapable of application except where things 'are generally accepted as good and safe'. The definition should be amended such that 'good oilfield practice includes...'.

Recommendation 69

Written (rather than verbal) approval from the DA (or new regulator) should be obtained before the commencement of well activities that lead to a physical change of a wellbore, other than in a true emergency situation (requiring amendment to regulation 17 of the Management of Well Operations Regulations).

Recommendation 70

The OPGGS Act should be amended to allow for a power to suspend a petroleum production licence (in addition to the current power to cancel a licence or suspend its conditions).

Recommendation 71

There should be a review to determine whether it is appropriate to introduce a rigorous civil penalty regime and/or substantially increase some or all of the penalties that can be imposed for breaches of legislative requirements relating to well integrity and safety.

Recommendation 72

NOPSA's prohibition powers should be extended such that a prohibition notice can be issued where a NOPSA Occupational Health and Safety Inspector believes, on reasonable grounds, that an activity is occurring or *may* occur at a facility involving an immediate threat to the health or safety of a person.

Recommendation 73

A single, independent regulatory body should be created, looking after safety as a primary objective, well integrity and environmental approvals. Industry policy and resource development and promotion activities should reside in government departments and not with the regulatory agency. The regulatory agency should be empowered (if that is necessary) to pass relevant petroleum information to government departments to assist them to perform the policy roles.

Recommendation 74

The proposal of the Productivity Commission's Research Report (*Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector*, April 2009) to establish a NOPR should be pursued at a minimum.

Recommendation 75

Responsibility for well integrity should be moved to NOPSA (as also proposed by the Productivity Commission).

Recommendation 76

In the meantime, the Minister should:

- a. consider revoking the existing delegation to the Director of Energy, NT DoR providing the functions and powers of the DA under the OPGGS Act and Regulations specified in item 1 of the Schedule to that instrument (the Minister's DA powers and functions) and transferring this delegation to either NOPSA, RET, or a DA from another state;
- b. enquire into whether the other DAs to whom he has delegated his functions and powers relating to well integrity are adequately fulfilling their roles; and
- c. consider amendments to the OPGGS Act to enable DAs to be given direction as to the performance of their regulatory roles.

Recommendation 77

The recommendations of the Inquiry in relation to suitable ways of achieving well integrity contained in Chapter 3 be included in a guidance manual that is issued for the assistance of industry and regulators.

5. ARRESTING THE BLOWOUT

The Blowout and subsequent evacuation of the *West Atlas* rig

- 5.1. On 21 August 2009 at about 5.30am (CST) the H1 Well kicked and discharged approximately 40 barrels of fluid and gas. At the time of the kick, the derrick and cantilever of the *West Atlas* were positioned over the H4 Well.
- 5.2. The unexpected discharge of 40 barrels of fluid and gas caused the *West Atlas*' gas alarms to activate and the Inquiry has heard that all personnel on board the *West Atlas* were instructed to assemble at their muster locations in accordance with *West Atlas*' emergency response procedures. Shortly after the initial kick, the discharge from the H1 Well subsided and personnel were stood down from their muster stations and directed to return to normal duties. The Inquiry has heard that, following a decision taken by PTTEPAA and Atlas personnel both on the rig and onshore in Perth, preparations commenced to skid the cantilever of the *West Atlas* over to the H1 Well to enable installation of an RTTS packer in the H1 Well so as to secure it and prevent further unexpected discharge of fluid and gas.
- 5.3. At approximately 7.30am (CST) as the skidding of the cantilever was about to begin, the H1 Well kicked again, this time discharging a large quantity of fluid and gas from the wellbore. The Inquiry has heard that a column of fluid was expelled and continued to flow from the H1 Well, hitting the underside of the *West Atlas* and cascading from the Montara WHP into the Timor Sea.
- 5.4. Once again the *West Atlas* gas alarm sounded and all personnel assembled at their muster locations in accordance with *West Atlas*' emergency response procedures. The *West Atlas* OIM, Mr Trueman, the PTTEPAA Day Drilling Supervisor, Mr O'Shea, and the PTTEPAA Well Construction Manager, Mr Duncan (who was visiting the *West Atlas* at the time) placed calls to the PTTEPAA Drilling Superintendent and to the *West Atlas* Rig Manager in Perth to notify them of the Blowout and of the decision to evacuate the *West Atlas*.
- 5.5. Between about 7.35am and 7.45am on 21 August 2009, all non-essential personnel were evacuated from the *West Atlas* using lifeboats #1 and #2 and the *West Atlas*' main engines were shut down. At about 8.10am all remaining personnel were evacuated from the *West Atlas* using lifeboat #3.³⁴⁷ The three lifeboats conveyed all 69 personnel from the *West Atlas* to the nearby

³⁴⁷ Atlas Drilling (S) Pte Ltd, Submission to the Inquiry, paragraphs 31-32.

Lady Audrey supply ship where all personnel were accounted for by about 8.50am.³⁴⁸ All 69 personnel were then transferred to the *Java Constructor*, a nearby construction vessel operated by Clough Limited and contracted by PTTEPAA. Over the course of the day, 62 personnel were transferred by helicopter to Truscott Airbase and subsequently flown on to Darwin.

- 5.6. The Inquiry has heard that the evacuation of the *West Atlas* was controlled and coordinated by Atlas (under the direction of the OIM) in accordance with the *West Atlas* Safety Case Revision (including the *West Atlas* Safety Management System) for the Montara drilling campaign. The Inquiry understands that Atlas' procedures governed the evacuation of the *West Atlas* until 'PTTEPAA's contracted marine vessel and aviation resources' were required 'for evacuation of personnel from the field location to an onshore location', at which point PTTEPAA's Emergency Response Plan was activated.³⁴⁹
- 5.7. By about 8am on 21 August 2009 PTTEPAA had assembled its Emergency Response Group (**ERG**) in Perth. The ERG comprised a team of about 30 people rostered so as to provide for 24 hour monitoring of operations relating to the Blowout.³⁵⁰ Several key personnel (including the *West Atlas* OIM and the three PTTEPAA Drilling Supervisors) remained on board the *Java Constructor* and maintained contact with the ERG whilst assessing the situation at the WHP and the *West Atlas*.³⁵¹ The Inquiry heard from Mr Jacob that the ERG was comprised of personnel from outside PTTEPAA's Well Construction Group³⁵² and that Mr Jacob was, 'for want of a better term, incident commander within the organisation', with the Well Construction Group reporting to him for the purposes of developing a response to the Blowout.³⁵³

Finding 53

The Inquiry is of the view that the actions of Atlas and PTTEPAA personnel on board the *West Atlas* on 21 August 2009 in the immediate aftermath of the Blowout are to be commended. The safe evacuation of 69 personnel from a highly flammable environment without notable incident is testament to the effective emergency response procedures developed by Atlas for use on board the *West Atlas* and to their smooth execution.

³⁴⁸ PTTEPAA Incident Report to NOPSA 2 October 2009, PTT.9001.0008.0075.

³⁴⁹ Statutory Declaration of Andrew Charles Jacob 31 March 2010, paragraph 123.

³⁵⁰ PTTEPAA, Submission to the Inquiry, Term of Reference 5, paragraph 1.

³⁵¹ PTTEPAA Incident Report to NOPSA 2 October 2009, PTT.9001.0008.0075.

³⁵² T1808:37 (Jacob).

³⁵³ T1761:35-39 (Jacob).



Courtesy of NOPSA, source unknown

Notifications and initial engagement with the regulators

Notification of incident

- 5.8. At 9.49am on 21 August 2009, in accordance with its obligations under clause 82 of Schedule 3 of the OPGGS Act, PTTEPAA notified NOPSA of the Blowout.³⁵⁴
- 5.9. At some unspecified time on the morning of 21 August 2009, in accordance with its obligations under regulation 26 of the MoE Regulations, PTTEPAA telephoned the NT DoR incident notification telephone number and left a recorded message notifying the NT DoR of the Blowout.³⁵⁵

³⁵⁴ NOPSA, Submission to the Inquiry, Appendix 3, p. 23; PTTEPAA, Submission to the Inquiry, Term of Reference 6, A.

³⁵⁵ Northern Territory, Submission to the Inquiry, paragraph 99.

Combat Agency handover

- 5.10. At 7.48pm on 21 August 2009, PTTEPAA formally requested that AMSA take control of the clean-up operations.³⁵⁶ By 22 August 2009:³⁵⁷
- a. PTTEPAA had also contacted the NT DoR to hand Combat Agency responsibility over to the NT DoR as the Statutory Agency (under the National Plan); and
 - b. in accordance with the Combat Agency Transfer Operational Protocol,³⁵⁸ the NT DoR had also formally handed the role to AMSA.
- 5.11. There is some lack of clarity as to which agency (AMSA or the NT DoR) assumed, or was asked by PTTEPAA to assume, the role of Combat Agency. It would appear from evidence before the Inquiry that PTTEPAA had asked both AMSA and the NT DoR to assume the role and that, formally, the NT DoR handed the role to AMSA.³⁵⁹ For all practical purposes, however, the Inquiry understands that AMSA assumed the role of Combat Agency by about 9pm on 21 August 2009.³⁶⁰
- 5.12. Chapter 6 considers in greater detail the legislative obligations applicable to PTTEPAA and the interactions between it, AMSA and other agencies in relation to clean-up operations.

Engagement with NOPSA

- 5.13. On 22 August 2009 NOPSA issued Prohibition Notice 221 to Atlas³⁶¹ and Prohibition Notice 222 to PTTEPAA³⁶² in relation to the *West Atlas* and the WHP respectively. The effect of the prohibition notices was to prohibit activities that would involve placing personnel at or near either facility.
- 5.14. On 25 August 2009 NOPSA initiated a meeting with PTTEPAA and Atlas in order to clarify with them the regulatory requirements applicable to both companies in relation to the response to the Blowout. The meeting was held at NOPSA's

³⁵⁶ AMSA, Submission to the Inquiry, Appendix 2.

³⁵⁷ Email from NT DoR to AMSA, 22 August 2009, NTG.0001.0001.0249.

³⁵⁸ AMSA, Submission to the Inquiry, Appendix 3.

³⁵⁹ Email from NT DoR to AMSA, 22 August 2009.

³⁶⁰ AMSA Situation Report: 9.00pm Friday 21 August 2009 (all times AEST), DEW.9000.0022.0300 – 'AMSA will accept coordination for oil spill response activities'.

³⁶¹ Prohibition Notice 221, NOP.9000.0016.0014.

³⁶² Prohibition Notice 222, NOP.9000.0016. 0116.

offices on 31 August 2009.³⁶³ The Inquiry has heard from NOPSA that various options for stopping the Blowout were discussed at this meeting, with a particular focus on the drilling of a Relief Well by the Atlas-owned *West Triton* rig.³⁶⁴ NOPSA has advised that following that meeting it made arrangements for the allocation of resources in preparation for assessment of a revised Safety Case for the *West Triton*.

Reporting

- 5.15. In accordance with its legislative obligations PTTEPAA lodged initial written incident reports about the Blowout with NOPSA on 25 August 2009 and with the NT DoR on 26 August 2009.³⁶⁵ PTTEPAA lodged its root cause analysis incident report with NOPSA on 2 October 2009.
- 5.16. Atlas also lodged initial written notification of the Blowout with NOPSA and advised that it was undertaking an investigation with a view to providing, with NOPSA's agreement, a more detailed root cause analysis after the WHP/*West Atlas* had been secured.³⁶⁶

Exploration of options to stop the Blowout

- 5.17. Whilst simultaneously considering alternative options, PTTEPAA commenced preparations to drill the Relief Well in the immediate aftermath of the Blowout. The Relief Well is considered in greater detail below.

Engagement of ALERT Disaster Control - well control engineering and management

- 5.18. In the hours following the Blowout, PTTEPAA contacted and engaged ALERT to provide specialist advice and well control services in relation to the Blowout.³⁶⁷ The Inquiry understands that ALERT is one of only two or three companies of its kind in the world.

³⁶³ PTTEPAA submission to the Inquiry in response to the Inquiry's draft findings in relation to arresting the Blowout.

³⁶⁴ NOPSA, Submission to the Inquiry, Appendix 3, p. 23.

³⁶⁵ PTTEPAA, Submission to the Inquiry, Term of Reference 6 A.

³⁶⁶ Letter from Donald Millar of Seadrill to NOPSA, 1 October 2009, SEA.003.012.4038.

³⁶⁷ PTTEPAA, Submission to the Inquiry, Term of Reference 5, paragraph 2; ALERT was engaged by PTTEPAA under an existing contract between ALERT and PTTEPAA's Thai parent company, PTT Exploration and Production Public Company Limited (see Statutory Declaration of Andrew Charles Jacob, 31 March 2010, paragraph 158; and T1905:11-13 (Jacob)).

- 5.19. A specialist team from ALERT arrived in Perth from Singapore on 22 August 2009. ALERT's recommendation upon initial assessment of the situation was to deluge the *WHP/West Atlas* with seawater so as to reduce the risk of ignition (or fire in the event of ignition) of the hydrocarbons emanating from the H1 Well, and to simultaneously prepare to both:
- a. board the *WHP/West Atlas* and undertake the surface capping of the H1 Well; and
 - b. drill a relief well.³⁶⁸
- 5.20. The Inquiry has made a number of approaches to ALERT with a view to hearing from it in relation to its views about the response to the Blowout and to the various well control options canvassed by PTTEPAA in the days following the Blowout. This might have given the Inquiry a potentially valuable and important insight into the specialist business of relief well design. However, ALERT has not provided any assistance to the Inquiry.

Finding 54

The Inquiry has no reason to question the expertise of ALERT. All of the indicators suggest that it carried out its role effectively. It is notable, however, that ALERT has not made any effort to engage with the Inquiry and provide it with information that may be of assistance to the petroleum industry and to regulators in Australia and around the world.

Water deluge of the *WHP/West Atlas*

- 5.21. The Inquiry has heard that a technique commonly employed to address the ignition risk posed by a blowout is to deluge the affected facility with large volumes of seawater. Water deluge operations would have involved using 'high volume water pump capacity units' set on two vessels located within 50 to 60 metres of the *WHP/West Atlas* to spray water onto the *WHP/West Atlas*.³⁶⁹ Rather than itself providing a well control solution, the purpose of a water deluging operation is to minimise risks inherent in a blowout situation whilst well control activities such as surface capping of the well are undertaken.

³⁶⁸ PTTEPAA, Submission to the Inquiry, Term of Reference 5, paragraph 3.

³⁶⁹ Statutory Declaration of Andrew Charles Jacob, 31 March 2010, paragraph 157; T1906:4-10 (Jacob).

- 5.22. The Inquiry understands that water deluge operations are not without risk and that such operations will not, in every instance, necessarily prevent or reduce the impact of an ignition of hydrocarbons.³⁷⁰
- 5.23. Mr Jacob told the Inquiry that each of the well control experts that PTTEPAA had consulted had recommended commencing water deluge of the WHP/*West Atlas*.³⁷¹ The Inquiry heard that ALERT's biggest concern in recommending water deluge operations was to minimise the risk of a fire that would lead to a 'structural failure' of the cantilever and derrick of the *West Atlas* and which would consequently complicate efforts to control the H1 Well.³⁷² Accordingly, PTTEPAA commenced the mobilisation of ALERT deluge equipment³⁷³ from Singapore.³⁷⁴

Engagement with NOPSAs/the NT DoR regarding water deluge operations

- 5.24. On 27 August 2009 PTTEPAA undertook a HAZID identification process in relation to proposed water deluge operations for the WHP/*West Atlas*. Between about 31 August and 11 September 2009, PTTEPAA liaised with NOPSAs in order to seek a variation to Prohibition Notice 222 that would allow two vessels to enter the vicinity of the WHP/*West Atlas* to commence water deluge operations.
- 5.25. On 31 August 2009 PTTEPAA wrote to NOPSAs:³⁷⁵
- a. enclosing a report detailing PTTEPAA's HAZID Workshop undertaken in relation to a proposal to water deluge the WHP/*West Atlas* using equipment on board two support vessels to be located in the vicinity of the WHP/*West Atlas*;

³⁷⁰ In a supplementary submission to the Inquiry NOPSAs provided evidence of a deluge operation in the Gulf of Mexico in 2001 that did not prevent ignition of a gas cloud (see letter from Jane Cutler to the Inquiry, 20 April 2010, pp. 3-5, CORR.0001.0005.0001); Mr Jacob also told the Inquiry that 'there is some evidence that deluging a gas cloud can actually initiate a fire by static electricity' (T1908:7-8 (Jacob)).

³⁷¹ T1753:13 (Jacob).

³⁷² T1905:35-39 (Jacob).

³⁷³ '...ALERT, have prepackaged skids, new pumping, big-volume seawater pump systems – fire hydrants, if you like. So they were mobilised on to a couple of vessels on the stern, some to put up a blanket to protect the vessel itself from the heat, and then there would be fire hydrants to project the high-volume seawater at the platform itself...' (T1906:4-10 (Jacob)).

³⁷⁴ Statutory Declaration of Andrew Charles Jacob, 31 March 2010, paragraph 157.

³⁷⁵ Letter from Andy Jacob of PTTEPAA to Simon Schubach of NOPSAs, 31 August 2009, NOP.9000.0016.0133.

- b. seeking NOPSA's confirmation that all hazards had been identified and that the prohibition notices issued on 22 August 2009 in respect of both facilities would cease to have effect to the extent that a person may be 'placed at a workplace at the part of the facility...in the manner described' in PTTEPAA's enclosed HAZID Workshop report; and
 - c. enclosing a Gas Dispersion Modelling Report.
- 5.26. Also on 31 August 2009 at a meeting at NOPSA's offices, PTTEPAA gave a presentation to NOPSA outlining the case for water deluge of the *WHP/West Atlas*.³⁷⁶
- 5.27. On 2 September 2009, PTTEPAA wrote to the NT DoR enclosing its presentation to NOPSA and notifying the NT DoR of its proposal to deluge the *WHP/West Atlas*. PTTEPAA advised the NT DoR that it expected the 'water deluge operations to commence on or about 4 September 2009'.³⁷⁷ It is apparent that as at 2 September 2009, PTTEPAA was not aware of any misgivings that NOPSA may have had in relation to the safety risks involved in the proposed water deluge operations.
- 5.28. On 3 September 2009 NOPSA wrote to PTTEPAA requesting that PTTEPAA revise its submission and provide clarification in relation to the 'risk of ignition and associated consequences, additional risk due to presence of vessels and water deluge including the risks of physical impact and static charge, and assumptions and methodology used in gas dispersion modelling'.³⁷⁸ NOPSA also advised PTTEPAA that Prohibition Notice 222 remained in force.³⁷⁹
- 5.29. On 7 September 2009 PTTEPAA submitted a 144 page Case for Safety to NOPSA.³⁸⁰ The Case for Safety set out the reasoning behind the proposed water deluge operations and the risk assessment undertaken by PTTEPAA in relation to the placement of vessels and personnel in the vicinity of the *WHP/West Atlas* so as to enable deluging of the facilities.³⁸¹ The Inquiry notes that the Case for

³⁷⁶ NOPSA, Submission to the Inquiry, Appendix 3, p. 24.

³⁷⁷ Letter from Andy Jacob of PTTEPAA to Jerry Whitfield of NT DoR, 2 September 09, GEO.0002.0001.0529.

³⁷⁸ NOPSA, Submission to the Inquiry, Appendix 3, p. 24.

³⁷⁹ Letter from Jane Cutler to the Inquiry, 20 April 2010, CORR.0001.0005.0001.

³⁸⁰ PTTEPAA Montara H1 Well Release Response – Case for Safety 7 September 2009, AMO.9000.0012.0374.

³⁸¹ NOPSA has clarified for the Inquiry that PTTEPAA's Case for Safety in relation to the proposed water deluging of the *WHP/West Atlas* was not a 'safety case' within the meaning of the relevant regulatory regime and in fact was simply a submission – Letter from Jane Cutler of NOPSA to the Inquiry, 20 April 2010, CORR.0001.0005.0001.

Safety advanced by PTTEPAA is not to be confused with a revision of any safety case or other safety case submission as defined by the *Petroleum Submerged Lands (Management of Safety on Offshore Facilities) Regulations 1996* (the **MOSOF Regulations**). Rather, PTTEPAA's submissions to NOPSA in relation to water deluge operations were specifically directed to:

...providing a written demonstration...that for any proposed activity involving placing personnel at the [WHP] all hazards had been identified, the risks had been thoroughly and comprehensively assessed and that control measures to reduce the risks to a level that is as low as reasonably practicable had been identified and implemented.³⁸²

- 5.30. PTTEPAA stated in its submission to the Inquiry that between 7 and 11 September 2009 NOPSA 'raised a significant number of questions in relation to the safety case for deluging the WHP and *West Atlas*'.³⁸³ Specifically, on 11 September 2009, NOPSA wrote to PTTEPAA setting out in significant detail the deficiencies of PTTEPAA's Case for Safety and advising that PTTEPAA had failed to satisfy NOPSA that the immediate risk to the health and safety of personnel in undertaking water deluge operations had been removed.³⁸⁴ NOPSA has told the Inquiry that not only did its internal team determine that PTTEPAA's submissions failed to make a case for the safety of water deluge operations, but an external specialist risk assessment consultant engaged by NOPSA independently concluded that 'the PTTEPAA submissions had several significant weaknesses and lacked rigour'.³⁸⁵
- 5.31. In response to PTTEPAA's submissions in support of water deluge operations,³⁸⁶ NOPSA issued Prohibition Notices 223 and 224 on 11 September 2009 in respect of the WHP³⁸⁷ and *West Atlas*³⁸⁸ respectively. The new prohibition notices prohibited any work requiring a person to be at or near the WHP/*West Atlas* other than work directly related to fire fighting in the event of ignition of the hydrocarbons. The prohibition notices were to remain in effect until such time as PTTEPAA/Atlas could demonstrate the presence of at least one effective well control barrier in the H1 Well.

³⁸² Letter from Jane Cutler to the Inquiry, 20 April 2010, p. 1, CORR.0001.0005.0001.

³⁸³ PTTEPAA, Submission to the Inquiry, Term of Reference 5, paragraph 11.

³⁸⁴ Letter from Simon Schubach of NOPSA to Andy Jacob of PTTEPAA, 11 September 2009, PTT.9003.0029.0247.

³⁸⁵ Letter from Jane Cutler to the Inquiry, 20 April 2010, p. 2, CORR.0001.0005.0001.

³⁸⁶ NOPSA, Submission to the Inquiry, Appendix 3, p. 24.

³⁸⁷ Prohibition Notice 223, NOP.9000.0017.0382.

³⁸⁸ Prohibition Notice 224, NOP.9000.0018.0128.

- 5.32. Also on 11 September 2009, NOPSA requested in accordance with regulation 35 of the MOSOF Regulations that PTTEPAA submit to NOPSA a revision to its existing safety case for the WHP, addressing in particular, ‘activities associated with implementation of well control barrier(s) into the H1-ST1 well’.³⁸⁹

Abandonment of water deluge proposal

- 5.33. The Inquiry heard that while PTTEPAA believed, based on advice from well control specialists such as ALERT, that the risk to personnel on vessels located in the vicinity of the WHP/*West Atlas* was an acceptable risk, its failure to convince NOPSA of this was a deciding factor in PTTEPAA’s abandonment of the proposed water deluge operations. In particular, Mr Jacob told the Inquiry:

We made a decision at that time that our resources were better deployed on other things than trying to further convince. We had got to the point where we didn’t understand why it wasn’t acceptable, and we believed we had done everything reasonable to convince them of it being an acceptable position.

...

We decided that further submissions were not going to be – we didn’t know what else we could do to make a further submission and therefore decided to orientate those resources on to other matters.³⁹⁰

- 5.34. The Inquiry also heard from Mr Jacob that while ALERT necessarily had input into PTTEPAA’s submissions to NOPSA in relation to the proposed water deluge operations, no separate and detailed risk assessment prepared by ALERT was ever presented to NOPSA in support of PTTEPAA’s submissions. In response to examination by Counsel Assisting in relation to whether PTTEPAA had attributed to ALERT certain information in connection with PTTEPAA’s submissions, Mr Jacob said:

I’m quite sure that NOPSA were fully aware that ALERT were involved in the process. I don’t think attributing it to ALERT would have made any difference to NOPSA.³⁹¹

- 5.35. Mr Jacob told the Inquiry that he believed that PTTEPAA had ‘completely exhausted the lines of communication with NOPSA’ in relation to the safety of water deluge operations.³⁹²

³⁸⁹ Letter from Jeremy Dunster of NOPSA to Andy Jacob of PTTEPAA, 11 September 2009, PTT.9003.0029.0255.

³⁹⁰ T1754:29–1755:1 (Jacob).

³⁹¹ T1938:33–36 (Jacob).

³⁹² T1754:40–42 (Jacob).

- 5.36. PTTEPAA's submission to this Inquiry makes it clear that PTTEPAA was under the distinct impression that in light of NOPSA's clear regulatory mandate to 'prioritise the safety of personnel above both the environment and property damage considerations...it was unlikely that NOPSA would approve any work that required personnel to be at or near the WHP or *West Atlas* other than for fire fighting purposes'.³⁹³ It was on this basis that PTTEPAA decided against proceeding any further with its proposal to water deluge the WHP/*West Atlas*.

Finding 55

The Inquiry accepts that from its own perspective, PTTEPAA experienced some difficulty in achieving active and meaningful engagement with NOPSA in relation to the safety risks of the proposed water deluge operations. However the Inquiry notes that PTTEPAA's efforts may have benefited from greater identification and inclusion of ALERT in its engagement strategy, especially given the novel situation that faced both PTTEPAA and NOPSA.³⁹⁴

Surface capping of the H1 Well

- 5.37. The Inquiry heard that in addition to commencing preparations for the drilling of the Relief Well, PTTEPAA also considered the option of capping the H1 Well at the surface where the 20" conductor casing was tied back to the WHP.
- 5.38. Surface capping of the H1 Well would have involved personnel boarding the WHP/*West Atlas* and attempting to retract the cantilever of the *West Atlas* from its position above the H1 Well. This was to ensure that there would be no impediment to the flow of hydrocarbons emanating in a vertical, and consequently safer, direction. The Inquiry understands that the following procedure for surface capping the H1 Well once the cantilever had been retracted was considered by PTTEPAA:³⁹⁵
- a. a wellhead would be lifted and placed in position on the 20" conductor casing;
 - b. a BOP would then be attached to the wellhead and activated, effectively closing off the flow of hydrocarbons;

³⁹³ PTTEPAA, Submission to the Inquiry, Term of Reference 5, paragraph 14.

³⁹⁴ PTTEPAA submitted (without leave) additional evidence to the Inquiry (in its response to the Inquiry's draft preliminary findings in relation to arresting the Blowout) that ALERT's principal was in fact present at 'all meetings between NOPSA and PTTEPAA in the early stages of the Blowout'. The Inquiry considers that PTTEPAA's evidence does not provide an antidote to its concern that the expertise of ALERT may have been utilised to greater effect in PTTEPAA's engagement with NOPSA.

³⁹⁵ PTTEPAA, Submission to the Inquiry, Term of Reference 5, paragraph 18.

- c. mud with a sufficient kill weight to counteract the pressure of the hydrocarbons flowing from the wellbore would then be pumped into the H1 Well through the BOP; and
- d. once control of the H1 Well was achieved, mechanical plugs would be set within the H1 Well to secure it.

5.39. PTTEPAA's submission to the Inquiry stated that its assessment of the surface capping option was that it involved a significant risk to human life, not least because the operation required a number of personnel to board the WHP/*West Atlas* and work within the highly flammable gas cloud that engulfed the facilities at the time. The Inquiry understands that PTTEPAA did not proceed with the surface capping option because:³⁹⁶

- a. a real risk of fatality existed – approximately 25 to 30 per cent chance of death;³⁹⁷
- b. there was an increased risk of ignition introduced by personnel conducting work to retract the cantilever of the *West Atlas* in a highly flammable environment;³⁹⁸
- c. given NOPSA's rejection of PTTEPAA's submissions in relation to seeking to place water deluge vessels in the vicinity of the WHP/*West Atlas*, NOPSA was unlikely to accept a submission seeking to board personnel on the WHP/*West Atlas* to undertake surface capping of the H1 Well;³⁹⁹ and
- d. the surface capping option was logistically difficult because it required:⁴⁰⁰
 - i. a specialised BOP designed with well kill functionality only (the BOP required to cap the H1 Well was not the standard BOP that was onboard the *West Atlas* at the time of the Blowout) to be sourced from Singapore;⁴⁰¹ and
 - ii. a crane barge (or other heavy lifting vessel of a type that is not generally readily available) to be sourced and located very close to the *West Atlas*.

5.40. The Inquiry heard that ultimately PTTEPAA found itself in a position whereby it was unable to reconcile the risks posed to personnel with the benefits of

³⁹⁶ PTTEPAA, Submission to the Inquiry, Term of Reference 5, paragraph 20.

³⁹⁷ T1911:30 (Jacob).

³⁹⁸ Ibid.

³⁹⁹ Ibid.

⁴⁰⁰ Statutory Declaration of Andrew Charles Jacob, 31 March 2010, paragraph 163.

⁴⁰¹ T1910:30 (Jacob).

pursuing the surface capping option, and the safety of personnel naturally took priority.⁴⁰²

- 5.41. In addition to its concerns about the safety of the surface capping option, PTTEPAA determined that a successful surface capping operation would stop the Blowout only 11 days⁴⁰³ earlier than the forecast date for the conclusion of a successful relief well operation. Mr Jacob told the Inquiry that in these circumstances, and where the risks associated with surface capping remained at an unacceptable level, PTTEPAA decided that surface capping of the H1 Well was not a suitable option to pursue.⁴⁰⁴

Engagement with NOPSA

- 5.42. The Inquiry has heard that in spite of the risks inherent in undertaking well control operations such as by way of surface capping, specialists such as ALERT are equipped to handle and mitigate those risks and should have been afforded special consideration in any assessment of risks to safety involved in a surface capping option.⁴⁰⁵ Mr Jacob also told the Inquiry that while surface capping operations had been assessed by PTTEPAA as carrying a high risk of fatality, ALERT personnel were nevertheless prepared to carry out such operations.⁴⁰⁶
- 5.43. Furthermore, the Inquiry has seen evidence to suggest that ALERT was ‘more than confident in achieving a successful outcome through the application of modern risk management principles and proven well control techniques and practices’ in relation to proposed surface capping operations in respect of the H1 Well.⁴⁰⁷
- 5.44. Mr Jacob told the Inquiry that he believed that NOPSA had been advised of ALERT’s assessment of a surface capping option and of the fact that both PTTEPAA ‘and Alert had a large concern over the potential fatality’.⁴⁰⁸ However, on the evidence currently before the Inquiry, it is not clear whether PTTEPAA ever conveyed to NOPSA that ALERT’s recommendations and considerations

⁴⁰² T1756:44-46 (Jacob).

⁴⁰³ Mr Jacob told the Inquiry that the estimate of 11 days was based upon the success of the relief well operation after three attempts rather than the five attempts it actually took to intercept the H1 Well (T1909:35 (Jacob)).

⁴⁰⁴ Statutory Declaration of Andrew Charles Jacob, 31 March 2010, paragraphs 162 and 169.

⁴⁰⁵ Elmer P Danenberger, Submission to the Inquiry, p. 4.

⁴⁰⁶ T1756:19 (Jacob).

⁴⁰⁷ Alert Well Control Executive Briefing Montara H1 ST-1 Well Control Operations Revision 1 August 2009, PTT.9002.0001.0186.

⁴⁰⁸ T1939:17-18 (Jacob).

evidenced that it was nevertheless confident of being able to carry out successful surface capping operations, including by placing ALERT personnel on the WHP.⁴⁰⁹

- 5.45. NOPSA has submitted to the Inquiry that PTTEPAA's submissions to NOPSA in relation to Prohibition Notice 222 'did not propose, or in any way address surface well capping operations from the Montara WHP' and that 'the second PTTEPAA submission dated 7 September 2009 specifically excluded consideration of such an activity'.⁴¹⁰ It is not clear to the Inquiry the extent to which, if at all, NOPSA was actively engaged by PTTEPAA in relation to the consideration of the surface capping option.
- 5.46. As noted above the Inquiry has approached ALERT in order gain some insight into its involvement in the development of the surface capping option and to seek to understand the nature of the risk assessments (if any) undertaken in relation to such an operation in circumstances where personnel involved are highly specialised and have access to specialised equipment. The Inquiry has not received any assistance from ALERT that would enable the Inquiry to address this issue in more detail.

Finding 56

The Inquiry finds that while surface capping of the H1 Well clearly carried with it significant risk to the safety of personnel involved in such operations, there may have been some room for further consideration of the option in light of ALERT's recommendations to PTTEPAA. It appears that there was little in the way of consultation between PTTEPAA and NOPSA in relation to the surface capping option, in particular in relation to ALERT's involvement in assessing the risks involved.⁴¹¹

⁴⁰⁹ NOPSA stated in its letter to the Inquiry of 24 May 2010: 'Presumably...[PTTEPAA] was in a position to describe to NOPSA how the [surface capping] option could have been conducted safely but [PTTEPAA] did not do so. This is not surprising since [PTTEPAA], with the benefit of the Alert assessment, still considered the risk of fatality to be at 25 to 30%'.

⁴¹⁰ Letter from Jane Cutler to the Inquiry, 20 April 2010, p. 2, CORR.0001.0005.0001.

⁴¹¹ NOPSA in its letter to the Inquiry of 24 May 2010 noted that '[s]pecifically, no written submission was made by [PTTEPAA] to NOPSA in relation to "surface capping" of the H1 well'.

Subsea well control

- 5.47. PTTEPAA submitted to the Inquiry that in the weeks immediately following the Blowout it also considered two further means of controlling the H1 Well. These were referred to as the subsea options and involved either:⁴¹²
- a. crushing the casing at a point between the sea surface and the seabed in order to block the flow of hydrocarbons up the casing to the surface; or
 - b. cutting and capping the casing underwater.
- 5.48. The Inquiry understands that the subsea options were devised and considered by the Well Construction Group of PTTEPAA. Mr Jacob told the Inquiry that while ALERT was aware that these options were being considered, they were not actively involved in their development and ALERT instead maintained its focus on the surface capping and Relief Well options.⁴¹³
- 5.49. The Inquiry has heard that PTTEPAA decided not to proceed with the subsea options because:⁴¹⁴
- a. it was considered too risky for divers to enter the water in the vicinity of the WHP/*West Atlas*, and a Remote Operated Vessel (**ROV**) would be required to manoeuvre the 15 tonne machine required to crush the casing;
 - b. the 15 tonne machine required to crush the casing would have been very difficult to manoeuvre using a ROV;
 - c. cutting and capping the casing using a ROV may not have been effective in controlling the H1 Well, and may have compromised alternative intervention activity such as drilling the Relief Well;
 - d. use of a ROV would have also required the presence of a support vessel in the vicinity of the WHP/*West Atlas*;
 - e. PTTEPAA considered that the risk to the safety of the personnel that would need to be involved was too high;
 - f. the risk of ignition was ‘ever-present’; and
 - g. PTTEPAA anticipated that given NOPSA’s rejection of PTTEPAA’s submissions in relation to seeking to place water deluge vessels in the vicinity of the

⁴¹² PTTEPAA, Submission to the Inquiry, Term of Reference 5, paragraph 21.

⁴¹³ T1912:26-29 (Jacob).

⁴¹⁴ PTTEPAA, Submission to the Inquiry, Term of Reference 5, paragraph 22.

WHP/*West Atlas*, NOPSA was unlikely to accept a submission seeking to allow either of the two possible subsea options considered by PTTEPAA.

- 5.50. It appears that, on the evidence before the Inquiry, there was little or no engagement between PTTEPAA and NOPSA in relation to consideration of the possible subsea options for addressing the Blowout.

Voluntary ignition of the H1 Well

- 5.51. The Inquiry has heard that another option that was available to PTTEPAA to control the flow of hydrocarbons from the H1 Well was to perform a controlled ignition of the H1 Well.⁴¹⁵

- 5.52. Mr Jacob advised the Inquiry that PTTEPAA did fleetingly consider igniting the H1 Well as a means of well control. However, the option was:

...ruled out on the basis of ALERT's advice that within 20 to 30 minutes we would collapse the drilling derrick...and that at some time after that there was the potential to collapse the rig itself onto the wellhead platform, and that would have caused significant problems with any future well control requirements, ie accessing the well, in order to secure it after you've done the relief well and the plug. We still had to get to the well at some point. Basically, ALERT's advice was that we should do everything we could not to cause an ignition.⁴¹⁶

Finding 57

The Inquiry finds that in assessing the merits of various available well control options PTTEPAA gave highest consideration to the potential risks to the safety of those personnel that would be involved in any such well control operations. In particular, the Inquiry finds that in assessing the risks associated with controlling the H1 Well either at the surface (capping) or subsea, PTTEPAA was competent in arriving at its decision not to pursue these methods of well control in the light of the high degree of risk to the safety of personnel.

⁴¹⁵ NUKA Research & Planning Group 2010, *Montara Oil Spill Inquiry Analysis – Oil Spill Response Report to WWF-Australia*, February 2010, p. 13.

⁴¹⁶ T1921:12-24 (Jacob).

Finding 58

However, the Inquiry has some concerns in relation to the apparent lack of collaboration between PTTEPAA and NOPSA insofar as considering all available well control options was concerned. The Inquiry observed a reluctance on the part of PTTEPAA to commit ongoing resources to engaging in a more collaborative response, and a similar reluctance on the part of NOPSA to reach outside the boundaries of its current operator engagement policy.⁴¹⁷ This was an emergency situation and one that clearly required NOPSA and PTTEPAA to work more closely together than they ultimately did.

Finding 59

The Inquiry finds that unilateral decision-making on the part of PTTEPAA in relation to information dissemination to the regulator may have prematurely confined otherwise viable options for well control.

Finding 60

In particular, the Inquiry is of the view that when confronted with a blowout situation, a company together with the regulator should fully pursue all options simultaneously and only rule out each option when it is clear to the regulator and company that that option should be pursued no further.

Finding 61

In the event that Australia faces another major emergency well control incident, well control decisions should not be left solely in the hands of an operator (that is, without full and collaborative exploration of available options with the regulator) either by way of conscious decision or by way of inaction.⁴¹⁸ The Inquiry finds that any such outcome is likely to be viewed as wholly unsatisfactory. The public interest requires that all well control options be pursued and that there is a full and transparent explanation to the public as to which options are being ruled out and why (see below as to the provision and coordination of information).

⁴¹⁷ NOPSA in its letter to the Inquiry of 24 May 2010 notes that 'NOPSA's current functions do not provide for collaborative decisionmaking [sic] of any sort with an operator...'. The Inquiry notes that its findings are made in the context of an emergency situation and not in the ordinary course of NOPSA's business and that NOPSA should in any future emergency situation give due consideration to that context when considering the strictures of its 'current functions'.

⁴¹⁸ Paragraphs 5.99-5.105 describe the Inquiry's findings as to the need for a central coordinating body in the event of future well control incidents.

Recommendation 78

In the future, and in the interests of ensuring that all possible well control options are comprehensively pursued to exhaustion, decisions as to well control response options should be the result of collaboration between the regulator and the operator rather than leaving one party to make unilateral judgements as to the appropriateness of various well control operations. The regulator should provide transparent and contemporaneous explanations to the public of all well control options under consideration at any particular time.

The Relief Well

- 5.53. PTTEPAA has advised the Inquiry that amongst the various options that it considered for responding to the Blowout was the drilling of the Relief Well. PTTEPAA's submission to the Inquiry stated that by 23 August 2009, PTTEPAA had decided to drill the Relief Well whilst simultaneously continuing to consider alternative well control options.⁴¹⁹
- 5.54. The Inquiry understands that preparations for the drilling of the Relief Well included, among other things:
- a. identifying a suitable rig to drill the Relief Well;
 - b. the preparation by Atlas of a revision to the existing Safety Case for the *West Triton* rig;
 - c. preparing a WOMP and drilling program for the Relief Well for submission to the NT DoR;
 - d. preparing addenda to the two Environment Plans applicable to the licence areas AC/L7 and AC/L8 for submission to the NT DoR; and
 - e. seeking an exemption (to be granted by the Minister for the Environment) from the application of all provisions of Part 3 and Chapter 4 of the EPBC Act.

Identification of a suitable rig

- 5.55. PTTEPAA submitted to the Inquiry that between 21 and 23 August 2009, PTTEPAA made enquiries of several operators as to the availability of a suitable drilling rig located in the vicinity of the Montara Oilfield for the purposes of drilling the Relief Well.⁴²⁰ By 23 August 2009, PTTEPAA had contracted the Atlas-owned *West Triton* jack-up rig, which at the time was not under contract, but

⁴¹⁹ PTTEPAA, Submission to the Inquiry, Term of Reference 5, paragraphs 22-23.

⁴²⁰ Ibid, paragraph 26.

which was located in Batam, Indonesia.⁴²¹ PTTEPAA has advised the Inquiry that after 23 August 2009, it continued to consider alternative rigs which may have been able to reach the Montara WHP earlier than the *West Triton*.⁴²²

5.56. The Inquiry has heard that three alternative rigs were considered and dismissed as viable options by PTTEPAA. These were:⁴²³

- a. the *Ocean Shield* jack-up rig which was located at the Blacktip field in the Joseph Bonaparte Gulf in the Timor Sea;
- b. the *Ensco 104* jack-up rig which was located at Baya-Undan in the Joint Petroleum Development Area and was undertaking critical drilling operations; and
- c. the *Songa Mecur* semi-submersible rig which was at the time located in Dampier.

5.57. The Inquiry understands that PTTEPAA's selection of the *West Triton* as the most appropriate rig to undertake the drilling of the Relief Well was based on the following considerations:

- a. the *West Triton* was not, at the relevant time, under contract;⁴²⁴
- b. the *West Triton* was a jack-up rig and more suitable than, for example, a semi-submersible rig such as the *Songa Mecur*,⁴²⁵ in circumstances where the collection of 'critical magnetic ranging data...best gathered from a fixed platform' was necessary in order to enable accurate interception by the Relief Well of the H1 Well;⁴²⁶ and
- c. the *West Triton* had an existing NOPSA-approved Safety Case for which only a revision would be necessary to enable it to undertake operations specific to the drilling of the Relief Well.⁴²⁷

5.58. Mr Jacob's evidence to the Inquiry was that 'cost was not a factor relevant to PTTEPAA's engagement of the *West Triton* rather than any other rig...'.⁴²⁸

⁴²¹ PTTEPAA, Submission to the Inquiry, Term of Reference 5, paragraph 27.

⁴²² Ibid, paragraph 28.

⁴²³ Ibid.

⁴²⁴ Ibid, paragraph 27.

⁴²⁵ GA agreed with PTTEPAA's assessment that the *Songa Mecur* was not a suitable rig in the circumstances (see email from GA to RET, 26 August 2009, GEO.0001.0001.0120).

⁴²⁶ PTTEPAA, Submission to the Inquiry, Term of Reference 5, paragraph 28.

⁴²⁷ Email from Craig Duncan of PTTEPAA to PTTEPAA Executive, 22 August 2009, PTT.9002.0005.0007; PTTEPAA, Submission to the Inquiry, Term of Reference 5, paragraph 27.

5.59. Several submissions to the Inquiry raised concerns about PTTEPAA's choice of drilling rig and the consequent length of time taken to mobilize and transport the *West Triton*. Mr Danenberger for example submitted that:

[PTTEPAA]'s comment that the *Ocean Star* [sic] "was on a tight program to enable them to produce first gas and meet its contractual arrangements" is stunning. Did [PTTEPAA] and the other parties understand the significance of this incident? The [PTTEPAA] submission also mentions contractual and indemnity issues. These issues should be explained.

...

Offshore operators and contractors have a long history of doing everything possible to assist during well control emergencies. I do not believe this "Good Samaritan" attitude has been superseded by indemnity, cost, and contract concerns. If it has, legislation and regulations need to be reviewed to make sure that nearby operators and contractors respond promptly to emergencies.⁴²⁹

5.60. Nuka Research & Planning Group, LLC submitted that:

The...[Inquiry] should consider whether the regulatory agencies had the authority to intervene in the process of securing a drilling rig in a more timely manner. If such authority was present but un-exercised, it might be an area to improve regulations.⁴³⁰

5.61. Mr Jacob told the Inquiry that, to the best of his recollection, when PTTEPAA contacted ENI Australia (ENI)⁴³¹ to enquire as to the availability of the *Ocean Shield* jack-up rig, it was advised that the rig could be available in six to nine days.⁴³² This was because the *Ocean Shield* was at a critical point in its drilling program from which it was unable to withdraw safely and quickly.⁴³³ PTTEPAA was further advised that it would need to provide indemnities against any contractual penalties incurred by ENI if the *Ocean Shield* rig was unable to meet its existing commitment in the Blacktip field as a consequence of engagement by PTTEPAA for the purposes of relief well drilling. Mr Jacob went on to tell the Inquiry that PTTEPAA requested more information as to the potential costs involved in providing indemnities. However when PTTEPAA pressed for a response from ENI a couple of days later it was advised that:

⁴²⁸ Statutory Declaration of Andrew Charles Jacob, 31 March 2010, paragraph 180.

⁴²⁹ Elmer P Danenberger, Submission to the Inquiry, p 4.

⁴³⁰ Nuka Research & Planning Group, *Montara Oil Spill Inquiry Analysis*, p. 14.

⁴³¹ The *Ocean Shield* rig, operated by Diamond Offshore, was working for ENI Australia in the Blacktip field in the Joseph Bonaparte Gulf in the Timor Sea (see PTTEPAA, Submission to the Inquiry, Term of Reference 5, paragraph 28).

⁴³² T1916:24-30 (Jacob).

⁴³³ T1917:17-20 (Jacob); PTTEPAA, Submission to the Inquiry, Term of Reference 5, paragraph 28.

...the operation had moved on to the next phase and the rig therefore wouldn't be available for another period of time, which, at that point...it was only about three days' difference between that rig and the *West Triton*, which...[PTTEPAA had] already mobilised. Then because they were still working in the hole and therefore there could still be other problems...[PTTEPAA] didn't pursue it any further after that.⁴³⁴

Finding 62

The Inquiry notes that Mr Jacob's evidence was to the effect that cost was not a factor in PTTEPAA's selection of a rig to drill the Relief Well. The Inquiry also notes, however, that cost might still have been a residual consideration in relation to the provision of indemnities. For example, had the question of indemnities not been raised as an issue, it is possible that the *Ocean Shield* may not have moved on to the next stage in its drilling operations and would have been available for engagement to drill the Relief Well.

Finding 63

In this instance the Inquiry finds that PTTEPAA did give adequate consideration to the availability of rigs other than the *West Triton*.

Finding 64

The Inquiry notes that the responsible Minister had the power to give a direction under the OPGGS Act to PTTEPAA to use a particular rig and that, in this case, such a direction was not made.

Finding 65

The Inquiry finds that even if the Minister had directed the release of the *Ocean Shield* for the purpose of drilling the Relief Well, there may have been little utility in doing so given the exigencies of the *Ocean Shield's* drilling program at the time.

5.62. The Inquiry also received submissions expressing a preference for the imposition of a regulatory requirement that would see a relief well rig identified prior to any blowout. Harvey Consulting, LLC cited by way of example the regime applicable in Canada whereby a relief well rig must be identified and available for immediate intervention in the event of a blowout, prior to the commencement of drilling operations. Harvey Consulting, LLC submitted that:⁴³⁵

Locating a suitable, technically capable rig, with qualified crew, and executing a contractual arrangement for an extremely dangerous, hazardous mission, is something that should be planned well in advance.

⁴³⁴ T1916:44–1917:9 (Jacob).

⁴³⁵ Harvey Consulting, LLC *Montara Oil Spill – WWF Input to Australian Government Commission of Inquiry* 3 March 2010.

5.63. WWF-Australia also submitted that:⁴³⁶

The Montara incident demonstrates the need for the location of back-up rig [sic] to be identified in advance of drilling proceeding, and that the location of such a facility should allow it to be deployed within days, and not weeks as occurred in this instance.

Finding 66

In the light of the relative infrequency of blowouts and the high costs of contracting a drilling rig, the Inquiry finds that it would be neither practical nor cost effective to require that an operator ensure that a rig is always on standby in contemplation of a possible blowout. This is particularly so given the remote location of many offshore drilling operations and the relatively small size of the Australian offshore petroleum industry.

Finding 67

Similarly, identification of a relief well rig prior to commencement of operations is likely to be challenging in the light of location, frequency of changes to drilling programs, and general rig availability. Depending on the circumstances and specifics of a blowout, the type of relief well rig required in any particular situation is likely to vary. Consequently, the Inquiry finds that it is necessary to retain a degree of flexibility in relation to an operator's choice of relief well rig.

Finding 68

The Inquiry finds that there should, however, be a regulatory requirement that prior to the commencement of drilling operations, the owner/operator make meaningful enquiries as to the availability of potential rigs on a contingency basis.

Recommendation 79

The regulator, rather than the responsible Minister, should be given the power to direct an operator to use a particular rig for the purpose of well control operations, if appropriate in the circumstances, and the power should be used in the future if that rig is the best option available. This would necessarily involve the operator fully compensating for the use of the rig and any other associated costs. The Inquiry suggests that this power could be invoked and given effect as a condition of an operator's licence.

Recommendation 80

The regulatory regime should also impose an obligation on an operator to ascertain the availability, and provide details to the regulator, of any potential relief well rigs, prior to the commencement of drilling operations (including prior to each phase of a drilling operation where applicable).

⁴³⁶ WWF-Australia, Submission to the Inquiry.

Drilling the Relief Well

- 5.64. The *West Triton* departed from Singapore on 27 August 2009 and arrived at the Relief Well location in the vicinity of the Montara WHP some 16 days later in the early hours of 11 September 2009.⁴³⁷ On 13 September 2009, just over 3 weeks after the start of the Blowout, the *West Triton* commenced Relief Well drilling operations.⁴³⁸
- 5.65. The Atlas revision to the *West Triton* Safety Case for the drilling of the Relief Well was reviewed and accepted by NOPSA on 7 September 2009.⁴³⁹
- 5.66. The Inquiry has heard that the personnel on board the *West Triton* comprised, among others, Atlas personnel and several PTTEPAA Drilling Supervisors.⁴⁴⁰ In terms of specialist oversight of the Relief Well, Mr Jacob advised that in addition to ALERT, PTTEPAA had also engaged a well engineer from AGR Drilling to provide for external review of PTTEPAA's response effort:
- We were utilising a drilling team that had been responsible for an operation that had resulted in a blowout. We didn't know at that stage how that had occurred, but obviously something had not gone right, so I felt it prudent, from my own knowledge at that time, to have somebody outside of that group involved. His prime role was to monitor what was happening with the relief well and to be able to give me some independent advice as to how that was going and how the planning was going, and it was a sounding board for me and for any issues that I might have rather than disturbing the team actually working on the well.⁴⁴¹
- 5.67. The Inquiry also heard that PTTEPAA liaised with and received technical support from its parent company in Bangkok in relation to the Relief Well, although that support was provided from Bangkok rather than by a representative(s) relocated to Australia for the duration of the response.⁴⁴²
- 5.68. The *West Triton* was positioned approximately 2km from the WHP/*West Atlas* and some 2.6km (measured from the rotary table of the *West Triton*) from the target of the Relief Well, that is, a point approximately 100m above the 9⁵/₈" casing shoe of the H1 Well.⁴⁴³ The Inquiry heard that the location of the

⁴³⁷ PTTEPAA Daily Drilling Report, Montara H1 ST1 RW1, 11 September 2009, PTT.9003.0017.0335; PTTEPAA, Submission to the Inquiry, Term of Reference 5, paragraph 29.

⁴³⁸ Atlas, Submission to the Inquiry, paragraph 37.

⁴³⁹ NOPSA, Submission to the Inquiry, Appendix 3.

⁴⁴⁰ T1809:2 (Jacob).

⁴⁴¹ T1811:30-41 (Jacob).

⁴⁴² T1936:37-46 (Jacob).

⁴⁴³ Atlas, Submission to the Inquiry, paragraph 33.

West Triton was determined primarily by the need to drill the Relief Well at the correct angle, but also by meteorological factors such as air currents impacting upon the direction in which the gas plume from the H1 Well was drifting.⁴⁴⁴

- 5.69. The Inquiry understands that the Relief Well plan involved:⁴⁴⁵
- a. drilling the Relief Well in the direction of the H1 Well;
 - b. using vector magnetic passive ranging to locate the H1 Well;
 - c. once the H1 Well was located, plugging and sidetracking the Relief Well in order to then intercept the H1 Well;
 - d. upon successful interception of the H1 Well, pumping kill weight mud to counteract the pressure of the formation and stop the flow of hydrocarbons; and
 - e. setting cement plugs in the H1 Well using the Relief Well and/or setting a mechanical plug in the H1 Well from the WHP.

Compliance with regulatory requirements

- 5.70. PTTEPAA submitted to the Inquiry that between 28 August and 10 September 2009:⁴⁴⁶
- a. Atlas submitted and NOPSA accepted a revised Safety Case in respect of the *West Triton's* Relief Well operations;
 - b. PTTEPAA submitted and the NT DoR approved a WOMP and a Relief Well drilling program;
 - c. PTTEPAA submitted and the NT DoR approved addenda to its existing Environment Plans already in place for activities in the Montara Oilfield; and
 - d. PTTEPAA sought and DEWHA granted an exemption under the EPBC Act in relation to the drilling of the Relief Well.
- 5.71. The Inquiry notes that the Relief Well WOMP as submitted to the NT DoR was in much the same terms and format as the H1 Well WOMP submitted to the NT DoR in November 2008. In this regard, the Inquiry has before it evidence that both the Victorian DPI and GA upon review of the Relief Well WOMP and drilling

⁴⁴⁴ T1913:11-17 (Jacob).

⁴⁴⁵ Atlas, Submission to the Inquiry, paragraph 33; PTTEPAA, Submission to the Inquiry, Term of Reference 5, paragraph 24.

⁴⁴⁶ PTTEPAA, Submission to the Inquiry, Term of Reference 5, Table F; *Ibid*, Term of Reference 6, Table A.

program (at the request of the NT DoR), found the Relief Well WOMP and drilling program to be deficient in a number of respects. The DPI declined to make a recommendation to the NT DoR to accept the Relief Well WOMP and approve the drilling program. Notwithstanding the DPI's comments, the Relief Well drilling program was approved by the NT DoR on 10 September 2009.⁴⁴⁷ Approval was granted for operations up to, but not including, the actual interception and well kill of the H1 Well. The NT DoR indicated to GA that further information would be sought from PTTEPAA prior to approval of interception.⁴⁴⁸ On 21 September 2009 the NT DoR approved a revised version of the Relief Well drilling program, which included the interception and well kill of the H1 Well. PTTEPAA made subsequent applications to the NT DoR for approval.⁴⁴⁹

- a. to sidetrack the Relief Well in order to ultimately achieve its target of intercepting the H1 Well; and
- b. to plug and abandon the Relief Well and suspend the H1 Well.

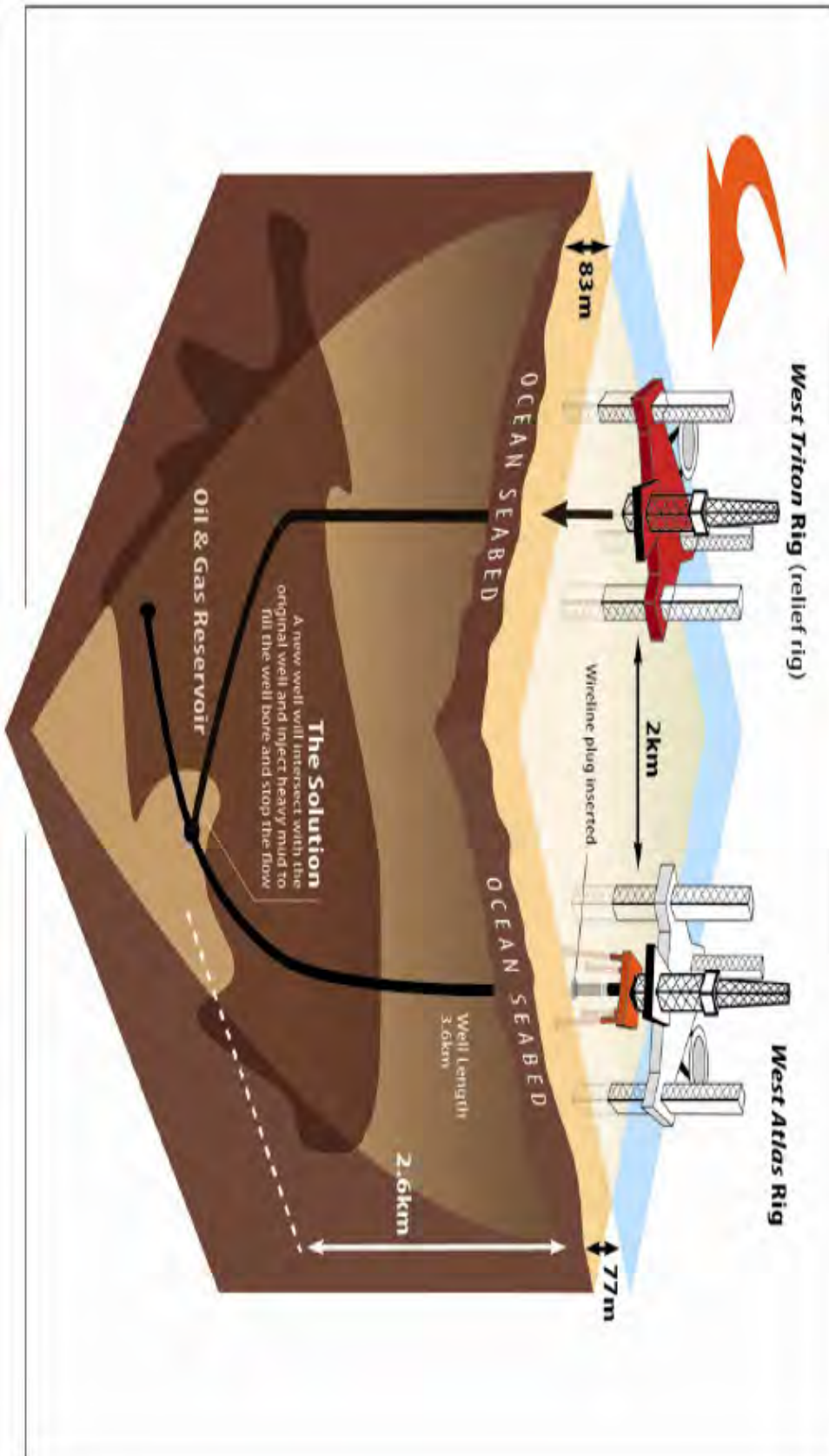
⁴⁴⁷ PTTEPAA, Submission to the Inquiry, Term of Reference 5, Table F.

⁴⁴⁸ Email from Alan Holland of NT DoR to Xu Donghai of GA, 9 September 2009, RET.0010.0001.1549.

⁴⁴⁹ PTTEPAA, Submission to the Inquiry, Term of Reference 5, Table F.

Well Repair Plan

How the Montara Platform leak will be stopped



Courtesy of PTTEPAA

Chronological account of the Relief Well drilling operations

5.72. After 4 unsuccessful attempts and approximately 10 weeks after the Blowout, the Relief Well successfully intercepted the H1 Well on the morning of 1 November 2009. The following table details the timeline of the drilling of the Relief Well.⁴⁵⁰

Date	Relief Well
14 September 2009 (25 days since Blowout)	Drilling commenced.
15 September 2009	26" hole was drilled to a measured depth of 149m and conductor casing run and cemented in position.
21 September 2009	Drilling of 17½" hole to a measured depth of 1,622m completed.
22 September 2009	13¾" casing run and cemented into position – approximately 1000m vertically above H1 Well.
24 September 2009	12¼" hole drilled to measured depth of 2,300m.
30 September 2009	9⅝" liner run in hole.
5 October 2009	8½" hole drilled from a measured depth of 2,375m to 2,600m – approximately 5m above the H1 Well.
6 October 2009 (47 days since Blowout)	<u>First</u> attempt to intersect the H1 Well. Relief Well drilled past H1 Well within a range of approximately 4.5m. Relief Well was plugged with cement and direction of drilling changed by sidetracking the Relief Well.

⁴⁵⁰ Ibid, paragraph 31-60.

<p>13 October 2009</p> <p>(54 days since Blowout)</p>	<p><u>Second</u> attempt to intercept H1 Well.</p> <p>Relief Well drilled past the H1 Well within a range of approximately 0.7m.</p> <p>Relief Well was plugged with cement and direction of drilling changed by sidetracking.</p>
<p>17 October 2009</p> <p>(58 days since Blowout)</p>	<p><u>Third</u> attempt to intercept H1 Well.</p> <p>Relief Well drilled past the H1 Well within a range of approximately 0.53m.</p> <p>Relief Well was plugged with cement and direction of drilling changed by sidetracking.</p>
<p>24 October 2009</p> <p>(65 days since Blowout)</p>	<p>Whipstock placed in Relief Well to divert the drill bit onto a path at an angle to the drilled hole.</p> <p><u>Fourth</u> attempt to intercept H1 Well failed when whipstock became stuck approximately 30m from its destination.</p> <p>Backed out of hole and sidetracked Relief Well.</p>
<p>28 October 2009</p>	<p><u>Fifth</u> attempt to intercept H1 Well commenced.</p>
<p>1 November 2009</p> <p>(73 days since Blowout)</p>	<p>H1 Well successfully intercepted at 9.30am (CST).</p> <p>Heavy mud (1.3sg) pumped through Relief Well and into H1 Well.</p> <p>Flow of hydrocarbons in H1 Well reduced, however insufficient amount of heavy mud (1.3sg) available to completely kill the H1 Well.</p> <p>Seawater pumped into H1 Well to maintain well control.</p>
<p>1 November 2009</p>	<p>Fire broke out on the WHP at approximately 12.10pm (CST).</p>

1 November 2009	Decision made following risk assessment that it was safe to pump a heavier mud (1.6sg) into H1 Well. Preparation of 1.6sg kill weight mud commenced (including sourcing additional chemicals from various locations).
3 November 2009	Preparation of 1.6sg kill weight mud complete.
3 November 2009 (75 days since Blowout)	Flow of hydrocarbons stopped after 3,400 barrels of kill weight mud (1.6sg) pumped into H1 Well.
3 November 2009	Fire extinguished at 3.48pm (CST). ⁴⁵¹
22 November 2009	ALERT personnel board the <i>West Atlas</i> .
23 November 2009	ALERT personnel board the WHP.
27 November 2009	320 barrels of cement pumped via Relief Well into H1 Well.
30 November 2009	Inflatable AGE Pressure Test Packer installed in H1 Well but pressure test not completed due to failure to achieve good pressure test. Packer tested in Darwin and no problem identified. There is some suggestion that the pressure test failed due to the wear on the inside of the 9 ⁵ / ₈ " casing caused by continuous flow of fluid through the casing since 21 August 2009. Consequently the Packer was unable to

⁴⁵¹ PTTEP Australasia TIMOR SEA OPERATIONS Incident Information #87, 3 November 2009: <http://www.coogeeresources.com.au/uploads/MediaRelease87_03-11-09.pdf>.

⁴⁵² T1758:10-16 (Jacob).

	set within the worn section of the 9 ⁵ / ₈ " casing. ⁴⁵²
2 December 2009 ⁴⁵³	First isolation packer / mechanical plug set in H1 Well at a measured depth of approximately 2,000m in H1 Well. Second isolation packer / mechanical plug set in H1 Well at a measured depth of approximately 1,800m.
3 December 2009	1,400m long cement plug set at bottom of Relief Well.
5 December 2009	<i>West Triton</i> demobilised and returned to Singapore. ⁴⁵⁴
December 2009	Operations suspended due to presence of Cyclone Laurence. ⁴⁵⁵
13 January 2009	PTTEPAA reported that operations to plug and secure the H1 Well were complete. ⁴⁵⁶

Securing the H1 Well

- 5.73. On 11 September 2009 (as noted at paragraph 5.30 above), NOPSA requested that PTTEPAA submit a revision to its existing Montara Construction and Installation Safety Case. On 21 September 2009 PTTEPAA submitted Revision 0 of the Montara Construction and Installation Safety Case, WHP Clearing and H1-ST1 Well Plugging Revision to NOPSA (the **WHP Safety Case Revision**).⁴⁵⁷
- 5.74. On 25 September 2009, NOPSA requested that PTTEPAA incorporate additional information into the WHP Safety Case Revision. The WHP Safety Case Revision was amended by PTTEPAA to incorporate further information 3 times, the second and third amendments taking place after the H1 Well had been intercepted by the Relief Well.⁴⁵⁸ On 20 November 2009, NOPSA accepted the

⁴⁵³ Email from Andy Jacob of PTTEPAA entitled Montara H1 Update 2 December 2009, DEW.9001.0024.0219.

⁴⁵⁴ PTTEP Australasia TIMOR SEA OPERATIONS Incident Information #97, 13 January 2010, <http://www.coogeerresources.com.au/uploads/MediaRelease97_13-01-10.pdf>.

⁴⁵⁵ Ibid.

⁴⁵⁶ Ibid.

⁴⁵⁷ Letter from Andy Jacob of PTTEPAA to Jeremy Dunster of NOPSA, 21 September 2009, NOP.9000.0011.0399.

⁴⁵⁸ Email from Christine Collins of PTTEPAA to Catherine Noonan of PTTEPAA, 23 December 2009, PTT.9002.0008.0249.

WHP Safety Case Revision. This meant that PTTEPAA/ALERT personnel were permitted to access the WHP in order to finally secure the H1 Well.

- 5.75. PTTEPAA also sought and was granted approval by the NT DoR to undertake operations to clear the WHP and plug the H1 Well, including the setting of a mechanical packer in the H1 Well.

Success of the Relief Well

- 5.76. The Inquiry has heard that it is not unusual for a relief well to miss its target several times prior to a successful intercept.⁴⁵⁹ The Inquiry is not critical of the number of attempts taken to intercept the H1 Well, not least because PTTEPAA had engaged with industry experts in order to peer review the drilling of the Relief Well and to advise industry of other options under consideration. In this regard, the Inquiry heard from PTTEPAA that representatives of Woodside, Inpex, Chevron, Apache, Total, AGR Drilling, Seadrill, SPD, Schlumberger, Vermilion Oil and Gas, Boots & Coots and PTTEPAA's parent company met with PTTEPAA on 26 October 2009 just prior to the fifth attempt to intersect the H1 Well, and 'consensus was reached...that the approach preferred by PTTEPAA with respect to the Relief Well was the most appropriate approach in the circumstances'.⁴⁶⁰ Of greater concern to the Inquiry is the lack of accurate estimates and information provided by PTTEPAA at the time in relation to the length of time it would take to stop the Blowout.⁴⁶¹
- 5.77. Perhaps more significant than the number of interception attempts was that the available volume of mud initially used to kill the H1 Well was of insufficient weight to stop the flow of hydrocarbons from the wellbore.⁴⁶²
- 5.78. Mr Jacob told the Inquiry that PTTEPAA had initially, in accordance with modelling obtained by ALERT, used mud with a specific gravity of 1.3 sg in an

⁴⁵⁹ PTTEPAA, Submission to the Inquiry, Term of Reference 5, paragraph 30(i); Statutory Declaration of Andrew Charles Jacob, 31 March 2010, paragraph 183; NUKA Research & Planning Group, *Montara Oil Spill Inquiry Analysis*, p. 14; Northern Territory, Submission to the Inquiry, paragraph 108.

⁴⁶⁰ PTTEPAA, Submission to the Inquiry, Term of Reference 8, paragraph 6.

⁴⁶¹ PTTEPAA submitted to the Inquiry in response to the Inquiry's draft preliminary findings in relation to arresting the Blowout, that 'PTTEPAA was focussed on drilling the relief well and were reliant on industry experts to give them accurate indications of the anticipated time to complete the relief operation. No criticism should be directed re provision of timeline estimates. They were estimates provided as best they could at the time'. The Inquiry is aware of these factors, but as discussed below, notes that ideally PTTEPAA should have provided more information as to the factors that might have affected the Relief Well timeline estimates that it provided to the public.

⁴⁶² Atlas, Submission to the Inquiry, p. 9.

attempt to stop the Blowout.⁴⁶³ Ultimately, however, it was necessary for PTTEPAA to source and use mud with specific gravity of 1.6 sg to kill the H1 Well. While Mr Jacob was at a loss to explain to the Inquiry why PTTEPAA did not use mud with a specific gravity of 1.6 sg in its first attempt to stop the Blowout,⁴⁶⁴ documents produced to the Inquiry in fact evidence that the use of mud with a specific gravity of 1.6 sg had been recommended only as a back-up option because it could potentially compromise the integrity of the Relief Well.⁴⁶⁵

5.79. The Inquiry heard that as a consequence of the exhaustion of the mud supplies on board the *West Triton*, it became necessary to pump seawater through the Relief Well into the H1 Well so as to maintain pressure in the H1 Well whilst additional mud was sourced by PTTEPAA. It was during this period that the H1 Well ignited.⁴⁶⁶

5.80. When asked about the cause of the fire and whether the pumping of seawater could have led to ignition of the H1 Well, Mr Jacob told the Inquiry that:

...by carrying out the interception, there is a potential that we drew maybe more gas into the well and therefore changed the characteristics of the fluids that were coming up the well – changed the composition. I still don't know what the ignition source was, but it could have been a piece of cement travelling up the well and hitting metal on the wellhead platform on the underside of the rig, and if the gas composition of that fluid had changed, that may have been enough to have allowed an ignition to have occurred. But obviously something changed in the characteristics.

I don't believe that the seawater would have had any impact on that side of things, because, in effect, that's what you're doing when you're deluging – putting seawater on to it.⁴⁶⁷

5.81. The Inquiry has received no further evidence as to the cause of the fire that broke out on the WHP on 1 November 2009. The Inquiry does not consider that the cause of the fire is a matter of contention and as such does not address this aspect of the Blowout further.

⁴⁶³ Add Energy was contracted by ALERT to provide modelling in relation to the Relief Well (see T1940:15-17 (Jacob)).

⁴⁶⁴ T1757:28-36 (Jacob).

⁴⁶⁵ ALERT Well Control Report Montara H1, ST-1 Well Control Operations Montara H1, ST-1-RW-1 Relief Well Operations Recommendations and Considerations Revision 1 September 2009, para 3.8, PTT.9003.0094.0132.

⁴⁶⁶ T1920:8 (Jacob).

⁴⁶⁷ T1920:13-31 (Jacob).

Finding 69

It is incumbent upon operators and, to some extent, regulators to manage the risks following a blowout in order to minimise the resulting impact.

Finding 70

While a number of issues arose for PTTEPAA in responding to the Blowout, ultimately the Inquiry finds that PTTEPAA carried out its response effort diligently and with vigour and a due sense of urgency.

Finding 71

The Inquiry finds that while securing the H1 Well appears to have taken a not insignificant amount of time, the exigencies of the particular situation and location of the Montara Oilfield contributed significantly to the response's extended timeframe, and PTTEPAA acted appropriately in the circumstances in undertaking to drill the Relief Well.



Courtesy of PTTEPAA

NOPSA's role in the response to the Blowout

5.82. The Inquiry has heard that NOPSA maintained an ongoing liaison with RET, AMSA, NT DoR and the NOPSA Board in relation to NOPSA's enforcement activities and to the particular action taken in issuing the prohibition notices.⁴⁶⁸

5.83. As noted above, the Inquiry heard from Mr Jacob that PTTEPAA determined not to pursue approval from NOPSA for water deluge operations because it was unable to ascertain what more it could do in order to present an acceptable submission to NOPSA that would have resulted in NOPSA lifting or varying Prohibition Notice 222. A key aspect of the problem identified by PTTEPAA in this regard became apparent upon further examination of Mr Jacob by Counsel Assisting:

Q. One further possibility, at least, was to engage with NOPSA in order to get a better understanding of what it considered to be the absolutely irreducible minimum requirements so that you could see whether you could satisfy those?

A. NOPSA will not give you those. NOPSA assess the documents that you put forward. They do not lay down guidelines as to what is acceptable. That's not the way they work.⁴⁶⁹

5.84. Mr Jacob further stated that:

NOPSA would...undertake a review of that documentation, would then ask questions and there would be some interaction or responses to those questions, and it would go on, so forth, until there was either acceptance or rejection of the safety case.

During the course of the incident, we talked to them and suggested that this was not a very productive way of doing things, given the incident was occurring, that we needed more interaction with them. They did change their process to have a more ongoing interaction, so rather than waiting for full documentation, as we supplied information, they would review it and come back to us.⁴⁷⁰

5.85. PTTEPAA also submitted to the Inquiry that it was:

...grateful to NOPSA for its agreement to adopt this more consultative approach to review between operator and regulator and to raise questions as they occurred to the Inspectors.⁴⁷¹

⁴⁶⁸ NOPSA, Submission to the Inquiry, Appendix 3, p. 23.

⁴⁶⁹ T1755:3-11 (Jacob).

⁴⁷⁰ T1755:18-30 (Jacob).

⁴⁷¹ PTTEPAA, Submission to the Inquiry, Term of Reference 6, paragraph 6.

5.86. The Inquiry heard that PTTEPAA offered to have NOPSA officers attend the PTTEPAA office in Perth in order to facilitate a closer working relationship between safety engineers, but that that proposal was rejected by NOPSA.⁴⁷² Messrs Bills and Agostini learned during the course of their 2009 review of NOPSA that NOPSA was generally reluctant to send staff to attend operator HAZID workshops because of the potential that such close involvement of NOPSA with the operator 'could compromise the function of the regulator and [NOPSA] has developed a specific policy controlling NOPSA's interactions with operators'.⁴⁷³ The Inquiry speculates that perhaps the basis for NOPSA's rejection of PTTEPAA's proposal stems from this specific policy.

Finding 72

It is critical in circumstances such as those following the Blowout that NOPSA's policy relating to engagement and interaction with operators should be applied flexibly in order to provide for the expeditious development and assessment of response options.

5.87. Messrs Bills and Agostini also identified a reluctance on the part of NOPSA to engage with operators at the development stage of an operator's safety case.⁴⁷⁴ Whilst the Bills and Agostini review did not specifically contemplate engagement between NOPSA and the operator in the context of development and management of safety-related submissions in an emergency situation, the Inquiry is of the view that the observed reluctance was much the same following the Blowout.

5.88. The Inquiry heard from Mr Jacob that in his opinion (in relation to the proposed water deluge operations):

...it really comes down to the difference between the well control company looking at the holistic event and how best to deal with the whole event, whereas NOPSA is looking on a much more narrow basis of purely occupational health and safety of personnel involved in it. At that time there was nobody at risk, because there was nobody at the wellhead platform. So by introducing a vessel into the area, we were introducing people to risk, so we were increasing the risk to people.⁴⁷⁵

5.89. The evidence before the Inquiry tends to suggest that PTTEPAA appears to have assumed, without any real basis for doing so, that NOPSA was fully apprised of the degree to which ALERT was involved in a risk assessment of the proposed

⁴⁷² T1755:32-35 (Jacob).

⁴⁷³ Bills and Agostini, *Offshore Petroleum Safety Regulation*, paragraph 2.23, NOP.9003.0001.0001.

⁴⁷⁴ Ibid, paragraphs 2.16; 2.17; and 2.19.

⁴⁷⁵ T1908:23-31 (Jacob).

water deluge operations, and indeed the extent to which information from ALERT was incorporated into PTTEPAA's submission.⁴⁷⁶ The Inquiry notes that without such information, it was unlikely that NOPSA could fully appreciate the risk-related arguments in favour of the water deluge proposal.

Finding 73

It was incumbent upon PTTEPAA to ensure that it supplied to NOPSA all information as to relevant risk assessments. In this regard, PTTEPAA took too unilateral an approach to its interactions with NOPSA.

- 5.90. NOPSA submitted to the Inquiry that in relation to its assessment of an operator's safety case, its role is to:
- ...provide independent assurance that health and safety risks are properly controlled by the operator in challenging the commitments made by the operator in the safety case and then selectively verifying the implementation of the operator's risk management arrangements through planned inspection and audit.⁴⁷⁷
- 5.91. The Inquiry does not disagree that NOPSA's role is to challenge the operator as to aspects of its safety case prior to the commencement of, or during, normal drilling operations. However, the Inquiry notes that while PTTEPAA's submissions to NOPSA in relation to the safety of water deluge operations did not come within the rubric of the safety case regime, it appears that NOPSA nevertheless in substance applied its policy of safety case assessment to PTTEPAA's water deluge submissions.
- 5.92. In submissions received by the Inquiry in response to its draft preliminary findings:
- a. NOPSA disputed that it took the approach described above to PTTEPAA's water deluge submission and that, in any event, PTTEPAA's 'submissions on this matter were materially deficient and technically flawed';⁴⁷⁸ and
 - b. PTTEPAA submitted that as a consequence of NOPSA's approach 'there was little in the way of NOPSA issued policy or guideline to inform the form or content of the submission'. In fact, PTTEPAA considered that 'its submission

⁴⁷⁶ T1938:33-36 (Jacob). The Inquiry notes that while the Case for Safety put to NOPSA by PTTEPAA did not appear to include any detailed risk assessment by ALERT in relation to the proposed water deluge operations, it briefly described the operational involvement of ALERT in those proposed operations.

⁴⁷⁷ NOPSA, Submission to the Inquiry, p. 7.

⁴⁷⁸ Letter from NOPSA to the Inquiry, 24 May 2010.

on water deluge was both comprehensive and competent and [was] surprised by NOPSA's comments'.⁴⁷⁹

- 5.93. The submissions of both PTTEPAA and NOPSA as summarised above aptly illustrate the reason for the Inquiry's concerns regarding consideration of well control options following the Blowout, and the deficiencies in the engagement strategy adopted by both PTTEPAA and NOPSA. The Inquiry notes that a post-blowout emergency situation may require a more flexible and possibly holistic approach on the part of the regulator. In order to achieve a future approach such as this, the Inquiry suggests that the offshore petroleum industry and NOPSA together undertake to review options for well control and the necessary questions and risks involved so as to enable them to be more prepared, a proposition with which Mr Jacob wholeheartedly agreed.⁴⁸⁰

Finding 74

The Inquiry does not find NOPSA's enforcement action in assessing the safety risks related to the Blowout to have been deficient. It is clear to the Inquiry that decisions regarding the safety of personnel and the relative risks of various well control options are not simple and warrant close attention and scrutiny, and that each party involved in the risk assessment process should have access to the outcomes of such scrutiny.

Finding 75

In this instance the Inquiry finds that consideration by PTTEPAA and NOPSA of all of the various options for responding to the Blowout should have been undertaken on a more collaborative, consultative basis.

Recommendation 81

NOPSA develop a policy of engagement with operators so as to enable experts (including safety experts) to canvas all available options for well control in the event of a blowout.

⁴⁷⁹ Letter from PTTEPAA's solicitors to the Solicitor Assisting the Inquiry, 27 May 2010.

⁴⁸⁰ T1912:3-10 (Jacob).

Recommendation 82

The Inquiry also supports Bills and Agostini's recommendation:

'...in relation to safety case development and compliance overall, that NOPSA revise its approach to interacting with operators prior to the safety case assessment process and subsequently direct more resources into its advisory functions. We further recommend that NOPSA develop and implement a formal plan for supporting and guiding each operator prior to safety case acceptance, as well as for ongoing compliance with that safety case, recognising the unique experience, capabilities and assessed risk of that operator. Each plan needs to include advice, education and liaison meetings with the operators. The plan needs to be continuously reviewed and reassessed based on the latest information, including the interaction with the operator'.⁴⁸¹

Recommendation 83

The regulator should pre-assess and review in a generic sense, and in conjunction with the offshore petroleum industry, available options for well control in the event of a blowout. Being 'match fit' in this sense will enable a quicker and more effective response in terms of safety assessment, and will ensure that expectations of both operator and regulator are more readily aligned.

The offshore petroleum industry's role in the response to the Blowout

- 5.94. Quite apart from safety, environmental and commercial concerns, blowouts undoubtedly have significant impact on the offshore petroleum industry as a whole.
- 5.95. Responding to a blowout is a technically challenging and expensive exercise. The Inquiry is consequently of the view that it is of critical importance that every effort is made to use the considerable expertise that resides within the offshore petroleum industry, both in Australia and internationally.
- 5.96. The Inquiry understands that the offshore petroleum industry's response to the Blowout comprised:
- contributions to AMOSC⁴⁸² by its subscribers (of which PTTEPAA is one); and
 - offers and provision of assistance to PTTEPAA by industry participants.
- 5.97. PTTEPAA's submission to the Inquiry sets out the assistance offered to or requested by PTTEPAA, and the companies involved in peer review or providing advice to PTTEPAA on the various aspects of the response.⁴⁸³ PTTEPAA held peer

⁴⁸¹ Bills and Agostini, *Offshore Petroleum Safety Regulation*, Recommendation 3, p xiii.

⁴⁸² Further detail on the involvement of AMOSC in the response to the Blowout is provided in Chapter 6.

⁴⁸³ PTTEPAA, Submission to the Inquiry, Term of Reference 8, pp. 2-9.

review meetings with a number of representatives of the offshore petroleum industry in relation to:⁴⁸⁴

- a. on 26 October 2009, the progress of the Relief Well operation; and
- b. on 12 November 2009, the cementing programs for the H1 Well and the Relief Well.

5.98. Over thirty companies and experts provided advice and assistance to PTTEPAA in its response efforts. The Inquiry understands that PTTEPAA also received a number of offers of assistance that were not ultimately taken up.

Finding 76

The Inquiry commends the offshore petroleum industry for what appears to the Inquiry to have been a cohesive and responsive approach to the difficulties faced by PTTEPAA in responding to the Blowout, through regular contribution as subscribers to AMOSC, the peer review process, and through direct support and advice offered and provided, upon request, to PTTEPAA.

Coordination of the response and provision of information

Logistical coordination

5.99. This Chapter earlier described the various options that PTTEPAA considered in responding to the Blowout, and set out the Inquiry's finding that a more collaborative and consultative approach should have been adopted between PTTEPAA and NOPSA in relation to the consideration and approval of those options. It is apparent to the Inquiry that whilst PTTEPAA acted with vigour and a due sense of urgency in implementing its response to the Blowout, the approach by both PTTEPAA and regulators alike was somewhat disjointed and may well have benefited from oversight by a central coordinating/facilitating government body. In particular, while the Inquiry does not question the judgments that were ultimately made by operators and regulators alike, the Inquiry is nevertheless of the view that a central coordinating body might have engendered and encouraged a more holistic approach to response operations by all those involved.

5.100. The Blowout and the response to it was, in effect, an emergency situation of national importance. While the companies involved had ultimate responsibility to stop the flow of hydrocarbons, the Commonwealth should have seen it as its role to ensure that all available options to stem the Blowout were fully explored

⁴⁸⁴ Ibid, paragraphs 4, 9–11.

and that the environmental and other responses were up to the mark. In this context, on the regulatory/policy side there were different roles being performed by the NT DoR (as the delegate of the DA), NOPSA, AMSA, RET, and DEWHA. From time to time there needed to be interaction with state agencies, other Commonwealth agencies and neighbouring countries. All of this demanded that there be a Commonwealth control centre so that actions could be coordinated and decisions taken.

- 5.101. In this regard, the action that AMSA took to convene daily meetings of agencies was appropriate (see Chapter 6) but the remit needed to be much more than those meetings took on board. The Commonwealth needed to be in a position to better inform itself and, if required, to direct PTTEPAA to undertake (or not undertake) certain actions (for example, in terms of addressing the Blowout and environmental remediation, for which there are pre-existing powers in the OPGGS Act).
- 5.102. If a blowout had been in state waters or on land, it is doubtful that the companies concerned would have been given so much latitude in terms of the response. By way of example, when the coal ship ran aground in April 2010 on the Great Barrier Reef it was hardly going to be left to the ship's captain to determine the response to the emergency.
- 5.103. Although the Inquiry finds that PTTEPAA did respond appropriately, for the future, in offshore waters, the Commonwealth needs to be prepared to step in and to take charge in a coordinated fashion.
- 5.104. The Inquiry considers that it would be appropriate in the future for such a central coordinating/facilitating role to be undertaken by a Ministerial appointee from either:
- a. the Commonwealth Department with responsibility for upstream petroleum (currently RET); or
 - b. if established in accordance with recommendations made by the Productivity Commission⁴⁸⁵ and this report, NOPR.
- 5.105. As discussed in Chapter 4, the Inquiry considers that the current regulatory regime would enable any such body to issue directions to an operator/owner.⁴⁸⁶

⁴⁸⁵ Productivity Commission, *Review of the Regulatory Burden on Upstream Petroleum (Oil & Gas) Sector*, p. 292.

⁴⁸⁶ See, for example, s 574 of the OPGGS Act.

Recommendation 84

In any future similar blowout or offshore emergency situation, the Minister appoint (through either a NOPR or the relevant Department) a senior public servant to establish and oversight a central coordinating body that will facilitate interaction between regulators, industry, AMSA and the owner/operator. Primary responsibility for stopping a blowout should remain with the owner/operator but should be subject to direction from the central coordinating body in consultation with stakeholders (including the owner/operator).

Provision of information

- 5.106. During and after the Blowout, information relating to various aspects of the Blowout was publicly available from a number of sources, including:
- a. PTTEPAA's website (Relief Well drilling, progress of efforts to stop Blowout);
 - b. media releases and announcements by the Ministers responsible for resources and the environment;
 - c. RET (limited updates on the spill through its newsletter the Australian Petroleum News);
 - d. DEWHA (environmental updates relating to the Blowout);
 - e. AMSA (operational clean-up information); and
 - f. NOPSA (safety-relevant information).

Provision of information by PTTEPAA

- 5.107. Mr Jacob told the Inquiry that PTTEPAA had provided an initial estimate of the volume of oil spilling per day from the H1 Well to AMSA. Upon advice from AMSA that the estimate was not a priority, monitoring of volumes spilled by PTTEPAA and consequently provision of information to the public as to the volume ceased.⁴⁸⁷ The issue of provision of information as to the volume of oil spilled is considered in more detail in Chapter 6.
- 5.108. PTTEPAA provided 97 Incident Information updates on its website, during the course of its response to the Blowout. This included information on the Blowout itself and plans for, and updates as to the progress of, the Relief Well. PTTEPAA also published incident photographs, audio releases, fact sheets and frequently asked questions. This information was very useful for interested parties and, as

⁴⁸⁷ T1899:15-21 (Jacob).

it was frequently updated, could be used to establish how PTTEPAA's response to the Blowout was progressing on an almost daily basis.

- 5.109. The Inquiry notes, however, that in providing information to both the public and to government, PTTEPAA appears to have consistently underestimated the expected time within which the H1 Well would be successfully 'killed'. The Inquiry understands that relief well drilling is both technically challenging and that multiple passes at the target well may well be required before interception is achieved. This would have necessarily impacted upon PTTEPAA's projections.
- 5.110. As a result of PTTEPAA's advice to regulators and the public on the timing of the Relief Well process, both the Government and the public underestimated the time it actually took to stop the Blowout. Beyond the estimated date to stop the Blowout of early October 2009, hydrocarbons continued to escape into the ocean and the atmosphere for several more weeks, until the H1 Well was finally 'killed' on 3 November 2009.

Finding 77

The information provided by PTTEPAA on the technical aspects of the response was good. However, a more conservative estimate of the time it would take to 'kill' the H1 Well would have been more appropriate. With the benefit of hindsight, the Inquiry finds that PTTEPAA might have qualified its estimates of time by providing more information as to, for example, the challenges of drilling a relief well, including a projection of the likely number of attempts it would take to eventually intercept the H1 Well.

- 5.111. The Inquiry has heard that despite having provided a significant amount of information in relation to Relief Well operations, PTTEPAA was criticised by environmental organisations for not providing a broader range of information on the Blowout, including information about environmental impacts, environmental monitoring, and information about the amount and the extent of the spread of the oil.⁴⁸⁸ The Inquiry notes that although PTTEPAA had handed over the role of Combat Agency to AMSA, this did not cover responsibility for all aspects of the spill, and ideally PTTEPAA's information briefs could have contained more information about clean-up operations and environmental impacts.⁴⁸⁹ However, the Inquiry has heard that there was some confusion as to who was responsible for the provision of general information about the incident, largely between AMSA and PTTEPAA, which may have resulted in some

⁴⁸⁸ See WWF-Australia, Submission to the Inquiry, pp. 22, 28-30; Wilderness Society/Environs Kimberley, pp. 7-8.

⁴⁸⁹ Provision of information in relation to environmental monitoring, spread of the oil, and environmental impact is considered in Chapter 6 of this Report.

gaps in the information that was publicly available during the response to the Blowout.⁴⁹⁰

Coordination of publicly available information

- 5.112. The Australian Emergency Management Arrangements⁴⁹¹ recognise the importance of public messaging in the event of an emergency, as well as the coordination of policy and strategy. In the case of the Blowout, although priority was appropriately given to arranging the response and clean-up operations, it is apparent to the Inquiry that there were some deficiencies in the way that information was provided to the public.
- 5.113. The Inquiry anticipates that as a part of its role, the government coordinating/facilitating body would be responsible for the coordination of information and provision of that information to stakeholders, and where appropriate, to the public. In this regard, the Inquiry notes the website established by the US Coast Guard with acknowledged input from all relevant stakeholders in the wake of the blowout in the Gulf of Mexico in April 2010.

Finding 78

The Inquiry finds that each agency/organisation involved with the Blowout endeavoured to make some information about the response to the Blowout available to the public by way of publication on its respective website. The resultant array of information was fragmented with some significant gaps. There was a lack of coordinated and publicly available information about the Blowout; even between government agencies, the coordination and provision of public information did not appear to be effectively coordinated.

Recommendation 85

The body established to undertake a central coordination and facilitation role in the event of any future blowout in Commonwealth waters should undertake to make all relevant information publically available from one, authoritative and easy to access source.

⁴⁹⁰ The Inquiry has heard that PTTEPAA had referred questions beyond AMSA's stated remit to AMSA. AMSA noted in its first situation report that PTTEPAA was responsible for media, as PTTEPAA had responsibility for incident coordination; and that AMSA's role was to provide assistance in relation to clean-up operations (see AMSA *Situation Report: pm Friday 21 August 2009*, AMS.9000.0001.0001). However, it transpired that PTTEPAA was at the same time referring questions broader than just the clean-up to AMSA, including in regard to the expected size and scale of the leak, and the impact on the environment.

⁴⁹¹ Attorney General's Department 2009, *Australian Emergency Management Arrangements*, <<http://www.ema.gov.au>>.

5.114. The Inquiry notes that PTTEPAA did not publicise information about the circumstances and causes of the Blowout. The reasons for this are canvassed in Chapter 7.

6. ENVIRONMENTAL RESPONSE

The Response to the Blowout

- 6.1. Following the Blowout on 21 August 2009 PTTEPAA recognised very quickly that the necessary response to the Blowout would be beyond the company's capacity. PTTEPAA handed the management of response operations to AMSA on that day.
- 6.2. The response operation was of a complexity and magnitude rarely experienced, particularly because of the remoteness of the operation. AMSA led the response creditably for 104 days from 21 August until 3 December 2009. Given the scale and remote location of the Blowout, and the need for a national response, the Inquiry agrees with the decision of PTTEPAA to transfer the response operation to AMSA.
- 6.3. AMSA was guided by the National Plan.⁴⁹² The National Plan, which is underpinned by an Inter-Governmental Agreement (**IGA**)⁴⁹³ between the Commonwealth, the states and the Northern Territory, provides the national framework for responding to marine pollution incidents. In all response arrangements under the National Plan, there is both a Statutory Agency⁴⁹⁴ and a Combat Agency.⁴⁹⁵ The IGA and National Plan allocate responsibility for these two key roles based on the circumstances of the spill, such as its source, location and scale. The National Plan also establishes a number of operational roles which support the Combat Agency, including the ESC who provides advice on environmental priorities and preferred response options.
- 6.4. As Combat Agency, AMSA assumed control of the operation and established an Incident Coordination Group (**ICG**) with representatives from DEWHA, RET, PTTEPAA, the Australian Fisheries Management Authority (**AFMA**), the

⁴⁹² The National Plan comprises two national contingency plans – the *National Marine Chemical Spill Contingency Plan* and the *National Marine Oil Spill Contingency Plan* – the latter of which applied in this response.

⁴⁹³ The *Inter-Governmental Agreement on the National Plan to Combat Pollution of the Sea by Oil and Other Noxious and Hazardous Substances*.

⁴⁹⁴ The Statutory Agency is the relevant government agency assigned the oversight of the response, institution of prosecutions and the recovery of clean-up costs.

⁴⁹⁵ The Combat Agency is the government agency or company assigned the operational responsibility for responding to an oil spill in accordance with the National Plan.

Department of Prime Minister and Cabinet, AMOSC⁴⁹⁶ and the Department of Foreign Affairs and Trade. This group met every weekday from 24 August until 9 November 2009, and then every second weekday until the response ended on 3 December 2009.

- 6.5. The Statutory Agency role under the National Plan fell to the NT DoR in accordance with its role as the DA for the Montara Oilfield development. In its submission AMSA stated that ‘at times this did not appear to be clear to all stakeholders, and from AMSA’s perspective the Designated Authority played no part in the response’.⁴⁹⁷ This is notwithstanding the Statutory Agency’s key role under the National Plan as well as the powers under the OPGGS Act to direct a registered titleholder to undertake any required ‘clean-up or other remediation of the effects of the escape of petroleum’.⁴⁹⁸ The NT DoR was also absent from the ICG which meant that AMSA alone coordinated the environmental response. RET agreed with NT DoR that RET would represent the Commonwealth Minister for Resources and Energy’s interests at the ICG in its capacity as the JA and as the agency with administrative authority for the OPGGS Act. This was to allow NT DoR to focus its resources on other matters including the assessment of approvals necessary for activities associated with efforts to arrest the Blowout.⁴⁹⁹
- 6.6. It is evident that responsibilities under the National Plan need to be clearly understood and acknowledged by all of the parties involved.

Finding 79

The Inquiry finds that the roles and responsibilities under the National Plan should be clarified. The overall response required consideration of a number of tasks in addition to the demanding clean-up job that AMSA had to start on 21 August 2009.⁵⁰⁰ The Inquiry considers that it would have been preferable for RET to coordinate and chair meetings of the ICG.

- 6.7. The ongoing operations utilised equipment from oil industry stockpiles in Singapore and Geelong, as well as AMSA stockpiles in Darwin and cities in other states. Response personnel were provided by the oil industry and AMSA as well

⁴⁹⁶ AMOSC is a subsidiary of the Australian Institute of Petroleum which is financed by nine participating oil companies and other subscriber companies (including PTTEPAA) who have access to AMOSC stockpiles of equipment and personnel in the event of an oil spill.

⁴⁹⁷ AMSA, Submission to the Inquiry, p. 8.

⁴⁹⁸ See s 574(2) and 782(1) item 7 of the OPGGS Act.

⁴⁹⁹ Letter from RET to the Inquiry, 24 May 2010.

⁵⁰⁰ Other tasks included information exchange between government agencies and the provision of advice to relevant Ministers.

as through the National Response Team⁵⁰¹ arrangements (including state and territory assistance). Assistance was also provided by New Zealand personnel in accordance with formal arrangements between Australia and New Zealand. PTTEPAA provided a liaison officer who was located in AMSA's Canberra office for the first several days of the response. During the response, 43 National Response Team personnel from all jurisdictions were used at various times.⁵⁰² AMOSC, its international equivalent Oil Spill Response (**OSR**), and Australian oil companies also provided 41 personnel who were directly involved in the response.

- 6.8. On 21 August 2009 (day 1) the AMSA Incident Controller established the overall response objective as the protection of Ashmore Reef which was later amended to include the protection of Cartier Island and the Western Australian coastline. A response strategy was developed in consultation with relevant stakeholders. The response objective was determined on the basis of the following factors:⁵⁰³
- a. the remote location of the Montara WHP and the associated delays this would cause in mobilising a response operation;
 - b. information contained within a database (known as the Oil Spill Response Atlas) maintained by AMSA. This identified Ashmore Reef and Cartier Island as features of interest but had limited information on birdlife and fisheries in the region;
 - c. environmental information provided by DEWHA on 25 August 2009 identifying Ashmore Reef and Cartier Island as significant environmental features;
 - d. trajectory models showing potential movement of the already spilled oil which indicated that it threatened Ashmore Reef, and to a lesser extent Cartier Island;⁵⁰⁴
 - e. the overall protection response priorities as set out in the National Plan⁵⁰⁵ including, in particular, that habitats should be considered a higher priority than species; and

⁵⁰¹ The National Response Team supports the National Plan and consists of 63 appropriately trained personnel, nine from each state and the Northern Territory.

⁵⁰² AMSA, Submission to the Inquiry, p. 5.

⁵⁰³ Statutory Declaration of Mr Jamie Storrie, 9 April 2010, paragraph 11.

⁵⁰⁴ Modelling was undertaken by Asia Pacific Applied Science Associates (APASA).

⁵⁰⁵ That is, in order of descending priority: human health and safety; habitat and cultural resources; rare and/or endangered flora and fauna; commercial resources; and amenities (see Section 3, p. 2 of the *National Marine Oil Spill Contingency Plan*).

- f. an environmental report provided by the Western Australian Department of Environment and Conservation on 25 August 2009 highlighting the conservation values of the Kimberley coastline.

Use of oil dispersants

- 6.9. The National Plan identifies a number of alternative or complementary response options. These include surveillance, the use of dispersants, control and recovery, in-situ burning, shoreline clean-up and bioremediation. The preferred options for specific regions or locations are reflected in the OSCPs that sit under the National Plan. The OSCP for the Montara Oilfield identified the use of chemical dispersants as one of three priority treatment options, and noted that it was particularly useful when the spill was large and when the slick was moving towards sensitive areas.



Courtesy of Mark Hamilton Photography

- 6.10. While dispersants do not eliminate the problem of an oil spill, the impact on sensitive areas can be reduced because dispersants accelerate the weathering and breaking down of oil at sea. Dispersants act to move oil below the surface and into the upper five metres of the water column. Oil spill dispersants can

effectively reduce exposure of sea birds to oil as most sea birds are oiled by slicks on the surface of the sea or in near shore coastal habitats.

- 6.11. The key consideration in the case of the Blowout was, however, the judgment that it would be necessary to use dispersants to protect the sensitive areas of the Ashmore Reef and Cartier Island and, potentially, the Western Australian coast. AMSA's decision was based on a NEBA which was updated as new information came to hand. DEWHA concurred with the conclusions of the NEBA.⁵⁰⁶ The critical factors influencing the NEBA were as follows:⁵⁰⁷
- a. the response objective of protecting Ashmore Reef, and the information which informed that decision;
 - b. limitations to potential containment and recovery operations in the remote offshore environment (including effectiveness, safety concerns and time required to initiate action);
 - c. there was a limited timeframe for effective use of dispersants which were considered to be effective on 'fresh' oil only within approximately 48 hours of release;
 - d. adequate water depths in the area (dispersants should not be used in shallow waters of less than 5m depth); and
 - e. the impact of dispersants and dispersed oil on fish.
- 6.12. Dispersant operations commenced on 23 August and continued until 1 November 2009. Over this time, up to around 184,000 litres were deployed.⁵⁰⁸ Only dispersants that meet a specified minimum level of effectiveness and have a specified maximum level of acceptable toxicity to two temperate and two tropical fish species are approved for use in Australian waters.⁵⁰⁹ At present, ten oil spill dispersants have been pre-approved for use in Australia by AMSA.⁵¹⁰ All of the dispersants that were used during the response to the Blowout had pre-approval (Ardrox 6120; Corexit 9500 and 9527; Tergo R-40; and Slickgone NS and LTSW). Dispersants were selected on the basis of available

⁵⁰⁶ DEWHA 2009, *Review of Net Environment Benefit Analysis for the response to the Montara oil well release*, September 2009. Prepared for AMSA 29 September 2009, DEW.9001.0012.0392.

⁵⁰⁷ Statutory Declaration of Mr Jamie Storrie, 9 April 2010, paragraph 11.iii.

⁵⁰⁸ Letter from AMSA to the Inquiry, 27 May 2010.

⁵⁰⁹ AMSA, Submission to the Inquiry, p. 6.

⁵¹⁰ List available at:

<[http://www.amsa.gov.au/Marine Environment Protection/National plan/General Information/Dispersants Information/FAQ Oil Spills Dispersants.asp](http://www.amsa.gov.au/Marine_Environment_Protection/National_plan/General_Information/Dispersants_Information/FAQ_Oil_Spills_Dispersants.asp)>.

stocks taking into account the logistics of transporting the quantities required to support the response operation.⁵¹¹

- 6.13. Dispersants can also represent a human health hazard as they can cause eye, skin or respiratory irritation with prolonged exposure. AMSA advised the Inquiry that it took measures to ensure the health and safety of officers using dispersants as well as people on vessels and fishermen in the region (including the use of protective clothing and masks, as well as aerial surveillance).⁵¹² AMSA further stated that, given dispersant spraying aircraft were deployed very close to the water surface and were directed by an accompanying surveillance aircraft, the likelihood of dispersants hitting a non-target vessel was considered 'very low'.⁵¹³
- 6.14. A number of submissions to the Inquiry commented on AMSA's decision to use chemical dispersants as the primary response option.⁵¹⁴ The issues raised included the adequacy of the NEBA, the lack of independent environmental advice as an input to this decision, and the potential impacts of dispersants and dispersed oil on species and ecosystems including fish species, coral spawn and benthic communities.
- 6.15. During the response operation, AIMS advised AMSA that coral spawning could be expected over a five day period commencing on 11 October 2009, and recommended that oil dispersant operations should cease during this period if the results of an assessment of the benefits of applying dispersants revealed there to be only a slight benefit. AMSA's assessment was that 'the benefit being accrued through dispersant use was significant in terms of preventing more serious environmental harm',⁵¹⁵ and the decision was therefore made to continue deploying dispersants. Aircraft observers were also advised to watch for coral spawn so that operations could be adjusted as required, however none were observed.
- 6.16. There are valid concerns about the use of dispersants because of the significant impacts dispersant/oil mixes can have on subsurface organisms such as fish larvae and coral spawn. It is not always the case that dispersants

⁵¹¹ Statutory Declaration of Mr Graham Peachey, 23 February 2010, p. 3.

⁵¹² T2349-2353 (Storrie).

⁵¹³ T2390:29 (Storrie).

⁵¹⁴ See for example AIMS, Submission to the Inquiry; WWF-Australia, Submission to the Inquiry; and DEWHA, Submission to the Inquiry.

⁵¹⁵ Statutory Declaration of Mr Graham Peachey, 23 February 2010, p. 3.

should be used in open waters since they necessarily involve adding a further pollutant to the sea.

- 6.17. However, it must be acknowledged that there is no response option which will avoid all environmental impacts.

Finding 80

The Inquiry concurs with the decision that was made to use dispersants in this case given the need to avoid oil impacting on Ashmore Reef and Cartier Island and the coastline of Western Australia. The decision was consistent with information available to AMSA at the time.

Containment and recovery operations

- 6.18. AMSA undertook containment and recovery operations from 5 September until 3 December 2009. This involved two vessels working together to manoeuvre a 300m containment boom incorporating a 'skimmer' to recover oil.⁵¹⁶
- 6.19. In its submission AMSA noted that it is relatively unusual for such containment and recovery operations to be possible in open waters where even a low swell and moderate winds can make booms ineffective. The clean-up of Montara oil was facilitated by the favourable climatic conditions which allowed the recovery of 844,000 litres of oil water mixture over 35 days of operations. Of this amount, it is estimated that some 493,000 litres was oil or oil emulsion.⁵¹⁷ AMSA indicated that this represents approximately 10 per cent of the total oil spilled and is in line with international experience with such operations.⁵¹⁸
- 6.20. No recoverable oil was located after 15 November 2009. Containment and recovery vessels returned to Darwin where they remained on standby.
- 6.21. A concept of operations for shoreline clean-up of Ashmore Reef was also developed by AMSA and DEWHA. Fortunately, there was ultimately no requirement to implement this plan.⁵¹⁹

⁵¹⁶ AMSA, Submission to the Inquiry, p. 10.

⁵¹⁷ Ibid, p. 11.

⁵¹⁸ Statutory Declaration of Mr Graham Peachey, 23 February, p. 7.

⁵¹⁹ AMSA, Submission to the Inquiry, p. 11.

Finding 81

The Inquiry considers that the containment and recovery operations went well, particularly in view of the remoteness of the area. For the future, AMSA needs to work with the petroleum industry and AMOSC to assess whether more and better equipment should be on standby. Serious though this incident was, it is conceivable that spills of a much greater magnitude could occur in the future. Contingency planning, including the availability of adequate resources and equipment and how that should be deployed, needs to be based on a much worse incident than this one.

Wildlife response and ESC role

- 6.22. The wildlife response was initiated in accordance with the Incident Action Plan (IAP) approved by the Incident Controller from the first week of the Blowout. Oiled wildlife response kits were deployed by AMSA and AMOSC in accordance with the IAP. AMSA also provided information to DEWHA to assist with response planning.
- 6.23. DEWHA's role under the National Plan was initially to provide advice on relevant habitats and species. It also participated in the ICG meetings and formed the view that the oiled wildlife and environmental impact elements of the response required greater focus. This included contacting PTTEPAA regarding Scientific Monitoring.⁵²⁰
- 6.24. In addition to DEWHA and AMSA, the wildlife response involved a range of Commonwealth, state and territory agencies. These included the Australian Customs and Border Protection Service, the Northern Territory, Queensland and Western Australian Governments and the Great Barrier Reef Marine Park Authority. This assistance included the provision of equipment, wildlife response facilities, logistical support and expert response officers. A remote site stabilisation centre was established at Ashmore Island to provide primary care and triage and to rehabilitate birds. On 18 September 2009, DEWHA entered into an agreement with Western Australia to establish a joint wildlife response centre in Broome to enhance response capacity. However, there was never a sufficient number of oiled birds to warrant its use.
- 6.25. As part of the wildlife response, DEWHA commissioned a wildlife survey in the region of the oil spill. The survey was conducted between 25 September and 4 October 2009 by a team of three independent marine biologists.⁵²¹ Their

⁵²⁰ DEWHA, Supplementary Submission to the Inquiry, p. 10.

⁵²¹ Watson JEM, Joseph LN and Watson AWT 2009, *A rapid assessment of the impacts of the Montara oil leak on birds, cetaceans and marine reptiles, report to DEWHA*, October 23 2009.

purpose was to identify what species were in the region, what behaviour those species were exhibiting, and if the oil spill had resulted in any behavioural and physical impacts. The survey identified a high diversity and abundance of birds, cetaceans, sea snakes and turtles and recommended further monitoring (for a minimum of five years) to ascertain the oil spill impacts on wildlife.

- 6.26. The Blowout has raised questions about the National Plan in relation to the performance of the ESC role and the wildlife response role in Commonwealth waters. DEWHA had portfolio responsibilities for the management of Commonwealth marine areas and considered that this aspect of the overall response required greater attention.⁵²² DEWHA conducted wildlife response activities which involved a potentially significant unfunded liability since cost recovery was not assured. Cost recovery for wildlife response activities, like cost recovery for the activities of other agencies involved in response operations, depended on arrangements being agreed with PTTEPAA.
- 6.27. DEWHA did well to do what it did given the constraints it faced. DEWHA's appointment as the ESC under the National Plan on 15 September 2009 (26 days after the Blowout) came far too late. AMSA has acknowledged this delay. At the outset, the ESC role was performed by a number of AMSA officers who also had other important roles in the overall AMSA response. The 'dual role of AMSA officers resulted in a partial "vacuum" in terms of the critical issues that are normally addressed by an ESC for the first few weeks of the response'.⁵²³ The Inquiry understands that AMSA's intention is to work with DEWHA and other relevant Commonwealth agencies to amend and update the National Plan to provide clear guidance on the ESC role in Commonwealth waters and the necessary training required.
- 6.28. A further problem was that the National Plan clearly allocates responsibility for oiled wildlife response in state and territory waters to state or territory environment protection agencies and specifies that wildlife response plans be developed.⁵²⁴ However, the National Plan does not specify what arrangements should apply in remote Commonwealth waters.
- 6.29. The ESC was transferred to DEWHA on 15 September 2009 with responsibility for oiled wildlife response⁵²⁵ and advice regarding environmental impacts and

⁵²² DEWHA, Supplementary Submission to the Inquiry, p. 10.

⁵²³ Incident Analysis Team 2010, *Response to the Montara Wellhead Platform Incident*, March 2010, p. 27.

⁵²⁴ AMSA 2005, *National Marine Oil Spill Contingency Plan*, Section 2, p. 15.

⁵²⁵ Oiled wildlife response is not usually an ESC responsibility under the National Plan.

preferred response options.⁵²⁶ DEWHA submitted to the Inquiry that with this appointment it gained 'the authority to mobilise equipment and personnel to respond to affected wildlife and facilitate cost recovery processes'.⁵²⁷ The appointment also assured relevant state and territory agencies of cost recovery provisions, and strengthened DEWHA's position to negotiate Scientific Monitoring arrangements with PTTEPAA.⁵²⁸

- 6.30. Assumption of the ESC role did not overcome DEWHA's limited capacity to conduct operations in the marine environment. DEWHA's function predominantly involves policy and planning and it had no prior experience of an incident of this kind. Most service delivery functions, such as surveillance, monitoring and marine park management, are contracted to either state agencies or Australian Customs and Border Protection Command. DEWHA's commitment to the ESC role involved the use of resources in Canberra and having a liaison officer located on site. However, prior to the Blowout the officers involved had not participated in training or response exercises provided for under the National Plan.⁵²⁹

Finding 82

Given the anticipated extent of future offshore activity, arrangements for mobilisation of expertise and operational capability should be clearly established under the National Plan. In its supplementary submission DEWHA noted, and the Inquiry agrees, that it may be cost effective to have arrangements in place to utilise the operational capability of the states and territories in Commonwealth waters.⁵³⁰ The Inquiry believes that DEWHA should also investigate the scope for ensuring that its staff are equipped for response activities by participating in appropriate training activities.

Recommendation 86

The National Plan should be reviewed to clarify the arrangements to apply in Commonwealth waters regarding key roles and responsibilities, including in relation to the ESC, in the event of an oil spill. This should also address any necessary training required.

⁵²⁶ DEWHA, Supplementary Submission to the Inquiry, Attachment B: email correspondence between DEWHA and AMSA dated 14 and 15 September 2009 confirming transfer of ESC role including oiled wildlife response.

⁵²⁷ DEWHA, Submission to the Inquiry, p. 23.

⁵²⁸ DEWHA, Supplementary Submission to the Inquiry, pp. 10-11.

⁵²⁹ Ibid, p. 11.

⁵³⁰ Ibid, p. 13.

Recommendation 87

DEWHA should participate in training programs and exercises relevant to an oil spill in the marine environment.

Monitoring

- 6.31. Under the National Plan two types of monitoring can be undertaken in response to an oil spill: Operational Monitoring and Scientific Monitoring.⁵³¹ Operational Monitoring provides information of direct relevance to spill response operations, that is, information specifically needed to plan and execute response or clean-up strategies. Scientific Monitoring relates to non-operational issues and includes short-term environmental damage assessments, longer term damage assessments (including recovery), and all post spill monitoring activities.
- 6.32. The National Plan draws a distinction between the two types of monitoring on the basis of cost recovery arrangements. Reimbursement of costs and expenditure on monitoring by AMSA is limited to Operational Monitoring alone. This distinction arises from international arrangements for compensation concerning the shipping industry.⁵³²
- 6.33. Both Operational Monitoring and Scientific Monitoring programs were initiated during the response operation. AMSA immediately initiated an Operational Monitoring program on 21 August 2009 in accordance with its responsibilities as the Combat Agency for the response operation.⁵³³ The objectives were to understand the physical and chemical characteristics of the oil, to determine the movement and fate of the oil, to assess whether the response operations were effective, and to evaluate the immediate effects on the environment. The monitoring included trajectory modelling, aerial and vessel surveillance, shoreline surveys, the collection and analysis of oil samples, use of satellite imagery and tracking buoys, water sampling, fluorometry analysis, and biopsies of dead fauna.
- 6.34. The Operational Monitoring program was designed specifically to support decisions required as part of the response operation rather than to assist with environmental damage assessment. The water quality sampling that was

⁵³¹ AMSA 2003, *Oil Spill Monitoring Handbook*, prepared by Wardrop Consulting and Cawthron Institute for AMSA and MSA, published by AMSA, Canberra:
<http://www.amsa.gov.au/marine_environment_protection/national_plan/Contingency_Plans_and_Management/Research_Development_and_Technology/Oil_Spill_Monitoring_Handbook.pdf>.

⁵³² See, for example, the *International Convention on Civil Liability for Oil Pollution Damage*, and the International Oil Pollution Compensation Funds.

⁵³³ AMSA, Submission to the Inquiry, p. 18.

undertaken may have met operational requirements but it was not adequate for environmental purposes. It did not produce adequate information about the horizontal and vertical distribution of oil and dispersants that was important to understanding the impact of the oil spill on wildlife and ecosystems.⁵³⁴

- 6.35. Arrangements for long term Scientific Monitoring were not agreed until 49 days into the response operation, although DEWHA had raised the need for long term environmental monitoring with PTTEPAA on the third day and PTTEPAA provided a draft monitoring plan on the 13th day. This situation arose because the OSCP did not require provision to be made for Scientific Monitoring, DEWHA was not initially allocated the ESC role, and the National Plan did not provide for cost recovery of such monitoring. Furthermore, DEWHA had no recourse under the EPBC Act to require PTTEPAA to undertake monitoring.⁵³⁵ It was therefore necessary to establish arrangements for Scientific Monitoring through negotiation between DEWHA and PTTEPAA as well as through broader consultation with relevant experts.
- 6.36. A Memorandum of Understanding (MoU) signed on 9 October 2009 established the *Monitoring Plan for the Montara Well Release Timor Sea* (the Monitoring Plan).⁵³⁶ The MoU set out decision-making arrangements for the Monitoring Plan and indicated that all studies would be funded by the company.⁵³⁷ PTTEPAA is to be commended for its cooperation in relation to the Monitoring Plan and its decision to fund all Scientific Monitoring studies.
- 6.37. The Monitoring Plan refers to five Operational Monitoring studies undertaken by AMSA and seven Scientific Monitoring studies. If triggered, the Scientific Monitoring studies may result in impact monitoring for up to eight years. The activation triggers for the implementation of these studies were to be informed by the results of Operational Monitoring. Nearly all of these studies have been triggered or commenced by agreement.

⁵³⁴ DEWHA, Submission to the Inquiry, pp. 50-51.

⁵³⁵ This was because a requirement to undertake Scientific Monitoring in the event of an oil spill was not included as a condition of approval under the EPBC Act. Nor was there a requirement for Scientific Monitoring included in the approval obtained under the OPGGS Act and subordinate regulations. This is addressed later in this Chapter under the heading 'The Regulatory Framework for Environment Protection'.

⁵³⁶ Wardrop Consulting 2009, *Monitoring Plan for the Montara Well Release Timor Sea*, as agreed between PTTEPAA and DEWHA, October 9th 2009:
<<http://www.environment.gov.au/coasts/publications/pubs/montara-monitoring-plan.pdf>>.

⁵³⁷ Memorandum of Understanding for Environmental Monitoring Programme to be conducted following blowout of Montara H1 well on 21 August 2009, between PTTEP and DEWHA, signed 9 October 2009.

- 6.38. The Monitoring Plan was the subject of consultation and peer-review involving a number of stakeholders and experts, including the Western Australian and Northern Territory Governments, AFMA, AIMS and CSIRO. DEWHA also established a Technical Advisory Group to assist in the development and implementation of the Monitoring Plan.
- 6.39. In view of the time needed to negotiate the arrangement and to consult with the various relevant experts, DEWHA considered that the Monitoring Plan could not have been developed more rapidly.⁵³⁸ That might have been the practical reality; however, the Inquiry is concerned about the shortcomings in the National Plan, and the broader environmental regulatory framework, in relation to powers and funding, which resulted in a delay in the commencement of the Monitoring Plan.

Finding 83

In the Inquiry's view, the prolonged delay in undertaking Scientific Monitoring of the impact of the oil spill was unacceptable. The delay has restricted the scope for assessment of the environmental damage from the Blowout. DEWHA's response should not have been dependant on PTTEPAA's willingness to cooperate and fund the Monitoring Plan.

- 6.40. This view was reflected in a number of submissions received by the Inquiry. For example, AIMS noted that 'sampling of fish from the commercial fishery for the presence of hydrocarbons has still not occurred as of mid December 2009, 18 weeks after the uncontrolled release and seven weeks after the uncontrolled release was stopped. The most appropriate time-frame would have been during the uncontrolled release'.⁵³⁹ AIMS considered that the ultimate cause of the delayed Scientific Monitoring response was related to a deficiency in Australian national laws and international maritime conventions regarding natural resource damage assessment from spills from rigs.⁵⁴⁰ AIMS also noted that Australia currently does not have legislation that requires ecological damages to be assessed and that there is no statutory basis for compensation to be claimed for environmental damage assessment. DEWHA stated that the National Plan does not adequately provide for the coordination of, or resourcing for, short-term and long-term Scientific Monitoring.⁵⁴¹

⁵³⁸ DEWHA, Supplementary Submission to the Inquiry, p. 19.

⁵³⁹ AIMS, Submission to the Inquiry, p. 6.

⁵⁴⁰ Ibid, p. 8.

⁵⁴¹ DEWHA, Supplementary submission to the Inquiry, p. 12.

- 6.41. A number of submissions raised concerns about the adequacy of monitoring on other grounds.⁵⁴² In relation to the Operational Monitoring component of the Monitoring Plan, these included concerns about the adequacy of water sampling, a general lack of scientific rigour, delays in releasing monitoring results, access to these results, the inadequacy of linkages between Operational Monitoring and Scientific Monitoring, and the limited value of results from an environmental assessment perspective.
- 6.42. In relation to the Scientific Monitoring, issues were raised about the use of ‘triggers’ for the implementation of various studies. Under the Monitoring Plan the commencement of Scientific Monitoring is largely dependent on the breaching of environmental ‘triggers’, which are in turn to be informed by the results of Operational Monitoring. PTTEPAA has informed the Inquiry that it was necessary to incorporate triggers so that monitoring resources could be best directed on the basis of risk and need. However, this framework was criticised because it created further delays in the commencement of Scientific Monitoring studies while results were produced and agreement was reached about whether a trigger had been met. It also means that there is no certainty that all components of the program will be conducted. Concerns were also raised about a potential conflict of interest that might arise for PTTEPAA given its involvement in the design and implementation of the Scientific Monitoring and the reporting of results.
- 6.43. Most of the issues identified in relation to the Monitoring Plan are attributable to the haste with which it had to be put together and the lack of any prior commitment to Scientific Monitoring in the event of an oil spill. The Inquiry’s recommendations in relation to changes to the regulatory framework to establish obligations for companies involved in an incident would obviate much of the problem in the future.⁵⁴³ The Inquiry also considers that it may still be worthwhile to have the Monitoring Plan peer reviewed to see if there are likely to be net benefits from making changes to it and to inform any response to a future incident.
- 6.44. Implementation of the Inquiry’s recommendations would give the environmental regulator control of the content and timing of Scientific Monitoring. This would then remove any basis for concerns in relation to

⁵⁴² See for example, Submissions to the Inquiry from University of Western Australia, AIMS, WWF-Australia, and DEWHA.

⁵⁴³ This is addressed later in this Chapter under the heading ‘The Regulatory Framework for Environment Protection’.

potential conflicts of interest for owner/operators, but it would not prevent them from being consulted about monitoring arrangements.

- 6.45. A better integration of Operational and Scientific Monitoring is needed in the event of an oil spill. This could be facilitated through better preparatory work. More attention should be given to the content of the OSCPs (required as a condition of approval under both the EPBC Act and the MOE Regulations) to ensure they incorporate monitoring requirements. This should include liaison between the owner/operators and AMSA to ensure consistency of proposed OSCPs with the National Plan. The significance of promptly implementing Scientific Monitoring should be reflected in the National Plan. There may also be scope, consistent with the Marine Bioregional Planning processes led by DEWHA and currently underway for all Commonwealth waters, to improve the availability on a regional basis of data that would inform a monitoring program, particularly in environmentally sensitive areas and areas of interest to offshore petroleum drilling and production. Monitoring programs should be peer reviewed; they should be publicly available; and the outcomes of monitoring programs following a blowout need to be reported publicly, including drawing together the threads from the various components.
- 6.46. The Inquiry supports the removal of the distinction between the funding of Operational and Scientific Monitoring in the National Plan. However, the Inquiry notes that this may be constrained by existing arrangements relating to oil spills from tankers which have been established under international conventions. The Claims Manual of the International Oil Pollution Compensation Fund 1992 provides that contributions may be paid for the costs of post-spill studies to establish the nature and extent of environmental damage caused by an oil spill and to determine whether or not reinstatement measures are necessary and feasible.⁵⁴⁴ However, these arrangements do not extend to oil spills from offshore petroleum developments. If the funding distinction cannot be resolved in the context of the National Plan, implementation of the Inquiry's recommendations in relation to the regulatory framework would still provide a sufficient basis for compelling an owner/operator to bear the costs of Scientific Monitoring in Commonwealth waters.⁵⁴⁵

⁵⁴⁴ *Claims Manual of the International Oil Pollution Compensation Fund 1992*, December 2008 Edition, pp. 13, 35-37.

⁵⁴⁵ This is addressed later in this Chapter under the heading 'The Regulatory Framework for Environment Protection'.

6.47. The Inquiry sees value in DEWHA, working with AMSA and experts in the field, to develop ‘off the shelf’ environmental monitoring programs. These should be designed to reflect the different circumstances that are likely to govern response activities in Commonwealth waters (for example, difficulties that might arise from differences between temperate and tropical waters, different environmental features, and the likely characteristics of hydrocarbons in different regions). This analysis should be subject to expert peer review. The objective of this suggested approach would be to create plans that can be readily adapted and speedily implemented to meet the needs of a particular event.

Recommendation 88

The National Plan should be revised to ensure that it fully comprehends environmental matters and that it recognises the importance of the prompt implementation of Scientific Monitoring to facilitate the assessment of the environmental impacts of an incident.

Recommendation 89

Procedures for the approval of development projects should ensure that conditions of approval are comprehensive and clearly set out the obligations of their proponents in relation to environmental matters (including expected monitoring and remediation obligations).

Recommendation 90

DEWHA, in concert with AMSA and with expert input, should develop ‘off the shelf’ monitoring programs that can be speedily implemented following incidents in Commonwealth waters. In this context, the utility of the current Scientific Monitoring program should be peer reviewed to inform future policy.

Funding arrangements under the National Plan

6.48. The National Plan is funded by levies (Protection of the Sea Levy or **PSL**) on the shipping industry, which are prescribed in the *Protection of the Sea (Shipping Levy) Act 1981* and the *Protection of the Sea (Shipping Levy Collection) Act 1981*. The PSL is related to the prevention of, and the response to, ship-sourced pollution. There is no statutory provision for a similar levy on the offshore petroleum industry.

6.49. The IGA provides that the funding of National Plan obligations in relation to both preparedness to respond to an incident and to any response to an incident should be guided by the polluter pays principle.⁵⁴⁶ Under the National Plan,

⁵⁴⁶ See Paragraph 21 of Appendix 1 to the *National Marine Oil Spill Contingency Plan*.

AMSA will reimburse the reasonable costs incurred by a Statutory Agency or Combat Agency and other assisting authorities and will then seek to recover these costs from the polluter.⁵⁴⁷

- 6.50. The DA has the power under the OPGGS Act to direct a title holder to clean-up or remediate the effects of an escape of petroleum.⁵⁴⁸ However, the Inquiry has seen no evidence to suggest that use of this power was considered by the NT DoR following the Blowout.
- 6.51. As the PSL is related to ship-sourced pollution, AMSA immediately sought and received written confirmation from PTTEPAA that it would be responsible for all costs in relation to the Montara oil spill response.⁵⁴⁹ PTTEPAA is to be commended for its cooperation in this matter; its response was both timely and appropriate. However, it should not be necessary for the Combat Agency to explore the availability of funding on a case by case basis especially when a rapid response to an incident may be required.
- 6.52. It is desirable that, consistent with the principles stated in the IGA, statutory arrangements be put in place now to ensure that the costs of any incident in Commonwealth waters that is dealt with under the National Plan are paid for by the polluter, whether that be the operator of a ship or of an offshore petroleum installation. This would make the position clear at the outset for the companies involved in any incident, their insurers, the Combat Agency, the Statutory Agency and the public.
- 6.53. The gap in funding for the National Plan is addressed, to some extent, by the arrangements that have been put in place between AMSA and industry organisations such as AMOSC and OSR. While these arrangements are laudable they are voluntary and do not encompass all industry players. They rely on the goodwill and willingness of the petroleum industry to be involved.
- 6.54. Consideration needs to be given to whether this kind of arrangement is sufficient for dealing with the risk of an oil spill from the offshore petroleum sector. The Montara incident analysis undertaken under the National Plan recommended that the offshore petroleum industry (including AMOSC) should

⁵⁴⁷ See paragraph 23 of Schedule 1 of Appendix 1 to the *National Marine Oil Spill Contingency Plan*.

⁵⁴⁸ See ss 574(2) and 782(1) of the OPGGS Act.

⁵⁴⁹ AMSA, Submission to the Inquiry, p. 22.

be more heavily relied upon to provide leadership and resources in the event of a spill from an offshore petroleum facility.⁵⁵⁰

- 6.55. In addition to ensuring funding is available for the response to an offshore incident, the Inquiry considers that statutory arrangements should be put in place to require a direct contribution by the offshore petroleum industry to the costs of maintaining Australia's national pollution response capability under the National Plan framework. This requires funding for preparedness arrangements under the National Plan be contributed on the basis that costs are equitably shared between the shipping and offshore petroleum sectors, taking into account the risks associated with each sector and existing contributions.

Recommendation 91

The funding arrangements that support the National Plan should be reviewed to ensure that the costs associated with both preparedness and response capability are equitably shared between the shipping and offshore petroleum industries.

Recommendation 92

The National Plan should specify that the cost of responding to an oil spill, or other damage to the offshore marine environment, will be totally met by the owner/operator. This would be consistent with the Inquiry's recommendation for legislative changes to the regulatory framework concerning owner/operators meeting the cost of monitoring and remediation of environmental damage.

Implications for the National Plan Framework

- 6.56. Despite the apparent success of the response operation, the Blowout has highlighted a number of questions about Australia's oil spill response framework.
- 6.57. The National Plan did not envisage an oil spill of the magnitude and duration of the Blowout from a remote offshore platform. This was the first time that Australia had to respond to a significant oil spill so far offshore and for such a length of time.
- 6.58. The unprecedented nature, scale and remote location of the incident severely tested AMSA's resources along with those of others involved in the response.⁵⁵¹ Had a response been required beyond 3 December 2009 it would have seriously challenged Australia's capacity to sustain its response effort. The Inquiry

⁵⁵⁰ Incident Analysis Team, Response to the Montara Wellhead Platform Incident, p. 34.

⁵⁵¹ AMSA, Submission to the Inquiry, p. 8.

considers that, overall, AMSA performed very well in responding to an unusual and taxing incident.

- 6.59. AMSA has concluded that the National Plan provides an adequate framework that can be adapted effectively to cope with differing events, particularly given arrangements for additional resourcing and assistance through formal agreement with the oil industry and in accordance with the *International Convention on Oil Pollution Preparedness, Response and Cooperation*.⁵⁵²
- 6.60. Nevertheless, the expansion of the offshore petroleum industry that is in prospect will be accompanied by an increase in environmental risks. It would be prudent to revisit the risk assessment that underlies the preparedness arrangements of the National Plan to ensure adequate preparation for future incidents of this nature. AMSA, together with AMOSC, should continue to review the state of readiness of equipment and other relevant resources with a view to the likely expansion of the industry in future years. Further, while this spill was a significant one, it could have been larger and more challenging. Future planning should take into account what is needed to deal with the consequences of a far bigger blowout, potentially of heavier crudes and with reef and shoreline systems at risk. It should also address the implications for the National Plan arrangements if the source of an emergency were to be in Commonwealth waters, or an adjacent state or territory, but the impacts were likely to be felt in another state or territory.
- 6.61. The IGA provides the basis for access to equipment and dispersant stockpiles in the case of an oil spill. These arrangements are supported by state, local and industry OSCP. An OSCP was in place for the Montara Oilfield consistent with this requirement, but the plan was reportedly of limited value in the response operations and was not relied upon by AMSA.⁵⁵³

Recommendation 93

The National Plan should be reviewed:

- a. to ensure that it adequately addresses the risks associated with offshore oil and gas exploration;**
- b. to revisit the underlying risk assessment undertaken to inform capacity and preparedness under the National Plan;**

⁵⁵² Ibid, p. 9.

⁵⁵³ Statutory Declaration of Mr Graham Peachey, 23 February 2010, p. 10.

- c. **to ensure that response operations can be coordinated effectively with state and territory arrangements where a response requires operations across Commonwealth and state or territory borders; and**
- d. **to explore the state of readiness of equipment and resources in the context of the future expansion of the petroleum industry. This should be undertaken by AMSA in consultation with AMOSC.**

Environmental Impact

- 6.62. Offshore oil spills can have widespread and long-term environmental consequences, including mortality or long-term impacts on marine life and birds, and damage to marine and shoreline habitats and ecosystems, with consequences for other species and public amenity (let alone the commercial consequences).
- 6.63. While the Blowout was substantial and sustained, impacts on the Ashmore Reef National Nature Reserve, the Cartier Island Marine Reserve, or the Kimberley coast of Western Australia were largely avoided. This reflected both the effort made in the response operation and other factors including the remoteness of the Montara WHP and favourable currents and climatic conditions.
- 6.64. It is unlikely that the actual impact of the Blowout on wildlife and the environment will ever be known. There is little evidence that the Inquiry can draw on to illustrate the consequences. This does not mean that they are not real or substantial. Rather, the area is vast and remote and there is no firm data available against which pre and post spill comparisons can be made. Ongoing and long-term Scientific Monitoring may assist in getting a better understanding of the extent of the consequences, although this is doubtful in part because the monitoring was delayed in its formulation and implementation.
- 6.65. In an era of growth in the offshore petroleum sector in Australia, the Blowout provides an important reminder of the very real environmental risks that accompany the substantial economic benefits from this development. It underlines the need for a more effective environmental regulatory structure bearing on well integrity issues, backed by an emergency response framework that will ensure that environment protection and sustainable development objectives can be achieved. This episode has revealed a number of major deficiencies in Australia's environmental regulatory regime and oil spill response arrangements that should be addressed with a view to improving Australia's capacity to respond to any future offshore oil spills.

The North-west Marine Environment

- 6.66. The Montara Oilfield is located in remote Commonwealth waters within the North-west Marine Region. The region has a rich marine environment which supports a number of commercial, recreational and indigenous fisheries.
- 6.67. DEWHA is currently preparing the North-west Region Marine Bioregional Plan, which is expected to be released this year. It will identify key habitats, flora and fauna, natural processes, human uses and benefits, and threats to the long-term ecological sustainability of the region. DEWHA released a *North-west Bioregional Profile* in 2008 to bring together the best available information for the region,⁵⁵⁴ but there will remain gaps in baseline survey data for many species and ecosystems in the region, which will only be practical to fill over time.⁵⁵⁵
- 6.68. The Montara Oilfield is in relatively shallow waters that include a large area of continental shelf and continental slope. Water depths at the Montara Oilfield vary from around 70 to 80m. The region experiences highly variable tidal regimes and seasonal cyclones, and is influenced by a complex system of ocean currents that generally result in warm and nutrient-poor surface waters of low salinity. The most ecologically productive offshore areas in the Timor Sea are those associated with coral reefs, and shallow (10-30m) banks or shoals.
- 6.69. The reefs and islands of the region include a range of important ecological communities, including those of Ashmore, Cartier, Scott and Seringapatam Reefs. Ashmore Reef (145km north-west of the Montara Oilfield) and Cartier Island (95km west of the Montara Oilfield) are Commonwealth marine reserves and as such have been relatively well-studied. The Ashmore Reef National Nature Reserve is also listed as a Ramsar⁵⁵⁶ site of international significance and protected under Commonwealth environment legislation. Ashmore Reef has a known fauna of 250 species of corals, 545 fish, 406 molluscs, and 175 echinoderms.⁵⁵⁷
- 6.70. The reefs and islands are a significant breeding area for green turtles and support significant feeding populations of loggerhead turtles and hawksbill

⁵⁵⁴ DEWHA 2008, *North-west Marine Bioregional Plan, Bioregional Profile*, <www.environment.gov.au/coasts/mbp/publications/north-west/bioregional-profile.html>.

⁵⁵⁵ Even for the relatively intensively studied and much used Great Barrier Reef Marine Park of Queensland, there are major knowledge gaps in terms of species and ecosystems.

⁵⁵⁶ See the Convention on Wetlands (Ramsar, Iran 1971), known as the Ramsar Convention.

⁵⁵⁷ URS Australia Pty Ltd 2003, *Montara Field Development Preliminary Information*, p. 22.

turtles. Ashmore Reef has a high coverage of seagrass that supports a small dugong population that breeds and feeds around the reef. Ashmore Reef is also internationally recognised for its abundance and diversity of sea snakes.⁵⁵⁸

- 6.71. Both Ashmore Reef and Cartier Island are important for migratory shorebirds and support significant seabird colonies. Many of the species are listed under international conventions and are protected by Commonwealth legislation.
- 6.72. Coral reefs and surrounding waters in the region support a high biomass of fish species. A number of shoals are located in all directions around the Montara Oilfield and peak at 10-15m below the sea surface, the closest being the Vulcan Shoal approximately 30km to the south-west. These areas are thought to be associated with higher levels of species diversity and abundance but this is not well documented.
- 6.73. The Kimberley coast is located approximately 250km south of the Montara Oilfield and is an important food source for many marine species.⁵⁵⁹ Winter and spring calving grounds for humpback whales are located in Camden Sound, and whales are regularly seen up to 50km offshore.⁵⁶⁰ Adele Island is an important breeding ground for migratory birds. Coastal mangroves, seagrasses and algal mats also provide important animal habitats.
- 6.74. In addition to oil and gas exploration, the North-west Marine Region and adjacent coastal areas support a number of industries and activities including ports, shipping, commercial and recreational fishing, pearling and aquaculture, marine tourism, salt production, agriculture, and defence-related activities.⁵⁶¹ The remote and pristine Kimberley region is rapidly becoming a popular tourism destination and tourists are also travelling more frequently out to isolated coral atolls for fishing and diving, including Scott Reef, Seringapatam Reef, Ashmore Reef and Cartier Island.⁵⁶²

The extent of the pollution

- 6.75. The Blowout began on 21 August 2009 and continued unabated for 74 days (or nearly 11 weeks) until 3 November 2009.

⁵⁵⁸ DEWHA, *North-west Marine Bioregional Plan, Bioregional Profile*, p. 41.

⁵⁵⁹ DEWHA, *North-west Marine Bioregional Plan, Bioregional Profile*, p. 34.

⁵⁶⁰ URS Australia Pty Ltd, *Montara Field Development Preliminary Information*, p. 21; DEWHA, *North-west Marine Bioregional Plan, Bioregional Profile*, p. 34.

⁵⁶¹ DEWHA, *North-west Marine Bioregional Plan, Bioregional Profile*, p. 112.

⁵⁶² *Ibid*, p. 131.



Courtesy of PTTEPAA

- 6.76. On 21 August 2009 PTTEPAA advised AMSA that the volume of the oil spilling as a result of the Blowout might be between 200 to 400 barrels per day.⁵⁶³ The worst case scenario of 400 barrels per day was then used for the purpose of initial response planning. This would equate to a total volume of approximately 29,600 barrels over the 74 days of the Blowout.
- 6.77. In evidence given during the Inquiry's public hearing, Mr Jacob of PTTEPAA advised that the initial release of oil could have been as high as 1000 to 1500 barrels per day.⁵⁶⁴ It is possible that the total volume may therefore have been much higher than initially estimated by PTTEPAA.
- 6.78. If the total volume of oil released was around 29,600 barrels, it would establish the Blowout as the largest spill from an offshore oil platform, and the third largest spill by volume in Australia's history.⁵⁶⁵

⁵⁶³ Statutory Declaration of Mr Jamie Storrie, 9 April 2010, paragraph 29.

⁵⁶⁴ T1922:34-35 (Jacob).

⁵⁶⁵ A total volume of 29,600 barrels of Montara oil equates to approximately 4,736 tonnes. The *Kirki* spilled 17,280 tonnes in 1991 and the *Princess Anne Marie* spilled 14,800 tonnes in 1975 (see http://www.amsa.gov.au/marine_environment_protection/major_oil_spills_in_australia/).

- 6.79. In his evidence to the Inquiry, Mr Storrie of AMSA stated that he tried to verify the estimate of 400 barrels per day.⁵⁶⁶ In doing so, Mr Storrie relied on observation of the colour, spatial extent and percentage cover within the spatial extent. As a result of this assessment AMSA did not consider, given the possible margin for error, that it was necessary to revise the estimate of 400 barrels per day. AMSA's focus was on the need for information to guide the clean-up operation.
- 6.80. It appears that no further attempt was made to produce a more accurate estimate of the rate of the release of oil, despite the availability of techniques that might be used for this purpose.⁵⁶⁷ There was no improvement over the duration of the incident in the information provided about the amount of the release of oil. Better information could have aided the public and Government in understanding the scale of potential environmental impacts from the incident.
- 6.81. The calm weather conditions experienced at the time of the Blowout meant that the movement of the oil and oil residues was driven by currents rather than wind. In its submission, AMSA noted that the westerly Indonesian Throughflow ocean current acted as a barrier to the north of the affected area and a combination of distance and current prevented any oil from reaching the Kimberley coastline.⁵⁶⁸
- 6.82. AMSA also stated that most of the oil remained within 35km of the Montara WHP, with patches of sheen and weathered oil carried further away as climatic conditions varied over the period of the Blowout. Sheen and weathered oil was observed in Indonesia's EEZ in September 2009, reaching to within 94km of the island of Palau Roti.⁵⁶⁹ Some weathered oil was also observed in the Joint Petroleum Development Area established by the 2002 Timor Sea Treaty between Australia and Timor Leste.
- 6.83. Reports of the extent of surface pollution at the time and immediately after the Blowout ranged from around 6,000 km² to around 25,000 km².⁵⁷⁰ The full

⁵⁶⁶ T2384-88 (Storrie).

⁵⁶⁷ For example, see the work undertaken by the US National Incident Command's Flow Rate Technical Group established to develop an independent, preliminary estimate of the amount of oil flowing from the leaking oil well in the Gulf of Mexico (*Deepwater Horizon* blowout).

⁵⁶⁸ AMSA, Submission to the Inquiry, p. 12.

⁵⁶⁹ *Ibid*, p. 13.

⁵⁷⁰ AES 2009, *Biodiversity Survey of the Montara Field Oil Leak, Report for WWF, 22 October 2009*; Nuka, *Montara Oil Spill Inquiry Analysis*.

extent of the area in which patches of oil or sheen were observed is shown in **Chart 1** below. **Chart 1** provides a graphic representation of the area prepared for the Inquiry by AMSA.⁵⁷¹ It does not represent the extent of any actual oil slick seen during the oil spill; rather, it shows the area in which isolated patches of oil and sheen were seen by aerial surveillance aircraft at various times during the period between 21 August and 25 November 2009. **Chart 2** compares the observed extent of the oil with modelling of the possible extent of the oil spread in the absence of any response. Based on **Chart 1**, it is estimated that the total area across which patches of sheen or weathered oil products from the Blowout were observed could have been as large as 90,000 km².

- 6.84. Although water sampling was undertaken, this was primarily directed at operational matters associated with the clean-up. It was not directed at establishing, for example, the extent of the spread of the oil/dispersant mix, which affects mainly the five metres of the water column below the surface. Targeted water sampling as part of the Scientific Monitoring arrangements (which were too late in any event) would have also assisted in gaining a better understanding of the impacts of hydrocarbons and dispersants, especially on sub-surface ecosystems, including fish larvae and coral spawn.

Finding 84

The Inquiry has not seen data that indicated the distribution of the oil and dispersant mix beneath the sea surface. This is a major shortcoming of the response. There should have been a thorough sub-surface sampling of the oil/dispersant mix. This was important to inform judgements about the environmental consequences of the Blowout.

⁵⁷¹ Attachment to Statutory Declaration of Mr Jamie Storrie, 9 April 2010.

ANNEX A1 Montara Well Observed Oil Extent - Montara Well Head Incident



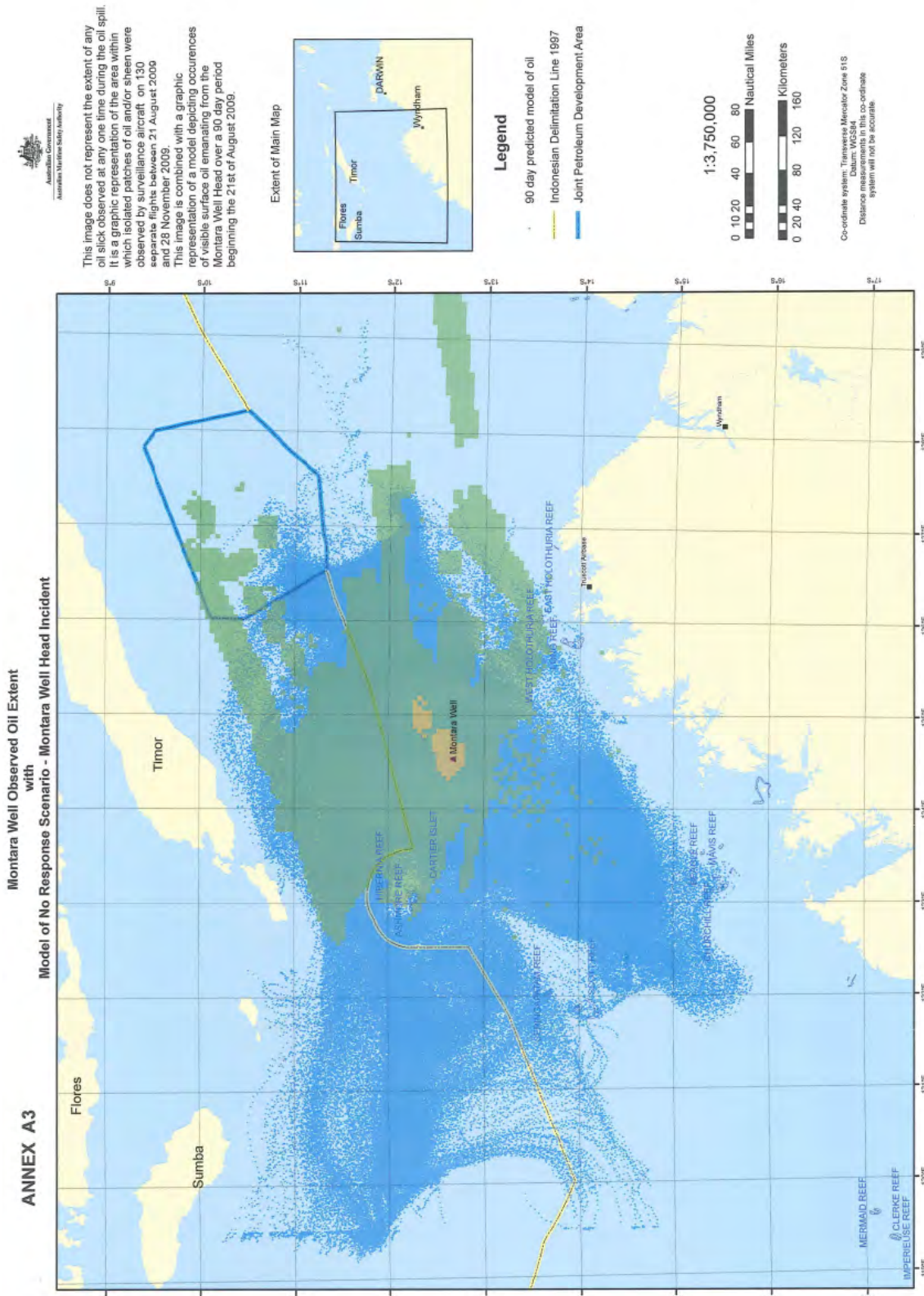
This image does not represent the extent of any oil slick observed at any one time during the oil spill. It is a graphic representation of the area within which isolated patches of oil and/or sheen were observed by surveillance aircraft on 130 separate flights between 21 August 2009 and 28 November 2009.



Chart 1 – Observed Extent of Oil

Source: Statutory Declaration of Mr Jamie Storrie, 9 April 2010

Chart 2 – Observed Extent of Oil (Green) and Predicted Extent of Oil with Nil Response (Blue)



Source: Statutory Declaration of Mr Jamie Storrie, 9 April 2010

- 6.85. The information in **Chart 1** could only be compiled after the response ended in December 2009. However, it was not available to the Inquiry, and to the public, until April 2010. Information about the spread of the oil, as with information about the volume of the spill, should have been available much earlier. During the period of the response there should have been regular and authoritative updates of information in view of the public interest in the issue. This is a matter that should, in the Inquiry's view, be taken up in the context of reviewing arrangements for the handling of future incidents.

Finding 85

Estimation of the volume and spread of the oil should be undertaken by the Combat Agency (bearing in mind that the Combat Agency must have access to this information, and confidence in it, to plan response operations). The responsibility for informing the public about the volume and extent of an oil spill should also be clearly established. This should rest with the body which, as the Inquiry recommends in Chapter 5, should undertake the central coordination and facilitation role, including the provision of information to the public through an authoritative and easy to access source.

Recommendation 94

Procedures and accountabilities should be established to ensure, in the event of a future incident, that:

- a. there is adequate monitoring of the volume of oil spilt and the spread of the oil (both surface and sub-surface dispersed oil); and**
- b. information about the volume and spread of the oil is made available to the public through regular updates.**

Environmental effects

- 6.86. It is apparent that the response strategy of preventing oil from impacting on sensitive marine resources, particularly Ashmore Reef, Cartier Island and the Kimberley coast of Western Australia, was largely achieved. AMSA provided the Inquiry with an estimate of the possible spread of the surface oil had no response operation been undertaken (see Chart 2 above). Comparison of this with Chart 1 provides some indication of the effect of the response operation in reducing the total extent of the oil slick.
- 6.87. The extent of the pollution was nevertheless significant. Both oil and oil dispersants can have a toxic effect on sea birds, marine mammals and other megafauna, corals, coral larvae, and fish larvae, affecting photosynthesis, respiration and reproduction. It is not possible to draw any firm conclusions at this stage about the damage caused by the oil and the dispersants used to break the oil down in the marine environment. Adequate data is not available.

- 6.88. Some information was provided as a result of the Operational Monitoring undertaken to inform the clean-up operations during the response to the Blowout and preliminary wildlife surveys commissioned by DEWHA and WWF-Australia.
- 6.89. Information in the submissions made to the Inquiry by PTTEPAA⁵⁷² and DEWHA⁵⁷³ provide a brief summary of the observed wildlife toll from the Blowout. However, these observations have provided only partial data about wildlife fatalities. Animals that may have died in oil affected water may not have stayed afloat for very long, making it unlikely that they could be detected in large numbers in the vast area of open water over which the oil and oil residue was dispersed.
- 6.90. The impact of the Blowout on less visible but more delicate organisms, such as coral spawn and fish larvae, may be profound but may not become apparent for some years, if at all.
- 6.91. Further assessment will be assisted by the results of the Scientific Monitoring studies. Ongoing Scientific Monitoring is required to understand the impacts of the Blowout. This was supported by a number of the submissions to the Inquiry, including those by AIMS, the University of Western Australia and DEWHA, as well as the authors of preliminary reports commissioned by AMSA and DEWHA.⁵⁷⁴

Finding 86

Despite ongoing monitoring, it is unlikely that the full extent of environmental damage from the Montara oil spill will ever be established. The ability to detect environmental damage is generally greater during a blowout than after the flow has been stopped and

⁵⁷² PTTEPAA, Submission to the Inquiry, Term of Reference 7, pp. 10-11.

⁵⁷³ DEWHA, Submission to the Inquiry, p. 25.

⁵⁷⁴ Gagnon MM 2009, *Report on biopsy collections from specimens collected from the surrounds of the West Atlas oil leak - Fish specimens*. Curtin University of Technology, 29 September 2009: <<http://www.environment.gov.au/coasts/publications/pubs/montara-fish-report.pdf>>; and Watson, et al, *A rapid assessment of the impacts of the Montara oil leak on birds, cetaceans and marine reptiles*.

⁵⁷⁵ AIMS, Submission to the Inquiry, p. 6.

The regulatory framework for environment protection

- 6.92. The regulatory framework for the management of the marine environment reflects Australia's federal system, with powers shared between the Commonwealth and the state and Northern Territory governments. As discussed in Chapter 4, in accordance with the Offshore Constitutional Settlement of 1979, the states and the Northern Territory are responsible for coastal waters within three nautical miles of the territorial sea. The Commonwealth is responsible for the offshore marine area between the territorial sea and 200 nautical miles from the coast.
- 6.93. Until the 1970s the Commonwealth had no comprehensive system for the protection of the environment and regulation of most environmental matters was undertaken by the states and territories. Since that time, the Commonwealth's role as an environmental regulator has been defined in national environmental law. The national legislative framework was designed to operate alongside state and territory legislation. As the Montara Oilfield is located in Commonwealth waters it is regulated solely under Commonwealth environmental protection legislation, in particular under the EPBC Act, the OPGGS Act, and the MOE Regulations.⁵⁷⁶

Approval of the development of the Montara Oilfield under the EPBC Act

- 6.94. The EPBC Act is the Commonwealth's premier environmental legislation and provides for the protection and conservation of matters of NES, including listed threatened species and communities, listed migratory species, World Heritage Properties, Ramsar wetlands, and the Commonwealth marine environment. By focusing on matters of NES, the EPBC Act attempts to minimise duplication with concurrent state/territory environmental legislation. The EPBC Act sets out a regulatory framework for environmental assessment of actions that have, will have or are likely to have a significant impact on a matter of NES.⁵⁷⁷
- 6.95. The Minister for the Environment determined that the development of the Montara Oilfield would be a controlled action pursuant to s 75 of the EPBC Act on 29 August 2002. The controlling provision for the action was stated to be the Commonwealth marine environment (ss 23 and 24A). The action did not trigger the controlling provisions for listed threatened or migratory species, the Ashmore Reef National Nature Reserve Ramsar site, or Commonwealth land

⁵⁷⁶ Recently amended and renamed the *Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009*.

⁵⁷⁷ Chapter 4 of the EPBC Act.

located on Ashmore and Cartier Islands. Although the assessment process considered the possibility of a large (15,000m³) oil spill, it was considered that impacts on these key sensitive areas were unlikely, particularly given their considerable distance from the Montara Oilfield.

6.96. On 3 September 2003 the following action was approved by a delegate for the Minister for the Environment:

To drill and operate Montara 4, Montara 5 and Montara 6 wells for the purpose of oil production and to re-complete and operate Montara 3 for use as a gas re-injection well in Permit Area AC/RL3, in the Timor Sea approximately 200km from the coast of Western Australia, (EPBC 2002/755).⁵⁷⁸

6.97. The documentation submitted to the Minister for the Environment was made available on the DEWHA website at the time but did not attract any comment from the public. To ensure that environmental impacts were managed at an acceptable level, the operation of the Montara Oilfield was approved subject to six conditions.

- a. Condition 1: Submission of an OSCP for the Minister's approval outlining the means by which the environmental effects of any hydrocarbon spills would be mitigated for the Minister's approval. The condition required that the OSCP be approved prior to the commencement of operations.
- b. Condition 2: Submission of a decommissioning plan.
- c. Condition 3: Monitoring of produced formation water during operations, as described in the assessment documentation. If the modelled amount of produced formation water was exceeded, a plan was required to outline the likely environmental impacts and the measures required to mitigate them.
- d. Condition 4: Submission of a certificate of compliance by 1 July each year after the commencement of construction, reporting on compliance with the conditions of approval.
- e. Condition 5: A provision that the proponent may submit a revised version of the plans required under Conditions 1, 2 and/or 3 for the Minister's approval.
- f. Condition 6: A provision that the Minister may request specified revisions to the plans approved pursuant to Conditions 1, 2 and/or 3, if it was necessary

⁵⁷⁸ Approval for the Montara Oilfield development under the EPBC Act, available at: http://www.environment.gov.au/cgi-bin/epbc/epbc_ap.pl?name=current_referral_detail&proposal_id=755.

or desirable for the better protection of the environment. The proponent was required to comply with any such request.

- 6.98. DEWHA identified the development of the Montara Oilfield for potential audit as part of its strategic audit program and PTTEPAA was advised of this by letter dated 22 January 2009.⁵⁷⁹ This audit is currently being undertaken.⁵⁸⁰
- 6.99. In its submission to the Inquiry DEWHA stated that it would not have been possible to impose different conditions on the development of the Montara Oilfield under the EPBC Act that would have prevented the occurrence of the Blowout.⁵⁸¹ The Inquiry agrees with this assessment. This would have required conditions that addressed well integrity issues which are more properly addressed by the DA in the context of the OPGGS Act.
- 6.100. The six conditions attached to the approval of the development of the Montara Oilfield have been met according to DEWHA's understanding of the facts. Condition 1 was of most relevance to the Inquiry because it related to the implementation of the OSCP. DEWHA submitted that the OSCP was adequately implemented since carriage of response operations was passed to AMSA in view of the magnitude of the Blowout.⁵⁸²
- 6.101. Experience with the Blowout has, nevertheless, revealed the need for considerable improvement in the EPBC Act approval process. Once a development is approved under the EPBC Act, the compliance, offence and penalty provisions under the Act relate only to compliance with the specific conditions of the approval, no matter what has subsequently occurred.⁵⁸³ DEWHA's supplementary submission to the Inquiry stated:

The particular legal problem in the case of the Uncontrolled Release is that the spill occurred during the course of taking an action that has EPBC

⁵⁷⁹ DEWHA, Submission to the Inquiry, p. 35.

⁵⁸⁰ DEWHA, Supplementary Submission to the Inquiry, p. 4.

⁵⁸¹ DEWHA, Submission to the Inquiry, p. 34.

⁵⁸² Ibid, p. 18.

⁵⁸³ The EPBC Act includes a wide range of coercive powers as well as criminal, civil and administrative sanctions for breaches of the Act. For example, the undertaking of an action with a significant impact on a protected matter without approval may be a criminal offence (with a maximum imprisonment of 7 years) or attract a civil penalty (with a maximum penalty of \$5.5 million for a corporation). The Act also imposes civil penalties of up to \$1.1 million for a corporation that contravenes any condition attached to an approval (see section 142). The Minister may also suspend or revoke an approval in certain circumstances when a contravention of an approval condition has occurred (see sections 144 and 145). However, these provisions are not valid when a project has been assessed and approved under the EPBC Act and no contravention of an approval condition has occurred.

Act approval. Unless a breach of conditions could be demonstrated, no direct compliance action could be taken.⁵⁸⁴

Finding 87

It is extraordinary that despite the environmental consequences, in the case of the Blowout there seems to be no ground for action under the Commonwealth's premier environmental legislation. This is a weakness that needs to be addressed for the future.

- 6.102. The only approval condition that may have been breached is Condition 1 which required that the OSCP be approved prior to commencement of operations. The OSCP was not approved by DEWHA until after drilling had commenced at the Montara WHP. This appears to have resulted from a misunderstanding about the meaning of 'operations'. PTTEPAA interpreted it as not restraining PTTEPAA from carrying out drilling, and that the OSCP only needed to be approved before the commissioning or start-up phase of the commercial extraction of hydrocarbons. However, the OSCP was in place prior to the Blowout and this misunderstanding is not of consequence for present purposes. But it does illustrate the need for care on DEWHA's part in framing the terms of approval conditions.
- 6.103. A key lesson to draw from the Blowout is that it is essential that there be adequate approval and condition setting processes. The regulatory framework applicable to Commonwealth waters includes both the EPBC Act and the OPGGS Act but it differs from that which applies to coastal waters and terrestrial developments. In Commonwealth waters the EPBC Act is not bolstered by the state and territory environmental law that also applies to coastal waters and terrestrial developments.

Finding 88

The assessment of the development of the Montara Oilfield and the conditions attached to its approval under the EPBC Act did not foresee an incident of the duration and extent of the Blowout. While an OSCP was required as a condition of approval, there were no requirements for Scientific Monitoring to be undertaken, or for the remediation of environmental damage, in the case of an oil spill. An effort should now be made to ensure that Scientific Monitoring obligations and, if necessary, remediation work are included in conditions of approval for future projects. Furthermore, there would be considerable benefit in legislating to require that existing petroleum operators in Commonwealth waters are also obligated to meet such requirements. The Inquiry does not regard this as involving a retrospective requirement as it would only apply to any future events.

⁵⁸⁴ DEWHA, Supplementary Submission to the Inquiry, p. 6.

Approval under the OPGGS Act

- 6.104. Chapter 4 describes the regulation of the offshore petroleum industry in Commonwealth waters under the OPGGS Act. Before an operator carries out an activity in a permit or licence area it is required to have an approved environment plan under the MOE Regulation.
- 6.105. The development of the Montara Oilfield was approved under the OPGGS Act regulations by the NT DoR in its capacity as the delegate of the DA. In its submission to the Inquiry the Northern Territory stated that the following environment plans were in effect on 21 August 2009⁵⁸⁵ in accordance with the MOE Regulations:
- a. Montara Development – Production and Exploration Drilling Environment Plan, Rev:0 October 2007 approved on 15 October 2007; and
 - b. Montara Development - Installation and Commissioning Environment Plan, Rev: 1 June 2009, submitted on 29 June 2009 and approved on 7 July 2009.
- 6.106. The aim of an environment plan is to reduce the environmental risks and impacts from petroleum activities to as low a level as reasonably practicable.⁵⁸⁶ It essentially deals with important rig/WHP specific issues, such as waste management, liquid discharges and hazardous wastes. In Commonwealth waters, the environment plan complements the overarching EPBC Act approval. Consistency between these approvals is important.
- 6.107. The Northern Territory has stated that it was satisfied the plans met the requirements of the OPGGS Act, the MOE Regulations and the applicable guidelines.⁵⁸⁷
- 6.108. As with the assessment under the EPBC Act, both of the environment plans considered the possibility of a large oil spill (using modelling of a 15,000m³ spill).
- 6.109. The Installation and Commissioning Environment Plan indicated that PTTEPAA's existing OSCP and Emergency Response Plan for its Timor Sea operations would

⁵⁸⁵ Northern Territory, Submission to the Inquiry, pp. 13-14.

⁵⁸⁶ Department of Resources, Energy and Tourism 2005, *Guidelines for the Preparation and Submission of an Environment Plan: Under the Petroleum (Submerged Lands) (Management of Environment) Regulations 1999*, p. 4.

⁵⁸⁷ Northern Territory, Submission to the Inquiry, pp. 15-16.

apply to the Montara Oilfield. The same OSCP was used for compliance with both the MOE Regulations and approval Condition 1 under the EPBC Act.⁵⁸⁸

- 6.110. Consistent with the MOE Regulations, the Montara environment plans include a list of 'reportable' and 'recordable' incidents. Reportable incidents are incidents that have the potential to result in moderate to catastrophic environmental consequences as categorised by the risk assessment process within the environment plan. They are to be reported to the NT DoR, as the delegate of the DA, within two hours (oral) and three days (written) of the incident. Reportable incidents in the Installation and Commissioning Environment Plan were:
- a. uncontrolled release of oil/oil spill greater than 80 litres;
 - b. death or injury of a listed species, migratory species, whale or cetacean (EPBC Act Chapter 5, Part 13, Divisions 1-4);
 - c. exceeding permitted oil content of produced formation water discharges; and
 - d. accidental discharge of hydro-test fluids.
- 6.111. The OSCP identified three oil spill treatment priorities: (i) monitoring (natural weathering and dispersal); (ii) chemical dispersants; and (iii) containment and recovery.⁵⁸⁹ Monitoring and natural dispersal was the preferred option to be undertaken when the oil type, sea state and trajectory calculations indicated that a slick would not impact the coastline. Where spills were moving towards sensitive areas, treatment with chemical dispersant was to be considered.
- 6.112. It is apparent that PTTEPAA complied with relevant provisions of its OSCP and environment plans insofar as it promptly notified the spill to the appropriate authorities. AMSA considered that the OSCP fitted with the National Plan but identified some shortcomings.⁵⁹⁰ It identified a disconnect between the response strategies the OSCP contained and the response resources that were actually put in place on-site before the Blowout occurred. The OSCP also appeared to overestimate the evaporative loss and underestimate the residual oil and wax following weathering. It is therefore uncertain whether PTTEPAA was ever in a position to fully implement the response strategies in its OSCP. In the future, OSCPs need to be reviewed by AMSA to ensure that they are aligned or consistent with the National Plan before they are approved. AMSA considers

⁵⁸⁸ PTTEPAA 2009, *Oil Spill Contingency Plan*, version dated 19 May 2009.

⁵⁸⁹ *Ibid*, p. 55.

⁵⁹⁰ Statutory Declaration of Mr Graham Peachey, 23 February 2010, p. 10.

there should also be (i) an assessment of capability against the approved OSCP once field operations commence; and (ii) a requirement for exercises to be carried out to assess the ongoing effectiveness of the OSCP.⁵⁹¹ The Inquiry shares this view.

Finding 89

The Inquiry sees value in having both environment plans and OSCPs prepared for new developments made public. This would be consistent with the publication of the documentation relating to the assessment and approval of development proposals under the EPBC Act. This would allow an increased degree of public scrutiny of development proposals and the operation of DAs but need not pose commercial-in-confidence issues.

Legislative or regulatory changes

- 6.113. In the Inquiry's view, changes should be made to the regulatory framework to establish adequate powers for the protection of the environment in Commonwealth waters. This would avoid a repetition of the circumstances in which the Commonwealth Government had to negotiate an arrangement for Scientific Monitoring with PTTEPAA. The significance of the time taken to do this and to commence Scientific Monitoring was discussed earlier in this Chapter.
- 6.114. The need for additional powers was also identified in the recent independent review of the EPBC Act conducted by Dr Allan Hawke. That review recommended that the EPBC Act should incorporate a provision to issue Environment Protection Orders which could be used to require a developer to take particular action either to stop a damaging action, or to undertake measures to remediate damage.⁵⁹² Environment Protection Orders or similar notices can be issued in most states and territories in Australia to ensure compliance with environmental protection objectives and legislation.⁵⁹³
- 6.115. In its supplementary submission to the Inquiry, DEWHA set out a number of options that could form new provisions in the EPBC Act.⁵⁹⁴ DEWHA envisaged new contravention provisions that could include the Environmental Protection Orders proposed by Dr Hawke, and inquiry powers, similar to a royal commission, to investigate serious incidents involving environmental harm.

⁵⁹¹ Letter from AMSA to the Inquiry, 24 May 2010, p. 8.

⁵⁹² Hawke A 2009, *The Australian Environment Act – Report of the Independent Review of the EPBC Act 1999*, October 2009, p. 274.

⁵⁹³ See for example the *Environment Protection Act 1993* (SA), s 93; the *Environment Protection Act 1994* (Qld), s 358; and the *Protection of the Environment Operations Act 1997* (NSW), Chapter 4.

⁵⁹⁴ DEWHA, Supplementary Submission to the Inquiry, pp. 6-7.

6.116. The Inquiry considers that the coverage of environmental regulation in the Commonwealth marine environment should be increased. The Inquiry appreciates that this would significantly extend the reach of the EPBC Act and that it would have implications beyond the offshore petroleum industry. It is important though that the Commonwealth's environmental protection legislation is at least equivalent in its coverage to that which applies if pollution originates onshore, or in state or territory waters. There are also offshore petroleum industry-specific aspects that require 'belts and braces' measures which need to be addressed through the OPGGS Act.

Finding 90

The environmental protection regime for Commonwealth waters should include the following elements to embody the polluter pays principle:

- a) the Government should have the power to require the companies involved in an incident – both prospectively and already approved projects – to undertake Scientific Monitoring of the environmental impacts of an incident, and to undertake actions to remediate any damage resulting from the incident to a required standard;
- b) the costs of undertaking Scientific Monitoring or of remediating the damage arising from a significant incident should be fully borne by the companies involved, whether the monitoring or remediation is undertaken by the company or by Commonwealth, state or territory agencies or other parties. Further it should be the environmental regulatory agencies that determine the nature of Scientific Monitoring arrangements and remediation required, not the company involved;
- c) regulatory authorities should be satisfied that companies have adequate insurance arrangements in place to allow them to meet their obligations; and
- d) there should be provision for the payment of penalties for pollution on a no fault basis, which should be similar in scale to that which would be applicable in state regimes.

6.117. The Inquiry considers that the regime outlined above should be established in relevant legislation. This should include amendment of the EPBC Act to provide such powers to the Commonwealth Minister for the Environment.

6.118. The Inquiry notes that the OPGGS Act makes provision for the DA to direct a titleholder to undertake actions to clean-up or otherwise remediate the effects of an escape of petroleum.⁵⁹⁵ However, the Inquiry is not aware of whether consideration was given to drawing on this power in relation to the Montara Blowout. The OPGGS Act also requires titleholders to maintain insurance to

⁵⁹⁵ See ss 574(2) and 782(1) of the OPGGS Act.

meet the costs of complying with such directions.⁵⁹⁶ As noted in Chapter 4, the adequacy of the insurance arrangements that applied to the Montara Oilfield was not properly assessed by the NT DoR. The Inquiry also notes that the Hawke review and the recent Productivity Commission review of regulatory burden on the upstream petroleum sector⁵⁹⁷ both referred to a potential duplication between the EPBC Act and MOE Regulations.

- 6.119. Amendment of the EPBC Act as proposed would, however, have a broader application than the OPGGS Act. It is also relevant that the OPGGS Act does not cover the cost of Scientific Monitoring of environmental impacts. Nor does it include penalty provisions relating to environmental damage resulting from an oil spill.⁵⁹⁸ It is important, nevertheless, to minimise duplication of other Commonwealth legislation or applicable state and territory provisions.
- 6.120. There are provisions under the EPBC Act for streamlining assessment and approval processes and minimising regulatory burden that could provide a guide as to how this might be achieved. There are bilateral agreements under Part 5 of the EPBC Act between the Commonwealth and the relevant state or territory which minimise duplication in the environmental assessment and approval processes in relation to terrestrial environments and coastal waters. This is achieved through the Commonwealth accreditation of the assessment and approval processes of a state or territory. The Hawke Review and the Productivity Commission both identified the scope for a bilateral agreement between the Commonwealth and DAs for offshore petroleum developments. In Commonwealth waters, such an arrangement could require, for example, that a single environment plan be submitted to meet the regulatory requirements of both the OPGGS Act and the EPBC Act, thus reducing regulatory burden and ensuring a consistent approach to assessment and approval.

Recommendation 95

The regulatory framework should provide that in respect of all activities in Commonwealth waters:

- a. there are powers to require companies involved in an incident causing significant environmental damage to undertake actions to remediate the damage to a standard determined by the regulatory authorities;**

⁵⁹⁶ See s 571(1) of the OPGGS Act.

⁵⁹⁷ Productivity Commission, *Review of Regulatory Burden on the Upstream Petroleum (Oil & Gas) Sector*.

⁵⁹⁸ Although, the Inquiry notes that failure of a registered titleholder to comply with a direction made by the DA under s 574 of the OPGGS Act incurs a penalty: see s 576 of the OPGGS Act.

- b. the nature of the Scientific Monitoring and the remediation required should be determined by environmental regulatory agencies rather than the companies involved;**
- c. the costs of all Scientific Monitoring and remediation should be fully borne by the companies involved, whether the remediation is undertaken by the companies or another party to the standard determined by the regulatory authorities; and**
- d. penalties should be payable for pollution on a no fault basis.**

The EPBC Act should be amended to include the powers in a, b, c and d above. These powers should be applicable to both prospective and existing operations in Commonwealth waters.

Recommendation 96

The obligation of companies involved in an incident to meet the full costs of monitoring and remediation should be made a condition of approval of proposals under the EPBC Act and OPGGS Act. Suitable arrangements (insurance or otherwise) need to be in place to ensure that companies have this capacity.

Recommendation 97

Environment plans and OSCPs should be made publicly available as a condition of approval of proposals under the OPGGS Act, and should clearly set out Scientific Monitoring requirements in the event of an oil spill.

Recommendation 98

The Government should examine the scope for a single environment plan to meet the regulatory requirements of both the OPGGS Act and the EPBC Act. This could possibly be achieved by way of bilateral agreements and accreditation arrangements and/or legislative amendment.

Recommendation 99

OSCPs should be endorsed by AMSA prior to regulatory approval to ensure that they align with the National Plan. Once field operations commence, the capability of operators should be assessed against their plans, and exercises conducted to ensure the plans remain effective.

Recommendation 100

Arrangements should be developed to minimise duplication between the EPBC Act and the OPGSS Act Environment Regulation.

7. REVIEW OF PTTEPAA'S PERMIT AND LICENCE AT MONTARA AND OTHER MATTERS

Introduction

- 7.1. Paragraph 11 of the Inquiry's Terms of Reference 11 directs the Inquiry to:
- Consider, assess and make recommendations in relation to any other matter the Commission of Inquiry considers relevant to or arising from the Uncontrolled Release...
- 7.2. The Inquiry considers that the Minister should, as the JA for the offshore area of the Territory of Ashmore and Cartier Islands, undertake a review of PTTEPAA's permit and licence pursuant to various provisions of the OPGGS Act.
- 7.3. The Inquiry notes that s 274 of the OPGGS Act sets out various grounds for cancellation of a petroleum exploration permit and/or a petroleum production licence. Those grounds include non-compliance by a registered titleholder with a provision of Chapter 6 of the OPGGS Act or the regulations in force thereunder. Chapter 6 of the Act includes subsection 569(1) which requires a titleholder to carry out all petroleum exploration and recovery operations in a permit/licence area in 'a proper and workmanlike manner and in accordance with good oilfield practice'. That same subsection also requires a titleholder to 'control the flow, and prevent the waste or escape' of petroleum.
- 7.4. In considering any review of PTTEPAA's permit and licence, the Minister would need to consider whether PTTEPAA had, with respect to the Blowout in the H1 Well at the Montara Oilfield, contravened subsection 569(1) of the OPGGS Act and/or the regulations in force under that Act. For reasons previously stated, it is not for the Inquiry to determine whether any non-compliance has actually occurred.
- 7.5. If, in carrying out a review, the Minister considered that PTTEPAA had contravened the OPGGS Act or regulations, it is recommended that the Minister should then give consideration to exercising the power of cancellation conferred by s 275 of the OPGGS Act.
- 7.6. The Inquiry emphasises that it is not recommending to the Minister that he actually cancel PTTEPAA's permit and licence. Rather, the Inquiry's recommendation is that the Minister consider (i) whether ground(s) for cancellation exist; and (ii) if so, whether or not it is appropriate to cancel PTTEPAA's permit and licence.

- 7.7. It is worthy of reiteration that it is for the Minister (rather than this Inquiry) to form a view as to whether PTTEPAA has contravened the OPGGS Act or regulations. Moreover, various provisions of the OPGGS Act make clear that it would not be appropriate for the Inquiry to positively recommend cancellation of PTTEPAA's permit or licence even if the Minister were to be satisfied of contravention. For instance:
- a. subsection 275(2) of the OPGGS Act provides that, before exercising any power to cancel, the Minister must take into account any action taken by PTTEPAA to either remove the ground(s) of cancellation or to prevent the recurrence of the ground(s); and
 - b. subsection 276(3) of the OPGGS Act provides that, in deciding whether to cancel a permit or licence, the Minister must take into account any submission made about that question by PTTEPAA.
- 7.8. The Inquiry cannot know what action might actually be taken by PTTEPAA to prevent the recurrence of breaches of the OPGGS Act and/or regulations at the Montara Oilfield. Further, the Inquiry is not in a position to know the content of any submissions which PTTEPAA might advance to the Minister under subsection 276(3).
- 7.9. Indeed, the Inquiry notes that PTTEPAA has expended considerable time and effort devising an Action Plan⁵⁹⁹ to address matters of concern raised during the Inquiry. In any review of PTTEPAA's licence, it is therefore recommended that the Minister give consideration to the extent to which PTTEPAA has implemented the Action Plan. The Inquiry considers that if this Action Plan is implemented it should go a long way to restoring confidence in PTTEPAA's ability and commitment to operate as a responsible licensee at the Montara Oilfield.
- 7.10. The Inquiry's recommendation that the Minister give consideration to the question of cancellation (by issuing a 'show cause' notice to PTTEPAA under s 276 of the OPGGS Act) is based on the following factors:
- a. the *nature* and *extent* of PTTEPAA's deficiencies with respect to the H1 Well at the Montara Oilfield;
 - b. the *nature* and *extent* of PTTEPAA's deficiencies with respect to all other wells at the Montara Oilfield;

⁵⁹⁹ This Action Plan was submitted to the Inquiry well after the close of the public hearing.

- c. PTTEPAA's failure to properly investigate the circumstances and likely causes of the Blowout;
- d. PTTEPAA's provision of palpably false and misleading information to NOPSA and to this Inquiry;
- e. PTTEPAA's withholding of relevant information from NOPSA and the NT DoR;
- f. the self-justifying and deflective position adopted by PTTEPAA throughout most of this Inquiry. In this regard, PTTEPAA only really acknowledged the nature and extent of its deficiencies in managing well control at the Montara Oilfield toward the very end of the Inquiry's public hearing – that is, after compulsory powers were exercised to test (and find wanting) the blame avoidant position which PTTEPAA had, to that point, steadfastly adopted; and
- g. the fact that the Inquiry is not in a position to make any assessment of PTTEPAA's implementation of the abovementioned Action Plan. Whilst the Action Plan is an impressive document, it was produced very late in the Inquiry's process and awaits implementation.

Nature and extent of deficiencies in PTTEPAA's well control with respect to the H1 Well

- 7.11. As noted in Chapter 3, PTTEPAA succumbed to a significant number of serious deficiencies in its approach to well control in the H1 Well, and those deficiencies were emblematic of larger systemic problems which afflicted PTTEPAA in the lead up to the Blowout. By way of summary:
- a. both onshore and on-rig personnel from PTTEPAA were directly involved in over-displacement of cement beneath the float valves in the 9½" casing shoe of the H1 Well on 7 March 2009. These personnel acted contrary to sensible oilfield practice in the course of that cementing operation;
 - b. both on-rig and onshore personnel from PTTEPAA were directly involved in the use of an incorrect volume of tail cement in the course of the same cementing operation;
 - c. both on-rig and onshore personnel from PTTEPAA failed to recognise, in the aftermath of the cementing operation on 7 March 2009, that a wet shoe had been created. These failures occurred (i) during the course of preparation of contemporaneous documents by on-rig personnel; and (ii) upon review of those documents by onshore personnel;

- d. on-rig and onshore personnel from PTTEPAA failed to ensure that a test of the cemented shoe was carried out. This failure was contrary to sensible oilfield practice and PTTEPAA's own standards;
- e. on-rig and onshore personnel from PTTEPAA were implicated in deferment of installation of the 13 $\frac{3}{8}$ " PCCC, contrary to sensible oilfield practice. They were also implicated in the failure to install the 13 $\frac{3}{8}$ " PCCC as a secondary barrier against a blowout;
- f. on-rig and onshore personnel from PTTEPAA were directly involved in the removal and non-reinstallation of the 9 $\frac{5}{8}$ " PCCC on 20 August 2009. Their actions in this regard were contrary to sensible oilfield practice and PTTEPAA's own standards;
- g. PTTEPAA failed to carry out a sufficiently detailed risk assessment in relation to the general topic of use of PCCCs as secondary barriers against a blowout, particularly in the context of batched tie-back operations which were to occur at the Montara Oilfield;
- h. there was widespread misunderstanding on the part of PTTEPAA's personnel as to the barrier status of the displacement fluid contained within the 9 $\frac{5}{8}$ " casing in the H1 Well. On-rig and onshore personnel from PTTEPAA wrongly considered that the fluid could be relied upon as an effective barrier against a blowout. Their approach to that question was contrary to sensible oilfield practice and PTTEPAA's own standards;
- i. too much weight was given by PTTEPAA personnel to the absence of detectible signs of flow prior to and immediately after removal of the 9 $\frac{5}{8}$ " PCCC. Further, there was inadequate monitoring of the well after that removal;
- j. there were a large number of significant deficiencies in various PTTEPAA documents dealing with well control;
- k. there were significant deficiencies in PTTEPAA's management systems for recording and communicating information within the company;
- l. there were significant deficiencies in the formal and informal arrangements which PTTEPAA set in place between it and Atlas with respect to risk management in the context of well control;
- m. there were deficiencies in PTTEPAA's logistics management; and
- n. PTTEPAA did not have effective internal systems in place to achieve a high level of quality assurance with respect to well operations: first, PTTEPAA personnel were non-vigilant in the performance of day-to-day supervision of

subordinates; secondly, there were no random or systematic audits undertaken in the relevant period; thirdly, PTTEPAA adopted a non-systematic approach to acquiring and maintaining levels of knowledge and expertise; and fourthly, PTTEPAA's governance structures were non-robust.

Finding 91

PTTEPAA succumbed to a large number of serious deficiencies in its approach to well control in the H1 Well, as set out in paragraph 7.11 of this Report.

Finding 92

Those deficiencies were emblematic of larger systemic problems which afflicted PTTEPAA in the lead up to the Blowout.

Deficiencies in PTTEPAA's management of other wells at the Montara Oilfield

7.12. Well control problems were not confined to the H1 Well. The Inquiry received evidence to the effect that PTTEPAA succumbed to a large number of deficiencies with respect to control of every other well at the Montara Oilfield.⁶⁰⁰

Problems with the cemented casing shoe in the GI Well

7.13. Problems occurred with bumping of the plugs during the course of cementing the casing shoe in the GI Well.

7.14. Although a post WOC pressure test was carried out, gas bubbling was subsequently observed up the 13 $\frac{3}{8}$ " and 9 $\frac{5}{8}$ " annulus.⁶⁰¹ This gas bubbling should have been the subject of a detailed risk assessment, but was not. A proper risk assessment may have indicated the need for remedial strategies.⁶⁰² Indeed, the Inquiry considers that, at the very least, a cement

⁶⁰⁰ The Inquiry's findings in this Chapter are based on documentary and oral evidence canvassed in the course of the public hearing. Since then, the Inquiry notes that PTTEPAA submitted a detailed review of well control at the Montara Oilfield undertaken by a consultant, AGR Petroleum. The Inquiry has not had the opportunity to canvass the AGR Report with any witnesses, but notes that it generally accords with the Inquiry's findings set out above.

⁶⁰¹ It was suspected that this gas was migrating from a small sand within the Woolaston formation, but the source was never properly established. See report from Mr Graham Ross, 29 October 2009, SEA.003.015.2934.

⁶⁰² Report from Mr Graham Ross, 24 September 2009, SEA.001.006.4675.

bond log test should have been carried out to determine the location and density of cement.⁶⁰³

- 7.15. Rather than carrying out a proper risk assessment, including by way of further tests and consideration of possible remedial action, PTTEPAA simply placed a 13 $\frac{3}{8}$ " PCCC in the GI Well as a secondary annulus barrier. However, as noted by Mr Ross in a report dated 24 September 2009:

It is not satisfactory simply to place a pressure retaining corrosion cap on top of a leak path and forget about it. Now we are in [a] situation where we have to assume that there is a problem with the annulus that will require remedial action. The issue is that a BOP really needs to be installed before the 13 $\frac{3}{8}$ " PCCC can be released and remedial work can be conducted. This means moving a rig into position over a well that may be problematic to repair but importantly is not properly barriered off. The risks associated with such an operation need to be properly assessed.⁶⁰⁴

- 7.16. The Inquiry notes that another expert, Mr Stewart McGregor (an Engineering Manager with AGR Petroleum Services) stated as follows in a report to PTTEPAA of 19 October 2009:

However, the gas bubbles which were being monitored and ultimately addressed with the installation of a 13 $\frac{3}{8}$ " pressure containing cap add more complexity. Since the source or composition of the gas bubbles is unknown, and taking a worst case view, the casing cement job has been either compromised internally (unlikely given the good pressure test) or the annulus is not sealing (channelling or a micro annulus).

Other explanations for the gas bubbles do exist. However, as no one source can be proved either way it would be prudent to assume the worst in this case. In my view, if the casing job is compromised it cannot be viewed as a barrier although this is not stated explicitly in the PTTEPAA management system.⁶⁰⁵

- 7.17. Thus, two independent experts who looked into the significance of the gas bubbling in the GI Well formed the view that it raised serious issues about the integrity of the annulus cement as a primary barrier. Both Mr Ross and Mr McGregor considered that further investigation and remedial action was warranted. However, the Phase 1B Drilling Program (which was in force at the

⁶⁰³ On 29 October 2009 Mr Graham Ross, an independent expert, produced a report to Atlas in which he stated: '...The TOC (top of cement) cannot be accurately ascertained from displacement pressure in deviated or horizontal wells such as the Montara Wells, due to the likelihood for channelling and potential for slump post displacement. Likewise the quality of the cement in place cannot be established without a CBL (cement bond logging test). Simulations are useful but verification has to be obtained by log'. The Inquiry accepts the broad thrust of these opinions.

⁶⁰⁴ Report from Mr Graham Ross, 24 September 2009, SEA.001.006.4675.

⁶⁰⁵ Email from Mr Stewart McGregor to Mr Craig Duncan, 19 October 2009, PTT.9002.0106.0239.

time) simply provided as follows in relation to the tie-back of the 13 $\frac{3}{8}$ " casing of the GI Well:

125) Check the well for flow with the 13 $\frac{3}{8}$ " corrosion cap removed. Nipple-down the diverter.

The annulus may still be 'bubbling' like it was prior to suspension - this is acceptable, flowing is not acceptable.

- 7.18. The Inquiry also notes that the Phase 1B Drilling Program made provision for installation of a BOP over the GI Well at step 1148 - many days, perhaps weeks, after removal of the PCCC.
- 7.19. It is clear, therefore, that PTTEPAA had no proper appreciation of the potential problems associated with the primary barrier in the GI Well. PTTEPAA was proposing to proceed in a manner which, but for the Blowout in the H1 Well, would have left the GI Well dependent upon a questionable primary barrier in the 13 $\frac{3}{8}$ " and 9 $\frac{5}{8}$ " annulus for a long period of time.

Non-testing of secondary barriers in the GI Well

- 7.20. The 9 $\frac{5}{8}$ " PCCC and 13 $\frac{3}{8}$ " PCCC installed in the GI Well were not tested for integrity after installation.

Problems with the H2 Well

- 7.21. In the H2 Well, no satisfactory 13 $\frac{3}{8}$ " casing shoe test was obtained, and severe losses were encountered immediately below the casing shoe due to weak formation.⁶⁰⁶ The chances of a good 13 $\frac{3}{8}$ " cement job on the H2 Well were slim.⁶⁰⁷ No further testing or remedial action was undertaken by PTTEPAA.
- 7.22. The cement plug within the 9 $\frac{5}{8}$ " casing string of the H2 Well was not tested for integrity after installation.
- 7.23. The 13 $\frac{3}{8}$ " PCCC installed in the H2 Well was also not tested for integrity after installation.

⁶⁰⁶ Report from Mr Graham Ross, 29 October 2009, SEA.003.015.2951.

⁶⁰⁷ PTTEPAA objected to this conclusion. It is based on a written report of Mr Graham Ross, 29 October 2009, p. 5, SEA.003.015.2947.

Problems with the H3 Well

- 7.24. During the cementing of the 9 $\frac{5}{8}$ " casing shoe in the H3 Well the plugs did not bump, although the float valves held. A post WOC pressure test is not mentioned in Mr Ross' analysis of well construction activities relating to the H3 Well.⁶⁰⁸ Mr Duncan told the Inquiry that such a test had not been carried out.⁶⁰⁹
- 7.25. The cement plug in the 9 $\frac{5}{8}$ " casing of the H3 Well was not tagged or pressure tested after installation.
- 7.26. The 13 $\frac{3}{8}$ " PCCC installed in the H3 Well was not tested for integrity after installation.

Problems with the H4 Well

- 7.27. Cement was under-displaced during the course of the cementing of the 13 $\frac{3}{8}$ " casing shoe in the H4 Well, most probably due to a rig pump problem or the pit running dry. Cement was tagged at 481 metres above the shoe, which meant only 109 metres of cement were placed into the annulus.⁶¹⁰
- 7.28. The cement plug installed in the 9 $\frac{5}{8}$ " casing string of the H4 Well was not tested for integrity after installation.
- 7.29. The 13 $\frac{3}{8}$ " PCCC installed in the H4 Well was not tested for integrity after installation.

Conclusion

- 7.30. On any view, the above list of well control deficiencies is significant. It shows that the deficiencies which occurred with respect to the H1 Well (and which led to the Blowout) can properly be seen as part of a larger problem with respect to PTTEPAA's overall management of well control at the Montara Oilfield.
- 7.31. Put simply, PTTEPAA did not achieve proper control of any of the five wells at the Montara Oilfield. Indeed, multiple deficiencies existed in each other well.

⁶⁰⁸ Ibid, SEA.003.015.2948-2951.

⁶⁰⁹ Mr Duncan thought the well involved was the H2 Well, but it seems reasonably clear that it is the H3 Well. This finding is supported by the AGR Report dated 1 April 2010, which PTTEPAA submitted after the conclusion of the Inquiry's public hearing.

⁶¹⁰ Report from Mr Graham Ross, 29 October 2009, SEA.003.015.2952.

7.32. The Inquiry notes the following evidence given by Mr Jacob:⁶¹¹

Q. As I understand it, in the aftermath of the blowout of the H1 well on 21 August last year, [PTTEPAA] didn't really conduct any detailed investigation as to the state of suspension of the other wells?

A. Not thorough enough, no.

Q. And really only acquired significant information about the deficiencies in the standard of suspension as a result of your hearing the evidence in this Commission of Inquiry; is that right?

A. That's my understanding, yes.

...

Q. To the best of your knowledge and understanding, has [PTTEPAA] raised with anyone outside its own organisation, up to the time the public hearings in this inquiry commenced, the fact that the other wells might not be properly secured?

A. I don't believe so. I'm not 100 per cent sure, but I don't believe so.

Q. Indeed, your evidence, sir, was that it wasn't in a position to do so, because it hadn't learned of that?

A. As I said, from my side, yes.

Q. So in circumstances in which it knew of significant deficiencies with respect to the H1 well that had led to a blowout, it was content to allow its own personnel and personnel from other entities to re-enter upon the platform without properly satisfying itself as to the sufficiency of the primary and secondary barriers in those other wells?

A. Yes, it appears to be, yes.

Q. Do you agree with me, sir, that [PTTEPAA]'s approach in that regard was seriously flawed?

A. Yes, it is not good practice.

7.33. The Inquiry notes that although Mr Jacob was not aware of deficiencies in well control with respect to other wells at the Montara Oilfield, Mr Duncan was aware of at least some of those deficiencies.⁶¹² The evidence before the Inquiry indicates that PTTEPAA did not inform the NT DoR or NOPSA of any deficiencies in well control with respect to other wells at the Montara Oilfield.

⁶¹¹ T1877 (Jacob).

⁶¹² T1535-T1539 (Duncan).

Finding 93

PTTEPAA did not achieve proper control in any of the five wells at the Montara Oilfield. Multiple deficiencies of a significant kind existed in each well.

The nature and extent of well control deficiencies can properly be seen as part of a larger problem with respect to management of well operations at the Montara Oilfield. PTTEPAA had at least some knowledge of well control deficiencies at the Montara Oilfield, but it did not inform either the NT DoR or NOPSA of any of the deficiencies of which it was aware.

Deficiencies in PTTEPAA's investigation into the circumstances and likely causes of the Blowout

- 7.34. Very soon after the Blowout PTTEPAA should have taken steps to properly inform itself as to the circumstances and likely causes of the Blowout.
- 7.35. This is hardly a controversial proposition. Soon after the Blowout PTTEPAA knew that:
- a. it would be called upon by regulatory authorities (such as the NT DoR and NOPSA) to give an account of the circumstances and likely causes of the Blowout;
 - b. those matters would be relevant to planning the Relief Well to kill the Blowout;
 - c. the Commonwealth Government, and the public at large, wanted to gain a proper understanding of why the Blowout occurred; and
 - d. this Commission of Inquiry had been established to inquire into, amongst other things, the circumstances and likely causes of the Blowout.
- 7.36. Notwithstanding these matters, PTTEPAA's investigations into the Blowout were manifestly deficient. Those investigations consisted of:
- a. a joint investigation carried out by PTTEPAA and its parent company, in respect of which PTTEPAA and its parent company have claimed legal professional privilege; and
 - b. an investigation undertaken by Mr Jacob and Ms Breadmore, PTTEPAA's in-house legal counsel. This investigation had input from PTTEPAA personnel (primarily Mr Duncan) and Halliburton personnel.⁶¹³ The investigation

⁶¹³ See page 15 of PTTEPAA's report to NOPSA dated 2 October 2009. This report was prepared by Ms Breadmore, checked by Mr Duncan, and approved by Mr Jacob.

included a document review carried out by Ms Breadmore, without any expert well engineering input.⁶¹⁴

7.37. Mr Jacob informed the Inquiry that the first-mentioned (that is, privileged) investigation was no more extensive than the investigation which he and Ms Breadmore carried out.⁶¹⁵ The Inquiry accepts this evidence: first, Mr Jacob told the Inquiry that he was briefed on the outcome of the privileged investigation; and secondly, whatever the precise scope of the privileged investigation it was clearly insufficient to properly inform PTTEPAA of the circumstances and likely causes of the Blowout - as evidenced by the significant deficiencies in the information PTTEPAA later provided to NOPSA and to this Inquiry (see below). Finally, Mr Jacob gave the following evidence to the Inquiry:⁶¹⁶

Q. Is it the case that there is not a single person in [PTTEPAA] who, prior to the commencement of these public hearings, had carried out a detailed inquiry into the circumstances surrounding the blowout with a view to gaining a proper understanding as to how it might have occurred; is that the position?

A. Yes. There was no internal investigation for that purpose, no. You are correct...

Q. Not a single [PTTEPAA] person undertook that task?

A. Well, the individuals involved, Mr Duncan and Mr Wilson in particular, undertook a lot of review of the paperwork in order for them to prepare their statements to the Commission, but they didn't produce reports internally, no.

Q. Of course, they were personally involved, weren't they?

A. Yes.

Q. Do you see the merit, now, in hindsight of [PTTEPAA] itself carrying out a detailed investigation into the circumstances surrounding the blowout so that someone independent of those personally involved could form a proper understanding as to what might have led to the blowout and be in a position to assist the Commissioner?

A. Yes, I do, now...

...

Q. I see. And understand, sir, that I am not taking you to task in relation to information that those personally involved have given to the Inquiry. You understand, sir, that I'm now directing your attention to the absence of any independent consideration of the circumstances surrounding the blowout by someone in [PTTEPAA] not personally involved in the events under consideration?

A. Mmm-hmm.

⁶¹⁴ T1707 - T1708 (Jacob).

⁶¹⁵ T1577 (Jacob).

⁶¹⁶ T1615 (Jacob); T1617-8 (Jacob).

Q. I mean, it is an obvious thing to do, isn't it, sir?

A. It is, in the cold light of day, yes.

Q. I'm suggesting to you that it does not take the cold light of day or hindsight to understand that when you have a blowout, which threatens harm to the environment and threatens human lives, you should inquire into it in a manner that enables you to satisfy yourself as to how it might have occurred?

A. Yes.

Q. And you didn't do that?

A. We didn't do it fully enough.

Q. You didn't do it virtually at all, sir?

A. No, I would object to that, because we had to establish certain things in order to kill the well, et cetera, which was part of all that. I agree with you that an independent [investigation] would be a better way to go about it and certainly would be something we would do in the future, but I don't accept that we did nothing. We have done a lot.

Q. You, sir, have virtually done nothing to put yourself in a position where you could independently assess the circumstances surrounding the blowout and what might have led to it?

A. At this stage, yes.

7.38. Mr Jacob went on to tell the Inquiry that in the aftermath of the Blowout PTTEPAA's focus was to kill the H1 Well via the Relief Well, which was an urgent and complex operation. Accordingly, PTTEPAA's efforts were directed primarily to that end. Mr Jacob also gave evidence to the effect that, together with other senior PTTEPAA personnel, he was involved full time in pursuing various matters relating to the Blowout right up until the end of 2009,⁶¹⁷ and so he was not well placed personally to undertake a detailed investigation into the circumstances and likely causes of the Blowout.

7.39. The Inquiry accepts that Mr Jacob was not well-placed, in the aftermath of the Blowout, to *personally* devote *large* amounts of time to an investigation into its circumstances and likely causes. However, the Inquiry does not accept that PTTEPAA, through Mr Jacob, was entitled to proceed in the manner it did in the aftermath of the Blowout. In this regard, the Inquiry notes the following:

- a. it would have taken only 5-10 minutes to read the DDR of 7 March 2009, the Cementing Report of 7 March 2009, and the Seven Day Operational Forecast in place as at 20 August 2009.⁶¹⁸ So doing would or should have informed

⁶¹⁷ These matters included environmental protection and monitoring measures, and necessary interactions with various stakeholders (including government).

⁶¹⁸ These three documents were the obvious documents which PTTEPAA should have called for and examined closely.

PTTEPAA of significant matters of which it remained unaware until mid-way through the Inquiry's public hearing. Mr Jacob accepted this;⁶¹⁹

- b. PTTEPAA could readily have purchased outside consultancy expertise to undertake a detailed review of, and report on, the circumstances and likely causes of the Blowout. Indeed, Mr Jacob conceded that there was much to be said in favour of obtaining external expert input, because of the objectivity and independence which such experts would be able to bring to bear in undertaking an examination;
- c. it was not reasonable for PTTEPAA to rely upon Ms Breadmore's document review in circumstances where she did not possess any well engineering expertise;
- d. PTTEPAA could readily have sought and obtained assistance from its parent company to undertake a detailed review of, and report on, the circumstances and likely causes of the Blowout;
- e. PTTEPAA was in a position to provide this Inquiry with a submission on 22 December 2009, running to over 126 pages – of which 47 dealt with the circumstances and likely causes of the Blowout. Accordingly, PTTEPAA was willing to expend considerable effort explaining its position, but failed to bring any independent analysis to bear on that position, particularly with respect to the actions and omissions of its onshore personnel; and
- f. in the lead up to the Inquiry PTTEPAA (through Mr Jacob) had many weeks to properly investigate the circumstances and likely causes of the Blowout. It did not do so. Rather, PTTEPAA sought to rely upon a series of Statutory Declarations made by its personnel which were highly defensive in tenor and text, and which adhered to positions on a wide range of issues which were found wanting in significant respects. Because PTTEPAA failed to properly inform itself of readily ascertainable matters, the Inquiry was treated to the spectacle of every PTTEPAA-related witness abandoning substantial parts of their pre-hearing Statutory Declarations in the course of the Inquiry's public hearing.

7.40. Even when PTTEPAA was provided with a copy of the Atlas Report it preferred, in the main, to adopt an argumentative and finger-pointing position, rather than undertake an objective assessment of the points made in that report.⁶²⁰

⁶¹⁹ T1870-T1871 (Jacob).

- 7.41. Mr Jacob told the Inquiry that he actually made a conscious decision *not* to undertake or arrange a detailed investigation into the circumstances and likely causes of the Blowout, because he anticipated that those matters would be covered by the Inquiry. Based on Mr Jacob's evidence, it appears that senior PTTEPAA management, including the current CEO, accepted or supported this approach.
- 7.42. The Inquiry considers that PTTEPAA's investigative inertia was both extraordinary and irresponsible. Mr Jacob admitted as much, albeit belatedly and with the benefit of hindsight.
- 7.43. In this regard, it is instructive to compare and contrast PTTEPAA's approach with that of Atlas. Atlas assembled an investigation team within days of the Blowout occurring. Within a matter of weeks it received external expert assistance by way of detailed written analysis, which it factored into its investigation. In its submission to the Inquiry in December 2009 Atlas advised:
- Atlas is undertaking ongoing investigations into the likely causes of the hydrocarbon release and any changes to its systems and practice that should be implemented. It will provide details of the outcomes of those investigations to the Commissioner as soon as they are available.
- 7.44. In due course, Atlas produced a very detailed and comprehensive report to the Inquiry (the Atlas Report). The Atlas Report was self-critical in various respects, and was completed in full knowledge that its contents would be made available to the Inquiry (a Notice to Produce was served well in advance of completion of the Atlas Report). The Atlas Report was issued by a senior Atlas employee who was not personally involved in the events between March and August 2009. In addition, there were two members of the Investigation Group and four members of the Technical Review Team who were involved in the preparation of the Atlas Report. One of the Technical Review Team members was Mr Ross, a wholly independent qualified expert.
- 7.45. From the very outset of the Inquiry's public hearing, the Atlas witnesses (Mr Gouldin and Mr Millar) were helpful, candid, and balanced in the evidence they gave. By way of contrast, PTTEPAA did not volunteer, in any sort of candid or unguarded way, any criticisms of the performance of its onshore personnel until Mr Jacob gave evidence. And although Mr Jacob was frank and forthcoming in accepting a long list of criticisms of PTTEPAA's performance as

⁶²⁰ PTTEPAA did accept, in the face of the Atlas Report, that a post-WOC pressure test should have been carried out. However, it laid the blame for this omission on the on-rig personnel, and strenuously resisted the idea that onshore personnel were implicated.

titleholder, it has to be observed that he did so only after listening to concessions and admissions made by each and every previous PTTEPAA-related witness.

- 7.46. In submissions filed after the public hearing and the release of the Inquiry's preliminary findings to PTTEPAA, it advanced various arguments concerning the above criticisms of its conduct. Those arguments and the Inquiry's responses are as follows:
- a. PTTEPAA noted that it was very busy in the aftermath of the Blowout. This is offered as an 'explanation', rather than as a 'excuse'. For reasons stated above, it is a seriously inadequate explanation;
 - b. PTTEPAA stated that it 'was conscious of the fact that it was not endangering the safety of personnel by not focussing on a very detailed root cause analysis...'. This is because it only allowed a very limited number of personnel on the WHP, being experts from ALERT and representatives from PTTEPAA. This is a poor argument. The fact is that it did expose those personnel to risks by not properly informing itself and them of the myriad well control deficiencies at the Montara Oilfield;
 - c. PTTEPAA noted that in most regulatory schemes, the incident or accident is over by the time a report is required, whereas control of the H1 Well was not generally secured until January 2010. In this regard PTTEPAA sought to draw an analogy with the 2006 Beaconsfield Mine Accident. These arguments are weak. As the Blowout demonstrates, an offshore petroleum incident may take five to six months to resolve. It is manifestly unreasonable for a licensee to expect that it can wait that long to investigate the causes of a blowout of the kind which occurred here. The Inquiry accepts that it is not simply a matter of 'walking and chewing gum at the same time'. However, the plain fact of the matter is that PTTEPAA could have, and should have, undertaken a proper investigation into the cause of the Blowout in a timely fashion, notwithstanding how busy it was in the aftermath of the Blowout; and
 - d. in addition to preparing regulatory reports, PTTEPAA was required to prepare detailed submissions and respond to the Inquiry's summons. Again, this is a poor 'explanation'. PTTEPAA submissions were filed four months after the Blowout, and the summonses to PTTEPAA were generally returnable as and from January 2010 (some five months after the Blowout).

- 7.47. The above ‘explanations’ by PTTEPAA ignore the reality of the regulatory regime in which PTTEPAA was required to operate, and the predictable consequences of a blowout. Further, all of the explanations offered by PTTEPAA fail to address the matters set out in paragraph 7.39 above.

Finding 94

PTTEPAA’s own investigations into the circumstances and likely causes of the Blowout were manifestly deficient.

Finding 95

PTTEPAA’s failure to properly investigate the Blowout was irresponsible and inexcusable. It allowed personnel (albeit limited in number) to attend the WHP without properly informing itself or them of myriad well control deficiencies at the Montara Oilfield.

Deficiencies in the information provided by PTTEPAA to NOPSA and to this Inquiry as to the circumstances and likely causes of the Blowout

- 7.48. The egregious failure of PTTEPAA to come to grips with the circumstances and likely causes of the Blowout cannot be regarded as a matter of little significance or as a side issue. It resulted in PTTEPAA, on numerous occasions, giving false and misleading information to various officials. Further, that failure undermines the extent to which PTTEPAA can be relied upon to make proper judgments, and act responsibly, when its interests are at stake.

Information provided to NOPSA by PTTEPAA

- 7.49. On 2 October 2009 PTTEPAA submitted a so-called ‘Incident Report’ to NOPSA. This Incident Report was prepared by PTTEPAA’s in-house legal counsel Ms Breadmore, was checked by Mr Duncan, and was approved by Mr Jacob. The Incident Report appears to have been issued for internal review within PTTEPAA in late September 2009, some four weeks after the Blowout.
- 7.50. The Incident Report is a largely unhelpful and self-justifying document.
- 7.51. For instance, the Incident Report adopted a self-justifying position in relation to the removal and non-reinstallation of the 9 $\frac{5}{8}$ ” PCCC, as to which the following account was given:

The 9 $\frac{5}{8}$ ” pressure containing anti-corrosion cap was removed on 20 August 2009 for operations to clean up the 13 $\frac{3}{8}$ ” corroded casing threads in the H1 Well. No trapped pressure or flow was observed following its removal...The 9 $\frac{5}{8}$ ” cap was not re-installed before skidding the drilling package to the H4 Well. However, re-installation of that cap

was not required by the Drilling Program due to the nature of the 'batch' tie-back operations. The deviation from the Drilling Program on 20 August 2009... resulted in approximately 15 hours without a pressure containing corrosion cap on the 9 $\frac{5}{8}$ " casing before the uncontrolled flow. However, there would in any event have been approximately 8-10 hours without a pressure containing cap on the 9 $\frac{5}{8}$ " casing if the tie-back operations had proceeded on 20 August 2009 as per the Drilling Program absent the deviation.

7.52. In addition to being self-justifying, the last sentence in the above extract is quite wrong and PTTEPAA should have understood this.⁶²¹

7.53. In dealing with the substitution of PCCCs for a cement plug, the Incident Report did not address the suitability of PCCCs as barriers. It merely relied upon the fact of the NT DoR's approval of their use.

7.54. In relation to the cementing of the 9 $\frac{5}{8}$ " casing shoe the Incident Report was seriously misleading. It stated:

Backflow of hydrocarbons through the shoe track during the cementing job suggests that the valves in the float collar failed because they did not hold pressure. This was discussed by the Drilling Superintendent and the Drilling Supervisor, and the decision was made to instruct the crew to hold the pressure on the casing until the cement had set. After releasing pressure, no pressure differential or flow was observed. Therefore, there was no reason to suspect at that time that the backflow had compromised the cement job...

7.55. This account contains no mention whatsoever of a pumping back of cement beneath the float collar. It also suggests, quite wrongly, that there was no reason to suspect that the cemented shoe lacked integrity.

7.56. Significantly, the Incident Report to NOPSA went on to state as follows in relation to the integrity/control of other wells at the Montara Oilfield:

PTTEPAA has firstly undertaken a review of the suspension status of the other Montara development wells at the WHP facility in order to assess whether there are any well hazards indicated by the constructed condition of those wells that present a well control risk.

⁶²¹ PTTEPAA later asserted that the H1 Well would have been exposed to atmosphere for a period of 24 hours, and Mr Jacob in his oral evidence suggested that the period might have been as much as three days. The Inquiry's estimate is in the order of 36-48 hours.

PTTEPAA then set out brief descriptions of the barriers in place in each of the H2, H3, H4 and GI Wells. No deficiency was identified. It was then stated:

Based on this review, PTTEPAA has assessed that the risk of a similar incident occurring when MODU facility operations recommence...**is as low as reasonably practicable.** [emphasis added]

- 7.57. PTTEPAA's risk assessment was extraordinarily superficial and plainly flawed, having regard to the nature and extent of problems now known in relation to the other wells (see above).
- 7.58. The upshot is that PTTEPAA seriously misled NOPSA in a number of important respects in its Incident Report of 2 October 2009.
- 7.59. Subsequently, on 19 October 2009 PTTEPAA was informed by Mr Stewart McGregor (AGR Petroleum Services) that serious issues existed with respect to the integrity of the cemented casing shoe in the GI Well. Mr McGregor also advised PTTEPAA that, as neither of the PCCCs in the GI Well was tested, they could not be considered to be verified barriers against a blowout.⁶²²
- 7.60. PTTEPAA did not inform either the NT DoR or NOPSA of this information.
- 7.61. Further, it appears that Mr McGregor's information did not trigger any reconsideration of well control with respect to the other wells at the Montara Oilfield, even though the non-testing of PCCCs on the GI Well had obvious implications for other wells at the Montara Oilfield.
- 7.62. Then, on 25 November 2009, Mr Jacob advised NOPSA in writing as follows:
- There were no deviations from the PTTEPAA Australasia Well Constructions Standards in relation to the temporary suspension of Montara wells GI, H1, H2, H3 and H4.
- 7.63. The plain fact of the matter is that, contrary to Mr Jacob's assertion, PTTEPAA had failed to comply with its own standards with respect to each and every well at the Montara Oilfield, and all of the wells involved multiple departures from those standards.
- 7.64. Then, on 17 February 2010, Mr Jacob was interviewed by NOPSA officials in relation to the Blowout. This interview took place around four weeks prior to the commencement of the Inquiry's public hearing. In that interview Mr Jacob

⁶²² Email from Mr Stewart McGregor to Mr Craig Duncan, 19 October 2009, PTT.9002.0106.0238-39.

told NOPSAs that the contents of PTTEPAA's earlier Incident Report remained accurate.⁶²³ Due to serious inadequacies in Mr Jacob's state of knowledge, he then proceeded to provide further false and/or misleading information to NOPSAs. For instance:

- a. Mr Jacob told NOPSAs that the use of the wrong volume of cement resulted from a failure on the part of on-rig personnel to implement an onshore change. This was misleading. It gave the impression that onshore personnel from PTTEPAA were not implicated in the wrong use of tail cement, whereas in fact Mr Wilson had been asked to check Mr Treasure's figures but failed to do so;
- b. Mr Jacob told NOPSAs that the non-installation of the 13 $\frac{3}{8}$ " PCCC occurred in the following circumstances:

...when the individuals on the rig went to install the cap as part of the drilling program they discovered that it...was corroded and they determined it was unsuitable to be put into the well and therefore it wasn't at that time. So if it had been better preserved it would have been in a condition to have been utilised.

Mr Jacob accepted in his oral evidence to the Inquiry that this account was false;

- c. Mr Jacob told NOPSAs that the displacement fluid in the 9 $\frac{5}{8}$ " casing in the H1 Well was a proven barrier against a blowout. This was false;
- d. Mr Jacob told NOPSAs that information provided by personnel on the rig to Mr Wilson 'indicated that the casing had been tested okay...they checked the cement integrity and that was okay'. This was a seriously misleading account of the content of the information supplied by on-rig PTTEPAA personnel to onshore personnel. Properly analysed, the information provided by on-rig personnel indicated the existence of a wet shoe which should have been tested, but was not;
- e. Mr Jacob told NOPSAs that the earlier-than-scheduled removal of the 9 $\frac{5}{8}$ " PCCC on the H1 Well on 20 August 2009 involved a change in timing only, as the cap would have been removed during the program in any event. Again, this information was seriously misleading. Mr Jacob subsequently accepted in his oral evidence to the Inquiry that the early removal, and

⁶²³ Mr Jacob told NOPSAs: '...we would now confirm that we believe the...flow to be through the 9 $\frac{5}{8}$ " casing which was one of the three potential causes that we had identified in this report. Other than that, we believe the document remains accurate'.

non-reinstallation, of the 9 $\frac{5}{8}$ " PCCC was a significant event which was not properly risk assessed by PTTEPAA personnel on-rig and onshore; and

- f. Mr Jacob also gave a very misleading account of the cementing operation in the H1 Well on 7 March 2009. He stated:

...upon realising that they had flow back, my understanding is that they shut in the valves in order to prevent any further flow back. They then made a calculation of the volume that had been expelled from the – through the floats and they pumped that volume back into the – through the floats again. And then they maintained the pressure on the – that pressure on the cement until the cement had set.

The plain fact of the matter is that no calculation was ever made of the volume that had flowed back from beneath the floats. Nor was that particular volume pumped back. Rather, that volume plus 9.25 barrels of inhibited seawater were pumped back.

- 7.65. The Inquiry does not find that Mr Jacob deliberately provided false and misleading information to NOPSA. However, the steps he took to inform himself as to the circumstances and likely causes of the Blowout were so inadequate that he failed to gain any proper understanding of those matters. This led him to supply a good deal of false and misleading information to NOPSA.⁶²⁴
- 7.66. There is a further aspect of Mr Jacob's interview with NOPSA that warrants attention. Mr Jacob made a conscious decision during that interview to withhold particular information from NOPSA, as indicated by the following questions and answers.

Q. Okay. Before the suspension, Andy, we asked the question if as a result of their investigations has PTTEPAA identified anything reasonably practicable that they could have done prior to the events of 21 August 2009 which would have prevented the flow from the H1 ST1?

A. PTTEPAA has not as yet identified the cause of the flow in the well and therefore it is unable to provide an answer to that question.

...

Q. Okay. Would it be reasonably practicable to have reinstalled the 9 $\frac{5}{8}$ " MLS corrosion caps after the threads on the 13 $\frac{3}{8}$ " MLS hanger had been cleaned?

A. I am unable to answer that question at this time.

⁶²⁴ Mr Jacob admitted this in his oral evidence to the Inquiry, for example at T1722-T1745. He also admitted that misinforming NOPSA was manifestly unsatisfactory, for example at T1745.

Q. When you say you're 'unable to answer that question' is that because your not prepared to answer the question or you just don't have the information?:

A. I wasn't on the rig at the time, so I am not aware of whether it was a practicable thing to do or not.

Q. Could we ask you to seek an answer for that question?

A. At this time we're probably not prepared to answer that either.

Q. Okay.

Q. So probably not, or not?

A. Sorry.

Q. Not prepared?

A. Not prepared to answer.

Q. Okay. And would it be reasonably practicable to have installed the BOPs before removing the 9½" MLS corrosion caps thereby ensuring that a barrier was installed before removing the cap?

A. Again, I am not prepared to answer at this time.

...

Q. ...Was there a risk to the health of any person at or near the Montara Well Head Platform facility and the *West Atlas* facility on 20 August 2009 and 21 August 2009 as a result of the uncontrolled release of hydrocarbons from the H1 ST1 Well?

A. I am not willing to provide an answer at this time.

Q. On 21 August 2009 was there a potential danger of fire and explosion of the hydrocarbons fluids flowing from the H1 ST1 Well?

A. Again, not prepared to answer at this time.

Q. On 20 August 2009 and 21 August 2009 did PTTEPAA take all reasonable and practicable steps to provide and maintain a physical environment at the facility that was safe and without risk to health?

A. Again, not prepared to answer at this time.

7.67. The Inquiry readily accepts that it was within Mr Jacob's and PTTEPAA's legal rights to refuse to supply the above requested information, as the interview was conducted on a voluntary basis. However, Mr Jacob's interview with NOPSA demonstrates that PTTEPAA was prepared to volunteer information when it considered it to be in its best interests to do so, but was also content to withhold information on the same basis. That state of affairs does not reflect well upon PTTEPAA as a corporate citizen.

7.68. When Mr Jacob made his original Statutory Declaration dated 8 March 2010 he still had not taken any real steps to personally satisfy himself as to the circumstances and likely causes of the Blowout. His sources of information were largely limited to PTTEPAA's legal counsel (Ms Breadmore) and members of PTTEPAA's Well Construction Department who were personally involved in the events on 7 March 2009 and 20 August 2009. Prior to giving evidence he did not read the Statutory Declarations of other PTTEPAA-related witnesses, and he did not read the Atlas Submission to the Inquiry.

7.69. After hearing evidence given by a succession of PTTEPAA-related witnesses, Mr Jacob made significant changes to his Statutory Declaration and then, in the witness box, Mr Jacob made a further series of concessions on behalf of PTTEPAA. Whilst, in one sense, Mr Jacob is to be commended for his willingness to make those concessions, it must also be acknowledge that by the time he entered the witness box he had little choice in the light of the evidence which had, by then, come to light.

7.70. Further, Mr Jacob's candour in the witness box does not justify PTTEPAA's inert approach to this Inquiry. In this regard, the Inquiry notes the following additional evidence given by Mr Jacob:

Q. You see, sir, the evidence you are giving gets close to an assertion that you kept yourself in a state of steadfast ignorance as to what was being offered to this Inquiry concerning the possible causes of the blowout. Do you agree with that?

A. I can see how you can come to that, yes.

Q. It is a pretty extraordinary approach; would you agree?

A. Looking back, yes.

A. Yes.

...

Q. I suggest to you, sir, that you don't need the wisdom of hindsight to actually understand the serious pitfalls in the approach which you took on behalf of [PTTEPAA] in that regard; do you agree?

A. I took the decision at the time based what I was thinking with regard to myself giving evidence to the Commission. It was flawed, yes.

Q. Not only was it flawed, but it was adhered to in circumstances in which you knew information was being offered to this Commission about significant issues which warranted consideration, but you yourself didn't even bother to read that material, much less satisfy yourself about those issues?

A. That's what happened, yes.

7.71. In reaching this conclusion the Inquiry has taken into account the positive findings made elsewhere in this Report concerning PTTEPAA. For instance, the Inquiry notes the following positive findings concerning PTTEPAA:

- a. PTTEPAA performed commendably in the immediate aftermath of the Blowout;
- b. PTTEPAA assessed the merits of well control options after the Blowout in a manner which, appropriately, gave paramountcy to the safety of personnel;
- c. PTTEPAA's response effort was diligent and vigorous; and
- d. PTTEPAA ought to be commended for its cooperation in relation to the Monitoring Plan and its decision to fund all Scientific Monitoring studies.

7.72. However, these factors stop short of persuading the Inquiry that it should not recommend a review of PTTEPAA's permit and licence, having regard to the large number of matters which support the carrying out of a review.

Conclusion

7.73. The overall outcome appears to be as follows:

- a. PTTEPAA failed to properly investigate the circumstances and likely causes of the Blowout. Its failure to do so was manifestly unreasonable;
- b. in the seven months since the Blowout PTTEPAA has supplied a good deal of false and misleading information to NOPSA and to this Inquiry;
- c. PTTEPAA only acknowledged the nature and extent of its deficiencies with respect to well control at the Montara Oilfield in circumstances where, practically and legally, it could not really do otherwise.

7.74. This outcome reflects very poorly upon PTTEPAA.

7.75. When these factors are combined with the material dealt with in paragraphs 7.11 to 7.33 above, the Inquiry considers that PTTEPAA's Montara Oilfield permit and licence should be reviewed. It may be that, in due course, PTTEPAA will be able to persuade the Minister that (i) it did not breach the OPGGS Act and regulations; or (ii) it has taken sufficient steps to address the many deficiencies in its practices and corporate culture. Indeed, as noted above, PTTEPAA has produced a very worthwhile Action Plan to address those deficiencies. Whilst the Action Plan comes somewhat belatedly, it is very comprehensive and captures most of the industry recommendations which the Inquiry makes in this Report. If PTTEPAA manages to implement its Action Plan it may turn the burden of this Inquiry into an opportunity to adopt best practice in the offshore petroleum industry.

Finding 96

In the aftermath of the Blowout PTTEPAA seriously misled NOPSA in a number of important respects (over a six month period).

Finding 97

In the aftermath of the Blowout PTTEPAA received information which indicated a lack of well integrity in the GI Well which it did not pass on to either the NT DoR or NOPSA.

Finding 98

Although there is no evidence that PTTEPAA *deliberately* provided false and/or misleading information to NOPSA, the fact it did so reflects very poorly upon it.

Finding 99

Further, there is evidence that PTTEPAA was prepared to volunteer information when it considered it to be in its best interests to do so, but was content to withhold information on the same basis.

Finding 100

In the course of the Inquiry, PTTEPAA largely adopted an argumentative and finger-pointing position. It only acknowledged the nature and extent of its deficiencies when, practically and legally, it could not really do otherwise.

Additional matter

- 7.76. As noted above, a joint investigation of some sort was carried out by PTTEPAA and its parent company, which resulted in the creation of a report. In this Inquiry, PTTEPAA and its parent company have claimed legal professional privilege (**LPP**) in respect of this report.
- 7.77. The Inquiry is concerned that PTTEPAA might have manoeuvred itself into a position whereby LPP could be claimed over this report. In the face of a request for information from NOPSA, PTTEPAA's in-house counsel sent an email to Mr Jacob and Mr Duncan on 27 August 2009 which stated:
- Please don't commence any internal investigation of the incident (including actioning of this request from NOPSA) until legal professional privilege between the company and Mallesons is formally established (which is imminent - I will receive the retainer letter from Mallesons shortly).
- 7.78. This email is consistent with the unsurprising possibility that PTTEPAA intended, immediately after the Blowout, to conduct an investigation into its causes for all sorts of purposes - for example, it needed to understand what might have caused the Blowout in order to plan how to kill the H1 Well, which was a major priority at that time. Yet PTTEPAA now claims that its dominant purpose in carrying out this investigation was simply to protect its legal interests.
- 7.79. In the end, the Inquiry did not need to finally resolve whether the report which resulted from this investigation was privileged or not (noting that any such resolution may ultimately have required judicial adjudication). The Inquiry notes and accepts that PTTEPAA was within its rights to agitate a claim of privilege.

7.80. However, the Inquiry considers it unsatisfactory that LPP (assuming it exists) operated to preclude the Inquiry having access to the only written report obtained by PTTEPAA concerning the circumstances and likely causes of the Blowout. The Inquiry recommends that the Minister consider legislative amendments which make clear that (i) the Minister can direct a titleholder to obtain an independent report into the circumstances and likely causes of a blowout; and (ii) the Minister can direct that such a report be provided to him (that is, legal professional privilege cannot be asserted as a reason for not providing such a report).

Recommendation 101

The Minister should, as the JA for the offshore area of the Territory of Ashmore and Cartier Islands, undertake a review of PTTEPAA's permit and licence to operate at the Montara Oilfield.

Recommendation 102

For the purposes of that review, the Minister should issue a 'show cause' notice to PTTEPAA under s 276 of the OPGGS Act.

Recommendation 103

In carrying out a review of PTTEPAA's permit and licence, the Minister should have regard to this Report, particularly (i) the adverse findings set out in this Chapter; and (ii) the extent to which PTTEPAA has implemented the Action Plan submitted to the Inquiry, or otherwise addressed the matters canvassed in this Report.

Recommendation 104

The Minister consider legislative amendments to the OPGGS Act which make clear that (i) the Minister can direct a titleholder to obtain an independent report into the circumstances and likely causes of a blowout; and (ii) the Minister can direct that such a report be provided to him (and such direction overrides any legal professional privilege which otherwise attaches to the report).

Recommendation 105

In view of the numerous well integrity problems in all of the Montara Oilfield wells, the Minister should commission a detailed audit of all the other offshore wells operated by PTTEPAA to determine whether they too may suffer from well integrity problems.

8. FINDINGS AND RECOMMENDATIONS

CHAPTER 3 - THE CIRCUMSTANCES AND LIKELY CAUSES OF THE BLOWOUT

Finding 1

A direct and proximate cause of the Blowout was the defective installation by PTTEPAA of a cemented shoe in the 9 $\frac{5}{8}$ " casing of the H1 Well on 7 March 2009. This cemented shoe was intended to operate as the primary barrier against a blowout.

Finding 2

The installation of the cemented shoe was defective in that, after failure of floats/valves located in the shoe apparatus, displacement fluid was pumped beneath the float collar which resulted in over-displacement of cement from the casing shoe track and in the area outside the casing shoe (called the annulus).

Finding 3

The pumping back of this displacement fluid was contrary to sensible oilfield practice, and led to a so-called 'wet shoe'. The result was that the cemented shoe lacked integrity as a barrier.

Finding 4

The acts and omissions of PTTEPAA personnel, both on-rig and onshore, were directly responsible for the creation and non-detection of the defective cemented casing shoe.

Finding 5

Although Halliburton played a role in the actual cementing operation its role was, relevantly, confined to the performance of machinist services on the rig (rather than onshore advisory services). The Inquiry heard no evidence of any deficiency in Halliburton's performance of that role. PTTEPAA did not seek advisory input from Halliburton personnel onshore in relation to the problems which arose in the course of the cementing operation.

Finding 6

Atlas personnel were not relevantly involved in the actual installation of the cemented casing shoe.

Finding 7

However, the direct and proximate causes of the Blowout include failures on the part of personnel from both PTTEPAA and Atlas (on-rig and onshore) to recognise, in the aftermath of the cementing operation on 7 March 2009, that a wet shoe had been created. These failures occurred at each of two stages: first, during the course of preparation, by on-rig personnel, of contemporaneous documents which described the cementing operation; and secondly, upon review of those documents by onshore personnel from each organisation (which occurred soon after the cementing operation).

Finding 8

PTTEPAA bears a larger measure of responsibility for these failures than Atlas. This is because (i) under arrangements agreed between them, PTTEPAA took on primary responsibility for well control; and (ii) in its day-to-day operations PTTEPAA did not in fact rely upon Atlas for expert supervisory oversight of well control operations.

Finding 9

The direct and proximate causes of the Blowout include failures on the part of personnel from both PTTEPAA and Atlas, on-rig and onshore, to ensure that a test of the cemented casing shoe was carried out (that is, a test after waiting on the cement to set).

Finding 10

These failures were contrary to sensible oilfield practice, and were also contrary to PTTEPAA's own Well Construction Standards.

Finding 11

It is likely that, if a test had been carried out, it would have confirmed the unreliability of the cemented casing shoe as a barrier. In any event, remedial action could and should have been taken, in which case the Blowout would not have occurred.

Finding 12

PTTEPAA bears a higher measure of responsibility for these failures than Atlas. This is because (i) under arrangements agreed between them, PTTEPAA took on primary responsibility for well control; and (ii) in its day-to-day operations PTTEPAA did not in fact rely upon Atlas for expert supervisory oversight of well control operations.

Finding 13

Another factor which may have directly and proximately contributed to the Blowout was the use by PTTEPAA of an incorrect volume of ‘tail’ cement in the course of the cementing of the shoe in the H1 Well on 7 March 2009. This may have led to the creation of channels or ‘wormholes’ in the cement surrounding the 9 $\frac{5}{8}$ ” casing string and casing shoe, thereby further compromising the integrity of the cemented casing shoe as a barrier. Whilst it is unlikely that this directly contributed to the Blowout, the possibility that it did so cannot be excluded.

Finding 14

Again, both on-rig and onshore personnel from PTTEPAA were involved in the creation of this defect.

Finding 15

The use of an incorrect volume of tail cement – even if it did not cause the Blowout – is further evidence of an unsatisfactory approach by PTTEPAA to issues affecting well integrity.

Finding 16

The direct and proximate causes of the Blowout include the failure to install a PCCC on the 13 $\frac{3}{8}$ ” casing string of the H1 Well. This should have occurred in early/mid March 2009. This PCCC was intended to operate as a secondary barrier against a blowout.

Finding 17

The non-installation of a 13 $\frac{3}{8}$ ” PCCC was contrary to sensible oilfield practice, and was also contrary to PTTEPAA’s own Well Construction Standards.

Finding 18

If the 13 $\frac{3}{8}$ ” PCCC had been installed it would have operated as a secondary barrier against a blowout. Further, failure to install a 13 $\frac{3}{8}$ ” PCCC led to the removal of the 9 $\frac{5}{8}$ ” PCCC in August 2009, thereby leaving the H1 Well without any secondary barriers against a blowout.

Finding 19

The non-installation of the 13 $\frac{3}{8}$ ” PCCC should have been detected by on-rig personnel from both PTTEPAA and Atlas. However, PTTEPAA bears a larger measure of responsibility for this cause than Atlas. This is because (i) under arrangements agreed between them, PTTEPAA took on primary responsibility for well control; (ii) in its day-to-day operations PTTEPAA did not in fact rely upon Atlas for expert supervisory oversight of well control operations; and (iii) it was PTTEPAA-related personnel who mistakenly reported that the 13 $\frac{3}{8}$ ” PCCC had been installed.

Finding 20

The direct and proximate causes of the Blowout include removal, and non-reinstallation, of a PCCC on the 9 $\frac{5}{8}$ " casing string of the H1 Well around midday on 20 August 2009. This PCCC was intended to operate as a secondary barrier against a blowout.

Finding 21

The absence of a 9 $\frac{5}{8}$ " PCCC from midday 20 August 2009 was contrary to sensible oilfield practice, and was also contrary to PTTEPAA's own Well Construction Standards.

Finding 22

The Blowout occurred approximately 15 hours after removal of the 9 $\frac{5}{8}$ " PCCC. If the 9 $\frac{5}{8}$ " PCCC had remained in place, or been re-installed, the Blowout would not have occurred.

Finding 23

Personnel from PTTEPAA were responsible for the decision to remove, and not re-install, the 9 $\frac{5}{8}$ " PCCC. However, Atlas' OIM did not take any steps to ensure that the 9 $\frac{5}{8}$ " PCCC was re-installed, despite being aware of its removal.

Finding 24

In respect of these failures the largest share of responsibility must be borne by PTTEPAA rather than Atlas. Under arrangements agreed between them, PTTEPAA took on primary responsibility for well control, and in its day-to-day operations it did not in fact rely upon Atlas for expert supervisory oversight of well control operations.

Finding 25

A factor which is likely to have indirectly contributed to the Blowout is that a sufficiently detailed risk assessment was not undertaken by PTTEPAA in relation to the general topic of use of PCCCs as secondary barriers against a blowout, particularly in the context of batched tie-back operations which were to occur at Montara.

Finding 26

The absence of such a risk assessment meant, for instance, that (i) PTTEPAA personnel wrongly thought that the PCCCs in question were designed to operate as barriers against a blowout; (ii) PTTEPAA personnel wrongly thought that the PCCCs were able to be tested and verified post-installation in accordance with the manufacturer's instructions; and (iii) PTTEPAA personnel did not properly appreciate one significant advantage which other types of barriers have over PCCCs in the context of batched tie-back operations: namely, other barriers can remain in place during and after tie-back, whereas PCCCs must be removed prior to tie-back of a casing string.

Finding 27

Had the use of PCCCs been properly risk assessed a decision would probably have been reached to rely upon some other form of secondary barrier such as a cement plug. In that event, it is unlikely the Blowout would have occurred.

Finding 28

The PCCC used in the H1 Well should have been tested by PTTEPAA soon after installation. However, no instruction was given by PTTEPAA to carry out such a test.

Finding 29

Had such an instruction been given it may have come to light that (i) the manufacturer did not endorse any post-installation test for barrier integrity; and (ii) at that point in time there was no method or equipment available to reliably test the PCCC after installation. That may have prompted a review of the use of PCCCs as barriers.

Finding 30

Further, as noted above, in the absence of any such test it is possible that the 9 $\frac{5}{8}$ " PCCC on the H1 Well was not working properly after installation, which might explain the absence of any detectable pressure beneath the PCCC prior to its removal.

Finding 31

An indirect and systemic factor which contributed to the Blowout was widespread misunderstanding on the part of PTTEPAA personnel as to the barrier status of the displacement fluid contained within the 9 $\frac{5}{8}$ " casing in the H1 Well. Misconceptions as to the status of the casing fluid influenced PTTEPAA's approach to well control.

Finding 32

Both on-rig and onshore personnel from PTTEPAA wrongly considered that the fluid could be relied upon as an effective barrier against a blowout.

Finding 33

Their approach to that question was contrary, in fundamental respects, to sensible oilfield practice with respect to well control. It was also contrary to PTTEPAA's own Well Construction Standards.

Finding 34

In the lead up to the Blowout, both on-rig and onshore personnel from PTTEPAA attached too much weight to the absence of observable signs of flow from the reservoir. There is reliable evidence to the effect that Atlas personnel succumbed to the same mistake.

Finding 35

Similarly, personnel from both PTTEPAA and Atlas failed to ensure that the dynamics of the casing fluid were properly monitored after removal of the 9 $\frac{5}{8}$ " PCCC.

Finding 36

There were a large number of significant deficiencies in various PTTEPAA documents dealing with well control – such as the WOMP, the Well Construction Standards, the two Drilling Programs in force in March and August 2009, and instructions given to drillers. These deficiencies were, in aggregate, an important systemic factor which indirectly contributed to the Blowout.

Finding 37

There were a number of significant deficiencies in PTTEPAA's management systems for recording and communicating information within the company – between personnel working day and night shifts, between personnel at the time of hitch handover (usually on 21 day cycles), between on-rig and onshore personnel, and between onshore personnel. These deficiencies were, in aggregate, an important systemic factor which indirectly contributed to the Blowout.

Finding 38

There were considerable deficiencies in the formal and informal arrangements which PTTEPAA and Atlas adopted for managing risks arising out of operations affecting the safety interests of both entities.

Finding 39

The respective roles and responsibilities of PTTEPAA and Atlas, particularly with respect to well control, were not adequately defined, documented or implemented.

Finding 40

These deficiencies, taken together, constitute one of the most significant indirect causes of the Blowout.

Finding 41

There were some deficiencies in PTTEPAA's logistics management. Of most significance was the fact that no-one identified or appreciated that the 13 $\frac{3}{8}$ " PCCC which was meant to be installed on the H1 Well was in fact shipped back to Darwin after the wells at the Montara Oilfield were suspended.

Finding 42

PTTEPAA did not have effective internal systems in place to achieve a high level of quality assurance with respect to well control operations. In particular, systems were not in place to ensure (i) vigilant day-to-day supervision of subordinate personnel; (ii) monitoring of well operations through internal audits.

Finding 43

These deficiencies contributed to the development and non-detection of inadequate well control practices.

Finding 44

Had key personnel from both PTTEPAA and Atlas (on-rig and onshore) possessed a greater level of knowledge and expertise in relation to cementing operations, it is likely they would have detected (i) the problem with the cemented casing shoe, thereby enabling remedial steps to be taken; and (ii) many other deficiencies in PTTEPAA's approach to well control at the Montara Oilfield.

Finding 45

PTTEPAA did not have effective internal systems in place to acquire and maintain an appropriate level of knowledge and expertise on the part of its personnel. Atlas' systems for acquiring and maintaining appropriate levels of expertise may also require review.

Finding 46

PTTEPAA's internal governance structures post-acquisition were somewhat deficient: first, there was less committee oversight of important decisions which is likely to have reduced the level of quality assurance; secondly, there was an attenuation in the lines of accountability when decision-making was located offshore in Bangkok.

Finding 47

Had more rigorous internal governance structures been in place it is possible that risks associated with the operations at Montara may have been identified and addressed.

Finding 48

Deficiencies in the performance of the NT DoR's role as regulator did not contribute *directly* to the Blowout. However, they did contribute to the development and non-detection of poor well control attitudes and practices on the part of PTTEPAA.

Finding 49

Deficiencies in the NT DoR's role as regulator included (i) failure to undertake a proper assessment of the use of PCCCs in a batched drilling context in March 2009, when it approved PTTEPAA's use of PCCCs as secondary barriers on the H1 Well; (ii) failure to insist upon proper well control when it formally approved PTTEPAA's Phase 1B Drilling Program in July 2009 (noting that this Drilling Program contemplated that the H1 Well would be exposed to atmosphere for a somewhat indeterminate, but unsatisfactory, length of time whilst PTTEPAA undertook batched tie-back operations on other wells); and (iii) failure to adequately monitor PTTEPAA's compliance with good oilfield practice with respect to well control.

Finding 50

Deficiencies in the applicable regulatory regime may have led to (i) gaps and shortfalls in regulatory oversight by the NT DoR; and (ii) confusion on the part of PTTEPAA and Atlas concerning their respective roles and responsibilities in relation to well control.

Finding 51

In any event, regulation of well control by a single regulator, with comprehensive oversight of general industry practice and responsibility for all aspects of offshore operations, is likely to lead to higher standards of well control on the part of industry participants.

General recommendations regarding the well integrity framework

Recommendation 1

The Minister should appoint a senior policy adviser to investigate and report on the best means to implement the recommendations contained in this Chapter.

Recommendation 2

WOMPs submitted by licensees to the regulator(s) should continue to be the primary framework document for achieving well integrity.

Recommendation 3

WOMPs should be comprehensive and freestanding, rather than an overarching document cross-referencing many other documents (although the Inquiry also recommends a freestanding well control manual; this should be a guide to rig and onshore personnel on good oilfield practice).

Recommendation 4

The concept of ‘good oilfield practice’ should be supplemented by the requirement to incorporate into WOMPs non-exhaustive minimum compliance standards in relation to well control: for example, stipulations as to when BOPs and/or well control systems must be in place and when they can be removed and minimum barrier requirements (a number of other factors that should be stipulated are outlined in other recommendations below).

Recommendation 5

Well construction and management plans should include provision(s) for reviewing the integrity of barriers at safety-critical times or milestones, such as (i) prior to suspension involving departure of the rig from the platform; (ii) prior to re-entry of a well after suspension; (iii) prior to removal of any barrier.

Recommendation 6

Well construction and management plans, and drilling programs, should include provision for testing and verifying the integrity of all barriers as soon as practicable after installation.

Recommendation 7

Well construction and management plans should include provision for an independent compliance review of well integrity (i) in the event of stipulated triggers; and (ii) at least once in the period between perceived achievement of well integrity and production. The independent compliance review should be undertaken by an expert who is not involved in the day-to-day drilling operations. Reviews should be completed in sufficient time to enable results to be implemented in a meaningful manner.

Recommendation 8

Wellbore gas bubbling should be regarded as a trigger for independent review of well integrity. Industry and regulators should identify and document other triggers.

Recommendation 9

If a risk assessment or compliance review is triggered by the happening of a pre-determined event, specific consideration should be given to whether a ‘hold point’ should be introduced such that work must cease until the problem is resolved (and the subject of appropriate certification).

Recommendation 10

A separate, identifiable barrier manual should be agreed upon and used by licensees, rig operators, and cementing contractors. These manuals should set out best industry practice in relation to achieving and maintaining well integrity. They should describe barrier types, barrier standards, general principles of well integrity, testing and verification methods and technologies, standard operating procedures (including procedures for the capture and communication of relevant information within and between relevant stakeholder entities). Barrier manuals should address blowout control during drilling, completion, re-entry, tie-back of casing strings and so on. Barrier manuals should be the subject of expert external review, and should be regularly updated.

Recommendation 11

Memoranda of Agreement should be entered into between operators in relation to provision of emergency assistance in the event of blowouts.

General recommendations regarding well integrity practices

Recommendation 12

Pre-drilling assessments should include a risk assessment of the worst-case blowout scenario.

Recommendation 13

Problems which arise in the course of installing barriers must be the subject of consultation between licensees, rig operators, and contractors (if used). A proper risk assessment should then be carried out and remedial steps (including further testing/verification) should be agreed upon, and documented in writing before the performance of remedial work whenever practicable. Joint written certification as to resolution of the problem should take place before resumption of drilling operations. Senior onshore representatives of stakeholder entities should be involved in that certification process.

Recommendation 14

Licensees should be subject to an express obligation to inform regulators of problems which arise in the course of installing barriers, even if they consider that well integrity is not thereby compromised. The information should be provided by way of special report, rather than included in a standard reporting document (such as a DDR). The information provided should include risk assessment details.

Recommendation 15

As soon as a risk of barrier failure arises, no other activities should take place in the well other than those directed to removal of the risk.

Recommendation 16

The use/type of barriers (including any change requests relating thereto) must be the subject of consultation between licensees and rig operators prior to installation. A proper risk assessment should be carried out, agreed upon, and documented in writing before installation. Joint written certification as to the appropriateness of the use of particular barriers should take place before installation. Senior onshore representatives of stakeholder entities should be involved in that certification process.

Recommendation 17

The successful installation of every barrier should be the subject of written verification within and between licensees and rig operators; and should be the subject of explicit reporting to the relevant regulator(s).

Recommendation 18

Removal of a barrier must be the subject of consultation between licensees and rig operators prior to removal. A proper risk assessment should be carried out and agreed upon, and documented in writing before removal. Joint written certification as to the appropriateness of removal should take place before removal. Senior onshore representatives of stakeholder entities should be involved in that certification process.

Recommendation 19

Licensees should be subject to an express obligation to inform regulators of the proposed removal of a barrier, even if they consider that well integrity is not thereby compromised. The information should be provided by way of special report, rather than included in a standard reporting document (such as a DDR). The information provided should include risk assessment details. Removal of a barrier should not take place without prior written approval of the relevant regulator(s).

Recommendation 20

If a dispute arises between a licensee and a rig operator in relation to a well control issue, and is not resolved between them, the matter must be raised with the relevant regulator before discretionary operations proceed.

Recommendation 21

Perceived time and cost savings relating to any matters impacting upon well control should be subjected to rigorous safety assessment.

Recommendation 22

Wells drilled into hydrocarbon zones should be treated as live wells, with the potential to blowout unless a documented risk assessment establishes otherwise.

Recommendation 23

Use of single strings of intermediate casing to penetrate hydrocarbon bearing zones should be carefully risk assessed. Multiple strings of intermediate casing have the advantage of isolating lost circulation zones and sealing off anomalous pressure zones. If intermediate casing is set in a hydrocarbon zone it should be treated as production casing.

General recommendations regarding well control barriers

(a) Minimum barrier requirements

Recommendation 24

A *minimum* of two barriers should be in place at all times (including during batched operations) whenever it is reasonably practicable to do so.

Recommendation 25

Reliance upon one barrier against a blowout must not take place except with the prior written approval of the relevant regulator and then only in a true emergency situation (see below).

Recommendation 26

Regulatory approval to rely on only one barrier should not be given unless (i) a proper risk assessment is carried out; (ii) exceptional circumstances exist; and (iii) risks involved are reduced to 'as low as reasonably practicable'. The default position must be that well integrity must be assured.

Recommendation 27

Licensees and rig operators should install an additional barrier whenever (i) there is any real doubt as to the integrity of any barrier; (ii) whenever the risk of flow from a reservoir increases materially in the course of operations; and (iii) where the consequences of a blowout are grave (for example, for reef systems or shorelines).

Recommendation 28

The industry standard of two barriers should be replaced with the concept of 'two *or more* barriers' as a minimum standard. A *minimum* standard when operations proceed normally should never be regarded as a *sufficient* standard in other circumstances.

(b) Cementing

Recommendation 29

Industry, regulators, and training/research institutions should develop standards that address best practices for cementing operations (including liaising, as appropriate, with overseas regulators) with a view to overcoming problems which can effect the integrity of cemented casing shoes, annulus and cement plugs.

Recommendation 30

Tracking and analysis of cementing problems/failures should occur to assess industry trends, principal causes, remedial techniques and so on.

Recommendation 31

It is recommended that industry, regulators, and training/research institutions liaise with one another with a view to developing better techniques for testing and verifying the integrity of cemented casing shoes as barriers (particularly in atypical situations such as where the casing shoe is located within a reservoir in a horizontal or high angle position at great depth).

Recommendation 32

Cement integrity should be evaluated wherever practicable by way of cement evaluation tests, rather than relying on pre-operational calculations of cement and displacement fluid volumes.

Recommendation 33

It should be standard industry practice to re-test a cemented casing shoe (that is, after WOC) whenever the plugs do not bump or the float valves apparently fail. Standard industry practice should require consideration of other tests in addition to a repeat pressure test.

Recommendation 34

Any indication of a compromised cemented shoe which cannot be resolved with a high measure of confidence should result in the installation of additional well control barrier(s).

Recommendation 35

Volumes of cement used in connection with barrier installation should be calculated with the assistance of a pro-forma which records all relevant baseline data, which should be verified by onshore personnel.

General recommendations regarding barrier installation and removal

Recommendation 36

If performance of barrier installation is outsourced by a licensee, the contractor (for example, the cementing company) should be engaged on terms which clearly require the provision of expert advisory services by the contractor with respect to barrier integrity.

Recommendation 37

Consideration should be given to ways to ensure that contractors who are involved in barrier installation (such as cementing companies) have a direct interest in the performance of works to a proper standard. In particular, consideration should be given to (i) preventing contractors from avoiding the economic consequences of negligent installation of barriers; and/or (ii) imposing specific legislative standards of workmanship on contractors with respect to well control (similar to those which presently apply to licensees).

Recommendation 38

Horizontal or high angle penetration of a reservoir should be avoided *wherever practicable* until such time as the apparent problems associated with the cementing of a casing shoe in these situations are satisfactorily overcome. If a casing string does penetrate a well horizontally or at a high angle, standard practice should be to install two secondary barriers in addition to the cemented casing shoe.

Recommendation 39

The BOP and rig should not move from a well until barrier integrity has been verified.

Recommendation 40

Barriers should not be installed or removed off-line. The derrick should be located over a well at the time of removal and installation of any barrier. This will enable more decisive action to be taken in the event a problem arises.

Recommendation 41

Secondary barriers (including PCCCs) should only be installed, tested, and removed with a BOP in place unless a documented risk assessment indicates that well control can be maintained at all times.

Recommendation 42

PCCCs should be installed in a timely manner (for example, to prevent corrosion in the MLS apparatus). Non-installation in order to park a BOP is not acceptable.

Recommendation 43

Wells should be re-entered with a BOP in place unless a documented risk assessment indicates that well control can be maintained at all times.

Recommendation 44

Any equipment (including PCCCs) used as, or to install, a barrier should be manufactured for that purpose and be generally recognised as fit for purpose. If equipment is designed in-house by a licensee or rig operator it should not be approved for use unless and until it is subjected to expert external analysis.

Recommendation 45

Manufacturers should be consulted about how to address non-routine operational problems affecting their well control equipment.

Recommendation 46

Drilling programs dealing with barrier installation should incorporate relevant aspects of manufacturer's instructions.

Recommendation 47

Any pro-formas used by licensees, rig operators and contractors for recording information about installation of barriers should explicitly provide for 'exception reporting', that is, the form should include provision for recording any unforeseen or untoward events which occur in the course of installation.

Recommendation 48

Careful consideration must be given to equipment compatibility as part of well construction design.

General recommendations regarding batch drilling

Recommendation 49

Batched drilling operations should only be undertaken after careful assessment of the special risks which such operations give rise to; well control must be maintained during the course of batched drilling operations.

Recommendation 50

Where multiple wells are drilled, operations and occurrences at one well must be carefully assessed for any implications with respect to well control at other wells.

Recommendation 51

The mere fact that the rig is over the platform should not be regarded by licensees or regulators as sufficient justification for reliance on only one barrier. The default position should be that producible wells are shut-in when a rig is moved on and off a platform, or when a drilling unit is moved between wells on a platform.

General recommendations regarding communications and logistics

Recommendation 52

Relevant personnel from licensees and rig operators should meet face to face to agree on, and document, well control issues/arrangements prior to commencement of drilling operations. Well control should be regarded as a so-called SIMOP to signify its critical importance to both licensees and rig operators, and to ensure that they each take responsibility for achievement and maintenance of well control.

Recommendation 53

Prior to commencement of drilling operations, senior representatives of the licensee and rig operator should exchange certificates to the effect that their respective key personnel and contractors have been informed in writing of agreed well control arrangements.

Recommendation 54

Information relevant to well control must be captured and communicated *within* and *between* licensees and rig operators (and relevant third party contractors), in a manner which ensures it comes to the attention of relevant personnel. In particular, protocols should be developed to ensure that changes in shift and hitch do not operate as communication barriers.

Recommendation 55

All communications between on-rig and onshore personnel relating to well control should be documented in a timely manner.

Recommendation 56

Logistics management of well control equipment should be conducted in such a way as to operate as a check against deficient well control practices, for example, use of serial numbers to track availability, testing, and deployment of well control equipment.

General recommendations regarding professional standards and training

Recommendation 57

Decision-making about well control issues should be professionalised. Industry participants must recognise that decision-makers owe independent duties to the public, not just their employer or principal, in relation to well control. Risk management in the context of well control needs to be understood as an ethical/professional duty. Self-regulation contemplates self-regulation by the industry, not just by individual licensees and operators.

Recommendation 58

Existing well control training programs should be reviewed by the industry, regulators and training providers, with a focus on well control accidents that have occurred (in Australia and overseas).

Recommendation 59

A specific focus on well control training should be mandatory for key personnel involved in well control operations (including both on-rig personnel and onshore personnel in supervisory capacities).

Recommendation 60

Licensees and rig operators (and third party contractors involved in well control operations) should specifically assess, and document, the nature and extent of knowledge/skills of relevant personnel in relation to well control (including familiarity of personnel with agency-specific requirements and procedures). Training needs and opportunities should be identified. This process should take place on engagement and at appropriate intervals.

Recommendation 61

Licensees, rig operators, and relevant third party contractors should develop well control competency standards for their key personnel. Wherever possible, the competencies of key personnel should be benchmarked against their roles and responsibilities.

Recommendation 62

Licensees, rig operators and relevant third party contractors should develop well control competency standards for key personnel in other entities involved in well control operations.

Recommendation 63

Achievement and maintenance of well control should be written into the job responsibilities of key personnel, at every level up to and including CEOs. That is, a functional line of accountability for well control must exist up to, and including, CEOs.

Recommendation 64

Supervision/oversight of well control operations (within licensees, rig operators and by regulators) must occur without assuming adherence to good oilfield practice. The opposite assumption should prevail: namely adherence to good oilfield practice may well be compromised by the pursuit of time and cost savings.

Recommendation 65

Licensees and rig operators should be astute in ensuring that corporate systems and culture encourage rather than discourage raising of well control issues. For instance, do performance bonuses or rewards actually encourage or discourage reporting of issues? Is there a system in place to enable anonymous reporting of well control concerns? What whistleblower protections are in place?

CHAPTER 4 - THE REGULATORY REGIME: WELL INTEGRITY AND SAFETY

Finding 52

Some of the more significant findings of the Inquiry in relation to the subject matter of this Chapter can be summarised as follows:

- a) the existing legislative regime is largely sufficient to allow effective monitoring and enforcement by regulators of offshore petroleum-related operations – the inadequacies identified by the Inquiry relate primarily to the implementation of this legislation. However, the Inquiry has identified some relatively minor amendments to applicable legislation which it considers would reduce the risk of an event such as the Blowout occurring again;
- b) in assessing PTTEPAA's applications for suspension and/or drilling activities, the NT DoR conducted little more than a 'tick and flick' exercise;
- c) the NT DoR was not otherwise sufficiently diligent in ensuring that principles of good oilfield practice were followed by PTTEPAA;
- d) the NT DoR's regulation of offshore petroleum-related operations was deficient insofar as there were insufficient means of discovering inadequacies in PTTEPAA's operations bearing upon well integrity;
- e) the NT DoR should either not have approved a number of applications for suspension and drilling programs that PTTEPAA submitted to it, or should have sought additional information to satisfy itself that risks were being adequately addressed. This includes the Phase 1B Drilling Program that PTTEPAA was following at the time of the Blowout:
 - i) in particular, while it is incumbent on owner/operators to fully assess risks and to provide all relevant information to the regulator, regulatory authorities should not assume that they will do so. A regulator also needs to ask searching questions and to take steps to satisfy itself that good oilfield practices are being followed; and

f) the NT DoR fell well short of what good contemporary regulatory practice required in relation to the regulation of matters bearing upon well integrity in the offshore area it was responsible for.

Recommendation 66

The Inquiry supports the objective (rather than prescriptive) approach to regulation now followed in Australia. However, the pendulum has swung too far away from prescriptive standards. In some areas relating to well integrity there needs to be minimum standards.

Recommendation 67

To better ensure that 'risks' are identified and managed in accordance with sound engineering principles and good oilfield practice, it is recommended that regulation 25(1)(a)(i) and (2)(a)(i) of the Management of Well Operations Regulations, be reworded as follows: 'A titleholder must not commence / continue a well activity if...a well integrity hazard exists in relation to the well'.

Recommendation 68

The definition of 'good oilfield practice' in the OPGGS Act is unduly narrow. The current definition is incapable of application except where things 'are generally accepted as good and safe'. The definition should be amended such that 'good oilfield practice includes...'.

Recommendation 69

Written (rather than verbal) approval from the DA (or new regulator) should be obtained before the commencement of well activities that lead to a physical change of a wellbore, other than in a true emergency situation (requiring amendment to regulation 17 of the Management of Well Operations Regulations).

Recommendation 70

The OPGGS Act should be amended to allow for a power to suspend a petroleum production licence (in addition to the current power to cancel a licence or suspend its conditions).

Recommendation 71

There should be a review to determine whether it is appropriate to introduce a rigorous civil penalty regime and/or substantially increase some or all of the penalties that can be imposed for breaches of legislative requirements relating to well integrity and safety.

Recommendation 72

NOPSA's prohibition powers should be extended such that a prohibition notice can be issued where a NOPSA Occupational Health and Safety Inspector believes, on reasonable grounds, that an activity is occurring or *may* occur at a facility involving an immediate threat to the health or safety of a person.

Recommendation 73

A single, independent regulatory body should be created, looking after safety as a primary objective, well integrity and environmental approvals. Industry policy and resource development and promotion activities should reside in government departments and not with the regulatory agency. The regulatory agency should be empowered (if that is necessary) to pass relevant petroleum information to government departments to assist them to perform the policy roles.

Recommendation 74

The proposal of the Productivity Commission's Research Report (*Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector*, April 2009) to establish a NOPR should be pursued at a minimum.

Recommendation 75

Responsibility for well integrity should be moved to NOPSA (as also proposed by the Productivity Commission).

Recommendation 76

In the meantime, the Minister should:

- a. consider revoking the existing delegation to the Director of Energy, NT DoR providing the functions and powers of the DA under the OPGGS Act and Regulations specified in item 1 of the Schedule to that instrument (the Minister's DA powers and functions) and transferring this delegation to either NOPSA, RET, or a DA from another state;
- b. enquire into whether the other DAs to whom he has delegated his functions and powers relating to well integrity are adequately fulfilling their roles; and
- c. consider amendments to the OPGGS Act to enable DAs to be given direction as to the performance of their regulatory roles.

Recommendation 77

The recommendations of the Inquiry in relation to suitable ways of achieving well integrity contained in Chapter 3 be included in a guidance manual that is issued for the assistance of industry and regulators.

CHAPTER 5 - ARRESTING THE BLOWOUT

Finding 53

The Inquiry is of the view that the actions of Atlas and PTTEPAA personnel on board the *West Atlas* on 21 August 2009 in the immediate aftermath of the Blowout are to be commended. The safe evacuation of 69 personnel from a highly flammable environment without notable incident is testament to the effective emergency response procedures developed by Atlas for use on board the *West Atlas* and to their smooth execution.

Finding 54

The Inquiry has no reason to question the expertise of ALERT. All of the indicators suggest that it carried out its role effectively. It is notable, however, that ALERT has not made any effort to engage with the Inquiry and provide it with information that may be of assistance to the petroleum industry and to regulators in Australia and around the world.

Finding 55

The Inquiry accepts that from its own perspective, PTTEPAA experienced some difficulty in achieving active and meaningful engagement with NOPSA in relation to the safety risks of the proposed water deluge operations. However the Inquiry notes that PTTEPAA's efforts may have benefited from greater identification and inclusion of ALERT in its engagement strategy, especially given the novel situation that faced both PTTEPAA and NOPSA.

Finding 56

The Inquiry finds that while surface capping of the H1 Well clearly carried with it significant risk to the safety of personnel involved in such operations, there may have been some room for further consideration of the option in light of ALERT's recommendations to PTTEPAA. It appears that there was little in the way of consultation between PTTEPAA and NOPSA in relation to the surface capping option, in particular in relation to ALERT's involvement in assessing the risks involved.

Finding 57

The Inquiry finds that in assessing the merits of various available well control options PTTEPAA gave highest consideration to the potential risks to the safety of those personnel that would be involved in any such well control operations. In particular, the Inquiry finds that in assessing the risks associated with controlling the H1 Well either at the surface (capping) or subsea, PTTEPAA was competent in arriving at its decision not to pursue these methods of well control in the light of the high degree of risk to the safety of personnel.

Finding 58

However, the Inquiry has some concerns in relation to the apparent lack of collaboration between PTTEPAA and NOPSA insofar as considering all available well control options was concerned. The Inquiry observed a reluctance on the part of PTTEPAA to commit ongoing resources to engaging in a more collaborative response, and a similar reluctance on the part of NOPSA to reach outside the boundaries of its current operator engagement policy. This was an emergency situation and one that clearly required NOPSA and PTTEPAA to work more closely together than they ultimately did.

Finding 59

The Inquiry finds that unilateral decision-making on the part of PTTEPAA in relation to information dissemination to the regulator may have prematurely confined otherwise viable options for well control.

Finding 60

In particular, the Inquiry is of the view that when confronted with a blowout situation, a company together with the regulator should fully pursue all options simultaneously and only rule out each option when it is clear to the regulator and company that that option should be pursued no further.

Finding 61

In the event that Australia faces another major emergency well control incident, well control decisions should not be left solely in the hands of an operator (that is, without full and collaborative exploration of available options with the regulator) either by way of conscious decision or by way of inaction. The Inquiry finds that any such outcome is likely to be viewed as wholly unsatisfactory. The public interest requires that all well control options be pursued and that there is a full and transparent explanation to the public as to which options are being ruled out and why (see below as to the provision and coordination of information).

Finding 62

The Inquiry notes that Mr Jacob's evidence was to the effect that cost was not a factor in PTTEPAA's selection of a rig to drill the Relief Well. The Inquiry also notes, however, that cost might still have been a residual consideration in relation to the provision of indemnities. For example, had the question of indemnities not been raised as an issue, it is possible that the *Ocean Shield* may not have moved on to the next stage in its drilling operations and would have been available for engagement to drill the Relief Well.

Finding 63

In this instance the Inquiry finds that PTTEPAA did give adequate consideration to the availability of rigs other than the *West Triton*.

Finding 64

The Inquiry notes that the responsible Minister had the power to give a direction under the OPGGS Act to PTTEPAA to use a particular rig and that, in this case, such a direction was not made.

Finding 65

The Inquiry finds that even if the Minister had directed the release of the *Ocean Shield* for the purpose of drilling the Relief Well, there may have been little utility in doing so given the exigencies of the *Ocean Shield's* drilling program at the time.

Finding 66

In the light of the relative infrequency of blowouts and the high costs of contracting a drilling rig, the Inquiry finds that it would be neither practical nor cost effective to require that an operator ensure that a rig is always on standby in contemplation of a possible blowout. This is particularly so given the remote location of many offshore drilling operations and the relatively small size of the Australian offshore petroleum industry.

Finding 67

Similarly, identification of a relief well rig prior to commencement of operations is likely to be challenging in the light of location, frequency of changes to drilling programs, and general rig availability. Depending on the circumstances and specifics of a blowout, the type of relief well rig required in any particular situation is likely to vary. Consequently, the Inquiry finds that it is necessary to retain a degree of flexibility in relation to an operator's choice of relief well rig.

Finding 68

The Inquiry finds that there should, however, be a regulatory requirement that prior to the commencement of drilling operations, the owner/operator make meaningful enquiries as to the availability of potential rigs on a contingency basis.

Finding 69

It is incumbent upon operators and, to some extent, regulators to manage the risks following a blowout in order to minimise the resulting impact.

Finding 70

While a number of issues arose for PTTEPAA in responding to the Blowout, ultimately the Inquiry finds that PTTEPAA carried out its response effort diligently and with vigour and a due sense of urgency.

Finding 71

The Inquiry finds that while securing the H1 Well appears to have taken a not insignificant amount of time, the exigencies of the particular situation and location of the Montara Oilfield contributed significantly to the response's extended timeframe, and PTTEPAA acted appropriately in the circumstances in undertaking to drill the Relief Well.

Finding 72

It is critical in circumstances such as those following the Blowout that NOPSA's policy relating to engagement and interaction with operators should be applied flexibly in order to provide for the expeditious development and assessment of response options.

Finding 73

It was incumbent upon PTTEPAA to ensure that it supplied to NOPSA all information as to relevant risk assessments. In this regard, PTTEPAA took too unilateral an approach to its interactions with NOPSA.

Finding 74

The Inquiry does not find NOPSA's enforcement action in assessing the safety risks related to the Blowout to have been deficient. It is clear to the Inquiry that decisions regarding the safety of personnel and the relative risks of various well control options are not simple and warrant close attention and scrutiny, and that each party involved in the risk assessment process should have access to the outcomes of such scrutiny.

Finding 75

In this instance the Inquiry finds that consideration by PTTEPAA and NOPSA of all of the various options for responding to the Blowout should have been undertaken on a more collaborative, consultative basis.

Finding 76

The Inquiry commends the offshore petroleum industry for what appears to the Inquiry to have been a cohesive and responsive approach to the difficulties faced by PTTEPAA in responding to the Blowout, through regular contribution as subscribers to AMOSC, the peer review process, and through direct support and advice offered and provided, upon request, to PTTEPAA.

Finding 77

The information provided by PTTEPAA on the technical aspects of the response was good. However, a more conservative estimate of the time it would take to 'kill' the H1 Well would have been more appropriate. With the benefit of hindsight, the Inquiry finds that PTTEPAA might have qualified its estimates of time by providing more information as to, for example, the challenges of drilling a relief well, including a projection of the likely number of attempts it would take to eventually intercept the H1 Well.

Finding 78

The Inquiry finds that each agency/organisation involved with the Blowout endeavoured to make some information about the response to the Blowout available to the public by way of publication on its respective website. The resultant array of information was fragmented with some significant gaps. There was a lack of coordinated and publicly available information about the Blowout; even between government agencies, the coordination and provision of public information did not appear to be effectively coordinated.

Recommendation 78

In the future, and in the interests of ensuring that all possible well control options are comprehensively pursued to exhaustion, decisions as to well control response options should be the result of collaboration between the regulator and the operator rather than leaving one party to make unilateral judgements as to the appropriateness of various well control operations. The regulator should provide transparent and contemporaneous explanations to the public of all well control options under consideration at any particular time.

Recommendation 79

The regulator, rather than the responsible Minister, should be given the power to direct an operator to use a particular rig for the purpose of well control operations, if appropriate in the circumstances, and the power should be used in the future if that rig is the best option available. This would necessarily involve the operator fully compensating for the use of the rig and any other associated costs. The Inquiry suggests that this power could be invoked and given effect as a condition of an operator's licence.

Recommendation 80

The regulatory regime should also impose an obligation on an operator to ascertain the availability, and provide details to the regulator, of any potential relief well rigs, prior to the commencement of drilling operations (including prior to each phase of a drilling operation where applicable).

Recommendation 81

NOPSA develop a policy of engagement with operators so as to enable experts (including safety experts) to canvas all available options for well control in the event of a blowout.

Recommendation 82

The Inquiry also supports Bills and Agostini's recommendation:

'...in relation to safety case development and compliance overall, that NOPSA revise its approach to interacting with operators prior to the safety case assessment process and subsequently direct more resources into its advisory functions. We further recommend that NOPSA develop and implement a formal plan for supporting and guiding each operator prior to safety case acceptance, as well as for ongoing compliance with that safety case, recognising the unique experience, capabilities and assessed risk of that operator. Each plan needs to include advice, education and liaison meetings with the operators. The plan needs to be continuously reviewed and reassessed based on the latest information, including the interaction with the operator'.

Recommendation 83

The regulator should pre-assess and review in a generic sense, and in conjunction with the offshore petroleum industry, available options for well control in the event of a blowout. Being 'match fit' in this sense will enable a quicker and more effective response in terms of safety assessment, and will ensure that expectations of both operator and regulator are more readily aligned.

Recommendation 84

In any future similar blowout or offshore emergency situation, the Minister appoint (through either a NOPR or the relevant Department) a senior public servant to establish and oversight a central coordinating body that will facilitate interaction between regulators, industry, AMSA and the owner/operator. Primary responsibility for stopping a blowout should remain with the owner/operator but should be subject to direction from the central coordinating body in consultation with stakeholders (including the owner/operator).

Recommendation 85

The body established to undertake a central coordination and facilitation role in the event of any future blowout in Commonwealth waters should undertake to make all relevant information publically available from one, authoritative and easy to access source.

CHAPTER 6 - ENVIRONMENTAL RESPONSE

Finding 79

The Inquiry finds that the roles and responsibilities under the National Plan should be clarified. The overall response required consideration of a number of tasks in addition to the demanding clean-up job that AMSA had to start on 21 August 2009. The Inquiry considers that it would have been preferable for RET to coordinate and chair meetings of the ICG.

Finding 80

The Inquiry concurs with the decision that was made to use dispersants in this case given the need to avoid oil impacting on Ashmore Reef and Cartier Island and the coastline of Western Australia. The decision was consistent with information available to AMSA at the time.

Finding 81

The Inquiry considers that the containment and recovery operations went well, particularly in view of the remoteness of the area. For the future, AMSA needs to work with the petroleum industry and AMOSC to assess whether more and better equipment should be on standby. Serious though this incident was, it is conceivable that spills of a much greater magnitude could occur in the future. Contingency planning, including the availability of adequate resources and equipment and how that should be deployed, needs to be based on a much worse incident than this one.

Finding 82

Given the anticipated extent of future offshore activity, arrangements for mobilisation of expertise and operational capability should be clearly established under the National Plan. In its supplementary submission DEWHA noted, and the Inquiry agrees, that it may be cost effective to have arrangements in place to utilise the operational capability of the states and territories in Commonwealth waters. The Inquiry believes that DEWHA should also investigate the scope for ensuring that its staff are equipped for response activities by participating in appropriate training activities.

Finding 83

In the Inquiry's view, the prolonged delay in undertaking Scientific Monitoring of the impact of the oil spill was unacceptable. The delay has restricted the scope for assessment of the environmental damage from the Blowout. DEWHA's response should not have been dependant on PTTEPAA's willingness to cooperate and fund the Monitoring Plan.

Finding 84

The Inquiry has not seen data that indicated the distribution of the oil and dispersant mix beneath the sea surface. This is a major shortcoming of the response. There should have been a thorough sub-surface sampling of the oil/dispersant mix. This was important to inform judgements about the environmental consequences of the Blowout.

Finding 85

Estimation of the volume and spread of the oil should be undertaken by the Combat Agency (bearing in mind that the Combat Agency must have access to this information, and confidence in it, to plan response operations). The responsibility for informing the public about the volume and extent of an oil spill should also be clearly established. This should rest with the body which, as the Inquiry recommends in Chapter 5, should undertake the central coordination and facilitation role, including the provision of information to the public through an authoritative and easy to access source.

Finding 86

Despite ongoing monitoring, it is unlikely that the full extent of environmental damage from the Montara oil spill will ever be established. The ability to detect environmental damage is generally greater during a blowout than after the flow has been stopped and will naturally decrease with time thereafter.

Finding 87

It is extraordinary that despite the environmental consequences, in the case of the Blowout there seems to be no ground for action under the Commonwealth's premier environmental legislation. This is a weakness that needs to be addressed for the future.

Finding 88

The assessment of the development of the Montara Oilfield and the conditions attached to its approval under the EPBC Act did not foresee an incident of the duration and extent of the Blowout. While an OSCP was required as a condition of approval, there were no requirements for Scientific Monitoring to be undertaken, or for the remediation of environmental damage, in the case of an oil spill. An effort should now be made to ensure that Scientific Monitoring obligations and, if necessary, remediation work are included in conditions of approval for future projects. Furthermore, there would be considerable benefit in legislating to require that existing petroleum operators in Commonwealth waters are also obligated to meet such requirements. The Inquiry does not regard this as involving a retrospective requirement as it would only apply to any future events.

Finding 89

The Inquiry sees value in having both environment plans and OSCPs prepared for new developments made public. This would be consistent with the publication of the documentation relating to the assessment and approval of development proposals under the EPBC Act. This would allow an increased degree of public scrutiny of development proposals and the operation of DAs but need not pose commercial-in-confidence issues.

Finding 90

The environmental protection regime for Commonwealth waters should include the following elements to embody the polluter pays principle:

- a) the Government should have the power to require the companies involved in an incident – both prospectively and already approved projects – to undertake Scientific Monitoring of the environmental impacts of an incident, and to undertake actions to remediate any damage resulting from the incident to a required standard;

- b) the costs of undertaking Scientific Monitoring or of remediating the damage arising from a significant incident should be fully borne by the companies involved, whether the monitoring or remediation is undertaken by the company or by Commonwealth, state or territory agencies or other parties. Further it should be the environmental regulatory agencies that determine the nature of Scientific Monitoring arrangements and remediation required, not the company involved;
- c) regulatory authorities should be satisfied that companies have adequate insurance arrangements in place to allow them to meet their obligations; and
- d) there should be provision for the payment of penalties for pollution on a no fault basis, which should be similar in scale to that which would be applicable in state regimes.

Recommendation 86

The National Plan should be reviewed to clarify the arrangements to apply in Commonwealth waters regarding key roles and responsibilities, including in relation to the ESC, in the event of an oil spill. This should also address any necessary training required.

Recommendation 87

DEWHA should participate in training programs and exercises relevant to an oil spill in the marine environment.

Recommendation 88

The National Plan should be revised to ensure that it fully comprehends environmental matters and that it recognises the importance of the prompt implementation of Scientific Monitoring to facilitate the assessment of the environmental impacts of an incident.

Recommendation 89

Procedures for the approval of development projects should ensure that conditions of approval are comprehensive and clearly set out the obligations of their proponents in relation to environmental matters (including expected monitoring and remediation obligations).

Recommendation 90

DEWHA, in concert with AMSA and with expert input, should develop 'off the shelf' monitoring programs that can be speedily implemented following incidents in Commonwealth waters. In this context, the utility of the current Scientific Monitoring program should be peer reviewed to inform future policy.

Recommendation 91

The funding arrangements that support the National Plan should be reviewed to ensure that the costs associated with both preparedness and response capability are equitably shared between the shipping and offshore petroleum industries.

Recommendation 92

The National Plan should specify that the cost of responding to an oil spill, or other damage to the offshore marine environment, will be totally met by the owner/operator. This would be consistent with the Inquiry's recommendation for legislative changes to the regulatory framework concerning owner/operators meeting the cost of monitoring and remediation of environmental damage.

Recommendation 93

The National Plan should be reviewed:

- a. to ensure that it adequately addresses the risks associated with offshore oil and gas exploration;
- b. to revisit the underlying risk assessment undertaken to inform capacity and preparedness under the National Plan;
- c. to ensure that response operations can be coordinated effectively with state and territory arrangements where a response requires operations across Commonwealth and state or territory borders; and
- d. to explore the state of readiness of equipment and resources in the context of the future expansion of the petroleum industry. This should be undertaken by AMSA in consultation with AMOSC.

Recommendation 94

Procedures and accountabilities should be established to ensure, in the event of a future incident, that:

- a. there is adequate monitoring of the volume of oil spilt and the spread of the oil (both surface and sub-surface dispersed oil); and
- b. information about the volume and spread of the oil is made available to the public through regular updates.

Recommendation 95

The regulatory framework should provide that in respect of all activities in Commonwealth waters:

- a. there are powers to require companies involved in an incident causing significant environmental damage to undertake actions to remediate the damage to a standard determined by the regulatory authorities;

- b. the nature of the Scientific Monitoring and the remediation required should be determined by environmental regulatory agencies rather than the companies involved;
- c. the costs of all Scientific Monitoring and remediation should be fully borne by the companies involved, whether the remediation is undertaken by the companies or another party to the standard determined by the regulatory authorities; and
- d. penalties should be payable for pollution on a no fault basis.

The EPBC Act should be amended to include the powers in a, b, c and d above. These powers should be applicable to both prospective and existing operations in Commonwealth waters.

Recommendation 96

The obligation of companies involved in an incident to meet the full costs of monitoring and remediation should be made a condition of approval of proposals under the EPBC Act and OPGGS Act. Suitable arrangements (insurance or otherwise) need to be in place to ensure that companies have this capacity.

Recommendation 97

Environment plans and OSCP's should be made publicly available as a condition of approval of proposals under the OPGGS Act, and should clearly set out Scientific Monitoring requirements in the event of an oil spill.

Recommendation 98

The Government should examine the scope for a single environment plan to meet the regulatory requirements of both the OPGGS Act and the EPBC Act. This could possibly be achieved by way of bilateral agreements and accreditation arrangements and/or legislative amendment.

Recommendation 99

OSCP's should be endorsed by AMSA prior to regulatory approval to ensure that they align with the National Plan. Once field operations commence, the capability of operators should be assessed against their plans, and exercises conducted to ensure the plans remain effective.

Recommendation 100

Arrangements should be developed to minimise duplication between the EPBC Act and the OPGSS Act Environment Regulation.

CHAPTER 7 - REVIEW OF PTTEPAA'S PERMIT AND LICENCE AT MONTARA AND OTHER MATTERS

Finding 91

PTTEPAA succumbed to a large number of serious deficiencies in its approach to well control in the H1 Well, as set out in paragraph 7.11 of this Report.

Finding 92

Those deficiencies were emblematic of larger systemic problems which afflicted PTTEPAA in the lead up to the Blowout.

Finding 93

PTTEPAA did not achieve proper control in any of the five wells at the Montara Oilfield. Multiple deficiencies of a significant kind existed in each well.

The nature and extent of well control deficiencies can properly be seen as part of a larger problem with respect to management of well operations at the Montara Oilfield. PTTEPAA had at least some knowledge of well control deficiencies at the Montara Oilfield, but it did not inform either the NT DoR or NOPSA of any of the deficiencies of which it was aware.

Finding 94

PTTEPAA's own investigations into the circumstances and likely causes of the Blowout were manifestly deficient.

Finding 95

PTTEPAA's failure to properly investigate the Blowout was irresponsible and inexcusable. It allowed personnel (albeit limited in number) to attend the WHP without properly informing itself or them of myriad well control deficiencies at the Montara Oilfield.

Finding 96

In the aftermath of the Blowout PTTEPAA seriously misled NOPSA in a number of important respects (over a six month period).

Finding 97

In the aftermath of the Blowout PTTEPAA received information which indicated a lack of well integrity in the GI Well which it did not pass on to either the NT DoR or NOPSA.

Finding 98

Although there is no evidence that PTTEPAA *deliberately* provided false and/or misleading information to NOPSA, the fact it did so reflects very poorly upon it.

Finding 99

Further, there is evidence that PTTEPAA was prepared to volunteer information when it considered it to be in its best interests to do so, but was content to withhold information on the same basis.

Finding 100

In the course of the Inquiry, PTTEPAA largely adopted an argumentative and finger-pointing position. It only acknowledged the nature and extent of its deficiencies when, practically and legally, it could not really do otherwise.

Recommendation 101

The Minister should, as the JA for the offshore area of the Territory of Ashmore and Cartier Islands, undertake a review of PTTEPAA's permit and licence to operate at the Montara Oilfield.

Recommendation 102

For the purposes of that review, the Minister should issue a 'show cause' notice to PTTEPAA under s 276 of the OPGGS Act.

Recommendation 103

In carrying out a review of PTTEPAA's permit and licence, the Minister should have regard to this Report, particularly (i) the adverse findings set out in this Chapter; and (ii) the extent to which PTTEPAA has implemented the Action Plan submitted to the Inquiry, or otherwise addressed the matters canvassed in this Report.

Recommendation 104

The Minister consider legislative amendments to the OPGGS Act which make clear that (i) the Minister can direct a titleholder to obtain an independent report into the circumstances and likely causes of a blowout; and (ii) the Minister can direct that such a report be provided to him (and such direction overrides any legal professional privilege which otherwise attaches to the report).

Recommendation 105

In view of the numerous well integrity problems in all of the Montara Oilfield wells, the Minister should commission a detailed audit of all the other offshore wells operated by PTTEPAA to determine whether they too may suffer from well integrity problems.

GLOSSARY

Term	Definition
Abandonment	Final plugging of a well and/or permanent dismantling of a production platform or other installation.
ALERT	ALERT Disaster Control (Asia) Pte Ltd – an international oil and gas well oil control engineering specialist contracted by PTTEPAA to provide specialist advice on possible options to contain the Blowout. ALERT also assisted with implementation of the elected option including by providing specialist engineers.
Annulus	The ring-shaped cavity between two concentric tubes, for example inner and outer strings of casing or between casing or drill string and the wellbore hole.
APPEA	The Australian Petroleum Production & Exploration Association is the peak national body representing Australia's oil and gas exploration and production industry.
As low as reasonably practicable	Principle that provides a means for assessing the tolerability of risk. A risk is as low as reasonably practicable if the cost of any reduction in that risk is grossly disproportionate to the benefit obtained from the reduction.
Atlas	Atlas Drilling (S) Pte Ltd – owner of the <i>West Atlas</i> and <i>West Triton</i> drilling rigs.
Australian Maritime Safety Authority (AMSA)	AMSA was established under the <i>Australian Maritime Safety Authority Act 1990</i> as a Commonwealth Government authority in the Transport and Regional Services portfolio. It is one of Australia's national safety agencies with a primary role in maritime safety, protection of the marine environment and aviation and maritime search and rescue and is largely self-funded through levies on the commercial shipping industry.
Australian Marine Oil Spill Centre (AMOSC)	Operates Australia's major oil spill response equipment stockpile on 24 hour stand-by for rapid response anywhere around the Australian coast. Activities of AMOSC are fully integrated into the National Plan, managed by AMSA on behalf of the Commonwealth, state and Northern Territory authorities and the oil and shipping industries.
Barrel (bbls)	Unit of volume measurement used for petroleum and its products: 1 barrel = 159 litres approximately.
Barrier	Method of preventing hydrocarbons from flowing to the atmosphere.
Batch drilling	When multiple wells with a similar configuration are drilled together for reasons of efficiency.

Term	Definition
Bleed off	Equalise or relieve pressure from a vessel or system. In order to conduct pressure tests, fluid is pumped into a vessel or system to increase the pressure. At the conclusion of the pressure test or treatment, the fluid must be extracted safely to equalise the pressure and allow subsequent phases of the operation to continue.
the Blowout	The uncontrolled release of hydrocarbons from the H1 Well which commenced on 21 August 2009.
Blowout Preventer (BOP)	A BOP is a large valve at the top of a well that may be closed off if control of formation fluids is lost. BOPs come in a variety of styles, sizes and pressure ratings. Some can close off an open wellbore, some can seal off other components of the well such as casing and tubing, and some can shear through the drill pipe.
Borehole	A well, especially referring to the case of the rock outside or below the casing.
Bottom hole	The deepest part of a well.
Bottom hole tool assembly	Comprises a drill bit, rotary steering tool, measurement whilst drilling device, a drilling jar and several drill collars which is run into the well on the end of the drill string.
Bottom plug	The first plug inserted into the casing during the cementing operations.
Bump (the plugs)	When the top plug hits the bottom plug.
Cantilever	A beam on the drill rig which is supported on only one end. The beam carries the load to the support where it is resisted by movement and shear stress.
Casing	The steel pipes with which a well is lined for protection against collapse of the borehole and unwanted leakage into or from rock formations or at the surface. Joints of casing are normally screwed together as they are run into the well.
Casing hanger	The lug or bracket from which the drill string is suspended at the mudline suspension system (MLS).
Casing shoe	The bottom of the casing string. Casing is run with special joints of casing on the bottom containing non return valves (NRV). One NRV is placed at the bottom of the casing and a second higher up. The space between the float valves is known as the cement shoe.
Casing string	The entire length of casing, tubing, sucker rods, or drill pipe run into the well.

Term	Definition
Cement	Used to set casing in the wellbore and seal off unproductive formations and apertures. Two types of cement are used – lead cement and tail cement.
Cement head	Apparatus used to pump cement into the well and pressure test the cement when it has set.
Cement plug	A plug of cement which is placed in the wellbore as a barrier.
Cement stringer	A narrow pipe through which cement is run through the bottom hole tool assembly. This pipe needs to be very narrow so it does not act like a piston and result in the cement being suctioned back out the well when it is pulled out prior to the well being pressurised and the plugs bumped.
Cement unit	Unit on the drilling rig utilised for the cementing operations of a well.
Check valve	A non-return valve, allowing only one-way flow.
Circulation	In drilling, the passage of fluids, primarily drilling mud, down the interior of the drill string and back to the surface via the annulus.
Combat Agency	Under the National Plan responsibilities are divided between the Statutory Agency and the Combat Agency. The Combat Agency is the government agency or company assigned the operational responsibility for responding to an oil spill in accordance with the National Plan. In this case the Combat Agency was PTTEPAA, which had operational responsibility to take action to respond to the marine pollution, however, this role was ultimately transferred to AMSA.
Completion	The activities and methods of preparing a well for the production of oil and gas or for other purposes, such as injection.
Conductor	First piece of casing which is cemented into the wellbore. It acts as the foundation for the well, support for the subsequent casing and protects against hole collapse due to unstable rock formations between the bottom of the hole and the surface.
Crude oil	Unrefined oil.
Daily Drilling Report (DDR)	PTTEPAA's daily report recording all online activities undertaken on a specified well over a 24 hour period.
Daily Operations Report (DOR)	Atlas' daily report recording all online activities undertaken by the rig.
Day Drilling Supervisor	Also Senior Drilling Supervisor, Company Man. An employee or contractor of the oil company who has overall responsibility overseeing the drilling of the wells.

Term	Definition
Derrick	The pylon-like steel tower which provides the vertical lifting capacity necessary to raise and lower the drill string into and out of the wellbore.
Department of the Environment, Water, Heritage and the Arts (DEWHA)	Commonwealth department responsible for the administration of the <i>Environment Protection and Biodiversity Conservation Act 1999</i> (the EPBC Act).
Designated Authority (DA)	The responsible state or Northern Territory Minister for the offshore area of a state or the Northern Territory.
Delegate of the Designated Authority	The role delegated by the Commonwealth under the OPGGS Act to the Northern Territory Department of Regional Development, Primary Industry, Fisheries and Resources (now the Department of Resources) in respect of the offshore area of the Territory of Ashmore and Cartier Islands.
Development well	Any well drilled in the course of extraction of reservoir hydrocarbons, whether specifically a production well or injection well.
Differential pressure	The difference between the pressure in a well due to the mud column and the pressure in the surrounding rock at any point.
Directional drilling	Use of the measurement whilst drilling device and rotary steering tool to direct the drill string in the hole.
Down hole	Down a wellbore.
Drill bit	Cutting device used to penetrate the rock formation.
Drill string	The series of pipe sections screwed together which act as a conduit for the Mud and is used to connect the bottom hole tool assembly with the top drive located on the drilling rig.
Drilling fluid	See Mud.
Drilling program	Program detailing the various phases of a drilling campaign.
Drilling rig	The permanent equipment needed for drilling a well. It comprises the derrick, the rotary table, a mud pump and mud circulation system, a BOP and a system for handling casing.
Drilling Superintendent	PTTEPAA's Drilling Superintendent – onshore.
Drilling Supervisor	PTTEPAA's Drilling Supervisor – on-rig.
Emergency Response Group (ERG)	Perth-based PTTEPAA group responsible for the management and coordination of emergencies.
Equivalent mud weight	Pressure felt by the formation when circulating with a certain mud weight and holding a backpressure.

Term	Definition
Environment plan	An environment plan describes proposed operations and the relevant surrounding environment. It should identify and assess any potential environmental effects and risks, describe the environmental performance objectives and standards applicable to the activities and outline the implementation strategy proposed to ensure that environmental performance objectives and standards are met.
ESC	Environmental and Scientific Coordinator under the National Plan
Float collar	Component installed near the bottom of the casing string on which the plugs land during the primary cementing operation. It typically consists of a short length of casing fitted with a check valve. This device may be a flapper-valve type, a spring-loaded ball valve or other type. The check-valve assembly fixed within the float collars is designed to prevent flow-back of the cement when pumping is stopped. Without a float collar, the cement pumped into the annulus could U-tube, or reverse flow back into the casing. The greater density of the cement than the mud inside the casing causes the U-tube effect.
Float shoe	Rounded profile component attached to the down hole end of a casing string. An integral check valve in the float shoe prevents reverse flow, or U-tubing, of cement from the annulus into the casing or flow of wellbore fluids into the casing string as it is run. The float shoe also guides the casing toward the centre of the hole to minimise hitting rock ledges or washouts as the casing is run into the wellbore.
Floating Production, Storage and Offloading (FPSO) facility	Type of floating tank system used and designed to take all of the oil and gas produced from nearby wells (subsea or at a platform), process it and store it until the oil or gas can be offloaded onto a tanker or transported through a pipeline.
Formation Integrity Test (FIT)	Pressure test which verifies the fracture gradient of the formation/rock (also leak off test).
Fracture pressure	The pressure at which a rock breaks.
Gas injection	Secondary recovery method by which gas is injected into and passed through the reservoir to maintain pressure and/or entrain heavier hydrocarbons left behind by primary production.
Gas-Oil Contact (GOC)	Level at which the gas and oil in the reservoir contact each other. In the Montara reservoir there are three levels – gas, oil and water.
GI Well	Gas Injection well drilled in the Montara Oilfield by PTTEPAA.
H1, H2, H3, H4 Wells	Production wells drilled in the Montara Oilfield by PTTEPAA.
H1 Well/ H1 ST1 Well	The well from which the Blowout emanated.
H1 ST1 RW1 Well	The Relief Well drilled by PTTEPAA.

Term	Definition
Horizontal drilling	Technique for deviating wells through up to 90° from the vertical but more importantly, 'horizontal' to the reservoir strata. While the main purpose of normal deviated drilling is to reach remote parts of a reservoir, with horizontal drilling the purpose is to keep the bore within a given productive horizon or formation to increase potential productivity.
Hydrocarbons	Organic compounds of carbon and hydrogen.
Hydrostatic pressure	Pressure exerted by a column of liquid at a given depth, such as that exerted by mud in a well.
Inhibited seawater	Seawater containing anti-corrosion chemicals.
Isolation packers	Mechanical plugs/barriers installed into a well.
Jack-up drilling rig	A type of drilling rig which is a mobile platform that is able to stand on the seabed supported by three legs. During transit, the platform floats on its hull and is typically towed to location by a tug boat. The supporting legs may be moved up and down and are secured to the seabed when in location. When the supporting legs are secured, the rig platform is jacked up to the required elevation.
Jacket	The leg structure of an offshore platform connected to the seabed.
<i>Java Constructor</i>	Construction vessel facility used to install the topsides on the Montara WHP jacket. The Java Constructor was also used to evacuate personnel from the <i>West Atlas</i> rig following the Blowout.
Kick	A flow of reservoir fluids into the wellbore during drilling operations. The kick is physically caused by the pressure in the wellbore being less than that of the formation fluids, thus causing flow. A well kick warns of the possibility of a blowout.
Kill	To inject mud into a flowing well to the density needed to overcome the reservoir pressure thus stopping the flow.
Lead cement	Type of cement which is pumped into the well first during cementing and has a lower density than tail cement.
Management of Well Operations Regulations	<i>Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004 (Cth).</i>
Measured depth	The total length of the drilled hole measured in kilometres.
Measurement Whilst Drilling device	Down hole instrument system used to monitor geological parameters and control the direction of the wellbore to the high degree of accuracy needed, for example, in horizontal drilling.

Term	Definition
Monitoring Plan	The Monitoring Plan for the Montara Well Release Timor Sea agreed between PTTEPAA and DEWHA for the purpose of monitoring the impacts on the environment of the Blowout. The Monitoring Plan included an Operational Monitoring Programme and a Scientific Monitoring Programme.
Montara Development Project	The development by PTTEPAA of the Montara, Skua and Swift/Swallow Oilfields, within the AC/L7 and AC/L8 Production License areas in the East Timor Sea.
Montara Oilfield	The Montara petroleum (oil and gas) accumulation. The objective of the Montara Development Project is to extract petroleum from the Montara Oilfield using four production wells (H1, H2 H3 and H4) and to re-inject gas into the Montara Oilfield using the GI well.
MOE Regulations	<i>Petroleum (Submerged Lands) (Management of Environment) Regulations 1999 (Cth).</i>
MOSOF Regulations	<i>Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996 (Cth) (also, the 1996 Regulations).</i>
Mud	<p>Drilling fluid used to transport cut rock fragments from the well, cool the drill bit and to provide hydraulic pressure to support the hole being drilled.</p> <p>The Mud is a complex mixture of fluids, solids and chemicals which must be carefully tailored to provide the correct physical and chemical characteristics required to stabilise the rock formations being drilled and safely drill the well.</p> <p>Heavy mud has barite added as a weighting agent, which provides increased density to the fluid, which in turn provides an increased hydrostatic head of pressure on the bottom of the hole.</p>
Mud line	The seabed or bed of any body of water where drilling is taking place.
Mud Line Suspension (MLS) system	Used to support (hang) the inner casing of a well on the outer casing. Comprises an MLS hanger on the outside of the inner casing and an MLS hang-off ring (or shoulder) on the inside of the outer casing.
National Plan	The <i>National Plan to Combat Pollution of the Sea by Oil and other Noxious and Hazardous Substances</i> . A key purpose of the National Plan is to maintain a national integrated framework for Government and industry, capable of effective response to oil pollution incidents in the marine environment.
Night Drilling Supervisor	Also PTTEPAA's Drilling Supervisor, Companyman – on-rig. Reports to Day Drilling Supervisor.
Nipple down	To take apart, disassemble and otherwise prepare to move the rig or blowout preventers

Term	Definition
Offshore Installation Manager (OIM)	Offshore Installation Manager of the <i>West Atlas</i> (an Atlas employee).
Oil-water contact	The lower end of the oil column in a reservoir with underlying water.
Offshore petroleum industry	The Inquiry adopts the definition of 'offshore petroleum industry' from the PTTEPAA Submission, Term of Reference 8 [1] – 'meaning the companies that are in the business of [offshore] oil and gas exploration or production'.
Operational Monitoring	Monitoring undertaken during oil spill response operations to provide information to directly assist in the planning and execution of the response. Also known as Type I Monitoring. During the Blowout, Operational Monitoring was managed by AMSA.
Overbalance	The amount of pressure (or force per unit area) in the wellbore that exceeds the pressure of fluids in the formation. This excess pressure is needed to prevent reservoir fluids (oil, gas, water) from entering the wellbore.
Packer	A mechanical seal used to isolate a section of well. It can be run into a wellbore with a smaller initial outside diameter than the bore of the casing string then mechanically expanded to seal the wellbore. Some packers are designed to be removable, while others are permanent.
Phase 1B Drilling Program	PTTEPAA's Montara Phase 1B Drilling & Completion Program June 2009 (approved by the NT DoR in July 2009).
Pore pressure	Hydrostatic pressure in a formation/rock. In general, pore pressure increases with drilling depth.
Pressure containing anti-corrosion caps (PCCC)	A cap which screws into the top of the casing. The cap protects the casing thread, hanger and other internal mechanisms.
Pressure testing	Used to test the integrity of casing or a cement shoe.
Pressure up	Pumping fluid into the casing to increase the pressure to a programmed test pressure.
Production	The full scale extraction of hydrocarbon reserves.
Production casing	The innermost steel lining of a well cemented in place and perforated for production. Note that production tubing is inserted inside this casing.
PTTEP Australasia (Ashmore Cartier) Pty Ltd (PTTEPAA)	Owners and operators of the Montara Development Project.
the Relief Well	The Montara H1 ST1 RW1 Well.

Term	Definition
Reservoir	A porous, fractured or cavitied rock formation with a geological seal forming a trap for producible hydrocarbons.
Riser	A pipe through which fluids flow upwards, as from a subsea wellhead or gathering pipeline to the deck of a platform.
Rotary Steering Tool (RST)	Tool used to steer the drill bit to enable controlled placement of the well within the rock formations
Rotary table	The heavy turntable at the centre of a drilling rig floor, which is rotated by the main rig power supply, and in turn rotates the drill string.
RTTS packer	Mechanical pressure isolation device inserted into a well. An RTTS Tool is a mechanical reusable packer run into the hole on a drillpipe and 'set' at a required depth to perform a specific task. Unlike a cement plug which is permanent (unless drilled out), an RTTS is retrievable and can be used to perform Pressure Testing, Chemical Treating and Cement Squeezing.
Running in	Inserting any tubular or tool into a well is known as 'running in'. Assembling and lowering in a string of casing is known as 'running casing'.
Safety case	Document prepared and submitted by the operator of a facility to NOPSA for acceptance pursuant to the MOSOF Regulations. Safety cases are required to make provision for the following matters in relation to health and safety of people at or near the facilities: <ul style="list-style-type: none"> - identification and assessment of risks; - the implementation of measures to eliminate the hazards or otherwise control the risks; - a comprehensive and integrated system for management of the hazards and risks; and - monitoring, audit, review and continuous improvement.
Scientific Monitoring	Monitoring that is not directly related to spill response operations. This may include the collection of information for environmental impact assessment. Also known as Type II Monitoring or environmental monitoring.
Shoe	Fitting on the lower end of a string casing which helps to direct the cement to the annulus.
Shoe track	Comprises a float shoe at the end of the casing, a section of casing and then a float collar.
Shoe track volume	Volume of the shoe track which is filled with cement during the cementing process.

Term	Definition
Sidetrack	Well re-drilled from an intermediate depth. Wells are re-directed or sidetracked for various reasons, but usually because of technical problems deeper in the original well.
Simultaneous operations (SIMOPS)	Those offshore operations which are undertaken jointly or which affect the safety interests of facility operators - in this case PTTEPAA in respect of the WHP, and Atlas in respect of the rig.
Skid (the derrick)	Move the derrick (including the drill floor) to a position above another wellhead, or 'slot' where a well is to be drilled or worked over.
Specific gravity (sg)	The relative density of a substance. Mathematically, in this case, it is the density of a substance divided by the density of fresh water.
Spud (a well)	Start drilling a new well.
Statutory Agency	Under the National Plan, responsibilities are divided between the Statutory Agency and the Combat Agency. The Statutory Agency is the government agency assigned the oversight of the response, institution of prosecutions and the recovery of clean-up costs.
Subsea options	The two options considered by PTTEPAA to stop the Blowout above the sea-bed, but below the sea surface. These involved either using a machine to crush the casing and block off the well flow or cutting the casing and capping it underwater.
Surface capping	An option considered by PTTEPAA to stop the Blowout which would have involved placing personnel on the WHP and the <i>West Atlas</i> and skidding the cantilever of the drilling rig inboard so the well flow was no longer hitting the underside of the drilling rig and then the wellhead would be lifted into place and the casing secured. Following the securing of the casing a BOP would be put in place and the wellhead closed in order to stop the flow. Once the flow was stopped mud would be used to kill the well and mechanical plugs then put in place.
Surface casing	The casing that is used between the conductor and the production casing.
Tail cement	Type of cement that is pumped in after the lead cement during cementing and has a higher density and thickening time than the lead cement to ensure a solid bond around the shoe track.
Tie-back	The process of adding a piece of casing to extend the well up to the mezzanine deck on the WHP. This is done in wells which have been suspended and abandoned for a period prior to work on the wells recommencing.
Top of Cement (TOC)	The height of cement (usually Tail Cement) in the annulus. The cement rises up the annulus to seal off formations and provides support to the casing.

Term	Definition
Top plug	The final plug inserted into the casing during the cementing operations.
Topsides/WHP Topsides	Part of the WHP placed on top of the Jacket and includes controls, process equipment and a helicopter deck.
Trash cap	A non-pressure containing cover to prevent debris entering the well.
Uncontrolled Release	The uncontrolled release of hydrocarbons from the H1 Well which commenced on 21 August 2009 (see also the Blowout).
Underbalance	The weight of a liquid in a wellbore is insufficient to hold back the pressure of the wellbore.
Wait On Cement (WOC)	Wait for the cement to set. The time period where the drillers wait on the samples of cement they have retained above surface to set before the pressure in the well is bled off again to check the casing.
Water deluge operations	Operations proposed by PTTEPAA that would have involved spraying the Montara WHP and <i>West Atlas</i> with water in order to dampen them to lessen the consequences should a fire occur.
Well Construction Standards	The purpose of Well Construction Standards is to provide standards for all aspects of well design, construction, testing, abandonment and intervention that involve a risk to safety, quality or integrity. The Well Construction Standards are applicable to all aspects of well design, well construction, well servicing and well abandonment.
Well Operations Management Plan (WOMP)	A WOMP is document that titleholder must submit to a Designated Authority in accordance with regulation 5 of the <i>Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004</i> (Cth) if that titleholder wishes to carry out a well activity for which such a WOMP is required (for example, prior to commencement of drilling a specific well). A WOMP should specify acceptable methods of conducting well operations in accordance with sound engineering principles and good oilfield practice.
Wellbore	The drilled hole. The casing string is inserted into the wellbore.
Wellhead	Connected to the top of the casing on the WHP. The wellhead has a flange or hub connector to which the BOP can be secured.
Wellhead Platform (WHP)	An offshore platform comprising the Jacket and Topsides.
<i>West Atlas</i>	<i>West Atlas</i> drilling rig – owned by Atlas and contracted by PTTEPAA to drill the Montara Oilfield wells.
<i>West Triton</i>	<i>West Triton</i> drilling rig – owned by Atlas and contracted by PTTEPAA to drill the Relief Well.
Whipstock	Tool for deviated drilling, basically a wedge-shaped block which is lowered into the well to divert the bit at an angle to the original hole.

Appendix A – Terms of Reference

With respect to the uncontrolled release of hydrocarbons at the Montara Wellhead Platform that commenced on 21 August 2009, and subsequent events including the fire that commenced on 1 November 2009 (together the Uncontrolled Release) the Inquiry will:

1. Investigate and identify the circumstances and likely cause(s) of the Uncontrolled Release.
2. Review the adequacy and effectiveness of the regulatory regime applicable to operations at or in connection with the Montara oil field, including under the Offshore Petroleum and Greenhouse Gas Storage Act 2006, and including the adequacy and effectiveness of all safety, environment, operations and resource management plans, and other arrangements approved by a regulator and in force at relevant times.
3. Assess the performance of relevant persons⁶²⁵ in carrying out their obligations under the regulatory regime.
4. Review the adequacy and effectiveness of monitoring and enforcement by regulators of relevant persons⁶²⁵, under the regulatory regime.
5. Assess the adequacy of the response to the Uncontrolled Release by the current title-holder of AC/L7, the owner and/or operator of the Montara Wellhead Platform and the owner and/or operator of the West Atlas drilling rig.
6. Assess the adequacy of regulatory obligations applicable to the titleholder of AC/L7, the owner and/or operator of the Montara Wellhead Platform, and the owner and/or operator of the West Atlas drilling rig in relation to the response to the incident and make any recommendations necessary to improve the regulatory obligations that may be applicable to any future incidents.
7. Assess and report on the environmental impacts following the Uncontrolled Release using available data and evidence including the outcomes from monitoring activities already underway, review any proposed environmental monitoring plans, and make recommendations on whether any further measures are warranted to protect the environment from the consequences of the Uncontrolled Release.

⁶²⁵ For the purposes of paragraphs 3 and 4, 'relevant persons' are persons who have engaged at any time in petroleum-related operations at the Montara Wellhead Platform that may have contributed to the cause(s) of the Uncontrolled Release, including but not limited to: the titleholder or a former titleholder of AC/L7 permit, a present or former owner or operator of the Montara Wellhead Platform, a present or former owner or operator of a drilling rig, a drilling contractor or a supplier or installer of plant or equipment.

8. Consider and comment on the offshore petroleum industry's response to the Uncontrolled Release.
9. Consider and comment on the provision and accessibility of relevant information regarding the Uncontrolled Release to affected stakeholders and the public.
10. Make recommendations to the Minister for Resources and Energy, and through the Minister for Resources and Energy, other relevant Commonwealth Ministers, regulators and industry, as appropriate, on any measures that might help to prevent similar incidents occurring in the future and any measures that might mitigate the safety, environmental, and resource impacts arising from such an incident. Measures may include improvements to industry practices or applicable regulatory regimes and their administration.
11. Consider, assess and make recommendations in relation to any other matter the Commission of Inquiry considers relevant to or arising from the Uncontrolled Release and the prevention of similar events occurring in the future.

Appendix B – Submissions to the Inquiry

Submissions to the Inquiry, together with the transcript of the public hearing and other relevant documents, can be accessed on the Inquiry’s website at

www.montarainquiry.gov.au.

Number	Submission
1	Mr Scott Ryan
2	Fire Fighting Technologies International Pty Ltd
3	A number of similar submissions have been received proposing constraints on the expansion of the petroleum industry on the North-West shelf of Australia’s Kimberley region. These submissions can be found on the Inquiry’s website.
4	James Kesteven
5	Australian Marine Oil Spill Centre
6	Cape Conservation Group Inc
7	Australian Marine Conservation Society
8	APPEA Ltd
9	Australian Conservation Foundation
10	Name kept confidential (Professional Engineer)
11	Brian Holland
12	Senator Rachel Siewert
13	Whale and Dolphin Conservation Society (International)
14	The Wilderness Society and Environs Kimberley
15	WWF-Australia
16	Australian Southern Blue Fin Tuna Industry Association Ltd (ASBTIA)
17	National Offshore Petroleum Safety Authority
18	Australian Government Department of the Environment, Water, Heritage and the Arts
19	Western Australian Fishing Industry Council (WAFIC)
20	Australian Institute of Marine Science (AIMS)
21	PTTEP Australasia (Ashmore Cartier) Pty Ltd
22	Atlas Drilling (S) Pte Ltd
23	Northern Territory

24	Australian Maritime Safety Authority
25	Kimberley Whale Watching
26	Labrador Holdings WA Pty., Ltd. Trustee of the Well Planning Trust. ABN: 1520471325
27	Australian Institute of Marine and Power Engineers
28	Department of Resources, Energy and Tourism
29	Tim Kelly
30	University of Western Australia
31	Elmer P. Danenberger
32	Colin Leach
33	Senator Rachel Siewert
34	Department of Transport WA
35	Australian Government Department of the Environment, Water, Heritage and the Arts
36	Tina Hunter, Bond University
37	WWF-Australia
38	West Timor Care Foundation (Yayasan Peduli Timor Barat)

Appendix C – The Inquiry Staff

The Commissioner was supported by the following people for varying periods during the course of the Inquiry. In addition, the Inquiry was assisted by e.law which provided document management services. Considerable administrative and IT support was provided by the Enabling Services Group of the Department of Resources, Energy and Tourism.

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